



BENCHMARKING AND SETTING EFFICIENCY TARGETS FOR THE AUSTRALIAN DNSPs

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EXPERT REPORT

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EXECUTIVE SUMMARY

I have been asked to review and answer specific questions on the AER's approach to assessing forecast operating expenditure (opex) as part of the AER's draft determinations for ActewAGL Distribution (AAD) published on the 27 November 2014. In undertaking its assessment of forecast opex, the AER has an overarching objective of the National Electricity Objective (NEO) set out in section 7 of the National Electricity Law (NEL), which reads:-

"The objective of this Law is 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."

Under the National Electricity Rules (NER) (6.5.6(c)) the AER, in relation to opex, has an obligation to

"(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (the operating expenditure criteria):

(1) the efficient costs of achieving the operating expenditure objectives; and

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

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

In November 2013 the AER published its *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*. These guidelines set out the AER's proposed approach for assessing forecast expenditure under the NER. On page 13 of the guidelines the AER states that it will use several types of benchmarking in its assessment process:

- economic benchmarking;
- category level benchmarking; and
- aggregate category benchmarking.

In my opinion, benchmarking is an important tool available to regulators in assessing the **efficiency** of regulated companies. However, its limitations must be considered in setting revenue allowances for companies and other tools / information should be used to supplement a benchmarking model(s).

In addition, a regulator must also consider how quickly and **prudently** an inefficient company may reduce its expenditure to an efficient level. If an expenditure level is set too low for the DNSP to achieve then the safe, secure, reliable operation of the network may be at risk, which is not in line with the long-term interests of consumers. In my opinion, when making their judgement on the efficiency gap inefficient companies should close over a regulatory period regulators should take into account:

- the robustness of the data and maturity of the dataset;
- the modelling technique used;
- the choice of the ‘frontier’; and
- the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.

The specific questions posed to me and my responses are set out below.

Is the AER's analysis robust having regard to the adjustments it makes for the DNSPs' different operating environments? Should additional and/or alternative adjustments be made to account for the DNSPs' different operating environments? If so, please specify which additional and/or alternative adjustments should be made.

After reviewing the AER's and its consultant's (Economic Insights) analysis and modelling, it is my opinion that:

- insufficient consideration has been given to the DNSPs' different operating environments within the benchmarking; and
- the Regulatory Information Notice (RIN) data in the form collected and used by the AER does not provided opex on a like-for-like basis across the DNSPs.

The former point is particularly critical as the AER has chosen to rely on international data (New Zealand and Ontario, Canada) that does not appear to have been robustly reviewed for operating environment differences either with Australia or across the countries. My brief examination of the datasets and their construction highlights major concerns for comparability, let alone differences in operating environments. Even if operating environment differences were identified, Economic Insights cites a lack of operating environment variables for Ontario, limiting them to using only the share of underground cables as a proportion of total line length. This was done despite the massive difference in climate between Australia and Ontario.

The RINs operating expenditure (Opex) data relied upon by the AER has not been sufficiently normalised for reporting differences before being used in the modelling. These include differences in the companies' CAMs and differences in companies treating activities as maintenance or replacement expenditure. The literature around the use of benchmarking for regulatory purposes (for example, Jamasb & Pollitt (2001), ACCC (2012)) note the importance of ensuring data is collected on a similar basis, is audited, and operating environment differences are controlled for. Jamasb & Pollitt (2001) noted that:

It is important that the regulators collect national and international data through formal co-operation and exchange. New regulators need to pay ample attention to developing good data collection and reporting systems. A precondition for

*international comparisons is to focus on improving the quality of the data collection process, auditing, and standardisation within and across countries.*¹

Failure to normalise the data may lead to unreliable results, and potentially the choice of inappropriate model specifications. Ofgem, considered to be a leader in benchmarking, spends a considerable amount of time setting out the cost categories, asset lists and reporting guidelines to ensure that the data is reported on a like-for-like basis regardless of the regulated companies' own internal cost reporting. I note that failure to normalise the data will impact on the category analysis, not just the econometric benchmarking.

Given the lack of scrutiny and difficulties in using international data, it is my opinion that Economic Insights' use of Ontario and NZ data is inappropriate as a supplement to the AER's RIN database. In relation to Economic Insights' observations about the (lack of) robustness of modelling using only the AER RIN dataset, I consider that it is more acceptable to use the Australian dataset, recognising and adjusting for the reporting differences, than to include non-comparable international data. Therefore, I have estimated alternative benchmarking models which only use Australian RIN data. In conducting this modelling I:

- normalised the AER data as best as I can with the information I have been provided and the limited time available;
- incorporated a greater range of operating environment variables; and
- used a range of parametric techniques.

I have not used non-parametric techniques as I consider there was an insufficient number of companies for DEA and the inability to produce descriptive statistics outweighs the benefits of these techniques.

I was unable to consistently produce robust results using stochastic frontier methods (SFA), likely due to the limited number of comparators, but I was able to produce results using corrected ordinary least squares (COLS) and random effects (using a generalised least squares estimator). I present the models' specifications in Table E.1 below and the efficiency results for the companies from these models in Figure E.1 and E.2 below. I ran these specifications using an OLS and RE (GLS) technique. I have included the results from Economic Insights' preferred model for comparative purposes.

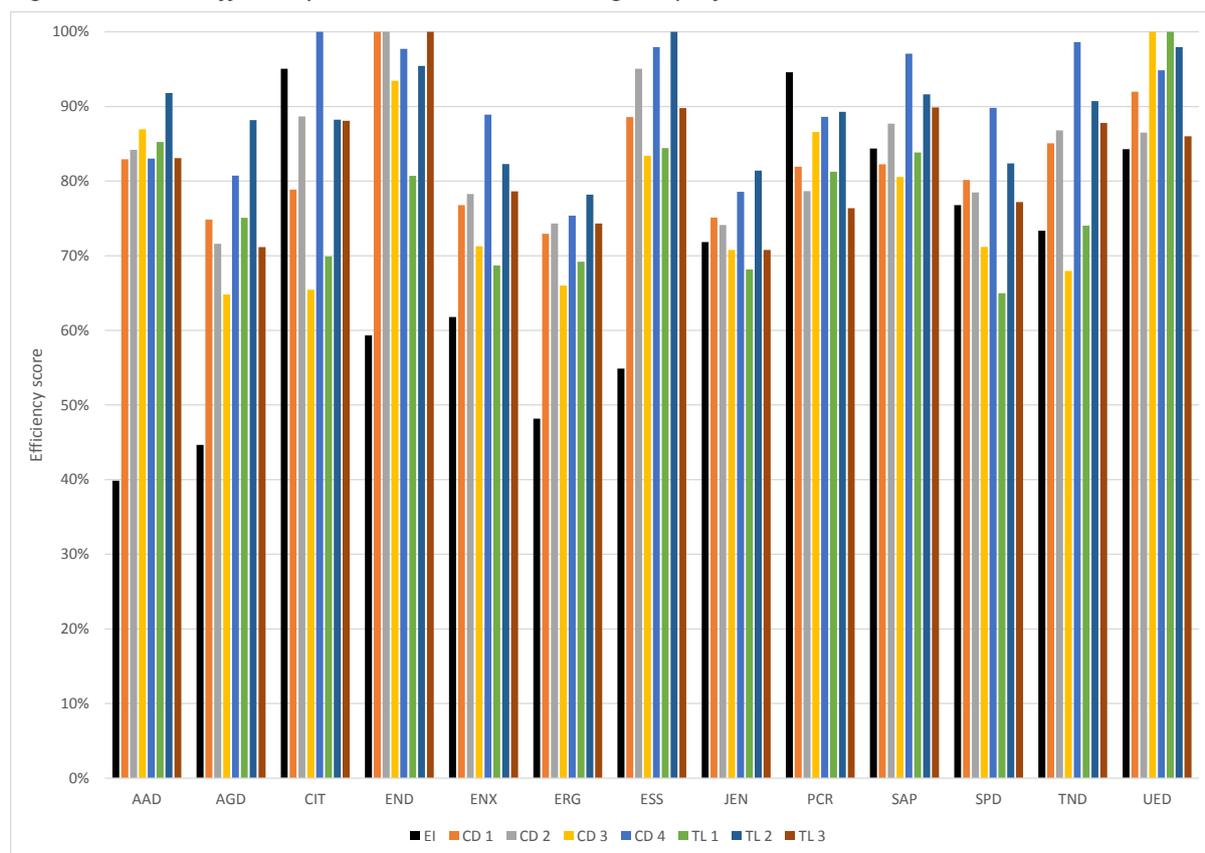
¹ Jamasb & Pollitt (2001), page 128. All references are collected together in ANNEX H.

Table E.1: Model specifications

	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
Functional form*	Cobb-Douglas	Cobb-Douglas	Cobb-Douglas	Cobb-Douglas	Translog	Translog	Translog
Circuit length	✓	✓	✓	✓	✓	✓	✓
Density (customer numbers/ length)	✓		✓	✓	✓	✓	✓
Density (customer numbers / coverage (Km ²))		✓					
Share of underground cables	✓	✓	✓	✓	✓	✓	✓
=> 132kV share of circuit	✓	✓	✓		✓	✓	✓
Share of SWER			✓				✓
RAB additions ²	✓	✓		✓	✓	✓	
Time trend	✓	✓	✓	✓	✓	✓	✓

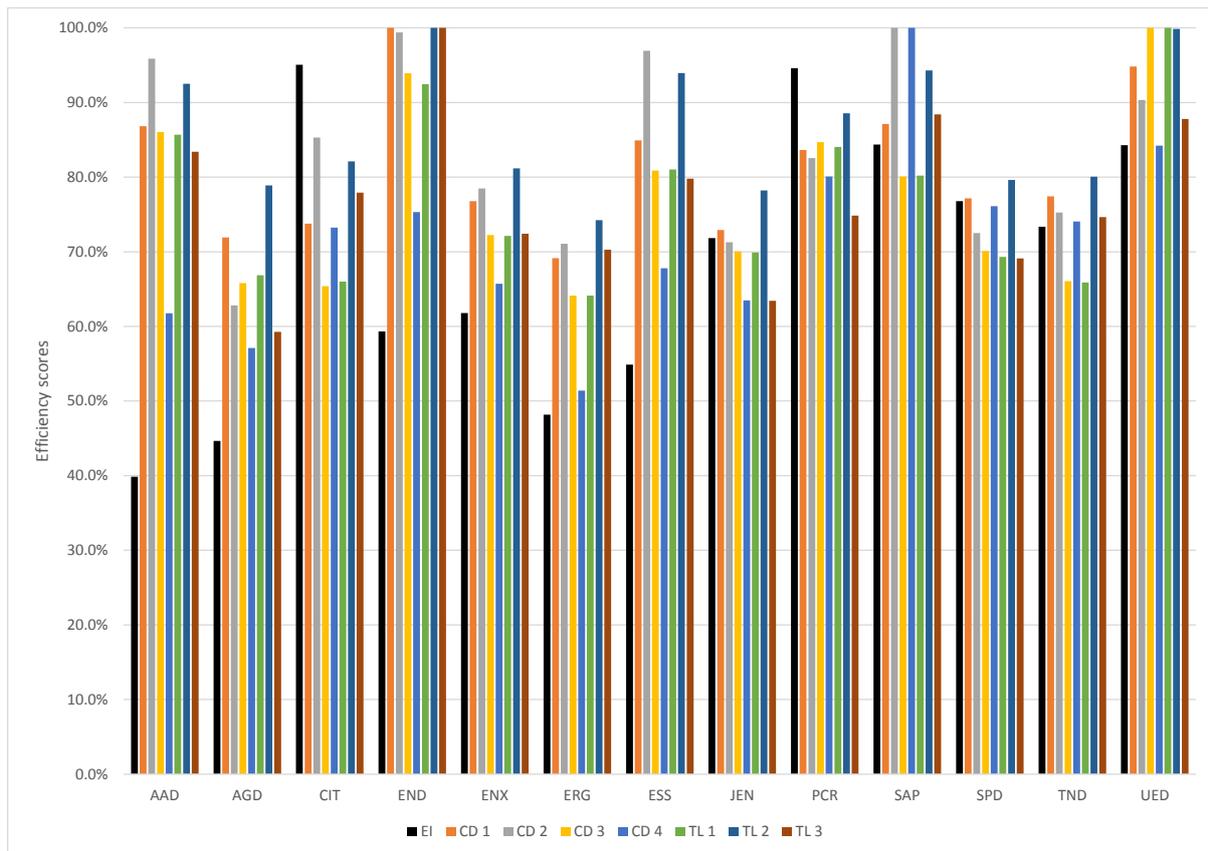
* Cobb-Douglas models require a constant return to scale across DNSPs while translog models allow for varying returns to scale. All variables except for the time trend are in logs.

Figure E.1 – OLS efficiency Scores vs. Economic Insights' preferred model



² 'RAB additions' provides an indication of the capex work that the DNSPs are undertaking and theory indicates that an increase in capex work, if not substitutable (and substituted) with opex, will lead to an increase in opex. This is Ofgem's reason for including the value of asset additions as a driver in its closely associated indirects opex model for RIIO-ED1. 'RAB additions' is not an ideal driver to use as inefficiencies ('gold plating') in capex may drive opex,

Figure E.2 – RE (GLS) efficiency Scores vs. Economic Insights’ preferred model



I found that the modelling was very sensitive to the inclusion of alternative operating environment variables. The efficiency scores varied across all DNSPs with environmental variables for higher voltage levels tending to favour the NSW and ACT networks. The sensitivity of the inefficiency results to the specification of the modelling indicates that significant caution should be placed on the results of any one specification as it is unlikely to control for all the differences between the companies. Including an operating environment variable for 132kV (and higher) line and cables significantly reduced the range of efficiency scores across the companies. In part this was likely because only six companies had lines or cables at this voltage level or above. However, as this variable is significant, and positive, in almost all the specifications I tested it does indicate that operating higher voltage lines and cables requires higher opex than lower voltage lines.

My findings indicate that a greater range of operating environment variables and models are almost certainly required to control for the differences between the DNSPs. For example, Ofgem during its recent RIIO-ED1 (electricity distribution) price control used a range of bottom-up models to assess the different activities within opex. It combined these models with its top-down models to develop an overall view of the distribution network operators’ efficiency.

however alternative drivers providing similar information but on the *required* level of capex ‘work’ undertaken were not available.

Even normalising for differences identified by Economic Insights/ AER prior to modelling leads to a different efficiency target for the DNSPs. Given these issues, the AER's reliance on the econometric analysis may not be in the long-term interests of consumers, and therefore not promoting the NEO, as the expenditure levels may be set below those required for the safe, secure, reliable operation of the network.

I have not tried to identify a suite of or single perfect model for opex benchmarking, this is a much more exhaustive process than the time allows. Rather, my analysis shows that there are operating environment differences that Economic Insights have not controlled for in its modelling. The modelling I have done provides a much tighter range of efficiency scores than those produced by Economic Insights' preferred model. In my opinion the aggregate level opex benchmarking should also be supplemented by activity level benchmarking using normalised costs, e.g., overheads.

What are the results of using the AER's proposed method of calculating the "efficiency frontier" on the alternative models? Are there alternative approaches to selecting the frontier than the approach adopted by the AER? How does AER's approach compare with international precedent? Under what circumstances could the AER have chosen such alternatives?

After reviewing the AER's proposed method of calculating the "efficiency frontier" on its preferred model and alternative models developed I consider that:

- the AER's approach of averaging the efficiency over companies that achieve an efficiency score of at least 75% is very model specific;³ and
- if a different specification was run and all companies achieved efficiency score of over 75% then the AER's approach would not work in the way intended, in my opinion, as the frontier would be an average over all the DNSPs' efficiency scores.

As the alternative models I estimated show a much tighter range of efficiency scores the AER's method is not appropriate. Alternative approaches could be to use the upper quartile point (either the upper quartile company or in between the companies that form the upper quartile), a median or average frontier. The latter two approaches might be more appropriate given uncertainty over the RIN data and the scope for further more robust normalisations.

My review of precedent from regulators in other jurisdictions indicates that regulators choose a frontier taking into account a range of factors, including their confidence in the data, techniques and robustness of the modelling. It is worth noting that when regulatory judgement is applied to the frontier after it is estimated via SFA it calls into question why this more complex and less transparent technique was chosen in the first place.

Given the lack of explanatory variables in the modelling and the wide range of efficiency scores I would expect the AER to have adopted a much more cautious approach to setting the

³ I note that Economic Insights refer to using the top-quartile in its report (Economic Insights (2014), page v), however it does not use a quartile. Rather it simply specifies that scores over 75% should be averaged across.

efficiency target in line with international precedent (discussed further in the following chapter). At the very least, greater consideration should have been given to the differences across the group of efficient and the group of inefficient companies. The AER conducted supporting analysis via its category analysis, however this was flawed due to the same issues of normalisation affecting the econometric model.

How do measurement error, specification, and techniques affect the choice of model(s) and the frontier?

In regulatory benchmarking, specification and techniques, which are chosen by the regulator, will impact on the regulator's choice of a frontier (efficiency target). Measurement error is a consideration for regulators in choosing a technique or specification to use. Some frontier based models, e.g. Stochastic Frontier Analysis (SFA), use strong assumptions to deal with measurement error while in others, e.g. Corrected Ordinary Least Squares, the regulator will adjust its findings/ efficiency target to reflect the measurement error. In my opinion, recognising and taking into account measurement error is as important as the theory or data that lead to the choice of model specification or technique.

Evidence from international regulators indicates that measurement error plays a significant part in their decisions on where to set the frontier and how much to 'aim-off' this. The regulator also takes into account the specification of the models, whether the drivers used in the modelling do not take account of (or differentiate between) all the costs faced by the regulated companies, and then adjustments to allowances may be made. Jamasb & Pollitt (2001) noted that sufficient data and comparators are required for the application of frontier methods.⁴ I interpret "sufficient data" to also mean the quality and robustness of the data as the authors discuss these issues in latter sections of their paper.

In relation to 'aiming-off' the frontier (or choosing a less challenging frontier), regulators have shown a large degree of discretion in determining the extent to which inefficient companies need to close the gap to the frontier and how quickly they need to do this. This is even after the regulator has used its discretion in choosing a frontier. In making their judgement regulators take into account:

- the robustness of the data and maturity of the dataset;
- the modelling technique used;
- the choice of the 'frontier'; and
- the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.

In almost all cases they have taken a more cautious approach than using a simple frontier in order to recognise the limitations of the modelling and the economic costs and risks placed on the companies. This is not dissimilar to the revenue and pricing principles that the AER

⁴ Jamasb & Pollitt (2001), page 108.

must take into account as set out in Section 7A of the National Electricity Law. It is often the case that regulators are required to take into account both the interests of consumers and the ongoing financeability of an efficient regulated company. If a regulator were to set either an unrealistic or unachievable efficiency target for a regulated companies then both of these aims and the promotion of the NEO may be put at risk.

Does the way in which the AER applies its "inefficiency adjustment" meet objective criteria (minimises measurement error, reflects operating environment, and incorporates realistic targets)?

As I state above, regulators need to consider a range of factors when determining and setting an 'inefficiency' adjustment. International precedent indicates that regulators have tended to be cautious in their approaches to setting efficiency targets and the speed at which they should be closed. Measurement error and the ability to control for operating environment differences appear to have been two key considerations for regulators when choosing the frontier. However, when it has come to setting the inefficiency adjustment regulators have been mindful of the ongoing financeability of the companies and the feasibility of them achieving the reductions.

For example, Meyrick and Associates (Meyrick (2003)) in its work for the New Zealand Commerce Commission for its 2004 electricity distribution networks price control noted that while it had identified a substantial range in companies' efficiency "[g]iven the need to minimise risks given the variable quality of the available data and residual uncertainties, we reduce the range of C factors [relative productivity and profitability factors] to -1, 0 and 1 per cent".⁵ Meyrick noted, in relation to overall prices, that:

Given the capital intensive nature of electricity lines businesses and the long lived nature of the assets involved, it is unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time. Rather, a timeframe of a decade, or two five-year regulatory periods, is likely to be necessary for businesses performing near the bottom of the range to lift themselves into the middle of the pack. This timeframe would allow sufficient time for asset bases to be adjusted significantly, new work practices to be adopted and bedded down and for amalgamations and rationalisations to be implemented and consolidated. It is, however, reasonable to expect profitability levels to be adjusted over a shorter period, say one regulatory period of five years. This should allow sufficient time for adjustment in a sustainable fashion without incurring the risk of financial stress or failure resulting from large PO adjustments.⁶

While the AER's SFA approach makes an assumption to deal with measurement error, the single environmental control variable of share of underground cables and the lack of normalisation for opex indicates to me that the AER's inefficiency adjustment is of a much greater magnitude than those applied by other regulators given the circumstances.

⁵ Meyrick (2003), page 63. The Meyrick report was led by Dr Denis Lawrence who is now Director of Economic Insights and who led the benchmarking work for the AER.

⁶ Ibid.

In addition, while the AER has taken into account Economic Insights’ proposals for adjusting the frontier for some company-specific factors, these only relate to the differences between the inefficient Australian companies and the Australian ‘frontier’ and do not reflect the operating differences between Australia and the other countries which have not been controlled for. In other words, while Economic Insights state that it has benchmarked Australian companies only against Australian companies, because the international data has influenced the coefficients (see Table E.2) AAD is being compared against a statistically significantly different frontier slope determined primarily by New Zealand and Ontario data. One can see from the table that the coefficients on the AER RIN data are significantly different from NZ and Ontario. The coefficient for customer numbers on the Australian data alone is statistically significantly different from that in the full dataset.

Table E.2: Comparison of coefficients across countries/regions

Variable	Medium dataset		Australia	New Zealand	Ontario
	Coefficient	95% C.I.	Coefficient	Coefficient	Coefficient
Log(CustomerNos)	0.667***	0.49, 0.84	1.146***	0.566***	0.732***
Log(CircuitLength)	0.106***	0.03, 0.18	0.13	0.201*	0.041
Log(RMDemand)	0.214***	0.06, 0.37	-0.242	0.206*	0.234**
Log(ShareUGC)	-0.131***	-0.20, -0.07	-0.021	-0.088	-0.211***
Year	0.018***	0.01, 0.02	0.034***	0.023***	0.010***
New Zealand	0.05	-0.15, 0.25			
Canada	0.157**	0.01, 0.30			
Constant	-26.53***	-34.3, -18.8	-58.778***	-37.122***	-9.690**
Additional statistics					
Observations	544	-	104	144	296

Note: significance stars as follows, *10%, **5%, ***1%.

Overall in my opinion, the AER has not sufficiently recognised the limitations of opex modelling, particularly when using data that may not be comparable, in setting the efficiency targets for AAD and the NSW Networks. This may result in the expenditure level being set to low for the ongoing financeability, safety, reliability and/or security of a network to be achieved.

If the definition of the efficiency frontier is subject to regulatory discretion, how has the AER exercised its discretion in selecting its preferred approach?

Regulators operate under legislation which can impact on the level of discretion they are able to apply. However, an almost universal obligation on regulators is for them to have regard to the long term interests of consumers. This clearly covers a range of factors, but the ongoing viability of the service provider is a critical aspect of this. Regulators need to have regard for the entire regulatory ‘package’ that they put in place. This ranges from the cost assessment through to the incentives and financeability of the service providers. While I understand that

the AER has no specific requirement under the legislation to have regard to the financeability of the DNSPs, this is implicit in the National Electricity Objective (NEO) having regard to the long term interests of consumers.⁷ I note that the AEMC, in its final rule determination,⁸ indicated clearly that the AER should treat benchmarking as just one of various considerations:

Benchmarking is but one tool the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal.

As Haney & Pollitt (2012) set out, efficiency analysis happens within a process. This process is interactive and involves negotiation and ex post review. Benchmarking is a useful tool in this process, but not the only source of evidence.⁹ For example, the authors note that the Finnish regulator uses a number of frontier benchmarking methods, but it only applies the results to their negotiation based method of regulation.¹⁰

In my opinion this is because the 'efficient and prudent operation' of a DNSP requires realistic and achievable price paths, and ongoing financing. Specifically, if the AER were to raise doubts in the minds of credit agencies about the credit-worthiness of a DNSP, it would likely face a higher WACC, which would translate into higher revenue requirements, to the detriment of future consumers which would not be in line with the NEO.

Is it appropriate to set more than one frontier and is there precedence for this?

There are several options that regulators may adopt when setting a frontier:

- a single benchmark for all companies (this could be based on a single model or multiple models) and applying the same rate of catch-up;
- a single benchmark for all companies, but apply different rates of catch-up; or
- multiple benchmarks taking account of different factors, for example the size of the company.

In more developed regulatory regimes the approach has been to set a single benchmark for all companies. However, this has been after adjustments for operating environment differences have been incorporated and before specific allowances for differences have been set. Setting different frontiers has been used by regulators for instance in yardstick regulation, where the frontier is set by peer groups rather than the frontier companies.¹¹

As I have stated above, regulators use their discretion in setting frontier's to ensure the ongoing operations of the network services provides for the long-term interests of consumers in line with the NEO.

⁷ National Electricity (South Australia) Act 1996—19.12.2013, Schedule—National Electricity Law, Part 1, para 7.

⁸ AEMC (2012), page 107.

⁹ Haney & Pollitt (2012), page 7.

¹⁰ Haney & Pollitt (2012), page 36.

¹¹ The National Energy Commission (CNE) in Chile used this type of approach.

GLOSSARY

Term	Definition
AAD	ActewAGL
AER	Australian Energy Regulator
AGD	AusGrid
Between estimator	Refers to the variation across comparators' explanatory variables in a data set. It is used in conjunction with the within estimator (variation in the company's explanatory variables over time) in panel or pooled regressions to estimate the coefficients on explanatory variables.
Capex	Capital expenditure
CIT	Citipower
Cobb-Douglas model	The Cobb-Douglas (or log-linear) model transforms the variables into logarithms prior to estimation. This model is deemed superior to a linear model in the cost modelling literature as it does not require marginal costs to be constant as in the linear model. Even so, the Cobb-Douglas model is in itself restrictive because, inter alia, it assumes that the extent of returns to scale is the same irrespective of firm size. Compare with translog model.
Corrected OLS (COLS)	See ordinary least squares (OLS) defined below. COLS follows the same statistical technique as OLS (i.e. estimating a line of best fit by minimising the sum of squared errors), however the 'average' line is shifted towards a 'frontier' point i.e., this may be an upper quartile (best) performing company in terms of relatively low costs for its level of outputs. The average line is shifted by changing the intercept point, but no change is made to the slope of the line.
Correlation (coefficient)	A correlation coefficient is the measure of linear interdependence between two variables. The value ranges from -1 to 1, with -1 indicating a perfect negative correlation and 1 indicating a perfect positive correlation. Zero indicates the absence of correlation between the variables.
Data envelopment analysis (DEA)	A quantitative non-parametric technique that optimises the number of inputs required for a particular output and vice versa. It does not require assumptions on the functional form, but it also does not allow statistical testing on the significance of explanatory variables.
DNSP	Distribution network service provider
END	Endeavour Energy
ENX	Energex
ERG	Ergon
ESS	Essential Energy

Generalised least squares (GLS)	GLS is a technique for estimating the unknown parameters in a linear regression model. It is applied, for example, when some of the assumptions of the classical regression model break down – such as when the variance of the disturbances is assumed to be non-constant across observations (heteroskedasticity) or when there may be correlation between the disturbances (autocorrelation). The technique is used to estimate the random effects panel model (where there is dependence between observations of the same firm over time).
Hausman test	This test provides information on whether the fixed or random effects treatment is most appropriate. A high value of the statistic (which represents a rejection of the null hypothesis) indicates that the fixed effects model is preferred to the random effects model. Otherwise the random effects treatment is preferred.
Heteroskedasticity	One of the assumptions underpinning the classical linear regression model is that the disturbances are homoskedastic (that is have a constant variance). When the disturbances are heteroskedastic this means that the variance of the disturbances is not constant across firms (an example is where the disturbances increase as firm size increases).
JEN	Jemena Electricity Networks
Maximum likelihood estimation (MLE)	This is a method of estimating the parameters of a statistical model. Under the standard assumptions underpinning the classical linear regression model, MLE produces identical estimates to those produced by OLS. However, MLE has been shown to have desirable (large sample) properties under a wide range of assumptions (unlike OLS) and this method is therefore used in a wide range of contexts, including stochastic frontier analysis. Information is needed concerning the distribution of the errors to implement MLE.
Menu regulation	Menu regulation is a form of regulation where regulated companies are no longer presented with a ‘take it or appeal it’ regulatory offer regarding the allowed level of expenditure, but are instead given a range of options from which to choose.
Multicollinearity	An exact linear relationship between two or more explanatory variables characterises the extreme case of perfect collinearity (approximate linear relationships between variables are more common in practice). In the former case (perfect collinearity) the OLS procedure cannot be implemented. The latter case (approximate linear relationships) results in high standard errors. Whilst the parameter estimates and estimates of the standard errors are not biased as such, the problem is that it will be hard to draw conclusions on the impact of individual variables on the dependent variable. The overall predictive power of the model is not reduced (only the ability to use the coefficients individually).
NEL	National Electricity Law
NEO	National Electricity Objective

NER	National Electricity Rules
Normalise/ Normalisation	In this report, this means ensure that reported data is on a like-for-like basis. For example, ensuring that different CAMs do not affect a benchmark of overall opex.
Opex	Operating expenditure
Ordinary Least Squares (OLS)	OLS is a method by which linear regression analysis seeks to derive a relationship between company performance and characteristics of the production process. This method is used when companies have relatively similar inputs and outputs. Using available information to estimate a line of best fit (by minimising the sum of squared errors) the average cost or production function is calculated.
PCR	Powercor
Pooled OLS	The pooled OLS model treats the data as if it was a cross-section – that is, e.g. 90 firms, rather than a panel of 10 firms over nine years. This approach does not therefore recognise the panel structure of the data, and can be tested against the panel model variants. It is however a simple model that is used by economic regulators in particular.
Pooled Stochastic Frontier Analysis (SFA) model	This is a maximum likelihood estimation model that is the same as COLS except that a one-sided error term is included to permit the existence of inefficiency (with the error term decomposed into its noise and inefficiency components). This approach requires distributional assumptions on the error components.
Process/ activity benchmarking	This is more simplistic type of benchmarking and may not involve frontier based approaches. Type of benchmarking may include: ratio, run-rate, unit cost, engineering assessment, etc.
Real price effects (RPEs)	The amount by which certain input prices are expected to move relative to CPI (either increased/ decreasing at a faster rate).
RIN	Regulatory Information Notice
SAP	SA Power Networks
SPD	SP AusNet (distribution)
Time invariant efficiency model: Fixed Effects (FE)	<p>This is the standard fixed effects model used in the panel data literature, except that in this case the fixed effects terms are given an inefficiency interpretation. In the fixed effects model, firm-specific effects (unobserved differences between firms) are estimated as fixed parameters to be estimated, by including firm-specific dummy variables in the regression. However, the true distinction between fixed and random effects is whether the effects are correlated with the other regressors or not (in the case of random effects the effects are assumed to be uncorrelated with the regressors, whereas in fixed effects the effects are permitted to be correlated with the regressors).</p> <p>It is sometimes said that this approach is concerned only with the particular firms in the sample (i.e. that the sample contains all</p>

	relevant firms and there are therefore no additional firms outside the sample of interest). The random effects model treats the unobserved firm effects as randomly distributed across firms (so here I see the current sample as being drawn from a wider sample or population). It has been pointed out in the literature that in fact the fixed effects model can be reformulated and estimated as a random effects model, so the distinction concerning whether the effects are stochastic or not is erroneous (see, for example, Greene, <i>Econometric Analysis</i> , 5 th Edition, page 285).
Time invariant efficiency model: Random Effects (RE)	This is the standard random effects model used in the panel data literature, except that in this case the random effects terms are given an inefficiency interpretation. The random effects specification imposes the assumption that the unobserved individual effects are uncorrelated with the regressors.
Time-invariant SFA model	This is a maximum likelihood model and an extension of the random effects model but now with distributional assumptions imposed and with estimation proceeding via MLE, not generalised least squares (GLS), as in the standard panel data random effects model. See Pitt and Lee (1981).
Time varying SFA model	This is a maximum likelihood model that extends the model above to permit efficiency to vary over time but in a restricted way, since the direction of efficiency change over time must be the same for all firms (and thus rankings cannot change). See Battese and Coelli (1992)
Skewness	Skewness is a term used to describe non-symmetric distribution (a right skewed distribution has a longer “tail” to the right and vice versa for a left skewed distribution).
TND	TasNetworks (distribution)
Total factor productivity (TFP)	A measure of the economy’s long-term technological change.
Totex	Total expenditure (opex + capex)
Translog model	The translog model is one of the so-called flexible functional forms and is used routinely in the academic literature. In the current context one of its particular advantages is that it allows the degree of returns to scale to vary with firm size. The Cobb-Douglas is nested within the translog so it is possible to test the Cobb-Douglas restriction.
UED	United Energy Distribution
Within estimator	Refers to the variation in the company’s explanatory variables over time in a data set. It is used in conjunction with the between estimator (variation across companies’ explanatory variables) in panel or pooled regressions to estimate the coefficients on explanatory variables.

1. INTRODUCTION

I have been asked by ActewAGL to prepare this report as an expert witness to the Australian Energy Regulator's (AER's) upcoming regulatory determination for ActewAGL to apply from the period commencing on 1 July 2014 to 30 June 2019.

Specifically, I have been asked to review and answer specific questions on the AER's approach to assessing forecast opex and on the AER's interpretation and use of the efficiency scores estimated by models developed by Economic Insights, the AER's economic consultants. In undertaking this work, I have relied on the Regulatory Information Notices (RINs) collected by the Australian Economic Regulator and the support of colleagues at CEPA in the data analysis. The full instructions with these questions are set out in ANNEX F. However, I have also set them out in Section 2.

In order to address the questions posed I have approached this project in two separate phases. In the first phase I have considered the data made available by the AER, made appropriate adjustments to normalise the data and developed benchmarking models for the Australian DNSPs. In the second phase, taking account of the first phase and the AER's benchmarking approach, I address the questions around the calculation and use of an efficiency target.

1.1. Statement of credentials

Professor David Newbery.

I am CEPA's Chairman. I am a Research Fellow in the Control and Power Research Group at Imperial College London and Emeritus Professor of Applied Economics at the University of Cambridge, where I was Director of the Department of Applied Economics from 1988 - 2003. I am Research Director of the Electricity Policy Research Group at the University of Cambridge, a multi-disciplinary research group supported by public funding from various Research Councils and from stakeholders in industry and regulatory agencies. I was the 2013 President of the International Association for Energy Economics. I spent two years as a Division Chief in the World Bank and have been a visiting Professor at Berkeley, Princeton, Stanford and Yale. I am a fellow of both the Econometric Society and the British Academy. I am the Deputy Independent Member of the Single Electricity Market of the island of Ireland, and was Chairman of the Dutch Electricity Market Surveillance Committee from 2001-5 and a member of the Competition Commission from 1996 to 2002.

I am an internationally recognised expert on economic regulation and reform of network industries and the transport sector. I have led and participated on numerous CEPA assignments in the Economic Regulation and Competition practice area for clients such as the UK's Ofgem (Office of Gas and Electricity Markets), the Portuguese Competition Commission, the Dutch Office of Energy Regulation and other regulatory agencies and regulated companies.

My publications include the book *Privatization, Restructuring and Regulation of Network Utilities* (MIT Press, 2000). I was the guest editor of *The Energy Journal* (2005) issue on European electricity liberalisation, and the recipient of a Festschrift “Papers in Honor of David Newbery: The future of electricity” in *The Energy Journal* (2008).

In preparing this report, I have been assisted principally by three CEPA colleagues, **Ian Alexander**, **Joel Cook** and **Ian Johnson**. Notwithstanding this assistance, the opinions in this report are my own and I take full responsibility for them.

I have read the Federal Court of Australia’s Practice Note CM7, June 2013, which provides guidelines on the preparation of Expert Witness Reports. I understand these guidelines and have complied with the Practice Note.

1.2. Structure of the report

The structure of this report is as follows:

- In Section 2 I set out the rules and guidelines under which the AER has assessed opex.
- In Section 3 I set out my assessment of the AER’s modelling and provide a summary of alternative models I have developed.
- In Section 4 I set out regulatory considerations for choosing a ‘frontier’, international precedent and my opinion on the AER’s approach.
- In Section 5 I set out my high level conclusions on the AER’s approach to forecast opex assessment and how its approach fits with achieving the NEO.

2. BACKGROUND

I have been asked to consider the AER's approach to calculating opex as part of its draft determination process for the AER's regulatory determination for ActewAGL to apply from the period commencing on 1 July 2014 to 30 June 2019. I have also been asked to address a number of questions related to the AER's approach to assessing opex. In particular, I have been asked to address question on the AER's consultant's, Economic Insights', modelling and on the AER's interpretation and use of the efficiency scores estimated by the models.

In order to undertake this critique it is important to understand the objectives and obligations the AER is under. The AER's overarching objective is the National Electricity Objective (NEO) set out in section 7 of the National Electricity Law, which reads:-

"The objective of this Law is 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 AER's specific obligations in respect to opex efficiency assessment are set out in the National Electricity Rules (NER) for assessing opex.

2.1. National Electricity Rules (NER)

The NER rules provide specific guidance for the assessment of opex; in assessing opex the AER must have regard for the NER opex criteria described in NER6.5.6(a) and reproduced below:

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

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

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

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

to the relevant extent:

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

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

(4) *maintain the safety of the distribution system through the supply of standard control services.*¹²

After receiving the DNSP's regulatory proposal, the AER must either accept or reject the DNSP's proposed forecast opex on the basis of the operating expenditure criteria described in NER6.5.6(c) and (d), and reproduced below (**emphasis added**):

“(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (the operating expenditure criteria):

- (1) the efficient costs of achieving the operating expenditure objectives; and*
- (2) the costs that a **prudent operator** would require to achieve the operating expenditure objectives; and*
- (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*

(d) If the AER is not satisfied as referred to in paragraph (c), it must not accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal.”¹³

In undertaking its assessment, the AER is required to take into account the operating expenditure factors. The operating expenditure factors are described in NER 6.5.6(e) and reproduced below:

“(e) In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the operating expenditure factors):

- (1) [Deleted]*
- (2) [Deleted]*
- (3) [Deleted]*
- (4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;*
- (5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*
- (5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;*
- (6) the relative prices of operating and capital inputs;*
- (7) the substitution possibilities between operating and capital expenditure;*
- (8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;*
- (9) the extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;*

¹² National Electricity Rules 6.5.6, Version 65, 1 October 2014

¹³ National Electricity Rules 6.5.6, Version 65, 1 October 2014

(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);

(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);

(12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.”¹⁴

2.2. Expenditure Forecast Assessment Guidelines

In November 2013 the AER published its *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*. These guidelines set out the AER’s proposed approach for assessing forecast expenditure under the NER. On page 13 of the guidelines the AER state that it will use several types of benchmarking:

- economic benchmarking;
- category level benchmarking; and
- aggregate category benchmarking.

In relation to economic benchmarking the AER made the following statement:

Economic benchmarking applies economic theory to measure the efficiency of a DNSP’s use of inputs to produce outputs, having regard to operating environment factors. It will enable us to compare the performance of a DNSP with its own past performance and the performance of other DNSPs. We will apply a range of economic benchmarking techniques, including (but not necessarily limited to):

- *multilateral total factor productivity*
- *data envelopment analysis*
- *econometric modelling.*¹⁵

In relation to category and aggregate category analysis the AER state:

We will benchmark across DNSPs by expenditure categories on a number of levels including:

- *total capex and total opex*
- *high level categories (drivers) of expenditure (for example customer driven capex or maintenance opex)*
- *subcategories of expenditure.*

We may benchmark further at the following low levels:

¹⁴ National Electricity Rules 6.5.6, Version 65, 1 October 2014

¹⁵ AER (2013), *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, page 13.

- unit costs associated with given works (for example, the direct labour and material cost required to replace a pole)
- unit volumes associated with given works (for example, kilometres of conductor replaced per year).

...

In addition to detailed category benchmarks we are likely to use aggregated category benchmarks, which capture information such as how much a DNSP spends per kilometre of line length or the amount of energy it delivers. We intend to improve these benchmarks by capturing the effects of scale and density on DNSP expenditures.¹⁶

While the AER set out that it would undertake a range of modelling in assessing forecast opex, I note that in setting the opex efficiency targets for the DNSPs the AER has relied almost solely on a single model (a Cobb-Douglas Stochastic Frontier Analysis (SFA) model). In AAD's case, the AER makes three adjustments to the frontier estimated via this model:¹⁷

1. Rather than using the National Energy Market (NEM) frontier service provider, CitiPower, as the benchmark for efficiency comparisons, the AER set a lower benchmark based on an average of the efficiency scores of the most efficient service providers in the NEM.
2. The AER modify the benchmark efficiency target (by 30%) to account for operating environment factors specific to AAD.
3. Because the Cobb Douglas SFA model efficiency scores represent ActewAGL's average efficiency for the benchmarking period. The AER applied a trend to move the substitute base opex from a forecast of the average amount for the 2006 to 2013 period to a forecast for 2012–13, the base year.

The AER also presents other econometric models (ordinary least squares) and MTFP which it considers support its SFA findings. It also presents category analysis which it states support its findings from the economic benchmarking.¹⁸

I discuss and provide my view on the AER's and Economic Insights' approach to benchmarking in more detail in Section 3. I have not been asked to investigate the category analysis in depth, it appears that the AER has not made the same adjustments to this analysis as it does for the SFA, e.g., recognising AAD's different capitalisation approach relative to the other DNSPs. In addition, as set out in Section 3 I consider that there are a number of other normalisations required to the DNSPs' data to allow for like-for-like comparison. These would also impact on the category analysis.

¹⁶ AER (2013), *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pages 13-14.

¹⁷ AER, *Draft decision ActewAGL distribution determination 2015/16 to 2018/19, Attachment 7: Operating Expenditure*, 27 November, page 7-27.

¹⁸ AER, *Draft decision ActewAGL distribution determination 2015/16 to 2018/19, Attachment 7: Operating Expenditure*, 27 November, page 7-31.

2.3. Key aspects

There are two key overarching aspects to the opex assessment (set out as points one and two in NER6.5.6(c)):

1. efficient costs; and
2. prudent operator.

Below I set out two simple high level interpretations of these aspects of opex assessment and allowance setting.

2.3.1. Efficient costs

It is appropriate to bear in mind two key points regulators should consider in relation to setting efficiency targets for regulated companies:

1. how much confidence can be placed on the assessment approach used to determine opex efficiency (regardless of whether the approach was based on top-down model(s), bottom-up engineering assessment or a combination); and
2. given the magnitude of a company's estimated inefficiency (taking into account the above), what is a reasonable speed at which it can close the efficiency gap without compromising the overall regulatory objective.

The simple interpretation of these points is that, the less confident a regulator is of the assessment then the more cautious it should be in setting an efficiency target and if there is a significant gap to close then it is more likely that the regulated company will need longer to close it. If either of these points are violated and if the DNSP's efficiency gap is large then its continuing operation may be adversely affected and/or the company's financing costs will increase. Also caught in the above points, but not explicitly set out, is the choice of what an efficient target might be (i.e. frontier, upper quartile, or average).

I discuss all the above in greater detail throughout this report. The AER's modelling/assessment approach is considered in Sections 3 and 4, while the discussion around the choice of an efficiency target is set out Section 5.

2.3.2. Prudent operator

The NER is specific in regards to the opex building block, but it is not specific on whether (or how) the opex building block should be considered in relation to the overall revenue requirements of the regulated company, aside from explicitly recognising the opex/ capex trade-off. The use of the term "prudent" in NER6.5.6(c) is therefore of critical importance in my opinion. NERA (2014) considered that a critical aspect of 'prudence' is the process and reasoning that is followed by DNSPs in developing their forecasts.¹⁹ Extending this interpretation to the 'sustainability' of the network, it would be imprudent for a DNSP not to

¹⁹ NERA (2014).

consider the impact on its reliability, quality of service and/or financeability from significantly reducing its opex or capex (including dividend payments) in a very short space of time.

2.4. Instructions

I have been asked to address a number of questions related to the AER's approach to assessing opex. In particular, I have been asked to address question on the AER's consultant's, Economic Insights', modelling and on AER's interpretation and use of the 'efficiency scores estimated by the models. The questions that I have been asked to consider are:

- Is the AER's analysis robust having regard to the adjustments it makes for the DNSPs' different operating environments? Should additional and/or alternative adjustments be made to account for the DNSPs' different operating environments? If so, please specify which additional and/or alternative adjustments should be made.
- What are the results of using the AER's proposed method of calculating the "efficiency frontier" on the alternative models? How does the AER's approach compare with international precedent?
- How do measurement error, specification, and techniques affect the choice of model(s) and the frontier?
- Does the way in which the AER applies its "inefficiency adjustment" meet objective criteria (minimises measurement error, reflects operating environment, and incorporates realistic targets)?
- Are there alternative approaches to selecting the frontier than the simple average of the top-quartile? Under what circumstances could the AER have chosen such alternatives?
- If the definition of the efficiency frontier is subject to regulatory discretion, how has the AER exercised its discretion in selecting its preferred approach?
- Is it appropriate to set more than one frontier and is there precedence for this?

I address these questions in the remainder of this report.

3. BENCHMARKING – DATA AND APPROACHES

In this Section I address the following questions posed to me by AAD:

- Is the AER's analysis robust having regard to the adjustments it makes for the DNSPs' different operating environments? Should additional and/or alternative adjustments be made to account for the DNSPs' different operating environments?
- What are the results of using the AER's proposed method of calculating the "efficiency frontier" on the alternative models? How does the AER's approach compare with international precedent?

3.1. Introduction

It goes without saying that robust benchmarking depends on reliable and relevant data, combined with a detailed understanding of the available data. Regulators and academics have highlighted the need for consistent data (that data from different sources measures the same object in the same way), in addition to a sufficient number of data points across companies in order to conduct benchmarking and to be confident in the robustness of the results. The regulator can proceed to choose or test a range of comparative benchmarking techniques once it:

- fully understands the available data;
- has made appropriate adjustments to normalise it across companies; and
- considers that there are a sufficient number of observations and explanatory variables.

Following this, the regulator should step back and consider: the plausibility of the results, the feasibility and practicalities of imposing targets on inefficient companies that will effectively reduce their inefficiency, close the gap to the efficient frontier and hence pass on the benefits of improved performance to consumers.

In this section I discuss the data that the AER and Economic Insights have used in their benchmarking and the need for further or alternative adjustments. I then set out the different modelling techniques that have been used by regulators and academics to establish the relative (in)efficiency of companies. Through following these steps I have undertaken to establish whether alternative models, using the Australian data normalised for differences that I can readily identify, can produce robust estimates efficiency estimates for the Australian DNSPs.

3.2. Data analysis

This section describes the data used in Economic Insights' benchmarking models. I focus first on the Australian data contained in the Economic Benchmarking (EB) and Category Analysis (CA) Regulatory Information Notices (RINs). I then set out my observations on this dataset, adjustments that have been made to it by the AER/ Economic Insights, and additional

adjustments that I argue are necessary for making data comparable across DNSPs. I then examine and compare this to the international data from Canada and New Zealand that was used by Economic Insights.

3.2.1. Australian RIN Data

The AER/ Economic Insights' adopted methodology focuses on benchmarking DNSPs' network services opex only, as reported in the EB RINs, tables 3.2.1 or 3.2.2. This covers a period from 2006 to 2013 based on each DNSP's reporting year²⁰ and is the AER's first attempt at collecting a consistent dataset for benchmarking across these 13 DNSPs. Previously data on DNSPs performance and expenditure were collected by state regulators. In developing the RIN guidelines the AER hosted a number of workshops with the DNSPs from the initiation of the programme in December 2012 to the collection of the data in October 2013. These workshops were intended to ensure a clear understanding of the scope of the RIN and to clarify requirements on the DNSPs for reporting that data.

The RIN dataset is therefore a new dataset with DNSPs reporting based on its requirements for the first time and being required to provide historical information reallocated according to these RIN guidelines.

Prior to using the RIN data, Economic Insights made adjustments to opex for three companies: END, ERG, and ESS. I understand that the differences for END are due to misallocated metering costs, while the differences for ERG and ESS are due to solar feed-in tariffs. Clearly these adjustments have been applied to make opex costs more consistent across DNSPs. Since comparable data is a logical prerequisite for benchmarking analysis, I do not see anything wrong with these adjustments.

Consultation between the AER and AAD identified five areas of adjustment of specific relevance to AAD, which Economic Insights outlines as:

- AAD's capitalisation policy;
- different control services connection coverage;
- backyard reticulation;
- taxes and levies; and
- occupational and safety regulations.

Economic Insights has taken account of these adjustments and proposed that the frontier for AAD could be adjusted by 30% as a result.²¹ While I do not disagree that adjustments should be made where data are inconsistent, given the magnitude of the adjustments proposed by Economic Insights I consider that it would be more appropriate to make these adjustments

²⁰ Some DNSPs, such as AAD, report at different intervals to the rest of the industry.

²¹ Economic Insights (2014), page 51.

before modelling (which would be consistent with the adjustments used for END, ERG, and ESS), as the inconsistent data are likely to affect the modelling.

After reviewing the opex data used in the modelling it appears that capitalisation policy is one factor that can and should be adjusted for across the industry before any modelling. The need for this stems from the AER's reporting guidelines for the RINs as they allow DNSPs to report costs using their own cost allocation methodology (CAM). For network operating costs (i.e. those that are benchmarked) the AER specifically instruct: "Opex must be prepared in accordance with DNSP's Cost Allocation Approach ... for the most recent completed Regulatory Year ..." ²² The issues this raises for comparability purposes was further highlighted by the AER themselves in their "Overheads and accounting issues" workshop in 2013. They specifically note "discretion in expensing/capitalisation" and "lack of comparability" as problems. ²³

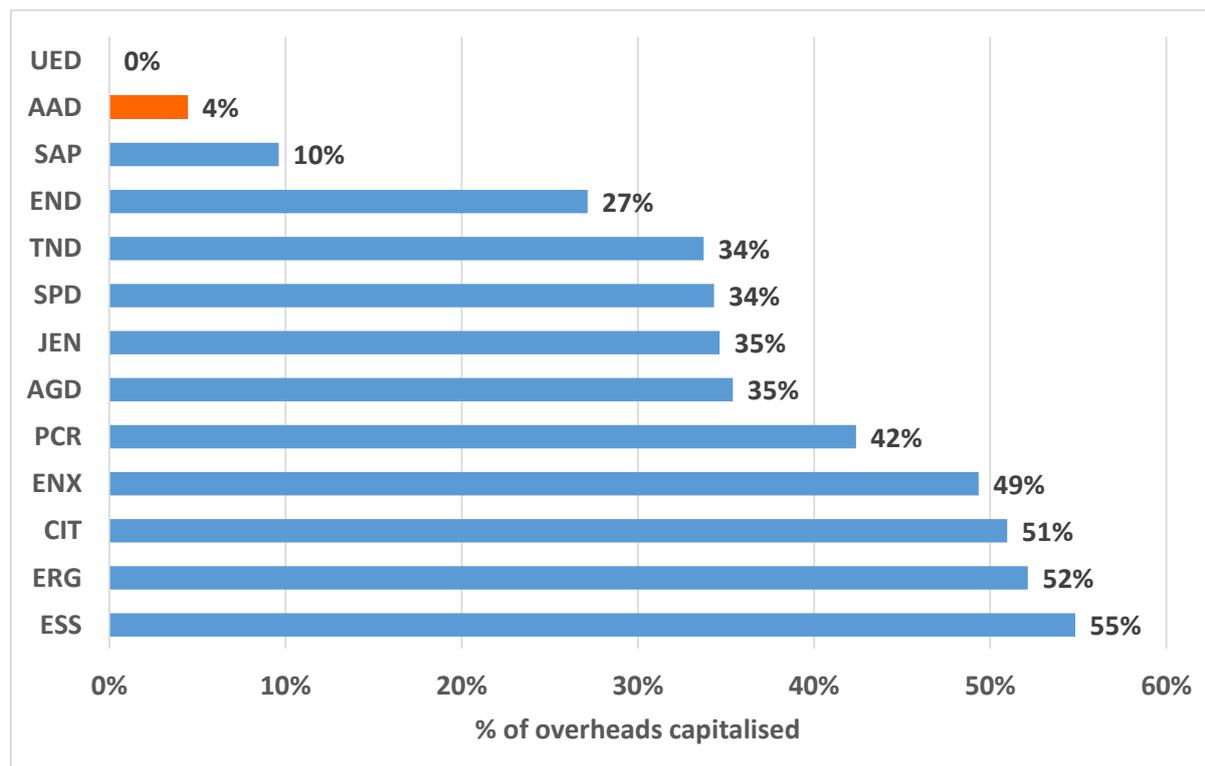
I have derived specific adjustment factors based on capitalised overheads as a proportion of total opex from Category Analysis RIN Expenditure Summary tables. These are done on a yearly basis by DNSP. This factor uplifts opex for all the companies (aside from United Energy which does not report any capitalised overheads) and brings costs onto a comparable pre-capitalisation basis. Barring evidence to the contrary, I assume that these capitalisation policies, calculated on total opex, extend to network services opex. For earlier periods not covered by the Category Analysis RINs (2006-08) I have applied the average adjustment to network opex. I am aware that some adjustments may have been made to the Category Analysis RINs since their publication. Any such changes have not been captured in my calculation, but my understanding is that the effect on capitalisation rates is marginal. While I recognise that this adjustment is a simplification, I consider that this is a pragmatic approach to normalising the data and that it is more appropriate to apply it than to proceed with unadjusted data. There is a relationship between capex and opex spend, i.e., if a company undertakes a relatively high level of capital work it is likely to need to increase its opex to support this work while it is being carried out, although once completed, the capital may reduce future opex. Therefore, as I have converted the opex into pre-capitalisation values it may be prudent to include a driver that reflects the volume of capital work.

Average overhead capitalisation rates are shown in Figure 3.1 below (AAD in orange), more detail on the calculation and magnitudes of adjustment is provided in ANNEX A.

²² AER 2013, Economic Benchmarking RIN For distribution network services providers – Instructions and Definitions, p.20

²³AER 2013, Expenditure Forecast Assessment Guidelines, Category analysis – Overheads and accounting issues (workshop).

Figure 3.1: Capitalisation of overheads



For the remaining adjustments noted above in the bulleted list, Economic Insights noted that the AER estimated the opex impact for each (approximate values summarised in Table 3.1 below). Barring more detailed information to suggest otherwise, I use these values as additional adjustment factors to AAD’s and the NSWs DNSPs’ opex, pre-modelling.

Table 3.1: Additional opex adjustments

	% impact on opex	Adjustment to AAD	Adjustment to NSWs DNSPs
Different control services connection coverage	+ 4.5%	- 4.5%	-
Backyard reticulation	+ 3.0%	- 3.0%	-
Taxes and levies	+ 2.5%	- 2.5%	-
Occupational and safety regulations	+ 0.5%	- 0.5%	- 0.5%
Total	+ 10.5%	- 10.5%	- 0.5%

Economic Insights also proposed adjustments to NSW DNSPs for their comparatively high level of sub-transmission voltage lines. The AER noted that these may be up to twice as expensive as regular voltage line, in relation to opex, and Economic Insights calculated a, what it terms, “conservative” adjustment of 10% to account for this. I do not propose making this adjustment (neither pre-modelling nor post-modelling) as I attempt to explicitly control for this operational difference by the inclusion of specific voltage level variables in the econometric models.

Most regulators also attempt to normalise for one-off and uncontrollable costs. For example, for DPCR5 Ofgem adjusted reported opex for any capital expenditure, one-offs and other non-comparable cost elements, and in its recent RIIO-ED1 Final Determinations Ofgem decided to excluded a number of cost areas for its econometric totex models and also normalise for factors such as regional wage differences.²⁴ Economic Insights has noted one such ‘one-off’ cost relating to the bushfire aftermath for Victorian DNSPs, but do not make any adjustments to the data for this. Furthermore, given the level of detail available it is unclear if it constitutes an unusual level of expenditure relative to other DNSPs’ bushfire-related expenses and I find it unlikely that it would affect all Victorian DNSPs equally, or only Victorian DNSPs for that matter. Also, the level of detail provided in the RINs is insufficient to make a judgment on one-off costs or additional uncontrollable cost categories (beyond the six categories provided in Table 3.2 of the EB RINs). I therefore refrain from making additional adjustments to the data, but note that regulatory best practices dictates that these costs should be controlled for.

Even before normalising costs, regulators in other jurisdictions, e.g. Ofgem and Ofwat, have spent many years establishing and refining reporting requirement to ensure that activity level and/ or cost categories are reported on a like-for-like basis. For instance, Ofgem’s regulatory reporting guidelines (RIGS) specify that painting of a transformer is not a refurbishment (capex) activity, but should be reported as opex.²⁵ This means that when Ofgem conducted its unit level benchmarking, as part of RIIO-ED1, it had greater confidence in the comparability of costs and volumes across the network operators and knew that the aggregate level costs, e.g. opex, asset replacement expenditure, were built up on this basis. This is a critical point as AAD’s engineering advisers, Advisian, has identified that DNSPs treat activities differently in terms of maintenance or replacement.²⁶ The specific example given by Advisian is ‘pole top structure’.²⁷ A number of DNSPs were capitalising these costs (as ‘replacement’) while AAD was treating is as maintenance. Advisian identified this specific instance as being material, thus impacting on the opex benchmarking.

Taking the adjustments in Table 3.1, the overhead capitalisation adjustment (i.e. CAM differences) and the adjustment for pole top structures expenditure reporting into account brings network opex onto a basis that is, I consider, more consistent based on the information available. For clarity, these adjustments are made to the data prior to modelling and as such I do not apply any adjustments to estimated efficiency scores post-modelling.

I recognise that these adjustments are conservative and Advisian have identified a number of other areas where costs could be normalised, e.g., vegetation management.²⁸ In addition,

²⁴ Ofgem (2014b).

²⁵ Ofgem (2012), page 141.

²⁶ See Advisian (2015).

²⁷ Ibid, pages 78-80.

²⁸ Advisian (2015).

AAD identified a number of one-off costs that affected 2012/13 expenditure.²⁹ I have not adjusted for these costs as it is likely that other DNSPs would have one-off costs for which there is not sufficient time available to assess all the evidence. This instead highlights that there is still work to be done in normalising the data for consistency.

More detail on adjustments is provided in ANNEX A.

3.2.2. International data

Economic Insights tested their benchmarking models using only the AER's RIN economic benchmarking data on 13 DNSPs over an eight-year period. They concluded that "there was insufficient variation in the data set to allow us to reliably estimate even a simple version of an opex cost function model (e.g. a Cobb–Douglas LSE model with three output variables and two operating environment variables)."³⁰ Note, the MPFP relies only on the RIN data and while it is a different technique the unreliability, if generated from variations (or lack thereof) that affected the econometric techniques is likely to impact the MPFP results as well.

Economic Insights considered that in order to produce reliable results it needed to expand its dataset. Economic Insights chose to use New Zealand (NZ) DNSP data, collected by the NZ Commerce Commission, and data from DNSPs in Ontario, Canada. The latter was collected by the Ontario Energy Board. The full NZ dataset covers 27 DNSPs from 1997 to 2013, while the full Ontario dataset covers 73 DNSPs from 2002 to 2012.

Economic Insights note that NZ and Ontario have a small number of large DNSPs and a large number of small DNSPs, therefore it came up with some arbitrary customer 'cut-off' points to identify different possible subsets of data:

- a large dataset of 86 DNSPs (all those with >10,000 customers);
- a medium-sized dataset of somewhat larger 68 DNSPs (those with >20,000);
- a smaller dataset of 37 larger DNSPs (those with >50,000); and
- a reduced dataset of 25 of the largest DNSPs (those with >100,000).

Economic Insights did not use any other criteria to choose the cut-off points i.e., length of network and/or density are not used. Economic Insights did not provide any reason for its choice of cut-off points, such as evidence of economies of scale in customer numbers.

While Economic Insights stated that it did testing on the different sized datasets it prefers the 'medium' sized one which contains the 13 Australian DNSPs, 18 New Zealand DNSPs and 37 Ontario DNSPs (though they note that the results were quite close to those obtained using the 'large' dataset). Aside from stating that the NZ dataset was "constructed in a similar fashion to the AER's economic benchmarking RIN database in terms of variable coverage"³¹

²⁹ ActewAGL (2014), Confidential, *Operating and capital expenditure 'site visit' clarifications: 2015-19 Subsequent regulatory control period*, October 2014, page 13.

³⁰ Economic Insights (2014), page 28.

³¹ Ibid, page 29.

Economic Insights did not provide any analysis on the operating differences between the networks in NZ and Australia. While Economic Insights noted Ontario's climate being different to Australia's, it states that the Ontario database is attractive because it offers data for 73 DNSPs over 11 years.³²

The only concession that Economic Insights made for the different operating environments across the different countries, besides the 'share of underground cables', is to introduce a dummy variable for NZ and Ontario, i.e. if the DNSP is from New Zealand then the NZ dummy variable will be one, otherwise it will be zero, and similarly for Ontario. Economic Insights stated that the dummy variables "pick up differences in opex coverage (as well as systematic differences in operating environment factors such as the impact of harsher winter conditions in Ontario)".³³

However, even a brief examination of the datasets and their construction highlights major concerns for comparability. For example, additional adjustments were made to costs in the Ontario dataset to take account of HV transmission services, LV charges, and incremental Smart Meter opex.³⁴ Notably, the RIN data itself has no voltage related adjustments³⁵ and excludes metering costs (metering is reported in a separate line item in RIN Table 3.2). The NZ dataset was built up by Economic Insights themselves, while being based on data collected by the NZ Commerce Commission. In a productivity workshop in May 2014 they note that opex needs "uniform treatment of asset refurbishment and allocation of corporate overheads,"³⁶ and it constructed opex in such a way as to try to control for this. As noted already, this is something that Economic Insights did not do to the RIN data. It is also unclear how capitalisation has been treated in the Ontario data. Economic Insights go on to note specific deficiencies related to the NZ measure of opex, particularly that it assumes equivalent coverage of opex components across DNSPs. This in itself is a large assumption and goes against international approaches which try to normalise for uncontrollable and DNSP-specific costs.

Including a dummy variable in the model specification does not necessarily control for these within and across country differences. A dummy variable only controls for level differences between datasets not cost relationship differences. A very simple illustration of this is provided in Figure 3.2 below.

³² Ibid, page 29.

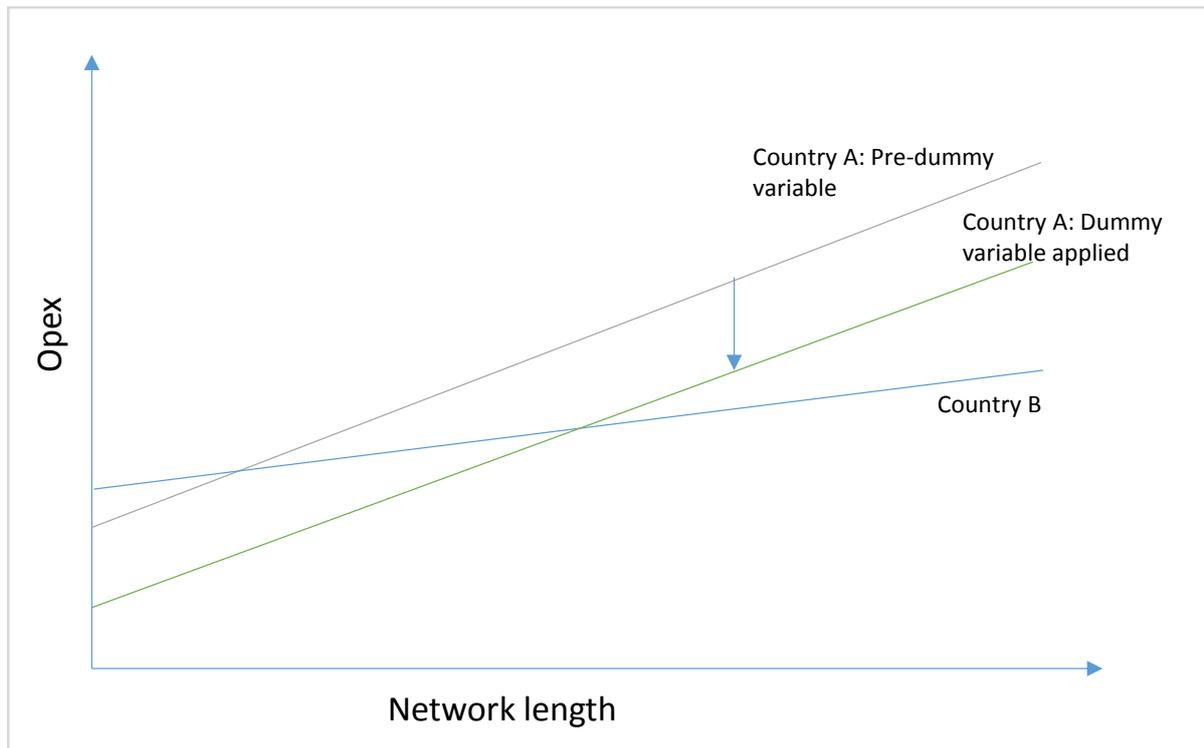
³³ Ibid, page 31.

³⁴ Pacific Economics Group (2014).

³⁵ As mentioned before, Economic Insights makes an adjustment to NSW DNSP efficiency scores for sub-transmission related assets, but this is done post-modelling.

³⁶ Economic Insights, *Productivity Analysis of Electricity Distribution*, Commerce Commission Workshop May 2014.

Figure 3.2: Illustration of the use of a dummy variable



The introduction of the dummy variable takes a fixed amount of Country A’s opex per network length to bring its average in line with Country B’s. However, the slope of the line (the relationship between opex and network length) is not impacted by the introduction of the country dummy variable. A proper econometric analysis is more complex than this and should take account of country-specific slopes, which will require more variables to take this into account. For example, if the relative prices of labour and capital differ, then one would expect a different relationship between cost and customer numbers (e.g. higher labour costs should lead to more capex and lower maintenance costs, but higher costs of dealing with customers).

What this means in practice is that if one dataset, i.e., Ontario, provides more data points to the regression analysis then it will have a greater influence on the slopes (coefficients) estimated by the regression models. I illustrate this in Table 3.2 below. In the table I set out the results of estimating Economic Insights’ preferred SFA model specification on Ontario, NZ, and Australia separately, and compare the coefficients on the cost drivers/ explanatory variables. Note that Ontario has almost three times as many observations as Australia and that Australia accounts for only about one-fifth of the data points used.

Table 3.2: Comparison of coefficients across countries/regions

Variable	Medium dataset		Australia	New Zealand	Ontario
	Coefficient	95% C.I.	Coefficient	Coefficient	Coefficient
Log(CustomerNos)	0.667***	0.49 ,0.84	1.146***	0.566***	0.732***
Log(CircuitLength)	0.106***	0.03, 0.18	0.13	0.201*	0.041
Log(RMDemand)	0.214***	0.06, 0.37	-0.242	0.206*	0.234**

	Medium dataset		Australia	New Zealand	Ontario
Variable	Coefficient	95% C.I.	Coefficient	Coefficient	Coefficient
Log(ShareUGC)	-0.131***	-0.20, -0.07	-0.021	-0.088	-0.211***
Year	0.018***	0.01, 0.02	0.034***	0.023***	0.010***
New Zealand	0.05	-0.15, 0.25			
Canada	0.157**	0.01, 0.30			
Constant	-26.53***	-34.3, -18.8	-58.778***	-37.122***	-9.690**
Additional statistics					
Observations	544	-	104	144	296

Note: significance stars as follows, *10%, **5%, ***1%.

One can see from the table that the coefficients on the AER RIN data are significantly different from NZ and Ontario. The coefficient for customer numbers on the Australian data alone is statistically significantly different from that in the full dataset. Unsurprisingly, as they supply a greater number of observations, the coefficient in the medium dataset (the one preferred by Economic Insights and including all the countries/ regions) are driven by Ontario and NZ. This analysis indicates that there is a different relationship between opex and the cost drivers (customer numbers, circuit length and ratcheted maximum demand) across the countries/ regions and Economic Insights has not controlled for these differences.

Jamasb & Pollitt (2009) noted that frontier methods using international data may not be appropriate for benchmarking even if data has been properly standardised, for example if firms are compared to a frontier that is set by companies of radically different size.³⁷ One can also add that differences in the cost of labour (both those arising from different standards of living but also those arising from different social security and labour tax systems, and different regulatory and union requirements) are also likely to affect the costs that are efficiently achievable given these institutional constraints. As already noted, differences in the relative costs of capital and labour are likely to lead to different efficient choices in network design, meter reading and customer handling and hence in different relationships between costs and any one cost driver. In this respect, Economic Insights has not provided any detailed analysis on whether the relationship between the cost drivers and costs are in fact the same across countries. Instead, as I mentioned above, Economic Insights have simply included a country specific dummy variable in the models to capture all differing operating environment factors and opex coverage.

As the ACCC states in its 2012 working paper, *Benchmarking Opex and Capex in Energy Networks*, caution should be exercised when using international data “[i]n-depth examination of the data is required to ensure consistency, comparability and quality”³⁸. I agree with this principle and in my view, based on Economic Insights report, sufficient scrutiny or analysis of

³⁷ Ibid. p110.

³⁸ ACCC (2012), page 151.

the data does not appear to have been conducted in order meet these criteria and satisfy the inclusion of the international data for benchmarking Australian DNSPs. It appears little attention has been paid to exactly what costs are included, whether these costs are comparable to the RINs and what adjustments have been or still need to be made to Ontario and NZ data. This point is also summarised concisely by Jamasb & Pollitt (2009):

International benchmarking raises particular difficulties. The most notable issue is that of comparability and quality of data... in international benchmarking quality of data is of greater importance than in national comparisons. For example, the data used needs to sufficiently represent different types (e.g. urban vs. rural) and sizes of utilities, and to take account of differences in standards and definitions. In addition, input and output variables for international benchmarking models should reflect possible differences across countries.³⁹

It is important that the regulators collect national and international data through formal co-operation and exchange. New regulators need to pay ample attention to developing good data collection and reporting systems. A precondition for international comparisons is to focus on improving the quality of the data collection process, auditing, and standardisation within and across countries.⁴⁰

Therefore, given the lack of scrutiny and difficulties in using international data, it is my opinion that Economic Insights' use of Ontario and NZ data is inappropriate as a supplement to the AER's RIN database.

In relation to Economic Insights' observations about the (lack of) robustness of modelling using only the AER RIN dataset, I consider that it is more acceptable to use the Australian dataset recognising and adjusting for the reporting differences than including non-comparable international data.⁴¹

3.3. Modelling techniques

Various techniques are available to the regulator to estimate costs. These include both parametric (e.g. econometric analysis) and non-parametric approaches (e.g. DEA and TFP indices). In broad terms, parametric approaches allow for a more comprehensive view of industry dynamics such as economies of scale and density, which are particularly important in regulated network industries where these factors may vary greatly. In addition, unlike non-parametric approaches, parametric methods allow for hypothesis tests between alternative model specifications to be conducted. This allows for direct comparisons between models and also, provides greater statistical confidence in the reliability of the chosen model. A general disadvantage, though, is the need to specify a functional form for the cost function. Non-parametric approaches offer the benefit of not requiring the specification of a functional,

³⁹ Jamasb & Pollitt (2001), p110.

⁴⁰ Ibid. p128

⁴¹ A similar issue to that identified by Economic Insights was raised by Gibbens and Zachary (2013) in the UK in relation to Ofgem's benchmarking. Gibbens and Zachary considered that there was too little variation in the explanatory variables for inefficiency to be separated from heterogeneity. Ofgem noted the authors' concerns, and proceeded to use pooled OLS, noting that SFA and RE was not appropriate in this case.

but they do not allow the same statistical testing as parametric techniques and are usually sensitive to the choice of input and output variables.

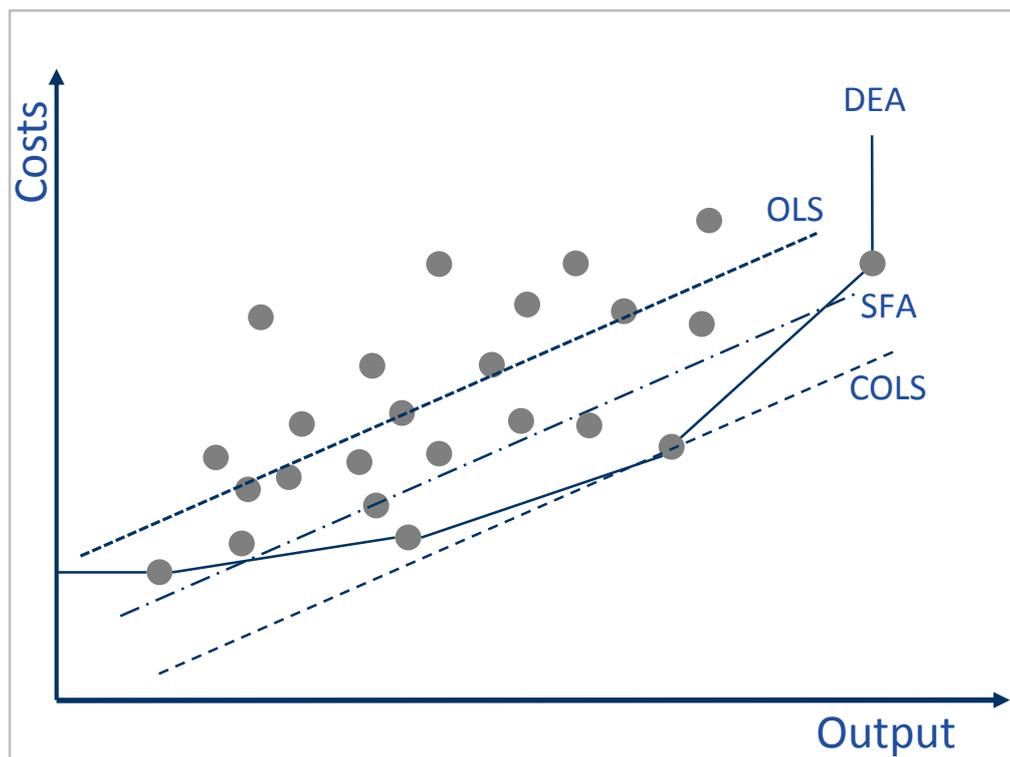
As each broad approach has merits and weaknesses, regulators should consider testing different approaches. Haney & Pollitt (2009) note that regulators should pursue a combination of approaches to examine consistency and robustness, and the judgement of decision-makers is crucial. Their analysis should be supplemented with “subjective judgement as to the weight placed on the results from each technique.”⁴² It is my view that this advice is not limited to using a combination of different approaches, but also a combination of different models and specifications.

In addition to the more advanced parametric or non-parametric techniques, regulators also employ a range of bottom-up techniques for assessing efficiency including engineering assessment, run rate, and simple ratio analysis. For example, in addition to its totex benchmarking models Ofgem still undertakes unit cost benchmarking for asset replacement activities. For the purposes of this paper, I refers to these approaches as process/ activity models.

I detail the characteristics of various advanced approaches in ANNEX B, highlighting particular strengths and weaknesses of each when it comes to cost and efficiency assessment. Figure 3.3 illustrates the four main advanced approaches used by regulators.

⁴² Haney & Pollitt (2009), p5817-5818.

Figure 3.3: Illustration of benchmarking models



Ordinary least squares (OLS) is a method for estimating the determinants and performance of the average company. Such models estimate a line of 'best fit' to observed data points by minimising the sum of the squared deviations of the observations from the fitted line. COLS models 'correct' the line of best fit to pass through the frontier, although regulators often chose a company/ point away from the frontier to take account of measurement error. The SFA approach attempts to address this issue by explicitly separately estimating inefficiency and random error/ noise. However, this advantage does come at the cost of a more complex econometric specification and it also requires relatively strong assumptions in regard to the statistical distribution of inefficiency. DEA is a linear programme technique which identifies a frontier that picks out the extremes of the data set and so 'envelops' the companies' observations.

A general point regarding the use of panel or pooled data (which can be used by most parametric or non-parametric methods), is that they comprise both a time and cross-sectional element. This increases the burden of checking for consistency of data in both dimensions. That is, it requires knowledge of how the cost structure varies both between companies and within companies over time. This requires consistent cost allocation policies between sub-company components for all companies, and knowledge about allocation policies over time. This can be particularly problematic when dealing with international data as a single country regulator may not have insight into such policies of international companies, especially if collaboration between regulators is not present.

In general, regulators use a wide variety of techniques and often more than one. Regulators tend to take a view on what techniques are appropriate taking account some of the following factors:

- number of data points available (both the number of companies and the number of years);
- robustness of the data;
- transparency and replicability of the technique; and
- robustness and plausibility of the results.

3.4. Cost drivers and operational characteristics

The choice of cost drivers was limited by those that were available in the RINs, as well as an additional measure of service area provided by Advisian.⁴³ From these I have identified core cost drivers that capture scale and density characteristics as well as other operational environment factors. Some cost drivers have more than one possible measurement, for example density. It should be noted that while alternatives represent the same concept they may have significant different interpretations. I have chosen to use the transformation of customer numbers divided by length for circuit density. This provides a different interpretation of the coefficient, but in a log model the overall results are the same as if customer numbers alone was used as an explanatory variable. Definitions and rationale of these variables are summarised in ANNEX D.

The core cost drivers are network length, customer density per line km, customer density per km², peak capacity and energy throughput. These represent what I consider to be the key drivers of network opex and are also supported by their extensive use in electricity distribution benchmarking studies.⁴⁴ There are some high positive correlations between these variables and as such I expect that multicollinearity will exist in models which include a number of these variables. Variables identified as operational characteristics allow us to control for other differences across networks, such as proportion of EHV/132kV, SWER and underground circuits. Many of these characteristics, for example transmission and subtransmission differences,⁴⁵ have been flagged as being drivers of relative differences between DNSPs' opex.

While peak capacity may be an important driver for totex, it is less likely to be as an important a driver for opex depending on the other drivers included in the model. This is because, while it partly reflects the scale of a network, scale variables such as customer numbers and line

⁴³ Advisian (2015).

⁴⁴ Jamasb & Pollitt (2001) take stock of variables that had been included in electricity benchmarking studies up to the time of publishing. These core variables appeared quite often in benchmarking work either by regulators or academics.

⁴⁵ Advisian note that legacy planning decisions of these voltages remain significant unaccounted factors explaining AAD's relative opex performance.

length are likely to provide better indicators of the level of maintenance and vegetation management required. Likewise, for business support/ call centre costs, customer numbers will be a more appropriate driver than maximum demand.

RAB additions will likely explain costs associated with network control & systems operation, network planning and network planning.⁴⁶ RAB additions is not an ideal driver as it may mean that inefficient spending on capex (gold plating) is rewarded or that the trade-off between capex and opex is not recognised.⁴⁷ However, I consider that as the level of capex, including both replacement and growth related expenditure, undertaken by a firm is an important driver of opex, RAB additions provides a reasonable proxy in light of no ready alternative. I note that Ofgem, during RIIO-ED1, used the value of asset additions (companies' forecast asset additions multiplied by Ofgem's view of unit costs) as a driver for closely associated indirect opex.⁴⁸

To help determine appropriate drivers to include, I note the following points:

- Circuit density based on customer numbers divided by line length gives the same overall results as including only customer numbers in the model, but the coefficient can be interpreted on the basis of changes in density.
- Advisian advised AAD that single wire earth return (SWER) lines are likely to have a lower opex requirement associated with them.⁴⁹
- Economic Insights (2014) notes that analysis undertaken by the AER indicates that subtransmission lines over 66kV are likely to have opex requirements per kilometre twice as high as lower voltage lines.⁵⁰

In relation to economies of scale and density, international evidence has suggested that economies of scale and density in electricity distribution are likely to exist. Olmez (2008) estimated that economies of scale existed if the 14 GB distribution network operator licences were modelled. However, the author finds that if the licences are grouped by ownership then the existence of constant returns to scale could not be rejected. Farsi et al (2010), estimated that medium to large French electricity distribution networks exhibited economies of scale, while their findings were less conclusive on smaller networks. Both Olmez and Farsi used a number of output variables to establish the scale economies, namely customer numbers, units distributed and network length. I consider that it is prudent to test for economies of scale and density using translog functions.

⁴⁶ This is in line with Ofgem use of the value of asset additions as a driver for closely associated indirect opex.

⁴⁷ In addition I was unable to adjust it for capitalised overheads (i.e., the RAB additions includes opex that is also captured in the dependent variable).

⁴⁸ In Ofgem's COLS model, the coefficient on this (natural logged) variable was 0.332, indicating that a 1% increase in closely associated indirect opex would lead to a 0.3% increase in capex. See Ofgem (2014b), page 195.

⁴⁹ Advisian (2015), pages 57-59.

⁵⁰ Economic Insights (2014), page 48.

It is worth noting that, while Economic Insights could not test for the inclusion of additional environment operating differences when it used the international data set it did test using some as part of its MTFP. Economic Insights (2014) used second stage regression analysis to determine whether additional explanatory variables were significant.⁵¹ However, Economic Insights included all the additional variables (eight) in a single regression including, customer numbers, customer density, energy density, demand density and SAIDI. Given the correlations which exist between these variables it is not necessarily surprising that the coefficients were not significant in Economic Insights' regression. The presence of multicollinearity, while not a problem in itself for the models' predictions, might disguise the significance of some of the variables. I therefore do not place much weight on Economic Insights' findings for this single regression.

3.5. Alternative benchmarking models

I have approached the modelling using economic theory and statistical testing, and relied in part on the general-to-specific approach – i.e. starting with a model including a large number of theoretically correct variables and reducing these in line with theory, statistical testing and robustness. In some cases I have retained variables which are insignificant in the modelling but have the expected sign and their inclusion fits with the theory. Some regulators, in particular Ofgem, have switched to totex modelling rather than relying solely on more disaggregated level models. The advantage of totex models is that they remove the opex and capex trade-offs, are only impacted by cost allocation inside and outside of the price control and they give an aggregate view of efficiency. However, totex models require robust and consistent measures for capex as well as opex, and capex is relatively lumpy. I do not have sufficient confidence in the data available to undertake totex (econometric) modelling at this time. I do consider that this is something the AER should explore in the future when the data are more well developed and robust.

As discussed in Section 3.2.1, I have made additional adjustments to the data prior to modelling to control for various factors such as the different CAMs and treatment of activities.⁵²

In trying different specifications some of my general observations are:

- Maximum demand, ratchet maximum demand, and transformer capacity were not generally significant in the models. This is likely down to the correlation between these variables and others included in the modelling. While multicollinearity itself is not a problem, the more parsimonious model did not appear unduly affected by the exclusion of these variables.

⁵¹ Economic Insights (2014), pages 23-24.

⁵² For some companies this substantially changes their opex modelled, therefore I have provided some sensitivity analysis in ANNEX E which compares the results for some models of using the unadjusted opex against the adjusted opex.

- RAB additions was often significant in models. This is consistent with my expectation that increased levels of capex should lead to higher opex (even after taking account of the potential trade-off between them). RAB additions is not an ideal driver as it may mean that inefficient spending on capex is rewarded and I was able to adjust it for capitalised overheads (i.e., the RAB additions includes opex that is also captured in the dependent variable). However, as discussed in Section 3.4, I consider that the level of capex undertaken by a firm is an important driver of opex given design, control centre and other operational requirements of undertaking capex.
- Incorporating a variable for the share of subtransmission line, 132kV and above, is generally significant and has an impact on the efficiency scores. A variable for the share of 132kV has a very large impact on efficiency scores, however, this may be in part that only six – AAD, AGD, END, ENX, ERG and ESS – DNSPs have 132kV line/ cable. While this may mean that the variable partially acts as a dummy for these DNSPs, as the proportions are different across the DNSPs the significance indicates that it is likely explaining some operating environment differences. This may reflect the increased costs of managing a higher voltage network (e.g. control centre) and increased costs from maintaining the network (e.g. bigger towers).
- A density variable based on customers per square kilometre is generally significant in the models and produces different efficiency scores than the density variable based on customers per km of line.⁵³
- Using the entire circuit length or route length does not make much difference to models' coefficients. As such, the results for circuit length are shown as this is more consistent with the calculation of the SWER, underground cables and subtransmission variables.
- In some specifications the share of underground cabling becoming insignificant. However, I have tended to leave this in given its theoretical significance as a cost driver and the coefficient is as expected, i.e. a small negative value indicating as the share of underground cables increase opex decreases.

I have been unable to estimate SFA models on a robust and consistent basis. In most cases the SFA models will not converge and results are not produced. In cases where the models do converge a small change to the specification (i.e. additional variable included) would result in non-convergence, thus indicating the lack of robustness in the models. Therefore, I present results for only OLS and RE (GLS) models below. For clarity and simplicity I have kept the same specifications across both the OLS and RE (GLS) models, however, some of the statistical testing indicated that for particular specifications one technique might be preferred to the other.

⁵³ Note, Advisian provided us a single area value for each DNSP. I have used this for the area covered for each year the dataset covers. Ideally this would vary year-to-year, but as this is unlikely to vary significantly I consider it a reasonable assumption to make.

The criteria I used to assess the models is set out in ANNEX C. In some cases the models presented did not pass all statistical tests, however they were still consistent with theory and produced plausible results. I have not tried to identify a suite of or single perfect model for opex benchmarking, as this is a much more exhaustive process than the time allows. However, I do consider that the models developed explain the production/ cost functions of the DNSPs and their operating environments better than Economic Insights' model. For reference, Economic Insights' preferred specification was an SFA model including the following variables (excluding the dummy variables for the countries):

- customer numbers;
- circuit length;
- ratchet maximum demand;
- share of underground cables; and
- time trend.

OLS

Table 3.3 presents results from our initial model runs using OLS techniques with adjustments to opex for different CAMs, capitalisation and additional factors noted by the AER/ Economic Insights set out in Section 3.2.1.

Table 3.3: OLS alternative model specifications⁵⁴

Variable	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
Functional form/estimator/data structure	Cobb-Douglas/ OLS/ pooled	Cobb-Douglas/ OLS/ pooled	Cobb-Douglas/ OLS/ pooled	Cobb-Douglas/ OLS/ pooled	Translog/ OLS/ pooled	Translog/ OLS/ pooled	Translog/ OLS/ pooled
Log(Circuit length)	0.520***	0.357***	0.931***	0.488***	0.952***	0.628***	0.384***
Log(Density - length)	0.471***		0.914***	0.277**	0.858***	0.564***	
Log(Density – Km ²)		0.087***					0.081**
Log(length)^2					0.171	0.187	-0.006
*Log(density)^2					0.480***	0.229*	0.008
*Log(length*density)					0.512***	0.360**	0.013
Log(share of underground cables)	-0.155**	-0.047	-0.269**	-0.081	-0.181	-0.165**	
Log(RAB additions)	0.378***	0.508***		0.518***		0.359***	0.482***
Log(=> 132kV share of circuit)	0.039***	0.027**	0.077***		0.057***	0.026**	0.028
Log(share of SWER)				-0.040*			
Year	0.004	-0.01	0.043***	-0.014	0.042***	0.006	-0.009
Constant	-0.822	26.984	-73.815***	34.543	-73.129***	-4.827	24.712
Additional statistics							
R-squared	0.98	0.975	0.963	0.975	0.971	0.984	0.975

Significance stars: ***1%, **5%, *10%

⁵⁴ All scale variables shown at the sample mean.

Efficiency scores and rankings are shown in Figure 3.4 and Table 3.4 below. These are shown against Economic Insights' preferred SFA specification.

Figure 3.4: OLS efficiency Scores vs. Economic Insights' preferred model

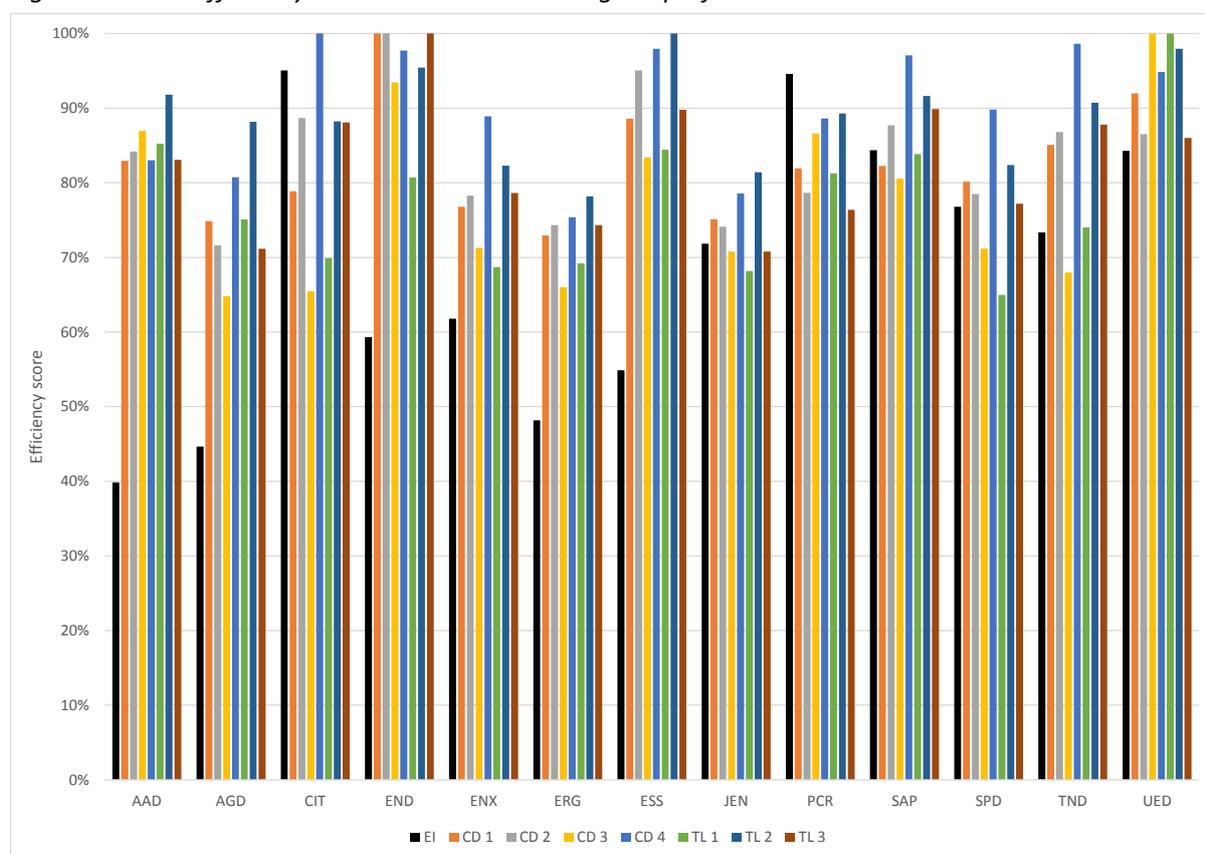


Table 3.4: OLS efficiency rankings

	EI	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
AAD	13	5	7	3	10	2	4	7
AGD	12	12	13	13	11	7	9	12
CIT	1	9	3	12	1	9	8	4
END	9	1	1	2	4	6	3	1
ENX	8	10	10	7	8	11	11	8
ERG	11	13	11	11	13	10	13	11
ESS	10	3	2	5	3	3	1	3
JEN	7	11	12	9	12	12	12	13
PCR	2	7	8	4	9	5	7	10
SAP	3	6	4	6	5	4	5	2
SPD	5	8	9	8	7	13	10	9
TND	6	4	5	10	2	8	6	5
UED	4	2	6	1	6	1	2	6

While there is variation in the efficiency scores (and rankings across the models) the range of scores from the alternative models is significantly tighter than those estimated by Economic Insights. The lowest efficiency score is above 60%. While it may be argued that the ‘share of 132kV circuit’ may be capturing other differences between the NSW, ACT and QLD networks and those of the other states, its general ‘significance’ and the significance of RAB additions in specifications without share of 123kV indicates that there are operating differences that the Economic Insights’ model was not picking up. The coefficients on the length variable in the Cobb-Douglas models indicate that there are economies of scale present in the data as in all cases a 1% increase in length will lead to a less than 1% increase in opex, holding all other variables constant. Likewise there appears to be economies of density. The translog models indicate varying returns to scale and density, but these are more difficult to interpret due to the interaction terms with density.

The frontier and implied reduction target for AAD, based on Economic Insights’ method of using the average over the upper percentile performers, are shown in Table 3.5. I also provide the results of using alternative methods based on using the upper quartile (as per Ofgem’s current (RIIO-ED1) approach) and median efficiency score (which Ofgem has used in previous price controls (DPCR5) for capex benchmarking). As the efficiency scores increase Economic Insights proposed approach of using the average across the companies’ efficiency scores above 75% is even less intuitive as, if all scores are above 75%, it would simply average across these scores.

Table 3.5: OLS models’ efficiency targets

	EI	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
AAD Adjusted target	66.3%	84.6%	86.3%	88.3%	89.5%	82.5%	88.9%	85.5%
AAD implied distance to frontier*	39.9%	1.9%	2.4%	1.6%	7.3%	-3.3%	-3.3%	2.9%
Alternative upper quartile adjustments								
Upper quartile target	N/A**	85.1%	87.7%	86.6%	97.7%	83.8%	91.8%	88.1%
UQ implied distance to frontier*	N/A**	2.5%	4.0%	-0.4%	15.1%	-1.7%	0.0%	5.7%
Median target	N/A**	81.9%	84.2%	71.3%	89.8%	75.1%	89.3%	83.1%
Median implied distance to frontier*	N/A**	-1.2%	0.0%	-22.0%	7.6%	-13.6%	-2.8%	0.0%

* A positive indicates inefficiency relative to proposed frontier.

** These approaches cannot be applied as the expenditure as the frontier cannot be ‘normalised’ for the different reporting and operating environments.

RE (GLS)

In Table 3.6 I presents results from our initial model runs using OLS techniques with adjustments to opex for different CAMs, capitalisation and additional factors noted by the AER/ Economic Insights set out in Section 3.2.1.

Table 3.6: RE (GLS) alternative model specifications⁵⁵

Variable	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
Functional form/estimator/data structure	Cobb-Douglas/ GLS/ Panel	Cobb-Douglas/ GLS/ Panel	Cobb-Douglas/ GLS/ Panel	Cobb-Douglas/ GLS/ Panel	Translog/ GLS/ Panel	Translog/ GLS/ Panel	Translog/ GLS/ Panel
Log(Circuit length)	0.708***	0.609***	0.946***	0.767***	0.955***	0.758***	0.552***
Log(Density - length)	0.630***		0.933***	0.495***	0.939***	0.672***	
Log(Density – Km ²)		0.150***					0.126***
*Log(length)^2					0.02	0.08	-0.117
*Log(density)^2					0.04	0.091	0.001
*Log(length*density)					0.047	0.134	-0.041
Log(share of underground cables)	-0.147*	-0.007	-0.257**	0.001	-0.251*	-0.143	
RAB additions	0.215***	0.258***		0.278***		0.215***	0.230***
Log(=> 132kV share of circuit)	0.053***	0.050***	0.077***		0.076***	0.046***	0.062***
Log(share of SWER)				-0.021			
Year	0.019***	0.012*	0.043***	0.006	0.042***	0.019***	0.015***
Constant	-28.400**	-14.419	-73.380***	-3.532	-73.079***	-27.708**	-20.025*
Additional statistics							
R-squared [†]	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Significance stars: ***1%, **5%, *10%

[†] R-squared values provided by GLS models in STATA (the estimation software I used) are not meaningful.⁵⁶

⁵⁵ All scale variables shown at the sample mean.

⁵⁶ See Greene (2008), page 156.

Efficiency scores and rankings are shown in Figure 3.4 and Table 3.7 below. These are shown against Economic Insights' preferred SFA specification.

Figure 3.5: RE (GLS) efficiency Scores vs. Economic Insights' preferred model

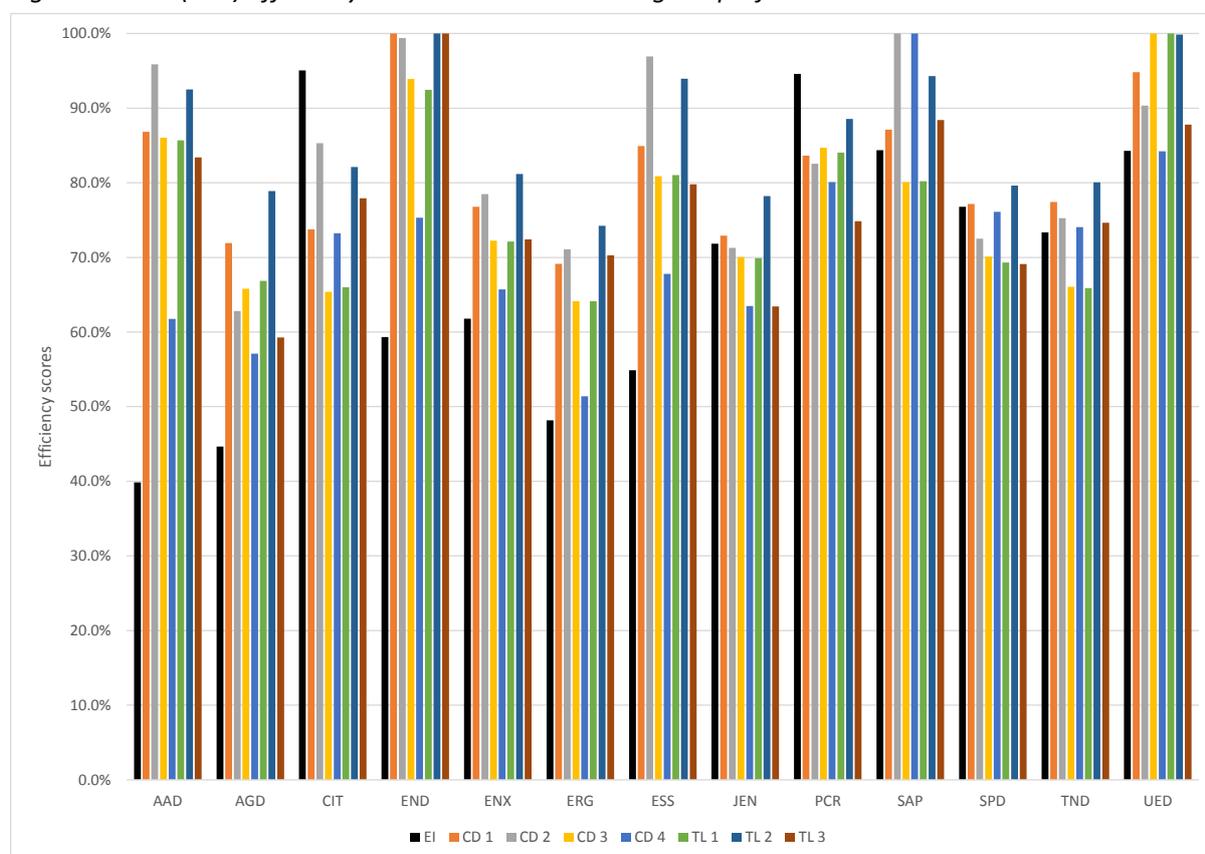


Table 3.7: RE (GLS) Efficiency rankings

	EI	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
AAD	13	4	4	3	11	3	5	4
AGD	12	12	13	11	12	10	11	13
CIT	1	10	6	12	7	11	7	6
END	9	1	2	2	5	2	1	1
ENX	8	9	8	7	9	7	8	9
ERG	11	13	12	13	13	13	13	10
ESS	10	5	3	5	8	5	4	5
JEN	7	11	11	9	10	8	12	12
PCR	2	6	7	4	3	4	6	7
SAP	3	3	1	6	1	6	3	2
SPD	5	8	10	8	4	9	10	11
TND	6	7	9	10	6	12	9	8
UED	4	2	5	1	2	1	2	3

The RE (GLS) models produce relatively similar results for the efficiency scores across the DNSPs although there is greater variation across the model specifications. As with the OLS models the range of efficiency scores is much tighter than in Economic Insights' results. Excluding the share of 132kV circuit variable has a greater impact on the efficiency scores than the OLS models. Here the lowest efficiency score is slightly over 50%.

The frontier and implied reduction target for AAD based on Economic Insights' method of using the average over the upper percentile performers are shown in Table 3.8. I also provide the results of using alternative methods based on using the upper quartile (as per Ofgem's approach) and median efficiency score.

Table 3.8: RE (GLS) models' efficiency targets

	EI	CD 1	CD 2	CD 3	CD 4	TL 1	TL 2	TL 3
AAD Adjusted target	66.3%	85.4%	89.6%	87.5%	83.3%	87.1%	87.2%	88.1%
AAD implied distance to frontier*	39.9%	-1.7%	-7.0%	1.6%	25.9%	1.6%	-6.1%	5.3%
Alternative upper quartile adjustments								
Upper quartile target	N/A**	86.8%	95.9%	84.7%	76.1%	84.0%	93.9%	83.4%
UQ implied distance to frontier*	N/A**	0.0%	0.0%	-1.6%	18.9%	-2.0%	1.5%	0.0%
Median target	N/A**	77.4%	82.5%	72.2%	73.2%	72.1%	82.1%	74.8%
Median implied distance to frontier*	N/A**	-12.1%	-16.1%	-19.1%	15.7%	-18.8%	-12.7%	-11.4%

* A positive indicates inefficiency relative to proposed frontier.

** These approaches cannot be applied as the expenditure as the frontier cannot be 'normalised' for the different reporting and operating environments.

3.6. Conclusions

Is the AER's analysis robust having regard to the adjustments it makes for the DNSPs' different operating environments? Should additional and/or alternative adjustments be made to account for the DNSPs' different operating environments? If so, please specify which additional and/or alternative adjustments should be made.

After reviewing the AER's and its consultant's (Economic Insights) analysis and modelling, it is my opinion that:

- insufficient consideration has been given to the DNSPs' different operating environments within the benchmarking; and
- the RIN data in the form collected and used by the AER does not provided opex on a like-for-like basis across the DNSPs.

The former point is particularly critical as the AER has chosen to rely on international data (New Zealand and Ontario, Canada) that does not appear to have been robustly reviewed for

operating environment differences either with Australia or across the countries. My brief examination of the datasets and their construction highlights major concerns for comparability, let alone differences in operating environments. Even if operating environment differences were identified, Economic Insights cites a lack of operating environment variables for Ontario, limiting them to using only the share of underground cables as a proportion of total line length. This was done despite the massive difference in climate between Australia and Ontario.

The RINs operating expenditure (Opex) data relied upon by the AER has not been sufficiently normalised for reporting differences before being used in the modelling. These include differences in the companies' CAMs and differences in companies treating activities as maintenance or replacement expenditure. The literature around the use of benchmarking for regulatory purposes (for example, Jamasb & Pollitt (2009), ACCC (2012)) note the importance of ensuring data is collected on a similar basis, is audited, and operating environment differences are controlled for. Failure to normalise the data may lead to unreliable results, and potentially the choice of inappropriate model specifications. Ofgem, considered to be a leader in benchmarking, spends a considerable amount of time setting out the cost categories, asset lists, and reporting guidelines to ensure that the data is reported on a like-for-like basis regardless of the regulated companies' own internal cost reporting. I note that failure to normalise the data will impact on the category analysis, not just the econometric benchmarking.

Given the lack of scrutiny and difficulties in using international data, it is my opinion that Economic Insights' use of Ontario and NZ data is inappropriate as a supplement to the AER's RIN database. In relation to Economic Insights' observations about the (lack of) robustness of modelling using only the AER RIN dataset, I consider that it is more acceptable to use the Australian dataset, recognising and adjusting for the reporting differences, than to include non-comparable international data.

Therefore, I have estimated alternative benchmarking models which only use Australian RIN data. In conducting this modelling I:

- normalised the AER data as best as I can with the information I have been provided and the limited time available;
- incorporated a greater range of operating environment variables; and
- used a range of parametric techniques.

I have not used non-parametric techniques as I consider there was an insufficient number of companies for DEA and the inability to produce descriptive statistics outweighs the benefits of these techniques.

I found that the modelling was very sensitive to the inclusion of operating environment variables. The efficiency scores varied across all DNSPs with environmental variables for higher voltage levels tending to favour the NSW and ACT networks. The sensitivity of the

inefficiency results to the specification of the modelling indicates that significant caution should be placed on the results of any one specification as it is unlikely to control for all the differences between the companies. Including an operating environment variable for 132kV (and higher) line and cables significantly reduced the range of efficiency scores across the companies. In part this was likely because only six companies had lines or cables at this voltage level or above. However, as this variable is significant, and positive, in almost all the specifications I tested it does indicate that operating higher voltage lines and cables requires higher opex than lower voltage lines.

My findings indicate that a greater range of operating environment variables and models are almost certainly required to control for the differences between the DNSPs. For example, Ofgem during its recent RIIO-ED1 (electricity distribution) price control used a range of bottom-up models to assess the different activities within opex. It combined these models with its top-down models to develop an overall view of the distribution network operators' efficiency.

Even normalising for differences identified by Economic Insights/ AER prior to modelling leads to a different efficiency target for the DNSPs. Given these issues, the AER's reliance on the econometric analysis may not be in the long-term interests of consumers, and therefore not promoting the NEO, as the expenditure levels may be set below those required for the safe, secure, and reliable operation of the network.

I have not tried to identify a suite of or single perfect model for opex benchmarking, as this is a much more exhaustive process than the time allows. Rather, my analysis shows that there are operating environment differences that Economic Insights have not controlled for in its modelling. The modelling I have done provides a much tighter range of efficiency scores than those produced by Economic Insights' preferred model. In my opinion the aggregate level opex benchmarking should also be supplemented by activity level benchmarking using normalised costs, e.g., overheads.

What are the results of using the AER's proposed method of calculating the "efficiency frontier" on the alternative models? How does the AER's approach compare with international precedent?

After reviewing the AER's proposed method of calculating the "efficiency frontier" on its preferred model and alternative models developed I consider that:

- the AER's approach of averaging the efficiency over companies that achieve an efficiency score of at least 75% is very model specific; and
- if a different specification was run and all companies achieved efficiency score of over 75% then the AER's approach would not work in the way intended, in my opinion, as the frontier would be an average over all the DNSPs' efficiency scores.

I compare the AER's approach to international precedent in the next section. However, my review of precedent from regulators in other jurisdictions indicates that they choose a frontier

taking into account a range of factors, including their confidence in the data, techniques and robustness of the modelling.

Given the lack of explanatory variables in the modelling and the wide range of efficiency scores I would have expected the AER to have adopted a much more cautious approach to setting the efficiency target in line with international precedent (discussed further in the following section).

4. CHOICE AND APPLICATION OF EFFICIENCY ADJUSTMENT

In this Section I address the following questions posed to me by AAD:

- *How does the AER's approach [to calculating the 'efficiency frontier'] compare with international precedent?*
- How do measurement error, specification, and techniques affect the choice of model(s) and the frontier?
- Does the way in which the AER applies its "inefficiency adjustment" meet objective criteria (minimises measurement error, reflects operating environment, and incorporates realistic targets)?
- Are there alternative approaches to selecting the frontier than the simple average of the top-quartile? Under what circumstances could the AER have chosen such alternatives?
- If the definition of the efficiency frontier is subject to regulatory discretion, how has the AER exercised its discretion in selecting its preferred approach?
- Is it appropriate to set more than one frontier and is there precedence for this?

4.1. Introduction

In this section I discuss the approaches used by regulators to determine and set relative (catch-up) efficiency adjustments for companies identified to be inefficient. As ongoing productivity change is applied on an annual basis I have not included this in my discussion in this section.

Under price-cap (and revenue-cap) regulation the regulator sets an initial price P_0 . This price is then adjusted from one year to the next for changes in inflation (rate of input price increase or CPI) and a target efficiency/ productivity change factor "X". Accordingly, the price in period 1 is given by:

$$P_1 = P_0(1 + \text{CPI} - X)$$

Regulators in general have applied one of two approaches when making an adjustment for relative inefficiency in allowances for price control periods:

- **Full P0 adjustment**, whereby the regulator applies the full (100%) estimated relative inefficiency adjustment at the start of the price control period (i.e. to the initial price).⁵⁷
- **Glide-path**, whereby the regulator determines that the inefficiency adjustment should be spread over a number of years. The prices/ allowances would then be set so that the company would "glide" towards the efficient frontier.

⁵⁷ Note, a P0 adjustment can also refer to any adjustment made at the start of a price control, in order to differentiate from a 'glide-path' for the purposes of this paper I assume a P0 adjustment involves applying the full relative inefficiency adjustment.

There are many different options for the use of a glide-path. For example, a sizeable reduction to prices could be applied in the first year(s) of a price control (a partial P0 adjustment) with the remaining efficiency gap closed over the rest of the price control (or into future price controls). Different options may be chosen from a menu which holds the Present Discounted Value (PDV) of the resulting revenue streams (discounting at the company's WACC) constant.

In addition to choosing between applying a Full P0 adjustment or a glide-path or some intermediate combination, regulators may also use their judgement to determine the extent to which inefficient companies must close the efficiency gap. In considering its judgement a regulator will take account of a number of factors, including:

- the robustness of the data;
- the modelling technique used;
- the choice of the 'frontier'; and
- the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.

I note that the AER stated that “[i]t is not clear from the information before us that transitioning to an efficient level of opex is consistent with the incentive framework provided by NEL and the NER.”⁵⁸ I do not comment on the legality of this, rather I present the different options that other regulators have used when applying inefficiency adjustments and where possible their reasons.

In the following sections I discuss how the robustness of the data, modelling technique and choice of frontier may influence a regulator's decision with specific reference to the AER's current price control review. I then provide evidence from regulators' decisions in other jurisdictions – with specific examples of the evolution in regulators' approaches – and I then set out my conclusions in relation to current Australian DNSP price control review.

4.2. Implications from data and modelling techniques

As I have set out in the preceding section, after reviewing the international data and the RIN data I have concerns about the robustness of inefficiency estimates that may be produced using these data sets. Supporting this is an Economic Insights comment that its attempts at estimating benchmarking models using only the RIN data did not allow them to reliably estimate simple a version (e.g. Cobb-Douglas) of an opex cost function, a finding supported by the analysis in Table 3.2.⁵⁹

While large variation in inefficiency modelling is not altogether unusual, regulators need to ensure that they fully take into account the reliability and limitations of the data, particularly

⁵⁸ AER, *Draft decision: ActewAGL distribution determination 201-15 to 2018-19 Overview*, November 2014, page 11.

⁵⁹ Economic Insights (2014), page 28.

the different cost allocation practises across the Australian companies and, critically, those of any international companies included in the analysis, in making their determinations. Jamasb and Pollitt (2001, p128) state that:

[R]egulators need to pay ample attention to developing good data collection and reporting systems. A precondition for international comparisons is to focus on the improving the quality of data collection process, auditing, and standardisation within and across countries.

ACCC also supported this assertion and stated in its working paper (ACCC (2012)) that caution should be exercised when using international data and that “[i]n-depth examination of the data is required to ensure consistency, comparability and quality”⁶⁰.

Inconsistent data across DNSPs means that not only are modelling results unlikely to be correct, but also that an inappropriate model specification or technique may be chosen. In addition, as Economic Insights point out, the use of international data has limited the number of environmental variables that could be included. Economic Insights only included one variable – for the proportion of underground cabling – in its preferred model specification despite the massive difference in climate between Australia and Ontario.

Regulators, e.g. Ofgem, have relied on COLS approaches because of these problems. COLS allows them the discretion of selecting the specific ‘correction’ to the OLS in choosing where they consider an appropriate frontier to lie.⁶¹ For example, if a regulator considered that there was a great deal of variability in the data, and that some of it may be due to measurement error, then a less challenging target may be chosen (e.g. the upper third rather than the upper quartile). This approach recognises that there may be factors or reporting issues that the regulator either is aware of, but cannot adjust for, or it does not have full sight of.

SFA, in theory, takes account of measurement error in the model. However, this advantage comes at the cost of a more complex econometric specification and it also requires relatively strong assumptions about the statistical distribution of the inefficiency modelled. These assumptions are needed to identify the decomposition of the residual into inefficiency and random error. If these assumptions are not valid, the resulting estimates and decomposition will be biased. It is worth noting that when regulatory judgement is applied to the frontier after it is estimated via SFA it calls into question why this more complex and less transparent technique was chosen in the first place.

Economic Insight proposed that the AER use the average over efficiency score above 75% as the benchmark.⁶² It considers that this approach “allows for general limitations of the models with respect to the specification of outputs and inputs, data imperfections and other

⁶⁰ ACCC (2012), page 151.

⁶¹ This is in contrast to the regulator assuming that there is no measurement error in the residual and the ‘correct’ line must go through the frontier company.

⁶² I note that Economic Insights refer to using the top-quartile in its report (Economic Insights (2014), page v), however, it does not use a quartile. Rather it simply specifies that scores over 75% should be averaged.

uncertainties."⁶³ While Economic Insights state that the country-specific dummy variables control for systematic differences between the countries, our analysis indicates that there are different within-country relationships between the cost drivers and explanatory variables included in Economic Insights models (Table 3.2). In other words, based on Economic Insights specification, but running the model with only one country's data in, adding one customer in Ontario has a quite different impact on costs than adding one customer in Australia.

Alternative, non-parametric, techniques such as DEA and MTFP suffer from the same issues around measurement error, model specification and frontier choice. Regulators have exercised judgement in using the estimates from these models to a similar extent as for parametric approaches.

An alternative to setting a single frontier for all the regulated companies is to use multiple frontiers to recognise the unobserved (or heterogeneity) between firms that is not captured via the explanatory variables. If this heterogeneity cannot be controlled for in the modelling it may result in different 'efficiency' groups or wide ranges of efficiency scores being identified in the modelling. Controlling for differences and setting multiple efficiency targets could be done via a modelling process called latent class modelling (LCM) which attempts to allocate firms to clusters on a statistical basis.⁶⁴ These sub-samples can then be analysed using the techniques discussed above and specific frontiers set for each. While this approach has generally not been used by regulators, academic work (see Filippini (2010) and Llorca (2014)) indicates that, at least with a large sample, it is a viable approach. One could argue that so long as sufficient explanatory variables are available and it is considered that the firms have similar cost or production functions then treating them as a single group is appropriate.

As I discuss in the next section, even after regulators choose the 'frontier', most will still exercise discretion as to the extent of the inefficiency gap that the inefficient companies must close and the time period over which they should achieve this.

4.3. International precedent

In most regulated industries, glide-paths have generally been employed by regulators rather than full PO adjustments when the scale of the inefficiency adjustment has meant that it was not feasible (i.e., reducing staff numbers, adopting new business practices, impact on financeability) for the inefficient company(ies) to close the entire gap to the frontier in a single year. Glide-paths are therefore designed to reflect:

- the degree of catch-up considered to be required to achieve an efficient operating cost base;
- the time period for which this is could be achieved; and
- how the 'efficient frontier' was calculated.

⁶³ Economic Insights (2014), page 47.

⁶⁴ See Haney (2012), page 28.

Regulators do need to be cautious in the use of a glide-path as there is a risk that inefficient companies will be rewarded if they are able to cut costs quicker than the glide-path indicates, although this can be corrected at the next price control review.

There are many schools of thought around the choice of an efficiency target. Regulators in Western European countries tend to set a 'frontier' type target, i.e., using DEA, COLS or SFA, although, given the level of discretion regulators apply, the overall approach they choose is generally more of a starting point than a mechanistic application. North American regulators have tended to use a more 'average' type frontier.⁶⁵ In relation to North American studies, Lowry (2005) argues that based on basic criteria of accuracy and fairness an "average efficiency standard is a worthy alternative to a frontier standard."⁶⁶ However, one could argue that the way in which Western European regulators determine and apply a 'frontier' is not in line with the literature and the author's view of a 'frontier'. Rather the Western European regulators take a view on the accuracy and robustness of their modelling and they apply discretion by adjusting the frontiers while ensuring the consumers' interests are taken into account through the reliability, safety and financial viability of regulated utilities. Jamasb & Pollitt (2001) noted that:

*Average benchmarking methods may be used to mimic competition among firms with relatively similar costs or when there is lack of sufficient data and comparators for the application of frontier methods.*⁶⁷

New Zealand provides an example of taking account of the size of the inefficiency adjustment and the time required to close the gap. Meyrick and Associates (Meyrick (2003)) in work for the New Zealand Commerce Commission for its 2004 electricity distribution networks price control noted that while it had identified a substantial range in companies' efficiencies "[g]iven the need to minimise risks given the variable quality of the available data and residual uncertainties, we reduce the range of C factors [relative productivity and profitability factors] to -1, 0 and 1 per cent".⁶⁸ Meyrick noted, in relation to overall prices, that:

Given the capital intensive nature of electricity lines businesses and the long lived nature of the assets involved, it is unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time. Rather, a timeframe of a decade, or two five-year regulatory periods, is likely to be necessary for businesses performing near the bottom of the range to lift themselves into the middle of the pack. This timeframe would allow sufficient time for asset bases to be adjusted significantly, new work practices to be adopted and bedded down and for amalgamations and rationalisations to be implemented and consolidated. It is, however, reasonable to expect profitability levels to be adjusted over a shorter period, say one regulatory period of five years. This should allow sufficient time for

⁶⁵ Lowry (2005), page 76.

⁶⁶ Lowry (2005), page 77.

⁶⁷ Jamasb & Pollitt (2001), page 108.

⁶⁸ Meyrick (2003), page 63. The Meyrick report was led by Dr. Denis Lawrence who is now Director of Economic Insights and who led the benchmarking work for the AER.

*adjustment in a sustainable fashion without incurring the risk of financial stress or failure resulting from large PO adjustments.*⁶⁹

In almost all cases regulators have taken a more cautious approach than using a simple frontier in order to recognise the limitations of the modelling and the economic costs and risks placed on the companies. This is not dissimilar to the revenue and pricing principles that the AER must take into account as set out in Section 7A of the National Electricity Law (NEL).

In Table 4.1 overleaf I set out regulators' decisions in different jurisdictions, around the application of a PO or glide-path to opex (in some cases the regulators only undertake efficiency analysis on totex; where this is the case I have reported the totex inefficiency adjustment).

⁶⁹ Meyrick (2003), page 63.

Table 4.1: International precedent

Regulator and sector	Price control period/ number	PO or glide-path	Percentage of inefficiency gap to close	Period of reduction	Benchmarking method	Benchmark	Comments
Ofgem – Electricity distribution†	2000-2005 (3rd)	Glide-path	75%	2 years	COLS/ P/A	Frontier	
	2005-2010 (4th)	PO	100%	1 year	COLS (DEA cross-check)	Upper quartile	
	2010-2015 (5th)	PO	100%	1 year	COLS	Upper quartile	Menu results in 25% of companies' view used in setting allowance
	2015-2023 (6th)	PO	100%	1 year	COLS, P/A	Upper quartile	Menu results in 25% of companies' view used in setting allowance
NZ Commerce Commission – Electricity distribution	2004-2009 (1 st)	Glide-path	n/a	5 years	MTFP	N/A (7 out of 28 deemed 'inefficient')	1% per annum 'catch-up' applied to those deemed 'inefficient'
Ontario – Electricity distribution		Glide-path	N/A		GLS	Groupings	Worst performers assigned 0.6% per annum 'stretch' factor
Ofwat – Water and sewerage	1995-2000 (1 st)	Glide-path	50%	5 years	P/A	Frontier	Companies 'catch-up' efficiency based on which band (three in total) they fall into
	2000-2005 (2 nd)	Glide-path	75%	5 years	COLS and P/A	Frontier	Companies 'catch-up' efficiency based on which band (five in total) they fall into
	2005-2010 (3 rd)	Glide-path	60%	5 years	COLS and P/A	Frontier	Companies 'catch-up' efficiency based on which band (five in total) they fall into
	2010-2015 (4 th)	Glide-path	60%	5 years	COLS and P/A	Frontier	Companies 'catch-up' efficiency based on which band (five in total) they fall into
	2015-2020	PO	100%	1 year	COLS and GLS(RE)	Upper quartile	Company specific factors applied after the modelling. Menu results in 25% of companies' view used in setting allowance.
ORR - Rail	2009-2015	Glide-path	67%	5 years	P/A, RUOE analysis	N/A	Benchmark based on other regulated industries performance
EnergieControl - Austria*	2005-09	Glide-path	25.24%	8 years	COLS, DEA	Frontier	

Regulator and sector	Price control period/ number	P0 or glide-path	Percentage of inefficiency gap to close	Period of reduction	Benchmarking method	Benchmark	Comments
CREG (Belgium) – Electricity distribution*	2007	Glide-path	10% (average), 29% (max)	5 years	DEA		
ANEEL (Brazil) – Electricity distribution*	2007-11	Glide-path	10%	4 years	N/A		
EMV (Finland) – Electricity distribution*	2007-11	Glide-path	18% (average)	8 years	DEA and SFA	Frontier (less 16% for uncertainty)	
CONELEC (Ecuador) – Electricity distribution*	2007	P0	50%	1 year	Percentage caps		
CFE (Mexico) – Electricity distribution*	1996-06	Glide-path	50%	5 years	COLS, DEA		

Note: P/A – Process/ activity benchmarking

[†] The first and second price controls were undertaken by Offer (Ofgem predecessor) and it used benchmarking for both, however very little detail about how this was conducted are available in the public arena.

* Data for electricity distribution sector, sourced from Haney & Pollitt (2009).

The information set out in Table 4.1 above indicates that more often than not regulators apply a glide-path. The evidence from the UK suggests that only when regulators have collected data on a transparent and consistent basis over a long period, and have tried and tested models, are they confident enough to not make a further discretionary adjustment to the frontier, and that the frontier is then based on the upper quartile. Even then it is worth noting that regulators tend to make adjustments, including mitigating factors, for one-off expenditure, menu regulation, and/or company specific-factors which all impact on companies' regulated allowances. In addition, with a few exceptions, regardless of technique or choice of benchmark regulators have tended to 'offset' the catch-up to the frontier required by the companies.

Of particular interest is the evolution of the regulators approaches over time. I consider two specific examples – that of Ofgem (the GB energy regulator) and Ofwat (the England and Wales water and sewerage regulator) – in more detail below. These regulators have conducted price controls for over 20 years and are generally considered leaders in their sectors.

Ofgem

Ofgem, for the third electricity distribution network price control review conducted in 1998-2000 (DPCR3) for the period 2000-05, determined that inefficient companies should move three-quarters of the way to the frontier by 2001/02 and then retain that position relative to the frontier.^{70,71} Ofgem had stated that this approach was “consistent with the likely path of cost reduction, while ensuring these companies will have sufficient resources towards the end of the period to further improve quality of supply.”⁷² Ofgem's used two approaches to estimate opex efficiency:

- an Account Consultancy report; and
- a COLS regression model.⁷³

The two approaches used produced relatively similar results. Estimated potential savings for the network operators ranged from negative 4% (i.e. above the frontier) to positive 41%. It does not appear from its report that Ofgem used these in a deterministic way. Interestingly, the largest reduction, 29%, to opex from DPCR2 to DPCR3 was to one of the companies at the frontier of both the accounting assessment and COLS analysis. It is not possible to decompose the opex PO adjustment into its component parts from the publically available information,

⁷⁰ There is little detail available on the models and techniques used by OFFER (Ofgem's predecessor) for the first and second price controls.

⁷¹ Ofgem (1999a), page 21.

⁷² Ofgem (1999b), page 2.

⁷³ Ofgem used a different approach to COLS than what would be considered 'normal' (or best practise) today. It rotated the line of best fit from OLS to pass through the frontier company while holding the intercept constant. This was done as it received an expert view that the intercept (fixed cost) would be implausibly low if the line was 'shifted' to pass through the frontier company.

but a large proportion of the opex allowance reductions appear to have come from Ofgem (a) reallocating overhead costs from the distribution business to the supply business and (b) applying savings from mergers across the networks.⁷⁴

During its fourth electricity distribution price control (DPCR4 for 2005-10), conducted in 2003 to 2004, Ofgem stated that there was a balance to be found between making a P0 adjustment and setting a price path via the X-factor. Ofgem noted that in coming to its decisions it considered two main factors:

- the financial profile of the companies – Ofgem had a duty (and still does) to ensure that DNOs can finance their licenced activities; and
- that the path of prices reflects cost trends and is sustainable.⁷⁵

Ofgem chose to apply the full relative (in)efficiency adjustment as a P0 adjustment.⁷⁶ The maximum reduction applied by Ofgem to the distribution network operators' opex forecasts was 27%.⁷⁷ However, Ofgem noted that the greatest cuts to forecast are to companies whose "forecasts show costs substantially higher than normalised 2002/03 levels".⁷⁸ The largest cut Ofgem made to opex allowances from DPCR3 to DPCR4 was 10.7% (including efficiency savings achieved in DPCR3, future efficiency and other adjustments).⁷⁹

For DPCR5 (conducted 2008 to 2009 for the period 2010-15), Ofgem again chose to apply the full relative (in)efficiency adjustment to the distribution network operators' forecasts. The maximum reduction was 9%, although it is worth noting that overall the distribution network operators' opex allowances increased significantly from the previous price control.⁸⁰ Even during this price control review, its fifth price control and the third one that relied more heavily on comparative benchmarking, Ofgem noted that it benchmarked network operating costs at the upper third "due to greater variability in the data".⁸¹ In addition, Ofgem decided on using an upper quartile for closely associated indirect costs as there was a smaller range of costs across the DNOs.⁸² Ofgem used a large number (around 40) of models to cover opex, these consisted of aggregate level models to models covering groups of specific activities. Ofgem then weighted these models together before determining the upper quartile/ third target for business support and closely associated indirects.

After setting its efficiency benchmarking to take account of measurement error and variability in the data, Ofgem used a full P0 adjustment for opex in DPCR5. It noted that this was a tough

⁷⁴ Ofgem (1999a), page 16.

⁷⁵ Ofgem (2004a), page 111.

⁷⁶ However, DNOs that had been 'single' at the start of 2002/03 will only need to move 50% of the way to the upper quartile by 2004/05. The remaining half of the gap to the upper quartile is closed by the fifth year after any merger or after the start of the price control, whichever is sooner. Ofgem (2004b), pages 73-74.

⁷⁷ Ofgem (2004b), page 77.

⁷⁸ Ibid.

⁷⁹ Ibid, page 128.

⁸⁰ Ofgem (2009a), page 35.

⁸¹ Ibid, page 4.

⁸² Ofgem (2009b), page 4.

stance and its justification for deviating from its past policies of allowing network operators time to restructure and become more efficient was that it was allowing revenues to increase.⁸³ It considered that companies would find it easier to close the efficiency gap quickly than if revenues and costs were falling.⁸⁴

It is worth noting that Ofgem had introduced menu regulation for a proportion of opex in DPCR5 (in DPCR4 the menu only related to capex). Its application of menu regulation meant that companies' allowances reflected 75% of Ofgem's view and 25% of their forecast opex included in the menu. Ofgem do this to recognise that it does not have perfect information.

In its recently published final proposals for the electricity distribution price control from 2015 (RIIO-ED1), Ofgem focused on total expenditure (totex) allowances and does not provide opex-specific efficiency targets. Ofgem stated that it used a tool-kit approach to benchmarking, recognising that there is no definitive answer for assessing comparative efficiency. It placed a 50% weight on a bottom-up process/ activity assessment of the companies' historical and forecast expenditure. Two totex models were each given 25% weightings. Ofgem noted that the different approaches each have their advantages and disadvantages "[t]he advantage of totex models is that they internalise opex and capex trade-offs, are relatively immune to cost categorisation issues and they give an aggregate view of efficiency. The disaggregated model uses activity drivers that more closely match the costs being considered."⁸⁵ The largest reduction to a distribution network operator's forecast expenditure over RIIO-ED1 was 11%.⁸⁶ I summarise Ofgem's approach to cost assessment during RIIO-ED1 in Text Box 4.1 below.

Text Box 4.1: Ofgem RIIO-ED1 case study⁸⁷

Ofgem's RIIO-ED1 price control review is its most recent electricity distribution price control review. It is the sixth price control review undertaken for electricity distribution networks and Ofgem collected more detailed and consistent data than during previous price controls. Ofgem had carefully specified different activities classifications in its reporting guidance and data template in order to collect data before companies' cost allocation approaches were applied i.e., all business support costs are captured together rather than those after some proportion has been capitalised. This helps ensure that activity costs are benchmarked on a like-for-like bases. Ofgem capitalises a fixed proportion (85%) of all expenditure, the rest (15%) is funded within the financial year.

Ofgem employed a 'tool-kit' approach to cost assessment that relied on a number of activity level models (disaggregated model) and two totex models, one based on a scale variable which incorporated MEAV (modern equivalent asset valuation) and customer numbers, and one which used a weighted aggregate of costs drivers from the disaggregated model. The MEAV variable used by Ofgem is based on each company's asset volumes (around 100 different asset classes) weighted together with Ofgem's view of unit costs. Because it takes into account the network operators' existing assets, the MEAV variable has a number of beneficial attributes: it incorporates density as it reflects the assets required to service different urban/rural areas; it reflects legacy network

⁸³ Ibid, page 11

⁸⁴ Ibid.

⁸⁵ Ofgem (2014a), page 26.

⁸⁶ Ofgem (2014b), page 12.

⁸⁷ Ibid.

arrangements; and it reflects other environmental operating differences. As part of its assessment, Ofgem reviewed the network operators' narratives and supporting evidence, including historical costs, performance data and forecasts.

Ofgem weighted together the three different models before determining the frontier (upper quartile). It did this to avoid 'cherry-picking' the network operators' performance in each of the models. Ofgem used the upper quartile rather than the frontier to account for other factors that may influence the network operators' costs.

Ofgem excluded a number of areas from its totex analysis and also normalised (pre-modelling) for differences in the operators' expenditure (e.g. it made company-specific adjustments for two operators, a regional labour adjustment, and applied DNO cost allocation for indirect costs).

In its disaggregated activity level benchmarking Ofgem used a mixture of regression analysis, age-based-modelling, ratio analysis, trend analysis, and technical assessment by engineering consultants. In particular for operating expenditure, for closely associated indirect costs Ofgem used a combination of regression analysis, ratio analysis and run rate analysis and a qualitative review. Business support costs were assessed at an aggregate level using ratio benchmarking (using MEAV as the cost driver).

Ofgem included almost all totex expenditure in its menu regulation (the Information Quality Incentive) which means that only 75% of its view (post upper quartile) is used to set the network operators' allowances. The remaining 25% is based on the network operators' forecasts.

In all its price controls, Ofgem has tried to only include controllable costs (i.e. licences fees, etc, are excluded) in its benchmarking and has excluded cost areas where it does not consider the available cost drivers explain these activities (e.g. critical national infrastructure protection costs).

Ofwat

For its first price control (PR94), Ofwat used company-specific glide-paths and anticipated that over the five years of the price control (1995-2000) the company-specific element of the X-factor would bring most companies about half way to the efficient frontier.⁸⁸ Ofwat considered that its approach took account of "uncertainties involved in identifying the efficiency frontier".⁸⁹ For PR99 (its second price control), Ofwat determined that companies should catch-up 75% of the efficiency gap over five years,⁹⁰ while for PR04 (its third price control) Ofwat set the catch-up as 60% of the efficiency gap for base opex over five years,⁹¹ In relation to the latter, Ofwat stated that it made "judgements about the speed and extent to which it [a company] can catch up with the performance of the best."⁹²

For PR09, Ofwat also determined that companies should catch-up 60% of the gap over the five years of the price control.⁹³ Ofwat used a range of opex models, for different activities, to determine companies' (in)efficiency. Its models were generally OLS based, or simple unit

⁸⁸ Ofwat (1994), page 31.

⁸⁹ Ibid.

⁹⁰ Ofwat (1999), page 97.

⁹¹ Ofwat (2004), page 156.

⁹² Ibid, page 12.

⁹³ Ofwat (2009), page 107.

cost models, using only one year of data even though Ofwat had been collecting data on a relatively consistent basis since 1999.

During its most recent price control review (PR14), Ofwat used base-opex and capex models, and totex based econometric models to determine the allowances for companies.⁹⁴ Ofwat used two different techniques for its advanced econometric modelling, COLS and RE(GLS) models. It used more simplistic unit cost models for enhancement capex.⁹⁵ All the models were weighted together before the frontier (upper quartile) was estimated to avoid cherry-picking the efficient companies across the models and setting an implausible target. Ofwat made adjustments for company-specific factors after the modelling, however as it had been collecting consistent and audited data over a long period it had confidence that the companies' expenditure was on a like-for-like basis. It also developed and put in place the models before receiving the companies' business plans, thus adjustments had to be made after the modelling. It considered that 'one-of-costs' were unlikely to have impacted on the modelling coefficients. In addition, Ofwat's 'menu' means that 25% of the companies forecast is taken into account when Ofwat sets the allowances.

4.4. Efficiency targets and financeability

It is important to bear in mind that both Ofgem and Ofwat consider their proposals as 'packages' (i.e. financing, incentives, expenditure allowance) and that looking at a single 'block' does not tell the whole story of how the allowances are set. In particular, both regulators undertake financial modelling on the expenditure allowances, how this may affect their credit rating, and hence impact the WACC. Text Box 4.2 below sets out Ofgem's RIIO-ED1 approach to assessing financeability. If the efficiency challenge set for the companies is considered too tough then they regulator may choose to aim-off the frontier, choose a less challenging frontier, and/or profile the revenue/ price-path.

*Text Box 4.2: Ofgem RIIO-ED1 case study*⁹⁶

Ofgem have an established approach for considering financeability in the context of network regulation in GB. The regulator has a duty to ensure that the companies are able to finance themselves and a network condition exists within the licence of each regulated energy network to possess an investment grade credit rating.

In making this financeability assessment, Ofgem consider the financeability metrics that form part of the rating agencies' assessments. These metrics comprise 40% of the ratings available for Moody's, with other criteria e.g. stability of the regulatory regime, contributing to the overall assessment. One of these metrics, the Post Maintenance Interest Cover Ratio (PMICR) is currently challenging due to the low real interest rate and high inflation (using RPI inflation) macroeconomic environment. The Competition Commission (now CMA) had previously targeted a ratio of 1.4x, however accepted a ratio of 1.2x for the Northern Ireland Electricity (NIE) determination.

⁹⁴ Ofwat (2014).

⁹⁵ Enhancement capex relates to capex projects that 'enhance' the network and are not solely related to maintenance or replacement capex.

⁹⁶ Sources: PwC (2014) and UK Competition Commission (2014).

The regulator, in making this assessment, looks at a range of plausible outcomes and at both the notional and actual financial positions for the regulated companies. For the cost of debt indexation under RIIO, Ofgem use broad BBB and A rated non-financial corporates in setting an allowance, although networks do benefit from the 'halo effect' on debt yields.

A regulated companies' ongoing financing is a key aspect to ensuring the achievement of the NEO. In particular, it relates to the 'prudence' of a regulated company as it is not prudent for them to reduce a large opex inefficiency gap in a very short space of time.

4.5. Conclusions

What are the results of using the AER's proposed method of calculating the "efficiency frontier" on the alternative models? Are there alternative approaches to selecting the frontier than the simple average of the top-quartile and how does the AER's approach compare with international precedent? Under what circumstances could the AER have chosen such alternatives?

My review of precedent from regulators in other jurisdictions indicates that regulators choose a frontier taking into account a range of factors, including their confidence in the data, techniques and robustness of the modelling.

As I noted in my conclusions to the preceding section, the AER's approach of averaging the efficiency over companies that achieve an efficiency score of at least 75% is very model specific. If a different specification were run and all companies achieved efficiency scores of over 75% then the AER's approach would not work as intended, rather it would provide an average target.

Given the lack of explanatory variables in the modelling and the wide range of efficiency scores I would have expected the AER to have adopted a much more cautious approach to setting the efficiency target in line with international precedent (discussed further in the following section). At the very least greater consideration should have been given to the differences across the group of efficient and the group of inefficient companies. The AER conducted supporting analysis via its category analysis, however this was flawed due to the issues around normalising the data identified in Section 3.

How do measurement error, specification, and techniques affect the choice of model(s) and the frontier?

In regulatory benchmarking, specification and techniques, which are chosen by the regulator, will impact on the regulator's choice of a frontier (efficiency target). Measurement error is a consideration for regulators in choosing a technique or specification to use. Some frontier based models, e.g. Stochastic Frontier Analysis (SFA), use strong assumptions to deal with measurement error, while in others, e.g. Corrected Ordinary Least Squares the regulator will adjust its findings/ efficiency target to reflect the measurement error. In my opinion, recognising and taking into account measurement error is as important as the theory or data that lead to the choice of model specification or technique.

Evidence from international regulators indicates that measurement error plays a significant part in their decisions on where to set the frontier and how much to 'aim-off' this. The regulator also takes into account the specification of the models, whether the drivers used in the modelling do not take account of (or differentiate between) all the costs faced by the regulated companies, and then adjustments to allowances may be made. Jamasb & Pollitt (2001) noted that sufficient data and comparators are required for the application of frontier methods.⁹⁷ I interpret "sufficient data" to also mean the quality and robustness of the data as the authors discuss these issues in latter sections of their paper.

In relation to 'aiming-off' the frontier (or choosing a less challenging frontier), regulators have shown a large degree of discretion in determining the extent to which inefficient companies need to close the gap to the frontier and how quickly they need to do this. This is even after the regulator has used its discretion in choosing a frontier. In making their judgement regulators take into account:

- the robustness of the data and maturity of the dataset;
- the modelling technique used;
- the choice of the 'frontier'; and
- the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.

In almost all cases they have taken a more cautious approach than using a simple frontier in order to recognise the limitations of the modelling and the economic costs and risks placed on the companies. This is not dissimilar to the revenue and pricing principles that the AER must take into account as set out in Section 7A of the NEL. It is often the case that regulators are required to take into account both the interests of consumers and the ongoing financeability of an efficient regulated company. If a regulator were to set either an unrealistic or unachievable efficiency target for a regulated companies then both of these aims and the promotion of the NEO may be put at risk.

Does the way in which the AER applies its "inefficiency adjustment" meet objective criteria (minimises measurement error, reflects operating environment, and incorporates realistic targets)?

As I state above, regulators need to consider a range of factors when determining and setting an 'inefficiency' adjustment. International precedent indicates that regulators have tended to be cautious in their approaches to setting efficiency targets and the speed at which they should be closed. Measurement error and the ability to control for operating environment differences appear to have been two key considerations for regulators when choosing the frontier. However, when it has come to setting the inefficiency adjustment regulators have

⁹⁷ Jamasb & Pollitt (2001), page 108.

been mindful to the ongoing financeability of the companies and the feasibility of them achieving the reductions.

An example of this was the approach proposed by Meyrick and Associates (Meyrick (2003)).⁹⁸ The authors proposed to the New Zealand Commerce Commission that it set, for its 2004 electricity distribution networks price control, relatively small efficiency gain factors to minimise risk, take account of the quality of the data, and to reflect the fact that the businesses would need time to adopt new work practices.

While the AER's SFA approach makes an assumption to deal with measurement error, the single environmental control variable of share of underground cables and the lack of normalisation for opex indicates to me that the AER's inefficiency adjustment is of a much greater magnitude than those applied by other regulators given the circumstances.

In addition, while the AER has taken into account Economic Insights' proposals for adjusting the frontier for some company-specific factors, these only relate to the differences between the inefficient Australian companies and the Australian 'frontier' and do not reflect the operating differences between Australia and the other countries which have not been controlled for. In other words, while Economic Insights state that it has benchmarked Australian companies only against Australian companies, because the international data has influenced the coefficients (see Section 3.2.2.) AAD is being compared against a statistically significantly different frontier slope determined primarily by New Zealand and Ontario data.

Overall, in my opinion, the AER has not sufficiently recognised the limitations of opex modelling, particularly when using data that may not be comparable, when setting the efficiency targets for AAD and the NSW Networks. This may result in the expenditure level being set too low for the ongoing financeability, safety, reliability and/or security of a network to be achieved.

If the definition of the efficiency frontier is subject to regulatory discretion, how has the AER exercised its discretion in selecting its preferred approach?

Regulators operate under legislation that can impact on the level of discretion they are able to apply. However, an almost universal obligation on regulators is for them to have regard to the long-term interests of consumers. This clearly covers a range of factors, but the ongoing viability of the service provider is a critical aspect of this. Regulators need to have regard for the entire regulatory 'package' that they put in place. This ranges from the cost assessment through to the incentives and financeability of the service providers. While I understand that the AER has no specific requirement under the legislation to have regard to the financeability of the DNSPs, this is implicit in the national electricity objective (NEO) having regard to the long-term interests of consumers.⁹⁹ I note that the AEMC, in its final rule determination,¹⁰⁰

⁹⁸ Meyrick (2003), page 63.

⁹⁹ National Electricity (South Australia) Act 1996—19.12.2013, Schedule—National Electricity Law, Part 1, para 7.

¹⁰⁰ AEMC (2012), page 107.

indicated clearly that the AER should treat benchmarking as just one of various considerations:

Benchmarking is but one tool the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal.

As the authors of Haney & Pollitt (2012) set out, efficiency analysis happens within a process. This process is interactive and involves negotiation and *ex post* review. Benchmarking is a useful tool in this process, but not the only source of evidence.¹⁰¹ For example, the authors note that the Finnish regulator uses a number of frontier benchmarking methods, but it only applies the results to their negotiation-based method of regulation.¹⁰²

In my opinion this is because the 'efficient and prudent operation' of a DNSP requires realistic and achievable price paths, and ongoing financing. Specifically, if the AER were to raise doubts in the minds of credit agencies about the credit-worthiness of a DNSP, it would likely face a higher WACC, which would translate into higher revenue requirements, to the detriment of future consumers, which would not in line with the NEO.

Is it appropriate to set more than one frontier and is there precedence for this?

There are several options that regulators may adopt when setting a frontier:

- a single benchmark for all companies (this could be based on a single model or multiple models) and applying the same rate of catch-up;
- a single benchmark for all companies, but apply different rates of catch-up; or
- multiple benchmarks taking account of different factors, for example the size of the company.

In more developed regulatory regimes the approach has been to set a single benchmark for all companies. However, this has been after adjustments for operating environment differences have been incorporated and before specific allowances for differences have been set. Setting different frontiers has been used by regulators for instance in yardstick regulation where the frontier is set by peer groups rather than the frontier companies.¹⁰³ In addition, latent class modelling (LCM) also offers a way of setting multiple frontiers based on grouped characteristics. However, LCM requires a large dataset and it involves additional statistical testing and assumptions around the different cost/ production functions faced by utilities. While there is academic support for this method, it has not yet been used extensively by regulators.

As I have stated above, regulators use their discretion in setting frontiers to ensure the ongoing operations of the network services provides for the long-term interests of consumers. While the AER may have confidence in its modelling, which I do not, it also needs

¹⁰¹ Haney & Pollitt (2012)), page 7.

¹⁰² Haney & Pollitt (2012), page 36.

¹⁰³ The National Energy Commission (CNE) in Chile used this type of approach.

to consider how a prudent operator might reduce its opex while maintaining reliability, safety and financeability of its network.

5. CONCLUSIONS

The AER's overarching objective is the National Electricity Objective (NEO) set out in section 7 of the National Electricity Law (NEL), which reads:-

"The objective of this Law is 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."

Under the National Electricity Rules (NER) (6.5.6(c)) the AER, in relation to opex, has an obligation to

"(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (the operating expenditure criteria):

(1) the efficient costs of achieving the operating expenditure objectives; and

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

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

Benchmarking is an important tool available to regulators in assessing the efficiency of regulated companies. However, its limitations must be considered in setting revenue allowances for companies and other tools / information should be used to supplement a benchmarking model(s).

While the AER's guidelines for assessing future opex are in line with best practice, from my analysis it is not clear that the AER's application of its opex benchmarking for its AAD draft determinations are. In particular my investigations indicate that:

- the international data (New Zealand and Ontario) that the AER and its consultants relied on is inconsistent the Australia RIN data;
- insufficient consideration has been given to the DNSPs' different operating environments within the benchmarking (and the use of international data does not allow for additional environmental operating variables to be used, besides underground cabling); and
- the Regulatory Information Notice (RIN) data in the form collected and used by the AER do not provided opex on a like-for-like basis across the DNSPs.

The AER has made some adjustments to the frontier for the inconsistencies in the reporting across DNSPs (the latter point). However, this is a second-best approach and data should be normalised prior to modelling to ensure like-for-like comparisons. If the AER had consistent data across the DNSPs it may not have needed to rely on international data which is reported

differently from the Australian DNSPs and is inconsistent with the Australian operating environment.

While the AER has undertaken category analysis to supplement its econometric benchmarking this has also been done on non-normalised data and in my opinion some of the results are not robust and therefore cannot be relied on to support the AER opex benchmarks.

In addition, a regulator must also consider how quickly and prudently an inefficient company may reduce its expenditure to an efficient level. In making their judgement on the efficiency gap inefficient companies should close over a regulatory period regulators should take into account:

- the robustness of the data and maturity of the dataset;
- the modelling technique used;
- the choice of the 'frontier'; and
- the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.

Given these issues one would expect the AER, in line with international precedent, and particularly as it has relied on a single model, to have taken a more cautious approach to setting the efficiency target and the speed at which inefficient companies must achieve it than the AER did. In my opinion, the AER's efficiency adjustment for AAD's forecast opex does not sufficiently recognise the measurement error and lack of explanatory variables in the data and model. In addition, in my opinion the speed at which the AER has set the companies to reduce the inefficiency gap, given the AER estimates, is not prudent and would put at risk the achievement of the NEO.

In my opinion this is because the 'efficient and prudent operation' of a DNSP requires realistic and achievable price paths, and ongoing financing. Specifically, if the AER were to raise doubts in the minds of credit agencies about the credit-worthiness of a DNSP, it would likely face a higher WACC, which would translate into higher revenue requirements, to the detriment of future consumers.

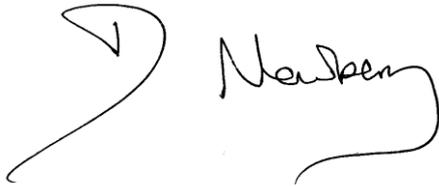
In my opinion, the AER needs to continue to develop its reporting guidelines, normalise the data and test its dataset to ensure that like-for-like comparisons are made. The AER should look at incorporating a greater variety of environmental operating variables in its models and to develop a greater suite of models to assist its decision making. This should include the AER investigating using activity level (e.g. vegetation management) in a more quantitative way to support its top-down models. In addition, the AER should use its discretion in choosing a frontier to ensure that challenging, but achievable, price paths / revenue allowances are set.

6. DECLARATION

The opinions contained in this report are based wholly or substantially on the specialised knowledge gained through training, study and experience outlined in the Curriculum Vitae that is attached in ANNEX F.

I have made all inquiries that I believe are desirable and appropriate and that no matters of significance that I regard as relevant has, to my knowledge, been withheld from the Court.

Signature:

A handwritten signature in black ink, consisting of a large, stylized initial 'D' followed by the name 'Newbery' in a cursive script.

Professor David Newbery, Chairman, CEPA Ltd

ANNEX A ADJUSTMENTS TO DATA

This annex outlines my approach to making normalisations for differences in overhead capitalisation rates across DNSPs and the additional required adjustments flagged by the AER and Economic Insights for AAD and NSW DNSPs. The most practical way to proceed is with a short description, a worked example, and then the final results.

The goal of the normalisation is to adjust the data for overhead capitalisation and bring opex onto pre-capitalised basis. The procedure is:

1. Obtain total amount of overhead capitalisation for each available year.
2. Divide overhead capitalisation by total opex.
3. Apply the average of available years where overhead rates are unavailable.

Table A.1: Example of adjustment factor

		2008/09	2009/10	2010/11	2011/12	2012/13
A	capitalised network overheads	113,359	159,705	188,373	193,887	186,089
B	capitalised corporate overheads	25,181	28,020	35,288	34,921	26,387
C	network overheads	202,374	259,310	278,780	326,852	253,280
D	corporate overheads	122,159	118,641	89,837	99,978	58,719
E	TOTAL OPEX	463,073	565,676	592,278	655,639	524,474
	Adjustment to opex, (A+B)/E	30%	33%	38%	35%	41%

The implicit assumption that I am using is that this overhead capitalisation rate in total opex extends to the more granular network opex category that is used for benchmarking. Also, as I have mentioned, I use the average of available data to adjust years for which overhead rates were unavailable.

I adjusted for pole top structures expenditure in a similar way to the capitalisation. For each DNSP, I took the total repex for pole top structures for each year set out in the Category Analysis RIN, and divided this by the total opex set out in the Category Analysis RIN. This provided pole top structure repex as a percentage of opex. I then multiplied the network service opex in the Economic Benchmarking RIN by 1 plus this percentage to give a non-pole top structures capitalised opex. I use the average of available data to adjust years for which overhead rates were unavailable. This is a conservative approach to this adjustment since, unlike overheads, pole top structure expenditure likely does not apply to all categories of 'consistent opex' reported in the EB RINs. That is, AAD (and other DNSPs that did not capitalise pole top structures) likely have a higher proportion of pole top structure expenditure in network opex than in, say, metering opex. Therefore, the adjustment factor may in reality be larger for network opex in some cases since capitalised pole structure expenditure should be reallocated to only a few opex categories.

ANNEX B ADVANCED BENCHMARKING APPROACHES

Table B.1: Advanced benchmarking approaches and their strengths and weaknesses

Estimation Method	Description	Strengths	Weaknesses
Parametric Approaches			
Pooled Ordinary Least Squares (OLS)	The Pooled OLS model treats the data as if it was series of multiple cross-sections – that is, e.g. 130 firms rather than 13 companies over 10 years. Not recognising the structure of the data causes the OLS estimator to place equal weight on the between variation (i.e. differences between companies) and within variation (i.e. differences between years for the same company) when calculating the estimate.	<p>Strong regulatory precedent exists for evaluating company costs using this method; both Ofgem and Ofwat have adopted this technique as part of their current price reviews.</p> <p>Use of pooled data increases the sample size and few distributional assumptions are required. Estimates of efficiency are also variable over time.</p>	<p>OLS does not distinguish between white noise, heterogeneity, and inefficiency, unlike the rest of the parametric methods below which make some assumptions about the decomposition of residuals into noise and other components such as inefficiency.</p> <p>Although efficiency is allowed to vary over time, there is no structure to this variation.</p>
Pooled Stochastic Frontier Analysis (SFA)	This is a maximum likelihood estimation (MLE) model requiring distributional assumptions on the error term and is the same as OLS except that a one-sided error term.	The one-sided error term explicitly recognises the existence of inefficiency (with the error term decomposed into its noise and inefficiency components).	<p>The pooled element of this technique means that the data is (like Pooled OLS above) treated as a cross-section, thus the structure of the data is ignored and the same implications follow.</p> <p>This model does not try to control for company heterogeneity, and requires strong assumptions about the form of the distribution of errors.</p> <p>In practice the technique is data-intensive and may be difficult to implement.</p>
Time invariant panel method - Random Effects (RE)	In our case, it uses generalised least squares (GLS), which places more weight on the within variation than OLS when	Panel methods in general have the advantage that estimation takes into account the structure of the data. That is, it	The model does not distinguish between unobserved heterogeneity and inefficiency.

Estimation Method	Description	Strengths	Weaknesses
	<p>calculating parameter estimates. There are two broad categories of panel methods, Random Effects models (RE) and Fixed Effects (FE) models.</p> <p>RE require that firm-specific effects be uncorrelated with cost drivers. The error term thus captures the company effect and white noise. The company effect is assumed to be randomly distributed across firms (within and out of sample), while noise is assumed to have an expected value of zero, thus allowing us to estimate the average company effect, which is interpreted as inefficiency.</p>	<p>recognises there are 13 DNSPs over time, rather than different companies each year.</p> <p>The structure imposed on the error term allows efficiency is differentiated from white noise.</p> <p>RE models are perceived to yield more precise coefficients than FE and OLS models but have unclear properties in small samples.</p> <p>There is also regulatory precedent as Ofwat is currently using this technique as part of its suite of models developed by CEPA.</p>	<p>Efficiency is assumed to be constant over time.</p>
Time invariant panel method - Fixed Effects (FE)	<p>FE is estimated via OLS. It allows for company specific effects to be correlated with cost drivers by estimating the company effect as a parameter in estimation.</p>	<p>Company effects can be recast and interpreted as inefficiency, thus the model is able to differentiate inefficiency from white noise.</p> <p>Produces unbiased and consistent parameter estimates in the presence of correlation between company effects and cost drivers.</p>	<p>Efficiency is assumed to be constant over time.</p> <p>Estimates may be less precise than estimated from RE (GLS). That is, although estimators are unbiased and consistent they may be less accurate.</p> <p>This model cannot deal with time invariant regressors and the inclusion of company effects means that the number of parameters estimated grows with the number of companies.</p>
Time varying true RE	<p>This is a maximum likelihood variant of the above RE model that attempts to decompose the company effect into inefficiency and unobserved heterogeneity.</p>	<p>This model differentiates between firm specific heterogeneity (non-time variant) and inefficiency (variable over time).</p>	<p>Requires distributional assumptions about both the error and heterogeneity terms.</p>

Estimation Method	Description	Strengths	Weaknesses
			This model can also have difficulties separating persistent inefficiency from time invariant heterogeneity.
Time varying SFA (BC92) ¹⁰⁴	This is a MLE model requiring distributional assumptions on both the error term and on efficiency. It extends the model suggested by Pitt and Lee to permit efficiency to vary over time but in a restricted way, since the direction of efficiency change over time must be the same for all firms (and thus rankings cannot change).	Allows for white noise to be separated from inefficiency and imposes a structure on the progression of inefficiency over time.	Requires distributional assumptions on both the white noise and inefficiency components. In practice, these models have proven to be hard to implement, and although they have been considered by regulators, they have not been pursued. This is in part due to data intensiveness of the method.
Non Parametric Approaches			
Data Envelopment Analysis (DEA)	Non-parametric approach that calculates, rather than estimates, the frontier using linear programming techniques.	<p>No imposition of prior set of input and output weights on the data required.</p> <p>No specification of a cost/ production function required.</p> <p>Can incorporate uncontrollable factors, e.g. environmental.</p> <p>Can calculate technical and allocative efficiency.</p> <p>With panel data, can extend to calculate Malmquist productivity indices.</p>	<p>Efficiency scores tend to be sensitive to the choice of input and output variables and, in some circumstances, inappropriate choices may lead to relatively inefficient firms defining the frontier.</p> <p>No information on statistical significance or confidence intervals is provided.</p> <p>No allowance for stochastic factors and measurement errors.</p>
Multilateral Total factor productivity (MTFP)	Non-parametric approach that calculates changes in the use of efficiency with which multiple (volumes of) inputs are	<p>Simple to apply and interpret.</p> <p>Comparisons can be made between firms, as well as for the same firm at different times.</p>	Does not allow for the evaluation of uncertainty associated with the results.

¹⁰⁴ See Battese and Coelli,(1992).

Estimation Method	Description	Strengths	Weaknesses
	transformed into multiple outputs (volumes).		Provides only limited ability to control for differences in the business environments of firms in the sample group. Unable to distinguish scale effects from efficiency differences. ¹⁰⁵
Partial factor productivity (PFP) – the AER refers to this as its Category analysis.	PFP measures compare the ratio of a single output to a single input across firms and over time (for example labour productivity).	Easy to compute and understand. Can be used to cross check DEA and COLS results for plausibility and transparency.	Does not allow for evaluation of uncertainty associated with calculating benchmark. Although can control for some differences in operating environment, many it cannot control for. The restriction to some of the factors used in production means that the approach can be misleading. Cannot give an overall measure of potential for cost improvement which has a strong theoretical rationale.

¹⁰⁵ Without recourse to econometric estimation.

ANNEX C MODEL ASSESSMENT CRITERIA

Introduction

In assessing benchmarking model(s) I apply consider the following assessment criteria:

- theoretical correctness;
- statistical performance;
- robustness testing; and
- practical implementation issues.

Figure C.1 below briefly illustrates the broad logic of my model selection process. However, as there are often trade-offs in model specifications and there is not always an objective way to assess the models I use a traffic light approach (red – cannot be used, amber – used with caution, green – good/usable) to assess model viability.

Results coding

There is no single metric or method to assess the models mechanistically. Therefore, in order to assess the models I have adopted a ‘traffic light’ system to indicate how well a model performs against a given criterion i.e. a green light relates to good, an amber light corresponds to acceptable but with a few issues, and a red light means the model is flawed.

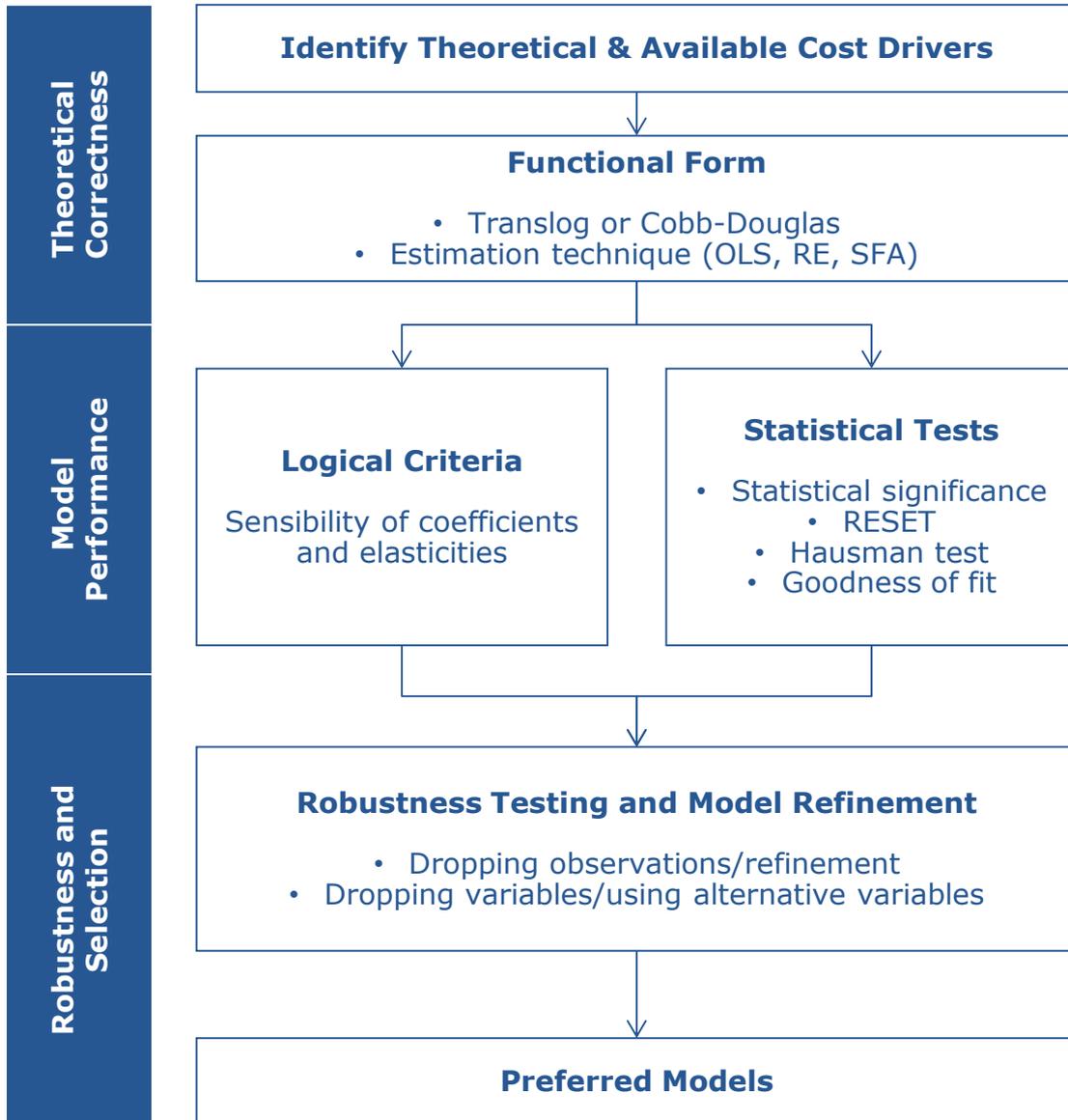
In this sub-section I describe the method of assigning traffic lights to a short-list of models.

I have not attempted to estimate models where there may be concerns about their practical implementation. I therefore only assigned traffic lights for the remaining three categories, i.e. coefficients, statistical test, and robustness checks. I considered whether the model meets a set of criteria for each category, listed by priority in Table C.1 below. The boundary between Amber and Green depends on whether the model satisfies the top criteria.

Table C.1: Traffic light criteria in order of priority

	Coefficients	Statistical test	Robustness check
	<ol style="list-style-type: none"> 1. Coefficient signs were not consistent with expectations (i.e. negative when positive expected) and there are no offsetting reasons (e.g. multicollinearity). 2. All coefficients were insignificant and there are no offsetting reasons (e.g. multicollinearity). 	<ol style="list-style-type: none"> 1. Failed multiple statistical tests. 2. R-squared is very low (less than 0.6). 	<ol style="list-style-type: none"> 1. Coefficients are very sensitive to sample choice. 2. Efficiency rankings are unstable and not highly correlated with other models.
 	<ol style="list-style-type: none"> 1. Coefficient signs were in line with expectations and levels/ elasticities relatively sensible. <i>If not, given Amber.</i> 2. All coefficients were significant or there are potentially offsetting reasons (e.g. multicollinearity). <i>If not, given Amber.</i> 	<ol style="list-style-type: none"> 1. Passed all statistical tests (RESET and pooling). <i>If not, given Amber.</i> 2. Goodness of fit above 0.80. <i>If not, given Amber.</i> 	<ol style="list-style-type: none"> 1. Not very sensitive to sample choice (i.e. removal of companies). <i>If not, given Amber.</i> 2. Efficiency rankings are generally in line with other models and efficiency scores appear plausible. <i>If not, given Amber.</i>

Figure C.1: Model Selection Criteria



Theoretical correctness

This first step is critical to the logical interpretation of models within an economic and regulatory framework. I considered theoretical drivers of cost, drawing on regulatory precedent, as well as the practicality of implementation given the available Australian data provided through the RINs. Additionally, I considered the implications of differing functional forms and estimation techniques in estimating economies of scale, density and inefficiency.

The basis for modelling opex costs of electricity distribution companies is well developed in regulatory and academic settings and provides a strong foundation and precedent for the selection of cost drivers. Jamasb and Pollitt (2001) document explanatory variables used in previous benchmarking exercises which include, among others: electricity delivered (e.g. GWh), customer numbers, transformer numbers, network density, service area, reliability, network size, maximum demand, labour, etc. What we are trying to capture are main elements of network scale, density, electricity throughput, quality/ reliability, and other operating environment factors.

I also explored both Cobb-Douglas and translog specifications of the cost function. One of the main differences being that translog specifications allow for varying degrees of economies of scale and/ or density across the industry as well as interactions between relevant cost drivers (e.g. interactions between scale and density), while Cobb-Douglas models assume constant elasticities throughout the sample.¹⁰⁶ The translog specification is particularly relevant given the differences in scale and density that exist between DNSPs.

The choice of functional form is important as it may imply particular assumptions regarding efficiency score. For example, COLS models, which are pooled OLS models, allow inefficiency to vary over time but ignore the panel structure of the data. Random effects, on the other hand, takes specific account of panel structure but assumes constant inefficiency over time. Haney and Pollit (2009) argue that regulators should use a number of techniques where possible to ensure robustness and consistency of results. Therefore I consider both pooled and panel techniques, as well as more data intensive SFA models. By default this implies some degree of subjectivity when calculating efficiency scores as various modelling results must be considered and weighted together. This question is explored further in a separate section of this report, but efficiency results are assessed throughout our model assessment process.

Finally, I will also briefly consider the benchmarking of totex costs, which as Haney and Pollit (2009) note better reflects trade-offs between opex and capex from an economic efficiency perspective. This is the direction which regulators such as Ofgem have taken, though stable models may be difficult to find if capex profiles are volatile.

¹⁰⁶ NB: elasticities with respect to cost drivers are calculated across the whole sample, not just within subsamples. Therefore including international data assumes that relationships between costs and cost drivers are the same across all countries and all DNSPs.

Statistical Performance

In reviewing our preferred models, I looked for the following aspects:

- *Significance of variables*: There should be a rationale behind the choice of the independent variable and I would like there to be statistically significant at the 1% confidence level.
- *Expected sign*: If the variable is significant and selected based on a well-thought out rationale, I would expect the sign of the coefficient to match the expectations around the direction of the posited relationship.
- *Adjusted R²*: Although not a primary measure of our model's predictive strength, it does give an indication of goodness of fit under an OLS model.
- *Robustness*: In running tests on our model, I tried to ensure that the model itself is robust – by this I mean that it is in the correct functional form, has the correct selection of variables (no omitted variables or unnecessary ones included), does not suffer from heteroskedasticity and that a normal distribution is an appropriate assumption for the cost.

ANNEX D EXPLANATORY VARIABLES

This annex summarises the cost drivers identified from the Economic Benchmarking RINs and provides summary analysis of data characteristics.

Table D.1: Explanatory Variables

	Driver	Variable	Rationale
Core drivers	Length	Route length (km)	Total length of lines, not including dual circuits. This is a scale variable as it measures total network length.
		Circuit length (km)	Total length of circuits, including dual circuit lines. This is a scale variable as it measures total circuit length. Since some lines include more than one circuit this may be more appropriate than route length as a measure of network length. This is also broken down into different circuit voltages and over/underground cabling. Therefore, it can be used as an indicator of operating environment characteristics as well.
	Customer numbers	# of connections	Number of customers connected (i.e. connections). This is a scale variable as it is a measure of total consumer base. This is broken down into customer type by usage and location and can therefore be used as an indicator of operating environment characteristics.
	Customer density	Customers/ route length	Operating environment indicator of network density. This uses route length and does not capture dual circuit lines. This can be transformed into an indicator variable to define subsamples for latent class model.
		Customers/ circuit length	Operating environment indicator of network density. This uses route length and does not capture dual circuit lines. This can be transformed into an indicator variable to define subsamples for are latent class model.
		Customers/ km ² service area	Operating environment indicator of network density. Service area numbers have been calculated and provided by Advisian and are constant over the dataset.
	Peak capacity	Maximum demand (MW)	Coincident annual maximum demand at transmission connection point. This is a scale variable as it is a proxy for maximum system capacity. It is also an output variable as it is a measure of yearly peak demand.
		Ratcheted maximum	A ratcheted version of the above. This attempts to proxy peak capacity more closely by assuming

	Driver	Variable	Rationale
		demand (MW)	capacity does not decrease from year to year and that it is at least as much as the highest historical maximum demand.
		Transformer capacity (MVA)	Distribution transformer capacity, excluding cold spare capacity. This is a measure of peak capacity as it measures the total system capacity at the zone substation level.
	Throughput	Energy delivered (GWh)	This is an output measure and related to both scale of network and network usage.
Operational characteristics	Capacity usage (%)		Operational indicator as it measures the percentage of total network capacity used.
	Share of urban customers		Rural/urban indicator of network composition. Rural networks may be more costly due to factors including longer fleet distances, more property, etc.
	Share of residential customers		Operational characteristic as it measures composition of consumer base.
	Share of HV circuit length		Network design characteristic. HV cables may be more expensive to maintain but also reduce losses.
	Share of SWER circuit length		Network design characteristic. SWER cables are much cheaper to maintain. They may also serve as a rural/ urban indicator.
	Share of single step transformer capacity		Network design characteristic. Measures the share of transformer capacity at the zone substation level where there is only single step transformation to achieve distribution voltage. Multiple step transformation is more expensive as it requires a larger number of transformers.
Quality of service	Reliability	SAIFI or SAIDI	Quality of service indicators of customer interruptions. These are imperfect measures as they may be influenced by other factors such as underground cabling, which is typically more reliable.
Capital measures	Capital additions*	RAB additions (AUD)	Capex driver to control for pre-capitalised expenditure contained in network opex as a result of pre-modelling adjustments for differing capitalisation rates. Deflated.
	Capital stock	RAB (AUD)	This is a measure of capital stock. I note there are likely issues in using this variable as it cannot be confirmed that it has been calculated on a consistent basis across DNSPs. Deflated.

*I have not attempted to remove the capitalised overheads from the RAB additions.

The correlations between the cost drivers listed above are set out in Table D.2 overleaf.

Table D.2: Correlations

ID		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	Route length	1																			
2	Circuit length	1.00	1																		
3	Customer numbers	0.26	0.28	1																	
4	Customer density (route)	-0.67	-0.68	-0.24	1																
5	Customer density (Circuit)	-0.70	-0.70	-0.19	0.98	1															
6	Customer density (area)	0.40	0.38	-0.13	-0.09	-0.16	1														
7	Maximum demand	0.18	0.19	0.97	-0.17	-0.11	-0.25	1													
8	Ratcheted maximum demand	0.17	0.19	0.97	-0.17	-0.11	-0.25	1.00	1												
9	Transformer capacity	0.40	0.41	0.96	-0.31	-0.25	-0.10	0.94	0.95	1											
10	Energy delivered	0.23	0.24	0.96	-0.19	-0.12	-0.23	0.98	0.98	0.95	1										
11	Capacity usage	-0.41	-0.41	-0.19	0.29	0.27	-0.38	-0.18	-0.19	-0.36	-0.21	1									
12	Share of urban customers	-0.72	-0.72	-0.05	0.81	0.85	-0.44	0.05	0.06	-0.12	0.02	0.22	1								
13	Share of residential customers	-0.52	-0.50	0.25	0.18	0.19	-0.42	0.25	0.25	0.12	0.20	0.01	0.52	1							
14	Share of 132kV circuits	0.05	0.07	0.47	-0.14	-0.06	-0.38	0.57	0.57	0.51	0.62	-0.37	0.24	0.37	1						
15	Share of SWER circuits	0.70	0.71	0.04	-0.65	-0.69	-0.10	-0.02	-0.01	0.11	0.00	0.16	-0.63	-0.45	-0.16	1					
16	Share of single step transformer	-0.16	-0.18	-0.74	0.17	0.12	0.24	-0.83	-0.83	-0.77	-0.84	0.45	-0.06	-0.26	-0.77	0.15	1				
17	Share of underground cable	-0.66	-0.67	-0.06	0.66	0.74	-0.40	0.06	0.07	-0.06	0.04	0.01	0.89	0.43	0.41	-0.66	-0.14	1			
18	Reliability (SAIFI)	0.70	0.71	0.04	-0.67	-0.72	0.24	-0.03	-0.04	0.10	0.02	-0.15	-0.81	-0.42	-0.10	0.70	0.01	-0.83	1		
19	Reliability (SAIDI)	0.84	0.85	0.11	-0.74	-0.78	0.28	0.05	0.05	0.21	0.11	-0.29	-0.82	-0.50	0.00	0.75	-0.09	-0.80	0.93	1	
20	RAB additions	0.38	0.39	0.84	-0.25	-0.19	-0.01	0.83	0.84	0.90	0.87	-0.43	-0.11	0.08	0.60	0.02	-0.73	-0.03	0.12	0.23	1

ANNEX E SENSITIVITY ANALYSIS

As set out in ANNEX A I have made some adjustments to the data for the DNSPs' different CAMs and the capitalisation of pole top structure work. Data was only available for five years (2008/09 to 2012/13) for adjusting the CAM and pole top structures. I used the average over these years to adjust the data from 2005/06 to 2007/08. As this is quite a significant assumption, I have undertaken some sensitivity analysis by first excluding the adjustments, in turn, and using a 'shortened' dataset which only covers the years for which data was available (2008/09 to 2012/13).

Figures E.1 and E.2 show the results of this testing. Not unexpectedly, the biggest variation occurs when no adjustment is made for the CAMs or pole top structures. Shortening the data set has little impact apart from UED.

Figure E.1: Adjustment sensitivity testing – OLS models

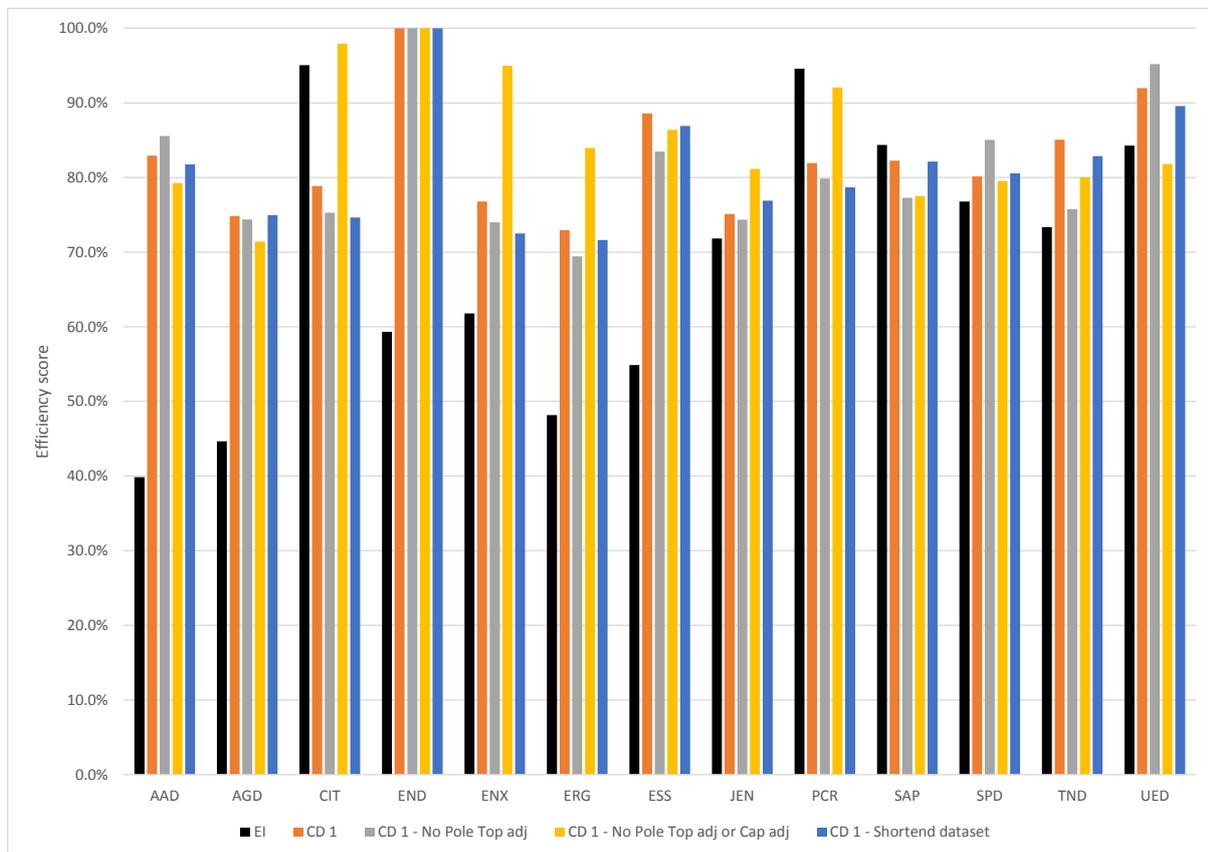
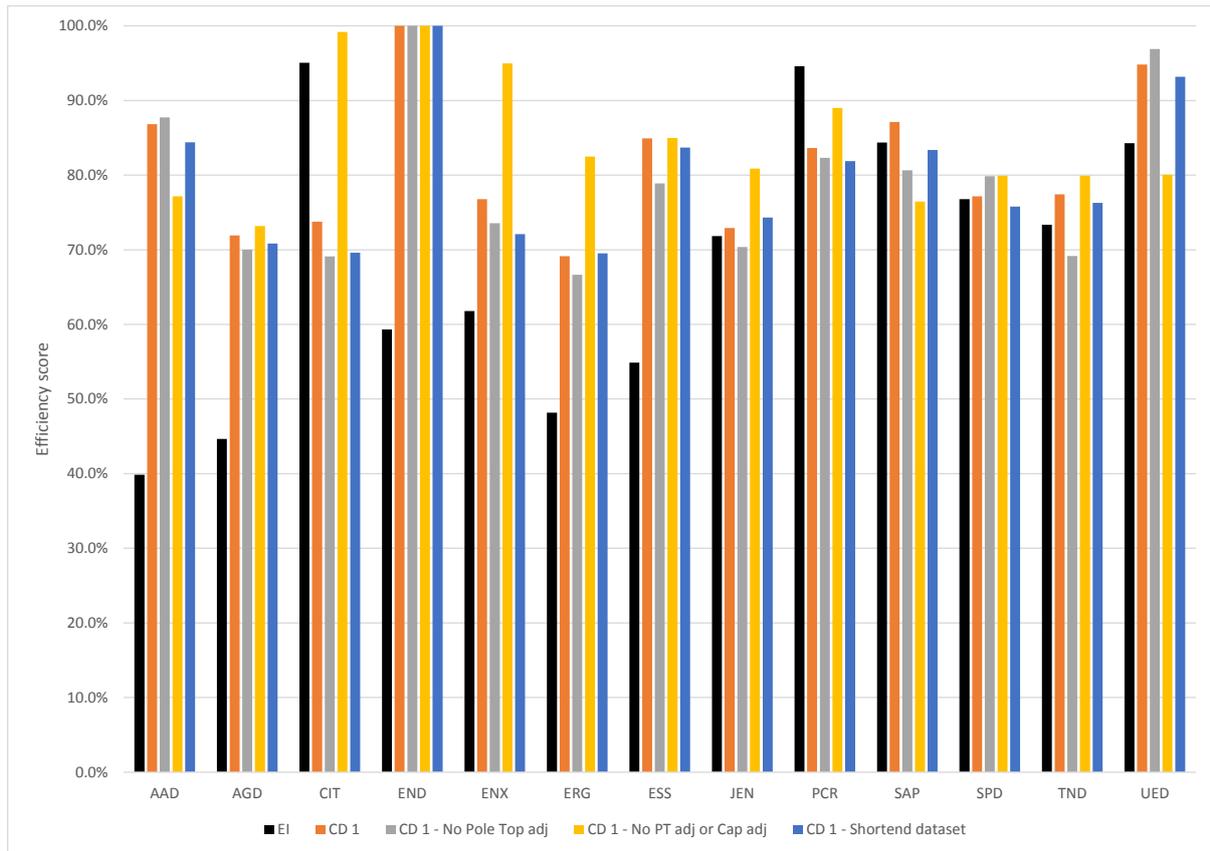


Figure E.2: Adjustment sensitivity testing – RE (GLS) models



Professor David Newbery, CEPA Vice-Chairman**Summary**

I am CEPA's Chairman. I am a Research Fellow in the Control and Power Research Group at Imperial College London and Emeritus Professor of Applied Economics at the University of Cambridge, where I was Director of the Department of Applied Economics from 1988 - 2003. I am Research Director of the Electricity Policy Research Group at the University of Cambridge, a multi-disciplinary research group supported by public funding from various Research Councils and support from stakeholders in industry and regulatory agencies. I was the 2013 President of the International Association for Energy Economics. I spent two years as a Division Chief in the World Bank and have been a visiting Professor at Berkeley, Princeton, Stanford and Yale. I am a fellow of both the Econometric Society and the British Academy. I am the Deputy Independent Member of the Single Electricity Market of the island of Ireland, and was Chairman of the Dutch Electricity Market Surveillance Committee from 2001-5 and a member of the Competition Commission from 1996 to 2002.

I am an internationally recognised expert on economic regulation and reform of network industries and the transport sector. I have led and participated on numerous CEPA assignments in the Economic Regulation and Competition practice area for clients such as the UK's Ofgem (Office of Gas and Electricity Markets), the Portuguese Competition Commission, the Dutch Office of Energy Regulation and other regulatory agencies and regulated companies.

My publications include the book *Privatization, Restructuring and Regulation of Network Utilities* (MIT Press, 2000). I was the guest editor of *The Energy Journal* (2005) issue on European electricity liberalisation, and the recipient of a Festschrift "Papers in Honor of David Newbery: The future of electricity" in *The Energy Journal* (2008).

Selected Experience

- Expert Advisor during the preparation for first electricity price control in the Netherlands. Then acted as Chairman of the Dutch Electricity Market Surveillance Committee between 2001 and 2005.

Experience as CEPA's Chairman:

- Expert Advisor, Market power and liquidity in the Single Electricity Market (SEM) for CER/NIAUR. David was the expert advisor for CEPA's high profile advice on how to promote competition and liquidity in the SEM. The advice covers: (i) sources of market power in the SEM; (ii) the degree and quality of liquidity in the SEM; and (iii) likely changes to market power and liquidity over the next 10 years.
- Expert Advisor, CEPA detailed study for DEFRA determining the direct and indirect costs and benefits to the Russian Federation from ratifying the Kyoto Protocol.
- Expert Advisor, CEPA study for the Dutch electricity regulator NMa on the economic issues associated with the potential development of a new electricity interconnector between the UK and the Netherlands, called BritNed.
- Expert Advisor, CEPA support to the Irish Commission for Energy Regulation for the price control review of the gas transmission and distribution networks for 2007-2012.
- Expert Advisor, CEPA advice to Northern Ireland's Strategic Investment Board on how to ensure that the water reform strategy is effective, efficient and meets its stated goals, particularly with respect to the removal of the need for government subsidy.

- Expert Advisor, part of a CEPA team that carried out an international comparison of the approaches regulators adopt to determining the appropriate cost of capital allowance, carried out for the Dutch electricity regulator.

Advisory experience in infrastructure sector:

- Member of World Bank teams advising the governments of Hungary, the Czech Republic and Bulgaria on regulatory reforms and restructuring of the electricity, gas and oil sectors needed to meet the European Community Electricity Directives and improve sector performance.
- Worked with CET on preparing the privatisation of Poland's 33 electricity distribution companies.
- Consultant to the National Treasury of South Africa on the reform of the electricity industry 2007-8 providing a range of expertise and advice on the structure of the market and the impact of proposed policy changes on the market participants.
- Occasional consultancies to the Dutch Ministry of Economic Affairs, most recently on policy towards electricity mergers (January, 2003); policy towards electricity security of supply (September 2002); experience of Dutch 3-G spectrum auction (via Erasmus university, Rotterdam); cost-benefit analysis of Schiphol Airport expansion (January, 2001).
- Co-Project Director, series of studies for Portugal's Competition Authority examining the gas and electricity markets, proposed mergers and remedies to mitigate any effects on competition.
- Provided economic advice to Ofgas and then Ofgem under an annually renewed sequence of contracts. Under the final contract, David advised on methodology for setting gas transport tariffs, storage, price reviews, the regulatory asset base, and a variety of ad hoc issues. David advised Ofgas on the network code and the regulation of TransCo; Ofgem and Offer on use-of-system pricing and reforms of the pool.
- Wrote a report on Ofgem's project TransmiT on setting transmission tariffs, and co-authored a report on Ofgem's Integrated Transmission Planning and Regulation.
- Wrote a report for DG-ENER on the benefits of electricity market integration, and another on long-term contracts for interconnector use.
- Directed a sequence of four large research projects on the British energy markets under contracts with the ESRC (1989-2003), and several projects studying tax reforms and the transition of Hungary to the market economy, financed by the ESRC, PHARE, & ACE.

Qualifications

2001	ScD, University of Cambridge
1976	PhD Economics, University of Cambridge
1968	MA Economics, University of Cambridge
1965	Part II Economics (First) , University of Cambridge
1964	BA Economics, University of Cambridge
1963	Part II Mathematics Tripos, University of Cambridge

Employment History

2001 – present	Chairman, CEPA
1988 – present	Professor of Applied Economics, University of Cambridge
1988 – 2003	Director of Department of Applied Economics, University of Cambridge
1987 – 1988	Ford Visiting Professor at University of California, Berkley

1985 and 1987	Visiting Professor, Princeton University; Visiting Scholar, IMF
1981 – 1983	Division Chief, World Bank, Washington, D.C.
1966 – 1988	Lecturer then Reader in Economics; Fellow and Director of Studies in Economics, Churchill College, University of Cambridge

Professional Positions

- President, European Economic Association (1996)
- President of the International Association for Energy Economics, 2014
- Member of the Competition Commission (1996 – 2002)
- Member of the Environmental Economics Academic Panel, Department of the Environment (now Defra)
- Harry Johnson Prize of Canadian Economic Association (1993)
- Fellow of British Academy (1991)
- CBE 2012
- Frisch Medal of the Econometric Society (September 1990)

Selected Publications

Book

- Newbery, D.M. (2000), *Privatization, Restructuring and Regulation of Network Utilities*, (The Walras-Pareto Lectures, 1995), MIT Press, 2000, ISBN 0-262-14068-3 pp466+xvi. See <http://mitpress.mit.edu/books/privatization-restructuring-and-regulation-network-utilities>

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8 January 2015

Dear Professor Newberry

AER'S USE OF ECONOMIC BENCHMARKING

ActewAGL Distribution (ActewAGL) would like to engage Cambridge Economic Policy Associates (CEPA) to provide an expert opinion on the Australian Energy Regulator's (AER's) use of economic benchmarking for the purpose of its draft decision on the distribution determination for ActewAGL for the 2015/16 to 2018/19 subsequent regulatory control period published by the AER on 27 November 2014 (**Draft Decision**).

1. PURPOSE

The purpose of this brief is to set out the nature, scope and purpose of the work that ActewAGL is seeking CEPA to undertake. The scope of the work is set out in section 3 below.

2. BACKGROUND

ActewAGL operates and owns the ACT's electricity distribution network. The AER is responsible for the economic regulation of electricity distribution services in the ACT under the National Electricity Law (NEL). The AER is required to make distribution determinations for distribution network service providers (DNSPs), including ActewAGL under the National Electricity Rules (NER).¹ The constituent decisions on which such a distribution determination is predicated relevantly include:²

¹ Where we refer in these instructions to provisions in Chapter 6 of the NER we are referring to the provisions in Chapter 6 contained in version 58 of the NER. Clause 11.56.4 of the Savings and Transitional Rules in Chapter 11 of the NER provides that except as specified in that clause, "current Chapter 6" governs the making of a distribution determination for the subsequent regulatory control period for NSW and ACT DNSPs. Clause 11.65.2(a) of the NER provides that references to "current Chapter 6" are to be read as Chapter 6 of the NER as in force immediately after the *National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013* came into force. That Rule came into force on 26 September 2013 and version 58 of the NER was the version of the NER in force from 26 September 2013. Accordingly, the NER currently provides that Chapter 6 in version 58 of the NER applies to the making of distribution determinations for NSW and ACT DNSPs for the subsequent regulatory control period. Accordingly, your expert opinion should also be based on the provisions of Chapter 6 in version 58 of the NER.

² Clause 6.12.1(2) and (4) of the NER.

- a decision on the annual revenue allowance for the DNSP for each regulatory year of the regulatory control period to which the determination relates; and
- a decision in which the AER either accepts the DNSP's total operating expenditure (**opex**) forecast for that regulatory control period or does not accept that forecast, in which case the AER must determine an estimate of the DNSP's required opex for that period.

The annual revenue allowance for the DNSP for each regulatory year of the regulatory control period must be determined using a building block approach, under which the building blocks relevantly include the forecast opex for that year as accepted or substituted by the AER in making the distribution determination.³

In 2012 significant amendments were made to the NER governing the economic regulation of DNSPs through the Australian Energy Market Commission's (AEMC's) Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 (2012 Rule Determination)*. As a result of those changes, the AEMC deferred the full regulatory determination process for the 2014-2019 regulatory control period. As part of the transitional arrangements under the NER,⁴ on 16 April 2014 the AER determined a placeholder distribution determination for a transitional regulatory control period (1 July 2014 to 30 June 2015) and is in the process of making a distribution determination for ActewAGL for the 2015/16-2018/19 subsequent regulatory control period (1 July 2015 to 30 June 2019).

In making ActewAGL's distribution determination for the subsequent regulatory control period, the AER is required to determine a "notional" annual revenue allowance for the transitional regulatory control period.⁵ The AER must adjust ActewAGL's total revenue requirement for the subsequent regulatory control period (1 July 2015 to 30 June 2019) by increasing or decreasing the annual revenue allowance(s) for one or more of the regulatory years of the subsequent regulatory control period.⁶ The amount of that adjustment is calculated as the amount of the annual revenue allowance approved for the transitional regulatory control period in its placeholder distribution determination for that period less the amount of the "notional" annual revenue allowance for the transitional regulatory control period determined in the distribution determination for the subsequent regulatory control period (subject to modifications as set out in the AER's Framework and Approach Paper).

ActewAGL submitted its regulatory proposal for the subsequent regulatory control period (2015/16-2018/19) to the AER in July 2014 (**ActewAGL's Subsequent Regulatory Proposal**).⁷ The AER published its draft distribution decision on the regulatory proposal on 27 November 2014. ActewAGL's revised regulatory proposal is due in January 2015 and the AER expects to publish a final decision in April 2015 in respect of the subsequent regulatory control period (1 July 2015 to 30 June 2019).

NER Requirements

The AER is required to accept a DNSP's forecast opex where it is satisfied that the forecast opex for the regulatory control period reasonably reflects the following criteria (**opex criteria**) in clause 6.5.6(c) of the NER being:

³ Clause 6.4.3(a)(7) and (b)(7) of the NER.

⁴ Division 2 of Part ZW of Chapter 11 of the NER.

⁵ Clause 11.56.4(c) of the NER.

⁶ Clause 11.56.4(h) and (i) of the NER.

⁷ ActewAGL first submitted its regulatory proposal to the AER on 2 June 2014. The AER issued ActewAGL with a notice under clause 6.9.1(a) of the NER, to resubmit its regulatory proposal on the basis that it was not compliant with the NER. On 10 July 2014, ActewAGL resubmitted its regulatory proposal which addressed the deficiencies identified by the AER.

- the efficient costs of achieving the opex objectives in clause 6.5.6(a) of the NER (**opex objectives**);
- the costs that a prudent operator would require to achieve the opex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

Similarly if the AER is not so satisfied and, accordingly, does not accept the DNSP's forecast of required opex, the AER must estimate the DNSP's required opex that it is satisfied reasonably reflects the opex criteria taking into account the opex factors (clauses 6.5.6(d) and 6.12.1(4)(ii)).

The opex objectives in clause 6.5.6(a) of the NER are to:

- meet or manage the expected demand for standard control services over the regulatory control period;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
 - the quality, reliability or security of supply of standard control services; or
 - the reliability or security of the distribution system through the supply of standard control services,
 to the relevant extent:
 - maintain the quality, reliability and security of supply of standard control services; and
 - maintain the reliability and security of the distribution system through the supply of standard control services; and
- maintain the safety of the distribution system through the supply of standard control services.

In deciding whether or not it is satisfied that the forecast opex for the regulatory control period reasonably reflects the opex criteria, the AER must have regard to certain factors specified in clause 6.5.6(e) of the NER, including, relevantly:

- the most recent annual benchmarking report that has been published under clause 6.27 of the NER and the benchmark opex that would be incurred by an efficient DNSP over the relevant regulatory control period (clause 6.5.6(e)(4)). Under clause 6.27 of the NER, the AER must prepare and publish an annual benchmarking report which should describe the relative efficiency of each DNSP in providing direct control services over a 12 month period;
- the actual and expected operating expenditure of the DNSP during any preceding regulatory control periods (clause 6.5.6(e)(5));
- the relative prices of operating and capital inputs (clause 6.5.6(e)(6));

- the substitution possibilities between opex and capital expenditure (**capex**) (clause 6.5.6(e)(7)); and
- any other factor the AER considers relevant and which the AER has notified the DNSP in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3 is an operating expenditure factor (clause 6.5.6(e)(12)).

In discussing the use of benchmarking in assessing opex and capex allowances under the NER, the AEMC states in its 2012 Rule Determination:⁸

..when undertaking a benchmarking exercise, circumstances exogenous to a NSP should generally be taken into account and endogenous circumstances should generally not be considered. In respect of each NSP, the AER must exercise its judgement as to the circumstances which should or should not be included. However exogenous factors to be taken into account are likely to include:

- *geographic factors: topography and climate;*
- *customer factors: density of the customer base (urban v rural), load profile, mix of customers between industrial and domestic;*
- *network factors: age, mix of underground and overhead lines, though this will depend on the extent to which this is at the election of the NSP; and*
- *jurisdictional factors: reliability and service standards.*

If there are some exogenous factors that the AER has difficulty taking adequate account of when undertaking benchmarking, then the use to which it puts the results and the weight it attaches the results can reflect the confidence it has in the robustness of its analysis.

Endogenous factors not to be taken into account may include:

- *the nature of ownership of the NSP;*
- *quality of management; and*
- *financial decisions.*

It is also expected that similar considerations be made when undertaking the annual benchmarking report.

AER's Approach to Assessing Expenditure Forecasts

In 2013, following the significant changes to the NER in 2012, the AER undertook a Better Regulation program. As part of that program in November and December 2013 the AER published a number of Guidelines, together with Explanatory Statements, relevant to its assessment of DNSPs' expenditure proposals. Relevantly, in November 2013, as required by clause 6.2.8(a) of the NER, the AER published the following:

- the AER's *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013 (**Expenditure Forecast Assessment Guideline**); and
- the AER's *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013 (**Expenditure Forecast Assessment Explanatory Statement**).

⁸ Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, p113.

The Expenditure Forecast Assessment Guideline specifies the approach the AER proposes to use to assess the forecasts of opex and capex that form part of the DNSPs' regulatory proposals and the information the AER requires for the purpose of that assessment.⁹ The Guideline is not mandatory and does not bind the AER or DNSPs, however, if the AER makes a distribution determination which is not in accordance with the Guideline, the AER must state its reasons for departing from the Guideline in that determination.¹⁰

AER's approach to assessing opex forecasts

For the purpose of making the distribution determination for ActewAGL for the subsequent regulatory control period, opex forecasts for the transitional and subsequent regulatory control periods will be assessed by the AER having regard to the approach set out in the Expenditure Forecast Assessment Guideline.

In its Expenditure Forecast Assessment Guideline, the AER states that it prefers to follow a "base-step-trend" approach to assessing most opex.¹¹ Under this approach, the AER uses a "revealed cost" approach to assessing base opex. It assesses whether opex in the base year is efficient and, if necessary, adjusts the DNSP's revealed costs to remove inefficient costs. The AER then accounts for any changes in efficient costs in the base year and each year of the forecast regulatory control period. The AER states that typically it will adjust base year opex by applying an annual rate of change for each year of the forecast regulatory control period (which accounts for changes in real prices, output growth and productivity in that period).¹² In addition, step changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria in the NER.¹³

In describing its proposed general approach to assessing DNSP's forecast expenditure, the AER states in its Expenditure Forecast Assessment Guideline:¹⁴

We will typically compare the DNSP'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 DNSP's forecast at the total level; others will assess components of the DNSP's forecast. Our estimate is unlikely to exactly match the DNSP's forecast. However, by comparing it to the DNSP's forecast, we can form a view as to whether or not we consider the DNSP's forecast reasonably reflects the expenditure criteria.

Therefore, if a DNSP'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 DNSP'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 DNSP's forecast reasonably reflects the expenditure criteria, we will accept the forecast. Whether we accept a DNSP's forecast or do not accept it, we will provide the reasons for our decision.

⁹ Clause 6.4.5(a) of the NER.

¹⁰ Clause 6.2.8(e) of the NER.

¹¹ Expenditure Forecast Assessment Guideline, p22.

¹² Expenditure Forecast Assessment Guideline, p23; Expenditure Forecast Assessment Explanatory Statement, p61.

¹³ Expenditure Forecast Assessment Guideline, p24. See also Expenditure Forecast Assessment Explanatory Statement, p61.

¹⁴ Expenditure Forecast Assessment Guideline, pp7-8; Expenditure Forecast Assessment Explanatory Statement, p42.

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, 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 DNSP operated under 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 DNSPs 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 DNSP supplies.

Consequently we apply various incentive schemes (such as the efficiency benefit sharing scheme (EBSS), the service target performance incentive scheme (STPIS) and the capital expenditure sharing scheme (CESS)) to provide DNSPs with a continuous incentive to improve their efficiency in supplying electricity services to the standard demanded by consumers.

While we examine revealed costs in the first instance, we must test whether DNSPs have responded to the incentive framework in place. That is, we must determine whether or not the DNSP's revealed costs are efficient. For example, whether the DNSP's past performance was efficient relative to its peers and whether the DNSP 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 DNSP's revealed costs.

...

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

In describing its approach to assessing opex in its Expenditure Forecast Assessment Guideline, the AER states:¹⁵

We prefer a 'base-step-trend' approach to assessing most opex criteria. However, when appropriate, we may assess some opex categories using other forecasting techniques, such as an efficient benchmark amount. We will assess opex categories forecast using other forecasting techniques on a case-by-case using the assessment techniques outlined in section 2.4. We will also assess whether using alternative forecasting techniques in combination with a 'base-step-trend' approach produces a total opex forecast consistent with the opex criteria.

The AER discusses its approach to assessing opex in section 5 of its Expenditure Forecast Assessment Explanatory Statement. The AER states:¹⁶

¹⁵ Expenditure Forecast Assessment Guideline, p22.

¹⁶ Expenditure Forecast Assessment Explanatory Statement, p61.

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.

The AER states in its Expenditure Forecast Assessment Explanatory Statement that it may adjust base opex to remove inefficient costs for two reasons, being:¹⁷

- a DNSP's recurrent expenditure is inefficient compared to its peers; and/or
- a DNSP'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 DNSP's expenditure is inefficient, the AER states it will consider:¹⁸

- the results of its expenditure review techniques, including economic benchmarking, category analysis and detailed engineering review; and
- the DNSP's proposal and stakeholder submissions.

The AER states in its Expenditure Forecast Assessment Guideline that it will assess opex for the forecast regulatory control period by applying an annual rate of change for each year of the forecast regulatory control period where the annual rate of change for year t is:¹⁹

$$\text{Rate of change}_t = \text{output growth}_t + \text{real price growth}_t - \text{productivity growth}_t$$

In respect of determining the efficient opex in the base year using various assessment techniques and the relationship with the productivity growth element of the rate of change, the AER states in the Expenditure Forecast Assessment Explanatory Statement:²⁰

¹⁷ Expenditure Forecast Expenditure Assessment Explanatory Statement p93.

¹⁸ Expenditure Forecast Expenditure Assessment Explanatory Statement p93.

¹⁹ Expenditure Forecast Assessment Guideline, p23.

²¹ Expenditure Forecast Assessment Guideline, section 2.4.1.

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 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.

AER's benchmarking assessment techniques

The assessment techniques the AER states that it will use for assessing opex and capex include economic benchmarking, category benchmarking and aggregated category benchmarking.²¹

In respect of economic benchmarking, the Expenditure Forecast Assessment Guideline states:²²

Economic benchmarking applies economic theory to measure the efficiency of a DNSP's use of inputs to produce outputs, having regard to operating environment factors. It will enable us to compare the performance of a DNSP with its own past performance and the performance of other DNSPs. We will apply a range of economic benchmarking techniques, including (but not necessarily limited to):

- *multilateral total factor productivity*
- *data envelopment analysis*
- *econometric modelling.*

In respect of category level benchmarking, the Expenditure Forecast Assessment Guideline states:²³

We will benchmark across DNSPs by expenditure categories on a number of levels including:

- *total capex and total opex*
- *high level categories (drivers) of expenditure (for example customer driven capex or maintenance opex)*

²¹ Expenditure Forecast Assessment Guideline, section 2.4.1.

²² Expenditure Forecast Assessment Guideline, p13.

²³ Expenditure Forecast Assessment Guideline, p13.

- *subcategories of expenditure.*

We may benchmark further at the following low levels:

- *unit costs associated with given works (for example, the direct labour and material cost required to replace a pole)*
- *unit volumes associated with given works (for example, kilometres of conductor replaced per year).*

In respect of aggregated category benchmarking the Expenditure Forecast Assessment Guideline states:²⁴

In addition to detailed category benchmarks we are likely to use aggregated category benchmarks, which capture information such as how much a DNSP spends per kilometre of line length or the amount of energy it delivers. We intend to improve these benchmarks by capturing the effects of scale and density on DNSP expenditures.

In its Expenditure Forecast Assessment Explanatory Statement, the AER states in respect of economic benchmarking and category analysis techniques:²⁵

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. 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.*

In addition, the Expenditure Forecast Assessment Explanatory Statement states in respect of economic benchmarking:²⁶

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),

²⁴ Expenditure Forecast Assessment Guideline, p13.

²⁵ Expenditure Forecast Assessment Explanatory Statement, p13.

²⁶ Expenditure Forecast Assessment Explanatory Statement, pp78-79.

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):

- 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.*

The AER expands on its approach to economic benchmarking in Attachment A to the Expenditure Forecast Assessment Guideline and outlines its economic benchmarking data requirements in Attachment B to the Expenditure Forecast Assessment Guideline. We recommend that you review those Attachments.

AER's Economic benchmarking report

Consistent with its stated approach in its Expenditure Forecast Assessment Guideline and Expenditure Forecast Assessment Explanatory Statement, for the purposes of assessing DNSPs' expenditure forecasts (including opex forecasts) for their forthcoming regulatory control periods the AER sought benchmarking analysis information from DNSPs. To this end the AER issued final regulatory information notices for economic benchmarking requirements on 28 November 2013.

ActewAGL provided information to the AER in response to its benchmarking regulatory information notice.²⁷

The AER released a draft *Electricity distribution network service providers, Annual benchmarking report* to ActewAGL and other DNSPs on a confidential basis in August 2014. The AER published its final *Electricity distribution network service providers, Annual benchmarking report* in November 2014.

ActewAGL's approach to forecasting opex

For the 2014-19 regulatory period, ActewAGL has used the fourth year (2012-13) of the previous regulatory control period as the base year for forecasting opex where using a base year approach. Further details of ActewAGL's forecasting approach are contained in ActewAGL's Subsequent Regulatory Proposal (see section 8.7, from page 222).

AER's use of benchmarking in its draft ACT distribution decision

The AER concluded in the Draft Decision that it was not satisfied ActewAGL's forecast opex reasonably reflected the opex criteria. Accordingly, the AER rejected the forecast opex included in ActewAGL's building block proposal. The AER substituted ActewAGL's total opex forecast with the AER's total opex forecast, which it considered reasonably reflected the opex criteria.²⁸ The AER's draft decision in respect of opex is contained in Attachment 7 to the Draft Decision.

²⁷ This information is available at <http://www.aer.gov.au/node/24311>.

²⁸ Overview to Draft Decision, p51 and Attachment 7, p7-7.

In assessing ActewAGL's forecast opex, the AER generally followed the approach set out in its Expenditure Forecast Assessment Guideline and Expenditure Forecast Assessment Explanatory Statement. Like ActewAGL, the AER used 2012-13 as the base year for its opex forecast, subject to its considerations in respect of efficiency adjustments.²⁹

The AER concluded that the main difference between its opex forecast and ActewAGL's forecast was the portion of opex in the base year that was efficient.³⁰ The AER's detailed analysis of ActewAGL's base year opex is contained in Appendix A to Attachment 7 to the Draft Decision.

In assessing base year opex, under clause 6.5.6(e)(12) of the NER the AER took into account the following two opex factors in addition to the factors specified in clauses 6.5.6(e)(4) to 6.5.6(e)(10):³¹

- the AER's benchmarking data sets including, but not limited to:
 - data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN;
 - any relevant data from international sources; and
 - data sets that support econometric modelling and other assessment techniques consistent with the approach in the AER's Expenditure Forecast Assessment Guideline,as updated from time to time; and
- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.

The AER tested the efficiency of ActewAGL's historical opex using a combination of assessment techniques, including economic benchmarking. For the purpose of its Draft Decision and its distribution determinations in respect of NSW DNSPs, the AER engaged Economic Insights Pty Ltd (**Economic Insights**) to assist with the application of economic benchmarking and advise on:³²

- whether the AER should make adjustments to base opex for the NSW and ACT DNSPs based on the results from economic benchmarking models; and
- the productivity change to be applied to forecast opex for the NSW and ACT DNSPs.

In its report, Economic Insights use a range of economic benchmarking methods to assess the relative opex cost efficiency of Australian DNSPs, including a Cobb Douglas stochastic frontier analysis opex cost function model, Cobb Douglas and Translog least squares econometrics (LSE) opex cost function models

²⁹ Attachment 7, p7-36.

³⁰ Overview to Draft Decision, p51.

³¹ Attachment 7, p7-11 and p7-24.

³² Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014 (**Economic Insights Report**), piv. While the Draft Decision refers to an Economic Insights Report of October 2014 (see for example, footnote 35 of Appendix 7), the 17 November 2014 report is the report provided on the AER's website in connection with the Draft Decision. Accordingly, the references in this letter are to that report.

and multilateral total factor productivity (MTFP) and multilateral partial factor productivity (MPFP) indexes.³³

In assessing base year opex in the Draft Decision, the AER relied on the analysis in the Economic Insights Report to compare ActewAGL to its peers using those benchmarking techniques. The benchmarking results are described in Appendix A of Attachment 7 to the Draft Decision. The AER found that the benchmarking analysis undertaken by Economic Insights revealed that ActewAGL spends opex about 40 per cent as efficiently as the most efficient service providers in the NEM (CitiPower and Powercor) on four different measures.³⁴ The AER considered that other simpler benchmarking techniques such as partial performance indicators and category analysis corroborated those results.³⁵ The AER also examined potential sources of inefficiency or high costs that might explain the gap in performance between ActewAGL and its peers. This included consideration of ActewAGL's labour and workforce practices and vegetation management.³⁶

Following its analysis of ActewAGL's forecast opex, the AER concluded that it was satisfied that it did not reasonably reflect the opex criteria and, accordingly, an adjustment was necessary. On the advice of Economic Insights the AER used results from its preferred benchmarking model, the Cobb Douglas Stochastic Frontier Analysis model, as a starting point for determining an alternative estimate of what it considered reasonably reflected base year opex.³⁷ However, rather than mechanically applying the efficiency adjustment predicted by the model, the AER made three adjustments to the "raw" benchmarking results in favour of ActewAGL. The AER describes those adjustments in Attachment 7 to the Draft Decision as follows:³⁸

Rather than using the National Energy Market (NEM) frontier service provider, CitiPower, as the benchmark for efficiency comparisons, the first adjustment is to set a lower benchmark based on an average of the efficiency scores of the most efficient service providers in the NEM. This reduces the benchmark efficiency target by 9 percentage points to 0.86 from 0.95.

The second adjustment is to modify the benchmark efficiency target to account for operating environment factors specific to the ACT. We are satisfied that a 30 per cent operating environment adjustment is appropriate for ActewAGL. This effectively reduces the benchmark efficiency target by 20 percentage points to 0.66.

Additionally we have made a third adjustment because the Cobb Douglas SFA model efficiency scores represent ActewAGL's average efficiency for the benchmarking period. We have applied a trend to move the substitute base opex from a forecast of the average amount for the 2006 to 2013 period to a forecast for 2012–13, the base year. In trending the average amount forward, we have used essentially the same rate of change method we use to determine the trend component of our base step trend methodology. For this reason, the percentage reduction differs to the average efficiency score.

³³ Economic Insights Report, p1v and Draft Decision, pp7-52 to 7-61.

³⁴ Overview to Draft Decision, p52 and Attachment 7, pp7-26 to 7-27.

³⁵ Overview to Draft Decision, p52 and Attachment 7, pp7-29 to 7-31, pp7-61 to 7-64 and p7-70.

³⁶ Overview to Draft Decision, p52 and Attachment 7 pp7-31 to 7-33 and pp7-77 to 7-89.

³⁷ Attachment 7, p 7-19, p7.27.

³⁸ Attachment 7, p7-27. See also Attachment 7, pp7-123 to 7-125. Further, the AER describes its analysis in respect of operating environment factors that require adjustments to the benchmarking results at pp7-90 to 7-122 of the Attachment 7 to the Draft Decision.

The AER also relied on economic benchmarking and the Economic Insights Report in determining the rate of change for opex. In assessing the output change component of the rate of change formula, the AER chose the same output change measures and weightings used in the Economic Insights Report.³⁹ Further, the AER based its forecast productivity on analysis in the Economic Insights Report and the AER's assessment of overall productivity trends for the forecast period.⁴⁰

3. SCOPE OF WORK

ActewAGL would like CEPA to undertake the following:

1. Develop opex cost benchmarking models using techniques such as OLS, panel, and SFA.
2. In developing those models CEPA should consider, and discuss in its expert report, the following:
 - Is the AER's analysis robust having regard to the adjustments it makes for the DNSPs' different operating environments? Should additional and/or alternative adjustments be made to account for the DNSPs' different operating environments? If so, please specify which additional and/or alternative adjustments should be made
 - What are the results of using the AER's proposed method of calculating the "efficiency frontier" on the alternative models?
 - How do measurement error, specification, and techniques affect the choice of model(s) and the frontier?
3. In its expert report, CEPA should consider and prepare a response to the following:
 - Does the way in which the AER applies its "inefficiency adjustment" meet objective criteria (minimises measurement error, reflects operating environment, and incorporates realistic targets)?
 - How does the AER's approach compare with international precedent?
4. In its expert report, CEPA should provide analysis and respond to the following:
 - Are there alternative approaches to selecting the frontier than the approach adopted by the AER?
 - Under what circumstances could the AER have chosen such alternatives?
 - If the definition of the efficiency frontier is subject to regulatory discretion, how has the AER exercised its discretion in selecting its preferred approach?
 - Is it appropriate to set more than one frontier and is there precedence for this?
5. CEPA should address any other matters it considers relevant in its expert report.

³⁹ Attachment 7, pp7-129 to 7-130 and pp7-138 to 7-139.

⁴⁰ Attachment 7, pp7-130 and pp7-139 to 7-143.

For the purpose of undertaking this work, we will provide you with a copy of the documents listed in Attachment A to this letter.

4. EXPERT WITNESS

ActewAGL anticipates providing a copy of CEPA's report and models to the AER in response to the AER's Draft Decision in respect of its Subsequent Regulatory Proposal.

To this end, ActewAGL has attached a copy of the Federal Court of Australia's Practice Note "Expert Witnesses in Proceedings in the Federal Court of Australia" (Attachment B). The Practice Note contains useful direction regarding the steps that should be taken by expert witnesses to ensure the veracity of their reports. ActewAGL requires CEPA to comply with the Practice Note in preparing its report and models.

A list of all documents provided to CEPA, as well as those documents relied on by CEPA, should be included in the expert report and those documents should be annexed to the report or, in the alternative, provided to ActewAGL if they were not provided to CEPA by ActewAGL.

In addition, you should attach a copy of your CV containing your qualifications and relevant experience to your expert report.

5. TIMING

ActewAGL requests CEPA to deliver its final report and models by 19 January 2015.

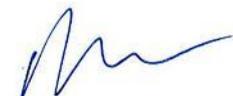
6. CONTACT

Usman Saadat, Manager of Regulatory Affairs, will be the day to day contact for CEPA in relation to the AER's benchmarking approach. Usman's contact details are:

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Please contact Usman if you have any questions regarding the preparation of your report.

Yours sincerely



David Graham

Director, Regulatory Affairs and Pricing

Attachment A

List of documents

1. ActewAGL's regulatory proposal for the subsequent regulatory control period (2015/16-2018/19) (resubmitted 10 July 2014).
2. ActewAGL's response to AER Site Visit Questions, (submitted 3 October 2014).
3. AER, *Draft decision ActewAGL distribution determination 2015/16 to 2018/19* published on 27 November 2014 (**Draft Decision**), Overview.
4. AER, Draft Decision, Attachment 7: Operating Expenditure, November 2014.
5. AER, Draft Decision, Economic Insights – benchmarking draft decision data sets - November 2014.
6. AER, Draft Decision, opex base year adjustment modelling files - November 2014.
7. AER, Draft Decision, category analysis metrics - November 2014.
8. AER, Draft Decision, opex model - November 2014.
9. AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014.
10. Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014.
11. Chapter 6 and Chapter 10 in version 58 of the National Electricity Rules.
12. Division 2 of Part ZW and Part ZY of Chapter 11 of the National Electricity Rules.
13. AER, *Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.
14. AER, *Final Regulatory Information Notice for Economic Benchmarking Requirements*, 28 November 2013.
15. AER, *Better Regulation Explanatory Statement, Regulatory Information Notices to Collect Information for Economic Benchmarking*, November 2013.
16. AER, Draft Decision, Pacific Economics Group – Database for Distribution Network Services in the US and Australia, November 2014.

ANNEX H DOCUMENTS PROVIDED AND THOSE I RELIED ON

ACCC (2012), *Benchmarking Opex and Capex in Energy Networks*, Working Paper, May 2012

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AER, Draft Decision, Economic Insights productivity files - November 2014.

AER, Draft Decision, opex base year adjustment modelling files - November 2014.

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AER, *Category analysis benchmarking metrics*, 19 August 2014.

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AER, Economic Insights contract variation terms of reference, March 2014.

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