Energex

Response to AER Issues Paper – Qld electricity distribution regulatory proposals

January 2015

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Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Executive Summary

Energex takes this opportunity to respond to the AER's Issues Paper, focussing on the matters raised by the AER that Energex believes are fundamental to the AER's assessment of the regulatory proposal and the making of the April 2015 distribution determination.

Energex is committed to the efficient and effective provision of network and connection services for our customers in South East Queensland. Key to the delivery of this commitment is balancing the sometimes competing objectives of outcomes for customers in terms of price and service, effective risk management in all aspects of operation and investment, and appropriate performance and return to shareholders.

To fulfil this commitment Energex believes it is critical that the April 2015 distribution determination by the AER must be consistent with the October 2015 distribution determination. Energex will be basing its capital and operating programs for 2015-16 on the April 2015 distribution determination. Therefore the determination must be reasonable, rational and support the delivery of services to customers in accordance with the National Electricity Objective (NEO).

The AER has raised a number of matters in its Issues Paper which Energex believes require addressing prior to the April 2015 distribution determination. The NEL requires the AER to ensure that Energex is informed of material issues under consideration and is given reasonable opportunity to respond before a determination is made. This response to the AER's Issues Paper seeks to respond to material, or potentially material matters highlighted by the AER in that Paper.

Of particular concern to Energex is the statement by the AER that in relation to benchmarking, the work undertaken in the New South Wales (NSW)/Australian Capital Territory (ACT) Draft Decisions (referred to in this submission as the *Draft Determinations*) is relevant to the revenue proposal submitted by Energex. The AER has invited submissions on the benchmarking results and their implications. Energex is of the view that the AER's initial benchmarking report should be subject to appropriate scrutiny and review before it is used to set operating cost allowances as has been the case in the *Draft Determinations*. This response identifies specific concerns regarding model specification, variability of results, the extent to which network characteristics are fully accounted for and excessive reliance on benchmarking.

The AER in its Issues Paper has raised a number of questions about Energex's proposed capital expenditure and the impacts on the regulated asset base (RAB). It appears that the impacts of indexation of the RAB are either ignored or understated. With the average life of assets being between 30 and 40 years, the annual straight line depreciation is of a similar order as the annual indexation, resulting in a sustained RAB with little actual capital expenditure. Energex is of the view that a number of the depreciation building block elements are not transparent resulting in limited and potentially biased consideration of Energex's proposed asset replacement program.

Taking the matters of the RAB growth and depreciation further, Energex believes that the most prudent solution within the regulatory framework, to apply any material downward pressure on the RAB in the longer term, is an alternative form of depreciation. Energex believes that this option must be explored during its revised regulatory proposal.

While the AER's Issues Paper does not outline specific positions on the rate of return, it does make reference to the *Draft Determinations* stating that in those decisions the AER, after applying the Rate of Return guideline, was satisfied that this resulted in an allowed rate of return which achieved the rate of return objective. These decisions are clearly significant as they represent the first application of the AER's Rate of Return guideline. Energex has significant concerns on rate of return issues particularly relating to the return on equity and the value of imputation credits. These concerns are informed by SFG and by a report by SFG discussing initial views on the required return on equity under the *Draft Determinations*. Energex intends to submit a more detailed response on the value of imputation credits in coming weeks.

1. Regulatory Requirements

The *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, resulted in a number of significant changes to the economic regulation of network service providers under chapter 6 of the National Electricity Rules (the Rules). As a result of this Rule change, transitional arrangements for Queensland were drafted and are set out in Part ZW in chapter 11 of the Rules.

Energex submitted its regulatory proposal to the AER on 31 October 2014 for the regulatory control period commencing 1 July 2015. Under the transitional arrangements, at the time the AER publishes the April 2015 distribution determination for Queensland electricity distribution businesses, the AER must also invite submissions on the revocation and substitution of that determination.

It is important to note that the determination that the AER must publish by 30 April 2015, is indeed a distribution determination and a reviewable regulatory decision that will be applied from 1 July 2015. In making this determination the AER is required to address a number of considerations outlined in the National Electricity Law (NEL).

Firstly, section 16 of the NEL requires that the AER must, in performing or exercising an AER economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (NEO).

The NEO, set out in section 7 of the NEL reads:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-*
>
> *(a) Price, quality, safety, reliability and security of supply of electricity; and*
> *(b) The reliability, safety and security of the national electricity system.*

In accordance with procedural fairness and pursuant to section 16(1)(b) of the NEL, the AER must, in making a distribution determination, ensure that Energex is "informed of material issues under consideration by the AER and is given a reasonable opportunity to make submissions in respect of that determination <u>before it is made</u>". Furthermore, the AEMC has previously stated that "restricting the NSP from making submissions in respect of the regulatory determination before it is made would create an inconsistency with sections 16 and 28ZC of the NEL."[1] By lodging this submission within the timeframe set by the AER in the Issues Paper, Energex does not concede that it has been informed of material issues under consideration by the AER nor that it has been given a reasonable opportunity to make submissions.

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[1] AEMC's Final Position Paper in relation to the *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* 15 November 2012, page 127

Even though the AER was not required to publish an Issues Paper[2], the AER has published an Issues Paper for the Queensland electricity distribution regulatory proposals. This submission addresses issues foreshadowed in the Issues Paper, including aspects of the *Draft Determinations* which have the potential to affect the AER's decision in respect of Energex's regulatory proposal.

Preferably the October 2015 distribution determination will not depart significantly from the April 2015 distribution determination which it replaces. It is in both customers and Energex's interests that these distribution determinations largely align to provide for a smooth transition to the next regulatory control period and minimise any implementation costs. Any significant changes could potentially compromise the business' delivery of safe, reliable and secure supply of electricity and therefore compromise the achievement of the NEO. In making this submission on the Issues Paper, Energex is seeking to have material points of difference identified and considered prior to the AER making its April 2015 distribution determination in accordance with section 16(1)(b) of the NEL.

[2] Rule 11.60.3(b)(1) of the Rules

2. Benchmarking and Network Characteristics

Section 2 responds to the AER's comments on benchmarking (including recent application as part of the *Draft Determinations*) outlined in section 4.6 of the Issues Paper.

The AER has relied heavily on benchmarking to determine the allowed revenue for NSW and the ACT Distribution Network Service Providers (DNSPs) over the 2015-2019 regulatory control period. The economic benchmarking was undertaken by Economic Insights. The AER is in the process of drafting determinations for the Queensland DNSPs and has questioned Energex regarding the extent to which certain environmental factors affect Energex's operating costs.

It is apparent from the AER's recent *Draft Determinations* that the AER considers the analysis undertaken by Economic Insights based on multilateral total factor productivity (MTFP) and stochastic frontier analysis (SFA) to reliably indicate the extent of operating cost inefficiency of the DNSPs. In the case of Energex, the average opex efficiency score across a range of measures is approximately 60%, implying that the AER may reduce its allowed operating costs by up to 40% over the next regulatory cycle.

Energex considers it inappropriate for the AER to rely upon statistical, econometric and index number approaches until such time as it possesses a database of DNSPs information in which there is robust data on all of the likely determinants of DNSPs' costs. Energex considers that the assessment undertaken by Economic Insights, at least as it has been applied by the AER is fundamentally flawed. The assessment has failed to properly assess the impact of network characteristics (such as the extent of sub-transmission assets across DNSPs) on operating costs to a standard that could be used to underpin regulatory decisions. As a result of this shortcoming, Energex is of the view that the AER erroneously determined operating cost allowances that allow for network characteristics and/or the characteristics of the business. Energex has reached this conclusion for the following reasons.

2.1 A degree of arbitrariness in the choice over models

In the MTFP model a range of different model specifications were investigated which resulted in different outcomes. By way of example:

- inclusion of all transformer capacity as an input to the MTFP when there is a sample of DNSPs with different mixes of one and two stage transformation disadvantaged those DNSPs with two-stage transformation assets. As a result, the AER chose a model that excluded the first transformation stage (i.e. that related to the provision of high voltage transmission); and

- linear rather than multiplicative treatment of lines by representing lines as kms rather than MVA*kms, which was adopted on the basis that the latter model tended to disadvantage the DNSPs with geographically large networks at the expense of the DNSPs with geographically small networks.

These specifications tend to indicate that the overall measure of efficiency derived from the MTFP analysis (and also from the other forms of analysis) is sensitive to the representation of outputs that are, in their nature, capital invested by the DNSP (e.g. transformer capacity and overhead lines).

There is an element of arbitrariness associated with these adjustments. From an analytical perspective, the question of whether one model rather than another introduces a bias rests on a normative view on what constitutes efficient operation. In respect of the MVA*kms versus kms measure, for example, it is far from clear that the DNSPs will achieve the greatest efficiency through incentives to maximise line length rather than incentives to maximise the product of line length and capacity (i.e. to substitute fewer higher capacity circuits for more low capacity circuits where circumstances dictate). Hence, the precise extent of bias each DNSP faces under each output representation is unclear.

2.2 The range of efficiency scores is very large

Frontier Economics conducted an analysis of the efficiency of total expenditure (investment and operating costs) of the UK distributors having regard to their customer density.[3] Frontier found an efficiency range of no more than 20% (i.e. the least efficient firm was only 20% less efficient than the most efficient firm).[4]

In contrast, the MTFP analysis of Australian firms encompassed an efficiency range of more than 50%. In 2013, the best performer, CitiPower (which serves the city of Melbourne only), used 13% fewer inputs, on a weighted quantity basis, than the next best performer, and was 29% better than the average (i.e. the average score was 71%), and 47% above the worst performer, Essential Energy. In effect, on the basis that the MTFP model properly accounts for material environmental and related factors, the results suggest that CitiPower uses half the level of inputs to serve its customers than does Essential Energy.

The large range of Australian inefficiency is surprising given the maturity of the businesses and the technology on which they rely, the high capital intensity of the activities, and the consistency of the system of national economic regulation they have operated under since the 1990s. This suggests that other factors are very likely contributing to the observed level of inefficiency which is not properly adjusted for in the model and may well not be controllable.

The multilateral opex partial factor productivity (opex MPFP) scores are even more dramatic. The opex MPFP of the best performer (CitiPower) is three times that of the worst performer

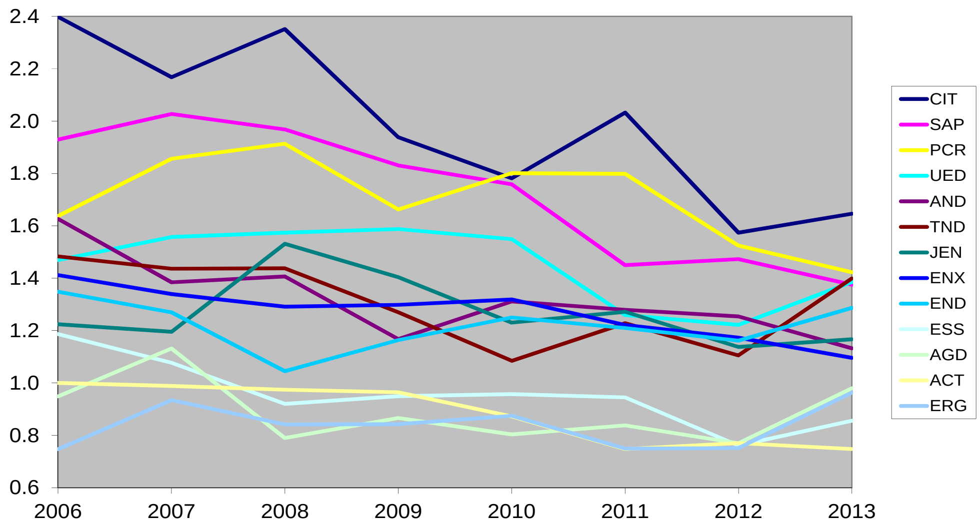
[3] Frontier Economics (2013) *Total cost benchmarking at RIIO-ED1 – Phase 2 report – Volume 1, A Report Prepared for OFGEM*, April.

[4] Notably, Frontier Economics did not use capital stock as a quantity capital input but used capital expenditure in the period, to avoid issues to do with network condition and characteristics. They also used customer density (customers per square km) as an explanatory rather than customer per circuit km.

Ergon Energy in 2006, and more than twice that of the next worst performer ActewAGL in 2013.

To put this in perspective, having adjusted for network density and complexity of transformation, in 2006 Ergon Energy used three times as many people to deliver its outputs than CitiPower. By 2013, Ergon Energy was using twice the amount of CitiPower. A similar story arises in the capital multilateral partial factor productivity (capex MPFP) measures. In 2013, ActewAGL used three times the quantity of capital than CitiPower to produce its outputs. Essential Energy used twice the quantity.

Figure 1 Opex multilateral PFP results



Data source: Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, November 2014, page 20.

In Energex's view, the large range of MTFP (and associated opex and capex MPFP) scores which contrast with analysis of efficiency in some other jurisdictions give rise to a significant concern that:

- Economic Insight's analysis has erroneously determined the level of operating cost efficiency; and/or
- the analysis has failed to properly distinguish between operating costs that are and are not under the DNSP's control, erroneously characterising the latter as sources of inefficiency.

In so far as the second of these factors is the case, it is most likely that the analysis has failed to fully recognise the impact that each DNSP's network characteristics have on operating costs. The relevant network characteristics are likely to extend beyond those that are included in the benchmarking analysis to include, for example:

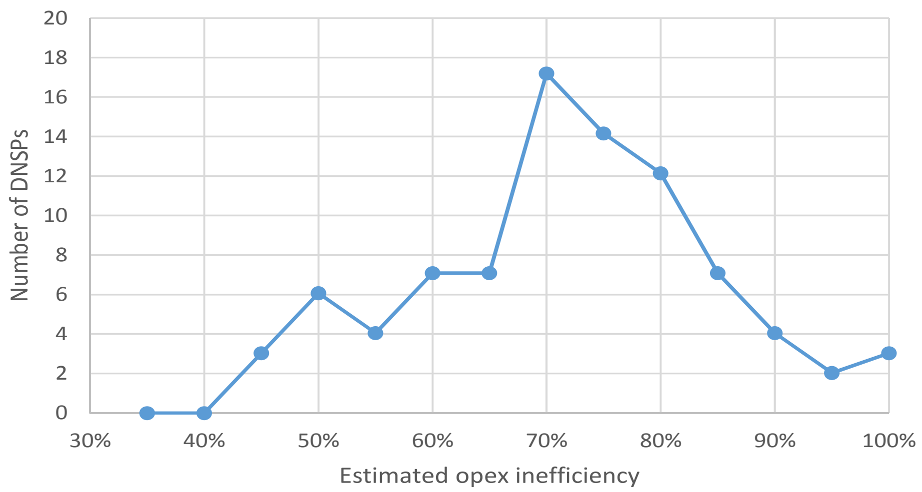
- extent of transmission and sub-transmission assets;
- asset age and type;

- detail of network topology, disposition of demand etc.; and
- legacy investment decisions and choices.

2.2.1 High levels of inefficiency

Energex has similar concerns in respect of the international database. Using the AER data, it is apparent that the observed level of inefficiency (the average level across 87 DNSPs) was low, at 69% (see Figure 2 below).[5]

Figure 2 Spread of opex inefficiency using SFA CD (large database)



Data source: Synergies calculations based on AER's Economic Benchmarking RIN files, November 2014.

This means that, on average, DNSPs should be able to reduce their operating costs by 31% to achieve apparent efficiency. What makes this level somewhat surprising is that the whole sample of DNSPs operate in environments that might be expected to give reasonable incentives to reduce operating costs, and have been doing so for a considerable length of time.[6] Furthermore, the mean observed level of opex inefficiency (29%) was greater than the maximum level of inefficiency that Frontier observed in its analysis of total costs for UK distributors (20%). Such results should be subject to review and scrutiny before being applied to the determination of revenues which ultimately fund the security, reliability and quality of electricity supply for customers.

2.3 Evidence of the importance of network characteristics

There appears to be a strong relationship between the capital MPFP and opex MPFP scores (specifically, as shown in Figures 3 and 4 below). Collectively, these appear to indicate that

[5] The efficiency scores for the whole sample were not published by the AER.

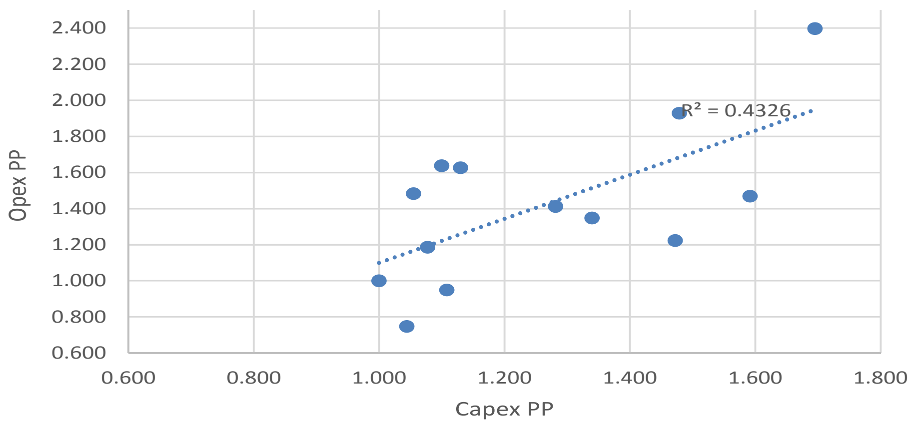
[6] One common theme of the Australian and Canadian regulatory regimes in which the firms operate is that, over the regulatory cycle, they keep as profits some or all of the operating costs they save relative to their projected costs, although this will be reset. Accordingly, one would expect operating efficiency to move towards the frontier.

capital productivity is an important determinant of operating cost productivity. Since capital productivity is, in essence, a measure of the quantity of assets used to deliver a certain quantity of outputs, it follows that operating cost efficiency is to a significant extent determined by the capital stock of each DNSP.

This leaves Energex with a very serious concern that the AER may require Energex to reduce its operating costs to a level that would only be appropriate for a network that Energex does not, in practice, own, operate and maintain.

Figure 3 indicates that 43% of the observed variation in the opex MPFP score is explained by the capex MPFP score.

Figure 3 2013 relationship between capex and opex partial productivity

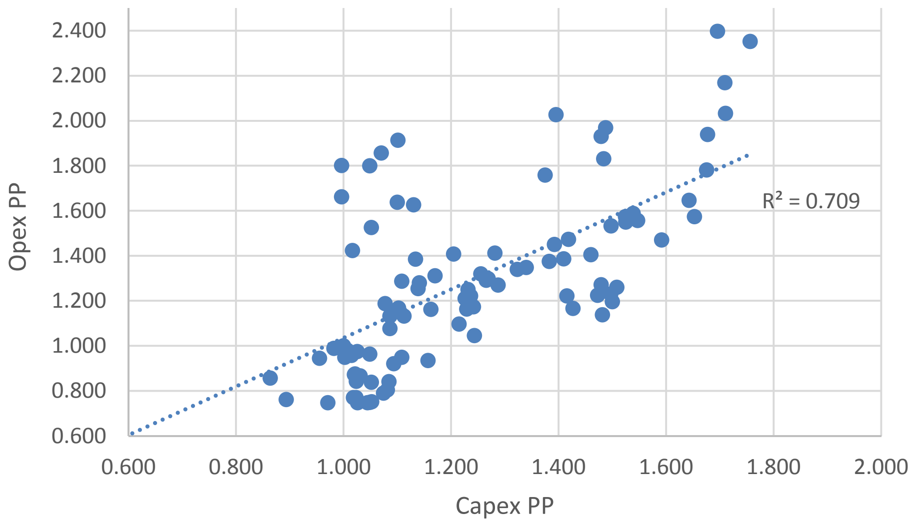


Data source: Synergies calculations based on AER's Economic Benchmarking RIN files, November 2014.

The relationship is more apparent over time. Figure 4 shows the relationship between capex partial productivity and opex partial productivity over the period 2006-2013, excluding Tasmania (TasNetworks), which exhibits an R^2 (indicative of the strength of the relationship) in excess of 70%.[7].

[7] Some caution is necessary in interpreting R^2 values for time series data such as this. Slightly more sophisticated econometric analysis of the data using ordinary least squares determines that close to 50% of the observed opex MPFP score can be explained by the capex MFPP scores and a time dummy.

Figure 4 **2006-2013 relationship between capex and opex partial productivity (ex-Tasmania)**



Data source: Synergies calculations based on AER Economic Benchmarking RIN files, November 2014.

Further evidence that the AER may have failed to properly differentiate controllable and uncontrollable efficiency comes from Data Envelopment Analysis (DEA) analysis of combined Australia and New Zealand data.[8] The Australia New Zealand data is sufficiently comprehensive to support this type of analysis, although it must be made clear that it would be more robust if the data from Ontario used by the AER was equally comprehensive. Nevertheless, a two output (circuit km and peak demand), three input (opex, MVA transformer capacity, user cost of capital on all other [non-transformer] assets) indicates a similar level of overall efficiency for Energex as the opex MPFP score, of around 60%), but indicates that the controllable quantum of inefficiency lies between 0% and 24%. The remaining inefficiency is, the DEA suggests, due to scale effects.

2.4 Sub-Transmission and Network Structure

Unlike Victorian and South Australian DNSPs, Energex has significant sub-transmission assets. Energex is of the view that failure to account for this material difference in network characteristics is a fundamental flaw in the benchmarking results and their application to determine operating cost allowances.

Energex takes supply from Powerlink at 132 kV and 110kV and operates an extensive 132 kV and 110 kV sub-transmission network. This includes 1,173 km of high voltage overhead line, 146 km of high voltage underground cable and 41 bulk supply substations. Of the other Australian DNSPs in the sample, 7 report no sub-transmission assets (>66kV), Ausgrid, Essential Energy and Endeavour Energy report similar quanta, Ergon Energy considerably more and ActewAGL about one tenth the level. The value range is between 1% and 4% of

8 Unlike SFA and related approaches, DEA does not impose a functional form on the production technology choices of the benchmark firms.

the total line length. Of the international DNSPs only Counties Power and Vector report any sub-transmission lines.[9]

It is notable that each of the DNSPs with high levels of sub-transmission are in the lower half of the reported opex productivity scores which, *prima facie*, could indicate that management of sub-transmission assets results in DNSPs incurring substantially higher operating costs than their counterparts.

Economic Insights did not take into account the extent of sub-transmission assets in its MTFP analysis (by including it as an output), although they did include overhead transmission lines as an input.[10] Nor did they take it into account in the opex MPFP analysis either in the second stage econometric analysis of opex MPFP scores or by its inclusion as an output. Furthermore, it does not appear that it was possible to estimate the impact of sub-transmission assets using the econometric analysis of operating cost efficiency (SFA and Ordinary Least Squares (OLS)) because the length of high voltage transmission was not reported uniformly across the database.

Economic Insights estimated additional operating costs for high voltage lines using analysis reported by the AER which estimated the impact on operating costs of higher voltage lines. Economic Insights then made an *ad hoc* assessment of the overall impact on operating costs based on overall high voltage line length. They derived operating cost disadvantages of between 2.5% and 10% depending upon the DNSP.[11] This analysis was separate from the MTFP or econometric estimations of operating cost performance.

The operation and maintenance of these high value assets requires specialist skills, more extensive maintenance and monitoring regimes that are more comparable to Transmission Network Service Providers activities than distribution. The additional requirements of operating and maintaining a sub-transmission network impact inspections, planned maintenance, network operations and vegetation management costs. By way of example, Energex engages a specialist contractor to undertake the vegetation management of 132 kV and 110 kV overhead line corridors. These assets also require more complex and faster operating protection than the rest of Energex's distribution network.

Based on its analysis, Energex considers that the requirement to operate sub-transmission as well as distribution assets increases its operating costs by more than the range assumed by Economic Insights.

2.5 Demand side management

Energex has concerns regarding how demand side management (DSM) expenditure is accounted for under economic benchmarking. Specifically, Energex considers that the AER's application of the benchmarking should remove DSM expenditure from the opex input. This is so as not to introduce a bias into the relative efficiency scores, particularly the

9 AER Draft Decision (2014) *Economic Insights DNSP productivity files*, November.
10 Economic Insights (2014) *Economic Benchmarking of NSW and ACT DNSPs*, November, p. 48.
11 Economic Insights (2014) *Economic Benchmarking of NSW and ACT DNSPs*, November, p. 48.

opex MPFP score which the AER is relying heavily on in making its assessment of a DNSP's opex forecasts. Moreover, the AER's application of economic benchmarking techniques should not reduce or remove the financial incentives for Energex and other DNSPs to undertake DSM programs to the detriment of the long term interests of consumers.

2.5.1 Review DNSPs' historical DSM expenditure

The AER's benchmarking RIN data provides information on the amount of demand management expenditure incurred by DNSPs over the 2005-06 to 2012-13 period. Table 1 below provides details of this expenditure.

Table 1 Expenditure on demand side management ($000)

DNSP	05-06	06-07	07-08	08-09	09-10	10-11	11-12	12-13	Total
Energex	1,940	3,463	4,445	9,855	8,661	12,397	18,740	16,089	**75,592**
ActewAGL	-	-	-	-	-	36	39	66	**141**
Ausgrid	3,376	3,472	3,304	1,5445	7,183	4,755	5,782	4,230	**33,648**
CitiPower	-	-	-	-	-	-	-	-	**-**
Endeavour	-	-	-	-	-	-	-	-	**-**
Ergon Energy	-	-	-	-	-	-	9,134	-	**9,134**
Essential Energy	-	-	-	-	-	-	-	-	**-**
Jemena	-	-	-	-	-	-	-	-	**-**
Powercor	-	-	-	-	-	-	-	-	**-**
SA Power Networks	863	3,435	2,315	3,482	1,558	5,117	2,258	3,007	**22,035**
SP AusNet	-	-	-	-	-	36	575	232	**843**
TasNetworks	-	-	-	-	-	-	-	262	**262**
United Energy	-	-	-	-	-	-	-	-	**-**

Source: AER DNSP Annual Benchmarking Report PPIs and underlying data

Table 1 indicates that Energex spent considerably more ($75.6 million) on demand management initiatives during the period than any other DNSP. Energex's expenditure has ramped up noticeably in the 2010-15 regulatory control period as it has implemented the Demand Management Strategy set out in its 2010-15 Regulatory Proposal and is expected to deliver a targeted peak demand reduction of 144MW over the period.[12]

The next closest DNSP, Ausgrid, spent less than half Energex's amount ($33.6 million), with the majority of DNSPs spending less than $1 million. Table 2 shows average annual demand management expenditure as a proportion of annual total opex for the 2005-06 to 2012-13 period.

12 Energex (2009), Regulatory Proposal for the period July 2010 to June 2015, July, pp 78-93

Table 2 **Average annual demand side management expenditure as a proportion of annual opex**

DNSP	Average (%)
Energex	2.62
ActewAGL	0.02
Ausgrid	0.86
CitiPower	-
Endeavour	-
Ergon Energy	0.26
Essential Energy	-
Jemena	-
Powercor	-
SA Power Networks	1.77
SP AusNet	0.05
TasNetworks	0.05
United Energy	-

Source: AER DNSP Annual Benchmarking Report PPIs and underlying data

Table 2 indicates that average annual demand management expenditure for Energex (as a proportion of annual total opex) was 2.62% for the period, compared to 1.77% for SA Power Networks and less than 1% for all other DNSPs.

Tables 1 and 2 indicate that Energex spends substantially more on demand management initiatives than any other DNSP in the AER's benchmarking sample. The implications of this discrepancy in DSM expenditure across DNSPs are discussed in the next section.

2.5.2 Consideration of capital and operating expenditure trade-offs with the application of benchmarking

The use of non-network alternatives like demand management are an important aspect of optimising the available capacity in the distribution network to meet forecast demand. Thus operational assets such as demand management have the potential to significantly delay or avoid network investments (both in the distribution network and in the upstream transmission network) and therefore generate substantial cost savings to customers.

This has important implications in the context of the AER's application of economic benchmarking techniques because implementation of programs such as DSM program directly and indirectly affects the reported quantities and values (of a capital and expensed nature) used as inputs and outputs in techniques such as MTFP and DEA.

In respect of the AER's statistical analysis of Energex's operating and capital efficiency, Energex:

- continues to expend opex on a number of DSM programs in the expectation of future capital and operating cost savings, which in the short term are increasing its reported opex input relative to other DNSPs resulting in its opex PFP and MTFP scores being relatively lower (worse) than would otherwise be the case; and

- has reduced peak demand through implementation of the DSM initiatives, which will have resulted in relatively lower capital-related outputs (specifically system capacity) than other DNSPs and correspondingly lower capital PFP and MTFP scores than would otherwise be the case.

In the context of Energex's reported (by the AER) opex inefficiency of around 50% compared to the best performer amongst Australian DNSPs (Citipower) in 2012-13,[13] its DSM expenditure is, at a minimum, accounting for around 1.4% of this 'gap' in the 2010-15 regulatory period (given Citipower reports zero expenditure on DSM in its Benchmarking RIN data over the whole RIN benchmarking reporting period). Based on Energex's intention to maintain its DSM expenditure in the 2015-20 regulatory period at broadly current levels, this expenditure will continue to exert a downward bias on Energex's MTFP scores in the absence of any adjustments made to these scores.

Any use of benchmarking must not disadvantage those businesses pursuing efficient and effective capex/opex trade-offs. In the context of the current benchmarking report, the simplest adjustment to make would be to simply remove DSM expenditure from the estimation of the opex input. This would serve to remove the actual current downward bias in Energex's opex PFP and aggregate MTFP scores.

[13] AER (2014), Electricity distribution network service providers, Annual Benchmarking Report , November, p 34

3. Regulatory asset base

Section 3 responds to the AER's comments on the size of the RAB outlined in section 3.3 of the Issues Paper and raises consideration of accelerated depreciation.

In the Issues Paper, the AER has questioned the forecast rate of growth in Energex's Regulatory Asset Bases (RAB) over the forthcoming regulatory period. The RAB is an outcome of the application of the Rules. The AER notes that Energex's RAB is forecast to increase 21 per cent over the period and states that:

> *given the distributors' relatively flat demand forecasts, we will investigate why the RABs are proposed to continue to grow so significantly.*[14]

There are two relevant considerations associated with the RAB that both explain the proposed increase and ensure its appropriateness. The first concerns the derivation of the RAB and, in particular, the treatment of depreciation within this process. The second relates to the additions to the RAB and, specifically, the regulatory framework that applies to these additions. If the RAB is to be considered an issue, then Energex proposes that alternative depreciation profiles must be considered.

3.1 Derivation of the Regulatory Asset Base

The RAB represents unrecovered past capital investments made by infrastructure owners such as Energex. Clause 6.5.1 and Schedule 6.2 of the Rules prescribe how the RAB is to be calculated. In essence, the RAB is equal to:

- the opening RAB (from the previous regulatory period)
- plus new capex
- minus asset disposals
- minus depreciation
- plus inflation.
- The growth in Energex's RAB over the 2015-16 to 2019-20 regulatory period reflects the interaction of the various RAB components and, in particular, the impact of regulatory depreciation.

Energex's capital expenditure in the current and previous regulatory periods was undertaken in direct response to legislative obligations associated with increasing network reliability and service quality. In particular, the Queensland Government 2004 Electricity Distribution and Service Delivery for the 21st Century (EDSD) Report recommended a number of initiatives,

[14] AER. (2014) Issues Paper – QLD electricity distribution regulatory proposals 2015-16 to 2019-20, December, p19.

including N-1 security standards. The associated increased capital expenditure required to meet these obligations was subsequently approved by the regulator.

Average capital expenditure for the 2015-16 to 2019-20 regulatory period is relatively low (30 per cent lower than actual capital expenditure in the current regulatory period), with the principal sources of capex being forecast replacement expenditure (54 per cent) and forecast augmentation expenditure (22 per cent).

3.2 Additions to RAB

Average regulatory depreciation (straight line depreciation less inflation on the opening RAB) is significantly lower than the forecast capital spend (in large part, this reflects the long remaining life of Energex's existing RAB and the consequent relatively high levels for the offsetting inflation adjustment). As a result, Energex's RAB continues to increase over the period, albeit at a lower rate than the current regulatory period. Energex is of the view that the regulatory depreciation approach obscures the impact of inflation and consequently the magnitude of the annual straight line depreciation, resulting in misinformed comparisons between replacement capital expenditure and depreciation allowances.

3.3 Regulatory Depreciation

One option available to the AER to address the size of the RAB is to contemplate accelerated depreciation given lower utilisation of networks more generally and the potential for asset stranding which may ultimately have a major adverse impact on incentives for efficient investment in distribution networks.

Depreciation profiles operate to achieve an inter-temporal allocation for the recovery of the original investment in an asset, therefore it is economically efficient for those users who value the service more highly to pay more for a service than a subsequent user who places a lower value on the use of an asset (because, for example, the availability of less costly substitutes).

Consequently, in the face of uncertainty surrounding future asset utilisation, the AER should be prepared to consider accelerated depreciation for potentially at-risk assets and ensure that it is set so that financial capital maintenance and economic efficiency is achieved. Specifically, Energex considers that in such circumstances, depreciation should be set with regard to the:

- timing of providing any accelerated depreciation such that it considers both the potential profile of asset usage and the practical application of full cost recovery by DNSPs; and
- implications for prices charged to consumers at a point in time as well as over time.

For example, where an asset class, group of assets or section of the network is likely to be at risk of stranding (through, for example, underutilisation or obsolescence) the AER should consider a diminishing value depreciation profile that facilitates full cost recovery of past efficient investment by allowing the DNSP to pre-emptively recover the majority of costs before the asset is actually stranded by minimising any residual value to be recouped at that time.

In relation to price implications and the desirability of avoiding price volatility, accelerated depreciation should ideally be undertaken at a time when customer prices are falling rather than rising (for example, as part of the 2015-16 to 2019-20 regulatory reset process). In this way, customer impacts are minimised and the prospect of exacerbating the asset's stranding risk (via higher relative prices) is reduced.

In summary, the AER is obligated under the NEL to ensure that Energex is provided with a reasonable opportunity to recover at least its efficient costs. In an environment of heightened asset stranding risk, this requires a more flexible approach to asset depreciation than that currently applied by the AER.

4. Capital Expenditure – Assessing Repex

Section 4 responds to the AER's comments on Energex's proposed repex outlined in section 3.2 of the Issues Paper.

Energex has forecast significantly higher replacement capex over the next regulatory period. Annual forecast replacement capex in the order of $355 million over the period is proposed compared with actual expenditure in the current regulatory period of around $220 million in 2014-15 dollars. However, replacement capex increased substantially over the current period from $130 million in 2010-11 to around $310 million in 2014-15 (2014-15 dollars).

The AER has raised this increased expenditure in their Issues Paper of December 2014 while acknowledging that the increase will be largely offset by lower expected augmentation capex. Nevertheless, if the AER were to subject its replacement capex forecast to a detailed assessment, Energex considers appropriate criteria ought to be adopted for that assessment.

One criteria, among others, that the AER employs in the assessment of the reasonableness of replacement capex is a comparison of the annual replacement capex forecast spend with forecast asset depreciation. The main issue that Energex wishes to raise here relates to the measure of depreciation used in any such comparison.

Generally speaking there are two measures that could be employed in this comparison, namely:

- the depreciation allowance used in the asset roll-forward of the RAB which is usually expressed in nominal terms and based on straight line depreciation profiles; and
- a measure of depreciation which better reflects actual asset consumption and change in 'market' value over the period. Such a measure could incorporate more appropriate asset lives, asset condition/remaining economic life, etc.

While it is not the intention of this paper to discuss the relative merits of these two general approaches, Energex wishes to highlight an issue which results from the manner in which the AER expresses 'regulatory depreciation' in both the asset roll-forward and building block revenue (MAR) calculation.

The AER calculates regulatory depreciation based on the real or uninflated value of the RAB and assumes straight-line depreciation. The derived real depreciation cost is then inflated using an assumed inflation rate to reflect nominal depreciation. The nominal depreciation amount is then adjusted by deducting the value of forecast annual inflation of the asset base.

The reason why the AER nets total asset inflation off nominal depreciation (termed regulatory depreciation) is because it wants to maintain consistency between the depreciation cost it uses to update the RAB and that used to estimate the MAR (under the return of capital component).[15]

However, it should be recognised that the resultant net regulatory depreciation used for these purposes does not provide a reasonable measure against which to compare replacement capex. The inflation adjustment of the depreciation component in the MAR calculation is undertaken solely to avoid the inclusion of a capital growth component in the total revenues to be recovered by the DNSP's tariffs. The capital growth component of total return (which is determined using the WACC and is the sum of capital growth and profit after tax) will be earned independently of the pricing activities of the DNSP.

Therefore, if the AER considers that a comparison between depreciation and forecast replacement capex provides a useful basis against which to assess the level of the proposed capex expenditure, then it is not appropriate to use the inflation adjusted or so called regulatory depreciation amount.

Moreover, the gross (nominal) depreciation amount is likely to materially understate the actual cost of asset replacement (given changes in the capital value of assets over time). However, gross depreciation is less inappropriate than the net (regulatory) depreciation approach used by the AER. This comparison is provided in Table 4.

Table 4 Comparison of Nominal Repex and Nominal (gross) depreciation ($M)

	2015/16	2016/17	2017/18	2018/19	2019/20
Regulatory depreciation	73.6	86.2	101.6	113.4	126.9
Nominal Depreciation	359.0	387.0	418.0	444.0	471.0
Nominal Replacement capex	372.3	388.8	372.2	394.5	382.2

Data source: Energex Regulatory Proposal and PTRM model.

Note: Nominal Replacement capex derived from Energex Regulatory Proposal, Table 9.1 and assuming inflation of 2.54% p.a.

Table 4 shows that Energex's proposed replacement capex is on average approximately 93% of the forecast nominal straight-line depreciation over the regulatory period.

15 AER (2008). Proposed electricity distribution network service providers roll forward model – explanatory statement, April, p. 6.

5. Rate of Return Issues

Section 5 responds to the AER's comments on rate of return outlined in section 5 of the Issues Paper.

5.1 Overview

The return on capital is one of the key building blocks comprising Energex's Annual Revenue Requirement and therefore has a significant impact on prices. It also determines the returns that Energex delivers to its shareholders as the providers of capital to the business.

Energex concurs with the AER that the "certainty and predictability of outcomes in rate of return issues will materially benefit the long term interests of consumers."[16] This is also important for investors, particularly from the perspective of regulatory risk. However, it is not evident as to how the current framework, based on the AER's Rate of Return Guideline (the ***Guideline***), delivers that certainty and predictability, as the AER still has considerable discretion in how the Guideline is applied and how certain parameters are estimated.

The Issues Paper does not canvass any specific positions that the AER intends to take in response to Energex's proposed allowed rate of return or more specifically its proposed return on equity. The Issues Paper does, however, make reference to the AER's recent *Draft Determinations* stating that in making those *Draft Determinations* the AER applied the Guideline after considering a large amount of material and that the AER was satisfied that this resulted in an allowed rate of return which achieved the rate of return objective. While Energex accepts that the AER must assess each regulatory proposal on its own merits, the same contentious issues relating to rate of return are common to all businesses and Energex does take issue with the AER's approach as reflected in the *Draft Determinations*.

Given the volume of material presented by the NSW, the ACT and Tasmania businesses and the AER's detailed response, Energex is still undertaking further analysis, which will be presented to the AER in the coming weeks. This response to the Issues Paper is, therefore, a high level response. It is accompanied by:

(a) a report from SFG Consulting (***SFG***)[17], presented in Attachment 1 addressing issues arising in respect of return on equity from the *Draft Determinations* and also addresses Energex's estimate of return on equity (which is the same estimate as arrived at using Energex's modified Sharpe Lintner Capital Asset Pricing Model (SL CAPM) approach) using the alternative multi model approach;

(b) a separate paper presented in Attachment 2 addressing issues arising in respect of gamma from the *Draft Determinations*.

[16] Australian Energy Regulator (2014). Issues Paper, QLD Electricity Distribution Regulatory Proposals 2015-16 to 2019-20, December, p.31.
[17] SFG (2015) The required return on equity: Preliminary response to the AER draft decisions, January

5.1 Return on equity

It is clear from the *Draft Determinations* that the estimation of the return on equity remains a contentious issue. The key issue continues to be the role and application of relevant alternative estimation methods, financial models, market data and other evidence. The requirement for the AER to have regard to this evidence was one of the most significant changes to come out of the AEMC's rule change process. The change emanated from the industry's recognition that sole reliance on the SL CAPM, without regard to alternative estimation methods, financial models, market data and other evidence, was producing outcomes that were not consistent with the allowed rate of return objective, particularly following the GFC.

5.2.1 Issues with the AER's approach

Energex's overarching concern with the AER's approach as reflected in the *Draft Determinations* continues to be:

(a) its conclusion that the SL CAPM is the "superior" model and therefore its exclusive reliance on that model as its foundation model; and

(b) its relegation of the alternative relevant models (Black CAPM and Dividend Discount Models) to having a secondary role, in such a way that effectively results in them having no practical influence on the outcome. Further the Fama-French model has no role.

These concerns are dealt with in detail in the accompanying report by SFG which demonstrates how the AER's estimation process "neuters all but the AER's favoured subset of 'primary' evidence"[18]. It also reiterates why the relevant alternative models should be considered alongside the SL CAPM. It is not proposed that any of these models provides a superior alternative. However, they should not be relegated a status that effectively "neuters" their influence on the return on equity outcome. All relevant models warrant consideration in estimating the return on equity.

5.3 Energex's approach

Nearly all of the businesses that have lodged regulatory proposals since the finalisation of the AER's Guideline have departed from that Guideline on the choice, and application, of models. Energex notes that the majority of businesses have used a multi-model approach to estimate the return on equity.

As submitted in its Regulatory Proposal, Energex also supports the multi-model approach and for that reason has included in the accompanying report of SFG which sets out an estimate of the return on equity using the multi model approach.

However, to the extent that the AER continues to apply the SL CAPM as the foundation model, Energex has submitted and continues to maintain, that in order to provide an

[18] SFG Consulting (2015). The Required Return on Equity: Initial Review of the AER Draft Decisions, Report for Energex, para. 12.

outcome that satisfies the requirements of the Rules and NEL, the AER's application of the SLCAPM must be such as to have proper regard to relevant alternative models and evidence. This approach by Energex does not endorse the SL CAPM as the 'superior' model. Instead, it sought to overcome its deficiencies by using these other models to inform the SL CAPM's parameter estimates. The approach was set out in the report of SFG[19] which accompanied Energex's Regulatory Proposal (an approach Energex refers to as the ***modified SL CAPM***).

Not surprisingly, SFG's estimate of return on equity applying the multi-model approach is exactly the same as the estimate arrived at using the 'modified' SL CAPM approach. This is because the practical consequence of the modified SL CAPM is to give these other relevant models and evidence a primary role in estimating the return on equity, rather than a secondary role, in such a way that effectively results in them having no practical influence on the outcome. Having regard to each of the SL CAPM, Black CAPM, Fama-French and Dividend Discount Models is necessary in order to produce an estimate that satisfies the requirements of the Rules and NEL, having regard to prevailing financial market conditions.

If Energex's modified SL CAPM approach is not determined to be the correct approach to estimating the return on equity then Energex, as submitted in its Regulatory Proposal, supports the use of the multi model approach which derives the same estimate of return on equity as the modified SL CAPM approach.

5.4 Return on debt

Energex has no specific comments on the return on debt. Its Regulatory Proposal sets out its rationale for its departures, including the weighted average approach to estimate the annual return on debt. At this stage, it has no issue with the AER's proposed approach to rely on both the RBA and Bloomberg series as they are both reputable, independent data sources. It also notes the importance of ensuring that the estimates reflect a ten year tenor. Energex's preferred approach to estimate a ten year return on debt is the QTC extrapolation methodology outlined in its Regulatory Proposal.

5.5 Gamma

Energex proposed a value for gamma of 0.25 in its Regulatory Proposal. As is evidenced by the *Draft Determinations*, the correct value for gamma continues to be a contentious issue. It has also been subject of widespread departures by network businesses from the Guideline.

Energex notes the AER's proposal in the *Draft Determinations* to reduce the value of gamma to 0.4. However, the AER's reasoning is still largely based on the same conceptual framework and evidence that it applied in the Guideline. Energex considers the AER's approach in the *Draft Determinations* to still be the subject of error. Its reasons are more fully set out in the attached paper.

Energex is currently undertaking further analysis based on the *Draft Determinations* and intends to submit further information to the AER on this issue in the coming weeks.

[19] SFG 2014 Energex Estimating the required return on equity, August

6. Metering Exit Fee

Section 6 responds to the AER's comments on metering outlined in section 7.1 of the Issues Paper.

Unlike in NSW Framework and Approach (F & A) decision, the AER specifically included a metering exit fee in the Queensland F & A decision to be classified as an alternative control service (ACS). The F & A defines the meter exit fee as the recovery of stranded asset costs associated with the removal of meter/s from customer's premises before the end of its useful life at the request of the customer (or customer's retailer)[20]. Energex's proposed exit fee aligns with the F & A, is a representation of the written down value (WDV) of electromechanical and electronic meters contained in the metering asset base (MAB) spread over the current meter volume, namely an average value per meter.

The AER has indicated in the Issues Paper that the exit or transfer fee is likely to inhibit development of effective competition for the provision of metering services[21]. However, such considerations were required to be addressed at the F & A stage as the rules require the AER to have regard to the 'form of regulation factors' set out in the National Electricity Law.[22]

As provided for under rule 6.12.3(b), the classification of distribution services <u>must</u> be as set out in the F & A paper, unless the AER considers that unforeseen circumstances justify departing from the classification set out in that paper. Energex does not believe that there have been <u>unforeseen</u> circumstances (e.g. change to legislation or policy) that would justify the AER departing from its F & A classification decision to allow a meter exit fee for stranded asset costs.

It is noted that, in the *Draft Determinations*, the AER indicated that the administrative costs associated with switching customers to an alternative metering provider should be classified as a meter exit fee and an ACS, whereas the capital charges associated with a metering asset being made redundant are not an ACS exit fee but should be recovered as a standard control service.[23] Energex does not support this proposed approach as it is clearly antithetical to the reasoning in the F & A and the AER's decision to classify metering services as an ACS.

Energex maintains its position outlined in its Regulatory Proposal that metering exit fees are appropriate to apply to the particular customer who has elected to churn and who believes that they will benefit from competition. Without exit fees the likely impact will be further upward pressure on the RAB (given the AER's position in the *Draft Determinations*) and all customers paying for the 'sunk' cost of the meter despite not accruing any direct benefit.

[20] Final Framework and Approach for Energex and Ergon Energy, regulatory control period commencing 1 July 2015, April 2015, Appendix B page 116
[21] Issues Paper Queensland electricity distribution regulatory proposals, December 2014, page 41
[22] NER clause 6.2.1(c); NEL section 2 F
[23] NSW Draft Decision 2014-19, Attachment 16: Classification of distribution services, page 146

7. Load control

The AER identifies managing and optimising existing load control as a driver of Energex's forecast opex in section 4.2 of the Issues Paper. While the AER does not raise the issue of load control per se in the Issues Paper, Energex makes this representation given concerns regarding some of the AER's questions on the regulatory proposal in relation to the treatment of load control.

7.1 Classification

Whilst the AER has not specifically flagged load control in the Issues Paper and therefore have not provided affected stakeholders with an opportunity to provide feedback, Energex believes that the classification and ongoing treatment of load control is a significant issue in Queensland. Therefore Energex provides the following comments that should be taken into consideration by the AER.

The AER's Draft Decision for NSW acknowledges that distributors rely on load control to manage the network but argues that load control does not need to be classified as a standard control service or to be in the RAB to be effective. Rather, the AER has contended that load control can be achieved through tariffs or other arrangements, which give the customer an incentive or reason to allow the distributor to have control over the customer's load.[24]

However, unlike NSW, the AER's Framework and Approach (F & A) for Energex and Ergon Energy confirmed that load control services relate to network operation and are not metering related. As such, the AER proposed to retain load control within network services and classify it as a standard control service.[25] Energex confirmed this classification in its Regulatory Proposal and refrained from proposing to apply the ambiguous service category of 'metering related load control', which in the F & A, the AER indicated relates to a request from a customer (or customer's retailer) to upgrade an existing load control service.[26]

As provided for under rule 6.12.3(b), the classification of load control services must be as set out in the F & A paper, unless the AER considers that unforeseen circumstances justify departing from the classification set out in that paper. Energex does not believe that there have been unforeseen circumstances that would justify the AER departing from its F & A classification decision.

[24] NSW Draft Decision 2014-19, Attachment 13: Classification of distribution services, page 12
[25] Final Framework and Approach for Energex and Ergon Energy, regulatory control period commencing 1 July 2015, April 2015, page 26.
[26] Ibid

Furthermore, section 16(2) of the NEL states that the AER must take into account the revenue and pricing principles when making a distribution determination relating to direct control network services.[27]

7.2 Load control and network planning

Load control has been an integral component of Energex's network topology since the 1950s with approximately 690,000 of Energex's customers on a controlled load tariff. Energex's network planning and development has evolved over many years with load control as an integral part of the planning, for example:

- Energex's network planning processes for new infrastructure automatically includes the benefits of load control[28]
- Design standards for the LV and HV networks inherently include demand benefits of load control
- Load control can be used to manage network loading during emergencies

Energex actively manages its load control system to achieve optimal results. This work includes ongoing monitoring of load profiles and regular changes to the load control scheduling system to allow for seasonal changes to network loads. The recent upgrades to Energex's load control system have provided the capability to address peak demand at individual zone substations. Leveraging this robust system provides a low cost and proven method of executing load control across the Energex network. As the program is tailored to individual zone substations, coupled with the management of new types of controlled customer loads (such as pool pumps and PeakSmart air-conditioners), more optimal load management will be possible.

Energex's access to diversified load control allows Energex to shift and manage 550 MW in winter[29] and 150 MW in summer of peak load, which reduces peak demand and helps defer capital intensive network augmentation. These facilities also provide Energex with a valuable tool for network management and contingency planning. The benefits of load control are shared amongst all customers in the form of more efficient network operation and investment.

Therefore, if the AER did depart from the F & A to classify load control services as an ACS then customers would be required to fully fund the cost of the relay and meter. However, Energex is concerned that while the individual customer requesting a load control tariff funds the cost of the relay the benefits of load control do not accrue to that particular customer but rather the benefits accrue to all connected customers through reduced network augmentation expenditure.

[27] A reference to 'direct control network services' is defined in the NEL as a reference to an 'electricity network service.'
[28] Refer to Energex's Distribution Annual Planning Report
[29] The majority of Energex's load control manages hot water systems

If Energex was not able to maintain access to load control then it is estimated that the current 22% of winter peaking substations would increase to 42%, necessitating significant network investment. Therefore, retaining load control as a SCS meets the NEO by ensuring that the efficient investment and operation of the network continues for the long term interests of all customers connected to the network.

7.3 Load control and tariffs

Energex disagrees with the AER's assessment in the *Draft Determinations* that load control services do not need to be a SCS to be effective. The AER has argued that load control can be achieved through arrangements with customers e.g. tariffs or other agreements, which give a customer an incentive to allow a distributor to have control over the customer's load.

However, the value of distributor managed load control cannot be achieved through tariffs. Broad based market network tariffs in Queensland cannot reflect locational costs – costs are presumed to be the same regardless of what point in the LV network customers are connected. This broad brush tariff approach enables Energex to send blunt signals to customers, but does not allow Energex to target particular geographic areas that are peaking. Distributor managed load control does facilitate demand reductions in targeted locations, above what the broad brush tariff signal will send. Given that load control is managed in a locational dynamic manner, this benefit is expected to remain even if locational tariffs are able to be offered in the Queensland market in the future.

While the right tariffs to incentivise reduced demand are part of the solution, they will not of themselves prevent peaks on hot days. Energex's Reward Based Tariff trials proved that customers can and will respond to the right tariffs, but fatigue can have an impact on successive hot days. The optimal result for demand management is a combination of the right tariffs and targeted demand management strategies, which enable the distributor to "press the button" and remove load from the network on a peak day.

7.4 Billing issues

In the *Draft Determinations* the AER has defined metering services to make it clear that load control that forms part of the meter (integrated meter) is to be classified as an ACS.[30] However, Energex has serious concerns with the billing implications of such a decision. That is, Energex has approximately 90,000 integrated meters with load control. If these were to be removed from the RAB then Energex would have to separately bill those customers whereas those customers with load control but not in an integrated meter would have a different billing arrangement. The administrative costs of such an approach are prohibitive.

[30] Attachment 13 page 13