Base Year Opex Overview 2020-25

January 2019

Part of the Energy Queensland Group

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1. Overview

Our proposed base year for both Energex and Ergon Energy is 2018-19. This attachment explains why we consider this and the resulting Base Year Operating Expenditure (opex) estimates[1] – before our proposed adjustments – are appropriate.

As explained in our Regulatory Proposals for both network businesses, Base Year Opex is used as the starting point for forecasting opex over the 2020-25 regulatory control period. To ensure that forecast opex is efficient, then, we need to ensure that Base Year Opex – before our proposed adjustments – is efficient.

1.1 Why we selected 2018-19

We selected 2018-19 as our base year because it represents a realistic expectation of the efficient and sustainable on-going opex that is required to provide our standard control services (SCS) in the 2020-25 regulatory control period.

We chose 2018-19 because:

- Doing so continues the well-accepted regulatory practice of using the most recent year for which audited data is available by the time of the Australian Energy Regulator's (AER) final Distribution Determination
- It is the first year where our operations – and associated costs – largely reflect a harmonised approach following the establishment of Energy Queensland and the merger of Energex with Ergon Energy. Choosing a prior year would require significant adjustments to reflect the incomplete nature of the business merger savings in those years. We have incorporated expected 2019-20 savings into our forecast to ensure that they are passed on to our customers
- We have achieved efficiencies over the 2015-20 regulatory control period through the merger savings achieved in Energy Queensland. Our 2018-19 opex base year estimates for both Energex and Ergon Energy are below, or in line with, the efficient opex forecast determined by the AER for the 2015-20 regulatory control period, and
- The AER deemed that it was appropriate to use revealed costs to set our opex allowances for the 2015-20 regulatory control period. Consequentially, it was also appropriate to apply the Efficiency Benefit Sharing Scheme (EBSS) to this period. Our underspend against the AER's allowance in each business shows that we have responded appropriately to the incentives in the AER's EBSS. It reinforces our proposal to use as the base year the most recent year of actuals at the time the AER makes its final Distribution Determination for us – being the 2018-19 year.

1.2 Why 2018-19 Base Year Opex is efficient

Despite the reasons for selecting 2018-19 noted above, we still need to ensure that Base Year Opex is efficient for both Energex and Ergon Energy.

Our approach is to consider a range of information, including:

- **Our performance over the current and previous periods** – this shows both network businesses have reduced their opex over time leading to the historically low opex reflected in the Base Year Opex when compare to the 2010-15 and 2015-20 regulatory control periods

[1] We have had to estimate our 2018-19 opex for use in the two Regulatory Proposals, as actual data is not available at the time of our submission. We will update our Base Year Opex in our Revised Regulatory Proposals in response to the AER's draft Distribution Determination, by which time our actual 2018-19 opex will be known.

- **Comparison of actual opex to that allowed by the AER** – actual and estimated opex for both network businesses in 2018-19 is below that allowed by the AER
- **Economic benchmarking** – this shows that there is no basis for adjusting down the Base Year Opex for either network, although we note that we have volunteered a number of adjustments in our Regulatory Proposals as part of our Base-Step-Trend (BST) forecast – this document does not consider these adjustments, and
- **Category analysis** – this shows that although some categories of opex in prior years look higher than other distribution network service providers (DNSPs), this is explainable once operating environment factors (OEFs) and data issues are considered, or when offset by other categories where opex looks lower than that for other DNSPs.

After providing some background, this attachment provides more detail on the economic benchmarking and category analysis of our Base Year Opex. That detail supports our proposal that our Base Year Opex is efficient and should be used as the basis to forecast opex for both networks over the 2020-25 regulatory control period.

2. Purpose and structure of this document

This attachment supports Energex and Ergon Energy's Regulatory Proposals to the AER. It references other supporting documentation that further explains and justifies the detail of Energex and Ergon Energy's 2018-19 opex for SCS (Base Year Opex). It provides benchmarking and category analysis comparing Energex and Ergon Energy's opex performance to other Australian DNSPs that demonstrate that our Base Year Opex is efficient.

The document is structured as follows:

- **Chapter 3** gives background information on the categories and key drivers of Energex and Ergon Energy's opex, and on the impact of external cost drivers on our current expenditure, such as from operating environment factors (OEFs)
- **Chapter 4** explains the economic benchmarking that we engaged Frontier Economics to undertake and what this means for Base Year Opex for both Energex and Ergon Energy
- **Chapter 5** undertakes category analysis on the opex performance of Energex and Ergon Energy relative to other Australian DNSPs over the period 2012 to 2017
- **Appendix A** explains our Cost Allocation Method (CAM) and Capitalisation Policy, and
- **Appendix B** includes definitions, acronyms and abbreviations used throughout the document.

3. Background information

This section provides context for more detailed discussions in subsequent sections. In particular, we:

- Set out our opex categories
- Set out the key drivers of our opex
- Recognise the impact of external cost drivers on our current expenditure (i.e. OEFs), and
- Discusses the impact of the merger of Energex and Ergon Energy.

Chapter 4 considers Energex and Ergon Energy's performance using economic benchmarking, and the factors that impact the outcomes. Chapter 5 then considers how external cost drivers and any other factors may affect each AER cost category individually – namely, vegetation management, inspections and maintenance, emergency response and other non-network costs including customer service/call centres, fuel and technical trade training.

3.1 Opex categories

Energex and Ergon Energy each have six opex categories as are described in Figure 3.1 below.

Figure 3.1: Opex categories

RIN Category	Service Description
Vegetation management	• Planned programs and reactive maintenance activities in managing vegetation to provide a safe and reliable network
Maintenance	• Inspection programs to detect potential defects requiring remedial response. • Maintenance plans to ensure delivery of supply, reliability, security and safety objectives.
Emergency response	• Works undertaken after a failure of an asset to either restore the network to a state in which it can perform its required function or render the installation safe • Repair of damaged equipment and all storm-related repairs.
Non-network	• Expenditure relating to IT and communications assets, non-network buildings and property assets, fittings and fixtures, and other non-network assets
Network overheads	• Overhead costs including the provision of network, control and management services that cannot be directly identified with a specific operational activity (eg. network management, planning, network control and operational switching personnel, quality and standards functions, network billing, customer services, demand side management, levies etc.)
Corporate overheads	• Provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity (eg. executive management, legal, HR, finance, debt raising etc)

3.2 Opex drivers

The key drivers of our opex include:

- Security, performance and reliability needs of customers
- Inspecting and maintaining assets to ensure that they are operating safely and efficiently over their lifetimes
- Meeting legislative and regulatory requirements
- Responding to storm and extreme weather events to restore supply
- Meeting growth in our network as measured by the number of connected customers, line length and the ratcheted maximum demand of our customers
- Actively managing vegetation near our assets, and
- Addressing aging infrastructure and asset-related safety hazards.

Energex and Ergon Energy's opex forecasts are our response to these drivers so that, together with our capital expenditure (capex) forecasts, we manage our overall network risk and deliver the service performance outcomes that our customers expect and value.

Much of our opex is fixed in nature, at least in the short-term – which means that we cannot easily reduce or increase that expenditure for different levels of output. Table 3.1 notes some examples of operating activities that may broadly be considered either fixed or variable in nature. However, in practice, we do not have enough information to split our actual expenditure between those two measures of cost.

Table 3.1: Examples of fixed and variable costs

Nature of costs	Examples of opex activities
Fixed	Corporate functions such as finance, regulatory management, human resources, legal and business support services Engineering asset management functions
Variable	Network planned maintenance costs Emergency response to unplanned maintenance requirements Customer service costs such as those provided through the customer call centre

Cost definitions

- **Variable costs** are costs that will change as our output of customer numbers and our network's system physical capacity changes.
- **Fixed costs** are costs which by their nature will be incurred regardless of movements in our outputs.

What this means

Fixed and variable costs may be considered end points on a range of cost characteristics. Within this range, we will incur costs that vary on a one-for-one basis with certain outputs as well as costs that will vary in a stepped nature.

3.3 The role of OEFs

OEFs are important when considering both economic benchmarking and category analysis as they provide a methodology for comparison between businesses on a like-for-like basis after differences in the operating environments have been considered.

We engaged Frontier Economics to look at OEFs when applying economic benchmarking to Energex and Ergon Energy. Its analysis shows the impact that these can have on benchmarking results by looking at the OEFs quantified by the AER previously and by Sapere-Merz in recent work undertaken for the AER (see analysis in Chapter 4).[2] Although we do not seek to separately quantify the impact of OEFs on our economic benchmarking results at this stage, Frontier Economics recommends how the work done to date by the AER and Sapere-Merz could be improved.

Similarly, we consider OEFs qualitatively when undertaking category analysis in Chapter 5 and use them to explain how our expenditure may vary from other networks. To inform that analysis, this section outlines key OEFs and network characteristics that affect the opex incurred by our networks.

The AER recognised in its 2018 Annual Electricity Distribution Network Service Providers Benchmarking Report (The Benchmarking Report) that:

> *"our [the AER's] benchmarking models **do not** directly account for differences in legislative or regulatory obligations, climate and geography. These may materially affect the operating costs in different jurisdictions and hence may have an impact on our [the AER's] measures of the relative efficiency of each DNSP in the NEM." (emphasis added)*

In an attempt to address this limitation, the AER retained Sapere-Merz to provide independent technical advice about material differences in operating environments between 13 of the 14 Australian DNSPs in the National Electricity Market (excluding Power and Water Corporation). In its report[3], Sapere-Merz recommended the largest adjustment was required for Ergon Energy and the second largest was needed for Energex. These adjustments were to account for the costs associated with our unique operating conditions. Although we consider – and Frontier Economics[4] has shown – that the estimate from Sapere-Merz is on the low side, it rightly highlights the significant impact exogenous factors have on the costs we incur.

After considering how our unique OEFs influence key Base Year Opex categories, most opex categories for both network businesses were historically comparable to our peers. Overhead expenditure was the exception. We have recognised this and have made significant steps to reduce these costs during the 2015-20 regulatory control period. We have proposed further overhead cost reductions in our Regulatory Proposals, recognising the timing of the improvement we are seeking in overhead costs.

The rest of this subsection considers the key network characteristics and OEFs that affect our networks. This informs our category analysis in Chapter 5.

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2 Frontier Economics, AER Benchmarking, A report prepared for Energy Queensland, January 2019; and Frontier Economics, AER Operating Environment Factors, A report prepared for Energy Queensland, January 2019.

3 Sapere Research Group and Merz Consulting, Independent review of Operating Environment actors used to adjust efficient operating expenditure for economic benchmarking, August 2018.

4 Frontier Economics, AER Operating Environment Factors, A Report Prepared for Energy Queensland, January 2019.

3.3.1 Network characteristics and operating environment

The Energex and Ergon Energy networks have a unique mixture of features and face a distinct set of OEFs – all of which influence the costs we incur. While Frontier Economics identified a significant number of material OEFs impacting the costs of operating our networks,[5] this section focuses on a subset of these OEFs that are particularly relevant to the category analysis benchmarking shown later in this document. However, we maintain that all OEFs should ultimately be considered when considering opex efficiency. They are summarised in Table 3.2.

Table 3.2: Key network characteristics and OEFs

Factor	Energex	Ergon Energy
Customer density	Average as the network covers both urban and rural areas	Low customer density as network primarily covers sparsely populated rural areas
Route line length	Average	High. Second highest in the NEM reflecting this size of the area covered by the network.
Overhead lines proportion of total network	Average	High primarily because it is uneconomic to underground rural assets
Exposure to extreme weather and extended storm seasons	Above average due to severe storm exposure in south-east Queensland	High due to cyclone and severe storm exposure in equatorial, sub-tropical and tropical regions of regional Queensland
Proportion of sub-transmission assets	Low	High
Uptake of solar PV	High	High

3.3.2 Customer density

Ergon Energy has responsibility for the distribution of electricity to 97% of the geographic area of Queensland and as such owns and operates a large rural network. The Ergon Energy network not only covers large distances, but also has a low customer density compared to most other networks in the NEM.

In contrast, Energex covers the major urban areas and some less populated rural areas in south-east Queensland. The Energex network serves the second highest number of customers in the NEM. However, its customer density is lower than its urban peers, such as Ausgrid (AGD) and Endeavour (END).

[5] Ibid.

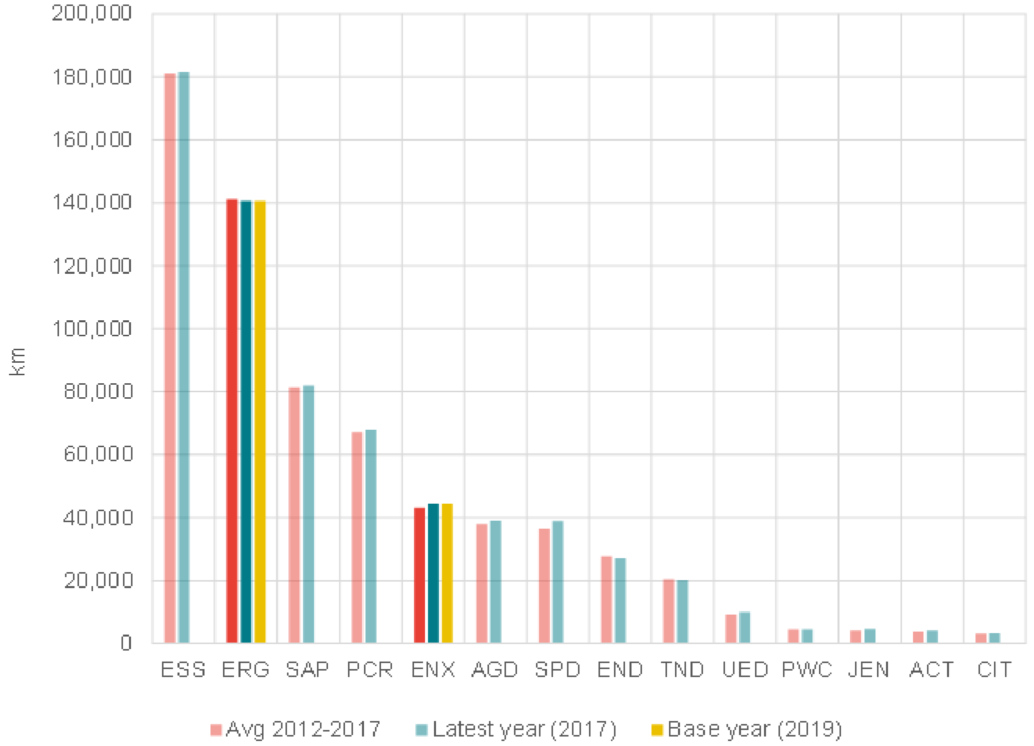
Figure 3.2: Customer density

Source: Economic benchmarking Regulatory Information Notice (RIN) data published by the AER. EQL analysis.

3.3.3 Network length

A comparison of route line length emphasises the large distances and thus geographical diversity which Ergon Energy has to contend with and the general difference in its network compared to most other DNSPs. These distances mean that Ergon Energy's crews have to travel greater distances to maintain network assets and to respond to emergencies. As highlighted by Figure 3.2 and Figure 3.3 Ergon Energy's closest peer is Essential Energy (ESS).

Figure 3.3: Route line length



Source: Economic benchmarking RIN data published by the AER. EQL analysis.

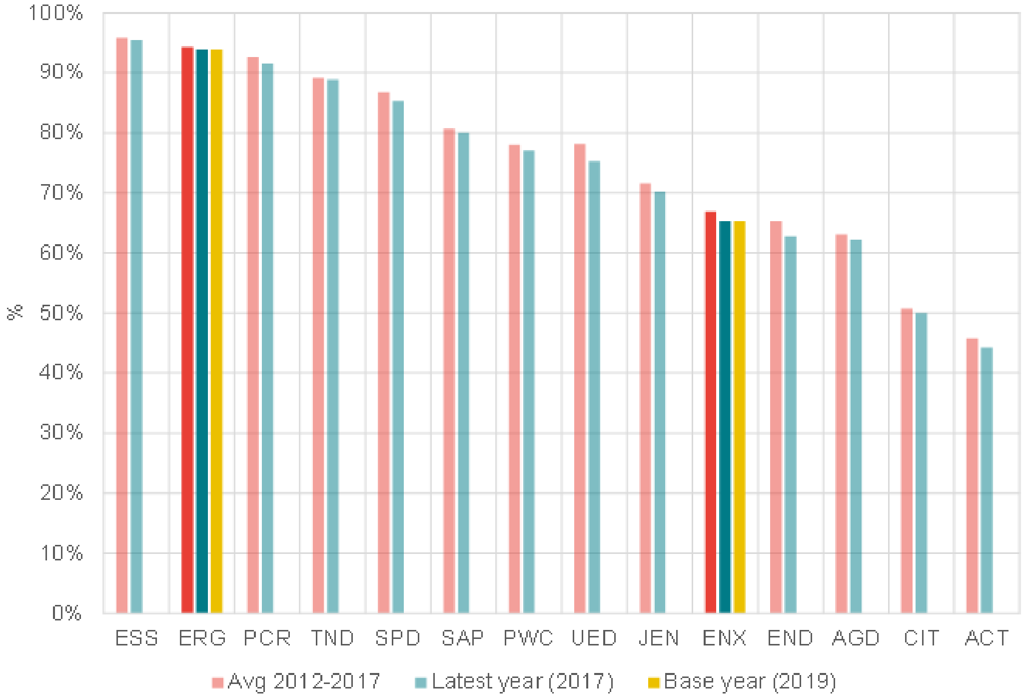
For large rural networks like Ergon Energy, distance (using route line length as a proxy) is the most appropriate measure for benchmarking most opex categories.

The exceptions are the opex categories of Maintenance, Emergency Response and Vegetation Management, but only because, along with distance, the proportion of overhead network also impacts these categories. Ergon Energy's network is basically an overhead network (as shown in Figure 3.4), whereas Energex's network, like many of its close peers, is a mixture of overhead and underground lines.

Similarly, the number of interruptions is a more appropriate measure for benchmarking Emergency Response expenditure than other measures. Interruptions, especially those caused by weather and climate related events, are a key driver of that expenditure.

As a result, we believe overhead circuit length is a better normaliser for Maintenance and Vegetation Management expenditure and the number of interruptions a better normaliser for Emergency Response than route line length for Ergon Energy. We consider customer numbers are a more appropriate measure for comparing all of Energex's opex categories than alternative measures, such as line length.

Figure 3.4: Proportion of overhead circuit length



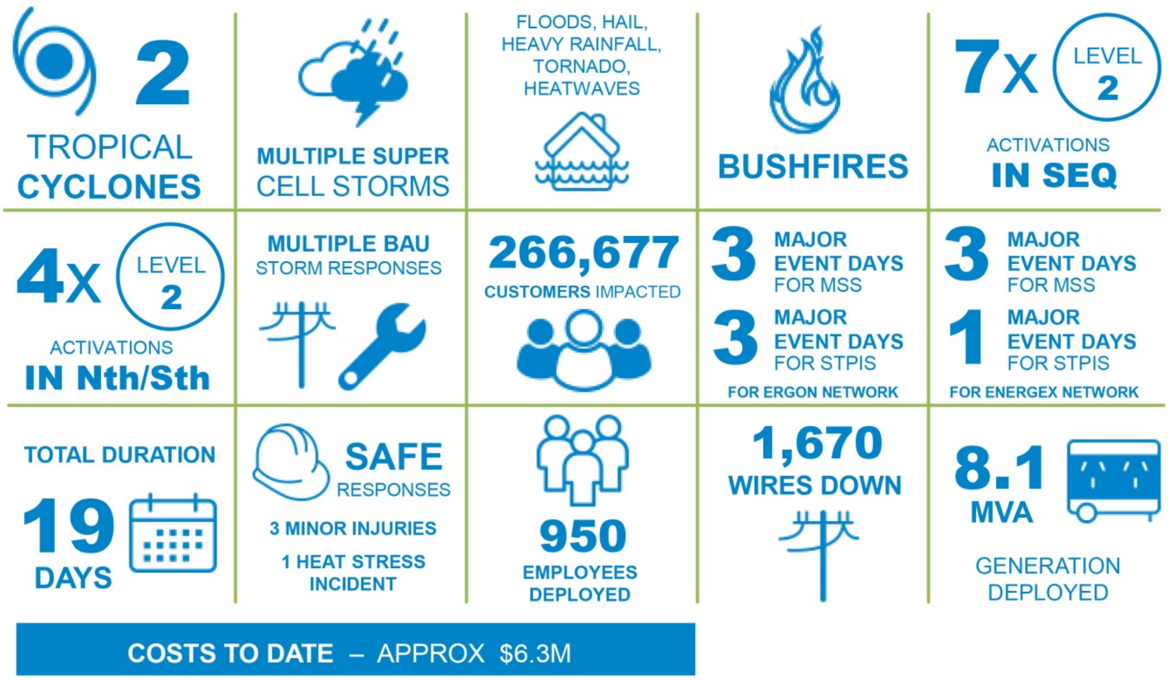
Source: Economic benchmarking RIN data published by the AER. EQL analysis.

3.3.4 Weather and climate

Compared to other Australian DNSPs, Energex has a higher probability of extreme weather events and Ergon Energy has a far higher probability of extreme weather events. The Bureau of Meteorology's (BOM) maps of the prevalence of cyclones (Figure 3.6) and lightning (Figure 3.7) illustrate these phenomena.

As a result, we need to spend more effort preparing for and responding to storms and extreme weather events. For example, Figure 3.5 provides a snapshot of our storm and extreme weather activity across both networks for the current year to date (i.e. as at January 2019). Total expenditure this year has been modest so far, reflects the limited damage caused by the cyclones we have endured.

Figure 3.5: Energy Queensland storm and extreme weather activity



Source: EQL analysis.

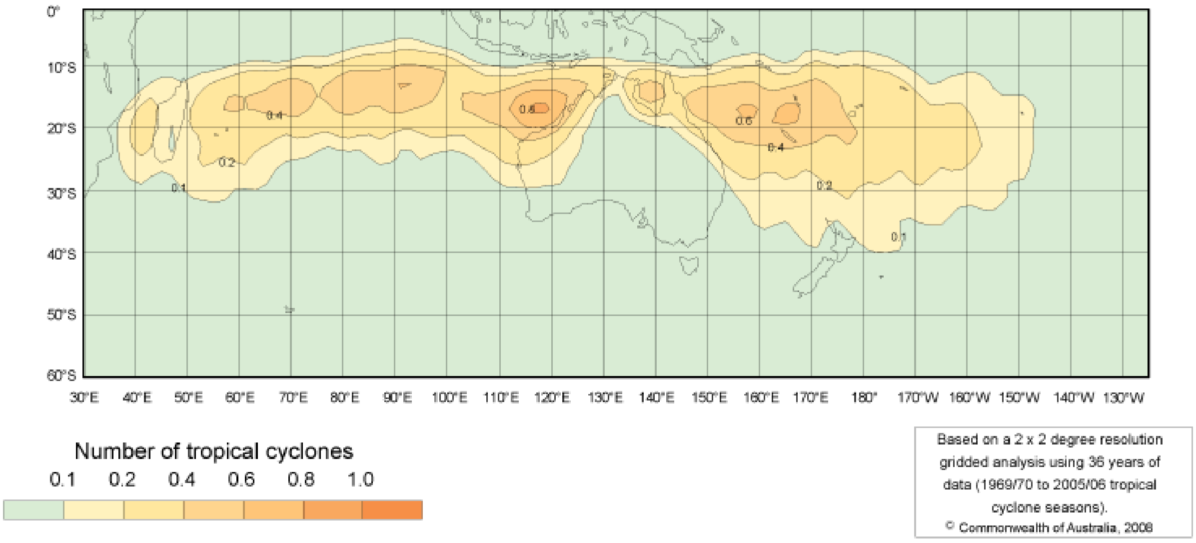
Sapere-Merz estimated that Ergon Energy requires more opex than other DNSPs in the NEM to account for our planning, mobilisation, fault rectification and demobilisation in response to cyclones (5.24% upward adjustment to efficient opex).[6] We consider, and Frontier Economics[7] has shown, the estimates from Sapere-Merz are on the low side and do not adjust for severe storms because of concerns of duplication with other OEF adjustments. However, the Sapere-Merz findings rightly highlight weather related events as a material issue.

Figure 3.6 and Figure 3.7 indicate that south-east Queensland experiences close to the highest frequency of severe storms in the NEM. This results in significant planning, mobilisation, fault rectification and demobilisation responding to damage across Energex's network during each storm season. Although Sapere-Merz did not identify any cyclone or severe storm related OEFs for Energex, we consider that they remain significant factors that affect how we operate and maintain the network and help explain differences between Energex's emergency response expenditure and that of other networks (see discussion in Section 5.6).

6 Sapere Research Group and Merz Consulting, Independent review of Operating Environment actors used to adjust efficient operating expenditure for economic benchmarking, August 2018.

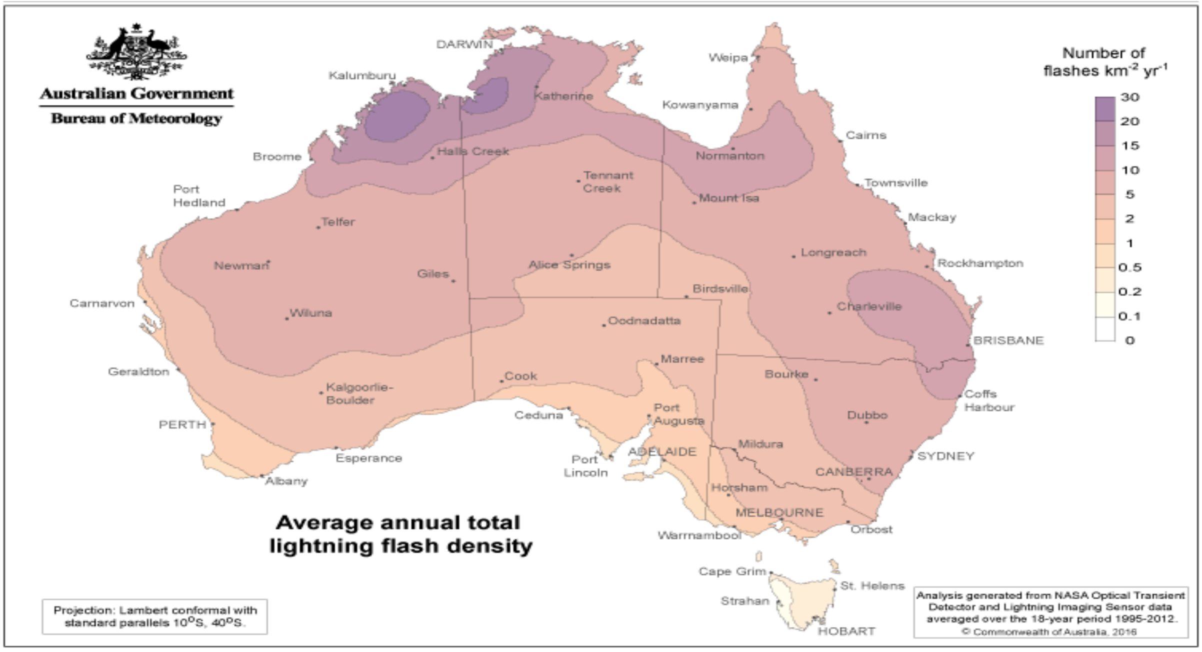
7 Frontier Economics, AER Operating Environment Factors, A report prepared for Energy Queensland, January 2019.

Figure 3.6: Average annual number of tropical cyclones



Source: Bureau of Meteorology.

Figure 3.7: Average annual total lightning flash density (1995 to 2012)



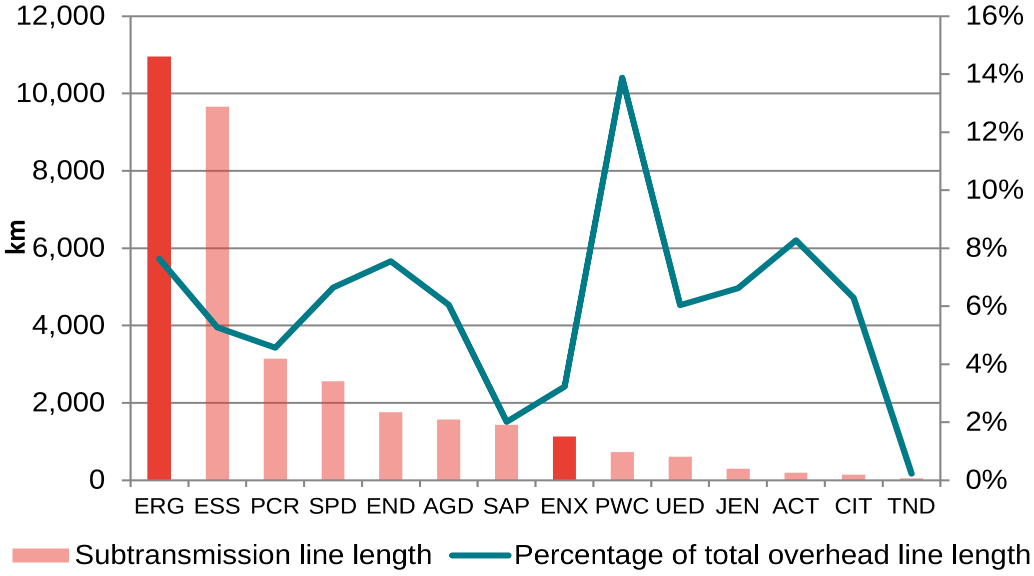
Source: Bureau of Meteorology.

3.3.5 Sub-transmission lines

Ergon Energy also has extended lengths of sub-transmission lines (Figure 3.8). Sapere-Merz's analysis suggested that we require six percent more opex than other Australian DNSPs to maintain Ergon Energy's sub-transmission assets.[8]

[8] Sapere Research Group and Merz Consulting, Independent review of Operating Environment actors used to adjust efficient operating expenditure for economic benchmarking, August 2018.

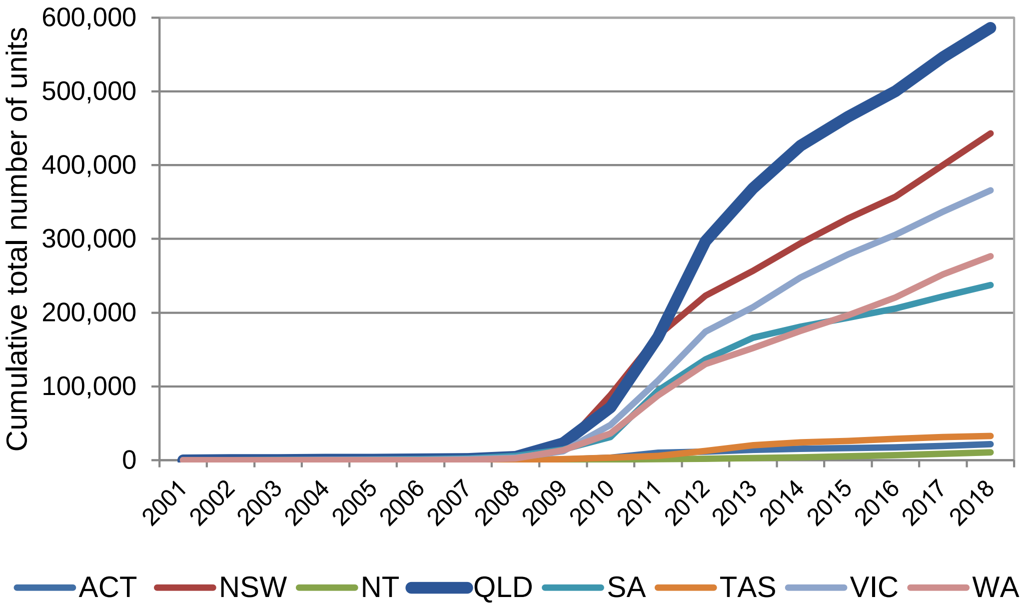
Figure 3.8: Sub-transmission line length and its proportion of total overhead line length (average 2012-2017)



3.3.6 Photovoltaic solar systems

Both Ergon Energy and Energex's network areas also have a high uptake of photovoltaic (PV) solar systems. Figure 3.9 shows the high take-up of solar PV installations across Queensland. Most installations to date do not control terminal voltage and their combined impact is resulting in an increasing level of voltage management complaints. This increases our opex as we identify and manage this issue.

Figure 3.9: Small generation units – solar (cumulative totals based on year deemed)



Source: Downloaded from Clean Energy Regulator's website on 11/12/2018. Date as at 31/10/2018.

Note: this data set includes most, but not all, of the rooftop solar PV systems in Australia. It also does not account for systems that have been decommissioned.

3.4 Energex and Ergon Energy Merger

3.4.1 Targeted savings

In the 2015-16 Mid-Year Fiscal and Economic Review (MYFER), the Queensland Government announced the merger of Energex and Ergon Energy under the banner of Energy Queensland Limited (EQL).

The merger was accompanied by a clear intent to achieve cost reductions and efficiencies in SCS opex and capex (totex) in the two regulated network businesses to the benefit of customers. The merger took effect from 30 June 2016.

Notwithstanding the reductions already targeted for the two businesses in the 2015-20 Regulatory Proposals and subsequent determinations, an additional savings target of approximately $562 million totex net of implementation costs over four years (2016-17 to 2019-20) was adopted to improve further on this baseline. These further targeted savings were against the forward estimates at that time, which approximated the AER's expenditure allowances over the 2016-20 (four year) period.

The reductions achieved in these four years are referred to as "post-merger" savings to distinguish them from those already achieved by the two businesses in 2015-16.

3.4.2 The savings we have realised

The combined entity has successfully achieved the savings target through a combination of approaches, such as (but not limited to):

- Scale benefits such as:
  - Unit rate improvement to direct projects through optimising crew size, work program, depot management, resources and productivity improvements, and
  - Removing duplication in corporate overhead functions
- Re-negotiations with suppliers
- Selection of and adoption of best practices from within the legacy entities
- Reconsideration of work practices, scheduling and technology such as:
  - Improving asset strategies and standards and balancing network risk and customer outcomes
  - Better procurement price outcomes in network equipment, field service contract, corporate service contract, corporate real estate consolidation and sublease, and
  - Reducing spending on building new network assets or replacing old network assets by adopting enhanced network technologies and asset management strategies
- Reducing capex and maintenance projects, and
- A general re-examination of planned spend to ensure spend is prudent and efficient.

Some of these savings were envisaged and planned through formal merger savings initiatives – known as roadmaps – while other opportunities presented themselves after the merger. Furthermore, the external environment was also not static, and the businesses had to respond to changing requirements to ensure continued safe and reliable operation of the network. Some of these changes reduced the actual cost base, while conversely other costs increased.

It is not practical – and in some instances may be misleading – to attribute cost reductions to any of these individual internal or environmental factors, actions or decisions as outlined above in isolation. To measure how we are progressing against the target as objectively as possible against a stable baseline, we use the 2015-20 totex allowance to monitor our progress. The reduction in cost compared to the regulatory allowance is partially offset by implementation costs – so the term “net” savings is used to describe this measure.

In 2018-19, we expect to achieve approximately $93 million of post-merger net savings and expect to achieve cumulative post-merger net savings of $578.6 million by the end of 2019-20 – which exceeds the initial estimate of $562 million. These have been built into our opex forecasts for both Energex and Ergon Energy.

In addition, both Energex and Ergon Energy achieved reductions before the merger. We expect to achieve total totex savings against the regulatory allowances for the current five-year regulatory control period (2015-16 to 2019-20) of approximately $735 million across the two network businesses, net of implementation costs. Achieving these savings ambitions is a fundamental element of our financial strategy.

Table 3.3 shows the expected net savings over the period 2016-17 to 2019-20.

Table 3.3: Energex and Ergon Energy post-merger net savings over the 2015-20 regulatory control period

Consolidated Group ($M, Nominal)	Target	2017-18 Estimated Actuals	2018-19 Plan	2019-20 Plan	Total
AER SCS Totex Allowance		1,913.0	1,939.0	1,979.0	7,789.0
SCS Totex Actual / Target		1,707.0	1,795.7	1,798.8	7,022.5
Total Savings		**206.0**	**143.3**	**180.2**	**766.5**
Opex savings		35.0	53.3	71.4	189.7
Capex savings		171.0	90.0	108.8	576.8
Implementation and Redundancy costs		39.0	50.6	54.3	187.9
EQL net savings compared to AER	**562.0**	**167.0**	**92.7**	**125.9**	**578.6**

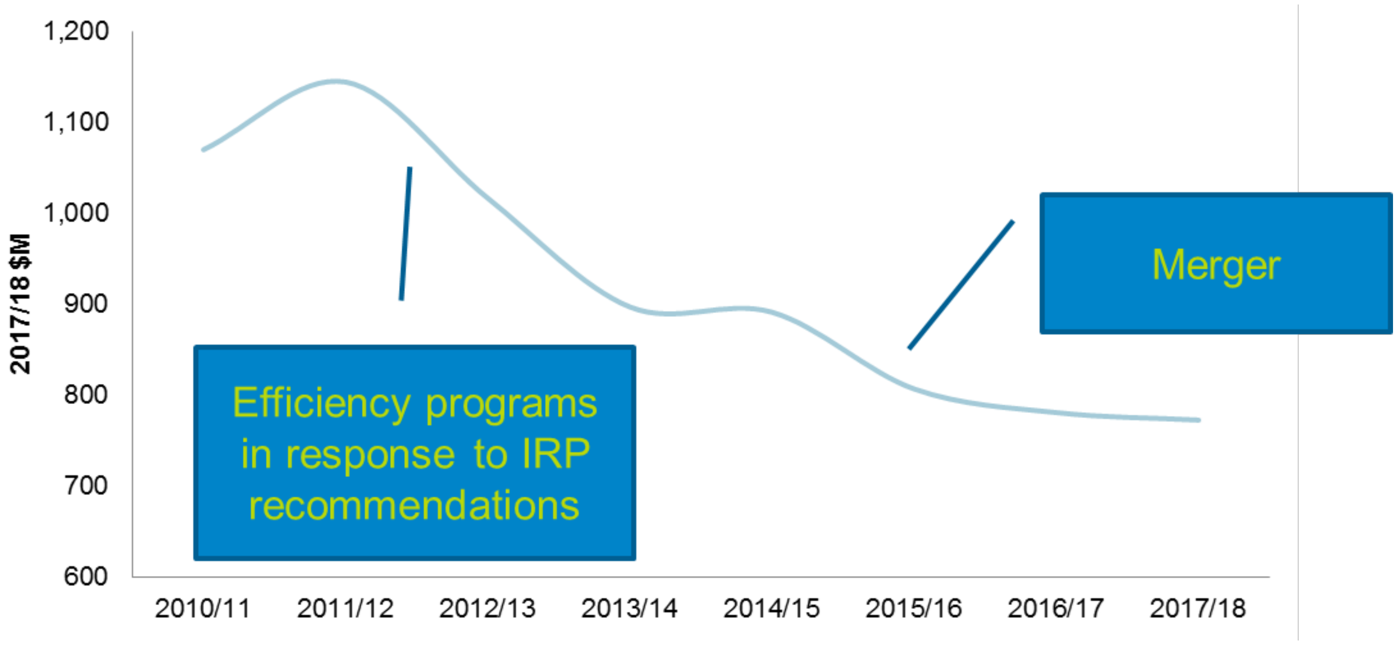
3.4.3 What these savings mean for customers

Achieving these savings enables Energy Queensland to operate and maintain its electricity distribution networks in a manner that is efficient while delivering on its safety and reliability standards – a benefit to our customers. The savings achieved through the merger have flowed predominantly to capex, whereas the associated restructuring costs necessary to implement the merger have reduced the profit of the organisation.

Savings in capex will flow into the next regulatory control period by lowering the regulatory asset base comparative to the value otherwise, which in turn lowers network prices. Customers will also benefit from having a lower Base Year Opex. We expect the merger savings to be sustained throughout the next regulatory control period, and are reflecting further savings in each regulatory proposal (see section 3.4.4).

The resulting impact of the post-merger savings to Energy Queensland’s indirect cost over the last two regulatory control periods is shown by Figure 3.10. These improvements are included in our indirect cost forecasts included in the Regulatory Proposals for our network businesses.

Figure 3.10: Energy Queensland indirect costs excluding restructuring



Note: The Independent Review Panel (IRP) was the result of a Queensland Government initiative that recommended changes to the network reliability standards in Queensland, targeted reductions in overhead expenses and improvements in operational efficiency, and structural reform.

3.4.4 What these savings mean for the Proposals

We have adopted the BST approach to forecast the total opex for each network business, which includes our overheads and anticipated 2019-20 savings as part of our Base Year Opex (see chapter 7 of our Proposals).

We have also built in proposed productivity savings to incorporate further management savings beyond what we have already realised to date through the merger .Specifically, we propose productivity savings (or factors) of:

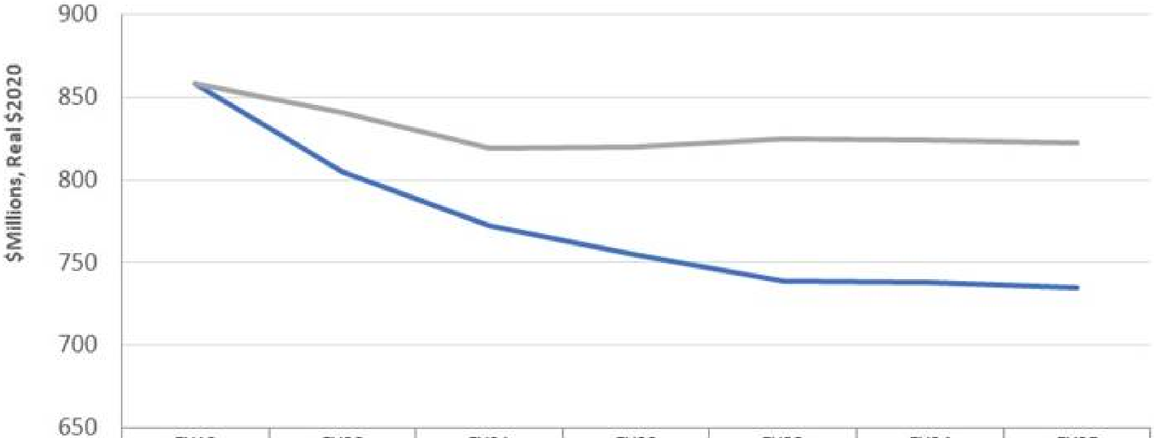
- 9%, or an annual 1.72% per year, in Energex's total opex costs (inclusive of overheads) over the 2020-25 regulatory control period.
- 14%, or an annual 2.58% per year, in Ergon Energy's total opex costs (inclusive of overheads) over the 2020-25 regulatory control period.

Management has committed to 10% top-down cost savings and 3% improvement in program of works labour costs to further reduce Energy Queensland's indirect costs which will contribute to these productivity savings.

We have proposed these productivity factors as alternatives to the productivity factors the AER is currently consulting on. As part of that consultation, the AER has proposed adopting an annual productivity factor of 1% per year. Our proposed productivity savings over the regulatory control period should be considered instead of (rather than additional) to that considered by the AER.

Figure 3.11 shows our existing forecast cost base compared with our proposal cost base after management savings for the 2020-25 regulatory control period.

Figure 3.11: Forecast Energy Queensland indirect costs over the 2020 to 2025 regulatory control period



	FY19	FY20	FY21	FY22	FY23	FY24	FY25
Regulatory Proposal Cost Base	858	805	772	754	739	738	734
Existing Forecast Cost Base	858	841	819	820	825	824	822

4. Economic benchmarking

Economic benchmarking is an important tool that, when properly used, can help inform whether our proposed Base Year Opex – before our volunteered adjustments – is efficient or not. In past decisions, the AER has used this tool to adjust Base Year Opex for some DNSPs to what it considers to be an efficient level. The AER has also recognised that economic benchmarking has its limitations and so should be used with care.

We engaged Frontier Economics to use economic benchmarking to compare the efficiency of our proposed Base Year Opex for Energex and Ergon Energy, having regard to (among other factors):

- The AER's latest annual benchmarking report
- Alternative approaches to using economic benchmarking
- Different input assumptions such as OEFs, and
- Any limitations from applying economic benchmarking. [9]

After undertaking this analysis, Frontier Economics concluded that there was no justification for using economic benchmarking to adjust down Base Year Opex for either network. It found that our Base Year Opex fell within or below the level of efficient opex estimated by the economic benchmarking models commonly used by the AER, as well as that of a wider range of model specifications.

These findings reinforce our proposals that the Base Year Opex for both of our networks *are* efficient and no efficiency adjustments are required to them – although our Regulatory Proposal volunteers certain adjustments.

4.1 Frontier Economics' results

Figure 4.1 and Figure 4.2 show that Base Year Opex for both networks (the light green bar) is below or consistent with estimates from the various model specifications. The first four sets of bars show the models that are commonly used by the AER. The other bars are alternatives, including those based on longer or alternative data samples.

The figures also show the impact of different OEF adjustments. The higher red bars use the OEF adjustments adopted by the AER in its decisions for the 2015-20 regulatory control period. The lower green bars use the OEFs adjustments estimated by Sapere-Merz more recently. As noted by Frontier Economics in its companion OEF report (and discussed briefly in Section 3.3),[10] the latter estimates appear to understate the likely impact of OEFs on the two networks – and so caution should be used when looking at those results.

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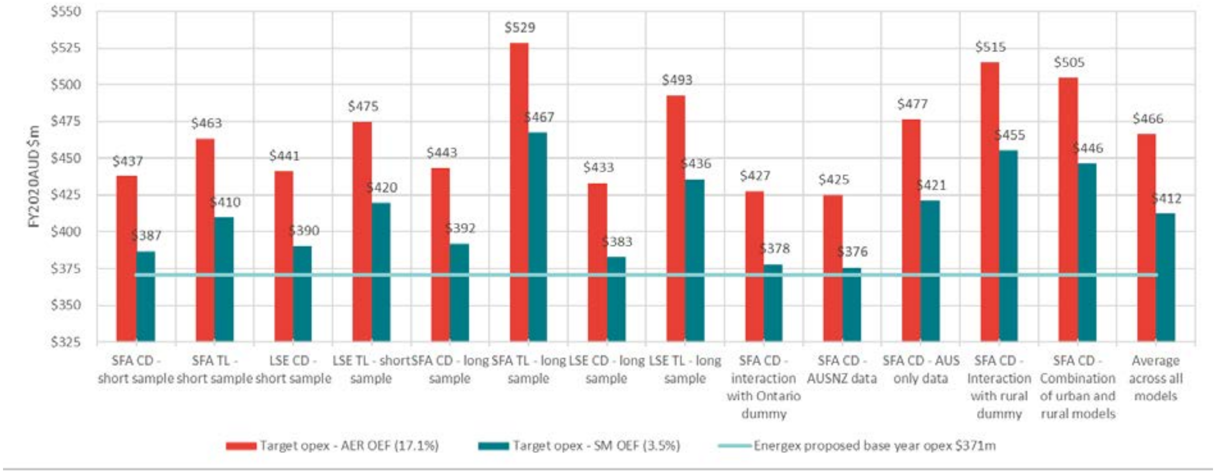
9 Benchmarking independent expert report, EGX ERG 6.002

10 OEF's independent expert report, EGX ERG 6.009

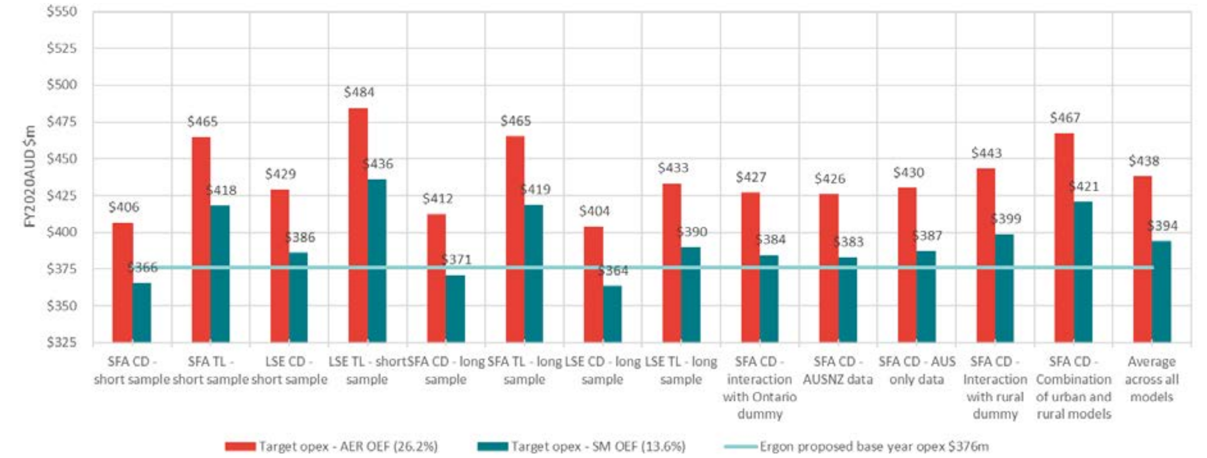
Figure 4.1: Energex comparison of Base Year Opex to estimated efficient opex



Source: Frontier Economics. [11]

Note: The horizontal green line shows Energex's pre-adjusted Base Year Opex expressed in FY2020 (mid-year) dollars of $371 million. Converted to year end dollars and adding the expected change from 2018-19 to 2019-20 gives the $376.6 million shown in Table 14 of the Energex Regulatory Proposal. A description of each econometric model specification is included in the Frontier Economics report.

Figure 4.2: Ergon Energy comparison of Base Year Opex to estimated efficient opex



Source: Frontier Economics. [12]

Note: The horizontal green line shows Ergon Energy's pre-adjusted Base Year Opex expressed in FY2020 (mid-year) dollars of $376 million. Converted to year end dollars and adding the expected change from 2018-19 to 2019-20 gives the $387.1 million shown in Table 14 of the Ergon Energy Regulatory Proposal. A description of each econometric model specification is included in the Frontier Economics report.

4.2 Frontier Economics' caution

Frontier Economics also reinforce that economic benchmarking should be used cautiously. The report highlighted some of the limitations of economic benchmarking, including:

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[11] Frontier Economics, AER Economic Benchmarking, A report prepared for Energy Queensland, January 2019, Figure 12.

[12] Frontier Economics, AER Economic Benchmarking, A report prepared for Energy Queensland, January 2019, Figure 12.

- Further work being needed to develop appropriate OEF estimates – getting these wrong can lead to incorrect conclusions being made about comparative efficiency
- Data limitations can and do lead to errors in benchmarking results – this includes relying on overseas data that may or may not inform the relationship between inputs and outputs of Australian DNSPs, or domestic data that has questionable reliability or may not be comparable across DNSPs, and
- Benchmarking results are highly sensitive to model specification, each with their own pros and cons – to overcome this sensitivity, a range of model specifications should be considered (as Frontier Economics has done).

Frontier Economics concluded: [13]

> *"We recommend that the AER apply the results from any benchmarking analysis with an appropriate degree of caution, recognising the significant practical challenges involved in performing benchmarking analysis, and taking account of issues relating to RIN data reporting and consistency, and issues with the quantification of OEFs in particular."*

This reinforces our proposal that economic benchmarking should inform, but not replace, our proposed Base Year Opex for both network businesses.

[13] Frontier Economics, AER Economic Benchmarking, A report prepared for Energy Queensland, January 2019, Section 4.3.

5. Category analysis benchmarking

This section examines our opex performance relative to other Australian DNSPs over the period 2012 to 2017. It also breaks down our historical performance into the key categories making up our opex and commonly used by the AER. As part of this analysis, our unique OEFs impacting each category are drawn out.

Our analysis suggests that:

- the total and direct opex of each network business is comparable to other networks when appropriately adjusted, as is the maintenance and emergency response expenditure. This is especially the case once OEFs are considered. This reinforces our conclusion that Base Year Opex (pre-adjustment) for both Energex and Ergon Energy is efficient and can be used as the basis for establishing the allowed opex for both networks over the 2020-25 regulatory control periods
- Ergon Energy's vegetation management expenditure is comparable to other networks, but Energex's is a little higher than some networks (although this is explainable), and
- the indirect opex including consideration of both total and corporate overheads is higher than other networks and supports our proposal to adopt significant management directed productivity savings in each network business.

While our network businesses are subject to a significant number of material OEFs, this document focuses on a small subset. Frontier Economics has examined a much larger sample of OEFs that affect us and has put forward a recommended framework for accounting for them in AER economic benchmarking.[14] This additional information should be considered alongside the information contained in this section.

This section should also be read in conjunction with the information presented in the rest of this document – which outlines in detail the justification for our Base Year Opex.

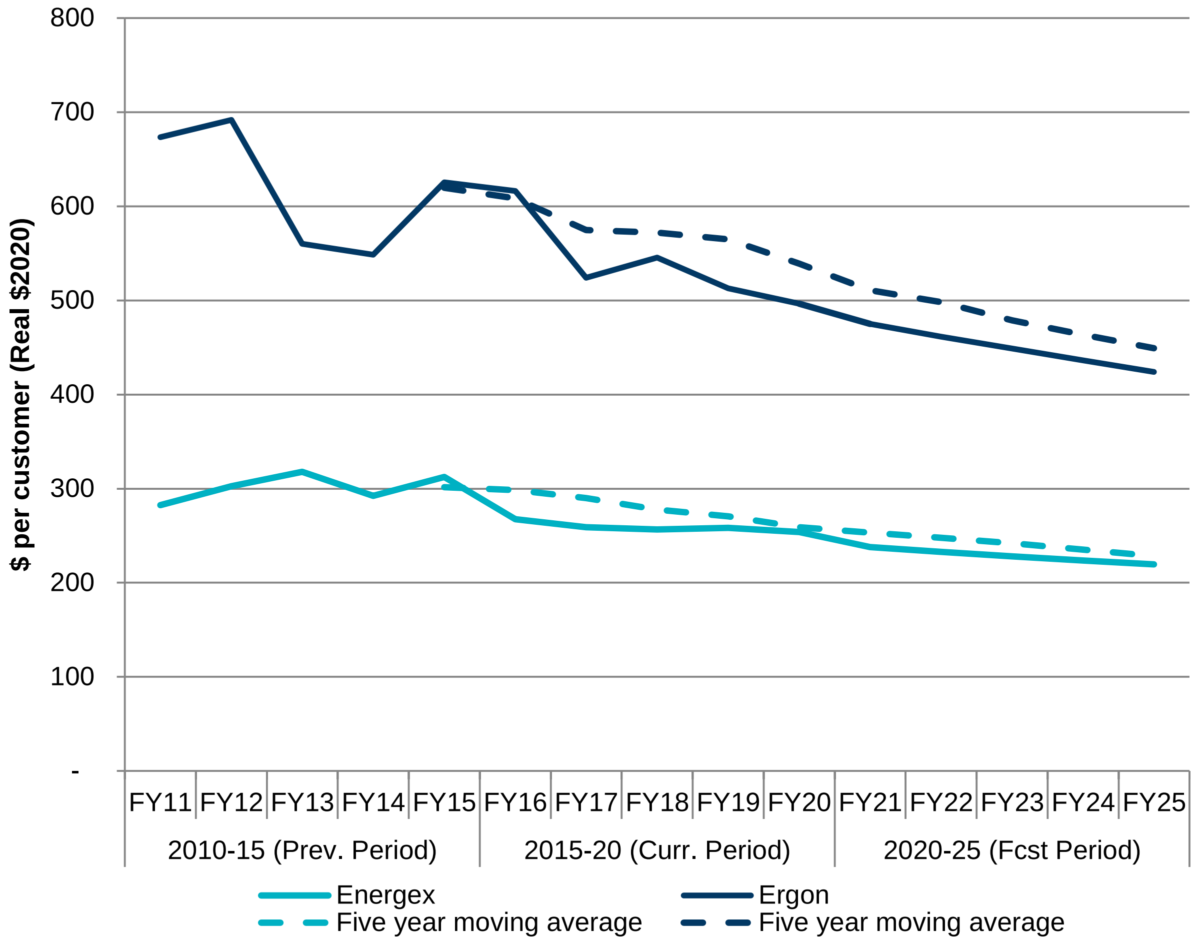
5.1 Total opex

As shown in Figure 5.1 our total opex costs on a per customer basis have been trending downwards over recent years, and our Regulatory Proposals will continue this trend.

The graph also shows that Ergon Energy's opex is higher on a per customer basis than Energex's. This is expected because Ergon Energy is predominantly a rural network with significantly higher costs associated with accessing, operating and maintaining its network. It also has a significantly larger exposure to key OEFs, such as cyclones.

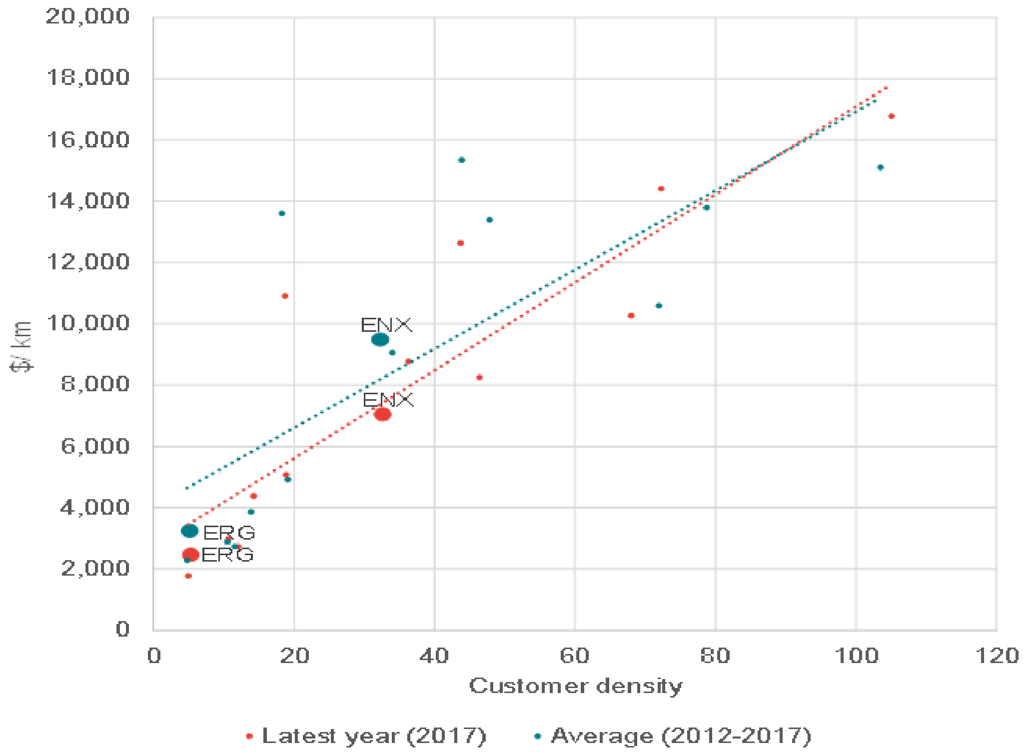
[14] Frontier Economics, AER Operating Environment Factors, A report prepared for Energy Queensland, January 2019.

Figure 5.1: Ergon Energy's and Energex's total opex costs on a per customer basis



Comparing Ergon Energy's total opex on a per route line length basis against customer density (Figure 5.2), its opex appears consistent with rural peers given its network characteristics and unique operating environment.

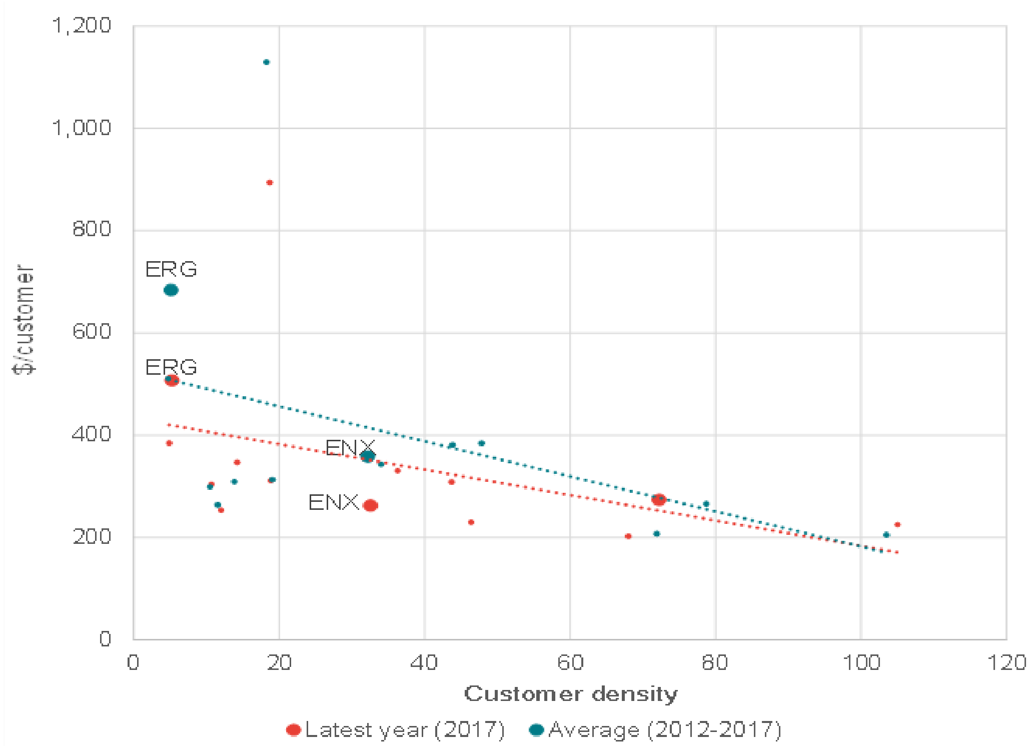
Figure 5.2: Total opex per km of route line length against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

Similarly when comparing Energex's total opex on a per customer basis with customer density in Figure 5.3, its opex also appears consistent with its DNSP peers.

Figure 5.3: Total opex per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

The next sections disaggregate total opex into its key categories.

5.2 Direct opex

5.2.1 Summary

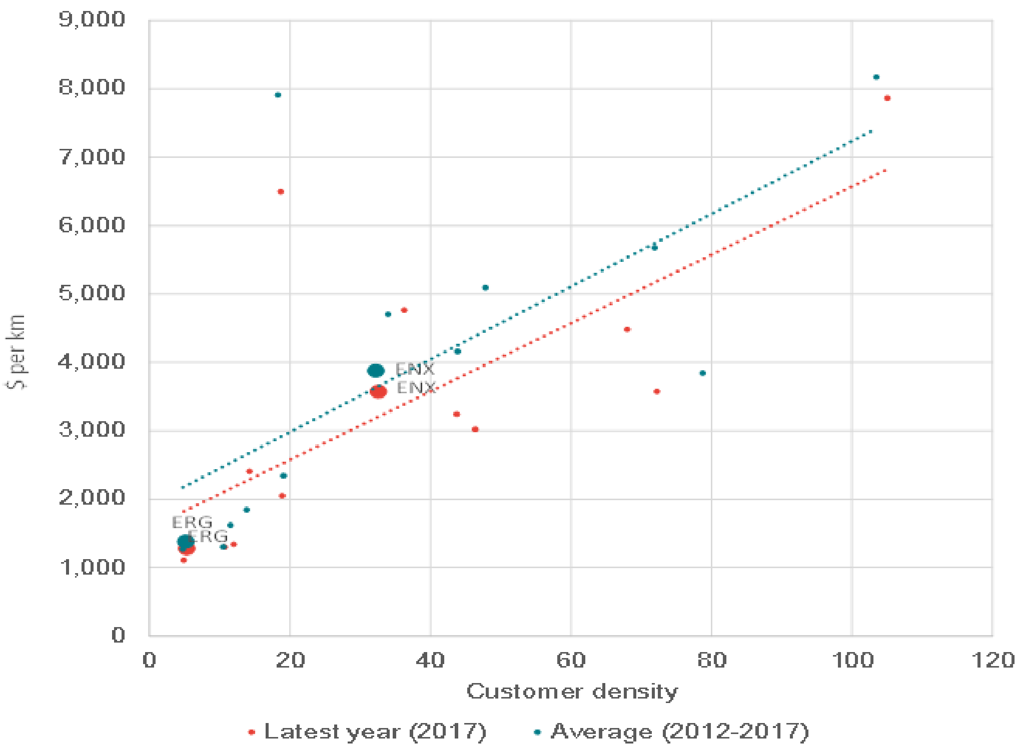
Direct opex includes expenditure on vegetation management, maintenance, and emergency response activities.

Our analysis suggests that both Energex and Ergon Energy's direct expenditure is comparable to their respective network peers when appropriate measures are used (e.g. on a per kilometre of route line length basis for Ergon Energy and customer basis for Energex).

5.2.2 Comparison to other networks

Figure 5.4 shows that Ergon Energy's direct opex on a per route line length basis against customer density also appears consistent with rural peers.

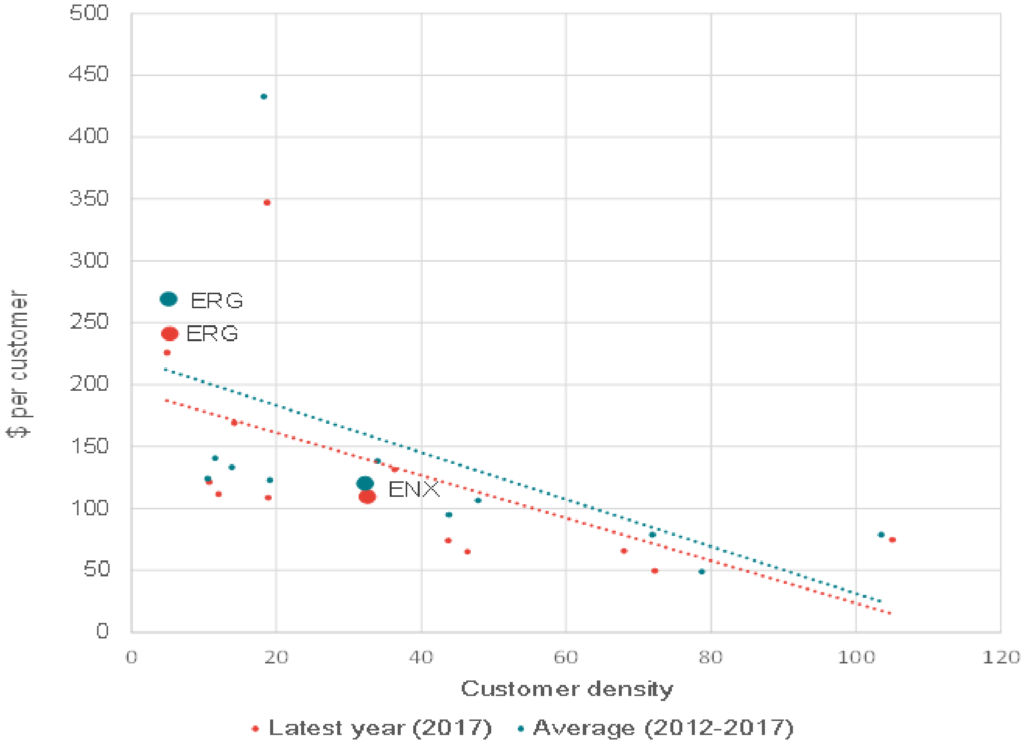
Figure 5.4: Total direct opex per kilometre of route line length against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

As shown in Figure 5.5, Energex's direct costs on a per customer basis compared with customer density shows a similar result to total opex. In other words, Energex's direct opex appears consistent with its closest peers.

Figure 5.5: Total direct opex per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

5.3 Indirect opex

5.3.1 Summary

Like other networks, Ergon Energy and Energex incur a range of indirect opex that covers non-network opex, network overheads and corporate overheads. However, because the approaches used to report these costs in the AER's category analysis RIN templates differ significantly across networks, we have aggregated them together to improve comparability.

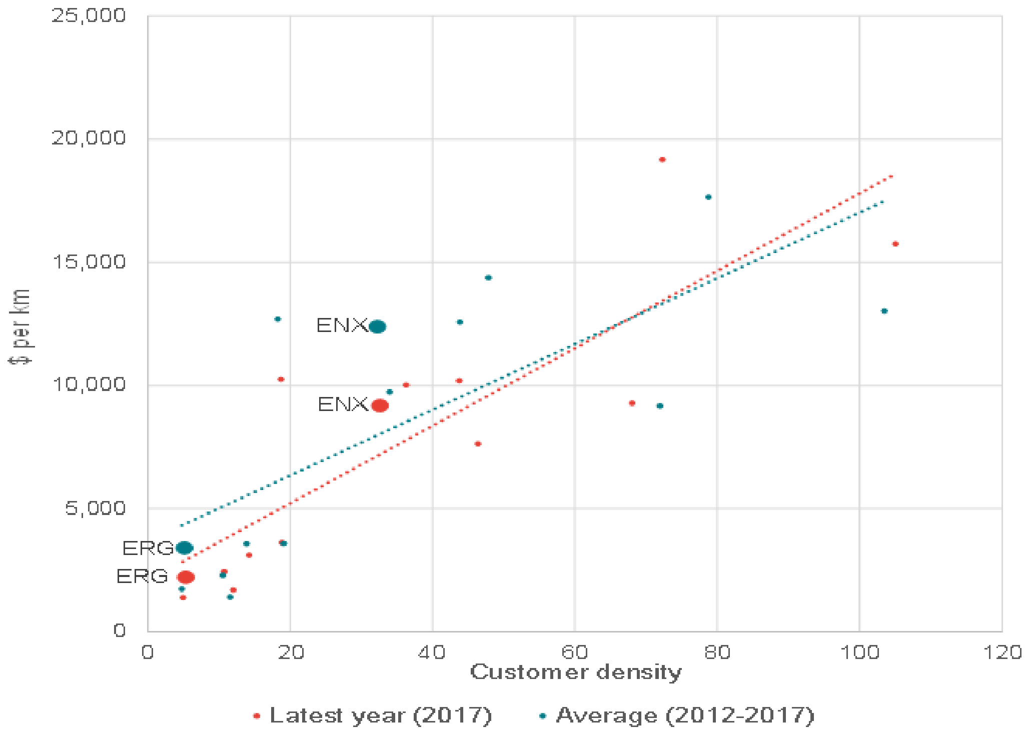
When we do so, the comparisons show that the indirect costs of both Energex and Ergon Energy do not materially differ from those of other Australian DNSPs over recent years.

5.3.2 Comparison to other networks

Figure 5.6 shows that on a per kilometre basis, Ergon Energy's indirect costs are very similar to those of its network peers. Similarly, Figure 5.7 shows that on a per customer basis, Energex's indirect costs are similar to its network peers.

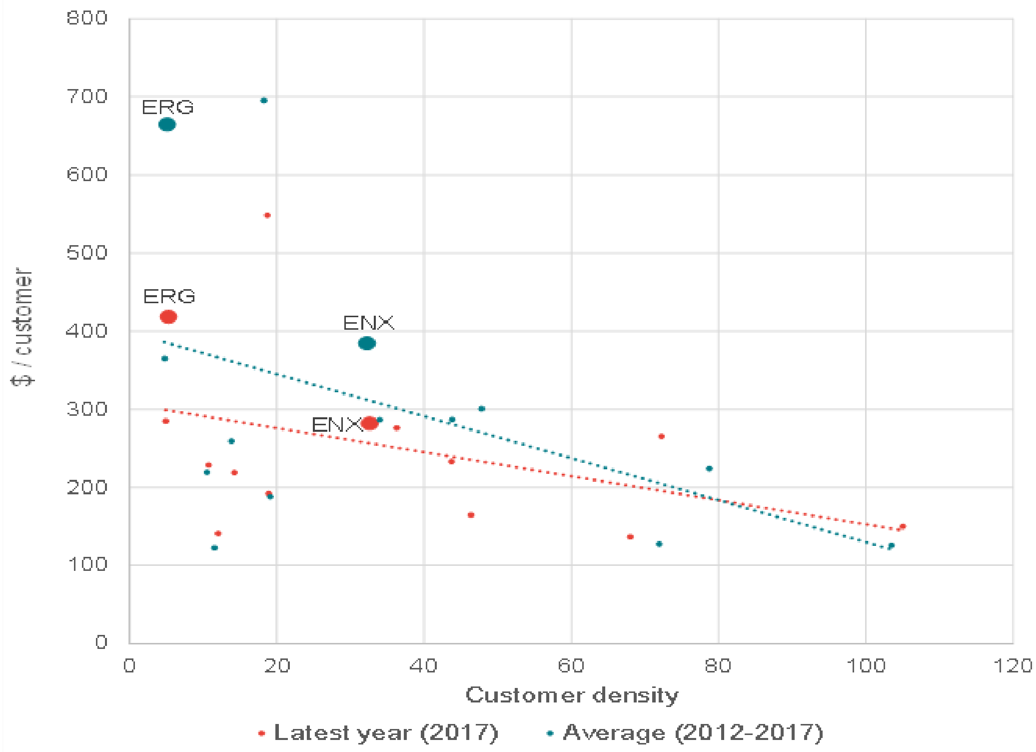
The two figures also show the significant improvement we have made in indirect costs in the most recent years. Figure 5.8 emphasises the significant improvements we have made over recent years – and which are reflected in our Base Year Opex.

Figure 5.6: Total indirect opex per kilometre of route line length against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

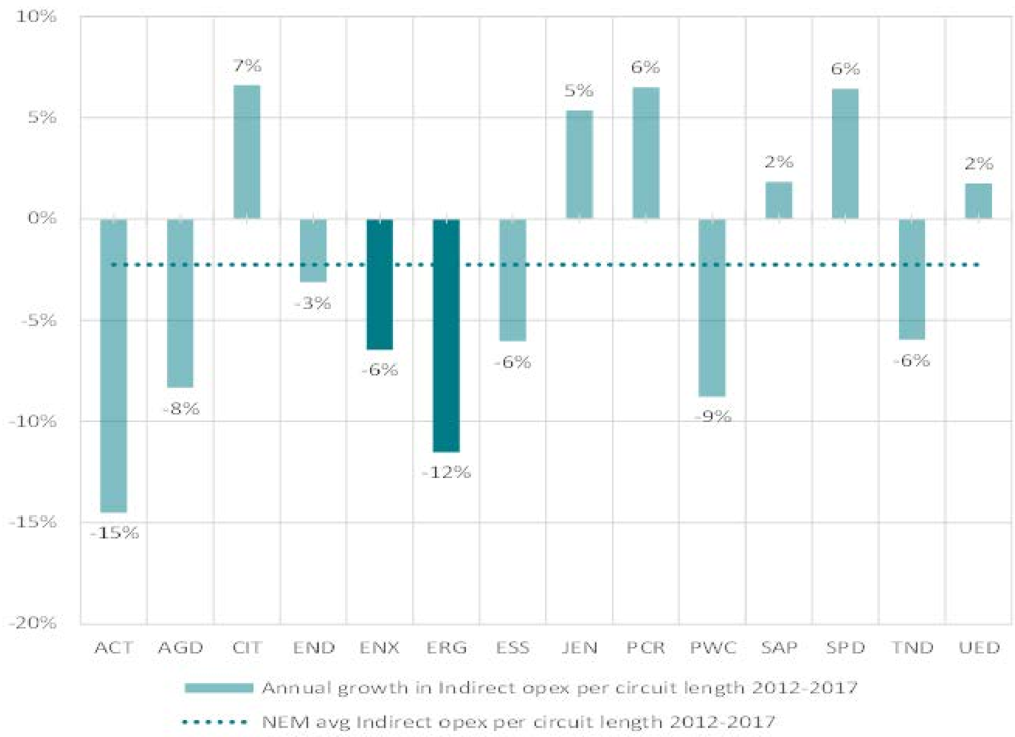
Figure 5.7: Total indirect opex per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

Figure 5.8 shows the average annual growth in indirect opex of Australian DNSPs for the 2012-2017 period. Both Energex and Ergon Energy have among the largest reductions over that period compared to their respective DNSP peers.

Figure 5.8: Annual growth in indirect opex per customer (2012 - 2017)



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

5.4 Vegetation management

5.4.1 Summary

Vegetation management expenditure covers planned programs and reactive maintenance activities undertaken to manage vegetation (i.e. trees) across our networks. We do this with the aim of providing a safe and reliable network.

Historically, vegetation management costs within Energex have appeared to be higher than industry peers. However, Energex's Base Year Opex includes a reduction in overall vegetation costs due to recent negotiations of vegetation management contracts. The new contracts will sustainably reduce vegetation management costs through a variety of means including data capture and analysis, improving corridor condition through removal of problematic vegetation, and through a larger contractual arrangement achieved as Energy Queensland.

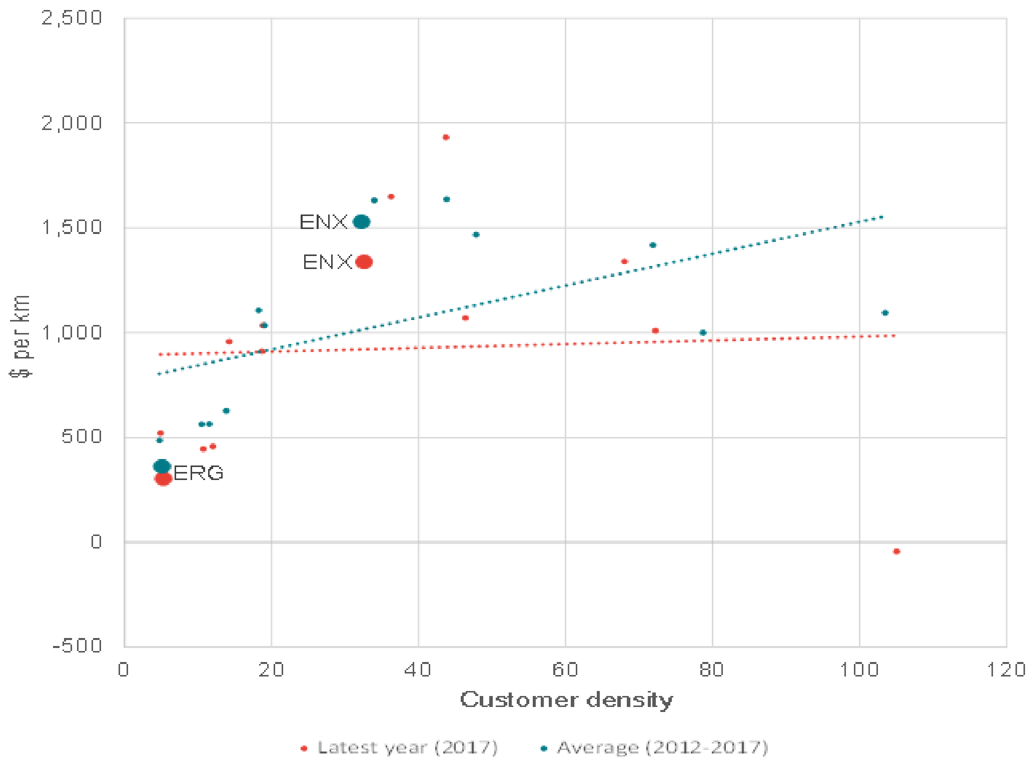
For Ergon Energy, vegetation management costs are comparable to its network peers, especially on a per kilometre basis.

5.4.2 Comparison to other networks

Figure 5.9 shows Energex's vegetation management costs appear relatively higher than its peers. This is in part due to the favourable vegetation growing conditions that cover the network, including in areas with higher customer density (which increases the costs of cutting and accessing trees).

In contrast, the figure also shows that Ergon Energy's vegetation management opex is among the lowest of all DNSPs (on a per overhead circuit line length basis). This relativity will further increase when the cost of network LiDAR scanning is reclassified to overhead lines inspection for RIN reporting purposes to be consistent with how other DNSPs treat it. This accounts for approximately 25% of vegetation management costs.

Figure 5.9: Vegetation maintenance opex per overhead circuit length against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

5.5 Maintenance

5.5.1 Summary

Maintenance expenditure covers the costs of inspection programs and implementing maintenance plans. Inspections are undertaken to detect potential defects on the network requiring remedial responses. Maintenance plans are developed and implemented to ensure delivery of supply, reliability, security and safety objectives.

Our analysis suggests that both Energex and Ergon Energy are comparable to their peers. Based on customer feedback, we have focused our expenditure forecasts on maintaining, not improving reliability performance, except for those mainly rural and remote customers currently receiving below standard service. Alignment of condition assessments, delivery timeframes and process improvements in inspection and defect management areas have been considered estimating Base Year Opex.

5.5.2 Comparison to other networks

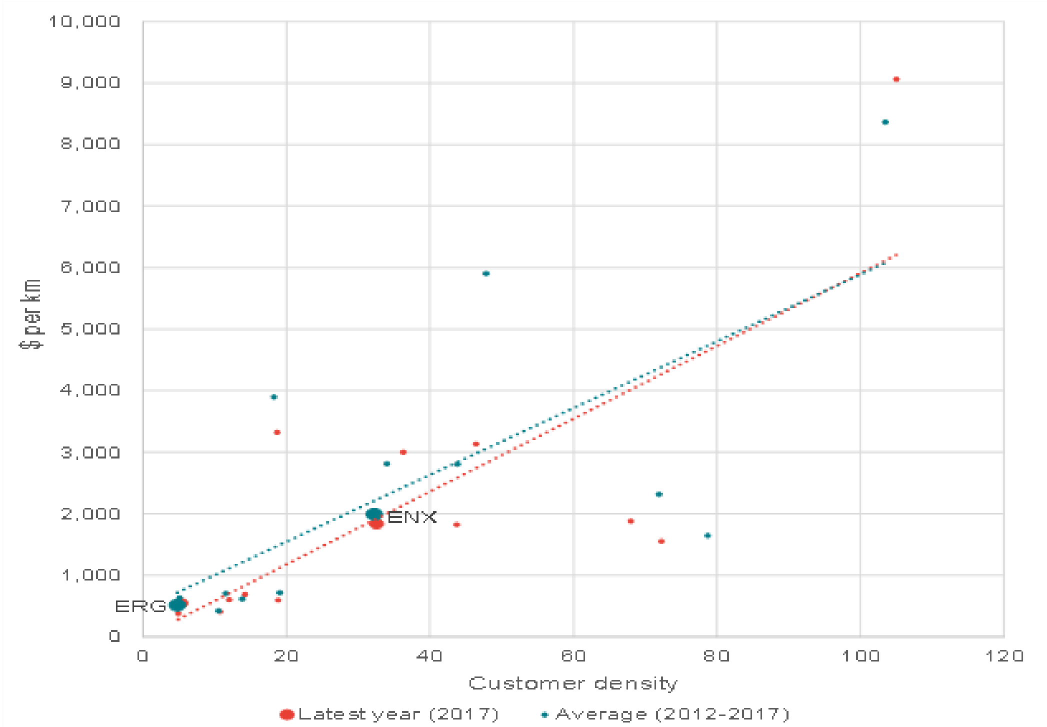
Figure 5.10 shows that historically both Ergon Energy's and Energex's maintenance expenditure has not been materially different to their peers. The small differences that are shown are explainable by the OEFs that apply to our networks.

For instance, if one considers Sapere-Merz's recommended[15] OEF adjustments for extended lengths of sub transmission lines (6%) and exposure to termites (1%) by reducing our historical maintenance opex for those adjustments, the proposed maintenance opex for our network businesses would have

[15] Sapere Research Group and Merz Consulting, Independent review of Operating Environment actors used to adjust efficient operating expenditure for economic benchmarking, August 2018,

been right on the average of other DNSPs for both time periods shown in Figure 5.10. Moreover, although we consider (and Frontier Economics has shown) that Sapere-Merz's estimates are on the low side,[16] its analysis nevertheless highlights that those OEFs are relevant when assessing the expenditure of our network businesses, including maintenance expenditure.

Figure 5.10: Maintenance opex per overhead circuit length against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

5.6 Emergency response

5.6.1 Summary

Emergency response expenditure covers the costs of work undertaken after a failure of an asset, needed either to restore the network to a state in which it can perform its required function or to render the installation safe. This includes repairing damaged equipment and all storm-related repairs – of which there can be many.

Our analysis suggests that Ergon Energy's emergency response opex is not materially inefficient, especially when looking at average expenditure per interruption over 2012-17. When looked at on a per customer basis, Energex's emergency response opex is comparable to its network peers.

Our customers are generally happy with the resilience of our distribution network, our operational readiness and our timely restoration of services after storms and other emergencies. Similar to our historical performance, the base year expenditure for Emergency Response reflects the emergency response challenges for our network businesses, and our ongoing commitment to meet our customers' and communities' expectations.

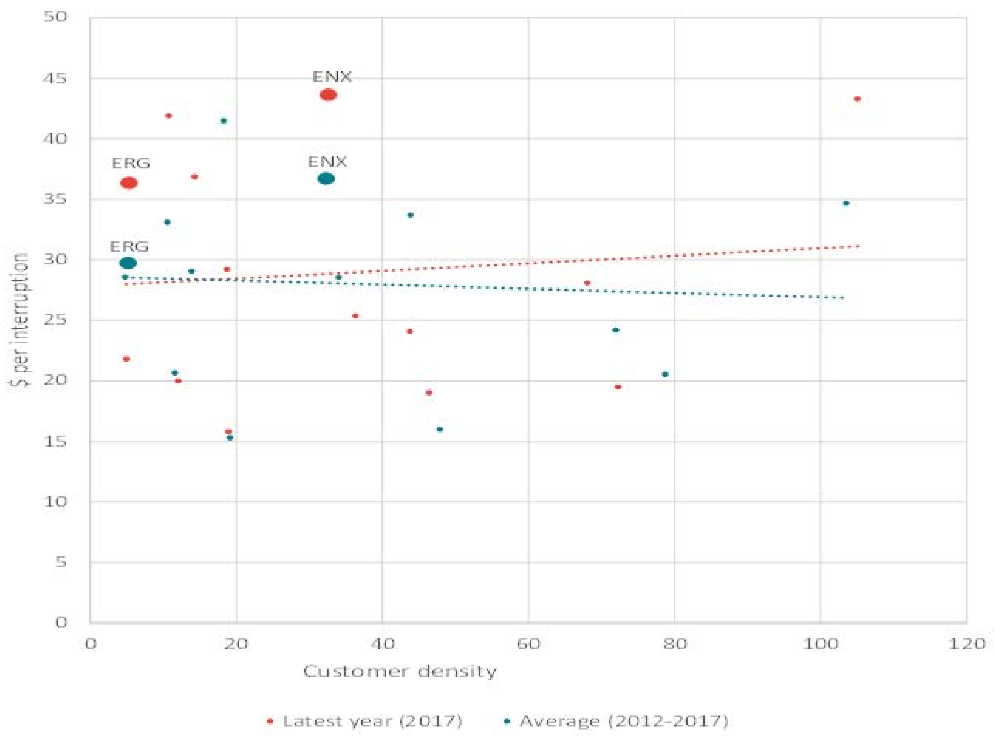
16 Frontier Economics, AER Operating Environment Factors (OEFs), A Report Prepared for Energy Queensland, December 2018

5.6.2 Comparison to other networks

It is problematic to compare emergency response performance between DNSPs in individual years due to the disproportionate impact a single cyclone or storm season can have. For example, in 2017 Cyclone Debbie resulted in Ergon Energy incurring the highest emergency response costs since Cyclone Oswald in 2013. As a result, we believe a greater focus should be given to the average historical performance and our ability to meet our customers and the communities' expectations on timely restoration of services after severe storms and other emergencies.

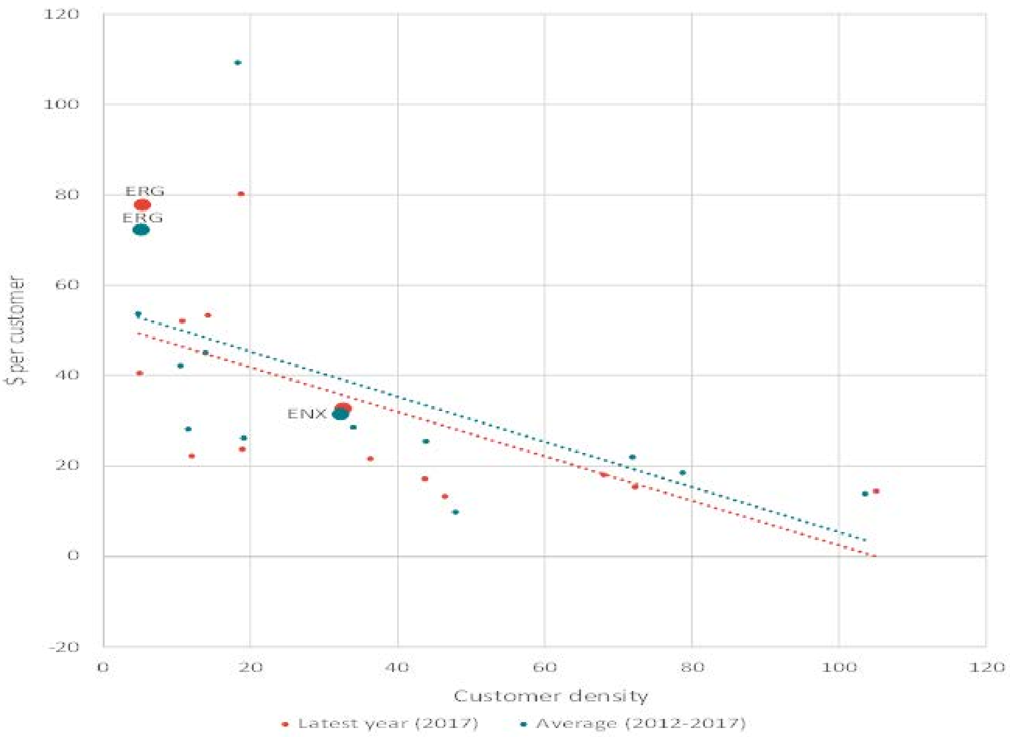
Figure 5.11 illustrates that on average Ergon Energy's historical emergency response opex has not been materially inefficient compared to other Australian DNSPs. This is particularly apparent given the extreme weather we face across a broad network coverage area and subsequent mobilisation of resources to respond to our customer's restoration expectations. While Figure 5.11 suggests Energex's emergency response costs are higher than its peers, they are not materially different from its peers on a per customer basis (as shown in Figure 5.12).

Figure 5.11: Emergency response opex per interruption against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

Figure 5.12: Emergency response opex per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

5.7 Non-network

5.7.1 Summary

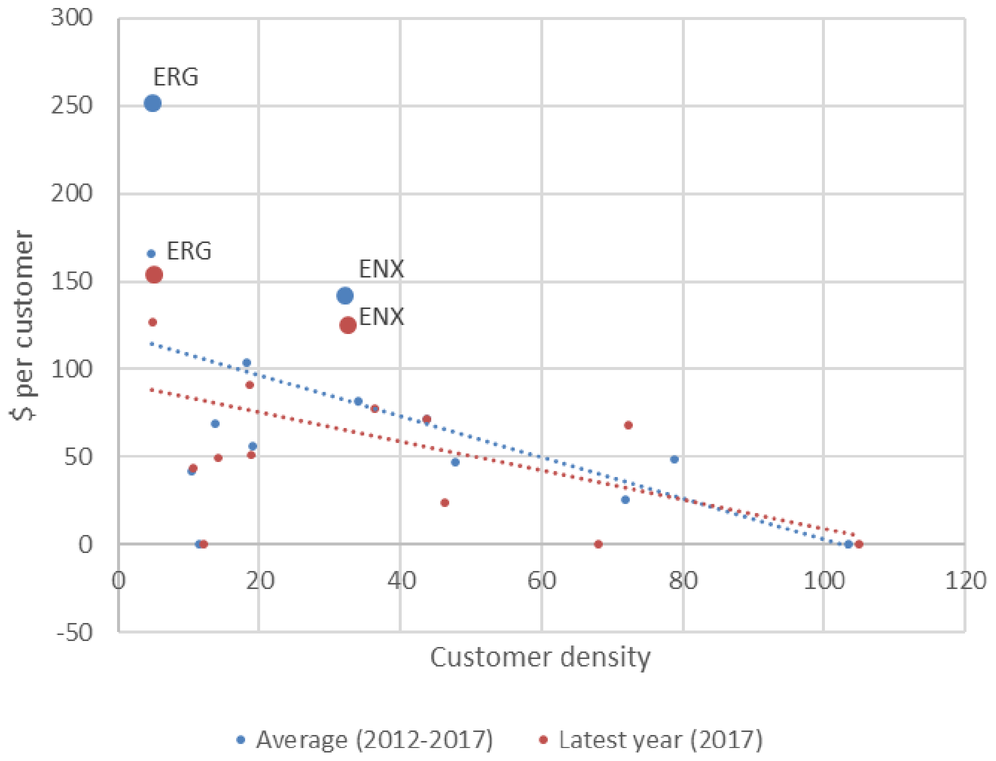
Non-network expenditure covers costs relating to information technology and communication assets, non-network buildings and property assets, fittings and fixtures, and other non-network assets.

Our analysis provides mixed results, suggesting that our non-network expenditure for both Energex and Ergon Energy is higher than their peers. However, this is largely because we capture some expenditure such as IT and property in this category (as well as other categories) that other DNSPs do not. The large balancing item (relative to others) provided by Energex and Ergon Energy when reporting is evidence of this.

5.7.2 Comparison to other networks

Figure 5.13 shows that both networks have relatively high non-network opex on a per customer basis.

Figure 5.13: Non-network opex per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

5.8 Overheads

This section describes the nature of our overheads. It explains how the expenditure of our network businesses has evolved over the current regulatory control period, and analyses how recent expenditure compares to other networks; and explains and justifies our overheads.

5.8.1 Summary

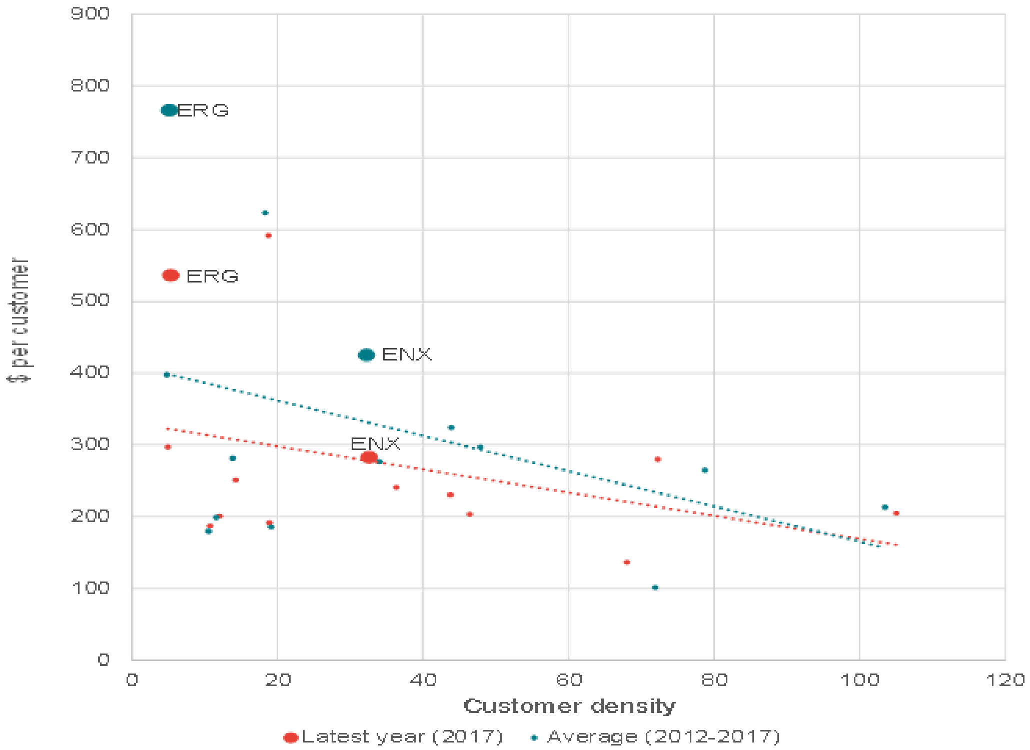
Overhead expenditure includes both network and corporate overheads. Network overheads include the cost of undertaking network, control and management activities that cannot be directly identified with a specific operational activity (e.g. network management, planning, network control, and customer services). Corporate overheads include the costs of support and other management activities undertaken by the corporate office that cannot be directly identified with specific operational activities (e.g. executive management, legal, HR, and finance). Our overhead expenditure is affected by our CAM and Capitalisation Policy discussed in Appendix A.

While we have achieved significant reductions (on a per customer basis) over the current regulatory control period (as discussed in section 3.4.2), we can achieve further cost reductions during the 2020-25 regulatory control period. This is why we are proposing productivity factors over that period that reflects our commitment to realise those reductions and pass the benefits onto our customers (through lower network charges).

5.8.2 Comparison to other networks

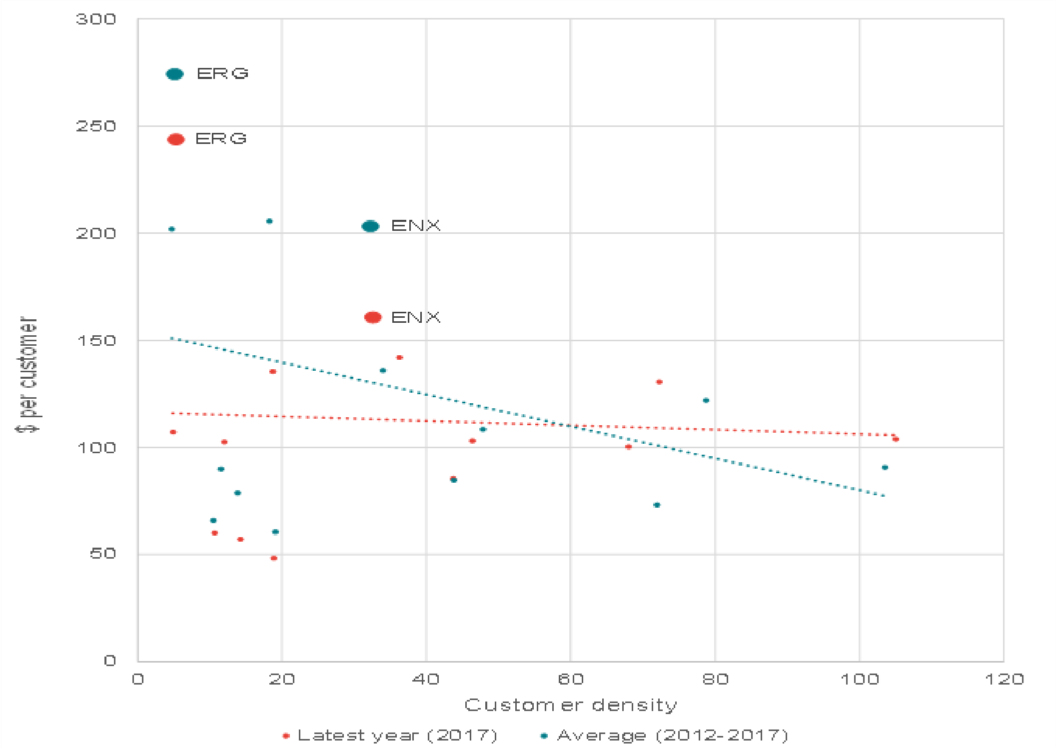
Figure 5.14 shows how our overhead expenditure on a per customer basis is significantly lower in 2017 than the average over 2012-17 – highlighting the success we have had in cutting costs over that period. We are committed to realising further reductions, notably in corporate overheads, where we will continue to achieve the relatively large savings (this can be seen in Figure 5.15). Our Base Year Opex calculation for each network business reflects this.

Figure 5.14: Total overheads (including capitalised costs) per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

Figure 5.15: Corporate overheads (including capitalised costs) per customer against customer density



Source: Category analysis and economic benchmarking RIN data published by the AER. EQL analysis.

APPENDIX A. Cost allocation and capitalisation

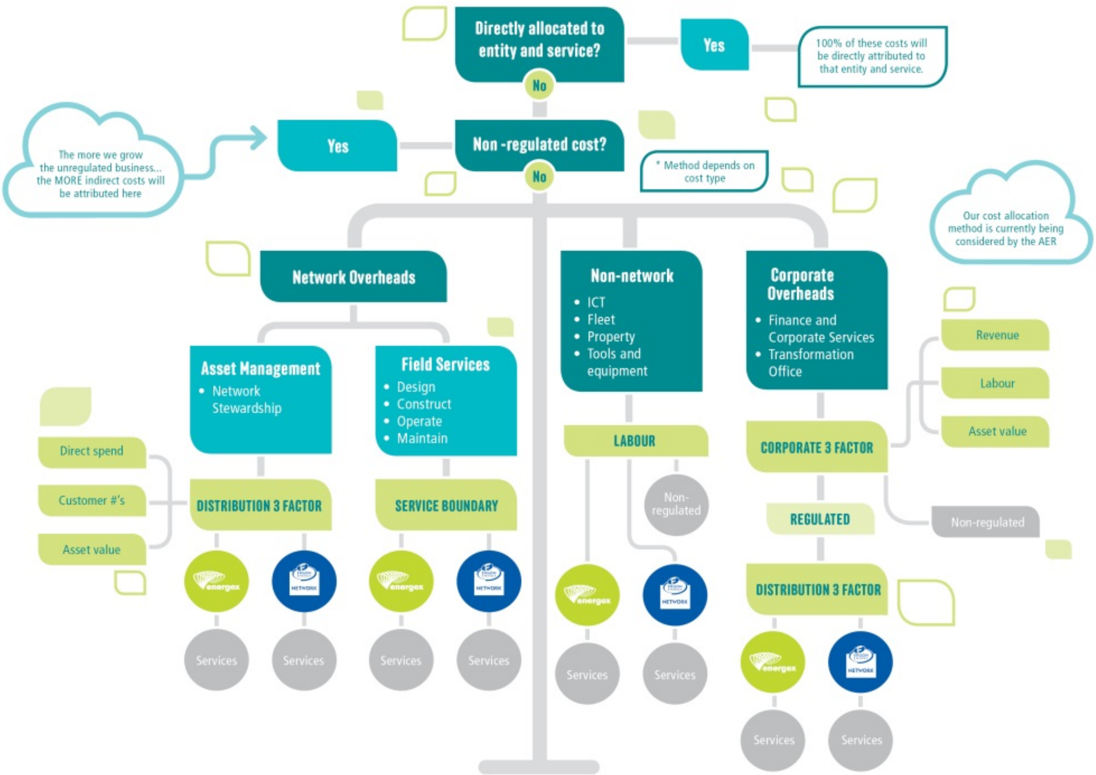
A.1 Allocation to services

The AER has approved Energex and Ergon Energy's new CAM. Under the CAM, we allocate our indirect costs between our distribution and other services in a manner whereby we share with customers the scale benefits from the merger of Energex and Ergon Energy under the Energy Queensland banner.

This means that our expenditure forecasts only include costs that properly relate to the electricity distribution services that Energex and Ergon Energy provides, and not costs related to other Energy Queensland businesses. We have also recast our historical expenditure using our new CAM, so that the trend in our historical and forecast expenditure can be compared.

Figure A.1 illustrates our approach to cost allocation in our new CAM.

Figure A.1: Energex and Ergon Energy's approach to cost allocation



The allocation of costs between the Energy Queensland businesses is as follows:

- **Network overheads – field services costs** are allocated between Energex and Ergon Energy by reference to the service boundary (i.e. using the geographic location of the cost being incurred). Because many of these costs relate to where the physical network is located, the service boundary is an appropriate causal allocator. For example, a line worker in Brisbane should have their indirect costs allocated to Energex as it is unreasonable that they would be undertaking work on Ergon Energy's network.
- **Network overheads – asset management costs** - unlike field services, the asset management component of network overheads does not depend on where the work is being undertaken. That is, it is quite plausible that a member of the asset management team, responsible for grid planning and optimisation, could be located in the Rockhampton region

but be doing work for Energex's network. Therefore, a distribution three factor method is used to allocate indirect costs between Energex and Ergon Energy by using equal weightings of direct expenditure, customer numbers and asset values.

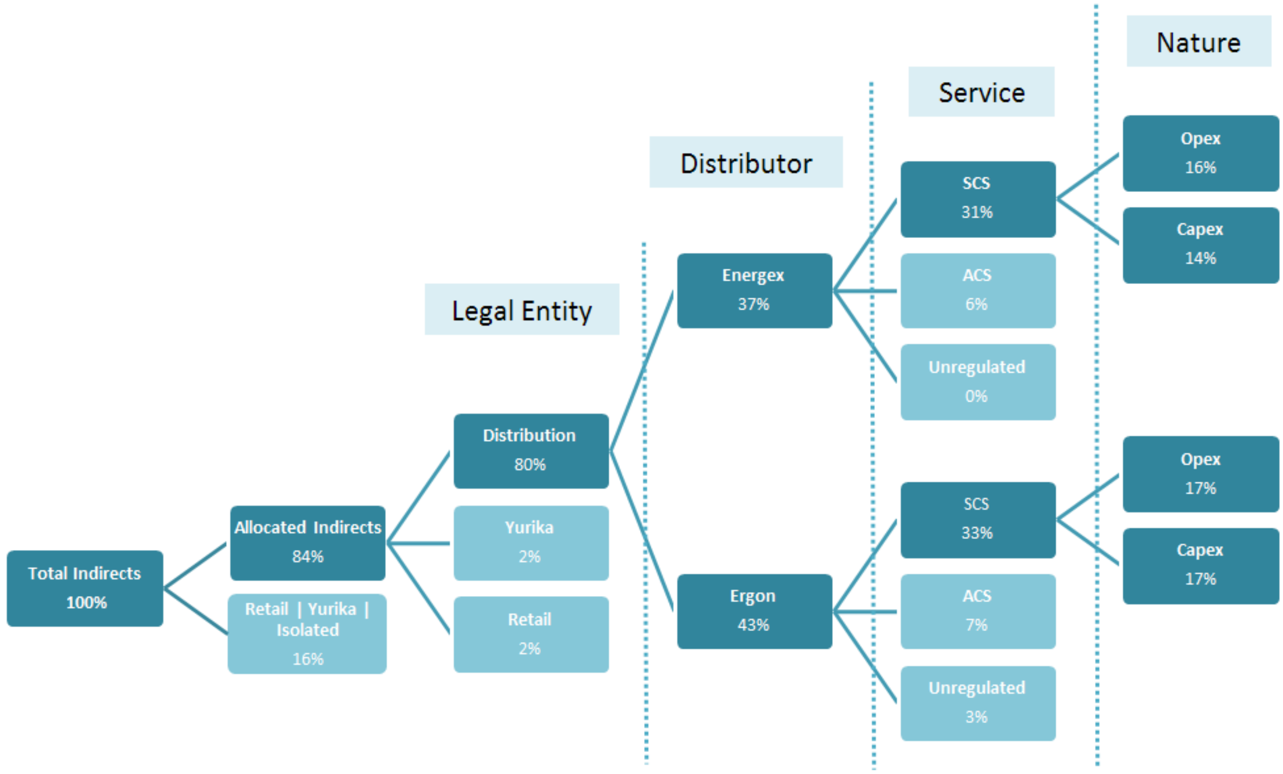
- **Non-network overheads** are allocated between Energex, Ergon Energy and the non-regulated businesses using labour as a causal allocator. This is because these indirect costs are closely aligned with their use by internal resources.
- **Corporate overheads** are initially split between the non-regulated and the regulated network businesses using a corporate three factor method which uses equal weightings of revenue, labour, and asset values to allocate these costs into the various areas. The corporate overheads that are allocated to the network businesses are then allocated between Energex and Ergon Energy using the distribution three factor method.

Once the indirect costs (being Network, Non-Network and Corporate overheads) have been allocated to Energex and Ergon Energy they are then further allocated to the different services types (being standard control services, alternate control services and unregulated services) based on a proportional allocation of direct expenditure.

A portion of overheads allocated to standard control services are capitalised based on our Capitalisation Policy. Our Capitalisation Policy is discussed in section A.2 below.

Using 2018-19 estimated expenditure, Figure A.2 shows the proportions in which costs are allocated from Energy Queensland to its businesses and then the allocation of network allocated costs between Energex and Ergon Energy, then to their types of distribution services and then between opex and capex for SCS using the Capitalisation Policy, which is discussed below.

Figure A.2: Allocation of EQL costs to Energex and Ergon Energy



A.2 Capitalisation Policy

To ensure the value of constructed assets correctly reflects all costs incurred, it is necessary to charge direct costs and indirect costs (overheads) that are directly attributable to constructing or readying the asset for use. Therefore, a portion of indirect costs allocated to standard control services are capitalised based on our Capitalisation Policy and Capitalisation Manual.

Our Capitalisation Policy complies with Australian Accounting Standards, with its application subject to an annual independent financial audit.

Applying this policy results in approximately 47 to 48 per cent of our overhead costs being capitalised. We understand that there is a wide range of capitalisation approaches and outcomes across DNSPs in the NEM, with the amount of overheads capitalised ranging from almost 0 per cent up to 50 per cent of overheads.

APPENDIX B. Definitions, acronyms, and abbreviations

Abbreviation	Description
ACT	ActewAGL (now called EvoEnergy)
AER	Australian Energy Regulator
AGD	Ausgrid
Capex	Capital expenditure
CIT	Citipower
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
END	Endeavour
Energex	Energex Limited
ENX	Energex Limited
Ergon Energy	Ergon Energy Corporation Limited
ERG	Ergon Energy Corporation Limited
ESS	Essential
JEN	Jemena
LiDAR	Light Detection and Ranging. It is a surveying method that measures distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. Differences in laser return times and wavelengths can then be used to make digital 3-D representations of the target.
NEM	National Electricity Market
NSP	Network Service Provider
OEF	Operating Environment Factor
Opex	Operating expenditure
PCR	Powercor
PWC	Power and Water
RIN	Regulatory Information Notice
SAP	SA Power Networks
SPD	AusNet
TND	TasNetworks
UED	United