Better Regulation

Explanatory Statement

Expenditure Forecast Assessment Guideline

November 2013

AUSTRALIAN ENERGY REGULATOR

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Shortened forms

Shortened term	Full title
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APA	APA Group
augex	augmentation (capital) expenditure
capex	Capital expenditure
CESS	capital expenditure sharing scheme
COSBOA	Council of Small Business of Australia
CPI	Consumer price index
CRG	Consumer Reference Group
DEA	Data envelopment analysis
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
EBSS	Efficiency benefit sharing scheme
ENA	Energy Networks Association
ERA	Economic Regulation Authority of Western Australia
EUAA	Energy Users Association of Australia
EURCC	Energy Users Rule Change Committee
F&A	Framework and Approach
MEU	Major Energy Users
MTFP	Multilateral total factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERA	NERA Economic Consulting
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSP	Network service provider

NSWIC	New South Wales Irrigators' Council
Ofgem	Office of Gas and Electricity Markets
opex	Operating expenditure
PC	Productivity Commission
PIAC	Public Interest Advocacy Centre
PTRM	Post-tax revenue model
RAB	Regulatory asset base
repex	replacement (capital) expenditure
SAPN	South Australia Power Networks
SFA	Stochastic frontier analysis
STPIS	Service target performance incentive scheme
TNSP	Transmission network service provider

Contents

Summary

The Australian Energy Regulator (AER) is Australia's independent national energy market regulator. We are guided in our role by the objectives set out in the National Electricity and Gas Laws which focus us on promoting the long term interests of consumers.

In 2012, the Australian Energy Market Commission (AEMC) changed the rules governing how we determine the total amount of revenue each electricity and gas network business can earn. The Council of Australian Governments also agreed to consumer focused reforms to energy markets in late 2012.

The Better Regulation program we initiated is part of this evolution of the regulatory regime. It includes:

- seven new guidelines outlining our approach to network regulation under the new regulatory framework
- a consumer reference group (CRG) to help consumers engage and contribute to our guideline development work
- an ongoing Consumer Challenge Panel (CCP) (appointed 1 July 2013) to assist us incorporate consumer interests in revenue determination processes.

National electricity and gas objectives

The objective of the National Electricity and Gas Laws is to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to—

(a) price, quality, safety, reliability and security of supply of energy; and

(b) the reliability, safety and security of the national energy systems.

This explanatory statement accompanies the Expenditure Forecast Assessment Guideline for electricity transmission and distribution networks (Guideline). The National Electricity Rules (NER) require us to develop the Guideline to specify:

- the approach we will use to assess capital expenditure (capex) and operating expenditure (opex) forecasts, and
- the information we require from network service providers (NSPs) to do so.

The NER require NSPs to provide the information set out in the Guideline with their regulatory proposals.

The Guideline marks a significant improvement in our approach to expenditure assessment. It reflects both a careful review of assessment techniques employed throughout our first round of network determinations and how these can be improved, but importantly, also sets out a number of new techniques. The Guideline encapsulates, for the first time, a single and complete point of reference for those seeking to understand the process of expenditure assessment under the recently revised NER.

In particular, the Guideline paves the way for a new, nationally consistent, reporting framework that will allow us to benchmark expenditure at a more detailed category level. This means we can compare drivers of expenditure and the accompanying costs of conducting similar activities by each NSP across the National Electricity Market (NEM).

The Guideline also marks the introduction of new economic benchmarking techniques such as multilateral total factor productivity, data envelopment analysis and econometric modelling. Economic benchmarking techniques will allow us to analyse the efficiency of NSPs over time and compared to their peers. They will also allow us to estimate a top down forecast of expenditure and estimate productivity change.

In addition to new techniques, we have taken the opportunity to refine and improve existing techniques to ensure the capex and opex allowances we approve are efficient. For example, we have implemented a new annual 'rate of change' approach to account for efficient changes in opex over time. This approach incorporates analysis of, and adjustments for, productivity. We have also developed a new augmentation capex (augex) tool to complement our existing replacement capex (repex) tool.

We will use our new and refined techniques in combination with existing techniques to form a view about forecast expenditure. While we intend to continue to rely on incentives for businesses to reveal efficient costs, we are now in a position to test the extent to which NSPs have responded to the incentive framework, and whether these costs should be used as the starting point for assessing expenditure forecasts.

The standardisation of our approach in the Guideline is intended to enhance the transparency of our decisions and accountability under the NER and National Electricity Law (NEL). The Guideline reflects the need for flexibility in applying various techniques, recognising the specific issues faced by each NSP and potential implementation issues, such as collecting and testing new data and techniques.

To facilitate the techniques specified in the Guideline, we will require much more information than in the past. Coinciding with the release of the Guideline, we have issued a series of Regulatory Information Notices (RINs) to obtain and publish our standardised dataset in several stages. Specifically:

- in late November we issued final RINs to all NSPs to collect back cast economic benchmarking data
- in early December we will issue draft RINs for the collection of data for driver-based category analysis, with final RINs to be released in February 2014
- over 2014 we will release datasets of NSP responses to the above RINs. We will undertake a testing and validation process for economic benchmarking data, and will use our data in publishing issues papers on expenditure issues for the next determinations, as well as in our first annual benchmarking report in September 2014.

We received 22 stakeholder submissions in response to the approaches and data requirements arising from our draft Guideline in August. Many of these submissions generally endorsed our approach, while raising many points which we have responded to in this explanatory statement and final Guideline. Overall we received constructive feedback from NSPs on areas where data requests could be reduced or streamlined with respect to what was anticipated in the draft Guideline. The resulting data requirements and expected cost on NSPs (which is ultimately borne by consumers) will be offset by significant expected improvements in the robustness of our assessments.

In contrast to the explanatory statement to the draft Guideline, this explanatory statement does not address details of new data reporting arrangements and assurance requirements. These issues are now being dealt with in consultation and documentation arising out of the development of RINs issued under the NEL. In particular, we have and will continue to publish explanatory statements accompanying RINs to provide more targeted commentary on finer details of our data requirements and to assist stakeholders in effectively engaging in these related processes. The Guideline provides our view of general information requirements that will be given effect through RINs for each NSP and at the time of individual network determination processes.

In implementing our Guideline we will be mindful of consumer interests as referenced in the National Electricity Objective (NEO) and in the revenue and pricing principles, but also as preferences are expressed directly through our new means of consumer engagement. In particular, we will take a long-term perspective, recognising consumer interests in terms of price impacts as well as on service delivery and network security arising from potential under or over-investment.

We consulted extensively with stakeholders in preparing the Guideline and will continue to do so with stakeholders in the release and analysis of new datasets. The Guideline provides an important catalyst in that it marks the commencement of a cycle of collection, publication and review of data on the relative efficiency of NSPs. This cycle of engagement will assist network users in participating more effectively in the process of setting efficient expenditure allowances. The public scrutiny of NSPs' performance, through the new annual benchmarking reports, is likely to encourage them to keep improving, and to identify areas that we are likely to target at the time of their next price review.

1 Introduction

The AER is responsible for the economic regulation of electricity transmission and distribution services in eastern and southern Australia under chapters 6 and 6A of the NER. We also monitor the wholesale electricity market and are responsible for compliance with and enforcement of the NER. We have similar roles for gas distribution and transmission under the National Gas Rules (NGR).

This explanatory statement is the final phase of development of the Expenditure Forecast Assessment Guideline for electricity NSPs. It forms part of our Better Regulation program of work following from the AEMC's changes to the NER and NGR made on 29 November 2012. These reforms aim to deliver an improved regulatory framework focused on the long-term interests of energy consumers.

The improved regulatory framework provides us with additional ability and flexibility in setting revenues and prices for NSPs.[1] One of the changes is a requirement for us to develop guidelines for electricity transmission and distribution.[2]

1.1 Purpose of the Guideline

The requirement for us to develop Guidelines arose after the AEMC amended the NER to address our concerns with expenditure assessment. We were concerned that restrictions in the NER resulted in inefficient NSP capex and opex allowances.[3] Specifically, we were concerned the language in the NER implied that the AER must determine expenditure allowances using the approach taken by the NSP in its proposal.[4]

The AEMC's rule amendments clarify the approach the AER may take to assess expenditure, and removes ambiguities—particularly regarding our ability to use benchmarking.[5] They require the AER to publish an annual benchmarking report, which we must consider when we assess expenditure proposals.[6] The amendments also facilitate early engagement between NSPs and the AER on NSP expenditure forecasting techniques. This is so the AER and NSPs are aware, in advance, of the information the AER requires to appropriately assess a NSP's proposal.[7] The Guideline forms part of this engagement process, which will save time and effort for the AER and NSPs later in the process.[8]

1.2 Purpose of the Explanatory Statement

This explanatory statement is a stand-alone document that focuses on how we developed the Guideline. It reflects the development of our positions and approach, in light of our consultation with stakeholders. It explains how we will assess expenditure, with a focus on improvements to our assessment approach.

This document follows the same format as the explanatory statement for the draft Guideline, but we have removed discussion on the particulars of our economic benchmarking and category analysis approaches, including the data requirements. The explanatory statements for the economic

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1 AEMC, *Rule determination: Rule change: Economic regulation of network service providers, and price and revenue regulation of gas services*, 29 November 2012, pp. 1 (AEMC, *Rule determination*, 29 November 2012).
2 AEMC, *Rule determination*, 29 November 2012, p.109.
3 AEMC, *Rule determination*, 29 November 2012, p. vii.
4 AER, *Directions paper submission*, 2 May 2012, p. 11 and Appendix 2.
5 AEMC, *Rule determination*, 29 November 2012, p. 92.
6 AEMC, *Rule determination*, 29 November 2012, pp.vii–viii.
7 AEMC, *Rule determination*, 29 November 2012, p. 114.
8 AEMC, *Rule determination*, 29 November 2012, p. 110.

benchmarking and category analysis RINs, respectively, contain this information. We will issue these RINs at approximately the same time as the Guideline.

1.3 Stakeholder engagement

An intended outcome of the AEMC's rule changes was to facilitate more timely and meaningful engagement between the AER, consumer representatives and NSPs.[9] In informing the Guidelines, we engaged extensively with NSP and consumer representatives. We published an issues paper, invited written submissions from stakeholders and held over approximately 20 workshops on our proposed approach to assessing expenditure.[10] We also held separate bilateral meetings upon request. We also liaised regularly with consumer representatives through the AER's Consumer Reference Group (CRG). Attachment D lists the CRG's verbal submissions and our responses.

Importantly, we were able to test the application of new techniques and their detailed design with NSPs, reflecting upon their views of cost drivers and operating environments. Consumer representatives also provided valuable input to the process, and challenged positions put forward by NSP representatives. We consider the views of stakeholders in detail in this explanatory statement.

1.4 Overview of expenditure assessment in the context of the regulatory review process

The AER's assessment of a NSP's capex and opex forecasts is part of a multi-stage process that commences with a 'framework and approach' (F&A) stage and ends with a final determination.[11] In the F&A stage, among other things, we must also publish a paper that outlines our proposed approach to assessing a NSP's proposal. Our final determination sets out the NSP's revenue allowance for the forthcoming regulatory control period, which is typically five years in length. The Guideline is a reference point throughout this process.

1.4.1 The Guideline

The Guideline is not a stage in the typical review process, but is a key input to it as well as a reference point. The amendments to the NER require us to publish the Guideline by 29 November 2013, and thereafter, a version of the Guideline must be in force at all times.[12] We do not need to develop a guideline as part of every review.

The Guideline must outline the types of assessments we will undertake in determining expenditure allowances and the information we require from NSPs to facilitate those assessments.[13] The NER do not stipulate how detailed the Guideline should be beyond these requirements. However, the Guideline provides guidance to NSPs on how we are likely to assess their expenditure forecasts and the information we will require from NSPs to do so.[14]

The Guideline is not binding on the AER or anyone else. However, if we make a determination that is not in accordance with the Guideline, we must state in our reasons for a determination why we departed from the Guideline.[15] NSPs are not required to explain departures from the Guideline.

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9 AEMC, *Rule determination*, November 2012, p. 32.
10 Summaries of workshop discussions are available from our website: http://www.aer.gov.au/node/19487.
11 The NER uses the terms 'determination' and 'decision' for distribution and transmission, respectively. However, in this explanatory statement, when we use 'determination' we are referring to transmission as well as distribution.
12 NER, clauses 6.4.5(b), 6A.5.6(b), 11.53.4 and 11.54.4.
13 AEMC, *Rule determination*, 29 November 2012, p.114.
14 We provide specific information requirements in RINs.
15 NER, clauses 6.2.8(c) and 6A.2.3(c).

However, they must provide, with their regulatory proposals, a document complying with the Guideline or—if we deviate from the Guideline as specified in the F&A process—the F&A paper.[16] The NER allow us to require a NSP to resubmit its regulatory proposal if it does not comply with the Guideline.[17] Therefore, we drafted the Guideline so it balances flexibility and certainty.

1.4.2 Framework and approach stage

The NER require a NSP to advise us, during the F&A process, of its approach to forecasting expenditure.[18] This allows us to consider the NSP's forecasting approach before we publish our F&A paper, which we must do 23 months before the NSP's existing determination expires. The F&A paper must advise the NSP of the specific information we require, and whether we will deviate from the Guideline.[19] That is, it will clarify how the Guideline will apply to the NSP under review. The F&A paper is not binding on the AER or the NSP, subject to some exceptions.[20]

While the NER place no restrictions on NSPs' forecasting methods, some of the techniques and data requirements specified in the Guideline and F&A paper (which NSPs must comply with) may draw NSPs away from methods they employed in the past. In particular, NSPs may find it useful to focus their approach to justifying their proposed opex allowances through the base-step-trend approach, if they have not used it in the past. This is explained in section 5.3 and chapter 6.

1.4.3 Determination stage

The determination stage commences when the NSP submits its proposal—17 months before its existing determination expires. At the same time, the NSP must submit accompanying information that complies with the Guideline, or any deviations we specify in our F&A paper.[21]

This information is not, and does not form part of, the NSP's expenditure forecast included in its proposal unless the NSP chooses to include the compliant information as part of its proposal.[22] However, if the NSP does not provide this information we may require the NSP to resubmit its regulatory proposal.[23]

When we assess the NSP's proposal we usually must publish an issues paper.[24] Following consultation with stakeholders, we then publish a draft determination. The NSP may submit a revised proposal in response to our draft determination, and then, following further consideration, we will publish our final determination. The purpose of the issues paper is to identify, reasonably early in the process, the key issues likely to be relevant in assessing the NSP's proposal.[25] We must hold a public forum and invite written submissions on the issues paper to encourage stakeholder engagement.[26] As

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16 NER, clauses 6.8.2(c2) and 6A.10.1(h).
17 NER, clauses 6.9.1 and 6A.11.1.
18 Clauses 6.8.1A and 6A.10.1B of the NER require the NSP to inform the AER of the methodology it proposes to use to prepare forecasts. It must do this at least 24 months prior to the expiry of the determination that applies to the NSP, or if there is none, then three months after the AER requires it to do so.
19 NER, clauses 6.8.1, 6.8.2(c2), 6A.10.1A and 6A.10.1(h).
20 NER, clauses 6.8.1(f) and 6A.10.1A(f). For example, clause 6.12.3 of the NER requires the classification of services and control mechanisms must be as per the framework and approach paper unless unforeseen circumstances warrant departure.
21 NER, clauses 6.8.2 and 6A.10.1.
22 AEMC, *Final rule change determination*, 29 November 2012, p.114.
23 NER, clauses 6.9.1 and 6A.11.1.
24 In some cases the NER do not require an issues paper to be published, see for example 11.56.4(o), however we may still do so.
25 We must publish an issues paper within 40 business days of determining that the NSP's proposal and accompanying information sufficiently complies with the NER and NEL. NER, clauses 6.9.3 and 6A.11.3.
26 NER, clauses 6.9.3 and 6A.11.3.

part of this process, we are likely to conduct a 'first pass' assessment, which will indicate our preliminary view on the NSP's expenditure forecasts.

Box 1.1 First pass assessment

Recent changes to the NER require us to publish issues papers as part of the regulatory determination process and annual benchmarking reports.

Given these requirements a new element of the process is the 'first pass' assessment, which will indicate our preliminary view on the NSP's proposal.

This first pass assessment will typically involve high level expenditure assessment (using economic benchmarking and category analysis) and consideration of the NSP's performance in the most recent annual benchmarking report.

It will enable us to identify and engage with stakeholders on key issues early in the determination process.

The next major step is for us to publish a draft determination, which includes the total capex and total opex forecasts we consider comply with the NER. We again facilitate stakeholder engagement by inviting written submissions on the draft determination and holding a predetermination conference.[27] A NSP may submit a revised proposal in response to our draft determination. However, it may only do so to incorporate the substance of any changes we require or to address matters we raise in the draft determination.[28] We may allow submissions on a revised proposal if we consider we require stakeholder input.[29]

Following public consultation and submissions, the final step is for us to make and publish a final determination, together with the reasons for the decision. We must do so no later than two months before the NSP's existing determination expires.[30] The final determination includes our conclusion on our assessment of expenditure forecasts and the estimate of total capex and total opex that we consider comply with the NER. This estimate may be different to the draft determination estimate, reflecting stakeholder submissions or other information.

This explanatory statement explains in further detail the expenditure assessment process that we apply throughout the regulatory review process, including the techniques we use to assess expenditure, and the information we require to do so.

1.4.4 Annual benchmarking reports

The NER now require us to publish annual benchmarking reports, beginning in September 2014.[31] The purpose of these reports is to describe, in reasonably plain language, the relative efficiency of each NSP in providing prescribed transmission services or direct control distribution services over a 12 month period.

Annual benchmarking reports are a key feature of the AEMC's recent rule change determination. The AEMC intended that the reports would be a useful tool for stakeholders (including consumers) to engage in the regulatory process and to have better information about the relative performance of NSPs.[32]

27 NER, clauses 6.10.2 and 6A.12.2.
28 NER, clauses 6.10.3 and 6A.12.3.
29 NER, clauses 6.10.3(e), 6.10.4, 6A.12.3(g) and 6A.12.4.
30 NER, clauses 6.11.1, 6.11.2, 6A.13.1 and 6A.13.2.
31 NER, clauses 6A.31 and 6.27.
32 AEMC, *Rule determination*, 29 November 2012, p.108.

The NER expenditure factors state that the AER must consider the most recent and published benchmarking report in making draft and final determinations. We must use our best endeavours to publish at a reasonable time prior to making a determination, any analysis on which we seek to rely, or to which we propose to refer, for the purposes of the determination.[33] The NER does not impose the same requirements at the draft decision stage.[34] However, the NEL requires that the AER must inform NSPs of material issues under consideration and give them a reasonable opportunity to make submissions about a determination before we make it.[35]

1.4.5 Updating the Guideline

We may amend the Guideline from time to time in accordance with the requirements of the NER.[36] Rather than setting a finite period for revision, we have drafted the Guideline in flexible manner so we can review and amend it as we consider appropriate.

1.5 Summary of key topics

This explanatory statement focuses on how we developed the Guideline, in light of extensive stakeholder consultation and industry guidance. In essence, we explain how we will assess expenditure, but with a particular focus on improvements to our approach. This explanatory statement addresses several key topics:

- New assessment techniques—We are expanding our regulatory toolkit to make greater use of benchmarking. In particular, we are implementing top down benchmarking techniques as recommended by the Productivity Commission (PC) and endorsed by the AEMC and the Australian Government.[37] We explain how we intend to apply these new techniques to assess expenditure forecasts.

- Refined techniques—We are refining some of our existing techniques to ensure the capex and opex allowances we approve are efficient. We explain our reasons for modifying the techniques, how this affects the way we assess expenditure and the interaction between the techniques and incentive schemes.

- Assessment principles—We explain some best practice principles we may consider when forming a view on NSPs' expenditure proposals. Our assessment techniques may complement each other in terms of the information they provide, so we may need to consider the appropriateness of certain techniques as part of our holistic assessment approach. These principles are equally relevant to the techniques that we use to assess expenditure and the techniques NSPs use to forecast expenditure.

1.6 Next steps

Table 1.1 shows the next steps in the Guideline's development. Full details of our expected consultations and other implementation milestones are contained in chapter 7.

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33 NER clauses 6.11.1(c) and 6A.13.1(a2).
34 NER clauses 6.10.1 and 6A.12.1.
35 NEL section 16.1(b).
36 NER, clauses 6.2.8(e), (f).
37 See, for example, *Productivity Commission, Electricity Network Regulatory Frameworks – Final Report*, Volume 1, 9 April 2013, pp. 27–32; AEMC, *Final rule change determination*, 29 November 2012, pp.vii–viii; Australian Government, *Response to the Productivity Commission Inquiry Report – Electricity Network Regulatory Frameworks*, June 2013, pp. i–ii.

Table 1.1 Milestones for Expenditure Forecast Assessment Guideline

Date	Economic Benchmarking	Annual reporting milestones	Reset RIN data
Early Dec 2013		Issue draft RIN for category analysis data (back cast)	Issue draft RINs for NSW/ACT DNSPs, Transend, TransGrid
Feb 2014		Issue final RIN for category analysis data (back cast)	Issue of final RINs for NSW/ACT DNSPs, Transend, TransGrid
3 Mar 2014	Unaudited RIN responses due		
Mar 2014	Data checking/ validation process commences		
30 April 2014	Audited RIN responses due		
May 2014	Publicly release data, seek submissions	RIN responses due	Reset RIN responses due for NSW/ACT DNSPs, Transend, TransGrid Issue final RINs for SAPN, Energex and Ergon Energy
July 2014	EBT models finalised, results included in issues papers		Category analysis results included in issues papers
Sept 2014		Publish first benchmarking report	

We will issue the category analysis and reset draft RINs for the NSW and ACT DNSPs, Transend and TransGrid in early December. Stakeholders will therefore have 20 business days to comment on the draft RINs. We intend to issue final category analysis RINs in February 2014. We will aim to provide NSPs with at least three months to provide us with their response after receiving a final RIN. The provision of this information will coincide with the lodgement of regulatory proposals of the NSW/ACT DNSPs, Transend and TransGrid in May 2014.

2 The Guideline: context and content

This chapter provides the context for our work in developing the Guideline. This context is important to understand our approach to consultation as well as the scope and content of the Guideline.

This chapter summarises the broad purpose and objectives of the Guideline and the improvements they introduce to the economic regulation of NSPs. It also discusses our approach to assessing capex and opex forecasts in previous determinations. This identifies the scope for improvements we seek to deliver using the new and standardised expenditure assessment techniques contained in the Guideline.

2.1 Recent rule changes and requirements

The AEMC published changes to the NER on 29 November 2012.[38] The rule changes enhance our capacity to determine the revenues of distribution and transmission businesses so consumers pay only efficient costs for reliable electricity supply.[39] These were the result of rule change proposals the AER and a group of large energy users (the Energy Users Rule Change Committee) separately submitted in 2011.

The AEMC changed several key areas of the determination process, notably:

- rate of return
- capex incentives
- setting capex and opex forecasts
- the regulatory process.

We are conducting a program of work to put the AEMC's changes to the NER into effect. Developing the Guideline is a major component of this work program.[40]

The AEMC's changes clarified some existing provisions and created new requirements for the AER and NSPs regarding expenditure forecasts. In particular the AEMC:

- reaffirmed the NSP's proposal should be the starting point for analysis and we should accept the proposal if we are satisfied it meets the legal requirements. However, the AEMC removed the requirement for our decision to be based on the NSP's proposal if we did not approve the proposal, or an element of it. It also removed the restriction in the distribution rules that our decision only amend the NSP's proposal to the minimum extent necessary to enable it to comply with the NER.
- confirmed the NER do not place any restrictions on us to consider various analytical techniques. The AEMC considered the principles of administrative law would be sufficient in ensuring NSPs

38 The AEMC also published changes to the National Gas Rules. This draft explanatory statement concerns only the changes to the NER, which applies to electricity distribution and transmission businesses.

39 www.aemc.gov.au/electricity/rule-changes/completed/economic-regulation-of-network-service-providers-.html (accessed 22 May 2013).

40 More information on the Better Regulation work program can be found on the AER's webpage: www.aer.gov.au/Better-regulation-reform-program

have a reasonable opportunity to respond to material we seek to rely upon. The addition of a new 'any other' capex/ opex factor also supports this.[41]

- reaffirmed the role of benchmarking as a key factor in determining the efficiency of NSP expenditures. The NER now require us to publish benchmarking reports annually and made these reports part of a capex/opex factor.[42] The AEMC also removed the 'individual circumstances' clause from the capex and opex prudence criterion.
- required us to publish the Guideline. The F&A process will determine how the Guideline applies to individual NSPs price/revenue determinations.
- required NSPs to inform us of their methods for forecasting expenditures 24 months before the next regulatory control period commences (this coincides with the F&A process).

The AEMC intended the Guideline to facilitate early engagement on a NSP's expenditure forecast methodology. This will ensure both we and NSPs are aware, in advance, of the information we require to assess a NSP's proposal. The Guideline will bring forward and potentially streamline the RIN stage(s) that currently occur, and will expedite our understanding of the NSP's approach to expenditure forecasting. The Guideline does not restrict our ability to use additional assessment techniques if we consider these are appropriate after reviewing a NSP's proposal.[43]

2.2 The AER's previous assessment approaches

Overall, we consider our first round of reviews reflected a transition to the national regulatory regime. The next section examines overall transitional and data collection issues, while sections 2.2.2 and 2.2.3 examine our approaches to assessing capex and opex in more detail.

2.2.1 Approach to data collection

Before transitioning to a national regulatory framework (which began in New South Wales and the ACT in 2008) state regulators were responsible for regulating DNSPs. These regulatory regimes imposed varying information requirements on DNSPs, and used different expenditure assessment approaches.

In our first round of distribution determinations, we recognised the transition to a national framework could potentially impose costs and create uncertainty for stakeholders. We also tended to adopt the previous regulatory regime's information requirements to enable time series comparisons.

While this enabled the transition to the national framework, it meant the opex and capex information collected differed for each jurisdiction. Inconsistent data requirements meant we could not rely on benchmarking analysis to any significant degree. This, in turn, hindered or at least delayed the development of more sophisticated benchmarking techniques and systematic assessment approaches across jurisdictions.

Expenditure information collected from DNSPs as well as TNSPs during this first cycle tended to be at the aggregate level, providing little opportunity to understand expenditure drivers beyond basic trend and ratio analysis. We typically had to request more detailed information, such as business cases, from NSPs. While such information was useful in deciding if particular projects or programs were

41 NER, clauses 6.5.6(e)(12), 6.5.7(e)(12), 6A.6.6(e)(14) and 6A.6.7(e)(14); AEMC, *Rule determination*, 29 November 2012, pp. 55, 106.

42 NER, clauses 6.5.6(e)(4), 6.5.7(e)(4), 6A.6.6(e)(4) and 6A.6.7(e)(4).

43 AEMC, *Rule determination*, 29 November 2012, p. 114.

efficient, we generally could not use this information for comparison or benchmarking because it was specific to the NSP or to particular projects or programs that were under consideration. This did not allow for meaningful insights on the efficiency of the NSP's overall expenditures, relative to other NSPs and over time. It also resulted in a dependency on detailed engineering reviews to consider the efficiency of NSP proposals, at the expense of developing a meaningful and ongoing understanding of NSP performance in-house and also among key stakeholders.

2.2.2 Capital expenditure

In previous determinations, we used broadly similar approaches to assess the different categories in NSPs' capex forecasts. However, the details of the approach may have differed between determinations, and between businesses. These differences reflected various factors including the transition from state-based regulation to national regulation for DNSPs; the availability and veracity of existing NSP data that could be used; differences between DNSPs and TNSPs; and the different circumstances surrounding each regulatory proposal.

The basic assessment elements were:

- assessment of the capital governance framework
- assessment of the capex forecasting method
- detailed review of a sample of projects and/or programs.

Capital governance framework assessment

We assessed the governance framework to see whether it reflected good industry practice. For example, we assessed whether the governance framework contained appropriate delegation and accountability. Assuming the governance framework reflected good industry practice, we then assessed whether the NSP followed the governance framework when developing its capex forecast.

Generally, we did not find the assessment of capital governance frameworks to be helpful in past determinations, especially considering their high cost. Given the general nature of capital governance frameworks, there was rarely a direct link between a NSP's capital governance framework and its capex forecast. We found that most capital governance frameworks were reasonable, but that did not adequately assure us that the NSP's capex forecast was reasonable; we viewed this framework as a necessary but not a sufficient requirement for NSPs in terms of justifying their expenditure proposals. Our capex forecast assessment invariably relied therefore much more on our assessment of the NSP's capex forecasting method and our detailed reviews (discussed below).

Expenditure forecasting method assessment

We assessed the methodology the NSP used to derive its capex forecast, including its assumptions, inputs and models. Similar to the capital governance framework review, we assessed whether the methodology would produce capex forecasts that reasonably reflect the NER criteria. NSPs had to justify any aspects of the model we considered did not appear reasonable. If the NSP could not justify its approach, we adjusted the methodology so it was a reasonable basis for developing capex forecasts that we considered reasonably reflected the NER criteria.

This is similar, for example, to our assessments of the probabilistic models that some TNSPs used to develop augmentation expenditure forecasts. We assessed the models and generally found them to be reasonable. However, in some cases, we did not consider the inputs to these models (such as demand forecasts or certain economic scenarios) to be reasonable, so we adjusted those particular inputs.[44]

We will continue to assess NSPs' capex forecasting methods in future determinations. As we discussed in section 2.1, however, the NER no longer constrain us to amend or substitute expenditure forecasts based on the NSP's proposal, which includes the capex forecasting method. This constraint was a problem in past determinations because many NSPs used 'bottom up builds' to derive their capex forecasts. Our assessments, therefore, relied largely on detailed reviews of projects and/or programs. In future reviews, we will also use other types of analysis to inform our capex forecast assessments (see section 5.4).

Detailed reviews

We performed detailed reviews of a sample of projects and/or programs that comprised the NSP's capex forecast. For TNSPs, it usually entailed sample project reviews. For DNSPs, it usually entailed reviews of material programs given the large number of projects. The detailed reviews analysed business cases, cost estimations and other supporting documentation. Technical (and other) consultants typically assisted us with the detailed reviews. We assessed asset management plans and business cases the NSP used to justify expenditure, and whether these documents and processes would produce efficient expenditure forecasts. This entailed assessing whether:

- there was a genuine need for expenditure projects and/or programs
- the processes would identify efficient and viable options for meeting the need
- the processes would result in selection of the most efficient (lowest net present value (NPV)) option.

We also considered any 'step changes' that might have occurred that would explain why forecasts were not consistent with prior trends. For TNSPs, we also assessed whether particular projects could be better classified as contingent projects.

On the one hand, detailed project reviews provided useful analysis in past determinations, particularly for TNSPs who tend to propose a small number of high value projects. On the other hand, detailed reviews are intrusive and are not feasible when assessing DNSPs' overall capex forecasts given the (typically) large number of projects. We also relied on the judgement and industry experience of consultants for the detailed reviews, including for sample selection and for adjusting project or program costs. Hence, we could not always rely on the results of a sample to make inferences about the remaining projects and programs or could only do so where there was a sufficient comparability in classes of projects between the sample projects and other parts of the program.

Our consultants also provided revised expenditure forecasts for projects they found to be inefficient in detailed reviews. Consultants typically have databases of the cost items that comprise NSP projects; the quality and currency of such databases vary, however, and they are usually not transparent. Hence, consultants tended to also rely on judgement and industry experience when proposing revised expenditure forecasts for projects.

While the NER do not require us to assess projects and programs, we are likely to continue to perform detailed reviews of some projects and/or programs in future determinations, particularly for

[44] For example, see AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 107–117.

TNSPs. In this regard, detailed reviews may still assist us in forming a view on whether a NSP's total forecast capex reasonably reflects the capex criteria because of the lumpy and often unique nature of certain capex activities. However, the Guidelines introduce assessment techniques and information requirements that will make our capex assessment approach more standardised, systematic and rigorous (see section 5.2).

2.2.3 Operating expenditure

We generally used the 'base-step-trend' approach as our primary tool to assess NSPs' opex proposals in past determinations. As with capex assessment (see section 2.2.2), the details of our approach may have differed between determinations, and between businesses. These differences reflected various factors including the transition from state-based regulation to national regulation, and the nature of each NSP’s regulatory proposal.

When using the base-step-trend approach, we typically used actual opex in a base year (usually the fourth year of the previous regulatory control period) as the starting point for base opex if the NSP was subject to an efficiency benefit sharing scheme (EBSS). If there was no efficiency sharing mechanism in place, we assessed the components of a NSP's base opex in more detail, sometimes with the assistance of technical consultants. If necessary, we removed inefficiencies and non-recurrent costs from actual expenditure in the base year. We also used various forms of benchmarking, such as ratio and trend analysis, to inform our assessment of opex forecasts.

We then adjusted base year opex to account for changes in circumstances that will drive changes in opex in the forecast regulatory control period. These adjustments included:

- escalating forecast increases in the size of the network ('scale escalation')
- escalating forecast real cost changes for labour and materials ('real cost escalation')
- adjusting for efficient costs not reflected in the base opex, such as costs due to changes in regulatory obligations and the external operating environment beyond the NSP's control (step changes).[45]

The base-step-trend approach is relatively established for assessing opex forecasts in determinations, and we will continue to use it in future determinations. The Guideline introduces assessment tools and information requirements that improve our application of the base-step-trend approach. Previous determinations made limited use of robust benchmarks, for example, so the relative efficiency of businesses and their productivity gains over time were not clear.

2.3 The Guideline—better regulatory processes and outcomes

This section outlines how the Guideline will implement the changes to the NER and improve the regulatory process for stakeholders at a broad level. Key changes include:

- national consistency (data requirements and assessment approach)
- more detailed information requirements
- greater transparency and consultation
- greater scope for benchmarking.

[45] AER, *Draft decision: Aurora Energy Pty Ltd 2012–13 to 2016–17*, November 2011, p. 158.

These changes attempt to address the limitations of our previous approach, as we discussed in section 2.2. Chapter 5 and Attachments A to C discuss how specific techniques and assessment methods in the Guideline will improve expenditure forecast assessment.

2.3.1 National consistency

The Guideline will set out a nationally consistent approach to assessing NSPs' opex and capex forecasts. They will also form the basis for developing nationally consistent information reporting templates for NSPs.[46] National consistency would contribute greatly towards expenditure forecast assessment approaches that are rigorous, transparent and cost effective.

Where possible, we aim to develop a suite of assessment approaches that optimises the regulatory process. A nationally consistent approach to expenditure forecasting assessment and data collection facilitates this in several ways. The Guideline will facilitate greater synergies because stakeholders will be able to transfer experience from one determination to other determinations. All stakeholders will face greater certainty and transparency about our approach and thus engage more fully before, and during, the determination timeframe.

Nationally consistent data will also facilitate the development of more sophisticated benchmarking techniques and other expenditure forecast assessment techniques (see Attachments A to C).

2.3.2 More detailed information requirements

The Guideline sets out the key information we will require to undertake more rigorous expenditure forecast assessment in future determinations. We will collect capex and opex information in a more detailed and disaggregated form than for previous determinations and annual reporting. We can then use various assessment techniques such as the models for replacement expenditure (repex) and augmentation expenditure (augex) in future determinations (see Attachment A).

In addition to forecasts of future work volumes and costs required for regulatory proposals, NSPs will be required to comply with RINs and Regulatory Information Orders (RIO) that record the actual works undertaken, and the input costs associated with these works. Going forward, we intend to request data for network health indicators related to network reliability and condition using these instruments. As soon as possible, we will also collect back cast data to enable us to test, validate and implement our new economic benchmarking techniques.

We will also use data submitted as part of annual reporting for benchmarking reports and to assess expenditure forecasts. We propose the categories and subcategories of expenditure used for annual reporting should be the same as those used for expenditure forecasts. This is consistent with a number of stakeholder submissions that indicated we should use the annual RIN process to gather information for broader regulatory purposes.[47]

2.3.3 Cost benefit of new assessment techniques and accompanying data requirements

The purpose of the new assessment techniques and data requirements is to assist the AER in determining a NSP's efficient level of expenditure. Throughout developing the Guidelines and selecting the assessment techniques we have been mindful of the additional costs they will impose on

46 This is discussed in more detail in chapter 6.

47 Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, p 18; Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper,* 15 March 2013, p. 2.

the NSPs and the AER. We consider the expected benefits of these techniques are significant enough to outweigh the additional costs the techniques will impose.

The NSW DNSPs suggested that the AER publish any cost benefit and/or options analysis conducted for the implementation of the new assessment methods, noting a particular interest in whether a staggered process in collecting information is beneficial in terms of lower costs and better quality information.[48]

The weighing up of options, including the expected costs and benefits of any proposed policy or regulatory proposal, is standard regulatory practice. Our approach to selecting techniques in accordance with such practice was to:

- identify the expected benefits of the new techniques
- identify the expected costs of acquiring data to apply the techniques
- evaluate whether the expected benefits of the techniques exceed the expected costs of accompanying data requirements.

Identifying benefits of new techniques

In accordance with COAG best practice regulation we define benefits as social benefits. Benefits are 'social' when measured irrespective of the people to whom they accrue and are not confined to formal market transactions.[49] However, societal benefits do not include wealth transfers where one party is simply made better off at the expense of another party. Social benefits are realised if consumers gain more than NSPs lose.

When assessing regulatory expenditure allowances we consider societal benefit is maximised when a NSP's expenditure is efficient. Given that energy is an essential input to the production of goods and services, the societal benefits from relatively small percentage efficiency gains could be highly material. This is particularly the case currently with increasing globalisation and global competition for goods and services and the resultant challenges facing big sections of the Australian economy. Achieving these economic efficiencies is also consistent with the NEO.

We consider the new assessment techniques will assist the AER's assessment of whether NSPs proposed expenditure is at efficient levels in the following ways:

- Economic benchmarking techniques assist in assessing the efficiency of NSPs relative to their performance across time and against other NSPs. These techniques develop an efficient production frontier. From this, we can measure a NSP's relative productive performance in terms of its distance from that frontier.[50] The techniques can control for the effects of scale, input mix, and operating environment factors for in measuring technical efficiency (that is, distance from the frontier).
- Category or driver-based analysis will assist in determining an efficient level of expenditure in a particular category of expenditure. The techniques included in this analysis include benchmarking, modelling and engineering reviews. We can use this analysis to contrast and compare factors influencing expenditure across NSPs.

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48 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, p. 12.
49 Council of Australian Governments, *Best Practice Regulation: A Guide for Ministerial Councils and National Standard Setting Bodies,* October 2007, p.21.
50 AER, *Guidelines issues paper*, December 2012, p. 50.

In addition, we consider the new techniques will improve the regulatory process for all stakeholders by:

- producing savings in administrative, legal and consultancy costs for the AER, NSPs and other stakeholders. We consider the increased transparency and consistency in regulatory process will reduce the costs of all parties associated with legal scrutiny, with potentially fewer and/or more limited appeals
- streamlining data collection and compliance processes
- reducing the ambiguity around the reason the AER requires certain information to assess regulatory proposals
- better informing users about matters which may affect their interests, thus enabling them to better engage and further their own interests through the regulatory process.

Identifying costs of accompanying data requirements

In developing the new assessment techniques, our ongoing consultation with NSPs has improved our understanding of the business and operational changes that will be required to comply with new data requirements. We acknowledge NSPs will face expenses as a consequence of adjusting to new reporting standards. This may include training staff, adjusting IT systems, and reorganising data compliance procedures.

For example, Jemena Electricity Networks and SA Power Networks estimated the cost of preparing back cast data requirements for the economic benchmarking techniques at $90,000 (excluding auditing costs)[51] and more than $1.5 million (including auditing costs for ten years of back cast data)[52] respectively. While these costs may seem significant, it is important to consider them in the context of the benefits identified above. Further, we expect NSPs would incur a large portion of these costs upfront. Costs should be lower in the medium to long term as compliance with our data requirements become routine activities.

In addition, we will incur costs associated with the new assessment techniques and data requirements. These include collecting and publishing data, assessing compliance with RINs and detailed reporting templates, and assessing confidentiality claims.[53] These will be ongoing costs. There will also be extra costs for AER staff to learn and apply new expenditure assessment techniques. These costs will primarily be associated with extra employee hours and refined information systems, but will likely be ongoing.

Evaluating benefits and costs

As mentioned above we consider setting efficient expenditure allowances maximises social benefit. Quantifying the benefits of the new assessment techniques requires projections of the extent of inefficient expenditure they can identify relative to if we did not apply the assessment techniques. The assumptions this would involve means we consider it is not possible to specifically quantify the benefits of these techniques.

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[51] Jemena Electricity Networks, *Draft economic benchmarking regulatory information notice (RIN) submissions from Jemena Electricity Networks to the Australian Energy Regulator*, 18 October 2013, p. 18.

[52] SA Power Networks, *Response to draft economic benchmarking RIN*, 18 October 2013, p. 3.

[53] AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 13.

However, we base our selection of techniques on whether the benefits exceed the costs. Given the magnitude of NSPs' expenditure proposals, it would take relatively few inefficient projects to be identified and adjusted before the benefits would outweigh the additional costs imposed by our new assessment techniques and data requirements. Further, forecast capex and opex allowances for the transmission and distribution NSPs totals approximately $61 billion over their current five year regulatory periods.[54] Balancing all these factors we consider the implementation of the new techniques and accompanying data requirements is net benefit positive.

2.3.4 Greater transparency and consultation

The Guideline sets out the techniques we will use as part of our expenditure forecast assessment approach (see Attachments A to C). NSPs and other stakeholders will thus have transparency about key areas of our assessment approach and decisions on efficient expenditure forecasts.

The Guideline, with the F&A process, will facilitate consultation on NSPs' forecasting approaches well before the determination process. In past determinations, this debate typically occurred after the draft decision, when there was limited opportunity for change and to collect new data to assess expenditure claims. We expect this new process will work towards ensuring the assessment methods are robust and strike an appropriate balance between information burdens and improved regulatory outcomes.

NSPs will get an early indication of areas of their expenditure forecast we may target for further review, from the published techniques in the Guideline, and from the data analysis we present in annual benchmarking reports. Ideally, the NSPs will address these potential concerns, appropriately justifying those areas in their regulatory proposals. This would increase the time we (and other stakeholders) can devote to analysing material issues and reduce the time spent gathering additional information or on other, less contentious, aspects of the proposal.

The Guideline also establishes data reporting requirements that will support new annual benchmarking reports. Along with existing performance measures and data on work volumes, this will create an effective means of publicly monitoring NSP efficiency. We expect such monitoring and scrutiny to positively influence NSP behaviour and deliver value for money for network customers, as well as enabling consumer representatives to more effectively engage in regulatory processes.

2.3.5 Greater scope for benchmarking

The AEMC's changes to the NER allow us to use benchmarking more widely across the NEM. Specifically, the NER require us to publish an annual benchmarking report,[55] which we must consider when assessing expenditure forecasts during a determination.[56] However, in the process of developing the Guideline, we have also taken the opportunity to refine our assessment approach to make greater use of benchmarking techniques. The Guideline is an efficient means to describe the information we will require to benchmark expenditure for determinations and annual benchmarking reports. However, the Guideline does not prevent us from using other benchmarking techniques in the future.

Benchmarking is a valuable assessment technique in natural monopoly regulation. It provides us and other stakeholders with the information to compare NSPs with themselves and their peers, which may

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[54] AER, *State of the energy market*, 2012, pp. 69–71.
[55] NER, clauses 6.27 and 6A.31.
[56] NER, clauses 6.5.6(e)(4) and 6.5.7(e)(4).

mitigate information asymmetry. Publication of benchmarking analysis may also act as a form of competitive pressure on NSPs.

Collecting better quality, nationally consistent data allows us to develop and use more sophisticated benchmarking techniques. Such benchmarking analysis provides a more rigorous approach to considering whether a NSP's expenditure forecast reflects efficient and prudent costs under the NER.[57] Attachments A to C describe the benchmarking techniques we will use in determinations and annual benchmarking reports.

[57] NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

3 Legislative requirements

This chapter outlines the requirements of the NEL and NER that govern the framework for assessing a NSP's expenditure proposal. Our Guideline must be consistent with and give effect to these requirements. The following sections of this chapter:

- summarise the relevant provisions of the NEL and NER
- discuss expenditure assessment tasks under these provisions
- explain our view of the role of the Guidelines in this assessment framework.

3.1 National Electricity Law requirements

The NEL sets out the requirements that govern how we must perform our economic regulatory functions and powers, including assessing a NSP's proposal. These requirements include the NEO, the revenue and pricing principles and procedural fairness.

3.1.1 The national electricity objective and the revenue and pricing principles

The NEL requires us to perform our economic regulatory functions in a manner that will, or is likely to, contribute to achieving the NEO.[58] The NEO is:[59]

> … 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—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The NEO is the overarching objective of the NEL and exists to ensure we regulate electricity networks effectively. As the Major Energy Users (MEU)[60] and the PC[61] noted, the second reading speech introducing the NEL explains the meaning of the NEO:[62]

> The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.
>
> The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised.

The second reading speech clarifies that the NEO is fundamentally an efficiency objective where 'efficiency' is delivering electricity services to the level demanded by consumers in the long run at the lowest cost. Innovation and investment are necessary to ensure NSPs continue to respond to

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58 NEL, section 16(1)(a).

59 NEL, section 7.

60 Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper,* 15 March 2013, pp. 4–7.

61 Productivity Commission, *Final report: Electricity network regulatory frameworks*, June 2013, pp. 133–134.

62 The NEO was initially called the national electricity market objective, which is why this quote refers to the 'market objective'. Second reading speech, National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005, Parliament of South Australia, Hansard of the House of Assembly, 9 February 2005, p. 1452. The purpose of the second reading speech is to explain the purpose, general principles and effect of the bill. See, for example, www.aph.gov.au/About_Parliament/House_of_Representatives/Powers_practice_and_procedure/00_-_Infosheets/Infosheet_7_-_Making_laws.

consumer needs and to improve productivity. However, to be efficient and maximise consumer welfare, service providers must innovate and invest at the lowest cost.

We agree with the MEU and the PC that the NEO seeks to emulate effectively competitive market outcomes.[63] In a competitive market, a firm has a continuous incentive to respond to consumer needs at the lowest cost (that is, operate efficiently) because competition may force it to exit the market if it does not. In addition, the firm has an incentive to improve its efficiency because it will enjoy greater market share if it can provide the best service at the lowest cost to the consumer. Essentially, the NEO imposes the pressures of competition on natural monopolies. In response to the explanatory statement for the draft Guideline, PIAC supported our interpretation of the NEO.[64]

The revenue and pricing principles support the NEO (and the competitive market outcomes concept). They are guiding principles to ensure a framework for efficient network investment exists, irrespective of how the regulatory regime and the industry evolve (via changes to the NER).[65] The relevant second reading speech explains that the revenue and pricing principles are:[66]

> …fundamental to ensuring that the Ministerial Council on Energy's intention of enhancing efficiency in the National Electricity Market is achieved.

The revenue and pricing principles reiterate the importance already enshrined in the NEO of ensuring NSPs have appropriate incentives to provide, and are compensated for providing, electricity services efficiently so that consumers receive the level of service they expect at the least cost.[67] They guide us to consider the regulatory and commercial risks involved in providing services, for example, in light of the economic implications for consumers of under- and over-investment in the network. They also guide us to consider the need to compensate NSPs for economically efficient investment so they have an incentive to maintain service levels, but not under- or over-utilise existing network assets.[68]

The NEL requires us to take the revenue and pricing principles into account whenever we exercise discretion in making those parts of a distribution determination or transmission determination relating to direct control network services.[69] This includes when we assess expenditure forecasts. However, we may also account for the revenue and pricing principles when performing or exercising our other economic regulatory functions or powers if we consider it appropriate.[70] The principles are:

> (2) 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.

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63 Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper,* 15 March 2013, pp. 4–7 Productivity Commission, *Final report: Electricity network regulatory frameworks*, June 2013, pp. 133–134.

64 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 4, 7.

65 Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

66 Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

67 Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

68 Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 965.

69 NEL, section 16(2)(a)(i).

70 NEL, section 16(2)(b).

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted [in a previous determination or in the Rules]

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

The regulatory framework under which we operate aims to facilitate the NEO and the revenue and pricing principles (and effectively competitive markets) in two ways. It requires us to:

- set NSP revenue allowances at the lowest long run cost required to provide the level of service from which customers gain the most value
- provide NSPs with incentives to pursue efficiency gains.

In response to the explanatory statement for the draft Guideline some submissions considered it was inappropriate to set revenue allowances based on 'minimum costs'. They considered that this interpretation is inconsistent with the first revenue and pricing principle[71], which states that NSPs should be provided with a reasonable opportunity to recover at least efficient costs.[72] They considered that our interpretation could lead to cherry picking of assessment techniques to achieve minimum cost intentions and suggested we remove references to 'minimum cost' in the Guideline and explanatory statement.[73]

We do not agree with these submissions. We are not setting revenue allowances based solely on minimum cost; we are setting them at the minimum cost to provide services to the standard required by the NER. In the context of expenditure, this is the minimum cost to achieve the expenditure objectives. We consider this is consistent with providing NSPs with a reasonable opportunity to recover *efficient* costs because efficient costs are by definition, the 'minimum cost' over the long run to achieve these objectives. As we explain in section 3.2.2, the expenditure objectives are essentially a proxy for the level of service from which customers gain the most value. We have, however, changed references to 'minimum cost' to 'lowest long run cost' to clarify that these costs reflect long term interests, as the NEO requires.

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71 NEL, clause 7a(2)

72 For example, Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 2, 13–14; ActewAGL, *Response to AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 2–3.

73 Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 2, 14; ActewAGL, *Response to AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 3.

In addition, rather than focussing solely on this single revenue and pricing principle, we must consider all of the revenue and pricing principles. When we consider all six principles revenue and pricing principles together, our view is that while we are required to take into account the interests of NSPs, the principles ultimately support the NEO—the long term interests of consumers. We need to encourage efficient investment, but not to the detriment of consumers. This view is shared by PIAC, who state that providing fair compensation to investors is the means to the end, not the end in itself.[74]

We reward NSPs in the short term for spending less in a regulatory control period than the forecast expenditure allowance that we determine to be efficient, while maintaining service standards. That is, our incentive framework encourages NSPs to continuously improve the efficiency with which they deliver electricity services without lowering service levels.

In theory, consumers benefit from this by paying the lowest cost for electricity services at the standard from which they gain the most value over the long term. In practice, this can be difficult to achieve because it relies on our ability to determine an efficient revenue allowance. This explanatory statement details the improvements we are making to our expenditure assessment approach to better achieve the NEO. We are also implementing a capex incentive scheme, in addition to our existing schemes, which further encourages NSPs to pursue efficiencies.

3.1.2 Procedural fairness

The NEL also requires that we afford NSPs procedural fairness. We must, in making a regulatory determination, ensure NSPs are:[75]

> (i) informed of material issues under consideration by the AER; and
>
> (ii) given a reasonable opportunity to make submissions in respect of that determination before it is made.

In essence, this protects a NSP if we materially change our analysis without notification.[76]

3.2 National Electricity Rules requirements

The NER set out specific requirements to ensure we assess and determine expenditure proposals in accordance with the NEL, and hence give effect to the NEO. They prescribe the process we must follow when assessing expenditure.

3.2.1 Expenditure criteria

The NER require us to assess total capex and opex forecasts against the capex and opex criteria (collectively, the expenditure criteria). We must decide whether we are satisfied that a NSP's proposed total capex forecast and total opex forecast reasonably reflect the following criteria:[77]

(1) the efficient costs of achieving the capex and opex objectives

(2) the costs that a prudent operator would require to achieve the capex and opex objectives

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capex and opex objectives.

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[74] Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 7.

[75] NEL, clause 16(1)(b).

[76] AEMC, *Rule determination*, 29 November 2012, p. 111.

[77] NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

These criteria intend to give effect to the NEO.[78] Accordingly, when we are determining whether a forecast reasonably reflects the expenditure criteria, we consider whether it reflects the lowest long term cost to consumers required to achieve the capex and opex objectives.

3.2.2 Expenditure objectives

The capex and opex objectives (collectively, the expenditure objectives) are to:[79]

(1) meet or manage the expected demand for standard control/prescribed transmission services over that period

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control/prescribed transmission services

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control/prescribed transmission services; or

(ii) the reliability or security of the distribution system through the supply of standard control/prescribed transmission services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control/prescribed transmission services; and

(iv) maintain the reliability and security of the system through the supply of standard control/prescribed transmission services; and

(4) maintain the safety of the system through the supply of standard control/prescribed transmission services.

Essentially, expected demand and the reliability, quality, security and safety standards (legislated or otherwise) are proxies for the level of service from which customers gain the most value. However, the shift towards a more consumer focused regulatory determination process will hopefully result in consumers having more input into ensuring service standards are at the level from which they gain the most value and for which they are willing to pay.[80] We expect the AEMC's recommended frameworks for distribution and transmission reliability will assist with this, once the requisite changes are made to the NEL, NER and other jurisdictional legislation.[81]

Recent changes to the expenditure objectives will also assist our expenditure assessments in this regard. The expenditure objectives now ensure that NSPs are only able to include in their proposals sufficient expenditure to comply with quality, reliability and security obligations in accordance with

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78 AEMC, *Rule determination*, 29 November 2012, p. 113.
79 NER, clauses 6.5.6(a), 6.5.7(a), 6A.6.6 and 6A.6.7.
80 AEMC, *Rule determination*, 29 November 2012, pp. 114–115, 174–175; NER, clauses 6.5.6(e)(5A), 6.5.7(e)(5A), 6A.6.6(e)(5A) and 6A.6.7(e)(5A).
81 See, for example, AEMC, *Final Report–Review of the national framework for transmission reliability*, 1 November 2013, pp. i–vii and AEMC, *Final Report—Review of the national framework for distribution reliability*, 27 September 2013, pp. i–v.

jurisdictional standards.[82] If NSPs have been delivering services at higher than required quality, reliability or security, we will not allow expenditure for the associated cost of maintaining this higher standard.

So, where there are jurisdictional regulatory obligations to achieve a certain level of service quality, reliability and security, we will assess expenditure proposals in accordance with these obligations rather than against current or voluntary standards.[83] Where jurisdictional standards are lower than NSPs' current standards, we expect NSPs to reduce the opex and capex from previous levels to comply with the jurisdictional obligations.

Where no jurisdictional standards apply, we will allow NSPs to recover the efficient costs of maintaining their current reliability and quality of service. Our schemes will provide NSPs with an incentive to move to different levels of reliability and quality of service where it is efficient to do so. This is because the STPIS (in conjunction with the other schemes) incentivises NSPs to provide services at a quality that aligns with customer preferences.

The assessment techniques we employ to examine the efficiency of past and forecast expenditures include considering the NSPs' legal obligations in addition to the quality of service or outputs they propose to deliver.

3.2.3 Expenditure factors

In determining whether expenditure reasonably reflects the expenditure criteria, we must consider the capex and opex factors (collectively, the expenditure factors).[84] The expenditure factors are not additional criteria for assessing forecasts. Rather, they guide our assessment under the expenditure criteria; much like the revenue and pricing principles guide our decision-making.

Essentially, these factors ensure that we consider certain information in forming our view on the reasonableness of a forecast.[85] Some examples are benchmarks, consumer input, past expenditure, input prices and investment options. We may also consider 'any other factor' (if necessary) but we must notify the relevant NSP before it submits its revised proposal if we intend to do so. We could, but are not required to, also raise other factors at the F&A stage.[86]

A key feature of the AEMC's recent rule change determination is that we must prepare annual benchmarking reports on the relative performance of NSPs. The AEMC intended the reports to be a useful tool for stakeholders, such as consumers, to engage in the regulatory process and to have better information about the relative performance of NSPs.[87] The expenditure factors require us to consider the most recent and published benchmarking report when assessing total capex and total opex proposals.

We will not necessarily have regard to every expenditure factor when assessing or determining every expenditure component; the NER do not require this.[88] Further, the NER do not prescribe weightings to the factors so we have discretion about how we may have regard to them, which we will explain in our reasons for a determination.

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82 AEMC, *Rule determination, National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. ii.

83 AEMC, *Rule determination*, 19 September 2013, pp. i–iii.

84 NER, clauses 6.5.6(c), 6.5.7(c) 6A.6.6(c) and 6A.6.7(c).

85 AEMC, *Rule determination*, 29 November 2012, p. 113.

86 AEMC, *Rule determination*, 29 November 2012, pp. 110–111.

87 AEMC, *Rule determination*, 29 November 2012, p. 108.

88 AEMC, *Rule determination*, 29 November 2012, p. 115.

3.3 The AER's task

Taking into account the NEL and NER requirements, our task is to form a view on NSPs' expenditure forecasts in the context of the broader incentive based regulatory framework, where the overarching objective is to maximise the economic welfare of consumers over the long term.[89] That is, when we assess whether a NSP's expenditure forecast reasonably reflects the expenditure criteria, we are also considering whether the NSP is responding to incentives and therefore is providing electricity services efficiently.

If we are satisfied that a NSP's total capex or total opex forecast reasonably reflects the expenditure criteria, we must accept the forecast.[90] If we are not satisfied, we must not accept the forecast.[91] In this case, we must estimate the total forecast that we are satisfied reasonably reflects the expenditure criteria.[92] That is, we must amend the NSP's estimate, or substitute it with our own estimate. What is reasonable is a matter for us to determine, based on the information before us.[93]

Two fundamental points are relevant to how we perform our task. First, the NER requires us to form a view on forecast total capex and opex, rather than subcomponents such as individual projects and programs. Second, we are not limited in the information we rely on to determine the reasonableness of a proposal and (if necessary) the appropriate substitute. Under the NER we are required to give reasons for our decisions.[94]

3.3.1 Total forecast assessment

The NER explicitly require us to form a view on total capex and total opex, not individual projects or programs.[95] In the past, we relied on project assessment in many cases to inform our opinion on total capex or opex. However, we are developing our assessment techniques and enhancing our approach so we can rely less on project assessment, particularly for DNSPs.

3.3.2 Information we can rely on

We are not limited in the information we can rely on to determine the reasonableness of a NSP's expenditure proposal. The information provided in the NSP's proposal is the starting point for our assessment approach because of the 'propose–respond' nature of the NER framework (that is, where we must form a view on the NSP's proposed expenditure forecast). The NSP is also best placed to understand and provide information on its network and know what expenditure it will require in the future.[96]

However, the NSP has an incentive to prepare its proposal in a manner that allows it to increase its cost allowances. Therefore, we need to test the NSP's proposal robustly. This means we must necessarily conduct our own analysis to assess its reasonableness. The AEMC has clarified that we are not limited in the techniques we may use to do this, whether they be benchmarking, information from stakeholders or other methods. The Guideline contains the techniques we intend to use, but we

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89 Second reading speech, National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005, Parliament of South Australia, Hansard of the House of Assembly, 9 February 2005, p. 1452.
90 NER, clauses 6.5.6(c), 6.5.7(c), 6.12.1(3)(i), 6.12.1(4)(i).
91 NER, clauses 6.5.6(d), 6.5.7(d).
92 NER, clauses 6.12.1(3)(ii), 6.12.1(4)(ii).
93 AEMC, *Rule determination*, 29 November 2012, p. 112.
94 NER, clauses 6.12.2, 6A.14.2
95 NER, clauses 6.5.6(c), 6.5.7(c), 6.12.1(3)(i), 6.12.1(4)(i); AEMC, *Rule determination*, 29 November 2012, p. 113.
96 AEMC, *Rule determination*, 29 November 2012, pp. 111–112.

may depart from the Guideline, with reasons, if we consider it appropriate. Importantly, the NER does not confine us to determining a substitute using the approach the NSP took in its proposal.[97]

Further, assessing the reasonableness of a NSP's proposal and determining an appropriate substitute are not separate exercises. As the AEMC clarifies, we could benchmark a NSP against its peers to form a view on whether the proposal is reasonable and (if necessary) what a substitute should be.[98]

Therefore, we have broad discretion in how we perform our task of assessing expenditure proposals, provided we comply with the NEL and NER requirements.

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97 Past versions of the NER required that we determine substitute amounts on the basis of the NSP's regulatory proposal, and amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER. This requirement no longer exists. NER, clauses 6.12.3 and AEMC, *Rule determination*, 29 November 2012, pp. 111–112.

98 AEMC, *Rule determination*, 29 November 2012, p. 112.

4 Role and content of the Guideline

The NER require the Guideline to specify our proposed approach to assessing opex and capex forecasts and information we require for the purposes of that assessment.[99] We have drafted the Guideline to give effect to the legal requirements outlined in the previous chapter and they provide guidance on how we will apply the legal framework when assessing proposals.

The Guideline is not binding on us or NSPs, but we must state why we depart from it in making determinations.[100] NSP's must provide with their regulatory proposals, a document complying with the Guideline or—if we deviate from the Guideline—the F&A paper.[101]

4.1 AER position

The AEMC intended the Guideline to facilitate early engagement between NSPs and the AER on how NSPs propose to forecast expenditure and the information we require to effectively assess expenditure proposals.[102] As such, we consider it appropriate to provide some transparency and certainty to stakeholders about the determination process.

However, the Guideline should remain flexible enough to account for the different circumstances that may underpin future expenditure assessments. It is not appropriate to use the Guideline to limit our discretion or restrict our ability to use and refine our assessment techniques. Instead, we will assess expenditure using a holistic approach and use the techniques we consider appropriate depending on the specific circumstances of each determination.[103]

Similarly, the Guideline is flexible enough for us to change information requirements as we gain further experience in assessing expenditure proposals. Ultimately, we give effect to the information requirements in the Guideline through regulatory information instruments to streamline compliance for NSPs by ensuring these instruments are consistent with F&A requirements. Accordingly, we do not consider it is desirable to set a term for revision in the Guideline. Rather, we will consult with interested parties if we consider substantial changes to the Guideline are necessary in the future.[104]

In response to submissions, we have moved some content from the explanatory statement to the final Guideline. However, we have not significantly altered our general assessment approach.

4.2 Reasons for AER position

We consider that the Guideline accords with the NER because it specifies our proposed approach to assessing expenditure and the information we require to do so. It also emphasises the NEO as the central element for our regulatory decision making and strikes the appropriate balance between flexibility and certainty. Accordingly, our general assessment approach and techniques in the final Guideline is not significantly different to the draft Guideline. However, we improved on the draft Guideline by including more detail and some additional content, such as the assessment principles.

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99 NER, clauses 6.4.5 and 6A.5.6.
100 NER, clause 6.2.8(c).
101 NER, clauses 6.8.2(c2) and 6A.10.1(h).
102 AEMC, *Rule determination*, 29 November 2012, pp. 108–110.
103 AER, *Better Regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, pp. 48–49.
104 NER, clauses 6.2.8 and 6A.2.3.

We received several submissions on the role and content of our draft Guideline and the general approach we propose to use to assess expenditure. Some submissions were supportive;[105] others considered we should make significant amendments to the Guideline.[106] We clarify our position in light of these submissions in the sections below. For the final Guideline, we have made some minor changes to our general approach and added some content. We discuss submissions on specific elements of our assessment approach and techniques later in this explanatory statement.

Some stakeholders supported our proposed general approach to assessing expenditure proposals. Key endorsements include:

- we have found the appropriate balance between flexibility and certainty in the Guideline[107]
- we are correct in stating the NEO is the central element of regulatory decision making and the purpose of regulating monopoly businesses is to emulate effective competitive markets[108]
- we are appropriately using discretion in accordance with the NER[109]
- our view that it is inappropriate and inconsistent with the NEO to allow inefficient NSPs to transition to the new regulatory regime or to propose a premium above efficient costs to balance risk is correct[110]
- our intention to make greater use of benchmarking and seek back cast data[111]
- our intention to improve the base-step-trend approach by testing revealed costs and incorporate a productivity measure.[112]

We found these submissions reinforced our view that we should be seeking better outcomes for consumers and that our approach is a step in the right direction.

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105 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 7; Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013, p. 3; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 5; Ethnic Communities' Council of NSW Inc., *ECC submission on AER draft expenditure forecast assessment guidelines*, 19 September 2013, pp. 1–2.

106 For example, Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013; NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013; ActewAGL, *Response to AER draft expenditure forecast assessment guidelines*, 20 September 2013, Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013; The Victorian Distributors, Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013.

107 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 9–10; Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013, p. 3; Australian Energy Market Operator, *AEMO submission on AER on expenditure forecast assessment guidelines*, 23 September 2013, p. 3.

108 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 7, 12–13.

109 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 7–9.

110 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 13–15. PIAC has inadvertently misquoted our explanatory statement for the draft Guidelines. We have not previously accepted the 'prudency premium'; some NSPs have proposed it in the past.

111 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 15; Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, pp. 18–19; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 12–15, 22.

112 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 24–27; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 7–9; Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, pp. 11–12.

Broadly, criticisms related to the:

- importance of the NSP's proposal
- purpose of the Guideline
- importance of the NER requirements
- importance of the NSP's circumstances
- differences between DNSPs and TNSPs.

Several submissions also suggested we should include more content in the Guideline, including a term for revision.[113]

4.2.1 The NSP's proposal

Some submissions commented that the draft Guideline did not adequately emphasise the importance of the NSP's proposal. In particular, these submissions were concerned with some of the language in the Guideline that suggested we would use a counterfactual forecast as the starting point for determining expenditure forecasts rather than the NSP's proposal. These submissions (citing the AEMC's rule determination) considered we should alter the Guideline to acknowledge the NSP's proposal:[114]

1. is the procedural starting point for determining an expenditure allowance and
2. will, in most cases, be the most significant input into our decisions.

The relevant AEMC comment that the submissions refer to in support of the suggested alterations is:[115]

> The NSP's proposal is necessarily the procedural starting point for the AER to determine a capex or opex allowance. The NSP has the most experience in how a network should be run, as well as holding all the data on past performance of its network, and is therefore in the best position to make judgments about what expenditure will be required in the future. Indeed, the NSP's proposal will in most cases be the most significant input into the AER's decision.

We agree that we should commence determining the efficient capex or opex allowance with the NSP's proposal, and our general approach is to consider the NSP's proposal in the first instance. The propose-respond regulatory model—where we must form a view on a NSP's proposed forecast—necessitates this. We do, however, note that the NER do not explicitly require us to start with the

113 SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 4; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 28–30; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 5; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 2–4; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 18–23.

114 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 8–10; NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, pp. 1–2; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 4; ActewAGL, *Response to AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2; Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 12–13; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 4.

115 AEMC, *Rule determination*, 29 November 2012, p. 111.

NSP's proposal. Rather, the NER state that we 'must have regard to' the information included in or accompanying the NSP's proposal (and other relevant information).[116]

Notwithstanding this, the final Guideline clarifies that we will commence with the NSP's proposal. Further, to the extent we consider that refining some of the language in the Guideline alleviates procedural concerns, we have done so. However, we do not agree that the Guideline should state categorically that the NSP's proposal is the most significant input into our decisions.

We agree with the above quote that the NSP has the most experience in running its network and accordingly should be best placed to make judgments about expenditure it requires in the future.[117] However, we cannot ignore the AEMC's observation that the NSP '[holds] all the data on past performance of its network'.[118] In addition to performance data, the NSP holds all other relevant data, including information about its actual costs, expenditures, demand and service quality. The regulator, on the other hand, has imperfect information.[119] So, the NSP may understand its network better than anyone else but it also has the informational advantage.

This information asymmetry, combined with the incentive to inflate expected expenditure needs,[120] means that although the NSP's proposal will be a significant input into our decision, we must necessarily rely on other information to test it robustly. Indeed, if we quote the remainder of the AEMC's comment (not included in the submissions cited above) we consider this approach is consistent with the NER and the AEMC's intent:[121]

> Importantly, though, [the NSP's proposal] should be only one of a number of inputs. Other stakeholders may also be able to provide relevant information, as will any consultants engaged by the AER. In addition, the AER can conduct its own analysis, including using objective evidence drawn from history, and the performance and experience of comparable NSPs. The techniques the AER may use to conduct this analysis are not limited, and in particular are not confined to the approach taken by the NSP in its proposal.

In addition, the AEMC later states:[122]

> To the extent the AER places probative value on the NSP's proposal, which is likely given the NSP's knowledge of its own network, then the AER should justify its conclusions by reference to it, in the same way it should regarding any other submission of probative value.

So, while the NSP's proposal is important, it is one of several pieces of evidence that we must consider when assessing whether we consider an expenditure proposal reasonably reflects the expenditure criteria.

Our view is consistent with PIAC's observation that the regulatory process is a propose-respond model, but we have the discretion to respond in a critical fashion because we do not need to base any substitute amount on the NSP's proposal. We are less constrained by the form of the NSP's proposal than in the past.[123] Given this, we are using the Guideline development opportunity to collect past performance data for all NSPs to enable us to assess expenditure using techniques that do not confine us to the approach taken by the NSP in its proposal. For example, we will compare the

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116 For example, NER, clauses 6.11.1(b) and 6A.13.1(a1).

117 We acknowledged this in our explanatory statement for the draft Guidelines. *AER, Better Regulation: Explanatory Statement: Draft Expenditure Forecast Assessment Guidelines*, August 2013, p. 20.

118 AEMC, *Rule determination*, 29 November 2012, p. 111.

119 Productivity Commission, *Electricity network regulatory frameworks – inquiry report*, Volume 1, 9 April 2013, pp. 188–192.

120 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, p. 8.

121 AEMC, *Rule determination*, 29 November 2012, pp. 111–112.

122 AEMC, *Rule determination*, 29 November 2012, p. 112.

123 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 9.

performance of a NSP over time and with its peers as a means of assessing the reasonableness of its regulatory proposal.

Therefore, NSPs should be on notice that, while we will commence our assessment with the NSP's proposal, our general approach is to use benchmarking and alternative forecasts as a means (but not necessarily the only means) of assessing its reasonableness. The AEMC is clear that this is an approach we could take:[124]

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

If our assessment shows that the NSP's forecast reasonably reflects the expenditure criteria, we will accept the forecast, as we must do.[125] However, given the nature of our regulatory task as noted above, we see no value in stating in the Guideline that the NSP's proposal will be the most significant input into our decisions.

4.2.2 The purpose of the Guideline

Several submissions consider that our draft Guideline extends beyond its intended purpose. For example, some submissions consider the Guideline:

- prescribes NSPs to use particular forecasting methodologies[126]
- places too much emphasis on developing substitute forecasts[127]
- places undue reliance on benchmarking, which introduces greater potential consequences of regulatory error.[128]

Prescription of methodologies

We have clarified the language in the Guideline to ensure it does not restrict the manner in which a NSP prepares its proposal. NSPs are free to prepare their expenditure forecasts in a manner they consider appropriate and propose them to the AER.[129] However, NSPs should carefully consider the Guideline requirements when they are preparing their forecasts.

124 AEMC, *Rule determination*, 29 November 2012, p. 112.

125 NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

126 For example, Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 11–12; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1, 4; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2; NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, p. 6.

127 For example, Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 8–10; SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 3; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 3.

128 Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 12–13; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 1–3; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 47.

129 For example, Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 11–12; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1, 4; Energex

One of the problems the Guideline is intended to overcome is the amount of time required to engage on expenditure models after a NSP submits its regulatory proposal. This is particularly an issue when the AER and the NSP cannot agree on the appropriate methodology.[130]

For this reason, the NER require NSPs to notify us of their proposed forecasting approaches[131] and, via the Guideline, allow us to specify the manner in which we propose to assess capex and opex forecasts. The Guideline also allows us to require NSPs to provide the necessary information to effectively assess their proposals.[132] At the framework and approach stage, we determine how the Guideline will apply to the specific NSP, including any expenditure methodologies we prefer.[133]

The NSP must submit, with its regulatory proposal, information in compliance with the application of the Guideline as we determine in the framework and approach paper.[134] Despite the non-binding nature of the Guideline, we can require the NSP to resubmit its regulatory proposal if it fails to comply with the information requirements in the Guideline.[135] Some stakeholders queried our ability to do this.[136] Clause 6.9.1(a)[137] permits the AER to require a DNSP to resubmit its regulatory proposal if the AER considers the proposal or accompanying information does not comply, in any respect, with the NER. In this case, non-compliance would be with clause 6.8.2(c2):[138]

> The *regulatory proposal* must be accompanied by information required by the *Expenditure Forecast Assessment Guidelines* as set out in the *framework and approach paper*.

Therefore, where we specify in the Guideline that we will use a particular approach, we encourage—but do not require—NSPs to adopt that approach when developing their forecasts. Ultimately we will be assessing expenditure in accordance with the Guideline and the framework and approach paper, so this will minimise duplication of effort on the part of the NSP.

For example, our approach to assessing opex is to primarily use the base-step-trend approach. NSPs need not prepare their regulatory proposals using this approach, but they will need to provide information to enable us to assess their proposals using a base-step-trend approach. It is our role to assess the proposal using the techniques we consider appropriate.[139] We do not consider it is appropriate to conduct, for example, a line by line assessment of a total opex forecast developed using a bottom up approach (although we may consider it appropriate to assess certain components of an opex forecast in this way).

Accordingly, at a minimum, we will require NSPs to provide the information we require to use the base-step-trend approach to assess their opex proposals. NSPs will need to identify how much of the annual forecast increases in opex are due to real price changes, output growth changes and productivity.. However, we may also decide at the framework and approach stage that it is necessary for the NSP to recast its opex forecast using a base-step-trend model if we consider this will be the

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Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2; NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, p. 6.

130 AEMC, *Rule determination*, 29 November 2012, p. 99.

131 NER, clauses 6.8.1A and 6A.10.1B

132 NER, clauses 6.4.5(a) and 6A.5.6(a).

133 AEMC, *Rule determination*, 29 November 2012, p. 99.

134 NER, clauses 6.8.2(c2) and 6A.10.1(h); AEMC, *Rule determination*, 29 November 2012, p. 109.

135 NER, clauses 6.9.1 and 6A.11 permit the AER to require resubmission of a regulatory/revenue proposal, respectively, if the AER considers the proposal or accompanying information does not comply, in any respect, with the NER.

136 Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2.

137 The chapter 6A equivalent is clause 6A.11.

138 The chapter 6A equivalent is clause 6A.10.1(h).

139 AEMC, *Rule determination*, 29 November 2012, p. 109.

most effective way for us to assess the NSP's opex proposal. This is consistent with the role of the Guideline and the intent of the NER.[140]

Emphasis on determining substitute forecasts

Some submissions consider we are placing too much emphasis on developing substitute forecasts.[141] We are not persuaded by these submissions because on one hand, they agree that assessing a NSP's proposal and determining an appropriate substitute are not separate exercises. However, on the other they state we are conflating our approaches to assessing and potentially substituting proposals.[142]

The AEMC's statement referred to above, noting the dual nature of our task, did not consider this was a concern. The Guideline specifies several techniques and approaches we will use to assess expenditure forecasts. Ultimately, our assessment will lead us to develop an alternative forecast to determine whether we are satisfied the NSP's forecast reasonably reflects the expenditure criteria. The alternative forecast may in turn become a substitute forecast depending on the outcome of this test.

Reliance on benchmarking

Some submissions consider we are relying too much on benchmarking in our general approach.[143] Ergon Energy is particularly concerned that the first pass approach will result in us making findings on key aspects of opex without considering each of the mandatory opex factors.[144] The ENA considers we should not use benchmarking because it will introduce greater potential consequences of regulatory error, as opposed to revealed costs.[145]

We disagree with these submissions. They do not provide any evidence that benchmarking is any less reliable than any other assessment technique. We must necessarily consider the accuracy of benchmarking alongside the accuracy of other techniques we use to form a view on expenditure proposals. These include the NSP's forecasting techniques and the subjective engineering judgment upon which they rely.

The NEL and NER require us to determine efficient expenditure allowances in the long term interests of consumers. Benchmarking is a fundamental technique for assessing the efficiency of NSPs' costs and we intend to use it. It may have some limitations, but it is no different to other assessment techniques in this regard; no technique is perfect. We use any technique taking into account both its usefulness and limitations that may exist. The Guideline provides a set of principles to determine the extent that we should rely on those results.

Further, the ENA's submission that benchmarking introduces greater potential consequences of regulatory error is not convincing.[146] Contrary to the ENA's view, we consider it is in the long term interests of consumers to set allowances that reflect efficient costs, even when efficient costs are

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140 NER, clauses 6.4.5(a) and 6A.5.6(a); AEMC, *Rule determination*, 29 November 2012, p. 109.

141 For example, ENA, pp. 8–10; SP AusNet, p. 3; Ergon Energy, p. 3.

142 For example, ENA, pp. 11–12.

143 Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 12–13; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 2 September 2013, pp. 1–3.

144 Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 12–13.

145 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 47.

146 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 47.

lower than revealed costs. If benchmarking demonstrates that a NSP's revealed costs are higher than an efficient benchmark it means that the NSP's costs have historically been too high. It does not mean that the benchmark allowance is 'inefficiently low'. The incentive to spend less than the AER's efficient allowance exists not to 'force NSPs to make inefficient expenditure decisions', but to encourage NSPs to continuously improve their efficiency. This is also in the long term interests of consumers.[147]

As we explain in section 1.4.3, the first pass approach is a high level assessment we will likely conduct at the issues paper stage to provide our preliminary view on a NSP's expenditure forecasts (and other elements of its proposal). We will predominantly use benchmarking for the first pass approach because the point of it is to provide an initial high level assessment, early in the process, so we can identify, and engage with stakeholders on, key issues. The efficiency of a NSP compared to itself and its peers is a key issue, and our benchmarking techniques allow us to make comparisons without delving into significant detail.

Whether or not we have regard to one or several expenditure factors during this intermediate step in the process of determining efficient expenditure, we are entitled to do so. As we explain in section 3.2, the NER require that we have regard to the expenditure factors when forming a view on *total* capex or opex.[148] We need not consider every factor when assessing every component of expenditure.[149] The NER also do not prescribe weightings to the factors so we have discretion as to how we have regard to them, which we will explain in our reasons for our decision.

In addition, as our Guideline states, we will use several techniques to assess expenditure, not just benchmarking:[150]

> When we assess capex and opex forecasts, we may use a number of assessment techniques to form a view on the reasonableness of the forecast. Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time.

The first pass approach does not necessarily preclude further assessment, nor does it determine the efficient level of expenditure.

We are, however, emphasising that we will be benchmarking more than we have previously. This is in response to:

- the AEMC's November 2012 amendments to the NER, which confirm we have discretion to undertake benchmarking in decision-making and require us to produce annual benchmarking reports;[151]
- the Productivity Commission's recommendations[152]
- the Australian Government's response to the Productivity Commission's recommendations[153]

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147 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 47.
148 NER, clauses 6.5.6(e), 6.5.7(e), 6A.6.6(e) and 6A.6.7(e).
149 AEMC, *Rule determination*, 29 November 2012, p. 115.
150 For example, AER, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 7.
151 For example, NER, clauses 6.5.6(c)(2), 6.5.7(c)(2), 6.12.3(f), 6A.6.6(c)(2), 6A.6.7(c)(2) and AEMC, *Rule determination*, 29 November 2012, pp. vii–viii, 25, 92.
152 Productivity Commission, *Electricity network regulatory frameworks – inquiry report*, Volume 1, 9 April 2013, pp. 2–3, 187.
153 Australian Government, *The Australian Government response to the Productivity Commission inquiry report – Electricity Network Regulatory Frameworks*, June 2013, pp. i–ii, 3–9.

- support from stakeholders.[154]

4.2.3 Importance of the NER requirements

Some submissions considered that our draft Guideline does not adequately 'give primacy to the NER.' In particular, the submissions were concerned with:[155]

- language we used in the draft Guideline explaining when we would not accept a NSP's forecast
- the level of detail explaining how we will use each of our proposed assessment principles, techniques and information requirements in accordance with the NER.

Accepting or not accepting a NSP's forecast

In the draft Guideline we stated that we will not accept a NSP's forecast if it is greater than the alternative estimate we develop using our assessment techniques if there is no satisfactory explanation for the difference. Specifically:[156]

> If a DNSP's total capex or opex forecast is (or components of these forecasts are) greater than estimates we develop using our assessment techniques and there is no satisfactory explanation for this difference, we will form the view that the DNSP's estimate does not reasonably reflect the expenditure criteria. In this case, we will amend the DNSP's forecast or substitute our own estimate that reasonably reflects the expenditure criteria.

Submissions were concerned that this introduced 'quasi-rules' or additional requirements that the NSP must satisfy, which undermine the NER. Submissions suggested, for example, that the AER would use the Guideline as a means of not accepting a NSP's proposal without providing reasons.[157] While we maintain the substance of the above statement, we have clarified our approach to assessing a NSP's forecast in the final Guideline and have provided some further information in this explanatory statement to clarify areas of concern.

First, the final Guideline explicitly states that we will give reasons for accepting or not accepting a NSP's forecast. While we would never simply substitute a NSP's forecast with an alternative estimate without providing reasons, this removes any such inference from the Guideline.

Second, (while not raised in submissions) we have removed the reference to components of forecasts in the above extract. It reflects the requirement in the NER for us to make a determination on *total* forecasts, regardless of whether or not we assess a forecast at a more disaggregated level. So, when deciding if we are satisfied that a NSP's capex or opex forecast reasonably reflects the expenditure

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154 For example, Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, pp 5, 8–9 and Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 4, 15–16.

155 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 6–7; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 4; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 3, 7–8; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 4–5.

156 See, for example, AER, *Better Regulation: Draft Expenditure Forecast Assessment Guideline for Electricity Distribution*, August 2013, p. 7.

157 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 6; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 7.

criteria, we compare the NSP's total of that forecast with the total of our estimate.[158] This does not mean we will not examine components of capex or opex forecasts.

However, we do not agree that the above extract is otherwise inappropriate. At a general level, when we assess a NSP's expenditure forecast, we will arrive at an alternative estimate based on the material before us. Necessarily, arriving at the alternative estimate will involve considering a range of assessment techniques. This includes examining the NSP's proposal and applying these assessment techniques. But, the end result will be a total forecast that we consider reasonably reflects the expenditure criteria. Our forecast may not match the NSP's forecast. However, by comparing our forecast to the NSP's forecast, we can form a view as to whether or not we consider the NSP's forecast reasonably reflects the expenditure criteria.

Given this, if a NSP's forecast is greater than our estimate, it will not, by definition, reasonably reflect the expenditure criteria. As the AEMC observes, there will likely be a certain margin of difference between the NSP's forecast and our forecast within which we could form the view that the NSP's forecast is acceptable.[159] In addition, the NSP may be able to adequately explain any apparent differences between its forecast and our estimate. However, this is something that we can determine only on a case by case basis, using our regulatory judgment. We (and consumer representatives) consider this approach is consistent with the NER.[160]

Detail on techniques, information requirements and principles

Some submissions considered that the Guideline does not explain the circumstances in which we will use each technique and information requirement to assess expenditure, the specific process we will follow and the weightings we will apply to each technique.[161] Some submissions also expressed concern that we will 'cherry pick' results of certain techniques to arrive at the lowest cost outcome.[162]

We consider it is not possible or desirable to embed this level of detail in the Guideline because we cannot know exactly how we will assess a NSP's proposal until we have seen it, along with any other information we require NSPs to provide. The exact manner in which we apply our techniques to reach a view on the reasonableness of a NSP's total capex or opex forecast is a matter for us to determine on a case by case basis. AEMO agrees that it is not in the interests of consumers or the AER to commit to a detailed assessment methodology before the relevant issues are understood.[163]

Further, it would not be sensible to use the Guideline to potentially constrain our discretion given the changes to NER specifically gave us more discretion than we have had in the past.[164] Some stakeholders agree that the Guideline strikes the appropriate balance between flexibility and certainty

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158 NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).

159 AEMC, *Rule determination*, 29 November 2012, p. 112.

160 For example, Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 9.

161 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 6–7; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 4; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 3, 7–8; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 4–5.

162 For example, CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 4–5, Huegin Consulting Group, *Submission of the AER expenditure guidelines – a review of the benchmarking techniques proposed*, 20 September 2013, p. 7.

163 Australian Energy Market Operator, *AEMO submission on AER on expenditure forecast assessment guidelines*, 23 September 2013, p. 3.

164 AEMC, *Rule determination*, 29 November 2012, p. 106.

by explaining our general approach in light of the requirements of the NEL and NER.[165] PIAC also raises an additional point about certainty, with which we agree:[166]

> [I]n the past, consumers have had to bear all the uncertainty about the proposed forecasting methodologies put forward by the NSPs and there was minimal transparency about the reasons for these differing methodologies or consideration of the long-term interests of consumers.

Stakeholders raised concerns about cherry picking in earlier consultation, and we addressed them in the explanatory statement for the draft Guideline[167] as well as our earlier Issues Paper.[168] We recognise that a NSP is unlikely to appear efficient or out-perform its peers in every element of service delivery or in assessment technique we employ. There may also be a reasonable basis for differences in benchmarking results between NSPs. The Guideline and this explanatory statement make clear that we will be taking a holistic approach to assessing expenditure. We will rely on several techniques for our assessment when they complement each other.[169]

This will depend on the proposal we are assessing, but typically, we expect we would apply a filtering process, where high level techniques indicate relative efficiency and particular areas to target for further review.[170] This does not necessarily mean that we will only use benchmarking in the first pass approach, nor does it mean we will not conduct more detailed investigation if the NSP 'passes' the first pass approach.[171] For example, we can also use the lower level techniques as a check on the results that our high level techniques show.

Accordingly, although we have made some minor amendments to the general approach in the Guideline, we have not significantly increased the level of detail.

Submissions regarding the assessment principles, were somewhat unclear. On the one hand, they considered the principles did not 'give primacy to the NER',[172] but on the other, they considered we should include the principles in the Guideline.[173]

We do not agree that the assessment principles interfere with the NER assessment framework. The assessment principles are a means of articulating what we consider is relevant when deciding how

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165 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 10; AEMO, p. 3.

166 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 10.

167 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013., p. 41.

168 AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 30.

169 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 10–11.

170 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 43.

171 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 11.

172 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 6–7; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 4; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 3, 7–8; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 4–5.

173 For example, APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013, p. 1; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 19; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 17; Ergon Energy Corporation Limited, *Submission on the Better Regulation Expenditure Forecast Assessment Guideline for Electricity Transmission and Distribution*, 20 September 2013, p. 4; SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1.

much to rely on approaches and assessment techniques to fulfil our obligations under the NER. We will use these principles in exercising our discretion when considering the extent that NSPs' forecasts or our alternative forecasts reasonably reflect the expenditure criteria. The principles are not additional hurdles to overcome and they cannot—nor do we intend for them to—replace the NER requirements. As PIAC notes, the principles exist to provide some reassurance to NSPs and stakeholders of the rigour and transparency that we apply.[174]

However, given we discuss the assessment principles in the explanatory statement for the Guideline, we have also decided to include them in the final Guideline. We discuss assessment principles further in section 5.5.

4.2.4 Importance of NSPs' circumstances

In response to the explanatory statement for the draft Guideline, some submissions considered that the Guideline does not adequately recognise the individual circumstances of NSPs. They consider we have misinterpreted the AEMC's intention behind removing the specific requirement to consider individual circumstances from the expenditure criteria.[175] Relevantly, the AEMC noted that removing the 'individual circumstances' clause does not enable us to disregard the NSP's circumstances.[176]

> Under the first expenditure criterion the AER is required to accept the forecast if it reasonably reflects the efficient costs of achieving the opex objectives. These include references to the costs to meet demand, comply with applicable obligations, and maintain quality, reliability and security of supply of services and of the system. These necessarily require an assessment of the individual circumstances of the business in meeting these objectives. So to the extent that different businesses have higher standards, different topographies or climates, for example, these provisions lead the AER to consider a NSP's individual circumstances in making a decision on its efficient costs.

We agree with the AEMC's view, but do not consider that we are disregarding NSPs' individual circumstances. Our approach is to examine the costs the objective prudent and efficient operator requires to achieve the expenditure objectives (as the capex and opex criteria require). To the extent certain exogenous factors specific to a NSP might impact on the costs of the objective prudent and efficient operator, we will need to take those factors into consideration.[177]

However, this does not mean that NSPs cannot be benchmarked. It was not the intention of the AEMC that the individual circumstances of NSPs restrict our ability to benchmark. Rather, it was to ensure that, while we have discretion as to when and how we use benchmarking in decision-making, we do so with the knowledge that there will be exogenous factors we may need to take into account.[178] For this purpose, we are collecting information about NSPs' operating environments and cost drivers to determine the exogenous factors we consider are relevant to benchmarking or otherwise assessing expenditure.

174 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 10.

175 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 2, 14–15; ActewAGL, *Response to AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 3; Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 8–9.

176 AEMC, *Rule determination*, 29 November 2012, p. 107.

177 AEMC, *Rule determination*, 29 November 2012, pp. 107, 113.

178 AEMC, *Rule determination*, 29 November 2012, pp. 107, 113.

4.2.5 Transmission Guideline

Grid Australia supports our decision to produce a separate Guideline to apply to TNSPs but considers the TNSP Guideline does not go far enough to account for the differences between DNSPs and TNSPs.[179] For example, Grid Australia considers the TNSP Guideline should acknowledge that:[180]

- economic benchmarking is not appropriate for TNSPs
- the assessment techniques applicable to TNSPs are those provided by Grid Australia in its 'straw man' guideline.

Grid Australia further suggests that the approach to assessing TNSPs should be the same as the AER's existing approach to transmission, but note that improvements can, and should, be made over time.[181]

While we do not agree with all of Grid Australia's suggestions (which we discuss further in Appendix A), we consider the final TNSP Guideline better accounts for differences between DNSPs and TNSPs. For example, the TNSP Guideline acknowledges that we are likely to continue to rely on detailed project review (to a greater extent than we will for DNSPs). We have also ensured the final Guideline includes TNSP specific data requirements and the capex assessment approach includes the TNSP-specific cost estimation risk factor. We are also not applying the augex model to TNSPs.

However, we have not otherwise limited our approach to assessing TNSPs. We consider that the assessment techniques we will apply to DNSPs are also applicable to TNSPs. The extent we decide to rely on our techniques when we assess a TNSP's (or a DNSP's) expenditure proposal will necessarily depend on the information we have before us when we assess the proposal. We will not pre-emptively rule out applying particular techniques in advance of receiving this information.

As we explain in section 2.3 and in the explanatory statement for the draft Guideline,[182] the Guideline development process has provided us with an opportunity to improve our approach to assessing expenditure. It would be a backwards step to continue to apply our existing approach given we have already identified several ways of improving it.

4.2.6 Guideline content

Several submissions proposed we could improve the content included in the Guideline. For example, some stakeholders considered we should include:

- a five year term for when we would revise the Guideline[183]
- substantive content about our assessment approach[184]

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179 Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 6.

180 Grid Australia, Grid Australia submission on AER draft expenditure forecast assessment guidelines, 20 September 2013, pp. 6–12.

181 Grid Australia, Grid Australia submission on AER draft expenditure forecast assessment guidelines, 20 September 2013, p. 6.

182 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. vii.

183 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 30; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 3; SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 4.

- only those assessment techniques that we are capable of applying[185]
- statements consistent with the explanatory statement.[186]

In addition, some submissions queried whether the Guideline would specify an approach to assessing debt and equity raising costs.[187]

Term for revision

We do not agree with submissions that the Guideline requires a five year term for revision.[188] Given that we have developed the Guideline to be flexible in terms of the assessment techniques we will apply, they may be relevant for several rounds of resets. Alternatively, if we decide that the Guideline does require amendment, we can instigate a formal revision process at any time, rather than restricting the process to a five year term. Other stakeholders support this approach.[189]

Substantive content on assessment approach

Some submissions suggest we should move some of the substantive content that exists in the explanatory statement into the Guideline. Such content includes:[190]

- the first pass approach
- assumptions on which we base our general approach
- our approach to assessing:
    - related party margins
    - real price escalation
    - step changes
    - interconnections between assessment techniques
- our approach to undertaking ex-post reviews.

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184 For example, Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 28–29; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 18–21; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 5; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2.

185 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 3–4.

186 For example, Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 18–23.

187 Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 18; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 12.

188 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 30; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 3; SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 4.

189 For example, Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, p. 23.

190 For example, Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, pp. 28–29; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 18–21; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 5; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2.

We agree with each of these suggestions and the final Guideline includes further content on these matters.

The ENA also submitted that the Guideline should clarify the sequencing of information provision and decision making for all parties. For example, they should be explicit about the matters in the expenditure assessment process that will not be specified in the Guideline but will be later addressed in the F&A paper or at the draft decision stage.[191]

While we see merit in further explanation of process, we consider the appropriate place for such discussion is this explanatory statement rather than the Guideline itsself. Chapter 7 contains some further detail on the sequencing of information provision and decision making. We have, however, included a high level typical assessment process diagram in the Guideline, based on attachment 3 to the ENA's submission.

As for matters that will not be specified in the Guideline, it is difficult to provide guidance on this. We will use the Guideline as the basis for assessing expenditure. We would typically depart from the Guideline only in circumstances where a NSP's proposed forecasting approach or regulatory proposal leads us to determine that we should depart from the Guideline. This could be the manner in which the Guideline applies to the NSP (at the F&A stage) or the approach we decide to take to assess a NSP's regulatory proposal (following submission by the NSP).

However, other circumstances could arise that may cause us to depart from the Guideline, but these circumstances may not become apparent until they actually occur. In any event, the NER allow us to depart from the Guideline as long as we provide reasons for doing so.[192]

Limited assessment techniques

The Victorian DNSPs consider that the Guideline should focus only on assessment techniques that we can employ in upcoming determinations rather than techniques we intend to apply at some point in the future.[193] The Victorian DNSPs also consider that the Guideline is misleading because it suggests that we could employ economic benchmarking techniques now when the explanatory statement for the draft Guideline suggests 'it is unlikely' we will rely on these techniques in the short term.[194]

We do not agree with this submission. First, it is not sensible to limit the techniques we can apply to assess expenditure when the current version of the NER provide us with greater discretion than in the past. Our flexible approach to techniques is consistent with NER requirements. We must use the Guideline to specify the assessment approach we propose to use and the information we require, but the Guideline need not contain further detail.[195] The AEMC also clarifies that the techniques we include in the Guideline are not an exhaustive list. We may use additional assessment techniques after reviewing the NSP's regulatory proposal if necessary.[196] As mentioned above, several stakeholders also support our flexible approach.[197]

191 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 29.

192 NER, clauses 6.2.8(c) and 6A.2.3(c).

193 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 1–4.

194 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 1–4.

195 NER, clauses 6.4.5(a) and 6A.5.6(a).

196 AEMC, *Rule determination*, 29 November 2012, p. 109.

197 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1; Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program –*

Second, contrary to the Victorian DNSPs' view, the explanatory statement for the draft Guideline did not state that it is unlikely we will rely on economic benchmarking in the short term. We said that we 'may not rely on some techniques' or 'may place less weight on them'. However, we did not specifically refer to 'economic benchmarking techniques'. Indeed, in the same section referred to by the Victorian DNSPs, we state that we intend to rely more on high level techniques than we have in the past.[198]

Elsewhere in the explanatory statement for the draft Guideline, we stated that it may not be appropriate to use stochastic frontier analysis (SFA)—one type of economic benchmarking—until we can obtain more robust data.[199] But we did not rule out using SFA later, and we have intentionally drafted the Guideline to accommodate refinements to our approach. Further, Appendix A of the explanatory statement for the draft Guideline was quite clear that we will use economic benchmarking going forward. Accordingly we do not consider the draft or final Guidelines are misleading.

Consistency with explanatory statement

We agree that the Guideline ought to be consistent with certain key statements from the explanatory statement for the draft Guideline, including:[200]

- we are unlikely to determine forecast expenditure is prudent and efficient if it is not supported with adequate economic justification
- our approach to assessing capex has changed significantly from our past approach.

The final Guideline reflects these statements.

Debt and equity raising costs

The Guideline does not include an approach for debt and equity raising costs. At workshops carried out as part of the Guideline development process, stakeholders suggested it would be more appropriate for the AER to consider these costs in the rate of return Guideline work stream.

However, in the consultation paper for the rate of return draft Guideline, we decided that from a cost-benefit perspective, it is not appropriate to calculate a specific allowance for debt and equity raising costs due to their low materiality. Rather, it would be more appropriate to remunerate these costs elsewhere in revenue building blocks such as through the estimates of the return on debt and return on equity or incorporation into capex and/or opex allowances.[201]

Therefore, these costs are not material enough to warrant specific consideration in Guideline, but NSPs will be free to propose these costs for assessment in their revenue proposals.

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response to draft expenditure forecast assessment guideline for electricity distribution, 1 October 2013, p. 3; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 9–10; Australian Energy Market Operator, *AEMO submission on AER on expenditure forecast assessment guidelines*, 23 September 2013, p. 3.

198 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, pp. 75–76.

199 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 53.

200 For example, Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 18–23.

201 AER, *Better Regulation: Rate of return guidelines: Consultation Paper*, May 2013, pp. 62–64.

5 Assessment approach

This chapter outlines our assessment approach, in light of the NEL and NER requirements discussed in chapter 3. The following sections of this chapter explain:

- our general approach and assumptions
- our approach to assessing opex
- our approach to assessing capex
- assessment techniques
- assessment principles.

5.1 Proposed general approach

For both capex and opex proposals, we propose to apply the same general approach to assess a NSP's forecasts. This general approach enables us to either accept the NSP's proposal or not accept it and substitute it with an alternative estimate.[202] In doing so, the NER require that we will examine the NSP's proposal and other relevant information.[203] The propose-respond framework necessitates that we commence our assessment with the NSP's proposal.[204] However, if we do not accept that a NSP's proposal reasonably reflects the expenditure criteria, the NSP's proposal is not a constraint to determining a substitute.[205]

We will typically compare the NSP's total forecast with an alternative estimate that we develop from relevant information sources. To calculate this alternative estimate we will consider a range of assessment techniques. Some of our techniques will assess the NSP's forecast at a total level; others will assess components of the NSP's forecast. Our estimate is unlikely to exactly match the NSP's forecast. However, by comparing it to the NSP's forecast, we can form a view as to whether or not we consider the NSP's forecast reasonably reflects the expenditure criteria.

Therefore, if a NSP's total capex or opex forecast is greater than the estimates we develop using our assessment techniques, and there is no satisfactory explanation for this difference, we will form the view that the NSP's estimate does not reasonably reflect the expenditure criteria. In this case, we will substitute our own estimate that does reasonably reflect the expenditure criteria. If our estimate demonstrates that the NSP's forecast reasonably reflects the expenditure criteria, we will accept the forecast.[206] Whether we accept a NSP's forecast or do not accept it, we will provide the reasons for our decision.[207]

When we develop alternative estimates as a means of assessing a NSP's proposal, we will generally develop an efficient starting point or underlying efficient level of expenditure. We then adjust this for changes in demand forecasts, input costs and other efficient increases or decreases in expenditure,

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202 NER, clauses 6.5.6(c), 6.5.6(d), 6.5.7(c), 6.5.7(d), 6.12.1(3), 6.12.1(4), 6A.6.6(c), 6A.6.6(d), 6A.6.7(c), 6A.6.7(d), 6A.14.1(2) and 6A.14.1(3).
203 For example, NER, clauses 6.11.1(b) and 6A.13.1(a1).
204 AEMC, *Rule determination*, 29 November 2012, pp. 111–112.
205 Past versions of the NER required that we determine substitute amounts on the basis of the NSP's regulatory proposal, and amended from that basis only to the extent necessary to enable it to be approved in accordance with the NER. This requirement no longer exists. NER, clause 6.12.3 and AEMC, *Rule determination*, 29 November 2012, pp. 111–112.
206 NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c) and 6A.6.7(c).
207 NER, clauses 6.12.2, 6A.14.2.

allowing us to construct a total forecast that we are satisfied reasonably reflects the expenditure criteria.

For recurrent expenditure, we prefer to use revealed (past actual) costs as the starting point for assessing and determining efficient forecasts. If a NSP operated under, and responded to, an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future. The ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's allowance) because NSPs can retain a portion of cost savings made during the regulatory control period. However, the incentive to spend less than our allowance must not be to the detriment of the quality of the services the NSP supplies.

Consequently we apply various incentive schemes (the efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) and, going forward, the capital expenditure sharing scheme (CESS)) to provide NSPs with a continuous incentive to improve their efficiency in supplying electricity services to the standard demanded by consumers (as explained in chapter 3). We discuss incentive frameworks in more detail in chapter 6.

While we examine revealed costs in the first instance, we must test whether NSPs have responded to the incentive framework in place. That is, we must determine whether or not the NSP's revealed costs are efficient. For example, whether the NSP's past performance was efficient relative to its peers and whether the NSP has improved its efficiency over time. For this reason, we will assess the efficiency of base year expenditures using our techniques, beginning with economic benchmarking and category analysis, to determine if it is appropriate for us to rely on a NSP's revealed costs.[208]

We rely on revealed costs for opex to a greater extent than for capex because we consider opex is largely recurrent. Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes or needs. This issue may be magnified for TNSPs, who tend to commission smaller volumes of large, high cost projects. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across NSPs) when forming a view on forecast unit costs.

Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements, including utilising our repex model and other information.

However, capex is not currently subject to an incentive scheme like the EBSS. This means that even if past actual expenditures and volumes indicate a particular NSP's likely future expenditure, we cannot presume it is efficient. We are implementing a CESS, which may mitigate this issue to some extent. Consequently, and given the presence of non-recurrent expenditures, our assessment approach is typically more detailed for capex than for opex. It may be necessary to review projects and programs to inform our opinion on total forecast capex (especially for TNSPs).

Our approach for both opex and capex will place greater reliance on benchmarking techniques than we have in the past. We will use benchmarking to determine the appropriateness of revealed costs, for example. We will also benchmark NSPs across standardised expenditure categories to compare relative efficiency.

[208] Attachments A to C explain in detail how we will conduct economic benchmarking and category analysis.

In some cases, we may determine that an efficient total capex or opex allowance is significantly below what the NSP has historically spent. Some stakeholders submitted that if we significantly reduce a NSP's allowance, it may not be realistic for the NSP to make the necessary efficiency savings immediately; rather, a period to transition to the efficient level would be appropriate.[209] We disagree that such an approach is warranted and so do some stakeholders.[210]

We must be satisfied that the opex or capex forecast reasonably reflects the efficient costs of a prudent operator (not the NSP in question), given reasonable expectations of demand and cost inputs, to achieve the expenditure objectives (taking account of appropriate differences in operating environments). If the prudent and efficient allowance to achieve the objectives is significantly lower than actual past expenditure, a prudent operator would take the necessary action to improve its efficiency. That is, mirroring what would be expected under competitive market conditions, we would expect NSPs (including their shareholders) to bear the cost of any inefficiency rather than passing this onto consumers through inefficient or inflated prices. It is up to the NSP in question to determine how best to manage its costs within the efficient revenue allowances we set.

5.1.1 Assumptions

Our general approach is based on two assumptions:

- the efficiency criterion and the prudence criterion in the NER are complementary
- past expenditure was at least sufficient to achieve the expenditure objectives in the past.

Efficiency and prudence are complementary

We consider that efficient costs complement the costs that a prudent operator would require to achieve the expenditure objectives.[211] Prudent expenditure is that which reflects the best course of action, considering available alternatives. Efficient expenditure results in the lowest cost to consumers over the long term. That is, prudent and efficient expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.

Some past regulatory proposals posited that a prudent operator would apply a premium above efficient costs to balance risk.[212] We do not agree that such an approach is consistent with the NEO. Our view is that risks ought to be borne by those best placed to meet them, and consumers are not best placed. In addition, the weighted average cost of capital compensates NSPs for non-diversifiable risk, so it is not appropriate to charge consumers a further premium on prices.

Past expenditure was sufficient to achieve the objectives

When we rely on past actual expenditure as an indication of required forecast expenditure, we assume that the past expenditure incurred by the NSP was sufficient for it to achieve the expenditure objectives. That is, the NSP's past expenditure was the amount required to manage and operate its network at that time, in a manner that achieved the expenditure objectives.

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209 Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 16–17.

210 For example, Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 13–14.

211 See, for example, AER, *Final decision: Victorian distribution determination*, October 2010, p. 313; AER, *Draft decision: Aurora Energy distribution determination*, November 2011, pp. 111, 156.

212 AER, *Final decision: Victorian distribution determination*, October 2010, p. 313.

When we make this assumption, expenditure forecasts need to account for changes to the assumed efficient starting point expenditure. Accounting for such changes (including in demand, input costs, regulatory obligations and productivity) ensures the NSP receives an efficient allowance that a prudent operator would require to achieve the expenditure objectives for the forthcoming regulatory control period.

5.1.2 Assessment approaches common to opex and capex

When considering whether capex and opex forecasts reasonably reflect the expenditure criteria, we apply certain assessment approaches and use a variety of assessment techniques. Some of the approaches are specific to capex or opex. Others are common to capex and opex assessment. For example, for both capex and opex, we will always consider whether:

- forecasts are supported by economic analysis
- related party margins impact on forecast expenditure
- adjustments are required for real price escalation
- adjustments are required for efficient increases or decreases in expenditure (step changes).

The remainder of this section explains these common approaches in detail. We outline opex-specific and capex-specific approaches in sections 5.2 and 5.3. Section 5.4 contains detailed explanation of our assessment techniques, which are:

- benchmarking (economic techniques and category analysis)
- predictive modelling
- trend analysis
- governance reviews
- methodology reviews
- cost–benefit analysis
- detailed project review (including engineering review).

Economic justification for forecast expenditure

AER position

Without adequate economic justification, we are unlikely to determine forecast expenditure is efficient and prudent. By economic justification, we mean that a DNSP must demonstrate that it is making expenditure decisions under a quantitatively-based economic framework consistent with minimising the long run cost of achieving the expenditure objectives.

Reasons for AER position

Economic justification may be more or less detailed, depending on the value of the expenditure and the uncertainty around the expenditure decision. However, in all cases it should at least demonstrate that the forecast expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives (is prudent and efficient). While not exhaustive, economic justification could include outputs from the following techniques (that will often be used in combination):

- predictive modelling (to demonstrate forecast costs and volumes are required to achieve the expenditure objectives)
- trend analysis (to demonstrate forecast costs and volumes are in line with past works to achieve the expenditure objectives)
- benchmarking (to demonstrate forecast volumes and/or costs are in line with outcomes achieved by other firms)
- documentation explaining procurement procedures (to demonstrate forecast volumes and/or unit costs reflect a competitive market outcome)
- engineering analysis (to demonstrate efficient and prudent expenditure options were considered when determining final projects)
- cost–benefit analysis (to demonstrate the expenditure gives the highest net benefit to achieve the outcomes desired). This will be consistent with the lowest net cost in present value terms for a given outcome. Cost–benefit analysis should also show the expenditure is cost–benefit positive unless the expenditure is legally required irrespective of the net benefit.

Generally, we consider it is likely cost–benefit analysis will be required for all material step changes and for the majority of significant capex (including material expenditure decisions related to relatively recurrent capex), particularly where RIT-T or RIT-D requirements apply.

Some examples of information we will require from NSPs to support their proposals includes:

- clear economic analysis justifying the forecast expenditure based on need or driver, including explicit considerations of efficiency over the long term and how expenditures will deliver value for consumers. NSPs must demonstrate that material expenditure decisions (including expenditure options selected) are prudent and efficient
- explanation of why forecast expenditure materially differs from their historical expenditure (once adjusted for changes in the volume or nature of works)
- demonstration that efficient work and efficiency trade-offs have been made, particularly with respect to choices between opex and capex
- information on forecast changes in network condition and reliability given forecast work volumes.

Related party margins

This section considers issues with assessing the efficiency of forecast expenditures that involve related parties. The Expenditure Incentives Guideline explains how we will treat related party margins actually paid, as it relates to calculating a NSP's regulatory asset base.

NSPs may outsource activities to external parties to make up for a lack of internal expertise or to access economies of scope and other efficiencies (among other reasons). These external parties may be completely independent of the NSP, or they may be separate legal entities related to the NSP through common ownership ('related parties'). In some cases, a related party arrangement might exist because the parties were related at the time the outsourcing transaction was made and this arrangement is difficult to unravel.

Outsourced activities are mostly network operating/maintenance and corporate services, but may also include activities related to capex, such as equipment maintenance or asset management.

In cases of related party outsourcing, the NSP's expenditure forecasts may be based on charges paid (or to be paid) to related parties. These charges may include a margin above the direct costs incurred (or to be incurred) by the related party. Generally, we have concerns with these arrangements because NSPs may not face appropriate incentives to seek the lowest cost in negotiation with their related parties. Rather, they have an incentive to retain efficiency and other gains within the common ownership structure and to not share these with their customers.

AER position

We propose to use a two stage approach to assess related party contracts and margins. Our approach is based on our Victorian gas access arrangement review (GAAR) determination in March 2013.[213]

Reasons for AER position

In the recent determination for the Victorian 2013–17 gas access arrangements, we used a conceptual framework to assess proposed expenditure that included related party contracts. The framework adopted a two-stage process for assessing such contracts.[214] We will use this same approach to assess related party contracts and margins for electricity transmission and distribution.

The first stage acts as an initial filter. It determines which contracts it is reasonable to presume reflect efficient costs and costs that would be incurred by a prudent operator—the 'presumption threshold'. In assessing this presumption threshold, we consider two relevant questions:

- Did the NSP have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent renegotiation)?[215]
- If yes, was a competitive open tender process conducted in a competitive market?

The second stage depends on the outcome of the first stage. If a NSP has no incentive to agree to non-arm's length terms, or obtains an outsourcing arrangement through a competitive market process, we consider it reasonable to presume that the contract price reflects efficient costs and is consistent with the NEL and NER.[216]

However, if the outsourcing arrangement was not competitively tendered, we do not consider it reasonable to assume that costs within such agreements are efficient. Such circumstances (non-arm's length, non-competitive) might influence a NSP to artificially inflate expenditures, particularly via the addition of profits or margins in addition to expenditures for direct and indirect cost recovery.[217] In such cases, we consider it necessary to investigate in more detail outsourcing arrangements that fail the presumption threshold. Specifically, we will consider whether:

- the total contractual cost is prudent and efficient

[213] AER, *Draft decision: Victorian access arrangement 2013–17, Part 3 Appendices*, September 2012, pp. 103–104.
[214] See: AER, *Draft decision: Envestra 2013–17, Draft decision appendices, Appendix E*, 24 September 2012, pp. 101–116.
[215] An indicator of potential incentives to agree to non-arm's length terms includes situations when the contract was entered into (or renegotiated) as part of a broader transaction.
[216] The AER's reasons for presuming certain outsourcing arrangements obtained through a competitive market process are efficient and prudent are discussed in AER, *Final decision: Victorian distribution determination*, October 2010, pp. 163–303.
[217] AER, *Final decision: Victorian distribution determination*, October 2010, p. 150.

- outsourcing accords with good industry practice
- the costs within the contract relate wholly to providing the regulated service
- there is any double counting[218] of costs within the contract.

Overall assessment of contracts that fail the presumption threshold will address the following questions:

- Is the margin efficient?—The forecast costs incurred via the outsourcing arrangement are efficient if the margin above the external provider's direct costs is efficient. We consider a margin is efficient if it is comparable to margins earned by similar providers in competitive markets.
- Are the NSP's historical costs efficient?—We will benchmark the NSP's historical costs against those of other NSPs to form a view on whether the NSP's historical costs are efficient and prudent.

Efficient costs are those expected costs based on outcomes in a workably competitive market. We will need complete information on contracts that fail the presumption threshold to determine whether they reflect such efficient costs.[219] In line with our category analysis, we require NSPs to provide the total contract price and, for related party contracts, the related party's profit margin. NSPs already engaged in related party contracts are required to provide us with expenditures including and excluding margins. In contracts where the contractor's margin is not explicit, we will consider supporting information (see below) to examine the nature of the contracting terms and arrangements. For example, the contractor's margin on top of its direct costs may be expressed in alternative terms such as management fees or incentive payments, and we will examine these fees or payments.

We will also require NSPs to provide other supporting information that justifies the efficiency of costs under these contracts, as well as information relevant to satisfying our presumption threshold, including:

- details/explanation of the NSP's ownership structure
- a description of the tender processes, including tender documents, bid details and tender evaluation
- a description of outsourcing arrangements
- justification of amounts paid to related parties (for example, a consultant's report on benchmarking of margins)
- copies of related party contracts
- probity reports by an external auditor on the NSP's tender process.

As we already applied this assessment approach in previous determinations,[220] we believe the approach is transparent and well-understood. In future resets, we will assess outsourcing contracts

[218] This could occur where services provided under the contract include cost categories the NSP is also seeking an allowance for elsewhere in its regulatory proposal, or where there has been a transfer of risk to the contractor without a commensurate reduction in risk compensation in other elements of the NSP's building block proposal.

[219] We will assess individual contracts that fail the presumption threshold, but will have regard for materiality in terms of the total contract price and the scope/scale of services.

[220] AER, *Draft decision: Victorian access arrangement 2013–17, Part 3 Appendices*, September 2012, pp. 103–104.

using the same approach whilst consulting with NSPs and having regard to information confidentiality requirements of the NER.

Our examination of related party contracts as a specific cost item also relates to new NER requirements for treating capitalised related party margins when rolling forward the regulatory asset base (RAB).[221] Previously, all capex incurred was rolled into the RAB. Under the new NER, as part of ex post reviews of capex—which are required if a NSP's expenditure exceeds its forecast—we may exclude from the RAB capitalised related party margins that we assess as inflated or inefficient.[222] Our approach to exclude margins from the RAB should be consistent with that applied when examining forecast amounts. We address this in the Expenditure Incentives Guideline.

Submissions to the draft Guideline suggested that weaknesses in a NSP's open tender process may not be apparent to the AER, or that the supplier market may not be workably competitive. COSBOA expressed concerns that tenders and tender processes can contain flaws and omissions which provide an opportunity for a NSP to inflate costs. This may result in a tender price that is not a good proxy for a competitive market price.[223]

PIAC commented that services are outsourced to a relatively small field of registered service providers, and usually on a confidential basis for the long-term delivery of multiple services. This creates barriers to switching to, and barriers to entry for, lower cost and more innovative suppliers, leading to a limited market of suppliers.[224] PIAC acknowledged the benefits of outsourcing; however, it argued that even contracts that have been tendered openly should not be assumed to reflect efficient prices. It therefore supports the application of benchmarking to outsourced contract prices.[225]

Our approach is based on our GAAR determination which amended our previous approach in the Victorian electricity determination (2010)[226] and the South Australia/Queensland GAAR.[227]

Our South Australia/Queensland GAAR decision was tested in the Tribunal in a merits review of, among other things, our decision on outsourcing arrangements. The Tribunal found that our decision that a detailed analysis of the outsourcing contract[228] was required, was "entirely appropriate", given incentives for non-arm's length arrangements.[229] The Tribunal also considered that the two-stage test may be an appropriate vehicle for this type of analysis.[230]

For the reasons set out above, we will continue with a two-stage approach in assessing outsourcing contracts. Where contracts fail the first stage, we will review them in detail. Detailed assessments will include benchmarking to determine the efficient expenditure allowance, an assessment approach supported by the MEU.

221 NER, clauses S6.2.2A and S6A.2.2A.
222 NER, clauses S6.2.1(g), S6.2.2A, S6A.2.1(g) and S6A.2.2A.
223 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 6.
224 Public Interest Advocacy Centre, *A firm basis: submission to the AER's Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, p. 19.
225 Public Interest Advocacy Centre, A firm basis: submission to the AER's Draft Expenditure Forecast Assessment Guidelines, 20 September 2013, p. 19.
226 AER, *Final decision: Victorian distribution determination*, 29 October 2010, pp. 298–303.
227 AER, *Draft decision: Queensland gas access arrangement review final decision 2011–16*, February 2011, pp. 131–136; and AER, *Final decision: Envestra Ltd, Access arrangement proposal for the SA gas network, 1 July 2011–30 June 2016, June 2011, Appendix C, pp. 232–244.*
228 Envestra SA's outsourcing contract with the APA Group.
229 Application by Envestra Limited (No 2) [2012] ACompT 3 at [253].
230 Application by Envestra Limited (No 2) [2012] ACompT 3 at [267].

In the first instance, we consider that the contract price is likely to be a good proxy for the competitive market price if the outsourced services were subject to a competitive tender process. If the outsourced services were provided via competitive tender in a competitive market, there can be a reasonable degree of assurance that these services are being provided efficiently, and that the prices charged for these services reflect a competitive market price.

However, if we have cause to consider that there were deficiencies in the tender process or that the supplier market is not workably competitive, we will move away from this presumption and conduct further detailed examination, and benchmarking.

Real price escalators

Input prices paid by NSPs may not change at the same rate as the consumer price index. In recent years, strong competition for labour from related industries (such as the mining sector) resulted in strong labour price growth in many states. The commodities boom also saw the price of raw materials rise significantly. This in turn influenced the prices of the materials purchased by NSPs. Further, the Australian dollar has been at record highs until recently, lowering the price of imports. All of these factors, and others, have made it more difficult to forecast the costs NSPs face for the inputs they use.

AER position

Our preferred approach to assessing labour price changes over the forecast period is to use the wage price index (WPI) published by the Australian Bureau of Statistics (ABS). The labour price measure should be consistent with the treatment of forecast productivity change. The net impact of labour price changes and labour productivity should reflect the pure price change. For opex, we will apply a single productivity measure in the forecast rate of change that accounts for forecast labour productivity changes (see section 5.3).

We expect NSPs to provide evidence in their regulatory proposals of the materials costs they paid. NSPs must demonstrate the proposed approach they chose to forecast materials cost changes reasonably accounted for changes in prices they paid in the past. Without this evidence it is unlikely we will be satisfied that the forecasts proposed produce unbiased forecasts of the costs the NSPs will pay for materials.

Reasons for AER position

Labour price changes

Labour costs represent a significant proportion of NSPs' costs and thus labour price changes are an important consideration when forecasting expenditure. This is particularly true for opex, which can mostly comprise labour costs. We expect the WPI[231] published by the ABS will remain our preferred labour price index to account for labour price changes over the forecast period.

When assessing the impact of labour price changes, it is important to distinguish between labour price changes and labour cost changes. To the extent labour prices increase to compensate workers for increased productivity, labour costs will not increase at the same rate since less labour is required to produce the same output. Consequently, unless labour productivity improvements are captured elsewhere in NSPs' expenditure forecasts, forecasts of changes in labour prices should be productivity adjusted. For the reasons discussed in section 5.3, our preferred approach is to apply a

231 Previously called the labour price index (LPI).

single productivity measure in the forecast rate of change. This productivity measure would include forecast labour productivity changes. Consequently forecast increases in the labour price would not need to be productivity adjusted under this approach.

Another important, and related, consideration is the choice of labour price measure, namely the WPI or average weekly ordinary time earnings (AWOTE), which is also reported by the ABS. One key difference between these two measures is the AWOTE measure includes compositional labour change. That is, AWOTE captures the price impact of using more or less higher skilled labour. We prefer to use the WPI because including compositional labour changes tends to increase the volatility in the AWOTE series, making it more difficult to forecast. We expect the WPI will remain our preferred labour price index. However, to the extent expenditure forecasts are adjusted using a productivity measure that matches the labour price measure, the impact of the labour price measure choice should be reduced.

A further consideration is the source of the forecasts used. The forecasts produced for the AER have often varied significantly from the forecasts produced for and proposed by the NSPs. We have tested the accuracy of labour price forecasts in the past and will continue to analyse the labour price forecasters' past performance when determining the appropriate labour price forecasts to rely on.

Materials price changes

Materials price changes are an important driver of costs, particularly capex, given their potential volatility. As Ergon Energy noted:

> Materials are often purchased on the basis of large, long-term contracts, and due to the specialised nature of the equipment, are exposed to currency and other fluctuations that will not necessarily align with local economic drivers.[232]

Further, the ENA noted the inputs used by the NSPs are often industry specific, so prices can diverge from the input prices of other industries.[233]

For a number of resets now, we (and NSPs) have used an input price modelling approach to forecast materials costs. This approach forecasts the cost of the inputs used to manufacture the materials (such as copper, aluminium and steel) and assigns input weightings to generate a forecast of the cost of those materials. Now that this forecasting approach has been in place for a number of years we think it is an appropriate time to review how well it has worked. Although evidence is readily available to assess the accuracy of our approach to forecasting input costs, we have seen limited evidence to demonstrate that the weightings applied have produced unbiased forecasts of the costs the NSPs paid for materials. We consider it important that such evidence be provided because, as stated by the ENA:

> …the changes in the prices of manufactured materials are not solely influenced by the changes in the raw materials that are used. Consequently, the price of manufactured network materials may not be well correlated with raw material costs.[234]

Consequently, we expect NSPs to provide evidence of the materials costs they paid in their regulatory proposals. They must demonstrate the proposed approach they chose to forecast materials cost changes reasonably reflected the change in prices they paid for materials in the past such that we can

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232 Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator,* 15 March 2013, p. 17.

233 Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, Attachment B, p. 9.

234 Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, Attachment B, p. 9.

determine whether NSPs' forecasts are reliable. NSPs should also explain why future price changes will be consistent with past price changes. Currently we are unable to determine whether or not forecasts are reliable because we have no way of testing the relationship between input costs and materials prices.

Step changes

We are required to determine capex and opex forecasts that reasonably reflect the efficient costs a prudent operator would require to achieve the expenditure objectives. The expenditure objectives include compliance with regulatory obligations or requirements. Regulatory obligations or requirements may change over time, so a NSP may face a step up or down in the expenditure it requires to comply with its obligations.

Another important consideration is the impact of the forecast capital program on opex (and vice versa), since there is a degree of substitutability between capex and opex. A NSP may choose to bring forward the replacement of certain assets (compared to its previous practice) and avoid maintenance expenditure, for example. Such an approach may be prudent and efficient.

AER position

Our likely approach is to separately identify and assess the prudence and efficiency of any forecast cost increases associated with new regulatory obligations and capex/opex trade-offs. We may use several techniques to do this, including examining the economic justification for the investment or expenditure decisions and technical expert review of the inputs into this analysis.

We will also consider whether the proposed step change is funded though other aspects of the expenditure allowance. For example, proposed step changes that improve efficiency should be funded through the costs avoided by the step change and the associated rewards from the CESS or EBSS. Also, opex step changes may not be required for new regulatory obligations if the rate of change incorporates forecast productivity change net of productivity losses due to regulatory change.

Reasons for AER position

To justify additional costs for a new regulatory obligation NSPs must show:

- there is a binding (that is, uncontrollable) change in regulatory obligations that affects their efficient forecast expenditure
- when this change event occurs and when it is efficient to incur expenditure to comply with the changed obligation
- the options considered to meet the change in regulatory obligations
- that they selected an efficient option—that is, the NSP took appropriate steps to minimise its expected cost of compliance from the time there was sufficient certainty that the obligation would become binding
- when they can be expected to make the changes to meet the changed legal obligations
- the efficient costs associated with making the step change
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts.

Forecast expenditure (including volumes and cost of different categories of works) related to any changes in obligations, or other step changes (for example, due to efficient capex opex trade-off), should be reported as such in the relevant category of opex and capex.

We consider the following general points can be made about our expected assessment of step changes:

- We will approve expenditure for works we consider can be completed over the regulatory period. This is consistent with our past approach where we have not approved expenditure to meet an obligation if we considered the NSP would be unable to meet the obligation within the regulatory period.
- We will only approve expenditure based on efficient timing of works. This is consistent with past decisions if we considered it inefficient to complete works over the regulatory period. Therefore, when there is a binding legal timeframe for compliance, NSPs should show they selected efficient expenditure timing to comply with the legal timeframe. Where obligations have no binding timeframe for compliance, works should be undertaken when efficient to do so.

We expect to make two changes to past assessment practice:

- Under the base-step-trend approach to setting opex, step changes caused by incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for high costs resulting from changed obligations. Under this approach, only changes in costs that demonstrably do not reflect historic 'average' changes will be compensated as separate step changes in forecast opex. An example of something demonstrably different would be the higher costs associated with vegetation management due to regulatory changes following the 2009 Victorian Bushfires Royal Commission.
- For category assessments generally (i.e. capex as well as base year opex), we will require NSPs to separately identify step changes for changes in obligations against the core expenditure categories (for example, augmentation, replacement, vegetation management). Previously, NSPs reported, and we assessed, some step changes as part of a separate environment, safety and legal expenditure category. We consider it is important to report and assess changes in obligations in the context of the core category they affect. This will ensure a consistent assessment approach is applied to all NSPs.

NSPs will be expected to justify the cost of all step changes with clear economic analysis, including quantitative estimates of expected expenditure associated with viable options. We will also look for the NSPs to justify the step change by reference to known cost drivers (for example, volumes of different types of works) if cost drivers are identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for NSPs to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

Stakeholders commented that the cost of a given change in obligations will differ between NSPs[235] and it can be difficult to capture the incremental cost of a change in obligations for an existing

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235 Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, p. 6; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator,* 15 March 2013, p. 16; CitiPower, Powercor Australia and SA Power Networks, *Joint*

activity.[236] Aurora commented that expenditure associated with a changed regulatory obligation cannot be disaggregated in a way that will improve accuracy in forecasting and efficiency assessments.[237] Grid Australia considered it would be difficult to determine sub categories of expenditure that will assist with forecasting changes in regulatory obligations, and individual businesses are best placed to identify the costs required to meet changes in obligations. It considered the AER should assess the impact of changes on TNSPs during a regulatory determination process based upon the individual circumstances of the TNSP and information provided by it.[238] The MEU commented that benchmarks need to be assessed on a common basis and therefore step changes must be identified and adjusted for in historical benchmarks. Adjusted benchmarks should then be refined as actual costs are revealed over time.[239] One NSP queried whether the short term costs to achieve dynamic efficiency gains could be claimed as step changes.[240]

NSPs also queried how the AER would measure the impact of ongoing changes in regulatory burden in historic data including:

- how to determine the 'base level' of regulation
- how to determine material increases in regulatory costs over time
- whether CPI could be used as a proxy for increases in regulatory burden over time.[241]

NSPs also queried whether they would be adequately compensated for all step changes if changes in regulatory burden over time were captured in the productivity measure.[242]

We consider the cost of a given change in obligations may differ between NSPs depending on the nature of the change. However, we expect the NSPs to justify their forecast expenditure and quantify the incremental costs associated with changes in existing obligations. Where step changes materially affect historical benchmarks we may make adjustments to the historical benchmarks to account for these changes.

Whether short-term costs to achieve dynamic efficiency gains should be allowed as step changes depends on NSPs already being adequately compensated for these costs under the regulatory regime, including via compensation under any incentive schemes. We expect NSPs to bear any short-term cost of implementing efficiency improvements in expectation of being rewarded through expenditure incentive mechanisms such as the EBSS.

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response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B – Category analysis, 15 March 2013, p. 6.

236 Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator,* 15 March 2013, p. 16; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B – Category analysis,* 15 March 2013, p. 6.

237 Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission,* 19 March 2013, p. 21.

238 Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper,* 15 March 2013, p. 38.

239 Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper,* 15 March 2013, pp. 35–36.

240 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 6.

241 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 6.

242 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, pp. 6–7.

To the extent that changes in regulatory burden are already compensated through the productivity measure, they will not be compensated again explicitly as step changes. We will consider what might constitute a compensable step change at resets, but our starting position is only exceptional events are likely to require explicit compensation if we use a productivity measure that captures regulatory change over time.

Where businesses do not justify step changes sufficiently, we may use the historical expenditure, adjusted for cost and volume drivers, as a basis for determining an efficient level of forecast expenditure if we consider this gives a reasonable estimate. NSPs will need to perform a cost–benefit analysis to show that meeting standards that have not been met before is efficient and prudent. If new smart electricity meters showed extra non-compliance with voltage standards relative to current reporting and investigation procedures, for example, we will be likely to require a cost–benefit analysis to show any augmentation (materially in excess of current levels) to comply with the current standards was efficient and prudent.

5.2 Capital expenditure approach

5.2.1 AER position

We intend to use a combination of top down and bottom up assessment to assess forecast capex. Broadly, we expect the capex assessment approach will use observable historic costs of the NSP and its peers, combined with technical advice and detailed project reviews, to estimate the efficient and prudent forecast expenditure an NSP will require to meet its legal obligations given its forecast investment drivers (expected demand growth, condition-based replacements, new connections, regulatory changes etc.) over the regulatory period.

Relative to prior assessments, we intend to use a broader range of assessment techniques and to collect consistent data to aid our assessment. We consider improved and standardised data will make these processes more effective and efficient when assessing forecast capex. We also consider some standardisation of process and data should make preparing and assessing revenue proposals simpler.

The key changes likely to affect the assessment of capex relative to the status quo are:

- a greater requirement for the economic justification of expenditure and increased data requirements to support proposals
- the use of top down economic benchmarking and greater category level benchmarking
- the introduction of the Capital Expenditure Sharing Scheme (CESS).

Elements of the capex assessment process will include:

- reviewing the economic justification for expenditure
- reviewing the expenditure forecasting methodology and resulting expenditure forecasts
- top down economic benchmarking
- reviewing governance and policies
- trend analysis
- category benchmarking

- targeted review of high value or high risk projects and programs
- sample review of projects and programs and applying efficiency findings to other expenditure forecasts.

Where our assessment finds the NSP's forecast is not adequately justified or inefficient, we will use our capex approach to estimate efficient and prudent expenditure and substitute this for the NSPs proposal. In arriving at a view of an efficient capex allowance, we will challenge the assumptions and other relevant aspects of the NSP's proposal using these techniques. We will present the results of analysis using our various techniques as appropriate through issues papers, benchmarking reports and ultimately in our draft and final decisions.

The remainder of this section covers developing expenditure categories based on cost drivers and assessing risk factors applicable to transmission capex forecasts. The techniques used in our assessments are covered in section 5.4. The overlap with the CESS is covered in chapter 6.

5.2.2 Reasons for AER position

Generally, we consider our approach and proposed processes and techniques should provide sufficient flexibility to allow the AER to undertake best practice regulatory assessment across the different capex categories. Where forecast expenditure is a relatively small amount, or relatively stable, simplified analysis such as trend analysis combined with an overview of governance procedures and potentially some high level benchmarking, is likely to be appropriate. However, where expenditure is relatively material or is not predictable over time, more detailed project review and rigorous benchmarking will be warranted.

We have not changed our proposed approach as articulated in the draft Guideline and supporting explanatory statement. While a number of submissions were received on the draft guideline, the AER does not consider any changes to the assessment approach are required. That said, we have been liaising with NSPs regarding the quantum of data required to support our capex assessment approach and are carefully considering the associated costs of regulatory compliance.

The EUAA generally supported the AERs' approach, the use of replacement and augmentation modelling, and its approach to benchmarking activity. The EUAA also supported leaving the precise approach relatively open, with room to move in the application and use of these methodologies.[243]

PIAC submitted that it supports the developments in capex and that the Draft Guideline appears to suggest the AER's approach has changed in line with the AEMC's reforms. However, it was concerned the statement by the AER that its 'general approach to assessing total forecast capex will not be significantly different from our approach in the past'[244] diluted the message of regulatory commitment of the AER to implement change.[245]

To clarify, we are strongly committed to implementing the changes outlined in the Final Guideline and supporting Explanatory Statement and these do represent a significant enhancement to our assessment approach. These include commitments to the collection and use of standardised data for category analysis (including benchmarking), and the requirement on NSPs to provide better quality

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243 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p.1.
244 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 12.
245 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 5, 21.

justifications for forecast capital expenditure. We have also removed the phrase quoted by PIAC from the Guideline. However, we remain of the view that, despite the materiality of the changes that are being made to capex assessment, the majority of the Guideline relating to capex assessment essentially reflects prior practice and as such should be relatively predictable.

While supporting the AER undertaking more rigorous capex assessment, COSBOA raised concerns about its detailed and intrusive nature at the lower level and the significant regulatory compliance that would be involved.[246] COSBOA submitted the capex approach will increase complexity for consumers and make the approach more difficult to understand.[247] COSBOA also submitted the AER has not been clear why it believes the benefits of the capex approach and collecting the necessary data will outweigh the costs.[248] While accepting the AER's judgment on these matters, COSBOA considered the AER should be prepared to review the approach and make adjustments where necessary.[249]

We acknowledge that more detailed information requirements will increase regulatory compliance costs somewhat and may increase the complexity of the regulatory process to some degree. However, we consider that increased compliance costs are justified given the large amounts of expenditure involved and given the relatively limited information previously available to the AER in the past. We are also mindful of ensuring consumers are effectively engaged in our expenditure assessment process through the publication of analysis in issues papers, benchmarking reports and in determinations. We will be liaising with the sector over the coming year to consider how best to release and package information to deal with a range of stakeholders, including NSPs and consumer representatives. Providing stakeholders with useful information (rather than just high volumes of raw data) enhances transparency, facilitates their own assessment of issues, and should generally enhance confidence in the regulatory regime.

The AER will also review and refine its assessment approach in an ongoing manner as appropriate, however we consider they are unlikely to change in the short term. This is because we have closely liaised with the sector in developing the Guideline over the last year and also sought to maintain some flexibility in our approach by specifying assessment categories and data requirements at a reasonably general level. There is also the need for regulatory stability and predictability and giving these approaches sufficient time to be fully tested before any substantial changes are made. That said, the supporting data requirements will be refined and updated as required on an ongoing basis.

NSWIC submitted that the Guideline should incorporate a regulated efficiency dividend for both capex and opex.[250]

We do not consider an explicit regulatory dividend is necessary as we will either implicitly or explicitly consider expected productivity gains when assessing forecast capex expenditure. Taking expected productivity changes into account when assessing NSP forecasts, or when developing substitute expenditure allowances, should have a similar effect as having an explicit efficiency dividend. We also note that in considering capex forecasts we will consider any proposed real cost escalators. This will including consideration of:

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246 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 54.

247 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 9.

248 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 9.

249 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 9—10.

250 New South Wales Irrigators' Council, *Submission to the AER – draft expenditure forecast assessment guideline for transmission*, 20 September 2013, p. 4.

- labour cost forecasts and if these reflect a realistic expectation of the cost inputs required to achieve the capex and opex objectives
- if forecasts inputs for material escalation and exchange rates reflect the most recent data.

In addition to taking productivity changes into account in assessing NSP forecasts, we have introduced a new capital expenditure incentive scheme that should incentivise NSPs to reduce capex in a manner that is in the long term benefit of consumers.

5.2.3 Categories for capex assessment

AER position

We will examine forecast work volumes and costs in the context of the different capex drivers. To do this, we will split capex into high level, standardised categories that reflect the primary drivers of capex. The high level categories are:

- repex
- augex
- connection and customer driven works capex
- non-network capex.[251]

Within each category we may then break down expenditure into discreet subcategories with different cost drivers. The level of disaggregation is likely to be driven by the materiality of the expenditure and the relative differences in costs between different types of expenditure.

We are likely to break expenditure down into subcategories where it is expected to improve our ability to test key forecast expenditure drivers related to material projects or program.

Reasons for AER position

We consider the categories outlined above have distinct expenditure (cost and volume) drivers and should be examined independently for this reason. They are also consistent with the expenditure drivers identified in the issues paper and accommodate stakeholder comments made at workshops prior to the publication of our draft Guideline.[252] We have not changed our proposed approach as articulated in the explanatory statement for the draft Guideline.

The majority of stakeholders supported the expenditure drivers that were identified in our issues paper,[253] CitiPower, Powercor and SA Power Networks submitted in response to the draft Guideline

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[251] Note the considerations in this section are equally applicable to analysis of opex categories, which are also detailed in Attachment B.

[252] AER, *Better Regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 97; AER, 'Meeting summary – Selection of expenditure categories', *Workshop 2: Category analysis work-stream – Category selection (Transmission and Distribution)*, 28 February 2013.

[253] Energex, *Energex response to AER's Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues Paper*, 15 March 2013, p. 1; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator*, 15 March 2013, pp. 13–14; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment B – Category analysis*, 15 March 2013, p. 1; SP AusNet, *Expenditure Forecast Assessment Guidelines—Issues Paper*, 15 March 2013, p. 23; United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator*, 19 March 2013, p. 14.

that they are broadly comfortable with the AER's general approach to examining work volumes and costs in the context of the AER's proposed high level expenditure categories (as noted above).[254]

We may further disaggregate these categories via distinct lower level expenditure drivers. By considering expenditure at the subcategory and lower levels, we can better examine the prudence and efficiency of a NSP's proposed expenditure. In many situations, quantitative relationships should exist between expenditure drivers and forecasts, and may be used to estimate prudent and efficient future expenditure. Using standardised lower level subcategories should also allow direct comparison of forecast with benchmark figures based on other NSPs' performance. We consider that lower level analysis of standardised categories will allow us to better control for differences across businesses in many situations and to understand how expenditure is affected by the different cost drivers a given NSP faces. This should help us form a view about whether the total forecast capex reasonably reflects the capex criteria. We also consider this information should allow NSPs to identify potential areas of inefficiency in their operations and target these areas for performance improvement.

We will seek to as clearly define reporting data categories to ensure data is as comparable as possible across NSPs to support our assessments. We consider this is likely to be an ongoing process of refinement undertaken through formal regulatory information gathering processes and other information exchange with NSPs.

We acknowledge that the list of drivers was not exhaustive and firms have different characteristics that influence their efficient and prudent costs. However, we consider the key drivers identified support our suggested categorisation and approach to category based analysis and differences in efficient and prudent costs across NSPs can be identified and allowed for.

We are also aware of the cost trade-offs between categories of work and between capital and operating expenditures. To avoid perceived 'cherry picking' we intend to consider potential trade-offs when examining category level forecast expenditure when setting an overall regulatory allowance.

Attachment A provides more detail on our likely assessment approach specific for each capex subcategory.

5.2.4 Cost estimation risk factors (transmission only)

Cost estimation risk factors (risk factors) are typically a component of a TNSP's methodology for forecasting capex. We acknowledge that TNSPs face uncertainty when developing their capex forecasts, and invariably there is a difference between what TNSPs forecast for particular project cost items and what they actually incur.

AER position

Our objective is to standardise the way we assess TNSPs' risk factor estimates. Our assessment approach will remain largely the same as the approach we used in recent determinations and will involve reviewing:

- information TNSPs provide to support the risk factor, including any consultant advice
- comparisons of TNSP project specific actual and expected capex

254 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 8.

- any consultant advice commissioned by the AER.

We will require TNSPs to substantiate their proposed risk factors for the projects they propose by demonstrating they:

- identified the risks to estimation (both upside and downside)
- developed strategies to mitigate any downside risks
- quantified the uncertainty that remains after implementing the mitigation strategies.

TNSPs are required to identify both the risks to the cost estimates and the potential mitigation strategies applicable to each project. We consider there are two types of risk to project estimates:

- Inherent risks represent uncertainty associated with the cost build-up of the project. This is borne out of assumptions used in estimating the unit cost and volumes of the inputs for the project.
- Contingent risks represent uncertainty created by events outside the cost build-up estimate. These events can include unforseen weather impacts, industrial action, safety, planning approval, design development. Typically, TNSPs included a contingent allowance in their cost build up, effectively an amount added to each project accounting for identifiable contingent risks.

After identifying these risks TNSPs will be required to quantify the residual risk that remains after implementing the relevant mitigation strategies. We consider this residual is the risk factor that applies to the TNSPs capex forecast. TNSPs must demonstrate they followed this process in supporting information substantiating their proposed risk factor estimate.

We consider TNSPs should have discretion to the methodology they use to estimate the risk factor, given the complex and discrete nature of the transactions involved.

Reasons for AER position

We consider there is justification for recognising cost estimation risk for TNSPs (and not DNSPs) because:

- transmission projects typically involve longer planning and construction lead times than distribution projects. This lag may result in greater divergence between the assumptions used in the forecast and the actual cost because circumstances change
- transmission projects may be unique or with limited precedent compared with distribution projects. Hence cost items used in the estimation process may be based on relatively less experience
- DNSPs' capex programs involve more projects, reducing the risk of any individual project on overall capex outcomes because of diversification.

The MEU in its submission noted the AER expounds considerably on the cost estimation risks faced by TNSPs and proposes to allow the TNSPs some latitude in assessing the cost estimation risk allowance. The MEU accepts there are increased risks when there is a limited historical data to develop costs and longer lead times for project completion, but considers this risk is overstated by NSPs.[255]

We also received the following submissions supporting our technique of assessing cost estimation risk factors:

- PIAC supports the AER's rejection of adding additional risk premiums in NSPs' expenditure proposals, as they compound in their effect across categories of expenditure—risk should be borne by the party best placed to manage the risk, which is generally not consumers.[256]
- COSBOA agrees with the AER's rejection of adding additional risk premiums in NSPs' expenditure proposals, noting NSPs, not consumers, are best placed to manage risks. COSBOA considers it will be important for the AER to find more objective and verifiable ways to deal with TNSP cost estimation risks. The application of a meaningful CESS may help but the application of benchmarking techniques will still be necessary to limit such risks. COSBOA encourages the AER and AEMO to pursue the development of a 'price book' of project cost components for benchmarking.[257]

We consider there are two broad sources of variance between budgeted and outturn project costs:

- methodology uncertainty: arising from shortcomings in the methodology applied
- estimation risks: arise from deficiencies in the data applied to the technique.

When assessing the methodology a TNSP deploys to estimate its risk factor, we will be mindful of the following:

- the process undertaken to identify the risks to the estimates and the extent to which this process can be independently verified
- the portion of the identified risks consumers should bear in accordance with the NEL
- potential double counting of real price escalators, pass through events and other contingencies which are compensated for elsewhere in our determinations
- the extent to which the TNSP has (or should have) improved its ability to forecast its capex over time
- the time period between the forecast preparation and project completion
- the period of the project lifecycle (for example, the concept phase)
- the robustness of the data used to generate the risk factor estimate.

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255 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, pp. 16–17.

256 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 4, 14–15.

257 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 6, 10.

5.3 Opex approach

5.3.1 AER position

Under the NER we must accept or not accept a NSP's opex forecast.[258] Whether we consider the proposed forecast reasonably reflects the opex criteria governs this choice. If we do not accept the forecast, we must estimate the required expenditure that reasonably reflects the opex criteria. The criteria provide that the forecast must reasonably reflect the efficient costs that a prudent operator would require to meet expenditure objectives given a realistic forecast of demand and cost inputs.[259]

We intend to adopt the same general approach to assessing opex forecasts as we have in the past. However, we also intend to use a broader range of assessment techniques and to collect consistent data to aid our assessment.

Consistent with past practice, we prefer using a revealed cost approach to assess most opex cost categories (which assumes opex is largely recurrent). Specifically we intend to use the 'base-step-trend' approach. If a NSP has operated under an effective incentive framework, and sought to maximise its profits, the actual opex incurred in a base year should be a good indicator of the efficient opex required. However, we must test this, and if we determine that a NSP's revealed costs are not efficient, we will adjust them to remove inefficient costs. Details of our base year assessment approach are below.

Once we have assessed the efficient opex in the base year we then account for any changes in efficient costs in the base year and each year of the forecast regulatory control period. There are several reasons why efficient opex in a regulatory control period could differ from the base year. Typically, we will adjust base year opex for:

- output growth
- real price growth
- productivity growth.

An annual 'rate of change' will incorporate these factors. Any other costs base opex and the rate of change do not compensate can be added as a step change. When assessing step changes particular consideration must be given to whether the costs are already compensated for elsewhere in the opex forecast.

5.3.2 Reasons for AER position

We consider the revealed cost base-step-trend forecasting approach is a robust means of testing an opex forecast against the opex criteria. There are a number of reasons why efficient opex in forecast regulatory control period will be different from actual expenditure in an efficient base year. It is necessary to take these into account to ensure forecast opex reasonably reflects the opex criteria:

- Increased demand for NSPs' outputs may require them to expand their networks. It is reasonable that an efficient NSP will require more inputs, and thus greater opex, to deliver more output. We therefore include forecast output growth in the rate of change formula.

[258] NER clauses 6.12.1.(4)(i) and 6A.14.1.(3)(i).
[259] NER clauses 6.5.6(c) and 6A.6.6(c).

- It is reasonable to assume that the cost of inputs for an efficient firm to produce the same level of output may change at a rate different to CPI. Consequently it is reasonable to account for real cost changes in inputs. We therefore include real price growth in the rate of change formula.
- It is reasonable to assume efficient NSPs will improve productivity over the forecast regulatory control period. For example, we would expect economies of scale to be realised from output growth. We therefore include forecast productivity growth in the rate of change formula.
- There may be other reasons beyond a NSPs' control that will increase or decrease its costs. For example, regulatory obligations may change. This may require NSPs to increase or reduce expenditure to meet those new obligations. For this reason we allow for other incremental changes above (or below) base year opex, which we refer to as step changes.

This accounts for all drivers of expenditure change.

Assessing base opex

Since we use revealed cost to assess opex forecasts, we must first test whether those revealed costs reasonably reflect the opex criteria.[260] If they do not, the opex forecasts will also not reasonably reflect the criteria. We will likely apply all of our assessment techniques to assess whether base opex reasonably reflects the opex criteria. We will likely assess base year expenditure exclusive of any movements in provisions that occurred in that year. This section on base opex assessment should be read in conjunction with section 6.3.1 as it relates to incentives under the EBSS.

We agree with CitiPower, Powercor and SA Power Networks and the ENA that the EBSS provides a strong continuous efficiency incentive and therefore base year opex should be an efficient starting point for forecasting opex.[261] However, this is only true if the NSP responds to that incentive. In some circumstances NSPs may face competing incentives and base year expenditure may not efficient. Consequently we also agree with PIAC, MEU, COSBOA and Uniting Care that we cannot assume the efficiency of base expenditure and must test it.[262]

If we identify material inefficiencies in actual base year expenditure we will not use it as base opex. In this case, we will consider two options for base opex:

1. using a different year of actual expenditure for base opex that does reasonably reflect the opex criteria
2. adjusting actual base year expenditure so it reasonably reflects the opex criteria.

If we find base opex does require adjustment, we will likely apply all of our techniques to determine the adjustment. CitiPower, Powercor and SA Power Networks stated that if we apply economic benchmarking to assess or substitute base year opex, we should make clear what principles will apply to set the benchmark and how the model and benchmark will account for differences in NSPs'

260 We may not use the revealed cost approach to forecast all cost categories. For example, we typically forecast debt raising costs based on the costs of a benchmark firm.

261 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 10; Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 4, 47.

262 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013 pp. 5, 24–25; Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 12, Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 5, 7–9, Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013, p. 4.

uncontrollable operating conditions.[263] The principles we will use are set out in section 5.5. Attachments A and C discuss how our economic benchmarking techniques and category analysis will account for network specific conditions.

NSPs raised concerns about departing from a revealed cost approach and relying more on benchmarking to determine base opex. NSPs considered benchmarking techniques are likely to provide an imprecise assessment of the efficiency of base opex and a benchmark substitute may be inefficiently low.[264] As we discuss further in chapter 6, we agree with PIAC, MEU, COSBOA and Uniting Care that we cannot assume the efficiency of base expenditure and must test it.[265]

Grid Australia also submitted we should transition adjustments made to base year expenditure over the period rather than apply them in a single year. It considered doing so will ensure there is not undue pressure to achieve reduced expenditure allowances that could compromise reliability of supply.[266] However, we do not consider this would be consistent with the opex criteria. For example, we are required to set opex allowances that, among other things, reasonably reflect the costs a prudent operator would require to achieve the opex objectives. Where this allowance is less than what a particular NSP has proposed, we expect the NSP's shareholders to absorb any additional costs of meeting reliability and other requirements, rather than passing this cost onto consumers.[267]

We discuss our proposed approach to conducting benchmarking in Attachments A (economic benchmarking techniques) and C (category analysis). Considerations generic to assessments of particular expenditure categories (including opex) are also contained in section 5.1.2 above. Chapter 6 further discusses how the determination of base opex impacts the opex incentive.

Once-off factors in the base year and the EBSS

We are now explicitly required to have regard to whether an opex forecast is consistent with any incentive schemes that apply to a NSP.[268] Consequently, when determining whether to adjust or substitute base year expenditure, we will also have regard to whether rewards or penalties accrued under the EBSS will provide fair sharing of efficiency gains or losses between the NSP and its customers.

A NSP should be largely indifferent in the choice of base year. Although a different base year will derive a different opex forecast, any change to the opex forecast should be offset by a similar but opposite change to the increment/decrement accrued under the EBSS. That is, the opex forecast, net of any EBSS carryover, should be similar (see Box 5.1). Given this, one of our primary considerations

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263 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 10.

264 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 4, 47; Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, p. 9; Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 4.

265 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 5, 24–25, Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 12, Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 5, 7–9, Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013, p. 4.

266 Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 16–18.

267 AER, *Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 23.

268 NER clauses 6.5.6(e)(8) and 6A.6.6(e)(8).

when assessing the appropriateness of a base year is whether the expenditure in that year is most reflective of the efficient costs of a prudent NSP.

However, there may not always be a base year available that is reflective of the efficient costs of a prudent NSP. This may be due to one-off factors in the potential base years. This impacts how we treat the expected expenditure in the final year, which we do not know at the time of a determination.

The deemed final year opex equation in our draft guideline assumed all efficiency gains (or losses) made in the base year were recurrent (that is, any underspend in the final year was equal to the underspend in the base year). This was to ensure consistency between the opex forecast and the EBSS so that the EBSS provides a continuous incentive. However, this may not always be an appropriate assumption. Incenta commented that, when testing the efficiency of an NSP's base year, it is important to ensure one-off factors do not impact the expenditure in the base year and that adjustments are made if such one-off factors exist.[269] If base year expenditure was significantly lower (higher) than ongoing efficient opex due to a one-off factor, then the opex forecast would be artificially low (high). The NSP would be sufficiently compensated through the EBSS carryover, however the 'optics' could be misleading. That is, a NSP's actual expenditure would appear high when compared against its opex allowance (not factoring in the EBSS carryover).

Box 5.1 Revenue impact of non-recurrent efficiency gains in the base year

Take the example of an NSP with an opex allowance of 100 dollars. Its actual opex is as forecast in every year except the fourth year of a five year regulatory control period, when it spends 90 dollars. For simplicity assume there is no output, real price or productivity growth. If we use the fourth year to forecast opex for the next regulatory control period the forecast would be 90 for each year of the next regulatory control period. The EBSS assumes the final year underspend is equal to the base year underspend. Thus the NSP would receive a 10 dollar carryover payment in the first four years of the next regulatory control period.

However, if the third year was chosen as the base year, forecast opex would be 100 for each year of the next regulatory control period. Again the EBSS assumes the final year underspend is equal to the base year underspend, which is now zero. This results in an assumed incremental loss of 10 dollars in the fifth year. Thus the NSP would receive a single carryover penalty of ten dollars in the fifth year of the next regulatory control period. In both scenarios the NSP would receive 100 dollars in each year of the next regulatory control period, except the final year when it would receive 90 dollars. Thus the NSP would pay back the non-recurrent efficiency gain six years later, sharing it between itself and network users.

To address the issue of one-off factors in the base year we have relaxed the assumption that all efficiency gains made in the base year are recurrent. The estimated final year equation (which we previously called the deemed final year equation) now allows one-off cost reductions in the base year to be added back on to the estimated final year opex to ensure if reflects efficient ongoing expenditure and is not artificially low. To ensure NSPs have a continuous incentive in the final year we have made a corresponding adjustment to the EBSS. This effectively shifts revenue from the EBSS carryover to the opex forecast. For this reason, we will estimate final year expenditure to be:

$$Estimated\ final\ year\ opex = F_f - (F_b - A_b) + non\text{-}recurrent\ efficiency\ gain_b$$

where:

- F_f is the determined opex allowance for the final year of the preceding regulatory control period

[269] Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, p. 13.

- F_b is the determined opex allowance for the base year
- A_b is the amount of actual opex in the base year
- non-recurrent efficiency $gains_b$ is the non-recurrent efficiency gain in the base year.

Applying the rate of change to the estimated final year opex

We then use this estimated final year opex (taking into account an efficiency adjustment, if required) to assess opex for the following regulatory control period by applying the rate of change. However, the Victorian DNSPs considered the rate of change formula in the draft guideline incorrectly referred to final year opex even though base year opex is usually set to actual opex in the base year. The Victorian DNSPs suggested the term 'base year opex' should replace 'deemed final year opex'.[270] However, estimated final year opex is a function of actual expenditure in the base year and it does not restrict the choice of base year. To ensure NSPs are provided a continuous incentive to reduce opex, the rate of change formula should escalate forecast opex from the estimated final year opex not base opex. We note this approach is consistent with our approach for the last Victorian electricity price review.

Assessing real price growth

The Victorian DNSPs noted that we have previously expressed a preference for the Australian Bureau of Statistics' wage price index to forecast changes in labour costs. They considered the decision on which real price escalator to use should be left to the determination and assessed against the opex criteria at that time. Further, they stated we should use the same real price growth factor for economic benchmarking and opex forecasts to ensure consistency across the two.[271]

We agree we should use the same real price growth factor used for economic benchmarking as we do for to forecast opex. This will ensure consistency between the productivity measure, determined by the economic benchmarking, and the real price measure. Some price measures capture productivity changes as well as pure price changes. For example, average weekly ordinary time earnings captures labour composition productivity. If average weekly ordinary times earnings is not used for both the opex forecast and economic benchmarking then this form of productivity could be captured twice or not all.

Consistent with the draft Guideline, the final Guideline does not require specific real price measures. NSPs are free to propose whichever price index they consider is most appropriate. The guideline only requires the real price measures used to forecast productivity growth be the same as that used in the rate of change formula.

Assessing productivity

We will incorporate forecast productivity change in the annual 'rate of change' we apply to base opex when assessing opex. The forecast productivity change will be the best estimate of the shift in the productivity frontier.

Forecast opex must reflect the efficient costs of a prudent firm.[272] To do this it must reflect the productivity improvements it is reasonable to expect a prudent NSP can achieve. This is consistent

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270 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013,* pp. 5–6.

271 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013*, p. 12.

272 NER clauses 6.5.6(c)(1), 6.5.6(c)(2), 6A.6.6(c)(1) and 6A.6.6(c)(2).

with the productivity improvements an efficient firm operating in a competitive market would be able to retain. All else equal, a price taker in a competitive market will maintain constant profits if it matches the industry average productivity improvements reflected in the market price. If it is able to make further productivity improvements, it will be able to increase its profits until the rest of the industry catches up, and this is reflected in the market price. Similarly, if a NSP is able to improve productivity beyond that forecast, it is able to retain those efficiency gains for a period through the EBSS.

One of the refinements to our opex assessment approach will be how we incorporate productivity improvements. Previously, we did not forecast a single productivity measure. This created a risk of double counting productivity gains when, for example, we considered economies of scale and labour. As a result, we only applied economies of scale to output growth escalation.

Over time, we intend to develop a single productivity forecast through econometric modelling of the opex cost function (see Attachment A). Applying this single productivity forecast helps avoid the risk of double counting productivity growth. Another advantage of this approach is that it should be more transparent than our previous approach.

PIAC supported the explicit inclusion of a productivity measure in the annual 'rate of change' in opex.[273] The MEU, however, was concerned the productivity adjustment, based on the performance of the most efficient businesses, will impose a lesser drive for productivity improvement on inefficient NSPs than is needed. It noted the proposed approach assumes each NSP is operating at the efficient frontier, but it is unlikely that all are operating at this point.[274] This assumption is necessary, however, because we will assess the efficiency of each NSP's base year expenditure. The forecast productivity change of an efficient individual NSP can be disaggregated into 'catching up to the frontier' and frontier shift. We will assess the efficiency of base year opex, and adjust where we identify material inefficiencies, capturing any 'catch up' required. Thus the forecast productivity change included in the rate of change should only represent the forecast shift in the productivity frontier.

The following subsections explain our approach to productivity change in terms of:

- the revenue and pricing principles
- the technical change component of forecast productivity change
- productivity forecasts being firm specific
- estimating productivity frontier shift.

The revenue and pricing principles

NSPs stated the proposed productivity forecast may not meet the revenue and pricing principles which require NSPs be given a reasonable opportunity to recover at least their efficient costs. NSPs proposed the productivity forecast should only capture efficiencies exogenous to the business, and not those derived from management effort. They proposed forecast productivity should be limited economies of scale.[275]

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273 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 5, 26–27.

274 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 15.

275 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 3, 30–31; Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, 15–16; The Victorian Distributors, *Vic DNSP's joint submission on AER draft*

However, not accounting for forecast productivity change would not be consistent with the opex criteria. Forecast opex must reflect the efficient costs of a prudent firm.[276] We must therefore forecast the productivity improvements it is reasonable to expect a prudent NSP can achieve. Consequently, the only way to meet both the revenue and pricing principles and the opex criteria is to incorporate the best available forecast of productivity change. We also noted in section 3.1.1 that some NSPs have tended to emphasise the pricing principle of 'at least efficient cost' at the expense of other principles and requirements of the legal framework.

CitiPower, Powercor and SA Power Networks stated they did not support including forecast productivity change in the opex rate of change formula.[277] They stated economy wide productivity change dampens CPI growth, all else equal, particularly in relation to wages and monetary policy. They considered that to include forecast productivity change in the rate of change formula would require evidence that the electricity network industry was able to make greater productivity improvements than the general economy.[278]

CitiPower, Powercor and SA Power Networks appear to be referring to the Bernstein-Sappington framework for productivity-based regulation.[279] Under that framework the X factor in CPI–X is based on a term combining the difference between the industry and economy-wide TFP growth rates and the difference between the industry and economy-wide input price growth rates. However, this does not translate to the building blocks framework where we adopt a different approach to regulation. Under the building block framework we explicitly set the X factor to equate to the net present value of the forecast revenue and the forecast revenue requirement using an assumed rate of inflation. The opex productivity growth rate is just one of the factors that feeds into the revenue requirement. The X factor is not the productivity growth rate as it is in the case of the Bernstein-Sappington framework.

The technical change component of forecast productivity change

Similarly, Incenta Economic Consulting stated, in a report prepared for Grid Australia, that while the opex partial productivity growth forecast included in the opex 'rate of change' should include the effects of economies of scale and changes in business or operating environment factors, it should not include the residual time trend element. Incenta noted that, while it agreed with the inclusion of the technology-related component of the residual time-trend element, it was concerned that this could not be separated from other elements that might be of a 'one-off' nature and not be repeatable in the next regulatory period.[280] Incenta cited four such factors it considered would be inappropriate to include the effects of:

1. the effect of the less efficient firms 'catching up' to their peers, to the extent that this effect had not been able to be eliminated though alternative means

2. productivity growth that is a consequence of efficiency-improving capital expenditure

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expenditure forecast assessment guidelines, 20 September 2013, pp. 2, 12; Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, pp. 9–12; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 11.

276 NER clauses 6.5.6(c)(1), 6.5.6(c)(2), 6A.6.6(c)(1) and 6A.6.6(c)(2).

277 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 10.

278 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 10.

279 Bernstein and Sappington, *How to Determine the X in RPI – X Regulation: A User's Guide*, June 1998.

280 Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, pp. 10–13.

3. productivity growth that is the consequence of past one-off operating expenditures (such as corporate restructures and/or redundancy costs) that may have been excluded from consideration or not fully reflected in the productivity time trend

4. a reduction in productivity growth resulting from new obligations being imposed on NSPs.[281]

Similarly, CitiPower, Powercor and SA Power Networks also stated including the proposed forecast productivity change would incorrectly assume:

- historical average productivity change is achievable in the future
- cost reductions from one off events will be repeated in the future.[282]

Regarding Incenta's first factor, the importance of the 'catch-up' effect will depend on the distribution of NSP efficiency levels relative to best practice and the size of the sample available to estimate an opex cost function. If only a small number of firms are operating inefficiently then the parameter estimates and resulting opex partial productivity growth rate obtained from the operating cost function will not be unduly influenced by catch-up. The productivity and econometric studies Economic Insights undertook for the Victorian gas distribution businesses provides an example of this.[283]

Economic Insights' study found that, of the three Victorian gas distribution businesses, Multinet and Envestra Victoria had strong productivity growth in the post-privatisation era of 1999 to 2005. Their productivity growth was more modest from 2005 to 2011 after they became relatively efficient.[284] SP AusNet, on the other hand, had relatively flat productivity performance from 1999 to 2004 but then exhibited stronger productivity growth from 2004 to 2010.[285] Because the operating cost function was estimated using a sample of 144 observations from 11 gas distribution businesses, the residual time-trend element included in the opex partial productivity forecast for SP AusNet was 0.6 per cent per annum,[286] despite SP AusNet having exhibited opex partial productivity growth of 8.4 per cent per annum over the last five years of the sample.[287] That is, the forecast residual time-trend element reflected frontier changes rather than extrapolating recent past rapid catch-up performance.

If there is a wide spread and more even distribution of efficiency levels then the effects of catch-up could be excluded by limiting the sample for the estimation of the opex cost function to the relatively efficient NSPs. There would be some trade-off, however, as the reduction in sample size would limit the complexity of the opex cost function that could be estimated for the efficient subset.

The methodologies we have proposed are thus capable of removing the effects of catch-up, to the extent they are relevant.

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281 Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, p. 12.

282 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 10–11.

283 Economic Insights, *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*, Report prepared for Envestra Victoria, Multinet and SP AusNet, March 2012; Economic Insights, *Econometric Estimates of the Victorian Gas Distribution Businesses' Efficiency and Future Productivity Growth*, Report prepared for SP AusNet, March 2012.

284 Economic Insights, *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*, Report prepared for Envestra Victoria, Multinet and SP AusNet, March 2012, pp. 23–29.

285 Economic Insights, *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*, Report prepared for Envestra Victoria, Multinet and SP AusNet, March 2012, pp. 30–32.

286 Economic Insights, *Econometric Estimates of the Victorian Gas Distribution Businesses' Efficiency and Future Productivity Growth*, Report prepared for SP AusNet, March 2012, pp. 4, 21.

287 Economic Insights, *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*, Report prepared for Envestra Victoria, Multinet and SP AusNet, March 2012, p. 32.

Regarding the second factor nominated by Incenta, the effects of efficiency-improving capital expenditure, Incenta quotes the example of the increasing role of information and communications technology (ICT) in the operation of modern utility businesses. However, the effects of ICT improvements are ongoing and widespread across all facets of operations and are unlikely to be of a 'one-off' nature. Indeed, this is likely to be one of the principal sources of technical change going forward. Incenta also note that, where a proposed capital project is justified as a substitution for operating expenditure, we will treat the saving in opex as a step change. It would thus be unreasonable to remove the effects of efficiency-improving capital expenditure from the productivity forecast.

The third factor Incenta suggests be excluded from productivity trends (the consequence of past one-off operating expenditures that may have been excluded from consideration or not fully reflected in the productivity time trend) is similar in effect to the catch-up factor discussed above. Indeed, in the example of the Victorian gas distribution businesses quoted above, SP AusNet was able to achieve its catch-up to best practice between 2004 and 2010 in part by restructuring its operations. Economic Insights noted:

> SP AusNet made significant savings in the network operations component of opex as it extracted synergies from the operation of the 3 networks it owns and operates. Many of these synergies were generated by the combined network operations centre it operates. However, once these synergies have been fully extracted there can be expected to be a flattening out of network operations costs and this was observed in 2011.[288]

As noted above, by estimating the components of productivity change and their driver coefficients from a sufficiently wide sample, the effects of these one-off changes for one firm are not reflected in productivity forecasts for that firm.

Finally, Incenta point to the effects of new obligations being imposed on NSPs that may reduce productivity growth as a reason to exclude the time-trend component of productivity growth. We have previously dealt with new obligations by incorporating a step change. However, changes in obligations and regulatory burden occur continually and are reflected in past productivity performance. It is only if future new obligations impose a relatively larger change in productivity growth than have past changes in obligations that there would be a case for adjusting the productivity growth rate.

On balance, we consider the four issues raised by Incenta do not warrant the exclusion of the residual time-trend component of opex partial productivity growth. The forecasting methods we have proposed are capable of allowing for the one-off nature of the factors and, in some cases, the factors cited are part of the ongoing process of technical change. To exclude the residual time-trend component would not produce opex forecasts consistent with the opex criteria.

Productivity forecasts will be firm specific

CitiPower, Powercor and SA Power Networks further stated including the proposed forecast productivity change would incorrectly assume all NSPs have the same ability to achieve the same level of productivity change, which will not be the case.[289]

However, we will not assume all NSPs have the same ability to achieve the same level of productivity change. As discussed in the explanatory statement for our draft guideline, the productivity forecast should be firm specific given it is intended to reflect the potential productivity change the NSP can

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288 Economic Insights, *Econometric Estimates of the Victorian Gas Distribution Businesses' Efficiency and Future Productivity Growth*, Report prepared for SP AusNet, March 2012.

289 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013,pp. 10–11.

achieve in the next regulatory control period. The proposed approach to forecasting productivity change addresses this by deriving a productivity forecast, specific to the NSP, that incorporates:

- forecast output growth
- forecast changes in NSP specific business conditions
- forecast technological change.[290]

The NSW DNSPs stated estimates of productivity would form a key component of their regulatory proposals, but they were concerned we may mechanistically apply a further productivity dividend without considering the efficiencies they have achieved to date.[291] As described in the explanatory statement for our draft guideline, the potential productivity change an NSP can achieve in the next regulatory control period should be considered in combination with any base year adjustment. The forecast productivity change of an efficient individual NSP can be disaggregated into 'catching up to the frontier' and frontier shift. Any base year adjustment we apply will capture any catch up required. Thus the forecast productivity change included in the rate of change should represent the forecast shift in the productivity frontier, not average industry performance.[292] To meet the opex criteria forecast productivity change should account for any 'catch up' required and frontier shift.

Contrastingly, the EUAA was concerned the use of constant productivity change estimates over the regulatory period could mean energy users will be deprived of step change reductions in opex that should occur for those NSPs whose efficiency is substantially below the efficiency frontier.[293] These concerns should be addressed through the assessment of NSPs base year expenditure. To the extent we find the NSP to be materially inefficient, or substantially below the efficiency frontier, we will adjust base opex to reflect the difference. This will effectively place the inefficient NSP on the efficiency frontier for forecasting purposes.

Estimating productivity frontier shift

We need to be able to decompose our productivity change measure into the sources of productivity change to separately apply the base year adjustment and productivity forecast. We propose to do this by:

- having regard to the partial factor productivity (PFP) differential in the base year together with information from category analysis benchmarking to gauge the scope of inefficiency to be removed by the base year adjustment
- using the PFP change of the most efficient business (or highly efficient businesses as a group) to gauge the scope of further productivity that may be achieved by individual businesses—this assumes that relevant drivers (such as technical change and scale change) and their impact remain the same over the two periods considered (historical versus forecast).

For some NSPs, future productivity gains may be substantially different from what they achieved in the past. For example, inefficient NSPs may significantly improve productivity and become highly efficient at the end of the sample period. This would reduce the potential for them to make further

290 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, pp. 36–37.

291 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, pp. 10–11.

292 AER, *Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 37.

293 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 3.

productivity gains in the following period. Similar issues apply to the productivity change achieved by the industry as a whole. If the group includes both efficient and inefficient NSPs, the industry-average productivity change may be higher than what an individual NSP can achieve. To the extent inefficient NSPs are catching up to the frontier, the industry average productivity change will include both the average moving closer to the frontier and the movement of the frontier itself. By decomposing productivity change into catching up to the frontier and frontier shift we can account for these.

Assessing step changes

The rate of change may not capture all cost changes that reasonably reflect the opex criteria. For this reason, we will also add step changes to our opex forecast where they are necessary to produce a forecast that is consistent with the opex criteria. We discuss our general approach to assessing step changes in section 5.1.2. Here we discuss considerations specific to the rate of change forecasting approach.

The MEU supported our new approach to step changes such as a more rigorous approach to cost estimation for step changes. It considered our new approach addresses some very basic concerns it identified over many revenue resets in the past.[294] Similarly, COSBOA stated our refined approach to assessing step changes should address some of its previous concerns. However COSBOA did express some concern that our proposed approach to step changes does little to provide a path to identifying step change reductions.[295] We are mindful NSPs do not have an incentive to identify negative step changes and that they can be difficult to identify due to information asymmetry. However, to the extent future negative step changes relate to changed regulatory obligations or industry best practice, these may be captured by the productivity forecast. We discuss our assessment of step changes for changed regulatory obligations or industry best practice more below.

PIAC stated the guideline should clarify that step changes should clearly link to significant exogenous events.[296] By contrast, NSPs stated the definition of step changes in the guideline was too restrictive and did not allow for some expenditure increases that would meet the opex criteria. The NSW DNSPs, for example, stated the NER did not define the term 'step change' and the use of such a concept could preclude costs that may satisfy the opex criteria.[297] We have amended the definition of step changes in the Guideline to clarify that they can include any expenditure required for forecast opex to meet the opex criteria. However, step changes should not be provided for costs compensated for elsewhere in the base-step-trend forecast. The Guideline then provides further guidance on the types of step change costs we consider the base-step-trend forecast would likely fund elsewhere.

The Victorian DNSPs considered limiting step changes to 'non-discretionary' expenditure and 'external to the control of the DNSP' would restrict expenditure necessary to meet the opex criteria.[298] We maintain, however, that discretionary changes are unlikely to require a step change. Since the rate of change incorporates output growth and price growth, any step change for an increase in the cost of inputs would represent a reduction in productivity. Since productivity change will be forecast separately, this would double count productivity change and would not be consistent with the opex criteria. In other words, an efficient NSP would only undertake the proposed (discretionary) step

294 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, pp. 13–14.

295 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 7.

296 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 5, 25–26.

297 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, p. 7.

298 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013,* pp. 8–9.

change if it reduces its total expenditure. Therefore discretionary step changes should be funded through the cost reductions they generate and hence rewarded through incentive arrangements. One exception to this is for capex/opex trade-offs. It may be efficient to increase opex if it reduces a NSP's capital costs. A step change may also be consistent with the opex criteria, if the driver for the step change is out of the NSP's control.

NSPs proposed a number of additional step change types including:

- changes in external obligations or in the interpretation of obligations[299]
- changes in good electricity industry practice[300]
- exogenous changes in the volume or scale of a NSP's activity[301]
- investments that support NSPs achieving dynamic efficiency[302]
- opex associated with new capex activity[303]
- where customer engagement has indicated support for new or increased activities.304

These are addressed briefly below.

Assessing step changes for changed obligations and good industry practice

If the step change was for the costs to meet a new regulatory obligation, it may be appropriate to provide a step change. Forecast opex should provide sufficient expenditure to comply with all applicable regulatory obligations or requirements.[305] However, the productivity measure included in the rate of change may compensate the NSP for past regulatory changes. Where the historical change in outputs and inputs is used to derived forecast productivity, that forecast will be net of productivity losses driven by the increased inputs required to meet new regulatory obligations imposed over the sample period.

Thus, if the forecast increase in the regulatory burden over the regulatory control period is consistent with the increase in regulatory burden over the sample period used, step changes would not be required for new regulatory obligations. Recognising the difficulty of determining the productivity impact of past regulatory obligation changes, we have not specified a particular assessment approach

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299 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 32–34; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 12.

300 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 32–34; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 12; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013*, pp. 9–10.

301 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013,pp. 32–34.

302 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013,pp. 32–34; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 12.

303 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 32–34.

304 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 12; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 32–34; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013*, pp. 9–10.

305 NER clause 6.5.6.(a)(2), 6A.6.6(a)(2).

at present. However we must account for it when assessing NSPs' opex forecasts. Otherwise, applying productivity in the rate of change and adding step changes would overstate the prudent and efficient opex required.

NSPs, however, raised concerns with this proposed approach to treating forecast costs associated with new regulatory obligations. These concerns mostly related to practical concerns rather than in principle ones.

APA submitted we should not apply the proposed 'trend' approach to operating expenditure step changes and instead assess each proposed step change on its merits. It did not consider it reasonably possible to determine whether future regulatory obligations were demonstratively different from historic ones. Consequently it considered there was a high risk this approach would not provide NSPs a reasonable opportunity to recover at least their efficient costs.[306] Similarly the Victorian DNSPs stated we should not adopt this because we have not tested its validity, nor have we assessed it against the opex criteria or revenue and pricing principles.[307] For the reasons above, we think providing step changes for regulatory obligation changes without accounting for those implicitly compensated for in the productivity measure would not comply with the opex criteria. The best way to comply with both the opex criteria and the revenue and pricing principles is to use the best estimate available of the incremental change in regulatory obligations, rather than providing step changes for the absolute amount.

CitiPower, Powercor and SA Power Networks considered our method for accounting for regulatory obligation changes captured in the productivity measure was unclear. They stated that if we adopt this approach the Guideline should set out how we intend to implement it.[308] We think it is reasonable to assume that, unless there is evidence to the contrary, the cost of meeting changed regulatory obligations in the forecast period will be similar to those incurred in the past. To test this we will consider any analysis provided by NSPs, our productivity analysis and the magnitude of step changes included in opex allowances in the past. We will be exploring how to test this empirically in the next round of reviews. Because further analysis is required, our approach is to reflect this issue 'in principle' in the Guideline drafting without being overly prescriptive.

Assessing step changes for exogenous changes in volume or scale

The ENA submitted that NSPs should be able to propose step changes for exogenous changes in the volume or scale of a NSP's activity.[309] We recognise that changes in the volume or scale of a NSP's activity will change its operating and maintenance costs. However, we expect step changes will not typically be required for exogenous changes in volume or scale. This is because the rate of change formula compensates NSPs for the increased expenditure required to increase scale through the output variable. That is, the rate of change formula escalates deemed final year opex by the forecast increase in outputs. Where the output variable of the rate of change formula captures scale changes, providing step changes as well would double count those cost increases and would not be consistent with the opex criteria.

[306] APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 1–2.
[307] The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013,* pp. 5, 11.
[308] CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 12.
[309] Energy Networks Association, *AER* b*etter regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 32.

Assessing step changes to achieve dynamic efficiency

The ENA also considered NSPs should be able to propose step changes for investments that support NSPs achieving dynamic efficiency, which are not reflected in a NSP's base opex and require a change in future behaviour. It considered the value from ensuring NSPs make correct investments at the right time would outweigh the value of moving firms towards the productive efficiency frontier at a point in time. It stated this would better support the long term interests of consumers.[310]

As noted above discretionary changes, including those to improve efficiency, are unlikely to require a step change. An efficient NSP would only undertake the proposed step change if it reduces its total expenditure. These cost reductions should fund the step change. Providing a step change to undertake an activity that will reduce a NSP's expenditure, in net terms, would not be consistent with the opex criteria nor the revenue and pricing principles.

We agree there is value from encouraging dynamic efficiency and pushing out the productive efficiency frontier. This is in the long term interests of consumers. However, the ex-ante opex allowance, in tandem with the EBSS, provides this incentive. Providing a step change for these costs would not be consistent with the opex criteria.

Assessing step changes for opex associated with new capex activity

Broadly, new capex can impact opex in two ways:

1. If the new capex is to increase output then we would expect opex to increase.

2. If the new capex activity does not increase output then we would expect opex to decrease.

With regard to the first point, we recognise changes in the volume or scale of a NSPs activity will change its operating and maintenance costs. However, as discussed above, we expect the output growth component of the rate of change formula to compensate NSPs for this.

If the new capex does not increase output then it must, if it is efficient, avoid greater opex in NPV terms. That is, over the life of the new asset a reduction in opex must outweigh the new capex. In these circumstances a negative step change may be appropriate.

The ENA viewed NSPs should be able to propose step changes for the opex associated with new capex activity that base opex will not reflect.[311] However, for the reasons above, we do not typically expect new capex would necessitate a positive step change since if additional opex is required the output growth component would normally compensate NSPs for this. To the extent a positive step change for a capex/opex trade-off is appropriate we would expect this to be less than the cost of the avoided capex. We would typically expect this to be associated with an increase in the average asset age.

Assessing projects driven by consumer benefit

The Victorian DNSPs stated the definition of step changes should recognise that expenditure may be required to ensure discretionary projects in the long term interest of consumers, but are of limited benefit to the DNSP, are undertaken. They proposed, in assessing such step changes, we should consider if the proposed project is:

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310 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 32–33.

311 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 33.

- in the long term interests of consumers
- expected to be net economic benefit positive over its life
- consistent with the opex criteria.[312]

We are not satisfied, however, that any such costs would meet the opex criteria. In fact, the inclusion of the opex criteria in this submission as only one of three factors to consider inappropriately relegates those criteria. To meet the opex criteria expenditure must be required to achieve the opex objectives, being to manage expected demand, comply with regulatory obligations, and to maintain reliability, security and safety. The discretionary projects contemplated by the DNSPs here seem to do more than this. That is, they would likely improve something rather than maintain it, and therefore would not satisfy the opex criteria. The STPIS provides a mechanism whereby NSPs can be funded (through incentive payments) for delivering improvements to service outcomes.

Assessing lumpy costs

Incenta submit that rigidly applying the 'revealed cost' method has the potential to materially misstate expenditure expectations where there are material lumpy categories of operating expenditure. It considered we should explore whether there are alternative methods for deriving regulatory allowances for lumpy operating expenditure items that maintain the incentive properties of the revealed cost method and EBSS.[313]

We agree with Incenta that caution is required were there are significant lumpy costs. However, the question is not whether individual cost categories are lumpy but whether total opex is lumpy. Forecasting some categories bottom up, for example, but others using revealed cost risks upwardly biased forecasts. This is because NSPs would have an incentive to only use an alternative forecasting approach for those lumpy cost categories where expenditure is atypically low in the base year. For categories where expenditure is higher than usual in the base year they have an incentive to forecast using revealed costs. Similarly, NSPs have an incentive to use an alternative forecasting approach where work volumes are expected to increase in the next period but use revealed cost for those categories where volumes are expected to decline. Consequently there is a risk that a 'hybrid' forecasting approach will give upwardly biased forecasts. If total opex is not materially lumpy then a revealed cost forecast is appropriate regardless of whether individual categories are lumpy or not.

We also note it is possible for the incremental form of the EBSS to provide a continuous incentive with bottom up forecasts. To do this the bottom up forecasts must be used as part of a revealed cost forecast. A revealed cost forecast simply means taking actual expenditure in the base year, and then adding the incremental change in forecast expenditure over the forecast period. So a bottom up forecast can be used as part of a revealed cost forecast if it is used to set the incremental change in opex rather than the absolute amount. Intuitively this makes sense since the EBSS is an incremental, not absolute, scheme.

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312 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013,* pp. 9–10.

313 Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, pp. 13–14.

5.4 Assessment techniques

5.4.1 AER position

We propose to apply our assessment techniques to review NSP's forecast expenditure. Our assessment techniques are:

- benchmarking (economic techniques and category analysis)
- methodology review
- governance and policy review
- predictive modelling
- trend analysis
- cost–benefit analysis
- detailed project review (including engineering review).

5.4.2 Reasons for AER position

When we assess capex and opex forecasts, we may use a number of assessment techniques, often in combination. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but in general, we will follow an assessment filtering process. That is, we will apply high level techniques in the first instance and apply more detailed techniques as required. For example, for the first pass assessment, we will likely use high level economic and category level benchmarking to determine relative efficiency and target areas for further review. We will, however, also use benchmarking techniques beyond the first pass assessment.

The first pass assessment will indicate the extent we need to investigate a NSP's proposal further. Typically, we will apply predictive modelling, trend analysis and governance or methodology reviews before using detailed techniques such as cost–benefit analysis and project or program review. While we intend to move away from detailed techniques such as project reviews, we are likely to rely on them in some cases, particularly to assess capex for TNSPs.

We intend to take a holistic approach and consider the inter-connections between our assessment techniques when determining total capex and opex forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques. For example, benchmarking analysis may indicate that a DNSP's unit cost for transformers at zone substations is high relative to other DNSPs. We would not simply adjust the expenditure forecast for zone substations by applying the benchmark unit cost without reference to the other assessment techniques we have used. For example, any inference we may make about expenditure on transformers and/or zone substations might also consider analysis from other techniques such as the augex model or detailed review. In addition, we will provide the NSP the opportunity to explain the result of the benchmarking analysis and, in particular, any reasons why a particular unit cost is high relative to other DNSPs.

Some stakeholders were concerned about the application of new assessment techniques in upcoming reviews. The NSW DNSPs raised concerns about the use of untried and untested assessment tools to immediately assess the NSW DNSPs forecasts, noting that these techniques would benefit from verifying the validity and the provision of evidence that the techniques would benefit consumers in the long term.[314]

The Victorian Distributors noted that in applying a technique, the AER should consider the time expected to collect and validate data and develop and test the models, demonstrate the models satisfy the principles set out by the ENA, and whether the data collection validation and model development will be completed before the DNSP being required to notify the AER of their expenditure forecast methodologies.[315]

In contrast, other stakeholders supported the AER's approach of using a range of techniques to assess expenditure.[316] In particular, PIAC generally supports the AER applying discretion to use a variety of techniques and the reliance placed on them depending on the nature of the NSP's expenditure proposal and the robustness of the techniques. PIAC considered the AER should not confine the tools it uses in future determinations by being too specific in the application of assessment techniques set out in the Guideline.[317]

We have decided to set out a suite of assessment techniques, some of which we have applied in previous reviews and some of which are new. New techniques, such as economic benchmarking and category analysis are aimed at providing us with information about the efficiency of NSPs expenditure that our existing techniques, we intend to do this over time in the context of the principles rather than excluding new techniques from the Guideline. In particular, the extent to which some techniques compare in relation to others in light of the principles will depend on the extent to which they have been developed.

That said, stakeholders did question the extent to which the techniques would be complimentary and provide the AER with additional information to assess expenditure proposals.[318] We are mindful that not all assessment techniques and forecasting methods will necessarily reinforce each other. Where there are differences between the findings of different techniques we will turn our mind to the reasons for this, consistent with our experience in reconciling alternative forecasting approaches in previous reviews.

Benchmarking

Benchmarking compares standardised measurements from alternative sources. We will be using benchmarking techniques more widely than in the past.

A number of stakeholders supported the use of benchmarking as an assessment tool in the Guideline.[319] PIAC noted that the application of economic benchmarking and category benchmarking

314 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, p. 10.

315 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013*, p. 4.

316 Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013 p. 3; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 9–10; Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013 p. 1; Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 21.

317 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 9–10.

318 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 10.
Huegin, *Submission on the AER Expenditure Guidelines, A review of the benchmarking techniques proposed*, 20 September 2013, p. 7.

319 Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013 p. 3; Public Interest Advocacy

would provide the AER with a balanced perspective. PIAC noted that too much emphasis on the high-level economic benchmarks would open the door to claims by NSPs that comparisons are not valid. In contrast, too much focus on the categories and sub-categories would lead to it becoming increasingly difficult to draw meaningful comparisons of the overall efficiency NSPs expenditures (including any opex and capex trade-offs).[320]

In contrast, the NSW DNSPs considered that category and economic benchmarking would be of limited value. In particular, the NSW DNSPs noted that the investment cycles of DNSPs are so disparate as not to enable like for like comparisons, and the Guideline does not explain how the AER will account for these differences. The NSW DNSPs also noted that NSPs do not have like for like approaches to categorising expenditure or reporting unit costs.[321]

We acknowledge that different benchmarking tools might have different roles in the expenditure assessment process, but note PIAC's view that it may be appropriate for the AER to place reliance on both in forming a view about forecast expenditure.

While we note that the use of some assessment techniques may increase over time as the size of data sets increase we do not consider that benchmarking will be of limited value. We are aware there are differences between NSPs operating environments that do need to be considered or accounted for where possible, but this should be put in the context of the common nature of the services provided and types of costs incurred by DNSPs and TNSPs in the NEM. In terms of accounting for differences, we have set out how particular techniques can account for differences in our category analysis and economic benchmarking work-streams (as set out in Attachments A and B). We note that a substantial amount of time has been devoted to setting out like for like reporting approaches in these work-streams.

Economic benchmarking

Economic benchmarking applies economic theory to measure the efficiency of a NSP's use of inputs to produce outputs, having regard to environmental factors. It will enable us to compare the performance of a NSP with its own past performance or the performance of other NSPs.

We propose to take a holistic approach to using economic benchmarking techniques, but intend to apply them consistently. We will determine which techniques to apply at the time of determinations, rather than specify economic benchmarking techniques in our Guideline. This will allow us to refine our techniques over time.

In determinations, we will use economic benchmarking models based on their intended use, and the availability and quality of data. Some models could be used to cross-check the results of other techniques. At this stage, it is likely we will apply multilateral total factor productivity (MTFP), data envelopment analysis (DEA) and an econometric technique to forecast opex. We anticipate including economic benchmarking in annual benchmarking reports.

We are likely to use economic benchmarking to (among other things):

Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 15; Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013,p. 18; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013,, p. 12.

320 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013,p. 15.

321 NSW DNSPs , *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, p. 8.

1. measure the rate of change in, and overall efficiency of, NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.

2. develop a top down total cost forecast of total expenditure.

3. develop a top down forecast of opex taking into account:

    - the efficiency of historical opex

    - the expected rate of change for opex.

Economic benchmarking will also indicate the drivers of efficiency change which will assist us in targeting our expenditure reviews.

We received a number of submissions on economic benchmarking (including on the extent to which the AER should expand its data set by looking at international benchmarking. These submissions are considered in Attachment D.

Category level benchmarking

Category level benchmarking allows us to compare expenditure across NSPs for categories at various levels of expenditure. It can inform us, for example, of whether a NSP's:

- base expenditure can be used for trend analysis

- forecast unit costs are likely to be efficient

- forecast work volumes are likely to be efficient

- forecast expenditure is likely to be efficient.

Category level benchmarking may also provide information to NSPs on where they may achieve efficiencies in their operations. For these reasons, we consider category benchmarking is justified as it should improve the effectiveness of our assessment and may assist NSPs in improving their operations over time.

We do not believe there is any inconsistency between the use of benchmarking and incentive regulation. While we prefer light handed incentive regulation, we expect benchmarking will create further incentives for NSPs to achieve efficiencies, and importantly, for customers not to be paying for inefficiency. This may be particularly useful when NSPs do not respond to the current regulatory regime's financial incentives.

At a minimum, we intend to use benchmarks to target further assessment. How determinatively we will use the results of benchmarking (or any technique) will depend on the results, considered in light of other information.

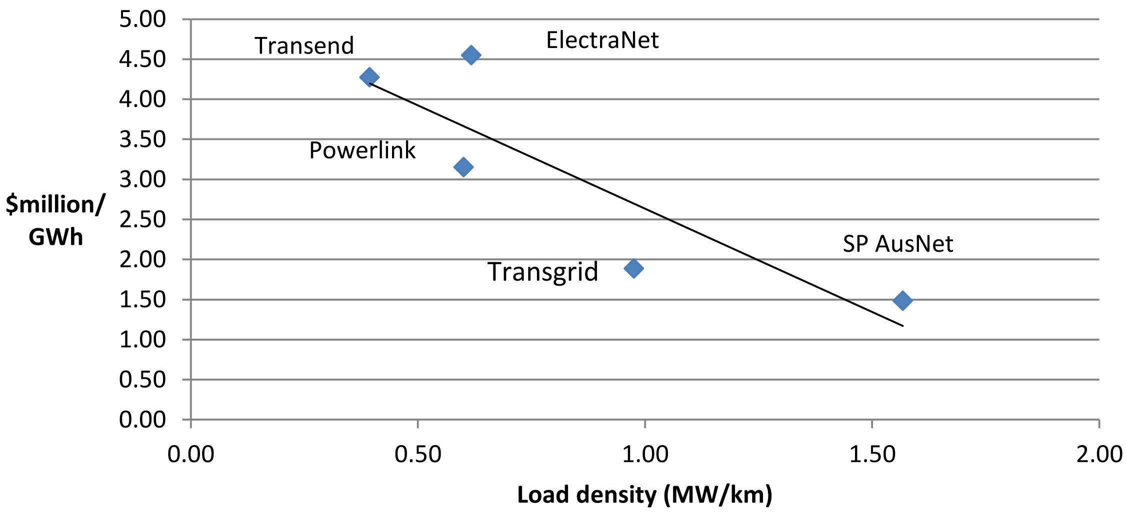
During consultation we discussed the prospect of developing a "price book" of project cost components for benchmarking transmission capex projects. This was considered relevant given the heterogeneity of such large projects, although the cost of more specific asset components may be more consistent and amenable to comparison. We typically ask our consultants to examine this level of detail in transmission capex assessments, but we see benefit in collecting and assessing this information ourselves. The Australian Energy Market Operator (AEMO) has already begun collating information that might be useful for this purpose. We will continue to liaise with AEMO and the TNSPs regarding the usefulness of this information.

Submissions on particular aspects of category level benchmarking are considered in Attachment B.

Aggregated category benchmarking

As well as category benchmarks, we will continue to use aggregated category benchmarks such as those presented in recent AER publications. Aggregated category benchmarking captures information such as how much a NSP spends per kilometre of line length or the amount of energy it delivers. Figure 5.1 provides a recent example of such benchmarking used in the issues paper published on the SP AusNet transmission revenue proposal.[322]

Figure 5.1 Opex/electricity transmitted ($million, nominal)



We intend to improve on these benchmarks by capturing the effects of scale and density on NSP expenditures. Overall, these data are already available and hence impose limited additional burden on NSPs in terms of data reporting.

Table 5.1 lists expenditures to be used and example scale/ density metrics. We will consult further with stakeholders about these classifications and their use. For example, these types of benchmarks may feature more heavily in annual benchmarking reports in lieu of more detailed benchmarking analysis (which may not be amenable for a summary annual report). We may also consider selectively publishing aggregated benchmarks alongside more detailed measures if they both highlight an issue with a particular activity or type of expenditure.

Table 5.1 Example category expenditure benchmarks

Expenditures	Volume metrics
$ total capex, opex	Customer numbers/connections
$ repex, augex, maintenance etc	Line length (km)
$ repex, augex etc per customer or km of line etc	RAB (depreciated and at current replacement cost)
	Customer numbers, energy delivered (GWh) and maximum demand per km of line

322 AER, *Issues Paper– SP AusNet's electricity transmission revenue proposal 2014–15 to 2016–17*, 1 May 2013, p. 31.

	Maximum demand (MW) per customer
	Maximum demand (MW) per km of line
	Network area serviced (km^2)
	Employee numbers

Methodology review

We will assess the methodology the NSP utilises to derive its expenditure forecasts, including assumptions, inputs and models. Similar to the governance framework review (see section 2.2.2), we will assess whether the NSP's methodology is a reasonable basis for developing expenditure forecasts that reasonably reflect the NER criteria.[323]

We expect NSPs to justify and explain how their forecasting methodology results in a prudent and efficient forecast. If a methodology (or aspects of it) does not appear reasonable, we will require further justification from the NSP. If we are not satisfied with further justification, we will adjust the methodology such that it is a reasonable basis for developing expenditure forecasts that reasonably reflect the NER criteria.[324] This is similar, for example, to our past assessments of the probabilistic models that some TNSPs used to develop augex forecasts. We assessed the model and generally found it to be reasonable. On the other hand, we did not consider inputs to the model such as the demand forecast or certain economic scenarios to be reasonable in some cases. We therefore made adjustments to those particular inputs to the model.[325]

We consider a good expenditure forecasting methodology should reflect the principles set out in section 5.5 and result in forecast expenditure that is accurate and unbiased.

The ENA raised concern about the expectation that NSPs should apply the principles in contrast with the AER’s position that it “may” but need not, apply the principles in its assessment. The ENA did not consider that it was appropriate for the AER to prescribe in the Guideline or the Explanatory Statement the nature, or features of the NSP’s forecasting method.[326]

We agree that the Guideline cannot prescribe the methodology applied by the NSP in developing its expenditure forecasts. However, we consider that it is consistent with the intent of this Guideline for us to provide guidance to NSPs about what we consider the characteristics of robust forecasting methodologies are. The principles are our current views of these characteristics, and we hope that this guidance will assist NSPs in preparing their forecasting methodologies.

Governance and policy review

A governance framework includes the processes by which a business goes about making investment and operational decisions to achieve its corporate goals. This involves development of investment plans and their efficient execution in consideration of a firm’s key policies and strategies. A good governance framework should:

323 NER, clauses 6.5.7(c) and 6A.6.7(c).
324 NER, clauses 6.5.7(c) and 6A.6.7(c).
325 For example, see AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2011, pp. 107–17.
326 Energy Networks Association, *AER* b*etter regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013,p. 20.

- identify network requirements
- develop viable options to meet these requirements
- result in a forecast of the expected expenditure to meet these requirements.[327]

This should directly lead to a relatively detailed list of network projects and activities that can then be further developed, evaluated and implemented as required. Through each stage of the governance processes there are checks to ensure the chosen investment or activity remains the best choice for the firm to make in the context of current policies and strategies. The governance framework encompasses all facets and levels of decision making, including asset management plans and business cases.

We will assess a NSP's governance framework against good industry practice. This will include assessment of asset management plans to determine if they are consistent with incurring efficient and prudent expenditure. The assessment will indicate whether the strategies, policies and procedures employed by the NSP would produce forecasts that reflect the expenditure criteria.[328] The assessment will also inform our detailed reviews, including identifying areas for detailed review, as well as the derivation of alternative forecasts if necessary (similar to past distribution and transmission determinations).[329]

We can use documents such as the Publicly Available Specification PAS 55:2008 and the International Infrastructure Management Manual for guidance and criteria on good industry practice.[330]

Where a NSP's governance framework is consistent with good industry practice, we will assess whether the NSP's capex forecasts replicate the outcomes of good governance. This includes assessing, in our detailed project reviews, whether the NSP appropriately utilised its capital governance framework when developing its capital program. If so, this may support an assessment that the NSP’s capex forecast reasonably reflects the capex criteria. However, findings of good governance will not be in any way determinative that expenditure forecasts are efficient and prudent. We expect a NSP to explain any departures from the framework.

Where a NSP's governance framework is not consistent with good industry practice, we will note which aspects of the framework the NSP can improve in future regulatory control periods. We may also use findings in relation to the governance framework to better target detailed project reviews on potential areas of concern. The more significant a framework's shortcomings, the less confidence we would have that the NSP can rely on the framework to produce a capex forecast that meets the NER criteria.[331] While not generally examined in detail, we may also assess the governance framework as it applies to opex decisions.

COSBOA had limited faith in the ability of methodology reviews, and governance and policy reviews to determine efficient expenditure by NSPs. COSBOA considered that such techniques should not be

[327] British Standards Institution, *Publically Available Specification 55*, 2008 (PAS 55).
[328] NER, clauses 6.5.7(c) and 6A.6.7(c).
[329] For example, see AER, *Draft decision: Aurora Energy Pty Ltd distribution determination 2012–13 to 2016–17*, November 2011, p. 114.
[330] Our consultants have referenced these documents in past determinations, for example: EMCa, *ElectraNet revenue determination: Technical review: Advice on forecast capital and operating expenditure, contingent projects and performance scheme parameters: Public (redacted) version*, 30 October 2012, p. 44; Nuttall Consulting, *Report – Capital expenditure: Victorian electricity distribution revenue review*, 4 June 2010, p. 41.
[331] NER, clauses 6.5.7(c) and 6A.6.7(c).

relied upon to set allowed expenditures and should be only be used if necessary (e.g., they can add something to the AER's decisions).[332]

We acknowledge that methodology and governance reviews aren't assessment techniques that produce an alternative efficient allowance themselves. However, these techniques do provide information regarding whether the process used by the NSP to develop the forecast was sound. These assessment techniques, in combination with other techniques, provide a set of information of assistance to the AER in forming a view about an NSP's forecast expenditure.

Predictive modelling

Predictive modelling uses statistical analysis to determine the expected efficient costs over the regulatory control period associated with the demand for electricity services for different categories of works.

We acknowledge that modelling will generally be a simplification of reality and will have inherent limitations as a result. We will consider any limitations in the modelling when using the results of modelling in our assessment.

The MEU was strongly supportive of the use of predictive models as they would provide a good indication of what level of expenditure is appropriate (such as repex and augex), recognising the inherent risks of using such models as definitive tools for setting allowances.[333] In contrast, COSBOA considered that the limitations associated with such tools may lead them to being of narrower value.[334] The NSW DNSPs expressed concerns about the deterministic use of the repex model.[335]

More detail on predictive modelling and submissions on its use are considered in Attachment A which covers the modelling of replacement and augmentation capex.

Trend analysis

We will compare a NSP's forecast expenditure and work volumes to its historical levels. In doing so, we will expect NSPs to explain where its forecast expenditures and volumes are materially different to recent history. In the absence of such explanation, we may conclude the NSP's forecast expenditure is not efficient and prudent. In such a case, we may consider historical expenditure in determining the best estimate of forecast expenditure.

We consider trend analysis provides a reasonably good technique for estimating future expenditure requirements where historical expenditure has similar drivers to future expenditure and these drivers can be forecast.

COSBOA supported the application of trend analysis, but considered it should be used according to fitness-for-purpose and should support not supplant other, more powerful techniques.[336] We agree that trend analysis should be applied when it is fit for purpose, and should not supplant other techniques where they are more relevant.

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332 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 15.

333 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 17.

334 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 15.

335 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, pp. 8,. 12–14.

336 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 15.

Cost–benefit analysis

Cost–benefit analysis is critical to best practice decision making. While the level of analysis may vary with the value of the expenditure, firms in competitive markets will normally only undertake investments they consider will create wealth for their shareholders. This requires the investments be net benefit positive. With the exception of expenditure to meet binding legal obligations, we consider economic justification for expenditure by a monopoly network business also requires positive expected net benefits demonstrated via cost benefit analysis.

All expenditure also needs to be prudent. To show efficiency we consider cost benefit analysis will normally be required to show the option chosen has the highest net benefit.[337] To demonstrate prudence, firms will need to show the decision reflects the best course of action, considering available alternatives. Generally, the project with the highest net benefit will have the lowest life cycle costs when compared to other projects on an equivalent basis. We consider this is consistent with achieving the lowest sustainable cost to achieve the network supply and reliability outcomes sought.

If options analysed have different characteristics, NSPs should show via cost benefit analysis that the option chosen is efficient relative to other options. For example, a cost benefit analysis could show a higher cost option is efficient over its life cycle due to a longer life, due to lower operating costs, or due to higher reliability. This means options must be directly comparable (for example via making lives comparable and comparing net benefits in present value terms) and all material incremental cost and benefits of different options should be accounted for.

In the absence of adequate economic justification and demonstration of the efficiency and prudency of the option selected, we are unlikely to determine forecast expenditure is efficient and prudent.

COSBOA considered that cost-benefit analysis can help to establish efficiency and prudency, particularly of projects, but also noted that it was prone to limitations and can be data/resource intensive. COSBOA considered cost-benefit analysis should be used sparingly to add to gaps in the AER's assessment, or where detailed assessment of projects is justified.[338]

PIAC supported the AER's view on the importance of cost benefit analysis to support projects or programs, but noted that in the past reviews not all projects for which increased expenditure had been sought had been subject to a formal cost-benefit study at the time of the proposal to the AER. PIAC considered that such major projects should not be accepted in future revenue determinations in the absence of an appropriate cost-benefit study.[339]

The MEU considered that there is a need to link actual costs incurred to those outlined in the regulatory investment test (RIT) to ensure that there has not been inefficient investment. The MEU considered that the AER should require the NSP to report its actual costs of the project compared to the RIT allowance and advise on any cost variances (and reasons) at the time the project us complete.[340]

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337 This is consistent with showing the expenditure results in the lowest sustainable cost. Where the investment cost outweigh the benefits, the cost benefit analysis should show the chosen option is the least negative from net benefit perspective.

338 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013 p. 15.

339 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 16.

340 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 15–16.

We are aware that our assessment needs to be commensurate with the task at hand, and note that this would lead us to expect to see cost benefit analysis applied in consideration of projects or programs of work. Indeed, this type of analysis is undertaken in the context of the RIT for transmission and distribution. The lack of cost benefit analysis supporting a project or program, or significant divergences between RIT and regulatory proposal forecasts would be relevant considerations in forming a view about proposed expenditure.

Detailed project review (including engineering review)

While new assessment techniques will allow us to rely less on detailed project review, we will continue to use it to assess expenditure, particularly for TNSPs, who tend to commission smaller volumes of large, high cost projects. However, our new assessment techniques will allow us to use detailed project review in a more targeted manner. We are likely to continue to perform detailed reviews of a sample of projects from different expenditure categories to inform our assessment of expenditure forecasts in those categories, with the assistance of technical consultants.

The detailed reviews will assess whether the NSP used processes that would derive efficient design, costs and timing for each project. This includes assessing whether the NSP followed good governance in developing each project and the business cases, cost–benefit analysis and other economic justification for the proposed project. If we find any sources of inefficiency, we will make the necessary adjustment(s) so the project costs reflect efficient costs. The detailed reviews will likely assess:

- the options the NSP investigated to address the economic requirement. For example, for augmentation projects:
  - the extent to which the NSP considered and provided for efficient and prudent non-network alternatives[341]
  - net present value analysis including scenario and options analysis
  - regulatory investment tests for transmission (RIT-Ts) and regulatory investment tests for distribution (RIT-Ds), if available
- whether the timing of the project is efficient
- unit costs and volumes, including comparisons with relevant benchmarks (see Attachment C)
- whether the project should more appropriately be included as a contingent project[342]
- deliverability of the project, given other capex and opex works
- the extent to which the NSP consulted with electricity consumers and how the NSP incorporated the concerns of electricity consumers in developing the project.[343] This is most relevant to core network expenditure (augex and repex) and may include the NSP's consideration of the value of customer reliability (VCR) standard or a similar appropriate standard.

[341] NER, clauses 6.5.7(c)(10) and 6A.6.7(c)(12).
[342] This principally relates to augex. See NER, clauses 6.5.7(c)(9A) and 6A.6.7(c)(10).
[343] NER, clauses 6.5.7(c)(5A) and 6A.6.7(c)(5A).

Technical experts will usually help us conduct these assessments by providing detailed engineering advice. We have previously received support for obtaining technical advice.[344]

We consider project review (including engineering review) will often be critical to assess expenditure forecasts. We also consider that assessments should be rigorous, fully justified and properly substantiated. However, the level of rigour and justification of techniques will often be proportionate to the value of the technique's output to the assessment process.

In line with stakeholder comments received in response to the issues paper[345] and also in response to the draft Guideline[346] we intend to target detailed project and engineering reviews and use these when other assessment techniques may be lacking.

5.5 Assessment principles

We have a number of assessment techniques available to us, including some we have not used before. Our assessment techniques may complement each other in terms of the information they provide, so we can use them in combination when forming a view on expenditure proposals. Accordingly, we have a holistic and flexible approach to using our assessment techniques.

This means we intend to give ourselves the ability to use all of our techniques when we assess expenditure, and to refine them over time. Depending on the assessment technique, we may be able to use it to assess expenditure in different ways—some that may be more robust than others. For example, while we intend to use economic benchmarking techniques, it may not be appropriate to use a data intensive benchmarking technique such as stochastic frontier analysis (SFA) until we can obtain robust data. However, this does not mean it will never be appropriate to use SFA.

5.5.1 AER position

We have added the principles to the Guideline, and may consider the principles where we need to form a view on our reliance on alternative assessment techniques, the NSP's forecasting methodology (or both).

This does not mean we intend to set out a detailed consideration of every principle whenever we choose a technique to assess expenditure—every principle may not always be relevant. While the principles are matters that we consider would be relevant in a comparison of alternative assessment techniques or forecasting methods, they do not limit the matters to which we could have regard to. It may also be that there are specific matters that become relevant in the context of a particular

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344 Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, p. 12; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper,* 15 March 2013, p. 3 Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator,* 15 March 2013, p. 9; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A – Expenditure forecast assessment guideline,* 15 March 2013, p. 5.

345 Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper,* 15 March 2013, p. 3.
Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator,* 15 March 2013, p. 9.
CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Attachment A – Expenditure forecast assessment guideline,* 15 March 2013, p. 5; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper, Australian Energy Regulator,* 15 March 2013, p. 9.

346 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 15–16.

determination that we should consider. We have set this out alongside the following principles in the Guideline.

Validity

Overall, we consider a technique must be valid, otherwise it is not useful. That is, it must be appropriate for what we need it to assess. In our case, this is typically efficiency (or inefficiency).

The PC suggests that valid techniques should account for time, adequately account for factors outside the control of NSPs and (where possible) use reliable data.[347] Generally, we will not be in a position to satisfy ourselves whether a technique is appropriate until after we receive data or information to test it.

Accuracy and reliability

We consider a technique is accurate when it produces unbiased results and is reliable when it produces consistent results. In our view, objective techniques (based on actual data) are inherently more accurate than subjective techniques (based on judgement); they are less susceptible to bias and therefore others can judge them fairly. Reliable techniques should produce similar results under consistent conditions. In some cases, techniques may require testing and calibration for us to be satisfied of their accuracy and reliability.

Robustness

Robust techniques remain valid under different assumptions, parameters and initial conditions. However, we also consider robust techniques must be complete. A technique that is lacking in some material respect cannot be robust.

Transparency

A technique that we or stakeholders are unable to test (sometimes referred to as a 'black box') is not transparent because it is not possible to assess the results in the context of the underlying assumptions, parameters and conditions. In our view, the more transparent a technique, the less susceptible it is to manipulation or gaming. Accordingly, we take an unfavourable view of forecasting approaches that are not transparent.

Parsimony

Multiple techniques may be able to provide the same information, but to varying degrees of accuracy and with varying degrees of complexity. We will typically prefer a simpler technique (or one with fewer free parameters) over more complex techniques, if they measure equally against other principles. Where possible, we intend to move away from assessment techniques that draw us and stakeholders into unnecessary detail when there are alternative techniques. We reiterate that our role is to assess total capex and opex forecasts. The NER do not require us to assess individual projects.[348]

Fitness for purpose

We agree with the PC that it is important to use the appropriate technique for the task.[349] As explained in our issues paper, no technique that we or NSPs rely on can produce a perfect forecast.[350]

[348] AEMC, *Rule determination*, 29 November 2012, p. 113.
[349] Productivity Commission, *Electricity Network Regulatory Frameworks – Final Report*, Volume 1, 9 April 2013, p. 181.
[350] AER, *Guidelines issues paper*, December 2012, p. 22.

However, the NER does not require us to produce precise estimates.[351] Rather, we must be satisfied that a NSP's forecast (or our substitute forecast) reasonably reflects the expenditure criteria. Accordingly, we will consider fitness for purpose in this context.

5.5.2 Reasons for AER position

We have decided to include the principles in the Guideline as they provide guidance to stakeholders on the matters that we may consider when presented with alternative assessment techniques or forecasting methodologies.

A number of stakeholders considered that the principles should be in the Guideline[352], noting that the inclusion of principles would provide guidance on how we would compare alternative assessment techniques or forecasting methods. However, NSPs and other stakeholders also noted that our primary considerations were the NER and the NEL and that the principles could not displace these.[353] Further, some stakeholders sought clarification on how the principles, techniques and information would be used to assess a NSP's forecast under the NER.[354]

While we have decided to include the principles in the Guideline, the principles are merely the AER's our view of the relevant considerations in making such an assessment — they do not displace the NER, which we agree are (along with the NEL) the AER's our primary consideration in assessing expenditure forecasts. In our view, the principles relate to the methods used to assess or forecast expenditure, rather than characteristics that forecast expenditure should reflect, which is set out in the NER.

The balance between certainty and flexibility

As mentioned above, some stakeholders considered that we had achieved an appropriate balance between providing certainty to NSPs and flexibility for the AER in the Guideline.[355]

PIAC noted the natural concern by some NSPs that this flexibility is introducing new uncertainties into the regulatory assessment process, but contended that the Guideline is not the place for such certainties. PIAC submitted that we had approached the question correctly by clearly setting out our broad principles for selecting different assessment techniques with our current views about the

351 AEMC, *Rule determination*, 29 November 2012, p. 112.

352 APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013,, p. 1; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 19; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 17; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission,* 20 September 2013, p.4; SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013 p. 1.

353 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 5; Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 6; Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission,* 20 September 2013, p. 4.

354 ActewAGL, *Response to AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 2; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013; Australian Energy Market Operator, *AEMO submission on AER on expenditure forecast assessment guidelines*, 23 September 2013, p. 3; Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 7–8.

355 Australian Energy Market Operator, *AEMO submission on AER on expenditure forecast assessment guidelines*, 23 September 2013, p. 3; Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 9–10.

strengths and limitations of the various techniques and where they are likely to add value in the regulatory determination process.[356]

In contrast, a number of other stakeholders sought an increase in the level of detail in Guideline to provide specific guidance on the circumstances in which each technique would be used, including on how we would weight the techniques. [357] The ENA proposed a series of additional weighting factors to include in the Guideline. The ENA additionally sought for us to extend the principles to apply to data as well as techniques and provided revised detailed definitions for some principles.[358]

In light of the views expressed by stakeholders, while we have decided to include the principles in the Guideline, we have decided against increasing the level of prescription within the principles by adding weighting factors or adopting more detailed definitions. We are not suggesting that the matters raised by the ENA on the descriptions of each of the principles are not relevant. Instead we are concerned that setting out this level of detail more narrowly confines the scope of the principles beyond what we consider appropriate.

As noted by the ENA, the principles are more accurately described as matters that we would have regard to in considering assessment techniques or forecasting methods.[359] We consider that this is the correct way of characterising the principles given that the NEL and NER are the primary considerations in forming a view on a NSP's forecast expenditure. For clarity, we consider that the principles would also be relevant to the level of reliance or weight that we place on a particular assessment technique or forecasting methodology amongst other techniques. We have amended the wording of the principles to better convey this perspective.

Comments on particular principles

COSBOA generally supported the list of principles in the draft Guideline, noting that they should support the assessment process, assist consumers to engage in and understand it, and help maintain control over detailed information requirements. In particular, COSBOA submitted we should retain the principle of parsimony, as it was concerned to ensure that we do not become overly zealous and unfocused in our pursuit of information.[360]

CitiPower, Powercor and SA Power Networks expressed concern about our statement that benchmarking is inherently more accurate than engineering reviews, contending that this was unfounded since both methods are subject to error and unlike benchmarking, engineering assessments directly consider the specific circumstances of the NSP.[361]

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356 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 10.

357 APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013, p. 1; CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 4; Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 7–8,,27.

358 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 27.

359 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 17.

360 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 19–20.

361 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 5.

Beyond suggesting that the AER should include more detailed descriptions of each of the principles, the ENA made the following points:[362]

- the principle of 'validity' was not required as it was covered under the principles of 'accuracy and reliability' and 'fitness for purpose'. It also considered that the reference to using reliable data 'where possible' should be removed.
- 'parsimony' should not be included as a principle as relative complexity of an assessment technique should not guide the selection of techniques.
- the principle of 'accuracy and reliability' should not make a distinction between objective and subjective as this did not say anything about the technique's accuracy.
- 'consistency and predictability' should be added to the principles. The ENA considered that consistency would create a tendency for the same techniques to be applied in the same circumstances, and be applied in a way that results in the assessment technique producing accurate and reliable results over time.

Broadly, we are not convinced there is merit in debating which principles should or should not be included in the Guideline. We are not committing to applying only or all of those in the Guideline at the time of review. Having said that, however, we disagree with the ENA's suggestions.

We do not agree with the ENA's view that the principle of 'validity' overlaps with the principle of 'fitness for purpose'. 'Validity' relates to extent to which a measure does what it claims to do, whereas 'fitness for purpose' acknowledges that a measure used for an informative purpose need not be as precise as a measure used determinatively.

We also do not agree with the ENA's view that 'parsimony' should be excluded as we consider that assessment methods or forecasting models should be no more complex than required. The description of the principle of parsimony recognises that it becomes relevant where the alternative assessment techniques or forecasting methods measure equally against the other principles.

We have decided to retain the reference to objective and subjective techniques in the description of 'accuracy and reliability', as we consider that subjective judgement may be less likely to provide unbiased estimates — particularly in contrast to techniques where approach and calculations are set out. However, noting CitiPower, Powercor and SA Power Networks' concern, we have decided to modify the description of 'accuracy and reliability' to replace the reference to specific methods to the particular attribute we are concerned about (data-based methods compared to those based on judgement).

We have decided not to adopt the ENA's proposed 'consistency and reliability' principle, as we consider that the substance of this principle is covered by the 'accuracy and reliability' principle.

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362 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 20–21, 24, 21–22, 26.

6 Consideration of incentive frameworks

This chapter considers the interaction between incentive frameworks and our approaches to assessing capex and opex forecasts.

We apply three incentive schemes: the Efficiency Sharing Benefit Scheme (EBSS), the STPIS and the demand management incentive scheme (DMIS).[363] In consultation with industry, we have developed a Capital Expenditure Sharing Scheme (CESS) and reviewed the EBSS as part of the Better Regulation program.

Our expected approach to assessing expenditure forecasts for the next regulatory period will affect incentives in the current period. Our default approach for opex is to rely on revealed expenditure in a single year. This influences the design of EBSS so that it delivers continuous incentives. However, we may use information other than a NSP's historical expenditure to assess and set forecast allowances. This section considers when we may depart from the revealed cost approach and should be read in conjunction with section 5.3.

For capex, our approach to ex post reviews may overlap with our assessment of expenditure forecasts. That is, in our ex-post review of capex, some of the results of expenditure forecast assessment techniques may be considered. Particularly, the results of benchmarking and the review of governance procedures may be of particular relevance.

While issues of demand management and service performance outcomes affect our expenditure forecast assessment, our assessment approach does not materially affect the incentives in the STPIS and the current DMIS.

This chapter should be read alongside the explanatory statements for the revised EBSS and CESS which more thoroughly examine the application of incentives.

6.1 Overview of incentive arrangements

6.1.1 Operating expenditure objectives

The EBSS shares opex efficiency gains and losses between NSPs and network users. The specific design of the EBSS addresses two issues:

1. If we set forecast opex allowances with reference to revealed costs in a specific year, the NSP has an incentive to increase its expenditure in that year so as to increase its opex allowance in the following regulatory control period.

2. Similarly, if we apply a revealed cost forecast, a NSP that is able to reduce (recurrent) expenditure near the beginning of the regulatory control period can retain the benefits of that reduction longer than if it were to reduce expenditure closer to the end of the period. Consequently, incentives weaken over the period.

[363] Under clause 6.6.3 of the NER we have the ability to publish a demand management and embedded generation connection incentive scheme (DEMEGCIS). Though we have not published a NEM wide DMEGCIS, under a previous version of the NER, we have prepared consistent demand management incentive schemes for each jurisdiction. Any new scheme will be developed following completion of the AEMC's forthcoming DMEGCIS rule change process.

The EBSS allows NSPs to retain the benefits of efficiency gains (losses) for the length of the carryover period, typically five years, irrespective of the year NSPs make the gain (loss). This provides NSPs a continuous incentive to pursue efficiency gains over a regulatory control period.

The current EBSS[364] is designed to work where opex is forecast using a single year of revealed costs (Box 6.1).

Box 6.1 Revealed costs, exogenous forecasts and the base-step-trend forecasting approach

A revealed cost forecasting approach relies on the historical costs (revealed costs) of the NSP. Where incentives are effective, a NSP's actual expenditures should 'reveal' its efficient costs. We do not, however, automatically assume incentives have been effective—we test this before relying on revealed costs. Revealed costs may mitigate the problem of information asymmetry faced by regulators of natural monopolies. An alternative method is to use exogenous forecasts, which could be based on the benchmark costs of another NSP, or on the estimated costs of undertaking activities. Because NSPs cannot influence exogenous forecasts through their actual performance these different forecast approaches have different incentive effects.

We commonly use the 'base-step-trend' approach to assess and determine forecast opex. This revealed cost approach uses a 'base year' of expenditure as the basis for the forecast. We then adjust it to account for changes in circumstances between the base year and the forecast period. These adjustments to base opex ensure it reflects prudent and efficient costs. This is particularly necessary if an EBSS was not in place in the base year regulatory control period. We then trend forward base opex by accounting for forecast changes to input costs, output growth and productivity improvements in the forecast period. Finally, we add any other efficient costs not reflected in base opex or the trend (referred to as step changes).

Typically, we use the revealed costs of the second or third last year in a regulatory control period as the base year. The second last year is the most recent available data at the time of the determination and likely to best reflect the forecast period. Sometimes, we use the third last year, being the most recent year of available data when the NSP submitted its regulatory proposal.

If the NSP does not expect its opex allowance to be set based on its revealed costs, the incentive properties of the existing EBSS will be affected. If we apply a pure exogenous forecast, there is no link between a NSP's actual expenditure and its forecasts, so the incentive to inflate base year expenditures (explained above) does not exist. Further, a NSP will retain all the benefits of reducing its expenditure since its allowance in the following period will be the same regardless, and will bear all the costs if its expenditure is above the exogenous allowance.

6.1.2 Capital expenditure incentives

We must make an ex post review of the prudency and efficiency of actual/historical capex[365] and some of our techniques for undertaking an ex post review may be common to our ex ante assessment of capex forecasts.

The CESS will share the rewards/penalties of underspends/overspends of forecast allowances between NSPs and their customers. Our proposed forecasting approach for capex does not rely on a particular method, including any pre-commitment to use base year expenditures. In this way, the incentives created under the CESS are not dependent on our forecasting approach in the same way as opex.

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[364] AER, *Electricity distribution network service providers efficiency benefit sharing scheme*, Version 1, June 2008; AER, *Final Electricity transmission network service providers efficiency benefit sharing scheme*, Version 1, September 2007.

[365] NER clauses S6.2.2 and SA6.2.2.

6.1.3 Service performance and demand management incentives

The STPIS provides an incentive for a NSP to maintain and improve the reliability of network services. The DMIS provides incentives for DNSPs to implement efficient non-network alternatives, or to manage the expected demand for standard control services.

6.2 AER position

6.2.1 Operating expenditure

Our opex forecasting assessment approach will impact NSPs' incentives to pursue efficiency gains. It is therefore appropriate to outline how we will forecast opex in advance of our determinations.

We will continue using a revealed cost base-step-trend forecast, in tandem with the current EBSS. We can thus perform a non-intrusive assessment of and determination on opex allowances. Our approach relies on the incentive framework to encourage NSPs to achieve continual efficiency gains. Further, it is appropriate for forecasting opex, given its recurrent nature.

In some instances, the revealed cost approach is not appropriate because historical expenditures are inefficient and revealed costs will not provide efficient forecasts. Specifically, the revealed cost approach may not be appropriate when a NSP is materially inefficient compared to its peers. A revealed cost forecast would yield an outcome inconsistent with the opex criteria, taking into account the opex factors.

For this reason we will scrutinise the efficiency of the base year expenditure. If we identify the above concerns, we will consider adjusting that base year. We will combine the accepted base year with our step-trend approach to set a forecast opex allowance for the regulatory control period.

Base year adjustments

We may make base year adjustments for two reasons:

1. a NSP's recurrent expenditure is inefficient compared to its peers
2. a NSP's base year expenditure is not reflective of efficient recurrent expenditure due to a one-off factor in the base year.

In deciding whether a NSP's expenditure is inefficient, we will consider:

- the results of our expenditure review techniques, including economic benchmarking, category analysis and detailed engineering review
- the NSP's proposal and stakeholder submissions.

If we find a NSP's expenditure to be inefficient after we review the NSP's proposal and other relevant information, we will consider whether applying the proposed base year would result in efficient outcomes. If we make an adjustment, it would likely be only to the extent required to address the inefficiency. We will then adjust the accepted or adjusted base year expenditures for step changes and trend adjustments as per the Guideline.

6.2.2 Capital expenditure

Our capex forecast assessment approach may overlap the ex post review of capex. For example, we may use an engineering review of projects/programs and a review of governance procedures, for both ex post and ex ante capex assessments. Further, we may apply benchmarking to review the efficiency of historical expenditure decisions. In ex post reviews, however, we must account for only information and analysis that the NSP could reasonably be expected to have considered or undertaken when it spent the relevant capex. For this reason, some differences may arise between our capex forecast assessment approach and our ex post expenditure review.

6.3 Reasons for AER position

6.3.1 Operating expenditure

Under the NER we must accept or not accept a NSP's opex forecast.[366] Whether we consider the proposed forecast reasonably reflects the opex criteria governs this choice. If we do not accept the forecast, we must estimate the required expenditure that reasonably reflects the opex criteria. The criteria provide that the forecast must reasonably reflect the efficient costs that a prudent operator would require to meet expenditure objectives given a realistic forecast of demand and cost inputs.[367]

A NSP's expectation about how its opex allowance will be forecast in the following regulatory control period influences its incentive to improve opex efficiency. Our preferred opex forecasting approach is a single year revealed cost forecasting approach. Opex is largely recurrent, so historical costs provide an indication of forecast requirements. Because we intend to continue to use a base year as the basis for forecasting opex, we require a mechanism to mitigate the incentive for NSPs to increase opex in the expected base year. We consider the EBSS is an effective mechanism for constraining this incentive. The incentive to reduce opex also declines through the regulatory control period when it is expected a single base year will be used to forecast opex. The EBSS also addresses this and provides a continuous incentive throughout the regulatory control period.[368]

In assessing forecast opex, we must have regard to whether the opex forecast is consistent with any opex incentive scheme.[369] Of importance here is our assessment of base opex. We may make base year adjustments for two reasons:

1. a NSP's recurrent expenditure is inefficient compared to its peers

2. a NSP's base year expenditure is not reflective of efficient recurrent expenditure due to a one-off factor in the base year.

We consider below the impacts of these adjustments on the incentive a NSP has to improve opex efficiency. A number of NSPs also raised concerns that including a productivity forecast in the opex forecast could undermine the operation of the EBSS. We also consider this below.

Efficiency of recurrent expenditure and the EBSS

As stated, we will use a single year revealed cost forecasting approach to assess opex forecasts. However, if the base year opex reflects inefficient costs, then continuing with a revealed cost approach may not result in a prudent, efficient forecast of costs consistent with the opex criteria. This situation may arise because a NSP does not respond to incentives or appropriate incentives were not in place for efficient expenditure decisions.

366 NER clauses 6.12.1.(4)(i) and 6A.14.1.(3)(i).
367 NER clauses 6.5.6(c) and 6A.6.6(c).
368 AER, *Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.
369 NER clauses 6.5.6(e)(8) and 6A.6.6(e)(8).

Where a NSP does not respond to incentives, the sharing of rewards or penalties would not be in the long term interests of consumers. Where a NSP responds to incentives, it will make efficient expenditure decisions regardless of the forecast. These efficient (historic) expenditures can then be used as the basis for opex forecasts.

Where there is an EBSS in place, there is a continuous incentive across a regulatory period for a NSP to pursue efficiency gains. Hence, when there is an EBSS in place and a NSP appropriately responds to incentives, revealed costs provide a good indication that forecasts will be efficient.

However, we will not assume a NSP is appropriately responding to incentives simply because an EBSS is in place. We must test the NSP's efficiency before relying on its revealed costs. We will likely use a number of techniques to assess the efficiency of a NSP's base year, including economic benchmarking techniques.

CitiPower, Powercor and SA Power Networks submitted that an examination of a bottom up forecast is a step away from incentive based regulation. They considered the Guideline should acknowledge and take account of the incentives created by the EBSS. Further, they considered economic benchmarking had inherent weaknesses that made it an inappropriate tool for deterministic application, such as an inability to adequately account for uncontrollable differences between NSPs.[370]

Similarly APA expressed further concern that we will create an asymmetry in forecasting risk for regulated businesses. It considered forecasting errors will lead to one-sided adjustments to future costs and that base year adjustments would be inconsistent with incentive regulation.[371]

We are not, however, stepping away from incentive regulation. The revealed cost forecasting approach remains our preferred approach. However, in some circumstances NSPs may face competing incentives and base year expenditure may not efficient. Consequently we cannot assume the efficiency of base expenditure and must test it.

Category analysis is only one of the tools we will use to assess the efficiency of base opex. It is not a bottom up build of base opex. Disaggregating expenditures and activity volumes to test a NSP's efficiency does not alter the fact the starting point for our assessment of base opex is the NSP's actual revealed costs. We will adjust revealed costs if we find them inefficient.

NSPs also questioned how we would determine whether NSPs were responding to the EBSS incentives.[372] NSPs' response to incentives, however, will not be our primary focus when assessing the efficiency of base year opex. Our first priority will be assessing whether base year opex is efficient. This is what is necessary to ensure forecast opex meets the opex criteria. To the extent we can determine whether NSPs are responding to incentives, this will inform our review of the effectiveness of the EBSS and the broader incentive framework.

Non-recurrent efficiency gains and the EBSS

Under version 1 of the EBSS, NSPs had an incentive to claim that base year costs were unsustainably low, hence they should not form the basis for forecast opex in the following regulatory

370 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 3, 9–10.

371 APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 2–3.

372 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 10; APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 2–3.

control period. In this way they could maximise their EBSS carryover in period one, through reducing expenditure late in the period, and then attempt to maximise their opex forecast for period two by proposing an alternative forecasting approach. If the revealed cost approach was not used to forecast expenditure they would not only retain all non-recurrent efficiency gains within the period, they would also receive a further reward through the EBSS as if the efficiency gain was recurrent. Thus they would retain more than 100 per cent of the non-recurrent efficiency gain and consumers would be worse off as a result of the gain. This was not in the long term interests of consumers. Consequently, in the explanatory statement to our Draft Guideline we stated we were unlikely to accept such proposals for a change in approach where an EBSS is in place.

This situation was a function of assumptions in both the opex forecasting approach and the EBSS. Version 1 of the EBSS assumed all efficiency gains made in the base year were recurrent (that is, the underspend in the final year was deemed to be equal to any observed underspend in the base year). For the reasons above, it was important the opex forecasting approach reflected the same assumption. However, this assumption may not always be appropriate. Incenta commented that, when testing the efficiency of a NSP's base year, it is important to ensure one-off factors do not impact the expenditure in the base year (and that adjustments are made if such one-off factors exist).[373] If base year expenditure was significantly lower (higher) than ongoing efficient opex, due to a one-off factor, then the opex forecast would be artificially low (high). The NSP would be sufficiently compensated through the EBSS carryover, however the 'optics' could be misleading. That is, an NSP's actual expenditure would appear high when compared against its regulatory allowance (not factoring in the EBSS carryover).

We have reconsidered whether it is necessary to make this assumption in both the opex forecast and the EBSS. We have determined this assumption is not necessary as long as the same assumption about final year expenditure is made in both the EBSS and opex forecast. Given this, we have relaxed the assumption that all efficiency gains made in the base year are recurrent. The estimated final year equation (which we previously called the deemed final year equation) now allows one-off efficiency gains in the base year to be added back on to the estimated final year opex to ensure if reflects efficient ongoing expenditure and is not artificially low. To ensure NSPs have a continuous incentive in the final year, we have made a corresponding adjustment to the EBSS. This effectively shifts revenue from the EBSS carryover to the opex forecast.

Forecast productivity changes

To accept a forecast of required opex, we must be satisfied that total forecast opex reasonably reflects the opex criteria (the efficient costs that a prudent operator would require to achieve the opex objectives). We consider the inclusion of the forecast productivity change is necessary for us to be satisfied that total forecast opex reasonably reflects the opex criteria. If we did not include forecast productivity change then total forecast opex would be greater than the efficient costs that a prudent operator would require (if productivity change is positive).

A number of NSPs raised concerns that including a productivity forecast in the opex forecast could undermine the operation of the EBSS.[374] Specifically, the Victorian DNSPs considered the productivity

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373 Incenta Economic Consulting, *Advice on certain issues in relation to the draft expenditure forecast assessment and efficiency benefit sharing scheme guidelines*, 20 September 2013, p. 13.

374 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 32; NERA Economic Consulting, *Holistic economic benchmarking – a report prepared for Grid Australia*, 20 September 2013, p. 31; Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 15–16; NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, pp. 10–11; CitiPower, Powercor and SA Power Networks, *Joint response to*

change factor should be removed from the rate of change parameter. They submitted including a productivity factor in the rate of change would contravene:

- clause 6.5.8(c)(3) of the NER, by penalising DNSPs that achieving an efficiency gain that is less than the productivity factor, notwithstanding the fact there has been an efficiency gain;
- clause 6.5.8(a) of the NER, by not providing a fair sharing of gains or losses under the EBSS, where such gains are losses are calculated relative to the productivity factor
- section 7A(3) of the NEL, by diminishing the effectiveness of the incentives, where there is no fair sharing of gains or losses under the EBSS (as above), and because incentives provided by the EBSS vis-à-vis the CESS would be unbalanced.[375]

These submissions misinterpret the term 'efficiency gain' in the context of clause 6.5.8. That clause provides for the sharing of:

> (1) the efficiency gains derived from the opex of NSPs for a regulatory control period being less than; and
>
> (2) the efficiency losses derived from the opex of NSPs for a regulatory control period being more than,
>
> the forecast operating expenditure **accepted or substituted by the AER** for that regulatory control period (emphasis added).

A gain or loss must be calculated relative to a starting point. It is clear that the starting point to calculate gains or losses in clause 6.5.8(a) is the forecast opex which we accept or substitute. It appears the Victorian NSPs submit we should calculate efficiency gains and losses relative to opex in previous years. This would be contrary to the plain wording of clause 6.5.8(a). It would also reward NSPs for reducing opex below previous opex but above the efficient level. This would undermine the forecast criteria and the NEO/NGO.

Section 7A(3) of the NEL, one of the revenue and pricing principles, requires that a NSP should be provided with effective incentives in order to promote economic efficiency. In this context it is important to provide NSPs with balanced incentives. For example, if incentives were not balanced a NSP may have an incentive to substitute capex with opex even if were less efficient to do so. Unbalanced incentives are unlikely to promote economic efficiency. The Victorian DNSPs, however, do not demonstrate why they consider the incentives provided by the EBSS and CESS would be unbalanced. It appears they are suggesting that by allowing NSPs to retain approximately 30 per cent of efficiency gains made beyond those forecast, the EBSS allows NSPs to retain less than 30 per cent of total efficiency gains. They imply this is inconsistent with the CESS which allows NSPs to retain 30 per cent of efficiency gains (losses). However, the CESS also rewards NSPs for efficiency gains (losses) relative to those included in the capex forecast.

In considering whether incentives are balanced, the critical consideration is whether the marginal sharing ratios are similar, not the absolute sharing ratios. Both the EBSS and CESS provide a marginal sharing ratio of approximately 30:70 (NSP:customers). When marginal sharing ratios are balanced, a NSP will have no incentive to substitute a dollar capex with a dollar of opex (or vice versa). But if the opex marginal sharing ratio was, for example, higher than the capex marginal sharing ratio, then the NSP would have an incentive to substitute opex with capex, even if it was more

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375 *AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 11; APA Group, *APA submission on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 2–3. The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013*, pp. 2, 12.

costly. This incentive would remain even if the opex absolute sharing ratio was lower than that for capex.

Timeframes

Table 6.1 outlines our proposed timeframes and steps for determining whether we will consider making adjustments to base year expenditures under the revealed cost approach.

Table 6.1 Timeframes for base year review

Publication	Decision
F&A paper and Annual benchmarking report	We will provide an initial view on whether we consider a NSP's historical costs are likely to reflect efficient costs.
Issues paper	In the issues paper, we will publish our first pass assessment using data from the NSP's proposal and base year. This assessment will provide our preliminary view of the proposed opex forecast based upon analysis that can be undertaken within the issues paper timeframes. We intend to run our benchmarking models as part of this process, including economic benchmarking (incorporating an econometric model of opex) and category analysis benchmarking.
Draft determination	We will set out the full base year assessment in the draft determination.
Final determination	We will consider our position in the draft in light of submissions.

In advance of the reviews commencing in 2014, we cannot, at the F&A stage, provide an opinion on whether a NSP's costs reflect efficient costs based on the category analysis and economic benchmarking techniques.. However, subject to data robustness, our aim is to incorporate analysis using these techniques in the issues paper for these reviews.

6.4 Capital expenditure approach

We do not expect the techniques that we use to assess capex forecasts will materially affect our application of the CESS. Similarly, we do not expect the CESS to materially affect our assessment of prudent and efficient forecast expenditure. However the application of the CESS potentially gives rise to issues of inefficient deferral of capex. We may also use our assessment techniques as part of our ex post review of capex.

These views are substantively unchanged from our draft Guideline.

We have also modified the CESS to allow adjustments to the CESS payments for capex deferrals in limited circumstances. We also expect the expenditure forecasting techniques may be used to identify where material deferral has occurred and determine what adjustment to the CESS payments may be required. Generally this section should be read in conjunction with the Capital Expenditure Incentive Guideline and associated explanatory statement.[376]

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[376] AER, *Better Regulation, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013; AER, *Better Regulation, Explanatory Statement, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013.

6.4.1 AER position

We will consider whether capex forecasts are consistent with the expected application of the CESS.[377] This includes consideration of the likely incentives created under the CESS in forming a view on the efficient and prudent expenditure forecast. Incentives created by the CESS should include the incentives to efficiently reduce and defer expenditure and could also create an incentive to undertake or defer expenditure in a way that is not prudent and efficient.

We will also consider the possible need for the expenditure forecasting techniques that may be used to identify where material deferral has occurred and determine what adjustment to the CESS payments may be required.

To ensure capex forecasts are consistent with the NSP's expected capex work program (including the NSP's ability to deliver that work program and any expected reductions or deferrals motivated by the CESS or otherwise) we are likely to consider the following when assessing forecast capex:

- the amount and type of capex deferred in the prior regulatory period
- the expenditure incurred relative to what was funded in previous regulatory periods and the rewards or penalties under the CESS
- various indicators of workload (for example, replacement and maintenance volumes) as well as network performance (including capacity and risk or "health" measures), including what NSPs were expected to deliver, and what they actually delivered over time.

In many areas, we are likely to use historical capex information to assist us with assessing NSPs' proposed forecasts. Examples are predictive modelling and trend assessments of replacement, augmentation and connections volumes, and various unit costs or estimated expenditure relative to cost drivers. This information should assist to identify material deferrals.

We note that our proposed approach is consistent with prior assessments and the requirement to assess what is prudent and efficient forecast expenditure taking into account the information before us.

We also expect annual performance reports to compare actual versus forecast spending and various workload and performance indicators. This should give all stakeholders some transparency about how capex savings are being achieved and if these are likely to be enduring efficiency savings. During revenue determinations we may also use this information to help target more detailed reviews of historic spending and spending deferrals during revenue determination processes and when assessing adjustments to CESS payments for deferrals.

6.4.2 Reasons for AER position

Our approach should allow us to assess what is prudent and efficient forecast expenditure taking into account past behaviour and likely incentives created under the CESS. We also consider our proposed approach should assist with determining any adjustment to CESS payments for material deferrals at the end of the regulatory period. We consider this forecasting approach, combined with the ability to adjust CESS payments for material deferrals, should place predominantly desirable incentives on NSPs to generate genuine efficiency savings.

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[377] NER clauses 6.5.7(e)(8) and 6A.6.7(e)(8) require us to consider whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to a NSP.

Unlike our approach to assessing opex forecasts, our approach to capex does not as heavily rely on the NSP's historical costs. The application of the CESS, and the incentives created under the scheme, should therefore not be unduly affected by our forecasting approach.

While we consider the CESS will generally create desirable incentives to pursue efficiency gains, both through permanent expenditure reductions and deferrals, we are mindful the application of the CESS potentially creates two issues:

- it may amplify the current incentive on NSPs to inflate forecasts to allow them to engage in short term deferrals at the end of the regulatory period
- It may create an undesirable incentive for NSPs to 'cut corners' and undertake unsustainably low or inefficient levels of expenditure.

We are also mindful that the ESCV removed the capital expenditure efficiency scheme applied to Victorian DNSPs between 2001 and 2006 because it considered that capex underspends may have resulted from capital investment deferral and that these deferrals may not have been efficient. The ESCV's scheme was similar to our proposed CESS.

Due to concerns particularly around potential inefficient deferrals, we indicated in the explanatory statement for the draft Guideline that we intended to take into consideration past deferrals in determining future allowances. Under this approach, if a NSP was to try to reduce expenditure (below an efficient or sustainable level), it might expect to get a lower capex allowance in the next regulatory period. This approach was aimed at reducing any incentives to incur unsustainably lower expenditure in order to profit under the CESS. Our application of replacement and augmentation modelling will highlight and take into account historical network outcomes (e.g. extensions in asset lives or increases in asset capacity utilisation) and resulting work volumes in the prior regulatory period when estimating prudent and efficient capex over the upcoming regulatory period. These approaches will implicitly take into account historical deferrals when estimating future work volumes and expenditures. In this context, NSPs can also provide further details to justify the prudency of short-term deferrals which led to temporary efficiency gains and which were considered efficient in an overall sense.

A number of submissions on the CESS were received following the release of the draft Incentive Guideline. These are addressed in the explanatory statement to the Capital Expenditure Incentive Guideline.[378]

After carefully considering submissions, we have modified the CESS to allow for adjustments to CESS payments to account for material deferrals. This would only apply if we had not already adjusted our forecast of capex to take account of deferral in the most recent regulatory period.

The intention of any adjustment for deferrals is to limit overcompensation for short term deferrals of capex and also lessen any undesirable incentives to undertake inefficient reductions or deferrals. The adjustment (where applied) is intended to limit the CESS reward to only 30% of the value of a deferral and in practice will be focused on material conduct (whether a single project, or significant volume of a single type of project). We propose to only apply an adjustment to CESS payments, where

- the amount of the deferred capex in the current regulatory control period is material, and

[378] AER, *Better Regulation, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013; AER, *Better Regulation, Explanatory Statement, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013.

- the amount of the estimated underspend in capex in the current regulatory control period is material, and
- total approved forecast capex in the next regulatory control period is materially higher than it is likely to have been if a material amount of capex was not deferred in the current regulatory period.

The calculation of the adjustments to CESS payments is covered in the Incentive Guideline.[379]

The modification of the CESS has not materially changed our approach to assessing forecasts as set in the explanatory statement for the draft Guideline.

Our approach of considering CESS rewards and penalties when setting capex allowances is also consistent with our approach to reviewing opex forecasts where we consider whether the outcomes of forecasts in conjunction with incentive schemes would result in efficient outcomes. The penalty or reward under the CESS is relevant to this consideration. We therefore may adjust the capex forecast if, taken together with the penalties or rewards of the CESS, it leads to an outcome that is not consistent with the long term interests of consumers.

6.4.3 Consistency with ex post review

In some circumstances, we must conduct an ex post review of capex.[380] This includes a review of capex overspends when they occur. We can exclude from the RAB:

- inefficient capex above the capex allowance
- inflated related party margins
- capitalised opex resulting from a change to a NSP's capitalisation policy.

We propose a staged approach to the ex post review. This assessment process will involve increasingly detailed examination of capex overspends, subject to certain thresholds being satisfied. The first step of the proposed review includes assessing the NSP's capex performance including comparing the NSP's performance against other NSPs. The economic and category analysis benchmarking that we propose may be relevant to this consideration. However, in determining whether capex meets the criteria, we must account for only information and analysis that the NSP could reasonably be expected to have considered or undertaken when it undertook the relevant capex.[381]

Later steps in the prudency and efficiency review include reviewing asset management and planning practices, and conducting targeted engineering reviews. These assessment techniques are intended to be similar to those that we apply to capex forecasts (considering only the information available to the NSP at the time).

379 AER, *Better Regulation, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013; AER, *Better Regulation, Explanatory Statement, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013.

380 NER, clauses S6.2.1(g), S6.2.2A, S6A.2.1(g) and S6A.2.2A.

381 NER, clauses S6.2.2 and S6A.2.2.

Our approach to ex post reviews has not changed since the release of the draft Guideline. Further information on the ex post review is contained in the Capital Expenditure Incentive Guideline and associated explanatory statement.[382]

6.5 Service target performance incentive scheme

Our approach to assessing expenditure forecasts interacts with the application of the STPIS. The STPIS rewards (penalises) NSPs for delivering better (worse) reliability than the benchmark level. The reward (penalty) is based on consumers' willingness to pay for reliability improvements. In this way the STPIS provides an incentive for NSPs to improve reliability if the value to network users of doing so is greater than the cost. Consequently it is not necessary to provide expenditure allowances for proposed works aimed to improve reliability levels. These should be funded through STPIS rewards. This is aligned with the previous expenditure objectives, which were to maintain the reliability of services rather than improve them.[383]

Recent changes to the expenditure objectives will impact our expenditure assessments in this regard. The expenditure objectives now ensure that NSPs are only able to include in their proposals sufficient expenditure to comply with quality, reliability and security obligations in accordance with jurisdictional standards.[384] If NSPs have been delivering services at higher than required quality, reliability or security, we will not allow expenditure for the associated cost of maintaining this higher standard.

So, where there are jurisdictional regulatory obligations to achieve a certain level of service quality, reliability and security, we will assess expenditure proposals in accordance with these obligations rather than against current or voluntary standards.[385] Where the jurisdictional standards are lower than NSPs' current standards, we will expect NSPs to reduce the opex and capex from previous levels to comply with the jurisdictional obligations. We will also need to adjust the STPIS targets to reflect the expected change in reliability.

Where no jurisdictional standards apply, we will allow NSPs to recover the efficient costs of maintaining their current reliability and quality of service.

Similarly, we note that providing network services at different levels of reliability imposes different cost requirements on NSPs. We will consider this when benchmarking NSPs.

6.6 Demand management incentive scheme

Under clause 6.6.3 of the NER we have the ability to publish a demand management and embedded generation connection incentive scheme (DMEGCIS). On 22 December 2011, the AEMC amended the NER to expand the demand management incentive scheme to include incentives for innovation in connection of embedded generation.[386] We developed our current schemes prior to this rule change and use the old title 'demand management incentive scheme' (DMIS).

The DMIS is designed to provide incentives for DNSPs to implement efficient non-network alternatives to manage the expected demand for distribution services. It includes a demand

382 AER, *Better Regulation, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013; AER, *Better Regulation, Explanatory Statement, Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, November 2013.

383 NER (version 57) clauses 6.5.6(a), 6.5.7(a), 6A.6.6(a) and 6A.6.7(a).

384 AEMC, *Rule determination*, 19 September 2013, p. ii.

385 AEMC, *Rule determination*, 19 September 2013, pp. i–iii.

386 AEMC, *Rule determination*, National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011, 22 December 2011.

management innovation allowance (DMIA) for demand management related activities. The DMIA is capped at an amount based on our current understanding of typical demand management project costs, and scaled to the relative size of each DNSP's average annual revenue allowance in the previous regulatory period. It provides DNSPs with an allowance to pursue demand management and embedded generation initiatives that may not otherwise be approved under the capex and opex criteria.

COSBOA, however, raised concerns that the current DMIS has shortcomings and that we should develop a new scheme as soon as practicable.[387] The Standing Council on Energy and Resources (SCER) is currently considering proposing changes to the NER to improve incentives for DNSPs to engage in efficient demand management. This has arisen from the AEMC's Power of Choice (PoC) review of demand side participation in the NEM. Consequently we will develop any new scheme following completion of the AEMC's forthcoming DMEGCIS rule change process. We intend to engage with stakeholders on a new DMEGCIS in parallel with the AEMC's DMIS rule change process.

Given the application of the DMIA, we are unlikely to approve expenditure proposals to research demand management and embedded generation, however we will consider any impacts on the NER expenditure assessment process as further rule changes are consulted upon.

[387] Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 21.

7 Implementation issues

This chapter provides an overview of the issues that may arise from implementing the Guideline, the significance of these issues and our measures to mitigate their impact. It discusses how we will manage these various issues in balancing the interests of NSPs and consumers.

In changing from our current approach for assessing expenditure forecasts to the approach in our Guideline, we may find issues in:

- providing enough time for stakeholders to respond to data requests
- providing ourselves enough time to assess expenditure proposals and publish annual benchmarking reports
- stakeholders' ability to provide data in the short term
- releasing data publicly
- ensuring a workable transition between existing and new data reporting requirements
- using new techniques.

NSPs may face additional costs in the short term when the Guideline changes some of the existing information reporting arrangements (see section 2.3.3). To some extent, these changes could affect data quality and the consistency of reported data between NSPs and over time. Further, we will need to resolve confidentiality issues to determine the amount of data available to the public.[388]

7.1 AER position

Since releasing the draft Guideline we have:

- consulted on preliminary expenditure information templates for category analysis. This consultation involved meetings with stakeholders and written submissions on information specified in the draft Guideline and accompanying explanatory statement
- issued draft and final RINs under the NEL on all NSPs to collect back cast economic benchmarking data.

We propose to issue RINs in December 2013 on all NSPs for the purposes of gathering information for the 2014 benchmarking report and for assessing regulatory proposals submitted in 2014. In the medium term, we will aim to consolidate our reporting requirements into a RIO. In the short term, we will also request NSPs to continue to collect data based on current information templates in accordance with the annual reporting RINs we have already issued.

We do not intend to subject the interconnectors to the same expenditure data requirements as other regulated networks. We will not include interconnectors in our economic benchmarking dataset but we will still be issuing RINs to gather data for resets when they arise.

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388 Refer to the AER's confidentiality guideline for further information.

7.1.1 Data collection timeframes

We aim to gather sufficient information to employ new, standardised assessment techniques for those regulatory resets occurring from 2014, including for the NSW/ACT DNSPs, Transend and TransGrid. We must also gather sufficient data for the first benchmarking report due to be published in September 2014.[389] Subsequent benchmarking reports are due in November of the respective year.[390]

We require benchmarking data for both of our benchmarking techniques—economic benchmarking and for category analysis. Our process for collecting and processing economic benchmarking and category analysis data operate on different timeframes. Specifics of these different timeframes are outlined below.

For 2014, standardised data for all techniques will be requested through expenditure specific RINs, with the required period of back cast data set out in the RINs themselves. We will also issue reset RINs on NSPs submitting regulatory proposals in 2014. These NSPs will be required to provide forecast expenditure data in the standard templates, as well as other information required in support of regulatory proposals (for example, detailed demand information).

From 2015 we will aim to obtain data for annual benchmarking reports by issuing regulatory information orders (RIOs).

Testing and validation process for economic benchmarking techniques

Final RINs collecting economic benchmarking data were issued in November 2013. NSPs have been requested to provide this information (unaudited) by 3 March 2014, allowing the AER to commence testing and validation in early 2014. Audited economic benchmarking data is due on 30 April 2014. As set out in the explanatory statement for the draft Guideline, the precise timings of the testing and validation process depends on the quality of the data provided in response to the RIN. We will set out more precise timings for this process in March 2014.

We will also collect some data required for economic benchmarking in the reset RINs. These data would be forecast outputs, inputs and environmental variables.

Data collection for category analysis

Reset RINs issued in February 2014 will primarily collect data for category analysis. This would provide NSPs at least three months after receiving a data request to provide us with their response. The provision of this information will also coincide with the lodgement of regulatory proposals of the NSW/ACT DNSPs, Transend and TransGrid in May 2014.

Note that the issuance of RINs and submission of regulatory proposals for Directlink will also coincide with these timeframes, however we anticipate that the expenditure assessment approach and data requirements with respect to Directlink will be diminished with respect to that anticipated for other NSPs.

Specific timeframes for NSW/ACT DNSPs, Transend and TransGrid

For the sake of clarity, and consistent with our current practice, we will continue to issue separate reset RINs for any NSP subject to an upcoming regulatory determination process. We are likely to

389 NER, clause 6.27(d).
390 NER, clause 6.27(c),(d),(e), clause 6A.31(c),(d),(e).

issue final reset RINs following the F&A process. This will occur in February 2014 for the NSW/ACT DNSPs, and Transend, TransGrid.

Table 7.1 illustrates our projected timings for the annual reporting process, and provides indicative dates for the issue and response to reset RINs out to 2016.

Table 7.1 Indicative timeframe for data requests and NSP responses: 2013 to 2016

Date	Economic benchmarking	Annual reporting milestones	Reset RIN data	Role in expenditure forecast assessment
28 Nov 2013	Issue final RIN			To collect information on input, output and environmental variables.
Early Dec 2013		Issue draft RIN for category analysis data (back cast)	Issue of draft RINs for NSW/ACT DNSPs, Transend and TransGrid	
Feb 2014		Issue final RIN for category analysis data (back cast)	Issue of final RINs for NSW/ACT DNSPs, Transend and TransGrid	Category analysis RIN: To provide historical information by expenditure category to the AER Reset RIN: To provide historic and forecast information to the AER to support its expenditure analysis.
3 Mar 2014	Unaudited RIN responses due			
Mar 2014	Begin data checking/ validation process			To address issues with economic benchmarking data.
30 April 2014	Audited RIN responses due Publicly release EBT data, seek submissions			
May 2014		RIN responses due	Reset RIN responses due for NSW/ACT DNSPs, Transend and TransGrid Issue final RINs for SAPN, Energex and Ergon Energy	
Sept 2014		Publish first benchmarking report		To present information on the relative efficiency and performance of NSPs.

Oct 2014		RIN responses due for SAPN, Energex and Ergon Energy	
Nov 2014		Issue final RINs for VIC DNSPs	
Jan 2015	Issue draft RIO for 2015 benchmarking report		
Apr 2015	Issue final RIO	RIN responses due for VIC DNSPs	Final RIO: To consolidate economic benchmarking and category analysis data requests.
May 2015		Issue final RIN for SP AusNet (transmission)	
Jul 2015	RIO responses due		
Aug 2015		Issue final RINs for Aurora	
Oct 2015		RIN response due for SP AusNet (transmission)	
Nov 2015	Publish 2015 benchmarking report		
Jan 2016	Issue draft RIO for 2016 benchmarking report	RIN responses due for Aurora	
Apr 2016	Issue final RIO		
Jul 2016	RIO responses due		
Aug 2016		Issue final RINs for ElectraNet and Murraylink	
Nov 2016	Publish 2016 benchmarking report		

7.2 Reasons for AER position

We have not significantly changed our proposed time-frames as articulated in the explanatory statement for the draft Guideline.

Our timeframes for data collection provide reasonable time for NSPs to compile data and for us to analyse that data for our assessment purposes. In particular, the timeframes will allow enough time for both us and all stakeholders to consider detailed issues in new and changed reporting requirements. They will also enable proper consideration of new data collected in time for our determinations commencing in 2014, as well as for our first annual benchmarking report.

We think it is more important to provide NSPs sufficient time to gather and validate their own data ahead of providing it to the AER for the purposes of benchmarking reports and determinations. This requires RINs to be developed and issued as soon as possible.

In submissions to the Explanatory Statement for the Draft Guideline, stakeholders raised concerns that the timeframes for data provision and release of the benchmarking report will create a compliance burden and uncertainty for NSPs, particularly for those with regulatory determinations in 2014.

The ENA considered that NSPs who submit regulatory proposals in 2014 will not be afforded due process if the AER uses benchmarking techniques because there is considerable uncertainty about the quality of the information and the sheer volume of information these NSPs will need to prepare.[391]

The NSW DNSPs commented that in addition to their current regulatory proposal, they will have to complete an economic benchmarking RIN in February 2014 and a reset RIN incorporating the category analysis data in May 2014. They requested the AER consult further with them on reducing the resourcing burden.[392]

Ergon raised concerns on a potential lack of due process in respect of the AER's proposed timetable for producing benchmarking results and making determinations on the efficiency of Ergon's opex. For example the AER:

- is likely to make conclusions on Ergon's historic spend a month before it submits its Regulatory Proposal
- may presume differences in expenditure are due to inefficiency due a lack of time to consult on reasons for the differences. This may lead to an incorrect first pass decision
- may penalise Ergon for spending above forecast, in which the forecast is determined after the expenditure has occurred. The AER will make a Final Determination four months into Ergon's regulatory control period.[393]

CP/PC/SAPN considered that the timeframe for the category analysis RIN is particularly tight considering the scope of data required and requirement of providing backcast information. They considered that it is unlikely they could provide the AER with data of a sufficient quality under such short timeframes.

[391] Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 4, 46–47.
[392] NSW DNSPs, Response to draft forecast expenditure assessment guidelines, 20 September 2013, p. 12.
[393] Ergon Energy Corporation Limited, *Submission on the better regulation: Draft expenditure forecast assessment guidelines for electricity distribution and transmission,* 20 September 2013, p. 8.

ActewAGL submitted its concern that the AER could apply unrefined, untested and unproven assessment techniques to its regulatory proposal in May 2014, and that potentially unreliable outcomes could be used to test its regulatory proposal and to set its regulatory allowance.[394]

We will consider NSPs concerns as part of the regulatory determination process. We are required under the NEL to afford NSPs procedural fairness when making a regulatory determination (see section 3.1.2). NSPs who submit regulatory proposals in 2014 will be afforded due process when the AER uses benchmarking techniques. In particular, NSPs will be able to make submissions to the AER when it conducts its first pass assessment in response to the issues paper, and also where the AER places reliance on its assessment techniques in making its draft decisions. Further consultation will also arise as a result of the AER's first benchmarking report.

We will consult with those NSPs that are submitting regulatory proposals in 2014 as we would consult with any other NSPs as part of our standard practice, noting that those NSPs submitting regulatory proposals in May 2014 that will do so without full visibility of our new techniques. The early data collection and testing of economic benchmarking models in early 2014 may assist, to some extent, in this regard.

To date we have been consulting with the NSW DNSPs on our information requirements for both economic benchmarking and category analysis; and have revised our templates to reduce the resourcing burden to all NSPs. We are required under the NER to produce a benchmarking report, and we aim to improve our assessment approach through the use of more detailed information. These objectives require a consistent data reporting standard and we recognise NSPs may face difficulty in complying with some parts of our data requests. We will continue to consult with NSPs on their ability to comply with our data requests.

We have decided not to limit the techniques that we can apply to reviewing NSPs forecast expenditure in 2014. That said, we will consider our assessment principles (see section 5.5) where we consider relevant in deciding what weight to place on new assessment techniques, our existing assessment techniques and the NSPs forecasting methodology.

The issuing of reset RINs will continue to coincide with the timing of F&A processes for each respective NSP. We will also consult with NSPs to manage any potential overlaps or inconsistencies between what we request annually and what we request separately for determination processes.

7.3 Other implementation issues

Stakeholders raised some issues that may arise in transition to expanded and consistent data reporting. Our views have not changed substantially from the Explanatory Statement to the Draft Guideline. Nevertheless, we intend to consult further with NSPs in managing these issues, which include data provision, quality, back casting and confidentiality. In particular, we address stakeholder comments on the auditing and certification process in full details in the explanatory statements to each of the respective economic benchmarking and category analysis RINs.

7.3.1 Short term data provision

Our views on short term data provision have not changed from the Explanatory Statement for the Draft Guideline.

394 ActewAGL, *Response to AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 4.

Some NSPs may be unable to provide certain data in the short term, but they can provide much of it. Some NSPs already have data that we intend to use for economic benchmarking. Similarly, when considering the information that we need for category assessments, we are mindful of the data that NSPs already report.

During consultation on the Guideline, NSPs noted their ability to provide new data may be affected by the visibility of costs incurred by contractors, as well as the time taken to implement new data reporting systems:

Some NSPs do not currently request specific information from some external providers under existing service contracts, and contractors may not be obliged to provide the data if it is not part of their current contractual arrangement. That said, we expect NSPs to obtain the requisite data from their contractors where contractual provisions or relationships currently allow.

NSPs are expected to provide all data we request. If they provide legitimate reasons for being unable to do so, we expect them to reasonably approximate or estimate these data. We will also consult with NSPs on reasonable timeframes to provide and comply with the data request.

Submissions following the Explanatory Statement for the Draft Guideline on short term data provision are addressed in section 7.3.2 as the comments also attributable to backcasting data and auditing assurance.

7.3.2 Data quality

We have refined our approach to recognising and addressing data quality from the Explanatory Statement for the Draft Guideline.

We have spent a significant amount of time revising our data requirements for both economic benchmarking and category analysis. Our revisions have been made following stakeholder feedback made in bilateral meetings, consultation workshops and through informal liaison. Data quality issues are examined in more detail in the respective explanatory statements to the RINs.

Back casting

Quality/reliability of back cast data

In response to the Explanatory Statement for the Draft Guideline, a number of stakeholders considered that the back cast data provided would not be useful or reliable for the AER's assessment purposes. Energex and the Victorian DNSPs consider that backc asting data will not address issues of consistency across DNSPs and across time due, for example, due to a lack of standardised reporting.[395] Energex note that economic benchmarking and category assessment will require the unique characteristics of NSPs to be adequately incorporated in analyses.[396]

CitiPower, Powercor and SA Power Networks submitted that 10 years of historical data is not reasonable, particularly in the timeframe provided and questioned the value when much of this date will be derived from extensive use of estimation and assumptions.[397] CP/PC/SAPN also raised concerns with the amount of category analysis information the AER requires. They consider there is a

395 Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 3–4; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 17.

396 Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 3–4.

397 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, pp. 3, 6.

risk the AER will push the NSPs to adopt largely arbitrary allocations in order to populate the category analysis RIN, which may leave NSPs at risk of providing materially misleading and unreliable information.[398]

CitiPower, Powercor and SA Power Networks are concerned that the AER is unduly rushing the data collection process, particularly with regard to the collection of back cast data. They note that the AER is only required to collect one year of data to meet its obligations under the NER to produce an annual benchmarking report. CitiPower, Powercor and SA Power Networks recommended that new data reporting requirements are only applied prospectively to improve benchmarking and data quality and allow NSPs to put systems in place to capture the data.[399]

The Victorian DNSPs consider that if the AER does collect back cast data the following should occur:

- To limit burden and cost the AER should only require the provision of data it knows will be required to populate the preferred model specification or test the sensitivity of the data/model specification.
- The AER should assess whether the data satisfies the principles set out by the Vic DNSPs and commit to not relying on information that is unreliable or potentially misleading.
- The AER must recognise the inherent limitations of the data and the resulting quality of results when applying any benchmarking techniques.
- If the AER applies any benchmarking in a deterministic manner, it must consider if this is consistent with the expenditure criteria, the revenue and pricing principles and the NEO.
- For category analysis data, the AER should either give NSPs an additional three months to provide the data, or refine the data list to enable the NSPs to comply. [400]

We are aware that the robustness of back cast data will vary depending on the NSP’s historical systems, and we will consider the data quality issues raised by NSPs, particularly where estimation of data is required. If NSPs are required to estimate some of the data they provide, we will request they provide an explanation of how the estimate was formulated. We consider that the risks associated with providing misleading and unreliable information are greatly reduced if there is transparency around the information provided. If NSPs detail their methodology for arriving at their estimates, we will gain an understanding of it was formed, and can factor this in when making comparisons.

We will request as much information that we consider is required to form a complete dataset. The amount of back cast data we request for economic benchmarking and category analysis is discussed in the explanatory statements accompanying the final economic benchmarking RIN and category analysis RIN.

More generally, we will consider data quality issues when assessing forecast expenditures. This is outlined in our assessment principles in the Guideline.

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398 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 7.

399 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 7.

400 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 18–19.

Compliance burden in providing back cast data

Energex anticipate difficulties in providing back c ast data because some of it has not previously been collected or reported.[401]

The Victorian DNSPs considered that the timeframe of three months to provide back cast data for economic benchmarking is insufficient, noting that assumptions will need to be developed for some data, data is expected to be of high quality and reliable, and be audited.[402]

The Victorian DNSPs suggested that when providing back cast data, NSPs should only be required to use best endeavours to provide information and not be required to provide information they don't have, is unreliable or potentially misleading.[403]

We have considered the compliance burdens on NSPs in developing of the economic benchmarking and category analysis RINs, and this is reflected in the explanatory statements for these RINs.

Auditing

A number of stakeholders commented on the difficulty in providing audited data, particularly where estimation is required to produce some data.

The ENA raised concerns with audit and assurance requirements, summarised as:

- The NSPs may bear risk of impaired regulatory outcomes, non-compliance with regulatory requirements and expending inefficient effort and cost that could arise from incompletely designed or unworkable, regulatory audit or assurance requirements
- The AER has not provided enough guidance on:
    - how it will obtain assurance
    - auditor qualification
    - terms of reference
    - the applicable financial reporting framework for each RIN and RIO
    - the circumstances when the AER will expect an auditor to provide different levels of assurance
    - auditor responsibilities
    - the relationship between auditors and NSPs and the AER.

The ENA submits that the AER should therefore commit to preparing Regulatory Accounting Guidelines.[404]

Energex commented that it would be difficult to provide data to an auditable standard, particularly where estimation is required. Where data is estimated, they consider that their auditors would not be

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401 Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 5.

402 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 18–19.

403 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 18.

404 Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 4, 40–45.

able to attest to the appropriateness of the estimation underpinning the estimate.[405] The Victorian DNSPs commented that it would be unclear whether an auditor would be willing to provide the requisite sign off for all the information.[406]

The NSW DNSPs considered that a positive audit will only be possible if the source of information can be verified in their information systems. Without this, auditors may provide a view on the DNSPs process for developing an estimate, but cannot testify to the robustness and accuracy of data.[407] They suggest the AER should not apply a positive level of assurance on information which is based on estimates or approximations. They also suggest that the AER impose less onerous review requirements, which may alleviate resourcing issues.[408]

The Victorian DNSPs suggested that the AER consider allowing an independent engineering consultant to sign off in the NSPs non-financial data and only require auditor sign off on financial data as auditors may not be prepared to provide the level of assurance the AER requires.[409]

The Victorian DNSPs also suggested that the AER should reconsider the audit requirements if the February 2014 deadline for economic benchmarking data is maintained, or if the audit requirements are maintained the NSPs should be provided an extra 3 months to provide the data.[410]

SP AusNet and CitiPower, Powercor and SA Power Networks agreed with the AER that data employed for benchmarking purposes should be audited and robust.[411] SP AusNet noted that such data may have previously been used for internal business needs and has not been audited or is unlikely to pass an audit test.[412] CitiPower, Powercor and SA Power Networks submitted it is unclear their auditors would be available in the timeframe for collecting economic benchmarking data and consider using other auditors is not practical.[413] CitiPower, Powercor and SA Power Networks suggested the AER carefully consider the standard of audit that can be practically achieved where assumptions and estimation must be applied.[414]

Jemena submitted that the level of assurance that can be provided for a large portion of the information is not a function of effort or time expended to obtain the estimates. It is the result of data not being collected for the retrospective time period for which the AER intends to request the information.[415] Jemena suggested that if the AER relaxes its auditing requirements, and allow for data to be provided subject to management sign-off only, then some data—with estimates could be made where gaps exist—could be compliant for the AER's intended use.[416]

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405 Energex Limited, *Energex submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 5.

406 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, pp. 2, 14–15, 17.

407 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, p. 12.

408 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, pp. 3, 12.

409 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 20.

410 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 19.

411 SP AusNet, SPA submission on AER draft expenditure forecast assessment guidelines, 20 September 2013, p. 4; CitiPower, Powercor and SA Power Networks, Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission, 20 September 2013, p. 6.

412 SP AusNet, *SPA submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 4.

413 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 6.

414 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 7.

415 Jemena Limited, *Jemena submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 2.

416 Jemena Limited, *Jemena submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 2–3.

Our approach to the auditing and certification process for economic benchmarking data is set out in the explanatory statement for the the final economic benchmarking RIN. The respective explanatory statements to the reset RINs and the back cast data RIN will set out the auditing and certification process for category analysis data. We consider stakeholder concerns on auditing issues in the respective explanatory statements because we consider these issues are not relevant to the development of the Guideline.

Streamlining the information provision process

The ENA suggested the AER clarify how the suite of regulatory instruments fit together as a coherent, integrated package. They considered that it is important that the information the AER requests NSPs to provide is appropriately coordinated and streamlined and that there is no unnecessary or duplicated information being requested.[417]

The NSW DNSPs suggested that the AER consider a more streamlined and tailored process to collecting information for the NSW DNSP resets. The AER should leverage reviewed information provided by them in the past and limit information requests to data available in their systems. They suggest the AER issue a single reset RIN, merging the information requests rather than collecting data through two processes.[418]

CitiPower, Powercor and SA Power Networks recommended the AER streamline the currently proposed three separate RIN processes over the next year.[419]

We recognise that NSPs face a considerable compliance burden in collecting the information we request; and we do aim to move toward collecting information annually through a single RIO. Following our post-draft Guideline consultation with NSPs we have reconciled our economic benchmarking and category analysis templates to avoid as much duplication as possible.

7.3.3 Data release and management

We have not changed our proposed approach to data release and management as set out in the Explanatory Statement for the draft Guideline.

In response to the Explanatory Statement for the Draft Guideline, stakeholders generally maintained their view that all data should be made publicly available, while recognising that confidentiality concerns need to be considered.

The ENA and Vic DNSPs considered that the data the AER relies on for benchmarking should be published.[420] The ENA considered that in the interests of transparency, the AER should not rely on any confidential information. [421] The Vic DNSPs considered that confidential information should not be used to benchmark other NSPs unless the other NSPs are provided access to the confidential information, by way of a confidentiality undertaking or some other measure.[422]

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417 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 35.

418 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, p. 3.

419 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 6.

420 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 3, 35; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 20.

421 Energy Networks Association, *AER better regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, p. 3, 35.

422 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013, p. 20.

The EUAA, COSBOA, MEU, Uniting Care and Canegrowers all supported the publication of the data the AER relies on for benchmarking; they considered it is important for consumer groups to engage with regulatory processes.[423] The MEU commented that unless consumers have access to the database developed by the AER to give them confidence about the legitimacy of the input provided by the NSP, there is a disconnect between what the NSP advises consumers and what the NSP is required to the AER.[424] Canegrowers considered that all the information submitted by NSPs to the AER in RINs should be made publicly available, immediately. The only suitable redactions would be for information which is deemed a breach of consumer or third party privacy.[425]

The ENA, Vic DNSPs and EUAA also submitted that the AER should release the models it uses for annual benchmarking and determination processes.[426] The Vic DNSPs suggested that the models will allow stakeholders to understand the analysis and also allow testing and consultation prior to publication of the annual benchmarking report.[427]

We will need to consider how we release data to the public, address any confidentiality concerns, and ensure transparency of the data released. We will also need to consider how best to manage data supplied formally through RINs or RIOs, and informally through bilateral requests. Nevertheless, we expect the majority of data provided to us by NSPs will be included in the database and released publicly in a routine manner. We recognise this data disclosure may raise confidentiality issues and expect these to be addressed quickly in accordance with our new Confidentiality Guidelines.[428] Confidential data should be identified as RINs are developed, hence we expect the process for eventually releasing this information will commence well ahead of it being actually obtained by us.

It may take longer than usual to publish data obtained through our first round of RINs. This is because of the need to establish and test internal processes for the storage and release of data. This process will likely be quicker for subsequent data requests.

7.3.4 Existing reporting requirements

We have not changed our views on existing reporting requirements as articulated in the Explanatory Statement for the draft Guideline.

We may request NSPs continue to provide expenditure and supporting data in accordance with the annual reporting RINs already issued by us. New data may not reconcile with existing data sets, and the quality of some data provided may not be ideal for our analysis in the short term. NSPs' provision of data in the same format as their current determinations is important in reconciling expenditure outcomes to what was proposed and determined at the time of previous price reviews. For this reason, dual reporting requirements may exist until the end of each NSP's current regulatory control period. For the sake of clarity, we are not going to ask for forecasts based on existing annual reporting RINs.

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423 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 22; Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 6; Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013, p. 4; CANEGROWERS, *Submission to the AER better regulation program*, 19 September 2013, p. 11.

424 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 6.

425 CANEGROWERS, *Submission to the AER better regulation program*, 19 September 2013, p. 11.

426 Energy Networks Association, *AER* better *regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement,* 20 September 2013, pp. 4, 39–40; The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines, 20 September 2013,* p. 20; Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1.

427 The Victorian Distributors, *Vic DNSP's joint submission on AER draft expenditure forecast assessment guidelines,* 20 September 2013*,* p. 20.

428 AER, *Better regulation – Confidentiality guideline*, 19 November 2013.

We consider the timeframes proposed for the new data requests do not clash with most of the existing reporting obligations. Non-Victorian DNSPs provide RIN responses in November/December each year. Under the proposed timeframe, these DNSPs will receive the new benchmarking data request in November 2013, after they submit the current RIN. TNSPs must provide their regulatory accounts no later than four months after the end of their regulatory accounting years.[429] However, the Victorian transmission regulatory accounting year does not align with other jurisdictions, so we intend to consult with TNSPs to resolve any issues that may arise.

7.3.5 Issues in applying assessment techniques

We have not changed our views on issues in applying assessment techniques as articulated in the Explanatory Statement for the draft Guideline.

Transitional issues will arise as we develop assessment techniques. These issues include those associated with data requirements (section 7.3.2), but also the effectiveness of the techniques. We noted a couple of limitations in our issues paper:

> Our experience and that of other regulators is that no single assessment technique is perfect and many require (at the request of the regulator or of regulated businesses) further data that cannot always be contemplated at the time the technique is defined conceptually.
>
> Some techniques may appear robust and agreed upon at an early stage, however, ultimately they may be abandoned or subject to revision if they cannot produce sufficiently reliable and accurate results.[430]

With these issues in mind, we may not rely on some techniques proposed in the Guideline in the short term, or we may place less weight on these techniques. Some approaches and techniques are less likely to be affected because we used them in previous determinations, including the repex model and the revealed cost approach to forecasting opex.

We will also refine our benchmarking techniques as we develop the benchmarking report. This refinement may occur when we identify a more appropriate alternative approach to compare expenditures across NSPs. For determinations, the weight we place on the new techniques in the Guideline is likely to change over time. In particular, we expect to rely more on high level techniques (including benchmarking) and less on more intrusive techniques (including detailed engineering and project reviews), whereas we relied heavily on the latter in the past (refer to section 2.2 on our previous assessment approach). The weight we decide to place on techniques will be considered in light of the assessment principles, where relevant.

Another issue that we face in applying new assessment techniques is our requirement to stagger determinations for NSPs. While the staggered timing creates difficulties for obtaining consistent data, it allows us to review and refine our data and techniques incrementally rather than on a wholesale basis.

The NSW DNSPs submitted in response to the Explanatory Statement for the Draft Guideline that they expect the AER to consult extensively with them during their regulatory determination process, and be transparent with the material it is intending to use. They would like reasonable opportunity to examine the AER's approach and explain any variances in inputs or outputs.[431]

We consider NSPs will be provided with reasonable opportunity to examine our assessment approach and explain reasons for variances. Under the NER we are required to consult with NSPs during the

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429 AER, *Electricity transmission service providers information guidelines*, September 2007, p. 11.
430 AER, *Guidelines issues paper*, December 2012, p. 36.
431 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, p. 10.

regulatory determination process, following both the release of the issues paper and the draft decision.[432]

The transparency of our assessment process will be increase with the public release of the data we use for our assessments.

432 NER, clauses 6.9.3(b), 6.10.2(a), 6A.11.3(b) and 6A.12.2(a)

Attachments

A Economic benchmarking

This attachment outlines our proposed approach to economic benchmarking. Economic benchmarking measures the efficiency of a firm in the use of its inputs to produce outputs. Accounting for the multiple inputs and outputs of network businesses distinguishes this technique from our other assessment techniques (which look at the partial productivity of undertaking specific activities or delivering certain outputs). It also accounts for the substitutability of different types of inputs and for the costs of providing different outputs.

A.1 AER position

Our proposed approach to economic benchmarking covers two matters:

1. the selection and application of economic benchmarking techniques and

2. our approach to data.

These matters are outlined in here and in Attachment B.

A.1.1 Economic benchmarking techniques

We propose to take a holistic approach to the selection of particular economic benchmarking techniques; however, we intend to apply them consistently.

Holistic approach to selection of economic benchmarking techniques

We are taking a holistic approach to economic benchmarking. This means that we will not specify economic benchmarking techniques in our Guideline but rather determine the application of economic benchmarking techniques at the time of determinations.

We will select economic benchmarking models based on the availability and quality of data, and intended use. Some models may simply be used to cross-check the results of other techniques. At this stage, it is likely we will apply multilateral total factor productivity (MTFP), data envelopment analysis (DEA) and an econometric technique to forecast operating expenditure (opex).

We anticipate including economic benchmarking in annual benchmarking reports.

Applications of economic benchmarking

We are likely to use economic benchmarking to (among other things):

1. measure the rate of change in, and overall efficiency of, NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.

2. develop a top down forecast of total expenditure.

3. develop a top down forecast of opex taking into account:

   - the efficiency of historical opex

   - expected rate of change for opex.

A.2 Reasons for AER position

We outline the reasons for our proposed approach to economic benchmarking below.

A.2.1 Application

In our issues paper we proposed to use economic benchmarking to:

- provide an overall and higher level test of relative efficiency, which may highlight issues that may be overlooked during lower level and detailed analysis[433]
- facilitate benchmarking that may not be possible as part of the category analysis (given data availability), including as a transitional measure
- reinforce findings made through other types of analysis, or otherwise highlight potential problems in assessment methods or data.

We received a number of submissions on our proposed approach to apply economic benchmarking. Further, we refined our proposed approach since releasing the issues paper. We address submissions and outline the reasons for our proposed approach in the following sections.

General comments on economic benchmarking

From a broad perspective, a number of submissions supported the introduction of economic benchmarking. These included submissions from the Canegrowers Organisation, the MEU and the Public Interest Advocacy Centre Ltd (the PIAC).[434] For example, the Major Energy Users Inc. (the MEU) submitted that economic benchmarking will provide a high level indication of the relative efficiencies of NSPs.[435] And the PIAC supported the AER's proposed high-level first pass techniques, submitting that they are consistent with an incentive-based approach to the economic regulation of NSPs and reward an NSP whose initial forecasts of expenditures are reasonably efficient. However the PIAC submitted that the AER should not be restricted from conducting more detailed investigation of expenditure proposals, regardless of the outcome of a high-level first pass assessment.[436]

The PC also commented on the application of benchmarking, recommending we**:**

- at this stage, use aggregate benchmarking to inform (but not as the exclusive basis for) determinations
- begin (ongoing) development of detailed benchmarking performance and control variables, with periodic review for relevance and compliance costs and publish benchmarking results and data.[437]

Our proposed approach is consistent with the PC's comments. It is our intention to develop benchmarking techniques to be used to better inform our determinations. Economic benchmarking will be used in conjunction with a number of other techniques to review expenditure forecasts.

Some submissions also noted the limitations of benchmarking and cautioned against its use deterministically.[438] We are aware of the limitations of economic benchmarking, noting that all

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433 For example, analysis of individual categories of expenditure may not account for the substitutability of inputs. This may make it difficult to distinguish between inefficient expenditure at the category level and expenditures that appear anomalous due to the selection of inputs.

434 Canegrowers, *Canegrowers Submission to the AER Better Regulation Program*, 19 September 2013, p. 6.

435 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, pp. 5, 7.

436 Public Interest Advocacy Centre, *A Firm Basis: Submission to the AER's Draft Expenditure Forecast Assessment Guideline*, 20 September 2013, p. 11.

437 Productivity Commission, *Electricity network regulatory frameworks – inquiry report*, Volume 1, 9 April 2013, p. 41.

438 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, p. 8; Huegin Consulting, *Submission on the AER Expenditure Guidelines: A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 8; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission,* 15 March 2013, p. 6; Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper,* 18 March 2013, p. 13; Aurora, *Issues Paper:*

assessment techniques and forecasting methods have flaws. That said, we consider economic benchmarking has several advantages:

- It accounts for the multiple inputs and outputs of network businesses.
- It may alleviate the need for detailed cost reviews.
- It is transparent, replicable and uses the revealed performance data of NSPs.

We intend to apply economic benchmarking in conjunction with other expenditure assessment techniques. However, we will not preclude placing at least some weight on it in determining expenditure allowances. At this stage, it is too early to form a view on the appropriate weight to apply to assessment techniques.

We expect NSPs to justify their expenditure proposals — particularly where they appear inefficient. However, we intend to provide stakeholders with many opportunities to comment on economic benchmarking data, modelling and regulatory applications. We will publish economic benchmarking data. Further we will consult on the development of economic benchmarking techniques and publish the results of economic benchmarking in issues papers and annual benchmarking reports.

Holistic approach

We propose to take a holistic approach to the selection of particular economic benchmarking techniques; however, we intend to apply them consistently. The holistic approach means that we will not set out our proposed economic benchmarking techniques and model specifications in the Guideline. Rather, we will determine the application of economic benchmarking techniques at the time of determinations.

There was support from stakeholders in relation to the use of the proposed holistic approach to economic benchmarking. The report prepared by NERA Economic Consulting (the NERA Report), that was provided as part of Grid Australia's submission, suggested that it is 'wise not to 'lock-in' either the particular benchmarking techniques it will adopt or how the results of its analysis will be used in the regulatory determination process, ahead of undertaking a transparent and robust development process of actual models, based on real NSP data.'[439]

The submission from the Council of Small Business of Australia (the COSBOA) supported our proposal to apply of a range of economic benchmarking techniques to determine if a Network Service Provider's (NSP's) revealed costs are efficient. The COSBOA submitted that we should place significant weight on the outcomes of techniques such as economic benchmarking.[440] The COSBOA's submission also supported our intention to determine which economic benchmarking techniques to apply at the time of determination rather than specify this in the Guideline. The COSBOA provided that: it expects that the AER would be able to apply at least MTFP, DEA and econometric benchmarking techniques initially; and that perceived initial shortcomings of economic benchmarking

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Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, 19 March 2013, pp. 3–4; Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, pp. 4–5; ActewAGL, *Response to Expenditure forecast assessment guidelines paper,* 15 March 2013, p. 2; SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper,* 15 March 2013, p. 3.

439 Grid Australia, *Submission in Response to Draft Expenditure Forecast Assessment Guideline*, 20 September 2013. NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 12–13.

440 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 5–9.

should not become an impediment to its application because other techniques are "less than perfect" and have flaws.[441]

The report prepared by Huegin Consulting (the Huegin Report), suggested that economic benchmarking is a useful informative tool for identifying differences in the cost outcomes between businesses and suggested that the results from economic benchmarking are a means to initiate investigations into productivity and efficiency improvement opportunities.[442] However, the Huegin Report also submitted that economic benchmarking lacks reliability and that the AER's holistic approach may use economic benchmarking techniques that are not complementary. It is submitted that the different techniques selected for inclusion by the AER have different technical origins and characteristics that rely on different assumptions.[443] Ergon Energy also submitted that it is concerned with the 'multifaceted' approach proposed by the AER to benchmarking. Ergon Energy submitted that: using multiple techniques does not necessarily increase the robustness of the overall approach; and that two or more of the intended techniques that provide a similar result in relation to relative efficiency of an NSP are not necessarily a sufficient means to substitute an NSP's more detailed forecast.[444] CitiPower, Powercor Australia and SA Power Networks submitted that they were concerned with the final selection and use of economic benchmarking techniques.[445]

We do not accept the proposition that it is inappropriate to undertake a holistic approach for economic benchmarking purposes. Each approach provides a 'top down' perspective on NSP cost performances using relatively high level data. Each approach provides an overall, higher level of guidance on the relative efficiency of NSPs costs. While each approach has different strengths and weaknesses, they each offer a different perspective on the relatively performance of NSPs. For example, multilateral total factor productivity indexes (MTFP) require a relatively small number of observations and provide information on NSPs' overall cost efficiency. The frontier methods, such as data envelopment analysis (DEA) and stochastic frontier analysis (SFA) require a relatively large number of observations, however these techniques can also provide a more detailed break-down of NSPs' efficiency performance.

We will select economic benchmarking models based on the availability and quality of data, and intended use. Some models may simply be used to cross-check the result of other techniques. We do not accept that different economic benchmarking techniques will necessarily produce different results. However, if necessary, we will test this as part of our model testing process. If different models produce different results, we will consider this when applying economic benchmarking. Again, while we propose to take a holistic approach to the selection of particular economic benchmarking techniques, we intend to apply them consistently.

Application of economic benchmarking

We will likely apply economic benchmarking to (among other things):

1. measure the rate of change in, and overall efficiency of, NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.

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441 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 12.

442 Huegin Consulting, *Submission on the AER Expenditure Guidelines: A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 8.

443 Huegin Consulting, *Submission on the AER Expenditure Guidelines: A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 7.

444 Ergon Energy, *Submission on the Better Regulation: Draft Expenditure Forecast Assessment Guideline for Electricity Distribution and Transmission Australian Energy Regulator*, 20 September 2013, p. 12.

445 CitiPower, Powercor Australia and SA Power Networks, *Joint Response to AER Draft Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 20 September 2013, p. 6.

2. develop a top down forecast of total expenditure.

3. develop a top down forecast of opex taking into account:

   - the efficiency of historical opex
   - expected rate of change for opex.

As part of the workshop consultation, we released an illustrative spreadsheet that provides example applications of economic benchmarking using a number of economic benchmarking techniques.[446] We expect to apply economic benchmarking as we outlined in the example. However, ultimately, we will decide how to apply it at the time of individual determinations, based on the availability and quality of data.

Our current view is that we will apply three economic benchmarking techniques:

- MTFP—this will be used primarily to measure the overall efficiency and productivity of NSPs.
- DEA—this is a more limited technique than MTFP, because it cannot incorporate as many input and output variables and because it requires more data. Therefore, we propose using it to cross-check the results of the MTFP analysis. It may be possible to decompose the efficiency scores of DEA to identify different types of inefficiency.
- An econometric technique to forecast operating expenditure—this will be used to develop a top down forecast of opex.

Review of relative efficiency and change in efficiency and productivity

As discussed in chapter 3 we must only accept forecasts of expenditure where they reflect the opex and capex criteria meeting the opex and capex objectives. Economic benchmarking measures the relative efficiency of historical costs and the rate of change in productivity and efficiency of historical costs.

The efficiency of historical costs is relevant to considering whether an NSP is responding to incentives. Where NSPs are not responding to incentives (or not responding quickly enough) it may not be appropriate to base an NSP's forecasts purely on its historical expenditures. Economic benchmarking will be one of several techniques that we will use when considering the efficiency of historical costs.

Economic benchmarking, together with other tools such as category analysis, can also provide guidance to targeted reviews of expenditure. For example, where an NSP appears to be relatively inefficient or does not show improving efficiency performance, economic benchmarking results can be decomposed to identify the sources of inefficiency.

Identifying sources of efficiency change

The examination of economic benchmarking results can highlight areas of expenditure forecasts that warrant further investigation. We can identify the sources of changes in efficiency, either from changes in inputs or outputs. This includes separating the efficiency scores into their individual components.

Figure A.1 illustrates possible components of a TFP index. The index is split into three input components (opex, lines and transformers) and the aggregate output component. This illustrates that,

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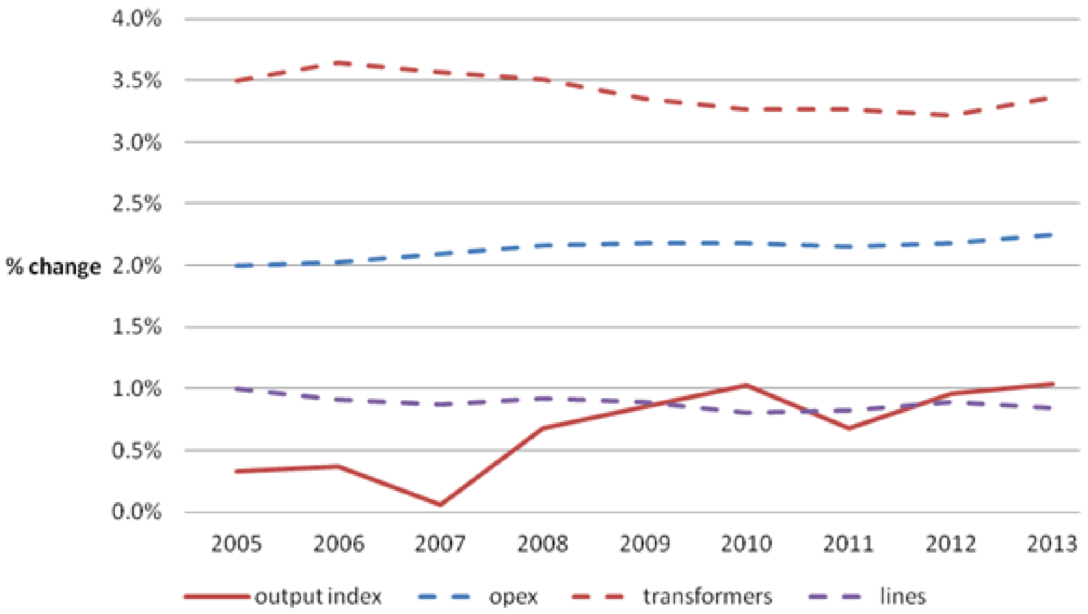
[446] The models, papers and presentations for this workshop have been published on our website at: http://www.aer.gov.au/node/20627.

although aggregate output increased, the increase in inputs was much greater. Historical transformer input is outstripping the growth of the other inputs markedly. Further, opex increased steadily over the period. Finally, the increase in the length of lines was stable. Based upon this example, historical transformer and opex growth appear to be the sources of the change in TFP and may warrant detailed review.

Figure A.1 Decomposition of change in TFP



Source: AER analysis

Consideration of efficiency components

We consider productive efficiency is most relevant for assessing cost forecasts. Productive efficiency is achieved where firms produce their goods and services at lowest cost.[447] The productive efficiency scores derived from economic benchmarking can also be deconstructed into their individual components (Table A.1). In a regulatory context, it may be necessary to consider the different components of efficiency separately. It may not be possible for NSPs to be scale efficient because they have little control over their outputs, for example. Further, there may be little scope for relatively efficient businesses to achieve efficiencies from technical change.

[447] Independent Inquiry into National Competition Policy (F Hilmer, Chair), *National Competition Policy*, Australian Government Publishing Service, Canberra, 1993.

Table A.1 Definitions of efficiency

Efficiency measure	Description
Technical efficiency	This is a firm's ability to achieve maximum output given its set of inputs.
Input mix allocative efficiency	This is a firm's ability to select the correct mix of input quantities to ensure the input price ratios equal the ratios of the corresponding marginal products (that is, the additional output obtained from an additional unit of input).
Cost efficiency	This is a firm's ability to produce a given level of output at minimum cost given the input prices it faces. Cost efficiency is achieved when both technical efficiency and input mix allocative efficiency are achieved.
Output mix allocative efficiency	This is a firm's ability to select the combination of output quantities in a way that ensures the ratio of output prices equals the ratio of marginal costs (that is, the additional cost corresponding to the production of an additional unit of product).
Scale efficiency	This measures the degree to which a firm optimises the size of its operations. A firm can be too small or too large, resulting in lower productivity associated with not operating at the technically optimal scale of operation.
Technical change	This is a change in the amount of inputs required to produce an output or a combination of outputs. Productivity change over time can be decomposed into technical change, scale efficiency change, input/output mix efficiency change and technical efficiency change.

Source: Coelli T, Estache A, Perelman S and Trujillo L, A primer on efficiency measurement for utilities and transport regulators, World Bank Publications, 2003, pp. 11–12.

We consider using benchmarking to measure and report relative productive efficiency will promote dynamic efficiency. Dynamic efficiency relates to industry making timely changes to technology and products in response to changes in consumer tastes and productive opportunities.[448] The responsiveness of industry is difficult to measure. However, dynamic efficiency can be promoted through appropriate incentives and competition.

Economic benchmarking does this. It creates reputational risk for NSPs, giving them a stronger incentive to adopt new technologies and business practices and to invest appropriately. Further, reporting productive efficiency accounting for all the factors of production provides information on dynamic efficiency. Using economic benchmarking in determinations also creates competitive pressures across NSPs, which will promote dynamic efficiency. If we forecast costs at the productively efficient level, NSPs that gain efficiencies through better management or innovation will retain a proportion of the efficiency gains.

Consideration of the appropriate benchmark

The benchmark level of efficiency is the level of efficiency against which NSPs are compared and should be able to operate at. We could set it at a number of possible levels, such as the top quartile middle or revealed frontier. This will depend on the robustness of the data and the model specification. In determining the benchmark level of efficiency performance we will consider the reliability of data and the potential error of expenditure assessment techniques. We do not propose to turn our mind to an appropriate benchmark until the testing and validation process.

A number of stakeholders submitted that they were concerned with how to interpret the results from economic benchmarking models. The concerns were in relation to how to interpret the resulting 'residual' from economic benchmarking techniques and the assumption that the 'residual' would be interpreted only as the relative inefficiencies of NSPs. It was submitted that this residual could be a

[448] Independent inquiry into national competition policy (F Hilmer, Chair), *National competition policy*, Australian Government Publishing Service, Canberra, 1993.

result of other factors, including a measure of actual costs that are not incorporated within the economic benchmarking model specification.[449]

The NSW DNSPs submitted that the use of benchmarks may lead to misleading conclusions unless the AER undertakes more detailed examination to determine whether the results are a measure of inefficiency.[450] Ergon Energy submitted that to infer that an NSP is inefficient purely because it is not on an efficient frontier is incorrect and suggested that attainment of efficiency may be a theoretical construct.[451] The NERA Report submitted that absolute efficiency cannot be measured or observed.[452] The NERA Report further suggested that it is important to recognise that costs which are not explained by a benchmarking model may be costs that have not been attributed to the explanatory variables included in the model.[453]

We consider that any forecasting approach may be subject to error. That is, the 'residual' generated by some economic benchmarking techniques may not merely be a measure of 'inefficiency' associated with an NSP. Rather, the results may be affected by the reliability of data and the potential error of the expenditure assessment techniques, including the model specification used. When there is uncertainty about the quality of the data and the appropriate model specification, and where different specifications provide different results, it may be necessary to use the results cautiously. The Productivity Commission suggested there will always be error in measuring the efficient frontier. The Productivity Commission recommended using a yardstick approach for judgments about allowable revenues—that is, to select a firm close to, but not at, the efficiency frontier.[454]

It is also important to note that we cannot measure the actual efficient frontier. All we can measure is a revealed efficiency frontier. This is because we are only sampling a subset of all NSPs worldwide. Further, the appropriate benchmark may differ depending on the sensitivity of benchmarking results to technique and model specification. The COSBOA noted that our intention is not to propose to set the benchmark level of efficiency until it has undertaken testing and validation of data. The COSBOA suggested that the minimum level should be approximately the top quartile of the revealed frontier for benchmarking to have a meaningful impact on NSP performance and to benefit consumers.[455] The COSBOA submitted that there are also strong reasons for going further than this to either the actual revealed frontier or by adopting a recommendation by the Productivity Commission of a 'yardstick approach' where an NSP is selected that is close to the frontier.[456]

Further, it is quite likely that the efficient frontier will be further out than the revealed frontier. This is because estimation techniques outlined above will be used to measure the relative efficiency of Australian NSPs only. However, at least some international NSPs are likely to be more efficient than those in Australia. As such, the revealed frontier may already be conservative.

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449 Huegin Consulting, *Submission on the AER Expenditure Guidelines*: *A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 11.

450 Ausgrid, Endeavour Energy and Essential Energy (the NSW DNSPs), *Joint Submission on AER Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, p. 8.

451 Ergon Energy, *Submission on the Better Regulation: Draft Expenditure Forecast Assessment Guideline for Electricity Distribution and Transmission Australian Energy Regulator*, 20 September 2013, p. 9.

452 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 8–9.

453 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, p. 27.

454 Productivity Commission, *Electricity network regulatory frameworks – inquiry report*, Volume 1, 9 April 2013, p. 31.

455 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 13.

456 Productivity Commission, *Electricity Network Regulatory Frameworks – Inquiry Report*, Volume 1, 9 April 2013, p. 31.

Depending on the technique used and its assumptions, the estimated efficient frontier may differ. Given that differing techniques may estimate the frontier in different manners, we will consider how they measure the frontier in the selection of the efficient benchmark.[457]

The appropriate benchmark may also differ depending on the sensitivity of benchmarking results to technique and model specification. When there is uncertainty about the appropriate model specification and different specifications provide different results, it may be necessary to use the results cautiously.

The efficient frontier will be estimated using economic benchmarking techniques incorporating all NSPs (transmission and distribution will be separately benchmarked). Due to the fact that NSPs produce multiple outputs there may well be a number of firms on the efficient frontier. The number of firms on the efficient frontier may also differ depending on the benchmarking technique applied. We do not consider that it is appropriate to determine the number of benchmark firms until the results of economic benchmarking become available.

Measurement of the rate of change in productivity

The measurement of the rate of change in productivity is also an important consideration when assessing expenditure forecasts. It is expected NSPs will become progressively more productive and efficient over time, and this should be reflected in efficient and prudent forecast expenditure. The change in productivity may indicate potential productivity change for the near future. Note that cost escalation over time incorporates:

- input price changes
- output growth
- productivity changes, including:
  - technical change (industry frontier shift)
  - technical efficiency change (efficiency catch up)
  - scale efficiency change

The rate of productivity change may differ depending on a NSP's relative efficiency. Several participants commented on the ability of NSPs to make productivity improvements. ENA noted some of its members have been subject to incentive regulation for more than 15 years, making large efficiency gains in the process and moving towards the efficiency frontier. For many of these businesses, large step changes in efficiency will not be possible, with only gradual year-on-year improvements being realistic.[458] We expect relatively efficient NSPs to be technically efficient and agree it is not appropriate to expect them to achieve further technical efficiencies. However, they should be able to achieve technical change in line with the rest of the industry.

Workshop participants proposed 'industry wide productivity' must include both private and public NSPs. Some suggested private providers are likely to be more productive and public providers less so. However, the small number of NSPs in Australia means it would not be reasonable to exclude

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[457] The different approaches to measuring the frontier using economic benchmarking are set out in our Issues Paper.

[458] Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper,* 8 March 2013, p. 15.

private providers, because the productivity measure would be based on an even smaller number of NSPs.[459]

We propose to include all NSPs in our benchmarking analysis regardless of ownership in order to review their relative efficiencies, as well as productivity changes and the sources of productivity changes in the past. However, for the purpose of forecasting efficient cost for the next regulatory period, we need to carefully consider the productivity improvement potential that can be achieved by each NSP. It can be the case that, for those businesses on or close to the frontier, large technical efficiency change in the past should not be factored into their forecasts of future productivity change. However, where it is expected that NSPs may be able to achieve further technical efficiency improvement, then this will be factored into forecasts.

We consider the expected change in productivity will depend on the source of productivity change:

- Technical change is expected to be consistent and incremental for all NSPs.
- Technical efficiency change will depend on the source of technical inefficiency:
  - If technical inefficiency is associated with opex, then it might be reasonable to assume that this can be eliminated quickly as opex is flexible in the short run.
  - Technical inefficiencies associated with capital inputs may take longer to achieve, given the long term nature of capital investment.
- Scale efficiency change will be aligned with the growth in outputs and the scale of operation.

NSPs also suggested the Guideline should identify the timeframe over which efficiency gains might be realised.[460] Our view on the incorporation of efficiency gains into forecast expenditure is detailed in section 5.1 above.

Total cost counterfactual forecast

Using the forecast of productivity change and historical costs we intend to develop a top down forecast of total costs. This forecast would provide a counterpoint to proposals—the counterfactual. The total cost counterfactual forecast will be one of a number of techniques applied in the first pass assessment of regulatory proposals.

Figure A.2 illustrates this potential application by presenting annual total cost estimates and forecasts proposed by an NSP (in columns) and reference annual total costs established under the economic-benchmarking approach (the line). The economic benchmarking approach is developed by taking historical expenditures and escalating them by the forecast rate of change in cost that accounts for potential input price change, output growth, and efficiency and productivity gains.

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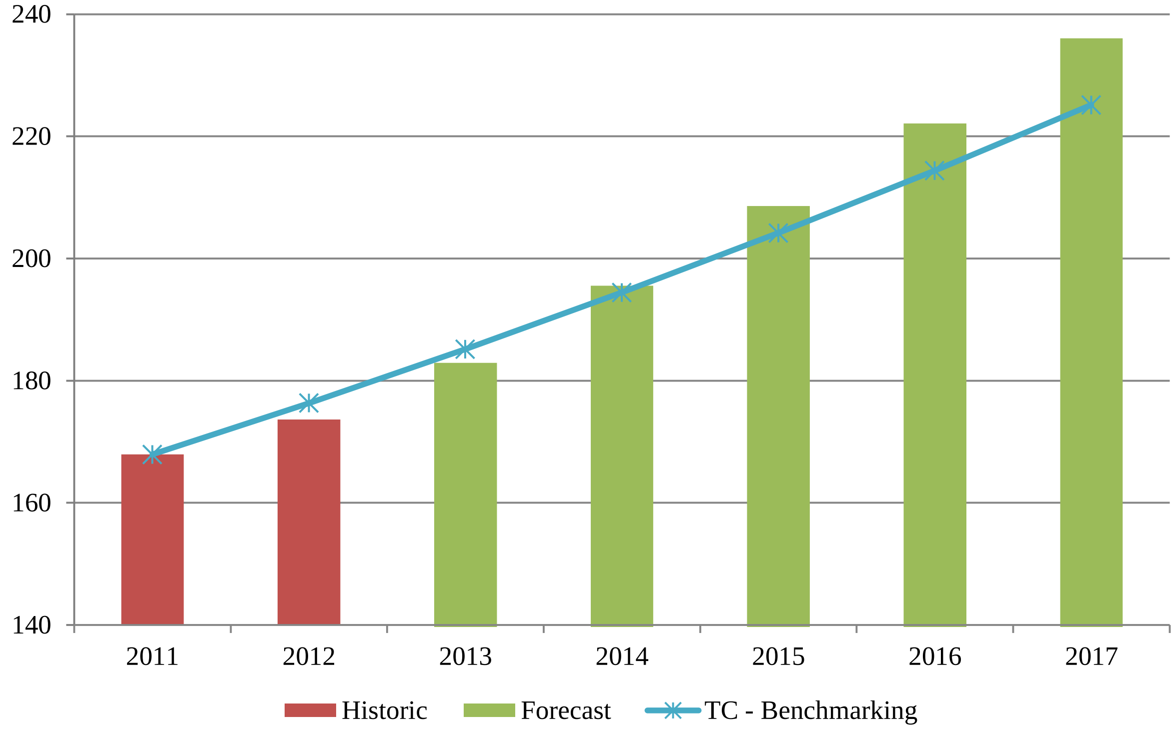
459 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 4.

460 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', *Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution)*, 8 May 2013, p. 3.

Figure A.2 Comparing Total Cost Forecasts[461]



Source: AER analysis

In this example, for four years of the forecast regulatory period (2014 to 2017), the NSP proposed higher total costs than those suggested by economic benchmarking. In a net present value sense, total costs proposed by the NSP for the forecast regulatory period are higher than the benchmarked total costs. The discrepancy in forecast costs may reflect a different view about demand outlook, input requirements and the potential scope for productivity and efficiency improvements. We will need to consider these differences in order to form a view on efficient costs.

Top down opex forecast

We also propose to use economic benchmarking to develop a top down forecast of opex that would:

- measure the relative efficiency of the opex base year and develop a potential substitute base year
- forecast the rate of change in opex, incorporating expected efficiency change based on historically observed efficiency change.

The resulting opex forecast for the forthcoming regulatory period provides an alternative set of estimates to NSP proposals. This proposed economic benchmarking application builds on the current revealed cost base-step-trend forecasting approach by:

- identifying potential inefficiency in the base year opex. This allows for the immediate or progressive removal of opex inefficiencies.
- forecasting expected opex efficiency and productivity change.

461 Where there is disagreement on input price changes and output growth rates, we may need to make two separate forecasts. This would illustrate the materiality of the differences in expected output growth and input price changes.

These are considered separately below.

Review of base year opex

Details about reviewing base year opex are currently considered in chapter 5. Essentially, we prefer to rely on the revealed cost base-step-trend forecasting approach that we currently apply. We propose adjusting the revealed cost base year when:

- an NSP appears materially inefficient in comparison to its peers
- in tandem with incentive schemes, the revealed cost forecast would yield an outcome that is not consistent with the opex criteria.

Economic benchmarking is one of a number of tools that we intend to apply to see if a NSP appears materially inefficient compared with its peers. Our likely near term approach is to use an econometric model to forecast opex requirements. We will use a regression of historical opex costs against outputs, input prices and environmental factors, based on an approach Economic Insights developed for SP AusNet's gas distribution network.[462]

The econometric technique assumes that, in the short term, capital inputs are exogenous to management control. Hence, we will include the quantity of capital in the regression as a control variable.

A regression is directly able to incorporate operating environment factors that may affect a NSP's costs. Further, statistical testing can be applied to measure the explanatory power of the technique and the sensitivity of benchmarking results.

In workshops one NSP commented that it would like to see flexible cost functions used to forecast opex.[463] We consider that a flexible cost function would be preferred, but a more restrictive function may prove more appropriate through statistical testing. The appropriate cost function will differ depending on the quantity and quality of data available.

Review of expected opex efficiency and productivity change

We consider that using the econometric technique to forecast the rate of change in opex is preferable to macro-based modelling for adjustments to labour cost escalation. The macro-based forecast is an approach that we used previously to forecast the rate of change in opex. Under this approach macro-economic and sector-level data are used in the forecasting model to forecast labour cost escalation. In some instances this has also included an adjustment for expected labour productivity change.

The econometric cost modelling offers a more coherent approach to forecasting opex escalation as it explicitly models input price changes, output growth and efficiency and productivity gains as cost drivers. By jointly accounting for the change in these factors, it mitigates the risk of double counting or inappropriately accommodating the drivers of the rate of change in opex. Further, the econometric approach can provide more firm-specific forecasts (hence accounts for the individual circumstances of NSPs) whereas the macro modelling approach assumes sector-level labour price changes and/or labour productivity change can be applied directly to a NSP.

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462 Economic Insights, *Econometric estimates of the Victorian gas distribution businesses' efficiency and future productivity growth*, Report prepared for SP AusNet, 28 March 2012.

463 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 2.

NSPs were concerned the economic benchmarking techniques will not necessarily represent the cost drivers that affect output growth for opex forecasting. They stated the quantity of capital is a prime driver of opex.[464] We consider that the outputs of a NSP are the same regardless of whether partial productivity or total productivity is being measured. The scale of a network should be measured in terms of its outputs. However, other relevant explanatory variables will be included in the regression to account for operating environment factors. Further, the quantity of capital is being included as a control variable.

Workshop participants submitted there is no one productivity growth factor for a NSP. Instead, different cost categories can have different productivity changes. Corporate overhead can have greater economies of scale than other cost categories, for example.[465] We note a NSP may have multiple sources of productivity change and their contribution to the overall productivity change may differ across cost categories. We consider that an econometric technique is an appropriate method for an overall forecast of these productivity gains. It has the ability to capture the relationships between inputs, outputs and environmental factors at the aggregate level. Further, it may mitigate the need for an intrusive review into sources of potential efficiency gains.

Other matters raised in submissions

Submissions also raised several other issues about applying economic benchmarking. These are considered below.

Having Regard to the Individual Circumstances of the Network

All NSPs use a range of inputs, including capital, fuel, labour, land, materials and services to produce outputs. This commonality means that economic benchmarking of costs can be used to measure the economic efficiency of an NSP by comparing its performance not only to other NSPs but also to its own past performance. However, it is important to recognise that NSPs do not operate under exactly the same operating environment conditions. Rather, economic benchmarking techniques need to account for operating environmental differences to ensure that when comparisons are made across NSPs, we are comparing like with like to the greatest extent possible.

A number of stakeholders submitted that NSPs face different factors that affect their levels of efficiency. The concern was that economic benchmarking will not be able to incorporate and account for these differences.[466] For example, the Huegin Report submitted that a 'main concern' is in relation to an assumption that Australian NSPs are comparable. The Huegin Report questions whether 'it is possible to compare Australian networks on a like-for like basis and there is an industry cost function that represents all NSPs in the NEM'.[467] Energex submitted that capturing comparable data that accurately reflects differences across businesses is a difficult task.[468]

A submission from Ausgrid, Endeavour Energy and Essential Energy (the NSW DNSPs) suggested that benchmarks and predictive models do not account for inherent differences between businesses. It was submitted that limitations of economic benchmarking includes an inability to account for characteristics, drivers and investment cycles and an inability to provide a 'like for like' comparison.

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464 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 2.

465 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013, p. 3.

466 ActewAGL, *Response to AER Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, p. 3.

467 Huegin Consulting, *Submission on the AER Expenditure Guidelines*: *A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 10 and p. 13.

468 Energex Limited, *Submission on AER Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, p. 4.

Further, the accounting systems and reporting systems of NSPs may affect the ability to compare NSPs.[469] And the NERA Report submitted that a 'fundamental weakness' of economic benchmarking is that it often overlooks environmental factors that are business specific.[470] Ergon Energy submitted that economic benchmarking is limited in Australia because of differences in environmental conditions, legacy accounting and reporting structures and the small number of businesses.[471]

In contrast, the submission by the MEU suggested that a recurring theme raised by NSPs is that all NSPs are different and to benchmark any NSP against others will result in distorted outcomes.[472] The MEU submitted that useful comparisons can nevertheless be obtained by careful selection of the benchmarking inputs and outputs, and of the categories used in the development of the dataset because there is considerable commonality of activities. Further, economic benchmarking can assist in providing a clear indication of what can be achieved by NSPs and the pursuit of NSP efficiency by the AER and consumers. Likewise, the PIAC submission suggests that the use of high-level economic benchmarking "opens the door for claims by NSPs that the comparisons are not valid".[473]

The COSBOA submitted that all businesses, including individual NSPs, are different in some respects.[474] However, the NSPs also have similarities, including similar cost drivers. The COSBOA submitted that it does not share the concerns of some NSPs that differences could detract from the AER's approach.

In our view, there is a sufficiently common basis to compare the economic efficiency of NSPs. NSPs use a range of common inputs, including capital, fuel, labour, land, materials and services to produce outputs. NSPs provide a range of common outputs. On this basis, economic benchmarking of costs can be a useful tool to measure the economic efficiency of an NSP by comparing its performance not only to other NSPs, but also to its own past performance over time.

However, it is also important to recognise that NSPs do not operate under exactly the same operating environment conditions. That is, operating environment conditions can have a significant impact on measured efficiency through their impact on network costs. It is desirable to adjust for the most important operating environmental differences to ensure that when comparisons are made across NSPs, we are comparing like with like to the greatest extent possible.

We can account for differences in efficiency across networks caused by operating environment factors by collecting the relevant data. The materiality of the operating environment factors can be tested as part of the data validation and testing process. That is, the results of sensitivity analyses will inform us in relation to the choice of environmental variables. The selection of environmental variables will also be informed by ongoing research and consultation with stakeholders as increasingly consistent, robust, and detailed data is collected.

Economic Benchmarking and TNSPs

We consider that there is merit in economic benchmarking for transmission networks. In our view, TNSPs should be expected to improve their productivity over time. We anticipate that the application

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469 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines*, 20 September 2013, p. 8.

470 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 52–53.

471 Ergon Energy, *Submission on the Better Regulation: Draft Expenditure Forecast Assessment Guideline for Electricity Distribution and Transmission Australian Energy Regulator*, 20 September 2013, p. 8.

472 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines*, 20 September 2013, pp. 8–9.

473 Public Interest Advocacy Centre, *A Firm Basis: Submission to the AER's Draft Expenditure Forecast Assessment Guideline*. 20 September 2013, p. 15.

474 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 10.

of economic benchmarking techniques will differ for distribution networks and transmissions networks. This is because their activities and outputs differ. Further, there will be less data for our economic benchmarking analysis because there are fewer transmission networks. This may limit the techniques that can be applied. However, until we attempt economic benchmarking of transmission networks, we will not have a final view on its applicability to TNSPs.

Some stakeholders submitted that there are specific challenges in relation to the application of economic benchmarking techniques to TNSPs. Grid Australia submitted the proposed economic benchmarking techniques are generally unsuitable for TNSPs.[475] The NERA Report submitted that economic benchmarking of TNSPs is more difficult because TNSPs typically undertake capex projects that involve large, relatively infrequent augmentation of replacement of particular assets or groups of assets, rather than a steady stream of smaller projects.[476]

As noted by the NERA Report we propose to apply a range of economic benchmarking techniques to measures of both opex and total costs. The NERA Report submitted that in case of total costs, the issue of the lumpy investment profile for transmission assets is potentially reduced since the assessment of capital costs takes into account both new capex and the existing asset base. The lumpy nature of transmission investment is therefore less of a difficulty in relation to the benchmarking applications being proposed.[477]

The COSBOA submitted that while some TNSPs' concerns in relation to the impact of 'lumpy investment' on economic benchmarking may have some validity, the concern is generally exaggerated.[478] Further, the COSBOA submitted that it is important to undertake a benchmarking exercise of TNSPs because similarities and homogeneity in relation to the operations of TNSP, including TNSPs' similar outputs and similar inputs at an aggregate level, make economic benchmarking a potentially useful tool.[479]

As discussed, we anticipate that the application of economic benchmarking techniques will differ for distribution networks and transmissions networks because their activities and outputs differ. Further, the availability of less data may limit the techniques that can be applied. However, until we attempt economic benchmarking of transmission networks, we will not have a final view on its applicability to TNSPs.

Sample Size and Quality of Data

We are seeking a broad range of data so we can apply a range of economic benchmarking techniques, and conduct sensitivity analysis on possible economic benchmarking model specifications.[480] The data obtained for economic benchmarking will be subject to extensive consultation as part of our data validation and model testing process. We will consider the availability and quality of data available when applying economic benchmarking.

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475 Grid Australia, *Submission in Response to Draft Expenditure Forecast Assessment Guideline*, 20 September 2013, p. 2.

476 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 11–12.

477 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, p. 11.

478 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 14.

479 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 14.

480 CitiPower, Powercor Australia and SA Power Networks supported the AER undertaking extensive sensitivity testing of its preferred economic benchmarking model. CitiPower, Powercor Australia and SA Power Networks, *Joint Response to AER Draft Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 20 September 2013, p. 13.

Some stakeholders submitted that there an 'insufficient' sample size to undertake MTFP, DEA or econometric analysis of NSPs.[481] In relation to economic benchmarking of TNSPs, the NERA Report notes that there are five transmission businesses operating in the National Electricity Market (the NEM). It is submitted that this will result in a relatively small available dataset. The NERA Report suggest that this, combined with the differences in operating environments between TNPs, will limit the ability of economic benchmarking techniques to assess the relative efficiency across TNSPs.[482]

The Huegin Report submitted that data from thirteen DNSPs is not sufficient to support economic models and to obtain results that contain the appropriate level of statistical significance for DNSPs. The Huegin Report submitted that a limited sample size may: limit the ability to remove differences in MTFP results due to factors such as data errors to infer the relative level of efficiency between NSPs; affect the results of DEA; and limit the ability to use econometric analysis.[483]

Energex submitted that while economic benchmarking is an appropriate technique for the AER to apply, data limitations mean that the results should be limited to providing a high-level 'reasonableness check' of a DNP's aggregate and/or category-level expenditure forecasts. Energex further submitted that it has 'serious reservations' in relation to whether the proposed benchmarking techniques, including the quality and consistency of the data collected, will be sufficiently robust to be used in a manner proposed by the AER.[484] Ergon submitted that the economic benchmarking techniques are limited by a number of factors, including the small number of businesses in Australia.[485]

A report by Incenta Economic Consulting submitted that the empirical estimation process will be 'subject to the availability of data spanning the relevant variables over a sufficient period and for a sufficient number of entities'. Incenta submitted that the data availability may limit our ability to apply economic benchmarking to TNSPs.[486]

The PIAC submitted that the ability and reliability of the data and the fact that the models are yet to be fully developed and tested, may limit the AER's ability to rely on economic benchmarking. The PIAC noted that data is limited because without the inclusion of international data, there is a relatively small number of NSPs in the NEM.[487]

When considering the data requirements for economic benchmarking, it is important to note that the quality of the data is important and further, cross-sectional and a time-series aspects to economic benchmarking efficiency assessments may have different data requirements. Longer time series provides a picture of the TFP growth rate over a larger time period than one calculated using a shorter time period. Ultimately the robustness of the long time series and the short time series depends on data quality.

That is, different methods of economic benchmarking require different numbers of observations. For example, MTFP indexing methods could be calculated with relatively fewer observations to produce

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481 Grid Australia, *Submission in Response to Draft Expenditure Forecast Assessment Guideline*, September 2013, p. 7. NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 8–10. Huegin Consulting, *Submission on the AER Expenditure Guidelines: A Review of the Benchmarking Techniques Proposed*, 20 September 2013, p. 13.

482 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, p. 9.

483 Huegin Consulting, *Submission on the AER Expenditure Guidelines*: *A Review of the Benchmarking Techniques Proposed*, 20 September 2013, pp. 10–13.

484 Energex Limited, *Submission on AER Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, pp. 2–3.

485 Ergon Energy, *Submission on the Better Regulation: Draft Expenditure Forecast Assessment Guideline for Electricity Distribution and Transmission Australian Energy Regulator*, 20 September 2013, p. 8.

486 Incenta Economic Consulting, *Expenditure Forecasting and Incentive Issues*, 20 September 2013, p. 2.

487 Public Interest Advocacy Centre, *A Firm Basis: Submission to the AER's Draft Expenditure Forecast Assessment Guideline*. 20 September 2013, p. 11.

unadjusted cost efficiency comparisons. Other methods, however, require more observations. In the case of econometric methods for example, this is required to provide sufficient degrees of freedom to be implementable and to reduce the impact of possible issues with multicollinearity. Economic benchmarking data requirements are discussed further in Economic Insights (2013).[488]

We are seeking a long historical data series from NSPs. This may be sufficient to undertake cross-sectional estimates of DNSP and TNSP efficiency using MTFP index methods. While this could be done with less data, additional data will provide additional context and confidence in relation to the results obtained. The use of a simple functional form combined with an additional data will provide an opportunity to adjust for a limited number of operating environment variables using second stage regression methods.

We understand that several years of data may be required for TNSPs to support regression based adjustments given the smaller number of TNSPs. Again, we will select economic benchmarking models based on the availability and quality of data and the intended use. Where there is limited data available for economic benchmarking purposes, we will consider this when we assess the robustness and reliability of the economic benchmarking results and the relative weight that we may place on economic benchmarking results in light of the other forecasting methodologies and assessment techniques available.

This approach is supported in a number of submissions. For example, the MEU submitted that our ability to rely on economic benchmarking results may be limited in the short run due to the possible limitations of the dataset available. However, the MEU submitted that benchmarking should include a wider sample of benchmarking entities than NSPs in the NEM and also supported that proposition that as the dataset improves, tools such as economic benchmarking may be relied upon to a greater extent.[489]

The Technical Report

The NERA Report refers to the ACCC's Economic Benchmarking Model: Technical Report (the Technical Report) that provided an illustrative example of the potential applications of MTFP, DEA and econometric methods.[490] The NERA Report submitted that there were a number of potential issues with the Technical Report.[491] These are addressed below.

Role of the Reference Firm

The NERA Report submitted that there is a problem with the use of a 'reference firm' in the MTFP analysis and that the results in the Technical Report depend on the selection of the reference observation.[492] However, the NERA Report has misinterpreted the role of the reference firm in this analysis in the Technical Report.

Because the MTFP index is calculated as a change between pairs of observations in the sample, it is necessary to set one observation as a reference or base firm when converting the MTFP index change values into a conventional (levels) index. Because of the structure of the MTFP index, the results are (purposefully) invariant to which observation is as the reference or base.

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488 Economic Insights, *Economic Benchmarking of Electricity Network Service Providers: Report Prepared for the Australian Energy Regulator*, 25 June 2013, p. 5 and pp. 94–97.

489 MEU, *Submission on AER Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, pp. 8–11.

490 RDB/ACCC, Economic Benchmarking Model: Technical Report, June 2013.

491 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 20–31.

492 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 20–26 and Box 2.1.

The regulatory application of the MTFP results includes two components. The first is the change necessary to achieve the highest productivity level observed in the sample over a period of 20 years (referred to as overall cost efficiency). The second is the extrapolated rate of productivity growth across the sample.

Because the first component is the ratio of the current year's MTFP level to the highest observed MTFP level, it will be invariant to which observation in the sample is set as the reference or base year in forming the MTFP levels index.

Specifically, the highest MTFP level occurs for NSP 1 in 2011. That is, NSP 1 has a ratio (relative to the highest MTFP level in the sample) of 1.0 in 2011. This is noted in cell 'Q5' of the TFP Analysis sheet of the excel file that accompanies the Technical Report and that contains the Economic Benchmarking Model. This should not be confused with the reference year, as the NERA Report has done.

Rather, the ratio relative to the highest MTFP score will be invariant to which observation is chosen as the base or reference year in forming the MTFP levels index. The results should not be reset in the manner in that was done in the NERA Report, by assigning a ratio of 1.0 to NSP 2. This is because NSP 2 is not the NSP with the highest observed MTFP level.

Application of MTFP Results in New Zealand Studies

The NERA Report also raised concerns in relation to the different application of MTFP results in previous New Zealand studies.[493] The NERA Report suggested that 'different X-factors were then applied to different groups based on these rankings, but these factors were not determined on the basis of the MTFP results and did not infer the removal of inefficiencies or potential cost reductions'.[494] However, this is incorrect. Lawrence (2003) describes the process as follows:

> 'For productivity adjustments we form the distributors into three groups with high, medium and low productivity levels. In 2003 the high productivity group (excluding Electricity Invercargill) was 15 per cent more productive on average than the middle productivity group which was in turn around 15 per cent more productive than the low productivity group. Using the distribution B factor of 1 per cent derived in section 5 for the middle group and a 10 year timeframe, the average productivity of the bottom group would have to increase by 2.5 per cent annually to reach the same average productivity level as the middle group after 10 years. Conversely, the high productivity group would have to change its average TFP by –0.5 per cent annually to reach the same average productivity level as the middle group after 10 years. This implies overall X factors of –0.5, 1 and 2.5 per cent per annum for the three groups or C factors of –1.5, 0 and 1.5 per cent per annum, respectively. Given the need to minimise risks given the variable quality of the available data and residual uncertainties, we reduce the range of C factors to –1, 0 and 1 per cent. This range also allows the high productivity group to maintain its absolute productivity levels while the other groups catch up.'[495]

Treatment of Capital Stock

The NERA Report submitted that a shortcoming of the proposed approach in the Technical Report is that it assumes that the NSP's capital stock is fixed for the period in which it is forecasting opex.[496]

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493 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, p. 25.

494 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, pp. 25–26.

495 D. Lawrence (2003), *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996–2003*, Report by Meyrick and Associates for the New Zealand Commerce Commission, Canberra, 19 December, p. 63. We also note that in relation to the references in the NERA Report in footnote 72 (p. 26) that Zeitsch, Lawrence and Salerian (1994) was the first Australian study to incorporate operating environment differences when calculating productivity gaps. Refer to J. Zeitsch, D. Lawrence and J. Salerian (1994), "Comparing Like With Like in Productivity Studies – Apples, Oranges and Electricity", Economic Record 70 (209), 162–70.

496 NERA Economic Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, p. 29.

This is not correct. Rather, the proposed method uses an opex cost function which assumes that the quantity of capital is fixed each year, but is allowed to vary between years. Interactions between opex and the capital stock (which is determined by capex and depreciation) are estimated via the coefficient on capital in the opex cost function.

Submissions raised in the Huegin Report

The Huegin Report submitted that they have concerns with aspects of economic benchmarking techniques.[497] For example, the Huegin Report submitted that MTFP is unable to account for different business conditions on efficiency results and unable to account for the influence of scale on efficiency results.[498] The Huegin Report further submitted that DEA is more suited to other industries where there is a more homogenous environment and that both MTFP and DEA are sensitive to the model specification used. And it was submitted that econometric analysis may be affected by omitted variable bias and the opex cost elasticity associated with increasing output is likely to be higher for a rural network than the estimated industry opex cost elasticity.

As previously discussed, economic benchmarking approaches have different strengths and weaknesses, and they each offer a different perspective on the relatively performance of NSPs. For example, MTFP provides information on NSPs' overall cost efficiency and productivity levels.

We are aware that the usefulness of frontier methods such as DEA reduces as the number of outputs and inputs is increased. This is because DEA may progressively identify more firms as relatively efficient because of unique output or input mixes. However, in our view, DEA is still likely to be an important role in economic benchmarking because it may be used to decompose efficiency scores and provide a more detailed break-down of an NSP's efficiency performance. DEA may also may be used to cross-check the results of MTFP analysis.

We are also aware of the importance of the model specification for economic benchmarking. As discussed, we intend to undertake sensitivity analysis in developing and finalising our model specifications. Our broad range of data requirements is designed to allow for rigorous sensitivity analysis in order to test the robustness of our economic benchmarking analysis and to further understand the relationships between the inputs, outputs and environmental variables. This will also assist in identifying and correcting for potential shortcomings or econometric issues, such as a 'missing-variable bias', in the proposed econometric models.

The Huegin Report suggested that NSP's with a predominantly rural network may have a different opex cost elasticity to the industry. The rural/urban distinction is potentially an important environmental variable that may affect NSPs costs. As discussed in the Explanatory Statement, we are collecting data in relation to operating environmental factors so that we can account for the potential differences in efficiency across networks caused by operating environmental factors such as urban or rural factors.

[497] Huegin Consulting, *Submission on the AER Expenditure Guidelines*: *A Review of the Benchmarking Techniques Proposed*, 20 September 2013, pp. 10–11.

[498] Also refer to Ergon Energy, *Submission on the Better Regulation: Draft Expenditure Forecast Assessment Guideline to Electricity Distribution and Transmission*, 20 September 2013, p. 10.

The cost of capital

Workshop participants discussed the sensitivity of economic benchmarking to the WACC. Specifically, they considered the efficiency of expenditure forecasts may be sensitive to the cost of capital used in the economic benchmarking analysis.[499] We are separately consulting on the WACC.

Economic Insights commented on the WACC to be used for economic benchmarking:

> For economic benchmarking purposes the annual user cost of capital should ideally use an exogenous or ex–ante approach as discussed in the preceding subsection. This is because producers base their production and investment decisions on the price of using capital they expect to prevail during the year ahead rather than being able to base them on the price of using capital actually realised in the year ahead (as would be only known with the benefit of perfect foresight). This points to using the WACC NSPs expect to prevail at the start of each year rather than the actual realised WACC for that year.
>
> Because NSPs operate under regulation which specifies a forecast WACC for regulatory periods of 5 years, it would appear reasonable to use the regulated WACC for all years in the relevant regulatory period for each NSP. But, because the regulatory periods do not coincide for all NSPs and because the regulatory WACC tends to change over time, this would lead to NSPs all having somewhat different WACCs for economic benchmarking purposes. While this may reflect reality, it has the downside of making it more difficult to compare like–with–like when making efficiency comparisons because capital is receiving different weights. It also makes it difficult to compare total costs across NSPs because they will be influenced by the use of different regulatory WACCs for each NSP.
>
> A pragmatic solution to this in the initial round of economic benchmarking may be to use a common WACC across all NSPs when assessing expenditure forecasts and, by extension, for historical comparisons of efficiency performance. A candidate WACC would be the WACC used in the most recent NSP regulatory determination which could be assumed to apply to all NSPs for both the forecast and historical period.
>
> Sensitivity analyses should be undertaken of the effect of using:
>
> - a common regulatory WACC across all NSPs
> - the WACC from the most recent regulatory determination for each NSP for all years for that NSP
> - the forecast WACCs for each regulatory period for each NSP, and
> - the realised (regulatory) WACC for each year.[500]

We consider the WACC for economic benchmarking should reflect the relevant WACC for the period under consideration. However, we note the practical issues involved in measuring this WACC. Therefore, we consider Economic Insights' proposal to use a common WACC across NSPs for assessing expenditure forecasts would be appropriate. We also consider it appropriate to use a common WACC across NSPs to measure historical efficiencies. However, we do not necessarily agree the forecast WACC and historical WACC should be the same.

We note the choice of WACC could potentially affect the outcomes of economic benchmarking analysis. However, the significance of this concern is not yet known. As recommended by Economic Insights, we intend to conduct sensitivity analysis of the appropriate WACC for economic benchmarking.

While we are aware that there are different approaches taken to estimate particular WACC parameters, this does not mean that this approach should be adopted in setting expenditure allowances. By setting expenditure allowances that account, to some extent, for frontier productivity

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499 AER, 'Meeting summary – NSP reliance on actual data, base step & trends, productivity change', Workshop 15: Category analysis work-stream – Reliance on actual data, base step and trends, productivity change (Transmission & Distribution), 8 May 2013 AER, 'Meeting summary – economic benchmarking applications ', *Workshop 17: Economic benchmarking techniques work-stream – Prescription in the EFA guideline, potential application techniques (Transmission & Distribution)*, 6 June 2013, pp. 2–3.

500 Economic Insights, *Economic Benchmarking of Electricity Network Service Providers*, 25 June 2013, p. 66.

performance and at the same time incentivising NSPs to better their historical performance will lead to continual improvement in productivity performance and shifting out the frontier over time. Such an approach is consistent with expenditure criteria, and promotes the NEO.

International Benchmarking

We consider international collaboration of economic benchmarking to be an appropriate goal in the long term and our economic benchmarking should not be limited to a comparison of Australian NSPs.

A number of stakeholders supported the extension of economic benchmarking to incorporate data from international NSPs. For example, the MEU submitted that international benchmarking would result in a better outcome for consumers.[501] That is, the AER should seek to identify other benchmarks that reflect overseas practices while also avoiding comparability issues arising from changes in exchange rates. The COSBOA also supported the extension of economic benchmarking to include international comparisons. The COSBOA submitted that there are benefits of using international data and providing comparison of efficiency levels of NSPs internationally and that "an appropriate goal may be to have such benchmarking operational by at least the end of the forthcoming round of regulatory determinations."[502] The NERA Report also suggested that one way to increase the sample size for economic benchmarking of TNSPs is to include international data on comparable TNSPs. The NERA Report notes that this is practiced by regulators in Europe and the United Kingdom, although this approach may create additional analytical issues.[503]

The PIAC submitted that reference to international best practice benchmarking will assist in ensuring that NSPs in Australia will continue to undertake ongoing innovation and productivity improvements.[504]

The PC also recommended international collaboration, which would facilitate meta-studies, which help identify common variables that lead to robust benchmarking results.[505]

We consider international collaboration of economic benchmarking to be an appropriate goal in the long term and our economic benchmarking should not be limited to a comparison of Australian NSPs. In our view, potential problems with availability of consistent and reliable international data and other analytical issues, may make implementation of an international benchmarking exercise difficult in the short term.

501 MEU, *Submission on AER Draft Expenditure Forecast Assessment Guidelines*, 20 September 2013, pp. 17–18.

502 Council of Small Business of Australia, Comments on AER draft expenditure assessment guidelines, 20 September 2013, pp. 14–15.

503 NERA Consulting, *Holistic Economic Benchmarking: A Report Prepared for Grid Australia*, 20 September 2013, p. 9.

504 Public Interest Advocacy Centre, *A Firm Basis: Submission to the AER's Draft Expenditure Forecast Assessment Guideline*, 20 September 2013, pp. 12–13.

B Economic benchmarking data requirements

Our holistic approach to economic benchmarking requires a holistic approach to data collection. We will collect a broad range of data so we can apply a range of economic benchmarking techniques, and conduct sensitivity analysis on possible economic benchmarking model specifications. A broad range of data, if publicly available, will also allow NSPs and other interested parties to undertake this process themselves. We will also require back casting to create time series of data, so we can consider NSPs' productivity performance over time.

Economic benchmarking techniques measure NSPs' efficiency by measuring their ability to convert inputs into outputs. Economic benchmarking analysis requires data on NSPs' inputs, outputs and environmental variables. Outputs are the total goods and services a firm delivers. Inputs are the resources a firm uses to deliver outputs to its customers. Environmental variables affect a firm's ability to convert inputs into outputs and are outside the firm management's control.

In response to submissions on our preliminary economic benchmarking data templates we amended some of the definitions to provide more clarity. A list of changes and the reasons for the changes was published in an explanatory statement with the draft economic benchmarking RIN.[506]

B.1 Model specification

The model specifications are our view of NSPs' outputs, inputs and operating environment variables that should be used for efficiency measurement. We based these specifications on our knowledge of NSP operations and the feedback we received from submissions and workshops on the data requirements for economic benchmarking. Our list of potential inputs, outputs and operating environment variables will allow for numerous model specifications to be tested.

Our views on the variables that we consider should be used for efficiency measurement provide up front guidance to stakeholders on potential model specifications and to provide a starting point to test as part of our testing and validation process. However, economic benchmarking is an iterative process that we aim to improve, so we expect to revisit and test our model specification over time.

Our preferred model specification reflects the inputs and outputs we consider should be used as a starting point to our economic benchmarking analysis and reflect a functional outputs specification rather than a billed outputs specification. However, the inclusion of other inputs and outputs, such as energy delivered, will be considered as a part of our model testing and validation process.

Table B.1 shows our list of DNSP outputs and inputs to be included in our model specifications. It is based on Economic Insights' recommended DNSP specification.[507] Table B.2 shows our list of TNSP outputs and inputs to be included in our model specifications which is also based on Economic Insights' recommended TNSP specification.[508] Our shortlist of outputs, inputs and environmental variables and the reasons for our position are discussed below. The shortlist does not exclude other variables from being included in future economic benchmarking analysis as more data becomes available.

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506 AER, *Better regulation explanatory statement – Regulatory information notices to collect information for economic benchmarking*, September 2013.

507 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 83.

508 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 90.

Table B.1 DNSP inputs and outputs

Inputs	Outputs
Preferred model specification	
Nominal opex / Weighted average price index	Customers (no.)
Overhead lines (MVA–kms)	Capacity (kVA*kms or MVA)
Underground cables (MVA–kms)	Interruptions (customer minutes)
Transformers and other (MVA)	
Other inputs and outputs	
Nominal RAB straight–line depreciation / Capital goods price index	Energy delivered (GWh)
Nominal depreciated RAB / Capital goods price index	Disaggregated customer types

Abbreviations: MVA – megavolt amperes, kVA – kilovolt amperes, GWH – gigawatt hour

Table B.2 TNSP inputs and outputs

Inputs	Outputs
Preferred model specification	
Nominal opex / Weighted average price index	Capacity (kVA*kms or MVA)
Overhead lines (MVA–kms)	Entry and exit points (no.)
Underground cables (MVA–kms)	Loss of supply events (no.)
Transformers and other (MVA)	Aggregate unplanned outage duration (customer mins)
Other inputs and outputs	
Nominal RAB straight–line depreciation / Capital goods price index	Energy delivered (GWh)
Nominal depreciated RAB / Capital goods price index	

Abbreviations: MVA – megavolt amperes, kVA – kilovolt amperes, GWh – gigawatt hour

More detail on the definitions and units of measurement used in the economic benchmarking RIN for DNSP's and TNSP's available on the AER website.[509]

B.1.1 Scope of services

AER position

We consider services classified under prescribed transmission services to be the appropriate scope of services for comparisons between TNSPs. We consider services are treated consistently, as defined in chapter 10 of the NER.

For DNSPs, there are differences between standard control services, negotiated services and alternative control services across jurisdictions, so we consider the DNSPs' 'poles and wires' activities

509 The economic benchmarking data templates are available at: http://www.aer.gov.au/node/21836

classified under network services to be the appropriate service to measure for economic benchmarking. Economic benchmarking requires a common coverage of services, and we prefer a narrow coverage because it imposes lighter information requirements.

Network complexity, system boundaries and network planning

We consider the choice of input variables and sensitivity analysis can account for differences in NSPs' system structures between jurisdictions. Material differences between jurisdictions should be accounted for so all DNSPs are compared in the same manner. Similarly, all TNSPs should be compared in the same manner.

We consider the following three differences relating to network planning, system boundaries and network planning should be taken into account in our economic benchmarking analysis:

1. the boundary between TNSPs and DNSPs across jurisdictions which may result in a simpler or more complicated network across jurisdictions,
2. transmission connection point planning conducted by Victorian DNSPs
3. aggregate costs of AEMO and SP AusNet relating to the planning and procuring of shared transmission network augmentations in Victoria.

We consider these differences can be quantitatively accounted for in our economic benchmarking templates based on the data than can be provided by NSPs and AEMO.

Reasons for AER position

For DNSPs, there are differences between standard control services, negotiated services and alternative control services across jurisdictions, so we consider the DNSPs' 'poles and wires' activities classified under network services to be the appropriate service to measure for economic benchmarking. Proper economic benchmarking requires a common coverage of services, and we prefer a narrow coverage because it imposes lighter information requirements.

In our recent DNSP determinations we grouped distribution services into the following seven service groups: [510]

- network services
- connection services
- metering services
- public lighting services
- fee-based services
- quoted services
- unregulated services.

[510] AER, *Final decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, 29 October 2010; AER, *Final Decision: South Australia electricity distribution network service provider: Distribution determination 2010–11 to 2014–15*, 6 May 2010; AER. *Final Decision: Queensland electricity distribution network service providers: distribution determination 2010–11 to 2014–15*, 6 May 2010.

We consider Economic Insights' recommendation — a narrow service coverage that only includes network services — to be appropriate.[511]

Network services are classified as standard control services across all states and territories; other services, such as connection services, are classified differently. Although a wider service coverage may better model a DNSP's overall functions, it may be impractical to include services that are not consistently classified as a standard control service. Customer funded connections, for example, are classified as unregulated in New South Wales, as an alternative control service in Queensland and as a negotiated service in South Australia.[512]

Our narrow service coverage will require DNSPs to exclude any non-network services classified under standard control services.

Network services are associated with the conveyance, and controlling the conveyance, of electricity through the network.[513] General examples of network services include:

- maintenance of substations, poles, lines and cables
- pole and other asset repairs and replacements
- planning and designing the network.

A list of the specific activities associated with network services is available in the framework and approach papers for each state.[514]

Network complexity, system boundaries and network planning

We did not receive submissions recommending any changes to our approach to accounting for network complexity, system boundaries and network planning.

However, Grid Australia identified several operating environment factors relating to different jurisdictional standards that are similar in nature to network complexity, system boundaries and network planning.

Grid Australia considered different jurisdictional standards will affect the level of redundancy in the transmission network where a more stringent standard will lead to higher costs compared to a more relaxed standard. Grid Australia also noted urban planning approvals can vary, which can lead to variances in cots for capital projects between jurisdictions.[515]

However, Grid Australia noted that they did not propose a measure for these factors and did not form a view on the materiality of each factor as this would be best done via sensitivity checks with actual

511 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 30.

512 AER, *Matters relevant to the framework and approach: ACT and New South Wales DNSPs 2014–19: Classification of electricity distribution services in the ACT and New South Wales, consultation paper*, December 2011, p. 13.

513 NER, Chapter 10.

514 AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, March 2013, pp. 77–79; AER, *Framework and approach paper Classification of services and control mechanisms Energy and Ergon Energy 2010–2015*, August 2008, p. 50; AER, *Framework and approach paper ETSA Utilities 2010–15*, November 2008, AER, *Framework and approach paper ETSA Utilities 2010–15, November 2008*, p. 14; AER, *Framework and approach paper for Victorian electricity distribution regulation CitiPower, Powercor, Jemena, SP AusNet and United Energy regulatory control period commencing 1 January 2011*, May 2009, p. 131; AER, *Stage 1 Framework and approach paper ActewAGL, March 2013*, p. 52; AER, *Framework and approach paper Aurora Energy Pty Ltd, 29 November 2010*, p. 139

515 Grid Australia, *Grid Australia environmental factors and effects*, 28 August 2013, pp. 1–2.

data.[516] Other operating environment factors that do not relate to jurisdictional standards are considered in our operating environment factors section later in this chapter.

For these factors to be included directly into our economic benchmarking model, an appropriate measure of jurisdictional differences would be required. Where a direct material impact on costs cannot be identified, additional information would be required as a part of a qualitative assessment.

For the three factors listed above, these have been accounted for directly in our templates by either requesting data relating to the actual costs of undertaking the activities or requesting more disaggregated data.

B.1.2 Economic benchmarking selection criteria

AER position

We have not made any changes to our economic benchmarking variable selection criteria from the draft Guideline. Table B.3, Table B.4 and Table B.5 set out our selection criteria for output variables, input variables and operating environment factors.

Table B.3 Criteria for selecting output variables

Criteria	Justification
The output aligns with the NEL and NER objectives	The NEL and NER provide a framework for reviewing NSP expenditure. Economic benchmarking outputs should align with the deliverables in the expenditure objectives to assist us in reviewing whether expenditure forecasts reflect efficient costs.
The output reflects services provided to customers	It is important to distinguish between the goods or services that a firm provides from the activities that it undertakes. Outputs should reflect the services that are provided to customers. Otherwise, economic benchmarking may incentivise activities customers do not value. Replacing a substation does not represent a service directly provided to a customer, for example. If replacing a substation was considered an output, an NSP may replace substations to appear more efficient, rather than undertake activities that will more directly deliver services for customers.
The output is significant	There are many output variables for NSPs. For economic benchmarking, the variables must be significant either in terms of their impact on customers or on costs of NSPs. This is consistent with the high level nature of economic benchmarking.

516 Grid Australia, E–mail, *Grid Australia environmental factors and effects*, 28 August 2013.

Table B.4 Criteria for selecting input variables

Criteria	Justification
Reflective of the production function	Inputs should reflect all the factors and resources an NSP uses to produce outputs modelled. The inputs should capture all the inputs an NSP uses in producing its output and be mutually exclusive so the factors of production are not double counted or omitted.
Measures of capital input quantities accurately reflect the quantity of annual capital service flow of assets the NSP employs	This ensures the depreciation profile used in forming the capital is consistent with the physical network asset depreciation characteristics.[517]
Capital user costs are based on the NSP's RAB	The annual user cost can be calculated differently. It is desirable for economic benchmarking analysis to use capital costs calculated based on the same methodology as the corresponding building blocks components. Otherwise the annual user cost of capital could be calculated differently, which may yield considerably different efficiency results over short periods of time during an asset's life.
Consistency with the NEL and NER	The NEL and NER provide a framework for reviewing NSP expenditure. The input variables for economic benchmarking should enable us to measure and assess the relative productivity efficiency of NSPs in the National Electricity Market (NEM).

Table B.5 Criteria for selecting operating environment variables

Criteria	Justification
The variable must have a material impact	There are numerous factors that may influence an NSP's ability to convert inputs into outputs. Only those with a material impact on costs should be selected.
The variable must be exogenous to the NSP's control	We consider operating environment variables are exogenous to an NSP's control. Where variables are endogenous, investment incentives may not align with desired outcomes for customers. Further, using endogenous variables may mask inefficient investment or expenditure.
The variable must be a primary driver of the NSP's costs	Many factors that could affect the performance might be correlated because they have the same driver. Line length and customer density may be negatively correlated, for example. If there is correlation, the primary driver of costs should be selected. Higher line length might reflect a lower customer density, so perhaps customer density should be selected as the operating environment variable because it may be considered to more directly influence costs.

Reasons for position

We consider that the selection criteria will provide stakeholders and the AER with guidance on identifying the appropriate variables to be included in economic benchmarking. Our economic benchmarking models cannot incorporate every variable that may have an impact on a NSP's costs. So we consider the variables we incorporate in our economic benchmarking should be the most reflective of a NSP's outputs, inputs and operating environment factors. The objective of our approach to economic benchmarking is to provide an overall view of NSPs' efficiency. Where it has not been possible to directly take a factor into account, we will consider this when applying economic benchmarking.

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517 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 53.

NERA submitted that the AER's criteria for selecting economic benchmarking variables is inherently subjective and the AER provides no guidance on how a variables would be assessed as 'material' or 'significant' [518]

We do not accept the proposition that our selection of economic benchmarking variables is inherently subjective. As discussed previously, our views on the model specification and the inclusion of variables will be based on a number of factors, including our knowledge of NSP operations and the feedback we received from submissions and workshops on the data requirements for economic benchmarking. We also consider that sensitivity analysis is a critical process in identifying the relative importance of each variable and whether that variable that should be included in our model specifications. Sensitivity analysis helps to identify appropriate economic benchmarking variables and assists in testing the overall robustness of our economic benchmarking techniques and to further understand the relationship between input, output and environmental variables. Without the benefit of the economic benchmarking data available to us, we do not consider it appropriate to set a materiality threshold.

NERA also noted it is not obvious how an assessment regarding the 'significance' of various outputs of a TNSP (such as system capacity versus the number of entry and exit points) would be undertaken, given they are denominated in different units.[519]

Our economic benchmarking model includes outputs that are measured in different units. The proportion each output variable contributes to total output in terms of quantity or cost will be determined by the outputs weights. Our methodology for determining the output weights is discussed in the output section below. To determine which of two output variables should be included in the model specification, we will undertake sensitivity analysis and consider the robustness of the data.

B.2 Outputs

Outputs are generally considered to be the total of the goods and services a business delivers. However, these can be difficult to define for NSPs because they deliver services that are less tangible or homogeneous than the outputs of other industries (such as manufacturing).[520] The services provided by NSPs have a number of dimensions. The variables used to model NSPs’ outputs consider these dimensions, including both the quality and quantity of services.

Given the difficulties associated with defining NSPs’ outputs, economic benchmarking studies have adopted varying output specifications.[521] Further, multiple measures can be used to measure individual aspects of network services. Because there is no single output specification used for economic benchmarking, we established principles and criteria for selecting NSP output variables. We consider the output of NSPs may be considered as the provision of required system capacity that takes into account the trade-off between increased reliability and the value that customers place on additional reliability. Each output variable examined in the sections below is discussed in relation to this definition of NSP output and the output selection criteria.

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518 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, p. 51.
519 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, p. 51.
520 Hattori T, Jamasb T and Pollitt MG, *Relative performance of UK and Japanese electricity distribution performance 1985–1998: lessons for incentive regulation*, Cambridge Working Papers in Economics 0212, Faculty of Economics, University of Cambridge, 2002, p. 4.
521 ACCC/AER, *Benchmarking opex and capex in energy networks,* Working paper no. 6, May 2012, pp. 53–5.
521 ACCC/AER, *Benchmarking opex and capex in energy networks,* Working paper no. 6, May 2012, pp. 53–5.

B.2.1 Billed versus functional outputs

Outputs can be measured on an 'as billed' basis or on a 'functional' basis. A significant proportion of a DNSP's revenue is charged through energy delivered ('as billed' basis); a NSP's costs, however, are focused on providing reliability to customers ('functional' basis).

AER position

We consider a functional outputs specification, rather than a billed outputs specification, is more appropriate for measuring NSPs' outputs under building block regulation. However, we consider data should be obtained for both functional and billed outputs to facilitate future sensitivity analysis.

Reasons for AER position

Economic Insights noted that under building block regulation there is typically no direct link between the revenue requirement that the DNSP is allowed by the regulator and how the DNSP structures its prices. The regulator sets the revenue requirement necessary to meet the objectives in the NER. However, the DNSP sets its prices based on pricing principles, which is a separate process to setting the revenue requirement.[522]

We support Economic Insights' recommendation to collect data that would support both functional and billed output specifications so we can undertake sensitivity analysis in the future.[523] It will also allow for comparisons with other economic benchmarking studies that use billed and/or functional outputs.

Stakeholders attending workshops preferred the functional outputs specification because there is little causal relationship between billed outputs (such as energy delivered) and NSPs' costs.

We did not receive any submissions in response to the draft Guideline on the use of either a billed outputs or functional outputs specification.

B.2.2 Output weights

AER position

Output weights are required to determine the proportion each output variable contributes to total output in terms of quantity or cost. We prefer to estimate an econometric cost function using the available data if appropriate, to determine output weights. Over time, more complex cost functions may be developed when more data are available.

Reasons for AER position

Economic Insights suggested alternative approaches, including using weights from previous studies and obtaining estimates from other DNSPs.[524] However, these approaches have limitations. First, using weights from previous cost function studies will limit our choice of output variables to the same outputs used in the previous studies. Second, obtaining estimates of the relative cost of producing each output from DNSPs may not be as objective as estimating a cost function. Nevertheless, information from previous cost function studies and from DNSPs will be useful in order to undertake sensitivity analysis.

[522] Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 6.
[523] Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 6.
[524] Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 22.

Workshop participants considered that using revenue shares to determine output weights would not represent the value of the output to customers. United Energy noted the absence of prices that reflect costs necessitates a move away from simple revenue shares as the basis for weighting the outputs.[525]

The EUAA supported the use of regression approaches to determine weighting factors for outputs.[526]

B.2.3 Customer numbers

AER position

We consider customer numbers meets all the selection criteria and it should be included as an output for DNSPs. We have amended the customer classes in the economic benchmarking RIN to residential, non-residential not on demand tariffs, non-residential low voltage demand tariff customers and non-residential high voltage demand tariff customers.[527]

Reasons for AER position

We consider that customer numbers are an appropriate output. In the workshops there was general agreement that customer numbers should be included as an output variable. Further, Economic Insights noted customer numbers have been used as a proxy for the quantity of the functions required by DNSPs to provide access regardless of the energy delivered. The functions required by DNSPs include metering services, customer connections, customer calls and connection related infrastructure.

The issues paper stated the reasons for using customer numbers:[528]

- There is a correlation between the number of customers and many distribution activities (relating to metering services, customer connections, customer calls, etc).[529]
- Network firms have a legal obligation to connect all customers within their designated area, and the firms have to maintain the power lines in operation even if they are only used seasonally.[530]

Economic Insights considered DNSPs are obliged to connect customers, so customer numbers reflect services directly provided to the customer and can be a significant part of DNSP costs which score well against our output selection criteria.[531] Economic Insights also recommended customers numbers disaggregated by customer type as an alternative output specification that does not use either peak demand or system capacity. Although this specification does not measure required system capacity, the specification can potentially measure a DNSP's ability to provide sufficient capacity to its customers.[532]

To better represent the DNSP's own customer mix, we have changed the small and large industrial customers categories to non-residential low voltage demand tariff customers and non-residential high

525 United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission, Issues Paper, Australian Energy Regulator,* 19 March 2013, p. 12.
526 Energy Users Association of Australia, 20 September 2013, p. 2.
527 AER, *Better regulation explanatory statement – Regulatory information notices to collect information for economic benchmarking*, September 2013, p. 32.
528 AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 83.
529 Coelli T, Gautier A, Perelman S and Saplacan-Pop R, 2010, *Estimating the cost of improving quality in electricity distribution: A parametric distance function approach*, Paper presented at Lunch Seminar in Energy, Environmental and Resource Economics Spring 2011, Swiss Federal Institute of Technology, Zurich, p. 7.
530 Kuosmanen T, *'Cost efficiency analysis of electricity distribution networks: Application of the StoNED method in the Finnish regulatory model*', April 2011, p. 10.
531 Economic Insights, Economic benchmarking of electricity network service providers, 25 June 2013, p. 9.
532 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 32.

voltage customers. The new customer classes better group customers in accordance with their technical characteristics such as connection voltage and whether they are on demand tariffs.[533]

B.2.4 Entry and exit point numbers

We consider it appropriate to include entry and exit point numbers as an output variable in our preferred model specification. It is comparable to using customer numbers for DNSPs. TNSPs charge generators and distribution networks for a connection point. They also provide activities such as metering services (regardless of the level of energy delivered) and they must maintain the quality, reliability and security of the electricity supply.

Economic Insights argued that entry and exit points are a proxy for the activities TNSPs provide at connection points, and we support this reasoning.[534] However, we acknowledge Economic Insights' observation that entry and exit point numbers meet the first and third selection criteria, but do not necessarily reflect services provided to customers.

B.2.5 System capacity, peak demand and energy delivered

AER position

Ideally, our model specification would capture 'required system capacity' as an output because this is the level of capacity required by customers to meet their needs (this is distinguished from the NSP's actual system capacity). However, data in relation to 'required system capacity' is difficult to observe directly. In the alternative, measures of 'system capacity' or 'maximum demand' may serve as a proxy. A potential problem with using a 'maximum demand' variable is the volatility of the data. Initially, we will use system capacity until an adequate data series of maximum demand that is less volatile can be developed.

We consider that data in relation to 'energy delivered' should be obtained for sensitivity analysis. Energy delivered is not a material driver of NSP's costs and is likely to receive a relatively small output weighting.

Reasons for position

We consider that as an output variable, both maximum demand and system capacity have strengths and weaknesses that warrant further investigation. We received several submissions supporting the use of maximum demand rather than system capacity. We will collect and test both measures of required system capacity.

The EUAA and COSBOA submitted that end users do not specify the level of capacity required and there is significant evidence of excess capacity through-out the NEM's networks. Actual demand should be accounted for so that possible inefficient overspending is not reflected in the benchmark efficiency assessment.[535]

The EUAA and COSBOA supported the use of rolling peak demand over 3–5 years as an appropriate outputs specification. It was submitted that a benefit of this measure is that it ameliorates the volatility of maximum demand data. Alternatively, system capacity that is available for utilization may also merit

533 AER, *Better regulation explanatory statement – Regulatory information notices to collect information for economic benchmarking*, September 2013, p. 33.

534 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 36.

535 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1; Council of small business Australia, *Australian Energy Regulatory – Better regulation program draft expenditure forecast assessment guidelines for electricity transmission and distribution comments*, September 2013, pp. 13–14.

investigation. The EUAA also noted that a three year rolling average would not require 14 years of historic data.[536] CitiPower, Powercor and SA Power Networks also supported a measure of utilisation for system capacity as it is important to distinguish between the capacity of the network that is provided and the capacity that is actually required to meet demand.[537]

The inclusion of the use of system capacity as our preferred measure of output in the explanatory statement to the Draft Guideline was due to the relatively volatile nature of maximum demand data compared with data in relation to measures of system capacity. Also the use of maximum demand does not distinguish between the length of line required by two NSPs who may have similar maximum demand but provides services in a rural area and the other in an urban area. The less dense rural NSP may appear relatively less efficient due to requiring more lines to provide similar maximum demand relative to the urban NSP. To account for this, a customer density or line length requirement would have to be added as an operating environment factor. The use of system capacity recognises lines as well as transformer requirements without needing to include line length as an operating environment factor.[538]

We will be using multiple measures of system capacity and maximum demand as part of our sensitivity analysis. This will include rolling average maximum demand and system capacity adjusted for utilisation.

The MEU also supported the use of maximum demand because expected peak demand decides the required level of augmentation and the use of system capacity will incentivise the provision of excess capacity.[539]

We agree that the use of system capacity as an output may provide an incentive for a NSP to provide more system capacity if the revenue requirement was directly linked to the efficiency measure. However, our network utilisation measure will identify those NSPs with higher utilisation factors as more efficient compared with those with lower utilisation. We also note capacity is built to ensure a level of security of supply. It may be preferable to apply system capacity and adjust for utilisation, rather than adopt an annual maximum demand measure which is based on changing preferences.

We previously noted in the long term a smoothed measure of maximum demand could be adopted. However, in 2014 for the purposes of the first annual benchmarking report, a three or five year smoothed measure of maximum demand will result in a reduced data set relative to using system capacity.

The calculation for a rolling maximum demand will reduce the number of data points available for economic benchmarking. For example, a five year rolling average with 10 years of back cast data would result in six data points, and a three year rolling average with 10 years of back cast data would result in eight data points. In contrast, a measure of system capacity would allow for all 10 years of back cast data to be used for economic benchmarking. This means that ten years of data in relation to smoothed maximum demand may not be available until additional economic benchmarking data is available.

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536 Energy Users Association of Australia, 20 September 2013, p. 2, Council of small business Australia, Australian Energy Regulatory – Better regulation program draft expenditure forecast assessment guidelines for electricity transmission and distribution comments, September 2013, pp. 13–14.

537 CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 13.

538 Economic Insights, Economic benchmarking of electricity network service providers, 25 June 2013, p. 14.

539 Major Energy Users, *Proposed guidelines for expenditure assessment – MEU comments on the draft guidelines, September 2013*, p. 19.

NERA noted the AER did not appear to disaggregate system capacity across transformer capacity and line/cable capacity.[540]

We note our economic benchmarking data template requires TNSPs to provide the line length and capacity at multiple voltage levels and to provide transformer capacity.[541]

NERA also distinguished between results associated with 'demand' and 'supply' side benchmarking models. Generally speaking, demand side models rely on variables that are determined by customer demand, such as the amount of energy delivered and peak demand. Supply side models generally include variables that are determined by NSPs' supply, such as system capacity. NERA submitted that as part of economic benchmarking undertaken in the New Zealand electricity sector: demand side models tend to produce results that suggest that urban distributers with dense networks are relatively more efficient; and supply side models tend to favour rural distributors with sparse networks.

We also note the results from economic benchmarking studies referred to by NERA relate to only a demand side or supply side models. More recent economic benchmarking studies combine both demand and supply models to form a comprehensive output measures.[542] Since we are using a more comprehensive model consistent with recent economic benchmarking work, we do not consider the issue relating to demand side and supply side models to be as significant. However, we will undertake sensitivity analysis and take this into account.

We did not receive further submissions on the use of energy delivered as a part of our sensitivity analysis. As discussed in the explanatory statement to the Draft Guideline, 'energy delivered' has been used as a variable in other economic benchmarking studies and can be used as a proxy for system capacity. However, peak demand and system capacity has more influence on the expenditure objectives than energy delivered. Consequently, energy delivered may not significantly affect a NSP's costs, relative to peak demand and system capacity.[543] For these reasons energy delivered will be considered as a part of our sensitivity analysis.

B.2.6 Reliability

AER position

We consider the variable 'reliability' satisfies all three output selection criteria. Improving reliability is a significant driver of NSP costs, it is valued by customers, and it is reflected in the capital expenditure (capex) and opex objectives.[544] We also recognise there are potential cost trade-offs between reliability and the price that consumers will have to pay for increased reliability.

In regards to the possibility of lagged effect between inputs and reliability, Economic Insights recommends using current year reliability initially and then formally testing for a lag between expenditure and reliability once a longer time series is available.[545] In the absence of quantitative evidence, our model specification will not include such a lag.

We consider the aggregate unplanned outage duration is an appropriate measure of reliability for NSPs. We will also include an extra measure of outage frequency for TNSPs that is not used in the DNSP output specification. TNSPs generally have fewer outages than DNSPs, but each outage may have a larger impact than a DNSP outage.

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540 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia, 20 September 2013*, p. 54.
541 The economic benchmarking data templates are available at: http://www.aer.gov.au/node/21836
542 Meyrick and Associates, *Regulation of Electricity Lines Businesses Resetting the Price Path Threshold – Comparative Option*, Report prepared for Commerce Commission, 3 September 2003, p. 36.
543 AER, Explanatory statement for the draft Expenditure forecast assessment guidelines, 20 August 2013, p. 105.
544 NER, cl. 6.5.6(a), 6.5.7(a), 6A.6.6(a) and 6A.6.7(a).
545 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 17.

To determine the output weight for reliability we intend to use a valuation of customer reliability (VCR). The VCR is used to value the benefit of reducing unserved energy in augmentation projects and may also be used to value the partial market benefit of reducing the likelihood of having unserved energy in the future.[546]

Reasons for AER position

As outlined above, we consider that reliability is an appropriate output. The EUAA agreed in principle with the use of quality measure in our benchmarking approach.[547] However, the EUAA and COSBOA considered the use of VCR is uncertain and susceptible to large variation which may undermine the reliability of and confidence in the benchmarking results.[548]

We agree that there is a possibility VCR could be susceptible to large variations. However the re-weighted regional VCRs used by AEMO show the VCR in each state has experienced a stable increase between 2007 and 2010.[549] Table B.6 shows the re-weighted VCRs.

Table B.6 Victorian survey results re-weighted to produce regional VCRs ($/kWh) Year

Year	New South Wales	Victoria	Queensland	South Australia	Tasmania
2007	35.08	50.26	37.20	38.04	42.02
2008	37.53	52.94	40.13	40.06	45.69
2009	40.07	56.18	42.00	43.12	48.44
2010	41.53	57.29	44.31	44.30	50.97

Source: AEMO.

We note the measure of VCR may be subject to re-weighting based on updated survey data results. We consider any changes in estimating the VCR should be applied consistently to ensure the weightings attributed to reliability does not change through time as a result of methodology changes. We also note the VCR results estimated by the AEMC were different to AEMO's estimates.[550] The most appropriate measure of VCR will be considered in developing our economic benchmarking models. We may conduct sensitivity analysis to determine the effect of the selected VCR on the results of economic benchmarking.

We did not receive further submissions on whether there was a lag between changes expenditure and observed changes in reliability. So consistent with our position in the draft decision we consider, in the absence of quantitative evidence, our preliminary model specification will not include such a lag. We agree with Economic Insights and consider the potential lagged effect between inputs and reliability should be tested as a part of our sensitivity analysis once the data becomes available.

We have considered the reliability data that we require in the development of our economic benchmarking data templates. Further information on the data requirements for economic benchmarking is available on our website.[551]

546 AEMO, *National value of customer reliability (VCR)*, 19 January 2012, p. 2.
547 Energy Users Association of Australia, 20 September 2013, p. 2.
548 Energy Users Association of Australia, 20 September 2013, p. 2. Council of small business Australia, *Australian Energy Regulatory – Better regulation program draft expenditure forecast assessment guidelines for electricity transmission and distribution comments*, September 2013, p. 13.
549 AEMO, *National value of customer reliability (VCR)*, 19 January 2012, p. 4.
550 AEMC, *Fact sheet: NSW customer survey on electricity reliability*, 31 August 2012, p. 2.
551 The economic benchmarking data templates are available at: http://www.aer.gov.au/node/21836

B.2.7 Revenue

Consistent with our position in the explanatory statement to the draft Guideline, we consider revenue data may be limited to providing output weights. Stakeholders considered there to be no link between revenue and functional outputs. However, revenue data could still be used in sensitivity analysis and to examine the link between revenue and billed outputs (such as customers and throughput).[552]

B.3 Inputs

Previous benchmarking studies broadly agreed on NSP inputs. As with many industries, the main types of resources NSPs use to provide outputs are labour, capital, material and other inputs.[553]

Economic Insights noted it was important to recognise some inputs are fully consumed within one time period. This makes their measurement relatively straightforward, as the relevant quantity and cost of these inputs are the amount of those inputs purchased in that year. These non-durable inputs include labour, materials and services.[554]

Capital inputs (or durable inputs) may last several years, so the costs and quantities associated with these inputs must be attributed over the life of the input. Most benchmarking studies include an opex input category and a capital input category.

B.3.1 Opex inputs

AER position

Consistent with our approach in the explanatory statement to the draft Guideline, we consider Economic Insight's recommendation to adopt a common opex coverage is consistent over time and across NSPs. Opex includes all costs of operating and maintaining the network, including inspection, maintenance and repair, vegetation management, and emergency response. Depreciation and all capital costs (including those associated with capital construction) should be excluded.[555]

As discussed above in our scope of services section, the classification of some services may vary across jurisdictions. We consider network services to be an appropriate basis for the comparison of opex costs.

Reasons for position

As outlined above, we propose to use a common service coverage to measure the opex input. We have not changed the intended approach to estimating the opex price index for economic benchmarking. The opex price index used to deflate opex should use the following price indices and weights as a starting point:

- electricity, gas, water and waste services (EGWWS) WPI—62.0 per cent
- intermediate inputs: domestic PPI—19.5 per cent
- data processing, web hosting and electronic information storage PPI—8.2 per cent
- other administrative services PPI—6.3 per cent

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552 AER, *Better Regulation: Explanatory statement: Draft Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*, August 2013, p. 106.

553 ACCC/AER, *Benchmarking opex and capex in energy networks*, Working paper no.6, May 2012, p. 142.

554 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 47.

555 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 54.

- legal and accounting PPI—3.0 per cent
- market research and statistical services PPI—1.0 per cent.

We note the weights use opex shares Pacific Economics Group (PEG) adopted in 2004, which were based on analysis of Victorian electricity DNSP regulatory accounts data.[556]

We consider it appropriate to use these existing weights as a starting point until analysis on DNSP and TNSP opex weights that use current data, is available. Economic Insights recommended WPI as the appropriate opex price index (not the AWOTE) and we agree. It has some theoretical advantages over the AWOTE. We used WPI in previous decisions, given concerns about the volatility of the AWOTE at the time.[557] However, further these purposes, the difference in net regulatory effect is minimal if either measure is applied consistently in economic benchmarking.[558] We consider it appropriate to use the AWOTE for sensitivity testing.

B.3.2 Capital inputs

AER position

We support Economic Insights' recommendation to use physical capital measures to proxy the annual capital service flow.[559] That is, before allocating the cost of assets over multiple years, it is necessary to estimate the quantity of capital inputs used in the production process each year. This is also known as the flow of capital services.[560]

The quantity of capital inputs employed each year in the production process will depend on the asset's physical depreciation profile. We consider capital inputs follow a one hoss shay depreciation profile, where the flow of capital services remains constant over time.

We agree with Economic Insight's recommendation that other measures of capital inputs, such as a RAB straight-line depreciation proxy, or depreciated RAB proxy, warrant further investigation.[561]

Reasons for position

We propose to use physical capital measures to approximate the capital service flow for economic benchmarking. We did not receive further submissions on the use of capital flow as a capital input. However, as discussed previously, NERA noted the 'lumpiness' of TNSP's capital expenditure profile may present difficulties in economic benchmarking TNSPs. Although, NERA further noted the extent to which this lumpiness of capex may pose a difficulty for benchmarking analysis depends on exactly what is being benchmarked.[562]

As discussed previously, economic benchmarking does not involve a process where capex is directly benchmarked. Rather, economic benchmarking uses the annual user cost of capital (AUC) as the associated annual input cost of capital, and the total stock of capital to calculate the flow of capital services into an NSP's production process. We noted in the explanatory statement to the Draft Guideline that capex is not an appropriate measure of capital inputs. Capex represents expenditure on new capital assets and, except under rare circumstances, is not equal to the annual use of capital

556 Pacific Economics Group (PEG) (2004), *TFP Research for Victoria's Power Distribution Industry, Report prepared for the Essential Services Commission*, Madison.
557 AER, *Draft decision: Powerlink transmission determination 2012–13 to 2016–17*, November 2012, pp. 57–59.
558 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 85.
559 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 85.
560 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 47.
561 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 63.
562 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, p. 11.

assets.[563] Further, as noted by NERA, because our approach incorporates the existing asset base and new capex, and because we do not propose to benchmark capex, the issue of NSPs' lumpy investment provide is reduced.

In relation to the possible use of alternative capital input methodologies, we consider RAB depreciation may be a useful starting point for measuring the annual capital input.[564] Economic Insights considered RAB depreciation could produce a series similar to a one hoss shay proxy in principle, but that it also identified the issues raised in submissions and recommended further investigating using RAB depreciation.[565]

We consider the RAB straight line depreciation proxy may provide a similar result to the one hoss shay physical capital measure in principle. Further, the depreciated RAB proxy is relatively simple to calculate. However, in practice these two methods may not produce results that are consistent with the use of physical capital measures. We agree with Economic Insight's recommendation that these two proxies warrant further investigation.

B.4 Operating environment factors

B.4.1 AER position

We have renamed environmental variables to operating environment factors. We consider this new name better reflects the differences between the NSPs exogenous operating conditions. Operating environment factors outside of a NSP's control can affect its ability to convert inputs into outputs. There is overlap between inputs, outputs and environmental variables used in previous economic benchmarking studies. Similar to outputs, there is a diversity of views in the economic literature on the choice of operating environment factors.

The operating environment factors discussed in this section have been identified as possible factors that may have a material effect on NSP efficiency. However, we do not currently have data on these environmental variables and our decision to incorporate these factors will depend on their materiality and statistical relationship once we have data.

Table B.7 shows a shortlist of the operating environment factors we will be collecting data for in the economic benchmarking RIN and from other sources such as the Bureau of Meteorology. More information on the format in which we will be collecting these variables is in the draft economic benchmarking RIN templates.[566]

Table B.7 Operating environment factors shortlist

DNSP operating environment factors	TNSP operating environment factors
Weather factors	**Weather factors**
Extreme heat days	Extreme heat days
Extreme cold days	Extreme cold days
Extreme wind days	Extreme wind days

563 The measures of capital are affected indirectly by capex. That is, capex, along with depreciation, do affect asset values from year to year. However, the new assets generally make a small contribution to measures of overall capital services flow. Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 50.

564 SP AusNet, *Expenditure Forecast Assessment Guidelines– Issues Paper,* 15 March 2013, p. 21.

565 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 63.

566 The economic benchmarking data templates are available at: http://www.aer.gov.au/node/21836

Terrain factors	Average wind speed
Bushfire risk	**Terrain factors**
Rural proportion	Bushfire risk
Vegetation encroachment: growth	Vegetation encroachment: growth
Vegetation encroachment: topography	Vegetation encroachment: topography
Vegetation encroachment: bushfire risk	Vegetation encroachment: bushfire risk
Standard vehicle access	Standard vehicle access
Network characteristics	Altitude
Line length	**Network characteristics**
Density factors	Line length
Customer density	Variability of dispatch
Energy density	Concentrated load distance
Demand density	

This shortlist is not an exhaustive list of all factors that may have an exogenous effect on NSPs costs and additional operating environment factors may be added as more robust data becomes available.

B.4.2 Reasons for AER position

Our operating environment factors short list reflects the operating environment factors we consider to have a material impact on NSPs costs and can potentially be collected on a consistent basis across all DNSPs and TNSPs.

PIAC noted category analysis goes some way to addressing the different exogenous circumstances facing each NSP. Aggregating category benchmarking may enable higher level comparisons of performance while controlling for the more obvious expenditure drivers such as size and load density.[567]

We consider utilising multiple assessment techniques to determine the effect of operating environment factors both qualitatively and quantitatively.

As discussed previously, NERA submitted that a weakness of economic benchmarking is that it overlooks operating environment factors that are business specific and 'inefficiency' may simply represent environment or other variables not taken into account. NERA submitted that the AER must recognise the limitations of conclusions drawn from economic benchmarking of firms operating in diverse circumstances.[568]

We consider it is important when interpreting our economic benchmarking results to recognise the data that has been used to model efficiency. Our selection criteria require the operating environment factors to be material and to also be the primary driver of costs. We note although not every possible exogenous factor has been included in our shortlist, some factors may have a similar effect to factors

567 Public Interest Advocacy Centre, *A firm basis: submission to the AER's Draft expenditure forecast assessment guideline*, 20 September 2013, p. 16.

568 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, p. 52.

we have already included. For example increases electricity quality and safety may result in an overall increase in a NSP's reliability so even though the effect of increased electricity quality and safety is not directly captured its overall effect does contribute to our measure of reliability.

Further, where a potential operating environment factor has not been included in our efficiency results quantitatively it may still be considered as a part of our qualitative analysis. NSPs can submit on the materiality of operating environment factors not included quantitatively when we release our models for consultation. This is particularly relevant for operating environment factors that may affect a small number of NSPs, such as a legislative requirement that applies to only one jurisdiction.

Weather factors

We consider it appropriate to account for differences in extreme weather conditions as environmental variables. Extreme hot and cold days place additional strain on a DNSP's network because customers have greater demand for heating and cooling. The additional load through extra air conditioner use may place a greater load on the network during peak energy use periods. However, at this stage, we cannot decide on a method for accounting for extreme weather until more data are available to perform sensitivity analysis.

We did not receive submissions on the appropriate temperature thresholds for extreme weather conditions. We have obtained weather data from the Bureau of Meteorology and will test various temperature thresholds as a part of our sensitivity analysis.

We consider research into the effect of weather on NSPs' networks should be conducted during our model testing and validation process. As a part of this process, stakeholders will be given the opportunity to conduct their own economic benchmarking analysis and submit this information to us.

Over time, as more analysis is conducted on the effect of weather on a NSP's network, a 'climatic' difficulty index (that measures the overall effects of extreme weather on a network) may be developed. It may include the effect of different temperatures that exceed the thresholds (that is, the difference between a 35°C degree-day and a 40°C degree-day) and it may account for sustained extreme weather conditions.

We consider an environmental variable that accounts for extreme wind conditions is also appropriate. Economic Insights recommended the number of days with peak wind gusts above 90 km/h. This wind speed is associated with extreme weather conditions such as cyclones and tornados, which may have a significant impact on reliability and costs for NSPs.[569]

Terrain factors

We consider terrain factors (such as bushfire risk, rural proportion, difficult terrain, vegetation growth and vegetation encroachment) are appropriate environmental variables to include in our short list. Differences in terrain are likely to have an impact on a NSP's costs, for example a NSP with a high proportion of its network in bushfire prone areas is likely to have more vegetation management costs than a more urban NSP that does not operate in bushfire prone areas. The extra costs associated with mitigating bushfire risk may include more stringent inspection and maintenance programs.

Collecting the urban and rural split can be used as an alternative to our density variables for DNSPs. Generally rural networks are more likely to require more poles and wires per customer, all else equal. We have removed the rural proportion variable for TNSPs because in general the TNSPs operate in rural areas so this variable is less relevant in controlling for differences in TNSPs costs. Further, the

569 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 75.

definition of rural proportion is more easily captured for DNSPs based on feeder classifications which do not apply to TNSPs.

The standard vehicle access variable is intended to be another measure of difficult terrain. Where there is no access to network infrastructure through a standard maintenance vehicle may require more expensive specialised equipment such as helicopters to access that part of network to perform maintenance. For TNSPs we have also included an altitude variable, this variable recognises additional costs that may be incurred due to designing and building transmission lines and its ongoing maintenance in higher altitude areas such as snow affected areas.

The vegetation variables are intended to capture three potential drivers of vegetation management; These are:

1. Topography – the type of environment the NSP's lines pass through. For example lines that run through trees will require more vegetation management than grasslands.

2. Regrowth – the rate at which vegetation regrows. For example a NSP in a tropical region or coastal region may have to undertake the same vegetation clearance tasks more frequently than a NSP in a dry inland region.

3. Legislative requirements – these requirements are a requirement beyond a NSP's control and provide an additional cost over NSPs that do not have this requirement. This includes assessing bushfire risk.

We note information on vegetation management related legislative requirements will be collected as a part of our category analysis. We consider capturing the extent of bushfire risk to be an important variable to assess the impact of bushfire related legislative requirements. Other legislative requirements will be assessed qualitatively as a part of our overall analysis on operating environment factors.

Network characteristics

We consider the following network characteristics, as recommended by Economic Insights, are appropriate environmental variables: [570]

- line length—The length of transmission lines is generally beyond TNSP and DNSP control and may depend on whether the line services major cities or regional areas.

- variability of dispatch and concentrated load distance—TNSPs that are closer to generation centres and concentrated large load centres have an advantage over TNSPs with more diffuse generation centres and more diffuse and smaller load centres. A similar measure is the proportion of non-thermal dispatch, such as hydro and wind turbines, which are generally more diffuse than thermal sources.

- degree of meshing—Economic Insights recommended a measure of transmission network density that reflects the degree of meshing versus extension of the network. A more meshed network will be able to provide higher levels of reliability than a less meshed network. A possible indicator is MVA system capacity per route kilometre of line.

We consider these network characteristics to be appropriate for sensitivity analysis, although we recognise the limitations in including all network characteristic variables. There may also be issues

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[570] Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 81.

with double counting and multicollinearity, which will limit the number of network characteristics to only the most material variables.

Density factors

We consider density variables are the most important environmental factors that may affect DNSPs' costs. A DNSP with lower customer density is likely to require more network assets to service the same number of customers, for example, than does a higher density DNSP. Since the lower density DNSP will require more inputs to produce the same level of outputs, it will appear to be inefficient relative to the higher density DNSP. Some adjustment for the impact is therefore required.

DNSP representatives noted demand density is more important than energy density as an environmental variable. We consider both types of density should be recognised as a potential environmental variable. There is likely to be some correlation between the density variables and it would not be practical to incorporate all the different density measures into one model.

We also note the choice of density variables must be made in conjunction with the selection of output variables to avoid double counting. If peak demand and customer numbers are modelled as outputs, for example, demand density does not need to be included as an operating environment factor.

Other factors

We received submissions on other operating environment factors, this section addresses operating environment factors that have not been included in our short list.

NERA noted it was not obvious how the AER would approach the following operating environment factors raised by Grid Australia:

- major circuit structures (for example, single circuit or double circuit, which can affect credible contingencies in the NEM)
- age and rating of existing network assets
- timing of a TNSP in its investment cycle, given the lumpy nature of investments; and
- the extent of the implications of NER 'technical envelope" requirements (for example, voltage stability, transient stability, voltage unbalance, and fault levels.)[571]

We previously noted network security, electricity quality and safety should not be included in our economic benchmarking analysis until a robust measure is available for these variables.[572]

We consider reliability, not system security, better reflects the quality of services provided to customers. System security is also difficult to quantify for economic benchmarking.[573]

We agree with Economic Insight's consideration that electricity quality and safety are important, but that they should not be included as an output variable. Safety and quality standards are a basic requirement of DNSP operation and are unlikely to be substantially different across DNSPs. There is also no single overall summary measure for quality and safety.[574]

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571 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia, 20 September 2013, pp. 51–52*.
572 AER, Explanatory statement for the draft Expenditure forecast assessment guidelines, 20 August 2013, p. 52.
573 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 21.
574 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 22.

We are also collecting asset life information for all assets including the asset lives at different voltage levels.

The lumpy nature of investment cycles is discussed previously. We consider the lumpy nature to affect the capex profile of NSPs but this relevant to economic benchmarking that uses capital flows, as opposed to capex, as an input into the production process.

More information on our position on operating environment variables is available in our explanatory statement to the draft economic benchmarking RIN.[575] We consider where a variable can be measured quantitatively with a clear definition, these can be incorporated into our economic benchmarking templates. However, other factors such as jurisdictional planning differences may have to be considered qualitatively if the quantitative effect cannot be identified.

B.5 Back cast data

B.5.1 AER position

We consider in general our back cast data requirements are aggregated at a high level and based on data that should already exist in the NSPs' systems. We note that there will be varying degrees of quality in the back cast data, but overall the quality of back cast data for the key outputs and inputs should be sufficient to conduct economic benchmarking analysis.

For robust economic benchmarking we will require backcast data. The process for obtaining back cast data will be independent of the annual RIN/RIO process. Generally, we expect NSPs already collect much of the back cast data for internal purposes. However, where actual data is not available we are requesting NSPs to provide their best estimate of the data.[576]

B.5.2 Reasons for AER position

We discuss our general position on back cast data chapter 7 and back cast data related to specific issues in the preliminary economic benchmarking templates in the explanatory statement for our economic benchmarking RIN.[577]

We recognise more assumptions (about factors such as cost allocations) will be required for older data than for more recent data. We have noted previously that NSPs will be required to state their assumptions and make them publicly available.[578]

The appropriate period and audit requirements for backcast economic benchmarking data will be considered in our economic benchmarking RIN.

B.6 Data validation and model testing

B.6.1 AER position

We consider there is merit in having a data validation and model testing process before applying economic benchmarking results. Modelling constraints mean most economic benchmarking

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575 AER, *Better regulation explanatory statement – Regulatory information notices to collect information for economic benchmarking*, September 2013, pp. 42–45.

576 AER, *Better regulation explanatory statement – Regulatory information notices to collect information for economic benchmarking*, September 2013, p. 14.

577 AER, *Better regulation explanatory statement – Regulatory information notices to collect information for economic benchmarking*, September 2013, pp. 14–17.

578 AER, Explanatory statement for the draft Expenditure forecast assessment guidelines, 20 August 2013, p. 118.

techniques cannot incorporate every variable that may affect an NSP's expenditure. Further, it may not be possible to collect the data required to apply every model specification.

B.6.2 Reasons for AER position

We consider stakeholders should be informed of preliminary economic benchmarking results before they are adopted in our draft and final regulatory determinations. Similarly, the first annual benchmarking report and that data should be made publicly available to allow for stakeholders to perform their own analysis. The consultation process for data validation and model testing is discussed below.

We consider a robust testing process that involves all stakeholders is desirable, especially for 2014 when the first annual benchmarking report is published. However, it may not be feasible to conduct the same specification testing process in subsequent years, unless there are material changes in the model specifications or data used for economic benchmarking, which in turn may cause substantial changes in the analysis and results. Stakeholders are also free to engage experts on economic benchmarking to prepare their feedback during our data validation and model testing process.

As set out in the implementation issues chapter, in light of the delay in data provision in 2014, it is likely that the testing and validation process will be conducted in tandem with our issues paper process reviews in 2014. However, the precise timings of the testing and validation process depends on the quality of the data provided in response to the RIN. We will set out precise timings for this process in March 2014.

The sections below discuss our intended processes to validate the data and test the model. In principle, the data validation and model testing processes should be transparent, consultative and well documented. We will use internal and external expertise when appropriate.

Data validation

We will commence our data validation process once we have received completed back cast data templates. This process will involve three phases:

1. We will conduct a preliminary check of data to identify anomalies and correct errors, and a confidentiality check to prepare the data for public release. This will involve bilateral consultation with the relevant NSPs if any issues arise. This is likely to be iterative.

2. We will publish refined data to allow interested parties to cross check data and conduct their own analysis.

3. Interested parties may provide feedback on overall data quality and any specific data issues that arise.

Several stakeholders submitted on the importance that economic benchmarking data be made publicly available to allow stakeholders to analyse all the data.[579] We agree with this sentiment we propose to make the economic benchmarking data being made public to all stakeholders.

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579 Citipower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013; p. 13. Major Energy Users, *Proposed guidelines for expenditure assessment – MEU comments on the draft guidelines, September 2013*, p. 6; Canegrowers, *Canegrowers submission to the AER Better Regulation program*, 19 September 2013, p. 11; Energy Networks Association, *AER Better Regulation – expenditure forecast assessment guidelines – submission on draft guidelines and explanatory statement*, 20 September 2013, p. 35; Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 22; Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1.

We consider submissions on the economic benchmarking data to be an important step and we will allow all stakeholders sufficient time to make submissions on the overall data set.

This process will help us establish a database with quality economic benchmarking data on NSPs and ensure interested parties can provide feedback before the economic benchmarking model is developed. The finalised database, which accounts for the feedback, will also be publicly released (subject to the confidential information constraints).

The database will be maintained and further developed when new data are collected in subsequent years.

Model development

We consider developing our economic benchmarking models should also be a consultative process.

The model development process will comprise the following steps:

- We will apply a model specification using inputs and outputs identified in Table B.1 and Table B.2 to determine the productivity and efficiency performance of each NSP, using appropriate benchmarking method(s).
- We will perform sensitivity analysis on model specifications, benchmarking methods, and changes in key assumptions to test the robustness of the results. More information about the sensitivity analysis is presented in the next section.
- We will review the performance of benchmarking analysis in terms of estimation stability, sensitivity of the results, and the validity of conclusions drawn.
- We will provide our benchmarking analysis and preliminary results to NSPs for comment.. Stakeholders are also invited to submit their own analysis while we develop our models.
- We will refine the benchmarking analysis based upon stakeholder comments.
- We will publish economic benchmarking results as a part of the first annual benchmarking report. Data underpinning economic benchmarking results may also be published at the framework and approach stage. Preliminary economic benchmarking results may also be published at the issues paper stage.

The process aims to ensure stakeholders interested in conducting their own analysis can replicate the benchmarking results reported in the annual benchmarking report and used in regulatory determinations. Stakeholders will also be able to provide feedback on the economic benchmarking results at the issues paper and draft decision stages.

Due to the delay in the provision of data to the AER from the timeframes envisaged in the draft explanatory statement, the AER may not have sufficient time to separately consult on the preliminary results of its models before publishing these at the issues paper stage. The precise timings of the model development process will depend on the quality of the data returns provided to the AER in 2014.

As discussed previously, the iterative process to economic benchmarking is supported by NERA who note that the AER should not be 'locking-in' the benchmarking techniques it will adopt or how the results of its analysis will be used in the regulatory determination process, ahead of undertaking a transparent and robust development process of actual models, based on real NSP data.[580]

NERA further noted the adequacy of input, output and operating environment factors are a matter of empirical analysis. The process adopted for model development must be sufficiently flexible to accommodate changes and variations in the factors considered, as part of the assessment process itself.[581]

We agree and for this reason we are collecting a broad range of data that will allow for flexibility for model development by stakeholders and the AER.

Sensitivity analysis

We consider sensitivity analysis is a critical process in developing and finalising our model specifications. Our broad range of data requirements is to allow for a rigorous sensitivity analysis.

Sensitivity analysis is a method for testing a model to identify where there may be sources of uncertainty. It is an important step in testing the robustness of our economic benchmarking analysis. It helps to identify appropriate economic benchmarking variables, to test the overall robustness of our economic benchmarking techniques and to further understand the relationships between our inputs, outputs and environmental variables.

It is adopted here to test the materiality of differences between alternative model specifications and/or benchmarking techniques. If a variable of interest has not been included in the preferred model specification, for example, it may be added in as a part of the testing phase. If this results in material difference from the results of the preferred model, further considerations to explain the sources of the differences are required. Further actions may include revising the model specifications or addressing the limitations in the usefulness of benchmarking results.

NERA noted the presence of consistent results across models is a necessary, but not sufficient, condition to demonstrate that a model is robust. MTFP and DEA may be biased in the same way so that they produce similar – but inaccurate – results.[582]

We previously noted if the different benchmarking techniques and model specifications, each with their own strengths and weaknesses, broadly produce similar results this may indicate the robustness of our benchmarking analysis and the validity of the inferences drawn from the results. Without performing such a sensitivity analysis, the robustness of our benchmarking analysis will remain in doubt. Our workshops also noted the imprecision in all assessment methodologies and why it is important to understand the error.[583]

We consider selecting inputs, outputs and other aspects of model specifications should be properly informed by sound economic theory, in-depth engineering knowledge and rigorous cost driver analysis. Public consultation with the stakeholders provides one way to improve our knowledge in the area. If model specifications cannot be settled this way, it is useful to apply multiple model specifications to test consistency. In some cases, the inability to produce consistent results requires further investigation so benchmarking results can be supported by more rigorous and refined analysis.

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580 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, p. 46.

581 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, p. 48.

582 NERA, *Holistic economic benchmarking – A report prepared for Grid Australia*, 20 September 2013, pp. 44–45.

583 AER, 'Meeting summary – economic benchmarking applications ', *Workshop 17: Economic benchmarking techniques work-stream – Prescription in the EFA guideline, potential application techniques (Transmission & Distribution)*, 6 June 2013, p. 4.

Importantly, not all variables that capture the essential aspects of NSP operation can be included in each model specification, given data availability and modelling constraints. Most benchmarking techniques inevitably require some degree of aggregation of inputs, outputs, and environmental factors into a few variables. Generally, as more variables are included in a regression, the degrees of freedom decrease and the results from a small sample are likely to be less informative. Similarly, as the number of inputs and output increases in DEA, the number of dimensions for comparing the NSPs accelerates, and the NSPs are more likely to be found efficient. Sensitivity analysis can help to identify the most relevant variables without exceeding the degrees of freedom restrictions inherent in the estimation techniques.[584] We will test multiple model specifications for each economic benchmarking technique.

[584] For example, the general rule of thumb for DEA is the sample size should be no less than the product of the number of inputs and number of outputs, or three times the sum of the number of inputs and outputs, whichever is larger.

C Category analysis

This attachment outlines our proposed approach to assessing the different categories of opex and capex, the reasoning for our proposed approach, and the data that we will require for our assessment.

As discussed in chapter 5 for opex assessment, we intend to assess the efficiency of base expenditure in more detail than previously and we intend to develop a single measure of productivity forecast to use to assess forecast expenditure. For capex we intend to assess expenditure categories in more detail than in the past. We will generally look for greater economic analysis to justify the expenditure. The analysis of standardised data outlined in this section will be used to assess NSPs' forecasts of expenditures as well as feature in our new annual benchmarking reports.

The data requirements described below are at a summary level. This is a change from the explanatory statement to the draft Guideline which had more detailed data requirements. We will set out the detailed data requirements, and justifications for them, in an explanatory document to accompany the RINs. We consider this appropriate as the detailed data requirements will not alter the approach to assessment or data requirements set out in the Guideline. It also reflects comments made by some NSPs that it was difficult to identify explanations for information requirements among the various sections of the explanatory statement to the draft Guideline. We will release draft RINs with our data requirements and an accompanying explanatory document in December 2013.

The remainder of this attachment covers the proposed approach to assessing:

- augmentation capex
- demand forecasts
- replacement capex
- customer initiated expenditure
- non-network expenditure
- maintenance and emergency response opex
- vegetation management opex
- overheads.

C.1 Augmentation expenditure

This section discusses the contents of clause 3.2 of the Guideline, which sets out our approach to assessing the augex component of a NSP's capex forecast. Augex is typically capex required to address constraints arising on the electricity network as demand increases.[585] Demand forecasts are therefore a critical input to NSPs' development of augex forecasts.[586] Section C.2 discusses our demand forecast assessment approach.

Increasing demand is generally an uncontrollable variable for NSPs. It increases the risk of the NSP not meeting the maximum demand at the desired quality or reliability standard.[587] One solution to these constraints is for NSPs to undertake augex projects. This typically involves augmenting network components to ensure they have sufficient capacity to meet forecast demand. Examples of augex projects include:

- increasing the capacity of substations
- establishing new substations
- upgrading existing lines
- establishing new lines.

An alternative to augmenting the network is for NSPs or other parties to implement non-network solutions to constraints, including demand management initiatives.

While demand is a principal driver, NSPs may undertake augmentations due to other reasons or constraints. For example, NSPs may undertake augmentation works because they produce net market benefits. NSPs may also undertake augmentation projects for fault level mitigation.

The efficient solution for such constraints—network augmentation or non-network solutions—will depend on various factors including network configuration, asset utilisation, demand growth and the feasibility of other options. This makes the expenditure profile for augmentation projects non-recurrent and less predictable than other expenditure types. Hence, trend analysis, by itself, is not ideal as a principal technique for augex assessment.[588]

Augex is a material expenditure category and can represent well over 50 per cent of capex in some years. The scale and proportion of augex work can vary dramatically across NSPs and over time.

C.1.1 AER position

When assessing a NSP's augex forecast, we will:

- assess a NSP's forecasting approach. This includes assessing the processes, documentation and models the NSP uses to derive the augex component of its capex forecast.

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585 Chapter 10 of the NER defines a 'constraint' as a limitation on the capability of a network, or part of the network, such that it is unacceptable to transfer the level of electrical power that would occur if the limitation was removed. Increasing demand may signify the level of electricity transferring through a particular area of a distribution network is approaching or exceeding the capacity of the zone substation that services the area, for example. We acknowledge non-demand driven augex may be efficient where, for example, legal obligations require them or market benefits exist.

586 As we discuss in section C.2, NSPs must specify the demand forecast they used to assess potential constraints (and solutions) in the network. Such considerations include whether the demand forecast they used is spatial or system level, raw or weather corrected at 50 per cent probability of exceedance (PoE) or 10 per cent PoE.

587 AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, p. 102.

588 Section C.1.2 discusses the non-mechanistic nature of augmentation projects in more detail.

- perform detailed reviews of a sample of augex projects with assistance from technical and other consultants. We will pay particular attention to the extent the NSP considered non-network solutions as alternatives to augmentation projects. We will need to see evidence that NSPs have comprehensively considered all viable options, including non-network options, in their analysis and in forming a view on the preferred approach to addressing the relevant need.
- infer the findings of those reviews to the rest of the augex population, or a subset of that population depending on the characteristics of the projects.
- undertake project cost analysis. We will collect volume and cost information on the major components that comprise augmentation projects. We will use this data to develop a database for the major expenditure items that comprise augex projects and to develop benchmarks. This will inform our assessment of individual augmentation projects through the use of average cost benchmarking, for example.[589] We may also use such benchmarks to assist in adjusting augex forecasts, if required.

For DNSPs we will also apply the "Augex model", which uses information on capacity, utilisation and demand patterns in network segments, and unit costs to produce an alternative augex forecast. Note that the augex model has different data requirements to project cost analysis. We describe the augex model, and its application in distribution determinations, in more detail below. For the avoidance of doubt, we will not use the augex model to assess the augex component of TNSPs' capex forecasts.

We will use project cost analysis and the augex model (for DNSPs) to inform and support our augex forecast assessment. Such analysis will enable greater comparison between NSPs and assist us in targeting projects and/or programs for detailed review. We will likely use project cost analysis and the augex model to assist in detailed reviews. We may use benchmark average costs of major assets to 'build up' an augmentation project and compare this with the NSP's project costing, for example. Project cost analysis and the augex model may also assist in adjusting augex forecasts if we find evidence of inefficiency.

While changes in demand are usually the principal drivers for augmentation projects, some augmentation projects may not be directly related to demand growth. NSPs may undertake an augmentation project because it produces net market benefits, for example.[590] We will request NSPs to indicate whether the augex information it provides is demand related or non-demand related. Nevertheless, we consider we will be able to use augmentation cost data to inform our assessment of such augex projects. We will also likely include such projects in our sample for detailed reviews.

Augex model

The augex model compares utilisation thresholds with forecasts of maximum demand to identify the parts of a network segment that may require augmentation.[591] The model then uses capacity factors to calculate required augmentation, and unit costs to derive an augex forecast for the NSP over a given period.[592] In this way, the augex model accounts for the main internal drivers of augex that may differ between DNSPs, namely peak demand growth and its impact on asset utilisation.

We will use the augex model to assess DNSPs' augex forecasts, including:[593]

589 The information we collect for project cost analysis are not inputs to the augex model. Rather, we will use augmentation project cost data for analysis that complements, but is separate to, the augex model.

590 Grid Australia, *Expenditure Forecast Assessment Guideline Issues Paper,* 18 March 2013, p. 33.

591 Asset utilisation is the proportion of the asset's capability under use during peak demand conditions.

592 For more information, see: AER, *Guidance document: AER augmentation model handbook*, November 2013.

593 For more information, see: AER, *Guidance document: AER augmentation model handbook*, November 2013.

- as a point of comparison with a DNSP's augex forecast
- for benchmarking
- as a filter to identify areas of the augex forecast that require detailed engineering review
- for informing any adjustments we make to a DNSP's augex forecast.[594]

Ideally, the augex model would assist in identifying outliers in a DNSP's augex forecast.[595] We do not intend to use the augex model as the sole reference point to deterministically set the augex component of a DNSP's capex forecast. The augex model is one of several techniques we will use to assess augex forecasts. However, this does not preclude us from substituting some or all of the forecasts from the augex model for some or all of the augex components of a NSP's capex forecast. We would do so if we consider it appropriate, after considering all available evidence at the time of a determination.

Summary of expected data requirements

NSPs must support their augex forecasts with comprehensive and rigorous evidence. As part of their proposals, NSPs must also provide documentation that details their consideration of solutions, including non-network solution, as it relates to material augex projects.[596] Documents that detail the NSPs' consideration of solutions include (but are not limited to) those the NSP developed as part of regulatory investment tests for transmission and distribution.

In addition, we will require NSPs to provide data for the purposes of augmentation project cost analysis and the augex model, which we discuss below.

Project cost analysis

We will collect expenditure and other information on the major equipment that comprise augmentation projects such as transformers for substations or overhead lines for feeders. We will also collect physical data such as voltage and capacity. We will also collect cost information on labour and other expenditures for those projects.

Augex model (for DNSPs)

The augex model handbook contains details on the augex model, including information requirements and the algorithms and assumptions that underpin it.[597] To summarise, the augex model requires information for network 'segments', where segments represent typical planning components (usually lines and substations of various types).[598] We will collect information for each segment of a DNSP's network including capacity, utilisation and demand patterns in network segments. The augex model will also require unit cost data ($ per kVA added).[599]

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594 AER, 'Meeting summary – repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream – Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 4; AER, 'Augex tool tutorial', *Workshop 10: Category analysis work-stream – Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013.

595 AER, 'Meeting summary – DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 1.

596 'Material' in this case will be defined in the relevant RIN.

597 AER, *Guidance document: AER augmentation model handbook*, November 2013.

598 AER, 'Slides – DNSP replacement and augmentation capex ', *Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution)*, 8 March 2013.

599 AER, *Guidance document: AER augmentation model handbook*, November 2013, p. 13.

C.1.2 Reasons for AER position

As discussed in section C.1.1, detailed project reviews will continue to be an important component of our augex forecast assessment approach. This is because augex projects are highly variable and unique, so trend analysis by itself does not provide an adequately rigorous assessment of augex (see 'Highly variable and unique nature of augmentation projects' section below).

To support our augex forecast assessment, we will collect more detailed information for the purposes of project cost analysis and the augex model (for DNSPs), as we discussed above. The analysis we perform with these datasets will provide a more complete picture of the augex forecast upfront and will add rigor and transparency to the augex forecast assessment process.

Project cost analysis and the augex model complement each other in distribution determinations. The augex model can identify the network segments where expenditure appears inefficient and hence require greater scrutiny, for example. This removes some of the reliance on judgement and our consultants' industry experience when selecting samples for detailed review. Experience may allow us to reduce or avoid the need to investigate some network segments if the model outcomes are consistent with efficient benchmarks for similar work.

We can use project cost analysis to compare the costs of major components of augmentation projects (such as transformers for substation augmentations) across NSPs and across time. Such information will be useful in a detailed project review as a check on the cost components that make up a NSP's augex project. This will add rigor, objectivity and transparency to detailed reviews compared with past determinations, where technical consultants' database of augmentation costs may have been disparate and incomplete. In these cases, our technical consultants would have needed to rely more on judgement and industry experience. While useful, basing assessments primarily on judgement and industry experience lacks transparency and rigor.

In the case of DNSPs, the augex model may not appropriately capture augmentation needs that are not related to demand growth. Project cost analysis, in conjunction with engineering reviews, provide a basis for assessing such projects.

By collecting information for project cost analysis and the augex model (for DNSPs), respectively, we will have a more systematic, transparent and consistent assessment approach. We will also be able to use such consistent data beyond the confines of a particular determination, for example, in our annual benchmarking reports and in subsequent determinations.

Application of our approach to DNSPs and TNSPs

We acknowledge the operating environments and cost drivers that affect DNSPs and TNSPs are different. We will reflect those differences in our approach to assessing augex forecasts.[600]

Firstly, we will apply the augex model only in distribution determinations, not transmission determinations. Grid Australia stated that augex for TNSPs depends to a greater extent on the circumstances of individual assets than is the case for DNSPs, for example. Hence, TNSPs rely on statistical projections of expenditure less than DNSPs. This is partly because TNSPs have fewer assets with higher consequences of failure than DNSPs.[601] We acknowledge TNSPs have fewer but higher cost assets. We will therefore focus our attention on the build-up of individual projects during a transmission determination through project cost analysis and detailed reviews. This does not preclude

[600] Chapters 6 and 6A of the NER also include slightly different capital expenditure factors, which reflect some of the differences between DNSPs and TNSPs.

[601] Grid Australia, *Better regulation program – Replacement and augmentation expenditure categories*, 26 April 2013, p. 1.

us from applying the augex model in transmission determinations in the future. Our experience with the augex model in distribution determinations will likely inform any future decisions (see the 'Augex model—Implementation issues' subsection below). Any decision to apply the augex model to TNSPs will follow the processes prescribed in the NER to depart from or amend the TNSP Guideline.

These differences do not detract from applying much of the other techniques to assess the augex forecasts of TNSPs and DNSPs. Detailed reviews are important in assessing augex generally because they are variable and unique for DNSPs and TNSPs. Similarly, project cost analysis is useful in targeting projects and/or programs for detailed review in distribution and transmission determinations. It will also inform the detailed review and any inferences from those reviews, including adjustments to augex forecasts.

Although we will apply largely the same techniques, differences between DNSPs and TNSPs mean we may emphasise different aspects of our approach in particular situations. As mentioned previously, we will not utilise the augex model when assessing a TNSP's augex forecast at this stage. We will likely rely on detailed reviews in the case of TNSPs, particularly if a TNSP has few augex projects in its capex forecast. On the other hand, and as Grid Australia noted, DNSP augmentation programs are more conducive to modelling or statistical projections, given they tend to be lower in cost but higher in volume compared to TNSP investments. Hence, we may place more emphasis on the augex model in a distribution determination, including for adjustments. Project cost analysis will support the augex model's analysis.

Similarly, the nature of proposals will differ, for example, between DNSPs, or even for the same DNSP across different regulatory control periods. Our assessment for each NSP will need to account for such differences.

Highly variable and unique nature of augmentation projects

While demand growth is a principal trigger for augmentation, the solution to any such trigger will often depend on various factors. Demand growth increases asset utilisation, which may introduce network issues such as voltage management or triggered augmentation. NSPs may respond to such issues in various ways through either network or non-network solutions. As we noted earlier, other factors may also trigger augmentation works such as fault level mitigation or net market benefits. Where network solutions are shown to be more appropriate and effective, the NSP must consider various factors to arrive at an efficient solution depending on the trigger, including:

- forecast demand growth rates
- location of load or generation
- network configuration, including existing technology and capabilities
- optimal timing of solutions, because although demand forecasts are the main determinant, augex projects may also require the completion of other network projects to be optimal
- land use restrictions
- easement size and availability
- community engagement or opposition.

Augmentation projects tend to be lumpy in nature given long asset lives and high up front fixed costs, resulting in building excess capacity to address demand growth.[602] Thus, past augex trends may not be a reliable indicator of future augex requirements, and techniques such as 'base-step-trend' are not typically appropriate for augex forecasts.

These issues also bring an extra layer of complication to augex forecast assessment. In addition to assessing the costs, we must be satisfied the NSP considered all viable options to arrive at the most efficient augmentation project. In previous determinations, we assessed such options analysis in the detailed project reviews, including NPV analysis as part of the RIT-T process. However, we regularly found issues, such as:

- consideration of a limited number and/or types of options
- cultural barriers to consideration of non-network solutions
- application of unreasonable assumptions
- misstatement of planning requirements.

As section C.1.1 outlined, we expect NSPs to provide more robust justifications for their proposed investments than they did in previous regulatory proposals.

The Council of Small Business Australia (COSBOA) endorsed our intention to pay close attention to how seriously NSPs have considered non-network solutions. However, COSBOA suggested we develop robust ways to do this and align incentives if it is to become a more significant option for NSPs.[603] We consider the Guideline provides a clear signal to NSPs that we expect them to seriously consider non-network options and to include them in the options analysis that support expenditure forecasts. In addition, techniques such as project cost analysis and, for DNSPs, the augex model will enable us to compare augex across NSPs and across regulatory control periods. This would enable us to target projects for detailed review in a more efficient manner. Collecting information for the purposes of project cost analysis would enable us to develop a database of the major cost components of augex projects. Project cost analysis may suggest a NSP's cost build-up of its augex forecast is reasonable, for example. We can then instruct engineering consultants to focus on the NSPs' consideration of options, paying particular attention to consideration of non-network solutions. This would include analysis of options the NSPs considered in RIT-Ts and RIT-Ds, as appropriate, under chapter 5 of the NER.[604]

Augex model

General issues

Stakeholders noted some limitations of the augex model in workshops and submissions.[605] Ausgrid, Endeavour Energy and Essential Energy (the NSW DNSPs) consider the augex model is limited in its use as a benchmark tool due to different network configurations and planning criteria, among other considerations.[606] CitiPower, Powercor and SA Power Networks submitted we should not rely on the

[602] AER, *Draft distribution determination: Aurora Energy Pty Ltd 2012–13 to 2016–17*, November 2011, p. 113.

[603] Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 16.

[604] NER, clauses 5.15, 5.16 and 5.17.

[605] AER, 'Meeting summary – DNSP replacement and augmentation capex', *Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution)*, 8 March 2013, p. 3; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 15 March 2013, pp. 15–17; United Energy and Multinet, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, *Issues Paper, Australian Energy Regulator*, 19 March 2013, p. 14.

[606] NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, pp. 13–14.

augex model when determining augex forecasts. They stated we should only use the augex model to identify further areas for investigation and potentially explain differences in cost drivers between DNSPs.[607]

COSBOA stated it favours the use of the augex model for (or to assist with) a point of comparison, benchmarking, filtering and adjustment purposes. COSBOA considers the AER's approach to recognising the differences in application of the model to TNSPs is reasonable and support its application to TNSPs. The augex model should be run annually and the results published so that forecast versus actual variances can be tracked and analysed, including by consumers.[608]

While any model will have limitations, we accept they may be more pronounced when modelling augex, given the variable nature of augmentation projects. Nevertheless, we consider the basic premise of the augex model is sound and it will provide a useful point of comparison for the augex component of DNSPs' capex forecasts. In past determinations, we had no points of comparison for augex forecasts except past expenditure. It will enable intra- and inter-company comparisons of historical and forecast augex, and the data we obtain will assist us in developing benchmarks, as user groups acknowledged in their submissions.[609] We will likely benchmark unit costs ($/kVA added), and capacity added per megawatt of peak demand increase, for example. We may also be able to use the augex model to assist in substituting or adjusting a DNSP's augex forecast if necessary.

As we stated in section C.1.1, the augex model is only one of several techniques we will use to assess augex forecasts. However, this does not preclude us from substituting some or all of the forecasts from the augex model for some or all of the augex components of a NSP's capex forecast. We would do so if we consider it appropriate, after considering all available evidence at the time of a determination.

Regarding more specific issues with the augex model, the NSW DNSPs consider that the augex handbook does not provide sufficient information on the AER's calibration techniques and the way it would use benchmarking in applying the model.[610] CitiPower, Powercor and SA Power Networks submitted that the augex model would not capture a significant component of augex and provided examples of such un-modelled augex.[611] We have updated the augex model handbook to address these concerns, particularly regarding benchmarking and un-modelled augex.[612]

Calibration refers to the process we will undertake to infer the value of utilisation thresholds, capacity factors and unit costs from historical data the DNSPs provides. There is no formulaic process to enable this as DNSPs may reasonably use various methods to estimate these augex model parameters. However, we will confirm whether the DNSPs' calculations of those augex model parameters are reasonable as part of the distribution determination process.

607 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 9.

608 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 16.

609 AER, *Guidance document: AER augmentation model handbook*, November 2013. pp. 8–9; AER, 'Slides – DNSP replacement and augmentation capex ', *Workshop 4: Category analysis work-stream – Replacement and demand driven augmentation (Distribution)*, 8 March 2013; AER, 'Meeting summary – repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream – Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 4..

610 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, p. 13.

611 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 9; CitiPower, Powercor Australia and SA Power Networks, *Joint response to AER Issues Paper Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission,* 15 March 2013, p. 16.

612 AER, *Guidance document: AER augmentation model handbook*, November 2013, pp. 18–22.

Implementation issues

We have not yet used the augex model in a regulatory determination, so we and other stakeholders may identify issues with the model not considered in our development of the Guideline. For the reasons discussed above, it is important to include the augex model in our suite of techniques for DNSPs. User groups stated stakeholders should focus on improving the augex model, rather than excluding it based on perceived limitations. One DNSP agreed with user groups as some preliminary tests of the model had begun to produce reasonable results.[613]

We attempted to minimise complications that may arise with the augex model through the consultation process for the Guideline. Applying the augex model in a distribution determination will help resolve other potential issues, similar to our introduction of the repex model during the Victorian and Tasmanian distribution determinations.[614]

There is also a question on the extent we can rely upon the augex model as a filter to target areas for detailed review. If a DNSP's augex forecast for zone substations is 'close' to the model's forecast, for example, can we accept the DNSP's forecast without further investigation? Experience will guide us in determining whether we want to investigate a segment. In the first tranche of determinations, we will likely review, in detail, projects from all network segments, even those the augex model suggests are efficient. This will help us understand how various circumstances can affect the application of the augex model, and how we can refine and improve this use.

Hence, the first tranche of distribution determinations will be a period of testing and learning regarding the application of the augex model. However, this does not preclude us from using the results of the model for the various purposes we discussed in section C.1.1 including benchmarking, or adjusting forecasts. We would do so where our testing suggests the model and its results are robust. We would also consider other relevant information and analysis when applying the model.

We will liaise with the NSW and ACT DNSPs to consider results of the model in the context of our overall assessment approach and to identify and resolve issues as they arise. We will communicate the results of this work with other DNSPs and stakeholders through appropriate forums, including through any benchmarking and/or modelling results we publish.

Uniting Care Australia recognises that there are some questions about the development of the augex (and repex) model where demand is static or potentially declining. Uniting Care Australia accepts that some refinement of this model will occur over time and are comfortable with an experience based learning approach.[615]

C.2 Demand forecast assessment

This section discusses section 3.2.1 of the Guideline, which sets out our approach to assessing the demand forecasts that a NSP uses as inputs to its expenditure forecasts. Under the NER, we must accept the capex forecast of a NSP if we are satisfied that capex forecast reasonably reflects (among other considerations) a realistic expectation of the demand forecast.[616] We must do the same for the opex forecast of a NSP.[617]

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613 AER, 'Meeting summary – repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream – Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 4.

614 AER, 'Meeting summary – repex model, augex model, and demand forecasting', *Workshop 10: Category analysis work-stream – Repex model, augex model, demand forecasting (Transmission and Distribution)*, 27 March 2013, p. 3.

615 Uniting Care Australia, *Submission to Australian Energy Regulator better regulation program – response to draft expenditure forecast assessment guideline for electricity distribution*, 1 October 2013, p. 4.

616 NER, clauses 6.5.7(c)(3) and 6A.6.7(c)(3).

617 NER, clauses 6.5.6(c)(3) and 6A.6.6(c)(3).

The NER do not require us to include a decision about demand forecasts in our determinations.[618] However, forecasts of maximum demand are a major input to investment decisions in electricity networks.[619] In particular, spatial demand forecasts are a major driver for augmentation decisions.[620] Augmentation expenditure (augex) is a significant component of NSPs' capex forecasts, comprising well over 50 per cent of capex in some years (section C.1). For this reason, demand forecast assessments are an important consideration in our determinations.

C.2.1 AER position

We will assess whether the approaches that a NSP uses to produce its demand forecast (including models, inputs and assumptions) are consistent with best practice demand forecasting. This explanatory statement to the Guideline formalises the elements that comprise best practice demand forecasting (we describe these elements below).

Our demand forecast assessment will include reviewing the technical elements of a NSP's forecasting approaches. We will assess, for example, weather correction approaches and regression techniques for rigor and supporting evidence. We will also carry out data validation and testing of the trends that underpin the demand forecasts. This work may include checking customer number growth in different regions of the network, or cross checking data from the NSP with other data sources. We will assess whether the NSP considered a variety of sources for its inputs, and whether the input selection process potentially introduces bias to the demand forecast.

We will likely review a sample of the NSPs' spatial demand forecasts given a full review of all spatial forecasts is infeasible. In distribution determinations, for example, we will likely review in detail the demand forecasts and forecasting approaches for a sample of zone substations. Preliminary analysis, including discussions with the DNSP and other stakeholders, will likely inform the appropriate approach for selecting zone substations for closer review. We may target our sample to include those zone substations associated with a relatively high capex forecast over the next regulatory control period.[621] Alternatively, we may choose a random sample or a mix of targeted and random sampling.

The extent to which we extrapolate our findings on the sample to all other zone substations will depend on the issues that arise and the nature of the NSP's forecast. Our detailed review will assess whether issues appear common in the forecast, or are confined to one part of the network. We may find, for example, an unreasonable demand forecast for only one zone substation in the sample. If so, we would not extrapolate adjustments for that zone substation to other zone substations. If we find a more general issue (such as reconciliation between the top down and bottom up forecasts), then we will likely infer findings from the detailed review to the rest of the spatial forecasts.

Demand forecast assessment principles

We will assess whether a NSP's approach exhibits the principles of best practice demand forecasting. We discuss each of these principles below.

[618] NER, clauses 6.12.1 and 6A.14.1.

[619] The NER define maximum demand as the 'highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.' We discuss the types of maximum demand information we require in section C.2.1.

[620] NSPs typically produce two types of forecast: system level (top down) and spatial (bottom up) forecasts. A system level forecast is the demand forecast that applies to the NSP's entire network. A spatial forecast applies to elements of the network. For transmission network service providers (TNSPs), spatial forecasts could be at the level of connection points with distribution network service providers (DNSPs) and major customers. For DNSPs, spatial forecasts could be at the level of connection point, zone substations and/or HV feeders.

[621] Our aim is to ensure reasonable demand forecasts underpin the NSP's capex and opex forecasts.

Accuracy and unbiasedness

A NSP should ensure its demand forecasting approaches produce demand forecasts that are unbiased and meet minimum accuracy requirements. Forecasting steps include careful management of data (including removal of outliers, and data normalisation) and construction of a forecasting model (that is, choosing a model based on sound theoretical grounds that closely fits the sample data).

We will compare a NSP's previous demand forecasts with its historical demand. We acknowledge demand forecasting is not a precise science and will inevitably contain errors. However, consistent over-forecasting or under-forecasting may indicate a systemic bias in a NSP's demand forecasting approach. When such systemic bias is present in past demand forecasts, we expect the NSP to explain how it has improved its demand forecasting approach to minimise such biases. In addition, the NSP will need to support any departure from recent historical trends with evidence and a good description of the approach and assumptions leading to the departure.

Transparency and repeatability

Demand forecasting approaches should be transparent and reproducible by independent sources. The NSPs should clearly describe the functional form of any specified models, including:

- the variables used in the model
- the number of observations used in the estimation process
- the estimated coefficients from the model used to derive the forecasts
- any thresholds or cut-offs applied to the data inputs
- the assumptions used to generate the forecasts.

NSPs should keep good documentation of their demand forecasting approach, which ensures consistency and minimises subjectivity in forecasts. This documentation should include justification of the use of judgment. It should also clearly describe the approaches used to validate and select the forecasting model.

Incorporation of key drivers

A best practice forecasting approach should incorporate all key drivers either directly or indirectly, and should rest on a sound theoretical base. NSPs should document and explain the theoretical basis and empirical evidence that underpin their selection of key drivers. They should also identify and use a suitably long time series of historical data in their demand forecasting.[622]

Weather normalisation

Correcting historical loads for abnormal weather conditions is an important aspect of demand forecasting. Long time series weather and demand data are required to establish a relationship between the two, and to conduct weather correction. The data are also necessary to establish the

[622] The ENA noted 'definitions such as a suitable long time series can be agreed with the AER'. It is difficult to prescribe or define what constitutes a 'suitably long time series' in the Guidelines for historical demand, or other relevant data. We expect to discuss such issues with NSPs early in the determination process, preferably during the framework and approach process. ENA, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, Attachment B, 8 March 2013, p. 10.

meaning of normal weather—that is, probability of exceedance (PoE) of 50 per cent-and relative values, which can include temperature and humidity.[623]

Weather correction is relevant to both system and spatial level forecasts. System level weather correction processes tend to be more robust and sophisticated due to data availability (such as temperature). Key driver variable data (such as dwelling stock and household income) may also not be available at a regional or zone substation level.

Model validation and testing

NSPs should validate and test the models they use to produce demand forecasts. Validation and testing includes assessing the statistical significance of explanatory variables, how well the model explains the data, the in-sample forecasting performance of the model against actual data, and out of sample forecast performance.

Use of the most recent input information

NSPs should use the most recent input information to derive their demand forecast. We may use more up to date input information as it becomes available during the determination process.

Spatial (bottom up) forecasts validated by independent system level (top down) forecasts

NSPs should prepare their spatial forecasts and system level forecasts independently of each other. Using system level data, a NSP is better able to identify and forecast the impact of macroeconomic, demographic and weather trends. On the other hand, spatial forecasts capture the underlying characteristics of individual areas in the network, including prospects for future load growth. They also have a more direct relationship with expenditure.

Generally, spatial forecasts should be constrained to system level forecasts. The reconciliation should consider the relationships between the variables that affect system level and spatial forecasts respectively. For example, NSPs should reconcile the economic growth assumptions in their spatial forecasts (which are more likely to use judgement) with those in their system forecasts (for which data are more readily available).[624]

Demand forecasts at different levels of aggregation should be consistent with each other. Inconsistency at the different levels of aggregation affects the overall reasonableness of the forecasts. Accuracy at the total level may, for example, mask errors at lower levels (for example, at zone substations) that cancel each other out.

Adjusting for temporary transfers

Before determining historical trends, NSPs must correct actual maximum demands at the spatial level to system normal conditions by adjusting for the impact of temporary and permanent network transfers arising from peak load sharing and maintenance.[625]

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623 PoE means the probability the actual weather will be such that the actual maximum demand will exceed the relevant maximum demand measure adjusted for weather correction. A 50% PoE means the maximum demand measure adjusted for weather correction is expected to be exceeded fifty out of every one hundred years.

624 For a more detailed treatment of the reasons to reconcile system level and spatial demand forecasts, see ACIL Allen Consulting, *Connection point forecasting: A nationally consistent methodology for forecasting maximum electricity demand: Report to Australian Energy Market Operator*, 26 June 2013, pp. 43–45.

625 ACIL Tasman, *Victorian Electricity Distribution Price Review: Review of maximum demand forecasts: Final report: Prepared for the Australian Energy Regulator*, 19 April 2010, p. 7.

Adjustment for discrete block loads

NSPs should account for large new developments in their forecasts. Discrete block loads may include aluminium smelters for TNSPs, and shopping centres and housing developments for DNSPs. They should include only block loads exceeding a certain size threshold in the forecasts. This approach avoids potential double counting, because historical demands incorporate block loads.

NSPs must also account for the probability that each development might experience delays or might not proceed.

Incorporation of maturity profile of service area in spatial time series

NSPs should recognise the phase of growth of each service area (as represented by zone substations for DNSPs, for example).

Use of load research

NSPs' demand forecasting approach should incorporate the findings of research on the characteristics of the load on their networks. For many networks, for example, it is important to establish the contributions of customers with air conditioners to normalised maximum demand. Such research can include regular surveys of customers, or appliance sales information to establish the proportion of residential customers who own air conditioning and other weather sensitive appliances over the period. The forecasting models should test the assumed relationship between customer types and network load.

Load research can incorporate many other factors that could affect the characteristics of the load on electricity networks, including:

- solar photovoltaic generation
- smart meters/smart grids
- energy efficiency policies
- price responsiveness
- demand management initiatives
- electric cars.

Regular review of demand forecasting approaches

NSPs should review their demand forecasting approaches on a regular basis. The review should ensure that the NSP appropriately collected and used data inputs and that the demand forecast approach meets the forecasting principles.

The review should also focus on past forecasting performance and consider the possible causes of any divergence of historical maximum demand from the forecasts.[626] The causes of the divergence could relate to factors such as differences between forecasts of explanatory variables and actual values, or because of issues with the models' specification.[627]

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626 We discussed this issue in the 'accuracy and unbiasedness' forecasting principle.

627 ACIL Allen Consulting, *Report to Australian Energy Market Operator: Connection point forecasting: A nationally consistent methodology for forecasting maximum electricity demand*, 26 June 2013, p. 8.

Summary of expected data requirements

This section summarises the information we will require to assess demand forecasts. These information requirements apply to both DNSPs and TNSPs. In short, we will require NSPs to provide historical and forecast maximum demand data that are relevant for making investment decisions in the network. We will also require NSPs to provide the models they use to produce their demand forecasts, including supporting documentation and data.

DNSPs already provided some of this information in RINs for previous determinations. TNSPs did not traditionally provide some of this information through the submission guidelines. However, they provided the information as part of their regulatory proposals, or in response to our requests during transmission determinations.

Historical demand data

We will require NSPs to provide various types of historical maximum demand data including raw maximum demand at system and spatial levels (in megawatts (MW) and megavolt amperes (MVA)). We will also require temperature corrected data at 10 per cent and 50 per cent PoE. In addition, we will require related information such as power factors and coincidence factors.

Demand forecast data

We will require NSPs to provide forecast maximum demand data at system and spatial levels (in megawatts (MW) and megavolt amperes (MVA)) at 10 per cent and 50 per cent PoE. In addition, we will require related data such as power factors and coincidence factors.

System demand forecast models and other information

Top down forecasts are often in the form of econometric models, which NSPs must provide in their proposals. To assess the system demand forecast, we require the NSPs' system demand forecast model or models, and supporting documentation.

Bottom up forecast models and other information

NSPs that use models to produce spatial demand forecasts should provide information consistent with the requirements for top down forecast models (noting the explanatory variables in the models may differ at the spatial level compared to the system level). We also expect NSPs to keep relevant information that supports any use of judgement to produce spatial demand forecasts.

C.2.2 Reasons for AER position

Our principles-based approach to demand forecast assessment (see section C.2.1) is broadly similar to our past approach, as we discussed in our issues paper.[628] In consultation, stakeholders generally considered the assessment approach that we described in the issues paper and in the explanatory statement to the draft Guideline was reasonable.[629]

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628 AER, *Better regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission: Issues paper*, December 2012, pp. 116–118.

629 Energy Networks Association, *Better Regulation – Expenditure forecast assessment guidelines for electricity distribution and transmission – Issues paper*, Attachment B, 8 March 2013, p. 10; Ergon Energy Corporation Limited, *Submission on the Better Regulation: Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission, Issues Paper*, *Australian Energy Regulator*, 15 March 2013, p. 18; Jemena, *Expenditure forecast assessment guidelines for electricity distribution and transmission*, 15 March 2013 p. 14; Major Energy Users, *AER guideline on Expenditure forecasts, Response to Issues Paper*, 15 March 2013, pp. 41–42; Aurora, *Issues Paper: Better Regulation Expenditure Forecast Assessment Guidelines for Electricity Distribution and Transmission*, 19 March 2013, p. 23.

A principles-based approach is appropriate because NSPs may reasonably use various approaches (including inputs, assumptions and models) to produce demand forecasts. Demand forecasting is not a precise science, so approaches will likely change over time as NSPs introduce refinements and improvements. The best practice demand forecasting principles in section C.2.1 apply to demand forecasting generally despite the heterogeneity and dynamic nature of forecasting approaches.

The NER did not (and do not) contain guidance on assessing demand forecasts other than referring to a subjective test that we be satisfied forecasts reasonably reflect a realistic expectation of demand.[630] We therefore had flexibility in making our demand forecast assessments in past determinations (and in future determinations). We require such flexibility because, as noted, NSPs may use different approaches to produce demand forecasts. On the other hand, this flexibility meant our assessment approach was ad hoc, which introduced some uncertainty for stakeholders. The lack of formal guiding principles (and associated information requirements) to our demand forecast assessment approach meant NSPs supported their demand forecasts with material that varied greatly in content, quality and rigor. As such, requesting further information from a NSP consumed time during our determination process.

In addition, NSPs often rely on the judgement of planning engineers to produce demand forecasts at the spatial level. This reliance is not inappropriate because demand forecasting at the lower levels requires detailed knowledge of factors that affect demand growth in the service area. These factors include town planning, subdivision approvals and land releases, and contact with major customers. The use of judgement, however, is not transparent and therefore not replicable if a NSP does not support it with appropriate evidence. It is not appropriate for us to accept expert judgement 'on trust'. Setting out our expectations that NSPs would provide evidence to support their use of judgement would ensure spatial forecasts are rigorous and replicable.

COSBOA stated its concern that NSPs' demand forecasts in past determinations generally overstated actual demand. This is most likely because NSPs have an incentive to over-invest in their networks because of the need to deliver conservatively set reliability standards and because they benefit financially from capex overspends. COSBOA therefore stated its strong support for us to improve the forecasting of demand, including the application of guiding principles, and the use of ‘top down’ and ‘bottom up’ forecasts.[631]

Similarly, the PIAC's submission supported improvements to the demand forecasting assessment process that reflect the principles set out in section C.2.1. The PIAC considered that demand growth for standard network services must be fully tested against both historical trends and updated market data.[632] The PIAC supports our commitment to improved forecasting methodologies for demand and expenditures. PIAC considers that improved forecasting by both the NSPs and the AER will underpin the effectiveness of the expenditure assessment process and also the regulatory incentive schemes.[633]

Canegrowers noted that Queensland NSPs have built large sections of their networks to cater for increased demand from specific consumer classes that were not realised. Canegrowers suggested this issue can be overcome by approving forecasts based on customer classes. This would encourage

630 NER, clauses 6.5.6(c)(3), 6.5.7(c)(3), 6A.6.6(c)(3) and 6A.6.7(c)(3).

631 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, pp. 16–17.

632 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, p. 13.

633 Public Interest Advocacy Centre, *A firm basis: Submission to the AER's draft expenditure forecast assessment guideline*, 20 September 2013, pp. 5, 17–18.

NSPs to engage with consumer groups when forecasting demand. This would ensure irrigators and other minor users do not pay for continued expenditure to manage non-existent peak-load growth.[634]

Canegrowers supported the use of annual benchmarking reports throughout the regulatory period to assess expenditure proposals against annually revised demand forecasts and accordingly, to account for step-changes (up or down) in expenditure. This would protect consumers from paying for forecasting errors on behalf of NSPs.[635] It also noted the issue of Queensland NSPs developing demand forecasts with large and persisting forecasting errors, which resulted in price increases in order to maintain regulated revenue streams. Under a revenue cap, reduced demand perversely increases prices, and higher prices further reduces demand and a negative cycle begins. Canegrowers submit that the AER must acknowledge and take steps to correct this negative price cycle as a matter of urgency.[636] NSWIC is also concerned that the draft Guideline allocate the majority of the demand forecasting risk to consumers. NSWIC believes this contradicts the AERs instruction that the Guideline be aligned with the long term interests of consumers.[637]

Errors in demand forecasting are always an issue we seek to address and minimise, alongside NSP biases in overstating demand, when assessing regulatory proposals. As noted above, we are seeking to significantly improve our approach to assessing demand forecasts and set clear expectations on NSPs in terms of the quality of information and the processes they employ. AEMO's increasing role in this area will also be beneficial.

The nature of forecasting risk affects customers in different ways depending on the form of control, and this is something we consider in deciding whether to use a price or revenue cap. Revenue caps provide limited flexibility to deal with forecasting risk, which has been detrimental for consumers in recent years as demand has unexpectedly slowed. However this has not been a consistent outcome across all jurisdictions and prior regulatory control periods. For example, Ergon and Energex were required to meet maximum demand beyond the regulator's forecast in two out of three years in the previous regulatory control period[638], with differences more pronounced in the three years prior to that.[639] These variations are an inevitable feature of the ex ante regulatory regime, and persistent cycles that would lead to pricing impacts are corrected for at regular intervals where forecasts are re-determined. The regulatory framework also provides for flexibility to deal with uncertain events in the form of pass through arrangements and contingent projects during control periods, as well as implicitly through sharing mechanisms on expenditure under and overspends. We are unable, and it would not be practical, to update demand data and reassess associated expenditures on an annual basis as suggested by Canegrowers.

We acknowledge Canegrowers' suggestion that we approve demand forecasts based on customer classes and the role such forecasts might play in ensuring particular users pay only for the costs they impose on the network. We note that SCER has recently issued a rule change request to the AEMC regarding amendments to key elements of distribution pricing rules, including consideration of how prices could be made more cost reflective, and how DNSPs and consumers can engage better in the price setting process. We encourage Canegrowers and other users to engage in this rule change consultation.[640]

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634 CANEGROWERS, *Submission to the AER better regulation program*, 19 September 2013, p. 7.
635 CANEGROWERS, *Submission to the AER better regulation program*, 19 September 2013, p. 6.
636 CANEGROWERS, *Submission to the AER better regulation program*, 19 September 2013, p. 5.
637 New South Wales Irrigators' Council, *Submission to the AER – draft expenditure forecast assessment guideline for transmission*, 20 September 2013, p. 4.
638 AER, *Queensland Draft distribution determination 2010–11 to 2014–15*, 25 November 2009, pp. 55–59
639 Queensland Department of Mines and Energy, *Detailed Report of the Independent Panel for Electricity Distribution and Service Delivery for the 21st Century (Somerville report)*, July 2004, p. 87.
640 http://www.scer.gov.au/files/2013/10/Distribution-Pricing-Principles-Rule-Change-Request.pdf

Confidentiality

In past determinations, many NSPs provided demand forecasts that their consultants produced using proprietary models. They did not provide those models on intellectual property grounds. While organisations that produce such models may be reputable, with expertise in modelling, it would be inappropriate for us to take their forecasts 'on trust'. We must consider whether a NSP's expenditure forecast reasonably reflects a realistic expectation of the demand forecast. We cannot do this effectively without assessing the model and the underpinning assumptions. We will discuss and resolve confidentiality issues with NSPs during the framework and approach process.

COSBOA stated it fully supports our desire to have all information associated with models used to forecast demand, including model specifications and assumptions, made public.[641]

Implementation issues

This section outlines issues and developments that may affect demand forecast assessments in future determinations. These issues and developments have implications for our demand forecast assessments and/or the way in which NSPs develop their forecasts. Naturally, other issues and developments may arise in the future that would have implications for our demand forecast assessments. In any case, we will still apply the assessment principles in section C.2.1 when assessing NSPs' demand forecasts.

Australian Energy Market Operator's development of a demand forecasting approach

On 23 November 2012 SCER agreed to a comprehensive package of reforms to address concerns about rising electricity prices.[642] In December 2012 the Council of Australian Governments (COAG) endorsed these reforms.[643] In light of changing demand patterns, SCER agreed to task AEMO with developing demand forecasts that we may use to inform future determinations.[644]

AEMO is conducting an ongoing program to enhance its demand forecasting capabilities at the transmission level.[645] Its demand forecasting approach produces both system level forecasts and connection point forecasts for transmission networks. AEMO published its demand forecasting approach for transmission connection points on 26 June 2013 (having published its approach for system level forecasting in 2012, updated in July 2013).[646] AEMO will produce the first tranche of demand forecasts under this approach for TransGrid and Transend in 2014, then other TNSPs thereafter. For those transmission determinations, AEMO will prepare demand forecasts independently of the TNSPs (although DNSPs have an important role in providing data).

Currently, AEMO is not conducting a program to develop demand forecasting approaches at the distribution level.[647] AEMO's current focus is to build its capability in developing forecasts at the transmission connection point level. Once it has completed this program, AEMO will liaise with us to determine whether it should similarly develop its capacity at the distribution level.

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641 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 17.

642 www.aemc.gov.au/market-reviews/completed/differences-between-actual-and-forecast-demand-in-network-regulation.html (accessed 17 October 2013).

643 www.scer.gov.au/workstreams/energy-market-reform/ (accessed 17 October 2013).

644 SCER, *Electricity: Putting consumers first*, December 2012, p. 13.

645 www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting (accessed 17 October 2013).

646 AEMO, *Executive summary: Connection point forecasting*, 26 June 2013, pp. 1–2; AEMO, *Forecasting methodology information paper: National electricity forecasting*, 31 July 2013.

647 AEMO's regional forecasts for TNSPs may be consistent with DNSP demand at connection points.

COSBOA considered AEMO's development of improved transmission level forecasts is important and provides an independent source of demand forecasts. AEMO's potential development of distribution level forecasts could do the same at this level.[648]

Similarly, we support AEMO's program to enhance its demand forecasting capabilities because it will provide an alternative view of future demand. We will consider AEMO's forecasts as a significant input to our demand forecast assessments. Depending on the circumstances of the determination, and the findings of our assessments, we may use AEMO's demand forecasts for various purposes—for example, when performing sensitivity tests on a NSP's demand forecasts. Alternatively, we may use AEMO's forecast as the substitute demand forecast if our assessment indicates it, rather than the NSP's forecast, best reflects NER requirements. The weight we place on AEMO's demand forecast will likely change over time as AEMO's forecasting models and approaches improve.

We encourage all spatial and system level forecasts to reconcile (as per the principles in section C.2.1). We encourage NSPs to reconcile spatial forecasts with top down forecasts they consider reasonable, noting that AEMO produces independent forecasts, and is looking to improve its work in this area. Given AEMO's role, we would find benefit in understanding the reasons the NSP did or did not consider AEMO's forecasts to be suitable for reconciling spatial forecasts. This may assist AEMO in developing its forecasting approaches, and would inform our own demand forecast assessments.

Publication of consultations on connection point and zone substation data rule change

The National Generators Forum (NGF) requested that AEMO publish half hourly demand data, by connection point, across the NEM. The NGF indicated these data will provide market participants with enhanced information on changing demand patterns in the NEM, facilitating generation planning and investment decisions.[649] AEMO is currently developing a business case to determine the feasibility of the connection point data proposal. It will further consult with stakeholders between July and December 2013 on aggregation criteria.[650]

On 26 April 2013, the AEMC started its consultation on a related rule change request by the NGF. The request seeks a new requirement on DNSPs under the NER to annually publish historical electricity load data for their networks at the zone substation level.[651] It seeks to introduce an additional requirement for DNSPs in the 'distribution annual planning report' process.[652] On 1 August 2013, the AEMC extended the period of time for making a draft rule determination on this rule change request until 5 December 2013. The time extension was intended to enable the NGF to investigate the quality of data the DNSPs are currently able to produce.[653] If the data the DNSPs provide are robust, the rule change is likely to provide benefits including better modelling of the key determinants of electricity demand changes at the sub-system level.[654] We expect such analysis will help our demand forecast assessment, particularly of DNSPs.

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648 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 17.

649 www.aemo.com.au/Consultations/National-Electricity-Market/Open/Proposal-to-publish-Connection-Point-Demand-Data (accessed 7 May 2013).

650 AEMC, *Consultation paper: National electricity amendment (Publication of zone substation data) Rule 2013*, 26 April 2013, p. 7.

651 www.aemc.gov.au/electricity/rule-changes/open/publication-of-zone-substation-data.html (accessed 17 October 2013).

652 NER, schedule 5.8.

653 www.aemc.gov.au/electricity/rule-changes/open/publication-of-zone-substation-data.html (accessed 17 October 2013).

654 AER, *AER submission on AEMC consultation paper — Publication of zone substation data rule (ERC0156)*, 24 May 2013, p. 1.

Energy Networks Association's climate change adaptation project

The ENA is developing an industry approach to support the capacity of its members in managing climate risk and resilience across core network business activities.[655] The project also aims to ensure consistency in how NSPs factor climate change risk in future network investment decisions.[656]

We understand NSPs may use the approach arising from the project as part of their demand forecasting processes. To the extent that NSPs do so, we will apply the assessment principles in section C.2.1 when assessing the effects of the approach on NSPs' demand forecasts.

C.3 Replacement capital expenditure

This section discusses the contents of section 3.1 of the Guideline, which sets out the AER’s approach to assessing the replacement expenditure (repex) component of a NSP’s capex forecast.

Replacement expenditure is the non-demand driven capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life. Economic life is determined by the age, condition, technology or environment of the existing asset. The capital expenditure is regarded as replacement expenditure if it is primarily determined by the existing assets ability to efficiently maintain its service performance requirement.

Repex is a material category of expenditure, generally accounting for 30–60 per cent of total network capex.[657]

C.3.1 AER position

When assessing a NSP's repex forecast, we will:

- assess the NSP's forecasting approach. This includes assessing the processes, documentation and models the NSP uses to derive the repex component of its capex forecast.
- consider benchmarks and perform trend analysis of historical actual and expected capex
- conduct replacement expenditure modelling
- perform detailed project reviews.

When a NSP's forecast repex shows a significant divergence from the historic trend or our expenditure modelling we will assess the information supporting the NSP's forecasting approach and move to conducting more detailed project reviews. The following sections discuss our assessment techniques for trend analysis and repex modelling. For a discussion of how we use the more general techniques see section 5.4.

Trend analysis of actual and forecast capex

We will consider a NSP’s historical actual and forecast repex for preceding regulatory control periods. We undertake trend analysis of the forecasting performance of NSPs by comparing the actual and forecast trends for each NSP’s repex. Where a deviation from the historical trend exists, we will use the information provided by the NSP to assess if it is in accordance with the expenditure criteria in the

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655 The ENA is the peak national body representing gas distribution and electricity transmission and distribution businesses throughout Australia. www.ena.asn.au/about-us/ (accessed 17 October 2013).

656 www.ena.asn.au/policy/innovation/climate-change-adaptation/ (accessed 17 October 2013).

657 AER, *Electricity network service providers, Replacement expenditure model handbook,* November 2013, p. 7.

NER. Changes in NSP obligations (for example, safety obligations or CO_2 emissions) could justify deviating from historical repex levels.

A major feature of an incentive based regulatory framework is the regulated firm should achieve efficiency gains whereby actual expenditure is lower than the forecast. However, the regulator must ensure the forecasts adopted are accurate and well substantiated. Differences between actual and forecast repex could be the result of efficiency gains, forecasting errors or some combination of the two. Where there are concerns about the ability of NSPs' forecasting models to reliably predict future asset replacement requirements, we have applied our repex model instead to forecast the required repex for the relevant expenditure items.[658]

Past trend analysis suggests NSPs' repex forecasts systematically overestimate capex.[659] This analysis has shown NSPs spend significantly less than their initial forecast or the repex allowance as part of the determination process. Further we have observed that actual repex follows a gradual increasing trend.[660]

We will continue undertaking trend analysis alongside assessing NSPs' policies, procedures, and forecasting methodologies when considering if the proposed expenditure forecast is justified.

Replacement expenditure modelling

In September 2009 we engaged Nuttall Consulting to develop a replacement capex forecasting model (repex model). Nuttall Consulting produced a high-level probability based model that forecasts repex for various asset categories based on their condition (using age as a proxy) and unit costs.[661] We then compared NSP forecasts with the repex model outputs to identify and target expenditure that required detailed engineering and business case review.

We will use the repex model to assess NSPs' asset life and unit cost trends over time, as well as comparing them to NSP benchmarks. In instances where we consider this shows a NSP's proposed repex does not conform to the capex criteria, it may be used (in combination with other techniques) to generate a substitute forecast.

We anticipate over time that comparing the actual and forecast volumes will provide a better understanding of changes in asset condition, failure rates, impacts of reliability outcomes and loading for the network. We consider the repex model will be less applicable to transmission determinations initially than to distribution determinations. This is because replacement for most TNSPs involves asset groups with unique projects that are lower in volume and higher in value than those for DNSPs. For these asset groups, we will collect more aggregated asset data, which are less comparable and predictable.

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658 AER, *Draft decision: Victorian electricity distribution network service providers distribution determination 2011–15*, June 2010, p. 338.

659 AER, *Draft decision: Victorian electricity distribution network service providers distribution determination 2011–15, Appendix I – Benchmarking* June 2010, pp. 61—65.

660 AER, *Draft decision: Victorian electricity distribution network service providers distribution determination 2011–15, Appendices*, June 2010, pp. 61–62.

661 AER, *Final decision: Aurora Energy Pty Ltd, 2012–13 to 2016–17*, 30 April 2012, p. 124.

Box 7.1 The repex model

The repex model combines data on the existing age and historical rates of replacement across categories of different assets, and assumptions about the probability of failure (or replacement prior to failure), to forecast replacement volumes into the near future.

For a population of similar assets, the replacement life may vary across the population. This can be due to a range of factors, such as its operational history, its environmental condition, the quality of its design and its installation. Asset age is used as a proxy for the many factors that drive individual asset replacements.

In developing our repex model, it was decided the model should have similar characteristics to those used by the UK regulator, Ofgem. For this form of model, the replacement life is defined as a probability distribution applicable for a particular population of assets. This probability distribution reflects the proportion of assets in a population that will be replaced at a given age.

The shape of the probability distribution should reflect the replacement characteristics across the population. Our repex model, similar to the Ofgem approach, assumes a normal distribution for the replacement life. The repex model also calibrates assumptions with respect to recent replacement history.

From a regulatory point of view, this form of replacement modelling provides a useful reference to assess regulatory proposals because it allows for high level benchmarking of replacement needs. It is a common framework that can be applied without the need to rely entirely on intrusive data collection and detailed analysis of the asset management plans of particular NSPs. That said, no model of this kind could predict with certainty when an asset will fail or need to be replaced. In addition to forecasting volumes for an individual NSP, the model can facilitate the benchmarking of assumed replacement lives and the unit cost of replacement.

Summary of expected data requirements

Repex is categorised into asset groups, which, for comparability, are separated into smaller asset categories according to characteristics that indicate the asset’s function. NSP's assets are designed to serve a discrete purpose or set of functions, hence we consider defining asset categories by function provides objectivity in asset type classification across NSPs. Further, grouping by function will band together assets with similar lives and unit costs. This approach gives us a defined set of high-level functional asset categories for benchmarking. The following tables provide an overview of the asset groups for DNSPs and TNSPs.

Table C.1 DNSP Replacement expenditure asset groups

Poles	Transformers
Pole top structures	Switchgear
Overhead conductors	Public lighting
Underground cables	Services
Other	

Source: AER analysis.

Table C.2 TNSP Replacement expenditure asset groups

Steel towers	Substation power transformers
Pole structures	Substation reactive plant
Conductors	Transmission cables
Substations switch bays	Other assets

Source: AER analysis.

For each of the asset categories we will require NSPs to provide data on:

- mean replacement asset life (years)
- standard deviation of the mean replacement asset life
- age profile data
- replacement unit cost ($ nominal)
- total number of asset replaced during the regulatory year
- total number of failures for each asset during the regulatory year.[662]
- total quantity (number) of each asset type that was commissioned in each financial year.

As noted above the repex model forecasts the condition based replacement (see We will use the repex model to assess NSPs' asset life and unit cost trends over time, as well as comparing them to NSP benchmarks. In instances where we consider this shows a NSP's proposed repex does not conform to the capex criteria, it may be used (in combination with other techniques) to generate a substitute forecast.

We anticipate over time that comparing the actual and forecast volumes will provide a better understanding of changes in asset condition, failure rates, impacts of reliability outcomes and loading for the network. We consider the repex model will be less applicable to transmission determinations initially than to distribution determinations. This is because replacement for most TNSPs involves asset groups with unique projects that are lower in volume and higher in value than those for DNSPs. For these asset groups, we will collect more aggregated asset data, which are less comparable and predictable.

Box 7.1). When factors not related to asset condition drive its replacement, such as changes in safety obligations, we expect NSPs to furnish us with information justifying the need and build-up of the expenditure.

C.3.2 Reasons for AER position

Our assessment approach specifies that we will assess the NSP's forecasting methodology and supporting material by using, amongst other methods, trend analysis and benchmarking. We consider that this overall approach strikes an appropriate balance between reliance on incentive arrangements (through trend/ modelling assessments), comparisons across NSPs in terms of expected standard lives and unit costs, and the need to engage in the details of the NSP's proposal where these other methods do not provide a complete view of the NSP's efficiency.

[662] Failures are instances of assets breaking down or being physically unable to operate.

While the repex model will useful in assessing proposed expenditure allowances, we expect to spend considerable effort liaising with consultants and with NSPs to examine the engineering and economic reasoning used to develop the expenditure forecast and whether it accords with the capex criteria.

Further, we will require NSPs to identify any differences between their own historical unit costs or replacement volumes that reflect any factor not already accounted for in the data set. Through benchmarking analysis, we will also expect NSPs to be able to explain differences in costs and expected lives of specific assets compared to their peers.

The following section discusses issues regarding our repex assessment techniques that were raised by stakeholders in submissions we received and consultation following the release of the Draft Guideline and explanatory statement.

Issues with repex model

In submissions we received the following comments from NSPs raising concerns with the use of the repex model:

- CitiPower, Powercor and SA Power Networks submitted that repex modelling should not be relied on and should only be used to identify further areas for investigation and potentially explain differences in cost drivers between DNSPs. They stated that the AER needs to seriously consider its view on re-calibration and the scope of information required to provide a robust data set They also noted concerns that the AER will not give appropriate consideration to the unique factors affecting each DNSP's replacement program cycles.[663]

The NSW DNSPs submitted concerns the AER would use its assessment tools to set allowances, rather than to review the substance of a DNSP's proposal.[664]Following the release of the Draft Guideline, stakeholders noted some limitations of the repex model. These related to aspects such as model calibration or the appropriateness of the probability distribution used in forecasting asset replacement. We have updated the repex model handbook to address these specific issues. [665]

We also received the following submissions supporting the use of the repex model:

- The EUAA support the use of the AER's repex and augex models and its approach to benchmarking productivity. The EUAA also supports leaving the precise approach relatively open, with room to move in the application and use of these methodologies.[666]
- MEU considers that the introduction of benchmarking and predictive assessment programs (such as the repex and augex models) will enhance the AER's ability to identify what might be efficient expenditure.[667]

Implementation issues

We used the repex model in our most recent distribution determinations, but we acknowledge the model has not been used for all NSPs.[668] Further, we expect stakeholders will identify issues over

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663 CitiPower, Powercor and SA Power Networks, *Joint response to AER draft expenditure forecast assessment guidelines for electricity distribution and transmission*, 20 September 2013, p. 8.
664 NSW DNSPs, *Response to draft forecast expenditure assessment guidelines,* 20 September 2013, pp. 7—8.
665 AER, *Electricity network service providers, Replacement expenditure model handbook,* November 2013.
666 Energy Users Association of Australia, *EUAA submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, p. 1.
667 Major Energy Users, *AER better regulation program – proposed guidelines for expenditure assessment – MEU comments on draft guidelines,* 20 September 2013, p. 17.
668 The repex model has been used in the most recent Aurora and Victorian DNSP determinations.

time. Applying the repex model in future determinations will familiarise stakeholders with it and aid in resolving any potential issues.

Some issues may only be identified with large scale implementation. We can resolve such problems only through experience and if we encounter issues, we will attempt to resolve them as they arise. Depending on the nature and extent of the issue, we may place less emphasis on the analysis of the repex model in a determination.

It is likely we will use the repex model as a first pass model in future determinations, in combination with other assessment techniques.[669] Initially, we will likely review proposed repex forecasts for all asset categories in detail, even those the repex model suggests are at reasonably efficient levels. This will help us to understand when we can rely on the repex model as a first pass model (and when we cannot).

C.4 Customer initiated works

This section discusses section 3.3 of the Guideline, which sets out how we propose to assess, as part of our revenue determinations, NSPs' forecast capex for providing customer initiated services. Customer-initiated services prepare the electricity network to support the connection of new and existing network customers. They comprise of the following activities:

- new customer connections for TNSPs and DNSPs
- other services:
  - meter activities associated with a new customer connection
  - augmentation of the shared network resulting from a new customer connection and by customer request
  - public lighting installation, replacement and maintenance activities
  - fee based services common across DNSPs
  - miscellaneous fee based and quoted services that are not consistently provided by DNSPs.

C.4.1 AER position

Our approach is to standardise the reporting of cost data for customer initiated works, to streamline the regulatory process and minimise regulatory burden for NSPs. We will do this through:

- designing uniform data reporting requirements, to group comparable customer-initiated work activities for DNSPs
- using data of comparable customer initiated works in category analysis. This may be used to better target detailed engineering analysis to inform our determinations of forecast expenditure requirements for NSPs
- indicating the likely cost data we would require TNSPs to report for use in detailed engineering reviews.

The Guideline outlines DNSPs' data reporting requirements in relation to our assessment techniques. Generally, we consider benchmarking analysis is suitable for those customer initiated works for which

669 See section **Error! Reference source not found.**.

expenditure is recurrent and volumes of particular activities reflect a similar scope of works over time or across NSPs.

Initially, we will not impose detailed reporting requirements on TNSPs to provide cost data for customer-initiated works within RIN templates. Reporting requirements for TNSPs may change over time as information provided in the course of detailed engineering review reveals the possibility for us to use benchmarking and/or trend analysis.

We will continue our approach of using trend analysis in setting expenditure allowances for the DNSPs' provision of customer-initiated services. However, we will also increasingly rely on new assessment techniques, in particular, category analysis benchmarking and more targeted detailed engineering reviews. Using category analysis, we will measure the relative efficiency of the DNSPs in providing customer-initiated services across the NEM. We will use those techniques also as screening tools, to select expenditure items for detailed engineering review. Furthermore, we will continue to use the engineering review for assessing the scale and scope of capital works, to determine whether forecast expenditure is efficient. In its submission to our Draft Guideline, COSBOA supported the application of benchmarking and trend analysis to assess customer-initiated capex forecasts.[670]

We will primarily use detailed engineering reviews to assess the expenditure requirements of TNSPs for providing customer-initiated works.

General Information reporting requirements

We will require NSPs to report historical and forecast input costs of customer-initiated works consistently. NSPs should disaggregate input costs into labour, material and contract categories, with the estimation method detailed. We would expect forecast input costs to be estimated on a reasonable basis, using current and robust data which reflects the expected economic cost of customer-initiated works. Historical costs should be measured as costs that are incurred 'on the job' and are reconcilable to the NSPs' internal cost recording systems. NSPs must report historical cost data in a way that is consistent over time. Without consistent reporting, we cannot conduct benchmarking analysis (that is, a like-for-like comparison of customer initiated works over time).

Data provided to us in regulatory proposals must be reconciled to the NSPs' internal planning documents. It must also reconcile to any models that NSPs provide as part of the regulatory process or use to justify their proposals. We may not accept, or may place low weight on, information sources that we find to be irreconcilable or inaccurate.

Classification of customer-initiated services

Data classifications of customer-initiated works will only apply to DNSPs. We acknowledge the scope and scale of customer-initiated works differ among the DNSPs, and we can use analysis such as benchmarking only for making like-for-like comparisons. To address difficulties in distinguishing efficiencies from genuine differences in each works' specifications, we have developed a screening procedure to compare those customer initiated works that are similar in nature across DNSPs. This procedure organises different types of customer initiated work into comparable groupings with common:

- customer type and voltage requirements
- connection type

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670 Council of Small Business of Australia, *Comments on AER draft expenditure assessment guidelines*, 20 September 2013, p. 18.

- meter type
- public lighting works
- common fee-based and quoted services.

C.4.2 Reasons for AER position

We developed expenditure reporting categories for customer-initiated works to address problems that we encountered in assessing NSPs' past revenue proposals. Our proposed approach will significantly improve our assessments in future determinations by:

- aligning the categorisation of expenditures across NSPs, increasing the scope for benchmarking of service costs;
- allowing a more transparent consideration of changes between historical and forecast unit costs, and the rates of activities/volumes in a NSP's supply of customer-initiated works. We will thus be able to rely more on the capex incentive framework, by using historical behaviour to challenge forecast expenditure proposals; and
- streamlining the assessment process, whereby regulatory proposals submit the same standardised information and NSPs have a predictable and clear expectation of the information they will be required to provide as part of the regulatory process. Having predictability for information requirements also means that NSPs will be expected to provide data that reconciles to their internal forecasting models and planning documents. In past determinations, we had to perform these reconciliations between multiple data sources at the expense of spending time analysing the information provided. Further, NSPs were burdened with information requests during determinations, which added to their regulatory costs.

The reasoning for selecting categories is discussed in the following sections.

Classifications of customer-initiated works

Our proposed classifications will only apply to DNSPs. The classifications will highlight cost differences, and we will use them in combination with other assessment techniques to determine the efficiency of a DNSP's expenditure forecast. We consider category benchmarking analysis is suitable for those customer-initiated works that have recurrent expenditure and include the same labour and material inputs over time. For customer-initiated works that are less typical, we may still use category benchmarking to assess elements of inputs that are consistently used over time and across DNSPs. If input costs are not conducive to benchmarking analysis, then we may require a detailed engineering review to assess expenditure.

We note that a number of the customer-initiated service activities we are collecting information for are a mix of standard and alternative control services, for which the related expenditure could be some combination of capex and opex. For the purpose of benchmarking, we consider it useful to have all activities reported together. This does not reflect our position on the classification of services as either standard or alternative control.

Connections classifications

Our classifications distinguish connection projects in terms of complexity. They accord with some DNSPs' existing connections classifications, while capturing the common cost structures faced by the DNSPs when performing a variety of connection works. The following project specifications largely account for cost differences between different connection types, and we will use them to implement benchmarking analysis:

- simple type connection — a low voltage (LV) connection of new/existing customers to existing network infrastructure with a single span of overhead wire or underground service wire and not requiring augmentation to the shared network
- complex type connection — a low voltage / high voltage (LV/HV) connection of new/existing customers that is not a simple type connection and may involve the installation of a distribution substation. It may also require alterations to upstream shared assets, with large extension to existing network infrastructure.

Meter classifications

We will allow DNSPs to specify the types of meters that they are using to provide meter services when reporting expenditure related to metering activities. The meter type and voltage requirements of the customer will dictate the costs of meter purchasing and the meter related maintenance activities. We expect the number of meter installations should be consistent with the overall volume of connections.

Public lighting classifications

We will allow DNSPs to specify the location of public lighting as either a major or minor road, which we expect is the main determinant to explain the costs of performing public lighting services.

Common fee based services

These categories consist of those fee-based services which are commonly provided by DNSPs. To the extent that these categories are comparable, we will use benchmarking analysis to assess the efficiency of DNSPs in providing these services. Where benchmarking analysis cannot be performed, a detailed engineering review or trend analysis may be used in the assessment of these costs. We have aligned our reporting requirements with categories of the DNSPs' existing alternative service schedule of charges to ensure consistency with current reporting, in order to minimise regulatory burden for DNSPs. We have developed consistent definitions so that the efficiency of DNSPs' providing these services can be compared across the NEM.

Miscellaneous fee based and quoted services

These categories consist of fee-based and quoted services which tend to be relatively less material and may also not consistently be provided by DNSPs across the NEM. For these services, we consider that benchmarking analysis will have only limited use, if any, to assess the efficiency of DNSPs. We will primarily rely on detailed engineering review and, or trend analysis to assess DNSPs' provision of these services.

Controlling for a NSP's unique circumstances

To meaningfully measure the relative efficiency of each NSP, we must consider customer-initiated expenditure in light of the unique circumstances faced by the NSP. As such, we identified a number of high-level descriptor metrics that may explain the difference in service cost over time and between DNSPs. We will use descriptor metrics as high-level indicators of the scope and scale of customer-initiated works to be undertaken over the regulatory period, and in assessing the comparability of DNSPs for category benchmarking analysis. For each customer-initiated service, the DNSPs must describe their services by allocating volumes of work activities and asset types used in service provision, as well as performance metrics to quantify their quality of service supply. The DNSPs' reporting requirements for the high-level descriptors may change over time as we refine our assessment approach to reviewing DNSPs' expenditure forecast requirements.

We consider that our list of high-level descriptor metrics caters to the DNSPs' and TNSPs' existing abilities to disaggregate total expenditure into categories of customer-initiated works. In submitting forecasts of customer-initiated works for past revenue proposals, DNSPs used similar categories to disaggregate their proposed expenditure.

The following subsections justify our selection of descriptor metrics.

Density

Reporting of this category will apply to DNSPs only. We will consider the density factor by using the CBD, urban and rural locational categories to measure the time and distance travelled to perform customer initiated works. Time and distance is expected to have an impact on the labour cost involved in providing connection works.[671] The density factor will also be useful for us to measure the distance between existing network infrastructure and new infrastructure associated with proposed connection works. While density impacts costs in different ways, a greater distance may contribute to expanding and developing the distribution network to increase coverage to a new area (such as a subdivision), which would increase its construction requirements and therefore the materials cost of the proposed connection works.[672]

Connection type

Reporting of this category will apply to TNSPs and DNSPs. Underground and overhead connection types are required for us to distinguish the physical characteristics of customer connections works. Underground connections require the construction of a service pit and may involve the breaking and re-instatement of ground surface. Overhead connections may necessitate the installation of a pole, or simply the addition of wiring to an existing pole. The difference between underground and overhead connections will significantly affect the cost configurations of connection works and the materials and labour input costs.

Additionally, TNSPs will be required to specify the voltage and rating of each of their proposed connection projects.

Inputs to customer-initiated services

We consider that the scope and scale of the same customer-initiated activities may be different for each DNSP, making services incomparable between DNSPs. In particular, DNSPs may use varying proportions of the same material and labour inputs, or different inputs, which are not comparable. To take account of these differences, we require DNSPs to disaggregate volumes of work activities and asset types used for providing customer-initiated services. As such, DNSPs must report volumes for the following:

- number and total spend for distribution substations used in each customer connection category (residential, commercial and industrial, embedded generation and subdivision)
- volume of meter types in the current population as either single/multi-phase or direct connect/connected via current transformer
- volume of different light types in the current population of lights, volume of cabling and poles replaced in the provision of public lighting services.

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671 SP AusNet, *Customer Connection Guide*, 11 March 2008, p. 6.

672 Aurora, *Customer initiated capital works (CICW) management plan*, March 2011, pp. 10–11; AEMO, *Victorian annual planning report: Appendix A – New investors guide*, 24 June 2011, pp. 12–13.

Transitional and implementation issues

Differences between transmission and distribution networks

We acknowledge the differences between customer-initiated works performed for distribution and transmission networks. In particular, the works for transmission networks typically:

- involve fewer projects, and ones that are performed less frequently, compared with distribution networks
- are larger and typically involve a higher cost per project, compared with distribution networks.

To the extent that standard equipment is consistently used as an input to providing customer-initiated services, we may use benchmarking analysis to assess the efficiency of transmission connection project costs incurred over time. Further, we acknowledge that transmission services are very different from distribution network services as classified under the NER. Specifically, connection point works and extension works have a different meaning for transmission networks and can be classified as negotiated or non-regulated services. We do not propose to collect information on negotiated services and non-regulated services for TNSPs.

Feasibility of reporting and benchmarking of standardised expenditure

In designing our reporting requirements, we considered the NSPs' existing ability to disaggregate categories of expenditure from capex forecasting models that they used to support previous revenue proposals. As such, we do not consider the data reporting requirements in our Final Guideline are inconsistent with the NSPs' existing ability to disaggregate expenditure related to customer-initiated works. Further, our reporting requirements are sufficient to address the deficiencies of the NSPs' current reporting requirements by generating data that is comparable across NSPs and allows us to reasonably compare customer-initiated works over time. We chose classifications and defined connection types, meter works, fee/quoted services and public lighting works that we can use to compare customer-initiated works across NSPs. We also designed a template for the DNSPs to report descriptor metrics that will explain scale, scope and locational differences across DNSPs, and allow us to account for the unique circumstances of each DNSP.

Accounting for key cost drivers

Consistent with NSP's submissions to date, and comments made in workshops, we chose the following factors, as the most significant elements which determine the cost of customer-initiated works, as well as for asset works captured in repex and augex data requirements:

- whether a connection is a replacement or new connection
- whether a connection is an underground or overhead connection
- the voltage of the connection
- the location of the connection
- maximum demand relative to asset capacity.

Additionally, DNSPs considered the costs of connection works for distribution networks are also influenced by:

- the location of connection works (e.g. CBD, rural or urban locations)

- the scale of a new development (that is, the size and density of subdivisions / newly constructed buildings)
- the reliability demands of the customer
- whether a connection is simple or complex.

We have taken account of these cost drivers for connections and others drivers for metering, public lighting and fee/quoted services by including the following items within our descriptor metrics of customer-initiated works:

- Volume of CBD, urban and rural locations
- Cost per subdivision lot of large and intermediate subdivision connections
- Volume and cost of metering activities for meter types 1–7
- Cost and volume of public lighting works on major and minor roads
- Quality of supply metrics to DNSP performance for provision of connections and public lighting services

Accounting for gifted assets

NSPs must disclose to us the estimated quantity of gifted assets constructed by developers and third parties. We will consider gifted assets when making revenue determinations and performing benchmarking analysis to assess the efficiency of a NSP's costs.

We note that some jurisdictions permit contracting of customer-initiated works to be performed by third parties. Where customer-initiated works are not undertaken by NSPs, we acknowledge that cost data may be unavailable for NSPs to report. In these instances, we do not require NSPs to report cost data for customer-initiated works. DNSPs commented in workshops that where connection works are performed by contracted third parties, under a contestable framework, they will generally not have actual data on these works. We may collect data to determine whether a customer-initiated service deemed as contestable is genuinely supported by a competitive market of third party contractors.

Customer contributions policy

Customer contributions are payments by each customer connecting to the network, to ensure the connection costs are borne by the customer requesting the connection and not the entire customer base. They represent the difference between the connection cost (including necessary augmentation of the upstream network) and the present value of the forecast network use of service charges that the DNSP expects to recover over the life of the connection.

We will assess the prudency of customer contributions forecasts to ensure they represent unbiased estimates. To adequately assess forecasts of customer contributions, we require DNSPs to explain in detail how they estimated the average costs for connections. In particular, DNSPs will be required to submit their connection policy to us for approval in the course of a revenue determination, in accordance with part DA of chapter six of the NER. Further, DNSPs should explain the following key assumptions in their calculation of the network use of system charges:

- the expected life of the connection
- the average consumption expected by customers over the life of the connection
- any other factors that a DNSP considers influence the expected network use of system charge.

In past determinations, some NSPs provided detailed modelling to explain their estimation of customer contributions over classes of customer connections. We consider this approach provides transparency that allows us to better assess DNSPs' proposed customer contributions. We expect all DNSPs to provide such modelling in future revenue proposals.

C.5 Non-network expenditure

This section discusses the contents of section 3.4 of the Guideline, which sets out our approach to assessing the non-network component of a NSP's expenditure forecast. It also considers supervisory control and data acquisition (SCADA) and network control expenditure .

In this expenditure category we expect to generally look at both capex and opex data when assessing expenditure forecasts. This is due to the ease of substitutability between opex and capex. In relation to capex forecast assessment we expect to use both capex and opex data for benchmarking and to undertake a bottom up assessment of efficient and prudent capex forecasts. Where a NSP proposes to expense non-network costs, we will use expenditure information in the non-network category to assist with the assessment of the overall efficiency of base year opex. We consider this is consistent with our preference for using a base step trend approach for opex. The discussion in the following sections refers to the overall assessment of non-network expenditure and should be read in this context.

NSPs' regulatory proposals can involve significant non-network expenditure, particularly IT and property related expenditure. Key issues in our past assessments included: proposals’ lack of economic justification for projects; an inability to benchmark expenditure across a business due to its different acquisition methods[673]; and trend analysis issues due to changes in acquisition methods over time.

C.5.1 AER position

Our assessment approach will remain broadly similar to our past approach. We will assess a NSP’s expenditure forecasts and how these were developed with reference to key volume and cost drivers. We will also consider how forecast expenditure compares to past expenditure, and the economic justification for any step changes in expenditure. However, we propose to standardise expenditure categories and how expenditure input costs are recorded, to target projects more systematically for detailed review.

For our assessment, we propose to break non-network expenditure into the following categories:

- IT and communications
- motor vehicles
- property
- other
- SCADA and network control.

When assessing NSPs’ forecast expenditures in these categories, we intend to focus on governance and asset management plans, the business cases underpinning expenditure, and the method used to develop the expenditure forecasts. We will use a combination of tools for our assessment, including trend analysis, cost–benefit analysis, benchmarking of costs, and detailed technical assessment. To

673 For example, purchasing versus leasing, which is opex.

aid our assessment we are likely to require NSPs to break down expenditure below these high level categories into sub categories of expenditure.

While we will aim to assess overall governance processes and all asset management plans, we will likely assess only a sample of projects and their business cases. Often, we will undertake the assessments with the help of technical experts. The sampling process is likely to target higher risk and high cost projects, and may also consider a random selection of projects.

We prefer a revealed cost approach to assessing forecast expenditure that is relatively recurrent. When non-network expenditure is recurrent, we may examine the prior period's expenditure to determine whether it is an efficient base for the assessment of forecasts. In doing so, we may examine asset management plans, business cases and benchmark expenditure of other NSPs.

For assessing non-recurrent expenditure, we propose to primarily examine the NSP's economic justifications for that expenditure, including any underlying business cases and cost–benefit analysis. We expect to receive clear economic justification for all material expenditure.

For all categories of expenditure, NSPs should forecast recurrent expenditure using identified volume and cost drivers. Further, they should economically justify all material expenditure and identify all key cost drivers for both recurrent and non-recurrent expenditure.

Generally, NSPs are expected to provide clear economic justifications of material non-recurrent expenditure so we can better assess them against the NER requirements.

Some costs are not incurred on a standalone basis—that is, NSPs incur costs for some items as part of a larger contractual arrangement. In this situation, we are likely to require NSPs to report estimated costs allocated to expenditure categories, and to indicate the costs were incurred as part of a package of supplied works/services. We are likely to require NSPs to state any assumptions used to allocate costs. This information should allow us to understand which costs are genuinely incurred versus resulting from allocations within, or subsequent to, a supply contract.

Given all the information before us, we will consider whether the proposed expenditure in each non-network category appears efficient and prudent. When we find expenditure is not efficient and prudent, we may substitute our own values for expenditure, in the context of setting an overall efficient and prudent expenditure allowance for the business. When project sampling indicates a degree of inefficiency, we may extrapolate that finding across all similar projects.

The remainder of this chapter outlines further processes related to the individual categories of non-network expenditure and SCADA and network control.

C.5.2 Reasons for AER position

We consider the proposed non-network expenditure categories reflect a reasonable breakdown. This breakdown includes separating SCADA and network control expenditure from IT and communications costs because these expenditures have distinct cost drivers. Having NSPs report consistently under these categories should allow for better comparability of expenditure over time and across businesses. Further, these categories cover the key expenditure categories examined in past regulatory decisions, and that we discussed with stakeholders at workshops prior to the release of the draft Guideline (who mostly accepted the categories).

Generally, we consider our current assessment processes, primarily trend analysis combined with detailed technical review, are appropriate. With adequate data, they should allow simplified assessment of recurrent expenditure through trend analysis and more detailed assessment and technical review of more complex lumpy investments. The separation of recurrent expenditure from non-recurrent expenditure should improve our assessment of recurrent expenditure via trend analysis. Further, greater standardisation of categories and cost inputs should facilitate improved assessment of forecasts via trend analysis and the benchmarking of a NSP's category costs against those of other NSPs.

Also, if NSPs provide more consistent asset management plans and business cases, then we should improve our assessment of the economic justifications for expenditure proposals. NSPs should improve how they justify and estimate their forecast expenditure by clearly and consistently linking forecast expenditures to cost drivers. In prior proposals, economic justification was often insufficient for us to conclude the proposed expenditure was efficient and prudent. This issue was particularly the case with step changes in expenditure that need to be economically justified and appropriately forecast.

Examination of total expenditure (opex as well as capex) should improve trend analysis and benchmarking for expenditure categories that are often undertaken using different procurement methods. Different procurement methods prevented effective benchmarking in previous regulatory decisions. NSPs supported us considering high level differences in procurement methods when examining forecast expenditure. However, as noted above, while we expect to examine total expenditure forecasts in this category for the purposes of benchmarking and performing a bottom-up assessment of forecast capex, in relation to the assessment of forecast opex we expect to use the expenditure reported in this expenditure category primarily to assist with the assessment of the efficiency of base opex.

The definitions related to each category of expenditure and specific detailed data requirements will be set out in RINs to be issued to each NSP.

The following sections cover assessment related to each category of non-network expenditure.

Assessment of IT and communications expenditure

We expect to assess expenditure forecasts broadly in line with our past assessment techniques. In doing so, we expect to primarily use trend analysis, an assessment of business cases and asset management plans, and technical review. In addition, we may use other techniques such as category benchmarking, if appropriate.

We expect to assess IT and communications expenditure in combination. However, to the extent that communications expenditure has cost drivers distinct from those of IT expenditure, NSPs should separately identify those cost drivers. As required, we will undertake a technical review of material IT and communications expenditure, particularly non-recurrent expenditure.

Assessment of motor vehicle expenditure

We expect to assess motor vehicle related expenditure by examining the number and types of different classes of motor vehicles, and the costs per motor vehicle in each class. Motor vehicle expenditure may be further disaggregated into sub categories (for example network versus non network expenditure).

Assessment of non-network building and property expenditure

We expect to assess recurrent expenditure primarily through trend analysis, and we may consider asset management plans, business cases and benchmark costs in assessing the efficiency of base expenditure. For non-recurrent expenditure, we are likely to assess business cases and we may conduct technical reviews of both recurrent and non-recurrent expenditure.

As in prior decisions, we propose to focus on large non-recurrent expenditures and the economic justifications and business cases that underpin them.

Assessment of non-network other expenditure

We are not suggesting material changes to the current assessment approach, other than expecting NSPs to provide clear economic justification of any material forecast expenditure, identification of cost drivers and departures from historic trends. We expect to assess this category primarily through trend analysis, and we may consider asset management plans, business cases and benchmark costs in assessing the efficiency of base expenditure. This may involve providing breakdowns of expenditure into NSP specific subcategories.

Assessment of SCADA and network control expenditure

We are not suggesting material changes to the current assessment approach, other than expecting NSPs to provide clear economic justification for any material forecast expenditure, identification of cost drivers and departures from historic trends.

We propose to assess recurrent expenditure primarily through trend analysis. To assess the efficiency of base expenditure, we may consider asset management plans, business cases and benchmark costs. For material non-recurrent expenditure, we are likely to assess the NSPs' business cases.

We acknowledge there is increasing amounts of equipment that has inbuilt SCADA and Network control functionality within it. We intend to consider how this type of equipment is categorised when we collect information from the NSPs.

C.6 Maintenance and emergency response expenditure

This section sets out our approach to assessing the maintenance and emergency response components of a NSP's opex. Maintenance and emergency response include all works to maintain the current working condition of an asset or to address the deterioration of an asset. These works include those that may be driven by reliability deterioration or an assessment of increasing risk of failure or performance degradation of a network asset. These expenditure categories are important because they can represent up to 55 per cent of opex for electricity NSPs.

Expenditure driven by deteriorating asset condition could include expenditure on both emergency and non-emergency rectification work, which can have significant cost differences. Non-emergency expenditure can be distinguished between replacements (capex) and other maintenance activities (opex)—a distinction that reflects the NSPs' repair-or-replace decisions. Non-emergency maintenance activities can also be distinguished between routine and non-routine activities. The timing of these activities depends on asset condition and decisions on when to replace the asset, which may vary over time and across NSPs. Further, NSPs' maintenance and emergency response activities and expenditure will differ depending on the asset to be inspected, repaired or replaced. The asset life may differ, for example, which would affect asset deterioration issues and repair-replace trade-off decisions.

Many NSPs currently report on routine maintenance activities that include asset inspection and vegetation management. For future assessments we propose to separate vegetation management from other routine maintenance activities.

C.6.1 AER position

We will consider maintenance and emergency response expenditure in the context of our overall opex assessment approach, specifically our assessment of efficient base year expenditures. To assess the efficient base year cost, we will use a variety of techniques, including analysis of individual opex categories. Our methods of reviewing maintenance and emergency response categories will include:

- trend analysis
- benchmarking of unit costs and workloads
- engineering review
- review of systems and governance frameworks.

We will consider inspections and periodic maintenance (routine expenditure) separate to reactive and condition-based maintenance (non-routine and emergency expenditure).

We intend to review base year maintenance and emergency response expenditures on a more disaggregated basis in future expenditure assessments. With disaggregated analysis, we can identify factors that cause expenditure to change over time, ensure expenditure consistency across NSPs over time, and identify uncontrollable factors that influence expenditure and differ across NSPs.

For DNSPs and TNSPs we will require maintenance opex to be divided into:

- routine maintenance—activities predominantly directed at discovering information on asset condition, and often undertaken at intervals that can be predicted
- non-routine maintenance—activities predominantly directed at managing asset condition. The timing of these activities depends on asset condition and decisions on when to replace the asset, which may vary over time and across NSPs.

We will require NSPs to break down each maintenance expenditure group by key drivers, mainly by comparable maintenance activities and asset types. With this disaggregated data, we will conduct benchmarking and trend analysis of NSPs with respect to drivers or volume measures (for example, the average inspection cost per pole structure). We will link this analysis to supporting information (such as asset condition, supply outage information, fault types etc.) that we will require from the NSPs.

If we find any significant departure from the trend and/or benchmark, we will subject it to detailed review when setting efficient opex allowances in our regulatory determinations. We will also factor the results of this analysis into our annual benchmarking reports.

If DNSPs perform inspections of electricity assets and vegetation simultaneously for maintenance purposes, we will require these costs to be reported as maintenance expenditure. For DNSPs, we also require opex for emergency response to be identified, namely for activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.

Emergency response expenditure is relatively unpredictable and not immediately amenable to trend or benchmarking assessment. However we will seek to separate expenditure caused by severe weather events from other expenditure. We will also request DNSPs to provide data on the following fault types experienced across their networks:

- asset failure as a result of degradation or fault of the asset, including overhead and underground assets

- vegetation, when the primary cause of an outage was vegetation related (including trees, shrubs, bark, creepers etc.). This driver can be further divided into:
  - vegetation grow-ins—that is, vegetation that has grown into the standard clearance area, coming into contact with a NSP's network assets
  - vegetation blow-ins and fall-ins—that is, wind-borne tree limbs or bark coming into contact with, or vegetation falling onto, a NSP's network assets.
- weather, including flooding, high winds, lightning and insulator pollution (but excluding vegetation related outages)
- third parties, including vehicle impact with assets (such as with high loads), vandalism, sabotage, theft and single premises outages when the failure originated from the consumer's assets
- overloads, that is asset failure or protection operation caused by excessive, unforeseen or unaddressed energy demand
- switching and protection error, including incorrect protection settings and inadvertent trips caused by authorised persons
- unknown causes of outages
- other, including inter-network switching or connection errors, transmission failure, load shedding, emergency shutdowns at the direction of police, fire, ambulance or other related bodies.

C.6.2 Reasons for AER position

Need for disaggregated expenditure data

By better understanding the expenditure drivers, we intend to significantly improve our ability to examine and determine efficient expenditures for these opex categories through benchmarking and trend analysis.

For routine maintenance activities in particular, we expect the cost of performing maintenance, once normalised by the volume and type of assets, to be relatively comparable over time and across the NSPs. Non-routine and emergency response opex will be relatively less easy to examine using trend analysis. However, we expect our comparisons of these expenditures combined with using other information (including supply outages, asset age and condition) will help us better understand NSPs' actual and base year expenditures.

These comparisons will identify material differences between a NSP's historical costs and workloads, and with those of other NSPs, so we can better scrutinise specific expenditures. Further, in combination with other techniques, they will inform us about the relative efficiency of the NSPs' expenditure and the impact of uncontrollable factors.

Maintenance activities

We will require a breakdown of maintenance expenditure by work activities on asset types. These activities will be comparable across NSPs and based upon existing material differences in actions such as the repair and inspection of assets. These categories will also help our analysis of the NSPs' repair-or-replace decisions and will draw on similar information used in repex assessment including age, condition and fault data.

Expenditure categories

During consultation, stakeholders did not raise any concerns about our categorisation of DNSP opex into routine maintenance, non-routine maintenance and emergency response. However, they offered the following comments on maintenance expenditure:

- DNSPs noted that they do not collect expenditure data by asset types but by activity or work program.
- DNSPs asked us to clarify the definition of non-routine maintenance. They also noted a task can involve both routine and non-routine maintenance, but cost reporting may not be delineated.
- NSPs noted inspection cycles for equipment vary (in number of years), so it makes more sense to assess performance and expenditure over the full cycle, which could be longer than the regulatory year or control period.
- NSPs wanted to clarify the definitions of a fault and an asset failure. Further, because these are output measures, we should consider what the relevant service measures are.
- TNSPs asked us to clarify the difference between corrective maintenance and emergency response, adding that emergency response is a minor cost for transmission, compared with corrective maintenance.[674]

On emergency response, stakeholders made the following comments:

- NSPs do not currently collect measures of severity (by duration or number of customers affected).[675]
- NSPs have found it hard to collect accurate, consistent data on causes of faults (animals, weather or asset condition).
- Voltage levels do not appear to drive costs, although they do drive priorities. Costs are driven more by asset type than voltage.
- Data on faults due to asset failure by asset type may be difficult to obtain.
- In terms of normalisation factors, NSPs commented that some measures of outage severity may offset each other—for example, the installation of more reclosers in rural areas results in worsening momentary interruption (MAIFI[676]) but improving system interruption (SAIFI[677]).[678]

We have considered these comments in developing the final Guideline. In particular, some comments reflected concerns about the level of detail we anticipated to gather under the draft Guideline, namely maintenance and emergency response expenditure by the same asset categories as in the repex model. This level of detail is no longer contemplated and not contained in the final Guideline. Specifics of data requirements, including definitions of expenditures and activities, will be determined in developing regulatory information instruments that give effect to the Guideline.

674 AER, 'Meeting summary – Operating & maintenance expenditure', *Workshop 11: Category analysis work-stream – Opex (Transmission & Distribution)*, 11 April 2013, p. 4.

675 Although we note that these data are or should be collected for STPIS and related performance reporting.

676 Momentary average interruption frequency index.

677 System average interruption frequency index.

678 AER, 'Meeting summary – Operating & maintenance expenditure', *Workshop 11: Category analysis work-stream – Opex (Transmission & Distribution)*, 11 April 2013, p. 3.

Implementation issues

During consultation, stakeholders questioned the ability of NSPs to provide disaggregated data on repairs and maintenance costs when they outsource activities. The NSPs might contract out their maintenance works, for example, on a medium- to long-term basis. Contracts might also be based on a lump sum payment, unit rates of work performed, or a combination of the two. Further, a contract might cover the total NSP service area or be broken into separate contracts to facilitate competition and comparison.

The accuracy of the data that we request may be affected by the persistence of existing contracts under which NSPs are not provided this information. In this case, we will require NSPs to use best endeavours (with an assurance report) to comply with our information requests—for example, to provide details on how information was estimated. Once existing contracts expire, we expect new contracts will enable NSPs to collect more accurate data from their service providers.

C.7 Vegetation management expenditure

This section sets out our approach to assessing the vegetation management component of a NSP's opex. Vegetation management is the process of keeping trees and other vegetation clear of electricity lines to reduce related outages and the potential for fire starts. Vegetation management also includes clearing easements and access tracks associated with electrical assets. It is an important expenditure category because it can represent up to one-third of operating expenditures for many NSPs. It is also unique because most NSPs outsource their vegetation management work to contractors.

We and our consultants have primarily relied on the revealed cost approach when setting our own vegetation management opex forecasts in past determinations. We:

- reviewed NSP vegetation management programs and historical expenditures
- trended forward vegetation management costs from a base year, accounting for the expected growth in relevant drivers
- assessed NSPs' estimated volumes and unit costs in response to step changes in expenditure.

As well as the revealed cost approach, we have also on occasion:

- compared vegetation management workloads across NSPs.[679]
- identified drivers and reviewed strategy, legislation and contracts.[680]

We intend to review vegetation management on a more disaggregated basis in our upcoming expenditure assessments. We also intend to inform our vegetation management review with benchmarking and trend analysis.

C.7.1 AER position

To assess base year expenditures, and as part of related analysis in annual benchmarking reports, we will assess the efficiency of a NSP's vegetation management expenditures. This will occur with both overall expenditures for vegetation management as well as for component expenditure items. Our process in assessing these expenditures is likely to occur in the following manner:

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679 For example see: Nuttall Consulting, *Report – Principle technical advisor: Aurora distribution revenue review: Operating expenditure base-line: A report to the AER*, November 2011, p. 43.

680 For example see: Nuttall Consulting, *Report – Principle technical advisor: Aurora distribution revenue review: Operating expenditure base-line: A report to the AER*, November 2011, pp. 43–44.

- We will examine and assess the disaggregated data provided to us by the NSP and assess the breakup of costs and outcomes. This would include but is not limited to:
  - trend assessment—we would examine base year costs of vegetation management activities by trending forward prior years' expenditures. This would be applied to activities such as tree cutting, inspections and vegetation corridor clearing.
  - category benchmarking—we would compare unit costs and drivers for specific vegetation management activities (for example, cost per tree cutting, vegetation corridor clearing) across NSPs. We would evaluate a NSP's performance with comparable NSPs. We will conduct further assessment when our techniques indicate a significant difference in the costs or effectiveness of a NSP's vegetation management program.
  - assessing data on vegetation caused outages and fire starts to determine the effectiveness of NSPs' vegetation management programs.
  - using information collected on normalisation factors such as legislative requirements for qualitative assessment. If we identify differences in unit costs across NSPs, we will consider if the normalisation factors can account for the difference.
- We will consider technical reviews, governance reviews and material submitted for review by the NSP.

C.7.2 Reasons for AER position

Vegetation management can make up a substantial part of a NSP's total opex. We therefore consider it cost effective to disaggregate this category to improve our ability to assess these costs. We currently assess vegetation management expenditure at the aggregate level. We have not systematically assessed this expenditure at a disaggregated level in the past, reflecting the lack of standardised data. As a result, we do not have a thorough understanding of vegetation management costs and activities across NSPs.

We will continue to assess vegetation management expenditure as part of our overall base step trend approach to opex at the aggregate level. We may adjust base year opex where there is evidence of inefficiency, including with respect to the vegetation management component of total opex.

We consider applying trend assessment to specific vegetation management activities is useful, given their predictable and recurrent nature. Trending forward actual data on specific activities will provide us with a better understanding of the reasonableness of NSPs' base year expenditures.

Benchmarking costs at the activity level will indicate the relative efficiency of the NSP in conducting vegetation management works. This will be useful in addition to trend assessment because it will indicate the NSPs' historical efficiencies, and it will allow us to adjust a NSP's revenue allowance accordingly. We intend to benchmark a number of activities on a per kilometre of line basis. We consider this is an effective comparative measure because a per unit comparison—specifically, a per kilometre measure—will be simple to calculate. Such benchmarks are expected to form a solid basis for comparing like activities and various cost differences between NSPs, and hence will help us understand NSPs' individual operating environments.

If they do so already, NSPs should also classify expenditure and quantitative measures according to 'zones'. Classification by zone is intended to broadly reflect material differences in the type and growth rates of vegetation as well as legal obligations that do not affect the network uniformly. This is expected to be the case only for NSPs operating over larger geographic areas.

Data availability

An issue with collecting disaggregated vegetation management data is that NSPs may not actually collect a large proportion of the data themselves. Much of the data could only be obtained via contractors.

NSPs generally contract their vegetation management works on a medium to long term basis. The contracts may be based on a lump sum payment, by unit rates of work performed, or a combination of the two. The contract may cover the total NSP service area or be broken into a number of separate contracts to facilitate competition and comparison. As noted above, we expect NSPs to provide disaggregated information on vegetation management activities in accordance with the materiality of these expenditures. Where information is not available from contractors, NSPs will be required to provide their best estimates of cost and volume data, and to outline their methods of estimation. We expect that as contracts expire, NSPs will ensure new contracts provide for the collection and reporting of more accurate data.

C.8 Overheads

This section sets out our approach to assessing the overheads component of a NSP's expenditures. NSPs, in addition to building, repairing and replacing network infrastructure, also incur expenditure on planning and managing how they undertake these activities. Various terms refer to this planning/managing expenditure, such as overheads, shared costs, indirect costs or fixed costs.

We use the terms ‘overheads’ and ‘shared costs’ interchangeably to refer to planning and managing expenditure. These costs cannot be directly attributed to the provision of a particular category of services or activities, but are typically allocated across different service categories or activities. By contrast, ‘direct costs’ are those costs that can be directly attributed to the provision of a particular category of services or activities.

Overheads represent a significant proportion (up to one third) of total expenditures. They can be further distinguished into two types—'direct' and 'indirect' overheads. We use the term ‘direct overheads’ to refer to activities that arise in the delivery of direct costs or activities on the physical network that may be attributed to direct cost categories. The other category of overheads we refer to as ‘indirect overheads’, which are intended to reflect activities that do not arise or vary in proportion to direct network activities.

Direct overheads typically include network planning, design and network system operations. Corporate overhead costs typically include those for executive management, legal and secretariat, human resources, finance and other corporate support activities.

C.8.1 AER position

We will examine overheads—aggregated, unallocated and before capitalisation—separately and benchmark these against those of other NSPs, and may also consider comparable firms in other (non-energy) industries. We also propose to examine particular overheads categories by collecting information on likely cost drivers and other benchmarking metrics to identify trends and material differences in costs incurred by the NSPs.

Examples of these metrics include those related to the size of the network, as well as measures to capture explanatory variables and their proxies (including direct expenditures and employee numbers). We will also request NSPs to explain how different approaches to capitalisation, cost allocation and jurisdictional factors (for example, service classification) affect their reporting of overheads.

If we find any significant departure from the trend and/or benchmark, we will subject it to detailed review when setting efficient (base year) expenditure allowances in our regulatory determinations. We will also factor the results of this analysis into our annual benchmarking reports.

For network overheads, we will continue to require NSPs to report against almost all of their existing subcategories as per their internal accounting or in existing annual RINs.[681] Similarly, for corporate overheads, NSPs will have discretion to report against almost all of their already existing subcategories. As NSPs have different organisational and corporate support structures, these subcategories under corporate overheads will vary across NSPs. However, we expect these subcategories to be largely consistent and will also assess or benchmark direct and corporate overheads as a group.

To the extent overheads are expensed, our consideration of overheads expenditure will be in the context of our overall opex assessment approach, including the assessment of efficient base year opex expenditure (section 5.3). Where overheads are capitalised, we will assess how overheads have been factored into the NSP's proposed capex forecasts and the need for a consistent treatment of expenditures across capex and opex.

Data specifications affecting direct cost categories - input and allocated costs

We will require NSPs to report costs for direct cost categories (e.g. repex, augex, routine maintenance, etc.) into direct labour, direct materials, and contract/outsourced costs. This should exclude allocated network overhead and corporate overhead. Because differences in NSPs' cost allocation methods and capitalisation policies affect the comparability of expenditure, we will compare direct costs only.

Reporting of input costs as well as any allocated costs should be in accordance with the NSP's capitalisation policies and cost allocation methods. Allocations should be reconcilable across direct cost categories as well as across business units where a NSP is involved in providing unregulated services. We will be seeking information to have visibility of these reconciliations to statutory accounts.

This information will be used to examine the materiality of differences in NSPs' corporate structures, policies and major contractual arrangements. Where NSPs are unable to provide disaggregated information on these input and allocated costs, they will be required to make best estimates of these costs, and explain why these estimates are reasonable and transparent.

C.8.2 Reasons for AER position

We intend to significantly improve our ability to examine and determine efficient overhead expenditures through benchmarking and trend analysis, with improved understanding of expenditure drivers.

By assessing network overhead and corporate overhead separately, we can compare these expenditures over time and across NSPs. Comparisons of these expenditures against supporting information—including cost allocation methods, capitalisation policies, service classifications and any outsourcing arrangements—will help us better understand NSPs' actual and forecast expenditures, and to scrutinise specific expenditures. Further, these comparisons will help us better understand the relative efficiency of a NSP's expenditure and the impact of uncontrollable factors.

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681 We anticipate prescribing several expenditure subcategories for Network Overheads and Corporate Overheads for both DNSPs and TNSPs to assist the AER in assessing comparable expenditures.

In addition to improving our understanding of overhead costs, the separate identification of these overhead costs from direct expenditure categories (such as repex, augex, routine maintenance) will better enable us to robustly assess those direct expenditure categories across NSPs. That is, the impact of NSPs' overheads allocation (and capitalisation) policies may be significant, and comparing direct expenditure without allocated overheads would ensure these policies do not detract from like for like comparisons across NSPs. Overheads (properly scaled for network size, etc.) will be assessed and benchmarked separately from direct costs.

We consider the benefits of our approach and the data required will outweigh the associated cost. The separate reporting of overheads costs will result in minimal burden on the NSPs. NSPs currently report overhead expenditures similar to the categories outlined above, and they should be able to identify costs from their existing reporting systems to align with any new, standardised overhead categories.[682] The benefits of our approach are likely to be substantial because we have not systematically assessed overhead costs in such a way before, and the separation of overheads from other direct expenditures will be necessary to effectively benchmark those direct expenditures.

Impact of cost allocation methods

The NSPs' different approaches to cost allocation are a source of incomparability in benchmarks. Some NSPs fully allocate their overhead costs to activities or by cost drivers, reporting items such as head office costs against categories such as asset augmentation and replacement. But other NSPs allocate costs by different methods or cost allocators.

During consultation, stakeholders noted:

- general support for separate reporting of overheads and, due to the NSPs' different cost allocation methods, for assessing overheads at an aggregate level before allocation and capitalisation.
- the inclusion of overheads in expenditure categories, and NSPs' different methods to allocate overheads, may adversely impact the AER's ability to benchmark expenditures
- there may be issues in assessing overheads at an aggregate level and also without an understanding of the different corporate structures or services provided by each NSP.

Reflecting on views expressed in consultation, we expect NSPs will maintain different cost allocation approaches in accordance with the NER and other accounting principles. Prescribing a standard cost allocation policy or method across all NSPs is unlikely to be feasible or achieve our objectives of comparability in data. Our approach to accounting for different cost allocation methods is to benchmark capex and opex direct costs only, and to separately benchmark unallocated overhead costs, which is intended to avoid problems associated with different approaches to cost allocation.

Issues around cost allocation may also affect direct costs (particularly labour)—for example, the use of work crews who complete multiple projects but whose time was not directly recorded against each project. This problem is similar for capitalisation policies (see below). NSPs have to document their processes and methods of estimating the allocation of historical data. Our approach to dealing with this issue is to obtain sufficient detail from NSPs on how they allocate such costs and prepare estimates more broadly. In particular, we will require NSPs to provide enough detail regarding these allocation issues to allow us to assess expenditure consistently across NSPs. These required details

[682] As previously mentioned, there are likely to be some prescribed (standardised) subcategories for Network Overheads and Corporate Overheads to assist the AER in assessing comparable expenditures.

will be stated in instructions to RINs, including the requirement to submit 'bases of preparation' and supporting information that are already required for auditing purposes.

Capitalisation policies

A NSP's capitalisation policy is its policy of reporting certain costs as capex or opex. As with cost allocation policies, these decisions of a NSP to classify costs in a certain way potentially detract from benchmarking comparisons. During consultation, NSPs questioned our intent on examining capitalisation policies, particularly whether it is related to ex post reviews of the RAB or to our benchmarking. They noted limited instances of changes to capitalisation policies mid-period that would warrant a reconsideration of RAB values. Further, the issue of capitalisation policies in the context of the ex-post review process is addressed by our separate Capital Expenditure Incentives Guideline.

Visibility of how capitalisation policies affect reported capex would be useful if they changed mid-period (in reflection of RAB issues). However, the more material issue for benchmarking is how capitalisation policies differ across NSPs at any time, and the extent to which the differences affect robust comparisons of direct costs. Our proposed solution is similar to our approach to assessing cost allocation policies. That is, we will require full visibility of the impact of different capitalisation policies at the detailed level across all cost categories. We will seek visibility on instances where NSPs capitalise or expense particular activities in our overheads reporting templates

Finally, we note the TNSP information guidelines require a recasting of historical expenditure data in regulatory proposals if capitalisation policies are changed. We will give effect to this requirement for all NSPs under the new Guideline and in RINs. That is, if a NSP changes its capitalisation policy, we will require it to identify how such a change affects any historical data on which we rely for category assessment (this is in addition to capex as it relates to the RAB provisions under the NER and our Capital Expenditure Incentives Guideline).

Input cost data

We will require NSPs to disaggregate cost categories into direct labour, direct materials and contracts (both with related and unrelated parties) while separately capturing network overhead and corporate overheads. This disaggregation serves multiple purposes:

- we will better understand expenditure drivers, because labour, materials and other inputs are each influenced by different factors that are controllable and uncontrollable by the NSP
- it will provide visibility on the extent to which NSPs are incurring more or less of a specific input cost which may indicate more efficient practices
- it will illustrate the scope of major contracts in covering various aspects of service delivery
- costs and other payments to related parties will be transparently identified and therefore assessable under our proposed approach (see section 5.1.2)
- it will be useful in considering the methods applied to account for input price escalators and how these should differ across NSPs and over time.

We will also request further disaggregation of labour costs to identify aspects such as overtime and skill levels which will be useful in examining different labour management practices and related efficiencies across NSPs.

D Summary of stakeholder submissions

Table D.1 Summary of submissions on our draft guidelines and explanatory statement

Issue	Respondent	Comments
General comments		
Role/objective of the Guidelines	ENA, Energex, Ergon, Vic DNSPs	The ENA considers the primary role of the Guidelines is to set out the AER's proposed approach to assessing forecasts of capex and opex contained in a NSP's regulatory proposal, and the information the AER requires to undertake the assessment. It is not to set out how a NSP must build up its forecasts to satisfy the requirements of the NER (pp. 1, 5). Energex considers the draft Guideline extends beyond the AER's assessment role into establishing requirements for a DNSP's forecasting methodology (including base-step-trend, specific step changes and productivity changes for opex) (pp. 1–2). Ergon is of the view that the application of the Guideline is to frame how the AER will assess and NSP's forecasts, not frame the preparation of its own substitute forecasts (pp. 3–4). Ergon comments that the AER is not empowered to use these Guidelines to dictate to a DNSP the manner in which an opex or capex forecast can be produced (pp. 4). The Vic DNSPs consider the objective of the Guideline should be to provide DNSPs with greater guidance on how the AER will assess their expenditure proposals, rather than to prescribe the basis on which they should prepare their forecasts (p. 1–3).
Content of Guidelines and Explanatory Statement	ENA, Energex, PIAC, AEMO, NSWIC, Vic DNSPs, Grid Australia	The ENA considers that substantive content about the AER's assessment approach should be contained in the Guidelines, not the Explanatory Statement. The Guidelines should be sufficiently detailed so they can be read as free standing documents (pp. 1, 28–29). Energex considers the Guidelines would benefit from the inclusion of the principles contained in the Explanatory Statement to choosing expenditure assessment techniques (p. 3). The Public Interest Advocacy Centre (PIAC) supports the AER's approach to separating the Guideline from the Explanatory Statement because it greatly assists stakeholders in understanding the AER's expectations for future economic determinations (pp. 3–4). AEMO considers the draft Guidelines strike an appropriate balance between certainty and flexibility. While NSPs value the opportunity to understand how the information they submit will be assessed, the AER should not commit to a detailed assessment methodology before the relevant issues are understood (p. 3). The New South Wales Irrigators Council (NSWIC) considers the lack of discernible difference between the proposed Guidelines and what the AER has applied in recent determinations is a concern. NSWIC considers that recent considerable increases in network charges mean that that the current framework needs significant change, which the proposed Guidelines are not indicating (p. 2). The Vic DNSPs submit the scope of the Guidelines should be refined, so that it provides greater clarity on the approach and techniques the AER intends to apply in the next round of distribution determinations, as opposed to those that may be applied at some point in the

		future (p. 1). The Vic DNSPs submit that if the AER focuses on developing assessment techniques that have limited application today, it will not fulfil its obligations under clause 6.4.5 of the NER and the Guideline will be inconsistent with the intent of the AEMC and the AER's stated intention of providing regulatory certainty (p. 3). In this context, the Draft Guideline still refers to techniques that are incapable of current use, for example the economic benchmarking techniques in chapter 3. The Guideline should be limited to techniques capable of being employed in the upcoming round of determinations. The Guidelines could be amended at the end of the current round of determinations in mid-2018 if it has been established that other techniques are capable of satisfying the principles (p. 3). The Vic DNSPs submit that the Draft Guideline suggests the economic benchmarking techniques could be employed now and that DNSPs should prepare their regulatory proposals accordingly, despite the AER acknowledging in the Explanatory Statement that is it unlikely these techniques will be relied on in the short run. This makes the Draft Guideline quite misleading and has the potential to create a significant amount of regulatory uncertainty and additional work for DNSPs as they prepare for their upcoming regulatory reviews (p. 3). The Vic DNSPs consider the Guideline should distinguish between techniques that are capable of being applied in the upcoming round of determinations and those that may be used in subsequent rounds where it is established they satisfy the assessment principles (p. 4). The Vic DNSPs consider that the Guideline should be able to operate on a stand-alone basis relative to the Explanatory Statement and incorporate any principles or criteria the AER intends to apply when assessing expenditure proposals (p. 2). Grid Australia submits that for the EFA Guideline to achieve its intended purpose, significantly more detail is required on the AER's expected approach to assessing forecast expenditure proposals and the application of related assessment techniques. Much of the material in the Explanatory Statement would be better promoted into the Guideline itself. There is also a need for the AER to set out its approach on some matters that are not presently addressed in either document (pp. 4–6).
Guideline revision	ENA, Vic DNSPs, SP AusNet	The ENA submits that the AER should set a five year term for the new Guidelines and formally review them before renewing them (pp. 3, 30). The Vic DNSPs consider that the AER should adopt a five year term for the new Guidelines (p3). SP AusNet suggests the AER provide an indication of when the Guideline may be subject to revision. SP AusNet adds that a planned review of the Guideline after a number of reviews would allow stakeholders to log their experiences and take a balanced view on how the Guideline may be improved. SP AusNet considers that this will promote a more stable and predictable regulatory regime (p. 4).
Separate Guidelines for transmission	Grid Australia	Grid Australia supports a TNSP specific Guideline. However, the current Guideline does not recognise the necessary differences in approach that exist between transmission and distribution. For example, the limited sample size given the small number of TNSPs in the NEM and their large and lumpy investment profile suggests that specific expert project reviews have a far more significant role than for distribution. A TNSP specific Guideline provides an opportunity for this to be set out in a transparent manner (p. 6).
General comments	Cotton Australia,	Cotton Australia provided a letter of support to the Canegrowers submission, as joint members of the National Farmers Federation and the Queensland Farmers Federation. Cotton Australia emphasise that the cotton growers and ginners have high reliance on electricity

	ECC	as an energy source and have been impacted significantly by the doubling of electricity prices over the past decade. Cotton Australia welcomes responses from the AER to the issues raised by the Canegrowers (p. 1). The Ethnic Communities Council of NSW (ECC) provided a letter of support to the position taken by the NSW Public Interest Advocacy Centre (PIAC) on the Expenditure Forecast Assessment Guidelines (pp. 1–2).
Guideline drafting	Vic DNSPs	The Vic DNSPs have identified a number of drafting issues associated with chapter 6 of the Draft Guidelines and suggested minor revisions, including clarifying regulatory as well as legal obligations, and providing clarity where the Guidelines request historic data (p. 21)
Interaction with incentive arrangements	MEU, COSBOA, APA, CP/PC/SAPN	The Major Energy Users (MEU) is concerned about the underlying incentives in the rules which have the potential to reduce (even overwhelm) the effectiveness of the explicit incentive programs. Whilst the EBSS probably assists in taking opex to the efficient frontier, the MEU is very concerned that the CESS will be effectively overwhelmed by the underlying incentive to overspend provided by the WACC differential. The MEU considers that a reliance on the explicit incentive programs to provide strong guidance for setting future expenditure needs more careful consideration than the AER applied in the Explanatory Statement on expenditure assessments (p. 21). The Council of Small Business Australia (COSBOA) notes the Explanatory Statement's discussion on how different assessment techniques can impact on the incentives NSPs face to improve costs. COSBOA points out that, even with exogenous forecasts (such as benchmarking), the application of benefit sharing would still provide an incentive for NSPs to outperform forecasts, as they would retain any savings they make before having to share them with consumers, particularly if expenditures are set on the basis of an efficiency frontier that is less than the most efficient NSP. As the objective is to improve the efficient costs of an NSP by having it move closer to the frontier, it is appropriate that it be provided with incentives to reach it. In addition, consumers would benefit from the more efficient costs of the NSP. Moreover, given the problems associated with application of the revealed costs approach and COSBOA's doubts about whether that technique will actually reveal the efficient costs, COSBOA doubts whether the benefits consumers are sharing in are real (p. 20). APA submits that it is concerned with how the AER would determine that a business was not responding to incentives, or that the forecast was inaccurate. In respect of responding to incentives, APA does not consider that the AER has adequately addressed concerns raised already in the consultation process as to how to differentiate between (i) a business that is not responding to an incentive, and (ii) a business that is not able to reduce costs in line with the AER’s expectation of efficient costs because the AER’s expectation is incorrect. In respect of inaccurate forecasts, APA is concerned that the AER will create an asymmetry in forecasting risk for regulated businesses. APA argues that the AER is suggesting that only those forecasts that turn out to be above efficient costs will be adjusted, and that this creates an unacceptable asymmetric risk on businesses that inevitable forecasting errors will lead to one-sided adjustments to future costs to claw back forecasting gains, without matching adjustments to allow recovery of forecasting losses. APA considers that the AER’s suggested adjustments would be inconsistent is (sic) incentive regulation, and ought not to be pursued in the Final Guideline (pp. 2–3). CP/PC/SAPN submit that they are concerned the Draft Guideline do not acknowledge the role of the incentive framework for driving costs and noted they have made numerous submissions on the inherent weaknesses of economic benchmarking, particularly its inability to adequately account for uncontrollable differences between NSPs which make it an inappropriate tool for deterministic application (p. 10).

		CP/PC/SAPN submit that an examination of a bottom up build is a step away from incentive based regulation. The Guideline should acknowledge and take account of the incentives created by the EBSS (pp. 3, 9). CP/PC/SAPN submit that in the context of the use of the AER using economic benchmarking to determine if NSPs are responding to the EBSS incentives, they do not consider economic benchmarking appropriate for making judgements on why NSPs are making particular decisions (p. 10).
Legislative requirements		
NEO and revenue and pricing principles	ENA, ActewAGL, PIAC	The ENA submits that it is inappropriate to use the term 'minimum costs' in the Guidelines and Explanatory Statement, emphasising the particular importance of section 7A(2) of the NEL, which states that NSPs should be provided with a reasonable opportunity to recover at least efficient costs. The AER should avoid cherry picking results of particular assessment techniques that give a 'minimum cost' because selective use of information may deliver outcomes that reflect less than genuinely efficient costs (pp. 2, 13–14). ActewAGL submits the draft Guidelines and Explanatory Statement should remove references to the AER determining revenues based on ‘minimum costs’. Rather, the basis should be ‘efficient costs’ and ‘reasonableness of a NSP’s proposal’ when assessed against the expenditure objectives (pp. 2–3). PIAC supports the explicit confirmation by the AER that the NEO is the overarching objective of the regulation of the NSPs and, therefore, the AER’s economic regulatory functions are directed at meeting the long-term interests of electricity consumers (pp. 4, 7). PIAC considers that too often the emphasis has been on the Revenue and Pricing principles, which taken alone can draw the attention to the compensation of investors rather than the long-term interests of consumers. PIAC has no issue with the role of economic regulation in encouraging and rewarding efficient investment in the electricity network but providing a fair compensation to investors is the means to the end, not the end in itself (p. 7). PIAC agrees that the revenue and pricing principles support the NEO by providing a framework for determining efficient investment. It is assisted in this by both the incentive-based regulatory framework and by the NER, which sets out specific requirements for the AER to make a determination on an NSP’s expenditure proposal in accordance with the NEL and hence to give effect to the NEO (p. 7).
Emulating effective competitive markets	PIAC	PIAC supports the AER's understanding that a fundamental purpose of the regulatory regime expressed in the NEO is to ‘emulate effective competitive markets’ (pp. 4, 12–13). PIAC considers that by highlighting the requirement to emulate effective competitive markets, the AER is also highlighting three important elements of the regulator’s responsibility in assessing expenditure proposals by the NSPs: the AER’s approach to assessing the ‘base’ year for the expenditure allowances must be rigorous and based on setting allowances that reflect the best available methodologies and other indicators of efficient and prudent expenditure; forecasts of both unit costs and demand growth for standard network services must be fully tested against both historical trends and updated market data; and the approach should build in the expectation that there will be ongoing innovation and that productivity improvements will be expected from the NSPs—reference to international best practice benchmarks will assist this process (pp. 12–13).

Assessment approach		
Primacy of the NER	ENA, Energex, Vic DNSPs, SP AusNet	The ENA submits that the Guidelines introduce inappropriate 'quasi-rules' that undermine the primacy of the NER. The AER should amend the Guidelines and Explanatory Statement to clarify specifically how the assessment principles, techniques and information requirements will be used to assess whether a NSP's proposal reasonably reflects the expenditure criteria (pp. 2, 6–7, 20). Energex notes that the NER (cl. 6.4.5) prescribe that in Guidelines the AER is to specify its assessment approach to capex and opex forecasts (p. 2). The Vic DNSPs submit the Guideline should clarify the NER should have primacy in the assessment of a DNSPs expenditure proposal (p. 4). SP AusNet raised a concern as to whether the AER has appropriately scoped the EFA Guideline. In particular, SP AusNet stresses that the AER not confuse the task of assessing the NSP's expenditure forecasts with the task of setting a substitute forecast. SP AusNet considers that drafting changes be made to the Guideline to clarify the AER's assessment approach against the NER criteria rather than focusing on how NSPs should forecast expenditure to facilitate the AER's development of a substitute forecast (p. 3).
Detail of AER assessment approach	ENA, Energex, PIAC, ActewAGL, NSW DNSPs	The ENA considers the Guidelines and Explanatory Statement should clarify the AER's assessment approach and specify a process the AER will follow, rather than the assessment techniques it will or may apply (pp. 2, 7–8). Energex considers the AER has prescribed or pre-determined forecasting methods in the Guidelines which contradicts the NEL. Energex seek clarification regarding the AER’s interpretation of clause 6.9.1 (p. 2). PIAC supports the AER's general assessment approach and accords with the intentions expressed by the AEMC in its Final Position Paper and the amended NER (p. 7). PIAC agrees that the AER can use multiple sources of information, forecasting approaches and other methods, to assess, amend or replace a NSP’s proposal in a flexible manner and at its own discretion (pp. 4, 9). PIAC considers that the proposed regulatory process is still essentially in the form of a 'propose-respond' model but the AER now has the discretion to respond in a more critical fashion and is less constrained by the form of the NSP's proposal (p. 9). ActewAGL submits the Draft Guidelines and Explanatory Statement should clarify how the AER will use the assessment principles, techniques and information requirements to assess whether the NSP’s forecasts reflect the expenditure criteria, and should clarify the process the AER intends to follow in assessing expenditure forecasts (p. 1). The NSW DNSPs consider the Draft Guidelines provide limited guidance on how the AER would apply its assessment tools to make its constituent decisions under clause 6.5.6 and 6.5.7 of the Rules. They are concerned by statements that suggest the AER will use its tools in a deterministic way without considering the DNSP’s regulatory proposal (p. 4). The NSW DNSPs suggest the AER methodically outline the principles underlying its assessment approach, and how these relate to marking its decision consistent with Clause 6.5.6 and 6.5.7 of the Rules. The AER should consider the AEMC’s policy guidance (p. 4).
The NSP's proposal as the starting	ENA, NSW DNSPs, ActewAGL, Grid	The ENA submits that the Guidelines and Explanatory Statement should acknowledge that the NSP's proposal is the procedural starting point for determining an expenditure allowance and that the NSP's proposal will, in most cases be the most significant input into the

point	Australia, Vic DNSPs	AER's decision (pp. 2, 8–10). The NSW DNSPs consider that the AER should not form a baseline estimate to reject the proposed opex of a DNSP. Rather, the AER must assess the forecast method proposed by a DNSP, and undertake further review of a DNSP's proposal to assess whether there is a deficiency in the forecast (p. 6). ActewAGL submits the Draft Guidelines and Explanatory Statement should make it clear, consistent with the Rules, that the AER will use the NSP's proposal as the procedural starting point to determine an expenditure allowance, and that this proposal will in most cases be the most significant input into the AER's decision (p. 2). Grid Australia submits that the Rules require that the starting point for assessing expenditure forecasts must be a TNSP's revenue proposal. The Explanatory Statement and Guideline, however, disproportionately focus on the derivation of the AER's own estimate of efficient costs. Both the AER's and the TNSP's estimate may be reasonable in accordance with the Rules, therefore, the task for the AER is to demonstrate how it will justify its decisions by reference to the revenue proposal (pp. 12–13). The Vic DNSPs submit that the Guideline should clarify the NSPs proposal is the starting point for any expenditure assessment (p. 4).
NSP's forecasting methodology	ENA, NSW DNSPs	The ENA considers the Guidelines should acknowledge that it is open to NSPs use the expenditure forecasting methodologies they consider appropriate and not impose any constraints on how NSPs prepare their forecasts (pp. 2, 11–13). The NSW DNSPs note that the Rules do not prescribe a method that a DNSP must use to develop expenditure forecasts, therefore they are concerned that the AER indicates they prefer DNSPs use the base, step, trend approach to forecast opex. DNSPs should be free to put forward a forecast approach that is fit for purpose (p. 6). The NSW DNSPs are concerned with the proposal that the AER may reject a DNSP's proposed expenditure if it is higher than the AER's counterfactual estimate, unless the DNSP can satisfactorily explain the differences. They consider this approach does not properly consider the Rules framework, which requires the AER use the DNSP's proposal as the starting point for its assessment (p. 1).
Consideration of NSPs' circumstances	ENA, ActewAGL	The ENA considers the Draft Guidelines and Explanatory Statement do not adequately acknowledge that the AER will consider the circumstances of NSPs (pp. 2, 14–15). ActewAGL submits the Draft Guidelines and Explanatory Statement should be amended to require the AER to consider the individual circumstances of NSPs in assessing their expenditure proposals and, further, for the AER to make explicit how its assessment has done so, giving effect to the first expenditure criterion (p. 3).
The AER's role in expenditure forecast assessment	PIAC, Vic DNSPs, CP/PC/SAPN	PIAC agrees that the AER's role is to set expenditure allowances on the basis of the reasonable costs of an efficient and prudent operator providing network services rather than a specific NSP. The recent amendments to the Rules allow the AER to exercise its discretion to achieve outcomes that represent a better balance between the interests of investors and consumers in line with the policy intentions captured in the NEO (pp. 4, 7–9). The Vic DNSPs submit that the Guideline should clarify that the role of the AER is to assess a DNSP's expenditure proposal and not to prescribe how a DNSP must forecast expenditure (p. 4). CP/PC/SAPN submit that the role of the AER is to assess if a DNSP's expenditure proposal meets the expenditure criteria and not to develop an alternative forecast. They submit the language in the Draft Guideline implies the AER has the power to mandate how a

		DNSP must forecast expenditure and it is the AER rather than the DNSP that is responsible for developing expenditure forecasts. The AER should consider re-framing the Guideline whereby the AER's approach is set out in the context of how it will go about assessing the NSP's expenditure forecasts, not how it intends to develop the NSP's expenditure forecasts (pp. 3–4).
Transitioning to new regulatory regime	PIAC, COSBOA	PIAC strongly supports the AER's very clear confirmation in the Draft Guideline that the AER will not adopt a transitional approach to expenditure allowances in the event that a NSP's current expenditure performance is significantly inferior to the efficient expenditure of an efficient benchmark service provider. PIAC agrees that the AER must be satisfied that the allowed capital and operating expenditure reasonably reflects the efficient costs of a prudent operator (not the NSP in question) (pp. 5–6, 13–14). PIAC notes that effective competitive markets do not provide for comfortable transition periods and it is the business and their owners who must absorb the financial risks of relative inefficiency rather than consumers (pp. 6, 13–14). COSBOA stated it is widely recognised and accepted that allowances provided to NSPs in past AER Determinations have been demonstrably inflated (inefficient) and it would be unacceptable to small business that this should continue, including through providing NSPs with transition periods to make the efficiency savings (p. 6).
Prudency premium, cost estimation risk factor, demand forecasting errors	PIAC, MEU, COSBOA, Canegrowers, NSWIC	PIAC supports the AER's rejection of adding additional risk premiums in NSPs' expenditure proposals, as these compound in their effect across categories of expenditure—risk should be borne by the party best placed to manage the risk, which is generally not consumers (pp. 4, 14–15). The MEU noted the AER expounds considerably on the cost estimation risks faced by TNSPs and proposes to allow the TNSPs some latitude in assessing the cost estimation risk allowance. The MEU accepts there are increased risks when there is a limited historical data to develop costs and longer lead times for project completion, but considers this risk is overstated by NSPs. The MEU considers the AER's proposed process is too lax and has the potential for TNSPs to propose solutions that appear efficient when assessed by the RIT but then allows the TNSP to spend more than the cost to provide the preferred solution in the RIT (pp. 16–17). COSBOA agrees with the AER's rejection of adding additional risk premiums in NSPs' expenditure proposals, noting NSPs, not consumers, are best placed to manage risks. COSBOA considers it will be important for the AER to find more objective and verifiable ways to deal with TNSP cost estimation risks. The application of a meaningful CESS may help but the application of benchmarking techniques will still be necessary to limit such risks. COSBOA encourages the AER and AEMO to pursue the development of a 'price book' of project cost components for benchmarking (pp. 6, 10). Canegrowers consider it is not appropriate to charge consumers a further premium on prices for NSP forecasting failures, as the weighted average cost of capital compensates NSPs for non-diversifiable risk. Canegrowers support the use of annual benchmarking reports to be used throughout the regulatory period to assess expenditure proposals against annually revised demand forecasts and accordingly, to account for step-changes (up or down) in expenditure. This would protect consumers from paying for forecasting errors on behalf of NSPs (p. 6). Canegrowers consider that in past regulatory determinations, Queensland NSPs developed demand forecasts with large and persisting forecasting errors. To maintain the regulated revenue stream, prices have had to make up the short-fall in allowed revenue. Under a revenue cap, reduced demand perversely increases prices, and higher prices further reduces demand and a negative cycle begins. The AER must acknowledge and take steps to correct this negative price cycle as a matter of urgency (p. 5). NSWIC is concerned that the Draft Guidelines allocate the majority of the demand forecasting risk to consumers. NSWIC believes this

		contradicts the AERs instruction that the Guidelines be aligned with the long term interests of consumers (p. 4).
First pass approach	PIAC, CP/PC/SAPN	PIAC considers emphasis on the high-level first pass techniques is consistent with an incentive based approach to the economic regulation of NSPs, particularly as it effectively (and, in PIAC's view, appropriately) rewards a NSP whose initial forecasts of expenditures are reasonably efficient. However, NSPs should not restrict the AER from conducting more detailed investigation of expenditure proposals even if they 'pass' the first pass stage (p. 11). CP/PC/SAPN submit that the AER should consider giving the first pass assessment a stronger role in the Guideline and provide clear guidance on how this process would work within the decision making criteria as described by CP/PC/SAPN (p5).
Forecasting	PIAC	PIAC supports the AER's commitment to improved forecasting methodologies for demand and expenditures – PIAC considers that improved forecasting by both the NSPs and the AER will underpin the effectiveness of the expenditure assessment process and also the regulatory incentive schemes (pp. 5, 17–18). PIAC considers strong statements about the new standards expected from NSPs forecasts (such as 'without adequate economic justification, we are unlikely to determine forecast expenditure is efficient and prudent') should be included in the Guidelines (p. 18).
Related party margins	PIAC, COSBOA	PIAC approves of the AER's systematic approach to assessing the expenditures embedded in related party contracts. However, PIAC considers that: the AER's approach to related party contracts should exist in the Guidelines the AER's approach raises problems of managing confidentiality of expenditure data and access to this by consumers the AER should not assume that an outsourced contract price is likely to be a good proxy for the competitive market price if the outsourced services were subject to a competitive tender process. The AER should apply benchmarking techniques to such service contracts unless it can be demonstrated that pricing is truly competitive and consumers are sharing appropriately in the economic benefits of outsourcing claimed by NSPs (pp. 5, 19–20). PIAC requests the AER consider some additional matters when assessing costs from related parties or other service providers: The AER's approach to assessing these costs should not be so onerous as to limit the ability of NSPs to adopt flexible and prudent economic practices It would be in the long term interests of consumers if NSPs could adopt more flexible operational arrangements in order to limit the overhang of fixed costs driving prices up further in the event of declining demand. Using related party service providers may be able to offset fixed costs by providing network services to other NSPs in the group or to third parties (pp. 19–20). COSBOA noted concerns that tenders and tender processes can contain flaws and omissions which provide an opening to inflate costs. COSBOA also noted the AER's response that it believes the contract price provides a good proxy for the competitive market price, but that it will "conduct further examination" if it believes the tender process was deficient. However, it may not be apparent to the AER that the tender price was not a good proxy or that there were deficiencies. COSBOA would prefer that the AER further investigate the scope to apply benchmarking techniques to related party margins (p. 6).

Assessment techniques		
Use of assessment techniques	EUAA, MEU, Vic DNSPs, Uniting Care Australia, PIAC, CP/PC/SAPN	The Energy Users Association of Australia (EUAA) support the use of the AER's Repex and Augex models and its approach to benchmarking productivity. The EUAA also supports leaving the precise approach relatively open, with room to move in the application and use of these methodologies (p. 1). MEU considers that the introduction of benchmarking and predictive assessment programs (such as the repex and augex models) will enhance the AER's ability to identify what might be efficient expenditure. Benchmarking will also provide a high level indication on the relative efficiencies of each NSP (pp. 5, 17). MEU notes the AER's proposal to use the revealed cost approach as its primary tool to set allowances. MEU recognise that the revealed cost approach needs to be used in the short term due to the absence of an adequate dataset, but as the other tools become more refined and there is a better dataset, MEU consider that the new tools should have greater standing in the analysis and setting of expenditure claims (p. 8, 10–11). The Vic DNSPs submit that when determining if a technique should be applied, the AER should consider: the time it is expected to take to collect and validate data, develop and test models, and demonstrate the models satisfy the assessment principles set out by the ENA (p. 4); and if the data collations and validation and model development and testing will be completed in advance of the DNSPs being required to notify the AER of their expenditure forecast methodologies (p. 4). Uniting Care supports the AER's ability to utilise a range of assessment techniques (p. 3). PIAC generally supports the AER applying discretion to use a variety of techniques and the reliance placed on them depending on the nature of the NSP's expenditure proposal and the robustness of the techniques. PIAC considers the AER should not confine the tools it uses in future determinations by being too specific in the application of assessment techniques set out in the Guidelines (pp. 9-10). PIAC considers it is essential that the techniques actually complement, rather than duplicate, each other. If the AER adds additional techniques, this will not necessarily improve the final answer, but muddy the waters if it is not clear how they are complementary (pp. 10–11). PIAC notes that too much emphasis on the high-level economic benchmarks opens the door for claims by NSPs that the comparisons are not valid as the AER has failed to recognise the different exogenous circumstances, but too much focus on the categories and sub-categories creates the risk that the AER (and consumers) will become lost in the esoteric details of the network businesses operations. Aggregated category benchmarking provides a useful middle ground. The regulatory art will be to apply the right balance (pp. 15-16). PIAC supports the AER's decision to proceed vigorously with the early introduction of both high-level economic benchmarking and category benchmarking, albeit acknowledging that the use of benchmarking should be subject to the AER's discretion and take into account the limitations of data and modelling capabilities (pp. 4, 15–16). CP/PC/SAPN consider that to mitigate the risk and perception of cherry picking, the AER should: look for consensus across multiple techniques

		apply the same assessment techniques in similar circumstances apply techniques in a way that will produce stable results through time (p. 5). CP/PC/SAPN consider the choice of techniques and their application should be resolved first by reference to the NER (p. 5).
Weighting of techniques	ENA, Vic DNSPs, CP/PC/SAPN	The ENA submit that (when multiple techniques can be used) assessment techniques should be weighted by non-numeric factors (acceptance, technique limitations, data limitations, corroboration, accommodating NSPs' differences, accommodating exogenous events) to find 'consensus' results across multiple techniques rather than an 'outlier' produced by a particular technique (pp. 3, 27). The Vic DNSPs agree with the ENA's submission on weighting of techniques when multiple techniques can be used (pp. 13–14). CP/PC/SAPN submit that the Guidelines include decision making criteria to indicate which technique will be applied in a given circumstance, including detailing the circumstances when each method will be used, the data and analysis required, how methods will be used and the weighting that would be used. This will allow CP/PC/SAPN to understand the AER's approach and would afford NSPs procedural fairness (pp. 3–4).
Cost benefit analysis	PIAC, MEU, NSW DNSPs, Uniting Care Australia	PIAC supports the better use and enforcement of cost-benefit analysis, particularly for larger projects, given the gaps observed by PIAC in some previous NSPs' proposals and the AER's determinations (pp. 5, 16–17). The MEU agree with the AER's past consideration that prudency does not necessarily lead to efficiency. Prudency implies that investment is required to ensure an improved outcome for consumers, but efficiency identifies if there is a net benefit - that the benefits of the investment more than offset its costs. The MEU consider there is a need to tie the RIT to the actual costs incurred to ensure that there has not been inefficient investment made. The AER should require the NSP to report to the AER the actual costs of the project compared to the RIT allowance and to advise on any cost variances (and reasons) at the time the project is complete. This would provide the AER with a track record of a NSP's actual RIT development performance as well as the basis for any ex post investigation as to inefficient investment (pp. 15–16). The NSW DNSPs suggest that the AER publish any cost benefit and/or options analysis conducted for the implementation of the new assessment methods. They would be particularly interested to see if a staggered process in collecting information is beneficial in terms of lower costs and better quality information (p. 12). Uniting Care submits that the additional burden that the Guideline puts on network businesses is of relatively minor cost and of great benefit to the regulatory process, efficiency of the market and the long term interests of consumers (p. 4).
Process reviews	COSBOA	COSBOA has limited faith in the ability of methodology reviews, and governance and policy reviews to determine efficient expenditure by NSPs. Such reviews are about processes which may or may not be followed exactly and may or may not impact on NSPs' expenditure decisions. COSBOA considers that such reviews should only be used when necessary (p. 15).
Assessment principles		
Inclusion of assessment principles within the Guidelines	ENA, Energex, AEMO, COSBOA, APA, Vic DNSPs,	The ENA submit that it is essential that the matters to which the AER will have regard to when selecting assessment techniques are included in the Guidelines. The AER should commit to having regard to those matters when determining the techniques to apply when

	SP AusNet	assessing expenditure (pp. 2, 17–19). Energex suggests that the assessment principles similar to those in the Explanatory Statement be incorporated into the Guidelines (p. 4). AEMO questions the value of adding further principles to the Guidelines given the NER and the NER already contain the principles to be applied by the AER during a revenue determination (p. 3). COSBOA does not see any reason why the Guidelines should not include the assessment principles. This would give stakeholders increased guidance and transparency about how the AER will implement the Guidelines and improve the transparency with which it administers them. COSBOA cannot see how inclusion would constraint an ability to refine the Guidelines, the techniques or the AER’s application of them (p. 19). APA submits that the Draft Guideline does not include details as to how the AER will choose between methodologies, and the consideration that will be relevant in deciding how much weight to place on different methodologies. APA considers that the clarity of the Guideline and the transparency of the AER’s approach would be enhanced if the proposed principles set out in the Draft Explanatory Statement were included in the Guideline (p. 1). The Vic DNSPs consider that any principles or criteria the AER intends to use for assessing expenditure forecasts should be included in the Guideline (p. 4). The Guideline is the only document with status under chapter 6 of the NER and should operate on a standalone basis (p. 4). SP AusNet agrees with the AER that the intention of the Guideline is not restrict the AER's ability to use additional assessment techniques if it is deemed appropriate to do so after having reviewed the NSP's proposal. However, SP AusNet considers it is important for the Guideline to outline the principles that the AER will apply to select assessment techniques. This will inform stakeholders of the AER's intended assessment approach, which is a key objective of the Guideline. SP AusNet considers that the inclusion of the principles in the Guideline will not bind the AER or limit its flexibility. Stakeholders should be able to rely on the Guideline to provide to provide a comprehensive description of the AER's approach to assessing NSP's forecast expenditure (p. 1).
General comments on the proposed principles	ENA, Vic DNSPs, Ergon, PIAC	The ENA consider that the assessment principles should apply to data requirements as well as techniques (pp. 2, 19). The ENA submit that the AER should not use the principles to place restrictions on NSPs' forecasting methods (pp. 3, 20). The ENA consider that the principles 'validity' and 'parsimony' should not be included. The ENA supported including 'Accuracy and reliability', 'robustness', 'transparency' and 'fitness for purpose' but considers the AER's descriptions were inappropriate. The ENA suggested a 'consistency and predictability' principle is also required (pp. 3, 20–27, 48–50). The Vic DNSPs submit that the AER should use the principles set out by the ENA when determining the assessment techniques to employ (pp. 2, 13). Consistent with the ENA's recommendation, the Vic DNSPs consider the principles should be applied to both the assessment techniques and associated data requirements (p. 13). Ergon submits that the AER's focus should be on satisfying the NEL and rules requirements rather than treating its own principles as an end in themselves (p. 4).

		PIAC supports the AER's decision to articulate a set of assessment principles but not be bound by them. PIAC agrees that these principles provide a high-level but sensible foundation for consistently assessing alternative methodologies. The reference to principles can also provide some reassurance to NSPs and other stakeholders of the rigour and transparency of the AER's selection process of techniques. However, it does not bind the AER to the principles in a rigid fashion, which would, in PIAC's view, be detrimental to the future exercise of the AER's regulatory discretion (pp. 4, 10).
Weighting factors	ENA, Ergon, NSW DNSPs, Energex	The ENA submit that the AER should apply assessment principles and weighting factors to determine what weight should be given in the next five years of resets to benchmarking and other techniques that rely on unreliable data (pp. 4, 45–46). Ergon comments that the Guideline does not consider the role of the AER in determining expenditure under the rules. In particular, there appears to be no clear consideration of how the AER intends to carefully weigh all factors in satisfying itself that it should reject a forecast on the basis that it does not reasonably reflect the criteria (p. 7). The NSW DNSPs consider that the current Rules framework requires the AER to consider the material put before it by the NSP, and weigh the probative value of that information relative to other material such as submissions and assessment tools undertaken by or for the AER. The AER's reasons must be bound by the criteria and factors in the Rules (p. 5). Energex consider that the Guideline should clearly articulate the individual assessment approaches and the circumstances under which each will be used and weighted (p. 3).
Opex approach		
Productivity adjustment, including the relationship with incentive schemes	ENA, EUAA, NERA, PIAC, NSW DNSPs, MEU, Grid Australia, Vic DNSPs, Incenta, CP/PC/SAPN, APA	The ENA submit that by proposing to use a productivity adjustment, the AER is inappropriately prescribing a NSP's opex forecasting methodology because it: undermines the 'reasonable opportunity to recover at least efficient costs' revenue and pricing principle because an allowance for 'potential productivity change' will have been removed from the opex allowance results in estimated productivity gains being passed through to consumers before they have been achieved, significantly undermining the effectiveness of the EBSS by potentially providing no share in the benefit to NSPs distorts the alignment between the CESS and the EBSS because productivity improvements do not apply to capex. Any consideration of pre-emptive productivity adjustments should be limited to economies of scale (pp. 3, 30–31). The EUAA is concerned that the use of constant productivity change estimates over the regulatory period can mean that energy users will be deprived of step change reductions in opex that should occur for those NSPs whose efficiency is substantially below the efficiency frontier (p. 3). NERA Economic Consulting (NERA) submit that the pre-emptive application of productivity gain inherent in the AER's application of economic benchmarking of opex may compromise the intentions of the EBSS by removing the prospect for TNSPs to be rewarded for management induced gains (p. 31). PIAC support the explicit inclusion of a productivity measure in the annual 'rate of change' in opex that is designed to drive on-going improvements in opex efficiency. PIAC believes that improving efficiency should be a continual process that reaches across the

regulatory assessment period and beyond (pp. 5, 26–27).

The NSW DNSPs are concerned the AER may use industry productivity factors based on economic benchmarking data to set allowances. They consider the AER may apply a further productivity dividend without considering the efficiencies they have achieved to date. The NSW DNSPs seek clarification on the compatibility of applying productivity in a forecast is compatible with its incentive schemes (pp. 10–11).

The MEU are concerned the new approach to productivity adjustment will be NSP specific. It will not impose on inefficient NSPs the pressure to increase productivity. Using TFP change from the performance of the most efficient businesses will impose a lesser drive for productivity improvement on inefficient NSPs than is needed. The MEU consider that the AER's approach assumes that each NSP is operating at the efficient frontier. This assumption is flawed because it is unlikely that all are operating at this point.

The MEU consider that the AER needs to more comprehensively develop its approach to productivity adjustments. Rather than assume that an NSP is at the efficient frontier, assessing the efficiency of the base year could provide a better indication as to the validity of the assumption (p. 15).

Grid Australia submit that caution is required to ensure that the application of a productivity factor does not compromise the integrity of the expected rewards under the EBSS or the recovery of efficient costs. Only those efficiencies that are exogenous to the business, and hence do not derive from management effort, should be captured within the productivity factor. Grid Australia suggests the most appropriate assumption about future productivity growth in operating expenditure would be to capture productivity growth that would arise from realising economies of scale (pp. 15–16).

The Vic DNSPs consider that even if the AER altered its starting position and allowed step changes in excess of the 'historic average' effect of regulatory changes, there is a question of whether it will be possible to develop a robust estimate of the effect of changes in regulatory obligations on the productivity factor. Given this, before requiring DNSPs to account for 'historic average' effect captured in the productivity factor, the AER should satisfy itself that:

it is possible to quantify the effect of changes in regulatory obligations embodied in the productivity factor in an accurate, reliable, robust and transparent manner and in a way that will ensure the opex criteria and the revenue and pricing principles in section 7A(2) of the NEL are satisfied; and

the effect of changes in regulatory obligations embodied in the productivity factor is material enough to warrant the significant costs that are likely to be involved in trying to estimate its value (p. 11).

The Vic DNSPs consider the productivity growth factor should be removed from the rate of change parameter, because it is inconsistent with a number of EBSS provisions in clause 6.5.8 of the National Electricity Rules and revenue and pricing principles. Including a productivity factor in the rate of change will contravene:

clause 6.5.8(c)(3) of the NER, by penalising DNSPs that achieving an efficiency gains less than the productivity factor, notwithstanding the fact there has been an efficiency gain;

clause 6.5.8(a) of the NER, by not providing a fair sharing of gains or losses under the EBSS, where such gains are losses are calculated relative to the productivity factor;

section 7A(2) of the NEL, where DNSPs may not have the opportunity to recover at least efficient costs; and

		section 7A(3) of the NEL, by diminishing the effectiveness of the incentives, where there is no fair sharing of gains or losses under the EBSS (as above), and because incentives provided by the EBSS vis-à-vis the CESS would be unbalanced (pp. 2,12). Incenta comment that the only sources of past productivity growth that can be identified and whose recurrence is reasonable to expect in the future should be included in the productivity adjustment. It is reasonable to factor in productivity growth associated with economies of scale, however it would be prudent exclude the residual time trend component.(pp. 9–12) CP/PC/SAPN submit that if the AER reduces an NSP's opex allowance by imposing productivity adjustments, this results in estimated productivity gains being passed through to consumers before they have been achieved. This will: significantly undermine the effectiveness of the EBSS and the NSP potentially receives no share in the benefit of efficiency improvements; may fail to allow the NSP the opportunity to recover their efficient costs as a result of estimation error; and risk being inconsistent with section 7A(3) of the NEL by not providing effective incentives (p. 11) CP/PC/SAPN submit that they do not support the use of economic benchmarking to develop opex productivity adjustments. CPI is already affected by economy wide productivity change and to apply additional frontier shift would require the AER to have evidence the electricity network industry was able to make productivity improvements as a faster rate than the general economy which has not been provided. Such adjustments incorrectly assume: historical average productivity change is achievable in the future cost reductions from one off events will be repeated in the future; and all NSPs have the same ability to achieve the same level of productivity change which will not be the case (pp. 10-11). APA submit that the AER should reconsider its approach, such that the efficiency of forecast expenditures is assessed on a forward looking basis, without consideration of efficiency rewards arising from the previous period. APA submit that the AER’s proposed approach would remove any incentive for businesses to make efficiency gains. This is because any expected rewards from those efficiency gains may not be awarded to the business in the following period, as forecasts costs may be adjusted to offset the efficiency gain (pp. 2–3).
Base year efficiency adjustment	Vic DNSPs	The Vic DNSP's consider the definition of base year opex creates some confusion with the inclusion of the 'efficiency adjustment' term (p. 5). It is unclear if an 'efficiency adjustment' will be applied in all circumstances, or only where a DNSP's revealed costs are found to be inconsistent with the opex criteria. The Vic DNSPs suggest either: the definition of 'efficiency adjustment' be amended so it is clear it will only be applied if a DNSP's revealed costs are found it be inconsistent with the opex criteria; or the term 'efficiency adjustment' be removed from the formula and the definition of the term 'base year opex' set out the alternative ways in which it may be measured, which will differ depending on whether or not the revealed costs are found to reasonably reflect the opex criteria (pp. 7–8). Generally, the Vic DNSPs consider a DNSP subject to the EBSS should not be subject to an efficiency adjustment because the EBSS is

		designed to encourage DNSPs to seek out efficiencies and reveal their true costs. Imposing additional efficiency adjustments would result in: the base year being set at a lower level that the efficient cost the operator incurs in providing the services contrary to s 7A(2) of the NEL; and the incentives provided by the EBSS being undermined contrary to s. 7A(3) of the NEL because the sharing ratio would be diluted and efficiency gains/losses would no longer be fairly shared between the DNSP and customers contrary to cl. 6.5.8(a) of the NER (p. 8).
Real price growth factor	Vic DNSPs	The Vic DNSPs submit that while the AER has expressed a preference for the Australian Bureau of Statistics' wage price index for labour costs, the decision on which real price escalator to use should be left to the determination and assessed at this time having regard to the opex criteria (p. 12). The same real price growth factor should be used for economic benchmarking and opex forecasts to ensure consistency across the two (p. 12).
Step changes	ENA, EUAA, PIAC, NSW DNSPs, MEU, COSBOA, APA, ActewAGL, Vic DNSPs, CP/PC/SAPN	The ENA consider the AER's (two) categories of allowable step changes are too restrictive, which inappropriately prescribes the NSP's opex forecasting methodology. The ENA considers NSPs should be able to propose six types of step changes: Changes in external obligations or in the interpretation of obligations (e.g. AER reporting obligations) Exogenous changes in the volume or scale of a NSP's activity Investments that support NSPs achieving dynamic efficiency that by definition is not reflected in base opex, and requires a change in a NSP's future behaviour Changes in good electricity industry practice Opex associated with new capex activity because by definition this is not in base opex New requirements to address concerns of electricity consumers, identified through engagement as required by the NER. The ENA consider NSPs should also be able to propose other step changes as they see fit (pp. 3, 32–34). The EUAA request further clarification on how step change adjustments in 'base' opex would work in practice (p. 3). PIAC consider the Final Guidelines should clarify that step changes in opex forecasts should be clearly linked to significant exogenous events, and a NSP's proposal should indicate both the quantum and the timing of the associated consumer benefits (pp. 5, 25–26). The NSW DNSPs note that the term 'step change' is not defined in the Rules. They consider the use of such a concept to exclude expenditure has the effect of precluding costs that may satisfy the criteria and factors in the Rules (p. 7). The MEU support the AER's new approach to step changes such as a more rigorous approach to cost estimation for step changes. The AER's new approach addresses some very basic concerns the MEU identified over many revenue resets in the past. The MEU also expressed its concerns on past approaches to assessing the 'trend' aspect of the base, step and trend approach. To overcome the concern that consumers are overpaying for using forecast data rather than actual inflation costs, the MEU recommended the AER develop its own inflation adjustment rather than apply the general CPI change. This approach of a 'Utilities Inflation Index' would obviate

the need to forecast these increments and require consumers to only pay for actual changes (pp. 13–14).

COSBOA consider it will be important for the AER to continue investigating more robust assessment of step changes. COSBOA is also concerned the AER's approach to step changes does little to provide a path to identifying step change reductions. COSBOA urged the AER to consider this before finalising the Guidelines. COSBOA acknowledge that the two changes the AER propose to make to its current approach, i.e. compensating for incremental (and presumably decremental) changes in opex through lower (higher) productivity and requiring NSPs to justify step changes through reference to core expenditure categories, should help to allay some of COSBOA's concerns (p. 7).

APA submit that the AER should not apply its proposed 'trend' approach to operating expenditure step changes and instead assess each proposed step change on its merits. The AER does not set out how it will make this assessment (of distinguishing historic average changes in obligations versus those demonstratively different from historic changes) and APA does not consider that such an assessment of regulatory obligations can reasonably be made. APA considers that the AER's proposed approach will by necessity be highly subjective, unable to be tested, and unable to be applied consistently across businesses. APA also considers that this approach is at high risk of not providing a service provider with a reasonable opportunity to recover at least the efficient costs of providing regulated services (pp. 1–2).

ActewAGL submit that the Guidelines should increase the number of matters eligible as step changes, and to allow NSPs to nominate additional step changes as part of efficient cost in their expenditure forecasting methodologies and regulatory proposals. ActewAGL submit that NSPs should be able to recover new costs according to the expenditure criteria, whether those costs are due to regulatory requirements, changes in acceptable standards or industry good practice (p. 4).

The Vic DNSPs consider that even if the AER altered its starting position and allowed step changes in excess of the 'historic average' effect of regulatory changes, there is a question of whether it will be possible to develop a robust estimate of the effect of changes in regulatory obligations on the productivity factor. Given this, before requiring DNSPs to account for 'historic average' effect captured in the productivity factor, the AER should satisfy itself that:

it is possible to quantify the effect of changes in regulatory obligations embodied in the productivity factor in an accurate, reliable, robust and transparent manner and in a way that will ensure the opex criteria and the revenue and pricing principles in section 7A(2) of the NEL are satisfied; and

the effect of changes in regulatory obligations embodied in the productivity factor is material enough to warrant the significant costs that are likely to be involved in trying to estimate its value (p. 11).

The Vic DNSPs consider:

The restrictive definition of step changes contemplated in section 5.3 should be removed, because it is contrary to the opex criteria, the revenue and pricing principles and the AER's current practice (pp. 4-5, 9).

The proposal to allow only exceptional regulatory obligation step changes because the productivity measure will already reflect the 'historic average' effect of changes in regulatory obligations should be removed, because no analysis has been undertaken to test the validity of this proposal, or to assess whether it satisfies the opex criteria or revenue and pricing principles in section 7A(2) (pp. 5, 11).

The use by the AER of the terms 'non-discretionary' and 'external to the control of the DNSP' inappropriately implies the AER will no longer recognise the validity of step changes from the following sources even if they are necessary to produce a forecast consistent with

	the opex criteria: Changes in the DNSPs operating environment Changes in the expenditure arising from changed practices and policies Changes in opex arising as a result of new capex projects Discretionary projects that are required to achieve the opex objectives set out in clauses 6.5.6(a)(1), (3)-(4) of the NER, or are otherwise in the long term interests of consumers as prescribed in the NEO (pp. 8–9). The Vic DNSPs consider the definition of step change should be modelled on the approach taken in the EPDR final decision, subject to the following refinements: The definition should explicitly refer to the proposed step change being consistent with the opex criteria Step changes should be allowed where the expenditure is required to enable the DNSP to act in accordance with 'good industry practice', as required by various provisions in the NER and other instruments Step changes should be allowed where expenditure is required to address the concerns of electricity consumers, as contemplated by clause 6.5.6(e)(5A) of the NER The AER should be able to have regard to the DNSP's network performance indicators (e.g. capacity, risk or network health indicators) when considering step changes proposed under clauses 6.5.6(a)(3) and (4) of the NER The definition should recognise, as was the case in the recent Victorian Gas Access Arrangement Review, that step changes may be required to ensure discretionary projects that are in the long term interest of consumers, but are of limited benefit to the DNSP, are undertaken. In deciding this, the AER could consider if the proposed project is: in the long term interests of consumers, as prescribed by the NEO expected to be net economic benefit positive over its life consistent with the opex criteria (pp. 9–10). CP/PC/SAPN submit that a bottom-up build is appropriate for step changes (p. 9). CP/PC/SAPN submit that limiting step changes to regulatory obligations and capex/opex trade-offs—if this is what is intended—may not take adequate account of section 7A(2) of the NEL (p. 12). CP/PC/SAPN submit that the AER should consider all cases where historic costs are not a reasonable basis for forecast costs with the onus on the NSP to justify the benefit of the step change. Examples might include: business practices and investment changes due to changes in external obligations changes in good industry practice where customer engagement has indicated support for new or increased activities dynamic efficiency impacts (p. 12). CP/PC/SAPN submit that how the AER intends to make adjustments for step changes not captured by the 'historical average changes'

		is unclear, and if this approach is to be adopted the Guideline should set out how it intends to implement it (p. 12).
Base year opex, revealed costs	PIAC, ENA, Energex, NSW DNSPs, MEU, COSBOA, Vic DNSPs, Uniting Care Australia, Incenta, Grid Australia	PIAC supports the AER's proposed approach of benchmarking the base year even when an EBSS has been in place because of the current limitations of the revealed cost approach (variations in spending versus allowance and the presumption that constant incentives are sufficient to prevent gaming the timing of revealed costs) (pp. 5, 24–25). The ENA submit that if the AER substitutes a forecast based on revealed costs with a benchmark, it may be inefficiently low. The AER should rely on the power of incentive arrangements that are strong and provide clear signals for a NSP to spend less than its allowance (pp. 4, 47). Energex submit that alternative methods to determining an efficient base year will be dependent on the quality of data and their ability to reflect the characteristics of the individual DNSP. This is likely to be a difficult task and an incentive based approach is likely to be more accurate. The AER should focus its efforts on improving incentive mechanisms rather than abandon the revealed cost approach (p. 4). The NSW DNSPs consider that the proposed opex forecast approach does not give sufficient regard to the criteria under 6.5.6 of the Rules. They view the AER as limiting its assessment to examining if the DNSP's proposal accords with its own method of setting a base year, and only allowing for trend, step and productivity changes (p. 4). The MEU considers the efficiency of the base year can be assessed by applying the high level benchmarking assessments to each year of the regulatory period and comparing these to the forecast benchmarking that result when setting the allowances for the period. By comparing the actual benchmarks for each year of the regulatory period with the forecast benchmarks, this will provide evidence on whether the assumption that the base year can be assumed to be efficient. This will provide an indication on the relative efficiency of the base year and provide justification for changing the base year if the fourth year is seen as inefficient (p. 12). COSBOA consider that while the revealed cost approach might be appropriate in principle, in practice, reliance on revealed costs in the past contributed to excessive expenditure allowances provided to the NSPs. COSBOA remain concerned that continued reliance on this approach will allow NSPs to continue to inflate their future expenditures. This makes the application of incentive frameworks such as the EBSS for opex and the CESS for capex more problematic. Consumers will still have to pay network charges that reflect inefficient costs. Hence, COSBOA strongly supports the application of a range of techniques, especially economic benchmarking, to determine if revealed costs are efficient. COSBOA considers the AER needs to place significant weight on the outcomes of these (pp. 5, 7–9). The Vic DNSPs consider the language used in the Draft Guideline inappropriately implies that the AER has the power to mandate the use of particular opex forecasting techniques, and overlooks the NER provisions which require the AER to firstly assess whether NSP proposals are consistent with the opex criteria. (pp. 5-6). A new section should be introduced to the Guidelines that recognises the possibility for alternative techniques to the base-step-trend approach to be employed and sets out how the AER would assess such proposals (p. 2). The Vic DNSPs suggest the AER model the revised Guideline section on sections B.6.1, B.7.1 and B.8.1 of the Explanatory Statement because these are more in keeping with what is contemplated by clause 6.4.5 of the NER (p. 6) The Vic DNSPs consider that the definition of base year opex in the AER's proposed base-step-trend formula: incorrectly refers to final year opex being used even though base year opex is usually set to actual opex in the base year and the AER has indicated it may utilise another base year if the revealed costs are found to be inconsistent with the opex criteria. The Vic DNSPs suggest the term 'deemed final year opex' be replaced with the term 'base year opex' to overcome the definitional issue (pp. 5–6).

		Uniting Care raise concerns about the interpretation of revealed cost as the process for determining base opex, significantly with regard to interpretations of efficiency of current expenditure. Uniting Care is not convinced that current opex and capex expenditure is near the efficiency frontier for many network businesses. Baseline data needs to be interpreted very carefully in terms of predictions about the relevant efficiency of a business based on revealed costs (p. 4). Incenta consider that benchmarking techniques are likely to provide a very imprecise guide as to the efficiency of one NSP relative to others (p. 9). Incenta comment that when testing the efficiency of an NSP's base year, is important to ensure that the expenditure in the base year is not affected by one-off factors (and that adjustments are made if this is the case) (p. 13). Incenta submit that applying the "revealed cost" method rigidly has the potential to materially misstate expenditure expectations where there are material, lumpy categories of operating expenditure. The AER should explore whether there are alternative methods for deriving regulatory allowances for lumpy operating expenditure items that maintain the incentive properties of the revealed cost method and EBSS (pp. 13–14). Grid Australia submit that adjustments that are made to base year expenditure should be transitioned over the period rather than applied in a single year. Doing so will ensure there is not undue pressure to achieve reduced expenditure allowances that could compromise reliability of supply (pp. 16–18). CP/PC/SAPN submit that the EBSS provides a strong continuous efficiency incentive and therefore the AER should be confident the re-current base year opex is an efficient starting point for forecasting opex. If the AER does apply economic benchmarking to assess or substitute base year opex, it needs to be clear what principles will apply to set the benchmark and how the model and benchmark will account for differences in NSPs' uncontrollable operating conditions (p. 10).
Capex approach		
Capex approach in the Guidelines	PIAC, COSBOA, NSWIC, CP/PC/SAPN	PIAC considers the Final Guidelines should make a stronger statement about the AER's commitment to changes in the assessment of capex, an area that PIAC considers has been one of the weaker aspects of the current regulatory regime – it dilutes the message of regulatory change. Having said this, the reforms in the Draft Guidelines appear to suggest the AER's approach has changed and is in line with the AEMC's reforms (pp. 5, 21). PIAC supports the developments in capex, as explained in the Explanatory Statement, but considers the Guidelines should be clear to NSPs that the 'world has changed' and so must their own approach to capex forecasting (pp. 21–24). COSBOA raised concerns about the proposed capex approach, including its detailed and intrusive nature at the lower level, with a significant level of regulatory compliance involved. COSBOA also raised concern that the AER has not always been clear about why it has formed a view that the benefits of applying its approach and collecting the necessary data will outweigh the costs. This will increase complexity for consumers and make the approach more difficult to understand. The AER should be prepared to review the performance of the approach and make adjustments if necessary (pp. 9–10, 19). NSWIC considers that the Guidelines should incorporate a regulated efficiency dividend for both capex and opex (p. 4). CP/PC/SAPN submit that they are broadly comfortable with the AER's general approach to examining work volumes and costs in the context of the AER's 4 proposed high level expenditure categories (p. 8).

Capital expenditure sharing scheme	PIAC	PIAC is concerned that the presence of a strong CESS will create even stronger incentives for NSPs to inflate their initial capex forecasts to increase the likelihood of receiving a reward for underspending or decrease the chance of receiving a penalty for overspending (pp. 23–24).
Capex productivity	PIAC, Uniting Care Australia	PIAC raises a concern that the capex assessment process does not identify any specific approach to ensuring productivity improvements. PIAC considers NSPs need to progressively improve productivity levels in both their capex and opex activities, particularly for the more routine capex investment activities (p. 5). Uniting Care submit that there should be scope for productivity measures to be incorporated into capex forecasting techniques (p. 4).
Demand	PIAC, Canegrowers	PIAC submits that the Guidelines should provide a framework for assessing expenditure proposal that is adaptable to changes in electricity supply and demand conditions. The Draft Guidelines provide little explanation about how contingent projects and RIT-D, RIT-T and non-network alternatives will be incorporated into the expenditure assessment process. For example, there is no discussion about how a forthcoming RIT-D will be considered in light of expenditures already approved in the determination process or whether the assessment process will hinder or facilitate the exploration of non-network alternatives in a future RIT-D process (pp. 20–21). Canegrowers note that Queensland NSPs have built large sections of their networks to cater for increased demand from specific consumer classes that has never been realised. The Canegrowers suggest that this issue can be overcome by approving forecasts based on customer classes, which would encourage NSPs to engage with consumer groups when forecasting demand. This would ensure irrigators and other minor users do not pay for continued expenditure to manage non-existent peak-load growth (p. 7).
Replacement expenditure modelling	CP/PC/SAPN	CP/PC/SAPN submit that repex modelling should not be relied on and should only be used to identify further areas for investigation and potentially explain differences in cost drivers between DNSPs (p. 8). CP/PC/SAPN submit that the AER needs to seriously consider their view on re-calibration and the scope of information required to provide a robust data set (p. 8).
Augmentation expenditure modelling	CP/PC/SAPN	CP/PC/SAPN submit that the augex model should not be relied on and should only be used to identify further areas for investigation and potentially explain differences in cost drivers between DNSPs (p. 9). CP/PC/SAPN submit that a significant component of augex capex will not be captured and highlighted that examples are set out in their response to the AER Issues Paper (p. 9).
Capex categories and PTRM	Vic DNSPs	The Vic DNSPs consider that the given the difference in proposed capex assessment categories relative to the current PTRM and roll forward model, the PTRM and roll forward model should be revised to make them consistent with the new capex reporting requirements (p. 21)
Non-capex solutions	Canegrowers	Canegrowers submit the AER needs to encourage non-capex mechanisms, such as developing time of use and critical peak pricing network tariff schedules that monetise cost of peak investment and incentivise utilisation in off-peak periods. This should form part of the AER's approach to assessing replacement and augmentation capex. A regulatory approach during expenditure assessment is needed because the current demand management incentive scheme is weak and non-binding, and will not deliver the required change in NSP expenditure behaviour (p. 7).

Information requirements

Relationship between Guidelines and regulatory instruments	ENA, Ergon	The ENA considers the AER should clarify that the information requirements in chapter 6 of the Guidelines are indicative only and NSPs are not required to provide this information unless it is detailed in a RIN or a RIO (pp. 2, 15–16). The ENA submits it is more appropriate to issue RIOs rather than RINs for information because RIOs ensure consistency and comparability, include an obligation to consult more broadly, and must be published (pp. 2, 15–16, 36). The ENA considers the AER should explain, in an attachment to the Guidelines, how the suite of regulatory instruments fit together so that the sequencing of information provision and decision making is clear to all parties, minimising the prospect of duplication, gaps or anomalies (pp. 3, 29–30, 35). Ergon submit that a RIO is the appropriate instrument with which to collect comparative information from NSPs (p. 4).
Net benefits of data requests	ENA, Ergon, Vic DNSPs	The ENA submits the AER should explain more fully how it has considers the costs and benefits of the information requirements (p. 34). Ergon remains unconvinced that the significant time and resources required to provide all of the required information, clearly translates to benefits to industry and customers (p. 4). The Vic DNSPs submit that the AER should further consider the information it will require to assess opex and capex forecasts, because it is unclear that all the information is: necessary; proportionate to the underlying issue the AER is trying the address; and expected to yield net economic benefit (p. 2). The Vic DNSPs consider that in relation to data generally: the AER should carefully consider the costs that will be incurred in collecting the range and volume of data proposed and consider if the proposed information is: necessary given the manner in which the AER intends to assess the forecast expenditure and the operation of incentive schemes; proportionate to the underlying issue the AER is trying to resolve; and expected to yield a net economic benefit having regard to both: the benefits of having the detailed disaggregated information; and the cost the NSP will incur providing the information and the AER in processing and assessing the information the AER should recognise and factor into how the data will be used in its decision making the quality of back cast data and its limited usefulness The Vic DNSPs consider that the highly granular information suggested in vegetation management where the AER has indicated it intends to continue to rely on aggregate data and the EBSS is not necessary, proportionate, and expected to yield economic net benefits and indicates that the AER has given insufficient consideration to whether the information requirements in Appendix B of the Explanatory Statement and chapter 6 of the Draft Guideline are required, proportionate and expected to yield a net economic benefit. For this reason, the Vic DNSPs submit the AER should conduct a rigorous and transparent review of its proposed information requirements including the timing and provision of backcast data and the sign off requirements for this data. This review should consider if less information should be collected from DNSPs whose base year opex is found to reasonably reflect the opex criteria (pp. 15–16,

		18). The Vic DNSPs consider the AER should replace the term 'on an ongoing basis' in relation to forecast information to 'as part of a DNSPs regulatory proposal' as this is more consistent with the AER's intent (p. 21).
Publication of information	ENA, EUAA, MEU, COSBOA, Vic DNSPs, Uniting Care Australia, Canegrowers	The ENA considers that all data on which the AER relies for benchmarking should be published and it should not rely on any confidential information for benchmarking, in the interests of transparency (pp. 3, 35). In addition the ENA considers that all benchmarking models should be published, and the AER should amend the Guidelines to this effect (pp. 4, 39–40). The EUAA requests the AER ensure that all benchmark modelling is made available on the AER's website so that this can be replicated and analysed by users and others (p. 1) The MEU comment that unless consumers have access to the database developed by the AER to give them confidence about the legitimacy of the input provided by the NSP, there is a disconnect between what the NSP advises consumers and what the NSP is required to the AER (p. 6). COSBOA endorses NSP and consumer comments in the Explanatory Statement about the importance of gaining access to benchmarking data to better engage in AER processes, including annual reports, regulatory determinations, and testing and validation. COSBOA would be concerned if significant data for benchmarking – economic and even category analysis – were kept confidential. The PC also supported that all benchmarking input data be publicly available given the NSPs are regulated monopolies (p. 22). The Vic DNSPs consider that confidential information should not be used for benchmarking unless the NSP has access to this information (p. 20). The Vic DNSPs generally consider that all data and models for annual benchmarking and during determination processes should be released as early as possible. This will enable all stakeholders to understand the analysis and also allow testing and consultation prior to publication of the annual benchmarking report (p. 20). Uniting Care highlights the importance of data collected by the AER for forecasting purposes being publicly available. This will enhance consumer engagement with regulatory processes and also provide clearer data about relative efficiency of network expenditure (p. 4). Canegrowers consider that all the information submitted by NSPs to the AER in regulatory information notices should be made publicly available, immediately. The only suitable redactions would be for information which is deemed a breach of consumer or third party privacy (p. 11).
Providing information	ENA, MEU, NSW DNSPs, CP/PC/SAPN	The ENA submits that NSPs should not be required to provide information that: they do not have is materially misleading or unreliable. But, the NSP should not be disadvantaged when it cannot provide information (e.g. The AER should not use another NSP's information instead) (pp. 3–4, 35–36).

		The ENA suggest the AER clarify how the suite of regulatory instruments fit together as a coherent, integrated package. They consider it is important that the information the AER requests NSPs to provide is appropriately coordinated and streamlined and that there is no unnecessary or duplicated information being requested (p. 35). The MEU stated the provision of additional data as a result of the AER's new information requirements do not involve as much cost as the NSPs alleged. MEU stated advice from its members that competent firms carry out considerable investigation of costs of activities and this information is collected in detail. Unless this data is collected, analysed and used to forecast future costs, they lose an essential ability to control their costs. For NSPs to provide the data in the format required should be a relatively simple exercise and the costs will far outweigh the benefits to consumers in terms of setting more efficient expenditure allowances (pp. 5, 21–22). The NSW DNSPs cannot provide much of the information required by the AER in an auditable form. They consider that the AER should only seek information that can be provided from a verifiable source within their systems. The NSW DNSPs suggest that any requirement to provide benchmarking data should occur following the submission of their regulatory proposals in May 2014. Otherwise they suggest that all required benchmarking information be incorporated in the reset RIN to be submitted in May 2014 (p. 1). The NSW DNSPs suggest the AER consider a more streamlined and tailored process to collecting information for the NSW DNSP resets. The AER should leverage reviewed information provided by them in the past and limit information requests to data available in their systems. They suggest the AER issue a single reset RIN, merging the information requests rather than collecting data through two processes (p. 3). CP/PC/SAPN recommend the AER streamline the currently proposed three separate RIN processes over the next year (p. 6). CP/PC/SAPN submit that it would not be appropriate for the AER to unfairly disadvantage a NSP who genuinely cannot provide information by, for example, substituting unit costs provided for another NSP in its determination (p. 7). CP/PC/SAPN submit that it is not permissible or appropriate for the AER to place the onus on NSPs to demonstrate the nature and quantum of uncontrollable factors that influence differences in expenditure across NSPs. The AER has information powers the NSPs do not have and is best placed to obtain the relevant information (p. 6).
Ability to provide data	NSW DNSPs, Jemena, CP/PC/SAPN	The NSW DNSPs note they will not be able to provide a significant proportion of the data in the AER’s draft templates to a high degree of confidence. The NSW DNSPs note previously raised issues including: retrospective collection of data requiring manual manipulation forecast data not aligning with their planning and information systems. They consider more detail is required, noting it is not apparent how the information will be meaningfully used. They suggest the AER publish a handbook on how it will use the information provided (p. 11). Jemena makes the following comments: The vast majority of the information requested by the AER has not historically been collected by Jemena and cannot be audited. While they can attempt to retrospectively estimate data, staff would have insufficient confidence in the resulting estimates to provide assurance to Jemena’s managing director, board of directors or auditors that the estimates are appropriate and can be relied upon by

		the AER for the intended purpose (p. 2). CP/PC/SAPN submit that they cannot provide much of the category information and if pushed into populating templates with large arbitrary assumptions there is a risk that they will provide materially miss leading information (pp. 7, 9). CP/PC/SAPN submit that the category analysis RIN timeframe is very tight, particularly given the scope and requirement to backcast 10 years of data and it is unlikely the AER can be provided category analysis data of sufficient quality within the timeframes (p. 7).
Backcast data	ENA, Energex, Vic DNSPs, SP AusNet, CP/PC/SAPN	The ENA objected to providing backcast data on the basis that the AER's request is inconsistent with the regulatory information instrument provisions in the NEL. The NEL requires the AER to turn its mind to the likely costs to the NSP of complying with the instrument and to how fit for purpose back cast information will be. The ENA considers back cast information will not be fit for purpose because NSPs will need to make significant assumptions and the burden on NSPs is not justified. The ENA submits the AER has not fully considers whether the information is 'reasonably necessary' for performing or exercising functions and powers under the NEL or NER. The ENA considers that with the exception of forecast information, it is not appropriate to use a RIN or RIO to require a NSP to provide information that is not in existence, or cannot be objectively derived from information that is in existence. The ENA submits that in some cases, the back cast information requirements will go beyond the common law requirement that the recipient of a section 155 notice (under the CCA) can only be required to furnish information which is within the knowledge of the recipient (Dunlop Olympic Ltd v Trade Practices Commission 62 FLR 145). The AER cannot insist that the NSP does whatever is required to provide information when it is not properly within the knowledge or control of the NSP (pp. 4, 36–39). Energex does not consider that the 10 year ‘backcasting’ exercise the AER is proposing as part of the development of the Guideline will address data issues of consistency across DNSPs and across time. It anticipates significant difficulties in providing backcast data, and the required estimation will significantly undermine data quality and consistency (pp. 3–5). The Vic DNSPs consider it is important to recognise that backcast data is not a good substitute to collecting non-backcast data (it is likely to have gaps and be poorer quality) because not all the backcast data required may be available or NSPs may not have recorded data in a standardised manner over time, or relative to other NSPs. These limitations must be factored into how the AER expects to use and does use the information (p. 17). The requirement to provide 10 years of independently audited backcast financial and non-financial data in such a short time period is unreasonable and it is unclear whether an auditor would be willing to provide the requisite sign off for all of the information (pp. 2,14–15,17). The Vic DNSPs consider there to be significant costs in collecting the range and volume of backcast data suggested by the AER: the net benefit of collecting backcast data is likely to be much lower than collecting prospective data because costs will be far higher and quality will be much lower three months for the provision of backcast data for economic benchmarking is insufficient given the expectation the data is: high quality and reliable; assumptions will need to be developed for some data; and the audit requirements (pp. 17–19)

		the AER should reconsider the audit requirements if the February 2014 deadline for economic benchmarking data is maintained, or if the audit requirements are maintained the NSPs should be provided an extra 3 months to provide the data for category analysis data, the AER should either give NSPs an additional three months to provide the data, or refine the data list to enable the NSPs to comply. the AER should consider allowing an independent engineering consultant to sign off in the NSPs non-financial data and only require auditor sign off on financial data as auditors may not be prepared to provide the level of assurance the AER requires (pp. 18–20). Based on these concerns, if the AER does collect backcast data it should: only require the provision of data it knows will be required to populate the preferred model specification or test the sensitivity of the data/model specification. Allow NSPs to only use best endeavours to provide information and not require them to provide information they don't have, that is unreliable or is potentially misleading. assess whether the data satisfies the principles set out by the Vic DNSPs and commit to not relying on information that is unreliable or potentially misleading. recognise the inherent limitations of the data and the resulting quality of results when applying any benchmarking techniques. consider if any application of benchmarking in a deterministic manner is consistent with the expenditure criteria, the revenue and pricing principles and the NEO. (pp. 18–20). SP AusNet raised concerns about providing the AER with back cast data to be used for benchmarking purposes. SP AusNet agrees with the AER that data employed for benchmarking purposes should be robust, noting that such data may have previously been used for internal business needs and has not been audited or is unlikely to pass an audit test. CP/PC/SAPN submit that 10 years of historical data is not reasonable, particularly in the timeframe provided and that the likely limitation on the quality of backcast data (and extensive use of estimation and assumptions) is likely to undermine the value of the AER's proposed benchmarking assessment (pp. 3, 6). CP/PC/SAPN strongly recommend new data reporting requirements are only applied prospectively to improve benchmarking and data quality and allow NSPs to put systems in place to capture the data. The draft category analysis RIN requires extensive data, much of which is not collected by the Businesses. Consequently, numerous assumptions and estimations would be required to complete the templates undermining the credibility of and stakeholder confidence in any benchmarking model. (pp. 3, 6).
Auditing and Director signoff	ENA, Energex, NSW DNSPs, Jemena, CP/PC/SAPN	The ENA raised concerns with audit and assurance requirements, summarised as: The NSPs may bear risk of impaired regulatory outcomes, non-compliance with regulatory requirements and expending inefficient effort and cost that could arise from incompletely designed or unworkable, regulatory audit or assurance requirements The AER has not provided enough guidance on: how it will obtain assurance

		auditor qualification terms of reference the applicable financial reporting framework for each RIN and RIO the circumstances when the AER will expect an auditor to provide different levels of assurance auditor responsibilities the relationship between auditors and NSPs and the AER. The ENA submits that the AER should therefore commit to preparing Regulatory Accounting Guidelines (pp. 4, 40–45). Energex considers it essential that the AER develop Regulatory Accounting Guidelines to ensure data for expenditure assessments is of the highest quality. All data must be audited against a clearly defined standard, however a significant amount of historic data will be difficult to provide to an auditable standard, thus rendering any audit effectively irrelevant. Where Energex is unable to gain unqualified audit opinion on backcast data, it will not be able to provide Directors' sign off and, as a consequence, will be unable to provide the data requested by the AER (pp. 4–5). The NSW DNSPs consider the AER should not apply a positive level of assurance on information which is based on estimates or approximations. They also suggest that the AER impose less onerous review requirements, which may alleviate resourcing issues (pp. 3, 12). The NSW DNSPs consider that a positive audit will only be possible if the source of information can be verified in their information systems. Without this, auditors may provide a view on the DNSPs process for developing an estimate, but cannot testify to the robustness and accuracy of data (p. 12). Jemena submits that the level of assurance that can be provided for a large portion of the information is not a function of effort or time expended to obtain the estimates. It is the result of data not being collected for the retrospective time period for which the AER intends to request the information (p. 2). Jemena suggests that if the AER relaxes its auditing requirements, and allow for data to be provided subject to management sign-off only, then some data —with estimates could be made where gaps exist— could be compliant for the AER's intended use (pp. 2–3). CP/PC/SAPN submit that the AER should have all benchmarking data audited, however they consider the AER should carefully consider the standard of audit that can be practically achieved where assumptions and estimation must be applied (p. 6). CP/PC/SAPN submit that it is unclear their auditors would be available in the timeframe for collecting economic benchmarking data and consider using other auditors is not practical (p. 7).
Implementation issues		
Uncertainty of new tools	ENA, NSW DNSPs, ActewAGL	The ENA considers that NSPs who submit regulatory proposals in 2014 will not be afforded due process if the AER uses benchmarking techniques because there is considerable uncertainty about the quality of the information and the sheer volume of information these NSPs will need to prepare (pp. 4, 46–47).

		The NSW DNSPs note that trying untried and untested assessment tools to the NSW determination process may potentially result in regulatory errors. They consider in the short term the AER should adopt a cautionary approach and consultative process to applying their tools (p. 1). ActewAGL submits it is concerned the AER could apply unrefined, untested and unproven assessment techniques to its regulatory proposal in May 2014, and that potentially unreliable outcomes could be used to test its regulatory proposal and to set its regulatory allowance (p. 4)
Consultation with NSPs considering upcoming determinations	NSW DNSPs, Ergon	The NSW DNSPs expect the AER to consult extensively with them during their regulatory determination process, and be transparent with the material it is intending to use. They would like reasonable opportunity to examine the AER's approach and explain any variances in inputs or outputs (p. 10). The NSW DNSPs note that in addition to their current regulatory proposal, they will have to complete an economic benchmarking RIN in February 2014 and a reset RIN incorporating the category analysis data in May 2014. They request the AER consult further with them on reducing the resourcing burden (p. 12). Ergon is concerned that there may be a lack of due process for Ergon in respect of the AER's proposed timetable for producing benchmarking results and making determinations on the efficiency of Ergon's opex (p. 8).
Economic benchmarking		
Limitations of economic benchmarking/ economic benchmarking techniques in practice	PIAC, Huegin, NSW DNSPs, Ergon, Energex, CP/PC/SAPN	While PIAC noted that economic benchmarking will have limitations in setting revenues overall, it supported the approach the AER had taken in the draft Guideline of complementing the detailed category level benchmarks with the top down economic benchmarking measures. PIAC noted that too much emphasis on the economic benchmarks would lead NSPs making claims about differences in environmental variables , while too much focus on the categories risked the regulatory becoming lost in the esoteric details of network business operations and make drawing overall conclusions about NSP expenditure (including trade-offs) difficult. (pp 15 – 16) PIAC cautions against relying solely on the first pass outcomes, even if a NSP appears to be performing close to the currently observed efficient frontier, or at least in the next round of determinations. PIAC is concerned that he first pass efficiency benchmarks are unlikely to reflect the optimal level of efficiency consumers should expect from NSPs because: the quality and reliability of data and models are yet to be fully developed and tested, which may limit the AER's reliance on them the number of NSPs in the benchmarking population is relatively small because it is based on primarily on NEM NSPs, with little reference to international best practice significant cross/common-ownership reduces the real population of firms for benchmarking the performance of government-owned NSPs could potentially skew benchmark outcomes several independent bodies including the PC and IPART have identified a continued decline in productivity in the electricity sector since 1999 that is multifactorial.

		Relying too heavily on the first pass assessment may therefore entrench, rather than remove the existing inefficiencies (pp. 11-12). PIAC considers that it is more important for consumers at this stage is that the decision-making process is transparent and comprehensive and includes the progressive development and objective evaluation of the assessment tools used (and not used) by the NSPs and by the AER in their assessments of the NSPs' proposals. The productivity inertia of previous years should no longer be subsidised by Australian business and households (p. 12). Huegin Consulting Group (Huegin) submits that given the sample size of thirteen networks, a second stage regression is unlikely to be large enough to remove differences in MTFP results due to uncontrollable business conditions, scale differences and data errors (p. 10). Huegin considers MTFP is unable to account for different business conditions on efficiency results and unable to account for the influence of scale on efficiency results. The operating environments in the NEM are more varied than those in the UK and the model outlined by the AER is unlikely to overcome these shortcomings of using MTFP to infer efficiency between networks (p. 10). Huegin considers MTFP and DEA are sensitive to the model specification and is concerned that in the case of contrary rankings the results will be discarded, whereas if the models provide similar rankings then the results will be endorsed and used (p. 11). Huegin considers DEA is more suited to other industries where there is a more homogenous environment and that it is no possible in Australia to address heterogeneity through clustering businesses into similar groups (p. 11). The NSW DNSPs consider that benchmarks and predictive models do not account for inherent differences between businesses, so do not have the necessary rigour to set an efficient forecast. These tools should only be used to target more thorough review of a DNSP's proposal (pp. 2, 4). The NSW DNSPs consider that the use of benchmarks may lead to misleading conclusions unless the AER undertakes more detailed examination to determine whether the anomaly is due to inefficiency. They consider the limitations of benchmarking are: an inability to account for characteristics, drivers and investment cycles, prohibiting 'like for like' comparisons current accounting and reporting systems that make comparisons highly problematic at present (p. 8). Ergon submits the opportunity to harness benchmarking as a cost adjustment technique is severely limited in Australia with its fact spectrum of environmental conditions, legacy accounting and reporting structures, and small number of businesses. Energex accept that benchmarking is an appropriate technique however, given data limitations, it should be limited to providing a high level reasonableness check of aggregate/ category expenditures (p. 2). CP/PC/SAPN consider the statement in the Explanatory Statement that benchmarking is inherently more reliable than engineering assessment is unfounded as both methods are subject to error and, unlike benchmarking, engineering assessments directly consider the circumstances of the NSP (p. 5).
Application of economic benchmarking	Huegin, NSWIC, MEU, COSBOA	Huegin note that model specifications change over time as new data arrives with each regulatory period. This may have significant consequences for the businesses that are forced to react to the signals produced by the models (p. 7). For example the UK regulator OFGEM has subsequently changed approach numerous times in the last decade (p. 8).

		Huegin considers benchmarking to be an informative process for identifying and communicating differences in the cost outcomes between businesses. The results are a means to initiate investigations into productivity and efficiency improvement opportunities. Benchmarking is not reliable in predicting an industry cost function and should not be used as a substitute for forecasts (p. 8). NSWIC notes the large divergence between recent demand forecasts and allowed revenues for NSPs. NSWIC considers it is important the benchmark reports are used for periodic reassessment of capex against annual revised demand figures (p. 3). The MEU considers the AER has introduced tools that will provide a better outcome for consumers than the current tool kit, and suggests that international benchmarking would result in a better outcome for consumers. The AER should seek to identify other benchmarks that reflect overseas practices without introducing the problem of exchange rates (that is, are not cost related) (pp. 17–18). COSBOA agrees with AER's intention to determine which techniques to apply at the time of determinations rather than specify this in the Guidelines. However, COSBOA would expect the AER to at least apply MTFP, DEA and econometric benchmarking. COSBA acknowledge benchmarking will need improvement in its use over time; however they consider this should not become an impediment to applying benchmarking, noting other techniques which are less than perfect have been applied in regulatory decisions (p. 12). COSBOA also supports the extension of benchmarking to include international comparisons. They consider the AER should treat this with greater urgency than as a 'long term goal' given the benefits it can provide (pp. 14–15).
Guidance/consultation on economic benchmarking	NERA, CP/PC/SAPN	NERA consider it is important that the AER provides clearer guidance on the intended interaction between the three proposed applications of benchmarking techniques (p. 13). It submits that: the AER has not been definitive on when the econometric benchmarking of opex would be undertaken. They consider it would appear contradictory for an NSP to satisfy a 'first pass' assessment of its total costs, but will still be subject to the top down modelling of opex (p.16) the AER has not comprehensively outlined how it will assess whether an NSP is responding to incentives (p.16) no guidance has been provided on when econometric benchmarking of opex would be used as the basis for determining the NSP's opex allowance for the forthcoming regulatory period (p. 30). CP/PC/SAPN submit that the AER should set out its proposed process for consulting with stakeholders on the proposed economic benchmarking models for the annual benchmarking report as soon as possible and all data is published and available to stakeholders as soon as possible (p. 13).
Holistic approach	Huegin, Ergon	Huegin considers the AER's approach to benchmarking are not complementary and the errors in one model do not cancel out the errors in another. The different techniques selected for inclusion by the AER have fundamentally different technical origins and characteristics that rely on different assumptions (p. 7). Ergon is concerned that the multifaceted approach proposed by the AER to benchmarking, combined with the unsuitability of many of those approaches to Ergon's business conditions, will lead to an unachievable outcome for Ergon merely because it is least suited to the weight of various approaches undertaken. Ergon does not believe that using multiple techniques is complementary or increases the robustness of the overall approach, nor does it believe that two or more of the intended techniques resulting in a similar indication is sufficient means to substitute an NSP's more detailed forecast (p. 12).

Economic theory	Huegin	Huegin noted two significant issues with using efficiency frontiers and industry cost production functions: 1. The validity of the models and veracity of the results they produce is poor due to the statistically insignificant sample size; 2. The random, experimental nature in which the models are constructed - by finding the model that best fits the available data - leads to a model of best fit at that point in time, rather than a robust, one-size-fits all formula for any industry participant (p. 7).
Measurement of efficiency, interpreting results as being 'inefficient'	Ergon, NERA, COSBOA	Ergon believes that to infer that an NSP is inefficient purely because it is not on an efficient frontier is incorrect. The AER should be careful not to confuse the attainment of efficiency as a theoretical construct. And how efficiency should be applied to businesses in the real world (p.9). NERA submits that absolute efficiency cannot be measured or observed (pp. 8–9). NERA submits that the language used by the AER in the Explanatory Statement and the technical report indicates a predisposition to interpret differences between actual and benchmarked costs as inefficient (p. 27). NERA submits that it is important to recognize that costs which are not explained by a benchmarking model are simply costs that cannot be attributed to the explanatory variables included in the model (p. 27). COSBOA notes the AER does not propose to set the benchmark level of efficiency until it has undertaken testing and validation of data. COSBOA suggests that the minimum level would need to be around the top quartile of the revealed frontier for benchmarking to have a meaningful impact on NSP performance and to benefit consumers. There are also strong reasons for going further than this to either the actual revealed frontier or by adopting the PC's recommendation of a yardstick approach (i.e. choosing a firm close to the frontier) (p. 13).
Application of economic benchmarking to the gas sector	APA	APA is concerned that the AER will decide inappropriately to use data gathered from the electricity sector to benchmark gas businesses in some areas. APA considers that differences between the electricity and gas sectors —in particular differences between cost drivers—would make this data inappropriate for application to the gas sector (pp. 4–5). APA submits that contractual outcomes in gas transmission provide more scope for individual arrangements than are available under the electricity regime. These arrangements mean that it is difficult to compare gas transmission assets as the contractual arrangements in place, and the markets they serve, can differ significantly. Existing contractual arrangements place pressure on gas transmission businesses in respect of service delivery and competitive market forces. Gas transmission businesses are therefore subject to counterparty pressure in relation to service delivery and prices. Private sector ownership also imposes pressures from investors to perform. This provides strong incentives for efficiency for gas businesses. These drivers operate in addition to regulatory drivers that incentivise efficient behaviour. As a result, APA considers that benchmarking may have limited value in the gas transmission sector. APA therefore submits that the AER consider the value and applicability of benchmarking to the gas transmission sector before embarking on a process of information gathering similar to that being undertaken in conjunction with the Guideline for electricity service providers (pp. 5–6).
Comments on economic benchmarking and operating expenditure	Huegin, NERA, Ergon	Huegin considers there to be to insufficient explanatory variables for economic metric analysis to account for the differences between NSP operational expenditures. There is also a risk of omitted variable bias due to the number of different opex drivers (p. 11). Huegin considers the input and output elasticities are likely to overstate the economics of scale that can be achieved by different

		businesses. The opex cost elasticity for increasing output in a rural network is likely to be higher than the estimated industry opex cost elasticity (p. 12). NERA comments that a fundamental shortcoming of the AER's proposed approach outlined in the technical report is that it assumes that a NSP's capital stock is fixed for the period in which it is forecasting opex (p. 29). NERA considers decisions that the AER is required to make as part of its regulatory determination relate to the efficient level of opex and additional capex required by the NSP, looking forward over the next regulatory period. Given these fundamental differences, it is difficult to identify any insights that the AER's proposed benchmarking analysis of total costs is capable of providing to assist the decisions it is required to make (p. 22). Ergon comments that the AER's proposed approach to assessing forecast opex elevates benchmarking above all other factors listed in clause 6.5.6(e)(4), resulting in presumptive (and potentially conclusive) findings on the efficiency of base year expenditure before any of the other factors are ever incorporated into the AER's assessment (p.12).
Comments on economic benchmarking and outputs	EUAA, MEU, COSBOA, NERA, CP/PC/SAPN	The EUAA considers there to be no certain VCR value, and large changes in VCR, which are quite possible, may undermine the reliability of the benchmarking results (p. 2). The EUAA considers the least possible capacity to provide reliable supply is the appropriate output. The EUAA considers there to be evidence of excess capacity through-out the NEM's networks following excessive demand forecasts by NSPs. The EUAA also considers system capacity is not objectively measured (p. 2). The EUAA supports the use of rolling peak demand over 3–5 years and network utilisation also merits further investigation (p. 2). The MEU considers NSPs should only be funded to provide capacity to meet future needs, not to set a specific capacity. Hence, the AER must include a benchmark based on non-coincident peak demand (which is the main driver of augmentation). To identify the benchmark for the forecast expenditure without testing this against historic non-coincident peak demand reduces the effectiveness of the measure (pp. 19–20). COSBOA is not convinced about the proposed use of 'loss of supply events' and 'aggregate unplanned outage duration' as outputs. COSBOA is also concerned about the use of the Value of Customer Reliability (VCR) to value reliability outputs. VCR is uncertain and susceptible to large variation, which may undermine the reliability of and confidence in the benchmarking results (p. 13). COSBOA also does not support the use of system capacity over actual demand as an output. Consumers benefit from the least possible capacity to provide reliable supply. There is significant evidence of excess capacity in NEM networks due to excessive demand forecasts approved in AER determinations but falling actual demand. Not accounting for actual demand in the specification of outputs risks that inefficient over-spending is not reflected in the benchmark efficiency assessment (p. 14). NERA submits that deciding whether a particular variable satisfies the AER’s criteria for selecting economic benchmarking variables is inherently subjective. For example, the requirement that an output variable is ‘significant’ and that an environmental variable must have a ‘material’ impact both involve subjective assessments regarding the extent of significance/materiality. It is not obvious how an assessment regarding the ‘significance’ of various outputs of a TNSP would be undertaken, given they are denominated in different units (i.e., system capacity vs. the number of entry and exit points). The AER provides no guidance on how these assessments are to be undertaken (p. 51)

		NERA submits demand side measures of outputs (i.e. energy delivered and peak demand) tend to find urban distributors with dense networks more efficient, whilst supply side models of NSP outputs (i.e. system capacity) tend to favour rural distributors with sparse networks (but long line lengths) (p. 53). CP/PC/SAPN submit that it is critical the AER estimate output weights to be applied in any total factor productivity model based on data from the NSPs and should consider and test the appropriateness of using different output weights for different NSPs to better reflect the differences in the contribution of each output to NSPs' costs (p. 12).
The sample size of TNSPs is too small for economic benchmarking	NERA, MEU, COSBOA, Grid Australia	NERA submits that a sample size of just five, compounded by the heterogeneity between TNSPs presents a serious limitation on the ability of benchmarking techniques to offer any meaningful conclusions as to the relative efficiency of TNSPs. It is likely that differences in efficiency are attributable to explanatory variables excluded from the analysis (p. 9). The MEU considers that benchmarking must also include a wider set of benchmarking entities than just the NEM NSPs (p. 9). COSBOA considers the AER must utilise benchmarking for TNSPs. The TNSPs' concerns about benchmarking—lumpy investments, small number of TNSPs—are valid, but exaggerated. COSBOA stated there are similarities and a homogeneity about the operations of TNSPs which make them amenable to benchmarking: they produce similar outputs, have similar inputs (especially at the aggregated level), would be subject to similar environmental variables and it is possible to introduce control variables (p. 14). Grid Australia submits that each of the benchmarking techniques identified by the AER, multilateral total factor productivity (MTFP), data envelopment analysis (DEA), and economic benchmarking are highly unsuitable for application to TNSPs. This is because it is not possible to develop a meaningful data set for these techniques with the limited number of TNSPs in the NEM, or to establish valid statistical confidence intervals in the benchmarking results. The TNSP specific Guideline should expressly acknowledge these limitations, recognising that a principled assessment of the techniques would see them ruled out for application to TNSPs (pp. 6–8).
Irregular nature of transmission investment	NERA	NERA comments that TNSPs typically undertake capex projects that involve large, relatively infrequent augmentation of replacement of particular assets or groups of assets, rather than a steady stream of smaller projects. NERA notes that the AER is proposing to apply benchmarking to opex and total costs. In the case of total costs, the issue of the lumpy investment profile for transmission assets is reduced; since the assessment of capital costs takes into account both new capex and the existing asset base. The lumpy nature of transmission investment is therefore less of a difficulty in relation to the benchmarking applications being proposed by the AER (p.11).
Benchmarking model development	NERA, PIAC, CP/PC/SAPN	NERA submits that benchmarking model development the process should be transparent and consultative (p. 33). The following steps should be adopted: Identification of appropriate economic theory Collection of relevant data, and expression of that data on a consistent basis Design and specification of alternative model forms Testing and amendment of model forms in light of their performance (stability, statistical reliability, agreement with theory /other evidence) (pp. 34–45).

		NERA comments that it can be expected that once the economic benchmarking data is collected the AER will need to undertake a process of data cleaning in order to ensure that, as far as possible, information is reported on a consistent basis across businesses and is therefore comparable. NERA comments that development of a robust benchmarking model will be an iterative process, with different model specifications being subject to assessment and modification in light of actual data (p. 45). PIAC notes that while some assessment tools such as economic modelling and benchmarking may be 'works in progress', this should not stop the AER implementing them as soon as possible, albeit with the understanding that the full application of benchmarking in the regulatory process may need to be modified in the initial instances. PIAC is pleased that the AER has indicated it will do so (p. 23). CP/PC/SAPN submit that the AER should undertake extensive sensitivity testing of its preferred economic benchmarking model (p. 13).
Differences in NSPs cost/demand drivers	NERA, MEU COSBOA	NERA submits it is not obvious that the following variables have been considered: major circuit structures (for example, single circuit or double circuit, which can affect credible contingencies in the NEM); age and rating of existing network assets; timing of a TNSP in its investment cycle, given the lumpy nature of investments; and the extent of implications of NER ‘technical envelope’ requirements (for example, voltage stability, transient stability, voltage unbalance, and fault levels). NERA submits that a fundamental weakness of economic benchmarking is that it often overlooks environmental factors that are business specific (pp. 52–53). The MEU considers a recurring theme put by the NSPs is that all NSPs are different and to benchmark any NSP against others will result in distorted outcomes. The MEU accepts there is some validity in the claims. Equally the MEU considers that by careful selection of the benchmarking inputs and outputs and of the categories used in the development of the dataset, there is considerable commonality of activities that can result in useful comparisons. These can assist in providing a clear indication of what can be achieved by NSPs and the pursuit of NSP efficiency by the AER and consumers (pp. 8–9). COSBOA acknowledged all businesses, including individual NSPs, are different in some respects. However, they also have similarities and display similar cost drivers. COSBOA do not share the concerns of some NSPs that differences could detract from the AER’s approach (p. 10).
Category analysis		
Category analysis application	Huegin, NSW DNSPs, Ergon	Huegin considers category analysis cannot be used because there is not one common cost driver for the different categories proposed by the AER and it is difficult to obtain any meaningful interpretation of efficiency because costs are rarely driven by a sole driver and those drivers never exhibit the same influence across different businesses. This may lead to the AER choosing metrics that make a particular NSP appear inefficient while ignoring other metrics that make them appear efficient (p. 12). The NSW DNSPs consider the deterministic use of high level tools may lead to erroneous outcomes; consequently, DNSPs may not be provided with sufficient allowances to maintain the safety, security of the network and to meet its regulatory obligations. They suggest a

		replacement program may be rejected based on the outcome of the repex model despite evidence to show the failure of the asset is likely (p. 8). Ergon is concerned about the level of information required in the recently released proposed RIN templates and the intended purpose of that data. Notwithstanding the inherent level of inaccuracy of much of the data at this level of disaggregation, the inference appears to be that the AER can, through disaggregating costs to lower levels, find the ratio or measure upon which an unadulterated comparison of efficiency can be made. There is not one level or numerator/denominator combination that inefficiency residual neatly fits within. There is always another series of questions that can be asked with each revealed level of detail about the differences between businesses that can explain variation across cost ratios (p.11).
Demand forecasting	AEMO, COSBOA	AEMO noted its work in developing independent connection point demand forecasts for transmission. These forecasts will be prepared independently of the network businesses (although DNSPs have an important role in providing data). AEMO welcomes the opportunity to work with the AER to ensure the AER has confidence in AEMO's forecasts (p. 1). AEMO suggested the demand data templates (tables 3.1 and 3.2) require amendment to clarify the purpose of the data being collected. AEMO further suggested collecting sub-transmission point demand forecasts as part of table 3.2. These forecasts provide greater transparency to enable the lower voltage network to be modelled in more detail. Thorough options analysis can be performed to deliver the most efficient solution for consumers (p. 6). COSBOA strongly supports the AER to improve the forecasting of demand, including the application of guiding principles, and the use of 'top down' and 'bottom up' forecasts. COSBOA fully supports the AER's desire to have all information associated with models used to forecast demand, including model specifications and assumptions, made public. The development of improved transmission level forecasts by AEMO is important and provides an independent source of demand forecasts for the AER and its current development of distribution level forecasts could do the same at this level (pp. 16–17).
Augex	AEMO, NSW DNSPs, COSBOA, Uniting Care Australia	AEMO noted additional funding is triggered in the augex model when asset utilisation meets a specified threshold. There is a risk the augex model could create incentives for NSPs to lower their notified network capability in order to achieve higher asset utilisation rates. The AER should therefore consider whether a proposed augex solution is the most efficient solutions to that need, and whether the forecast costs associated with the proposed solutions are efficient. AEMO suggested the AER collects information that allows it to scrutinise the basis of an asset's capability, including asset utilisation at peak and times and data on the extent of over-utilisation. NSPs should also be required to explain any reductions in asset ratings (pp. 2, 6). AEMO suggests creating a data template for new projects which requests information relating to additional capacity provided with the corresponding assets associated with that new project. The AER should also collect data on projects that relieve non-thermal issues such as voltage control and more specific information on land and line easement costs (p. 7). The NSW DNSPs consider that the augex and repex handbooks do not provide sufficient information on the AER's calibration techniques and the way it would use benchmarking in applying the model (p. 13). The NSW DNSPs consider the augex model is limited in its use as a benchmark tool due to different network configurations, planning criteria and the definition of the $/MVA cost factor. They also have further specific issues and clarifications (p. 13). COSBOA favours the use of the augex model for (or to assist with) point of comparison, benchmarking, filtering and adjustment purposes. COSBOA considers the AER's approach to recognising the differences in application of the model to TNSPs is reasonable

		and support its application to TNSPs. The augex model should be run annually and the results published so that forecast versus actual variances can be tracked and analysed, including by consumers. COSBOA also endorses the AER's intention to pay close attention to how seriously NSPs have considered non-network solutions. However, the AER will need to develop robust ways to do this and align incentives if it is to become a more significant option for NSPs. (p. 16). Uniting Care recognises that there are some questions about the development of the augex model where demand is static or potentially declining. Uniting Care accepts that some refinement of this model will occur over time and are comfortable with an experience based learning approach (p. 4).
Repex	AEMO, COSBOA, Uniting Care Australia	AEMO considers the current regulatory framework does not incentivise NSPs to prolong the life of assets, especially where those assets have a written down value of zero in the RAB. Noting the information requirements of the repex model, AEMO noted asset age is a relevant consideration when considering asset replacement. However, the AER should consider collecting other relevant factors including asset condition and performance, and historical utilisation. AEMO suggests that going forward, the information collected by the AER might be used to develop an incentive scheme that rewards NSPs for retaining and utilising assets if they believe it is technically capable. AEMO further stated the AER should collect information that allows it to scrutinise the average asset lives proposed by NSPs (pp. 3, 5). COSBOA considers the application of the repex model can help to avoid some of the worst excesses of NSPs overstating their repex requirements. COSBOA supports the use of this model for both DNSPs and TNSPs (modified as needed), combined with techniques such as trend analysis, benchmarking and (where necessary) examination of more detailed information provided by NSPs. The repex model should be run annually and the results published so that forecast versus actual variances can be tracked and analysed, including by consumers (pp. 17–18). Uniting Care recognises that there are some questions about the development of the repex model where demand is static or potentially declining. Uniting Care accepts that some refinement of this model will occur over time and are comfortable with an experience based learning approach (p. 4).
Quality of service data	AEMO	AEMO supports the provision of quality of service information and suggested additional data the AER can collect. Such data would assist in the calculation of probabilities of network outages which could then be applied to economic planning studies, including RIT-T assessments. (pp. 7–8).
Provision of handbooks	NSW DNSPs	The NSW DNSPs consider the AER provide a handbook for each worksheet which clearly sets out the purpose of the material it seeks to collect (p. 13).
Overheads	NSW DNSPs, COSBOA	The NSW DNSPs submit that the proposed direct/network/corporate overhead categorisation is not compatible with their recording systems. They question the ability to form meaningful conclusions from this data due to the differing ways DNSPs record information (p. 13). COSBOA supports the AER's approach of examining overheads separately (scaled appropriately) and to benchmark these. COSBOA also support full visibility of NSPs' capitalisation policies (p. 19).

Customer initiated capex	COSBOA	COSBOA supports the AER's proposed approach to assessing customer-initiated capex forecasts, in particular the application of techniques such as benchmarking and trend analysis. (p. 18).
Non-network capex	COSBOA	COSBOA supports the AER's proposed approach to assessing non-network capex forecasts, in particular the application of techniques such as benchmarking and trend analysis. COSBOA recognises that such techniques may be more difficult to apply to expenditures that are non-recurrent and subject to step changes. In such cases, it will be important that the AER ensure that NSPs support their proposals with robust information or else they should not be accepted (p. 18).
Maintenance and emergency response opex	COSBOA	COSBOA notes the unpredictable nature of emergency response expenditure makes it less amenable to benchmarking and trend analysis. The AER proposed a list of drivers to enable it to better understand how NSPs forecast these costs. COSBOA considers the AER's view is understandable and its requests for information reasonable. However, COSBOA is concerned this approach will not allow the AER to determine the efficiency and prudency of NSPs' proposals. COSBOA suggests that the AER consider these risks further during its finalisation of the Guidelines (p. 18).
Vegetation management	COSBOA	COSBOA notes the AER's intention to rely on a more disaggregated approach to assessing vegetation management opex in future, including trend analysis and category benchmarking. COSBOA generally support this approach noting the limitations in the AER's knowledge of these costs and the frequent contracting out activities of the NSPs. COSBOA considers the AER should place the onus on NSPs to provide all possible information, even if it is incomplete at first, and to improve information collection reasonably quickly (p. 19).
Misc.		
DMIA	COSBOA	COSBOA encourages the AER to develop a new demand management incentive scheme as soon as practicable given the known shortcomings in the current one (p. 21).

Table D.2 Summary of issues raised at CRG or CRG subgroup meetings - CRG meeting 22 August 2013

Issue	AER response
Benchmarking should include overseas networks. This will incorporate international best practice and show inefficiencies in the Australian market.	We agree that expanding our benchmarking dataset to include other network businesses may result in capturing a higher calibre of performance and efficiency. It would also potentially improve the robustness of modelling/ benchmarking through a deeper dataset (e.g. degrees of freedom and stability of average cost benchmarks). This is a medium term priority and we have begun liaising with the UK and NZ regulator to consider alignment of datasets.
Networks should be benchmarked to the performance of the most efficient firm and not the average firm.	We will consider the appropriate allowance for prudent NSPs as required under the NER in reflection of the data and circumstances at each determination.
Benchmarking against actual peak demand is as important as benchmarking against network capacity because peak demand indicates the amount of “spare” capacity available for use when assessing augmentation capex.	We agree that actual peak demand and network capacity are both important factors to consider when assessing many augmentation decisions. To this end we are collecting information on both peak demand and network capacity for the purposes of benchmarking. We are also collecting a measure of network capacity utilisation to measure the extent to which there is unutilized capacity within a network. In developing benchmarking models all of these parameters will be considered. Further, it is our intention to publish data on these measures which will allow all interested parties to consider these measures.
It is important to set capex and opex allowances that move networks to the efficiency frontier as soon as possible.	We are obliged under the NER to set allowances that reflect efficient costs rather than provide NSPs additional allowances above these amounts in reflection of any time they may take to become efficient.
Repex and Augex models should be run annually and reported to determine forecast versus actual variances.	Given we are collecting new data to input into the repex and augex models, we consider it is appropriate to initially only publish their results following thorough review undertaken during the determination process. As we become more familiar with the data and the models we will be in a better position to reassess whether it is appropriate to publish the repex and augex model outputs on an annual basis. Further, the repex and augex models are tools to guide our assessment of the NSPs expenditure forecast. They are but one aspect of our repex and augex, respectively, forecast assessment in a determination. Hence, their results are not necessarily appropriate to judge the NSPs' incremental forecasting performance.
The incentive arrangement do not address double dipping by claiming the same capex in two or more regulatory periods.	Our capex expenditure assessment approach should limit the ability of NSPs to claim capex that is not prudent and efficient and as a result claim excessive capex from regulatory period to regulatory period. This approach will consider capex deferrals in prior periods where this is relevant to assessing forecasts. The consideration of capex deferrals when determining CESS payments should also limit any benefit to NSPs under the CESS from claiming the same capex

	in subsequent regulatory periods.
Demand forecasting suggests a reduction in network growth while consumer costs are still rising. The draft guideline must ensure overly optimistic demand forecasts will not be set.	Errors in demand forecasting are always an issue we seek to address and minimise, alongside NSP biases in overstating demand, when assessing regulatory proposals. Our Guideline significantly improves our approach to assessing demand forecasts and set clear expectations on NSPs in terms of the quality of information and the processes they employ.
As the incentive system in the regulatory regime encourages over forecasting reviewing forecasting each year could stop errors occurring.	Regular reporting of actual expenditures in relation to approved amounts in benchmarking reports, and the public scrutiny this will bring, should ensure systemic issues in forecasting methods employed by NSPs are exposed.
There is little data available for consumers to understand and engage with demand forecasting by NSPs.	Subject to confidentiality claims, we will publish all data collected under our RINs. The "black box" nature of some NSP forecasting methodologies is an ongoing issue which we expect to resolve through appropriate confidentiality arrangements, and in consideration of what information is useful/ necessary for consumers to engage in our processes.
Demand in regional areas is driven by major industries. Where a major user exits the market there is a concern that smaller users are paying for a network with redundant assets.	SCER has recently initiated a rule change proposal around pricing arrangements in the NER which aim to make network prices more cost reflective, including through increased consumer engagement on tariff structures.
There is a difficulty in determining real costs without strong historical data from NSPs. The AER should indicate its confidence in data.	Our RINs seek to collect a sufficient time series of historic information to apply in our various techniques. The quality of this information will be backed by appropriate assurance requirements and sign-offs.
As AER decisions are clear regarding the data that NSPs must provide and collecting such data is a part of operating efficiently, NSPs should not be claiming a higher opex in order to collect data.	Regulatory compliance costs can be legitimately claimed in light of new or increased obligations (including data reporting requirements) and will be subject to scrutiny under the NER provisions. Ultimately we expect consumers to benefit from any increased data burden under our new assessment techniques.