Measurement of Inputs for Economic Benchmarking of Electricity Network Service Providers

Briefing Notes prepared for
Australian Energy Regulator

22 April 2013

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CONTENTS

Executive Summary ii
1 Background 1
2 NSP Input Quantity and Price Issues 2
2.1 Distribution cost coverage 2
2.2 Opex price index 3
2.3 Easements 6
2.4 Distribution network complexity 7
2.5 System capacity and capital input quantities 7
2.6 WACC for use in economic benchmarking 8
3 Input Specifications and Data Requirements 9
3.1 Short listed input specifications 9
3.2 Data requirements 13
References 30

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. These briefing notes provide background material for the sixth workshop which is on measuring inputs to be used for economic benchmarking of electricity network service providers (NSPs).

Inputs – issues for discussion

Data requirements

The DNSP and TNSP input data requirements to implement economic benchmarking are listed in tables 2 and 3, respectively, in section 3.2 along with preliminary variable definitions and an indication of whether the variable is currently collected in DNSP Regulatory Information Notices (RINs) or TNSP Information Disclosure Requirements (IDRs). The variables listed are required to support the short listed input specifications and a range of anticipated sensitivity analyses.

1) *Are there any variables missing from tables 2 and 3 in section 3.2 that should be there?*
2) *Are the definitions proposed appropriate for economic benchmarking?*
3) *Should any of the definitions be altered to ensure consistency of interpretation and hence data across DNSPs and across TNSPs?*

Distribution cost coverage

We propose to adopt a narrow definition of DNSP cost coverage which includes only costs associated with the AER’s network services group. 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 other activities 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.

4) *Do you foresee any problems with adopting this narrow coverage of DNSP costs?*

Opex price index

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.

We propose the price of opex be taken as a weighted average of either the ABS Electricity, gas, water and waste sector (EGWW) AWOTE labour index or the ABS Wages price index (WPI) and five ABS Producer price indexes (PPIs) covering business, computing, secretarial, legal and accounting, and public relations services used by DNSPs.

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.

5) *Are there other major items whose price should be reflected in the opex price index?*

6) *Is the composition of opex for TNSPs similar to that for DNSPs?*

Easements

Easements are rolled into the RAB at their purchase cost and indexed for CPI each year. The NSPs earn the WACC rate of return on easements but they are not depreciated. The most straightforward treatment of easements for economic benchmarking purposes is to add the return on easements to the relevant return on overhead lines and underground cables capital. The return of capital for overhead lines and underground cables remains unchanged as easements are assumed to have zero depreciation. This approach effectively assumes that the quantity of easement capital is directly related to the quantity of overhead lines and underground cables capital. An alternative, possibly more accurate, treatment would be to have easements as a separate capital input whose quantity is the route length of lines.

7) *Should the return on easements capital be simply added to the return on lines and cables capital?*

Distribution network complexity

Economic benchmarking implicitly assumes that all DNSPs have the same system boundary and 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. 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 (eg by focusing on the final distribution level of transformation).

8) *How should differences in distribution system structure be allowed for in economic benchmarking?*

Short listed input specifications

Based on Economic Insights (2013c), feedback at the third workshop and the discussion in section 2, we recommend that the NSP input specifications listed in table A be considered for use in economic benchmarking studies.

Table A: **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 (KVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / KVA
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

9) *Have any important inputs been left out of the short listed specifications?*

System capacity and capital input quantities

It should be noted the physical measure of system capacity output proposed and proposed physical proxies for capital input quantities are quite different.

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. Overhead lines and underground cable MVA–kilometres are included separately. Since underground cables are considerably more costly than overhead lines, they receive a correspondingly higher weight in forming the total input quantity. 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).

The system capacity output physical proxy that has been proposed, on the other hand, is the product of total line circuit length (in kilometres and unadjusted for capacity) and transformer capacity at the last or distribution transformer level only.

1 BACKGROUND

The Australian Energy Regulator (AER) has initiated a work stream 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 2012). 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 businesses.

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. In March 2013 a series of 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 is now moving into its second phase discussing specific measurement and data issues associated with the outputs, operating environment factors and inputs for use in economic benchmarking. These briefing notes provide background material for the third workshop of the second phase (and the sixth overall) on measuring inputs to be used for economic benchmarking of electricity NSPs.

The second section of the briefing notes discusses a number of input quantity and price issues arising from the first phase discussions. These include:

- distribution cost coverage
- the opex price index to be used
- the treatment of easements
- distribution network complexity
- system capacity and capital input quantities, and
- the WACC to be used.

The third section lists short listed input specifications based on discussions and feedback to date. It also lists the input data requirements for economic benchmarking of DNSPs and TNSPs and presents some preliminary input variable definitions.

2 NSP INPUT QUANTITY AND PRICE ISSUES

The primary issue for discussion at the sixth workshop is whether the DNSP and TNSP input data requirements to implement economic benchmarking listed in tables 1 and 2, respectively, in section 3.2 are complete. That is, are there any variables missing from tables 1 and 2 in section 3.2 that should be there? The tables also list preliminary variable definitions and give an indication of whether the variable is currently collected in DNSP RINs or TNSP IDRs. We are interested in feedback on whether the definitions are appropriate for economic benchmarking and whether any definitions should be altered to ensure consistency of interpretation and hence data across DNSPs and across TNSPs.

Before presenting the data requirements tables in section 3, in this section we discuss and provide further analysis on several issues raised in the third workshop.

2.1 Distribution cost coverage

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.

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, there is diverse treatment of the other six 'non–core' activities.

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.

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 costs associated with 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 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).

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.

2.2 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 2012) 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 Wages price index (WPI).

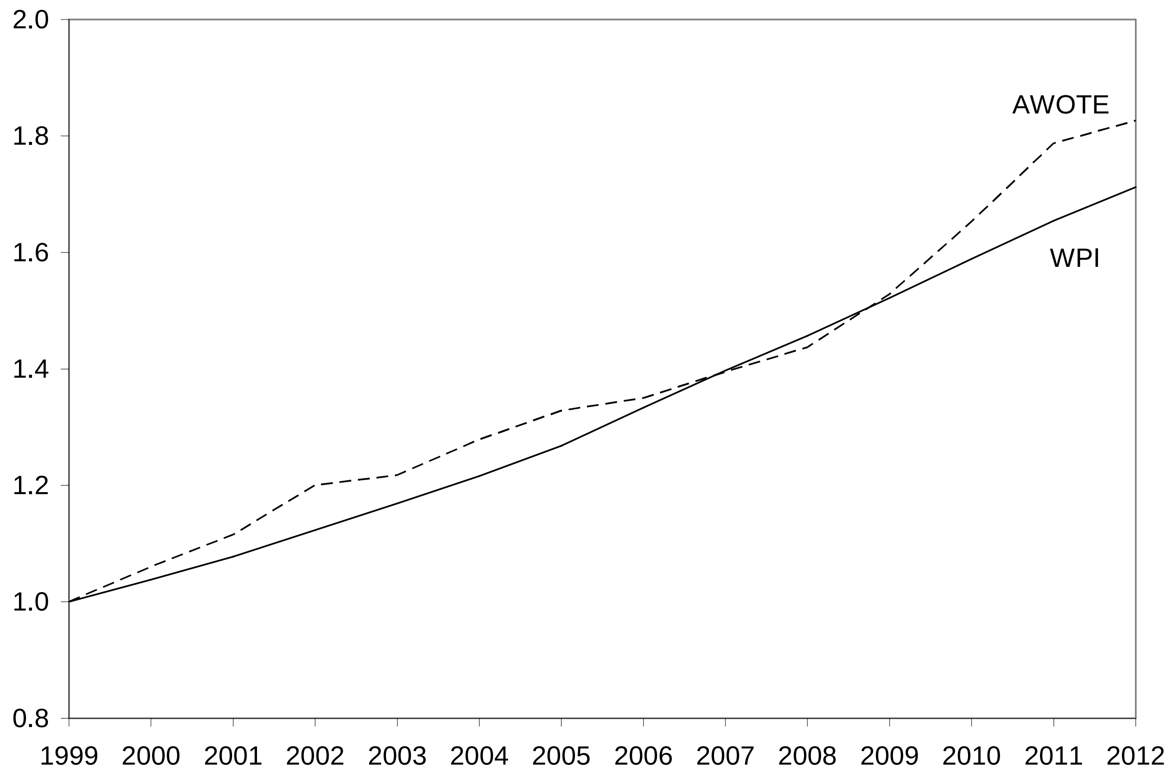
AWOTE and the WPI both have some advantages and disadvantages for efficiency measurement purposes. Whichever index is used, it is important to ensure that that index is used consistently across the different parts of the building blocks framework. In particular, if the opex rate of change approach is 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 reverse would likely be the case. 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).

2.3 Easements

Stakeholders at the third workshop noted easement valuation methods have differed amongst NSPs and that the valuation method may have a significant impact on the RAB.

The treatment of easements in the RAB is relatively straight forward. Easements are rolled into the RAB at their purchase cost and indexed for CPI each year. The NSPs earn the WACC rate of return on the easements but the easements are not depreciated. For assets where the value of the easements is mixed with the purchase price (such as for buildings) the proportionate value of the easements is estimated. The proportionate value that is the easement is treated as an easement and the remainder is treated as a depreciating asset. Easements that are leased are treated in exactly the same manner (ie their estimated value is included in the RAB – it is indexed to the CPI, not depreciated and NSPs earn the WACC return on it).

The most straightforward treatment of easements for economic benchmarking purposes is to add the return on easements to the relevant return on overhead lines and underground cables capital. Overhead line length versus underground cable length could be used to allocate easements between overhead and underground. The return of capital for overhead lines and underground cables remains unchanged as easements are assumed to have zero depreciation. This approach effectively assumes that the quantity of easement capital is directly related to the quantity of overhead lines and underground cables capital. An alternative, possibly more accurate, treatment would be to have easements as a separate capital input whose quantity is the route length of lines (as the easement is expected to be independent of the capacity of the line).

It is noted that the valuation of easements may not be consistent across jurisdictions. This is a similar issue to the initial capital bases of NSPs not all having been calculated on the same basis and some having been subsequently adjusted. Whether anything needs to be done about such differences depends on how the relevant input quantities are measured. If physical quantity proxies are used then the valuations do not need to be adjusted as they reflect the cost to the NSP and they do not distort the quantity measure. If deflated value proxies are used then some adjustment may need to be made (to the value that is deflated) to avoid distortions to the quantity measures.

2.4 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 3 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.

2.5 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.

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.

2.6 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.

3 INPUT SPECIFICATIONS AND DATA REQUIREMENTS

3.1 Short listed input specifications

Based on Economic Insights (2013c), feedback at the third workshop and the discussion in section 2, we recommend that the NSP input specifications listed in table 1 be considered for use in economic benchmarking studies.

Table 1: **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 (KVA)	AUC (Return of & on Transformers & other capital)	Transformers & other AUC / KVA
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 (2012) 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 AWOTE – 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 (2012). 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 1. 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 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 2009). 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 1 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 1 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.

3.2 Data requirements

The DNSP input data requirements to implement economic benchmarking are listed in table 2 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 short listed input specifications, possible alternative specifications which may be developed and a range of anticipated sensitivity analyses.

Stakeholders views are sought on whether the definitions proposed are appropriate for economic benchmarking purposes and whether any of the definitions should be altered to ensure consistency of interpretation and hence data across DNSPs.

The TNSP input data requirements to implement economic benchmarking are listed in table 3 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 short listed input specifications, possible alternative specifications which may be developed and a range of anticipated sensitivity analyses.

Stakeholders views are sought on whether the definitions proposed are appropriate for economic benchmarking purposes and whether any of the definitions should be altered to ensure consistency of interpretation and hence data across TNSPs.

Table 2: **Electricity DNSP input variables and preliminary definitions**

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 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[1]			
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	$m		
Emergency response	$m		
Other network maintenance	$m		
Other operating or maintenance costs (specify items > 5% total opex)	$m		
Total opex	$m		

[1] 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 ?
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[2]			
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 in MVA 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	Length sought, but segregation is by function (S/T, HV and LV). Capacity not sought.
O/H Low voltage distribution	km & MVA	0.4 MVA used in previous analysis[a] (by way of example)	
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		
(Other distribution voltages)	km & MVA	Alternatively, “legacy voltages” eg 6.6 kV may be captured into the nearest relevant voltage currently in use.	

[2] Some system data items are also sought in the Output Tables. They are repeated here for completeness.

Variable	Unit	Definition of variable	Data in RINs ?
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] (by way of example)	
(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.
U/G Low voltage distribution	km & MVA	0.4 MVA used in previous analysis[a] (by way of example)	
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]	

Variable	Unit	Definition of variable	Data in RINs ?
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	MVA	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
Distribution power transformer capacity owned by HVCs	MVA	Transformation capacity from HV 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 capacity within the HVC.	Not separated

Variable	Unit	Definition of variable	Data in RINs ?
Subtransmission power transformer capacity	MVA	Transformer capacity involved in intermediate level transformation capacity (ie subtransmission voltage eg 132 kV or 66 kV etc subtransmission to distribution level eg 22 kV or 11 kV) Give separate summations of normal assigned continuous capacity / rating (with forced cooling etc if relevant) and of nameplate continuous rating including forced cooling 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)
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	$m	Where used for provision of the Network services group component of Standard Control Services only	

Variable	Unit	Definition of variable	Data in RINs ?
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		
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 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		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		

Variable	Unit	Definition of variable	Data in RINs ?
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:		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 value			
Capital Contributions			
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		

Variable	Unit	Definition of variable	Data in RINs ?
Underground Sub-transmission assets (cables, ducts etc)	years		
Sub-transmission substations including transformers	years		
Other			
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	years		

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

Table 3: **Electricity TNSP input variables and preliminary definitions**

Variable	Unit	Definition of variable	Data in IDR?
		All items refer to Expenditure for the provision of Prescribed Transmission Services only. Expenditure for the relevant year – in $ of the year.	
OPERATION & MAINTENANCE EXPENDITURE			
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[3]			
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	$m		
Emergency response	$m		
Other network maintenance	$m		
Other operating costs (specify items > 5% total opex)			
Total opex	$m		
USE OF CAPITAL ASSETS AND ALLOCATIONS[4]			

[3] 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?
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 in MVA for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal, voltage drop or other limitation as relevant	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 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

[4] Some system data items are also sought in the Output Tables. They are repeated here for completeness.

Variable	Unit	Definition of variable	Data in IDR?
500 kV	km & MVA		Physical data generally not included
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		
Installed transmission system transformer capacity	MVA	Transformer capacity involved in each transformation level indicated below. Give separate summations of normal assigned continuous capacity / rating (with forced cooling etc if relevant) and of nameplate continuous rating including forced cooling 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	

Variable	Unit	Definition of variable	Data in IDR?
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		
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), including transformers etc	$m	Asset value of installations at intermediate locations for transmission service function	
Terminal points to DNSP systems including TNSP transformers	$m	Asset value of TNSP installations at connection point to DNSP	

Variable	Unit	Definition of variable	Data in IDR?
Transformer capacity for directly connected end–users owned by the TNSP	$m	Asset value of transformer capacity at connection point to directly connected end user where the capacity is owned by the TNSP	
Easements	$m		
Other assets (please specify)	$m		
RAB Roll forward to end of period			
For total asset base:		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 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:		As above	
Opening value	$m		

Variable	Unit	Definition of variable	Data in IDR?
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		
Disposals	$m		
Closing value for transmission switchyards, substations etc	$m		
For terminal point connections to DNSPs		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 terminal pointy connections to DNSP	$m		
For direct connection to end user (where equipment is owned by TNSP)		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 terminal pointy connections to DNSP	$m		
For easements:		As above	
Opening value	$m		
Inflation addition	$m		
Straight line depreciation	$m		
Regulatory depreciation	$m		
Actual additions (recognised in RAB)	$m		

Variable	Unit	Definition of variable	Data in IDR?
Disposals	$m		
Closing value for “other” asset value	$m		
For “other” asset base:		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 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		
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		

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