6.01

Ausgrid's proposed operating expenditure

Ausgrid

Contents

1 INTRODUCTION

The purpose of this document is to provide additional detail to support our proposed operating expenditure (opex) forecast for the 2019-24 Regulatory Period. It supports our Regulatory Proposal to the Australian Energy Regulator (AER) and references other supporting documentation which provide supplementary information for our opex forecast.

This document should be read in conjunction with Chapter 6 (Operating Expenditure) of our Regulatory Proposal.

This document provides context in terms of our alignment with the requirements of the National Electricity Rules (NER). Our proposed opex aligns with the NER and the AER's requirements with respect to opex forecasts, methodology and assumptions, as set out in:

- NER chapter 6 (6.5.6 and 6.12.1(4)) and schedule 6 (S6.1.2 and S6.1.3)
- The AER's Expenditure Forecast Assessment Guideline
- The Regulatory Information Notice issued by the AER on 30 January 2018, and
- Our license obligations.

We are confident our approach to opex is prudent and efficient. In particular, we note:

- We have transformed our business to provide a more sustainable cost base and to embed a culture of efficiency, including active consideration of opex-capex trade-offs
- Our costs benchmark well against our peers, reflecting our achievement of very substantial savings over the 2014-19 regulatory period
- We have taken account of customers' concerns regarding affordability in preparing our opex forecasts
- We have committed to demand management initiatives and changes to our vegetation practices that will deliver substantial value to our customers.

In the past we operated with a significantly higher cost base. The AER's determination for 2014-19 (or 2015 determination) set a significantly lower level of opex than we had proposed, which was reflected in a 14% average fall in prices in 2015/16. Since then, we have made a concerted effort to transition to a more sustainable level of opex, through an ambitious program of transformation designed to 'right-size' our workforce, improve our efficiency and reset our cost base.

Over the current regulatory period, we have reduced our annual underlying operating cost base by more than $100 million without compromising safety, reliability or customer outcomes. In the penultimate year (2017/18) of the current period, we expect to have reduced our recurrent opex to the level of the allowance set for us by the AER in its 2014-19 determination.

Benchmarking shows that we have made significant improvements over a range of measures, bringing our performance into line with our industry peers. Accordingly, the AER and our customers can have confidence that our transformation program has achieved levels of opex that are consistent with good practice in our industry.

In developing our opex forecast for the next regulatory period, we have applied the AER's preferred base-step-trend methodology. Accordingly, our forecasts lock in the ongoing saving of over $100 million a year we have made through transforming the business.

We are confident that the proposed opex reflects the efficient and prudent costs of achieving the opex objectives, and provides safe and reliable distributions services to our customers, in accordance with the requirements of the NER.

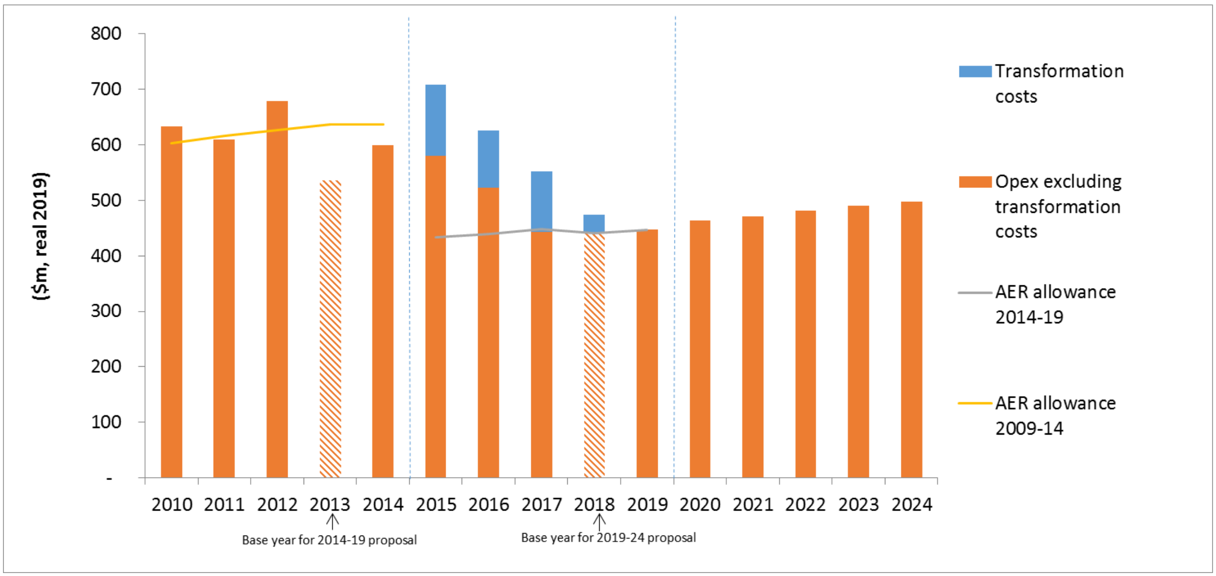
2 OPEX OVER TIME

During the current 2014-19 regulatory period, we have changed our business practices to deliver on-going opex reductions of more than $100 million per annum, making significant progress in moving to an efficient and sustainable level of opex. This translates into a $76 saving to customers per year.[1] The changes we have made have allowed us to:

- Lower costs without compromising safety or reliability
- Pass on cost savings to customers.

In the 2019-24 regulatory period, we will maintain the lower cost base achieved while ensuring reliability and improving safety where it is possible to do so. The figure below shows our forecast opex alongside our actual opex for the current and previous regulatory periods.

Figure 1. Actual and forecast opex for 2009/10 to 2023/24 ($m, in real FY19 terms)



The NER require an explanation of any significant variations in forecast opex from historical opex (S6.1.2(8)). In the past, we operated with a higher cost base. Mandated licence conditions, which increased reliability standards, and rising peak demand led to a rapid increase in capex from 2007 to 2012. Our operating cost base also had to increase to support this higher level of activity.

The AER's determination for 2014-19 set a significantly lower level of opex than we had proposed, which was reflected in a 14% average fall in prices in 2015/16. Since then we have moved as quickly as possible to close the gap between our actual expenditure and our allowance by making sustainable savings.

The AER's assessment of our past opex performance, and our customers' focus on affordability, made it our top priority to transform our cost base. We have therefore taken steps to transition our business to a more sustainable level of underlying opex, through an ambitious program of transformation designed to 'right-size' our workforce and improve our efficiency.

---

[1] This saving represents the difference between opex per customer in 2012/13 and 2017/18.

To ensure our forecast opex reflects our expected expenditure requirements over the next regulatory period, we also considered a number of factors that could impact this expenditure requirement. In general, some of the factors that will influence the level of opex required in the next regulatory period are:

- Regulatory obligations and changes to these obligations or the introduction of new obligations
- The relationship between forecast capex and opex
- Forecast changes in the cost of inputs (i.e. labour, materials etc) and the growth of outputs.

We have considered the impact of these factors on our opex needs for the next regulatory period. We have used our estimated underlying opex for 2017/18 as the efficient starting base. This excludes non-recurrent costs we expect to incur during 2017/18, for example transformation costs. To this base year opex we have incorporated the impact of the following factors to ensure that our forecast opex reflects our future needs. These factors, therefore, represent the reasons for changes between historical opex and forecast opex.

The specific factors are:

- The classification of Emergency Recoverable Works (ERW) as a regulated distribution service. These costs are not currently recovered through standard control services opex
- A Price Reform Research project to inform and expedite our transition to more cost reflective pricing as required by the AEMC’s rule change for Distribution Network Pricing arrangements
- Demand management (DM) initiatives, which will provide positive outcomes for customers through the deferral of capex
- Forecast changes in the prices of inputs. We anticipate that the rate of increase in labour costs for the next regulatory period will be above expected inflation
- Forecast growth in outputs. As we provide more output – for example by adding customers to our network or operating and maintaining more lines – our opex increases
- Forecast changes in productivity, to reflect expected industry-wide improvements in finding more efficient ways of delivering services. Historical trends suggest that the utility industry is not delivering greater productivity improvements than the broader economy (which is reflected in CPI).

Our performance in the current period and the circumstances we are expecting to face in the next period are critical factors we must take into account in developing forecast opex for the 2019-24 regulatory period. In addition to these factors, the NER also requires the AER, in making its decision on whether to accept the proposed forecast opex, to have regard to the extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by Ausgrid in the course of its engagement with customers.

One of the findings from our stakeholder engagement is customers’ concern about electricity prices. In the 2019-24 regulatory period, we have identified a number of cost increases which we are proposing to absorb through efficiency savings, including:

- Land tax is expected to increase by approximately 7% annually over the forecast period due to increased land values. This translates to approximately $30 million in additional opex over the 2019-24 regulatory period above the amount allowed through the base-step-trend approach
- Costs associated with customer operations activities such as storm readiness campaigns, customer surveys, complaints management, contact centre and customer connections are expected to be approximately $10 million higher than the amount allowed through the base-step-trend approach over the 2019-24 period

- IT costs associated with cyber security and data management are expected to be approximately $8 million higher than the amount allowed through the base-step-trend approach over the 2019-24 period.

In addition to focusing on affordability and sustainability, we are taking initiatives to deliver improved customer value within our opex forecast:

- We have changed our working practices for vegetation management in response to customer feedback. Our new approach of more frequent, less severe tree trimming maximises customer value through increased aesthetics and utility in suburban areas
- We are implementing an Advanced Distribution Management System to enable Ausgrid to take advantage of future industry and technological developments. This will better serve our customers by enabling the modern grid and allowing real-time identification of outages
- We are increasing our focus on education, developing a strategy to better engage with our Culturally and Linguistically Diverse customers and revamping our energy literacy material to identify and address any gaps to make information easier to access and understand.

In light of customers' concerns regarding affordability, we are not seeking to pass through any increased costs associated with these cost categories. Rather, we will absorb these cost increases and work hard to achieve efficiencies to offset these with reductions.

Having taken into account our performance in the current period, the circumstances we expect to face in the 2019-24 regulatory period, as well as customers' concerns, we have forecast an opex requirement for the next period of $2.4 billion (real FY19) (see table below)

Table 1. Forecast opex, 2019-24 ($m, real FY19)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Total	463	471	481	490	497	2,402

Note: Opex excluding debt raising costs. The table shows total opex over the next regulatory control period as well as for each individual year, as required under the NER 6.5.6(b)

This opex forecast represents the expenditure we consider reasonably reflects:

1) The efficient costs of achieving the opex objectives listed in clause 6.5.6(a) of the NER
2) The costs that a prudent operator would require to achieve the opex objectives
3) A realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives (together the 'opex criteria' – see Section 8).

In addition to this forecast opex, Ausgrid also proposes a forecast debt raising cost of $40 million (real FY19). The table below shows the forecast opex for each year of the next regulatory period identified into well-accepted categories,[2] including an allocation between transmission and distribution standard control services. The NER requires us to identify, for each category of expenditure, to what extent that forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable.[3] The 2019-24 regulatory period would be considered short run in economic terms. During this period, we will incur both:

- Variable costs, which change as our outputs (customer numbers, circuit length and ratcheted maximum demand) change
- Fixed costs, which are incurred regardless of movements in our outputs.

---

[2] As required by S6.1.2(1)(i) of the NER.
[3] S6.1.2(1)(iii) of the NER.

The table below shows those operating activities for which our costs may broadly be considered as either variable or largely fixed. We do not have information to identify fixed and variable costs for each of our opex categories.

Table 2. Fixed and variable operating activities

Nature of costs	Examples of opex activities
Fixed	Corporate support functions such as finance, human resources management and regulation. Property ownership.
Variable	Inspection, corrective maintenance and breakdown maintenance. Customer service functions, such as those provided through the customer contact centre.

Note: Classification of 'fixed costs' does not mean that these costs will not experience cost escalation over a given period. For example, a fixed activity may involve a number of staff. While the staff count may be fixed regardless of output growth, we would reasonably expect to incur cost growth due to wages growth for those staff.

This forecast opex is for the provision of standard control services[4] and represents expenditure that has been properly allocated to standard control services in accordance with the policies and principles set out in Ausgrid's Cost Allocation Method (CAM) as approved by the AER on 2 May 2014.[5] That is:

- Opex that is directly attributable to standard control services is allocated wholly to standard control services, for example, forecast maintenance expenditure
- Shared costs are allocated to standard control services, alternative control services and unregulated services based on the relevant allocators, such as the number of Full Time Equivalents (FTEs) or the floor space ratio.[6] For example, human resources management costs are allocated to standard control services based on the number of FTEs.

Our opex forecast also complies with the Regulatory Information Notice (RIN) issued by the AER on 30 January 2018 (see our RIN templates and RIN Schedule 1 response).[7] As required by the NER (S6.1.2(7)) we also present opex by category for the previous and current regulatory periods.[8]

Table 3. Total forecast opex ($m, real FY19)

	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Maintenance	141	144	146	149	152	732
Network support	117	119	124	126	127	613
Property	64	65	66	67	68	329
Information and communications technology (ICT)	52	53	54	55	56	268
Corporate support	90	91	91	93	95	459

[4] Clause S6.1.2 (1)(iv) requires Ausgrid to identify the categories of distribution services to which the forecast opex relates.
[5] As required by 6.5.6(b) of the NER. See Ausgrid, Cost Allocation Method, November 2013, available at https://www.ausgrid.com.au/-/media/Files/Industry/Regulation/Reports-and-plans/Ausgrid-Cost-Allocation-Method-2013.pdf.
[6] See table 3 of the approved CAM.
[7] As required by 6.5.6(b) of the NER.
[8] We have derived this split using the categories reported in RIN template 3.2.1, which is based on the categories of forecast spend in the base year (2017/18). The same split has been applied to total opex forecast over the 2019-24 period.

	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Total forecast opex (excl. debt raising costs)	**463**	**471**	**481**	**490**	**497**	**2,402**
Distribution	428	435	444	452	459	2,217
Transmission	36	36	37	38	38	185
Subtotal	**463**	**471**	**481**	**490**	**497**	**2,402**
Debt raising costs	8	8	8	8	8	40
Total forecast opex (incl. debt raising costs)	**471**	**479**	**489**	**498**	**505**	**2,443**

Note: Totals may not add due to rounding.

The figure below summarises our allocation of opex to the above programs in our base year (2017/18).

Figure 2. Forecast opex by program (%, 2017/18)

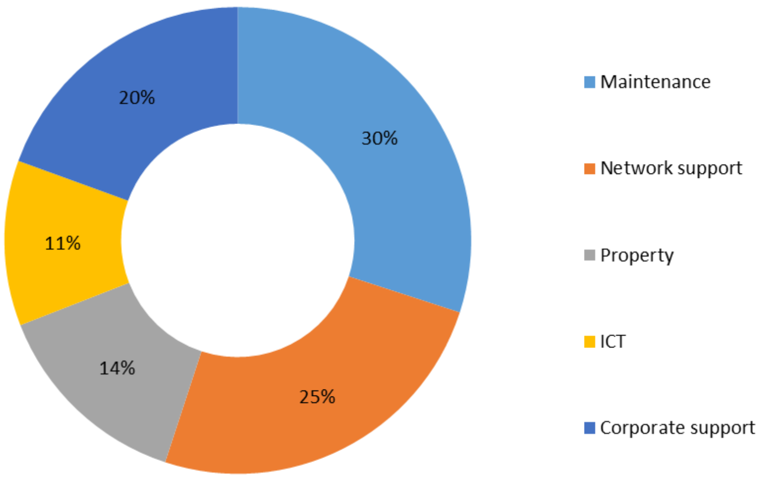


Table 4. Total opex by category ($m)

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
	Nominal								Real FY19	
Maintenance	212	230	242	235	268	282	199	177	132	134
Network support	188	194	244	185	169	98	108	96	110	112
Property	29	31	31	33	31	58	51	49	62	63
ICT	44	46	46	46	45	54	53	52	50	51
Corporate support	66	34	45	5	60	159	180	157	119	87
Total opex	**539**	**535**	**608**	**504**	**574**	**651**	**590**	**531**	**474**	**447**

Notes: Totals may not add due to rounding. From 2014/15 some metering activities became Alternative Control Services and the associated costs are no longer reported as part of SCS opex. Actual figures for 2009/10 to 2016/17 are from Economic Benchmarking RINs submitted to the AER and are presented in nominal terms. Forecast figures for 2017/18 and 2018/19 are presented in real FY19 terms. Forecast figures for 2017/18 include transformation costs that are excluded from our proposed base year opex.

3 FORECAST METHOD

As part of our Regulatory Proposal, the NER require us to include:

- The method used for developing the opex forecast
- Forecasts of key variables relied upon to derive the opex forecast (and the method used for developing those forecasts)
- The key assumptions that underlie the opex forecast.[9]

We outline this information in this section. A forecast opex model is also provided at Attachment 6.02.[10]

We have used a base-step-trend approach to forecast our opex for the 2019-24 regulatory period for most costs. This method aligns with the AER's preferred approach to forecasting most categories of opex, as outlined in the AER's Expenditure Forecast Assessment Guideline.[11] For the remaining costs (such as debt raising costs and the costs associated with step changes), we have used a specific or bottom up forecasting approach, which better reflects the nature of these costs.

This section sets our opex categories, explains the changes we have made to our opex forecasting methodology since the last determination, and describes the approach we have used to develop our opex forecast for the 2019-24 regulatory period. It then sets out the key variables we have used to derive our opex forecast and the key assumptions we have made.

3.1 Opex categories

Our forecast opex can be categorised into network maintenance, network support, property, ICT, corporate support, and other costs. The components of these broad categories of costs are described below.

Network maintenance

Our network maintenance opex comprises the following cost categories that reflect the activities undertaken to maintain the electricity network:

Inspection: Work associated with undertaking planned appraisal and routine preventative maintenance tasks. This category includes the cost of condition monitoring tasks and vegetation management. These tasks are predominantly scheduled and carried out in a repetitive manner with a levelled workload. Inspections identify corrective maintenance needs.

Corrective maintenance: All work associated with correcting defects that have not yet resulted in a "breakdown". Corrective maintenance occurs when an asset fails to meet the threshold criteria set to ensure it remains in working order until the next inspection maintenance cycle. These tasks are generally driven from the results of the inspection process.

Breakdown maintenance: All work associated with equipment that has ceased to perform its intended function (excluding nature-induced breakdown). Depending on the asset requiring maintenance, this activity may need to be undertaken in emergency conditions, generally at short notice. Breakdown activities generally result in higher costs as work may need to be carried out in emergency conditions outside normal working hours.

---

[9] Clause S6.1.2(2), (3) and (5).
[10] As required by RIN 10.1(a)
[11] See AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 22.

Nature-induced breakdown maintenance: All work associated with equipment that has ceased to perform its intended function due to factors beyond the equipment's design capability (e.g. causing an equipment malfunction). These failures cannot be managed through normal maintenance activities. Like breakdown maintenance, these activities may be carried out under emergency conditions and may lead to higher costs.

Non-direct maintenance: All work associated with the testing of plant, tools and equipment that are used to deliver the different maintenance activities defined above. This cost also includes any training and development required to deliver maintenance activities.

Engineering support: Work associated with local project planning, scheduling and coordination of maintenance works.

Network support

Costs pertaining to activities undertaken for customer operations, system control and engineering, planning and connection. These include:

- Customer operations, contact centre and data operations – these costs include facilitating new connections, responding to complaints and general enquiries concerning the distribution network, installation inspection and emergency response to installation and network safety issues
- System control – cost of 24 hour / 7 days a week monitoring and control of Ausgrid's infrastructure. This also includes emergency and incident management
- Engineering, planning and connection – costs of centralised engineering and planning activities associated with preparing asset engineering and investment standards, maintenance analysis, engineering investigations, equipment ratings, technical regulatory reports and planning associated with large customer connections

Property

Costs of various activities inherent in the ownership of properties (land and buildings) including the costs of complying with legal obligations pertaining to this ownership such as land registration, land tax payments and council rates.

Information and communications technology

Costs relating to the operation and maintenance of various IT technologies and telecommunication systems required for the effective operation of Ausgrid's infrastructure and day-to-day operations.

Corporate support

This opex group comprises the costs that would typically exist in any business, and include costs relating to:

- Finance functions
- Fleet and logistics management
- Insurance and self-insurance
- Human resources management
- Workers compensation, occupational health, wellbeing and safety
- Regulation
- Management, including the Board of Directors, Chief Executive Officer and Executive Leadership Team
- Training and development.

Other costs

These are opex costs relating to demand management (DM) and the costs associated with step changes.

3.2 Forecasting methodology for opex

Our expenditure forecasts for the 2014-19 determination were prepared in accordance with our Expenditure Forecasting Methodology of November 2013.[12] The AER raised concerns with our approach to forecasting opex[13] and our opex forecast was reduced significantly. The reduction was primarily a result of the AER's application of its benchmarking methodology to set our base level of opex, rather than using our actual costs.

We have used a base-step-trend approach to forecasting our opex for the 2019-24 regulatory period for most costs. For the remaining costs, we have used a specific or bottom up forecasting approach, which better reflects the nature of these costs.

Under the base-step-trend method we selected a base year of opex that we consider is representative of efficient costs. The base year is adjusted for one-off events (if any) before being "rolled forward" over the 2019-24 regulatory period, trending the costs to account for real input cost changes, network growth and expected productivity gains or losses. Finally, proposed step changes are added to reflect changes in costs relating to a change in regulatory obligations or an opex/capex trade-off.

This method ensures that forecast opex reasonably reflects a realistic expectation of the cost inputs and demand forecasts for the next regulatory period.

3.2.1 Efficient base year

We have adopted our estimated underlying opex for 2017/18 as our base year. This excludes costs we will incur during 2017/18 that we consider are non-recurrent costs.[14] We consider this is representative of our efficient, recurrent opex requirements for the 2019-24 regulatory period.

Our proposed base year reflects the outcome of our transformation program, which has allowed us to significantly reduce our opex. When compared to our historical opex, it is now below the levels previously allowed by the AER in its 2009-14 determination. Our opex performance is now in line with best practice among Australian distribution businesses (as shown in section 4). The AER and our customers can rely on our proposed base year to

[12] For opex we adopted a "fit for purpose" approach to forecasting expenditure and, rather than using total opex in the base year, we forecast specific categories of opex using different methods. In general, we forecast opex using variants of the base-step-trend approach. However, more detailed bottom up forecasts were developed for components of maintenance, demand management, Information Technology, insurance and property, to take into account changes in workload or drivers. These forecasts then superseded the underlying base year forecasts for those activities.

[13] The AER found that our opex forecasting method differed from its guideline forecasting approach in that it disaggregated total opex into cost categories and applied different forecasting methods to different cost categories. The AER considers that it is best to use consistent forecasting methods for all cost categories of opex. This is because the AER considers that hybrid forecasting methods (i.e. combining revealed cost and category specific methods) can produce biased opex forecasts. Using a category specific forecasting method for some opex categories may produce better forecasts of expenditure for those categories, but this may not produce a better forecast of total opex. For this reason the AER did not use category specific forecasting methods to separately forecast any of our opex categories in its substitute opex forecast (except debt raising costs). The AER formed its substitute opex forecast using its guideline forecasting approach with all opex categories included in the base level of opex (except debt raising costs).

[14] Non-recurrent costs are costs that are not incurred on a regular basis and are not representative of ongoing costs. Our estimated 2017/18 expenditure has been adjusted to exclude these non-recurrent costs, which include transformation costs.

forecast opex for the 2019-24 regulatory period, and have confidence that it contributes to efficiency and affordable prices.

3.2.2 Adjustment to the base year

In line with the AER's Final Framework and Approach paper[15], ERW will become a standard control service from the beginning of the next regulatory period. In previous determinations, the AER has adjusted base year costs to reflect changes in the service classification. We have followed the same approach here, as discussed in Section 5.

3.2.3 Trending the base year

We have trended the base year forward to account for:

- Real cost escalation – We have applied forecast real cost escalation to labour, which reflects the expected future price of this cost input
- Output growth – Expected changes in customer numbers, line length and peak demand mean that changes in our activity levels and opex are required
- Productivity growth – To reflect expected industry-wide improvements in finding more efficient ways of delivering services.

Our proposed trend adjustments are set out in Section 6.

3.2.4 Adding or subtracting step changes

We have considered whether there are any expected step changes in our opex over the 2019-24 regulatory period. Step changes are essentially factors that trigger a change in costs from the current amount required to provide standard control services. Where a step change is identified, forecast opex is adjusted to account for this change (which could be either positive or negative). In general step changes are allowed by the AER for changes in costs associated with:

- New (or revised) regulatory obligations
- Capex/opex trade-offs (i.e. where an increase in capex leads to a decrease in opex or vice versa).

Our proposed step changes are set out in Section 7.

3.2.5 Methods for forecasting other operating costs

While we have used the base-step-trend approach for most opex, there are some exceptions where alternative approaches have been used. We have forecast other opex using alternative methods where appropriate.

Forecast of debt raising costs: Our total forecast opex also includes an amount for debt raising costs. Ausgrid has adopted the method that the AER uses to derive this cost. That is, debt raising costs have been calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset base (see Chapter 7 of our Regulatory Proposal).

"Bottom up" method: The bottom up method essentially derives forecast opex by taking into account all the inputs and factors relevant to the activities being performed (e.g. number

[15] ERW are defined as emergency works to repair damage following a person's act or omission, for which that person is liable (for example, repairs to a power pole following a motor vehicle accident). The AER proposes to classify ERW as a standard control service (it is currently an unregulated distribution service), so it can be provided by a distribution business without triggering any ring-fencing requirements. We agree with this approach.

of tasks, the cost types required to perform each task, such as labour and materials, and the price of these cost inputs).

The table below summarises our opex categories and identifies which forecasting method we have used for each category.

Table 5. Forecast method by opex category

Opex category		Base-step-trend	Bottom up or specific forecast
Network maintenance	Inspection	✓	
	Corrective	✓	
	Breakdown	✓	
	Nature induced breakdown	✓	
	Non-direct maintenance	✓	
	Engineering support	✓	
Network support		✓	
Property management		✓	
ICT		✓	
Corporate support		✓	
Other costs	Debt raising costs		✓
	Step changes		✓

3.3 Key variables and assumptions

The NER require us to include in the Regulatory Proposal forecasts of key variables relied upon to derive the opex forecast and the method used for developing those forecasts.[16] The key variables used in the opex forecast relate to our proposed trend adjustments for opex and comprise:

- Real cost escalation
- Output growth
- Productivity growth.

The forecasts of these key variables and the methods for developing them are discussed in Section 6.

The NER also require Ausgrid to provide details of the key assumptions underpinning our forecast opex and a directors' certification as to the reasonableness of those key assumptions.[17] Attachment 5.11 provides details of our key assumptions and the directors' certification. The table below outlines our key assumptions relevant to the opex forecast.

---

[16] Clause S6.1.2(3).
[17] Clause S6.1.2(5).

Table 6. Key assumptions

Key assumption	Description	Applicability
Key assumption 1 – Regulatory obligations	It is assumed that forecast capex and opex for the 2019-24 regulatory period are based on current legislative and regulatory obligations. It is also assumed that no new substantive regulatory obligations and/or major change in scope of current regulatory obligations are anticipated or taken into account.	Capex and Opex
Key assumption 2 – demand and customer connections	Growth forecasts are based on a set of assumptions regarding spatial peak demand and customer connections over the 2019-2024 regulatory period, as set out in Attachment 5.07 of the Regulatory Proposal.	Capex and Opex
Key assumption 4 – Base year opex	Ausgrid's forecasting approach assumes that the amount of opex required to meet the opex objectives over the 2019-24 regulatory period will broadly reflect current opex requirements, with adjustments to reflect changes in input costs, outputs delivered, productivity and step changes. It is assumed that our estimated underlying opex for 2017/18 can be adopted as the base for deriving a forecast of efficient recurrent opex over the 2019-24 regulatory period.	Opex
Key assumption 5 – Trend adjustments	It is assumed that it is reasonable to escalate our estimated underlying opex for 2017/18 to reflect changes in input costs, outputs delivered and productivity over the 2019-24 regulatory period. The trend adjustments that have been assumed are set out in a table in Section 3 (of Attachment 5.11).*	Opex
Key assumption 6 – Forecast capex and opex	The reliability and customer outcomes set out in our Regulatory Proposal assume that all components of Ausgrid's 2019-24 Regulatory Proposal, including the capital and operating expenditure forecasts, will be approved by the AER.	Capex and Opex

* As part of our approach, we have included incremental opex between the base year and the final year of the current regulatory period in line with the AER's 2015 determination. This has the effect of applying the trend adjustments in the AER's 2015 determination and is consistent with the approach taken by the AER previously (e.g. TransGrid draft determination for the 2018-23 regulatory period). The forecast trend adjustments are then applied starting from estimated 2018/19 opex.

4 BASE YEAR EFFICIENCY AND BENCHMARKING

We propose adopting our estimated underlying opex for 2017/18 as our base year opex. Our underlying opex excludes non-recurrent costs that we expect to incur during 2017/18, including transformation costs. Our proposed base year is in line with our allowed opex for 2017/18 (as approved in the AER's 2015 Determination) and we consider it is representative of our efficient recurrent opex requirements for 2019-24.

Table 7. Base year ($m, real FY19)

Opex	2017/18
Base year	440.2

Our proposed base year reflects the outcome of our transformation program, which has allowed us to significantly reduce our opex. When compared to our historical opex, it is now below the levels previously allowed by the AER in its 2009-14 determination. The analysis and comparisons below show that the AER and our customers can have confidence that our transformation program has achieved levels of opex that are consistent with best practice in our industry, promoting our objective of keeping network bills affordable without compromising network safety or reliability.

4.1 Our performance under the AER's benchmarking and productivity models

In the AER's 2017 Benchmarking Report, our historical opex compared poorly to other businesses' (see charts below). However, it does not necessarily follow that our proposed base year will be found to be inefficient. A number of factors affect the benchmarking results presented in the report, including that:

- The report uses data up to 2015/16. Our opex was still relatively high then and includes transformation costs
- Some techniques used in the report, including the econometric models, estimate an average result over the period 2006-16. It will be some time before our performance improves under these approaches.[18]

[18] We also note that the models do not include adjustments for Operating Environment Factors (OEFs). OEFs are circumstances or features that may be unique to particular DNSPs which are not captured by the AER's econometric benchmarking models. The AER is currently reviewing its analysis of OEFs in consultation with industry and other interested parties. As noted in our submission to the AER's consultation, the AER's approach to assessing proposed operating expenditure is largely the same as in the 2015 determinations (and is therefore subject to the same limitations). We consider that this supports the position that the AER should continue to provide conservative/greater OEF coverage rather than less. This includes identifying and adjusting for 'immaterial' OEFs as well as material OEFs. OEFs that increase a DNSP's operating expenditure by 0.5% or more, relative to other DNSPs, have previously been considered by the AER to be immaterial. As evidenced by the 2015 determinations, the collective effect of immaterial OEF adjustments in the same direction can quickly become material. In addition, we consider that the inputs used by the AER should be consistent across the full range of economic benchmarking techniques (i.e. the productivity analysis, econometric models and OEF analysis and adjustments).

Figure 3. AER 2017 Benchmarking Report (extract)

Figure 15 MTFP by individual DNSP, 2006–16

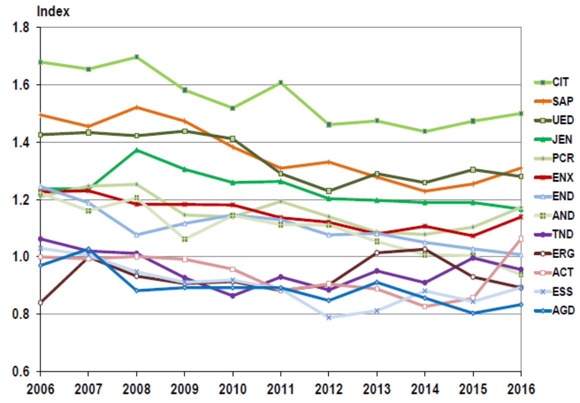
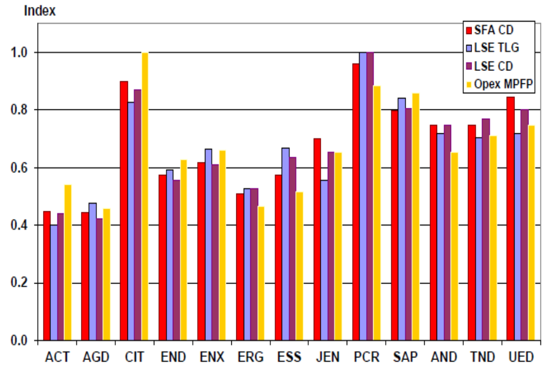


Figure 18 DNSP opex cost efficiency scores, (2006–16 average)



Source: Multilateral Total Factor Productivity (MTFP) by individual Distribution Network Service Provider (DNSP), 2006-16, and DNSP opex cost efficiency scores, (2006-16 average), from AER, *Annual Benchmarking Report – Electricity distribution network service providers*, pp 32 and 39, November 2017.

We have assessed our proposed base year using the methodology adopted by the AER in its 2015 determination for setting our efficient opex. We have also estimated our future performance under the productivity measures used by the AER, as set out below.

4.1.1 Proposed base year

In its 2015 determination, the AER used econometric benchmarking techniques to conclude that our opex was not at efficient levels. The AER substituted our proposed base year with its own estimate of efficient costs. Consistent with the improvement in our opex performance shown in Section 2, application of the method applied by the AER to estimate efficient costs shows that our proposed base year opex for 2017/18 would be accepted as efficient.

We have built a simple model to provide an indication of how Ausgrid's opex performance compares to a base year reflecting the AER's most recent (November 2017) econometric opex benchmarking. In summary, following the AER's approach for our determination in 2015, we reduced average annual opex over the 2006 to 2016 period by the efficiency target generated from Economic Insights' Cobb-Douglas stochastic frontier analysis (SFA) model.[19] This generates an average base year opex value which is then 'rolled forward' to estimate an efficient 2016 base year using the difference between the output drivers, undergrounding and technical change factors in the model between the average for the period and 2016. We then roll forward this estimate to 2017/18 using the increments between years in the AER's 2015 final determination. The 2017/18 estimate ($454 million in real FY19 terms) acts as a comparison point for our proposed 2017/18 base year opex ($440 million in real FY19 terms). The alternative estimate of opex for 2017/18 is higher than our proposed base year. Further details are set out in the box below and the attached model (Attachment 6.04).

[19] As outlined in AER, *Annual Benchmarking Report – Electricity distribution network service providers*, p 39, November 2017.

Testing our proposed base year using the AER's benchmarking approach

Our model is based on the AER's model 'AER Final decision Ausgrid distribution determination - Ausgrid 2015 - Opex base year adjustment – April.xlsx' and follows the same logic, namely:

- The Economic Insights (EI) SFA Cobb-Douglas (CD) model provides an average efficiency estimate for Ausgrid's opex over the period 2006 to 2016.
- The fifth ranked company's efficiency level, based on the EI SFA CD model, is set as the target efficient level. This is AusNet Services Distribution, which was also fifth ranked in the AER's 2015 determination.
- We apply the same adjustment for Operating Environment Factors (OEFs) as the AER used for Ausgrid in its 2015 final determination. This reduces our efficiency target, and provides the basis for setting the implied efficiency improvement factor or target reduction amount.
- The target reduction amount is applied to our average annual opex over the 2006 to 2016 period, to create an efficient average base year estimate. This estimate is then 'rolled forward' to give an efficient base opex estimate for 2016:
    - The coefficients of the output drivers in the EI SFA CD model (customer numbers, line length and maximum demand), which sum to 0.997, are adjusted so they sum to 1. This sets a constant return to scale constraint, which was applied by the AER in its 2015 determination
    - We calculate the difference in each output driver from the average across the period to 2016. These growth rates are weighted by the adjusted coefficients, to provide a weighted average output growth
    - The coefficient of the 'year' variable in the EI SFA CD model is assumed to reflect changes in technology. A technology growth rate is set based on the change from the mid-point of the period to 2016. As the coefficient of the year variable is positive, this growth factor increases base year opex
    - The share of underground cables (to total line length) is taken as a business conditions factor. As with the output drivers, the difference between undergrounding in 2016 and the average for the period is multiplied by the coefficient to provide an estimate of this growth factor
    - The base year average is then multiplied by the combined growth rate factor to give an estimate of efficient base opex for 2016.
- We then extend the above model by rolling forward the 2016 efficient base year opex to 2018 using the year-on-year change in AER's 2015 determination allowances. These provide a comparison point for our proposed base year opex for 2018.

4.1.2 Forecast opex productivity over the 1924 regulatory period

We have also examined our forecast opex productivity to 2024 based on the AER's methodology and using the information submitted in our RIN responses. The AER's methodology relies on an output index which reflects the weighted changes in:

- Energy throughput

- Ratcheted maximum demand[20]
- Customer numbers
- Circuit length
- Customer minutes lost.

The first four outputs are weighted together using the AER's weights, as calculated by Economic Insights and set out in the table below.

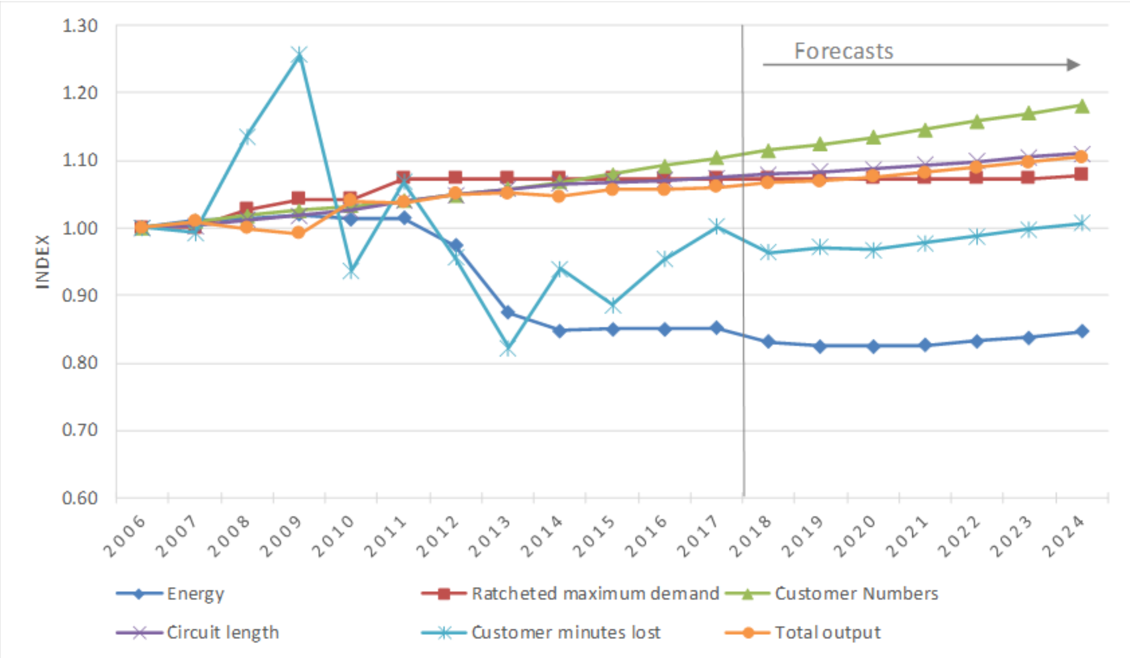
Table 8. Output weights

Output	Weight
Energy throughput	0.125
Ratcheted maximum demand	0.176
Customer numbers	0.458
Circuit length	0.238

Customer minutes lost is a quality measure, with an increase being treated as a negative quality improvement. A 'price' (or cost) for each minute off supply is calculated by Economic Insights by drawing on the Australian Energy Market Operator's (AEMO's) estimates for customer value of reliability and the proportion of different customer types. We have used the 2017 estimate calculated by Economic Insights and held it constant for the entire forecast period.

The indices for each of the five outputs and the weighted total output are shown in the figure below.

Figure 4. Output indices

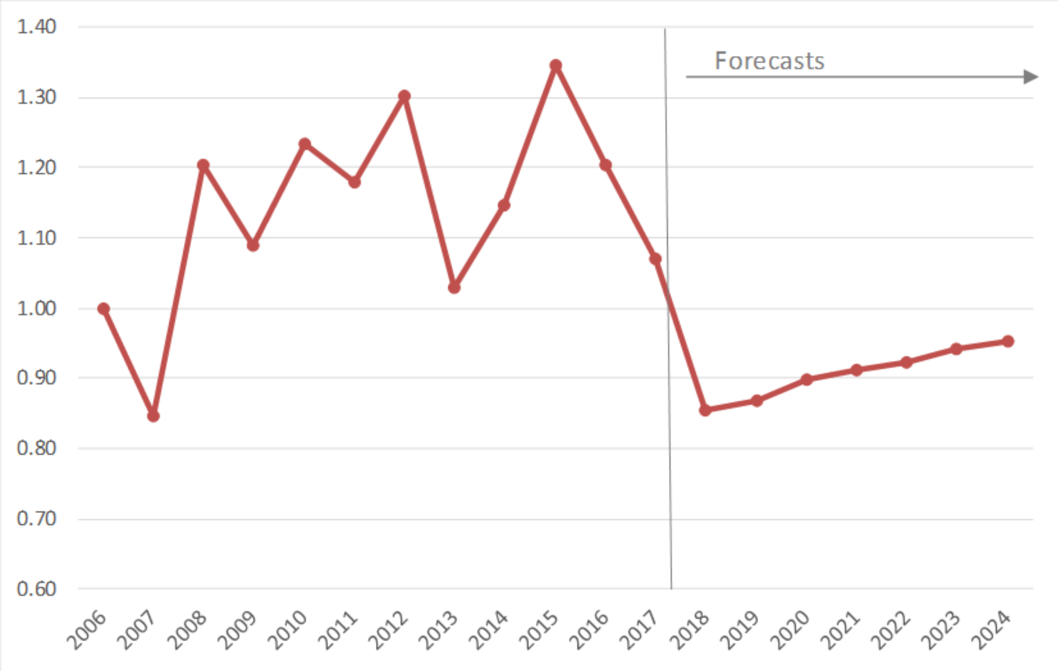


[20] The AER's approach uses historical raw non-coincident maximum demand to estimate its ratcheted maximum demand output index. We cannot forecast this 'raw' value and instead forecast weather adjusted non-coincident maximum demand. The 50% Probability of Exceedance forecast is used to trend forward our 2016-17 raw value.

The main driver of total output growth is customer numbers, which shows steady growth in every year and has a high weight (0.458). The increase in customer minutes lost is likely to be in line with the increasing number of customers, rather than reflecting deterioration in service.

Our forecast opex is used to create the AER's input index,[21] which is shown in the figure below.

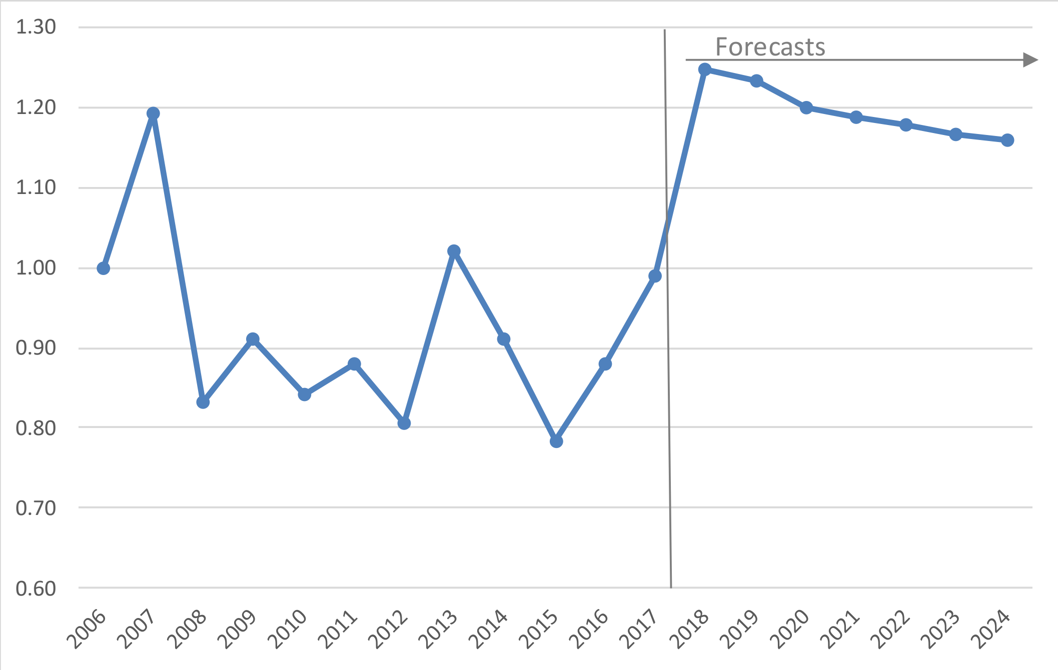
Figure 5. Opex index



Future opex productivity trends are estimated by combining the output and input indices (i.e. dividing the output index by the input index). The resulting productivity index is shown in the figure below.

[21] Our forecast opex is in real 2018-19 terms. CPI escalators have been used to convert the pre-2018 values in to 2018-19 real. That is, we have not forecast Economic Insights' opex price index (which is used for the 2006-2016 values in the AER's methodology) and instead have used CPI as a proxy for input price changes.

Figure 6. Ausgrid's opex productivity



We can see that from 2015 Ausgrid's opex productivity improves significantly, before reaching a more steady state. The movements in productivity from 2018 are largely driven by increases in opex due to a service classification change, real input price growth and step changes (as total output indicates a steady growth rate over the entire period).

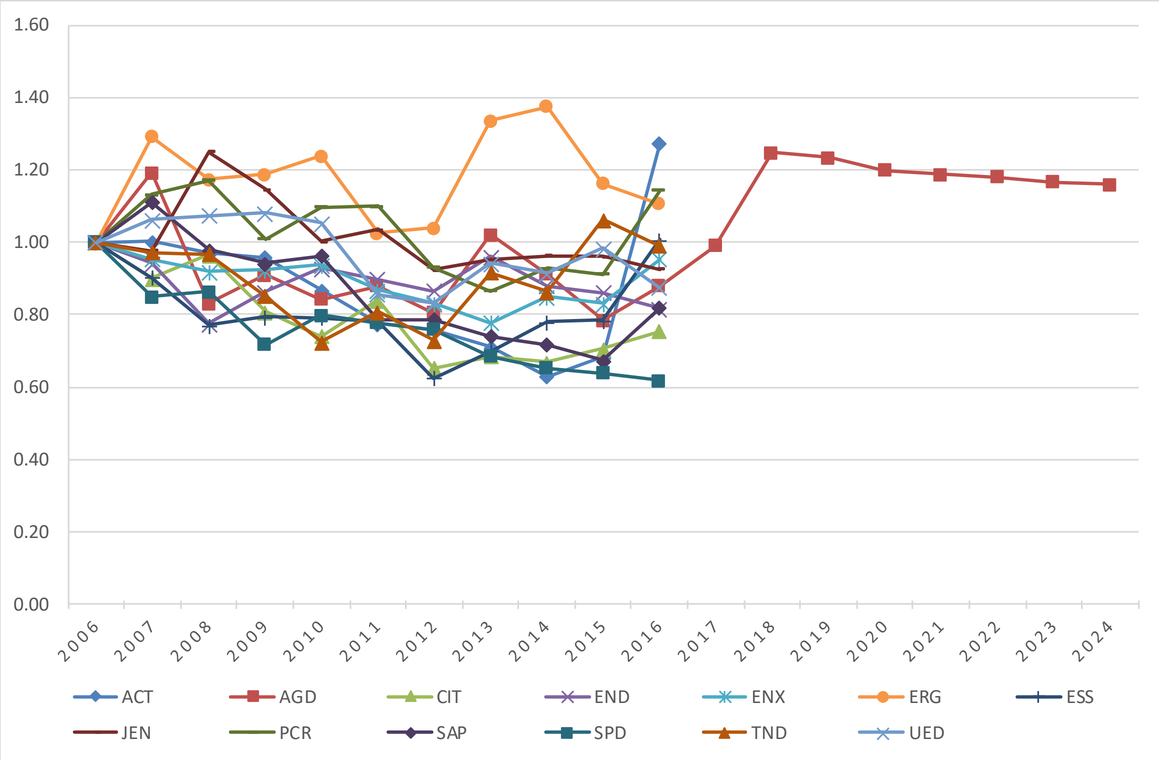
While we cannot compare Ausgrid's forecast productivity to that of the other DNSPs (as we do not have their forecast outputs and opex), we can compare historical and current performance. We have done this for:

- DNSPs' opex productivity trends using Partial Factor Productivity (PFP)
- DNSPs' *relative* productivity levels, using Economic Insights' opex Multilateral Partial Factor Productivity (MPFP) analysis.

We have used data from Economic Insights' 2017 benchmarking report for the AER to undertake this analysis.

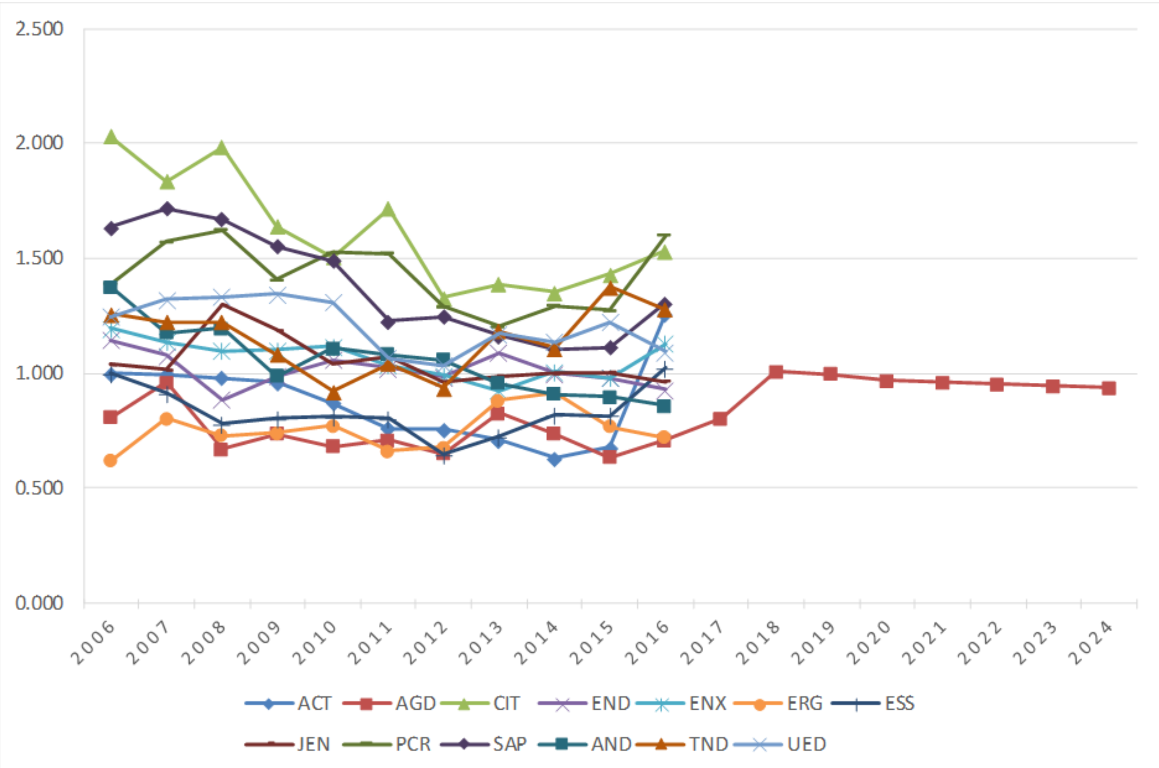
The figure below provides a comparison of the productivity trends of the 13 DNSPs. We can see that, assuming no changes in the other DNSPs' productivity, Ausgrid's strong forecast productivity performance will place it as one of the highest productivity achievers since 2006. Note that this is a 'pure' opex PFP measure for each DNSP since 2006 (hence it starts at 1 for all DNSPs) and therefore it does not reflect the relative efficiency of each DNSP.

Figure 7. DNSPs' opex productivity



We have also considered Ausgrid's performance against the other DNSPs using Economic Insights' opex MPFP model, which attempts to account for relative productivity levels across DNSPs (as well as the trends over time). In this case, Ausgrid's relative performance will improve, moving it from the bottom to the middle of the group.

Figure 8. DNSPs' opex MPFP



It is important to note that, because the opex MPFP analysis compares relative performance, changes in the other DNSPs' opex productivity will alter Ausgrid's position. This could either improve Ausgrid's relative performance or lead to a deterioration in its relative performance. However, for Ausgrid to not show an improvement in its relative performance all other DNSPs would need to have opex productivity growth as strong as Ausgrid's has been.[22]

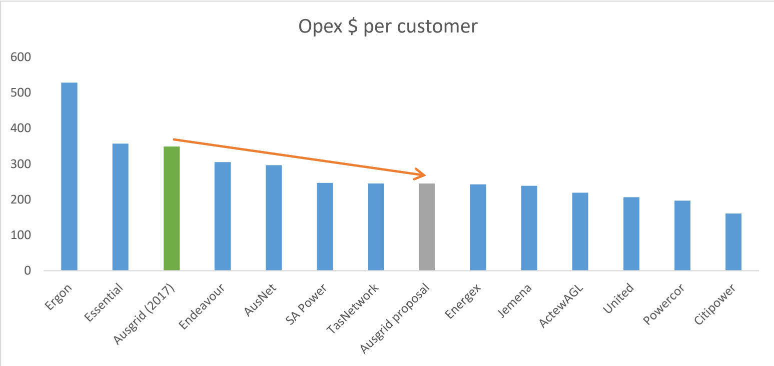
4.2 Changes in comparative opex performance

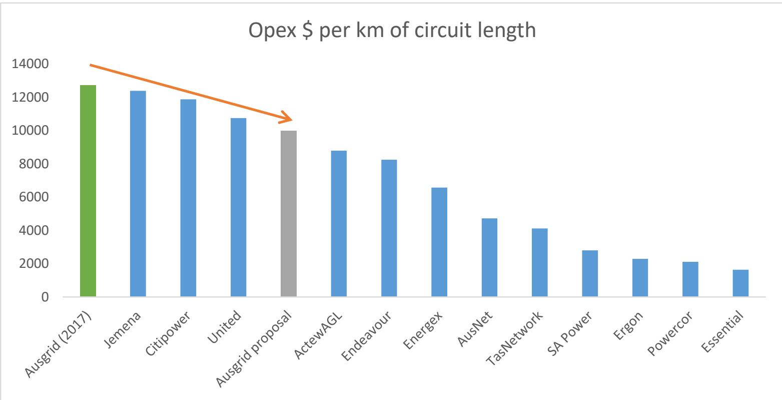
As part of our effort to improve opex performance over the 2019-24 regulatory period, we regularly measure ourselves against our peers – other Australian distribution businesses. These comparisons show that we have made significant progress over a range of measures, bringing our performance into line with best practice within our industry.

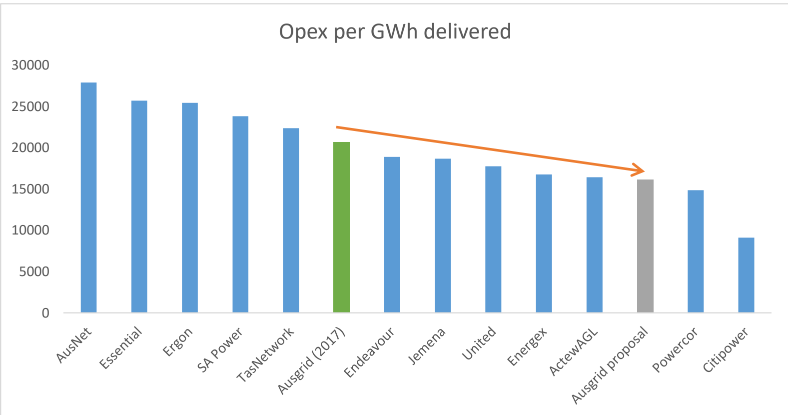
The charts below demonstrate our improved performance, using RIN data from 2016 and 2017. In the first set of charts, the green bar represents our actual performance in 2016/17, and the grey bar indicates our proposed base year for 2017/18. As can be seen, our proposed base year represents significant improvement in our comparative opex performance across each measure.

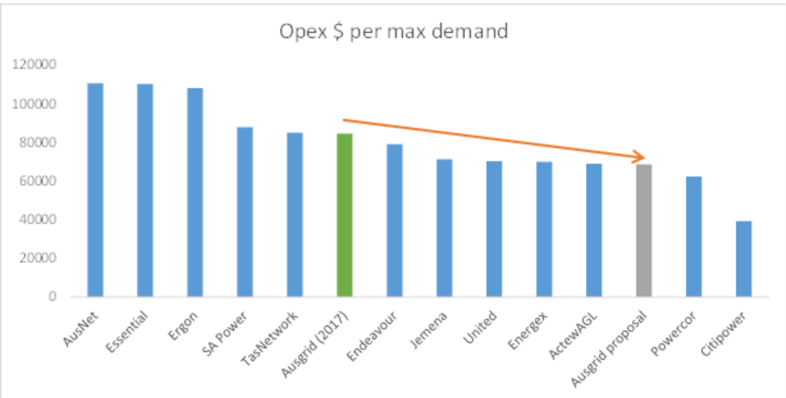
[22] We also note that the way Economic Insights has specified the input index in its models means that the productivity measure produced does not include any productivity encapsulated in the CPI.

Figure 9. Ausgrid benchmark performance (Based on 2016 and 2017 RIN data)



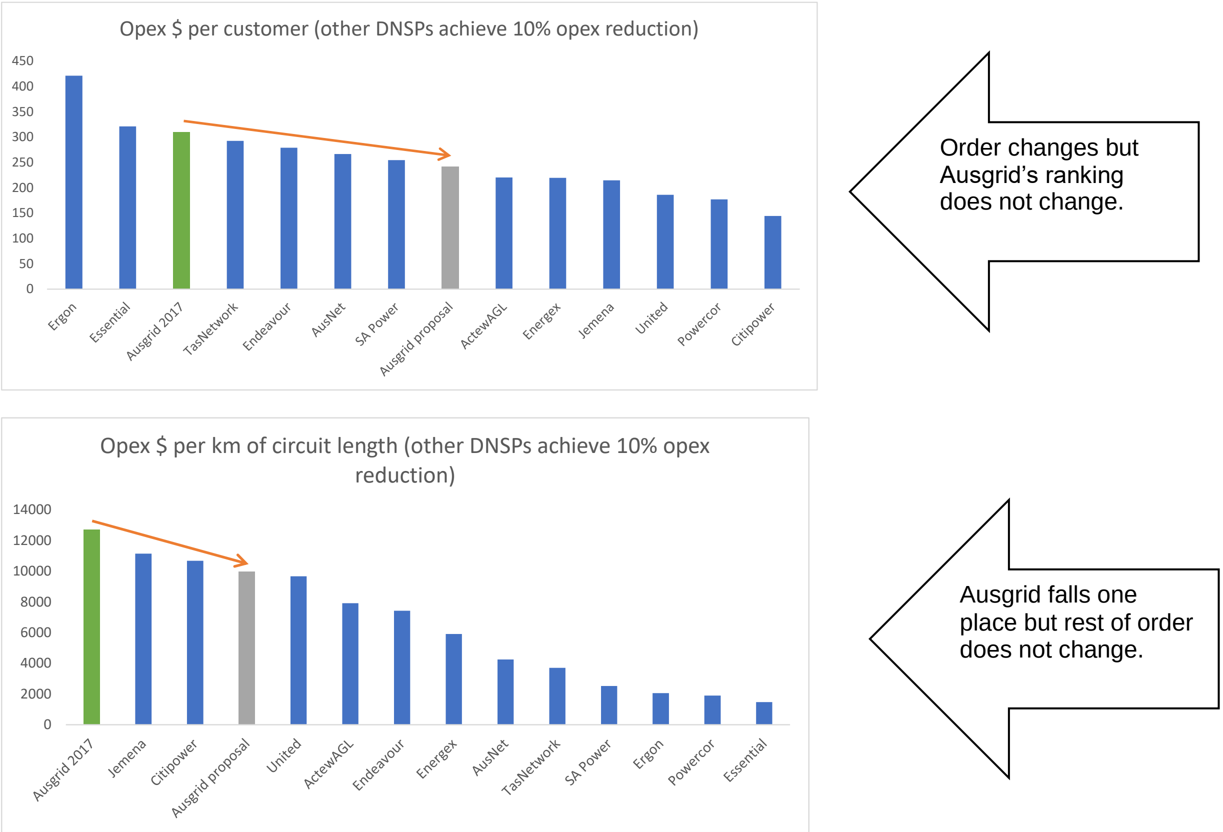






We have considered how sensitive these results are to potential changes made by other businesses. Our ranking in the simple benchmarks is insensitive to plausible changes in customer numbers and circuit length. However, our ranking does change if all other businesses reduce their opex by 10% – as shown in the bottom chart.[23]

Figure 10. Sensitivity for simple benchmark

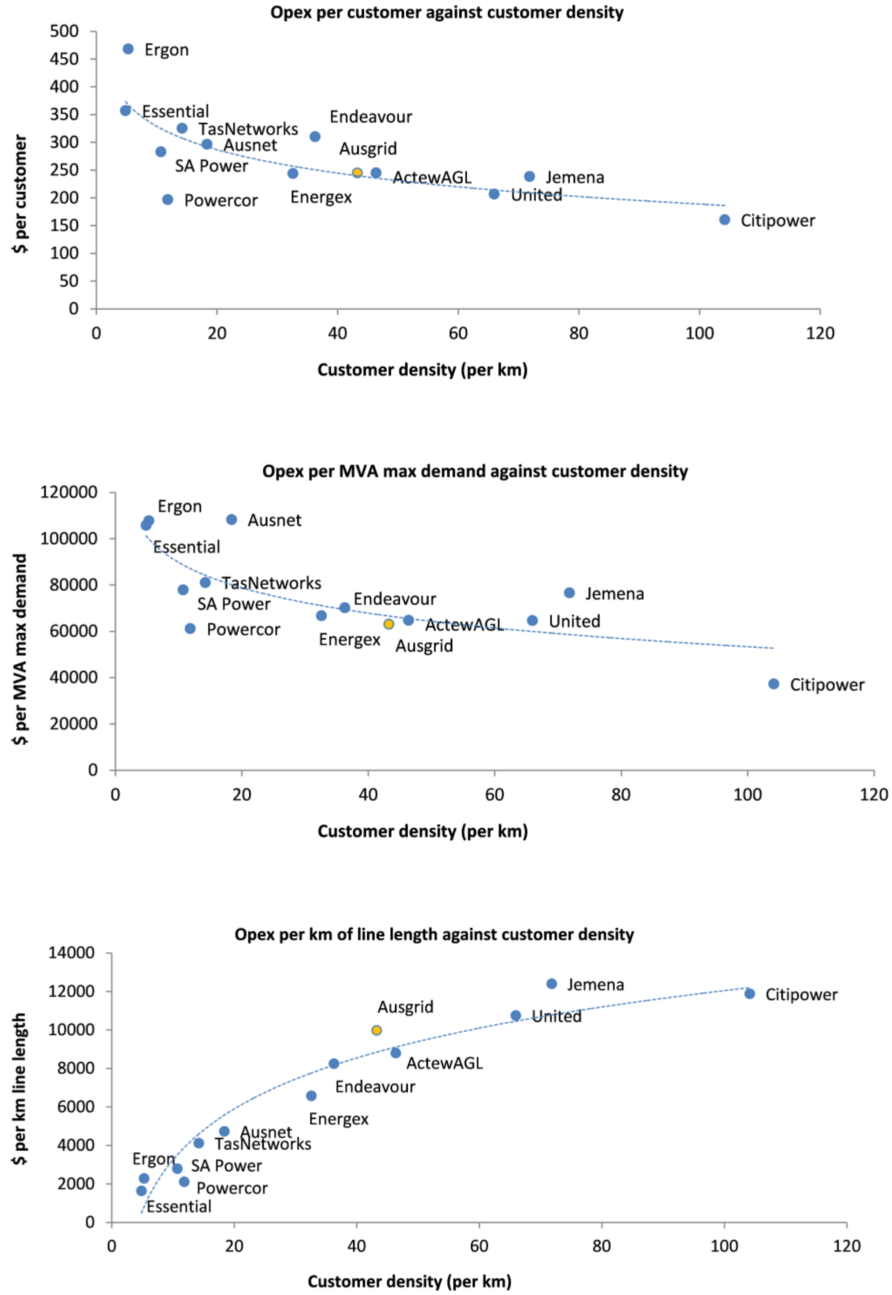


We also assess our performance on three of the same measures against customer density, estimated as the average number of customers per square kilometre. This is consistent with the AER's analysis in its 2015 determination. While no single measure can capture all the factors that determine opex, these comparisons highlight the difference between urban network businesses (such as Citipower) and rural businesses (such as Essential). Ausgrid's service environment is in between these extremes, distributing electricity in the Sydney, Central Coast and Hunter regions.

The charts below show the performance of our proposed base year under these measures (indicated with the yellow circle) and indicate that our opex performance is now largely in line with that of our peers.

[23] We also considered opex per maximum demand and opex per GWh. However, changes in demand are too volatile to identify plausible movements.

Figure 11. Relative performance – partial productivity measures



5 BASE YEAR ADJUSTMENT FOR SERVICE CLASSIFICATION

In line with the AER's Final Framework and Approach, ERW will become a standard control service from the beginning of the next regulatory period.

In previous determinations cost changes due to service classification changes have been addressed as part of the consideration of base opex (i.e. they are treated as an adjustment to the base level of opex). We have followed the same approach here.

We have estimated the adjustment for ERW as the full cost of repairing the damage (based on average historic costs) less the revenue we would expect to recover from parties found liable for causing damage to our network (based on average historic receipts from liable parties).[24] Historic costs and receipts are set out in the table below. The next table includes the proposed adjustment to base year opex, which equals the budgeted net recovery for 2017/18 expressed in 2018/19 dollars.

Table 9. ERW: costs incurred and recovered ($m, nominal)

Opex	Actual FY15	Actual FY16	Actual FY17	Budget FY18
Costs	6.62	7.64	7.90	6.75
Recovery	-1.09	-1.47	-1.66	-1.56
Opex net of recovery	5.52	6.17	6.25	5.19

Table 10. Proposed adjustment for ERW ($m, real FY19)

Opex	2017/18
Base year adjustment for ERW	5.36

[24] Due to the difficulty in predicting the occurrence of ERW (i.e. predicting when a vehicle might hit a pole or a third party damage a line), we use historical average costs and revenue to forecast future costs and revenues.

6 TREND ADJUSTMENTS

The next part of our approach to forecasting opex is to 'trend' our base year forward to take account of how opex changes over time.[25] To do this we have considered:

- Real price growth – to reflect movements in prices that are expected to be different to inflation
- Output growth – to account for changes in how much output we expect to deliver
- Productivity growth – to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

This approach is in line with current AER's practice, with one exception. While we have applied the AER's approach to forecasting output and productivity growth, we have deviated slightly in respect of real price growth.

Table 11. Forecast rate of change (%)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24
Price	0.52%	0.82%	1.04%	1.03%	0.80%
Output	0.75%	0.85%	0.85%	0.85%	0.88%
Productivity	-	-	-	-	-
Total	**1.27%**	**1.67%**	**1.90%**	**1.89%**	**1.68%**

6.1 Real price growth

Our base year opex reflects the current prices of cost inputs. Forecast opex needs to account for changes in the price of cost inputs in order to reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives in the forthcoming regulatory period. These price increases may not necessarily be at the same rate as inflation. They may be higher or lower than inflation due to a number of factors. The need to adjust forward forecasts to take into account real cost escalation is accepted by the AER as important in reflecting the opex criteria.

Ausgrid applied real cost escalation to base year opex to derive an opex forecast that reasonably reflects the realistic expectation of the cost inputs required to achieve the opex objectives.

As labour makes up the majority of our operating costs we have adjusted our base year to reflect forecast changes in wages. For all other costs we have kept it simple and applied the consumer price index. This approach is consistent with past AER practice.

It is important to distinguish between labour price changes and labour cost changes. To the extent labour prices increase to compensate workers for increased productivity, labour costs will not increase at the same rate, as less labour is required to produce the same output. Consequently, labour productivity improvements need to be captured in forecasts.

Our approach to adjusting the base year to reflect forecast changes in wages has applied a forecast of labour price increases which is not productivity adjusted. Rather, labour

[25] As part of our approach we have included incremental opex between the base year and the final year of the current regulatory period in line with the AER's 2015 determination. This has the effect of applying the trend adjustments in the AER's 2015 determination and is consistent with the approach taken by the AER previously (see e.g. TransGrid draft determination). The trend adjustments are then applied starting from estimated FY19 opex.

productivity is accounted for in our opex forecast through the productivity measure which we apply to the base year (see below).

To incorporate expected movements in our labour costs, we asked BIS Oxford Economics to forecast how much the price of labour will change.[26] We use these forecasts for our internal planning purposes and have aligned our Regulatory Proposal to these forecasts. We expect to update our opex forecast with the latest forecast change in real labour costs in the revised proposal. See Attachment RIN09 (BIS Oxford – Cost Escalation Report) for the methods and data used to develop the forecasts.

Table 12. Forecast change in real labour costs (%)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24
Labour	0.88%	1.37%	1.74%	1.73%	1.33%

While a significant proportion of our costs, labour does not make up 100% of our opex. To account for this we have only applied expected labour price growth to 59.7% of our opex. This percentage is not based on our actual costs but the AER's estimate of labour across all distribution businesses.

We have chosen to use 59.7% to ensure consistency with the AER's preferred benchmarking model (which uses this split[27]) and in turn the output and productivity growth estimates. Our approach of ensuring consistency across all components of the trend is in line with the AER's methodology.

The table below shows the combined effect of the labour cost increases and the assumed CPI increase in the costs of materials and other costs (i.e., contracted services).

Table 13. Forecast real price growth (%)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24
Price	0.52%	0.82%	1.04%	1.03%	0.80%

6.2 Output growth

As we provide more output – for example by adding customers to our network or operating and maintaining more lines – the costs of operating our network increase. Accordingly, we have applied an output growth factor to reflect how our costs change as we deliver more.

We have deployed the AER's current approach, which has two steps. First we forecast the expected growth in customer numbers, circuit length and ratcheted maximum demand as shown in the table below.

Growth forecasts are based on a set of assumptions regarding spatial peak demand and customer connections over the 2019-24 period, as set out in Attachment 5.07 of the Regulatory Proposal. The approach to forecasting circuit length is set out in the box below. In general, it is assumed that future growth in low voltage lines reflects historic growth. Growth in higher voltage lines is calculated on a project–specific basis.

[26] We note that the AER's past approach is to use an average of forecasts prepared by BIS Oxford Economics and Deloitte Access Economics. We have adopted BIS Oxford Economics forecasts, to be consistent with our internal planning forecasts.
[27] 2017 Economic Insights, *Economic benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report,* p.2.

Overhead network length of circuit at each voltage

Low voltage and 11kV data was trended based on the data from the past five historical years.

Single Wire Earth Return (SWER) and 22kV feeders have no projects issued or in development that are expected to alter their length and have been unchanged from the most recent measurement.

Subtransmission lengths were sourced from our capital plans for the subtransmission network. These capital plans holistically examine replacement, augmentation and customer connection needs for major areas of the subtransmission network.

Underground network circuit length at each voltage

Low voltage and 11kV data was trended based on the data from the past five historical years.

5kV lengths were based on the expected decommissioning dates of Blackwattle Bay and Camperdown zone substations.

SWER and 22kV feeders have no projects issued or in development that are expected to alter their length and have been unchanged from the most recent measurement.

Subtransmission lengths were sourced from our capital plans for the subtransmission network. These capital plans holistically examine replacement, augmentation and customer connection needs for major areas of the subtransmission network.

Table 14. Forecast change in outputs (%)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24
Customer numbers	0.91%	1.05%	1.03%	1.02%	1.01%
Circuit length	0.42%	0.43%	0.57%	0.58%	0.52%
Ratcheted maximum demand	-	-	-	-	0.38%

Second, we estimate how much our opex changes for a 1 percent increase in each of these outputs, as shown in the table below. To do this we have used the AER's preferred benchmarking model (i.e. Economic Insights' Cobb-Douglas SFA econometric model), to ensure consistency across estimating all components of the trend adjustment.

Table 15. Forecast change in outputs (%)

Output	Estimated change in opex for a 1% change in output
Customer numbers	0.7713%
Circuit length	0.0973%
Ratcheted maximum demand	0.1314%

We then combined these two steps to get our overall output growth forecast, which is set out below.

Table 16. Forecast output growth (%)

	2019/20	2020/21	2021/22	2022/23	2023/24
Output	0.75%	0.85%	0.85%	0.85%	0.88%

6.3 Productivity

We also adjust our base year opex for forecast changes in the productivity frontier for the industry over the next regulatory period. Estimating productivity, using the same methodology as previously applied by the AER, provides a negative productivity estimate.

Applying a negative productivity estimate means increasing opex each year. Rather than increase our opex forecast we have decided to apply no productivity growth. Our consideration of industry productivity is set out below.

6.3.1 Recent decisions and analysis

In its 2015 determination for Ausgrid, the AER set opex productivity growth at 0% per annum from 2014/15 to 2018/19. This was largely based on advice from Economic Insights that it should be set at zero, rather than the negative productivity estimate generated by its models. In making this recommendation, Economic Insights noted that as the AER was making an 'onerous' adjustment to the base year then there would be less scope to include a productivity adjustment.[28] The AER however used the -1.8% annual trend generated from Economic Insights' Cobb-Douglas SFA model as the productivity (or technical change) value to estimate Ausgrid's 2013/14 base year opex.

In its transmission decisions for AusNet (final, April 2017) and Transgrid (draft, September 2017), the AER proposed an annual opex productivity adjustment of 0.2%. This adjustment was based on Economic Insights' opex partial factor productivity modelling and covered the period 2006-2015.

In its recent benchmarking analysis (October 2017) for the distribution businesses, Economic Insights estimated a number of opex productivity series. These are presented in the table below.

Table 17. Opex productivity

Opex productivity	2006-2016	2006-2012	2012-2016
Opex PFP change including redundancy payments	-0.83%	-3.41%	3.05%
Opex PFP change excluding redundancy payments	-0.16%	-3.19%	4.39%
Cobb-Douglas SFA model	-1.8%	NA	NA

Source: Economic Insights (2017)

Economic Insights chose to split opex partial factor productivity (PFP) estimates into different time periods, based on opex peaking in 2012. Economic Insights claims that the increase in opex to 2012 reflected changing licence and regulatory requirements, and potential inefficiencies in delivering them. Since the peak in opex in 2012, opex PFP has significantly increased;more so if redundancy payments are excluded from the analysis. However, the longer-term trends (including those from the Cobb-Douglas SFA model) are still negative.

In its latest benchmarking report the AER noted the following:

> "*Data provided to the AER shows a number of DNPS are currently incurring significant redundancy costs as a proportion of total opex. These DNSPs would experience (assuming other inputs and outputs remain constant) a significant uplift in their TFP and opex PFP results when opex begins to decrease as redundancy costs wash out of the data and lower labour costs are realised. The size of the uplift for a DNSP will depend on the quantum of redundancy costs and labour costs saved relative to total opex.*"[29]

We have two comments on this statement. Firstly, it may be that the removal of redundancy costs increases *measured* productivity gains, but it does not by itself increase productivity. The reduction in the volume of labour, while still being able to produce the same or greater outputs (or with outputs falling less than inputs), is the productivity driver (which is why Economic Insights presented the two opex PFPs). As the redundancy and labour volume

---

[28] Economic Insights (2014), page 56-57.
[29] AER (October 2017), page 36.

reductions are 'one-offs', they should be treated as such and not as an indication of future achievable productivity gains.

In other words, the large productivity gains seen in the data for 2012-16 do not reflect a plausible frontier-shift measure, they predominately reflect 'catch-up' efficiency rather than frontier shift. It would be unrealistic to expect these 'productivity' gains to occur in future without further catch-up efficiencies identified (and set separately). In addition, those distribution business that have significantly reduced opex over this period (e.g. by significantly reducing labour volumes) will have less scope to make further efficiency gains, given the scale of improvements made in recent years.

Secondly, economic theory supports the use of longer-time series for productivity estimates to better adjust for the utilisation of inputs. Typically, productivity changes should be considered across a business cycle (peak-to-peak or trough-to-trough) as the choice of the start point and end point can have significant impacts on the estimate of annual averages.[30] For example, when the economy is growing, outputs such as energy throughput may increase without an immediate need to increase inputs. A long-term (e.g. 10 to 15-year) average smooths out any short-term volatility in productivity measures, allowing for a more consistent estimation of productivity over time. A productivity measure calculated over 2012-16 would not be considered a long-term measure.

Given the need to rely on a longer data series, the precedent that is provided from the recent transmission decisions and the previous NSW determinations, and the substantial catch-up efficiency captured in the measures, we do not consider that it would be a robust position for the AER to rely on the 2012-16 opex PFP estimate to forecast industry productivity over the forthcoming regulatory period.

6.3.2 Estimating industry productivity

As with output growth, we used Economic Insights' Cobb-Douglas SFA econometric model to forecast productivity growth, consistent with the AER's forecast expenditure assessment guideline[31] and past practice. This model currently estimates that productivity decreases by 1.80% per year.

The result from Economic Insights is consistent with estimates from the Australian Bureau of Statistics (ABS). We have reproduced the ABS' estimates for multifactor productivity (MFP) and labour productivity for the market sector and the electricity, gas, water and wastewater sector in the table below. Over the same 2006-16 period, the ABS estimated that multifactor productivity and labour productivity decreased by 2.6% and 1.9% respectively for the electricity, gas, water and wastewater sectors. Apart from labour productivity for the market sector, the ABS' estimates do not support an ongoing productivity adjustment.

---

[30] OECD 2011, *Measuring Productivity: Measurement of aggregate and industry-level* productivity growth, OECD Manual, p.119

[31] 2013 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, pp 23-24

Table 18. ABS productivity estimates 2006-2016 (%)

	Market sector	Electricity, gas, water and wastewater
Multifactor productivity	-0.13%	-2.6%
Labour productivity	1.3%	-1.9%

Source: ABS, 5260.0.55.002 - Estimates of Industry Multifactor Productivity, 2015-16, December 2016.

Applying negative productivity growth would increase our opex forecast. We have decided not to do this. Instead we have applied a productivity growth of zero, equivalent to not applying a productivity factor.

We also note that economy-wide productivity is incorporated in CPI (i.e. CPI measures the rate at which prices change, and reflects adjustments to productivity across the broader economy). As noted above, there is no evidence to suggest the utility industry is delivering greater productivity improvements than the wider economy.

Given the significant cost reductions we have achieved in the current regulatory period, and the forecast industry productivity growth, we propose no further productivity adjustment to our opex forecasts. This is consistent with the incentive properties in the AER's framework for assessing opex. We believe this is a reasonable approach.

7 STEP CHANGES

Step changes refer to increases or decreases in our opex associated with meeting new or changed regulatory obligations or opex/capex trade-offs. These factors represent forecast required opex not captured by the base year expenditure or trend escalation, and therefore they are added to the trend-adjusted base year.

Ausgrid has included two proposed step changes in its opex forecast as set out in the table below. One step change is for the efficient costs of a price reform research project to inform and expedite our transition to more cost reflective pricing as required by the AEMC's rule change for Distribution Network Pricing arrangements. The other step change is for efficient opex/capex trade-offs to procure DM solutions from the market that will postpone the requirement to replace or retire assets.

The proposed costs for each step change reflect forecast efficient expenditure not captured by base year opex,[32] or output and real price growth,[33] which would be incurred by a prudent service provider acting efficiently to achieve the opex objectives[34] and meet the opex criteria in the NER,[35] i.e. to achieve the lowest sustainable costs over the long term.

We note that the final RIN requests additional information relevant to proposed step changes. Our RIN response cross-references to this attachment to minimise duplication and streamline the AER's assessment process.

Table 19. Proposed opex step changes, 2019-24 ($m, real FY19)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24
Price reform research project	1.5	1.5	-	-	-
Demand Management	3.7	3.7	6.5	6.6	5.7
Total	5.2	5.2	6.5	6.6	5.7

7.1 Price reform research

Our aim is to strive towards prices that promote the efficient use of our network by our customers, as they continue to invest in distributed energy resources and engage in energy efficiency activities. Our proposed approach to pricing reforms is outlined in Chapter 10 of our Regulatory Proposal.

This research project is an important component of our proposal, as it will inform potential pricing decisions over the 2019-24 period, and thereafter. In particular, if the research program suggests residential customers will benefit from large-scale assignment to alternative cost reflective price arrangements, we can fast-track a transition to these prices using our proposed placeholder residential demand price structure (as discussed in Chapter 10 of our Regulatory Proposal).

---

[32] As we are not currently undertaking these activities.
[33] As these adjustments reflect expected growth in our network and services (as measured by customer numbers, line length and peak demand) and changes in the costs of inputs (rather than the inputs themselves).
[34] In summary these objectives are to:

- Meet or manage expected demand;
- Comply with all regulatory obligations; and
- Maintain the safety of the network.

[35] That is, that the opex forecast reasonably reflects:

- Efficient costs of meeting the opex objectives;
- Costs that a prudent operator would incur to achieve the opex objectives; and
- A realistic expectation of forecast demand and cost inputs required to achieve the opex objectives.

The appropriate design (and the respective merits/shortcomings) of a residential demand price structure is a matter on which there exists significant uncertainty and divergence of opinions. Since the number of customers with an advanced meter is expected to triple to approximately 900,000 over the next five years, the network cost consequences of inappropriately designing and implementing a demand price structure are significant.

The purpose of the price reform acceptance research project is to enable the adoption of network prices and/or incentives that promote the sustainable use of the network and deliver value to customers by reflecting the costs to deliver network services and the value of demand side participation. The scope of the research program will be developed collaboratively with stakeholders and will include:

- Customer and community research to understand the attitudes towards energy service pricing amongst consumers, community groups, retailers and aggregators
- A pilot for new pricing models. Ausgrid envisages at least one large scale trial to ensure findings are statistically relevant and applicable across a range of customer demographics
- Targeted education campaigns to help customers, retailers and aggregators understand new pricing arrangements.

Further details of the scope of the research project are provided in Attachment 3.01 (Ausgrid's innovation program).

The expected benefits of undertaking this research are:

- Operational: promote sustainable use of the network by reflecting the costs to deliver network services and the value of demand side participation. Improved predictability regarding retailer and customer responses to network pricing arrangements
- Customer: Deliver value to customers by understanding customer preferences and promoting customer education.

There will be a once-off $3.0 million cost to undertake this research project. The step change is expected to occur in 2019/20 and 2020/21 and is not recurrent in nature.

The relevant opex category is corporate overheads (which increases). The estimated effect on this category of expenditure over each year of the 2019-24 regulatory period, and in total, is set out in the table below.

Table 20. Forecast price reform research project opex ($m, in real FY19 terms)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Price reform research project	1.5	1.5	-	-	-	3.0

This estimate is based on our current expectations of the scope of the research program (to be developed collaboratively with stakeholders) and the cost of previous stakeholder research of similar scale undertaken by Ausgrid.

The driver of this step change is a change to the regulatory obligations for setting network prices, which requires us to transition to cost-reflective network prices, improve the transparency of our pricing information and consult with retailers and customers on the design of network prices.[36]

[36] AEMC rule change for Distribution Network Pricing Arrangements.

Under this rule change, network prices based on the new pricing objective and pricing principles will be gradually phased in from 2017. Key changes between the previous rule requirements, and the new rules are shown in the table below.

Table 21. Summary of key differences between previous rules relating to distribution network pricing and the new rules

	Previous rules	New rules
Pricing Principles		
Network pricing objective	No pricing objective.	Each network tariff should reflect the efficient costs of providing network services to the customers assigned to the tariff.
Long run marginal cost (LRMC)	DNSPs must take into account LRMC when setting network prices.	DNSPs must base network prices on LRMC.
Total efficient cost recovery	DNSPs must recover their allowed revenue with minimum distortion to efficient patterns of consumption.	The revenue recovered from each network tariff must reflect the DNSP's total efficient costs of serving the customers assigned to that tariff. DNSPs must recover their allowed revenue in a way that minimises distortions to the price signals for efficient usage provided by LRMC based prices.
Consumer impact principle	No principle.	DNSPs must manage the impact of annual changes in network prices on customers. DNSPs must set network prices which customers are reasonably capable of understanding.
Jurisdictional obligation principle	No principle.	DNSPs may depart from network prices that meet the LRMC and total efficient cost recovery principles to the extent necessary to meet jurisdictional pricing obligations.
Stand alone and avoidable costs	The revenue expected to be recovered from each tariff class should lie between the stand alone cost of serving the relevant customers and the avoidable cost of not serving those customers.	Clarification that compliance with this principle is mandatory.
Network Pricing Process		
Process to develop network prices	Network prices are developed by DNSPs and approved by the AER on an annual basis.	Two-stage process: 1. DNSPs must develop a Tariff Structure Statement (TSS) that sets out their network price structures as part of the regulatory determination process which applies for the five year regulatory control period. 2. Prices are developed by DNSPs, consistent with the price structures in the TSS and approved by the AER on an annual basis.
Consultation	DNSPs are not required to consult with stakeholders on network price structures.	DNSPs are required to describe how they have consulted with retailers and customers on the design of network prices and sought to address their concerns.

As highlighted in the table above, the rule change introduces a requirement for us to consult with retailers and customers on the design of network prices. Customer engagement and education is critical in ensuring that feedback is properly incorporated into the design of network prices and that customers fully understand the benefits of the new pricing structures. Not undertaking the research and education program would likely:

- Result in customer backlash should they perceive the proposed price structures as non-beneficial to them. This would result in delays to transitioning to cost-reflective prices.
- Significant network cost consequences of inappropriately designing and implementing a residential demand price structure.

7.2 Demand management

We plan to partner with customers to better manage demand. Consistent with customer feedback, our opex forecast includes expenditure to further develop our DM capabilities in the face of uncertainty over future technologies and energy demand and consumption patterns. For the 2019-24 regulatory period, we are proposing a targeted DM program consisting of six significant projects associated with the replacement or retirement of aged assets and a number of smaller projects associated with local augmentation of the network.

The step change is expected to occur in 2019-20 and continue throughout the 2019-24 regulatory period. The driver of the step change is opportunities we have identified for prudent and efficient opex for capex trade-offs over 2019-24. Not undertaking these opex activities would increase Ausgrid's capex requirements. The step change is not recurrent in nature.

The relevant opex category is network overheads (which increases) and the relevant capex categories are replacement and augmentation capital expenditure (which decrease). The estimated effect on these categories of expenditure over each year of the 2019-24 regulatory period and in total is set out in the tables below. An explanation of how we have estimated these amounts then follows.

Table 22. Forecast DM opex ($m, real FY19)

Opex	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Concord 11 kV switchgear (SWG) Replacement	0.7	0.7	1.3	0.7	1.3	**4.6**
Leightonfield 11 kV SWG Replacement	-	-	0.6	0.6	0.1	**1.3**
Lidcombe 11 kV SWG Replacement	-	-	0.6	0.6	0.6	**1.8**
Mascot 11kV SWG Replacement	1.3	0.7	0.7	1.3	0.2	**4.3**
St Ives 11kV SWG Replacement	-	-	0.6	0.6	1.2	**2.4**
Haymarket-Pyrmont 132 kV Feeder Replacement	1.3	1.4	1.4	1.4	1.4	**6.8**
High Voltage (HV) augmentation	0.3	0.9	1.3	1.4	1.1	**5.0**
Total	**3.7**	**3.7**	**6.5**	**6.6**	**5.7**	**26.1**

Note: Totals may not sum due to rounding.

Table 23. DM project capex impact ($m, real FY19)

Capex adjustments		2019/20	2020/21	2021/22	2022/23	2023/24	Total
Concord 11 kV SWG Replacement	Pre DM	10.7	9.6	1.5	-	-	**21.9**
	Post DM	-	0.1	1.1	5.9	13.9	**21.0**
Leightonfield 11 kV SWG Replacement	Pre DM	-	-	0.1	0.8	2.2	**3.1**
	Post DM	-	-	-	-	-	**-**
Lidcombe 11 kV SWG Replacement	Pre DM	-	-	-	-	0.0	**0.0**
	Post DM	-	-	-	-	-	**-**
Mascot 11kV SWG Replacement	Pre DM	2.4	18.2	22.2	6.7	0.2	**49.7**
	Post DM	-	0.1	1.4	2.4	18.2	**22.1**
St Ives 11kV SWG Replacement	Pre DM	-	-	-	0.1	1.3	**1.4**
	Post DM	-	-	-	-	-	**-**
Haymarket-Pyrmont 132 kV Feeder Replacement	Pre DM	-	-	0.6	1.7	15.4	**17.7**
	Post DM	-	-	-	-	-	**-**
HV augmentation	Pre DM	9.0	17.9	17.9	17.9	17.9	**80.7**
	Post DM	7.7	14.6	15.1	12.2	13.2	**62.8**
Total	Pre DM	**22.1**	**45.7**	**42.3**	**27.3**	**37.1**	**174.5**
	Post DM	**7.7**	**14.7**	**17.6**	**20.5**	**45.3**	**105.9**

Note: We assess the net present value of each competing network and non-network option over a 20 year time horizon to identify the preferred solution. This table presents the capex impact of the DM projects during the current regulatory period only. Further capex savings will be delivered beyond 2023/24. Totals may not sum due to rounding.

DM projects associated with replacement or retirement of aged assets

We estimate proposed DM expenditure on a case-by-case basis for larger projects at sub-transmission level, and on a modelled basis for the smaller projects at 11 kV level. For individual projects, a cost benefit assessment is used to assess the cost effectiveness of non-network solutions in comparison with network options over a 20 year time horizon.

For each project assessment, DM options were included alongside supply side options in developing the suite of potential solutions to meet the relevant network needs. We assess the net present value of each competing network and non-network option over a 20 year time horizon to identify the preferred solution. Where a non-network option is found to offer an equivalent (or higher) net present value, it is preferred. The potential for deferral of all capital projects above $1 million are considered in this process.

As part of the cost benefit analysis, assumptions are made about the likely scale of demand reductions possible and estimated costs of a non-network solution. These assumptions are based on previous experience with delivery of DM projects, submissions to non-network options reports from non-network solutions providers, and lessons learned from DM trials by Ausgrid and other networks in Australia.

Ausgrid has changed its network planning approach to a probabilistic planning approach for larger sub-transmission level network investments. Assessment of the expected unserved energy for these investments has allowed DM options to be considered for replacement projects along with demand driven network needs. Where non-network options can cost effectively reduce the expected unserved energy, DM solutions can form part of the least cost solution to an asset replacement need.

For the 2019-24 regulatory period, we assessed around 40 retirement or replacement projects comprising over $500 million in investment, for DM potential. This project by project assessment of major replacement expenditure projects has identified six projects where DM forms part of the least cost solution. A cost benefit assessment (see Attachment 6.05) was used to determine the preferred solution for each of these six projects. As part of this assessment, the preferred DM solution and the preferred network solution are both compared against the do nothing option. Where the DM option has an equal or higher net present value, the option including DM has been preferred.

In the assessment of these projects, Ausgrid has quantified an option value to reflect the expected benefit from a delay in network investment that may arise from new future solutions. This benefit might reflect lower future demand or new lower cost options to the need. Estimates for DM costs are principally based upon recent submissions from DM providers for TransGrid and Ausgrid's Powering Sydney's Future project and discussions with DM providers.

Six projects have been identified where DM forms part of the least cost solution. These projects each defer by three years the replacement of aged 11kV switchgear and a 132kV feeder. Opex is paid to customers (either directly or via aggregators) to reduce load (or generate additional local supply), lowering the estimated unserved energy in the event of a network failure or spike in demand, so fewer (if any) customers suffer an outage.

The following table presents a summary of the projects assessed as suitable for DM.

Table 24. Summary of DM projects associated with replacement or retirement of aged assets

Concord 11kV Switchgear Replacement	
Project Description	The driver for the project is the condition of the existing 11kV switchgear at the Concord 33/11kV Zone Substation, which is located in the Sydney Inner West Area of Ausgrid's network. The 11kV switchgear is compound insulated, 62 years of age, and is nearing the end of its life. The preferred network solution is that the switchgear is replaced with modern equivalent switchgear with control and protection equipment in a new switchroom building within the existing site.
Options Considered	We examined the following options as part of Ausgrid's planning process: 1. Replacement, which would involve the transfer of 11kV feeders from the old switchgear to the new switchgear in a new switchroom 2. Construction of a new 33/11kV Zone Substation on a green field site to replace the existing Concord 33/11kV Zone 3. Construction of a new 132/11kV Zone substation on a green field site to replace the existing Concord 33/11kV Zone 4. Consideration of DM.

DM Assessment	An analysis of non-network options considered how DM could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the unserved energy model and cost benefit assessment to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2021 to 2024. As such, this option is the preferred option. Details on the full cost benefit analysis of this project are in Attachment 5.14.
DM cost during 2019-24 Regulatory period	$4.6 million DM opex ($, real FY19)
Leightonfield 11kV Switchgear Replacement	
Project Description	The project is to replace the existing 11kV switchgear at Leightonfield, which is a “stand-alone” 33kV Zone Substation, supplied via Endeavour Energy’s network from its Guildford Subtransmission Substation. Leightonfield is in the Canterbury Bankstown region of Ausgrid’s network. The compound insulated switchgear is nearing the end of its life, and some of the 33kV equipment does not comply with Ausgrid’s safety standards. The work is to take place in two stages, the first of which addresses medium term issues with three 11kV switchgear panels. It is committed for completion in June 2018. The second stage involves rebuilding the zone substation, including the 11kV switchgear, 33kV switchgear and busbar and adding voltage-control plant.
Options Considered	We examined the following options as part of Ausgrid’s planning process: 1. Replacement of 11kV switchgear equipment within the existing Leightonfield site (brownfield) 2. Replacement of 11kV switchgear on a new site adjacent to existing Leightonfield Zone Substation (greenfield) 3. Construct a new 33/11kV Leightonfield Zone Substation 4. Consideration of DM.
DM Assessment	An analysis of non-network options considered how DM could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2025 to 2028. As such, this option is the preferred option. Details on the full cost benefit analysis of this project are in Attachment 5.14.
DM cost during 2019-24 Regulatory period	$1.3 million DM opex ($, real FY19)
Lidcombe 11kV Switchgear Replacement	
Project Description	The project is to retire and replace the existing 11kV switchgear at Lidcombe 33/11kV zone substation in the Inner West region of Ausgrid’s network. The compound insulated 11kV switchgear at Lidcombe is nearing the end of its life, and is considered to pose a risk to reliability of supply in that zone. Based on Ausgrid’s asset prioritisation process, Group 2 of the 11kV switchgear at Lidcombe zone substation is recommended for replacement within the next 5 years, and Group 1 of the 11kV switchgear in the next 5 to 10 years. The replacement options and timing analysis took into account that some of the 33kV cables that supply Lidcombe and Auburn Zones from Homebush STS are also in need of replacement.

Options Considered	As part of Ausgrid's planning process, the sub-options that were evaluated in various combinations for replacing the 11kV switchgear at Lidcombe and Auburn and the cables from Homebush STS included: 1. Replacing the 33kV cables between Homebush STS and Lidcombe and Auburn Zones, using current XLPE technology 2. A mixture of 33kV overhead construction and continued use of some existing HSL cables that have a reasonable assessed remaining life to supply Lidcombe and Auburn from Camellia in Endeavour Energy's network 3. Taking 132kV supply from a nearby overhead line, to supply a new 132/11kV Zone in the Auburn/ Lidcombe area, and transferring some, or all, of the load to it 4. Retirement of Auburn, Lidcombe or both Zones by transfer of all load to adjacent zones 5. Replacement of 11kV switchgear and associated refurbishment on the existing sites of Auburn and Lidcombe 6. Replacement of one or both Zone Substations by building on a new site near Lidcombe and/or Auburn 7. Consideration of DM.
DM Assessment	As the Group 2 11kV switchgear replacement project is already in progress, it is not feasible to use DM to defer the timing of this project. For the Group 1 11kV switchgear replacement project, an analysis of non-network options considered how DM could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2028 to 2031. As such, this option is the preferred option. Details on the full cost benefit analysis of this project are in Attachment 5.14.
DM cost during 2019-24 Regulatory period	$1.8 million DM opex ($, real FY19)
Mascot 11kV Switchgear Replacement	
Project Description	The driver for this project is the condition of the existing 11kV switchgear at the Mascot 33/11kV Zone Substation in the Eastern Sydney region of Ausgrid's network. The compound and air insulated switchgear, which includes oil-filled circuit breakers, is nearing the end of its life. The assessment of options took account of the fact that the six 33kV underground cables that supply Mascot from Bunnerong North Subtransmission Substation (STS) are also near the end of their lives, meaning that the entire zone substation and its source of supply needed to be considered together.
Options Considered	We examined the following options as part of Ausgrid's planning process: 1. Replace the Mascot 11kV switchgear on the same site with an equivalent modern design, while also replacing the existing 33kV cable supply from Bunnerong North STS with 33kV cables from a closer source (Alexandria STS) 2. Replace the Mascot 11kV switchgear on the same site with an equivalent modern design, while taking supply at 132kV instead of 33kV 3. Establish a replacement 132/11kV zone substation on an alternative site, and reconnect 11kV feeders to this site 4. Transfer of all 11kV load from Mascot to adjacent zones and decommission Mascot 5. Consideration of DM.

DM Assessment	An analysis of non-network options considered how DM could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2023 to 2026. As such, this option is the preferred option. Details on the full cost benefit analysis of this project are in Attachment 5.14.
DM cost during 2019-24 Regulatory period	$4.3 million DM opex ($, real FY19)
St Ives 11kV Switchgear Replacement	
Project Description	The project is to replace the 11kV switchgear at St Ives Zone Substation in the Upper North Shore Area of Ausgrid's network. The air insulated switchgear is nearing the end of its life, and based on our assessment of asset condition, the asset should be replaced by 2027.
Options Considered	We examined the following options as part of Ausgrid's planning process: 1. Replacement of 11kV switchgear at St Ives zone substation in spare space within the existing switchroom 2. Retirement of St Ives zone substation via 11kV load transfers to surrounding zones 3. Consideration of DM.
DM Assessment	An analysis of non-network options considered how DM could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2027 to 2030. As such, this option is the preferred option. Details on the full cost benefit analysis of this project are in Attachment 5.14.
DM cost during 2019-24 Regulatory period	$2.4 million DM opex ($, real FY19)
Haymarket-Pyrmont 132kV Feeder Replacement	
Project Description	The project is to replace 132kV cable 9S6/1 and cable 9S9/1 between TransGrid's Haymarket BSP and Pyrmont Subtransmission Substation with XLPE cables between the same terminals by summer 2026. The present 132kV cables are oil-filled, and 9S6/1 has experienced moderate oil leaks. The cable route is close to Darling Harbour and Pyrmont Bay, posing an environmental risk. The cables have been considered together because the least cost solution is for them to be laid at the same time in new adjacent ducts over most of their length.
Options Considered	We examined the following options as part of the Ausgrid's network planning process: 1. Like-for-like replacement – Haymarket BSP to Pyrmont STS using horizontal directional drilling (HDD) from near Wentworth Park to Pyrmont STS 2. Like-for-like replacement – Haymarket BSP to Pyrmont STS using a trench (two circuits in the same trench) 3. Like-for-like replacement – Haymarket to Pyrmont STS two single circuits in separate trenches 4. Replacement of feeders 9S6/1 and 9S9/1 by installing new 132kV feeders from Lane Cove STS to Pyrmont STS 5. Consideration of DM.

DM Assessment	An analysis of non-network options considered how DM could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2025/26 to 2028/29. As such, this option is the preferred option. Details on the full cost benefit analysis of this project are in Attachment 5.14.
DM cost during 2019-24 Regulatory period	$6.8 million DM opex ($, real FY19)

DM associated with local augmentation of the network

For the HV augmentation program, we have estimated the impact of DM on our projected program expenditure. While network reinforcement programs are traditionally not a significant source of projects which offer a material volume of viable DM options, we expect this to change, given the heightened focus within industry as a result of the Demand Management Incentive Scheme and programs driven by AEMO and the Australian Renewable Energy Agency.

Ausgrid undertook a top-down assessment of the viability of DM as an option for the HV augmentation program (see Attachment 6.05 for the cost-benefit analysis). This assessment was based on our estimates of the viability and costs of DM as an option in this investment category. These estimates are based on previous experience with delivery of DM projects, submissions to non-network options reports from non-network solutions providers and lessons learned from DM trials by Ausgrid and other networks in Australia.

This assessment identified $5 million (real FY19) of DM opex for the HV augmentation program during the 2019-24 regulatory period, resulting in a deferral of approximately $17 million (real FY19) of augmentation capex.

8 EXPENDITURE OBJECTIVES, CRITERIA AND FACTORS

We have proposed a total forecast opex for the 2019-24 regulatory period that we consider is required in order to achieve each of the opex objectives listed in clause 6.5.6(a) of the NER. The AER is required to make a decision on whether to accept or reject our total forecast opex. The AER must accept the total forecast opex if it is satisfied that the forecast of required opex reasonably reflects each of the opex criteria (opex criteria), having regard to the opex factors (opex factors). Below we identify how we have met the opex objectives, criteria and factors.

8.1 Achieving the opex objectives

The NER state that Ausgrid's forecast opex must be the expenditure that Ausgrid considers is needed to achieve each of the outcomes listed in clause 6.5.6(a), known as the 'operating expenditure objectives' (opex objectives). These objectives are: [37]

1. Meet or manage the expected demand for standard control services (objective 1).
2. Comply with all applicable regulatory obligations or requirements (objective 2).
3. Maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3).
4. Maintain the safety of the distribution system through the supply of standard control services (objective 4).

In order to achieve each of the opex objectives, Ausgrid must have the necessary capabilities, personnel and systems to undertake the necessary activities to achieve these objectives. For example, one of the opex objectives is to maintain the safety of the distribution system through the supply of standard control services. In order to achieve this objective, Ausgrid must have the capabilities, personnel and systems to undertake maintenance on the electrical network. Consequently, in undertaking these activities and in operating the necessary systems, Ausgrid must incur maintenance opex.

Ausgrid's total forecast opex therefore comprises of the costs of undertaking all the related activities and operating the necessary systems to deliver each of the opex objectives listed above. Our opex forecast for the 2019-24 regulatory period consists of five major cost categories, which we have grouped into three broad cost groups to illustrate how activities in each cost component contribute to the achievement of the opex expenditure objectives.

Table 25. Description of activities by opex cost groups

Opex cost group	Activities and relevance to opex expenditure objectives
Maintenance opex	Maintenance opex is required to undertake various activities on Ausgrid's electricity network to ensure compliance with regulatory obligations and to maintain system safety, security, reliability and quality of supply. Therefore, these activities and associated costs, are critical for achieving all of the opex expenditure objectives.
Operation and support	Operation expenditure covers those costs incurred in undertaking the required activities to directly support the operation of Ausgrid's network. Support expenditure is necessary for the normal operation of Ausgrid as a business and includes management/governance costs, financial/operational/compliance reporting, customer service and human resource

[37] See clause 6.5.6(a) for exact wording.

Opex cost group	Activities and relevance to opex expenditure objectives
	management costs. Also included in this group are IT support and property costs. These costs would be found in any typical business. These costs are essential to the effective running and operation of the network and are therefore required to achieve all of the opex expenditure objectives.
Other	This expenditure relates to demand management related activities which are required to manage demand on our network through various non-network alternatives. Expenditure of this nature is primarily aimed at addressing opex expenditure objective 1.

We have prepared our opex forecast in a manner that complies with the opex objectives specified in the NER. Specifically, we consider that our forecast meets the opex objectives for the following reasons:

- We have adopted a base-step-trend approach to forecasting most opex. We have used our estimated underlying opex for 2017/18 as the base year, as we consider this is representative of efficient, recurrent opex for the 2019-24 regulatory period.
- As demonstrated in the table below, the nature of the activities that we will undertake through our opex program is targeted at achieving the opex expenditure objectives. These activities are based on practices currently applied in the 2017/18 base year, and will only change in the 2019-24 period to accommodate changes to scope of works from step changes and the trend rate of change.
- We have assessed the sufficiency of our current compliance with safety, regulatory and compliance obligations to identify the need for any corrective action that might amount to a step change to our base year costs. Similarly, we have assessed foreseeable new or changed obligations that will affect the scope of our operating activities to identify the need for any step changes.
- We have robust plans, policies, procedures, governance frameworks, and strategies in place to support the delivery of our opex program, and have the requisite capability to deliver the opex program by acquiring and deploying the necessary labour and materials.

Table 26. Summary of our compliance with the opex objectives

Opex Objectives	Rule 6.5.6(a)	Addressed by
Meet or manage the expected demand for standard control services	(1)	We have trended our proposed base year opex to account for expected changes in output growth drivers such as customer numbers, peak demand and circuit length (see Chapter 6 of our Regulatory Proposal and Section 6 above). Our proposed opex forecast includes expenditure for demand management related activities necessary for managing demand as outlined in Chapter 6 of our Regulatory Proposal and Section 7 above.
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	(2)	We have assessed our current compliance obligations (and associated base year costs), as well as identifying additional new obligations that we expected to be in place over 2019-24 period. See Chapter 6 of our Regulatory Proposal and Section 7 above for our proposed step changes, and Attachment 6.03 (Network maintenance operating plan) for further details on how our proposed opex program allows us to comply with our applicable legislative and regulatory obligations.

Opex Objectives	Rule 6.5.6(a)	Addressed by
Maintain the quality, reliability and security of supply of standard control services	(3)	We have proactively sought to engage with our consumers to understand the level of service they value (see Chapter 2 of our Regulatory Proposal) to assist in the preparation of our opex expenditure program (see Chapter 6 of our Regulatory Proposal and Section 2 above), and have undertaken a deliverability assessment (see Attachment 5.12 (Resourcing and delivery strategy for 2019-24 period)) to ensure that we are in a position to meet these requirements.
Maintain the safety and security of the distribution system through the supply of standard control services.	(4)	

8.2 Meeting the opex criteria and factors

The AER is required to make a decision on whether to accept or reject our total forecast opex. The AER must accept Ausgrid's forecast or required opex if it is satisfied that the total forecast opex reasonably reflects each of the operating expenditure criteria (opex criteria), being:[38]

1. The efficient costs of achieving the opex objectives
2. The costs that a prudent operator would require to achieve the opex objectives
3. A realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In determining whether a forecast meets the opex criteria, the AER must have regard to the operating expenditure factors (opex factors) in clause 6.5.6(e) of the NER. This is because the opex factors are intended to represent factors that should be employed in developing a prudent and efficient expenditure forecast; and provide an indication as to whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects efficient costs. Consequently, consideration of the opex factors are intended to give the AER confidence that the proposed opex forecast reasonably reflects the efficient and prudent costs required to achieve the expenditure objectives, based on a realistic expectation of demand forecast and cost of inputs.

In previous submissions we have relied on the advice of National Economic Research Associates (NERA) to guide our understanding of the Rule requirements. In particular, we engaged NERA to provide expert economic advice on the interpretation of the opex criteria and on how to demonstrate that the forecast opex reasonably reflects these criteria. NERA considered that:

- The terms efficiency, prudency and realistic expectations have no observable measures but rather are principles that guide the AER's decision on the proposed expenditure forecast.
- Efficiency cannot be directly observed. There is no external measure of where the efficiency frontier lies. Efficiency is typically measured relative to other firms and must take into account the differences in characteristics, circumstances and operating environment of each firm.
- Prudent refers to the idea of 'carefully considering consequences' and 'carefully managing resources'.

[38] NER clause 6.5.6(c).

NERA further considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent. In this respect a number of the opex factors relate to the process used by the DNSP.
- Using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost. In this respect, a number of the opex factors represent partial checks of the forecast.

We have prepared our opex forecast in manner that is both consistent with, and gives effect to, the opex criteria and factors set out in clauses 6.5.6(c) and 6.5.6(e) of the NER. This is demonstrated through:

- Our adoption of our estimated underlying opex for 2017-18 as the base year in our base-step-trend approach to forecasting opex
- The development of demand forecasts based on good industry practice which have been independently reviewed
- Our consideration of opex/capex substitution possibilities
- Our incorporation of customer and stakeholder expectations to reduce opex whilst maintaining current service standards and continuing to invest in demand management programs
- Our provision of actual and forecast opex during the current and past regulatory periods, and explanation for any variances between our actual performance relative to our allowance
- Our consideration of industry benchmarking.

A summary of how our opex forecast meets the expenditure factors is outlined in the table below.

Table 27. Summary of how Ausgrid has met the expenditure factors

Opex Factors	Rule 6.5.6(e)	Addressed by
[**Deleted**]	(1)	Not applicable
[**Deleted**]	(2)	Not applicable
[**Deleted**]	(3)	Not applicable
The most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark opex that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*.	(4)	We have carefully reviewed the AER's most recent annual benchmarking report and other relevant measures of benchmark opex that would be incurred by an efficient DNSP. We have addressed our relative performance in the AER's 2017 Annual Benchmarking Report in Section 4 above.
The actual and expected opex of the *Distribution Network Service Provider* during any preceding *regulatory control periods*.	(5)	Chapter 6 of our Regulatory Proposal and Section 2 above detail our actual and estimated opex for the 2014-19 regulatory period and explain the key reasons for variances between Ausgrid's actual and estimated expenditure during the current period from the AER's allowance.

Opex Factors	Rule 6.5.6(e)	Addressed by
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers.	(5A)	We have proactively engaged with our customers to understand their concerns. Chapter 2 of our Regulatory Proposal, Attachment 2.01 (Extended stakeholder consultation report) and Attachment 2.02 (Customer and stakeholder engagement prior to 30 December 2017) set out our engagement approach, our key findings from our customer engagement activities and how Ausgrid has embedded customer engagement as part of its business as usual activities.
The relative prices of operating and capital inputs.	(6)	We have sought to assess all feasible options when addressing a need including opex and capex solutions. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation. We have applied appropriate escalators to the relative prices of inputs in our opex and capex forecasts (see Chapters 5 and 6 of our Regulatory Proposal, Section 6 above and Attachment RIN09 (BIS Oxford – Cost escalation report) for further details).
The substitution possibilities between operating and capital expenditure.	(7)	We have considered the substitution possibilities between opex and capex in developing our forecast opex. A key step in our capital network investment planning process is to consider a full range of alternative options, including whether there may be an opex solution that is more efficient in addressing the investment need. For example, our planning process explicitly considers the following opex substitution possibilities: • **Growth capex –** the primary opex substitution for customer and demand driven capex is demand management. Our processes directly consider whether there is a specific demand management opportunity, or whether historical experience indicates that demand management may prove more cost effective in addressing the issues. Our proposal includes a step change in relation to demand management as result of an identified capex trade-off (see Chapter 6 of our Regulatory Proposal and Section 7 above). • **Replacement capex –** the primary opex substitute is network maintenance. Our process for deriving the timing and need for replacement considers whether there is a less costly maintenance option. However, there is also the potential to use demand management as a substitute for replacement capex. Our proposal includes a step change in relation to demand management as result of an identified capex trade-off (see Chapter 6 of our Regulatory Proposal and Section 7 above). • **Reliability performance capex** – a means for improving reliability may be an opex solution such as corrective maintenance. We have considered these alternative options when developing our reliability compliance plan. • **Network support** – opex substitutions are a key consideration in our process for deriving replacement and non-system capex. In addition, we have considered the consequential impact on forecast opex from the following capex investment interactions: • **The impact of capex on maintenance costs** – the cost of maintenance is dependent on the number of assets impacted by the forecast replacement and capacity investment programs for the 2019-24 period. • **Information technology investment and consequential opex –** our expenditure on information technology systems requires a consequential opex increase to operate and maintain these systems.

Opex Factors	Rule 6.5.6(e)	Addressed by
		• **Property capital investment and statutory charges** – capital investment on property acquisitions has a corresponding impact on the amount of land tax paid, which is an opex expense.
Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8 or 6.6.2 to 6.6.4.	(8)	The regulatory framework, coupled with our new commercial focus and customers' expectations, provide strong incentives for Ausgrid to act prudently and efficiently when assessing our expenditure needs for the forthcoming regulatory period. The significant incentive schemes that our opex forecast considers include: • **EBSS –** this scheme will provide us with additional and consistent incentives to continuously reduce our operating costs to deliver lower prices for our customers. • **STPIS –** this scheme will help us maintain and improve our service performance and ultimately deliver better outcomes for customers. • **Demand Management Incentive Scheme and Innovation Allowance –** together these schemes will provide benefits to our customers by reducing network costs over time and thereby lowering prices in future regulatory periods.
The extent the opex forecast is referable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms.	(9)	There will be some opex attributable to a related party (PlusES Partnership) as they provide certain metering related standard control services to Ausgrid. The commercial terms and prices for these services are considered to be commercial arm's length terms.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	(9A)	Our proposed opex does not include an amount relating to a project that should be more appropriately included as a contingent project under clause 6.6A1(b).
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options.	(10)	We have considered all feasible options to address network needs, and have selected the most efficient option. In doing so, we have considered and made provision for efficient and prudent non-network alternatives (see Chapter 6 of our Regulatory Proposal and Section 7 above). Ausgrid has well defined demand management strategies and processes (see Section 8 of Ausgrid's RIN Schedule 1 response), and a track record of implementing demand management initiatives. We have also proposed that the DMIS and DMIA apply to Ausgrid, and have proposed a step change in relation to demand management projects and programs.
Any relevant final project assessment report (as defined in clause 5.10.2) *published* under clause 5.17.4(o), (p) or (s).	(11)	Ausgrid has not published any final project assessments under the regulatory investment test for distribution (RIT-D) that are relevant to our proposed opex. Any final project assessment reports published by Ausgrid are available at our website: https://www.ausgrid.com.au/Common/Industry/Regulation/Network-Planning/Regulatory-Investment-Test-Projects.aspx#.WrHvHrVlJD8
Any other factor the *AER* considers relevant and which the *AER* has notified the *Distribution Network Service Provider* in writing, prior to the submission of its revised *regulatory proposal* under clause 6.10.3, is an *operating expenditure factor*.	(12)	This factor is relevant for submission of a revised regulatory proposal and not this initial regulatory proposal.