Economic Benchmarking of Electricity Network Service Providers

Report prepared for
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EXECUTIVE SUMMARY

The Australian Energy Regulator (AER 2012a) has indicated that economic benchmarking will be one of a suite of assessment techniques to be detailed in its forthcoming expenditure forecast assessment guidelines. The AER is consulting extensively with network service providers in developing its approach to economic benchmarking. This includes conducting a series of workshops to seek feedback on the appropriate outputs, inputs and operating environment variables to be used in economic benchmarking.

The AER has engaged Economic Insights to assist with this consultation process and to provide advice on economic benchmarking. This report presents our draft findings and recommendations on the initial approach that should be adopted to network service provider (NSP) economic benchmarking.

Economic benchmarking

Economic benchmarking of costs measures the economic efficiency of an NSP by comparing its current performance to its own past performance and to the performance of other NSPs. All NSPs use a range of inputs including capital, labour, land, fuel, materials and services to produce the outputs they supply. If the NSP is not using its inputs as efficiently as possible then there is scope to lower energy delivery costs and, hence, the prices charged to energy consumers, through efficiency improvements.

Most economic benchmarking techniques compare the quantity of outputs produced to the quantity of inputs used and costs incurred over time and/or across NSPs. As no two NSPs operate under exactly the same operating environment conditions, it is important to account for operating environment differences when comparisons are made across NSPs to ensure that like is being compared with like to the extent possible.

Economic benchmarking is likely to have three principal uses in expenditure forecast assessment. These are:

- ‘first pass’ expenditure assessment at an early stage of the regulatory determination process designed to identify areas of the expenditure forecasts that warrant further investigation (AER 2012a, pp.32–4)
- reviewing the relative efficiency of historical NSP expenditure and whether base year expenditure can be trended forward or whether it may be necessary to make adjustments to base year expenditure to remove observed inefficiencies, and
- quantifying the feasible rate of efficiency change and productivity growth that a business can be expected to achieve over the next regulatory period.

The third of these would include separately examining costs that are flexible in the short run (eg opex) and costs that will need to be progressively adjusted over the longer term (eg capital inputs). This could also include consideration of how scale efficiencies change over time.

Recommended DNSP output and input specification

To measure economic efficiency and productivity change we require data on the price and quantity of each output and input (or, alternatively, one of these and their value as value is the product of price and quantity) and data on key operating environment conditions.

Our recommended distribution network service provider (DNSP) output and input specification for economic benchmarking is presented in table A. Two backup specifications are also presented in section 7.

Table A: **Recommended DNSP output and input specification**

Quantity	Value	Price
Outputs		
Customers (No)	Revenue * Cost share	Value / Customers
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Throughput (GWh)	Revenue * Cost share	Value / GWh
Interruptions (Customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
O/H lines (MVA–kms)	AUC (Return of & on O/H capital)	O/H AUC / MVA–kms
U/G cables (MVA–kms)	AUC (Return of & on U/G capital)	U/G AUC / MVA–kms
Transformers & other (MVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / MVA

[1] VCR per customer minute will vary by DNSP depending on the DNSP's energy deliveries.

Abbreviations: VCR – Value of Customer Reliability; EGWW – Electricity, gas, water and waste sector; WPI – Wage price index; O/H – overhead; U/G – underground; AUC – annual user cost of capital

The first output included is customer numbers representing relatively fixed services the DNSP supplies. These are activities the DNSP has to undertake regardless of the level of energy delivered and include connection related infrastructure (eg having more residential customers may require more local distribution transformers and low voltage mains), customer calls, etc. Using the analogy of comparing a DNSP's function to be similar to providing a road network, the DNSP will need to provide and maintain local access roads for its customers, regardless of the amount of traffic on those roads.

In line with previous energy network economic benchmarking studies (eg Coelli, *et al* 2008 and Economic Insights 2009b), we propose to measure the quantity of this output by the number of customers. The value of the output would be revenue multiplied by its cost share derived from a combination of econometric cost function analysis, evidence from previous studies and information provided by DNSPs on their allocation of costs across the various outputs. The price of this output would be its value divided by the number of connections.

The second output we recommend for inclusion is system capacity as approximated by the product of circuit line length and the total capacity of distribution level transformers. Going back to the road analogy, this output captures the quantity of 'road network' that the DNSP has to provide to cater for users' peak demands and energy consumption. We prefer this measure to the alternative that has been suggested of peak demand. Using peak demand would require some form of smoothing and the results would be affected by the form and degree of smoothing chosen. Given the long–lived nature of DNSP assets and the need to allow a margin above recent observed peak demands to allow for infrequent extreme weather conditions, the system capacity variable better reflects the underlying functional output. We are not convinced by arguments advanced that including system capacity as an output would provide an incentive for NSPs to overbuild capacity. NSPs take many technical factors into account when making decisions about the level of capacity required and the impact it would have on benchmarking results is not likely to be a significant driver. Including system capacity as an output also provides one means of recognising lines as well as transformer requirements without the need to account for line length as an operating environment factor. This is an important consideration given the limited scope to include operating environment factors in the short run. System capacity is also able to draw on robust data held and maintained by all DNSPs.

Once sufficient data observations become available inclusion of smoothed maximum demand with adjustment for customer density differences as an operating environment factor should be investigated and this is one of the backup specifications listed in section 3. It will also be possible to examine the degree of network utilisation over time to ascertain whether the provision of excess capacity is a problem.

The value of the system capacity output would be revenue multiplied by its cost share. The price of this output would be its value divided by the product of circuit length and distribution level transformer capacity.

The third recommended output is throughput or energy deliveries. While throughput has a small direct impact on DNSP costs, it reflects the main output customers are charged for and maintains consistency with earlier economic benchmarking studies, nearly all of which have included throughput as an output. While the majority of DNSP charges remain on throughput it is important to at least recognise throughput as a functional output DNSPs supply although it is likely to receive a small weight given its likely small impact of DNSP costs. Maintaining some similarity in output coverage to earlier studies provides a means of cross checking results. And, throughput data are likely to be the most robust for backcasting purposes. The value of the throughput output would be revenue multiplied by its cost share, which we would expect to be relatively small given that costs are not likely to be greatly influenced by small variations in throughput. The price of this output would be its value divided by energy deliveries.

The fourth output is the duration of customer interruptions which captures the DNSP's reliability performance. This is an important dimension of DNSP performance for customers. Treating interruptions as an 'undesirable' output allows it to be readily incorporated with a negative price and, hence, a negative value. We recommend adopting the distribution STPIS valuation of consumer reliability (VCR). As the STPIS VCR is presented as an amount per MWh consumed, this first has to be converted to an amount per customer minute depending on the individual DNSP's annual energy deliveries. The price is then the negative of the

DNSP's VCR per minute and the value of customer interruptions is the product of this negative price and the total minutes of customer interruptions.

Turning to the input side of the recommended specification, opex would be measured using a narrow coverage consistent with the AER's network services group component of standard control services. If necessary, adjustments would be made to remove accounting items that did not reflect current year input use. The recommended price of opex is a weighted average price index consisting of the ABS Wages price index and five Producer price indexes covering business, computing, secretarial, legal and accounting, and public relations services. The quantity of opex inputs is derived by deflating the value of opex by its price index.

The recommended capital input specification uses physical measures to proxy the quantities of three capital input components – overhead lines, underground cables, and transformers and other capital. The input quantities of overhead lines and underground cables are proxied by their respective MVA–kilometres (sum of kilometres of line by voltage class multiplied by the weighted average MVA rating for each class). This measure allows the aggregation of lines and cables of differing voltages and capacities into a robust aggregate measure. The input quantity of transformers and other capital is proxied by the NSP's total transformer capacity (at all transformation levels) in MVA. The other capital component is usually quite small for NSPs and, since much of this residual component is related to substations, it is included with transformer capital inputs.

This approach has the advantage of reflecting the one hoss shay physical depreciation characteristics of the individual component assets while using the most robust source of NSP data available (that from DNSP physical asset registers) and accurately capturing actual asset lives. This approach is also broadly similar in principle to the productive capital stock used by leading statistical agencies to proxy the quantity of aggregate structures inputs in sectoral and economy–wide productivity measurement. We believe this approach to measuring capital inputs is more robust and likely to be more accurate than approaches which rely on regulatory depreciation and depreciated asset value data.

The value of capital inputs or annual user cost is taken to be the return on capital and return of capital for each of the three components, calculated in a way which approximates the corresponding building blocks calculations. The input price for each of the three capital components is then derived by dividing their annual user cost by their respective physical quantity proxy. By using an exogenous user cost of capital covering the return on and return of capital it ensures consistency with other building blocks calculations.

Operating environment factors

The number of operating environment factors that can be allowed for in the recommended specification will depend on the number of observations available (due to degrees of freedom considerations). Initially, only a small number of operating environment factors are likely to be able to be included. We have considered candidate operating environment factors on the basis of their materiality, whether they are truly exogenous to the DNSP and whether they are a primary driver of DNSP costs. DNSP operating environment factors considered broadly covered aspects of network density, weather factors and terrain factors.

Some aspects of both customer density and energy density are already captured in the recommended specification with throughput, customer numbers and some aspects of length included as outputs (although length is less directly included). The priority for including a density operating environment factor therefore lies with a demand density variable (ie non–coincident maximum demand per customer), as maximum demand is not explicitly included in the recommended output specification.

Given that reliability is being included as an output it will be important to include extreme temperature days as the priority weather variable most likely to affect DNSP performance.

For terrain factors, we propose priority be given to including a vegetation encroachment indicator as this will have a particular impact on opex and economic benchmarking is more likely to have a role in assessing opex expenditure forecasts initially. Vegetation growth may also be a good indicator of other challenging climatic conditions facing the DNSP.

Recommended TNSP output and input specification

Table B: **Recommended TNSP specification**

Quantity	Value	Price
Outputs		
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Entry & exit points (No)	Revenue * Cost share	Value / No
Throughput (GWh)	Revenue * Cost share	Value / GWh
Loss of supply events (No)	–1 * Loss of supply events * Average customers affected * VCR per customer interruption	–1 * Average customers affected * VCR per customer interruption[1]
Aggregate unplanned outage duration (customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for Prescribed services adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
O/H lines (MVA–kms)	AUC (Return of & on O/H capital)	O/H AUC / MVA–kms
U/G cables (MVA–kms)	AUC (Return of & on U/G capital)	U/G AUC / MVA–kms
Transformers & other (MVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / MVA

[1] VCR per customer interruption and per minute will vary by TNSP depending on the TNSP’s energy deliveries

Abbreviations: VCR – Value of Customer Reliability; EGWW – Electricity, gas, water and waste sector; WPI – Wage price index; O/H – overhead; U/G – underground; AUC – annual user cost of capital

The recommended TNSP output and input specification is broadly similar to the recommended DNSP specification and is presented in table B.

The recommended TNSP output specification consists of an analogous system capacity component, a fixed component, and throughput and reliability variables.

The first output we recommend for inclusion is system capacity as approximated by the product of circuit line length and the total capacity of downstream–side transformers and of other exit locations. In the case of TNSPs there is likely to be less scope to independently vary capacity so concerns regarding the system capacity variable not distinguishing excess capacity are likely to be less relevant for TNSPs.

The second output is the number of entry and exit points (in place of the number of customers for DNSPs given that TNSPs do not directly service most end–customers). Entry and exit points are fixed outputs the TNSP has to provide, irrespective of demand and throughput variations, just as DNSPs have to provide customer access infrastructure and services. Returning to the road analogy, entry and exit points are the equivalent of freeway entry and departure ramps. A future refinement for this output component would be to adjust by the voltage level and/or capacity of each entry and exit point. The value of the output would be revenue multiplied by its cost share and the price would be its value divided by the number of entry and exit points.

The third recommended output is throughput or energy deliveries. While throughput has a small direct impact on TNSP costs, it reflects the main output of value to customers.

We include two reliability variables in the recommended TNSP output specification. These are the number of loss of supply events and the aggregate unplanned outage duration. The former quantity is expressed in terms of the number of outage events leading to interruptions to end–use customers while the latter quantity is the total number of customer minutes lost. The price of the former measure is the negative of the product of the number of customers affected and the relevant VCR per customer interruption from the DNSP STPIS. The price of the second reliability output is simply the negative of the relevant VCR per customer minute from the distribution STPIS. In both cases the value is derived as the product of the relevant quantity and price.

The recommended TNSP input specification is identical to the recommended DNSP input specification with TNSP voltage and weighted average MVA conversion factors replacing the corresponding DNSP items.

Operating environment factors

The number of operating environment factors that can be allowed for in the recommended specification will again depend on the number of observations available (due to degrees of freedom considerations). In the case of TNSPs there are likely to be fewer observations available than for DNSPs. We have considered candidate operating environment factors on the basis of their materiality, whether they are truly exogenous to the TNSP and whether they are a primary driver of TNSP costs. TNSP operating environment factors considered broadly covered weather factors, terrain factors and network characteristics.

Given that reliability is being included as an output it will be important to include at least one weather operating environment factor. We propose that extreme temperature days be included as the priority weather variable most likely to affect TNSP performance.

For terrain factors, we propose priority be given to including a vegetation encroachment indicator as this will have a particular impact on opex and economic benchmarking is more likely to have a role in assessing opex expenditure forecasts initially.

For TNSPs it will also be important to include allowance for network characteristics given the wide range of TNSP network configurations. We propose a concentrated load distance indicator of the greatest distance from a node having at least, say, 30 per cent of generation capacity to a node having at least, say, 30 per cent of load and a network density indicator of MVA system capacity per route kilometre be included as the priority measures. The first of these indicators reflects the fact that TNSPs with relatively short distances between concentrated generation centres and concentrated large load centres typically have a cost advantage compared to TNSPs with more diffuse generation centres and more diffuse and smaller load centres. The second indicator reflects the degree of meshing versus extension of the TNSP's network. Generally, a more meshed network will be able to provide higher levels of reliability than a more 'stringy', less meshed network.

Data requirements and observation numbers needed

The DNSP and TNSP output and input data requirements to implement economic benchmarking are listed in tables 14 and 15, respectively, in section 8 along with preliminary variable definitions and an indication of whether the variable is currently collected in DNSP Regulatory Information Notices (RINs) or the former TNSP Information Disclosure Requirements (IDRs). The variables listed are required to support the recommended and back–up output and input specifications, possible alternative specifications which may be developed and a range of anticipated sensitivity analyses.

We recommend the AER commence estimating cross sectional DNSP and TNSP efficiency using multilateral TFP index methods. This can be done with one year of data initially. More years of data would, of course, provide more confidence and context for the results obtained. Adjustment for a select number of operating environment variables using second stage regression methods could be undertaken using a simple functional form using one or two years of data for DNSPs. Several years of data may be required for TNSPs to support regression based adjustments given the smaller number of TNSPs compared to DNSPs. Backcasting of data for at least 8 years – say to 2005 – would support calculation of reasonably representative productivity trends using index number methods. This would also produce just over 100 observations in total for DNSPs which may be enough to support estimation of econometric total and operating cost functions with a small number of outputs, inputs and operating environment factors (along the lines of Economic Insights 2012b). More fully specified econometric and SFA models would likely require at least a decade of data to produce robust results.

1 BACKGROUND

The Australian Energy Regulator (AER) has initiated a workstream on expenditure forecast assessment (EFA) guidelines for electricity distribution and transmission as part of its Better Regulation program responding to the Australian Energy Market Commission's recent rule changes for electricity network regulation (AEMC 2012a). The rule changes clarify the AER's powers to undertake benchmarking and add a new requirement for the AER to publish annual benchmarking reports on electricity network service providers (NSPs).

The AER has indicated that economic benchmarking will be one of a suite of assessment techniques to be detailed in the EFA guideline. The AER is consulting extensively with network service providers in developing its approach to economic benchmarking. This includes conducting a series of workshops to seek feedback on the appropriate outputs, inputs and operating environment variables to be used in economic benchmarking and their specification, putting necessary data reporting mechanisms in place, and how economic benchmarking would be used in assessing NSPs' expenditure proposals.

The AER has engaged Economic Insights to assist with this consultation process and to provide advice on economic benchmarking. In March 2013 a series of three initial workshops were conducted discussing what the appropriate outputs, inputs and operating environment factors would be for economic benchmarking used as part of building blocks determinations. Briefing notes were prepared for each of these workshops (Economics Insights 2013a,b,c).

The consultation process then moved into its second phase with three workshops discussing specific measurement and data issues associated with the outputs, operating environment factors and inputs for use in economic benchmarking. Briefing notes were also prepared for each of these workshops (Economics Insights 2013d,e,f).

This report presents our findings and recommendations on the initial approach that should be adopted to NSP economic benchmarking. We present preferred and back–up output, input and operating environment factor specifications and recommended NSP data collection templates required to support economic benchmarking.

The second section of the report provides some background on the basics of economic benchmarking and why it is relevant to network regulation. The third, fourth and fifth sections review the options available for measuring distribution outputs, transmission outputs and NSP inputs, respectively. The sixth section then discusses a number of operating environment factor considerations and presents short lists of key indicators for distribution and transmission. In the seventh section we present our recommendations for the preferred specifications for distribution and transmission outputs, inputs and operating environment factors based on discussions and feedback received to date. We also present some alternate output and input specifications. We also discuss the initial uses of economic benchmarking within the building blocks framework and the minimum number of years that data would be required to implement the various options and methods. Finally, in the eighth section we present the recommended NSP data collection templates required to support economic benchmarking.

2 ECONOMIC BENCHMARKING

2.1 What is economic benchmarking?

Economic benchmarking of costs measures the economic efficiency performance of an NSP by comparing its current performance to its own past performance and to the performance of other NSPs. All NSPs use a range of inputs including capital, labour, land, fuel, materials and services to produce the outputs they supply. If the NSP is not using its inputs as efficiently as possible then there is scope to lower energy delivery costs and, hence, the prices charged to energy consumers, through efficiency improvements. This may come about through the use of:

- better quality inputs including a better trained workforce
- adoption of technological advances
- removal of restrictive work practices
- removal of other forms of potential waste such as 'gold plating', and
- better management through a more efficient organisational and institutional structure.

Overall economic efficiency has several components including:

- technical efficiency which requires that the maximum possible quantity of output is produced from the quantities of inputs the NSP has available or, alternatively, that the quantity of output required is produced from the minimum possible quantity of inputs
- allocative efficiency which requires that the NSP uses inputs in proportions consistent with minimising costs given current input prices
- cost efficiency which requires that the NSP produces its outputs at minimum possible cost (ie that it achieves both technical and allocative efficiency), and
- scale efficiency which requires that the NSP is operating at an optimal size.

Most economic benchmarking techniques compare the quantity of outputs produced to the quantity of inputs used and costs incurred either over time and/or across NSPs. As no two NSPs operate under exactly the same operating environment conditions, it is important to allow for operating environment differences when comparisons are made across NSPs to ensure that like is being compared with like to the extent possible.

The main economic benchmarking techniques include:

- total factor productivity (TFP) indexes which calculate growth rates of the total output quantity relative to total input quantity for an NSP over time
- multilateral TFP (MTFP) indexes which allow productivity levels as well as growth rates to be compared across NSPs
- econometric cost function models
- data envelopment analysis (DEA) which uses linear programming to construct an efficient production frontier from the included observations, and

- stochastic frontier analysis (SFA) which constructs an efficient production frontier from the included observations using statistical methods which allow for error.

These techniques aim to provide a holistic comparison of NSP cost performance. They differ from the simple benchmarking and other assessment techniques currently used in building block reviews (such as engineering reviews) which typically examine the relativity between specific activities rather than the efficiency performance of the NSP as a whole. The economic benchmarking techniques provide a 'top down' perspective on NSP cost performance using relatively high level data compared to the 'bottom up' item by item comparisons otherwise used. Economic benchmarking weights all the outputs by their relative importance which other techniques cannot do. This holistic perspective on the overall expenditure requirements of NSPs allows for the review of regulatory proposals without the need to go into minute detail. Thus, the costs and limitations of line–by–line assessments (that rely upon engineering expertise) are potentially mitigated.

The techniques have different strengths and weaknesses and each offers a different perspective on the relative performance of included NSPs. The TFP index number methods can be implemented with a relatively small number of observations and can handle a large number of outputs and inputs, provided the necessary data are available. However, while TFP methods provide information on overall cost efficiency, they do not allow this to be disaggregated into its component sources of efficiency such as technical and allocative efficiency.

To obtain this more detailed break–down of efficiency performance it is necessary to use one of the frontier methods such as DEA or SFA. However, these methods require a relatively large number of observations to be implementable, particularly if several output and several input components are included. It should also be noted that the frontier methods involve a trade–off regarding the number of outputs and inputs included. To adequately capture the functions performed by NSPs, it is likely to be necessary to include multiple outputs (and inputs) in the analysis. But the usefulness of the frontier methods (DEA and SFA) reduces as the number of outputs (and inputs) is increased (because these techniques will find progressively more firms 'efficient' simply because they have unique output or input mixes and no other firms they can be compared with). This trade–off highlights the 'top down' nature of economic benchmarking and why it is important to concentrate on a relatively small number of key outputs that capture the range of NSP functions.

2.2 Why the current interest in economic benchmarking?

The AER's electricity NSP price reviews to date have relied heavily on expert engineering reviews and historical trending of costs based on the assumption that revealed costs are relatively efficient. However, these tools are only a subset of the methods used by other regulators (see ACCC/AER 2012) and greater use of benchmarking has been frustrated by, among other things, the lack of consistent data available (see, for example, Economic Insights 2009a).

The AEMC (2012a, p.viii) observed that:

> ‘The Commission considers that benchmarking is a critical exercise in assessing the efficiency of a NSP and approving its capital expenditure and operating expenditure allowances. … The Commission will remove any potential constraints in the NER on the way the AER may use benchmarking.
>
> ‘Whilst benchmarking is a critical tool for the regulator, it can also be of assistance to consumers, providing them with relative information about network performance on NSPs.’

In response to the recent rule changes the AER (2012a) has proposed making greater use of two different streams of analysis in future reviews and reporting – category analysis and economic benchmarking. Category analysis is the more detailed of the two and attempts to link disaggregated cost data to a series of ‘drivers’ thought to influence each expenditure category. As such, it includes some elements of benchmarking (eg examining expenditure per unit of each explanatory variable across NSPs) and some elements of the trend analysis, revealed costs and modelling methods currently used.

The AER (2012a, p.31) has indicated that it sees the higher level economic benchmarking techniques as an important checking and screening method to be used in conjunction with the more disaggregated category analysis:

> ‘We are proposing to … conduct higher level [economic] benchmarking as a useful complement to category based analysis. In particular, we expect this type of analysis to:
>
> - provide an overall and higher–level test of relative efficiency, which may highlight issues that can potentially be overlooked during lower–level and detailed analysis
> - facilitate benchmarking which may not be possible as part of the category analysis due to data availability, including as a transitional measure
> - reinforce findings that are made through other types of analysis, otherwise highlighting potential problems in assessment methods or data.
>
> ‘It is hoped that the input/output based economic benchmarking techniques will be sufficient to test whether the largely revealed cost–based category analysis results can be relied upon and areas where further detailed review should occur.’

In practice, economic benchmarking is likely to play an important role in reviewing the relative efficiency of historical NSP expenditure and whether base year expenditure can be directly trended forward or whether it may be necessary to make adjustments to base year expenditure to remove observed inefficiencies. Economic benchmarking is also likely to play an important role in quantifying the feasible rate of efficiency change and productivity growth that a business can be expected to achieve over the next regulatory period. This would include separately examining costs that are flexible in the short run (eg opex) and costs that will need to be progressively adjusted over the longer term (eg capital inputs). This could also include consideration of how scale efficiencies may change over time. An example of how economic benchmarking methods can be used to calculate the rate of partial productivity growth that should be included in an opex rate of change roll–forward formula can be found in Economic Insights (2012b).

Economic benchmarking is also likely to be central to determining whether the revealed cost approach should be used (if the NSP is found to be operating efficiently in the economic benchmarking analysis) or whether a more detailed item by item building blocks or other type of review will be necessary (if the NSP is found to be inefficient in the economic benchmarking analysis).

2.3 Broad data requirements for economic benchmarking

Economic benchmarking requires data on the price and quantity (and hence value) of all outputs and inputs (noting that output prices may be 'shadow', or cost–reflective, prices where the output is not explicitly charged for)[1]. It also requires quantitative information on the key operating environment variables. This then allows any of the key economic benchmarking methods – TFP indexes, multilateral TFP indexes, econometric models, DEA and SFA models – to be implemented.

The availability of robust and consistent data to support a range of likely specifications is a prerequisite for the introduction of economic benchmarking. A key requirement for a robust and consistent database is detailed and consistent definitions of the way key variables have to be reported. Without this, data may have been supplied inconsistently across NSPs and also through time by each NSP.

If it proves feasible to 'backcast' data for a period of 8 to 10 years using historical data, once output and input variable lists and definitions are finalised, then it would be possible to use economic benchmarking methods in building blocks reviews in the near future, using more than one technique and with some allowance for operating environment differences. If backcasting is not possible and completely new databases have to be established going forward, then it may still be possible to include simple benchmarking using MTFP and with rudimentary adjustment for operating environment differences (see, for example, Lawrence 2000) in the next round of buildings blocks reviews.

Given that index number–based TFP methods can be implemented with relatively few observations, it will be possible to implement these methods first. Once a database with a larger number of observations is established it will be possible to implement econometric cost function models and the frontier methods such as DEA and SFA.

[1] If a 'billed' outputs specification is used then only those outputs consumers pay for are included and the relevant price is the price the consumer actually pays. But NSP charging regimes have generally evolved on the basis of historical practice and convenience and prices do not generally reflect underlying costs. As a result, key aspects of the service provided by NSPs may not be explicitly charged for. Using a 'functional' output specification, all of the key dimensions of the service provided are recognised and allocated cost–reflective or 'shadow' prices.

3 DNSP OUTPUTS

3.1 Billed or functional outputs?

Measuring the output of network businesses presents a number of challenges, especially where charging formats may not well reflect the cost of producing the various outputs. Outputs can be measured on an 'as billed' basis or on a broader 'functional' basis. This distinction arises because NSP charging practices have typically evolved on an ease of implementation and historical precedent basis rather than on a network cost reflective basis. Hence, many NSPs levy a high proportion of charges on energy throughput even though changes in aggregate energy throughput usually have little impact on the costs they face and dimensions that customers may value highly such as reliability, continuity or speedy restoration after any interruption are not explicitly charged for at all.

Under building blocks regulation there is typically not a direct link between the revenue requirement the DNSP is allowed by the regulator and how the DNSP structures its prices. Rather, the regulator typically sets the revenue requirement based on the DNSP being expected to meet a range of performance standards (including reliability performance) and other deliverables (or functional outputs) required to meet the expenditure objectives set out in clauses 6.5.6(a) and 6.5.7(a) of the National Electricity Rules (NER). DNSPs then set prices that have to be consistent with broad regulatory pricing principles but this is a separate process from setting the revenue requirement.

This differs significantly from productivity–based regulation where a case can be made that the 'billed' output specification should be used. This is because output (and, hence, productivity) needs to be measured in the same way that charges are levied to allow the NSP to recover its costs over time (see Economic Insights 2010 for an illustration). However, in the case of building blocks, it will be important to measure output (and hence efficiency) in a way that is broadly consistent with the output dimensions implicit in the setting of NSP revenue requirements. This points to using a functional rather than a billed outputs specification, a proposition universally supported by stakeholders during consultation. We believe it is important to collect data that would support both functional and billed output specifications going forward to allow sensitivity analysis to be undertaken.

It is also important to distinguish between outputs and operating environment variables as both will directly affect DNSP costs. Under most economic benchmarking applications a price and quantity are required for outputs but only a quantity is generally needed for operating environment variables. The distinction we draw between outputs and operating environment variables is that outputs reflect services directly provided to customers whereas operating environment variables do not.

3.2 Criteria for selecting DNSP outputs

Given that the outputs to be included in economic benchmarking for building blocks expenditure assessments will need to be chosen on a functional basis, we need to specify criteria to guide the selection of outputs.

The AER (2012a, p.74) proposed the following criteria for selecting outputs to be included in economic benchmarking:

1) the output aligns with the NEL and NER objectives
2) the output reflects services provided to customers, and
3) the output is significant.

The first selection criterion states that economic benchmarking outputs should reflect the deliverables the AER expects in setting the revenue requirement which are, in turn, those the AER believes are necessary to achieve the expenditure objectives specified in the NER. The NER expenditure objectives for both opex and capex are to:

- meet or manage the expected demand for standard control services
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services
- maintain the quality, reliability and security of supply of standard control services, and
- maintain the reliability, safety and security of the distribution system through the supply of standard control services.

If the outputs included in economic benchmarking are similar to those the DNSPs are financially supported to deliver, then economic benchmarking can help ensure the expenditure objectives are met at an efficient cost.

The second selection criterion is intended to ensure the outputs included reflect services provided directly to customers rather than activities undertaken by the DNSP which do not directly affect what the customer receives. If activities undertaken by the DNSP but which do not directly affect what customers receive are included as outputs in economic benchmarking, then there is a risk the DNSP would have an incentive to oversupply those activities and not concentrate sufficiently on meeting customers’ needs at an efficient cost.

The third selection criterion requires that only significant outputs be included. DNSPs provide a wide range of services but DNSP costs are dominated by a few key outputs and only those key services should be included to keep the analysis manageable and to be consistent with the high level nature of economic benchmarking. For instance, call centre operations are not normally a large part of DNSP costs and so call centre performance is not normally included as an output in DNSP economic benchmarking studies.

Stakeholders at the first workshop agreed that the AER (2012a) criteria above provided a reasonable basis on which to select outputs for use in economic benchmarking studies.

3.3 Billed outputs

Most economic benchmarking studies to date have included either all or a subset of billed outputs in their output coverage. However, the weights applied to billed components have typically varied between studies adopting a billed outputs only approach and those adopting a broader functional outputs approach. Those studies that have adopted the broader functional outputs approach have included additional outputs such as system capacity and reliability and attention has been drawn to the possible need to develop measures of system security (see, for example, Economic Insights 2009b). We focus first on billed outputs.

DNSPs usually charge for distribution services on three broad bases:

- throughput charges which reflect the volume of energy used by the customer
- fixed charges which have to be paid by the customer regardless of energy use, and
- maximum demand–based and/or contracted reserved capacity charges which guarantee the user a given amount of capacity, even at peak times, and which are normally only applied to relatively large (usually industrial) customers.

Most customers pay some combination of these three types of charges.

Energy delivered

Energy delivered is the service directly consumed by customers and has been included in nearly all economic benchmarking studies to date. However, in the current context, the case for including energy delivered is somewhat more arguable. This is because, provided there is sufficient capacity to meet current throughput levels, changes in throughput are likely to have at best a very marginal impact on the costs DNSPs face.

Some studies have included energy delivered because they argue it is a useful proxy for the load capacity of the network as the DNSP has to make sure it has the system capacity to deliver the throughput demanded (eg Coelli, et al 2010). This approach was supported by a recent study by Kuosmanen (2010) who found a high correlation between energy delivered and peak demand in Finland. The AER (2012a, p.78) has questioned whether this would apply to Australia where growth in annual peak demand has outstripped growth in energy delivered in recent years. The AER also noted that while it might be argued that energy delivered needs to be considered when considering a DNSP’s ability to meet or manage expected demand under the expenditure criteria, a contrary view is that energy networks need to be engineered to manage peak demand rather than energy delivered.

Considering energy delivered against the output selection criteria, it scores well against the second criterion in that it is a significant part of the service which customers see directly. However, it is less clear that it is important with regard to the first criterion of the DNSP meeting or managing expected demand as this is more influenced by peak demand rather than throughput. And, while energy delivered is significant to DNSPs in terms of revenue, it is unlikely to be directly significant in terms of costs.

Most workshop participants noted that although DNSPs generally derive the bulk of their charges from energy throughput, changes in throughput are not a significant cost driver and, hence, throughput should not be considered a significant output. For example, United Energy and Multinet (2013, p.10) noted:

> ‘UE particularly agrees with the concerns expressed by the AER over the use of energy (throughput) as an output, given that this is not a material cost driver, and given that recent empirical evidence illustrates the risk of declining (or at least plateauing) energy consumption in combination with increasing demand and therefore augmentation related capital expenditure.’

Similarly, the MEU (2013, p.31) noted:

> ‘Whilst energy used (because it is easily measured) is the measure that consumers assess their costs by, it is not the main driver of investment needed in a network.’

Others noted that because throughput is what customers see directly and pay for, it should not be ignored. We also note that throughput has been included as an output in nearly all previous network economic benchmarking studies (see AER 2012a, p.77). While the majority of DNSP charges remain on throughput it is important to at least recognise throughput as a functional output DNSPs supply although it is likely to receive a small weight given its expected small impact of DNSP costs. Maintaining some similarity in output coverage to earlier studies provides a means of cross checking results. And, throughput data are likely to be the most robust for backcasting purposes.

Given that throughput is what customers consume directly, the relative robustness of throughput data and its inclusion in nearly all previous economic benchmarking studies, we recommend that throughput still be considered for inclusion as an output, although it is likely to receive a relatively small weight. Disaggregation by type of customer and broad time of use (ie peak, off–peak, etc) should also be considered and the relevant data collected. Different types of customers are likely to use very different amounts of electricity and to require different amounts of infrastructure to supply (eg a residential customer will typically require considerably less transformer and line capacity to supply than a large industrial customer). Disaggregating throughput by customer type potentially provides a way of recognising differing resource intensiveness to supply and of allowing more like–with–like comparisons. Similarly, it will generally be more costly to supply throughput during peak times of the day than during off–peak times of the day.

Customer numbers

Customers typically face some fixed charges on their energy distribution bills. These charges are related to activities the DNSP has to undertake regardless of the level of energy delivered which include connection related infrastructure (eg having more residential customers may require more local distribution transformers and low voltage mains) and customer calls, etc. Going back to the ‘road’ analogy, the DNSP will need to provide and maintain local access roads for its customers, regardless of the amount of traffic on those roads. In previous economic benchmarking studies, the quantity of these functions has been proxied by the number of DNSP customers or, more specifically, the number of connections. The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system capacity. And the connection of new customers could be a significant cost driver.

Considering customer numbers against the output selection criteria, customer numbers are one indicator of the demand for distribution services and, in most cases, DNSPs have an obligation to supply customers. They also reflect services directly provided to the customer and can be a significant part of DNSP costs. The customer numbers output, therefore, scores well against the three selection criteria and should be included in economic benchmarking studies.

Previous studies have generally used the total number of customers to proxy the quantity of this output. It may be necessary to include more disaggregation of customer numbers to obtain a better proxy of the services DNSPs provide and their costs. For example, supply to a unit in a block of flats may be more costly if the block is regarded as a single 'customer supply point', or less costly if the connection is regarded and charged as a multitude of individual 'residential customers'.

In other industries moving from very aggregated output measures to more disaggregated measures has sometimes proven to be quite material. A similar result may be observed in energy distribution if those throughput categories and customer types that have higher per unit costs or charges have been increasing faster than those that have lower per unit costs or charges. Increasing the detail included on throughput and fixed output components should be a relatively straightforward improvement to make to current specifications. Disaggregation is consequently being sought by customer type (residential, farm, commercial, industrial) and by customer location (CBD, suburban, rural, remote). As was the case with disaggregating throughput, disaggregating customer numbers by type also potentially provides a way of recognising differing resource intensiveness to supply and of allowing more like–with–like comparisons.

Demand–based outputs

The treatment of the third billed output – demand–based and/or contracted reserved capacity charges – has been more variable in previous economic benchmarking studies. These charges mainly apply to large industrial customers. The appropriate quantities to use for this billed output are the (non–coincident) peak demands (in MW or MVA) for those customers that are charged on the basis of their actual observed peak demand and the MW or MVA of reserved capacity for those industrial customers that are subject to reservation charges.

This output scores well against the three selection criteria as it relates directly to the DNSP's ability to manage expected demand and maintain the quality, reliability and security of supply and the distribution system itself. It also reflects an important service provided directly to customers and will be significant for most DNSPs in terms of costs.

While not commonly reported in current regulatory data sets, this information should be relatively straightforward for DNSPs to provide as it will be an important component of their charging mechanism for demand tariff customers. The productivity study Economic Insights (2012a) prepared for the Victorian gas distribution businesses includes equivalent measures for gas distribution.

Attempts to proxy this output quantity by non–coincident system peak demand are likely to be problematic as this measure represents the peak energy entering the network at the bulk supply points and is likely to be a poor proxy for the contracted demands that large customers pay for. This is because diversification of demand within the network means that the total peak energy entering the network at any one time will be less than the sum of maximum demands at the final customer level (which will all occur at different times and which may determine local system capacity requirements). System peak demand is also generally quite volatile with erratic movements from year to year which are unlikely to reflect the costs of providing necessary system capacity in any one year. Contracted reserved capacity (and, to a lesser extent, actual peak demand from customers charged on this basis) is likely to move in a relatively smooth and monotonic fashion rather than to shift erratically from year to year. Annual climatic factors affecting residential and commercial demand may be a more significant contributor to observed volatility in system–wide peak demands.

3.4 Other functional outputs

In addition to the three billed outputs discussed above, there are a number of other functional outputs which are likely to be of particular importance for DNSP economic benchmarking in a building blocks context. These include system capacity, peak demand, reliability, system security and electricity quality and safety.

Network capacity to meet peak demand

There was some discussion at the first workshop as to whether it was more appropriate to include system capacity or peak demand as the primary functional output DNSPs supply. Economic Insights (2013a) noted that DNSP representatives had previously likened a DNSP's role to the provision of a road network. The road network operator has to make sure roads go to appropriate places and have sufficient capacity to meet peak demands but the road operator has little control over the volume of traffic on the road, either in total or at any particular time. The implication of this analogy is that it is then appropriate to measure the DNSP's performance by the availability of its network and the condition in which it has maintained it rather than by the throughput of the network (ie the volume of traffic using the road) either in total or at any particular time.

Other analysts, such as Turvey (2006), have made a similar point:

> 'what the enterprise provides is not gas, electricity, water or messages; it is the capacity to convey them. It follows that, to compare efficiencies, it is necessary to compare differences in capacities with different costs.'

A criticism, however, of including system capacity as a functional output is that it does not distinguish between those DNSPs who have provided just enough system capacity to meet peak demands and those who have provided excess capacity. Further, its use may create an incentive to overestimate future capacity needs and thus to provide excess capacity in the future. We are not convinced by arguments advanced that including system capacity as an output would provide an incentive for NSPs to overbuild capacity. NSPs take many technical factors into account when making decisions about the level of capacity required and the impact it would have on benchmarking results is not likely to be a significant driver. Including the recommended system capacity variable as an output also provides one means of recognising lines as well as transformer requirements without the need to account for line length as an operating environment factor. This is an important consideration given the limited scope to include operating environment factors in the short run. System capacity is also able to draw on robust data held and maintained by all DNSPs.

A number of workshop participants advocated the use of peak demand as a better measure of the load a DNSP has to be able to accommodate and as a more appropriate proxy for required system capacity. Economic Insights (2013a, p.11) noted that system peak demand tends to be quite volatile over time due to the influence of variable climatic conditions and other factors outside network control. Such volatility would present a significant problem for efficiency measurement as it would lead to corresponding volatility in efficiency scores for reasons beyond the NSP's control (as the NSP is unable to tailor its capacity year–by–year to match the peak that happens to occur in that year). If peak demand were to be included as an output, it may be more appropriate to include either a smoothed series or a 'ratcheted' variable that reduced the effect of such volatility. Given the prospect of decreases in energy usage and peak demands, a smoothed and possibly weather corrected series is likely to be more appropriate than a ratcheted series. For similar reasons, a number of DNSP representatives at the workshop suggested that the forecast peak demand series that the DNSP's previous price determination had been based on was a more appropriate peak demand series than actual peak demand as this was what the DNSP was expected to deliver capacity for in the current regulatory period.

Another DNSP representative suggested that, while the road network analogy was useful, a more relevant analogy might be to consider the case of a customer who has a requirement for electricity but there is no distribution network. The customer needs a way of getting the energy he requires from the transmission terminal station to his premises. The energy will be acquired from the NEM by the customer's retailer and is available at the terminal station at the relevant voltage.

In the absence of a distribution network the customer must construct its own poles and wires and transformers from the terminal station to its premises. Those facilities must have the capacity to meet the customer's demand, whatever it is, with the required reliability. The optimal size, and hence cost, of those facilities will be determined by the customer's:

- forecast maximum peak demand at some time in the future where the optimum capacity is a trade–off between building less capacity now in the knowledge that expansion will be required and costs incurred at some later time, and building more capacity now at higher cost but deferring the need for expansion. Once capacity is installed it cannot be readily removed or down–sized.
- reliability requirements which will determine, among other things, the level of redundant/standby capacity required. Once again that would be an optimisation (between additional costs now versus incurring the costs associated with lower reliability levels later) and could involve standby transformers and circuits or even a second line of poles and wires from a different terminal station or back–up generation onsite.

The capacity which will be provided is not determined by:

- energy throughput/load factor, although load factor may determine whether the customer builds 'distribution' assets at all. For example, if a customer has a very low load factor and/or is a long way from the terminal station, it may determine that it can meet its total energy, capacity and reliability requirements more economically by generating onsite.
- actual peak demand as it is from time to time.

This example implies that the principal output of the facilities that the customer installs, which are in fact distribution assets, is the capacity to carry energy when and as required from the terminal station to the customer's premises. There is also a correlation between installed capacity and reliability – all else equal, a system that has greater capacity/redundancy can be expected to meet demand, whatever it is from time to time, more reliably than one with less capacity/redundancy. Furthermore, capacity cannot be adjusted year–by–year to track short term variations in actual peak demand, so there is invariably some level of spare capacity in the system.

Once distribution is expanded to form a network then connections also become an output. And a network, as an aggregator, can take advantage of diversity so that total network capacity is only some fraction of the sum of individual customers' capacity requirements. A network also offers the benefits of economies of scale.

In its submission on the AER (2012a) Issues Paper, Jemena (2013, p.8) summarised the situation as follows:

> 'an NSP's principal functions are to provide connections and ensure that there is sufficient capacity to meet network users' peak requirements, whatever they are and whenever they occur, in all but extreme "1 in N" circumstances.
>
> 'We note that benchmarking studies often use observed peak demand as a proxy for capacity. We see this as problematic in that it implies that an efficient business is one that has just enough capacity to meet actual peak demand. That may have superficial attraction but it is not achievable in practice and is not dynamically efficient—capacity can only be increased in finite increments and, when additional capacity is required, it is more efficient to install "excess" capacity to meet forecast demand growth for a period than to expand in frequent small increments. It follows that there will always be spare capacity in a network. At the same time, there will be local bottlenecks as local peak demand increases to the limit of capacity installed at some earlier date to serve that locality. For an established NSP, total installed capacity changes only incrementally from year to year in response to the forecast trend in maximum peak demand and as local bottlenecks are addressed. It certainly does not change in response to short term variations in actual peak demand due to weather variations between years.
>
> 'Actual throughput and actual peak demand are not significant cost drivers in the short term: the provision of capacity to accommodate forecast maximum peak demand is a much more significant driver of input requirements and costs. The distributor is (and must be) compensated for the incurred cost of providing prudently installed capacity notwithstanding the fact that actual peak demand will vary and may reach the limit of capacity only rarely.'

SP AusNet (2013, p.22) noted in its submission:

> 'forecast peak demand, as approved in regulatory determinations, is what businesses are required to provide sufficient capacity for. As such, it drives investment planning and decision–making, and forms a basis for regulated revenues. In contrast, actual peak demand is not relevant as this is outside the control of the business and is not a driver of revenues.'

And SA Power Networks (2013, p.2) noted:

> ‘Network capacity should be considered with regard to peak demand forecasts. Networks seek to ensure supply during periods of extreme peak demand at an efficient level of costs.
>
> ‘Measures of spatial peak demand should be used rather than the system demand.’

Economic Insights agrees that actual peak demand is a poor indicator of the load capacity a DNSP is required to provide and, due to its volatility, using actual peak demand would likely lead to inappropriate volatility in efficiency results. A high degree of smoothing of actual or weather corrected peak demand would overcome the volatility problem while also giving a more accurate indication of required capacity. Ideally the probability of exceedance would also be taken into account in forming the smoothed series.

While forecast non–coincident maximum demand from the most recent regulatory determination may provide an indication of the loads the DNSP was expected to be able to meet and which were built into the building blocks revenue requirement, it also has some limitations. Once the building blocks allowance is set, DNSPs are expected to respond to the incentive to be efficient and this may include responding to lower than forecast demand and/or revised forecast demand. Furthermore, using forecast peak demand from the determination may provide an incentive for DNSPs to over–inflate forecasts in future reviews.

Maximum demands will provide an indication of the transformer capacity required by the DNSP, all else equal. They do not distinguish between the amount of lines required by two DNSPs who may have similar maximum demands but one of which is rural and the other of which is urban. One would expect the rural DNSP, having a lower customer density, to require a higher length of line to deliver the same forecast maximum demand. This will require the rural DNSP to use more inputs to deliver the same forecast maximum demand and, hence, make it appear less efficient unless it either gets some credit on the output side for its greater line length requirement or, alternatively, customer density is included as an operating environment factor.

Including system capacity as an output provides one means of recognising lines as well as transformer requirements without the need to account for line length as an environmental factor. For example, Economic Insights (2009b) included a broader measure of electricity distribution system capacity that recognised the role of lines as well as transformers. This was the simple product of the installed distribution transformer kVA capacity of the last level of transformation to the utilisation voltage and the totalled mains length (inclusive of all voltages but excluding services, streetlighting and communications lengths). The advantage of including such a measure is that it recognises the key dimensions of overall effective system capacity. It also reflects actual capacity supplied rather than a forecast capacity requirement that may or may not be met. And it does not have the volatility beyond the DNSP’s control which is a problem with the actual peak demand measure.

Considering the system capacity output against the three selection criteria, system capacity is clearly required to meet expected demand for distribution services and to maintain the quality, reliability and security of supply and the distribution system itself. It is also a significant part of DNSP costs. However, while it reflects a service provided to customers, it may not be the ideal measure since it will not distinguish between DNSPs who have provided adequate capacity to meet demands from those who have overinvested in system capacity. It may also penalise those DNSPs who have sought out new ways of managing demand (eg through demand management or embedded generation) compared to simply investing in more capacity which may be a more costly option. Despite these limitations, we consider system capacity to be an important variable to be considered in economic benchmarking. It is one that is readily measurable from robust data in DNSP data systems.

While including peak demand as an output may be consistent with meeting demand for distribution services as set out in the expenditure objectives, managing peak demand will likely require the use of time–of–use pricing and other demand management methods. Simply including either coincident or non–coincident system peak demand as an output in economic benchmarking may not incentivise DNSPs to take actions to smooth peaks and reduce the need for costly additional underutilised infrastructure. With regard to the second selection criterion, system peak demand does potentially reflect a service provided to customers but the provision of a high level of reliability at all times – and particularly peak periods when the costs to customers of outages will be highest – will be what individual customers observe and are most interested in receiving.

There are, thus, arguments for and against including system capacity versus smoothed maximum demand as a functional output. On balance, we are of the view that both measures warrant further investigation and sensitivity analysis should be undertaken. System capacity taking in both line length and transformer capacity is likely to be the best option in the short term as it requires a minimal number of observations to implement. Once sufficient data observations become available inclusion of smoothed maximum demand with adjustment for customer density differences as an operating environment factor should be investigated.

Given that system capacity and peak demand both have some limitations as outputs, an alternative could be to include customer numbers disaggregated by customer type (eg residential, commercial, small industrial, large industrial and other) and reliability as outputs. Together these variables could measure the DNSP’s success in providing adequate capacity to meet the various types of customers’ needs. Such a specification also warrants further investigation and analysis.

Reliability

Reliability is an important dimension of DNSP output and receives some prominence in the NER expenditure objectives where maintaining the reliability of both supply and the system itself are explicitly mentioned. Improving (or maintaining) reliability is generally a significant part of DNSP costs and it reflects an important part of the service directly provided to customers (although customers are not typically charged for reliability explicitly).

There was general agreement amongst workshop participants that reliability should, if possible, be included as a DNSP output.

In its submission on the AER (2012a) Issues Paper, SP AusNet (2013, p.22) noted:

> ‘Reliability is an important output variable, as it is something which customers value which is reflected in the NER capex and opex objectives. While there are practical challenges in expressing reliability as outputs in benchmarking functions, it is worthwhile trying to overcome these challenges given the importance of reliability as an output.’

Similarly, the Major Energy Users Group (2013, p.31) observed:

> ‘Ultimately consumers measure the value of the network in terms of amount of energy used and the reliability of supply as measured by SAIDI, SAIFI and other similar measures. Less investment is needed if these measures are low and more is needed when they are high. So using these measures provides a good indication of what investment is needed and where.’

In addition, reliability should be included to ensure DNSPs do not improve their measured efficiency performance by neglecting network maintenance and other initiatives important to maintaining and, where appropriate, improving reliability levels.

Reliability measures score well against the three output selection criteria. The expenditure objectives place emphasis on maintaining the ‘quality, reliability and security of supply of standard control services’ and it directly reflects an important aspect of the service provided to customers. Customers generally regard achieving high levels of reliability as significant and doing so can involve significant costs for DNSPs.

In this section we review three issues raised at the first workshop:

- is there a lag between expenditure changes and changes in reliability?
- how can reliability indexes be included as output quantities? and
- what weight should reliability outputs get?

Possible lags between expenditure and reliability changes

Several DNSP representatives at the first workshop suggested there was likely to be a lag between changes in expenditure and observed changes in reliability. However, no explanations were given as to why this might be the case. There will be some timing issues between years when expenditure is incurred and when a change in reliability might be observed. For example, expenditure at the end of one regulatory year may only lead to improved measured reliability in the next regulatory year. However, we would expect expenditure on improving reliability to be spread over the year which would considerably lessen this impact.

It should also be noted that economic benchmarking does not involve direct benchmarking of capex. Rather, economic benchmarking uses the total stock of capital as the input and its annual value is the annual user cost of capital (AUC). Hence, the impact of reliability–related capex on overall input use will be incremental whereas once the assets are in place they may have a more immediate impact on reliability performance.

Lags could also be observed if there is a program of expenditure required to upgrade troublesome feeders which takes some time to implement. For instance, only obvious weak points may be easily identified and remedied initially. However, this may then lead to other weak points on the feeder becoming more obvious which then require further expenditure and so on over a number of years.

Some DNSPs in remote parts of Australia have previously observed that it normally takes around three years for capital expenditure aimed at improving the performance of worst feeders to have a significant effect. This is because it takes time to complete interrelated projects aimed at strengthening the system overall. This would point to a relationship between input use now and reliability performance in two to three years' time. Others have observed that the lag may go in the opposite direction as it takes time for DNSPs to recognise problem areas, get approval for expenditure and then to implement the work program. This would point to a relationship between input use now and reliability performance two years ago.

The reverse is also likely the case. That is, if a DNSP stops spending on maintaining and improving its network then it may take a number of years for the network to 'run down' and the DNSP's reliability performance to drop off noticeably.

Reliability variables have been included in very few economic benchmarking studies to date (see ACCC/AER 2012, AER 2012a). Those that have included reliability measures (eg Coelli et al 2008, 2010 and Lawrence 2000) have typically not lagged them.

While there may be some grounds for expecting there to be a small lag between expenditure on reliability improvement initiatives and observed changes in reliability, we are of the view that initial economic benchmarking studies should include current year reliability. Once a longer time series of data becomes available there will be an opportunity to undertake testing of whether any lag is in fact present and which direction it goes in and to undertake sensitivity analysis of economic benchmarking results to including a lag on reliability variables. It would also be useful to examine the effects of including a rolling average reliability measure rather than a single year reliability measure. We expect the majority of the relationship to be captured in the current year.

Including reliability as an output quantity

Outputs in efficiency studies have generally been measured in such a way that an increase in the measured quantity of an output represents more of the output and, hence, a desired result. But both the frequency and duration of interruptions are measured by indexes where a decrease in the value of the index represents an improvement in service quality. It would be necessary to either include the indexes as undesirable or 'bad' outputs (ie a decrease in the measure represents an increase in overall output) or else to convert them to measures where an increase in the converted measure represents an increase in output. One of the ways of addressing this tried initially was to invert the reliability measures to produce an increase in the measure equating to an increase in output. However, this generally led to a non–linear transformation which produced distorted results. Another option tried was to look at the minutes the system was on–supply rather than the minutes it is off–supply which is what SAIDI measures. However, since most systems are interrupted for a relatively small number of minutes each year, using the number of minutes the system is uninterrupted effectively produces a constant variable that is of limited use.

The key reliability indexes of (distribution–related) SAIDI and SAIFI have been the main reliability measures used in DNSP economic benchmarking studies to date. They have mainly been included in econometric models where the need for more output to be represented by an increase in the variable is less of an issue. Some econometric studies have transformed the indexes into a more convenient form by multiplying them by total customer numbers (eg Coelli et al 2010). This produces measures of total customer minutes lost and total customer interruptions. We believe this representation is more consistent with the framework of economic benchmarking where we are looking at total outputs rather than outputs per customer. SAIDI and SAIFI are useful for communication purposes in that an individual customer can more readily understand what they mean but the overall total numbers of customer–minutes lost and customer interruptions are more appropriate for economic benchmarking studies.

Some economic benchmarking studies have included reliability as an input rather an output in recognition of a DNSP's ability to substitute between using opex and capital, on the one hand, and reduced reliability and associated penalties on the other (see Coelli et al 2008). Regulators in Finland and Norway have also used economic benchmarking models which included customer–minutes lost as an input whose cost is added to the DNSP's operating and capital costs, in recognition of the costs interruptions impose on customers (WIK–Consult 2011). This approach also warrants consideration.

It is desirable to have a way of including standard reliability measures as outputs in economic benchmarking studies, including index–based methods which are the most likely methods to be able to be implemented initially. We propose two alternative means of doing this be further investigated.

The first method involves including total customer–minutes lost or total customer interruptions (ie transformed SAIDI or SAIFI, respectively) as an undesirable or 'bad' output. This involves allocating a negative price to the measure and, hence, a negative weight in forming the total output measure. By giving the reliability measure a negative weight, it is then treated as a 'bad' rather than a 'good' output and reducing the value of the measure (ie improving reliability) will be consistent with increasing overall output. This approach follows the method developed by Pittman (1983) for including outputs of industrial pollution in studies of manufacturing productivity performance. It can be readily implemented using standard indexing methods and computer programs. A variant of this approach was adopted in Lawrence (2000) where interruption indexes were included as an undesirable output in an economic benchmarking study of 10 Australian DNSPs. How this undesirable output was weighted will be discussed further below.

The second method we believe warrants further investigation is to form a benchmark level of the maximum level of acceptable overall customer outages and subtract the actual level of outages from this benchmark level. This subtraction would produce a variable with the standard output characteristics where a higher value represented more of the output. That is, a low value of SAIDI representing higher reliability when subtracted from the benchmark level would produce a higher output quantity than would a high value of SAIDI representing lower reliability when subtracted from the benchmark. The problem with this approach is that there is likely to be a degree of arbitrariness in setting the target benchmark level of worst acceptable reliability. This could be related to jurisdictional standards but would need to be a common value across similar included DNSPs (eg grouped by CBD, urban, short rural and long rural) for economic benchmarking purposes. It would need to be set sufficiently high that it exceeded the worst observed performance to ensure the result of the subtraction was positive in all cases. The weighting method used would need to recognise diminishing customer valuations of improved reliability versus increasing DNSP marginal costs of providing further improvements.

A decision has to be made on whether priority should be given to including outage duration or number of outages performance in initial economic benchmarking studies. Most economic benchmarking studies to date have included duration of interruptions or minutes off–supply as the measure of reliability performance. We recommend that priority be given to including outage duration in the initial round of economic benchmarking studies in line with previous practice. However, we note that a case can be made that the number of customer interruptions is of most concern to customers in systems with high levels of reliability. That is, four separate interruptions of 15 minutes duration each on separate days may cause a customer more inconvenience than one interruption of 60 minutes duration at a similar time of the day.

While the number and length of interruptions are likely to be of most concern to customers and, hence, should receive highest priority for inclusion as outputs in economic benchmarking, other aspects of overall service quality such as momentary interruptions, customer service, quality of supply, etc are candidates for future inclusion.

What weight should reliability outputs get?

Customers normally prefer better quality service to inferior quality service and are prepared to pay a premium for better service. However, the size of the premium they are prepared to pay will depend on their individual preferences and the degree of quality involved. Consumers typically exhibit reduced marginal willingness to pay as the amount of quality increases. That is, as they attain higher quality levels, consumers value additional improvements in quality less so they are prepared to pay less to go from a very good service to an excellent service than they were to go from a poor service to a mediocre service.

DNSPs, on the other hand, face increasing marginal costs of improving quality. For instance, improved maintenance practices and some basic strengthening of the network may improve service quality from poor to medium at modest cost. However, to go from medium to high service quality levels is likely to require major capital expenditure to strengthen and possibly duplicate parts of the network and make greater use of undergrounding which will come at a much higher cost.

The optimal level of service quality will occur where the consumer’s marginal willingness to pay is equal to the DNSP’s marginal cost to improve service quality. For service quality levels below the optimum, consumers value a small increase in service quality by more than it costs the DNSP to produce it while for service quality levels higher than the optimum level, it costs the DNSP more to produce a small increase in quality than consumers value it.

For economic benchmarking purposes we need to decide whether reliability outputs should be valued according to the cost to the DNSP of improving reliability or according to the value placed on reliability by the consumer. The methods outlined in the previous section can be used to obtain estimates of the costs to the DNSP of reliability outputs. There are also a range of estimates of the value consumers place on reliability, the most recent of which is AEMC (2012b) (although this is an upper bound as it relates to outages at the most inconvenient time of the day). The DNSP STPIS service quality incentive scheme operated by the AER also contains incentive rates based on consumers' valuation of reliability performance (AER 2008b) and, for consistency, is likely to be the best source of estimates of customer valuation of reliability for economic benchmarking purposes.

If the STPIS is working as intended, we would expect customer valuations of reliability to be approximately equal to DNSP marginal costs of further improving reliability. However, we believe a good case can be made that reliability outputs should be valued according to the customer's valuation rather than the DNSP's costs of improving reliability. Given that customers will value successive improvements in reliability less highly whereas they will cost DNSPs increasingly more to supply, it is important that DNSPs not be given an incentive to keep increasing reliability beyond the point where their marginal costs exceed customers' marginal valuations of additional reliability.

Some European regulators have adopted a broadly similar approach although, as noted above, the cost of outages has been included as an additional input rather than reliability being explicitly included as an output. For example, the Finnish regulator includes the 'disadvantage to the customer caused by electricity supply outages' while the Norwegian regulator includes the cost of outages based on customer willingness to pay derived from a reference power price (WIK–Consult 2011).

Lawrence (2000) also valued the (undesirable) reliability output using an estimate of customer inconvenience from outages. Lawrence (2000) allocated a directly calculated value to the reliability variable based on customer valuation of inconvenience while using the cost elasticity approach to allocate weights to the other three output components based on the DNSPs' costs of supplying the other outputs (throughput, customer numbers and system capacity).

For the reliability variable in that study the value of minutes off supply was calculated by deriving the average kilowatt hours the DNSP supplies for every minute it is supplying electricity and multiplying this by 8.7 cents (the then average price paid by consumers for electricity per kilowatt hour consumed) and also by a penalty factor of 100 (reflecting the much higher inconvenience cost of power supplies interrupted) by the number of minutes off supply. The interruptions index then received a negative weight based on the estimated cost of interruptions to customers. It should be noted that the choice of the 100 times penalty factor was somewhat arbitrary but the study predated the major studies of consumer valuation of reliability in Australia. If this process were to be adopted now, the customer valuations of reliability included in the STPIS could be used instead. On average, this procedure adopted at the time involved a weight of around 8 per cent of DNSP revenue being allocated to the reliability output across the 10 included DNSPs.

As a practical way forward we recommend adopting the STPIS valuations of consumer reliability (VCR). As the STPIS VCR is presented as an amount per MWh consumed, this first has to be converted to an amount per customer minute depending on the individual

DNSP's annual energy deliveries. The VCR will thus differ for each DNSP. For the first approach of Lawrence (2000) of including interruptions as an undesirable output following the method developed by Pittman (1983), the value of customer outages would enter as the negative weight applied to interruptions. This method is easy to implement and produces relatively robust results.

For the second approach above of including the difference between observed reliability and a benchmark worst acceptable reliability performance, the transformed reliability output would simply be valued according to the STPIS customer valuations. This would lead to a DNSP with good reliability performance receiving a higher weight for that good performance than a DNSP with bad performance would receive for its performance. That is, the DNSP with good reliability performance would be rewarded by its good performance being associated with more 'revenue' in forming the output weight, just as would be the case with any other output.

System security

Security of supply and security of the distribution system receive explicit mention in the NER expenditure objectives. They refer to the DNSP's management of the system to reduce the probability of network assets failing or being overloaded. In some cases DNSPs are being required to meet higher statutory system security benchmarks (eg moving from n–1 to n–2 redundancy levels). While system security is a significant cost to DNSPs, it is not necessarily an output that reflects services provided to customers as customers are concerned about the reliability of the system as it affects them directly. As such, reliability may be the more appropriate measure to include as an output in economic benchmarking.

System security can also be quite difficult to quantify in a summary measure. Ofgem (2009) has attempted to form several different measures of system security based on the load on network assets, a health index reflecting asset age and condition and asset fault rates.

The system security issue is somewhat problematic. Some DNSPs have spend large amounts to strengthen their systems and provide higher levels of redundancy but current measures of output do not show any corresponding increase in 'output' (ie the benefits from increased system security will not be reflected in measures such as throughput, customer numbers or peak demand). It should also be noted that reliability measures may not reflect any change in output either. Rather, improving system security is providing an 'insurance' output that customers may value but which it is very hard to measure. One option could be to give DNSPs a score depending on what redundancy level they achieved (eg 1 for n–1, 2 for n–2, etc). This would be similar to the Ofgem 'network health' approach. But if the event being insured against by the system strengthening does not come to pass, then the extra output would not be reflected in different reliability performance. But insurance against such an event would have been provided nonetheless.

In the current context, system security measures are best considered descriptors of input condition and are not sufficiently close to reflecting services directly provided to customers to be included as an output in economic benchmarking (ie they do not satisfy the second output selection criterion to a sufficiently high degree). A further practical difficulty is the lack of comprehensive high level summary measures of system security that could be used in economic benchmarking.

Electricity quality and safety

The quality and safety of electricity supply and of the distribution system also receive explicit mention in the NER expenditure objectives. Electricity quality and safety is of obvious importance to customers so that their physical safety is protected and their equipment and appliances are not damaged. There are a number of specific measures of electricity quality and safety but no overall summary measure. Some workshop participants raised electricity quality and safety as a significant output but did not respond to requests to provide workable indicators. More widespread deployment and use of smart metering technology may allow useful indicators to be formed in the future.

While maintaining quality and safety overall may have a significant impact on DNSP costs, achieving these safety and quality standards are a necessary requirement of DNSP operation and are unlikely to be substantially different across DNSPs. As only a limited number of outputs can be included in an economic benchmarking study, we believe it is more important to prioritise the inclusion of other key outputs ahead of electricity quality and safety measures.

Broader obligations

Some overseas regulators have shown an interest recently in including a much wider range of considerations and obligations in DNSP output coverage and assessment. Ofgem (2012, p.7), for example, has listed the outcomes it expects network companies to deliver as:

- safety
- limited impact on the environment
- customer satisfaction
- delivery of social obligations.
- non-discriminatory and timely connection, and
- reliability and availability.

Three of these six outcomes (environmental, customer satisfaction and social obligations) represent a considerable broadening of (explicit) expectations on the DNSP. They are also relatively difficult to measure robustly and objectively. At this stage we do not propose to include these broader objectives as DNSP outputs for inclusion in economic benchmarking studies.

3.5 Calculating output weights

There was general agreement at the first workshop and in submissions on AER (2012a) that a functional outputs approach was more appropriate than a billed outputs approach for use in economic benchmarking used in a building blocks context. This is because DNSP pricing structures have often evolved on the basis of convenience rather than on any strong relationship to underlying relative costs. As a result, observed revenue shares will be of limited usefulness (in a building blocks context) in forming weights for those economic benchmarking techniques that aggregate output quantities into a measure of total output or for assessing the reasonableness of shadow weights for those techniques that allocate shadow weights in forming an efficiency measure.

In its submission on AER (2012a), United Energy noted:

> 'UE agrees … that the absence of prices that reflect costs necessitates a move away from simple revenue shares as the basis for weighting the outputs. In no way [are revenue shares] likely to be a true representation of either the value to the end customer of a particular output, or the cost to the business of providing that output.'

Rather, it will be necessary to form output weights based on the weights implicitly used in building blocks determinations. These are generally taken to be cost–reflective output weights.

There are three broad options available to form cost–reflective output weights for use in economic benchmarking:

- estimate the weights from an econometric cost function;
- use weights from previous cost function studies from a broadly comparable sample, or
- obtain estimates of the relative cost of producing each of the specified outputs from the DNSPs themselves.

We examine each of these options in turn.

Estimating cost function–based output weights

Most economic benchmarking studies using a functional outputs approach have formed estimates of cost–reflective output weights from econometric cost function models. This is done by using the relative shares of output cost elasticities in the sum of those elasticities because the cost elasticity shares reflect the cost of providing relevant output components.

The sophistication and complexity of the cost function that can be estimated depends on the extent of data and number of observations available. Very simple cost functions can be estimated with only a limited number of observations. For example, Lawrence (2000) estimated a simple log–linear cost function using 10 cross sectional DNSP observations which included a constant, three output quantities and an input price index.

Lawrence (2003) had access to more observations and was able to estimate a multi–output Leontief cost function using data for 28 DNSPs over 7 years. The cost function included the three outputs of throughput, system line capacity and connections. It included four inputs: operating expenses, overhead lines, underground lines and transformers. The cost function estimated the relationship between changes in total cost and changes in the outputs and then used the coefficients to generate the weights of each output in total cost. This simple model produced output cost share estimates for the three outputs included of 22 per cent for throughput, 32 per cent for network line capacity and 46 per cent for connections.

This functional form essentially assumes that DNSPs use inputs in fixed proportions for each output and is given by:

(1) $$C(y^t, w^t, t) = \sum_{i=1}^{M} w_i^t \left[\sum_{j=1}^{N} (a_{ij})^2 y_j^t (1 + b_i t)\right]$$

where there are M inputs and N outputs, w_i is an input price, y_j is an output and t is a time trend representing technological change. The input/output coefficients a_{ij} are squared to ensure the non–negativity requirement is satisfied, ie increasing the quantity of any output cannot be achieved by reducing an input quantity. This requires the use of non–linear regression methods. To conserve degrees of freedom a common rate of technological change for each input across the three outputs was imposed but this can be either positive or negative.

The estimating equations were the M input demand equations:

(2) $$x_i^t = \sum_{j=1}^{N} (a_{ij})^2 y_j^t (1 + b_i t)$$

where the i's represent the M inputs, the j's the N outputs and t is a time trend representing the seven years, 1996 to 2003.

The input demand equations were estimated separately for each of the 28 DNSPs using the non–linear regression facility in Shazam (White 1997) and data for the years 1996 to 2003. Given the limited number of observations and the absence of cross equation restrictions, each input demand equation was estimated separately.

The output cost shares for each output and each observation were then derived as follows:

(3) $$h_j^t = \{\sum_{i=1}^{M} w_i^t [(a_{ij})^2 y_j^t (1 + b_i t)]\} / \{\sum_{i=1}^{M} w_i^t [\sum_{j=1}^{N} (a_{ij})^2 y_j^t (1 + b_i t)]\} .$$

A weighted average of the estimated output cost shares for each observation was then used to form an overall estimated output cost share where the weight for each observation, b, is given by:

(4) $$s_b^t = C(b, y_b^t, w_b^t, t) / \sum_{b,t} C(b, y_b^t, w_b^t, t) .$$

Lawrence (2007) estimated a similar cost function model for the three Victorian gas distribution businesses using data for the years 1998 to 2006. For the equivalent three output components in gas distribution this produced an output cost share for throughput of 13 per cent, for customers of 49 per cent and for system capacity of 38 per cent. For a two output specification covering throughput and customer numbers it produced an output cost share for throughput of 25 per cent and for customers of 75 per cent.

As more observations become available then more complex cost functions can be estimated including flexible cost functions that include second order terms allowing second–order approximations instead of the first–order approximations of the simpler cost functions described above. The translog cost function is the most commonly used flexible cost function.

Economic Insights (2012b) provides an example of a simple second order operating cost function (as opposed to total cost function) for gas distribution businesses as follows:

(5) $$\ln C_{OM} = b_0 + b_D \ln D + b_C \ln C + \ln W_{OM} + 0.5 b_{DD} \ln D \ln D + 0.5 b_{CC} \ln C \ln C \\ + b_K \ln K + b_t t$$

where C_{OM} is operating cost, D is deliveries (or throughput), C is customer numbers, W_{OM} is the opex input price, K is pipeline length and t is a time trend. Note that the opex input price enters the operating cost function with a coefficient of one in this instance to ensure homogeneity of degree one in prices and pipeline length is included as a proxy for fixed capital inputs. Second order terms are included for outputs. In this instance the key operating environment characteristics of customer density and energy density enter through the inclusion of the two output variables and the capital quantity variable. The density drivers cannot be included as separate terms in addition to their constituent components due to multicollinearity.

The data used in this study were actual data for 11 gas distribution businesses covering actual data from 1999 onwards (where available) and forecast data from the latest regulatory determinations (where available) out to as far as 2017. In all, 144 observations were available. This study produced estimated output *operating* cost shares of 45 per cent for throughput and 55 per cent for customer numbers.

The sample of economic benchmarking studies listed above have used increasingly more sophisticated cost functions to estimate cost–reflective output weights as more observations have become available. Provided a relatively small number of outputs are included, the log linear cost function can be estimated on cross sectional data while the Leontief cost function can be estimated with a relatively small number of observations for each of the included DNSPs.

Using weights from previous cost function studies

Another common approach used in economic benchmarking studies has been to draw on the output weights obtained in earlier comparable economic benchmarking studies. For example, later Australian DNSP economic benchmarking in Lawrence (2005) and later New Zealand DNSP economic benchmarking in Economic Insights (2009b) both used the cost–reflective output weights derived in Lawrence (2003). Similarly, Economic Insights (2012a) economic benchmarking of the Victorian gas distribution businesses used the cost–reflective gas distribution output weights estimated in Lawrence (2007).

Previous studies will also provide useful information on the relative weights that can be expected across outputs. And, where several relevant previous studies are available, taking an average of the output weights obtained across those studies is also a way of making the most use of available information.

While drawing on the results of previous cost function studies is reasonable where the earlier studies were of industries comparable to the one at hand, it has the potential limitation of restricting the choice of outputs to similar components as used previously.

Obtaining relative cost estimates directly from DNSPs

While it is desirable to estimate the output weights to be used in economic benchmarking by objective and reproducible independent means, another alternative is to request the DNSPs to provide estimates of how their total costs should be allocated across the included output components. This process could also provide a useful ‘sanity check’ for output weights estimated by other means.

It would be necessary for the AER to provide guidance on how DNSP costs should be allocated across the nominated output components. The approach adopted should be consistent with that being developed in detail as part of the category analysis workstream.

Two broad methods of cost allocation that are commonly used in other industries are the fully distributed costs method and activity based cost accounting. The fully distributed cost method of cost allocation allocates the total costs incurred by an entity across all the nominated outputs. Under this approach costs are normally categorised as directly attributable costs and shared costs. Directly attributable costs are those that can be directly identified with or attributed to a particular nominated output. A direct relationship can sometimes be established based on functional responsibility. However, the main principle that is used to identify directly attributable costs is cost causality, ie directly attributable costs include all those costs that are causally related to a particular nominated output or at least clearly causally related.

The shared costs are those that are not clearly causally related to the particular nominated output. The fully distributed cost method allocates shared cost by an appropriate method that is normally chosen on the basis of being the best proxy of cost causality, even though conceptually a direct cost causation relationship does not exist. The three most popular allocators are relative outputs, relative directly attributable costs and relative revenues.

Although a well defined cost causality relationship can often not be established for the chosen indicator, there is a sense in which the supply of nominated output entails cost causation. That is, because the same shared costs may be used for a variety of purposes so that there is an opportunity cost in supplying the service for one nominated output rather than another.

However, because the allocation of shared costs is not unique, the resulting output weights may not bear a close resemblance to marginal costs.

Activity based cost accounting systems are a further refinement of the fully distributed cost approach. Such systems are effectively a systematic and detailed approach for establishing causal links between costs and nominated outputs and hence implementing the fully distributed cost methodology. The approach entails representing the business as a series of activities, each of which consumes resources and therefore generates costs.

The stages in an activity based costing system are as follows:

- costs are estimated for each discrete activity that can be identified within the business with a number of cost activity pools formed. Activities can be thought of as intermediate stages within the production process which contribute to one of more end products or services but do not constitute an end product or service in their own right
- costs of specific activity pools are then allocated to a nominated output depending on the number of ‘activity units’ consumed by the nominated output, and
- the total cost of the nominated output is the sum of the costs attributed from each cost activity pool.

Ideally, an activity is a task or group of tasks for which a single cost cause (or ‘driver’) can be established without incurring too many transactions costs. The implementation of the concept entails focusing on the purpose of the expenditure and identifying indicators that reflect cost causation. However, activity based cost accounting cannot be used where cost causation cannot be established. Where cost causation cannot be established, appropriate allocators are selected as in the fully distributed cost methodology described above. The main advantage of activity based cost accounting is in the transparency of the cost allocation process.

As noted above, the exact approach adopted should be consistent with that being developed in detail as part of the category analysis workstream but is likely to be a type of fully distributed costs model. The amount and allocation of shared costs would also need to be disclosed.

Once a cost allocation method is finalised, we believe it would be appropriate for the AER to implement requirements similar to those in the AER (2008a) cost allocation guidelines. This would require a DNSP's detailed principles and policies for attributing costs directly to, or allocating costs between nominated outputs to be sufficiently detailed to enable:

1) the AER to replicate the reported outcomes through the application of those principles and policies, and

2) the DNSP to demonstrate that it is meeting the specified requirements.

This means that a DNSP would be required to include information on the following matters to enable the AER to replicate its reported outcomes:

1) for directly attributable costs:
    a. the nature of each cost item
    b. the nominated output to which the cost item is to be directly attributed
    c. the characteristics of the cost item that associate it uniquely with a particular nominated output in order to make it a directly attributable cost, and
    d. how and where records will be maintained to enable the basis of attribution to be audited or otherwise verified by a third party, including the AER.

2) for shared costs:
    a. the nature of each cost item
    b. the nominated outputs between which each cost item is to be allocated
    c. the nature of the allocator, or allocators, to be used for allocating each cost item
    d. the reasons for selecting the allocator, or allocators, for each cost item and an explanation of why it is the most appropriate available allocator, or set of allocators, for the cost item
    e. whether the numeric quantity or percentage of the allocator, or allocators, to be applied for each cost item could be expected to:
        i. remain unchanged over the regulatory control period, or
        ii. change from time to time throughout the regulatory control period.

f. how and where records will be maintained to enable the allocation to be audited or otherwise verified by a third party, including the AER.

A DNSP would not be allowed to allocate the same cost more than once which means that:

- the same cost may not be treated as both a direct cost and a shared cost
- a direct cost may only be attributed once to a single nominated output, and
- a shared cost may only be allocated once between nominated outputs.

The AER would need to consult with DNSPs in advance of collecting these costs estimates to develop consistent, robust definitions of costs and to ensure as consistent a treatment as possible across DNSPs. If this approach was considered to be too resource intensive, an alternative would be for the AER to develop a method of allocating costs to outputs and then seek feedback on this from the DNSPs.

3.6 Scope of services

In addition to providing the core 'poles and wires' component of distribution networks, DNSPs also provide a range of supplementary services. These include customer funded connections, disconnections, emergency recoverable works, various metering services, inspection services, public lighting, energising/de–energising networks and other customer–specific services. Some DNSPs have also previously set up related businesses such as the supply of cable data services. The regulatory treatment of these 'non–core' activities has varied widely across the state and territories and legacy arrangements continue to impact current regulatory determinations.

In undertaking DSNP determinations, the AER first classifies services according to whether they are distribution services or non–distribution services. Distribution services are then classified according to whether they are direct control services, negotiated services or unclassified services. A negotiating framework is specified for negotiated services which are then subject to a negotiate/arbitrate form of regulation under the distribution determination. Unclassified services are not covered by the distribution determination.

Direct control services are then further split into standard control services and alternative control services. Standard control services are generally subject to price or revenue cap forms of control using a building blocks–based determination. Alternative control services are subject to similar forms of control but the determination need not be building blocks–based.

AER (2011) notes that it has proven useful in recent determinations to group distribution services according to the following seven service groups:

- network services
- connection services
- metering services
- public lighting services
- fee–based services

- quoted services, and
- unregulated services.

While network services or core 'poles and wires' activities are classed as standard control services in all states and territories, the diverse treatment of the other six 'non–core' activities is illustrated in table 1 where the classification of customer–funded connections and customer–specific services is compared across the six jurisdictions in the NEM. Customer–funded connections range from being standard control services in Victoria and the ACT to being unregulated in NSW while customer–specific services range from being standard control services in the ACT to being unregulated in NSW.

Table 1: **Comparison of regulatory classification of customer–funded connections and customer–specific services**

	Customer funded connections		Customer specific services	
	Activity description	**Classification**	**Activity description**	**Classification**
NSW service	Design and construction of new connection assets; design and construction of customer-funded network augmentations	Unregulated	Services requested by the customer which includes: asset relocation works; conversion to aerial bundled cable; temporary, stand-by, reserve or duplicate supplies, other customer-requested services which are non-standard	Unregulated
ACT equivalent service	Customer initiated replacements and relocations.	Standard control	Miscellaneous services	Standard control
QLD equivalent service	Design and construction of large customer connections	Alternative control	Services provided on a quoted service basis	Alternative control services
VIC equivalent service	New connections requiring augmentation works	Standard control	Services provided on a quoted service basis	Alternative control services
SA equivalent service	The provision of connections to the extent that a distribution network user is required to make a financial contribution in accordance with the Electricity Distribution Code.	Negotiated services	Non-standard and customer requested services	Negotiated services
TAS equivalent service	Where capital contributions are made by customers. That is, the customer contributes upfront to the cost of connection services.		Aurora (TAS DNSP) provides a range of non-standard services on a quoted service basis.	Alternative control

Source: AER (2011, p.13)

For economic benchmarking purposes we ideally need a common coverage of activities and, importantly, costs across all DNSPs. Given the current wide range of regulatory treatments of non–core activities, common coverage could be achieved by going with either a wide definition of included activities for economic benchmarking purposes or a narrow definition.

While going with a wider coverage (eg the first six service groups identified above) may be more consistent with the overall functions a distribution network is expected to perform, it is unlikely to be practical given that it would need to include reporting on activities beyond those currently classified as standard control services, some of which are likely to be supplied by an entity or entities other than the DNSP in some jurisdictions.

The most practical way forward is to adopt a narrow definition which includes only the network services group from the list above. This has the advantages of covering the core 'poles and wires' activity and only requiring data from the DNSP itself on standard control services. However, it will require DNSPs which have parts of the second to fifth service groups listed above classed as standard control services to exclude those activities (the sixth and seventh items in the list are not generally part of standard control services). That is, connection services, metering and public lighting, in particular, will need to be excluded from reported data using the relevant ring fencing arrangements (see AER 2012b). It will be important to ensure relevant ring fencing arrangements are adhered to so that NSPs are not provided with the opportunity to shift costs to unbenchmarked services in order to appear more efficient than they otherwise could be.

3.7 Short listed DNSP outputs and output specifications

Based on the analysis above and feedback received to date, Economic Insights recommends that the following short list be considered for use as DNSP outputs in economic benchmarking studies:

- customer numbers (total or by broad class or by location)
- system capacity (taking account of both transformer and line/cable capacity)
- smoothed non–coincident system peak demand
- reliability (total customer minutes off–supply and/or total customer interruptions)
- contracted reserved and charged for capacity (from large industrial customers), and
- throughput (total or by broad customer class or by location).

More specific definitions of the short listed outputs are provided in appendix A.

While a case can be made for the inclusion of additional output components, most economic benchmarking techniques are limited on practical implementation grounds to a relatively small number of outputs and so the most important ones have to be prioritised for inclusion. Consequently, most studies would use a subset of the output variables on the short list. System capacity and non–coincident peak demand would generally be used as alternatives rather than both being included as outputs. At this stage we have opted not to include the contracted reserved and charged for capacity variable as it is considered of lower priority in a functional output specification.

In table 2 we propose three DNSP output specifications for initial economic benchmarking analysis. The first specification includes four outputs: customer numbers, system capacity, throughput and reliability (duration of customer interruptions). The output values and, hence, weights for the first three outputs are derived using one (or more) of the methods outlined above – econometric cost function estimates, results of previous studies or estimates obtained form DNSPs. The output value and weight of the reliability output is derived as the negative of the product of total customer minutes interrupted and the distribution STPIS value of consumer reliability per customer minute.

Table 2: **Short listed DNSP output specifications**

Quantity	Value	Price
Specification 1		
Customers (No)	Revenue * Cost share	Value / Customers
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Throughput (GWh)	Revenue * Cost share	Value / GWh
Interruptions (Customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Specification 2		
Customers (No)	Revenue * Cost share	Value / Customers
Smoothed non–coincident peak demand (MVA)	Revenue * Cost share	Value / MVA
Throughput (GWh)	Revenue * Cost share	Value / GWh
Interruptions (Customer mins)	–1 * Customer mins * VCR per minute	–1 * VCR per customer minute[1]
Specification 3		
Residential Customers (No)	Revenue * Cost share	Value / Res Customers
Commercial Customers (No)	Revenue * Cost share	Value / Comm Customers
Sml Industrial Customers (No)	Revenue * Cost share	Value / Sml Ind Customers
Lge Industrial Customers (No)	Revenue * Cost share	Value / Lge Ind Customers
Interruptions (Customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]

[1] VCR per customer minute will vary by DNSP depending on the DNSP's energy deliveries

The prices of the first three outputs are derived by dividing the respective output value by its quantity. Following Pittman (1983), the price of outages (being a 'bad' output) is the negative of the VCR per minute.

This specification has the advantage of incorporating all the major functional outputs DNSPs supply using robust data that does not require supplementary adjustment. Many industry and academic analysts have noted that the DNSP's primary function is to provide the capacity necessary to meet demand at minimum cost. The capacity output is captured by the system capacity variable. Fixed components of DNSP output (such as providing access for each customer) are captured by the customer numbers output. While throughput has a small direct impact on DNSP costs, it reflects the main output of value to customers and maintains consistency with earlier economic benchmarking studies, nearly all of which have included throughput as an output. And the customer interruptions output captures reliability performance which is important to customers. Treating interruptions as an undesirable output allows it to be readily incorporated with a negative price and, hence, negative weight.

This specification also has the advantage of being able to draw on econometric estimates of output weights from previous studies that have included the first three outputs. And the negative share of the reliability output can be readily formed from information already used in the incentive component of building blocks. Further disaggregation of the customer numbers output could also be considered subject to being able to obtain reasonable estimates of the disaggregated output weights.

As noted above, a potential disadvantage with the first specification is that it does not distinguish between DNSPs which provide sufficient capacity to meet customer demands from those which have provided excess capacity. The second specification in table 2 attempts to address this issue by including smoothed non–coincident maximum demand instead of system capacity. The smoothed maximum demand variable is then used as a proxy for the system capacity required. Smoothing is required to remove the volatility associated with actual peak demand in response to variability in annual climatic and other conditions. However, the smoothing of actual non–coincident maximum demand necessary for it to be used as a proxy for system capacity introduces a degree of non–uniqueness as a range of smoothing methods could be used, all producing somewhat different results. Even a smoothed series may not adequately recognise constraints on a DNSP's ability to adjust its system capacity given the long–lived nature of its capital inputs and its capital intensity. This specification also takes no account of differences in customer density across included DNSPs which would have to be included as a separate operating environment factor.

Given that system capacity and peak demand both have some limitations as outputs, the third specification in table 2 includes customer numbers disaggregated by customer type (residential, commercial, small industrial and large industrial) and reliability as outputs. Together these variables could measure the DNSP's success in providing adequate capacity to meet customer needs. Like the second specification, this specification also takes no account of differences in customer density across included DNSPs which would have to be included as a separate operating environment factor.

4 TNSP OUTPUTS

Much of the material covered in section 3 relating to DNSP outputs also applies to TNSP outputs and will not be repeated in this section. For example, there has been universal agreement among stakeholders that TNSP output coverage should be on a functional rather than a billed basis. And the methods for forming output weights and including reliability outputs would be similar for both DNSPs and TNSPs.

4.1 Direct functional outputs versus secondary deliverables

While there was general agreement that outputs should be included on a functional rather than billed basis, another issue that needs to be considered is whether the functional outputs for TNSPs should be measured in terms of direct customer experience or whether ‘secondary deliverables’ (ie capacity required to deliver outputs now and in the future) should be used as a measure of TNSP outputs for economic benchmarking purposes. This is because TNSPs have very few outages and must meet strict system security standards. They are also somewhat removed from the final interface with end–consumers. Given the critical role of transmission in the overall electricity supply chain, perhaps what should be measured is the efficiency of TNSPs in delivering required system security as opposed to their direct impact on customers. The counter argument is that customers might not care about system security directly, and rather are only concerned with the actual service they receive. It could be argued TNSPs should be afforded the flexibility to make investment decisions and should be benchmarked on how these decisions ultimately affect customers. But there is also a risk that, should system security be benchmarked, TNSPs might be provided with an incentive to gold plate their networks. In the case of TNSPs, we believe it is important to consider some secondary deliverables, particularly in regard to leading indicators of likely future reliability.

It is also important to distinguish between outputs and operating environment variables as both will directly affect TNSP costs. Under most economic benchmarking applications a price and quantity are required for outputs but only a quantity is generally needed for operating environment variables. The distinction we draw between outputs and operating environment variables is that outputs reflect services directly (or indirectly in the case of secondary deliverables) provided to customers whereas operating environment variables do not. For example, the delivery of electricity to customers can be considered an output whereas weather effects, which can have a significant impact on NSP operations, are not an output as weather effects are not a service provided to customers.

4.2 Criteria for selecting TNSP outputs

Given that the outputs to be included in economic benchmarking for building blocks expenditure assessments will need to be chosen on a functional basis, we need to specify criteria to guide the selection of outputs.

The AER (2012a, p.74) proposed the following criteria for selecting outputs to be included in economic benchmarking:

1) the output aligns with the NEL and NER objectives
2) the output reflects services provided to customers, and
3) the output is significant.

The first selection criterion states that economic benchmarking outputs should reflect the deliverables the AER expects in setting the revenue requirement which are, in turn, those the AER believes are necessary to achieve the expenditure objectives specified in the NER. The NER expenditure objectives for both opex and capex are:

- meet or manage the expected demand for prescribed transmission services
- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services
- maintain the quality, reliability and security of supply of prescribed transmission services, and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

If the outputs included in economic benchmarking are consistent with those the TNSPs are financially supported to deliver then economic benchmarking can help ensure the expenditure objectives are met at an efficient cost.

The second selection criterion is intended to ensure the outputs included reflect services provided directly to customers rather than activities undertaken by the TNSP which do not directly affect what the customer receives. If activities undertaken by the TNSP but which do not directly affect what customers receive are included as outputs in economic benchmarking, then there is a risk the TNSP would have an incentive to oversupply those activities and not concentrate sufficiently on meeting customers' needs at an efficient cost. However, as noted above, given the characteristics of transmission and its critical role in the electricity supply chain, there may be a case for including as outputs in economic benchmarking secondary deliverables which are not directly provided to customers. If this route is taken then the second criterion becomes less relevant.

The third selection criterion requires that only significant outputs be included. TNSP costs are dominated by a few key outputs and only those key services should be included to keep the analysis manageable and to be consistent with the high level nature of economic benchmarking.

Stakeholders generally agreed that the proposed selection criteria were reasonable during the consultation process.

4.3 Billed outputs

TNSPs usually charge for transmission services on three broad bases:

- throughput charges which reflect the volume of energy passing through the transmission system
- fixed charges which have to be paid by the user regardless of energy throughput, and

- demand–based charges.

Most users pay some combination of these three types of charges.

TNSP charges are also generally disaggregated into four categories (Transgrid 2010, p.5):

- prescribed entry services which are provided by assets that are directly attributable to serving a generator, or group of generators, at a single connection point
- prescribed exit services which are provided by assets that are directly attributable to serving a transmission customer, or group of transmission customers, at a single connection point
- prescribed transmission use of system (TUOS) services which are provided by assets that are shared to a greater or lesser extent by all users, and
- prescribed common transmission services, which are services that benefit all transmission customers and cannot be reasonably allocated on a locational basis.

Energy throughput

Energy throughput is the TNSP service directly consumed by end–customers. However, the case for including energy throughput in economic benchmarking studies is somewhat more arguable. This is because, provided there is sufficient capacity to meet current throughput levels, changes in throughput are likely to have at best a marginal impact on the costs TNSPs face.

Considering energy throughput against the output selection criteria, it scores well against the second criterion in that it is the service which end–customers see directly. However, it is less clear that it is important with regard to the first criterion of the TNSP meeting or managing expected demand as this is more influenced by peak demand rather than throughput. And, while energy throughput is significant to some TNSPs in terms of revenue, it is unlikely to be directly significant in terms of costs.

Despite the case for including energy throughput as an output in the current context being arguable, we believe it should be included in initial output specifications although it would be expected to receive a relatively low weight. Sensitivity analysis should then be undertaken of the effects of including or excluding it. As was the case for DNSPs, maintaining some similarity in output coverage to earlier NSP studies provides a means of cross checking results. And, throughput data are likely to be the most robust for backcasting purposes. Throughput data would need to be collected in aggregate, for peak times and off–peak times and by type of user (eg distribution network, other connected transmission networks and directly connected end–users) as well as for those users paying throughput–based charges.

Entry and exit point numbers

Some TNSPs impose fixed charges for users at both entry and exit points from the transmission network. These charges are related to activities the TNSP has to undertake regardless of the level of energy throughput which include the establishment of the connection point itself as well as, for example, metering services and connection related capacity. They can be imposed on generators (upstream users) and downstream users including distribution networks, other connected transmission networks and directly connected end–users. Going back to the road analogy, the TNSP will need to provide and maintain entry and exit ramps to the freeway, regardless of the amount of traffic on the freeway. In economic benchmarking studies, the quantity of these functions could be proxied by the number of TNSP entry and exit points.

Considering entry and exit point numbers against the output selection criteria, entry and exit point numbers are one indicator of the requirement for transmission services and provide a proxy for the services the TNSP has to provide at connection points. This is a necessary part of maintaining the quality, reliability and security of supply of both transmission services and the transmission system itself. They do reflect services directly provided to users of the transmission network but may not be a good measure of services provided to end–customers. They could reflect services that can be a significant part of TNSP costs. The entry and exit point numbers output, therefore, scores well against the first and third selection criteria but less so against the second criterion. We believe this output should be considered for inclusion in economic benchmarking studies, possibly adjusted for voltage, as it is a billed item for some TNSPs and may be an important secondary deliverable. Data on entry and exit point numbers should be assembled and sensitivity analysis undertaken to determine the effect of using different output specifications on economic benchmarking results. Initial data collection is focused on collecting entry and exit point numbers by broad capacity class of the connection.

Demand–based outputs

Most TNSPs impose some demand–based charges – usually on a kilowatt (kW) of contracted and/or measured maximum demand per month basis.

This output scores well against the three selection criteria as it relates directly to the TNSP's ability to manage expected demand and maintain the quality, reliability and security of supply and the transmission system itself. It also reflects an important service provided to end–customers and will be significant for most TNSPs in terms of costs.

While not commonly reported in current regulatory data sets, this information should be relatively straightforward for TNSPs to provide as it will be an important component of their charging mechanism for demand tariff customers. The productivity study Economic Insights (2012a) undertook for the Victorian gas distribution businesses includes equivalent measures for gas distribution.

4.4 Other functional outputs

In addition to the three billed outputs discussed above, there are a number of other potential functional outputs which are likely to be of particular importance for economic benchmarking of TNSPs in a building blocks context. These include system capacity, peak demand and reliability.

Network capacity, peak demand and throughput

There was considerable discussion at the second workshop on how the output of a TNSP could be best represented and measured and whether it was more appropriate to include system capacity or peak demand as the primary functional output TNSPs supply. Grid Australia (2013, p.21) suggested the outputs of transmission network are best described as follows:

> 'Transmission networks provide capacity, to a level of reliability, in compliance with National Electricity Rule requirements, jurisdictional requirements and other regulatory obligations.'

It went on to note that the requirements on TNSPs under the NER include:

- requirements around stability, voltage unbalance, fault level tolerance and other aspects of the technical envelope of networks
- requirements relating to connections, such as the connection of new load and generation
- references throughout the Rules requiring functions to be performed in accordance with good electricity industry practice, and
- investment drivers considered under the Regulatory Investment Test – Transmission, which include both reliability and market benefits.

Economic Insights (2013b) noted that NSP representatives had previously likened an NSP's role to the provision of a road network. The road network operator has to make sure roads go to appropriate places and have sufficient capacity to meet peak demands but the road operator has little control over the volume of traffic on the road, either in total or at any particular time. The implication of this analogy is that it is then appropriate to measure the NSP's performance by the availability of its network and the condition in which it has maintained it rather than by the throughput of the network (ie the volume of traffic using the road, either in total or at a particular time).

Grid Australia (2013, p.21) noted that it 'agrees with the analogy in the Economic Insights paper that transmission networks provide outputs similar to roads, in the sense of capacity and entry and exit points'.

A criticism, however, of including system capacity as a functional output is that it does not distinguish between those TNSPs who have provided sufficient system capacity to meet forecast or actual peak demands and other requirements and those who have provided excess capacity. Further, its use may create an incentive to overestimate future capacity needs and thus to provide excess capacity in the future. There was some discussion at the workshop of whether the use of peak demand was a better measure of the load a TNSP has to be able to accommodate and whether it was an appropriate proxy for required system capacity. Economic Insights (2013b, p.11) noted that system peak demand tends to be somewhat volatile over time due to the influence of variable climatic conditions and other factors outside network control. If peak demand were to be included as an output, it may be more appropriate to include either a smoothed series or a 'ratcheted' variable that reduced the effect of such volatility. Given the prospect of decreases in energy usage and peak demands, a smoothed and possibly weather corrected series is likely to be more appropriate than a ratcheted series. For similar reasons, a number of NSP representatives at the first workshop suggested that the forecast peak demand series that the NSP's previous price determination had been based on was a more appropriate peak demand series than actual peak demand.

Grid Australia (2013, p.22) disagreed with the use of both peak demand and throughput as follows:

> 'Neither energy nor peak demand are outputs of a transmission network, or (for the most part) within the control of TNSPs. Rather, they are determined through the interaction between generators and consumers (via retailers) determining supply and demand in the electricity market. Therefore, Grid Australia does not support their inclusion as outputs for benchmarking purposes.'

Economic Insights agrees that actual peak demand is a poor indicator of the load capacity an efficient TNSP is required to provide as the TNSP is expected to provide a margin above actual peak demand to allow for unusual circumstances and this capacity will not vary in response to short run peak demand volatility. Further, due to its volatility, using actual peak demand would likely lead to inappropriate volatility in efficiency results. A high degree of smoothing of actual or weather corrected peak demand would overcome the volatility problem while also giving a more accurate indication of required capacity. Ideally the probability of exceedance would also be taken into account in forming the smoothed series.

While forecast non–coincident maximum demand from the most recent regulatory determination may provide an indication of the loads the TNSP was expected to be able to meet and which were built into the building blocks revenue requirement, it also has some limitations. Once the building blocks allowance is set, TNSPs are expected to respond to the incentive to be efficient and this may include responding to revised demand forecasts. Furthermore, using forecast peak demand from the determination may provide an incentive for TNSPs to over–inflate forecasts in future reviews.

Maximum demands will provide an indication of the transformer capacity required by the TNSP, all else equal. They do not distinguish between the amount of lines required by two TNSPs who may have similar forecast maximum demands but one of which transmits power between generation centres and load centres in close proximity and the other of which transmits between dispersed generation and load centres. One would expect the TNSP with more dispersed generation and load centres to require a higher length of line to deliver the same forecast maximum demand. This will require that TNSP to use more inputs to deliver the same forecast maximum demand and, hence, make it appear less efficient unless it either gets some credit on the output side for its greater line length requirement or, alternatively, distance between generation and load centres is included as an operating environment factor.

Including system capacity as an output provides one means of recognising lines as well as transformer requirements. For example, Economic Insights (2009b) included a broader measure of electricity distribution system capacity that recognised the role of lines as well as transformers (for DNSPs). This was the simple product of the installed distribution transformer kVA capacity of the last level of transformation to the utilisation voltage and the totalled mains circuit length (inclusive of all voltages but excluding services, streetlighting and communications lengths). The advantage of including such a measure is that it recognises the key dimensions of overall effective system capacity. It also reflects actual capacity available rather than a forecast capacity requirement that may or may not be met. And it does not have the volatility beyond the TNSP's control which is a problem with the actual peak demand measure. A comparable simple measure of approximate system capacity as the product of circuit length and downstream level transformer capacity could be readily implemented for TNSPs.

Grid Australia (2013, pp.22–3) supported the use of system capacity as a TNSP output but observed the following:

> 'System capacity is an appropriate output variable, as it reflects the service provided by TNSPs.
>
> 'The capacity output should include transformer capacity as well as line and cable capacity. A simple product based on bulk supply point capacity is unlikely to be a suitable summary measure, as it does not take into account inter–regional and intra–regional power transfers that utilise the transmission network.'

Economic Insights recognises that the simple product of TNSP line length and the sum of terminal point and directly–connected end–user transformer capacity is a relatively basic system capacity measure which may not fully capture the complexities of TNSP functions. In particular, interconnectors will need to be recognised as another source of demand and their capacity included in the simple measure. We are of the view that such an expanded product measure represents a useful starting point for subsequently developing more sophisticated measures of system capacity for use in economic benchmarking of TNSPs.

Considering the system capacity output against the three selection criteria, system capacity is clearly required to meet expected demand for transmission services and to maintain the quality, reliability and security of supply and the transmission system itself. It is also a significant part of TNSP costs. However, while it reflects a service provided to customers, it may not be the ideal measure since it will not distinguish between TNSPs who have provided adequate capacity to meet demands from those who have overinvested in system capacity. Despite these limitations, we consider system capacity to be an important variable to be considered in economic benchmarking. It is one that is readily measurable from robust data in TNSP data systems.

While including peak demand as an output may be consistent with meeting demand for transmission services as set out in the expenditure objectives, managing peak demand will likely require the use of time–of–use pricing and other demand management methods. With regard to the second selection criterion, system peak demand does potentially reflect a service provided to customers but the provision of a high level of reliability at all times – and particularly peak periods when the costs to customers of outages will be highest – will be what individual customers observe and are most interested in receiving.

There are, thus, arguments for and against including system capacity versus smoothed maximum demand as a functional output. On balance, we are of the view that both measures warrant further investigation and sensitivity analysis should be undertaken. System capacity taking in both line length and transformer capacity is likely to be the best option in the short term as it requires a minimal number of observations to implement. Once sufficient data observations become available inclusion of smoothed maximum demand should be investigated, along with more sophisticated measures of TNSP system capacity.

Most workshop participants noted that changes in throughput are not a significant cost driver for TNSPs and, hence, throughput should not be considered a significant output. However, others noted that because throughput is what customers see directly and pay for, it should not be ignored. We also note that throughput has been included as an output in nearly all previous network economic benchmarking studies (see AER 2012a, p.77).

Given that throughput is what customers consume directly, the relative robustness of throughput data and its inclusion in nearly all previous economic benchmarking studies, we recommend that throughput still be considered for inclusion as an output, although it is likely to receive a relatively small weight in light of its small impact on network costs.

Reliability

There was general agreement amongst stakeholders that reliability should, if possible, be included as a TNSP output.

Grid Australia (2013, p.23) noted:

> 'Grid Australia strongly supports the inclusion of reliability as a key output as it is a material driver of expenditure on transmission networks. Grid Australia acknowledges the issues associated with developing a measure for reliability and would be willing to assist in further consideration of this.'

In addition, reliability should be included to ensure TNSPs do not improve their measured efficiency performance by neglecting network maintenance and other initiatives important to maintaining and, where appropriate, further improving reliability levels.

Transmission system reliability is a key component of ensuring a reliable supply of electricity to end–users. Transmission networks are inherently reliable and generally include significant built–in redundancy. Interruptions to supply to end–consumers are relatively rare and generally only occur when there are multiple and significant concurrent events. However, given the interlinked nature of the electricity supply system, transmission line outages can have significant effects on end–customers both directly and indirectly. Even if the loss of supply through a transmission line does not lead to interruptions to end–customers, it can still have a significant impact on the market spot price for electricity in the wholesale market. This is because the market operator will immediately reconfigure the overall supply network and generation sources to get the system back to as close to an *n–1* level of redundancy as possible. This will likely involve having to constrain some generation sources' output while requiring additional higher cost generation from other generators who are not facing network congestion constraints.

Transmission network circuit availability is thus critical to ensuring not only the reliability of supply to end–customers but also to the efficient operation of the market and minimising spikes in the spot price for power. However, to ensure that the transmission system plays its role in ensuring efficient market operation, it is important for TNSPs to maximise circuit availability where and when it is most needed. Thus, it is not just a matter of the TNSP maximising its overall circuit availability but doing so in the locations and at the times which will minimise flow-on effects occurring in the wholesale market.

Given the importance of these aspects of TNSP performance to overall market operation, and the fact that these aspects of TNSP service provision are not explicitly charged for, the AER has spent considerable time developing and refining the TNSP Service Target Performance Incentive Scheme (STPIS). AER (2012c) presents the current and fourth iteration of the STPIS. The variables contained in the STPIS should thus be examined for their suitability as potential functional output variables to include in economic benchmarking of TNSPs.

The STPIS now contains three broad components covering service, market impact and network capability. The service component is intended to incentivise TNSPs to reduce the occurrence of unplanned outages and includes four sub–components (for all regulated TNSPs other than the point to point Directlink and Murray link): average circuit outage rate, loss of supply event frequency, average outage duration and proper operation of equipment.

The second broad component of the STPIS, that relating to market impact, measures the number of dispatch intervals where an outage on the TNSP's network results in a network outage constraint with a marginal value greater than $10/MWh. It is intended to provide an incentive to TNSPs to reduce the impact of planned and unplanned outages on wholesale market outcomes. TNSPs do so by reducing the length of planned outages and scheduling outages to occur during those times when there will be the least impact on the wholesale market. TNSPs are also incentivised to improve reliability on those elements of the network critical to the wholesale market to reduce the incidence of unplanned outages. This variable focuses TNSPs on avoiding those outages which cause the greatest overall costs to end–customers.

The third broad component of the STPIS relates to network capability and is intended to encourage TNSPs to deliver benefits through increased network capability, availability or reliability through the development of one–off projects that can be delivered by relatively low cost additions to operational and capital expenditure. The TNSP is rewarded if it completes agreed small projects which are prioritised according to their potential benefits for customers or impact on wholesale market outcomes.

There was some concern expressed at the second workshop that basing the reliability output heavily on the current STPIS parameters may not be appropriate as they are geared to time–series rather than cross–sectional comparisons. Grid Australia (2013, p.23) noted:

> 'the STPIS was specifically designed to provide incentives for TNSPs to continuously improve or maintain performance against their own historical performance in relation to operational measures (rather than capital investment). The parameters are therefore well defined for providing incentives to each TNSP but are not suited to comparison between TNSPs. For example, each TNSP has different thresholds for loss of supply events, in order to set meaningful targets given the different inherent performance characteristics of each network. Also, the market impact component counts dispatch intervals with a market impact of outages, but does not seek to normalise this for factors outside a TNSP's control such as market participant behaviour ...'

Economic Insights notes that the market impact component treats any constraint having a marginal impact greater than $10/MWh with the same weight to explicitly recognise participant behaviour. However, using the market impact component of the STPIS for economic benchmarking purposes may be problematic since it specifies a threshold change in the price level where the price level will be influenced by a range of factors, not all of which are under TNSP control, and whose severity will vary according to time and location.

We note that the definitions of loss of supply events do vary across TNSPs according to their inherent performance characteristics, although the major differences are between what constitutes a 'small' event and a 'large' event rather than the threshold for what constitutes an event. This means the loss of supply event indicator already includes some allowance for operating environment differences. We consider use of the variable to be a worthwhile starting point for economic benchmarking purposes pending further refinement and co–ordination with included operating environment factors.

Economic Insights (2013b) noted that the loss of supply frequency and average outage duration indicators both reflect the TNSP's success in meeting and managing expected demand and maintaining the quality, reliability and security of both transmission services and the transmission system. They also reflect the quality of the service provided to network users and the cost of improving this dimension of performance can be quite significant.

The loss of supply event frequency indicator measures the number of unplanned outages when there has been a loss of supply. This is further broken down into small events and large events. It is designed to encourage TNSPs to reduce response times to small and medium customer interruptions and to reduce the number of interruptions to large customers.

The average outage duration measures the average length of unplanned outages where a loss of supply to customers has occurred. It is intended to focus the TNSP on those unplanned outages with the greatest impact on customers. As was the case with DNSP reliability measures, we propose to include total outage duration as the output rather than average outage duration as normalisation of the indicator is not required for economic benchmarking.

Economic Insights (2013b, p.13) also noted that average circuit outage rate and the proper operation of equipment measures were important indicators of 'secondary deliverables'. That is, they provide useful information on the TNSP's ability to meet and manage expected demand and maintain the quality, reliability and security of both transmission services and the transmission system. However, they are not a service directly provided to end–customers but rather lead indicators of potential unreliability.

Grid Australia (2013, p.22) stated the following with regard to secondary deliverables:

> 'Outputs described by Economic Insights as 'secondary deliverables', such as system security, are required under the National Electricity Rules and to uphold the National Electricity Objective, and as such should be included as outputs.'

We agree that, in the case of transmission, key secondary deliverables warrant some recognition as outputs for economic benchmarking purposes. We therefore propose to include the average circuit outage rate and the proper operation of equipment measures in the short list of TNSP outputs.

The average circuit outage rate measures the actual number of times defined transmission circuits are unavailable due to unplanned (fault/forced) outages divided by the total number of defined (lines/transformer/reactive) circuits. Again, for economic benchmarking purposes, the total number of unplanned outage events will be used rather than the average per circuit.

The proper operation of equipment sub–component measures the number of incidents where a protection or control system has failed or where there has been incorrect operational isolation of equipment during maintenance. It is intended to be a lead indicator of reliability.

At the fifth workshop a number of stakeholders suggested that simply including TNSP system minutes off supply may provide a simpler option than using the STPIS variables. There was also discussion of how TNSP outages that do not lead to customers losing supply should be valued relative to those that do lead to customers losing supply. While there was agreement that application of a VCR–based price was appropriate for TNSP outages that do lead to customers losing supply, the general view was that this would be too high a price to apply to outages that do not lead to loss of supply. However, there were no suggestions as to how these outages should be priced.

As a practical way forward for economic benchmarking of TNSPs, we recommend adopting the distribution STPIS valuations of end–customer outages (AER 2008b) for TNSP outages that do lead to customers losing supply. For the first approach discussed in section 3.4 of Lawrence (2000) of including interruptions as an undesirable output following the method developed by Pittman (1983), the value of customer outages would enter as the negative weight applied to TNSP interruptions. This process would require an estimate to be made of the number of end–customers that would be affected by an outage for the TNSP.

For the second approach in section 3.4 of including the difference between observed reliability and a benchmark worst acceptable reliability performance, the transformed reliability output would simply be valued according to the distribution STPIS end–customer valuations. Again, this process would require an estimate to be made of the number of end–customers that would be affected by an outage for the TNSP. It would lead to a TNSP with good reliability performance receiving a higher weight for that good performance than a TNSP with bad performance would receive for its performance. That is, the TNSP with good reliability performance would be rewarded by its good performance being associated with more ‘revenue’ in forming the output weight, just as would be the case with any other output.

A priority for future work is the derivation of the appropriate price to apply to TNSP outages that do not lead to customers losing supply. Similarly, an appropriate price is required for the proper operation of equipment indicator. The market price is likely to play a role in pricing outages that do not directly affect end–use customers but, since luck plays a role in these outages having limited impact, a significant discount would have to be applied.

Broader obligations

Some overseas regulators have shown an interest recently in including a much wider range of considerations and obligations in NSP output coverage and assessment. Ofgem (2011), for example, has listed the outcomes it expects network companies to deliver as:

- safety

- limited impact on the environment
- customer satisfaction
- delivery of social obligations.
- non-discriminatory and timely connection, and
- reliability and availability.

Three of these six outcomes (environmental, customer satisfaction and social obligations) represent a considerable broadening of (explicit) expectations on the TNSP (although Ofgem is not including social obligations for TNSPs initially). They are also relatively difficult to measure robustly and objectively. At this stage we do not propose to include these broader objectives as TNSP outputs for inclusion in economic benchmarking studies.

Ofgem also proposes to include a suite of 'secondary deliverables' to ensure any risk to the long–term delivery of the primary outputs is managed. These secondary deliverables are:

- asset risk (asset health, criticality and replacement priorities)
- system unavailability and average circuit unreliability (ACU)
- faults, and
- failures.

The secondary forward–looking deliverables seek to identify and predict aspects of network performance where the effect would fall beyond the normal (short relative to asset life) regulatory period and seek to address the needs of customers in the longer term. In this broader context, Ofgem noted that 'delays in efficient network investment could undermine progress towards the UK's renewable energy targets, inhibit a competitive and efficient market, and threaten security of supply'. The secondary deliverables are thus related to the outputs that TNSPs should deliver to ensure delivery of primary outputs in future periods and are related to activities such as wider reinforcement works.

4.5 Short listed TNSP outputs and output specifications

Based on the discussion above, Economic Insights recommends that the following short list be considered for use as TNSP outputs in economic benchmarking studies:

- measured and smoothed non–coincident terminal maximum demands
- system capacity (taking account of both transformer and line/cable capacity)
- number of entry and exit points, possibly adjusted for voltage levels
- throughput (total or by broad user type or by location)
- number of loss of supply events, and
- aggregate unplanned outage duration.

We also recommend that the two lead indicators or secondary deliverable outputs from the STPIS service component – number of unplanned outage events and number of protection system failure events – also be included in the outputs short list as soon as appropriate prices to apply to these items are developed.

While a case can be made for the inclusion of additional output components, most economic benchmarking techniques are limited on practical implementation grounds to a relatively small number of outputs and so the most important ones have to be prioritised for inclusion. Consequently, most studies would use a subset of the output variables on the short list. System capacity and non–coincident maximum demand would generally be used as alternatives rather than both being included as outputs.

Table 3: **Short listed TNSP output specifications**

Quantity	Value	Price
Specification 1		
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Entry & exit points (No)	Revenue * Cost share	Value / No
Throughput (GWh)	Revenue * Cost share	Value / GWh
Loss of supply events (No)	–1 * Loss of supply events * Average customers affected * VCR per customer interruption	–1 * Average customers affected * VCR per customer interruption[1]
Aggregate unplanned outage duration (customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Specification 2		
Smoothed non–coincident peak demand (MVA)	Revenue * Cost share	Value / MVA
Entry & exit points (No)	Revenue * Cost share	Value / No
Throughput (GWh)	Revenue * Cost share	Value / GWh
Loss of supply events (No)	–1 * Loss of supply events * Average customers affected * VCR per customer interruption	–1 * Average customers affected * VCR per customer interruption[1]
Aggregate unplanned outage duration (customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]

[1] VCR per customer interruption and per minute will vary by TNSP depending on the TNSP's energy deliveries

In table 3 we propose two TNSP output specifications for initial economic benchmarking analysis. The first specification includes five outputs: system capacity, entry and exit points, throughput, loss of supply events and aggregate unplanned outage duration. The output values and, hence, weights for the first three outputs are derived using one (or more) of the methods outlined above – econometric cost function estimates, results of previous studies or estimates obtained from DNSPs. The output value and weight of the two reliability outputs are derived as the negative of the product of the total number of customer interruptions and customer minutes off supply and the distribution STPIS value of consumer reliability per customer interruption and per customer minute, respectively[2].

The prices of the first three outputs are derived by dividing the respective output value by its quantity. Following Pittman (1983), the prices of interruptions and durations (being 'bad' outputs) are the negative of the VCR per interruption and per customer minute, respectively.

This specification has the advantage of incorporating all the major functional outputs TNSPs supply using robust data that does not require supplementary adjustment. Many industry and academic analysts have noted that the TNSP's primary function is to provide the capacity necessary to meet demand at minimum cost. The capacity output is captured by the system capacity variable. Fixed components of TNSP output (such as providing access for each generator and downstream user) are captured by the number of entry and exit points. In future work this could be refined by adjusting for voltage. While throughput has a small direct impact on TNSP costs, it reflects the main output of value to customers. And the loss of supply events and unplanned outage duration outputs capture reliability performance which is important to customers. Treating interruptions and outages as undesirable outputs allows them to be readily incorporated with a negative price and, hence, negative weight.

As noted above, a potential disadvantage with the first specification is that it does not distinguish between TNSPs which provide sufficient capacity to meet customer demands from those which have provided excess capacity. The second specification in table 3 attempts to address this issue by including smoothed non–coincident maximum demand instead of system capacity. The smoothed maximum demand variable is then used as a proxy for the system capacity required. Smoothing is required to remove the volatility associated with actual peak demand in response to variability in annual climatic and other conditions. However, the smoothing of actual non–coincident maximum demand necessary for it to be used as a proxy for system capacity introduces a degree of non–uniqueness as a range of smoothing methods could be used, all producing somewhat different results. Even a smoothed series may not adequately recognise constraints on a TNSP's ability to adjust its system capacity given the long–lived nature of its capital inputs and its capital intensity. The other components of the second specification are the same as in the first specification.

[2] The two reliability variables could be both included or, alternatively, only one of the pair may be included. A final decision on this would need to be made once sensitivity analysis has been undertaken.

5 NSP INPUTS

5.1 Durable versus non–durable inputs

Economic benchmarking examines the efficiency of NSPs in converting inputs into outputs (usually on an annual basis). Such analysis generally requires a quantity measure of each input consumed and its corresponding price (or, alternatively, the cost of its annual input).

Different types of inputs

It is important at the outset to recognise that key inputs have quite different characteristics that require different treatment in economic benchmarking studies. Some inputs are completely consumed within the time period measured. This makes their measurement relatively straightforward as the relevant quantity and cost of these inputs are the amount of those inputs purchased in that year. These inputs include labour, materials and services. But other inputs – generally referred to as capital inputs – are durable and may last several years or, in the case of NSPs, several decades. NSP capital inputs generally include lines, cables and transformers.

Measuring capital input quantities

Capital inputs (or the use of assets) always present one of the major measurement difficulties in economic benchmarking studies. Being durable inputs that are not fully consumed in one time period, their cost has to be allocated over their lifetime and changes in their service capacity allowed for as they (potentially) physically deteriorate over time. Consequently, it is necessary to form estimates of the quantity of capital inputs used in the production process each year – generally known as the flow of capital services. This has to be distinguished from estimates of the quantity of the total stock of capital (which will be capable of providing inputs to annual production over several years or several decades, depending on the assets and their age).

The quantity of input or capital service that is available each year from an asset will depend on the physical depreciation profile of the asset (ie the extent to which the asset's capacity reduces over time due to wear and tear and other forms of deterioration). Some assets have little, if any, physical deterioration over time and their flow of capital services remains relatively constant over their lifetime. These assets are said to have 'one hoss shay' (also known as 'light bulb') physical depreciation characteristics. Other assets deteriorate more over time and are able to provide progressively less capital service flow as they get older. These assets may have:

- geometric physical depreciation profiles (capital services fall sharply from when the asset is first used)
- straight–line physical depreciation profiles (capital services fall by the same amount each year over the asset's lifetime) or,

- hyperbolic depreciation profiles (capital services fall gradually for most of the asset's life but then fall sharply towards the end of the asset's lifetime).

It is important to note here the difference between physical depreciation and the rate of depreciation used in forming the regulated asset base (RAB). The physical depreciation profile reflects changes in the asset's ability to provide annual capital service flow (ie the quantity of annual input provided to the production process). The regulatory depreciation rate, on the other hand, simply allocates the original cost of the asset over its lifetime. Assets with one hoss shay physical depreciation characteristics (ie no or very little annual physical depreciation) will still have annual regulatory (and financial) depreciation as the original cost of the asset is spread over its lifetime. Looking at this another way, the financial value of the one hoss shay asset falls at a constant rate each year (in constant prices) as it can supply its constant capital service flow for one less year going forward.

The capital service flow or quantity of annual input to production from an asset or group of assets cannot be directly observed because we can only observe the quantity of the stock of capital at any point in time. Consequently, it is necessary to use proxy measures of capital service flow. The capital service flow is usually assumed to be proportion to the capital stock (because the capital stock is observable whereas the service flow is not and because a directly proportional relationship appears reasonable).

Physical measures (eg MVA–kilometres of lines or kVA of transformers) are often used as a proxy for capital service flow from assets thought to have one hoss shay physical depreciation profiles. In principle the constant price undepreciated (or gross) capital asset value could also be used to proxy the service flow from an asset with one hoss shay physical characteristics (although it would likely be less accurate than using direct physical quantities). In practice, the constant price depreciated (or net) asset value is sometimes used as a proxy for the capital service flow from an asset. But this generally involves the implicit assumption that the asset's physical depreciation profile is of a form other than one hoss shay (eg geometric).

Since relatively few input components can be incorporated in economic benchmarking studies, it will be necessary to aggregate up the capital service flow from many assets into a small number of aggregate capital service flows (or quantities of annual capital input). What proxy is best used to represent these aggregated capital services will depend on several considerations including:

- the likely physical depreciation profiles of the constituent assets
- the robustness of the data used in forming the proxy – the more accurate the data is and the fewer assumptions that have to be made in deriving the proxy, the better, and
- whether the depreciation profile of the aggregate will mirror that of its constituent components.

Measuring annual capital input costs

Just as the quantity of the annual capital service flow (ie the quantity of capital's contribution to annual production) has to be distinguished from the quantity of the capital stock available, then so does the cost of capital's annual input to production have to be distinguished from the total asset value. When an asset is purchased, it will provide input to the production process over an extended period. Consequently, its cost should be spread over that same period. But in addition to the initial cost of the asset, there is also an opportunity cost of holding the asset each year. This opportunity cost may be offset to some extent if the asset is subject to capital gains (its price increases over time).

The NSP's total asset value will change from year to year based on financial depreciation (which reduces the asset value in the next year) and capex (which increases the asset value in the next year).

The annual cost of holding assets is generally referred to as the annual user cost of capital (AUC). Simple applications of the user cost contain three components:

- depreciation (which spreads the initial cost of the asset over its lifetime)
- plus the opportunity cost (which reflects the return funds used to purchase the asset would have earned had they been invested elsewhere)
- minus capital gains (which reflects increases in the price of the asset).

In building blocks the equivalent concepts are the return of capital (depreciation less inflation allowance) and the return on capital (opportunity cost).

In addition, building blocks reviews implicitly incorporate another important principle, that of ex ante financial capital maintenance (FCM). This means that, at the start of a regulatory period, a regulated business's forecast annual cost of capital is calculated in such a way that its financial capital would be maintained in present value terms. The relevant measure of financial capital is based on the NSP's RAB and the calculation is done using the regulatory weighted average cost of capital (WACC) as the discount rate. This provides the NSP with an incentive to achieve efficiency improvements and thereby improve its returns.

Since the building blocks method involves setting the price cap or, alternatively, the revenue cap for each NSP at the start of the regulatory period, forecasts have to be made of the annual revenue requirement stream over the coming regulatory period and of the quantities of outputs that will be sold over that period. Since the opening RAB for the regulatory period will be (largely) known, the annual revenue requirements for the upcoming regulatory period can be forecast based on forecasts of opex, capex and depreciation based on assumed asset lives. Once the forecasts of annual revenue requirements and output quantities have been made, the P_0 and X factors are set so that the net present value of the forecast operating revenue stream over the upcoming regulatory period is equated with the net present value of the forecast annual revenue requirement stream. Whether financial capital is in fact maintained in practice will, of course, depend on actual outcomes during the regulatory period, including the NSP's efficiency performance.

For economic benchmarking to be used as part of building blocks reviews, it will be important to use annual user costs of capital in economic benchmarking that approximate the way capital costs are calculated in the building blocks review. That is, exogenous user costs based on the WACC should be used which are consistent with ex ante FCM. But there are potentially an infinite number of annual user cost profiles that will satisfy FCM and these could lead to quite different measured efficiency outcomes. Similarly, simply using the

WACC in an exogenous user cost formula will not necessarily ensure FCM (depending on the formula). To reconcile the various components and ensure internal consistency between economic benchmarking results and the building blocks process (to the extent possible given that some NSPs have previously sought accelerated depreciation paths), the annual user cost in economic benchmarking should be calculated in approximately the same way as the corresponding building blocks components (using straight–line depreciation). Its dollar value should then approximate the sum of the corresponding building blocks return of and return on capital components.

The construction of exogenous user costs consistent with building blocks methods is illustrated in the Economic Insights (2010) model for the AEMC which uses a simplified version of the AER's (2008c) post–tax revenue model. Economic Insights (2012a, section 5.6) contains an application of this method to Victorian gas distribution businesses.

Using capex is not appropriate

The discussion above highlights the importance of using measures of the capital services flow as the quantity of capital and the annual user cost of capital as the associated annual input cost of capital in economic benchmarking studies. This allows the appropriate measure of inputs to be formed when comparing outputs produced to inputs used in deriving efficiency results. It is, hence, not appropriate to use capex as an input in its own right in economic benchmarking studies. Capex represents the purchase of new capital assets rather than having direct relevance to the annual use of capital inputs. Capex makes an indirect contribution to the appropriate capital measures by being part of the change in asset value from year to year (along with depreciation) and the new assets will make an additional (usually small) contribution to the overall capital services flow.

While regulators make use of various ratio indicators in assessing the reasonableness of forecast capex (and, in some cases, 'totex' which is the sum of opex and capex), it will not generally be appropriate to use either capex or totex as inputs in economic benchmarking studies. This is because, except under rare circumstances, these measures will approximate neither the service flow from capital inputs (both old and new) nor the annual user cost of capital which are the concepts relevant in measuring economic efficiency.

Capital construction activities are excluded

The focus of economic benchmarking will be on the efficiency of operating and maintaining the network (AER 2012a, pp.64–5). This means that the use of the NSP's own resources associated with the construction of new assets should be excluded from the input coverage. There is a risk otherwise that the cost of new assets will be counted twice – once through the NSP's expenditure on labour, materials and services used in constructing new assets and again when the asset enters the NSP's RAB. In practice, the construction of completely new lines will commonly be contracted out. There are, however, a number of grey areas such as the treatment of pole replacement which could be consider opex or, alternatively, be capitalised into the RAB.

The focus on operating and maintaining the network is again consistent with the building blocks regime where included labour, materials and services costs are only those used as part of operating and maintaining the network (ie opex). Labour, materials and services used in constructing new assets is excluded from opex. Rather, the cost of constructing new assets enters the allowed cost base as part of the RAB. It will, of course, be important that capitalisation policies (ie what is considered construction of a new asset versus what is considered repairs and, hence, part of opex) be as comparable as possible across NSPs. Otherwise, an input for one NSP (such as for a single pole replacement) may be expensed immediately (if treated as opex) versus the same input being treated as capital and the cost recovered in AUC over several years (or decades) for another NSP.

5.2 Distribution cost issues

Distribution cost coverage

As noted in section 3.6, in addition to providing the core ‘poles and wires’ component of distribution networks, DNSPs also provide a range of supplementary services. These include customer funded connections, disconnections, emergency recoverable works, various metering services, inspection services, public lighting, energising/de–energising networks and other customer–specific services. Some DNSPs have also previously set up related businesses such as the supply of cable data services. The regulatory treatment of these ‘non–core’ activities has varied widely across the state and territories and legacy arrangements continue to impact current regulatory determinations.

For economic benchmarking purposes we ideally need a common coverage of activities and, importantly, costs across all DNSPs. Given the current wide range of regulatory treatments of non–core activities, common cost coverage could be achieved by going with either a wide definition of included activities for economic benchmarking purposes or a narrow definition.

The most practical way forward is to adopt a narrow definition which includes only costs associated with the network services group from the list in section 3.6. This has the advantages of covering the core ‘poles and wires’ activity and only requiring data from the DNSP itself on standard control services. However, it will require DNSPs which have parts of the second to fifth service groups listed in section 3.6 classed as standard control services to exclude costs associated with those activities. That is, connection services and metering, in particular, will need to be excluded from reported costs using the relevant ring fencing arrangements (see AER 2012b). Put another way, inputs associated with non–core activities will not be included for economic benchmarking to ensure more like–with–like comparisons.

There was also discussion at the third workshop of whether standardisation of capitalisation policies could be achieved. Capitalisation and cost allocation are both being addressed in detail as part of the current AER category analysis workstream. The approach to these issues adopted for economic benchmarking should be consistent with the approach decided upon in the category analysis workstream.

It was also noted at the first workshop that Victorian DNSPs have to do the planning for transmission connection points whereas this is the responsibility of TNSPs in other states. The materiality of this issue is not clear at this point but it may warrant further consideration.

Distribution network complexity

There was some discussion at the third workshop of the important issue of TNSP/DNSP ‘boundaries’. Economic benchmarking implicitly assumes that all DNSPs have the same system boundary and broad system structure. But some DNSPs take their power at lower voltage from the transmission business and have relatively simple systems while others take their power at higher voltages and may have subtransmission and/or multiple transformation steps. Examples of the former are Tasmania and Victoria while NSW and Queensland are examples of the latter. But output is measured in the same way for all DNSPs, irrespective of their system boundary or structure. The DNSP that has the narrower boundary and simpler structure may appear more efficient, all else equal, as it will likely use less inputs per unit of measured output.

It will typically take longer to achieve improvements in capital efficiency, given the long–lived nature of NSP capital inputs, than it will to achieve opex efficiency improvements. The legacy system structure a DNSP has to work with may therefore have an impact on both its current measured efficiency level and its ability to achieve efficiency improvements over time.

Benchmarking may have a role to play in highlighting the more efficient longer term system structures. But, in the short run, it may be necessary to narrow the range of inputs included in benchmarking of systems with more complex legacy structures to allow more like–with–like comparisons to be made. In section 8 we attempt to disaggregate transformer inputs for those DNSPs with more complex system structures to identify situations where there are two HV transformation steps (eg 132 kV to 66 kV and then 66 kV to 11 kV). Combined with the disaggregation of line lengths into voltage classes, this should provide a basis for conducting sensitivity analysis around different included system structures. In practice there will also be extra opex associated with multiple levels of transformation within a DNSP but we expect this effect to be considerably smaller than the additional capital requirements associated with more complex system structures.

Similar issues also apply to TNSPs with some TNSPs having more internal voltage transformations than others. And, just as a DNSP with ‘narrow’ boundaries may appear to be more efficient, the corresponding TNSP supplying that DNSP will likely appear less efficient than its peers because it has ‘wider’ boundaries. A more like–with–like comparison in these situations might be obtained by comparing the overall efficiency of TNSPs and associated DNSPs combined.

5.3 Criteria for selecting NSP inputs

AER (2012a, p.62) proposed that two broad criteria be included for selecting the input measures to be used in economic benchmarking studies. These were that the input choice be consistent with the National Electricity Law (NEL) and National Electricity Rules (NER) and that it be reflective of the production function. The latter requirement was characterised as ensuring all inputs used by NSPs are included and that inputs should be ‘mutually exclusive and collectively exhaustive’. In other words, there should be no double counting across inputs and no omission of inputs. It was noted that where costs are shared across NSP and other business activities, the share of those costs allocated to the NSP activity should reflect its contribution to the production of NSP outputs.

In light of the discussion in section 5.1, Economic Insights believes there is merit in expanding the selection criteria for the choice of inputs to be used in economic benchmarking to the following:

1) input coverage is comprehensive and non–overlapping
2) measures of capital input quantities are to accurately reflect the quantity of annual capital service flow of assets employed by the NSP
3) capital user costs are to be based on the service provider's regulatory asset base (RAB) and should approximate the sum of the return of and return on capital components used in building blocks, and
4) be consistent with the NEL and NER.

The first selection criterion restates the AER's selection criterion of being reflective of the NSP production function. That is, the choice of inputs should capture all the key inputs used by the NSP in producing its output while ensuring no inputs (such as own construction of capital inputs) are double–counted. It also requires that where costs are shared between NSP and other business activities, costs allocated to the NSP activity should accurately reflect the contribution to production of NSP outputs.

The second selection criterion requires the capital input quantity used in economic benchmarking to accurately reflect the quantity of annual capital service flow of the assets employed by NSPs (that is, the depreciation profile used in forming the capital input quantity needs to be consistent with physical network asset depreciation characteristics). Energy network assets are generally characterised by relatively little decline in their service capacity over their lifetime (provided they are properly maintained). Overestimating the rate of decay in annual capital input service potential would bias efficiency comparison results.

The third selection criterion requires the annual user cost of capital measure used in economic benchmarking to approximate the return of and return on the RAB components used in building blocks regulation calculations (to the extent possible given that some NSPs have previously sought accelerated depreciation paths). The annual user cost of capital can be calculated in many different ways which can produce a wide range of annual user cost profiles over the asset's life while still satisfying underlying desirable properties such as using the WACC and being consistent with ex ante financial capital maintenance. Since we are dealing with assets that generally last several decades, such differences in the profile of annual user costs can lead to material differences in measured efficiency over short periods. This arises because the annual user cost of capital is the weight given to capital inputs relative to opex inputs in economic efficiency calculations. To ensure consistency between economic benchmarking results and building blocks calculations it is desirable for the economic benchmarking analysis to use capital costs calculated in approximately the same way as the corresponding building blocks components. Their dollar value should then approximate the sum of the corresponding building blocks return of and return on capital components.

The fourth selection criterion recognises that the NEL and NER provide a framework for reviewing NSP expenditure. Within this framework the AER must accept regulatory proposals where they reflect the efficient costs of delivering outputs. The input variables for economic benchmarking should therefore enable the AER to measure and assess the relative productive efficiency of NSPs in the National Electricity Market (NEM).

5.4 Opex inputs

Most network economic benchmarking studies have included two broad input categories: opex and capital. Some North American studies have separated opex into separate labour, materials and services components. However, with the increase in contracting out, separate measures of labour input have become increasingly difficult to obtain and potentially unrepresentative. Most Australian network economic benchmarking studies have consequently included just one aggregate opex input component.

Opex satisfies the selection criteria set out in section 5.3 for inclusion as an input component in economic benchmarking studies. Opex covers an important part of NSP inputs and needs to be included for input coverage to be comprehensive. Actions required to ensure opex is not overlapping and is comparable both over time and across NSPs will be discussed below. Opex also plays a significant role in the NER where it is identified as a key input component.

Since opex covers a diverse range of inputs that are consumed in the production process each year, it is generally not practical to measure the quantity of opex by aggregating up the quantities of each individual component of opex input. Instead, the quantity of opex input is generally measured indirectly by deflating the value of opex inputs by a representative input price index. The price index used for deflation will typically be a weighted average of labour and materials and services input price indexes where the weights reflect high level information available on the approximate composition of opex.

Opex inputs coverage

Opex includes all costs of operating and maintaining the network, including inspection, maintenance and repair, vegetation management and emergency response. Depreciation and all capital costs (including those associated with capital construction) should be excluded.

Common coverage of opex activities is highly desirable both over time for each NSP and also across NSPs. It is also important that opex included in economic benchmarking studies reflect only input usage in the relevant year. This may necessitate the removal of accounting–related adjustments from opex reported in regulatory accounts and some degree of adjustment to reflect common coverage over time. For example, Economic Insights (2012a, p.20) noted the following adjustments to Victorian gas distribution business (GDB) data to ensure a greater level of consistency in coverage and to ensure like–with–like comparisons over time:

> 'the opex values supplied by the GDBs were consistent with the GDBs' Regulatory Accounts but the focus has been on ensuring data reflects actual year–to–year operations. A number of accounting adjustments such as allowance for provisions have been excluded as they do not reflect the actual inputs used by the businesses in a particular year which is what we need for TFP purposes. To

> ensure consistency in functional coverage throughout the period, for those years prior to the introduction of FRC [Full Retail Contestability] each GDB's opex is increased by the amount of expenses incurred in the early years of FRC. In these early years FRC was expected to have only affected opex (and not capital) requirements.'

There should ideally be uniform treatment of asset refurbishment in cost reporting over time and also across NSPs where possible. That is, items such as isolated cases of pole replacement or sleeving of poles should be consistently capitalised (or not, as the case may be). Changes in reporting practices over time can give the appearance of improving or worsening opex efficiency when no change in actual efficiency may have in fact occurred. As noted above, the approach adopted for economic benchmarking should be consistent with that being developed in the category analysis workstream.

Similarly, consistent and rigorous allocation of corporate overheads over time is important. Changes in corporate overhead allocation policies across businesses in a 'multi–utility' may otherwise give the false appearance of opex efficiency improvements or deteriorations for NSP operations. Most cost allocation methodologies leave a relatively wide band of justifiable overhead cost allocations across constituent businesses. The important requirement for robust and reliable economic benchmarking results is that the allocation method used remains as consistent as possible over time for each NSP and preferably is as similar as possible across NSPs.

Land tax should be excluded from opex for economic benchmarking purposes because it:

- is largely uncontrollable
- varies significantly between states, and
- the amount can be easily identified and audited.

Opex price index

There was some discussion at the third workshop of whether opex prices facing NSPs vary across different regions of the country and of what were the appropriate price indexes to deflate opex by.

To determine whether opex prices facing NSPs vary across different parts of the country, it would be necessary to undertake a detailed comparison of enterprise bargaining awards (EBAs) for the same types of labour employed by NSPs and to conduct a survey of the prices paid for types of NSP labour not covered by EBAs and of the prices paid for common types of materials and services.

In the absence of solid evidence that differences in opex price levels across NSPs are material, we believe a reasonable starting position for economic benchmarking purposes is to assume that all NSPs face the same level of opex prices. Undertaking the detailed analysis necessary to establish whether there are material differences in opex price levels across NSPs is something that could be investigated once the benchmarking framework is in place. If material differences in price levels are found to exist then allowance for this could be introduced as a future refinement.

Of more immediate priority is determining whether the opex price index that has been used in recent economic benchmarking studies of electricity and gas DNSPs (see Economic Insights 2012a) should also be used for TNSPs. The opex price deflator is made up of a 62 per cent weighting on the Australian Bureau of Statistics' (ABS) Electricity, gas and water sector Labour price index with the balance of the weight being spread across five Producer price indexes (PPIs) covering business, computing, secretarial, legal and accounting, and public relations services. If the break–up of opex between labour, materials and services is materially different for TNSPs compared to DNSPs then there is a case for forming a separate TNSP opex price index reflecting the composition of opex for TNSPs.

There has been considerable debate over the last decade concerning the appropriate measure of labour prices to use for regulatory and economic benchmarking purposes. The two most commonly used measures in Australia to date are Average weekly ordinary time earnings (AWOTE) and the Labour price index (LPI). AWOTE shows average employee earnings from working the standard number of hours per week and includes agreed base rates of pay, over–award payments, penalty rates and other allowances, commissions and retainers, bonuses and incentive payments (including profit share schemes), leave pay and salary payments made to directors. It excludes overtime payments, termination payments and other payments not related to the reference period. It will reflect changes in earnings due to change in the composition of the workforce over time.

The LPI, on the other hand, is a measure of changes in wage and salary costs based on a weighted average of a surveyed basket of jobs. It excludes bonuses and also excludes the impact of changes in the quality or quantity of work performed and compositional effects such as shifts between sectors and within firms. The LPI was discontinued by the Australian Bureau of Statistics (ABS) in 2011 and replaced with a narrower measure known as the Wage price index (WPI).

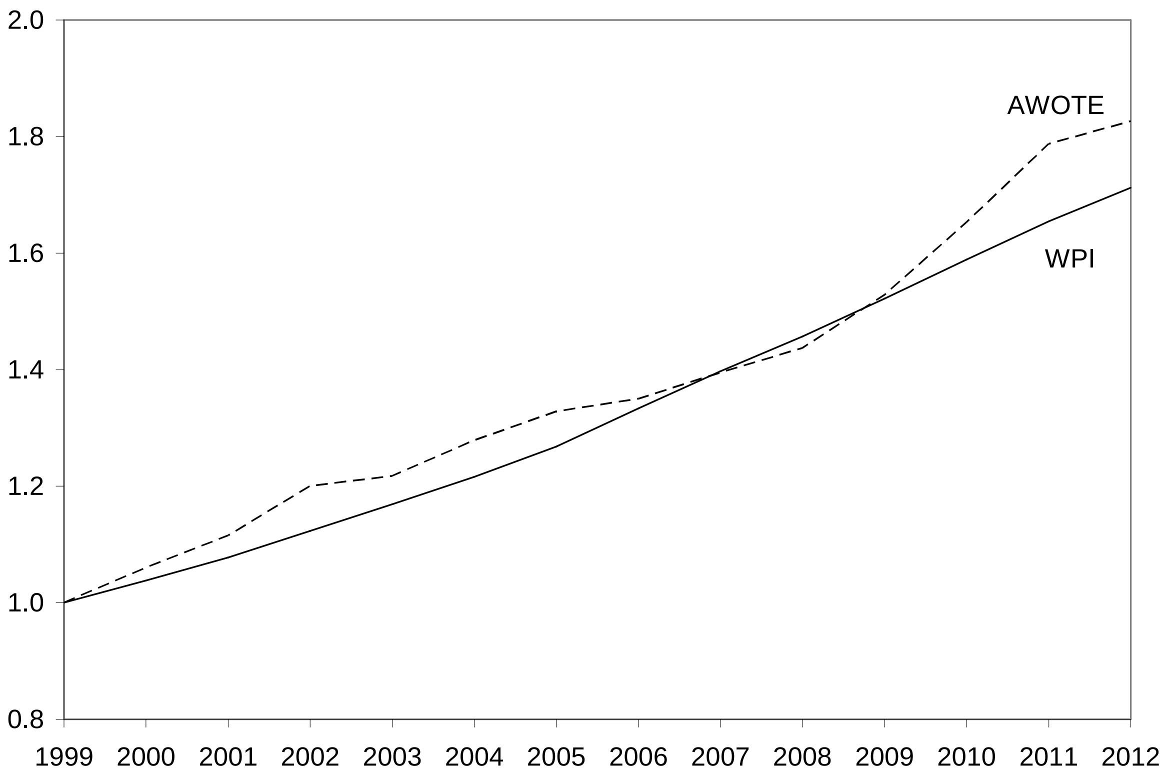
AWOTE and the WPI both have some advantages and disadvantages for efficiency measurement purposes. Whichever index is used, it is important to ensure that that index is used consistently across the different parts of the building blocks framework. In particular, if the opex rate of change approach is used (whereby opex is rolled forward according to the growth rate in opex prices plus the growth rate in output less the growth rate in opex partial productivity), then the same labour index should be used in calculating both the growth rate of opex input prices and the growth rate of opex partial productivity.

AWOTE will reflect compositional changes in the workforce and measures the actual price paid for an ordinary length week of labour input. Using this index to deflate labour costs implicitly assumes that the quality of labour input remains relatively constant over time.

The WPI, on the other hand, attempts to capture the price of a standard work week of labour of a given classification and abstracts from compositional changes in the firm's labour force. In principle, deflating labour costs by the WPI will produce a 'quality adjusted' quantity of labour. That is, it will convert actual hours worked by employees into a number of hours of its 'standard classification' equivalent. If changes in wage rates actually reflect changes in skill levels then deflating labour costs by the WPI produces a quality adjusted quantity series. However, if changes in wage rates and employee classifications actually reflect 'classification creep' resulting from a tight labour market (ie employers promote staff simply to retain them rather than because their skill levels have improved and their responsibilities expanded), then using the WPI will allocate too much of the increase in labour costs to quantity changes and not enough to price changes.

Actual AWOTE data are likely to better reflect labour price pressures in a tight labour market as they pick up the effect of employers prematurely promoting individuals they want to retain and ‘reclassifying’ jobs as a means of paying staff more to prevent them from being poached by other organisations. The actual WPI, on the other hand, may fail to capture these important characteristics of a tight labour market situation in a particular industry as it uses a fixed basket of job classifications that is not updated to reflect changing circumstances and the ongoing dynamics of labour markets.

Figure 1: **EGWW sector WPI and AWOTE labour indexes, 1999–2012**



Source: Economic Insights calculations using ABS 63020010g and 634509a

AWOTE and WPI are presented in index form in figure 1 for the period from 1999 to 2012. The two indexes move in a broadly similar pattern up to 2009, with some relative increase in AWOTE in more buoyant periods followed by a return to similar levels as the WPI in less buoyant periods. However, from 2009 AWOTE diverges markedly from WPI over the three ensuing years. These years coincide with an increased demand for labour from the mining sector as the construction phase of the mining boom gathered pace. NSP field staff have many of the skills sought by the mining and mine construction industries and so the increase in AWOTE relative to WPI over this period likely reflects NSPs paying their staff more and reclassifying them to retain their workforce. Such a large divergence over such a short period is unlikely to reflect actual upskilling of the NSP workforce. Consequently, there is a risk that using the WPI to deflate labour costs over this period would lead to an overestimate of the increase in the quantity of labour employed by NSPs (as the WPI is likely to underestimate wages growth for an employee with constant skills in these unusual labour market conditions). The effect of this would be to underestimate NSP productivity growth over this period. The reverse is likely to be the case when labour markets slacken following the winding down of the mining boom construction phase.

While the use of AWOTE would likely give a more accurate picture of NSP productivity growth in the above example, there are other circumstances where the use of the WPI would likely give a more accurate picture. For example, under more stable economic conditions where NSPs are genuinely upskilling over a prolonged period, the use of AWOTE may lead to an underestimate of the increase in quality adjusted labour input and hence overstate the rate of productivity growth.

For future economic benchmarking applications we believe both the AWOTE and WPI labour price indexes warrant further consideration. Both have some strengths and some weaknesses. It would be appropriate to test the sensitivity of economic benchmarking results to this choice. And it will be important to ensure consistency across relevant parts of the building blocks framework, in particular to ensure the same labour price index is used in the opex price and opex partial productivity components of the opex rate of change approach (when it is used).

5.5 Capital inputs

As discussed in section 5.1, capital inputs (or assets) always present one of the major measurement difficulties in economic benchmarking studies. Being durable inputs that are not fully consumed in one time period, their cost has to be allocated over their lifetime and any changes in their service capacity allowed for as they (potentially) physically deteriorate over time. Consequently, it is necessary to form estimates of the quantity of capital inputs used in the production process each year – generally known as the flow of capital services – and of the annual user cost of capital inputs. How this should be done and some of the relevant issues will be discussed in the following two sections.

Capital inputs satisfy the selection criteria set out in section 5.3 for inclusion as an input component in economic benchmarking studies. Capital inputs make up the major part of NSP inputs and need to be included for input coverage to be comprehensive. Capital inputs also play a significant role in the NER where they are identified as a key input component. The second and third selection criteria relate to how capital inputs should be included in economic benchmarking studies and will be discussed further below.

5.5.1 Measuring capital input quantities

Section 5.1 discussed the primary considerations for how durable inputs should be included in economic benchmarking studies. We noted that the capital service flow or quantity of annual input to production from an asset or group of assets cannot be directly observed. Consequently, it is necessary to use proxy measures of capital service flow. Since relatively few input components can be incorporated in economic benchmarking studies, it will be necessary to aggregate up the capital service flow from many assets into a small number of aggregate capital service flows (or quantities of annual capital inputs). No proxy measure for capital service flow will be perfect and what proxy is best used to represent these aggregated capital services will depend on several considerations including:

- the likely physical depreciation profiles of the constituent assets
- the robustness of the data used in forming the proxy – the more accurate the data is and the fewer assumptions that have to be made in deriving the proxy, the better, and
- whether the depreciation profile of the aggregate will mirror that of its constituent components.

Physical depreciation profiles of individual NSP assets

Energy network industry assets are typically subject to little physical deterioration over their lifetime and continue to supply a relatively steady stream of annual services over their lifetime, provided they are properly maintained. Consequently, their true physical depreciation profile is more likely to reflect the 'one hoss shay' or 'light bulb' assumption than that of either declining balance or straight–line depreciation. That is, they produce roughly the same service for each year of their life up to the end of their specified life rather than producing a given percentage or absolute amount less service every year.

AER (2012a, pp.66–8) discussed some of the issues associated with deriving a proxy for an individual NSP asset capital service flow. The AER acknowledged that assets may have higher failure rates at the start of and at the end of their lives. Early asset failures may occur due to bedding in problems but are likely to be relatively uncommon. Asset failures are more likely towards the end of the asset's life and the uncertainty surrounding timing of final failure is often recognised by use of a Weibull distribution for the asset's expected length of life. However, for most of the asset's life, it is likely to be providing a relatively constant service flow and the AER agreed physical depreciation for individual NSP assets can be approximated by a one hoss shay model.

If it is accepted that the major NSP assets have a physical depreciation profile similar to one hoss shay, then one suitable proxy for the quantity of capital input is the physical quantity of the asset. In the case of energy networks it is feasible to use the physical quantity proxy as there are relatively few asset types and readily available means of aggregating asset capacities (eg Lawrence 2003 and Economic Insights 2009b use MVA–kilometres to separately sum overhead line and underground cable capacities and kVA to sum transformer capacities). Accurate information on asset quantities will be readily available from NSP asset registers.

There are alternative proxies available for one hoss shay physical depreciation profiles, such as the constant price gross capital stock (ie no depreciation is deducted from the asset value), but these are likely to be less accurate (as will be discussed below) than the direct physical quantity proxies.

Some economic benchmarking studies have used capital input quantity proxies that involve physical depreciation profiles other than one hoss shay. These have generally involved using the constant price depreciated asset value as the proxy for capital service flow. For example, geometric physical depreciation profiles result from using simple applications of the perpetual inventory method to form asset values in constant prices.

We are of the view that capital service flow proxies based on physical depreciation profiles other than one hoss shay are unsuitable for the major NSP assets. Economic Insights (2009b, pp.63–4) summarised the situation as follows:

> ‘Suppose an EDB installs 100 MVA–kilometres of line with a 50 year life. In the first year of the asset’s life it will have a service potential of 100 MVA–kilometres. The question is how does this change over time? The one hoss shay approach would say that it remains at 100 MVA–kilometres for the next 49 years. The geometric approach … would say that this progressively declines – in fact relatively rapidly – so that by the 49th year the service potential of the line might only be, say, 2 MVA–kilometres.
>
> ‘While any simple proxy will be an approximation to the true underlying pattern of change in the service potential, those familiar with the operational characteristics of the electricity distribution industry agree that the service potential of the 100 MVA–kilometre line will change little over its lifetime. It may deteriorate to, say, 95 MVA–kilometres towards the end of its life but it will certainly not deteriorate rapidly and end up near zero at the end of its life. The geometric profile … thus has little to recommend it for measuring the productivity of energy distribution industries and the one hoss shay proxy will be far more appropriate.’

If the decay in the annual capital input quantity available to the production process is overestimated (eg by using a proxy for capital service flow that assumes a geometric physical depreciation profile) then the NSP’s efficiency will be correspondingly overestimated and economic benchmarking will be compromised. This is because using, for example, a proxy that assumes geometric physical depreciation will indicate that an NSP with old assets is using little capital input quantity compared to an NSP with new assets of the same rating. The NSP with old assets will then appear to be very efficient compared to the NSP with new assets, all else equal. If the assets actually have one hoss shay (or similar) characteristics then the capital input quantities of the two NSPs will in fact be similar. Because NSP capital inputs are long–lived, this issue assumes particular importance and emphasises the importance of using a capital input quantity proxy that accurately reflects the assets’ relatively one hoss shay characteristics.

Robustness of data considerations

Economic benchmarking needs to accurately reflect the quantity of output produced per unit of the quantity of input used. It is thus critical to have accurate measures of prices and quantities. It is likely to be desirable to use direct quantity measures wherever possible and minimise reliance on ‘indirect’ quantities derived by deflating values by a price index. This is because price indexes are formed at a much more aggregated and broad sectoral level (eg the overall Electricity, gas and water sector) and may not accurately reflect the prices of NSP capital goods.

Infrastructure industry capital goods price indexes from official statistical agency sources are likely to further be prone to small sample problems. Because NSP augmentation projects may be lumpy at times, particularly for TNSPs, it will be hard for statistical agencies to keep up with the costs that NSPs actually face in undertaking larger projects. This will particularly be the case where there is strong competition for key inputs such as construction labour from other rapidly expanding sectors of the economy. Conversely, statistical agency sampling from a small number of projects may produce volatile and unrepresentative price indexes for NSPs as a whole.

A further robustness problem with using asset value–based proxies relates to the quality of the asset value data itself. In Australia NSPs have been subject to economic regulation for a relatively short period compared to the length of life of their assets and there were generally no accurate records of the historic cost of assets available at the commencement of economic regulation. As a result, opening asset values for NSP RABs were generally formed using depreciated optimised replacement cost (DORC). The often subjective and circuitous nature of DORC valuations has been well documented by Johnstone (2003). DORC valuations have proved to be quite contentious and Australasian regulators stopped doing periodic DORC updates, choosing instead to draw a 'line in the sand'. In the case of some NSPs, the initial DORC values were further adjusted, interalia to protect pre–existing cross subsidies between consumers. While the quality of subsequent RAB roll–forward mechanisms has progressively been improved, the absence of a historic cost initial starting value and the relatively subjective nature of DORC–based initial values compromises the efficacy of asset value–based proxies for capital service flows.

Using depreciated asset value–based proxies also assumes that the asset value has been calculated on a consistent basis over time. However, large changes in depreciation allowances, among other things, have occurred over relatively short time periods (see, for example, Economic Insights 2009c, p.17). Simply using observed annual regulatory depreciation rates as the basis of forming the capital input quantity using the depreciated asset value approach could lead to significant distortions in economic benchmarking results.

Being engineering organisations, NSPs keep relatively meticulous records of their stock of physical assets. Additions and deletions of line, cable and transformer capacity are all accurately recorded to the day. The quality of physical asset data has improved even further in recent years with the advent of geographic information systems which pinpoint each asset's exact location and its physical attributes. Physical data are, therefore, very robust and will provide a very accurate representation of asset quantities. If the one hoss shay physical depreciation profile is accepted, then physical data will provide a very robust and direct estimate of capital service flow.

On data robustness grounds direct physical quantity measures are clearly preferable to asset–value based capital service flow proxies. In Australia, indirect asset–value based proxies are doubly compromised by the absence of historic cost initial values and the general need to use much more aggregate level price deflators that may not reflect the asset prices paid by NSPs.

Asset aggregation considerations

AER (2012a, p.68) notes that an argument has been advanced that, while individual NSP assets may all have one hoss shay physical depreciation characteristics, under certain assumptions, the aggregate of many different such assets may not have a one hoss shay physical depreciation profile. An example is quoted from the US Bureau of Economic Analysis that suggested that, under certain assumptions, the aggregate of many one hoss shay assets could even have something approaching a geometric depreciation profile.

The so–called ‘portfolio effect’ quoted in the Bureau of Economic Analysis example depends on there being a large number of firms with a wide spread of asset ages. In the case of the Australian NSPs there are relatively few firms and the age characteristics of the assets are likely to be similar. Indeed, the NSPs have previously highlighted the ‘bunched’ nature of previous network rollouts and the likelihood of an impending ‘wall of wire’ as assets all of similar age require replacement. These characteristics mean that this ‘portfolio effect’ argument in favour of geometric depreciation in aggregate is unlikely to apply in this case.

It needs to be recognised that the US Bureau of Economic Analysis is one of the few government statistical agencies currently using geometric depreciation in forming its aggregate capital stock measures. It should also be noted that the Bureau of Economic Analysis is not the US government agency with primary responsibility for producing official productivity statistics. Rather, this is done by the US Bureau of Labor Statistics.

The Bureau of Labor Statistics has been at the forefront of recognising that aggregate capital service flow measures should be delinked from constant price depreciated asset value measures. The Bureau of Labor Statistics has pioneered the use of ‘productive capital stock’ measures to proxy aggregate capital service flows. These productive capital stock measures make use of asset age–efficiency profiles. The age–efficiency profiles are assumed to be hyperbolic in shape (ie little deterioration in the early stages of the asset’s life but more in the later years).

A key parameter in the hyperbolic age–efficiency profile can be set to influence the degree of curvature. A value of one for this parameter leads to a flat or one hoss shay profile while a value of zero would give equal deterioration each year (ie approximate straight line deterioration). The Bureau of Labor Statistics, the ABS and Statistics New Zealand have all adopted the hyperbolic age–efficiency profile in their productivity studies and set this parameter at 0.5 for equipment and 0.75 for structures. That is, they are assuming closer to one hoss shay deterioration for structures in aggregate. This is the complete opposite of the aggregate geometric deterioration profile used by the Bureau of Economic Analysis and very different to the straight–line profile which would be used in NSP constant price RAB–based proxies. The particular characteristics of NSP assets mean they will be closer again to the one hoss shay end of the spectrum than structures in aggregate.

While the main statistical agencies adopt a practice for calculating aggregate productive capital stocks and service flows which assumes a depreciation profile close to one hoss shay depreciation, the area of aggregation is one that could benefit from further research. At this stage we are not persuaded that aggregation considerations mitigate against the use of physical quantity–based proxies for NSP capital service flows and are of the view that such measures best satisfy the second selection criterion in section 2.2 of accurately reflecting the quantity of annual capital service flow of assets employed by the NSP.

It is desirable to include three capital input categories including: overhead lines; underground cables; and, transformers and other capital[3]. These are the three main types of assets employed by NSPs. Underground cables are generally separated from overhead lines due to their different maintenance characteristics and considerably higher construction cost. The quantity of overhead and underground lines can be measured directly by their delivery capability (eg in MVA–kilometres) while transformers can be measured by their kVA rating. If included as a separate category, the quantity of other capital input usually has to be measured indirectly given its diverse composition and small size. As a result, it has often been combined with transformers because it includes a number of substation components.

Capital input requirements will also depend on the operational boundaries and system structure an NSP faces. For example, DNSPs with wider distribution functional boundaries taking their power at higher voltages and then having multiple stages of transformation will require more capital inputs than DNSPs with narrower functional boundaries and/or simpler systems taking their power at lower voltages and then only requiring one stage of transformation.

Using RAB depreciation as a proxy

AER (2012a, p.71) propose another proxy measure for capital service flows in the form of RAB depreciation. The AER argues that considerable effort is currently invested in compiling RAB data and the depreciation variable may provide potential for constructing a measure of capital service flow as it should, in principle, reflect the quantity of assets in operation each year.

Economic Insights is of the view that this potential measure warrants further investigation. In principle it could produce a series with some similarity to a one hoss shay proxy as each asset has its cost spread over its projected life in equal annual proportions. The sum of these annual nominal depreciation amounts across assets when deflated by an appropriate capital goods price index could, hence, have similar characteristics to a physical quantity–based proxy.

However, this proxy would be subject to the same limitations as other indirect proxies. While depreciation allowances have been increasingly standardised for new capex, the lack of a direct link between initial capital bases and historic cost mean that the initial capital base component of RAB depreciation will be less accurate. There will also be error introduced by assumed asset lives for both initial capital and subsequent capex not equalling actual realised asset lives (something that is not an issue with direct quantity–based proxies). The AER (2012a, p.71) also noted that asset lives allowed in RAB depreciation differ across jurisdictions and relative to asset lives assumed in the AER’s other assessment models.

Apart from these consistency issues, a RAB depreciation–based proxy would still need to be deflated by a capital goods price index representative of prices paid by NSPs (as opposed to the consumer price index deflation used in forming the real RAB). We have already noted the potential error this introduces given that most available capital goods price indexes are at a much more aggregate level than the NSP industry.

[3] Other capital includes some substation components, building fitouts and vehicles. It is generally a small percentage of total asset value and has often been combined with one of the other categories.

The difference between system capacity and capital input quantities

A question was raised at the third workshop as to whether there might be too much similarity between the physical measure of system capacity and proposed physical proxies for capital input quantities. We do not believe this to be a problem with the output and input quantity measures that have been proposed.

The physical capital input quantity for lines and cables that has been proposed is MVA–kilometres which is the sum of the product of the length of each line voltage category with a MVA conversion factor designed to reflect the weighted average capacity of that overall voltage class under normal circumstances (ie taking account of limits that may result from thermal, voltage drop or other technical considerations). Overhead lines and underground cable MVA–kilometres are included separately. The physical capital input quantity for transformers that has been proposed is their total MVA rating (ie both zone substation and distribution transformers are included). These capital input quantities are weighted by their respective annual user costs in forming the total input quantity. Since underground cables are considerably more costly than overhead lines, they receive a correspondingly higher weight in forming the total input quantity.

The system capacity physical proxy that has been proposed, on the other hand, is the product of total line and cable circuit length (in kilometres and unadjusted for capacity) and transformer capacity at the last or distribution transformer level only. That is, the line component of this product is not adjusted for the differing weighted average MVA capacities of different voltage classes as are the lines and cables input quantities and no distinction is made in the system capacity variable of the different cost weights applying to overhead lines and underground cables. And the transformer capacity that is included in the product to form system capacity is only the capacity of distribution transformers rather than the capacity of all transformers (both zone substation and distribution levels) that is included in the transformer input quantity. This is because it is the distribution transformers that determine the maximum demand that can be supplied to end–users. Zone substation and intermediate levels of transformation consume inputs but do not determine the demand that can ultimately be delivered to end–users.

The system capacity variable and the overhead lines, underground cables and transformer input quantity variables clearly have significant differences in specification. Once economic benchmarking data are assembled sensitivity analysis will permit the impact of different output and input specifications to be tested and correlations between variables to be calculated. If any concerns remain regarding interrelationships between these variables, smoothed peak demand can be used as an alternate proxy for system capacity.

5.5.2 Measuring annual capital user costs

In section 5.1 we noted that the cost of capital’s annual input to production has to be distinguished from the total asset value. When an asset is purchased, it will provide input to the production process over an extended period. Consequently, its cost should be spread over that same period. But in addition to the initial cost of the asset, there is also an opportunity cost of holding the asset each year. This opportunity cost may be offset to some extent if the asset is subject to capital gains (its price increases over time).

Just as capital service flow quantities could be measured either directly (using physical data) or indirectly (using deflated asset value data), then the annual cost of using capital inputs can also be measured either directly or indirectly. The direct approach involves applying a formula which includes an estimated depreciation rate, a rate reflecting the opportunity cost of capital and other factors such as taxation effects to the value of assets. This approach is also often referred to as being ‘exogenous’ as it does not depend on the outcome realised in the measurement period. It is effectively an ex ante measure of the shadow annual user cost of capital. The indirect approach, on the other hand, simply uses the residual of revenue minus operating costs. It is often referred to as being ‘endogenous’ as it measures the realised residual which is then allocated to capital. It is an ex post measure of the annual capital cost.

The sophistication of the direct annual user cost formula used in NSP economic benchmarking studies varies widely depending on the quantity and quality of relevant data available. An example of a basic before–tax annual user cost formula is given by:

$$u = \underset{\text{interest cost}}{rP} + \underset{\text{depreciation cost}}{\delta(1+\rho)P} - \underset{\text{capital gains}}{\rho P} \tag{1}$$

where: r is the nominal interest rate;

δ is the depreciation rate based on the asset’s economic life;

ρ is the inflation rate of capital items; and

P is the purchase price of capital.

Although they may make a reasonable approximation, these simple exogenous user cost of capital models are not necessarily consistent with the way capital costs are calculated in building blocks reviews (eg capital gains are calculated using capital goods prices rather than the general inflation rate used in building blocks). For economic benchmarking to be used as part of building blocks reviews, the annual user cost should approximate the sum of the building blocks return of and return on capital components.

The indirect approach of allocating a residual or ex post cost to capital of the difference between revenue and operating costs has been favoured by some regulatory agencies such as the US Federal Communications Commission (1997). A key advantage of this approach is that it is easy to implement and requires minimal data. However, calculating the annual capital cost endogenously will not result in ex ante FCM–consistent capital costs, except by accident.

A number of economic benchmarking studies have used this indirect approach to measuring capital costs. While it measures realised or ex post capital costs and may provide an approximation for ex ante capital costs for network industries where there has been a longish history of building blocks regulation, we believe it would not be appropriate to use this approach in economic benchmarking to be used in building blocks reviews. Rather, an exogenous approach to forming the annual user cost of capital which is consistent with the building blocks return of and return on capital components will best satisfy the third selection criterion in section 5.3.

WACC for use in economic benchmarking

Stakeholders at the third workshop noted that the annual user cost of capital is influenced by the WACC and WACC benchmarks are set at different times which may result in a substantial difference in costs. Stakeholders also noted that which percentile WACC is appropriate may depend on whether NSPs are expected to achieve frontier or only average efficiency performance and asked whether the WACC applying at the last building blocks determination for each NSP or a 'current year WACC' would be used. Another option would be to apply the WACC from the AER's latest NSP determination to all NSPs for economic benchmarking purposes.

The AER is undertaking a separate workstream on rate of return guidelines as part of its Better Regulation program. The approach to WACC adopted for economic benchmarking should be consistent with that decided on in the AER's rate of return workstream.

For economic benchmarking purposes the annual user cost of capital should ideally use an exogenous or ex–ante approach as discussed in the preceding subsection. This is because producers base their production and investment decisions on the price of using capital they expect to prevail during the year ahead rather than being able to base them on the price of using capital actually realised in the year ahead (as would be only known with the benefit of perfect foresight). This points to using the WACC NSPs expect to prevail at the start of each year rather than the actual realised WACC for that year.

Because NSPs operate under regulation which specifies a forecast WACC for regulatory periods of 5 years, it would appear reasonable to use the regulated WACC for all years in the relevant regulatory period for each NSP. But, because the regulatory periods do not coincide for all NSPs and because the regulatory WACC tends to change over time, this would lead to NSPs all having somewhat different WACCs for economic benchmarking purposes. While this may reflect reality, it has the downside of making it more difficult to compare like–with–like when making efficiency comparisons because capital is receiving different weights. It also makes it difficult to compare total costs across NSPs because they will be influenced by the use of different regulatory WACCs for each NSP.

A pragmatic solution to this in the initial round of economic benchmarking may be to use a common WACC across all NSPs when assessing expenditure forecasts and, by extension, for historical comparisons of efficiency performance. A candidate WACC would be the WACC used in the most recent NSP regulatory determination which could be assumed to apply to all NSPs for both the forecast and historical period.

Sensitivity analyses should be undertaken of the effect of using:

- a common regulatory WACC across all NSPs
- the WACC from the most recent regulatory determination for each NSP for all years for that NSP
- the forecast WACCs for each regulatory period for each NSP, and
- the realised (regulatory) WACC for each year.

5.6 Short listed input specifications

Based on Economic Insights (2013c,f), feedback at the third workshop and the discussion above, we recommend that the NSP input specifications listed in table 4 be considered for use in economic benchmarking studies.

Table 4: **Short listed input specifications**

Quantity	Cost	Price
Opex – AWOTE–based		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW AWOTE labour index and five ABS producer price indexes
Opex – WPI–based		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
Capital – Physical proxies		
O/H lines (MVA–kms)	AUC (Return of & on O/H capital)	O/H AUC / MVA–kms
U/G cables (MVA–kms)	AUC (Return of & on U/G capital)	U/G AUC / MVA–kms
Transformers & other (MVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / MVA
Capital – RAB straight–line depreciation proxy		
Nominal RAB straight–line depreciation / ABS EGWW CGPI	AUC (Return of & on capital)	AUC / Constant price RAB depreciation
Capital – Depreciated RAB proxy		
Nominal depreciated RAB / ABS EGWW CGPI	Revenue minus opex	(Revenue minus opex) / Constant price depreciated RAB

Abbreviations: EGWW – Electricity, gas, water and waste sector; AWOTE – Average weekly ordinary time earnings; WPI – Wages price index; O/H – overhead; U/G – underground; AUC – annual user cost of capital; CGPI – Capital goods price index

The short listed opex specifications take the cost of opex as being that for the network services group activities used by the AER. These are generally opex costs for standard control services but excluding connection services and metering, in particular, using the relevant ring fencing arrangements. In some cases it may be necessary to make further adjustments to exclude accounting items such as provisions which do not reflect input use in the reporting year.

The price of opex is taken as a weighted average of either the Electricity, gas, water and waste sector (EGWW) AWOTE labour index or the WPI and five ABS Producer price indexes (PPIs) as used in Economic Insights (2012a) and using opex shares reported in PEG (2004) based on analysis of Victorian electricity DNSP regulatory accounts data. The component price indexes and weights are as follows:

- EGWW sector labour input – 62.0 per cent
- Intermediate inputs – domestic PPI – 19.5 per cent
- Data processing, web hosting and electronic information storage PPI – 8.2 per cent
- Other administrative services – 6.3 per cent
- Legal and accounting PPI – 3.0 per cent, and
- Market research and statistical services PPI – 1.0 per cent.

These PPIs replace those used in earlier Australian electricity and gas network economic benchmarking studies. Many of the earlier PPIs were discontinued as the result of changes to the ABS National Accounts data made in 2007. If backcasting of network data prior to 2007 is possible, these PPIs can be spliced onto the earlier indexes as done in Economic Insights (2012a). It would be appropriate to confirm that the PPIs and price index weights listed above reflect current NSP opex activities and opex composition. This can likely be done using information being collected as part of the AER's Category Analysis workstream. Alternatively, it may be appropriate to form a new NSP opex price index using Category Analysis opex components and matching PPIs.

Finally, the quantity of opex inputs is derived by deflating the opex cost by the weighted average opex price index.

This specification of the opex input has the advantage of using relatively readily available data and, given the diverse composition of opex inputs, is likely to be the only practical option. It will not, for example, be possible to form an opex input quantity using direct physical measures given the diverse range of items included in opex. The accuracy of the approach proposed will depend on changes in ABS sectoral and economy–wide price indexes accurately reflecting changes in opex prices faced by all NSPs. It also assumes all NSPs face the same levels of opex component prices and have the same composition of opex. We believe these are reasonable starting assumptions which can be further tested and refined, if necessary, once more disaggregated data become available.

We include three short listed capital input specifications in table 4. The first uses physical measures to proxy the quantities of three capital input components – overhead lines, underground cables, and transformers and other capital. The input quantities of overhead lines and underground cables are proxied by their respective MVA–kilometres. This measure allows the aggregation of lines and cables of differing voltages and capacities into a robust aggregate measure. The input quantity of transformers and other capital is proxied by the NSP's total transformer capacity (at all transformation levels) in kVA. The other capital component is usually quite small for NSPs and, since much of this residual component is related to substations, it is included with transformer capital inputs.

The annual user cost for the first specification is taken to be the return on capital and return of capital for each of the three components, calculated in a way which approximates the corresponding building blocks calculations. The input price for each of the three capital components is then derived by dividing their annual user cost by their respective physical quantity proxy.

The first approach has the advantage of reflecting the one hoss shay physical depreciation characteristics of the individual component assets while using the most robust source of NSP data available (that from their asset registers) and accurately capturing actual asset lives. In its submission on AER (2012a), the Major Energy Users (MEU 2013, p.25) observed:

> 'The MEU has sought advice from its members (which are all capital intensive industries) and the "one hoss shay" approach is how they approach the measurement of capital services. Interestingly, a number have also indicated that rather than their assets declining in ability to provide the service over time, they have through judicious investment increased the output and productivity of the asset even beyond its original planned life.'

The first approach is also broadly similar in principle to the productive capital stock used by leading statistical agencies to proxy the quantity of aggregate structures inputs in productivity measurement. And by using an exogenous user cost of capital covering the return on and return of capital it ensures broad consistency with other building blocks calculations.

A small amount of extra data will be required to implement this approach. This mainly relates to information on line and cable lengths by voltage levels and transformer capacities. This physical data has been a significant omission from earlier regulatory reporting requirements in Australia and was identified by previous state regulators as a priority for future data reporting changes (see Economic Insights 2009a). The approach will also require NSP engineering staff to form estimated weighted averages of the MVA ratings of each of their line and cable broad voltage classes (under guidance from the AER to ensure comparability across NSPs). Most Australian NSPs have been able to readily supply this information for earlier economic benchmarking studies (eg Lawrence 2005). It will also be desirable for NSPs to supply disaggregated capex and length of life data to allow the roll–forward of the three component asset values and calculation of the corresponding return of and return on capital annual user costs. A less preferred alternative would be to disaggregate the overall return of and return on capital into estimates of the three components on a best endeavours basis.

The second capital input specification listed in table 4 involves deflating the nominal straight–line depreciation used in building blocks RAB calculations by the ABS EGWW Net capital stock Capital goods price index (CGPI) to derive a capital input quantity proxy. The capital annual user cost is taken to be the overall return on capital and return of capital, calculated in a way which approximates the corresponding building blocks calculations. The price of the capital input is then derived by deflating the annual user cost by the constant price straight–line RAB depreciation.

This approach has some similarities to the first capital input specification in that it approximates one hoss shay physical depreciation and hence reflects individual component carrying capacities and is broadly similar in principle to the productive capital stock used by leading statistical agencies to proxy the quantity of aggregate structures inputs in productivity measurement. It has the advantage of using existing regulatory data but assumes consistency of depreciation treatment in regulatory data over time and across NSPs and may not capture actual asset lives. It is also dependent on the accuracy and consistency of initial capital base values and is dependent on the ABS EGWW CGPI accurately capturing capital prices paid by NSPs.

In its submission on AER (2012a), United Energy and Multinet Gas (2013, p.9) noted some of the potential inconsistencies in RAB–based measures as follows:

> ‘the methodology used to derive the original starting value is (in some jurisdictions) likely to have deviated away from a cost based approach (e.g., DORC). … Since then, the RABs of different businesses will also have been affected by the regulatory lives adopted by those businesses, in particular, the extent to which these reflect engineering/useful lives, as well as the approach adopted for things such as customer contributions. Both will have impacted the RAB over time, yet the outputs will not have been affected by these decisions, thus the overall results of the economic benchmarking will be affected by these decisions.’

The third capital input specification listed in table 4 involves deflating the nominal depreciated RAB by the ABS EGWW Net capital stock Capital goods price index (CGPI) to derive a capital input quantity proxy. The endogenous approach to forming the cost of capital inputs is used in this instance which involves allocating the difference between revenue and opex as the cost of capital inputs. The price of the capital input is then derived by dividing the difference between revenue and opex by the constant price depreciated RAB.

This approach has the advantage of being relatively easy to implement and of using existing regulatory data. However, it is unlikely to reflect the carrying capacity of the component assets as it assumes ongoing reductions in asset carrying capacity each year. It also assumes consistency of treatment of depreciation and other RAB components in regulatory data over time and across NSPs and may not capture actual asset lives. It is also dependent on the accuracy and consistency of initial capital base values and is dependent on the ABS EGWW CGPI accurately capturing capital prices paid by NSPs.

In its submission on AER (2012a), the Energy Networks Association (2013, p.5) urged caution in relying on RAB measures for economic benchmarking as follows:

> ‘The AER will need to be careful in applying any economic benchmarking techniques that use Regulatory Asset Base (RAB) as an input measure. The RAB is affected not just by the size of a NSP’s network but also conversely by particular jurisdictions’ historical approaches to customer contributions and the age of the assets, being a depreciated value. Its use in comparative benchmarking may therefore lead to misleading or non-credible results.’

The endogenous approach to measuring the cost of capital inputs used in the third specification is easy to implement but has the disadvantage of not being consistent, except by accident, with the financial capital maintenance principle used in buildings blocks calculations. It should be noted that the preferred exogenous annual user cost approach used in the first two capital specifications could also be used in the third specification and, conversely, the less preferred endogenous approach could also be used in the first two specifications.

6 NSP OPERATING ENVIRONMENT FACTORS

Operating environment conditions can have a significant impact on network costs and measured efficiency and in many cases are beyond the control of managers. Consequently, to ensure reasonably like–with–like comparisons it is desirable to adjust for at least the most important operating environment differences that are truly exogenous to the NSP.

In practice, the number and type of operating environment factors that can be included in economic benchmarking studies is often limited by data availability, correlation with other included variables and degrees of freedom considerations.

It should be noted that the choice of a final specification of environmental variables will be informed by the results of sensitivity analyses and other ongoing research as progressively more robust, consistent and detailed data sets are assembled. The operating environment factors listed in this section are initial suggestions and will be subject to ongoing refinement and development in consultation with stakeholders.

6.1 Criteria for selecting NSP operating environment factors

The AER (2012, p.85) has proposed the following criteria for selecting operating environment factors:

1) the variable must have a material impact
2) the variable must be exogenous to the NSP's control, and
3) the variable must be a primary driver of NSP costs.

The first criterion concerns prioritising the many factors that affect NSPs' ability to convert inputs into outputs. Since relatively few operating environment factors can be included in economic benchmarking, it is important to concentrate on those that have the most significant effect and which vary the most across NSPs.

The second criterion relates to ensuring only factors that are genuinely exogenous to the DNSP (ie beyond management control) are included. Including factors that NSPs did have some control over could reduce incentives to minimise costs and operate efficiently.

The third criterion relates to ensuring that where a number of factors are correlated, only the one with the most direct impact on NSPs' costs is included.

Using these selection criteria we have identified three main types of operating environment factors as a priority for inclusion in economic NSP benchmarking studies. These include weather conditions, terrain and network characteristics.

Weather conditions such as storms, high wind and extreme heat can have a material impact on NSP operations and are clearly beyond management control. They are also a primary driver of NSP costs as they can have a significant impact on costs and vary significantly across NSPs.

Similarly, the terrain an NSP faces in its service area or area of operation will have a material impact on its costs with, for example, mountainous areas usually being more costly to traverse than flat areas and high risk bushfire prone areas requiring more regular maintenance activities and potentially more frequent management of vegetation encroachment. These characteristics are clearly beyond management control and are likely to be a primary driver of costs which also vary significantly across NSPs.

Finally, the NSP's network characteristics can have an important impact on costs. For DNSPs, for example, the customer density of their service area will be something that drives their costs of service provision and is beyond management control. Similarly, for TNSPs the relative concentration of generation and load centres and the distance between these will be an important driver of costs and be beyond network management control.

6.2 DNSP operating environment factors

There was general agreement at the first workshop that it is important to allow for a range of key operating environment factors, to the extent possible, when making efficiency comparisons across DNSPs. Economic Insights (2013a) suggested inclusion of customer density, energy density and climatic effects on the short list of operating environment factors. We have expanded our short list for potential inclusion as set out in table 5 below.

Density

As noted in Economic Insights (2013a), density variables are likely to be the most important operating environment factors affecting efficiency comparisons. A DNSP with lower customer density will generally require more poles and wires to reach its customers than will a DNSP with higher customer density but the same consumption per customer making the lower density DNSP appear generally less efficient unless the differing customer densities are allowed for. And being able to deliver more energy to each customer means that a DNSP will usually require fewer inputs to deliver a given volume of electricity as it will require less poles and wires than a less energy dense DNSP would require to reach more customers to deliver the same total volume. This points to including energy density as an operating environment factor which also takes in more effects than a customer mix variable.

Several DNSPs noted that demand density (kVA non–coincident peak demand/customer) is probably a more important operating environment factor to include than energy density as it is peak demand rather than throughput that determines the amount of infrastructure that has to be installed. We have added demand density to the short list.

All of the data required to include the density operating environment factors are included in the output data requirements listed in table 1 above. The choice of which density variables to include in economic benchmarking applications has to be made in conjunction with which output variables to include to avoid double counting of effects and multicollinearity issues. For instance, if both throughput and customer numbers are included as separate outputs, the need to include energy density as an operating environment factor is greatly reduced.

Weather

Extremely hot days now place very high loads on DNSP networks due to the high penetration of domestic air conditioners (among other things). Similarly, extremely cold spells can also place high demands on DNSP networks as greater use is then made of space heating. While the fuel source primarily used for space heating will vary from region to region, with gas being the major source in very cold areas, the increasing penetration of domestic air conditioners is likely to see increasing demand for electricity as greater use is made of reverse–cycle air conditioning for heating.

Table 5: **DNSP operating environment factor short list**

Variable	Definition	Source
Density factors		
Customer density	Customers/route kilometre of line (excluding services and public lighting)	RIN and DNSPs
Energy density	MWh/customer	RIN
Demand density	kVA non–coincident peak demand (at zone substation level)/customer	RIN
Weather factors		
Extreme heat days	Number of extreme cooling degree–days (above, say, 25° C)	BoM
Extreme cold days	Number of extreme heating degree–days (below, say, 12° C)	BoM
Extreme wind days	Number of days with peak wind gusts over, say, 90 km/hour	BoM
Terrain factors		
Bushfire risk	Number of days over 50 per cent of service area subject to severe or higher bushfire danger rating	BoM & FAs
Rural proportion	Percentage of distribution line route length classified as short rural or long rural	RIN
Vegetation encroachment	Percentage of spans requiring vegetation management on a cyclic pattern by the DNSP	DNSPs
Service area factors		
Line length	Route length of lines (excluding services and public lighting)	DNSPs

Abbreviations: RIN – Regulatory Information Notice; BoM – Bureau of Meteorology; FA – Fire Authority

Extreme hot and cold days can both be expected to place unusually high demands on distribution networks and networks have to be built to handle those extremes. Consequently, when undertaking efficiency comparisons it is desirable to allow for variations in extreme conditions across DNSPs. That is, if we have two otherwise similar DNSPs but one operates in a climate of greater temperature extremes (but the same overall average temperature) then the one operating in the more extreme conditions will require more lines and transformer inputs to handle the higher peak demands it is likely to face and would thus be at a relative disadvantage in unadjusted efficiency comparisons.

A common way of measuring the need for cooling and heating is by calculating the number of ‘degree–days’. A degree day is determined by calculating the mean daily temperature for the day and forming a difference between that daily mean and a base temperature. The mean daily temperature can be calculated by taking the average of the daily maximum and minimum temperatures.

The Australian Energy Market Operator (AEMO 2011, p.1) defines cooling degree days as follows:

> ‘A measurement designed to reflect the amount for energy required to cool a home or a business. The number of degrees that a day’s average temperature is above a base temperature (18.5° C), the temperature above which buildings need to be cooled.’

It similarly defines heating degree days as follows:

> ‘A measurement designed to reflect the amount for energy required to heat a home or a business. The number of degrees that a day's average temperature is below a base temperature (e.g. 18.5° C), the temperature below which buildings need to be heated.’

For the current application instead of using a so–called ‘balance point’ above which cooling is required and below which heating is required in calculating the number of degree–days, we suggest calculating extreme cooling degree days relative to a higher base temperature, say 25° C and extreme heating days relative to a lower base temperature, say 12° C. The precise values of the baselines would need to be determined in consultation with industry and meteorological experts. These values are initial suggestions only.

The temperature data required to calculate the numbers of extreme degree days are collected by the Bureau of Meteorology. An average result would need to be taken for a representative sample of weather reporting stations spread across each DNSP’s service area.

Extreme wind days can also pose problems for DNSPs and make it more likely trees and windborne debris will make contact with lines. High winds are also associated with extreme weather conditions such as cyclones and tornadoes. We propose to measure these effects by the number of days recorded with wind gusts above, say, 90 km/hour. This is the start of the ‘storm’ wind force classification which is above ‘gale’ force but less than ‘hurricane’ force. The wind data required to calculate the numbers of extreme degree days are collected by the Bureau of Meteorology. An average result would need to be taken for a representative sample of weather reporting stations spread across each DNSP’s service area.

Over time it may be possible to develop a more sophisticated index of ‘climatic difficulty’ based on a wider range of factors. Possible candidates for inclusion in the development of such an index are listed in table 6 along with preliminary definitions.

Table 6: **Candidates for inclusion in development of 'climatic difficulty' index**

Factor	Definition
Maximum temperature	Maximum temperature daily recorded by the Bureau of Meteorology within DNSP's service area.
Minimum temperature	Minimum temperature daily recorded by the Bureau of Meteorology within DNSP's service area.
Peak wind gusts	Daily peak wind gusts recorded by the Bureau of Meteorology within DNSP's service area.
Heatwaves	For the DNSP's service area: • Number of days with a maximum temperature of, say, 30 degrees or higher • Number of three or more consecutive days with an average temperature above, say, 25 degrees
Dry spells (10, 20, 30 and 40 days)	Number of dry spells (say,10, 20, 30 and 40 days) recorded by the Bureau of Meteorology within DNSP's service area.
Storm Events	Number of storm events as defined and recorded by the Bureau of Meteorology within DNSP's service area.
Lightning strikes	Number of lightning strikes recorded by the Bureau of Meteorology within DNSP's service area.

Terrain

Economic Insights (2013a) noted that the terrain of a DNSP's service area can have an important effect on its costs while being clearly beyond the DNSP's control. However, we also noted that there is currently a dearth of terrain summary indicators. Following discussions with stakeholders, we believe a useful start can be made by including three simpler and tractable indicators. We again note that choice of a final specification of terrain variables will be informed by the results of sensitivity analyses and other ongoing research as progressively more robust, consistent and detailed data sets are assembled.

The first relates to the bushfire risk the DNSP faces as a result of its service area location and terrain. DNSPs operating in high bushfire risk areas will need to undertake more stringent vegetation management, inspection and maintenance programs, thus increasing their costs relative to DNSPs operating in more temperate areas. A readily tractable way of measuring the bushfire risk faced by a DNSP is to measure the number of days in a year that over half its service area is subject to a bushfire danger rating of severe or higher (ie severe, extreme or catastrophic). The source data are held by state and territory fire authorities and by the Bureau of Meteorology. It is noted that the basis of bushfire danger classifications may vary somewhat across jurisdictions.

The second simple indicator of terrain we believe worthy of inclusion on the short list is the percentage of the DNSP's total distribution line length that is classified as short rural or long rural. This provides a ready way of distinguishing the extent to which the DNSP operates in rural areas as opposed to urban areas. Distribution line length classified as CDB, urban, short rural and long rural is currently collected as part of DNSP RINs. As noted above, rural areas will generally have lower customer and demand densities than urban areas, thus requiring more poles and wires per customer, all else equal.

The third simple terrain indicator relates to the degree of vegetation growth and encroachment on DNSP lines. DSNPs operating in forested and other heavily treed areas will typically have to spend more on vegetation management than DNSPs operating in grass land and other non–treed areas. We propose to capture this effect by the percentage of a DNSP's spans requiring vegetation management by the DNSP on a cyclic pattern. This information would need to be collected from DNSPs but be subject to external verification and review.

Service area

In its submission on the briefing notes for the first workshop, SA Power Networks (2013, p.2) noted that:

> 'Line length in kilometres needs to be recognised as an environmental factor, and should be used as the most cost reflective measure of service area.'

We agree that a DNSP's route line length (excluding services and public lighting) is probably the most effective measure of a DNSP's service area. Economic Insights (2013a) noted the difficulties with trying to use land area measurements of service area, particularly where only small parts of a remote region might actually be serviced by the DNSP. Route length gives a more accurate indication of the spread of the DNSP's network.

DNSP RINs currently appear to concentrate on collecting circuit line length data. This would need to be supplemented by separate reporting of route length.

As with other operating environment factors, a decision on whether to include route length as a proxy for service area would need to be made in conjunction with the output specification to be used to minimise double counting and multicollinearity problems.

6.3 TNSP operating environment factors

There was general agreement at the second workshop that it is important to allow for a range of key operating environment factors, to the extent possible, when making efficiency comparisons across TNSPs. Economic Insights (2013b) suggested inclusion of climatic effects, terrain and length and capacity measures on the short list of operating environment factors.

Grid Australia (2013, pp.24–5) identified a relatively long list of potential operating environment factors as follows:

- 'location(s) and type(s) of generation on each network
- variability of generation dispatch patterns due to intermittent generation, for example where contributions from hydro or wind generation are material
- location(s) and distribution of loads, whether centralised or distributed among major flow paths, across each network

- length/distance and topology, that is, the degree of meshing or extension of each transmission network, potentially reflected as "network density"
- system operating voltage and power carrying capabilities of lines
- major circuit structures (for example, single circuit or double circuit, which can impact on credible contingencies in the NEM)
- weather, that is, natural performance characteristics of the network related to storms, bushfires and other weather-related events which in turn can depend on factors such as altitude, wind and the propensity for natural phenomena such as cyclones
- terrain
- peak demand
- different jurisdictional standards such as planning standards
- age and rating of existing network assets
- the timing of a TNSP in its investment cycle, given the lumpy nature of investments
- extent of implications of NER "technical envelope" requirements, such as those in the schedules in Chapter 5 (e.g. voltage stability, transient stability, voltage unbalance, fault levels, etc), and
- variations in cost drivers between jurisdictions.'

Economic Insights recognises that each TNSP operates in a region with different customer bases, generators and generation fuels, interconnector characteristics, jurisdictional planning standards, topology and topography, voltages, and historic design legacies and capacities. We agree that, in an ideal world, it would be desirable to adjust for many of the factors identified by Grid Australia while noting that there is overlap between some of the factors listed and items identified as outputs. However, given degrees of freedom and multicollinearity constraints, it will only be possible to adjust for the most important operating environment factors initially. Consequently, we propose an initial operating environment factor short list as set out in table 7.

Weather

Extremely hot days now place very high loads on TNSP networks due to the high penetration of domestic air conditioners (among other things). Similarly, extremely cold spells can also place high demands on TNSP networks as greater use is then made of space heating. While the fuel source primarily used for space heating will vary from region to region, with gas being the major source in very cold areas, the increasing penetration of domestic air conditioners is likely to see increasing demand for electricity as greater use is made of reverse–cycle air conditioning for heating. Extreme hot and cold days can both be expected to place unusually high demands on energy networks and networks have to be built to handle those extremes. Consequently, when undertaking efficiency comparisons it is desirable to allow for variations in extreme conditions across TNSPs. That is, if we have two otherwise similar TNSPs but one operates in a climate of greater temperature extremes (but the same overall average temperature) then the one operating in the more extreme conditions will require more inputs to handle the higher peak demands it faces. As well as impacts on peak demand, extreme hot and cold conditions will also impact operationally on the TNSP.

Table 7: **TNSP operating environment factor short list**

Variable	**Definition**	**Source**
Weather factors		
Extreme heat days	Number of extreme cooling degree–days (above, say, 25° C)	BoM
Extreme cold days	Number of extreme heating degree–days (below, say, 12° C)	BoM
Extreme wind days	Number of days with peak wind gusts over, say, 90 km/hour	BoM
Average wind speed	Average recorded wind speeds for a representative sample of weather stations	BoM
Terrain factors		
Bushfire risk	Number of days over 50 per cent of service area subject to equivalent of NSW severe or higher bushfire danger rating	BoM & FAs
Rural proportion	Percentage of route line length classified as rural	TNSPs
Vegetation encroachment	Percentage of route line length requiring vegetation management by the TNSP on a cyclic pattern	TNSPs
Altitude	Percentage of circuit line length above 600 metres	TNSPs
Network characteristics		
Line length	Route length of lines	RIN
Variability of dispatch	Proportion of energy dispatch from non–thermal generators	TNSPs
Concentrated load distance	Greatest distance from node having at least, say, 30 per cent of generation capacity to node having at least, say, 30 per cent of load	TNSPs

Abbreviations: RIN – Regulatory Information Notice; BoM – Bureau of Meteorology; FA – Fire Authority

A common way of measuring the need for cooling and heating is by calculating the number of ‘degree–days’. A degree day is determined by calculating the mean daily temperature for the day and forming a difference between that daily mean and a base temperature. The mean daily temperature can be calculated by taking the average of the daily maximum and minimum temperatures.

As noted above, the Australian Energy Market Operator (AEMO 2011, p.1) defines cooling degree days as follows:

> ‘A measurement designed to reflect the amount for energy required to cool a home or a business. The number of degrees that a day’s average temperature is above a base temperature (18.5° C), the temperature above which buildings need to be cooled.’

It similarly defines heating degree days as follows:

> ‘A measurement designed to reflect the amount for energy required to heat a home or a business. The number of degrees that a day's average temperature is below a base temperature (e.g. 18.5° C), the temperature below which buildings need to be heated.’

For the current application instead of using a so–called ‘balance point’ above which cooling is required and below which heating is required in calculating the number of degree–days, we suggest calculating extreme cooling degree days relative to a higher base temperature, say 25° C and extreme heating days relative to a lower base temperature, say 12° C. The precise values of the baselines would need to be determined in consultation with industry and meteorological experts. These values are initial suggestions only.

The temperature data required to calculate the numbers of extreme degree days are collected by the Bureau of Meteorology. An average result would need to be taken for a representative sample of weather reporting stations spread across each TNSP’s load centre area and route length.

Extreme wind days can also pose problems for TNSPs and make it more likely trees and windborne debris will make contact with lines. High winds are also associated with extreme weather conditions such as cyclones and tornadoes. We propose to measure these effects by the number of days recorded with wind gusts above, say, 90 km/hour. This is the start of the ‘storm’ wind force classification which is above ‘gale’ force but less than ‘hurricane’ force. The wind data required to calculate the numbers of extreme degree days are collected by the Bureau of Meteorology. An average result would need to be taken for a representative sample of weather reporting stations spread along each TNSP’s route length.

As well as extreme wind events, average wind speeds can also affect TNSP costs as higher average wind speeds will cause lines to sway more and thus wear more. The average wind speed on a TNSP’s route is proposed as a measure of the degree of impact of wind on day to day wear and tear on transmission line conductors and fittings. This may be an important driver of opex costs beyond management control.

Terrain

Economic Insights (2013b) noted that the terrain of a TNSP’s service area can have an important effect on its costs while being clearly beyond the TNSP’s control. However, we also noted that there is currently a dearth of terrain summary indicators. Following discussions with stakeholders, we believe a useful start can be made by including four simple and tractable indicators.

The first relates to the bushfire risk the TNSP faces as a result of its line locations and terrain. TNSPs operating in high bushfire risk areas will need to undertake more stringent vegetation management, inspection and maintenance programs, thus increasing their costs relative to TNSPs operating in more temperate areas. A readily tractable way of measuring the bushfire risk faced by a TNSP is to measure the number of days in a year that over half its line length is subject to a bushfire danger rating of equivalent of NSW ‘severe’ or higher (ie severe, extreme or catastrophic). The source data are held by state and territory fire authorities and by the Bureau of Meteorology. It is noted that the basis of bushfire danger classifications may vary somewhat across jurisdictions.

The second simple indicator of terrain we believe worthy of inclusion on the short list is the percentage of the TNSP’s total line length that is classified as being in a rural area. This provides a ready way of distinguishing the extent to which the TNSP operates in rural areas as opposed to urban areas. Rural areas will often impose higher costs on the TNSP, particularly where lines traverse mountainous and forested areas and where there is a higher bushfire danger risk.

The third simple terrain indicator relates to the degree of vegetation growth and encroachment on TNSP lines. TSNPs traversing forested and other heavily treed areas will typically have to spend more on vegetation management than TNSPs traversing grass land and other non–treed areas. We propose to capture this effect by the percentage of a TNSP’s route line length requiring vegetation management by the TNSP on a cyclic pattern. This information would need to be collected from TNSPs but be subject to external verification and review.

Altitude or change in altitude (terrain gradient) may affect both TNSP capex (design) and opex (access) costs. Terrain gradient is not easily measurable. But altitude is readily measurable and so the fourth terrain indicator included is proportion of circuit length above 600 metres. Including altitude as a measure recognises that additional costs are incurred in designing and building transmission lines and in ongoing management of assets in higher altitude areas, particularly ice and snow affected areas, where more rugged terrain and challenging weather conditions are more likely to be encountered.

Network characteristics

As noted by Grid Australia, the characteristics of a network will have an impact on TNSP costs and many of these effects are beyond management control.

The distance a transmission line has to cover and the capacity required to service the size of the end load centre will, of course, be important drivers of TNSP costs and may also be important drivers of measured TNSP efficiency. Generators have traditionally been located close to coal fields and the main transmission lines have run from those generators to the major cities. Other transmission lines of possibly longer length and generally lesser capacity service regional load centres. The length and capacity of transmission lines required are largely beyond TNSP control and are primary cost drivers. As with other operating environment factors, a decision on whether to include route length as a proxy for TNSP length and capacity would need to be made in conjunction with the output specification to be used to minimise double counting and multicollinearity problems.

Some TNSPs will have relatively short distances between concentrated generation centres and concentrated large load centres. This will typically place these TNSPs at an advantage compared to TNSPs with more diffuse generation centres and more diffuse and smaller load centres. The greatest distance from a node having at least, say, 30 per cent of generation capacity to a node having at least, say, 30 per cent of load could be a useful indicator of this factor.

Similarly, a TNSP serving a concentrated group of thermal generators will generally have an advantage compared to a TNSP with a similar load but having to serve many diffuse non–thermal generators such as hydro and wind turbines which only generate for part of the day. The proportion of dispatch from non–thermal generators could be a useful indicator of this factor.

Finally, we require an indicator to measure transmission network density to reflect the degree of meshing versus extension of the network. Generally, a more meshed network will be able to provide higher levels of reliability than a more ‘stringy’, less meshed network. One possible indicator is MVA system capacity per route kilometre of line.

7 RECOMMENDATIONS

The AER has asked Economic Insights to provide recommended output and input specifications for the economic benchmarking of DNSPs and TNSPs. We present these recommendations in this section along with two back–up output and input specifications for both DNSPs and TNSPs. The recommendations are made based on our research for this project, extensive discussions with stakeholders spanning six separate workshops and our experience in applying economic benchmarking methods to energy network businesses over more than 20 years.

It should be noted that while we present recommended output and input specifications at this point in time, the choice of a final specification will need to be informed by the results of sensitivity analyses and other ongoing research as progressively more robust, consistent and detailed data sets are assembled. It should also be noted that the three output and three input specifications we present for DNSPs and the two output and three input specifications we present for TNSPs can, of course, be 'mixed and matched' to form a wider range of possible combinations.

7.1 Recommended DNSP output and input specification

Our recommended DNSP output and input specification is presented in table 8.

Table 8: **Recommended DNSP specification**

Quantity	Value	Price
Outputs		
Customers (No)	Revenue * Cost share	Value / Customers
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Throughput (GWh)	Revenue * Cost share	Value / GWh
Interruptions (Customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
O/H lines (MVA–kms)	AUC (Return of & on O/H capital)	O/H AUC / MVA–kms
U/G cables (MVA–kms)	AUC (Return of & on U/G capital)	U/G AUC / MVA–kms
Transformers & other (MVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / MVA

[1] VCR per customer minute will vary by DNSP depending on the DNSP's energy deliveries.

Abbreviations: EGWW – Electricity, gas, water and waste sector; WPI – Wage price index; O/H – overhead; U/G – underground; AUC – annual user cost of capital

The first output included is customer numbers representing relatively fixed services the DNSP supplies. These are activities the DNSP has to undertake regardless of the level of energy delivered and include connection related infrastructure (eg having more residential customers may require more local distribution transformers and low voltage mains), customer calls, etc. Going back to the road analogy discussed in section 3, the DNSP will need to provide and maintain local access roads for its customers, regardless of the amount of traffic on those roads.

In line with previous energy network economic benchmarking studies we propose to measure the quantity of this output by the number of customers, or connections to be more specific. The value of the output would be revenue multiplied by its cost share derived from a combination of econometric cost function analysis, evidence from previous studies and information provided by DNSPs on their allocation of costs across the various outputs. Previous studies have generally found the customer numbers output to receive around half the weight in multiple output specifications (see, for example, Lawrence 2003 and Economic Insights 2012a). The price of this output would be its value divided by the number of connections.

The second output we recommend for inclusion is system capacity as approximated by the product of circuit line length and the total capacity of distribution level transformers. Going back to the road analogy discussed in section 3, this output captures the quantity of 'road network' that the DNSP has to provide to cater for users' peak demands and energy consumption. We prefer this measure to the alternative that has been suggested of peak demand. Using peak demand would require some form of smoothing which makes the results dependent on the form and degree of smoothing undertaken. Given the long–lived nature of DNSP assets and the need to allow a margin above recent observed peak demands to allow for infrequent extreme weather conditions, the system capacity variable better reflects the underlying functional output. It is also able to draw on robust data held and maintained by all DNSPs.

We believe the advantages of using system capacity to measure this function far outweigh any possible disadvantage from it not distinguishing between DNSPs that have provided adequate capacity and those that may have provided excess capacity. We note that comparisons of network utilisation levels across DNSPs would provide more information on whether excess capacity was a relevant consideration but any such comparison would need to allow for differing operating environment conditions across DNSPs and whether greater extremes of weather conditions, for example, required more capacity to be in place compared to DNSPs with the same recent peak but facing more temperate conditions.

The value of the system capacity output would be revenue multiplied by its cost share. Previous studies have generally found the system capacity output to receive around 30 per cent of the weight in multiple output specifications (see, for example, Lawrence 2003 and Economic Insights 2012a). The price of this output would be its value divided by the product of circuit length and distribution level transformer capacity.

The third recommended output is throughput or energy deliveries. While throughput has a small direct impact on DNSP costs, it reflects the main output of value to customers and maintains consistency with earlier economic benchmarking studies, nearly all of which have included throughput as an output. The value of the throughput output would be revenue multiplied by its cost share, which we would expect to be relatively small given that costs are not likely to be greatly influenced by small variations in throughput. Previous studies have generally found the throughput output to receive around 20 per cent of the weight in multiple output specifications (see, for example, Lawrence 2003 and Economic Insights 2012a). The price of this output would be its value divided by energy deliveries.

The fourth output is the duration of customer interruptions which captures the DNSP's reliability performance. This is an important dimension of DNSP performance for customers. As discussed in section 3, treating interruptions as an undesirable output allows it to be readily incorporated with a negative price and, hence, a negative value. We recommend adopting the distribution STPIS valuation of consumer reliability (VCR). As the STPIS VCR is presented as an amount per MWh consumed, this first has to be converted to an amount per customer minute depending on the individual DNSP's annual energy deliveries. The price is then the negative of the DNSP's VCR per minute and the value of customer interruptions is the product of this negative price and the total minutes of customer interruptions. This method is easy to implement and will produce relatively robust results. An earlier Australian study using this approach found an average weight for the reliability output of around (minus) 8 per cent of revenue (Lawrence 2000).

Turning to the input side of the recommended specification, opex would be measured by the narrow coverage discussed in section 5 of taking expenditure consistent with the AER's network services group component of standard control services. If necessary, adjustments would be made to remove accounting items that did not reflect current year input use. The recommended price of opex is a weighted average price index consisting of the ABS Wages price index and five Producer price indexes covering business, computing, secretarial, legal and accounting, and public relations services and using the weights set out in section 5.6. The quantity of opex inputs is derived by deflating the value of opex by its price index.

There has been much debate over the merits of using the WPI or AWOTE as the appropriate labour price index. The WPI will be the more theoretically appropriate price index if labour price changes only reflect changes in skill levels and quality. However, in times of vigorous competition for labour between different sectors of the economy, labour price changes may reflect efforts to retain employees rather than any underlying changes in skill levels. In that situation AWOTE may be the better measure. While each measure has advantages and disadvantages, the important thing is to ensure that the same index is used in productivity and efficiency calculations and in the labour price component of rate of change roll forward calculations to ensure consistency. There would then be little difference in the net regulatory effect of using either the WPI or AWOTE. We have opted in favour of the WPI because it has some theoretical advantages and may be the preferable index to use in the longer term once labour markets return to more normal conditions.

The recommended capital input specification uses physical measures to proxy the quantities of three capital input components – overhead lines, underground cables, and transformers and other capital. The input quantities of overhead lines and underground cables are proxied by their respective MVA–kilometres. This measure allows the aggregation of lines and cables of differing voltages and capacities into a robust aggregate measure. The input quantity of transformers and other capital is proxied by the NSP's total transformer capacity (at all transformation levels) in MVA. The other capital component is usually quite small for NSPs and, since much of this residual component is related to substations, it is included with transformer capital inputs.

The value of capital inputs or annual user cost is taken to be the return on capital and return of capital for each of the three components, calculated in a way which approximates the corresponding building blocks calculations. The input price for each of the three capital components is then derived by dividing their annual user cost by their respective physical quantity proxy.

This approach has the advantage of reflecting the one hoss shay physical depreciation characteristics of the individual component assets while using the most robust source of NSP data available (that from DNSP physical asset registers) and accurately capturing actual asset lives. This approach is also broadly similar in principle to the productive capital stock used by leading statistical agencies to proxy the quantity of aggregate structures inputs in productivity measurement.

We believe this approach to measuring capital inputs is more robust and likely to be more accurate than approaches which rely on regulatory depreciation and depreciated asset data.

By using an exogenous user cost of capital covering the return on and return of capital it ensures consistency with other building blocks calculations.

Operating environment factors

The number of operating environment factors that can be allowed for in the recommended specification will depend on the number of observations available (as this process will likely have to either rely on econometric adjustments to efficiency scores or else rely on inclusion of more items directly into DEA or SFA methods). Some aspects of both customer density and energy density are already captured in the recommended specification with throughput, customer numbers and some aspects of length included as outputs (although length is less directly included). The priority for including a density operating environment factor therefore lies with the demand density variable listed in table 5.

Given that reliability is being included as an output it will be important to include at least one of the weather operating environment factors proposed in table 5. We propose that extreme temperature days be included as the priority weather variable most likely to affect DNSP performance. Extreme wind days should also be considered for inclusion.

Of the terrain factors included in table 5, we propose priority be given to including the vegetation encroachment indicator as this will have a particular impact on opex and economic benchmarking is more likely to have a role in assessing opex expenditure forecasts in the first instance. Vegetation growth may also be a good indicator of other challenging climatic conditions facing the DNSP.

7.2 Back–up DNSP output and input specifications

In this section we present two back–up DNSP output and input specifications. The first of these is presented in table 9.

Table 9: **Back–up DNSP specification #1**

Quantity	Value	Price
Outputs		
Customers (No)	Revenue * Cost share	Value / Customers
Smoothed non–coincident peak demand (MVA)	Revenue * Cost share	Value / MVA
Throughput (GWh)	Revenue * Cost share	Value / GWh
Interruptions (Customer mins)	–1 * Customer mins * VCR per minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
Nominal RAB straight–line depreciation / ABS EGWW CGPI	AUC (Return of & on capital)	AUC / Constant price RAB depreciation

[1] VCR per customer minute will vary by DNSP depending on the DNSP's energy deliveries.

Abbreviations: EGWW – Electricity, gas, water and waste sector; WPI – Wages price index; CGPI – Capital goods price index; AUC – annual user cost of capital

The output specification in table 9 is similar to the recommended DNSP output specification except that the system capacity variable is replaced by smoothed non–coincident peak demand which is used as a proxy for the system capacity required. This change would be one way of addressing any concerns regarding the system capacity variable's failure to distinguish potential excess capacity. Smoothing is required to remove the volatility associated with actual peak demand in response to variability in annual climatic and other conditions. However, the smoothing of actual non–coincident maximum demand necessary for it to be used as a proxy for system capacity introduces a degree of non–uniqueness as a range of smoothing methods could be used, all producing somewhat different results. And even a smoothed series may not adequately recognise constraints on a DNSP's ability to adjust its system capacity given the long–lived nature of its capital inputs and its capital intensity.

The first back–up specification does not include any length dimension in the system capacity proxy and so it will be necessary to include customer density or, alternatively, the route length proxy for service area as a priority operating environment factor. Conversely, given that a measure of peak demand is now included as well as an output along with customer numbers, we would not recommend including the peak density variable as an operating environment factor.

Turning to the input side, the opex specification is the same in this specification as in the recommended specification but we include a different measure of capital input. The capital input specification involves deflating the nominal straight–line depreciation used in building blocks RAB calculations by the ABS EGWW Net capital stock Capital goods price index to derive a capital input quantity proxy. The capital annual user cost is taken to be the overall return on capital and return of capital, calculated in a way which approximates the corresponding building blocks calculations, the same as in the recommended specification. The price of the capital input is then derived by deflating the annual user cost by the constant price straight–line RAB depreciation.

This approach has some similarities to the recommended capital input specification in that it approximates one hoss shay physical depreciation and hence reflects individual component carrying capacities. It has the advantage of using existing regulatory data but assumes consistency of depreciation treatment in regulatory data over time and across NSPs and may not capture actual asset lives. It is also dependent on the accuracy and consistency of initial capital base values and is dependent on the ABS EGWW CGPI accurately capturing capital prices paid by NSPs. For these reasons it is ranked behind the recommended physical measures proxy.

Table 10: **Back–up DNSP specification #2**

Quantity	**Value**	**Price**
Outputs		
Residential Customers (No)	Revenue * Cost share	Value / Res Customers
Commercial Customers (No)	Revenue * Cost share	Value / Comm Customers
Sml Industrial Customers (No)	Revenue * Cost share	Value / Sml Ind Customers
Lge Industrial Customers (No)	Revenue * Cost share	Value / Lge Ind Customers
Interruptions (Customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW AWOTE and five ABS producer price indexes
Nominal depreciated RAB / ABS EGWW CGPI	Revenue minus opex	(Revenue minus opex) / Constant price depreciated RAB

[1] VCR per customer minute will vary by DNSP depending on the DNSP's energy deliveries.

Abbreviations: EGWW – Electricity, gas, water and waste sector; AWOTE – Average weekly ordinary time earnings; CGPI – Capital goods price index

The second back–up specification is presented in table 10. Given that system capacity and peak demand both have some potential limitations as outputs, the output specification in table 10 includes customer numbers disaggregated by customer type (residential, commercial, small industrial and large industrial) and reliability as outputs. Together these variables could measure the DNSP's success in providing adequate capacity to meet customer needs. Such a specification has the disadvantage of not providing either a direct or indirect proxy for required system capacity. We hence anticipate it would be necessary to use both customer and energy density operating environment factors with this specification.

The input specification listed in table 10 differs from the recommended input specification in two ways. Firstly, the opex specification uses AWOTE to reflect labour input prices rather than the WPI. As noted above, both AWOTE and the WPI have advantages and disadvantages. Either can defensibly be used, provided that index is then used consistently across the building blocks framework. The second difference is that the capital input specification listed in table 10 involves deflating the nominal depreciated RAB by the ABS EGWW Net capital stock CGPI to derive a capital input quantity proxy. The endogenous approach to forming the cost of capital inputs is also used in this instance which involves allocating the difference between revenue and opex as the cost of capital inputs. The price of the capital input is then derived by dividing the difference between revenue and opex by the constant price depreciated RAB.

This approach has the advantage of being relatively easy to implement and of using existing regulatory data. However, it is unlikely to reflect the carrying capacity of the component assets as it assumes ongoing reductions in asset carrying capacity each year. It also assumes consistency of treatment of depreciation and other RAB components in regulatory data over time and across NSPs and may not capture actual asset lives. It is also dependent on the accuracy and consistency of initial capital base values and is dependent on the ABS EGWW CGPI accurately capturing capital prices paid by NSPs. For these reasons it is ranked behind the recommended physical measures proxy.

The endogenous approach to measuring the cost of capital inputs also has the disadvantage of not being consistent, except by accident, with the financial capital maintenance principle used in buildings blocks calculations. It is, however, worth testing the sensitivity of results to the use of the simpler endogenous approach to the recommended but more data intensive exogenous approach.

7.3 Recommended TNSP output and input specification

The recommended and back–up TNSP output and input specifications are broadly similar to the corresponding DNSP specifications except that there is only one back–up TNSP output specification. The recommended TNSP specification is presented in table 11.

The recommended output specification consists of an analogous system capacity component, fixed component, throughput and reliability variables to the recommended DNSP specification.

The first output we recommend for inclusion is system capacity as approximated by the product of circuit line length and the total capacity of downstream–side transformers. Going back to the road analogy discussed in section 3, this output captures the quantity of 'road network' that the TNSP has to provide to cater for users' peak demands and energy consumption. We prefer this measure to the alternative that has been suggested of peak demand. Using peak demand would require some form of smoothing which makes the results dependent on the form and degree of smoothing undertaken. Given the long–lived nature of TNSP assets and the need to allow a margin above recent observed peak demands to allow for infrequent extreme weather conditions, the system capacity variable better reflects the underlying functional output. It is also able to draw on robust data held and maintained by all TNSPs. In the case of TNSPs there is likely to be less scope to independently vary capacity so concerns regarding the system capacity variable not distinguishing excess capacity are likely to be less relevant than in the case of DNSPs.

Table 11: **Recommended TNSP specification**

Quantity	Value	Price
Outputs		
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Entry & exit points (No)	Revenue * Cost share	Value / No
Throughput (GWh)	Revenue * Cost share	Value / GWh
Loss of supply events (No)	–1 * Loss of supply events * Average customers affected * VCR per customer interruption	–1 * Average customers affected * VCR per customer interruption[1]
Aggregate unplanned outage duration (customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for Prescribed services adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
O/H lines (MVA–kms)	AUC (Return of & on O/H capital)	O/H AUC / MVA–kms
U/G cables (MVA–kms)	AUC (Return of & on U/G capital)	U/G AUC / MVA–kms
Transformers & other (MVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / MVA

1 VCR per customer interruption and per minute will vary by TNSP depending on the TNSP's energy deliveries

Abbreviations: EGWW – Electricity, gas, water and waste sector; WPI – Wages price index; O/H – overhead; U/G – underground; AUC – annual user cost of capital

The value of the system capacity output would be revenue multiplied by its cost share derived from a combination of econometric cost function analysis, evidence from previous studies and information provided by TNSPs on their allocation of costs across the various outputs. The price of this output would be its value divided by the product of circuit length and downstream–side transformer capacity.

The second output is the number of entry and exit points (in place of the number of customers for DNSPs). Entry and exit points are fixed outputs the TNSP has to provide, irrespective of demand and throughput variations, just as DNSPs have to provide customer access infrastructure and services. Returning to the road analogy, entry and exit points are the equivalent of freeway entry and departure ramps. A future refinement for this output component would be to adjust by the voltage level of each entry and exit point. The value of the output would be revenue multiplied by its cost share and the price would be its value divided by the number of entry and exit points.

The third recommended output is throughput or energy deliveries. While throughput has a small direct impact on TNSP costs, it reflects the main output of value to customers. The value of the throughput output would be revenue multiplied by its cost share, which we would expect to be relatively small given that costs are not likely to be greatly influenced by small variations in throughput. The price of this output would be its value divided by energy deliveries.

We include two reliability variables in the recommended TNSP output specification. These are the number of loss of supply events and the aggregate unplanned outage duration. The former quantity is expressed in terms of the number of outage events leading to interruptions to end users while the latter quantity is the total number of customer minutes lost. The price of the former measure is the negative of the product of the number of customers affected and the relevant VCR per customer interruption from the DNSP STPIS. The price of the second reliability output is simply the negative of the relevant VCR per customer minute from the distribution STPIS. In both cases the value is derived as the product of the relevant quantity and price.

The recommended TNSP input specification is identical to the recommended DNSP input specification with TNSP voltage and weighted average MVA conversion factors replacing the corresponding DNSP items.

Opex would be measured by the narrow coverage of taking expenditure consistent with Prescribed services. If necessary, adjustments would be made to remove accounting items that did not reflect current year input use. The recommended price of opex is a weighted average price index consisting of the ABS Wages price index and five Producer price indexes covering business, computing, secretarial, legal and accounting, and public relations services and initially using the weights set out in section 5.6. These weights may need to be adjusted to better reflect the range of activities undertaken by TNSPs as opposed to DNSPs. The quantity of opex inputs is derived by deflating the value of opex by its price index.

The recommended capital input specification uses physical measures to proxy the quantities of three capital input components – overhead lines, underground cables, and transformers and other capital. The input quantities of overhead lines and underground cables are proxied by their respective MVA–kilometres. This measure allows the aggregation of lines and cables of differing voltages and capacities into a robust aggregate measure. The input quantity of transformers and other capital is proxied by the TNSP’s total transformer capacity (at all transformation levels) in MVA. The other capital component is included with transformer capital inputs for convenience.

The value of capital inputs or annual user cost is taken to be the return on capital and return of capital for each of the three components, calculated in a way which approximates the corresponding building blocks calculations. The input price for each of the three capital components is then derived by dividing their annual user cost by their respective physical quantity proxy.

Operating environment factors

The number of operating environment factors that can be allowed for in the recommended specification will again depend on the number of observations available (as this process will likely have to either rely on econometric adjustments to efficiency scores or else rely on inclusion of more items directly into DEA or SFA methods). In the case of TNSPs there are likely to be fewer observations available than for DNSPs.

Given that reliability is being included as an output it will be important to include at least one of the weather operating environment factors proposed in table 7. We propose that extreme temperature days be included as the priority weather variable most likely to affect TNSP performance.

Of the terrain factors included in table 7, we propose priority be given to including the vegetation encroachment indicator as this will have a particular impact on opex and economic benchmarking is more likely to have a role in assessing opex expenditure forecasts in the first instance. Vegetation growth may also be a good indicator of other challenging climatic conditions facing the TNSP.

For TNSPs it will also be important to include allowance for network characteristics given the wide range of TNSP network configurations. We propose the concentrated load distance indicator from table 7 and the proposed network density indicator of MVA system capacity per route kilometre be included as the priority measures.

7.4 Back–up TNSP output and input specifications

In this section we present two back–up TNSP output and input specifications. The first of these is presented in table 12.

The first back-up TNSP specification uses the same output specification as the recommended specification. It has an analogous input specification to the first back–up DNSP specification with the constant price RAB straight–line depreciation now being the capital input quantity proxy. This capital input specification involves deflating the nominal straight–line depreciation used in building blocks RAB calculations by the ABS EGWW Net capital stock Capital goods price index to derive a capital input quantity proxy. The capital annual user cost is taken to be the overall return on capital and return of capital, calculated in a way which approximates the corresponding building blocks calculations, the same as in the recommended specification. The price of the capital input is then derived by deflating the annual user cost by the constant price straight–line RAB depreciation.

This approach has some similarities to the recommended capital input specification in that it approximates one hoss shay physical depreciation and hence reflects individual component carrying capacities. It has the advantage of using existing regulatory data but assumes consistency of depreciation treatment in regulatory data over time and across NSPs and may not capture actual asset lives. It is also dependent on the accuracy and consistency of initial capital base values and is dependent on the ABS EGWW CGPI accurately capturing capital prices paid by NSPs. For these reasons it is ranked behind the recommended physical measures proxy.

Table 12: **Back–up TNSP specification #1**

Quantity	Value	Price
Outputs		
System capacity (kVA*kms)	Revenue * Cost share	Value / kVA*kms
Entry & exit points (No)	Revenue * Cost share	Value / No
Throughput (GWh)	Revenue * Cost share	Value / GWh
Loss of supply events (No)	–1 * Loss of supply events * Average customers affected * VCR per customer interruption	–1 * Average customers affected * VCR per customer interruption[1]
Aggregate unplanned outage duration (customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW WPI and five ABS producer price indexes
Nominal RAB straight–line depreciation / ABS EGWW CGPI	AUC (Return of & on capital)	AUC / Constant price RAB depreciation

1 VCR per customer interruption and per minute will vary by TNSP depending on the TNSP's energy deliveries

Abbreviations: EGWW – Electricity, gas, water and waste sector; WPI – Wages price index; CGPI – Capital goods price index; AUC – annual user cost of capital

The second back–up TNSP output specification (listed in table 13) uses a smoothed non–coincident peak demand proxy for system capacity required in place of the actual system capacity variable. Smoothing is required to remove the volatility associated with actual peak demand in response to variability in annual climatic and other conditions. However, the smoothing of actual non–coincident maximum demand necessary for it to be used as a proxy for system capacity introduces a degree of non–uniqueness as a range of smoothing methods could be used, all producing somewhat different results. And even a smoothed series may not adequately recognise constraints on a TNSP's ability to adjust its system capacity given the long–lived nature of its capital inputs and its capital intensity. As there is now no length component in the output measures, it would be necessary to include a length–based operating environment factor with this specification.

The input specification for the second TNSP back–up specification is similar to that used in the second DNSP back–up with AWOTE replacing WPI in forming the opex price index and the constant price depreciated RAB value being used as the capital input quantity proxy. We again change to an endogenous capital annual user cost value in this specification.

Table 13: **Back–up TNSP specification #2**

Quantity	Value	Price
Outputs		
Smoothed non–coincident peak demand (MVA)	Revenue * Cost share	Value / MVA
Entry & exit points (No)	Revenue * Cost share	Value / No
Throughput (GWh)	Revenue * Cost share	Value / GWh
Loss of supply events (No)	–1 * Loss of supply events * Average customers affected * VCR per customer interruption	–1 * Average customers affected * VCR per customer interruption[1]
Aggregate unplanned outage duration (customer mins)	–1 * Customer mins * VCR per customer minute	–1 * VCR per customer minute[1]
Inputs		
Nominal opex / Weighted average price index	Opex (for network services group adjusted to remove accounting items not reflecting input use that year)	Weighted average of ABS EGWW AWOTE and five ABS producer price indexes
Nominal depreciated RAB / ABS EGWW CGPI	Revenue minus opex	(Revenue minus opex) / Constant price depreciated RAB

[1] VCR per customer interruption and per minute will vary by TNSP depending on the TNSP's energy deliveries

Abbreviations: EGWW – Electricity, gas, water and waste sector; AWOTE – Average weekly ordinary time earnings; CGPI – Capital goods price index

This approach again has the advantage of being relatively easy to implement and of using existing regulatory data. However, it is unlikely to reflect the carrying capacity of the component assets as it assumes ongoing reductions in asset carrying capacity each year. It also assumes consistency of treatment of depreciation and other RAB components in regulatory data over time and across TNSPs and may not capture actual asset lives. It is also dependent on the accuracy and consistency of initial capital base values and is dependent on the ABS EGWW CGPI accurately capturing capital prices paid by NSPs. For these reasons it is ranked behind the recommended physical measures proxy.

7.5 Uses of and observation numbers required for economic benchmarking

Economic benchmarking is likely to have three principal uses in expenditure forecast assessment. These are:

- 'first pass' expenditure assessment at an early stage of the regulatory determination process designed to identify areas of the expenditure forecasts that warrant further investigation (AER 2012a, pp.32–4)

- reviewing the relative efficiency of historical NSP expenditure and whether base year expenditure can be trended forward or whether it may be necessary to make adjustments to base year expenditure to remove observed inefficiencies, and
- quantifying the feasible rate of efficiency change and productivity growth that a business can be expected to achieve over the next regulatory period.

The third of these would include separately examining costs that are flexible in the short run (eg opex) and costs that will need to be progressively adjusted over the longer term (eg capital inputs). This could also include consideration of how scale efficiencies may change over time. An example of how economic benchmarking methods can be used to calculate the rate of partial productivity growth that should be included in an opex rate of change roll–forward formula can be found in Economic Insights (2012b).

There is thus both a cross sectional and a time series dimension to economic benchmarking efficiency assessments and the associated data requirements. Estimation of efficiency levels across businesses – as would be required for 'first pass' assessments and base expenditure year assessments – generally require fewer years of data than estimation of productivity growth rates. The AEMC (2011, p.23) was of the view that at least 8 years of data were required to form robust estimates of productivity growth trends that an entire regulatory determination could be based on (using a productivity–based regulation framework rather than building blocks). Fewer years of data would also provide relevant information on productivity growth rates but with less confidence that it was a representative trend. This could, however, still be useful in informing decisions on productivity growth rates to be built into rate of change formulae. Information on efficiency levels, on the other hand, can potentially be obtained from just one year of data although more than one year of data may provide added confidence in the result.

The number of observations required also depends on the economic benchmarking method used. Any number of outputs and inputs can be incorporated in the multilateral TFP indexing method with at least two observations to produce unadjusted cost efficiency comparisons. The only constraint is the availability of relevant data for the two (or more) observations. All other methods will require a considerable number of observations to provide sufficient 'degrees of freedom' to either be implementable or, with parametric methods, to reduce the impact of potential multicollinearity problems. For example, with the non–parametric DEA method there are different rules of thumb as to what the minimum number of organisations in the sample should be – one rule is that the number of organisations in the sample should be at least three times greater than the sum of the number of outputs and inputs included in the specification (Nunamaker 1985). If operating environment factors are also being included directly in the DEA analysis then these would be need to be added to the sum that is then multiplied by three. This rule would point to only a very rudimentary DEA specification being possible using Australian–only DNSP data (eg one output, two inputs and one operating environment factor). Including operating environment factors by way of a second stage regression would allow an extra output or input to be included.

With econometric cost function methods and SFA, several years of data for all DNSPs would be necessary to support relatively basic functional forms. Estimation of flexible functional forms such as the translog would likely require more than a decade of data for all DNSPs to produce robust results.

These considerations point to multilateral index number methods being the most feasible option for economic benchmarking initially. These methods will produce robust results (but not adjusted for operating environment factors) with a minimal requirement for numbers of observations.

Operating environment factors are usually incorporated in productivity analysis by the use of second stage regression analysis. That is, multilateral productivity index values are first calculated based on the nominated output and input specification (which can include as many outputs and inputs as available data allow). Those index values are then regressed against a range of operating environment factor variables. The regression identifies the relationship between the included operating environment factors and the productivity scores. This allows the productivity scores to be adjusted based on the estimated relationship with the operating environment factors and, using the values of each DNSP's operating environment variables, calculation of adjusted productivity scores that assume all DNSPs face the same value of the included operating environment factors. This then provides for more like–with–like comparisons to be made using the adjusted scores by taking into account the results of the regression analysis. An example of this process can be found in Lawrence (2007).

While many outputs and inputs can be included in productivity index number calculations – even when there are only a small number of observations – the ability to adjust the results for multiple operating environment factors will be constrained by the number of observations available. As the adjustment is done using regression methods, degrees of freedom and multicollinearity constraints apply. Simple functional forms can be used with relatively few observations (see, for example, Lawrence 2000). But use of more complex functional forms and inclusion of a larger number of operating environment factors will require more observations. Similarly, while operating environment factors can often be incorporated directly in econometric cost functions, DEA and SFA methods, a considerably larger number of observations is required to implement these methods and that is increased further by the direct inclusion of operating environment factors.

We recommend the AER commence estimating cross sectional DNSP and TNSP efficiency using multilateral TFP index methods. This can be done with one year of data initially. More years of data would, of course, provide more confidence and context for the results obtained. Adjustment for a select number of operating environment variables using second stage regression methods could be undertaken using a simple functional form using one or two years of data for DNSPs. Several years of data may be required for TNSPs to support regression based adjustments given the smaller number of TNSPs compared to DNSPs. Backcasting of data for at least 8 years – say to 2005 – would support calculation of reasonably representative productivity trends using index number methods. This would also produce just over 100 observations in total for DNSPs which may be enough to support estimation of econometric total and operating cost functions with a small number of outputs, inputs and operating environment factors (along the lines of Economic Insights 2012b). More fully specified econometric and SFA models would likely require at least a decade of data to produce robust results.

The data requirements listed in the following section have been formed with a view to supporting all economic benchmarking methods and a range of output and input specifications.

8 DNSP AND TNSP OUTPUT AND INPUT DATA REQUIREMENTS

The DNSP output and input data requirements to implement economic benchmarking are listed in table 14 along with preliminary variable definitions and an indication of whether the variable is currently collected in DNSP Regulatory Information Notices (RINs). The variables listed are required to support the recommended and back–up output and input specifications, possible alternative specifications which may be developed and a range of anticipated sensitivity analyses.

The TNSP output and input data requirements to implement economic benchmarking are listed in table 15 along with preliminary variable definitions and an indication of whether the variable is currently collected in TNSP Information Disclosure Requirements (IDRs). The variables listed are required to support the recommended and back–up output and input specifications, possible alternative specifications which may be developed and a range of anticipated sensitivity analyses.

Table 14: **Electricity DNSP output and input variables and preliminary definitions**

Variable	Unit	Definition of variable	Data in RINs?
DUOS REVENUE for regulated business activities		Annual Revenue earned from the provision of Standard Control Services only. Annual Revenue for the relevant year – in $ of the year. Use actual billing period data – ie without correction for "change in unread consumption" of metered customers in adjacent reading billing periods	Yes, no segregation by classes, chargeable quantity, etc. Given in $'000 nominal.
Revenue Grouping by chargeable quantity		Grouping to match tariff charging arrangements – ie not all DNSPs may have charges for all quantities	
Revenue from Fixed Customer Charges	$m	Supply availability charges independent of usage	
Revenue from Energy Delivery charges where time of use is not a determinant	$m	Revenue from metered supplies without time of use metering	
Revenue from On–Peak Energy Delivery charges	$m		
Revenue from Shoulder period Energy Delivery Charges	$m	Revenue from metered supplies with time of use metering. Include regularly controlled load in relevant period.	
Revenue from Off–Peak Energy Delivery charges	$m		
Revenue from energy delivered for uses which are "calculated" rather than "metered"	$m	Revenue from delivery of annual energy for traffic controls, phone or transport cubicles etc	
Revenue from Contracted Maximum Demand charges	$m	Annual Revenue from charges related to a "contracted" maximum demand, charged whether the demand is actually reached.	
Revenue from Measured Maximum Demand charges	$m	Annual revenue from charges related to measured maximum demands, whether "monthly reset" or "ratcheted"	
Revenue from other Sources	$m		
Total Revenue of the above	$m		
Revenue Grouping by Customer type or class			No segregation
Revenue from Domestic Customers	$m	Revenue from those with personal residential use	
Revenue from Non domestic customers not on demand tariffs	$m	Revenue from those not on demand tariffs	
Revenue from Low voltage demand tariff Customers	$m	Revenue from those on LV demand tariffs	

Variable	Unit	Definition of variable	Data in RINs?
Revenue from High voltage demand tariff Customers	$m	Revenue from those on HV demand tariffs	
Revenue from non-metered supplies	$m	Revenue from delivery of annual energy for traffic controls, phone or transport cubicles etc ie the delivery of energy element – not overall provision of say operation, maintenance etc of eg streetlights	
Revenue from Other Customers	$m	Including revenue for other tariffs eg agricultural, irrigation, etc	
Total Revenue of the above	$m		
Revenue (penalties) allowed (deducted) through incentive schemes (eg S factor) – $m	$m		
ENERGY DELIVERY			
Total Energy delivered	GWh	The amount of electricity transported out of the DNSP's network in the relevant regulatory year (measured in GWh). Metered or estimated at the customer charging location rather than the import location from the TNSP	
Energy Grouping - Delivery by chargeable quantity		Quantities relating to the chargeable revenue items listed above	Yes. Segregation sought is by customer type (domestic or non-domestic) and by supply voltage (S/T, HV or LV)
Energy Delivery where time of use is not a determinant	GWh	Energy to metered supplies without time of use metering or where time of use charging is not applied	Segregation by time of use not sought. “Controlled load” sought.
Energy Delivery at On-peak times	GWh	Energy to metered supplies with time of use metering used for time of use charging. Include regularly controlled load in relevant period.	
Energy Delivery at Shoulder times	GWh		
Energy Delivery at Off-peak times	GWh		

Variable	Unit	Definition of variable	Data in RINs?
Energy delivered for uses which are "calculated" rather than "metered"	GWh	Energy calculated as supplied for eg street lighting, traffic controls, phone or transport cubicles etc	Not sought
Energy - Received from TNSP by time of receipt			
Energy into DNSP network at On-peak times	GWh	Energy received into the DNSP network as measured at supply points from the TNSP.	
Energy into DNSP network at Shoulder times	GWh		
Energy into DNSP network at Off-peak times	GWh		
Energy - Received into DNSP system from embedded generation by time of receipt		Where metering allows separation from consumption	
Energy into DNSP network at On-peak times	GWh		
Energy into DNSP network at Shoulder times	GWh		
Energy into DNSP network at Off-peak times	GWh		
Energy Grouping - Customer type or class		Energy relating to the Customer Classes above	Yes. Segregation by customer type (domestic or non-domestic) and by supply voltage (S/T, HV or LV)
Domestic Customer Energy Deliveries	GWh	Generally those with personal residential use	
Commercial Customer Energy Deliveries	GWh	Generally those not on demand tariffs	
Small Industrial Customer Energy Deliveries	GWh	Generally those on LV demand tariffs	
Large Industrial Customer Energy Deliveries	GWh	Generally those on HV demand tariffs	
Other Customer Class Energy Deliveries	GWh	Including eg agricultural, irrigation, etc	
Delivery time period definitions			Not sought
On-peak changing periods	Days & hours	Days and hours when charges to users are at On-Peak time rates	
Shoulder charging periods	Days & hours	Days and hours when charges to users are at Shoulder time rates	
Off-peak charging periods	Days & hours	Days and hours when charges to users are at Off-Peak time rates	
SYSTEM DEMAND			
System Demand characteristics			

Variable	Unit	Definition of variable	Data in RINs?
Non–coincident Summated Raw System Annual Peak Demand	MW and MVA	Summation of actual raw maximum demands at the zone substation level independent of when they occur ie no weather normalisation etc	Yes – sought in MW and MVA. Raw and normalised sought. Summer and winter sought. Detail sought by zone substation
Non–coincident Summated Weather Adjusted System Annual Peak Demand	MW and MVA	Summation of weather adjusted maximum demands at the zone substation level independent of when they occur	
Coincident Raw System Annual Peak Demand	MW and MVA	Summation of actual raw demands at the zone substation level at the times when this summation is greatest, ie no weather normalisation etc	
Coincident Weather Adjusted System Annual Peak Demand	MW and MVA	Summation of weather normalised demands at the zone substation level at the times when this summation is greatest	
Demand supplied[4]			
Summated Chargeable Contracted Maximum Demand	MW and MVA	Summation here is of chargeable (monthly) demand bases for an annual charged quantity	
Summated Chargeable Measured Maximum Demand	MW and MVA	Summation here is of chargeable (monthly) demand bases for an annual charged quantity	
CUSTOMER NUMBERS			
Distribution Customer Numbers by Customer type or class		The average of the number of customer connection points measured on the first day of the Relevant Reporting Year and on the last day of Relevant Reporting Year. A metered customer is identified as having a National Metering Identifier. Customer Numbers relating to the Customer Classes above.	No segregation by customer type – see below
Domestic Customer Numbers	number	Generally the number with personal residential use	

4 For customers charged on this basis

Variable	Unit	Definition of variable	Data in RINs?
Commercial Customer Numbers	number	Generally the number of non-domestic customers not on demand tariffs	
Small Industrial Customer Numbers	number	Generally the number on LV demand tariffs	
Large Industrial Customer Numbers	number	Generally the number on HV demand tariffs	
Unmetered Customer Numbers	number	Customers where calculation is made for delivery of annual energy for eg street lighting, traffic controls, phone or transport cubicles etc	Yes. Segregated by CBD, Urban, Sort Rural, Long Rural
Other Customer Numbers	number	Including customers on other tariffs eg agricultural, irrigation, etc.	
Distribution Customer Numbers by Location on the network		Network type segregation as defined in STPIS scheme documents for DNSPs.	Yes. Segregated by CBD etc, Domestic / Non-domestic, and by supply voltage ie S/T, HV or LV
Customers on CBD network	number	Customers of all types and classes in CBD areas.	
Customers on Urban network	number	Customers of all types and classes in Urban areas.	
Customers on Short rural network	number	Customers of all types and classes in Short rural areas.	
Customers on Long rural network	number	Customers of all types and classes in Long rural areas.	
Total Customer Number	number		Yes. Start and end of period. Whole network and segregation by CBD, Urban, Rural short, Rural Long. Segregation also by voltage level, S/T, HV, LV Residential, LV non-residential.

Variable	Unit	Definition of variable	Data in RINs?
SYSTEM CAPACITY			
Distribution System Capacities Variables		Distribution system includes Overhead and Underground lines and cables in service that serve a distribution function, including distribution feeders, and the low voltage distribution system. These lines typically have a voltage of less than 33 kV. Distribution System excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	Feeder classification - (a) CBD; (b) Urban; (c) Rural Short; (d) Rural Long.

Variable	Unit	Definition of variable	Data in RINs?
O/H network circuit length and typical / averaged MVA capacity of circuit at each voltage		Calculated as circuit length from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. Indicate estimated typical or weighted average capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal or by voltage drop etc as relevant. – Give summer and winter rating if differentiated.	Length sought, but segregation is by function (S/T, HV and LV). Capacity not sought. Demand sought.
O/H Low voltage distribution	km & MVA	0.4 MVA used in previous analysis[a]	
O/H HV 11 kV	km & MVA	4 MVA used in previous analysis[a]	
O/H HV 22 kV	km & MVA	8 MVA used in previous analysis[a]	
O/H HV 33 kV (if used as distribution voltage)	km & MVA	15 MVA used in previous analysis[a]	
O/H SWER	km & MVA		

Variable	Unit	Definition of variable	Data in RINs?
(Other distribution voltages)	km & MVA	Alternatively, "legacy voltages" eg 6.6 kV may be captured into the nearest relevant voltage currently in use.	
Sub-transmission capacity variables		Sub-transmission system includes those parts of the distribution system (including power lines and towers, cables, pilot cables and substations as the case may be) that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, Includes overhead or underground lines and cables that serve a sub-transmission function in a Central Business District (CBD) or Urban area. Included in this category are sub-transmission lines that serve small groups of customers. These lines typically have a voltage of 33 kilovolts (kV) or more.	
O/H S/T 44/33 kV (if used as subtransmission)	km & MVA		
O/H S/T 66 kV	km & MVA		
O/H S/T 132 kV	km & MVA	80 MVA used in previous analysis[a]	
(Other S/T voltages)	km & MVA	Alternatively, "legacy voltages" eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Total overhead circuit km	km		
U/G network circuit length and typical / averaged MVA capacity of circuit at each voltage		Similarly to OH	Length sought, but segregation is by function (S/T, HV and LV). Capacity not sought. Demand sought
U/G Low voltage distribution	km & MVA	0.4 MVA used in previous analysis[a]	

Variable	Unit	Definition of variable	Data in RINs?
U/G HV 11 kV	km & MVA	4 MVA used in previous analysis[a]	
U/G HV 22 kV	km & MVA	8 MVA used in previous analysis[a]	
U/G HV 33 kV (if used as distribution voltage)	km & MVA	15 MVA used in previous analysis[a]	
(Other distribution voltages)	km & MVA	Alternatively, "legacy voltages" eg 6.6 kV may be captured into the nearest relevant voltage currently in use.	
U/G S/T 44/33 kV (if used as subtransmission)	km & MVA		
U/G S/T 66 kV	km & MVA		
U/G S/T 132 kV	km & MVA	80 MVA used in previous analysis[a]	
U/G (Other S/T voltages)	km & MVA	Alternatively, "legacy voltages" eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Total underground circuit km	km		
Distribution power transformer total installed capacity		Transformer capacity involved in lowest level transformation to the utilisation voltage of the customer. Do not include intermediate transformation capacity here (eg 132 kV or 66 kV subtransmission to 22 kV or 11 kV distribution level). Give summation of normal nameplate continuous capacity / rating (with forced cooling etc if relevant). Include only energised transformers, not cold spare capacity.	Transformer number and MVA capacity sought. Segregation by function (Distribution or Zone Substation)
Distribution power transformer capacity owned by utility	MVA	Transformation capacity owned by the respondent Give nameplate continuous rating including forced cooling if relevant	Not separated

Variable	Unit	Definition of variable	Data in RINs?
Distribution power transformer capacity owned by HVCs	MVA	Transformation capacity from HV of DNSP to customer utilisation voltage owned by customers connected at HV. This might include eg 11 kV or 22 kV to eg 3.3 kV as well as to LV Alternatively give summation of individual maximum demands of HVCs whenever they occur (ie the summation of single annual MD for each customer) as a proxy for delivery capacity within the HVC.	Not separated
Zone Substation power transformer capacity	MVA	Transformer capacity involved in intermediate level transformation (ie subtransmission or high voltage eg 132 kV, 66 kV or 33 kV etc to distribution level eg 22 kV or 11 kV) in either one or two steps Give summation of normal assigned continuous capacity / rating (with forced cooling etc if relevant). Include only energised transformers, not cold spare capacity Assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing.	Transformer number and MVA capacity sought. Segregation by function (Distribution or Zone Substation)
	MVA	Total installed capacity for first level transformation - eg 132 kV to 66 kV or 33 kV where there will be a second transformation before utilisation voltage	
	MVA	Total installed capacity for second level transformation - eg 66 kV or 33 kV to 22 kV or 11 kV	
		ALTERNATIVELY or ADDITIONALLY:	
	MVA	Total installed capacity where there is a single transformation - eg 132 kV or 66 kV to 22 kV or 11 kV	
	MVA	Total installed zone substation capacity	

Variable	Unit	Definition of variable	Data in RINs?
RELIABILITY			
SAIDI (System Average Interruption Duration Index)		The sum of the duration of each unplanned sustained Customer interruption (in minutes) (without any removal of excluded events and MEDs) divided by the total number of Distribution Customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).	
Distribution–related unplanned SAIDI (whole of network)	System minutes	The number of Distribution Customers used to derive SAIDI should reflect the relevant network type: Whole network – total Distribution Customers, etc	Yes. Whole network and segregation by CBD, Urban, Rural short, Rural long
SAIFI (System Average Interruption Frequency Index)		Unplanned Interruptions (SAIFI) (without any removal of excluded events and MEDs) - The total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.	
Distribution–related unplanned SAIFI (whole of network)		The number of distribution customers used to derive SAIFI should reflect the relevant network type: Whole network – total Distribution Customers, etc	Yes. Whole network and segregation by CBD, Urban, Rural short, Rural long. Sought also at feeder level.

Variable	Unit	Definition of variable	Data in RINs?
ENERGY NOT SUPPLIED			
Energy Not Supplied - Total	GWh	The estimate of energy not supplied to be based on average customer demand (multiplied by number of customers interrupted and the duration of the interruption). Average customer demand to be determined from (in order of preference): (a) average consumption of the customers interrupted based on their billing history (b) feeder demand at the time of the interruption divided by the number of customers on the feeder (c) average consumption of customers on the feeder based on their billing history (d) average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder.	
Energy Not Supplied (planned)	GWh	Total energy not supplied minus Energy Not Supplied – Unplanned	Sought at feeder level
Energy Not Supplied (unplanned)	GWh	The estimate of energy not supplied (due to unplanned outages) based as above	Sought at feeder level
SYSTEM LOSSES			
Line losses – %	percent	Distribution Losses - Calculated as (electricity imported minus electricity delivered) x 100 / (electricity imported) where electricity imported = (total electricity inflow into DNSP's distribution network including from embedded generation) minus (the total electricity outflow into the networks of the adjacent [connected] distribution network service providers or the transmission network(s)).	Yes – as percent of purchases

Variable	Unit	Definition of variable	Data in RINs ?
		All items refer to Expenditure for the provision of the Network services group component of Standard Control Services only. Connection and metering costs etc are to be excluded. Expenditure for the relevant year – in $ of the year.	
OPERATION & MAINTENANCE EXPENDITURE			Yes
Total Distribution O&M Expenditure (opex)	$m	Total Operations and Maintenance Expenditure (excluding interest, depreciation and all capital costs)	
Shared allocation of overheads to opex for distribution activities (eg head office) included in above	$m	Expenses charged to opex other than direct expenses and payments to contactors	
Opex expenditure for activities by contractors	$m	Expenditure on Operations and Maintenance for activities carried out under contract arrangements. To include all payments made including contractor's overheads and profits	
Opex by category[5]			
The costs of operating and maintaining the network (excluding all capital costs and capital construction costs) disaggregated as follows		Costs to include activities carried out under contract arrangements. Allocated overhead costs should be disaggregated to the relevant categories.	Segregation varies
Network operating costs	$m		Segregation varies
Network maintenance costs	$m		Segregation varies
Inspection	$m		
Maintenance and repair	$m		
Vegetation management at DNSP cost	$m		
Emergency response	$m		
Other network maintenance	$m		
Other operating or maintenance costs (specify items > 5% total opex)	$m		
Total opex	$m		

[5] Categories shown are illustrative. It is anticipated final categories will be similar to those derived in the AER's Category Analysis workstream.

Variable	Unit	Definition of variable	Data in RINs ?
Amounts included above payable for easement levy or similar direct charges on DNSP	$m		
Additionally, the following item may be required to facilitate like–with–like comparisons:			
HVC Opex estimate	$m	An estimate of the opex costs that would be associated with end–user contributed assets that are operated and maintained by directly connected end–users (eg transformers) if the operation and maintenance were provided by the DNSP (please describe basis of estimation).	Not sought
USE OF CAPITAL ASSETS AND ALLOCATIONS			
Regulatory Asset Base Values		RAB Value of Assets used for provision of the Network services group component of Standard Control Services only – Give opening value, and capex additions etc below similarly segregated to allow individual asset class roll-forward value averaged over the relevant period	Asset base segregation differs – S/T, Distribution system, and details for eg SCADA, IT public and also for alternative control items etc
Total	$m		Segregation varies
Overhead distribution assets (wires and poles)	$m		
Underground distribution assets (cables, ducts etc)	$m		
Distribution substations including transformers	$m		
Overhead Sub–transmission assets (wires and towers / poles etc)	$m		
Underground Sub-transmission assets (cables, ducts etc)	$m		
Sub–transmission substations including transformers	$m		
Easements	$m		
Other assets with long lives (please specify	$m	Where used for provision of the Network services group component of Standard Control Services only	

Variable	Unit	Definition of variable	Data in RINs ?
Other assets with short lives (please specify	$m	Where used for provision of the Network services group component of Standard Control Services only	
RAB Roll forward to end of period			Segregation varies
For total asset base:			
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for asset value	$m		
For overhead distribution assets:			
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for overhead distribution asset value	$m		
For underground distribution assets:			
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for underground asset value	$m		
For distribution substations and transformers:			
Opening value	$m		

Variable	Unit	Definition of variable	Data in RINs ?
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for distribution substations and transformers asset value	$m		
For overhead subtransmission assets:			
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for overhead subtransmission asset value	$m		
For underground subtransmission assets:			
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for underground subtransmission asset value	$m		
For subtransmission substations and transformers:			
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		

Variable	Unit	Definition of variable	Data in RINs ?
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for subtransmission substation and transformers asset value	$m		
For easements:			
Opening value	$m		
Inflation addition	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for easements asset value	$m		
For “other” asset items with long lives:		Where used for provision of the Network services group component of Standard Control Services only	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for “other” asset (long life) value			
For “other” asset items with short lives:		Where used for provision of the Network services group component of Standard Control Services only	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for “other” asset (short life) value			
Capital Contributions			

Variable	Unit	Definition of variable	Data in RINs ?
Value of Capital Contributions or Contributed Assets	$m		
Asset Lives – estimated service life		Estimated period after installation of new asset during which the asset will be capable of delivering the same effective service as it was at installation date – may not match "financial" or "tax" life	
Overhead distribution assets (wires and poles)	years		
Underground distribution assets (cables)	years		
Distribution substations including transformers	years		
Overhead Sub-transmission assets (wires and towers / poles etc)	years		
Underground Sub-transmission assets (cables, ducts etc)	years		
Sub-transmission substations including transformers	years		
"Other" assets with long lives	years	To match value classifications above	
"Other" assets with short lives	years		
Asset Lives – estimated residual service life		Estimated weighted average residual effective service life for the asset class at reporting date. May not match value for other reporting purposes	
Overhead distribution assets (wires and poles)	years		
Underground distribution assets (cables)	years		
Distribution substations including transformers	years		
Overhead Sub-transmission assets (wires and towers / poles etc)	years		
Underground Sub-transmission assets (cables, ducts etc)	years		
Sub-transmission substations including transformers	years		
"Other" assets with short lives	years	To match value classifications above	
"Other" assets with short lives	years		

[a] Used in Lawrence (2003, 2005) based on Parsons Brinckerhoff (2003)

Table 15: **Electricity TNSP output and input variables and preliminary definitions**

Variable	Unit	Definition of variable	Data in IDR?
TUOS Revenue for Prescribed Transmission Services	$m	Annual Revenue earned from the provision of Prescribed Transmission Services only. Annual Revenue for the relevant year – in $ of the year.	Network charges disclosed
Revenue Grouping by chargeable quantity		Grouping to match tariff charging arrangements – ie not all TNSPs may have charges for all quantities	May be some segregation in sheet PTS Rev Analysis
From Fixed Customer (Exit Point) Charges	$m		
From Variable Customer (Exit Point) Charges	$m		
From Fixed Generator (Entry Point) Charges	$m		
From Variable Generator (Entry Point) Charges	$m		
From Fixed Energy Usage Charges (Charge per day basis)	$m		
From Variable Energy Usage charges (Charge per kWh basis)	$m		
From Energy based Common Service and General Charges	$m	Where Common Service and General Charges are recovered on an energy basis	
From Fixed Demand based Usage Charges	$m	Where charges are made based on a "nominated / agreed" demand basis	
From Variable Demand based Usage Charges	$m	Where charges are made based on a "measured / actual" demand basis	
Revenue Grouping by type of connected equipment			
From Other connected transmission networks	$m		
From Distribution networks	$m		
From Directly connected end–users	$m		
From Generators	$m		
Total	$m		
Revenue/penalties from incentive schemes	$m		

Variable	Unit	Definition of variable	Data in IDR?
ENERGY DELIVERY		The amount of electricity transported through the TNSP's network in the relevant regulatory year (measured in GWh). Metered at the downstream charging location rather than the import location to the TNSP	May be some segregation in sheet PTS Rev Analysis
Total Energy transported	GWh		
Energy Grouping by Downstream Connection type			
To Other connected transmission networks	GWh		
To Distribution networks	GWh		
To Directly connected end–users (please specify voltages)	GWh		
Total energy transported	GWh	Energy measured at the output location or interconnector receiving end	
SYSTEM CAPACITY			
Transmission System Capacities			
O/H Line circuit length by voltage level – km and typical / averaged MVA capacity of circuit at each voltage		Calculated as circuit length (measured in kilometres) of lines in service (the total length of lines including interconnectors, backbone and spurs). A double circuit line counts as two lines. Indicate estimated typical or weighted average circuit capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit should be thermal line rating. Give summer and winter rating if differentiated	Physical data generally not included
500 kV	km & MVA		
330 kV	km & MVA		
275 kV	km & MVA		

Variable	Unit	Definition of variable	Data in IDR?
220 kV	km & MVA		
132 kV	km & MVA		
(Other transmission voltages)	km & MVA	Alternatively, "legacy voltages" or "alternative voltages" eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Other (please specify)	km & MVA		
Total overhead circuit kilometres	km		
U/G Cable circuit length by voltage level – km and typical / averaged MVA capacity of circuit at each voltage		Similarly to OH	Physical data generally not included
500 kV	km & MVA		
330 kV	km & MVA		
275 kV	km & MVA		
220 kV	km & MVA		
132 kV	km & MVA		
(Other transmission voltages)	km & MVA	Alternatively, "legacy voltages" or "alternative voltages" eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Other (please specify)	km & MVA		
Total underground circuit kilometres	km		

Variable	Unit	Definition of variable	Data in IDR?
Installed transmission system transformer capacity		Transformer capacity involved in transformation level indicated below. Give summation of normal assigned continuous capacity / rating (with forced cooling etc if relevant). Include only energised transformers, not cold spare capacity. Include capacity of tertiary windings etc as relevant. Assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing. Do not include step-up transformers at generation connection location	Physical data generally not included
Transmission substations (eg 500 kV to 330 kV)	MVA	Transformer capacity at intermediate locations for transmission service function	
Terminal points to DNSP systems	MVA	Transformer capacity at connection point to DNSP	
Transformer capacity for directly connected end–users owned by the TNSP	MVA	Transformer capacity at connection point to directly connected end user where the capacity is owned by the TNSP	
Transformer capacity for directly connected end–users owned by the end–user	MVA	Transformer capacity at connection point to directly connected end user where the capacity is owned by the directly connected end user. Alternatively give summation of non-coincident individual maximum demands of directly connected end users whenever they occur (ie the summation of a single annual MD for each customer) as a proxy for capacity within the end user's installation.	
Other (please specify)	MVA		
Interconnectors	MVA	TNSP Network capacity available for network interconnector purposes to another network – ie regarding other network as an export capacity required on the source network	

Variable	Unit	Definition of variable	Data in IDR?
System Demand	MW and MVA	As measured at the downstream / output connection locations	Physical data generally not included
Transmission System coincident maximum demand	MW and MVA	Raw coincident transmission system maximum demand without adjustment for weather etc. Include export demand at the time on interconnectors	
Transmission System coincident maximum demand	MW and MVA	Weather–corrected coincident transmission system maximum demand. Include export demand at the time on interconnectors	
Transmission System non-coincident summated maximum demand	MW and MVA	Summation of actual raw demands at the TNSP downstream connection and supply locations at the time when this summation is greatest ie no weather normalisation etc. Include export demand at the time on interconnectors	
Transmission System non-coincident summated maximum demand	MW and MVA	Summation of weather–corrected maximum demands at the TNSP downstream connection and supply locations at the time when this summation is greatest. Include export demand at the time on interconnectors	
CONNECTION POINT NUMBER			
Number of purely entry points to the transmission system at highest transmission voltage		Number of locations where energy in solely injected to the transmission system at highest transmission voltage	
Number of purely exit points from the transmission system at highest transmission voltage		Number of locations where energy is solely taken from the transmission system at highest transmission voltage	
Number of connection points where energy may enter or exit the transmission system at highest transmission voltage		Number of locations where energy transfer may be into or from the transmission system at highest transmission voltage	
Number of purely entry points to the transmission system at other than highest transmission voltage		Number of locations where energy in solely injected to the transmission system at other than highest transmission voltage	
Number of purely exit points from the transmission system at other than highest transmission voltage		Number of locations where energy is solely taken from the transmission system at other than highest transmission voltage	

Variable	Unit	Definition of variable	Data in IDR?
Number of connection points where energy may enter or exit the transmission system at other than highest transmission voltage		Number of locations where energy transfer may be into or from the transmission system at other than highest transmission voltage	
PERFORMANCE TO STPIS COMPONENTS		Definitions etc as specified in the December 2012 Electricity transmission network service providers Service target performance incentive scheme documents.	Service Standards performance has been sought, but new scheme data differs
1 - Service Component			
Service Parameter 1 – Average Circuit outage rate		Note, in particular, “outage” means “loss of connection” rather than loss of supply by a connected system or customer. To allow summation into an overall Average Circuit outage rate, both numerator (No. of Events with defined circuits unavailable per annum) and denominator (Total No. of defined circuits) are needed as well as the calculated percentage rate for each item.	
Lines outage rate - fault	percent		
Number of Lines fault outages	number		
Number of defined Lines	number	As used to calculate the outage rate above	
Transformers outage rate - fault	percent		
Number of Transformer fault outages	number		
Number of defined Transformers	number	As used to calculate the outage rate above	
Reactive plant outage rate - fault	percent		
Number of Reactive plant fault outages	number		
Number of defined Reactive plant	number	As used to calculate the outage rate above	
Lines outage rate – forced outage	percent		
Number of Lines forced outages	number		
Transformer outage rate – forced outage	percent		

Variable	Unit	Definition of variable	Data in IDR?
Number of Transformers forced outages	number		
Reactive plant outage rate – forced outage	percent		
Number of Reactive plant forced outages	number		
Service Parameter 2 – Loss of supply event frequency – number in ranges specified	number	Values for x and y are specified for individual TNSPs in the STPIS documents	
Number of events greater than x system minutes per annum	number		
Number of events greater than y system minutes per annum	number		
Service Parameter 3 – Average outage duration			
Average outage duration	minutes		
System Parameter 4 – Proper operation of equipment – number of failure events			
Failure of protection system	number		
Material failure of Supervisory Control and Data Acquisition (SCADA) system	number		
Incorrect operational isolation of primary or secondary equipment	number		
2 - Market Impact Component			
Market Impact Parameter	Number of dispatch intervals	Definition etc as specified in the December 2012 Electricity transmission network service providers Service target performance incentive scheme documents.	
3 - Network Capability Component		Not relevant for economic benchmarking of network performance	
Unsupplied system minutes	minutes	The amount of energy (MWh) not supplied to consumers divided by the maximum demand (MW) and multiplied by 60 to bring it to minutes	Published in AEMC Market Performance Review

Variable	Unit	Definition of variable	Data in IDR?
System losses	percent	Losses as percentage of Energy input to transmission system network	
OPERATION & MAINTENANCE EXPENDITURE		All items refer to Expenditure for the provision of Prescribed Transmission Services only. Expenditure for the relevant year – in $ of the year.	
Total Transmission O&M Expenditure (opex)	$m	Total Operations and Maintenance Expenditure (excluding interest, depreciation and all capital costs)	
Shared allocation of overheads to opex for transmission activities (eg head office) included in above	$m	Expenses charged to opex other than direct expenses and payments to contactors	
Opex expenditure for activities by contractors	$m	Expenditure on Operations and Maintenance for activities carried out under contract arrangements. To include all payments made including contractor's overheads and profits	
Opex by category[6]			
The costs of operating and maintaining the network (excluding all capital costs and capital construction costs) disaggregated as follows:		Costs to include activities carried out under contract arrangements. Allocated overhead costs should be disaggregated to the relevant categories	
Network operating costs	$m		
Network maintenance costs:	$m		
Inspection	$m		
Maintenance and repair	$m		
Vegetation management at TNSP cost	$m		
Emergency response	$m		
Other network maintenance	$m		
Other operating costs (specify items > 5% total opex)			
Total opex	$m		

[6] Categories shown are illustrative. It is anticipated final categories will be similar to those derived in the AER's Category Analysis workstream

Variable	Unit	Definition of variable	Data in IDR?
Amounts included above payable for easement levy or similar direct charges on TNSP	\$m		
USE OF CAPITAL ASSETS AND ALLOCATIONS			
Regulatory Asset Base Values		RAB Value of Assets used for provision of Prescribed Transmission Services only – Give opening value, and capex additions etc below similarly segregated to allow individual asset class roll-forward value averaged over the relevant period	
Total	\$m		
Overhead transmission assets (wires and towers/poles etc)	\$m		
Underground transmission assets (cables, ducts etc)	\$m		
Substations, switchyards, Transformers etc with transmission function		Asset value of installations involved in transformation level indicated below. Include value of energised transformers, not cold spare capacity. Include capacity of tertiary windings etc as relevant. Include relevant small equipment (eg CB's, CT's Do not include step-up transformers at generation connection location	
Transmission switchyards, substations etc (eg 500 kV to 330 kV and 330 kV to 132 kV), including transformers and including switchyards without transformers etc Including TNSP assets for connection to DNSPs or direct connected end use customers	\$m	Asset value of installations at intermediate locations for transmission service function	
Easements	\$m		
Other assets with long lives (please specify)	\$m	Where used for provision of Prescribed Transmission services only	
Other assets with short lives (please specify)	\$m		
RAB Roll forward to end of period			
For total asset base:		As above	

Variable	Unit	Definition of variable	Data in IDR?
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for asset value	$m		
For overhead transmission assets:		As above	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for overhead distribution asset value	$m		
For underground transmission assets:		As above	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for underground asset value	$m		
For transmission switchyards, substations etc including transformers and including switchyards without transformers and including TNSP assets for connection to DNSPs or direct connected end use customers:		As above	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		

Variable	Unit	Definition of variable	Data in IDR?
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for transmission switchyards, substations etc	$m		
For easements:		As above	
Opening value	$m		
Inflation addition	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for “other” asset value	$m		
For “other” assets with long lives:		As above	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for “other” asset (long life) value	$m		
For “other” assets with short lives:		As above	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for “other” asset (short life) value	$m		
Asset Lives – estimated service life	years	Estimated period after installation of new asset during which the asset will be capable of delivering the same effective service as it was at installation date – may not match “financial” or “tax” life	
Overhear transmission assets	years		
Underground transmission assets	years		
Switchyard, substation and transformer assets	years		

Variable	Unit	Definition of variable	Data in IDR?
“Other” assets with long lives	years		
“Other assets with short lives	years		
Asset Lives – estimated residual service life		Estimated weighted average residual effective service life for the asset class at reporting date. May not match value for other reporting purposes	
Overhear transmission assets	years		
Underground transmission assets	years		
Switchyard, substation and transformer assets	years		
“Other” assets with long lives	years		
“Other assets with short lives	years		

APPENDIX A: SHORT LISTED DNSP OUTPUTS DEFINITIONS

Table A1: **Short listed DNSP outputs and preliminary definitions**

Output	Suggested definition
Customer numbers (total or by broad class or by location)	The average of the number of customers measured on the first day of the Relevant Reporting Year and on the last day of Relevant Reporting Year Including inactive, unmetered, disconnected customers where supply is available from the network Segregation by Customer Class (eg Domestic, Non-domestic LV demand tariff customers, HV demand tariff customers etc) Segregation by location on the network (eg CBD, Urban, Short rural, Long rural)
Non–coincident peak demand	Summation of actual raw maximum demands (MVA and MW) at the zone substation level independent of when they occur (ie no weather normalisation etc).
System capacity (taking account of both transformer and line/cable capacity)	Assigned ratings (MVA) of all energised zone substation power transformers. Excluding VTs, CTs, station service transformers, non-energised and spare units. Nameplate ratings (MVA) of all energised distribution power transformers. Excluding VTs, CTs, station service transformers, non-energised and spare units Power transformer capacity involved in intermediate level transformation capacity (i.e. subtransmission voltages132kV/66kV/33kV) to distribution level (i.e. 22kV/11kV/6.6kV) Assigned and nameplate rating to recognise forced air and/or oil cooling adjustments where appropriate.
Reliability (total customer minutes off–supply and/or total customer interruptions)	SAIDI - The sum of the duration of each unplanned sustained Customer interruption (in minutes) (after removing excluded events and MEDs) divided by the total number of Distribution Customers. Unplanned SAIDI excludes momentary interruptions (one minute or less). SAIFI - Unplanned Interruptions (SAIFI) (after removing excluded events and MEDs) - The total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

Output	Suggested definition
Throughput (total and / or by broad customer class or by location).	Energy delivered to customers, measured at the customers locations. Total annual energy and Segregation by Customer Class (eg Domestic, Non-domestic, LV demand tariff customers, HV demand tariff customers etc) Segregation by location on the network (eg CBD, Urban, Short rural, Long rural)

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