Appendix A: Operating expenditure forecasts for Standard Control Services

Introduction and summary of changes

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 base year has been updated to 2013-14. We have also changed our approach to making adjustments to the base year.

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 is devastated by a major cyclone.

Appendix A: Operating expenditure forecast for Standard Control Services

1 Overview

Our revised forecast of operating expenditure requirements is substantially lower than our actual and estimated spend in the regulatory control period 2010-15 and lower than our October Regulatory Proposal. It incorporates efficiencies in vegetation management, line inspection and pole defect management. We will also continue to use non-network alternatives where possible to avoid employing costly capital solutions in line with NER requirements.

We outline in a number of supporting documents the reductions we have made to recurrent activity. This has led to us providing better price outcomes for customers in the regulatory control period 2015-20. We are also confident that we can leverage the initiatives and technologies we have been implementing recently and these will deliver even better outcomes in the next five years. Rather than seek to share these benefits over time through the traditional incentive mechanism arrangements, we have sought to deliver these through a reduction in overhead expenditure allowance in the first year of the period. We have done this in consideration of customer preferences for price relief now as well as other influencing factors.

There will be increases in some areas of expenditure, but we believe they represent the following:

- a need to comply with new regulatory obligations
- a trade-off against returns though the RAB for expenditure already incurred
- appropriate capital/operating expenditure trade-offs, and/or
- a trade-off against volatility in expenditure and prices when Ergon Energy's network is adversely affected by cyclone damage.

In summary, our forecasts include a new form of insurance cover given our unique exposure to extreme wind-generated events like Cyclone Yasi. We have also updated our forecasts to incorporate the anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the Minimalist Transitioning Approach reaches an end.

The total operating expenditure Ergon Energy requires to meet the operating expenditure objectives in the regulatory control period 2015-20 is provided below.

Table 37: Forecast operating expenditure, 2015-20

$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Operating expenditure	334,020	346,600	358,180	365,890	374,320	**1,779,010**

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 regulatory control period 2010-15 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 regulatory control period 2015-20
- 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.

Appendix E separately details our proposal in relation to the need for the AER to apply a transition path in the scenario where the AER rejects our proposal and substitutes it with a much lower forecast.

2 Components of our operating expenditure requirement

2.1 Direct operating expenditure

The components of our direct operating expenditure program are illustrated in Figure 8.

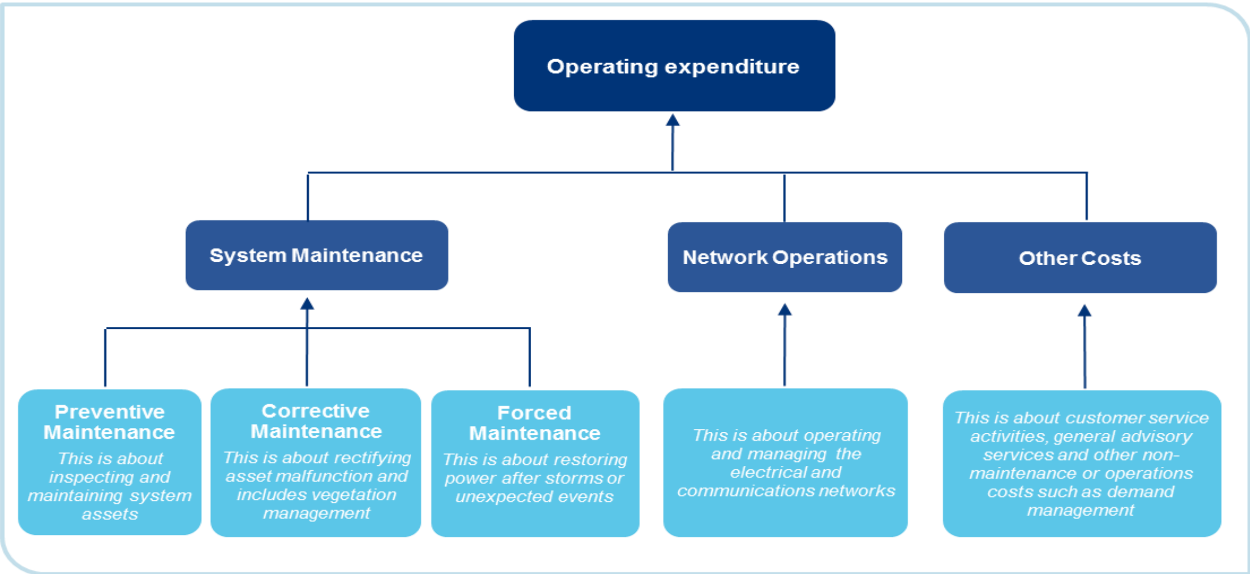

Figure 8: Components of our operating expenditure requirement

Ergon Energy's direct operating expenditure requirements 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.

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.

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 regulatory control period 2010-15, 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 regulatory control period 2015-20 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 alternative solutions, as a tactical response to network problems – primarily where growing customer peak demand requirements create the need to expand network capacity.

Table 38 shows that our total operating expenditure over the regulatory control period 2015-20 is expected to be 2.31% lower than our October Regulatory Proposal.

Table 38: Comparison between October and revised Regulatory Proposals, operating expenditure, 2015-20

$'000 (real 2014-15)	October Regulatory Proposal	Revised Regulatory Proposal	% difference
Total forecast operating expenditure	1,821,130	1,779,010	(2.31%)

Further information on the forecast expenditure for each category is provided in the supporting document *06.01.01 – (Revised) Operating Forecast Expenditure Summary Document (Opex Forecast 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 – (Revised) 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 period performance

Table 39 and Table 40 provide Ergon Energy's actual operating expenditure for each year of the previous two regulatory control periods, disaggregated by program of expenditure.[84] Information provided for both regulatory control periods are based on the CAM applying in the regulatory control period 2010-15. Expenditure associated with FiT payments has been excluded from the prior period performances. These costs do not form part of our Direct Control Services from 1 July 2015.

Table 39: 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**

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

Table 40: Operating expenditure by category, 2010-15

$'000 (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15 (estimate)	Total
Network Operating Costs						
Network Operating Costs	*36,168*	*35,075*	*34,775*	*35,241*	*33,997*	*175,257*
Network Maintenance Costs						
Preventive Maintenance	83,105	103,534	92,096	73,440	72,449	424,624
Corrective Maintenance	117,323	147,271	113,905	107,694	103,592	589,784
Forced Maintenance	105,368	67,059	73,115	69,413	66,652	381,607
Subtotal	*305,795*	*317,864*	*279,116*	*250,547*	*242,693*	*1,396,015*
Other Costs						
Meter Reading	12,985	14,282	13,330	13,195	14,186	67,978
Customer Services	20,980	27,338	32,389	26,125	31,580	138,413
Other Operating Costs	40,654	47,193	5,073	35,056	36,001	163,978
Subtotal	*74,619*	*88,813*	*50,793*	*74,377*	*81,767*	*370,368*
Total actual operating expenditure	**416,582**	**441,752**	**364,683**	**360,165**	**358,457**	**1,941,640**

As illustrated in Figure 9, Ergon Energy expects to deliver an operating program less than the AER approved allowance over the regulatory control period 2010-15.

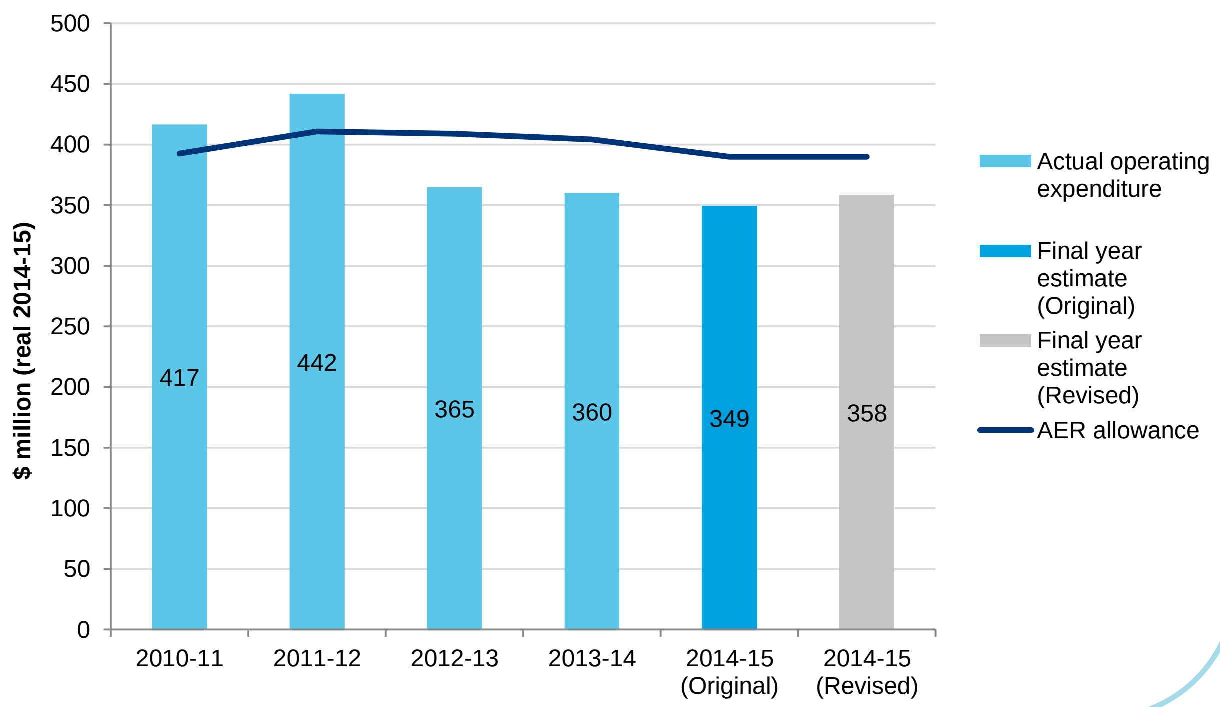

Figure 9: Comparison of operating expenditure, 2010-15

3.3 Key drivers of expenditure and outcomes in the previous 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.

Cyclone Yasi also impacted other programs of work. This combined with other major weather events (flooding and impacts from ex-Cyclone Oswald, and Cyclone Marcia) 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 9 above).

Our supporting document, *06.01.02 – (Revised) System Related Operating Expenditure Summary),* 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)*,[85] 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
- reducing total expenditure spend by over 20% against the regulatory allowance
- contracting business headcount substantially

[85] *0A.01.02 – (Revised) Ergon Energy's Journey to the Best Possible Price*.

- 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 regulatory control period 2010-15 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).

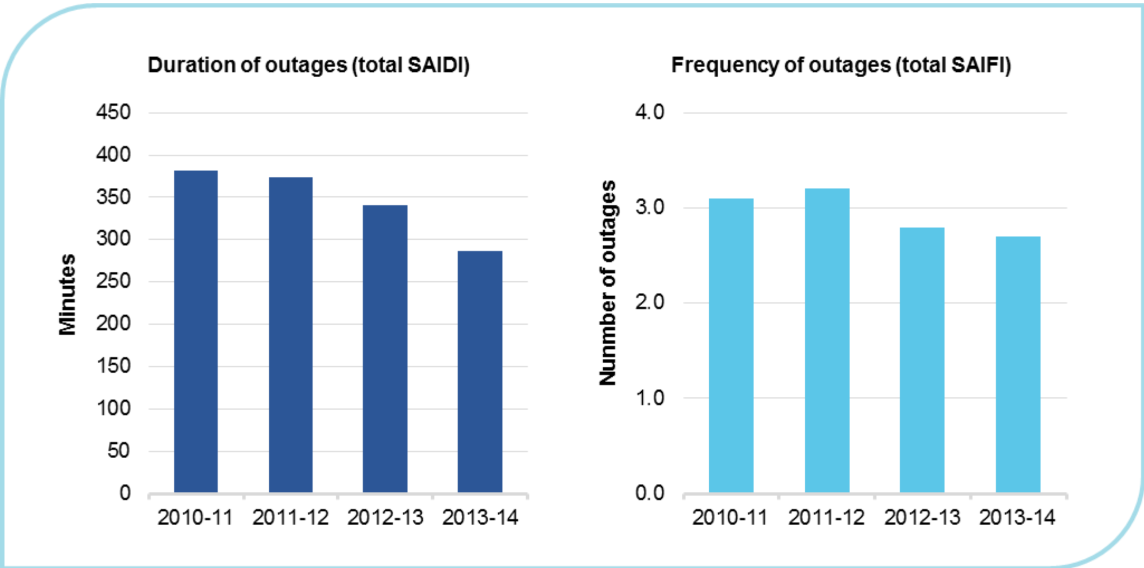

Figure 10: SAIDI and SAIFI, 2010-11 to 2013-14

Our customer engagement research is showing our customers are now generally satisfied with the level of supply they receive.[86] 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.

4 Factors influencing forecasts in 2015-20

This section considers the factors and challenges driving operating expenditure in the regulatory control period 2015-20 and the way in which we propose to respond.

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

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 regulatory control period 2015-20.

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 has continued until the end of the regulatory control period 2010-15. The changes will provide Ergon Energy with a further opportunity to review the way we will meet customers' 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 customer expectations to identify where further efficiencies can be achieved.

Our *Best Possible Price* document outlines how, in addition to reductions already made in the regulatory control period 2010-15, Ergon Energy has incorporated further reductions to our forecast operating expenditure requirement to deliver lower price outcomes for customers. As discussed in detail in the forecast methodology in Section 5, this adjustment takes the form of an upfront one-off adjustment to the operating expenditure required in the first year of our regulatory control period 2015-20.

Bringing forward future benefits for customers

The AER has stated that our decision to reduce forecast operating expenditure represents acknowledgement that expenditure in the base year is inefficient. This is a mischaracterisation of our forecasts and the incentive framework within which we operate. 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 customers, 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 customers in terms of making sustainable price reductions and strikes an appropriate balance with the incentives Ergon Energy will experience under the EBSS. Feedback from customers and other key stakeholders (including the CCP) also indicates there is support for energy companies to deliver the best possible price to customers as soon as possible, and not unduly defer or delay the sharing of benefits.[87]

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 customers, we are cognisant of our customers' 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 regulatory control period 2015-20 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.

AER benchmarking report

The AER published its annual benchmarking report on 27 November 2014.[88] Due to the timing of its release, Ergon Energy was unable to examine the report and consider the findings in developing our initial forecasts. Since then, we have examined the AER's approach to benchmarking and made submissions to the AER through the NSW and Queensland regulatory determination processes.

5 Forecast methodology

In the previous sections we identified the forecast operating expenditure requirements for the regulatory control period 2015-20 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,[89] 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,[90] setting out our approach for forecasting expenditure for the regulatory control period 2015-20, including our approach to operating expenditure. This section should therefore be read in conjunction with these documents.

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[87] *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, http://www.aer.gov.au/sites/default/files/Consumer%20Challenge%20Sub-Panel%202%20%28Hugh%20Grant%29%20-%20Presentation%20to%20Qld%20consumer%20forum%20-%208%20August%202014.pdf; 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/sites/default/files/CCP%20report%20prepared%20for%20AER%20Board%20-%20Rate%20of%20Return.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.

[88] AER (2014), *Electricity distribution network service providers, Annual benchmarking report*, November 2014.

[89] 06.01.01

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

5.1 Key assumptions

Table 41 outlines the key assumptions underpinning our operating expenditure forecasts for the regulatory control period 2015-20, consistent with NER requirements.[91] Except for the change to the base year, there have been no material changes since our October Regulatory Proposal. In June 2015, the directors of Ergon Energy reviewed the key assumptions and confirmed their continued application for this revised Regulatory Proposal.

Table 41: 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.
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 2013-14 audited financial statements are an appropriate starting point for the establishment of an efficient base year.	The 2013-14 financial year represented the most recent audited financial statements available for the purpose of forecasting for the regulatory control period 2015-20 to meet the timetable for submission to the AER on 3 July 2015 and the most logical representative base year.
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.
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.[92] 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.

[91] 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.*

[92] *06.02.02 – Jacobs: Cost Escalation Factors 2015-20* and *06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20*.

Assumption	Application
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 regulatory control period 2010-15. We have attempted to reconcile our approach with the AER's Expenditure Forecast Assessment Guideline,[93] 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*

Ergon Energy undertakes recurrent activity across a number of our various business units. Relevant to the regulation of Standard Control Services, Ergon Energy broadly categorises our recurrent activity into:

- direct (recurrent) costs for Standard Control Services comprising the key network service elements of maintenance, operations and customer service
- shared (support) costs, often referred to as overhead activities (such as the Finance function), which are aggregated and spread across all of Ergon Energy's direct expenditure including:
  - direct operating expenditure
  - direct capital expenditure
  - in some circumstances across direct costs for Alternative Control Services, unregulated and unclassified services.

The allocation of the latter category is based on the AER's approved approach for allocation in the CAM. Because the AER has approved allocations in this manner, aggregate Standard Control Service base year costs cannot be trended in a linear manner. This is because the overhead portion of the Standard Control Service base year will vary based on the steps outlined above, even if the overhead cost item itself trends in a linear manner.

The AER's Expenditure Forecast Assessment Guideline and Preliminary Determination appear to ignore the CAM approved by the AER. Instead, it applies the Expenditure Forecast Assessment

[93] Refer to http://www.aer.gov.au/node/18864#.

Guideline which assumes the combination of direct and allocated overhead expenditure for Standard Control Services trend in a linear fashion. However, this cannot be done without changing the CAM. Given the provisions of clause 6.5.6(b)(2) of the NER take primacy over the AER's preferred method in the Expenditure Forecast Assessment Guideline, our proposal has necessarily departed from the approach the AER has taken in the Preliminary Determination.

Ergon Energy does not believe that the Guidelines or the AER's considerations give it prerogative to depart from arrangements the AER itself dictated when it approved Ergon Energy's CAM. In other words, the AER cannot be satisfied of a total operating expenditure forecast unless it has considered the arrangements under an approved CAM and has applied them appropriately. The AER cannot abrogate this responsibility merely because it has considered other relevant factors.

Ergon Energy's approach to forecasting operating expenditure remains consistent with what we proposed in October 2014. However, we have simplified our modelling arrangements. We have also attempted to simplify our operating expenditure requirement without substantially amending our methodology.

Figure 11 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.

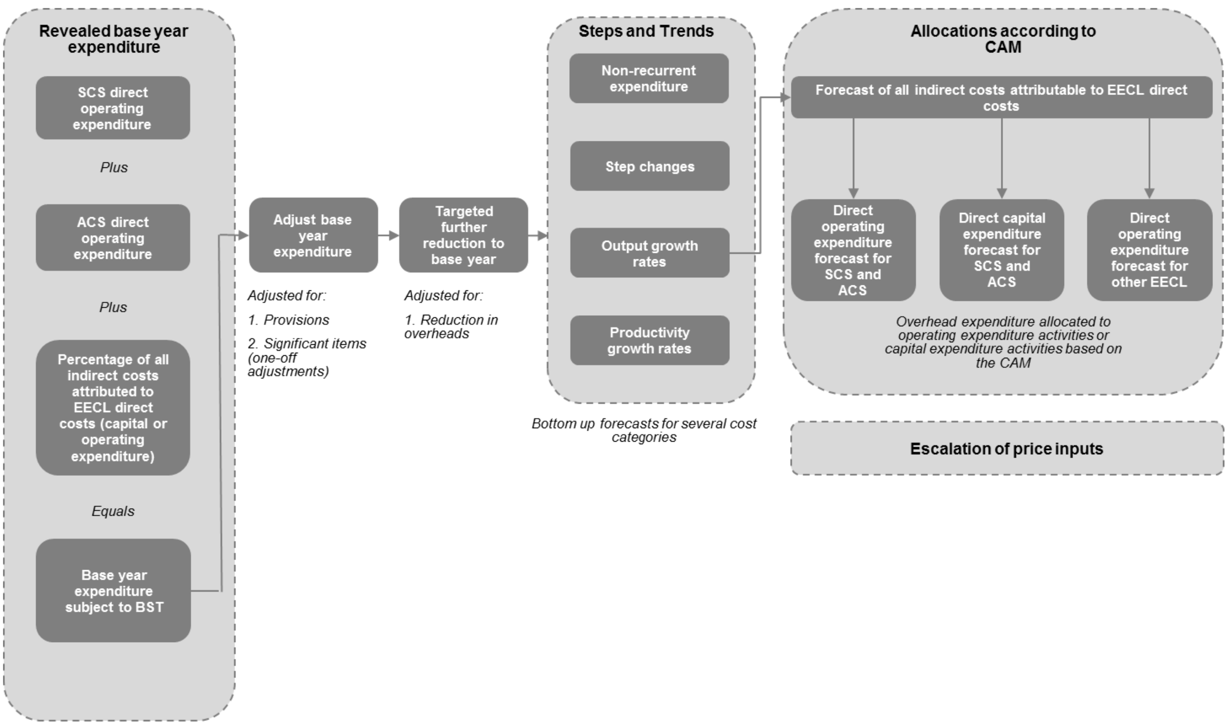

Figure 11: BST methodology

5.3 Base step trend forecasting approach

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

- Step 1: Selecting a base year and identifying the reported Standard Control Service operating expenditure (inclusive of the overhead allocation to these costs) for that base year

- Step 2: Identifying separately the components of the reported Standard Control Service operating expenditure in the base year:
    - The Standard Control Services direct operating expenditure costs inherent within the reported base year
    - The indirect costs allocated to the Standard Control Services direct operating expenditure costs which have been applied in accordance with the AER's CAM approved for Ergon Energy
- Step 3: Preparing both direct operating expenditure and indirect (overhead) costs for BST forecasting. This involves:
    - Identifying the Functional Areas implicit within the costs forecasts
    - Aggregating overhead costs attributable to Standard Control Services with any other overhead cost that has been allocated to Ergon Energy's regulated activities (i.e. Standard Control Services capital expenditure, public lighting capital and operating expenditure, metering capital and operating expenditure, and other Alternative Control Service capital and operating expenditure)
- Step 4: For both direct operating expenditure and overhead costs, making necessary adjustments to base year costs so they can be used for forecasting. This includes:
    - adjustments for movements in provisions
    - one-off adjustments to the base year
    - other adjustments due to service reclassification
- Step 5: For both direct and overhead costs, identifying and applying any step changes or non-recurrent operating expenditure
- Step 6: For both direct and overhead costs, applying a rate of change to reflect changes in expenditure consistent with workload drivers Step 7: Applying relevant price escalation to both the direct and overhead component of each Functional Area cost
- Step 8: Allocating overhead costs back to each of the Functional Area direct costs in accordance with the CAM.

Each of these steps is briefly described below. More detailed information is available in the *Opex Forecast Summary* document.

Steps 1 and 2: Base year 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 2013-14 financial accounts as the base year for the purposes of forecasting operating expenditure for the Regulatory Proposal. 2013-14 was the fourth year of Ergon Energy's regulatory control period 2010-15 and represents the most recent financial year for which audited regulatory accounts were available at the time the operating expenditure forecasts were prepared.

This is consistent with the AER's expectations[94] and is appropriate given precedents to use the most up-to-date information.

Step 3: Identifying the components of the base year costs

Ergon Energy has mapped our revealed costs from our audited 2013-14 financial data to groupings called 'Functional Area's for the purposes of our base year data. These Functional Areas are further mapped and combined into category level data for aggregate level reporting.

Some of the Functional Areas are, by nature, overhead activities. Where a Functional Area is an overhead cost, the overheads are aggregated and spread across all classifications, including Standard Control Services, Alternative Control Services, unregulated services and unclassified services.

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.

The reported 2013-14 operating expenditure for Standard Controls Services includes both a direct operating expenditure portion and an allocation for overheads. The overhead allocation is determined in accordance with the CAM under a four step process.

Because the AER has approved allocations in this manner, the reported Standard Control Service operating expenditure base year costs cannot be trended in a linear manner. This is because the overhead portion of the Standard Control Service operating expenditure base year will vary based on the four step process, even if the overhead costs (as an aggregate item) trend in a linear manner.

Because of this, Ergon Energy needs to:

1. Separate our base year cost into both direct and indirect portions.
2. Aggregate the indirect portion with other Ergon Energy overhead costs attributable to all activities.
3. Trend the direct and indirect portions separately.
4. Reallocate the indirect portion back to direct costs in accordance with the allocation process.

Step 4: Adjustments to the reported base year costs

Adjustments to the 2013-14 audited operating expenditure numbers have been made to remove expenditure incurred in the base year that does not support a recurrent cost for the purposes of forecasting. The adjustments may relate to specific one-off or unusual events (e.g. changes in service classification). Consistent with the Expenditure Forecast Assessment Guideline, Ergon Energy has also made adjustments to the base year operating expenditure to account for any movements in provisions. The removal of these items creates an efficient starting point or 'efficient base year' from which to commence the operating expenditure forecast. Our *Opex Forecast Summary* document details these adjustments.

[94] AER (2013), *Email to Energex and Ergon Energy*, 4 March 2013.

Step 5: Step changes and bottom up adjustments

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 or on an ongoing basis. The step changes and other bottom up adjustments we have proposed relate to:

- the Market Transaction Centre. Base year expenditure does not include anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the Minimalist Transitioning Approach reaches an end
- parametric insurance. Base year expenditure does not include expenditure relating to the efficient and prudent level of insurance required 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. This is because historically there has been a lack of available and efficiently priced insurance cover in the insurance markets
- ICT Asset Service Fee. Base year expenditure does not include Asset Service Fee expenditure required in the regulatory control period 2015-20 for ICT capital works that were approved in the previous period but were delivered after the 2013-14 year
- ICT Operating Fee (to overhead costs). Ergon Energy has included increased operating expenditure for a range of systems required to operate in a fully contestable market.

Our supporting document *06.01.04 – (Revised) Step Changes for Operating Costs* provides further information on step changes and non-recurrent expenditure.

Step 6: Trending base year expenditure for output growth

The AER recognises that distribution networks grow in size, and therefore face a corresponding increase in the cost associated with operating and maintaining the network. The annual growth rate of the network is determined with reference to network growth drivers that are considered to approximate the resultant growth in operating expenditure.

Ergon Energy has calculated two growth drivers:

- customer growth
- network growth.

In summary, Ergon Energy has not changed our approach to calculating workload drivers from our October Regulatory Proposal. However, growth factors have changed slightly based on updated information.

Ergon Energy has also incorporated a reduction in forecasts equivalent to 10% of our 2013-14 base year operating expenditure costs.[95] Additionally, we have applied an annual reduction of 0.75% to forecasting operating expenditure.[96]

Further information, including detailed analysis supporting the basis of the above drivers and reductions, is provided in the following documents supporting this appendix of the Regulatory Proposal:

- *Opex Forecast Summary* document

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[95] Excludes ICT and fleet related costs.

[96] Excludes ICT Asset Service Fee costs.

- supporting document *06.02.02 – Jacobs: Cost Escalation Factors 2015-20*.[97]

Step 7: Escalation for cost inputs

Ergon Energy has engaged Jacobs to develop real cost escalation factors for the four cost elements identified in the chart of accounts: labour, contractors, materials and other.
Ergon Energy dissects the 2012-13 base year costs into escalator categories and uses the revealed percentage split as a basis for forecasting any increases for the regulatory control period 2015-20.

We apply a two-step process to applying price escalation to our direct and overhead costs for forecasting purposes. This involves:

- de-escalating all of the costs in the BST model to 2012-13 dollars. This is because our capital expenditure inputs are in 2012-13 dollars. We convert all expenditure to common dollar un-escalated inputs in order to ensure allocation of overheads and price escalation occurs on a common dollar basis
- escalating all inputs (which are now in 2012-13 dollars) to 2014-15 dollars, using the relevant price escalators.

Step 8: Forecast and allocation of overhead costs

The above steps provide a forecast for both direct operating expenditure and the Ergon Energy regulated overhead portion of the forecast. Table 42 below sets out the forecast direct operating expenditure.

Table 42: Forecast direct operating expenditure (Standard Control Services)

SCS operating expenditure forecast ($m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
RIN reported operating expenditure ($13-14)	**472.32**						
Less FiT ($13-14)	(120.08)						
Subtotal	*352.24*						
Less overheads	(114.92)						
Base year direct costs ($13-14)	**237.32**	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**
Accounting adjustments	5.08						
CAM adjustments	4.35						
Adjusted base year operating expenditure ($13-14)	**246.75**	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**
Classification changes			(30.31)				
Adjustment for future efficiencies			(1.88)	(1.80)	(1.81)	(1.81)	(1.82)
Output growth		3.98	3.48	2.77	2.44	2.34	2.93

[97] This report is supported by *06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20*.

SCS operating expenditure forecast ($m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Step changes and bottom up							
Parametric insurance			13.00				
Market Transaction Centre			5.20				
Operating expenditure before escalation ($2013-14)	**246.75**	**250.73**	**240.22**	**241.19**	**241.82**	**242.35**	**243.46**
2012-13 de-escalation amount	(7.19)	(7.30)	(7.00)	(7.02)	(7.04)	(7.05)	(7.08)
Real price growth direct operating expenditure			17.72	19.75	21.77	23.82	25.97
Overheads ($2014-15)			83.07	92.68	101.63	106.78	111.96
Total SCS operating expenditure forecast ($2014-15)		**243.43**	**334.01**	**346.59**	**358.18**	**365.89**	**374.31**

Ergon Energy has applied the BST methodology to forecast our total overhead (support) costs for the regulatory control period 2015-20. The overhead forecast is outlined in Table 43.

Table 43: Forecast overheads for Ergon Energy regulated services

Overhead forecast	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
RIN reported operating expenditure less FiT	**352.24**						
Base year direct costs	237.32						
SCS operating expenditure overhead	114.92						
Overhead applied to other non-SCS operating expenditure activities	288.46						
Base year overhead costs	**403.38**	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**
Accounting adjustments	(0.71)						
CAM adjustments	(4.35)						
Adjusted base year operating expenditure	**398.33**	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**
Classification changes							
Adjustment for future efficiencies	(32.06)	0.00	(2.54)	(2.60)	(2.62)	(2.65)	(2.67)
Output growth		5.42	5.54	6.22	5.78	5.80	5.89
Step changes and bottom up							
Asset service fee	0.00	(6.12)	4.96	7.95	5.45	6.28	5.02
IT and communications costs			5.00				

Overhead forecast	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Overheads before escalation ($2013-14)	**366.26**	**365.56**	**378.52**	**390.08**	**398.69**	**408.12**	**416.36**
2012-13 de-escalation amount	(10.67)	(11.36)	(12.62)	(14.27)	(15.94)	(17.94)	(19.98)
Total overhead forecast ($2012-13)	**355.60**	**354.20**	**365.90**	**375.81**	**382.75**	**390.18**	**396.39**
Real price growth - overheads only			25.96	35.57	45.64	57.28	70.73
Total overhead forecast ($2014-15)		**354.20**	**391.86**	**411.38**	**428.39**	**447.46**	**467.12**

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.

For overhead costs, we allocate the overheads to Standard Control Services operating expenditure using the CAM process. This allocation is shown in Figure 12.

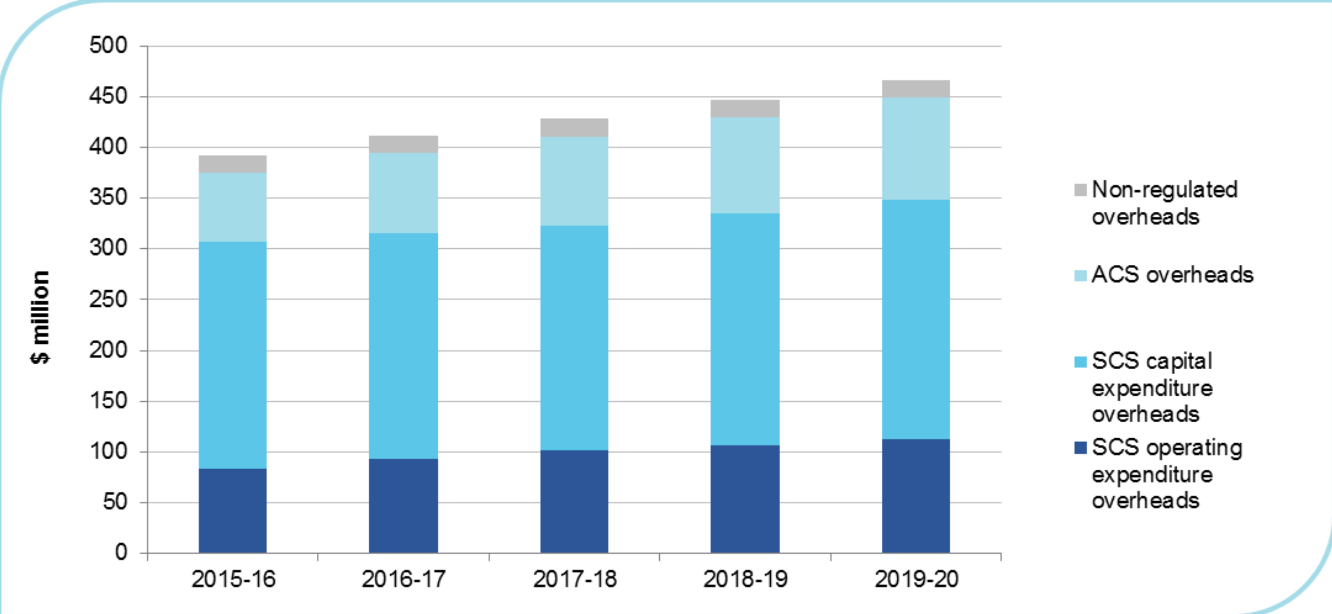

Figure 12: Allocation of forecast overheads to service categories

5.4 Other Issues

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 2.9 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[98] imposes a regulatory constraint on Ergon Energy requiring debt financing to be completed by 28 February each year to enable pricing proposals to be submitted to the AER earlier than is currently required. By extension, this requires Ergon Energy to refinance debt at least four months prior to the commencement of the next regulatory year.

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 four months ahead. If this occurs, the estimate for early issuance costs provided above should be recalculated based on a four 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 (in real $2014-15) as a revenue adjustment and we have adjusted our base year operating expenditure accordingly.

6 Outcomes for customers

The BST outcomes for Ergon Energy's Standard Control Services are depicted in Figure 13 below.[99]

[98] AEMC (2014), *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014.

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

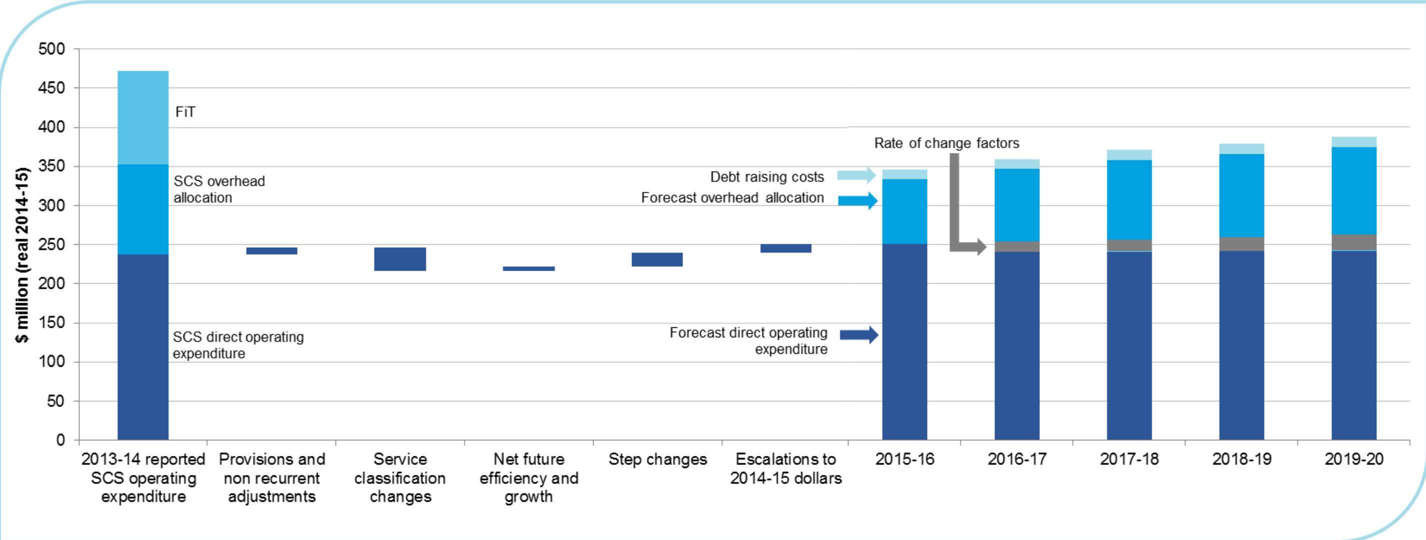

Figure 13: BST outcomes

7 Responding to the AER's Benchmarking Report and subsequent determinations

7.1 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.

At the time of our October Regulatory Proposal, 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[100] noted 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.

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

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

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."[101]

7.2 Our response to the AER's Preliminary Determination

Since we submitted our October Regulatory Proposal, the AER has released its benchmarking report and also made several draft and final determinations. We note in our submission to the AER's Preliminary Determination that we responded to a number of these processes as we saw the AER's application of new decision-making powers for the first time. Ergon Energy, like a number of NSPs, became increasingly concerned with the approach the AER was taking.

While the AER has made some changes to its approach, Ergon Energy is still of the view that the AER has not applied itself properly to the task of assessing our forecast operating expenditure. We have included a number of expert reports which attest to this in support of our submission to the AER's Preliminary Determination.

Ergon Energy has made some adjustments to our forecasts to reflect the AER's approach to calculating operating expenditure forecasts, and we have accepted some elements of the AER's decision in our revisions. Ergon Energy has also considered our forecasting approach and where necessary, fine-tuned it to make it easier to understand in the context of the AER's own assessment process.

Notwithstanding these changes, we remain opposed to the AER's assessment and substitution framework as they are likely to lead to skewed results that will not be in the long-term interests of consumers.

We have provided more detail in our submission in response to the AER's Preliminary Determination, particularly in *Opex (Base Year) – Response.*

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 – (Revised) 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.

The approach outlined in *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* remains applicable to this revised Regulatory Proposal. Where applicable or necessary, Ergon Energy has supplied updated information regarding any material changes to our forecasts

[101] *06.01.03 – Huegin Productivity Analysis*, p13.

and the application of the relevant NER requirements in the attachments that support this revised Regulatory Proposal.

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 regulatory control period 2015-20. 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 and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- *01.01.01 – (Revised) 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
(Revised) Ergon Energy's Journey to the Best Possible Price	0A.01.02	(Revised) Best Possible Price
Informing our plans, Our Engagement Program	0A.01.04	Engagement Program
(Revised) Legislative and Regulatory Obligations and Policy Requirements	01.01.01	(Revised) Legislative and Regulatory obligations
(Revised) Operating Forecast Expenditure Summary Document	06.01.01	(Revised) Opex forecast summary
(Revised) Step Changes for Operating Costs	06.01.04	(Revised) Step changes
Huegin Productivity Analysis	06.01.03	Ergon Opex Productivity Analysis
(Revised) Meeting Rule Requirements for Expenditure Forecasts	06.01.05	(Revised) Meeting the Rules requirements
Certification of reasonableness – expenditure forecast assumptions	06.01.06	Certification of reasonableness – expenditure forecast assumptions
(Revised) System related operating expenditure summary	06.01.02	(Revised) System related operating expenditure summary

Name	Ref	File name
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
Jacobs: Addendum Cost Escalation Factors 2015-20	06.02.07	Jacobs Addendum Cost Escalation Factors 2015-20
Our Capital Governance and our plans, policies and procedures	07.09.17	Governance, Plans, Policies and Procedures
Opex (Base Year) – Response	N/A	Ergon Energy – Opex (Base Year) – Response