PRELIMINARY DECISION
Ergon Energy determination
2015−16 to 2019−20

Overview

April 2015

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Note

This overview forms part of the AER's preliminary decision on Ergon Energy's 2015–20 distribution determination. It should be read with all other parts of the preliminary decision.

The preliminary decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure

Shortened form	Extended form
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Our preliminary decision

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission and distribution systems in all states and territories except Western Australian and the Northern Territory. Ergon Energy is one of two distribution network service providers (distributor) in Queensland and is responsible for providing electricity distribution services outside of south east Queensland to the far north and western areas of Queensland. We regulate the revenues Ergon Energy and other service providers can recover from their customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework under which we operate. Most relevantly, they set out how we must assess a regulatory proposal and make our decision.

The National Electricity Objective (NEO) sits at the centre of the NEL and NER. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

price, quality, safety, reliability and security of supply of electricity; and

the reliability, safety and security of the national electricity system.[1]

Under the NER, Ergon Energy must submit a regulatory proposal to us for approval.[2] It did this in October 2014. The central component of a regulatory proposal is the amount of revenue Ergon Energy proposes to recover from consumers over the 2015−20 regulatory control period.[3] We must assess Ergon Energy's proposal, using the NER's detailed rules. The NER addresses a range of constituent components of a regulatory proposal. We must decide whether to accept Ergon Energy's regulatory proposal. If we do not accept that Ergon Energy's proposal complies with the requirements of the NER, we must substitute an alternative amount of revenue that we are satisfied does comply. We must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NEO and to the greatest degree.

We regulate Ergon Energy's revenue, not its costs. Ergon Energy must then decide how best to use this revenue in providing distribution services and fulfilling its obligations. This provides incentives for distributors, such as Ergon Energy, to operate their businesses efficiently and, in the long run, at the least cost to consumers. It also provides incentives for distributors to innovate and invest in responses to changes in consumer needs and productive opportunities.[4] This is consistent with economic efficiency principles. It also means that the person who is best able to manage a risk, generally carries that risk.

1 NEL, s. 7.

2 NER, cl. 6.8.2.

3 NER, cll. 6.3.1 and 6.8.2.

4 Hansard, *SA House of Assembly*, 9 February 2005, p. 1452.

This overview, together with its attachments, constitutes our preliminary decision on Ergon Energy's regulatory proposal. This overview provides the reader with a summary of our preliminary decision and its constituent components. It offers an insight into the issues we covered, the conclusions we made, and how those conclusions were reached. We also explain why we are satisfied our decision contributes to the achievement of the NEO to the greatest degree and why we do not consider that Ergon Energy's proposal contributes to the achievement of the NEO to a satisfactory degree. In our attachments we set out detailed analysis of the constituent components that make up Ergon Energy's proposal and our preliminary decision on each of them.

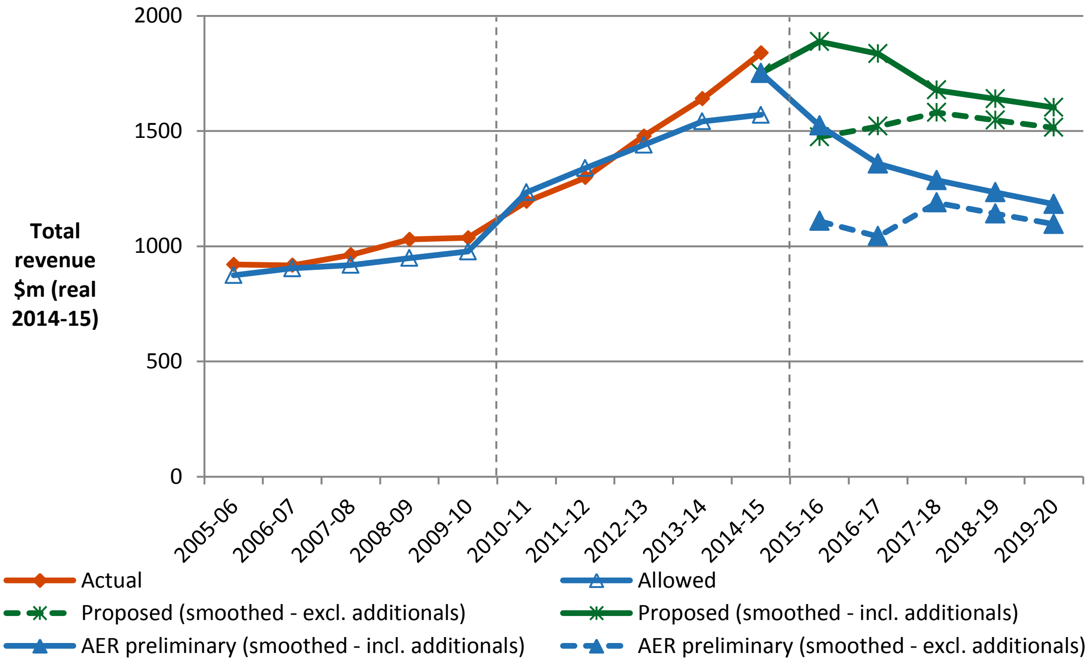
1.1 Decision

Our preliminary decision is that Ergon Energy can recover $6021.5 million ($ nominal) from consumers over the 2015–20 regulatory control period.[5] After a five-year period in which Ergon Energy's annual revenue increased each year we expect annual revenues to decline over the 2015−20 regulatory control period. To a large extent, this reflects much lower financing costs and our expectation that Ergon Energy can operate more efficiently in future. Ergon Energy does not agree with us. It proposed much higher financing costs and had allowed for few operational efficiency improvements going forward. A further aspect of the decline in Ergon Energy's forecast revenue requirement is the now closed solar bonus scheme that provides generous feed in tariffs (FiT) to eligible customers, which would add to its proposed revenue of $8241.7 million.[6] Neither Ergon Energy nor the AER are able to influence the significant costs that Ergon Energy incurs under this scheme. Figure 1 illustrates our overall decision.

5 This amount excludes other additional factors that will be recovered as part of DUoS but not within the building block revenue, such as the Solar Bonus Scheme feed-in tariff (FiT). The total expected revenue including the additionals is $7083.7 million.

6 This amount excludes other additional factors that will be recovered as part of DUoS but not within the building block revenue, such as the Solar Bonus Scheme feed-in tariff (FiT). Ergon Energy proposed a total expected revenue including the additionals of $9303.9 million.

Figure 1 Ergon Energy's past total revenue, proposed total revenue and AER total revenue allowance ($ million, 2014–15)



Source: AER analysis.

Notes: Additional amounts in DUoS include solar bonus scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20, estimated solar bonus scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, estimated DUoS under recovery for 2013–14, transitional capital contribution and shared assets under/over recovery from 2010–15, STPIS allowance from 2010–15 and DMIA over recovery from 2010–15. This is discussed further in attachment 1, annual revenue requirement.

The 'Allowed' 2014–15 data point is the amount allowed in the AER final decision excluding additionals. The 'Actual' 2014–15 data point is an updated forecast of the amount Ergon Energy actually expects to recover, including additionals, as submitted in its reset RIN. The 'AER preliminary' and 'Proposed' 2014–15 data points are the amount the service provider targeted in its 2014–15 regulatory proposal.

Distribution charges represent approximately 42 per cent, on average, of the annual electricity bill for Ergon Energy customers. If the lower distribution charges flowing from our decision passed through to customers, we would expect the average annual electricity bill for residential and small business customers to reduce over the 2015–20 regulatory control period. However, other factors may also affect a customer's electricity bill, such as the wholesale price of electricity.

Table 1 shows the estimated impact of our final decision on the average residential and small business customers' annual electricity bills in Ergon Energy's network area over the 2015–20 regulatory control period, compared with what was proposed by Ergon Energy. Our bill impact calculations adopt the network charges in our preliminary decision for Energex. This is because retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. The policy results in regulated retail electricity prices in Ergon Energy's distribution area being matched to those in Energex's area.

Table 1 AER's estimated impact of its preliminary decision on the average residential and small business customers' electricity bills in Ergon Energy's network for the 2015−20 period ($ nominal)[a]

	2014−15	2015−16	2016−17	2017−18	2018−19	2019−20
Ergon Energy proposal[a]						
Residential annual bill[b]	1914	1935	1958	1974	1989	2001
Annual change		21 (1.1%)	24 (1.2%)	16 (0.8%)	15 (0.8%)	12 (0.6%)
Small business annual bill[c]	2973	3005	3041	3066	3090	3108
Annual change		32 (1.1%)	37 (1.2%)	25 (0.8%)	23 (0.8%)	18 (0.6%)
AER preliminary decision[a]						
Residential annual bill[b]	1914	1880	1836	1820	1799	1782
Annual change		–34 (–1.8%)	–44 (–2.4%)	–16 (–0.9%)	–21 (–1.1%)	–17 (–0.9%)
Small business annual bill[c]	2973	2920	2851	2826	2794	2768
Annual change		–53 (–1.8%)	–69 (–2.4%)	–25 (–0.9%)	–32 (–1.1%)	–26 (–0.9%)

Source: AER analysis; QCA, Price comparator; QCA, *Final determination, Regulated retail electricity prices 2014–15*, May 2014, p.4.

(a) Energex's bill impacts are used for this table.

(b) Based on annual bill for typical consumption of 4100 kWh per year during the period 1 July 2014 to 30 June 2015.

(c) Based on the annual bill sourced from Energy Made Easy for a typical consumption of 10000 kWh per year during the period 1 July 2014 to 30 June 2015.

Within the figures presented above we have included a number of adjustments including forecast costs of the Queensland Solar Bonus Scheme FiT (and under recoveries related to this scheme from the 2010–15 regulatory control period). These include expected DUoS under recoveries in 2013–14 (which will be recovered in 2015–16), expected capital contributions pass throughs in 2015–16 and 2016–17, and a STPIS allowance whose recovery was deferred. The most significant of these additionals is the Solar Bonus Scheme FiT. The Scheme pays a government-mandated FiT to eligible customers for the electricity generated from solar photovoltaic (PV) systems and exported to the Queensland electricity grid.[7] While payments to PV owners are made by retailers, those costs are passed on to the distributors who then

[7] Customers who applied for the Queensland Solar Bonus Scheme FiT before 10 July 2012 are currently receiving 44 cents and will continue to receive that rate provided ongoing eligibility requirements are met. New customers must approach their electricity retailer to obtain a market feed-in tariff rate. We note that the SBS and arrangements to recover FiT related costs are subject to change by the Qld Government.

recover the costs through their network charges (DUoS) paid by all customers. Neither the Queensland distributors nor the AER are able to affect the amount of the costs to be recovered from network charges. However, we are able to smooth the impacts to avoid price fluctuations. The Solar Bonus Scheme is now closed to new customers. The costs of the scheme are expected to peak in 2015–16 and decline steadily until the scheme ends in 2028.

1.2 Contribution to the achievement of the NEO

We are satisfied that the total revenue approved in our preliminary decision contributes to the achievement of the NEO to the greatest degree. This is because our total revenue reflects the efficient, sustainable costs of providing network services in Ergon Energy's operating environment and the key drivers of efficient costs facing Ergon Energy. Our preliminary decision will promote the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers, as required by the NEO. We set out our reasons below and in our attachments.

The key drivers of costs facing a network service provider are:[8]

- its accumulated network investment (reflected in the size of its Regulatory Asset Base, or RAB)
- its expected growth in network investment (reflected in its capital expenditure (capex) program net of capital returned to the shareholders through depreciation)
- its financing costs (interest on borrowings and a return on equity to shareholders)
- its operating expenditure (opex) program (the cost of operating and maintaining its network)
- its taxation cost (taxable income at the corporate tax rate adjusted for the value of imputation credits).

From one regulatory control period to the next, the pressures on each of these drivers may change. For example, in periods of high demand growth, a service provider would expect to need a larger capex program. Similarly, during periods of high interest rates, a service provider would expect to pay more in financing costs.

The most important factors we see impacting on Ergon Energy's costs in the 2015–20 regulatory control period are:

- an improved investment environment compared to our 2010−15 decision, which translates to lower financing costs necessary to attract efficient investment.
- a consistent body of evidence demonstrating that Ergon Energy's past expenditure has been higher than necessary to maintain its network safely and reliably. This evidence has been confirmed by our own opex and capex analysis, including our benchmarking analysis.

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[8] How these key cost drivers impact total revenue is further explained in section 2 of this Overview.

- forecast demand, which is expected to remain reasonably flat over the 2015–20 regulatory control period. This means that Ergon Energy is under less pressure to expand its network than in the previous regulatory control period to meet the needs of additional customers or any increased demand from existing customers.
- changes to the Queensland Government's reliability standards. From 1 July 2014 the reliability standards, amongst other things, reduce the need to build new infrastructure for reliability purposes.[9]
- improvements in efficiency in how Ergon Energy operates its business
- its taxation costs (taxable income at the corporate tax rate adjusted for the value of the imputation credits).

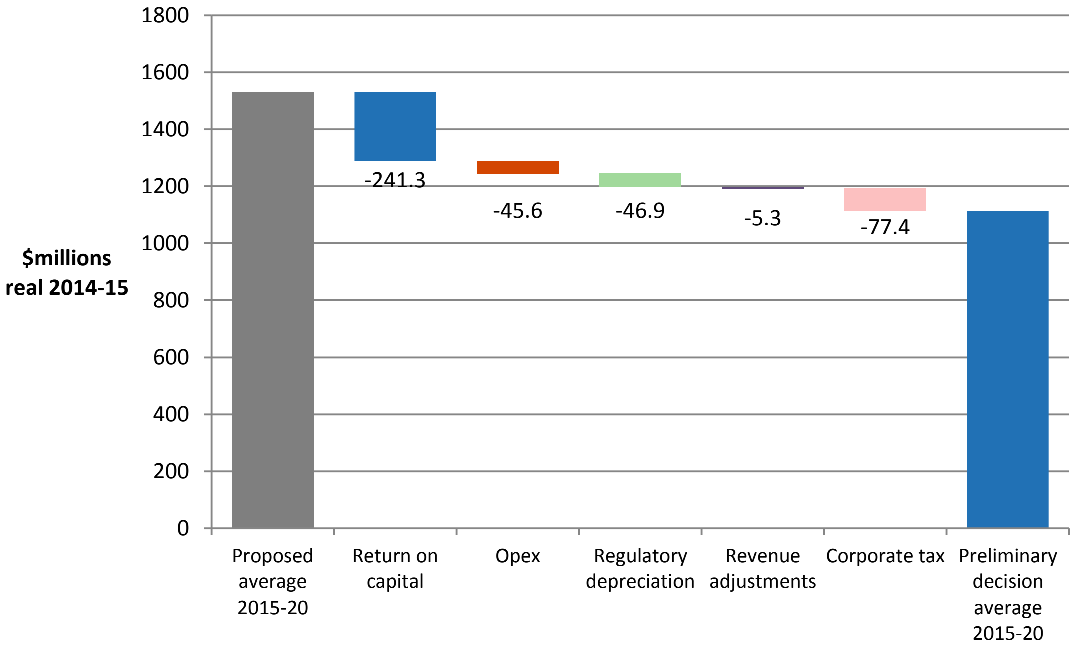
These factors are reflected throughout our preliminary decision and impact the different constituent components of our decision to varying degrees. At the total revenue level, they provide a consistent picture. The drivers of revenue for the 2015−20 regulatory control period indicate that a prudent and efficient service provider could provide safe and reliable distribution services with materially less revenue than Ergon Energy has proposed. We come to these views as a result of the detailed analysis for each constituent component of our preliminary decision.

In our preliminary decision we consider that Ergon Energy's proposal does not reflect the factors impacting on its cost drivers to a satisfactory extent. As a consequence, we also conclude that Ergon Energy has proposed to recover more revenue from its customers than is necessary for the safe and reliable operation of its network. It follows that we consider that Ergon Energy's proposal does not contribute to the achievement of the NEO to a satisfactory degree.

The two constituent components of our decision that drive most of the difference between Ergon Energy's regulatory proposal and our preliminary decision are the allowed rate of return and opex. Changes to the allowed rate of return also flow on to impact the corporate tax allowance given the reduction in overall revenue requirements. We discuss these further below. Figure 2 illustrates the key differences (in terms of constituent components, or building blocks, making up total revenue) between our preliminary decision and Ergon Energy's regulatory proposal.

9 DEWS, *Changes to electricity network reliability standards*; Refer to https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards

Figure 2 AER's preliminary decision and Ergon Energy's proposed annual building block costs ($ million 2014–15)



Source: AER analysis.

1.2.1 Rate of return

The rate of return provides a distributor with revenue to service the interest on its loans and to give a return on equity to shareholders. The allowed rate of return is a key determinant of allowed revenue.

The rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.[10] The NER refers to this requirement as the allowed rate of return objective.

Our preliminary decision is for a rate of return of 5.85 per cent compared to 8.02 per cent put forward by Ergon Energy in its regulatory proposal.[11]

We set out our approach to determining the Rate of Return in a Guideline we published in December 2013.[12] This Guideline is not binding. However, a distributor must provide reasons to justify any departure from the Guideline. Ergon Energy has proposed we

10 NER, cl. 6.5.2(b).

11 The rate of return that Ergon Energy included in its proposal is an indicative value. Its proposal includes provision for the AER to adjust this value based on updated information that was not available when Ergon Energy submitted its proposal.

12 AER, *Rate of Return Guideline*, December 2013: http://www.aer.gov.au/node/18859.

depart from the Guideline. We are not satisfied there are sufficient grounds to justify doing so.

Prevailing market conditions for debt and equity heavily influence the rate of return. Since Ergon Energy submitted its regulatory proposal in October 2014, interest rates have fallen further and financial market conditions have continued to ease. This means that the cost of debt and the returns required to attract equity are lower than when Ergon Energy submitted its proposal. We consider these factors should be reflected in the rate of return.

On a more technical level, the key difference between our preliminary decision and Ergon Energy's regulatory proposal in relation to rate of return is, that while Ergon Energy gives weight to other indicators on the return on equity and consider them informative, we do not consider them to be robust and other regulators do not use them.

The Guideline, (and indeed, this decision), marks a departure from our previous approach to estimating the return on debt and the return on equity. For the return on debt, we have used a gradual, forward looking transition. We set out this transition in the Guideline. Our approach to setting the return on debt received broad support from many stakeholders, including some service providers.[13] Ergon Energy and us agree on how to transition from the previous on-the-day regulatory approach to the new trailing average approach for the return on debt. For the return on equity, the expert evidence before us indicates that on balance employing our approach is expected to lead to a rate of return that achieves the allowed rate of return objective.

1.2.2 Operating expenditure

Opex is required to operate and maintain the distributor's network. Similar to rate of return it is a key driver of total revenue. Whether we should use Ergon Energy's historical costs as the starting point for forecasting its future costs is a key difference between our preliminary decision and Ergon Energy's regulatory proposal.

Under the NER, a distributor's proposal must include the forecast of total opex which the distributor considers is required in order to achieve each of the following (opex) objectives:

- meet or manage expected demand
- comply with certain obligations and service standards
- maintain the safety of the distribution system.[14]

Under the NER, we must assess Ergon Energy's proposal against certain criteria and decide whether to accept it.[15] That is, we must be satisfied that the level of opex

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[13] For example, TasNetworks, *Regulatory Proposal*, June 2014.

[14] NER, cll. 6.5.6(a).

[15] The opex criteria − NER, cl. 6.5.6(c).

reasonably reflects the costs that a prudent and efficient operator would require using a realistic expectation of demand and cost inputs, would require to achieve the opex objectives.[16] This means that it is not Ergon Energy's *actual* costs that are the central consideration. Rather, it is the costs Ergon Energy would incur, if it were a prudent and efficient operator, with efficient costs and a realistic expectation of demand and cost inputs.

We recognise that Ergon Energy may continue to incur costs above efficient levels. They may have contracts (such as enterprise bargaining agreements) and practices in place that affect how they reduce costs. We consider that, in accordance with the NEO, shareholders should bear the costs of inefficiencies not consumers. Consumers should pay no more than necessary for safe and reliable electricity services.

This is the second time we have set an opex forecast for Ergon Energy. For the 2015−20 regulatory control period we have access to a consistent body of evidence that indicates that Ergon Energy's historical costs are above a level that would reasonably reflect the opex criteria going forward. This evidence includes:

- various forms of benchmarking[17]
- analysis of specific expenditure categories[18]
- detailed review by Deloitte Access Economic of the extent to which Ergon Energy's base opex included inefficiencies identified by the Independent Review Panel (IRP) in 2012. [19]

These analyses indicate that Ergon Energy's distribution services can be provided at substantially lower cost while still maintaining safety and complying with reliability obligations.

In its regulatory proposal, Ergon Energy based its opex forecast on its historical costs. Given the evidence outlined above, we are not satisfied that those forecasts are the appropriate starting point for forecasting its opex for 2015−2020.

Instead, we have used a benchmarking analysis as the starting point for assessing Ergon Energy's base level of opex. We are satisfied that our resulting opex forecast reasonably reflects the opex criteria.

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16 NER, cl. 6.12.1(4).

17 See attachment 7 − Operating expenditure for more details.

18 See attachment 6 − Capital expenditure, and attachment 7 − operating expenditure for more details.

19 In May 2012, the (former) Queensland Government set up an interdepartmental committee (IDC) to examine electricity sector reform in response to rising costs in the electricity sector. The IDC commissioned an independent panel of experts, the IRP, to investigate areas of inefficiencies in the Queensland service providers. The task of the IRP was to develop options to improve the efficiency of capital and operating expenditure and deliver savings in corporate and overhead costs. In May 2013, the IRP found that through a series of reforms, Energex and Ergon could together achieve an estimated $1 400 million reduction in operational costs over the 2015-20 regulatory control period. The IRP made 45 recommendations, including 18 which focused on overhead expenses and operational efficiencies.

Our preliminary decision is for a forecast of total opex of $1629.9 million which is 10.5 per cent lower than the $1821.1 million put forward by Ergon Energy in its regulatory proposal.

When we applied our benchmarking analysis we made a number of adjustments to account for the particular exogenous characteristics of Ergon Energy's network that may influence its costs and, therefore, affect its benchmarking performance.[20] While our preferred benchmarking model accounts for several key network characteristics, others, such as the impact of cyclones, are better considered outside of the model because they may be particular to Ergon Energy.

However, even after incorporating these additional adjustments we found that other distributors in the National Electricity Market (NEM) provide safe and reliable distribution services at substantially lower cost levels than what Ergon Energy has proposed. This implies that the costs incurred by these distributors are a better reflection of the costs that a prudent operator of Ergon Energy's network— with efficient costs and realistic expectations of demand and cost inputs— would need to achieve the opex objective.

1.3 Assessment of options under the NEO

The NER recognises that there may be several potential decisions that contribute to the achievement of the NEO. Our role is to make a decision that we are satisfied contributes to the achievement of the NEO to the *greatest* degree.[21]

For at least two reasons, we consider that there will almost always be several decisions that contribute to the achievement of the NEO. First, the NER requires us to make forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. Second, there is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for several components of our decision there may be several plausible answers or several point estimates from within a range. This has the potential to create a multitude of potential overall decisions. In this decision we have approached this from a practical perspective, accepting that it is not possible to consider every possible permutation specifically. Where there are several plausible answers, we have selected what we are satisfied is the best outcome, under the NEL and NER.

In many cases, our approach results in an outcome towards the end of the range of options materially favourable to Ergon Energy (for example, our choice of equity beta). While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

20 For the reasons set out in attachment 7, we consider that the adjustments we have made are at least sufficient to take into account the environmental operating factors that may affect Ergon Energy's costs.

21 NEL, s. 16(1)(d).

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model
- the point at which we have set the benchmark for opex
- the allowances we have made for environmental operating factors in our benchmarking analysis.

We set out our detailed reasons in the attachments. They demonstrate that the constituent components of our decision comply with the NER's requirements. At an overall level our decision reflects the key reasons set out above, which indicate that Ergon Energy should recover less revenue than it has proposed or recovered in recent years. Our decision reflects these at both the constituent component and overall revenue levels.

Given our approach, we are satisfied that our decision will or is likely to contribute to the achievement of the NEO to the greatest degree.

1.4 Structure of the overview

The remainder of this overview discusses the overarching issues in this decision, including those above in more detail. It is structured as follows:

- Section 2 sets out the key constituent components making up our preliminary decision
- Section 3 set out our preliminary decision on classification of services, control mechanisms and incentive schemes
- Section 4 explains our views on the regulatory framework
- Section 5 outlines the process we undertook in reaching our preliminary decision.

2 Key elements of the building blocks

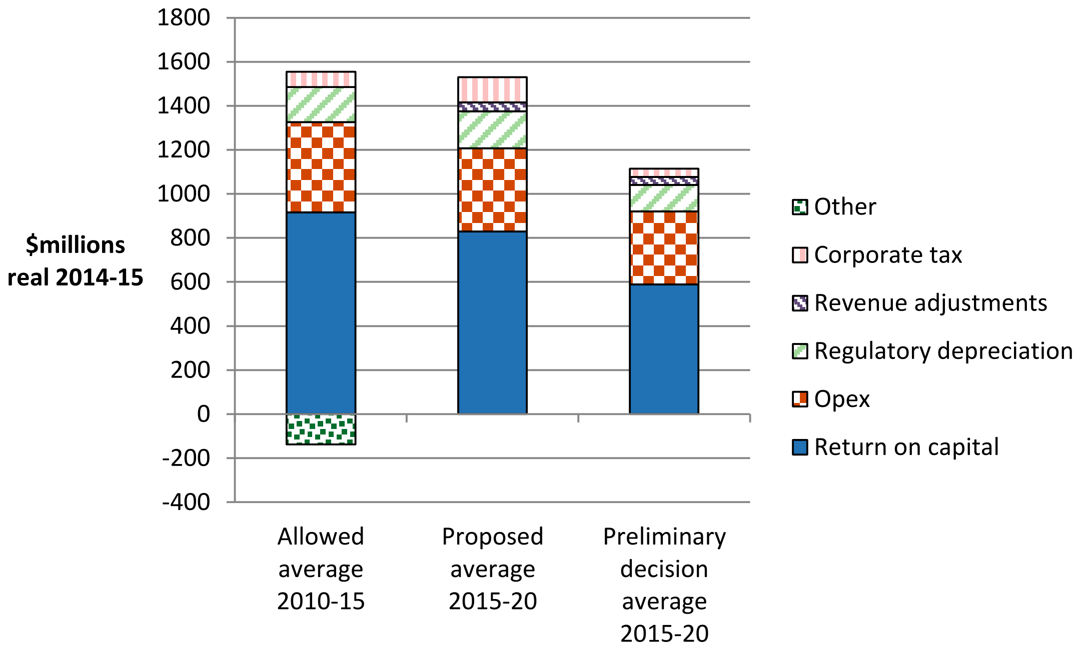
The constituent components of our preliminary decision include the building blocks we use to determine the revenue Ergon Energy may recover from its customers.

In setting our total revenue allowance for Ergon Energy of $6021.5 million ($nominal) for the 2015–20 regulatory control period we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation Guidelines. We also consider information provided by Ergon Energy, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions
- consider our allowed revenue against section 16 of the NEL, including the constituent decisions and the interrelationships we discussed in section 4.

Figure 3 and table 2 show our preliminary decision on Ergon Energy's revenues.

Figure 3 AER's preliminary decision on constituent components of total revenue ($ million 2014−15)



Source: AER analysis.

Note: The 'Other' category in the 'Allowed average' for 2010–15 is a revenue adjustment related largely to customer contributions. Because customer contributions were included in the RAB during those years, an offsetting revenue adjustment was made to prevent Ergon Energy earning a return on these contributions. The 'Revenue adjustments' is the closing balance of the DUoS unders/overs account as at 30 June 2015 plus the EBSS penalties/rewards related to the 2010–15 regulatory control period.

Table 2 AER's preliminary decision on Ergon Energy's revenues ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	590.8	617.1	640.4	658.9	674.6	3181.7
Regulatory depreciation[a]	106.7	121.2	137.3	147.2	142.3	654.6
Operating expenditure	327.5	342.1	356.4	372.9	389.0	1787.9
Revenue adjustments[b]	91.9	49.1	66.9	–21.4	–2.3	184.2
Corporate tax allowance	36.3	38.8	41.2	44.8	43.1	204.2
Annual revenue requirement (unsmoothed)	1153.1	1168.2	1242.3	1202.3	1246.7	6012.6
Annual expected revenue (exc. additionals)	**1137.7**	**1096.7**	**1282.1**	**1262.2**	**1242.7**	**6021.5**
X factor[c]	36.63%	6.00%	–14.00%	4.00%	4.00%	n/a
Additional amounts in DUoS[d]	424.3	331.7	104.9	102.1	99.2	1062.2
Annual expected revenue (smoothed – inc. additionals)	**1562.0**	**1428.4**	**1387.0**	**1364.3**	**1341.9**	**7083.7**
Annual change in revenue – inc. additionals	–10.8%	–8.6%	–2.9%	–1.6%	–1.6%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Revenue adjustments include efficiency benefit sharing scheme carry-overs, forecast DMIA and DUoS under recoveries.

(c) The X factor from 2016–17 to 2019–20 will be revised to reflect the annual return on debt update.

(d) Additional amounts in DUoS include solar bonus scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20, estimated solar bonus scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, estimated DUoS under recovery for 2013–14, transitional capital contribution and shared assets under/over recovery from 2010–15, STPIS allowance from 2010–15 and DMIA over recovery from 2010–15.

2.1 The building block approach

We have employed the building block approach to determine Ergon Energy's annual revenue requirement The building block costs, as illustrated in figure 4, include:[22]

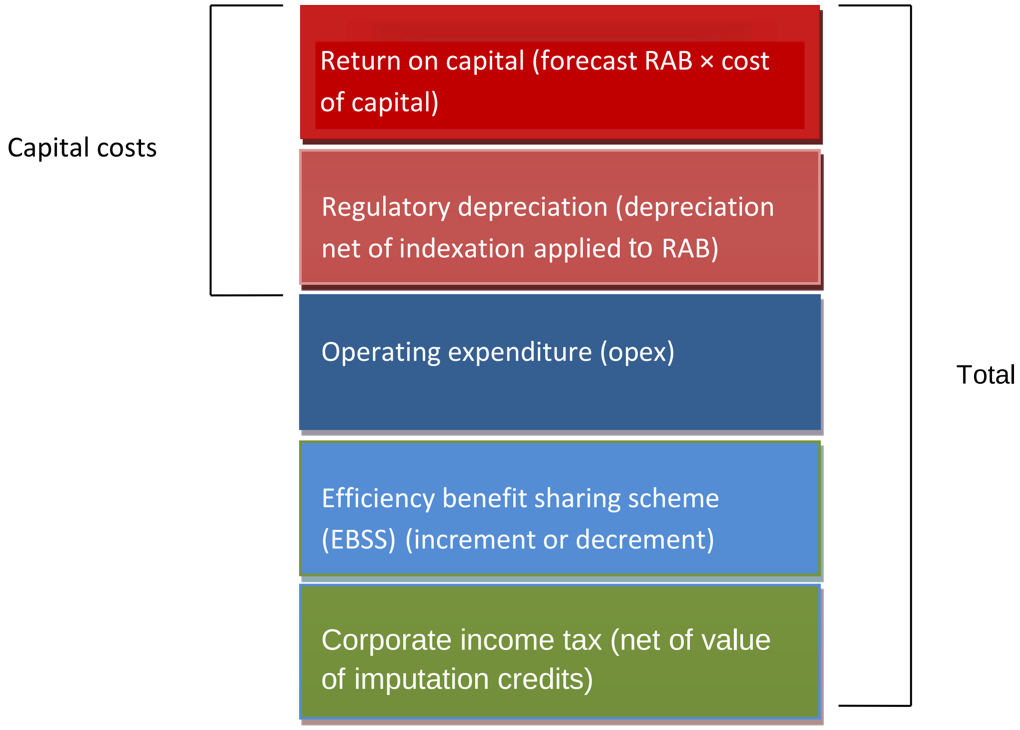
- a return on the Regulatory Asset Base (RAB) (return on capital)
- depreciation of the RAB (return of capital)

22 Because Ergon Energy has a balance on its unders/overs account at the end of the 2010–15 regulatory control period, this will also be included as a building block. This is not shown in the illustration as typically a service provider should be aiming for a zero balance.

- forecast opex
- increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of the RAB and therefore, the revenue generated from the return on capital and return of capital building blocks.

Figure 4 The building block approach for determining total revenue



The following section summarises our preliminary decision in relation to each building block and provides our high level reasons and analysis. The attachments provide a more detailed explanation of our analysis and findings.

2.2 Regulatory asset base

The RAB is the value of Ergon Energy's assets used to provide distribution network services. It is the value on which Ergon Energy earns a return on capital, and a depreciation allowance (return of capital) on assets in its RAB. We are required to assess Ergon Energy's proposed opening value for the RAB for each year of the 2015−2020 regulatory control period.[23]

Our preliminary decision is to set Ergon Energy's opening RAB at $10 102.2 million ($ nominal) as at 1 July 2015. We determine that the forecast depreciation approach is

23 NER, cll. 6.5.1 and S6.2.

to be used to establish Ergon Energy's opening RAB at the commencement of the 2020–25 regulatory control period. We forecast a closing RAB at 30 June 2020 of $11 773.7 million for Ergon Energy.

Tables 3 and 4 set out our preliminary decision on the roll forward of Ergon Energy's RAB for the 2010–15 regulatory control period and the forecast RAB for Ergon Energy during the 2015–2020 regulatory control period respectively.

Table 3 AER's preliminary decision on Ergon Energy's RAB for the 2010–15 regulatory control period ($ million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15[a]
Opening RAB	7148.9	7870.5	8393.0	9072.3	9681.3
Capital expenditure[b]	809.5	748.3	836.5	743.8	885.9
Inflation indexation on opening RAB	238.3	124.7	210.0	265.8	217.8
Less: straight-line depreciation	326.3	350.5	367.2	400.5	397.2
Closing RAB	7870.5	8393.0	9072.3	9681.3	10387.9
Difference between estimated and actual capex (1 July 2009 to 30 June 2010)					–132.8
Return on difference for 2009–10 capex					–78.3
Closing RAB as at 30 June 2015					10176.8
ACS (metering and other) assets removed					–74.6
Opening RAB as at 1 July 2015					**10102.2**

Source: AER analysis.

(a): Based on estimated capex. We will update the RAB roll forward in the substitute decision.

(b): Net of disposals and adjusted for CPI.

Table 4 AER's preliminary decision on Ergon Energy's RAB for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20
Opening RAB	10102.2	10551.0	10951.5	11266.7	11535.2
Capital expenditure[a]	555.4	521.7	452.5	415.7	380.8
Inflation indexation on opening RAB	257.6	269.0	279.3	287.3	294.1
Less: Straight-line depreciation	364.3	390.2	416.6	434.5	436.4
Closing RAB	**10551.0**	**10951.5**	**11266.7**	**11535.2**	**11773.7**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions.

Our decision not to accept Ergon Energy's proposed RAB is because we amended its RAB roll forward to account for the following:

- corrected input errors in the remaining asset lives as at 1 July 2010 used to roll forward the RAB and adjustments for capitalised provisions
- corrected an input error in the allocation of equity raising costs
- removed the updated amount of type 5 and 6 metering assets and shared assets from the RAB as at 1 July 2015
- removed the unregulated Hayman Island undersea cable from the RAB.

The opening RAB as at 1 July 2015 is $60.7 million (or 0.6 per cent) higher than the opening RAB of $10 041.5 million ($ nominal) Ergon Energy proposed. The error in remaining asset lives as at 1 July 2010 was the most significant adjustment and caused the net increase in the RAB, all other adjustments reduced the RAB.

We forecast Ergon Energy's closing RAB value at 30 June 2020 to be $11 773.7 million ($ nominal). This represents 92 per cent of what Ergon Energy proposed or $1093.3 million lower than the amount of $12 867.0 million ($ nominal) Ergon Energy proposed. The main reasons for these reductions are our adjustments to:

- forecast capex (attachment 6)
- forecast depreciation (attachment 5).

Details of our preliminary decision on the value of the RAB are set out in attachment 2.

2.3 Rate of return (return on capital)

The return on capital provides a distributor with revenue to service the interest on its loans and to give a return on equity to shareholders. This building block is calculated as a product of the rate of return and the value of the RAB. [24]

The NER sets out that the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.[25] The NER refers to this requirement as the allowed rate of return objective.

We have determined an allowed rate of return of 5.85 per cent (nominal vanilla[26]), subject to updating. We have not accepted Ergon Energy's proposed 8.02 per cent return.[27] In revenue terms, this is $4 490 million (55 per cent) of the $9 140 million

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[24] NER, cl. 6.5.2(a).

[25] NER, cl. 6.5.2(b).

[26] The nominal vanilla WACC combines a post-tax return on equity and a pre-tax return on debt, for consistency with other building blocks.

[27] The rate of return that Ergon Energy included in its proposal is an indicative value. Its proposal includes provision for the AER to adjust this value based on updated information that was not available when Ergon Energy submitted its proposal.

Ergon Energy proposed in its regulatory proposal. In accordance with the Guideline, we will update the rate of return annually, consistent with Ergon Energy's proposal and our approach to return on debt.[28] Table 5 sets out the parameters we have used to determine the rate of return.

Table 5 AER's preliminary decision on Ergon Energy's rate of return (nominal)

	AER decision 2010–15	Ergon Energy's proposal[a] 2015–16	AER preliminary decision[b] 2015–16	AER preliminary decision[b] 2016–20
Nominal risk free rate (return on equity)(c)	5.89%	3.63%	2.55%	2.55%
Equity risk premium	5.20%	6.87%	4.55%	4.55%
MRP	6.50%	7.57%	6.50%	6.50%
Equity beta	0.8	0.91	0.7	0.7
Nominal post–tax return on equity	11.09%	10.50%	7.1%	7.1%
Nominal pre–tax return on debt	8.87%	6.36%	5.01%	Updated annually(d)
Gearing	60%	60%	60%	60%
Nominal vanilla WACC	9.76%	8.02%	5.85	updated annually(d)
Forecast inflation	2.52%	2.57%	2.55%	2.55%

Source: AER analysis; Ergon Energy, *Regulatory proposal*, October 2014; AER, *Final decision: Queensland distribution determination 2010–11 to 2014–15*, May 2010.

(a) Ergon Energy used a multi-model approach to estimating return on equity. In applying this approach, Ergon Energy used single, consistent estimates of risk free rate and market risk premium but not of equity beta. However, an indicative equity beta estimate (for comparison purposes) can be calculated from Ergon Energy's proposed equity risk premium and market risk premium.

(b) This rate of return estimate will be used to determine prices to apply in the 2015–16 regulatory year. The rate of return, including the rate to apply to the 2015–16 regulatory year, will be updated in our substitute determination for Ergon Energy.

(c) Ergon Energy's risk free rate estimate was calculated using an averaging period 20 business days to 11 July 2014. AER preliminary decision risk free rate estimate is based on a 20 business day averaging period from 9 February to 6 March 2015.

(d) The allowed return on debt is to be updated annually and the nominal vanilla WACC will be updated annually to reflect the allowed return on debt. The allowed return on debt for 2015–16 has already been estimated. Return on debt allowances for subsequent years will be estimated based on the formula set out in the Return on Debt appendix to attachment 3.

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28 NER, cl. 6.5.2(i)(2).

Our approach

All NER requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective.[29] The NER recognises that there are several plausible answers that could achieve the allowed rate of return objective. [30] We agree with stakeholders that predictability of outcomes in rate of return issues could materially benefit the long term interests of consumers. [31]

We developed our approach prior to the submission of this regulatory proposal. As required by the rate of return framework, in December 2013, we published the Guideline[32] as contemplated by the NER.[33] The Guideline was designed through extensive consultation and involved effective and inclusive consumer participation.

Return on debt

Previously, we used an on-the-day approach to determine the return on debt.[34] This is the approach that many Australian regulators continue to use. However, for this decision, we have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.[35] This is consistent with the approach most stakeholders supported during the Guideline development process. We note that Ergon Energy agreed on the transition to the trailing average approach.

Return on equity

Ergon Energy has departed from our approach to determining the return on equity.[36] Our approach involves considering all the information before us, through a six step process as set out in the Guideline (foundation model approach). This includes detailed consideration of financial models for determining the return on equity.[37]

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29 NER, cl. 6.5.2(b).

30 AEMC, *Rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012: National gas amendment (Price and revenue regulation of gas services) Rule 2012*, 29 November 2012, p. 67 (AEMC, *Final rule change determination*, November 2012); AEMC, *Final rule change determination*, November 2012, p. iv, AEMC, *Final rule change determination*, November 2012, p. 38; The High Court of NZ stated: 'In determining WACC, precision is therefore an elusive and perhaps non-existent quality. Setting WACC is, we suggest, more of an art than a science. The use of WACC, in conjunction with RAB values, to set prices and revenue in price-quality regulation gives significance to WACC estimates that may not exist outside this context.' *Wellington International Airport Ltd & Others v Commerce Commission* [2013] NZHC 3289, para. 1189.

31 ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p. 1; AER, *Better regulation: Explanatory statement rate of return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp.185–186.

32 NER, cl. 6.5.2(m).

33 NER. cl. 6.5.2(m).

34 This involved determining the return on debt by reference to the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the 2015−20 regulatory control period.

35 In broad terms, this means that over the longer term the return on debt for any year will represent the average return on debt over the previous ten years.

36 Ergon Energy, *Regulatory proposal*, October 2014, p. 122.

37 NER, cl. 6.5.2(e)(1).

Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

We consider that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. The expert evidence before us also indicates on balance that employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.[38]

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at any given time.[39] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within range of other information available to inform the return on equity (see figure 5). Instead, Ergon Energy proposed that the return on equity be determined by applying all relevant models (the SL CAPM, Black CAPM, Dividend Discount Model and Fama-French model), as permitted under the NER.[40]

A detailed explanation of our findings on return on equity and this figure can be found in attachment 3: Rate of return.

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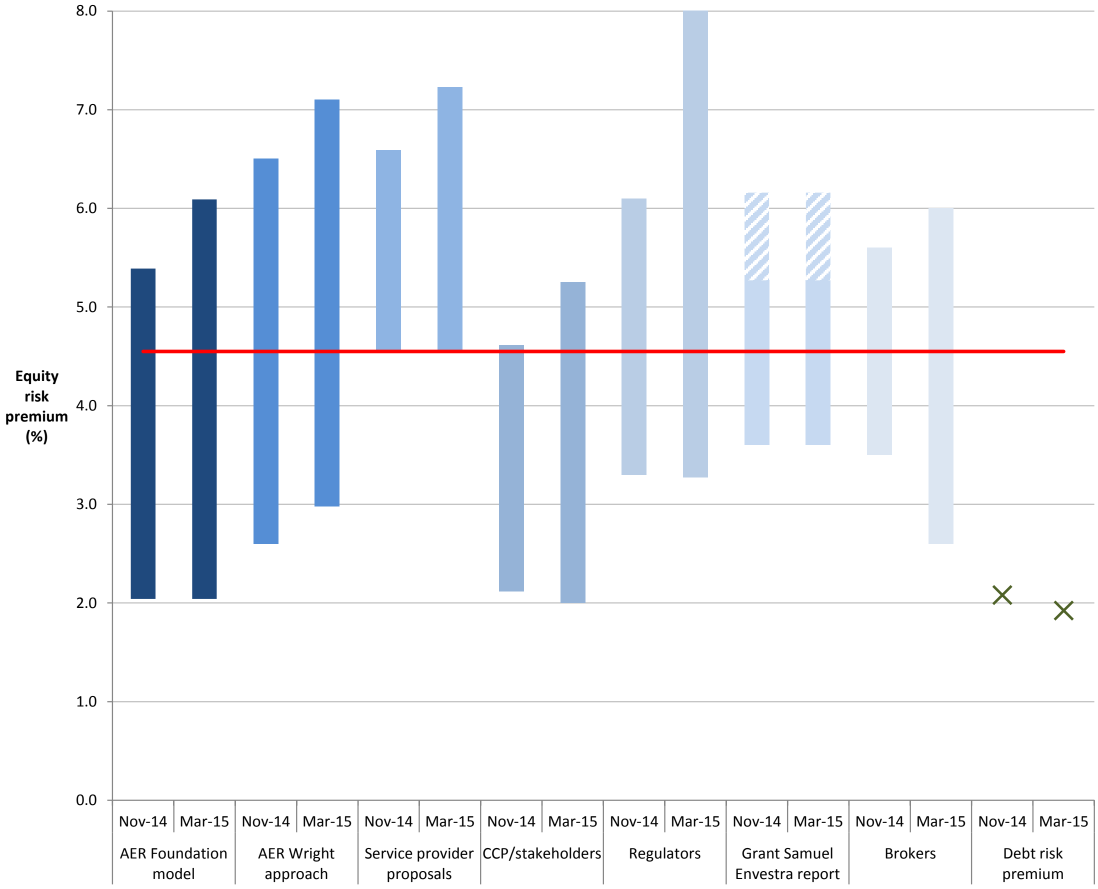
38 McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p. 13; John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p. 3.

39 Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

40 Ergon Energy, *Regulatory proposal*, October 2014, p. 122.

Figure 5 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports.

Notes: The AER foundation model ERP range uses the range and point estimate for MRP and equity beta as set out in step three. The calculation of the Wright approach, debt premium, brokers, and other regulators ranges is outlined in Appendices E.1, E.2, E.4, and E.5 respectively.

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel made no explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.[41]

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in April–May 2015.[42] Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

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[41] Grant Samuel, *Envestra: Financial services guide and independent expert's report*, March 2014, Appendix 3.

[42] ActewAGL, Ausgrid, Directlink, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena Gas Networks, SA Power Networks, TasNetworks, and TransGrid.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in April–May 2015. The lower bound is based on the Energy Users Association of Australia submission on NSW distributors' revised proposals. The upper bound is based on Origin's submission on ActewAGL's proposal.[43]

2.4 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[44] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NER requires that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[45] That is, the revenue granted to a service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

Our preliminary decision is to adopt a value of imputation credits of 0.4. This differs from Ergon Energy's proposed value of imputation credits of 0.25.

Although we have broadly maintained the approach to determining the value of imputation credits set out in the Rate of Return Guideline, we have re-examined the relevant evidence and estimates. This re-examination, and new evidence and advice considered for the first time since the Guideline, led us to depart from the value of 0.5 in the Guideline. Most notably, our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate in the Guideline.

Estimating the value of imputation credits is a complex and somewhat imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate and there is a range of evidence relevant to the utilisation rate:

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43 Energy Users Association of Australia, *Submission to NSW DNSP Revised Revenue Proposal to AER Draft Determination (2014 to 2019)*, February 2015, pp. 15–16; Origin Energy, *Submission to ActewAGL's regulatory proposal for 2014–19*, August 2014, p. 4.

44 *Income Tax Assessment Act 1997*, parts 3–6.

45 NER, cll. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3.

- the proportion of Australian equity held by domestic investors (the 'equity ownership approach').
- the reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics').
- implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics
- less reliance upon implied market value studies.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range of 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- the equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.31 and 0.44 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.44.
- the evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- an estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance on SFG's dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this study (0.32) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

2.5 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). We are required to decide on whether to approve the depreciation schedules submitted by Ergon Energy.[46] In doing so, we make determinations on the indexation of the RAB and depreciation building blocks for Ergon Energy's 2015−20 regulatory control period. The

[46] NER, cl. 6.12.1(8).

regulatory depreciation allowance is the net total of straight-line depreciation (negative) less the indexation of the RAB (positive).

Our preliminary decision is to determine alternative depreciation schedules, and hence, the depreciation allowance, to apply to Ergon Energy.[47] We have set the allowance at $654.6 million ($ nominal), or 27.6 per cent, less than the allowance Ergon Energy proposed.

Table 6 sets out our preliminary decision on Ergon Energy's depreciation allowance for the 2015–20 regulatory control period.

Table 6 AER's preliminary decision on Ergon Energy's depreciation allowance for the 2015−20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Straight-line depreciation	364.3	390.2	416.6	434.5	436.4	2042.0
Less: inflation indexation on opening RAB	257.6	269.0	279.3	287.3	294.1	1387.4
Regulatory depreciation	**106.7**	**121.2**	**137.3**	**147.2**	**142.3**	**654.6**

Source: AER analysis.

In coming to our preliminary decision to determine a regulatory depreciation allowance of $654.6 million ($nominal), we:

- accept Ergon Energy's proposed asset classes, its straight-line depreciation method, and the standard asset lives used to calculate the regulatory depreciation allowance. We consider Ergon Energy's proposed asset classes and standard asset lives are consistent with those approved at the 2010–15 distribution determination, and reflect the nature and economic lives of the assets.[48]
- do not accept Ergon Energy's proposed average depreciation approach to calculate the remaining asset lives at 1 July 2015. We instead substitute remaining asset lives calculated using a weighted average approach.
- made determinations on other components of Ergon Energy's proposal that also affect the forecast regulatory depreciation allowance—for example, the forecast capex (attachment 6) and the opening RAB value (attachment 2).[49]

Details of our preliminary decision on the regulatory depreciation allowance are set out in attachment 5.

47 NER, cl. 6.5.5(b).
48 NER, cl 6.5.5(b)(1).
49 NER, cl 6.5.5(a)(1).

2.6 Capital expenditure

Capex refers to the capital expenses incurred in the provision of network services. The return on and of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

We estimate total forecast capex of $2182 million ($2014−15) for Ergon Energy's 2015−20 regulatory control period. This is down from $3397 million ($2014−15) or 36 per cent of Ergon Energy's proposed capex.

Table 7shows our preliminary decision compared to Ergon Energy's proposal.

Table 7 AER preliminary decision on total net capex ($million 2014–15)

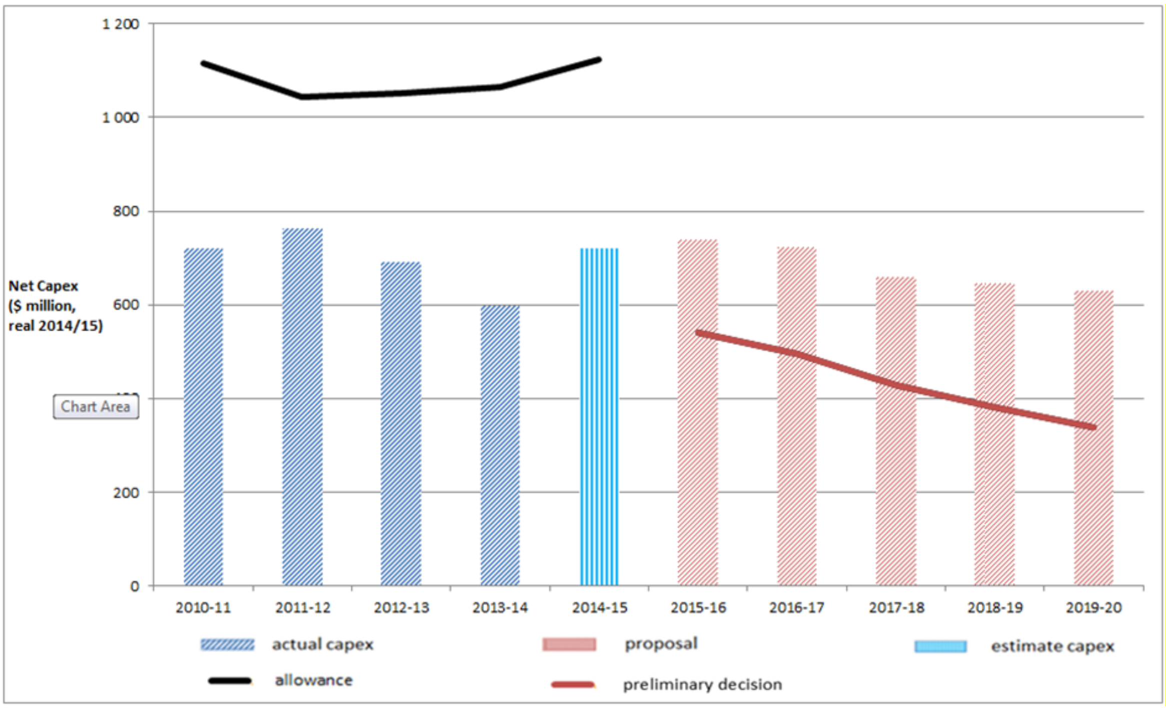
	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy's proposal	739.8	723.2	659.4	644.5	630.0	3397.0
AER preliminary decision	540.1	495.3	428.1	381.0	337.5	2182.0
Difference	-199.7	-227.9	-231.3	-263.5	-292.6	-1215.0
Percentage difference (%)	-27%	-32%	-35%	-41%	-46%	-36%

Source: Ergon Energy, *Regulatory Proposal*; AER analysis.

Note: Numbers may not add up due to rounding.

Figure 6 shows our preliminary decision compared to Ergon Energy's past and proposed capex and our preliminary decision.

Figure 6 AER preliminary decision compared to Ergon Energy's past and proposed capex and AER preliminary decisions ($million 2014−15)



Attachment 6 sets out our detailed reasons for our preliminary decision on Ergon Energy's total forecast capex. We examined Ergon Energy's forecasting methodology, key assumptions and past capex performance. We conclude that Ergon Energy's forecasting methodology predominately relies upon a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure and that the top-down constraints imposed by their governance process are insufficient for us to be able to conclude that Ergon Energy's forecasts are prudent and efficient.

The key areas of difference between our substitute estimate and Ergon Energy's proposal are below:

- We have reduced Ergon Energy's proposed total capex forecast by $720.2 million to account for our decision on labour and material escalators. We are not satisfied that the labour and material escalators proposed by Ergon Energy reflect the capex criteria. We have applied labour and material escalators consistent with those determined in our opex assessment.
- We have reduced the revenue which Ergon Energy proposed to recover from consumers for repex by 25 per cent. We have included in our substitute estimate of overall total capex $674.6 million ($2014−15) for a reduction of $219.7 million ($2014−15) to Ergon Energy's proposed repex. This reduction reflects the outcomes of our predictive modelling and evidence that Ergon Energy has an overly conservative risk management approach and a bias towards overestimation in its repex forecast.
- We have reduced Ergon Energy’s proposed augex allowance by 15 per cent. We have included in our substitute estimate of overall total capex $559.0 million ($2014−15) for a reduction of $101.1 million ($2014−15) to Ergon Energy's proposed augex. We found that Ergon Energy generally followed a robust methodology to estimate the cost of augmentation; however its proposed augex for its sub-transmission and distribution networks is overestimated. This is because Ergon Energy did not consider the potential to defer some proposed augmentation projects based on risk-analysis and the likelihood that forecast demand may not eventuate in all parts of the network.
- We have allowed $961.8 million ($2014−15) for capitalised overheads. This is a reduction of $55.3 million ($2014−15) or 5 per cent to Ergon Energy's proposed capitalised overheads. Our assessment of Ergon Energy's proposed direct capex demonstrates that a prudent and efficient distributor would not undertake the full range of direct capex contained in Ergon Energy's proposal, it follows there is a decrease in Ergon Energy’s capitalised overheads. However, we also note that 34 per cent of Ergon Energy's proposed $1,017.11 million ($2014−15) total capitalised overheads is attributable to information, communications and technology (ICT) services. We have identified some issues regarding this expenditure which we expect Ergon Energy to address in its revised proposal.
- We have included in our alternative estimate of overall total capex an amount of $420.3 million ($2014−15) for non-network capex. This is a reduction on Ergon Energy’s proposed non-network capex of $506.3 million ($2014−15). Our reduction reflects our conclusion that Ergon Energy’s forecast capex for fleet, buildings and

property assets does not reflect the efficient costs of a prudent and efficient operator. In our view, the major property project proposed for Townsville is not economically justified and would not be undertaken by a prudent and efficient operator in the 2015−20 regulatory control period. We also consider our substitute estimate of Ergon Energy's fleet capex is in line with its fleet service requirements and operational employee numbers

2.7 Operating expenditure

Opex includes forecast operating, maintenance and other non-capital costs incurred in the provision of distribution network services. It includes labour costs and other non-capital costs that Ergon Energy is likely to require during the 2015–20 regulatory control period for the efficient operation of its network.

We are not satisfied that Ergon Energy's forecast opex reasonably reflects the opex criteria.[50] We therefore do not accept the forecast opex Ergon Energy included in its building block proposal.[51] In reaching this point we have compared Ergon Energy's regulatory proposal with our substitute estimate of total opex in table 8.[52]

We estimate total forecast opex over the forecast period of $1629.9 million ($2014–15). This is 89.5 per cent of Ergon Energy's forecast opex.

Table 8 AER preliminary decision and Ergon Energy's proposed total opex ($ million, 2014–15)

Year ending 30 June	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy's proposal	349.6	356.1	363.6	372.9	379.0	1821.1
AER preliminary decision	314.4	320.3	325.4	332.0	337.8	1629.9
Difference	–35.2	–35.8	–38.3	–40.9	–41.1	–191.3

Source: AER analysis.

Note: Excludes debt raising costs.

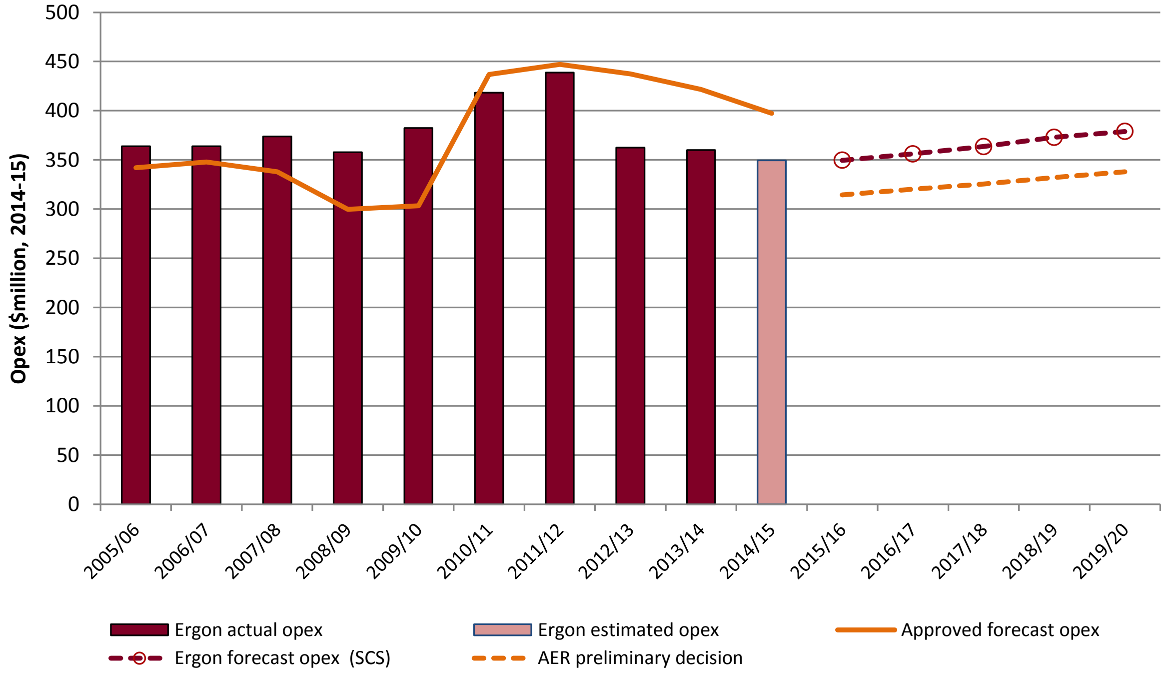
Figure 7 shows our preliminary decision compared to Ergon Energy's proposal, its past allowances and past actual expenditure.

50 NER, cl. 6.5.6(c).

51 NER, cl. 6.5.6(d).

52 NER, cl. 6.12.1(4)(ii).

Figure 7 AER preliminary decision compared to Ergon Energy's past and proposed opex ($million, 2014–15)

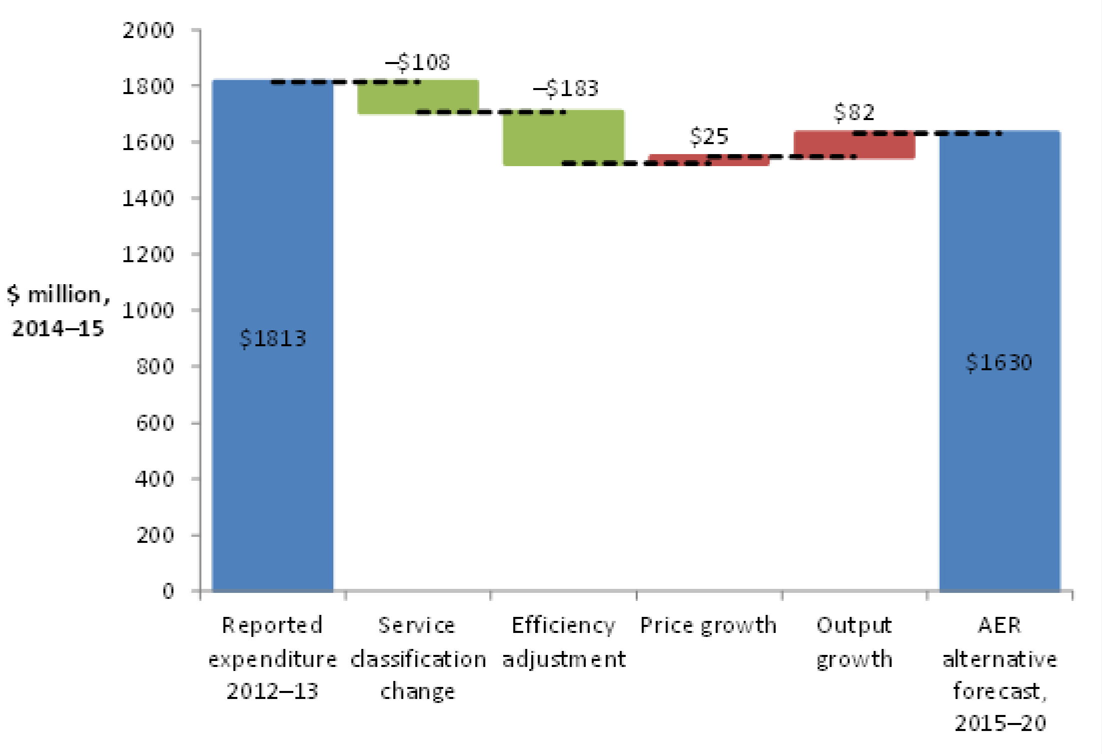


Note: The opex for the period 2005/06 to 2014/15 include some services that have been reclassified as ancillary reference services; the forecast opex for period 2015/16 to 2019/20 does not. The opex for the period 2005/06 to 2009/10 also includes debt raising costs; the opex and forecast opex for the period 2010/11 to 2019/20 do not.

Source: Ergon Energy, Regulatory accounts 2005/06 to 2009/10; Ergon Energy 2010/11–2014/15 PTRM, Annual Reporting RIN 2010/11–2013/14, *Regulatory proposal for the 2015–20 period* - Regulatory Information Notice; AER analysis.

Figure 9 illustrates how our forecast has been constructed. The starting point on the left is what Ergon Energy's opex would have been for the 2015–20 regulatory control period if it was set based on Ergon Energy's reported opex in 2012–13. The changes are discussed below.

Figure 91 Our preliminary decision opex forecast



The primary reason for the difference between our forecast opex amount and Ergon Energy's proposal reflects our views about the inefficiency of Ergon Energy's recent historical performance. We do not consider that its historical performance should be used as a starting point for the forecast of opex over the 2015−20 regulatory control period.

Ergon Energy's proposal is based on opex it incurred in 2012–13 (base year) in delivering standard control services. We assessed whether this is a reasonable starting point for forecasting Ergon Energy's opex over the 2015–20 period. We examined Ergon Energy's proposal using a number of different techniques including:

- top down benchmarking at both a total opex and category level
- detailed, qualitative reviews of the extent to which Ergon Energy and Energex had implemented the 2012 Independent Review Panel (IRP) investigation[53] into areas of inefficiencies in the Queensland service providers.

The body of evidence we assessed provided consistent evidence that Ergon Energy's historical costs including those proposed in the base year are above what a prudent and efficient operator would in incur in delivering safe and reliable network services to Ergon Energy's customers, given its operating environment.

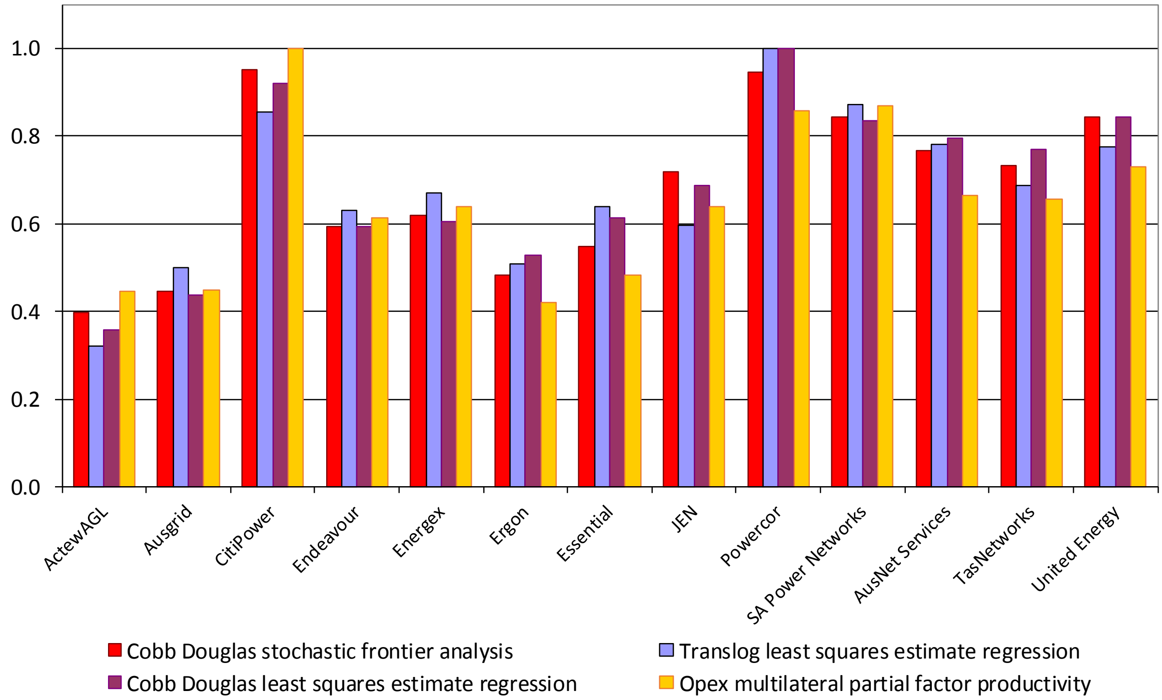
[53] Commissioned by the Interdepartmental Committee on Electricity Sector Reform (IDC), initiated by the Queensland Government.

Benchmarking

For this preliminary decision, we continue to rely on the economic benchmarking techniques developed by Economic Insights for assessing the relative efficiency of service providers compared to their peers. Economic Insights developed four benchmarking techniques that specifically compare opex performance, using data submitted by the distributors, over the period 2006 to 2013.

Figure 10 presents the results of each of Economic Insights' opex models for each distributor in the NEM. A score of 1 is the best score.

Figure 10 Econometric modelling and opex MPFP results (period average efficiency scores, 2006 to 2013)



Source: Economic Insights, 2014.

We are satisfied that Economic Insights' models are the best available for assessing opex efficiency. They are sophisticated techniques and similar to those used by regulators in other jurisdictions for benchmarking relative performance.[54] Economic Insights has reviewed in detail the critiques of its models and the alternative models presented by consultants engaged by Ergon Energy (and other service providers) and found its approach remains appropriate. Conversely, the alternative models presented

[54] ACCC/AER (2012), Benchmarking Opex and Capex in Energy Networks, ACCC/AER Working Paper number 6, May.

by other consultants contain assumptions or limitations that mean they are not appropriate.[55]

In addition to economic benchmarking, our analysis using partial performance indicators also show Ergon Energy to have higher costs than its peers.

Qualitative review

Deloitte found that while Energex and Ergon Energy have both achieved significant efficiency gains since the IRP's review (particularly reflected in FTE reductions), much of these benefits were realised after the 2012–13 base year. Deloitte also observed that the service providers have identified they can further reduce their costs. Further, the service providers have not yet addressed a number of IRP recommendations. Deloitte conclude that Ergon Energy's and Energex's opex prior to and in 2012–13 was higher than necessary to achieve efficient operations.[56]

Deloitte's key findings include:[57]

- Ergon Energy has high total labour costs compared to more efficient peers, which is a result of having too many employees rather than the cost per employee
- Ergon Energy's EBA prohibits certain activities (such as switching) from being conducted by a single person; in other states these activities can be performed by a single person
- certain EBA provisions, while not necessarily unique to Ergon Energy, limits its ability to quickly adjust their workforces flexibly and utilise them productively. This is amplified by the large proportion of employees engaged under EBAs. Examples include:
    - no forced redundancies
    - contractors are unable to perform certain tasks, such as switching (unique to QLD)
    - minimum apprentice numbers
    - restrictions on outsourcing
- Ergon Energy has not implemented the IRP's recommendation that they market test the information, communication and technology (ICT) services that SPARQ (a joint venture owned by Ergon and Energex) provides, resulting in inefficiency in base opex for both service providers
- Ergon Energy has not yet implemented a local service agenda LSA model for its regional depots, despite the IRP's recommendation (based on Powercor's success

55 Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, pp. iv-xi.

56 Deloitte, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. iv-xix.

57 Deloitte, *Queensland distribution network service providers - opex performance analysis*, April 2015, pp. iv-xix.

with this model) to do so. Deloitte considers Ergon Energy could realise efficiencies if it implemented an LSA model.

Our estimate of base opex

On the basis of the above factors, we consider that a forecast opex amount based primarily on Ergon Energy's recent historical opex would not reasonably reflect the opex criteria. We have substituted Ergon Energy's opex forecast with an alternative estimate that we are satisfied does reasonably reflect the opex criteria.

Our estimate of base opex is based on a benchmarking model that estimates the efficient cost of delivering network services based on a selection of cost drivers Ergon Energy faces. In applying the results of this model we had further regard to over 60 potential operating environment factors that may affect Ergon Energy's opex not explicitly captured in the model.

Economic Insights has also reconsidered the benchmark comparison point and decided a more cautious target is appropriate, particularly given this is the first time economic benchmarking is being used as the primary basis for an Australian regulatory decision. The benchmark comparison point is now the lowest of the efficiency scores in the top quartile of possible scores (AusNet Services).[58]

The adjustment we have made to Ergon Energy's base opex includes a:

- 24.4 per cent allowance for exogenous operating environment factors
- cautious benchmark comparison point of 0.77.

Table 9 shows our final determination estimate of efficient base year opex for Ergon Energy.

Table 9 Final determination estimate of efficient base year opex ($million 2013–14)

	Ergon Energy
Revealed base opex (adjusted)a	341.1
AER base opex	304.6
Difference	36.5
Percentage opex reduction	10.7%

Note: (a) we have adjusted Ergon Energy’s proposed opex for debt raising costs, new CAM (if applicable) and new service classifications.

58 Economic Insights, *Response to Consultants’ Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, pp. iv-xi.

Step changes

Step changes allow for adjustments to our estimate of opex that reflects the opex criteria to account for changed circumstances in the forecast period that we have not otherwise addressed in our alternative opex forecast.

Ergon Energy proposed step changes, non-recurrent expenditure adjustments and a bottom-up adjustment for parametric insurance totalling $146.4 million ($2014–15). We have not included any of these items in our opex estimate.

There were several reasons we did not include step changes proposed by Ergon Energy in our opex forecast, in particular:

- We were not satisfied Ergon Energy had demonstrated it faced increased regulatory obligations or requirements in the forecast period.
- The proposals were for costs which we would typically consider to be business as usual expenses, and therefore taken into account in our estimate of base opex.

2.8 Corporate income tax

The NER requires us to make a decision on the estimated cost of corporate income tax for Ergon Energy's 2015–20 regulatory control period.[59] The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for Ergon Energy over the 2015–20 regulatory control period. It enables Ergon Energy to recover the costs associated with the estimated corporate income tax payable during that period.

We forecast Ergon Energy's corporate income tax allowance at $204.2 million ($ nominal) over the 2015–20 regulatory control period as set out in table 10. This is instead of Ergon Energy's proposed cost of corporate income tax allowance of $621.4 million. Our preliminary decision is 38.5 per cent of the amount Ergon Energy proposed.

Table 10 AER's preliminary decision on Ergon Energy's cost of corporate income tax allowance for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Tax payable	60.5	64.6	68.6	74.6	71.9	340.3
Less: value of imputation credits	24.2	25.8	27.5	29.9	28.8	136.1
Corporate income tax allowance	**36.3**	**38.8**	**41.2**	**44.8**	**43.1**	**204.2**

Source: AER analysis.

59 NER, cl. 6.4.3(a)(4).

Our preliminary decision reflects our amendments to some of Ergon Energy's proposed inputs for forecasting the cost of corporate income tax such as the opening tax asset base, and the remaining tax asset lives. It also reflects our preliminary decision on the value of imputation credits (gamma) discussed in attachment 4. Our preliminary decision changes to other building block costs that affect revenues also impact the tax calculation.

Details of our preliminary decision on the corporate income tax allowance are set out in attachment 8.

3 Classification of services, control mechanisms and schemes

A range of factors, in addition to the building blocks, affect Ergon Energy's revenues. These include service classification, the control mechanism, incentive schemes to promote efficiency, and our approach to services charged to individual consumers. This section sets out our approach to these issues.

3.1 Classification of services and control mechanisms

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our preliminary decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Our preliminary decision is to retain the classification structure set out in our Framework and Approach (F&A),[60] subject to a small number of changes. The changes we have made will facilitate competition in the provision of metering services.

We have also refined the definitions of network services (standard control) and metering services (alternative control) to make clear our intended approach to the classification of load control services. Load control services provided by equipment located outside a type 5 or 6 meter are grouped with network services and classified standard control. Load control services provided by a type 5 or 6 meter are grouped with ancillary metering services and classified alternative control.

Figure 11 summarises our preliminary decision on service classifications for the 2015–20 regulatory control period.

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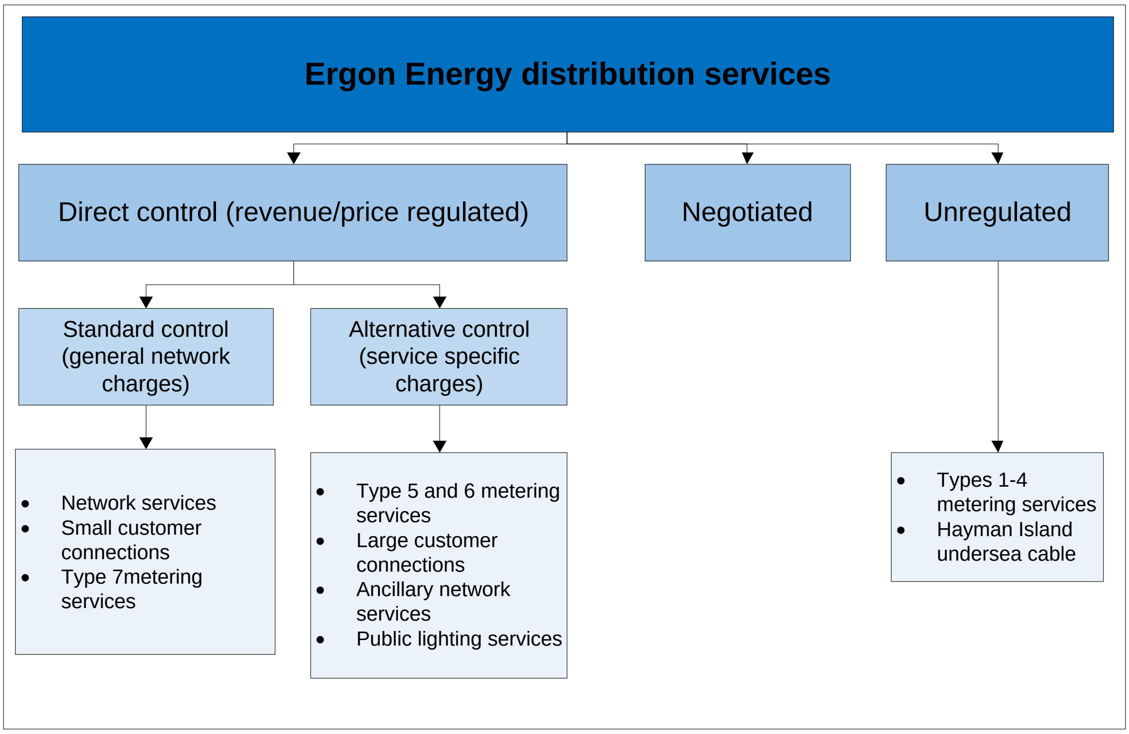
60 AER, *Final F&A for Energex and Ergon Energy*, April 2014.

Figure 11 AER preliminary decision on 2015–20 service classifications for Ergon Energy



Source: AER.

In accordance with our F&A, Ergon Energy will be subject to a 'revenue cap' form of control for standard control services over the next regulator control period. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap. The detailed prescription of how service charges are set is discussed in the control mechanisms attachment.[61]

3.2 Alternative control services

Alternative control services do not form part of Ergon Energy's revenue cap. Rather, the prices of these services are set individually. Our preliminary decision is to maintain the approach adopted in our F&A, that the form of control mechanism to apply to Ergon Energy's alternative control services will be price caps. Ergon Energy must demonstrate compliance with the control mechanism through an annual pricing proposal.

To avoid large metering transfer or exit fees, we consider Ergon Energy should recover the residual cost of its redundant meters from all customers through an alternative

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61 See attachment 13 for standard control services and attachment 16 for alternative control services.

control service charge. By switching, customers may avoid the operating costs that would be charged Ergon Energy for type 5 or 6 metering services.

We did not approve large upfront metering transfer or exit fees which would be a barrier to competitive entry. Instead, when a customer switches to a competitive metering provider, they will continue to pay a regulated annual charge that recovers the fixed capital costs associated with their past regulated type 5 or 6 metering service.

On 26 March 2015, the AEMC made a draft determination and draft rule in relation to the provision of metering and related services in the NEM. The rule change proposes to expand competition in metering and related services and facilitate a market led roll out of advanced metering technology.[62] We have sought to create a regulatory framework robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.

Our preliminary decision does not accept Ergon Energy's proposed:

- annual metering service charge, because the forecast capital and labour costs do not reasonably reflect the efficient costs of a prudent operator
- price caps for new and upgraded connections, for similar reasons
- transfer or exit fee to switching customers to recover residual metering or administrative costs.

3.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to Ergon Energy are:

- The capital expenditure sharing scheme (CESS)
- The service target performance incentive scheme (STPIS)
- The demand management incentive scheme (DMIS).

The AER has a forth scheme; the efficiency benefit sharing scheme (EBSS) which will not be applied to Ergon Energy. We discuss this below.

3.3.1 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) provides an additional incentive for service providers to pursue efficiency improvements in its opex.

Because opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period (step changes provide for increases where this is

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[62] AEMC, *Draft Rule Determination: National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, 26 March 2015.

not the case). Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period to forecast opex for the next regulatory control period. We call this the 'revealed cost approach'.

To encourage a distributor to become more efficient during the regulatory control period it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the distributor to retain efficiency savings and efficiency losses for a longer period of time. In total these rewards and penalties work together to provide a continuous incentive for a service provider to pursue efficiency gains over the regulatory control period. The EBSS also discourages a distributor from incurring opex in the expected base year in order to receive a higher opex allowance in the following regulatory control period.[63]

Our preliminary decision on the EBSS for Ergon Energy is outlined in Attachment 9.

3.3.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for network service providers whose capex becomes more efficient throughout the regulatory control period and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

The CESS is not predicated on addressing incentives resulting from a revealed cost forecasting approach. The purpose of the CESS is to provide a continuous incentive to deliver efficient overall capex and to share the benefits of capex efficiency gains (or costs of capex efficiency losses) between the distributor and consumers. The way in which capex underspends and overspends are shared occurs independently of how the EBSS applies, and independently of the precise amount of total forecast capex.[64]

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[63] These concepts are explained more fully in the explanatory statement to the EBSS, AER, *Efficiency benefit sharing scheme for electricity network service providers - explanatory statement*, November 2013.

[64] For capex, the sharing of underspends and overspends happens at the end of each regulatory control period when we update a network service provider's RAB to include new capex. If a network service provider spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the service provider had spent the full amount of the capex forecast.

We will apply version 1 of the CESS as set out the Capital Expenditure Incentives Guideline to Ergon Energy in the 2015–20 regulatory control period as Ergon Energy proposed.[65] Attachment 10 sets out our reasons for our preliminary decision on CESS.

3.3.3 Service target performance incentive scheme (STPIS)

We will apply the s-factor component of our national STPIS to Ergon Energy for the 2015–20 regulatory control period. We will not apply the guaranteed service level (GSL) component to Ergon Energy as the existing Queensland arrangements will continue to apply. We have accepted Ergon Energy's proposal to cap revenue at risk under the scheme at ±2 per cent.

The national STPIS is intended to balance the incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to distributors to maintain and improve service performance (where customers are willing to pay for these improvements).[66] Hence, the STPIS also provides an incentive for distributors to invest in further reliability improvements (via additional capex or opex) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

In conjunction with CESS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex are achieved efficiently, rather than at the expense of service levels to customers.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

Attachment 11 sets out our preliminary decision on Ergon Energy's service component parameter values.

3.3.4 Demand management incentive scheme

The demand management incentive scheme (DMIS) includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

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65 Ergon Energy, *Regulatory Proposal,* October 2014, p. 29.

66 AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009. (AER, *Electricity distribution STPIS*, Nov 2009

We have determined to continue Part A of the Demand Management Innovation Allowance (DMIA) to Ergon Energy in the 2015–20 regulatory control period. This is consistent with our proposed approach in final F&A.

Ergon Energy will continue to be able to recover an amount of $1 million ($2014-15) per annum in the 2015–20 regulatory control period for innovation.

4 Regulatory framework

The NEL and the NER provide the regulatory framework under which we operate. These set out how we must assess a regulatory proposal and make our decision. In this section we set out some key aspects of this framework.

The NEO is the central feature of the regulatory framework. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[67]

The NEL also includes the revenue and pricing principles (RPP), which support the NEO.[68] As the NEL requires,[69] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
>   - as the case requires, distribution determination or transmission determination; or

[67] NEL, s. 7.

[68] NEL, s. 7A.

[69] NEL, s. 16(2).

- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

- in the Rules.

> A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all of the elements of the NEO and consider each of the RPPs are equally vital.[70]

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes detailed rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[71] The AEMC has made it clear that, in relation to key aspects of revenue, the rules guide the AER, but do not dictate any specific regulatory outcome.[72] For example, the AEMC has said:

> Some stakeholders appear to have understood the objectives as imposing on the regulator a requirement and that failure to comply with this would mean the regulator is in breach of the rules. This is not the case. Although the language of an obligation is used in some objectives, it is not necessarily expected that the substance of the objective will always be fully achieved, but rather the regulator should be striving to achieve the objective as fully as possible.

Given this framework, we consider the NEO and how to achieve it throughout our decision making processes.

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70 Hansard, SA House of Assembly, 27 September 2007 p. 965; Hansard, SA House of Assembly, 26 September 2013, p. 7173.

71 NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* p. 8.

72 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 33-34; AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. 35-6.

4.1 Understanding the NEO

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.[73] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[74]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[75] In most industries, competition creates this outcome. Competition drives suppliers to develop their offerings to attract customers. Where a supplier's offering is not attractive it risks being displaced by other suppliers.

However, in the energy networks industry the usual competitive disciplines do not apply. Distributors are largely natural monopolies. In addition, many of the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the quality, reliability and price the distributors offer.

The NEL and NER aim to remedy the absence of competition by providing that we, as the regulator, make decisions that are in the long term interests of consumers. In particular, we might need to require the distributors to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory judgement to balance the NEO's various factors.

It is important to recognise that there are a number of plausible outcomes that may contribute to the achievement of the NEO. The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[76] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO to a satisfactory extent. For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[77] This could have significant longer term pricing implications for those consumers who continue to use network services.

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73 Hansard, SA House of Assembly, 9 February 2005, pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007, pp. 963–972.
Hansard, SA House of Assembly, 26 September 2013, pp. 7171–7176.

74 Hansard, SA House of Assembly, 26 September 2013, p. 7173.

75 Hansard, SA House of Assembly, 9 February 2005, p. 1452.

76 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50.

77 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[78] and could have adverse consequences for safety, security and reliability of the network.

4.2 The 2012 framework changes

This is the first decision we have made for Ergon Energy following changes to the NEL and NER in 2012 and 2013. The NEL and NER were amended to provide greater emphasis on the NEO and greater discretion to us.[79] The amended NER allow, and the AEMC has encouraged us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs.[80] Further, one of the purposes of these changes was to give consumers a clearer and more prominent role in the decision making process.[81]

In 2013, the NEL was changed with similar aims in mind. The long term interests of consumers are a key focus of the changes.[82] The changes also support analysing the decision *as a whole* in light of the NEO.[83]

The NEL now requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision.[84] It also anticipates the possibility of two or more decisions that will or are likely to contribute to the achievement of the NEO. It requires that, in those cases, we must make the decision we are satisfied will or is likely to contribute to the

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78 NEL, s. 7A(6).

79 NEL, ss. 16(1)(d) and 71P(2a)(c). AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. i, iii, iv, vi, vii, 8, 24 32, 36, 38, 45, 49, 67, 68, 90, 96 106, 112 and 113.
Hansard, SA House of Assembly, 26 September 2013 p. 7172.

80 For example, NER, cl. 6.5.2(b) and (c), 6.5.6(a) and 6.5.7(a).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. xi, 10, 19, 32 and 35.

81 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* esp. pp. 166–170.

82 Hansard, SA House of Assembly, 26 September 2013 p. 7171.

83 NEL, ss. 2, 16, 71A and 71P which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
Hansard, SA House of Assembly, 26 September 2013, pp. 7171 and 7173; See also NEL, ss. 2, 16 and 71A which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
SCER, *Regulation Impact Statement – Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks*' 6 June 2013, pp. i, ii, 6–7, 10, 36, 41 and 76.

84 NEL, s. 16(c).

achievement of the NEO to the greatest degree.[85] The NER requires that we provide reasons for our decisions.[86]

The NEL does not prescribe how we are to apply these overarching requirements and so in applying them, we have exercised our regulatory judgement. We have done so by determining revenue in accordance with the detailed provisions in the NER. This assessment is in each of our attachments. As part of that assessment, and in accordance with the NEL requirements, we identify and assess interrelationships between the constituent components of our preliminary decision. In the following sections, we explain our approach to evaluating these interrelationships and then set out how we assessed what will contribute to the achievement of the NEO to the greatest degree. Section 1 of this overview demonstrates how we have applied these approaches for this decision.

This preliminary decision is made under transitional rules made to allow for revenue determinations to be made across the National Electricity Market that apply the changes to the NEL and the NER described above. For distributors in Queensland and South Australia, this has involved the making of a 'preliminary decision which is revoked and substituted with a final decision (see sections 5.2.1 and 6 below for more detail), in lieu of the usual process of making draft and final decisions.

Under the usual process, our draft decision has no effect on revenues or prices. In contrast, this preliminary decision will be used to determine prices for the first year of the regulatory control period. Any difference between the preliminary and final decisions will be accounted for by way of an adjustment to revenues in the balance of the regulatory control period (see section 5.2.1).

4.2.1 Interrelationships

A distribution determination is a complex decision and must be considered as such. Considering constituent components in isolation ignores the importance of these interrelationships between the components and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[87] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark

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85 NEL, s. 16(1)(d).

86 NER, cl. 6.11.2(c).

87 SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013, p. 6.

efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our preliminary decision. These considerations are explored in the relevant attachments.

5 Process

The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of this preliminary decision.[88]

Below we set out the process we have followed leading up to Ergon Energy's submission of its regulatory proposal, to ensure that we have fully taken into account all views.

5.1 Better Regulation program

Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[89] The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[90]

The resulting Guidelines support our decision making framework as set out in section 16 of the NEL. Our consultation and engagement gives us confidence the approaches set out in the Guidelines, which we have applied in this decision, will result in decisions that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation Guidelines are available on our website and include:[91]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline for Network Service Providers
- Shared Assets Guideline
- Confidentiality Guideline.

5.2 Our engagement during the decision making process

Effective consultation with stakeholders is essential to the performance of our regulatory functions. In summary, throughout the review process, we engaged with stakeholders by:

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88 NEL, s. 16(1)(b).
89 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.
90 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.
91 www.aer.gov.au/Better-regulation-reform-program

- holding monthly meetings with Ergon Energy to discuss issues relevant to this decision. These meetings commenced in May 2013 to discuss the framework and approach. The meetings continued throughout our decision making process.
- establishing the CCP to assist us to make better regulatory determinations by providing input on issues of importance to consumers
- publishing an issues paper to help stakeholders engage with, and meaningfully respond to issues in Ergon Energy's regulatory proposal that we considered material to consumers
- hosting a public forum in Brisbane on 9 December 2014 so stakeholders could question the AER, the CCP and Ergon Energy on its regulatory proposal
- having Ergon Energy present its regulatory proposal to the AER Board on 16 January 2015, so questions could be raised and key issues explained
- having the CCP present its advice in response to Ergon Energy's regulatory proposal to the AER Board on 6 February 2015
- considering 33 submissions on Ergon Energy's regulatory proposal. A list of all submissions is at appendix B
- convening monthly meetings between the CCP and AER staff to discuss key issues
- ongoing formal and informal jurisdictional consumer forums from November 2013.
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of Ergon Energy's regulatory proposal
- having ongoing discussions with Ergon Energy about its regulatory proposal. In particular, our consultants and AER staff met with Ergon Energy to discuss opex, augex and repex. During this process, AER staff and our consultants considered over 65 responses to information requested from Ergon Energy.
- releasing a brief consultation paper on recovering the residual metering capital costs through an alternative control service charge and considering 19 submissions in response.

We investigated Ergon Energy's proposal by engaging with our consultants and visiting Ergon Energy at its offices. AER staff, including our technical advisors and Energy Market Consulting associates (EMCa) directly engaged with Ergon Energy staff involved in developing and managing the network, and tested material and information which underpins its regulatory proposal.

5.2.1 Revocation and substitution of preliminary decision

In November 2012, the AEMC introduced major changes to the economic regulation of electricity distributors under chapter 6 of the NER.[92]

To allow consumers to receive the benefit of the new rules the AEMC made transitional rules under chapter 11 of the NER. The NER provide that we will:[93]

- make a preliminary determination for the 2015−20 regulatory control period by 30 April 2015
- use the preliminary determination as a basis for approving prices for 1 July 2015 to 30 June 2016
- it will also set out how we will apply a revenue adjustment that will 'true up' Ergon Energy's revenue over the regulatory control period to account for any difference between the preliminary determination and the final decision affecting its revenue for the 2015−16 regulatory year.

The true-up will be calculated using forecasts as actual data for 2014−15 that will not be available when the final decision is published in October 2015.

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92 AEMC, *Final Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

93 NER, cl. 11.60.4.

6 Next steps

At time of publishing this preliminary decision for the 2015−20 regulatory control period, the NER requires us to invite written submissions on the revocation and substitution of our preliminary decision.[94] This invitation is published on the AER website.

Any person may make a written submission to us on our preliminary decision including the revocation and substitution of our decision. The NER also allowed Ergon Energy to make a submission in the form of revisions to its regulatory proposal submitted in October 2014.[95]

After considering submissions, including revisions that Ergon Energy may submit we must revoke our preliminary decision and substitute it with a final decision by 31 October 2015.[96] Key dates for our assessment process are set out in table 11 below.

Table 11 Key dates for our assessment process

Task	Date
Ergon Energy's regulatory proposal submitted to AER	30 October 2014
Published Ergon Energy's regulatory proposal and supporting documents	19 November 2014
AER released Issues paper on Ergon Energy's regulatory proposal	5 December 2014
AER public forum	9 December 2014
Stakeholder submissions on regulatory proposal closed	30 January 2015
AER issues preliminary decision	30 April 2015
AER conference to explain preliminary decisions	12 May 2015
Stakeholder submissions on AER's preliminary decision close	3 July 2015
Ergon Energy's revised proposal due to AER	3 July 2015
Stakeholder submissions on Ergon Energy's revised proposal close*	24 July 2015
AER issues final decision	31 October 2015

* The NER, under transitional provisions, did not provide for consultation on Ergon Energy's revised proposal, however we have added it to provide stakeholders with an opportunity to comment.

94 NER, cll. 6.11.2 and 11.60.4(a).
95 NER, cl. 11.60.4(b).
96 NER, cl. 11.60.4(c).

A Constituent decisions

Our preliminary distribution determination is predicated on the following decisions (constituent decisions):[97]

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to Ergon Energy for the 2015–20 regulatory control period (listed by service group): • Standard control services include network services, small customer connections and type 7 metering services • Alternative control services include metering types 5 and 6 metering services, large customer connections, ancillary network services and public lighting • Unregulated services includes type 1 to 4 metering services and the Hayman Island undersea cable. Attachment 13 discusses classification of services.
In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in Ergon Energy's building block proposal. Our preliminary decision on Ergon Energy's annual revenue requirement for each year of the 2015–20 period is set out in attachment 1 of the preliminary decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Ergon Energy's proposal that the regulatory control period will commence on 1 July 2015. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Ergon Energy's proposal that the length of the regulatory control period will be five years from 1 July 2015 to 30 June 2020.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER does not accept Ergon Energy's proposed total forecast capital expenditure of $3397.0 million ($2014–15). Our substitute estimate of Ergon Energy's total forecast capex for the 2015–20 regulatory control period is $2182.0 million ($2014–15). This is discussed in attachment 6 of the preliminary decision.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept Ergon Energy's proposed total forecast operating expenditure inclusive of debt raising costs of $1882.3 million ($2014–15). Our substitute estimate of Ergon Energy's total forecast opex for the 2015–20 regulatory control period is $1655.3 million ($2014–15). This is discussed in attachment 7 of the preliminary decision.
In accordance with clause 6.12.1(4A)(i) and (iv) the AER determines that Ergon Energy's proposed 'Aquis development project' and 'general contingent project for large customer connections' are not contingent projects. Our reasons for these conclusions are in attachment 6 of the preliminary decision.
In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept Ergon Energy's proposal of 8.02 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 5.85 per cent as set out in table 3.1 of attachment 3 of the preliminary decision. This rate of return will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 (appendix I) of the preliminary decision.
In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in f attachment 4 of the preliminary decision.
In accordance with clause 6.12.1(6) the AER's decision on Ergon Energy's regulatory asset base as at 1 July 2015 in accordance with clause 6.5.1 and schedule 6.2 is $10 102.2 million. This is set out in attachment 2 of the preliminary decision.

[97] NER, cl. 6.12.1.

Constituent decision
In accordance with clause 6.12.1(7) the AER does not accept Ergon Energy's proposed corporate income tax of $621.4 million ($ nominal). Our decision on Ergon Energy's corporate income tax is $204.2 million ($ nominal). This is set out in attachment 8 of the preliminary decision.
In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by Ergon Energy. This is set out in attachment 5 of the preliminary decision.
In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply: • In accordance with clause 6.12.1(9) of the NER, the AER's decision is that no expenditure will be subject to the EBSS for Ergon Energy in the 2015–20 regulatory control period. • In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Ergon Energy in the 2015–20 regulatory control period. • In accordance with clause 6.12.1(9) of the NER, the AER's Electricity distribution network service providers, Service target performance incentive scheme, November 2009 (STPIS) will apply to Ergon Energy in the 2015−20 regulatory control period. • In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to Ergon Energy for the 2015-20 regulatory control period. o We will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as Ergon Energy must comply with its existing Queensland jurisdictional guaranteed service level scheme. o A beta of 2.5 will be used to calculate the major event day boundary. o Our decision on the SAIDI and SAIFI incentive rates and performance targets to apply to Ergon Energy for the 2015-20 regulatory control period are set out in tables 11-1 and 11-3 of attachment 11 of this preliminary decision. o Our decision on the customer service incentive rate and performance target are set out in sections 11.1.2 and 11.1.3 of attachment 11 of this preliminary decision. o The revenue at risk for Ergon Energy will be capped at ±2.0 per cent. Within this there will be a cap of ±0.2 per cent on the telephone answering parameter for performance. Note: The meaning for year "t" under the price control formula for this determination is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision. • The AER has determined to continue Part A of the Demand Management Innovation Allowance (DMIA) for Ergon Energy in the 2015–20 regulatory control period
In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.
In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Ergon Energy for any given regulatory year is the total revenue (TAR) calculated using the formula in section 14.5.3 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14.
In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps. This is discussed in attachment 16.
In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is Ergon Energy must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 14.
In accordance with clause 6.12.1(14) the AER's decision on the additional pass through events that are to apply is to not to accept the nominated pass through events as proposed by Ergon Energy. The AER substitutes its own definitions for the following events:

Constituent decision
• insurance cap event • natural disaster event • insurance event.
In accordance with clause 6.12.1(15) the AER's decision is to approve Ergon Energy's proposed negotiating framework. The negotiating framework that is to apply to Ergon Energy is set out at attachment 17 of the preliminary decision.
In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in November 2014 to Ergon Energy. This is set out is at attachment 17of the preliminary decision.
In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes for Ergon Energy is set out at attachment 14 of the preliminary decision.
In accordance with clause 6.12.1(18) the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of Ergon Energy's regulatory control period (1 July 2020). This is discussed in attachment 2 of the preliminary decision.
In accordance with clause 6.12.1(19) the AER's decision on how Ergon Energy is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The AER accepts Ergon Energy's proposed methodology to account for under and over recovery of charges. However, we require Ergon Energy to treat specific charges as designated pricing proposal charges in subsequent pricing proposals. This is discussed in attachment 14 of the preliminary decision.
In accordance with clause 6.12.1(20) the AER's decision is we require Ergon Energy to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the preliminary decision.
In accordance with clause 6.12.1(21) the AER approves a modified version of the connection policy proposed by Ergon Energy in its regulatory proposal. This is set out in attachment 18 of the preliminary decision

B List of submissions

We received 33 submissions in response to Ergon Energy's regulatory proposal as listed below:

	Submission from	Date received	Submission on
1	Queensland Consumers Association	30/01/2015	Qld distributors
2	Darling Downs Cotton Growers	30/01/2015	Qld distributors
3	Energy Retailers Association of Australia (ERAA)	30/01/2015	Qld distributors
4	Local Government Association of Queensland	30/01/2015	Qld distributors
5	Cotton Australia	30/01/2015	Qld distributors
6	AngloAmerican (Confidential submission)	30/01/2015	Ergon Energy
7	SPA Consulting Engineers	30/01/2015	Ergon Energy
8	Vector Limited	30/01/2015	Qld and SA distributors
9	Canegrowers	30/01/2015	Qld distributors
10	Townsville Enterprise	30/01/2015	Ergon Energy
11	FNQ Regional Organisation of Councils	30/01/2015	Ergon Energy
12	Urban Development Institute of Australia (UDIA) Queensland	30/01/2015	Ergon Energy
13	Central Highlands Cotton Growers & Irrigators Inc.	30/01/2015	Qld distributors
14	Bundaberg Regional Irrigators Group	30/01/2015	Ergon Energy
15	Alliance of Electricity Consumers	30/01/2015	Ergon Energy
16	Electrical Trades Union (ETU)	30/01/2015	Qld distributors
17	Australian PV Institute	30/01/2015	Qld distributors
18	Canegrowers Isis	30/01/2015	Qld distributors
19	Origin	30/01/2015	Qld distributors
20	Ergon Energy	30/01/2015	Ergon Energy
21	National Irrigators' Council	30/01/2015	Ergon Energy
22	Queensland Resources Council (QRC)	30/01/2015	Ergon Energy
23	Cummings Economics	30/01/2015	Ergon Energy
24	Regional Development Australia Far North Queensland & Torres Strait Inc.	30/01/2015	Qld distributors
25	Queensland Council of Social Service (QCOSS)	30/01/2015	Qld distributors
26	Consumer Challenge Panel Sub-Panel 2	30/01/2015	Qld distributors
27	Total Environment Centre	30/01/2015	Qld distributors

	Submission from	Date received	Submission on
28	Australians in Retirement	30/01/2015	Qld distributors
29	Chamber of Commerce & Industry Queensland (CCIQ)	30/01/2015	Ergon Energy
30	COTA Qld	30/01/2015	Ergon Energy
31	Energy Users Association of Australian (EUAA)	30/01/2015	Ergon Energy
32	Queensland Farmers Federation	05/02/2015	Qld distributors
33	Mulpha Australia Ltd	11/02/2015	Ergon Energy