Appendix A: Operating expenditure forecasts for Standard Control Services

Introduction

Our operating expenditure program is critical to delivering a safe, dependable service.

We have achieved significant efficiency improvements in recent years, which have placed us well to deliver savings into 2015-20. However, the targets we have set for our operating costs are a challenge and will require significant reduction in costs in the future to deliver. We are looking to technology-based capabilities to support greater efficiencies moving forward.

We are increasing our operating expenditure on alternative non-network solutions to better manage demand on the network, as an alternative to capital investment, and looking at a new form of cyclone insurance cover.

Our proposal brings our operating costs for the 2015-20 regulatory control period down to $1.8 billion, from $1.9 billion in the previous period. Network Maintenance is our largest cost – at $1.3 billion over the five year period.

Customer benefits

Our operating expenditure program is critical to delivering on the full set of our service commitments to regional Queensland – most importantly to our safety and reliability commitments. This expenditure is also critical to our disaster management and storm/outage response capability, as well as to delivering on our guaranteed service levels. It also allows us to best support customer choice in economic electricity supply solutions.

We are aiming to continue to drive efficiencies, without compromising on our service standards.

Expenditure on alternative non-network solutions is central to delivering on our overall best possible price commitment, and our cyclone insurance cover proposal is about reducing the potential for a significant price shock impact if one or more of Queensland's coastal population centres was devastated by a major cyclone.

Appendix A: Operating expenditure forecast for Standard Control Services

1 Overview

Our proposed operating expenditure has reduced by approximately 6% from our actual and estimated spend in the current regulatory control period. It incorporates efficiencies in vegetation management, line inspection and pole defect management. At the same time, we are incorporating increasing expenditure in non-network alternatives to address network demand, rather than employing costly capital solutions. We are also proposing to include a new form of insurance cover given our unique exposure to extreme wind-generated events like Cyclone Yasi.

The total operating expenditure Ergon Energy requires to meet the operating expenditure objectives in the next regulatory control period is provided below.

Table 34: Forecast operating expenditure, 2015-20

$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Operating expenditure	349,600	356,070	363,610	372,890	378,960	**1,821,130**

This appendix outlines:

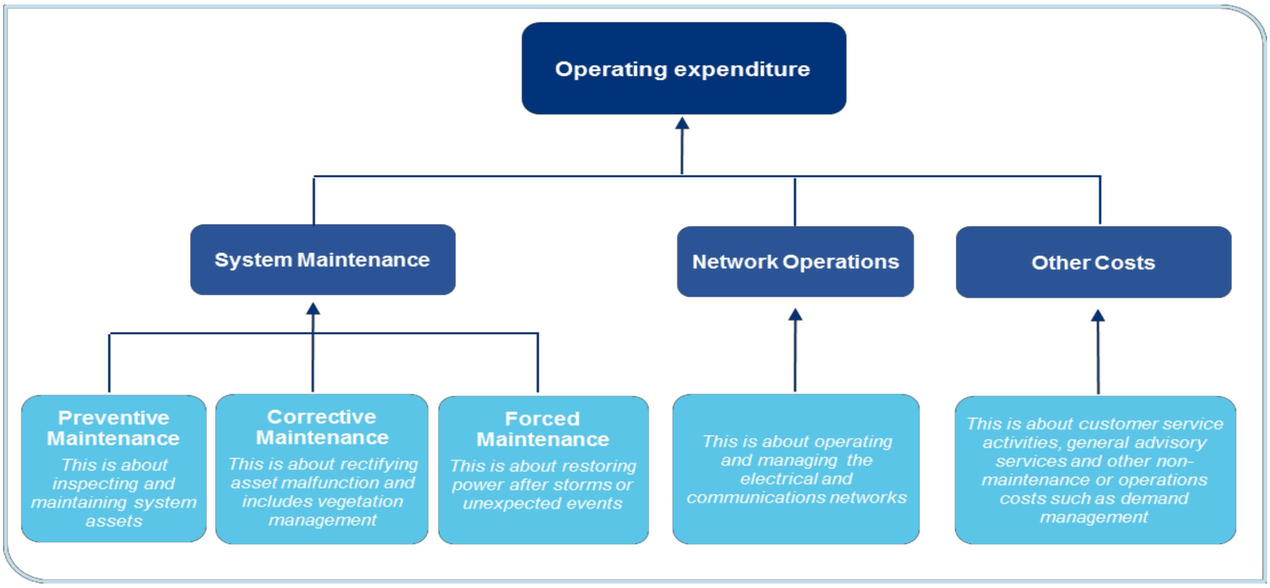
- why Ergon Energy incurs this level of operating expenditure, and the various categories of expenditure that make up Ergon Energy's operating program
- our level of operating expenditure in the current regulatory control period and how it compares to the efficient level of operating expenditure set by the AER for that period
- factors influencing our operating expenditure in the next regulatory control period
- our methodology, approach and assumptions underpinning our forecasts
- outcomes for customers as a result of our forecasts
- how our operating expenditure forecasts satisfy the operating expenditure criteria, having regard to the factors outlined in the NER.

2 Components of our operating expenditure requirement

2.1 Direct operating expenditure

The components of our direct operating expenditure program are illustrated in Figure 7.

Figure 7: Components of our operating expenditure requirement



Ergon Energy's direct operating expenditure requirements[67] are driven by Ergon Energy's customer commitments, regulatory and statutory requirements, codes of works and industry standards. The content of the network operating expenditure program balances these requirements within the funding proposed through:

- compliance with all applicable regulatory obligations or requirements
- maintaining the reliability, safety, and security of the distribution system
- managing the forecast demand for Standard Control Services reviewing cost and risk.

Network Maintenance: comprises of scheduled (routine) and non-scheduled (non-routine) inspection and maintenance activity across all Ergon Energy asset categories.

The routine maintenance programs are supported by maintenance strategies, management plans and Defect Classification Manuals specific to each asset category. Non-routine maintenance involves timely response to instances of non-compliance against acceptance criteria identified during the routine maintenance process. Such activity may include more intensive (frequent) inspection cycles as the most cost effective manner in extending asset life cognisant with safety and regulatory obligations.

Ergon Energy is also required to ensure that sufficient funding and resources are available to respond to unexpected or unplanned events and to safely and efficiently restore supply and asset integrity.

Network Operations: covers operating expenditure costs incurred or associated with the safe, effective, and reliable operation of the electricity network. The two primary components of network operations are**:**

- Network Operations that comprise the operational expenditure required to resource and operate Ergon Energy's network control centres
- System Operations that comprise the operational expenditure required to provide services such as system communications, operational technology software and related expenditure.

[67] Section 3 of our supporting document *06.01.02 – System related operating expenditure summary.*

Other Operating Costs: includes customer service activity such as education and customer contact in respect of electrical safety issues and other general advisory services.

In the current regulatory control period, this expenditure category also included meter reading costs associated with Ergon Energy's role as a Metering Data Provider for Types 5 and 6 metering installations. However, these costs will not be included in the operating expenditure requirement in the next regulatory control period as Default Metering Services will be classified as an Alternative Control Service. This means the costs of reading a Type 5 or 6 meter will be recovered as a separate charge from customers (where applicable).

Other operating costs also include demand management, which includes a range of non-network alternatives solutions, as a tactical response to network problems – primarily where growing customer peak demand requirements create the need to expand network capacity.

Table 35 provides Ergon Energy's forecast operating expenditure for each year of the next regulatory control period, disaggregated by program of expenditure.

Table 35: Proposed operating expenditure by category, 2015-20

$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Network Operating Costs						
Network Operating Costs	34,260	34,990	36,590	37,650	38,330	181,820
Network Maintenance Costs						
Preventive Maintenance	77,520	79,240	82,950	85,460	87,090	412,260
Corrective Maintenance	108,280	110,660	115,810	119,280	121,520	575,550
Forced Maintenance	64,750	65,990	68,860	70,720	71,850	342,170
Subtotal	*250,550*	*255,890*	*267,620*	*275,460*	*280,460*	*1,329,980*
Other Costs						
Customer Services	4,370	4,490	4,720	4,880	4,980	23,440
Other Operating Costs	60,420	60,700	54,680	54,900	55,190	285,890
Subtotal	*64,790*	*65,190*	*59,400*	*59,780*	*60,170*	*309,330*
Total forecast operating expenditure	**349,600**	**356,070**	**363,610**	**372,890**	**378,960**	**1,821,130**

Further information on the forecast expenditure for each category is provided in the supporting document *06.01.02 – System Related Operating Expenditure Summary* (*System Opex Summary*).

2.2 Overheads or support expenditure

Like all businesses, Ergon Energy accounts for a large portion of our costs as support expenditure or overhead. By their nature, these costs are allocated to direct cost activities (capital and operating expenditure, as well as to other services) consistent with a CAM approved by the AER. A full list of the overhead functional areas can be found in Attachment 1 of the supporting document *06.01.01 – Operating Expenditure Forecast Summary* (*Opex Forecast Summary)*. Examples of overhead costs include:

- Administrative Support
- Corporate Support

- Customer Service and Billing
- Engineering Standards, Technology and Support
- Finance
- Fleet
- Human Resources
- ICT
- Network Planning
- Network Safety
- Property.

3 Prior and current period performance

Table 36 and Table 37 provide Ergon Energy's actual operating expenditure for each year of the previous and current regulatory control periods, disaggregated by program of expenditure.[68]

For comparison purposes, we have categorised this information in the same way as our operating expenditure forecast set out in Table 35. Information provided for both regulatory control periods are based on the CAM applying in the current regulatory control period.

Expenditure associated with FiT payments has been excluded from the prior and current period performance. These costs do not form part of our Direct Control Services from 1 July 2015.

Table 36: Prior period operating expenditure by category, 2005-10

$'000 (real 2014-15)	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Network Operating Costs						
Network Operating Costs	20,067	30,804	36,157	35,709	33,154	155,891
Network Maintenance Costs						
Preventive Maintenance	64,454	68,736	114,756	104,269	77,516	429,732
Corrective Maintenance	99,981	132,078	85,117	98,768	114,012	529,954
Forced Maintenance	65,946	25,231	50,079	50,776	63,952	255,984
Subtotal	*230,381*	*226,045*	*249,951*	*253,813*	*255,479*	*1,215,670*
Other Costs						
Meter Reading	10,687	12,539	12,512	15,298	13,231	64,266
Customer Services	39,860	33,638	29,668	20,475	20,503	144,143
Other Operating Costs	22,662	24,054	22,328	26,786	22,639	118,470
Subtotal	*73,209*	*70,231*	*64,508*	*62,559*	*56,373*	*326,879*
Total actual operating expenditure	**323,657**	**327,080**	**350,616**	**352,081**	**345,006**	**1,698,440**

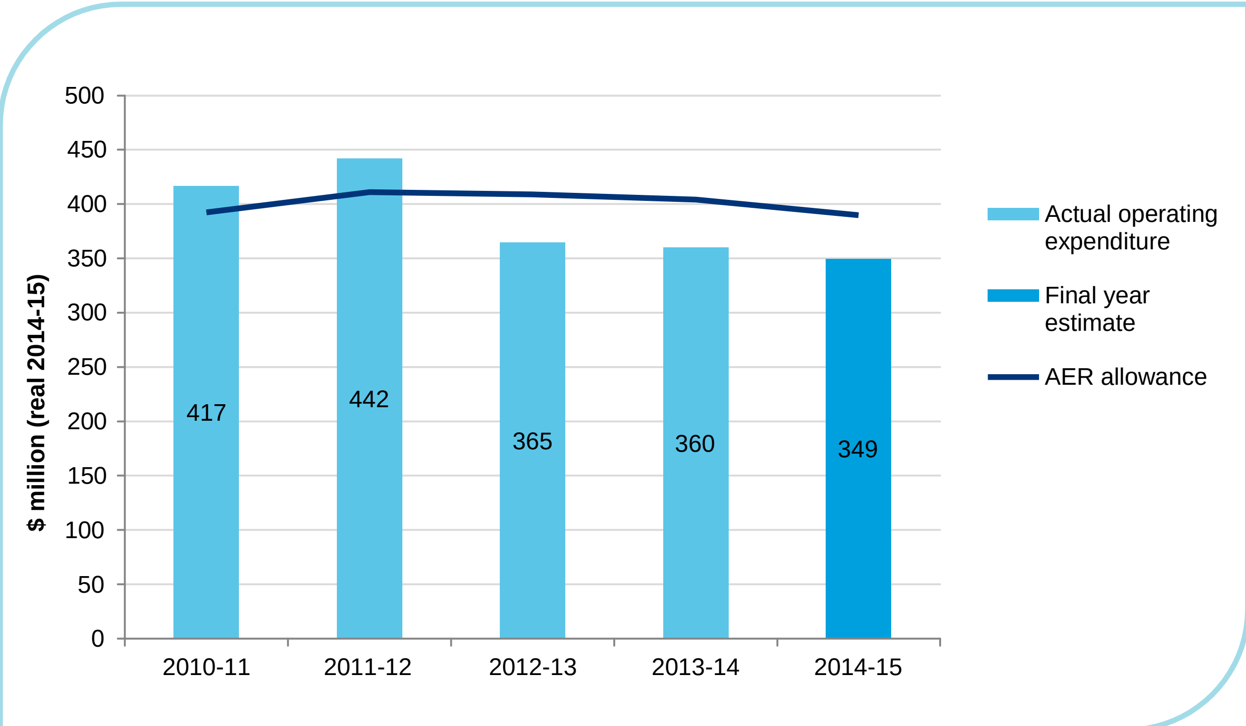
[68] NER, clause S6.1.2(7).

Table 37: Current period operating expenditure by category, 2010-15

$'000 (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Network Operating Costs						
Network Operating Costs	36,168	35,075	34,775	35,241	34,462	175,722
Network Maintenance Costs						
Preventive Maintenance	83,105	103,534	92,096	73,440	78,602	430,777
Corrective Maintenance	117,323	147,271	113,905	107,694	106,502	592,694
Forced Maintenance	105,368	67,059	73,115	69,413	63,850	378,805
Subtotal	*305,795*	*317,864*	*279,116*	*250,547*	*248,954*	*1,402,276*
Other Costs						
Meter Reading	12,985	14,282	13,330	13,195	14,070	67,862
Customer Services	20,980	27,338	32,389	26,125	16,089	122,922
Other Operating Costs	40,654	47,193	5,073	35,056	35,862	163,838
Subtotal	*74,619*	*88,813*	*50,793*	*74,377*	*66,021*	*354,622*
Total actual operating expenditure	**416,582**	**441,752**	**364,683**	**360,165**	**349,437**	**1,932,620**

As illustrated in Figure 8, Ergon Energy expects to deliver an operating program less than the AER approved allowance over the current regulatory control period.

Figure 8: Actual vs. allowed operating expenditure, 2010-15



The following sections summarise the factors that shaped our operating expenditure in the current regulatory control period. These factors will play a role in our need for ongoing operating expenditure to the level forecast.

3.3 Key drivers of expenditure and outcomes in the current period

Impacts of response and recovery

While lightning, storm activity, flooding, heavy rain and high wind drive a material amount of our traditional operating expenditure requirements, there are some events we simply cannot predict. The summer storm season of 2010-11 represented one of the worst seasons in our history. On 3 February 2011, Queensland was hit by the largest storm system in living memory – Cyclone Yasi. Cyclone Yasi crossed the Queensland coast at Mission Beach as a Category 5 cyclone, over 600 kilometres wide, with wind speeds of 295 kilometres per hour. It took out power supplies to nearly a third of our customer base, interrupting over 220,000 homes and businesses, and at least 50 major substations were off supply as part of the initial impact.

Our *System Opex Summary* document outlines the impact that Cyclone Yasi had on Ergon Energy's customers and network infrastructure, and the consequential impact on other programs of work. This combined with other major weather events (flooding and impacts from ex-cyclone Oswald) saw substantial increases against forecasts in some cost categories.

Increased focus on cost reductions

Despite substantial pressures and necessary expenditure from response and recovery efforts, we made deliberate and significant reductions to our underlying costs which resulted in us spending less than the operating expenditure allowance set by the AER (as shown in Figure 8 above).

Our *System Opex Summary* document outlines a number of deliberate initiatives aimed at improving outcomes for customers in terms of cost reductions. This included:

- developing and implementing, in partnership with Energex, a robust asset management framework, followed by a review of all maintenance programs with subsequent risk assessments. This resulted in the consolidation of programs, and improvements in out-turn expenditure
- efficiency improvements in maintenance program delivery and management.

Our supporting document, *Ergon Energy's Journey to the Best Possible Price (Best Possible Price)*,[69] notes the efficiency and effectiveness initiatives undertaken during this period. These initiatives, covering both direct and indirect expenditure, covered all elements of the business and were supported by an organisational restructure and adjustment to the workforce (employees and contractors) of over 600 positions.

During 2013-14 and 2014-15, Ergon Energy has been focused on delivering network services on budget (i.e. in accordance with 2012-13 adjusted levels) while establishing frameworks that will drive future cost savings. The outcomes to date from this continual focus on efficiency and effectiveness have included:

- signing off a new business direction and model
- implementing a new executive and senior management structure

[69] *0A.01.02 – Ergon Energy's Journey to the Best Possible Price*.

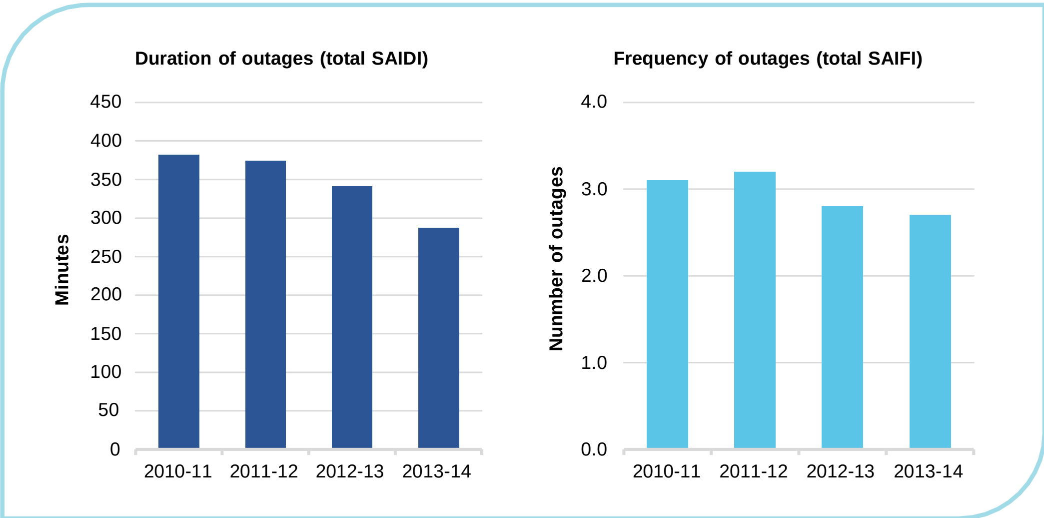
- reducing total expenditure spend by over 20% against the regulatory allowance
- contracting business headcount by 17.5% since April 2012
- success in securing new security and reliability standards that will ease investment.

Reliability of the network continued to improve

Throughout this period of change, we continued to deliver strong performance outcomes for our customers, with improvements in our reliability measures across all distribution feeder types. This reflects the significant investment and operational priority we have placed over the current regulatory control period on achieving the regulated Minimum Service Standards (MSS). The MSS includes two components:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI).

Figure 9: SAIDI and SAIFI, 2010-11 to 2013-14



Our consumer engagement research is showing our customers are now generally satisfied with the level of supply they receive.[70] Our research has also highlighted that customers on the whole do not believe that future improvements in reliability are required, particularly not at the expense of higher prices. As such, moving forward, our operating expenditure plans focus on maintaining reliability rather than making further broad-based improvements in this area.

[70] Refer to our supporting document *0A.01.04 – Informing our plans, Our Engagement Program.*

4 Factors influencing forecasts in 2015-20

This section considers the factors and challenges driving operating expenditure in the next regulatory control period and the way in which we propose to respond.

Operating expenditure is largely recurrent by nature, which means that actual operating expenditure incurred in previous years is typically viewed by the AER as an appropriate starting point for the calculation of efficient future requirements. Our forecasting methodology, which is based on a revealed cost approach, recognises this principle.

Nevertheless, in order for Ergon Energy to ensure that our operating expenditure forecasts enable us to achieve the operating expenditure objectives, it is necessary to examine the factors that will materially influence our operating expenditure over the next regulatory control period.

4.1 Our journey to the best possible price

For some time now, we have delivered substantial savings across our operating program, particularly in the areas of overhead cost reduction and workforce optimisation. Our focus on driving efficiencies will continue until the end of the current regulatory control period. The changes will provide Ergon Energy with a further opportunity to review the way we will meet consumers' expectations around reliability, performance and the range of services provided. Additional efficiency savings are expected to be leveraged through the implementation of new management structures, driving a culture of operational and financial efficiency.

We have also been undertaking further analysis on the evolving operating environment, anticipated regulatory and policy changes, future economic conditions and trends in energy consumption, innovation and consumer expectations to identify where further efficiencies can be achieved.

Our *Best Possible Price* document outlines how Ergon Energy made significant adjustments to our forecast operating expenditure requirement to deliver lower price outcomes for customers. As discussed in detail in the forecast methodology in Section 5, these adjustments take the form of an upfront one-off adjustment to our base year overhead costs (therefore impacting capital and operating expenditure) and an ongoing productivity adjustment.

Bringing forward future benefits for customers

Ergon Energy's actual operational overhead costs for 2013-14 and 2014-15 are likely to be at a higher level than the top down reduction in our forecast implies. This is because our commitment to future cost reductions are not certain, and even if realised, will only start to be delivered over the term of the regulatory control period 2015-20.

Normally, under the existing regulatory framework, any prospective benefits or cost reductions from innovation or other initiatives would be shared with customers in future regulatory control periods. In other words, proactive attempts to reduce costs would be passed on to customers over time.

We want to do more.

Ergon Energy is committed to improving the affordability of electricity for our customers, while not compromising safety and reliability. Based on our customer engagement activities we understand the majority of residential customers would prefer to see prices unchanged and for small businesses to see an immediate reduction in electricity prices.

With this in mind, Ergon Energy has prepared our forecasts in a way that passes on the anticipated savings from the above regulatory, structural and technological changes to our consumers, in full and at the start of the regulatory control period (i.e. 2015-16).

Our approach does not unnecessarily delay the bringing forward of benefits for consumers in terms of making sustainable price reductions and strikes an appropriate balance with the incentives Ergon Energy will experience under the EBSS. Feedback from consumers and other key stakeholders (including the Consumer Challenge Panel) also indicates there is support for energy companies to deliver the best possible price to consumers as soon as possible, and not unduly defer or delay the sharing of benefits.[71]

Attaining this level of reduction during the period represents a challenge for the organisation, but one which we believe can be achieved while meeting all of our regulatory and safety obligations. Further, while price is a key issue for consumers, we are cognisant of our consumers' expectations around network safety, reliability and being able to respond to whatever Mother Nature delivers.

Overall network reliability

As noted earlier, we have made good in-roads into improving the day-to-day reliability of our network. Our customer engagement has identified that our customers are now generally satisfied with the level of reliability we provide. As such, we will shift our focus in the next regulatory control period from making further improvements in reliability to maintaining the current level of supply. This will create downward pressure on the operational expenditure required for reliability works.

5 Forecast methodology

In the previous sections we identified the forecast operating expenditure requirements for the next regulatory control period and the drivers that influenced this program of work. This section provides an overview of the approach that we have adopted in developing these forecasts.

In support of this section we have also prepared our *Opex Forecast Summary* document,[72] which provides more detailed information and analysis on the methodologies applied. In addition to this, we submitted our Expenditure Forecast Methodology to the AER on 29 November 2013,[73] setting out our approach for forecasting expenditure for the next regulatory control period, including our approach to operating expenditure. This section should therefore be read in conjunction with these documents.

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[71] *0A.01.04 – Informing our plans, Our Engagement Program;* Consumer Challenge Panel (2014a), *Current and Emerging Issues for the Queensland Distributors' Revenue Determinations*, Queensland Consumers' Meeting 8 August 2014, Consumer Challenge Panel (2014b), *Smelling the Roses and Escaping the Rabbit Holes: the Value of Looking at Actual Outcomes in Deciding WACC, Prepared for the Board of the Australian Energy Regulator*, July 2014, https://www.aer.gov.au/system/files/CCP%20Rate%20of%20Return%20submission.pdf ; Ergon Energy (2014), *Customer Council AER2015 Working Group Meeting Notes*, 28 August 2014, https://www.ergon.com.au/__data/assets/pdf_file/0004/218416/Customer-Council-AER2015-Working-Group-August-meeting-notes.pdf

[72] 06.01.01

[73] Refer to https://www.ergon.com.au/network/network-management/future-investment

5.1 Key assumptions

Table 38 outlines the key assumptions underpinning our operating expenditure forecasts for the next regulatory control period, consistent with NER requirements.[74]

Table 38: Operating expenditure assumptions, 2015-20

Assumption	Application
Our current company structure, ownership arrangements and service classification will continue.	The operating expenditure forecasts are based on continuing the current company structure. Any future restructuring could change Ergon Energy's cost structure and would require changes to our CAM. The potential for future changes arising from recent announcements regarding the Queensland Government's Strong Choices Plan that could see the assets of distribution networks being subject to a leasing arrangement have not been factored into our expenditure assumptions for the regulatory control period 2015-20.
Our current legislative and regulatory obligations will not change materially.	The operating expenditure forecasts are designed to comply with the current legislative and regulatory obligations. If any material changes occur, they may be treated as a cost pass through event.
The AER will not depart from its preference stated in the Expenditure Forecast Assessment Guideline for network service providers (NSPs) to justify operating expenditure allowances using a BST methodology.	Ergon Energy has prepared our forecasts consistent with a BST methodology based on AER requests, both directly to Ergon Energy and through its Expenditure Forecast Assessment Guideline. We have taken into account the need for our forecasts to be consistent with our CAM, and have modified our methodology to be consistent with this. We also explained exceptions to adopting a BST for some operating expenditure functional areas.
The 2012-13 audited financial statements are an appropriate starting point for the establishment of an efficient base year.	The 2012-13 financial year represented the most recent audited financial statements available for the purpose of forecasting the regulatory control period 2015-20 to meet the timetable for submission to the AER on 31 October 2014 and the most logical representative base year. While the audit of 2013-14 financial accounts has been completed, the results of that financial audit were not available until the end of August 2014 to allow sufficient analysis to occur for submission of this Regulatory Proposal.
Adjustments to the base year expenditure are necessary and reasonable.	Consistent with a BST methodology, base year expenditure has been adjusted to account for non-recurring expenditure, step changes and other one-off adjustments to ensure our expenditure forecast meets NER requirements.

[74] NER, Schedule 6.1.2(5). Schedule 6.1.2(6) also requires the directors of Ergon Energy to certify the reasonableness of these assumptions. This is available at *06.01.06 – Certification of reasonableness – expenditure forecast assumptions.*

Assumption	Application
Rate of change factors applied for the period are realistic and reasonable.	Consistent with a BST methodology, we have applied input (price), output (driver) and productivity growth factors to the base year forecast. We have based these rate of change factors on independent expert advice and/or industry or regulatory precedents, including expert advice from Jacobs (SKM) that is included as an attachment supporting this Regulatory Proposal.[75] This approach ensures that these escalators appropriately reflect the increases in the cost of materials and other non-labour inputs, as well as the skills required and the market factors driving the demand and supply of labour for the provision of our services.
Our parametric insurance will cover the financial impact of extreme wind-generated weather events and our works delivery and expenditure requirements will not be materially disrupted by extreme weather events.	Extreme weather events, such as cyclones or major flood events, can interfere with our ability to implement planned operating expenditure programs such as inspections and maintenance. Appropriate adjustments to our base year forecast operating expenditure have been made to allow for the impacts of the costs of our parametric insurance proposal being included in the Regulatory Proposal forecasts for the regulatory control period 2015-20.

5.2 Revised approach to forecasting operating expenditure

Ergon Energy has traditionally prepared our operating expenditure forecasts through a bottom-up forecast of direct maintenance, operations and customer service costs, with overhead applied in a manner consistent with our CAM. This approach has generally been accepted by regulators in the past.

Our adoption of the BST methodology for forecasting the majority of our recurrent operating expenditure represents a substantial change in approach from that applied in developing our forecasts for the current regulatory control period. We have attempted to reconcile our approach with the AER's Expenditure Forecast Assessment Guideline, but have found that some departures have been necessary.

> *"…NSPs may find it useful to focus their approach to justifying their proposed opex allowances through the base-step-trend approach, if they have not used it in the past."*
>
> *AER, Better Regulation, Explanatory Statement – Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*

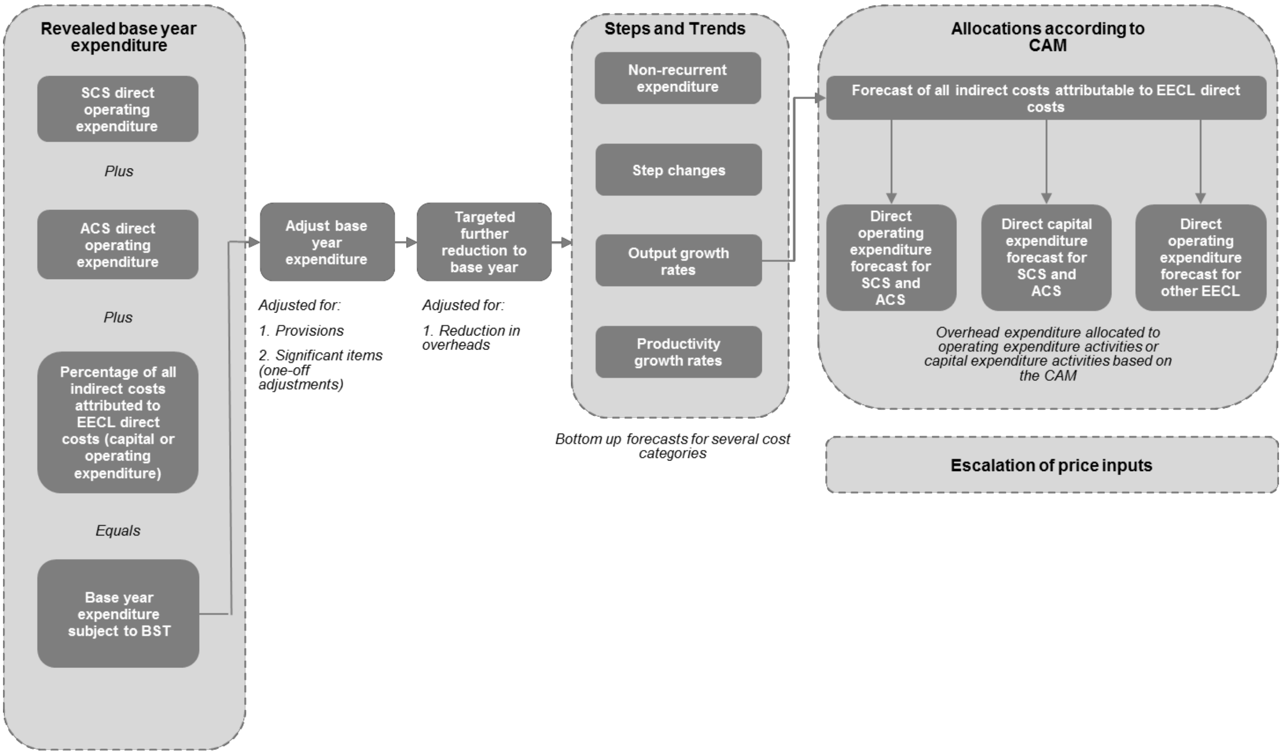
The NER requires that any forecast be developed on a basis consistent with Ergon Energy's approved CAM.[76] In order to be consistent with the Guideline and compliant with the NER, it has been necessary for Ergon Energy to apply a BST approach to most of our regulated direct and overhead expenditure that is not direct capital expenditure. As part of its Better Regulation work program, the AER released its Expenditure Forecast Assessment Guideline[77] and Explanatory Statement, [78] setting out the AER's intended approach to assessing expenditure forecasts. The Explanatory Statement appears to

[75] *06.02.02 – Jacobs: Cost Escalation Factors 2015-20*
[76] NER, clause 6.5.7(b)(2)
[77] Refer to http://www.aer.gov.au/node/18864#.
[78] Refer to https://www.aer.gov.au/system/files/Expenditure%20Forecast%20Assessment%20Guideline%20-%20Explanatory%20Statement%20-%20FINAL.pdf

indicate a preference by the AER for the application of a BST approach to the forecasting of operating expenditure requirements.

As a result, we have revised our operating expenditure forecasting approach for the next regulatory control period. Figure 10 outlines the approach we have taken for the development of our operating expenditure forecasts. Ergon Energy has used a BST approach for our operating expenditure, with the exception of those Functional Areas identified in Section 5.4 below.

Figure 10: BST methodology



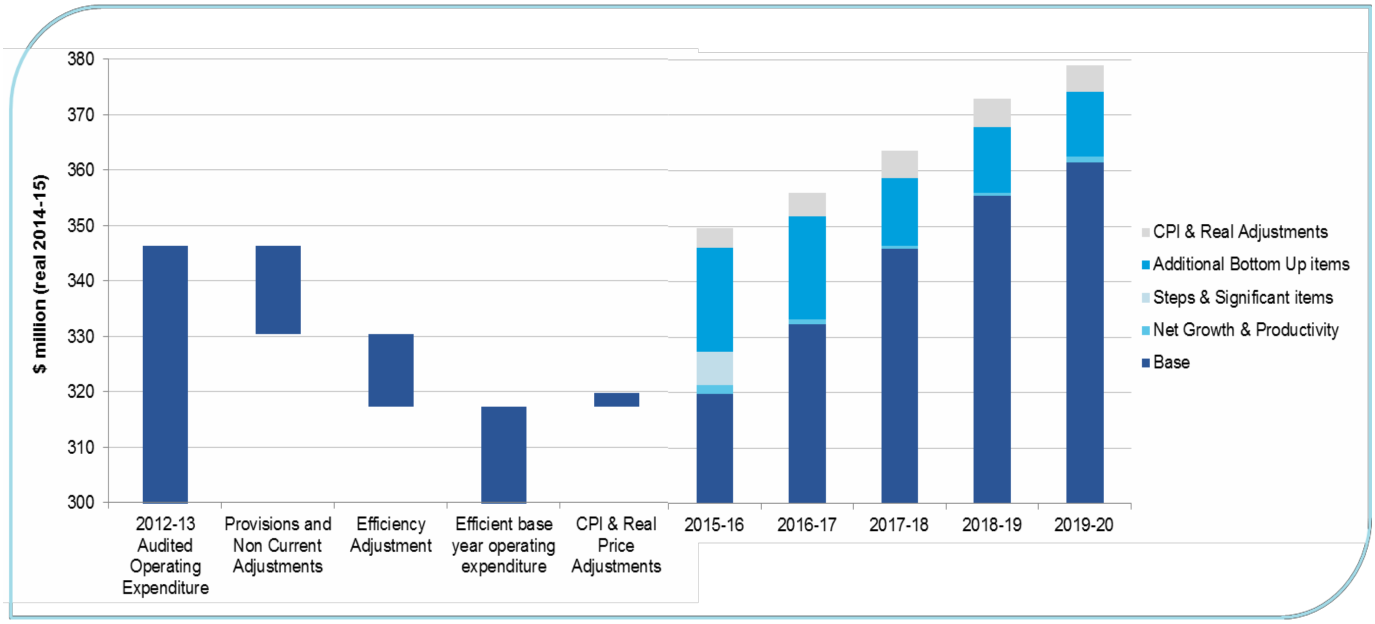
5.3 Base step trend forecasting approach

In simple terms, the BST methodology applied by Ergon Energy in preparing our operating expenditure forecasts involves:

- selecting a base year
- identifying the direct and indirect costs that need to be applied to BST
- making appropriate adjustments for movements in provisions
- making one-off adjustments to the base year
- making further targeted reductions to the base year
- identifying and applying any step changes
- applying a rate of change consisting of output growth, real price growth and productivity growth to establish the trend.

The BST outcomes for Ergon Energy's Standard Control Services are depicted in the Figure 11 below.[79]

Figure 11: BST outcomes for Ergon Energy



Base year assumption and approach to adjustments

The initial step in developing operating expenditure forecasts under the BST method involves selecting a base year to be used as the basis upon which to build the forecast.

Ergon Energy has chosen the 2012-13 financial accounts as the base year for the purposes of forecasting operating expenditure for the Regulatory Proposal. 2012-13 was the third year of Ergon Energy's current regulatory control period and represents the most recent financial year for which audited regulatory accounts were available at the time the operating expenditure forecasts were prepared.

Establishing Functional Areas for forecasting purposes

Ergon Energy has mapped our revealed costs from our audited 2012-13 financial data to groupings called 'Functional Areas' for the purposes of our base year data. For BST forecasting purposes, Ergon Energy identified the following Functional Areas that need to be mapped:

- direct Standard Control Services operating expenditure and Alternative Control Services operating expenditure
- overhead activities that are fully or partially attributed to direct Standard Control Services or Alternative Control Services activities.

Some Functional Areas are not included in the BST methodology and instead are subject to bottom up forecast (see Section 5.4).

[79] This represents the adjusted forecast following allocation of overheads in accordance with the CAM.

Adjustments to the base year for forecasting purposes

Adjustments to the 2012-13 audited operating expenditure numbers have been made to remove expenditure incurred in the base year that related to specific one-off or unusual events. In our *Opex Forecast Summary* document we detail the types of changes made. Examples include:

- movements in provisions consistent with the AER Guideline
- one-off adjustments to the base year revealed costs, such as forced maintenance associated with Cyclone Oswald and efficiencies likely to be achieved through improved understanding of asset condition and degradation and vegetation management.

Targeted further reduction in overhead costs

In seeking to address the long term interests of consumers to achieve further sustainable price reductions, Ergon Energy has proposed a further top down adjustment of 15% to be applied to all overhead cost Functional Areas except Fleet, ICT, and IT Asset Charges in our 2012-13 base year operational overhead costs, coupled with a broad based 1% productivity adjustment going forward. The rationale supporting this adjustment is detailed in our supporting document, *Best Possible Price.*[80]

Non-recurrent expenditure and step changes

We have incorporated areas of expenditure which were not captured in the base year but which are required, either in a certain year within the regulatory control period (non-recurrent expenditure) or on an ongoing basis (step changes in expenditure). Examples of areas of non-recurrent expenditure and step changes in expenditure include:

- additional demand management operating expenditure requirements aimed at deferring future capital expenditure but which were not included in the base year
- changes to the regulatory treatment of current period TUOS charges which are now required to be included as operating expenditure
- increases in ICT support costs due to the introduction of new systems.

Our supporting document *06.01.04 – Step Changes for Operating Costs* provides further information on step changes.

Rate of change factors

Ergon Energy's methodology trends the base year expenditure by applying a rate of change to each Functional Area on an annual basis comprised of:

- output growth
- real price growth
- productivity growth.

The change factors that Ergon Energy has applied were developed with reference to the relevant requirements of the NER with respect to realistic expectations of demand and recent AER determinations for other NSPs.

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[80] *0A.01.02 – Ergon Energy's Journey to the Best Possible Price.*

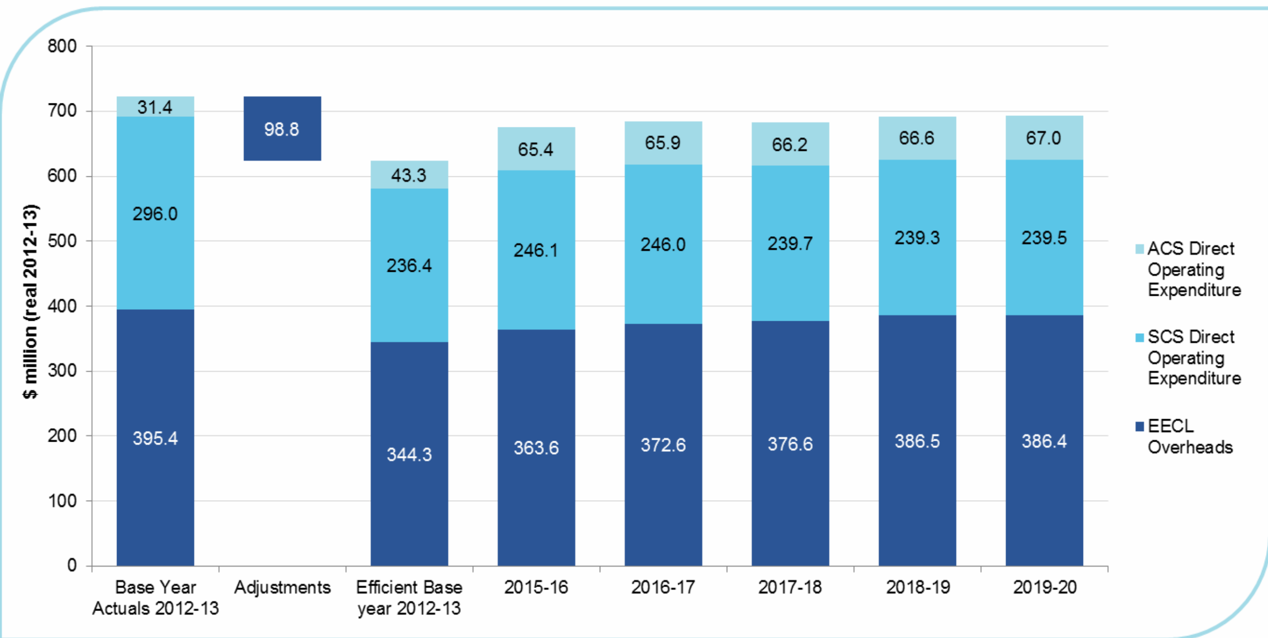
Detailed analysis supporting the basis for our rate of change factors is provided in the following documents supporting this appendix of the Regulatory Proposal:

- *Opex Forecast Summary* document – calculation of network and customer growth, and the productivity growth rate
- supporting document *06.02.02 – Jacobs: Cost Escalation Factors 2015-20.*

Allocation of forecasts according to the Cost Allocation Method

Figure 12 below shows the impact of the BST when applied to all Functional Areas, including Alternative Control Services direct operating expenditure and overhead cost pools.

Figure 12: Total forecast overhead using BST approach



Ergon Energy's CAM sets out how the Ergon Energy Group attributes costs to, or allocates costs between, the regulated distribution services and unregulated services provided by the Ergon Energy Group. Ergon Energy applies our CAM to prepare forecast operating expenditure to be submitted to the AER in accordance with clause 6.5.6 of the NER.

The process for the allocation of overhead costs to distribution services is as follows:

1. Allocation of overhead costs between the regulated distribution services provided by Ergon Energy and each of the unregulated services provided by the Ergon Energy Group.
2. For the costs allocated to the regulated distribution services provided by Ergon Energy, further allocation of the costs between regulated operating expenditure and regulated capital expenditure.
3. Calculation of the Shared Cost Percentage Rate for each of regulated operating expenditure and regulated capital expenditure. The Shared Cost Percentage Rate is the proportion of shared costs for a particular budgeted operating expenditure activity over the total budgeted operating expenditure.
4. Application of the Shared Cost Percentage Rate to direct operating expenditure and direct capital expenditure.

5.4 Use of bottom-up forecasting approach where BST is not appropriate

While the AER's Guideline appears to prefer the use of a BST methodology for operating expenditure, Ergon Energy has applied a bottom-up forecasting method for Functional Areas that are materially affected by scope changes, or are considered to be non-recurrent in nature. Ergon Energy considers that it would be inappropriate to forecast costs of this nature using a trend escalator.

The following Functional Areas were forecast using a bottom-up approach:

- Chumvale
- Powerlink
- ICT
- parametric insurance
- debt raising costs
- Demand Management Innovation Allowance.

Chumvale

"Chumvale" refers to the substation on the unregulated 220kV network which services the Cloncurry Township. Under clause 11.39 of the NER, the charges levied on Ergon Energy for the use of this line are treated as 'designated pricing proposal charges'. It is expected that the cost is passed through as TUOS charges via Ergon Energy's annual Pricing Proposal. The cost is not included in the operating expenditure building block, and is not reflected in the base year operating expenditure.

The transitional rules set out in Chapter 11 of the NER only apply for the current regulatory control period, which means that the cost will need to be included in the forecast operating expenditure used to determine the ARR for the next regulatory control period. The AER has already acknowledged that Ergon Energy may include these costs in our Regulatory Proposal for the next regulatory control period.[81]

This is considered to be a bottom up item as the cost was not part of the operating expenditure for the base year in the BST. Further, it is a recurrent operating cost for the next regulatory control period of which the cost is known with certainty and the annual charge is not trended.

The forecast charges for the use of the 220kV line are $0.80 million (in $2012-13) from 2015-16.

Powerlink

"Powerlink" refers to the cost for entry and exit services charged by Powerlink at four non-prescribed connection points – Queensland Nickel, Stoney Creek, Kings Creek and Oakey Town.[82] Under transitional clause 11.39 of the NER, the charges levied on Ergon Energy are treated as 'designated pricing proposal charges' in the current regulatory control period. It is expected that the cost is passed through to customers as TUOS charges via Ergon Energy's annual Pricing Proposal. The cost is not included in the operating expenditure building block, and is not reflected in the base year operating expenditure.

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[81] AER (2014a), Ibid.
[82] There will only be three non-prescribed connection points in the next regulatory control period.

The charges for the entry and exit services for the non-prescribed connection points are treated as adjustments to the base operating expenditure for 2015-16 and 2016-17, as these costs will be incurred as operating expenditure in those two years only. The connection points are expected to become regulated from 1 July 2017 (subject to AER approval), which means that the charges for the entry and exit services provided at those connection points will be included in the TUOS charges for the final three years of the next regulatory control period.

The forecast charges for these entry and exit services are $11.8 million (in $2012-13) for 2015-16 and 2016-17.

ICT operating expenditure

The scope of the ICT investments over the next regulatory control period will include all software, data, computer and communications hardware required to provide systems supporting business functions and processes in support of Ergon Energy's services.

Ergon Energy relies on a service level agreement with SPARQ for most of our ICT requirements. Ergon Energy accounts for the cost of SPARQ's service level agreement as operating expenditure. Because this will incorporate both ICT operating and investing activities, operating expenditure forecasts for the asset service fee and non capital project costs of ICT will have a different profile to other recurrent expenditure items and therefore will not adopt the common escalators.

Ergon Energy has identified that the BST forecasting method is considered not suitable for forecasting the following types of ICT operational expenditure:

- ICT Non Capital Project Costs, which consist of non-recurrent major investments that do not meet the capital definitions under relevant accounting standards
- ICT Asset Service Fees (depreciation and finance costs recovered by SPARQ through charges to Ergon Energy), which represent operational expenses resulting from non-recurrent major investments capitalised in SPARQ.

Ergon Energy has adopted a bottom-up approach to the calculation of these costs, which are represented in Table 39.

Table 39: SPARQ non capital project costs and asset service fees, real $2012-13 million

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Non Capital Project Costs	3.56	6.27	5.81	3.65	1.50	20.79
Asset service fees	30.43	34.08	36.33	43.26	43.07	187.19

The SPARQ service charge will also be subject to the corporate overhead allocation process in accordance with the CAM.

Parametric insurance

Ergon Energy's approach in the regulatory control period 2010-15 to funding damage or loss of electricity network assets caused by typical storms and low category rated cyclones is through a combination of the operating expenditure (forced maintenance) and capital expenditure (asset replacement), allowances set by the AER. For large storms and high category rated cyclones, Ergon Energy may fund the cost by using the cost pass through provisions in the NER.

As an alternative to historic arrangements, Ergon Energy has worked with our insurance broker, to develop options for covering the cost of damage or loss of electricity network assets caused by storms and cyclones.

Ergon Energy has identified a parametric insurance product that will address applicable NER requirements and provide an efficient and prudent level of insurance cover to mitigate the financial risks Ergon Energy faces in relation to damage caused to our electricity network by large scale storm and cyclone events. These costs have been incorporated within our operating expenditure forecast.

Detailed analysis supporting the cost and justifying parametric insurance as a cost in our operating expenditure forecast is provided in Section 2.10 of the *Opex Forecast Summary* document.

Debt raising costs

Ergon Energy is proposing a debt raising allowance to compensate for the transactional costs that a prudent service provider acting efficiently incurs while raising debt. Ergon Energy engaged Incenta Economic Consulting (Incenta) to undertake an independent review of the benchmark efficient costs for Ergon Energy, recognising the development of regulatory recognition of debt raising costs and its components.

Further information summarising Incenta's findings can be found in Section 2.11 of our *Opex Forecast Summary* document. The full Incenta Economic Consulting Report can be found in our supporting document *06.02.04 – Ergon Energy Debt Transaction Costs 30 June 2014*.

The Distribution Network Pricing Arrangements Rule change request,[83] if successful, will also impose a regulatory constraint on Ergon Energy requiring the estimate of the return on debt to be completed by 31 December each year to enable pricing proposals to be submitted to the AER earlier than is currently required. By extension, this will necessitate DNSPs also having to complete their financing transactions prior to 31 December.

In these circumstances, Standard & Poor's requirement to refinance debt three months ahead cannot be met, as the regulatory framework will actually require DNSPs to refinance debt six months ahead (i.e. six months prior to the commencement of the next regulatory year in the regulatory control period). If this occurs, the estimate for early issuance costs provided above should be recalculated based on a six months ahead refinancing period instead of three months ahead.

Demand Management Innovation Allowance

The DMIA represents expenditure related to activities undertaken in accordance with the innovation allowance provided by the AER under the DMIS.

Costs recovered under the DMIA:

- must not be recoverable under any other jurisdictional incentive scheme
- must not be recoverable under any other state or Commonwealth Government scheme
- must not be included in forecast capital or operating expenditure approved in the distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

For revenue modelling purposes, Ergon Energy has included the $5 million DMIA as a bottom-up line item in our operating expenditure forecast. To avoid double counting of the allowance, no further adjustments have been made to the revenue model.

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[83] AEMC (2014). *Draft Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 28 August 2014.

6 Outcomes for customers

Table 40 summarises the operating expenditure forecast comprised on both the BST and bottom-up forecasts.

Table 40: Proposed operating expenditure build up under the BST ($m)

Standard Control Service (SCS) operating expenditure forecast	2012-13	2012-13 Adjusted	2015-16	2016-17	2017-18	2018-19	2019-20
Base year operating expenditure	261.16	260.23	240.78	226.34	226.55	226.50	226.43
Change factors							
Output growth			3.52	2.47	2.22	2.19	2.78
Productivity growth			(2.41)	(2.26)	(2.27)	(2.27)	(2.26)
Step changes[1]							
Non-network alternatives			4.00				
Embedded generation			(0.50)				
Non-recurrent[1]							
Non-recurrent operating expenditure adjustments		(24.75)	(19.05)				
Total BST operating expenditure	**261.16**	**235.48**	**226.34**	**226.55**	**226.50**	**226.43**	**226.94**
Bottom-up adjustments[1]							
DMIA		0.88	0.93	0.90	0.88	0.86	0.84
Parametric insurance		-	12.03	11.73	11.44	11.15	10.87
Powerlink		-	5.88	5.92	-	-	-
Chumvale		-	0.83	0.82	0.81	0.80	0.79
Operating expenditure before escalation	**261.16**	**236.36**	**246.02**	**245.92**	**239.64**	**239.24**	**239.44**
Real price growth	-	-	20.21	23.22	25.95	29.04	32.26
Overheads ($2014-15)	85.11	80.82	83.37	86.91	98.02	104.62	107.25
Total SCS operating expenditure forecast ($2014-15)	**346.27**	**317.18**	**349.60**	**356.05**	**363.61**	**372.90**	**378.95**
Debt raising costs	-	-	11.57	11.97	12.30	12.55	12.82
Total SCS operating expenditure forecast including debt raising costs	**346.27**	**317.18**	**361.17**	**368.02**	**375.91**	**385.45**	**391.77**

Note 1: Adjustments that are made to overheads are factored into the overheads line item. The full effect of adjustments to overheads throughout the document will not be visible in Standard Control Service only tables and are allocated consistent with the CAM.

7 Recognising the AER's Expenditure Forecast Assessment Guideline

The AER's Expenditure Forecast Assessment Guideline sets out how the AER expects to assess a business' Regulatory Proposal and how it determines a substitute forecast when required. The AER's Guideline is not binding and must be departed from (with reason) if it will result in a decision or outcome inconsistent with the NER or the NEL.

In its information paper, the AER notes that its assessment techniques are underpinned by a nationally consistent framework for network businesses to report. The Guideline explains what data the AER needs and why. The AER notes the following assessments may be used:

- economic benchmarking – productivity measures used to assess a business' efficiency overall
- category level analysis – comparing how well a business delivers services for a range of individual activities and functions, including over time and with its peers
- predictive modelling – statistical analysis to predict future spending needs, currently used to assess the need for upgrades or replacement as demand changes (augmentation capital expenditure, or augex) and expenditure needed to replace aging assets (replacement capital expenditure, or repex)
- trend analysis – forecasting future expenditure based on historical information, particularly useful for operating expenditure where spending is largely recurrent and predictable
- cost benefit analysis – assessing whether the business has chosen spending options that reflect the best value for money
- project review – a detailed engineering examination of specific proposed projects or programs.

The AER's Guideline contains a great deal of prescription around different types of tools or techniques for assessing and/or substituting operating expenditure forecasts. However, it is not clear to us exactly how the AER will apply the Guideline to Ergon Energy and what information and models it will rely upon. This is particularly the case in the absence of the AER's annual benchmarking report.

We asked Huegin Consulting to consider the AER's Expenditure Forecast Assessment Guideline and assist us in whether the basis of our methodology and inputs would be consistent with a reasonable assessment of the forecasts consistent with the Guideline.

Huegin's report[84] notes significant limitations with the AER's models and underlying data. It recommended that low weight should be given to these techniques when determining the reasonableness of a forecast or substituting for another forecast.

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[84] Huegin (2014), *Productivity change in the context of the AER Guideline.* Refer to *06.01.03 – Huegin Productivity Analysis.*

Their conclusions, when considering Ergon Energy's approach in the context of the Guideline are as follows:

> "The Ergon Energy assumption of productivity improvement in their base-step-trend model for future opex lies within the range of outcomes possible from the economic benchmarking. Whilst this is not a basis to accept the Ergon Energy assumption, given the limitations of the modelling outlined in this report, there is certainly no basis to reject the assumption based on the modelling techniques within the AER's Expenditure Forecast Assessment Guideline."[85]

8 Meeting Rule requirements

The NER places obligations on Ergon Energy to provide information to assist the AER make a decision on the total operating expenditure for the period. We believe there is sufficient evidence in this Regulatory Proposal and supporting documents to satisfy the AER that our proposed operating expenditure reflects the operating expenditure criteria, subject to final adjustment of escalation factors and debt raising costs closer to the time of the Distribution Determination.

Our supporting document *06.01.05 – Meeting Rule Requirements for Expenditure Forecasts* provides substantial detail on:

- why the forecasts enable Ergon Energy to achieve each of the operating expenditure objectives
- why Ergon Energy believes there is sufficient evidence to satisfy the AER that the forecasts meet the operating expenditure criteria.

8.1 Plans, policies and strategies

We have in place a suite of proven and well established plans, policies and strategies which are used to guide and support the business' daily operations. These documents have been relied upon in the development of this Regulatory Proposal and associated expenditure forecasts.

We firmly believe that, taken together, these documents support the development of operating expenditure forecasts that will achieve all of the operating expenditure objectives in the next regulatory control period. This is because these plans, policies and strategies ensure that our operating expenditure forecasts have regard for the:

- number, age and condition of each class of distribution asset that is needed to deliver our Standard Control Services
- need to comply with relevant regulatory obligations
- service standards that we must deliver.

Our supporting document *07.09.17 – Our Capital Governance and our plans, policies and procedures* outlines Ergon Energy's framework for the development and prioritisation of our capital and operational expenditure investment program to meet the expenditure objectives, criteria and factors set out in the NER, supported by a hierarchy of governance bodies and approval authorities

[85] *06.01.03 – Huegin Productivity Analysis*, p13.

and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- *01.01.01 – Legislative and Regulatory Obligations and Policy Requirements*
- response to the RIN, Templates 7.1 and 7.3.

9 Supporting information

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
Ergon Energy's Journey to the Best Possible Price	0A.01.02	Best Possible Price
Informing our plans, Our Engagement Program	0A.01.04	Engagement Program
Operating Forecast Expenditure Summary Document	06.01.01	Opex forecast summary
System Related Operating Expenditure Forecasting Summary	06.01.02	System related operating expenditure summary
Step Changes for Operating Costs	06.01.04	Step changes
Meeting Rule Requirements for Expenditure Forecasts	06.01.05	Meeting the Rules requirements
Certification of reasonableness – expenditure forecast assumptions	06.01.06	Certification of reasonableness – expenditure forecast assumptions
Jacobs: Cost Escalation Factors 2015-20	06.02.02	Cost Escalation Factors 2015-20 SKM
Ergon Energy Debt Transaction Costs 30 June 2014	06.02.04	Incenta Report Debt Transaction Costs
Our Capital Governance and our plans, policies and procedures	07.09.17	Governance, Plans, Policies and Procedures