The Energy Queensland Group

Submission on the *Draft Annual Benchmarking Report Electricity Distribution Network Service Providers*

Australian Energy Regulator

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Part of the Energy Queensland Group

Submission on the *Draft Annual Benchmarking Report, Electricity Distribution Network Service Providers*

CONTENTS

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Submission on the Draft Annual Benchmarking Report, Electricity Distribution Network Service Providers

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INTRODUCTION

Ergon Energy Corporation Limited (Ergon Energy) and Energex Limited (Energex) welcome the opportunity to provide comment to the Australian Energy Regulator (AER) on its *Draft Annual Benchmarking Report, Electricity Distribution Network Service Providers* (2017 Draft Annual Benchmarking Report) currently anticipated for release in November 2017. This submission is provided by Ergon Energy and Energex as Distribution Network Service Providers (DNSPs) operating in Queensland as part of the Energy Queensland Limited group.

It is noted that in developing its Draft Annual Benchmarking Report the AER has been reviewing and undertaking analysis of the 2015-16 regulatory year responses to the Economic Benchmarking Regulatory Information Notice (EB RIN) issued. Answers to questions raised by the AER as well as feedback on other anomalies or errors relevant to 2015-16 EB RIN data have been provided informally, in addition to this response.

Should the AER require, Ergon Energy and Energex are available to discuss or provide further detail regarding the issues raised herein.

KEY MESSAGES

Generally, Ergon Energy and Energex continue to advocate benchmarking as a valuable tool that can provide insight to the relative performance of DNSPs. However, whilst acknowledging the additional analysis provided in relation to the relative changes in inputs and outputs over time, the AER's economic approach, modelling and specifications remain analogous to prior years.

The AER continues to focus on Multilateral Total Factor Productivity (MTFP) as the primary technique to compare 'DNSP's overall efficiency at providing electricity services' and 'track changes in efficiency over time'. Partial Productivity Indicators (PPIs) are used to support the results of MTFP and Multilateral Partial Factor Productivity (MPFP) indices (for both Capital and Operating) and the majority of selected inputs and outputs remain unchanged albeit, information has been updated for most recently received DNSP data (2015-16).

AER assumes the absolute MTFP score reflects operating "efficiency" relative to the current operating environment. Whereas the relative 'change' in the AER's MTFP measure over time maybe more reflective of an efficiency (or otherwise) response by DNSPs to their individual changing environments.

Ergon Energy and Energex's prior submitted concerns (on prior annual benchmarking reports or during resets) remain unchanged. The report falls short of addressing any matters previously identified:

- Whilst AER has undertaken and reflects upon, analysis of the key drivers of changes to network productivity (e.g. relative contributions of network inputs and outputs), there has been no evolution or refinement of the AER's benchmarking model despite significant feedback and commentary provided by NSPs and their consultants;
- Recent Australian Competition Tribunal's (ACT) and Federal Court decisions highlighting the analytical shortcomings, data quality issues and limitations in the interpretation of the econometric Opex benchmarking results do not appear to have been considered nor addressed;
- Data quality and other anomalies remain very important considerations, and datasets remain in their infancy. Differences in approaches taken and interpretations applied across NSPs are evident with simple investigation. Furthermore, network design, changes in SAIDI and accounting practices (amongst other things) pose possible influence to year on year variations in the AER's productivity results. An approach that is of sufficient quality to reliably inform

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Energy Queensland Limited ABN 96 612 535 583
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stakeholders of the relative efficiency of DNSPs, takes time and refinement.

- Limitations and physical barriers to perceived “high” performance are not considered in any analysis and subsequent conclusions made. Ergon Energy (for example) may never be perceived as a “high” performer under current model specifications due to the inherent physical challenges of operating a rural network over a large area. Whatever changes Ergon Energy makes to (reduce) Opex, or, regardless of any benefit of circuit length in the output- its low customer numbers, high SAIDI and higher total capacity of network required to transport electricity over long distances will continue to bias the current outturn benchmarking results.

The AER should consider and address the substantive body of material provided to date - from service providers, independent consultants and academics alike - and engage with a broad section of the industry relative to alternative approaches (or improvements to the current).

ECONOMIC BENCHMARKING DATA SET

Given prior submitted concerns as to the AER’s approach remain unchanged the focus herein has been on anomalies and/or errors identified, or conclusions made in the AER’s 2017 Draft Annual Benchmarking Report and associated memorandum and workbooks (by Economic Insights (EI)).

Anomalies and Errors

A number of errors have been identified and informally discussed with the AER prior to this submission (noted in **Appendix A** for completeness). These errors, as well as the below mentioned error in not recognising resubmitted operating expenditure (Opex) data by Ergon Energy, have impacted key variables in the AER’s benchmarking model and analysis including: Opex, RAB, Asset Cost, Total user cost, CAIDI, Depreciation, Return on Investment and MVAkms (circuit length times by circuit capacity). MTFPs and MPFPs may also be affected.

We acknowledge the AER’s collaborative approach to correction of these errors, though this may change some of the observations presented in the Draft Report.

Operating Expenditure

Ergon Energy

An error was identified in files “DERGDATA.txt”, “DNSP PPI master.xlsx” and “DNSP AUC.xlsx”, whereby DOPEX0201 Opex for Network Services did not reflect data resubmitted by Ergon Energy (31 October 2016) for 2015-16 and all historical years, for EB RIN table 3.2.1. Of note:

- Ergon Energy’s 2010-15 Cost Allocation Method (CAM) recognised under or over applied overheads as Other Operating Costs where not material. Upon final reconciliation of the shared costs allocated through the overhead allocation process at the end of 2014-15, $21.4M had been over-applied. In accordance with Ergon Energy’s 2010-15 CAM, this amount was determined to be not material and was not directly attributed or causally allocated – rather, the amounts were allocated entirely to the distribution business (negative Opex).

  Of note, Ergon Energy’s 2015-20 CAM saw such amounts remain **outside** the distribution business (corporate). Accordingly, a recast of historical information was presented in Table 3.2.2 – Opex Consistency, to reflect (amongst other things) this change in cost allocation approach for 2015-16 (and beyond).

  The impact of the changes between years in this variable alone (refer to reported DOPEX0112 data), caused fluctuations in total Opex for network services for Ergon Energy across years.

Importantly, it is reiterated that such alternative approaches to under/over recoveries (and other matters in DNSP approaches to cost allocation) serve to limit true comparability of the AER's modelling in this regard.

The AER considers Opex to be an immediate and short term input to the modelling of costs for provision of a DNSP's network services. In its analysis the AER questioned the large increase in Ergon Energy's reported Opex for Network Services (DOPEX0201) in recent years.

Based on the abovementioned resubmitted data, Ergon Energy makes the following comments on influences of reported Opex for Network Services over recent years:

- Preventative and corrective expenditure has been influenced by:
    - Preventative Maintenance in 2013-14 (and partially, 2012-13) was significantly lowered due to a move to aerial scoping for vegetation management and the "capitalisation" of the ROAMES first full flight cycle (in accordance with approved accounting procedures). The absence of the full value of ~$15m (overheads inclusive) for a cycle has artificially lowered Opex for Network Services in 2013-14.
    - 2014-15 was the first full year of ROAMES LiDAR inspection costs. Efficiencies in the vegetation management program reflective of improved processes, analysis and application of ROAMES information and management intervention started to be realised in 2015-16. Of note, this relative improvement has been maintained in 2016-17 and is expected to continue into future periods.
    - 2014-15 Opex for Network Services was also materially affected by weather and storm events. In all, the year represented a very active storm season with 37,700 events, the most significant being tropical cyclone Marcia. With a total event cost in the order of $30M, pole defect remediation programs, Failed In Service and Emergency Replacements works associated with Cyclone Marcia and other storm recoveries resulted in material rises in both forced maintenance (~$10M) and other network maintenance (~$11M).

      Such "one-off" influences have served to "artificially" influence Ergon Energy's efficiency in 2014-15. Importantly, this material spend does not reflect a decline in efficiency or productivity by Ergon Energy in carrying out its core network services.
    - During 2015-16 a strategy change was implemented to align all requirements for non-routine maintenance to our Defect Classification Manuals. This reduced number of non-compliance instances against acceptance criteria identified during the routine maintenance process resulting in less non-routine maintenance work across several asset classes;
    - A catch up on the Lines Maintenance Program Quantities in 2015-16 resulted from the previous year influence of TC Marcia and other delivery related impacts. Additionally some carryover of a carry-over of Preventative Maintenance expenditure from 2014-15 into 2015-16 as claims were completed, rechecked and verified; and
    - Of note, unit rate efficiencies for Lines Inspections have been implemented in 2016-17. This relative improvement compared to prior years is expected to continue.
- The following movements in reported Opex impact in the AER's modelling, and also do not serve to reflect changes in efficiency or productivity by Ergon Energy in carrying out its core network services:
    - Corporate restructuring resulted in$14.5M expenditure in 2014-15 (mainly redundancies) and a further $43.M in 2015-16, as a result of formation of Energy

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Queensland Limited group and a transition to workforce levels to align with the AER's 2015-20 Final Determination forecasts. Of note, while corporate restructuring has declined in 2016-17, it has remained at 2014-15 levels.

  - Not proceeding Network Initiated Capital Works increased to $28.6m in 2014-15 before declining in 2015-16 with $13.7m written off. This was primarily due to the relaxation of N-1 safety criteria and the Safety Net resulting in a number of projects considered no longer necessary. A residual amount was written off for the Blueprinting Phase of a Demand Management System Project for control centre automation as it was considered uneconomically feasible to proceed.

Energex

Energex makes the following comments with regards to its Opex for Network Services over recent years:

- The decline in Customer services (including call centre) expenditure is a reflection of:
  - productivity improvements achieved through automation of workflows and the cross skilling of staff, reducing the overall staffing numbers; and
  - fewer customer requested services including loss of supply calls and cold water complaints as a result of equipment upgrades and an increase in solar hot water systems.
- The introduction of a new contracting model for Vegetation management in 2014-15 resulted in significant savings;
- Other influences over reported Opex for Network Services over recent years which t do not serve to reflect changes in efficiency or productivity by Energex in carrying out its core network services include:
  - The reclassification of services in 2015-16 resulted in a large portion of the operating expenditure for Network billing and other energy market services (including meter reading) being moved to Alternative Control Services; and
  - Redundancy costs continuing to fall from the historical high of $51M in 2014-15 to $9.9M in 2015-16. This is expected to continue to fall over time.

Reliability

One of the outputs selected by the AER as representative of the services provided by NSPs, reflecting our need to provide customers with access to a safe and reliable supply of network, is Reliability. To include this measure in a benchmarking model without consideration or identification of the impact of the unique operating environment factors facing individual DNSPs is problematic.

Ergon Energy

A significant driver of the perceived productivity decrease for Ergon Energy between 2014 and 2016 has been Ergon Energy’s reliability inputs. Customer minutes off supply rose from 165 million unplanned minutes in 2014, to near 200 million minutes in 2015 and back to c.195 million minutes in 2016. The impact of severe storm seasons and weather events, not all of which are able to be excluded as Major Event Days (MEDS), alters the outturn reliability result in each year. As noted above, there will also be an associated impact on Opex in any given year due to the relative severity of storms impacting the network, in turn, possibly magnifying any perceived change in productivity.

Volatility in year on year SAIDI performance that is inherent in a network such as Ergon Energy’s will cause fluctuations of the MTFP and PFP scores that are not associated with changes in productivity or efficiency.

For example, from October to January 2016, periods of severe weather through the Central and Southern Highlands had a pronounced influence on the Long Rural (LR) SAIDI and SAIFI performance. Reliability performance in the period after January did however stabilise and across the later period of the year approached the forecast performance for the feeder category.

For 2015-16, two MEDs were identified associated with severe weather events. The exclusion of the interruptions occurring on MEDs effected performance variability in the Urban (UR) and Short rural (SR) categories. However these exclusions had limited influence on the LR category performance reported for 2015-16.

Although there were no cyclones that impacted Ergon Energy's supply network in 2015-16, the LR category was impacted by an early start to the summer storm season. The LR distribution network experienced a 19% increase in storm related supply interruption events in 2015-16 compared to the 5yr historical average. When compared to 2014-15, the LR feeder type experienced:

- 17% more unplanned supply interruption events,
- 2% more in unplanned customer interruptions; and
- 8% decrease in unplanned minutes of interrupted supply to customers

The annual variability in supply interruptions occurring in the rural areas is influenced significantly by the severity of weather events and in general by longer term weather patterns. The duration of the supply interruption events in these areas is extended (by comparison to the urban areas) because of the vast geographical spread of assets serviced by the regional depots and the interruption exposure resulting from the predominantly radial arrangement of the supply chain in this network type.

Ergon Energy continues to reiterate that reliability is problematic in its influence over benchmark modelling for several reasons:

- it is volatile and therefore moderate changes in SAIDI between years can outweigh all other changes in variables;
- the multiplicative nature of the variable (SAIDI times customers) means that large rural networks have much higher values for this variable;
- an increase in customers is "positive" from an output perspective. However, an increase in customers combined with a constant SAIDI (or even a slight to moderate improvement in SAIDI) will still cause a negative productivity statement (as more customers at the same SAIDI is more customer minutes off supply);
- the cause of fluctuations in SAIDI is often exogenous and much harder to keep constant for large, rural, radial networks.

The focus of Ergon Energy's capital investment strategy is transitioning from reliability improvement to reliability maintenance. As a result the longer term and underlying reliability performance levels are expected to stabilise in line with the transition in investment approach.

Annual reliability performance will however remain variable as a result of the strong link to weather pattern variation. The 2015-16, overall unplanned interruption duration and interruption frequency were comparable to 2014-15, with only a 1% improvement in average interruption duration and no change in average interruption frequency. Ergon Energy continues to monitor, analyse and undertake the remedial action to ensure that underlying reliability performance levels are maintained and only improved where it is prudent to do so.

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Energex

Energex's improvement in reliability has predominantly been due to improvements made in the resilience of the network over a period of years as a result of well targeted:

- Augmentation (AUGEX) programs to reduce the number of customers impacted by events;
- Replacement (REPEX) programs which reduced the failure rates of equipment;
- Vegetation management programs which delivered improved performance outcomes during storms.

Mild weather conditions in 2015-16 also contributed to this favourable performance.

Energex remains committed to the continual improvement of operational practices to achieve optimal reliability performance outcomes and operating efficiencies using our existing network infrastructure. However, the reliability of Energex's supply network can vary from year to year due to the uncertain nature of faults and weather events affecting the network. Recognition of such events by the AER in the DNSP Benchmarking Report would provide stakeholders with a better indication of the performance of each DNSP during a particular period.

Other

Ergon Energy

As noted in Appendix A, data supplied by Ergon Energy for MVA capacities of 66kV, 132kV and additional voltages for Overhead subtransmission Lines was called out by the AER as *showing erratic movements over the 2011 to 2016 period* to which end the AER *back cast the 2016 MVA factors for these three categories to 2012 to provide a more stable and plausible series*.

As previously disclosed in BOPs relating to this data and in other responses on information provided - the trends seen in the EB RIN data set for capacity data between regulatory years has been impacted by Ergon Energy's ongoing review of paper designs and field inspections to correct its system (Smallworld) data (e.g. conductors having incorrect construction, maximum design temperatures and fixing the data model –additional geometries). When incorporated in datasets, this has contributed to significant changes in capacity recorded. These data quality improvements are unable to be backcast. Therefore, the reported capacities each year represent the best data available at that time.

While Ergon Energy is now close to having a data set which can be used to accurately baseline its current performance and to judge future improvements, we expect similar movements in 2016-17 as field surveys on various transmission feeders confirm conductor type and size (construction), and how the maximum design temperatures can be increased with no/minimal change to the pole structure. There have been some feeders were the maximum design temperature has been increased by 5-10 degrees which can cause a significant MVA increase depending on the construction of the overhead line.

Ergon Energy is committed to continuing to improve the quality of the data, however it should be recognised that due to the system changes, staff training and awareness, the number and geographical spread of our assets this will be a long journey. The journey may show some (data) bumps along the way until the baseline data set is obtained. In this light, we question the appropriateness of substitutions of data.

Separately, the AER suggested that Ergon Energy did not supply an MVA factor for its overhead low voltage lines for 2016 and it substituted the same factor as that supplied for earlier years (0.1) for the purposes of its analysis. Ergon Energy has noted to the AER that it did provide this for its overhead low voltage lines for 2015-16 (0.0497149).

Unfortunately, a limitation of the AER's protected version templates is that formatting suggests ‘null’ values due to rounding or the display being limited in decimal places. This does raise concern as to how the data is extracted from the provided protected worksheets.

Of note, this variable has historically been impacted by data quality improvements (set out in BOPs) and has now “normalised” around 0.05 as reported for 2015-16 rather than the historical level substituted by the AER. Ergon Energy has requested that the submitted data be used by the AER in this instance.

Energex

As noted in Appendix A, for Energex’s Underground Distribution Lines (under 33kV) [2006 to 2016] the AER has substituted a capacity of 4 for Overhead 11kV rather than using data reported by Energex. On discussion with the AER, it was noted that Energex has supplied MVA factors of around 0.8 to 1.0 for its overhead 11kV lines but this was considered to be *implausibly low and not consistent with corresponding capacities supplied by comparable DNSPs*. Consequently, an MVA factor of 4 has been used for Energex’s overhead 11kV lines. A similar replacement was made for Energex’s underground 11kV cable capacity for similar reasons as noted in footnote 2 on page 15 of the 2014 Economic Insights report ‘*Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*’.

Based on feedback from Information Providers, it is not logical to use the same capacity for both overhead and underground. Furthermore, on review of data and basis of preparations’ (BOP) submitted by other DNSPs there appear to be variances as use (or not) of voltage limitations in data provided (i.e. differences in interpretation of RIN requirements). Energex has used voltage in their analysis (as interpreted to be required in the RIN), however on review, one NSP ignores voltage limited capacity (suggesting not readily available, and capacity in some rural lines will be overstated), whereas another notes voltage drop and thermal limits of circuit components other than overhead lines and cables have not been considered when establishing the capacities of lines.

Energex requests the AER undertake further investigation on this variable, prior to the assumption that others data is appropriate for substitution of that submitted by any one NSP. This issue has been raised with the AER on a number of occasions, in production of prior year benchmarking reports.

REPORT CONCLUSIONS

The following general comments are made relative to conclusions drawn throughout the AERs’ 2017 Draft Annual Benchmarking Report.

- **Section 3.1.3 Individual DNSP MTFP results** – the AER draws conclusion that the best performers over the past decade were individual Victorian and South Australian DNSPs. However, these are also the networks noted to have the largest productivity decline over the period (Figure 9 MTFP by state and territory, 2006–16). Can the AER comment on the extent to which this may indicate that the differences in absolute MTFP score reflect the underlying inherent productivity differences between networks; and, the relative year-on-year trends in productivity change reflect the efficiency with which the individual DNSPs are responding to changing circumstances in the external environment.

  This would be helpful for consumers, policy makers and NSPs to understand whether it is really the relative 'absolute' productivity level or the relative 'change' in the AER's MTFP measure over time that is more important in forming a view of the efficiency (or otherwise) of a DNSP.

- In **Section 3.1.4 Observations for 2015-16,** the AER makes conclusions as to the relative efficiency of each DNSP over the most recent 12 month period from 2015 to 2016, and productivity rankings of NSPs in the NEM for 2016 and their change (in ranking) compared

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with 2015. It would be particularly helpful for all parties to understand what the external influences are - and provide a much greater understanding of the inherent differences between the networks – if the AER could provide insight as to the driver of changes rather than relying on somewhat arbitrary methods such as the substantial OEF adjustments that the AER applied in its Opex benchmarking.

- Referring to **Figure 11 - Capital multilateral partial factor productivity (MPFP), 2006–16** the AER comments that *overall, there has been a moderate decline in capital productivity since 2006.* This appears to be contrary to the commonly cited premise of networks 'gold plating' or over-investing over the 2008-2014. In the current policy and customer affordability environment, it would be helpful if the AER could provide some more detailed commentary on what is driving relative capex and Opex PFP productivity trends. This would help pin point the issues that some NSP's seem to be feeling more acutely than others (and more proactively identify the emerging 'better practices' each year to facilitate faster adoption across the industry).
- In **Section 3.2.2 Econometric opex modelling,** AER notes that its three econometric models (Cobb-Douglas stochastic frontier analysis (SFA), Translog least squares econometrics (LSE), Cobb-Douglas LSE) were developed as part of assessments of the efficiency of DNSPs' Opex proposals in recent distribution determinations. It would be helpful for the AER to note how it intends to respond to the ACT and Federal Court commentary on the analytical shortcomings, data quality issues and significant limitations in the interpretation of the econometric Opex benchmarking results using these methods. This will provide greater confidence to DNSP's currently preparing their submissions and avoid misleading customers and policy makers on the veracity of these approaches.

  Specifically, it is potentially misleading for the AER not to have regard to (or at least acknowledge) recent commentary on the: (a) applicability and analytical concerns in the use of the overseas data; (b) arbitrary nature of the application of OEF's for networks; and (c) arbitrary nature of the AER's approach to setting the target efficiency score.
- Referring to **Figure 14 DNSP output and input percentage point contributions to average annual TFP change, 2006–2012** the AER states that aside from growth in Opex, growth in capital inputs was one of the largest contributing factors to annual decline in TFP. Furthermore, the AER goes on to conclude that this negative impact on TFP was partially offset by the positive contribution on TFP from growth in ratcheted maximum demand.

  An interpretation of this can simply be that replacing old (fully depreciated) assets without a much larger offsetting growth in customer numbers or demand will result in the network becoming less productive under this specification. Similarly, keeping older (fully depreciated) assets in service through increased maintenance may reflect as an increase in Opex (as the RAB contribution is zero). Conversely, accommodating more customers without increasing above the historical maximum demand does not provide any productivity improvement under this specification.

  Implied 'output' growth via growth in ratcheted maximum demand may also create a perverse incentive for NSPs to grow maximum demand - contrary to the intent of the DMIS, tariff reform and market changes currently under consultation.

  The AER should articulate insights on these influences in more depth, to aid in the understanding of the analysis by customers, commentators and policy makers, and improve the quality and depth of engagement during the determination processes.
- **Figure 15 DNSP output and input percentage point contributions to average annual TFP change, 2012–2016** notes slower growth in capital inputs contributed a reduction to TFP. It would be of interest to understand to what extent this simply reflects the WACC

applied across periods. Is this a genuine physical efficiency that the NSPs can influence or is it fundamentally a product of lower financing costs.

In noting that drivers of Opex performance include factors such as AER determinations (informed by benchmarking results) it would be prudent to mention the Federal Court decision and current NSW/ACT ACT remittal process for completeness – impacted NSP expenditure may ultimately be adjusted for in the future or excluded from the reported figures as a 'one-off' transition expense.

- On page 24 the AER comments that the rate of growth in TFP would also have been higher if redundancy costs were not counted in Opex. We question if treatments of redundancies distort the 'input growth' trends and request both raw and underlying figures be presented for transparency.
- The AER goes on to conclude that the negative contribution to TFP from energy supplied largely offset the positive contribution from ratcheted maximum demand. The fact that the specification used sees demand growth offset by reduced consumption as a 'neutral' productivity outcome raises concerns with the applicability of the model. In practice, this says that declining load factor is not a bad (or good) thing for network productivity. This fails to recognise that asset utilisation is 'almost everything' in infrastructure. When assets are highly utilised doing things that customers need, they are productive... in contrast the AER's specification implies that having higher capacity, increasingly underutilised assets is neutral. Again, it would be helpful for the AER to provide some more nuanced commentary around these issues to help industry, consumers and policy makers get a common understanding on what its benchmarking is trying to compare.
- **Section 4.2.2 Industry trend 2012-16: Decreasing opex and slower growth in capital inputs turns productivity positive**, concludes that a turnaround in TFP over 2012-16 was driven primarily by decreasing Opex and slower growth in capital inputs. It would be helpful for the AER to comment on the extent to which ‘slower growth in capital inputs’ is primarily due to slower growth in capex or lower financing costs.

  In commenting on approved Opex in South Australis in this section it is potentially misleading to not include a discussion of the ACT and Federal Court decisions for NSW/ACT given its prime focus on the AER's benchmarking methods.
- **Section 4.3 Impact of reform costs on productivity results** is helpful, though it would be of further interest to include a similar section on the impact of actual regulatory WACC on the Capital measures (understanding that the analysis is based on Annual User Cost using an 'averaged WACC') over time.
- In noting the impact of redundancy payments (page 34) on Opex, TFP and Opex PFP across years, can the AER provide the 'underlying' figures and trends to show how quickly businesses have responded. Similarly, if it is the relative productivity trend rather than purely the absolute level that proves to be an important comparator, the underlying Opex will provide a more meaningful measure for ongoing annual comparisons between the businesses and should be included here for transparency.

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APPENDIX A

Data file	Sheet	Description	Comment
DNS PPI master	Analysis	The following variables are incorrectly calculating the 5 year average on data from 2011 – 2015 (instead of using 2012 – 2016): RAB; CAIDI; Depreciation and Return on investment	All DNSPs analysis impacted. In particular masked Ergon Energy's (11th to 10th) and Energex's relative improvement (5th to 4th) in CAIDI compared to other DNSPs.
DNS PPI master	Analysis	Five year averages for the following variables are impacted by errors on the associated data sheets: Asset cost; Opex; Total user cost; RAB; Totex per MWh of energy delivered; Total user cost per km of route line length; Total user cost per km of circuit line length; Total user cost per customer; Asset cost per MW of maximum demand; Asset cost per MWh of energy delivered; Asset cost per km of route line length; Asset cost per customer; Opex per MW of maximum demand; Opex per MWh of energy delivered; Opex per km of route line length; Opex per customer; Return on investment;	All DNSPs analysis impacted
DNS PPI master	Total cost	Impacted by a data error on the Opex Sheet and Asset cost sheet.	Ergon Energy 2006 – 2015; All DNSPs analysis impacted in 2016.
DNS PPI master	Asset cost	Impacted by a data error on the RAB sheet	All DNSPs analysis impacted in 2016.
DNS PPI master	RAB	2016 Nominal RAB incorrectly calculated as opening RAB (DRAB0101) divided by two less First-stage of the two-step transformation at the Zone Substation level Network Service RAB for DNSPs with two-stage transformation. Correct formula is (opening RAB (DRAB0101) + closing RAB (DRAB0107)) divided by two less First-stage of the two-step transformation at the Zone Substation level Network Service RAB for DNSPs with two-stage transformation	All DNSPs analysis impacted in 2016.

Data file	Sheet	Description	Comment
DNS PPI master	Zone substation network service capex for DNSPs with two-stage transformation	Missing data for 2016, however the calculated figures relying on these numbers appear to have been correctly calculated.	All DNSPs impacted in 2016. Transparency of data issue, rather than a data or calculation error.
DNS PPI master	Opex	Resubmitted historical OPEX data provided as part of 2015-16 RIN process (31 October 2016) was not updated. Unable to comment on other DNSPs restatements or corrections.	Ergon Energy 2006 – 2015. Understates improvement over that period.
DNSP AUC	06ERG BB	Resubmitted historical Network services OPEX (31 October 2016) not updated. Unable to comment on other DNSPs. The following calculated variables appear to be impacted by this error: Operations & maintenance expenditure; Opex; Total tax expenses Error flows through to DNSP stacked and AUC data sheets AUC data sheets.	Ergon Energy 2006 – 2015. Understates improvement over that period.
DNSP AUC	05ENX BB	2016 – Overhead 33kV and above appears to have incorrectly excluded the totals for Easement. Variables impacted: Opening value; Inflation addition; Actual additions (recognised in RAB); Disposals; Closing value. The following calculated variables also impacted by this error: Debt / Equity Shares & Return variables; Building block components; Tax expenses (except for depreciation); Tax calculation; User cost of capital. Error flows through to DNSP stacked and AUC data sheets AUC data sheets.	Energex, 2016.

Data file	Sheet	Description	Comment
DERG DATA	n/a	Opex - Resubmitted data on 31 October 2016 has not been updated. Overhead Subtransmission Lines (33kV and over) [2012 to 2015 is impacted]. Unable to replicate the AER's result. Need advice on how the identified years have been calculated by the AER. Overhead Distribution Lines (under 33kV) [2016 only]. Unable to replicate the AER's result. Need advice on how the identified years have been calculated by the AER	Ergon Energy 2006 – 2015. Refer above.
DENX DATA	n/a	Overhead Distribution Lines (under 33kV) [2006 to 2016]. The AER used a capacity of 4 for Overhead 11kV. This is not the capacity which was reported by Energex. Underground Distribution Lines (under 33kV) [2006 to 2016]. The AER used a capacity of 4 for Overhead 11kV. This is not the capacity which was reported by Energex. Based on feedback from the Energex Information Provider, it is also not logical to use the same capacity for both overhead and underground. AUC Overhead Subtransmission [2016]. Comments provided against DNSP AUC file for more information on this error	Energex 2006 – 2016. Refer above.