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

Attachment 1 − Annual revenue requirement

April 2015

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Note

This attachment 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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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Contents

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

Shortened form	Extended form
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
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 Annual revenue requirement

The annual revenue requirement (ARR) is the sum of the various building block costs for each year of the regulatory control period before smoothing. The ARRs are smoothed across the period to reduce fluctuations between years and to determine expected revenues for each year. The expected revenues are the amounts that Ergon Energy will target for annual pricing purposes and recover from customers for the provision of standard control services for each year of the regulatory control period. This attachment sets out our preliminary decision on Ergon Energy's ARRs and expected revenues for the 2015–20 regulatory control period.

1.1 Preliminary decision

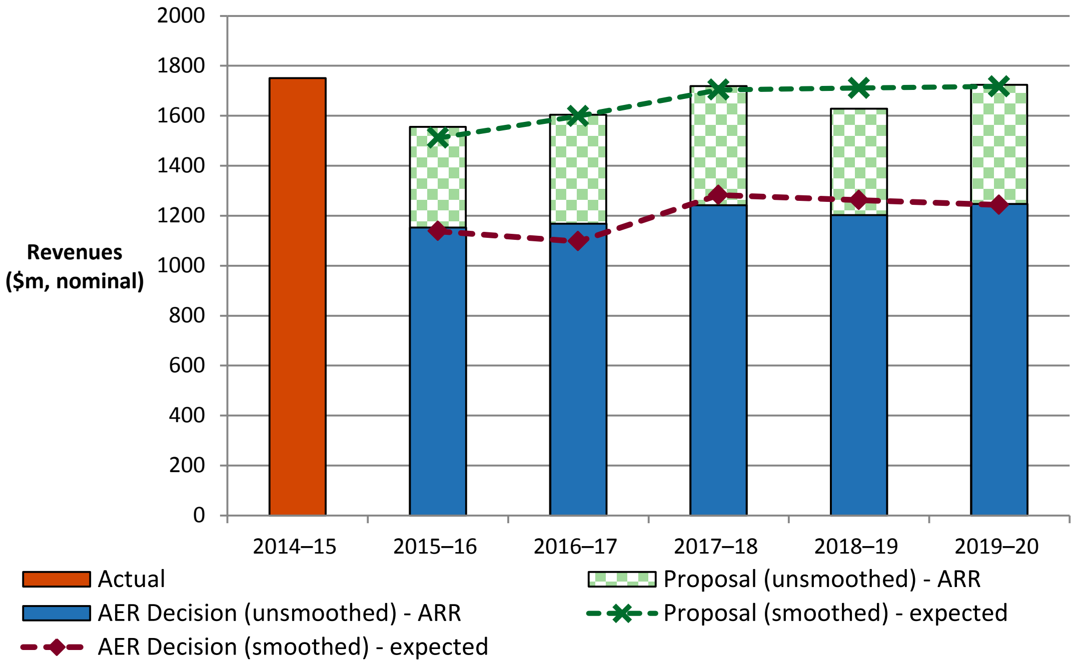
We do not accept Ergon Energy's proposed total revenue requirements of $8228.6 million over the 2015–20 regulatory control period. This is because we have not accepted the building block costs in Ergon Energy's proposal. We determine a total revenue requirement (excluding additionals) of $6012.6 million ($ nominal) for Ergon Energy for the 2015–20 regulatory control period, reflecting our preliminary decision on the various building block costs. This is a reduction of $2216.1 million ($ nominal) or 26.9 per cent to Ergon Energy's proposal.

As a result of our smoothing of the ARRs, our preliminary decision on the annual expected revenue and X factor for each regulatory year of the 2015–20 regulatory control period is set out in Table 1.1. Our preliminary decision is to approve total expected revenues (excluding additionals) of $6021.5 million ($ nominal) for the 2015–20 regulatory control period.

Figure 1.1 shows the difference between Ergon Energy's proposal and our preliminary decision.

Table 1.1 shows our preliminary decision on the building block costs, the ARR, annual expected revenue and X factor for each year of the 2015–20 regulatory control period.

Figure 1.1 AER's preliminary decision on Ergon Energy's revenues for the 2015–20 regulatory control period ($million, nominal)



Source: Ergon Energy, *Regulatory Proposal*, October 2014, pp. 27–28; AER analysis.

Table 1.1 AER's preliminary decision on Ergon Energy's revenues for 2015–20 regulatory control period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	590.8	617.0	640.4	658.9	674.6	3181.7
Regulatory depreciation	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[a]	91.9	49.1	66.9	–21.4	–2.3	184.2
Net 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[b]	36.63%	6.00%	–14.00%	4.00%	4.00%	n/a
Additional amounts in DUoS[c]	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) Revenue adjustments include efficiency benefit sharing scheme carry-overs, forecast DMIA and DUoS under recoveries.

(b) The X factors from 2016–17 to 2019–20 will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(c) 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.

1.2 Ergon Energy's proposal

Ergon Energy proposed total expected revenue (excluding additionals) of $8241.7 million ($ nominal) for the 2015–20 regulatory control period. Table 1.2 shows Ergon Energy's proposed building block costs, the ARR, expected revenue and X factor for each year of the 2015–20 regulatory control period.

Table 1.2 Ergon Energy's proposed revenues for the 2015–20 regulatory control period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	804.9	853.8	900.5	941.7	986.9	4487.8
Regulatory depreciation	173.5	191.7	207.7	160.8	170.3	903.9
Operating expenditure	370.5	387.2	405.7	426.6	444.8	2034.7
Efficiency benefit sharing scheme (carryover amounts)	96.1	55.1	79.7	–18.4	0.0	212.4
Net tax allowance	115.7	122.3	131.5	123.6	128.3	621.4
Shared assets adjustment[a]	–6.0	–6.2	–6.3	–6.5	–6.7	–31.7
Annual revenue requirement (unsmoothed)	1554.7	1603.9	1718.6	1627.8	1723.6	8228.6
Annual expected revenue (exc. additionals)	**1511.1**	**1598.5**	**1703.8**	**1710.7**	**1717.6**	**8241.7**
X factor	15.85%	–3.13%	–3.92%	2.11%	2.11%	n/a
Additional amounts in DUoS[b]	424.3	331.7	104.9	102.1	99.2	1062.2
Annual expected revenue (inc. additionals)	**1935.4**	**1930.2**	**1808.7**	**1812.8**	**1816.8**	**9303.9**

Source: Ergon Energy, *Regulatory Proposal*, October 2014, pp. 27–28; AER analysis.

(a) Ergon Energy proposed a separate line item for its proposed shared asset adjustment. While we have approved some proportion of this adjustment, it is included in our 'revenue adjustments' line.

(b) These amounts have been included based on information provided in Ergon Energy's proposal. Ergon Energy did not smooth its revenue having regard to these amounts. In contrast, while the amounts are not in the underlying building block, we have had regard to their impact on total revenue while smoothing the building blocks.

1.3 AER's assessment approach

We are required to determine the ARR for Ergon Energy for each year of the 2015–20 regulatory control period.[1]

In this determination we first calculate ARRs for each year of the 2015–20 regulatory control period. To do this we consider the various costs facing the service provider and the trade-offs and interactions between these costs, service quality and across years. This reflects the AER's holistic assessment of the service provider's proposal.

The ARR for each year is the sum of the building block costs. These building block costs are set out in section 1.3.1. The AER's post-tax revenue model (PTRM) brings together these building block costs and calculates the resulting ARRs.

We understand the trade-offs that occur between building block costs and test the sensitivity of these costs to their various driver elements. These trade-offs are discussed in the interrelationships section of the various attachments to this preliminary decision and are reflected in the calculations made in the PTRM developed by the AER.[2] Such understanding allows the AER to exercise judgement in determining the final inputs into the PTRM and the ARRs that result from this modelling.

Having determined the total revenue requirement for the 2015–20 regulatory control period, the ARRs for each regulatory year are smoothed across the 2015–20 regulatory control period. This is to reduce revenue variations between years and to come up with the expected revenue for each year. This is done through the determination of the X factors.[3] The X factor must equalise (in net present value terms) the total expected revenues to be earned by the service provider with the total revenue requirement for the 2015–20 regulatory control period.[4] The X factor must usually minimise, as far as reasonably possible, the variance between the expected revenue and ARR for the last regulatory year of the period.[5]

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1 NER, cl 6.3.2(a)(1).

2 There are trade-offs that are not modelled in the PTRM but are reflected in the inputs to the PTRM. For example, service quality is not explicitly modelled in the PTRM, but the trade-offs between service quality and price are reflected in the forecast capex and opex inputs to the model. Other trade-offs are obvious from the calculations in the PTRM. For example, while someone may expect a lower regulatory asset base to also lower revenues, the PTRM shows that this will not occur if the reduction in the regulatory asset base is due solely to an increase in the depreciation rate. In such circumstances, revenues increase as the increased depreciation allowance more than offsets the reduction in the return on capital caused by the lower regulatory asset base.

3 NER, cl 6.5.9(a).

4 NER, cl 6.5.9(3)(i). The X factors represent the rate of change in the real revenue path over the 2015–20 regulatory control period under the CPI–X framework.

5 NER, cl 6.5.9(b)(2).

For this preliminary decision, the expected revenue in the last year of the regulatory control period are not required to be as close as reasonably possible to the ARR for that year, due to the transitional provisions.[6] However, where practical we have sought to maintain this principle to avoid potential revenue shocks at the next reset. We therefore consider a divergence of up to 3 per cent between the expected revenue and ARR for the last year of the regulatory control period is reasonable, if this can promote smoother price changes over the regulatory control period.

We will also factor into our smoothing of Ergon Energy's expected revenues its projected additional revenue amounts to be recovered over the 2015–20 regulatory control period. These amounts are not a component of the building block costs set in this determination. However, they are forecast amounts Ergon Energy is entitled to recover—for example, as part of a jurisdictional scheme, and various under/over recoveries of schemes and pass throughs associated with the later years of the 2010–15 regulatory control period. These amounts will be added to the annual revenue target during the annual pricing approval processes. In addition, Ergon Energy is expecting large under recoveries of the feed-in tariffs in 2013–14 and 2014–15, which are to be recovered in 2015–16 and 2016–17. We will therefore factor these forecast revenues into our judgement of an appropriate path for smoothed revenue. This should result in smoother overall network prices for customers. Table 1.3 sets out the factors that are included in the building block revenue allowance, and those additional factors that we have had regard to for revenue smoothing purposes.[7]

Table 1.3 Factors included in the revenue building blocks and additional factors to inform smoothing

Included in revenue building blocks	Included as annual revenue adjustments
Standard building block costs (return on capital, depreciation, opex and tax)	Solar bonus scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20
Closing balance on DUoS unders/overs account as at 30 June 2015.	Estimated solar bonus scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15
DMIA forecast for 2015–20	Estimated DUoS under recovery for 2013–14
Adjustment for shared assets	Transitional capital contribution under/over recovery from 2010–15
EBSS payments for performance during 2010–15	Transitional shared assets under/over recovery from 2010–15
–	STPIS allowance from 2010–15
–	DMIA over recovery from 2010–15

Source: AER analysis.

6 NER, cl 11.60.3(b).

7 We have adopted the proposed additional revenue amounts for revenue smoothing in this preliminary decision. The amounts will be reviewed as part of the annual pricing approval process.

The building block costs (and the elements that drive those costs) used to determine the unsmoothed ARR are set out below.

1.3.1 The building block costs

The efficient costs to be recovered by a service provider can be thought of as being made up of various building block costs. Our preliminary decision assesses each of the building block costs and the elements that drive these costs. The building block costs are approved reflecting trade-offs and interactions between the cost elements, service quality and across years. Table 1.4 shows the building block costs that form the ARR for each year and where discussion on the elements that drive these costs can be found within this preliminary decision.

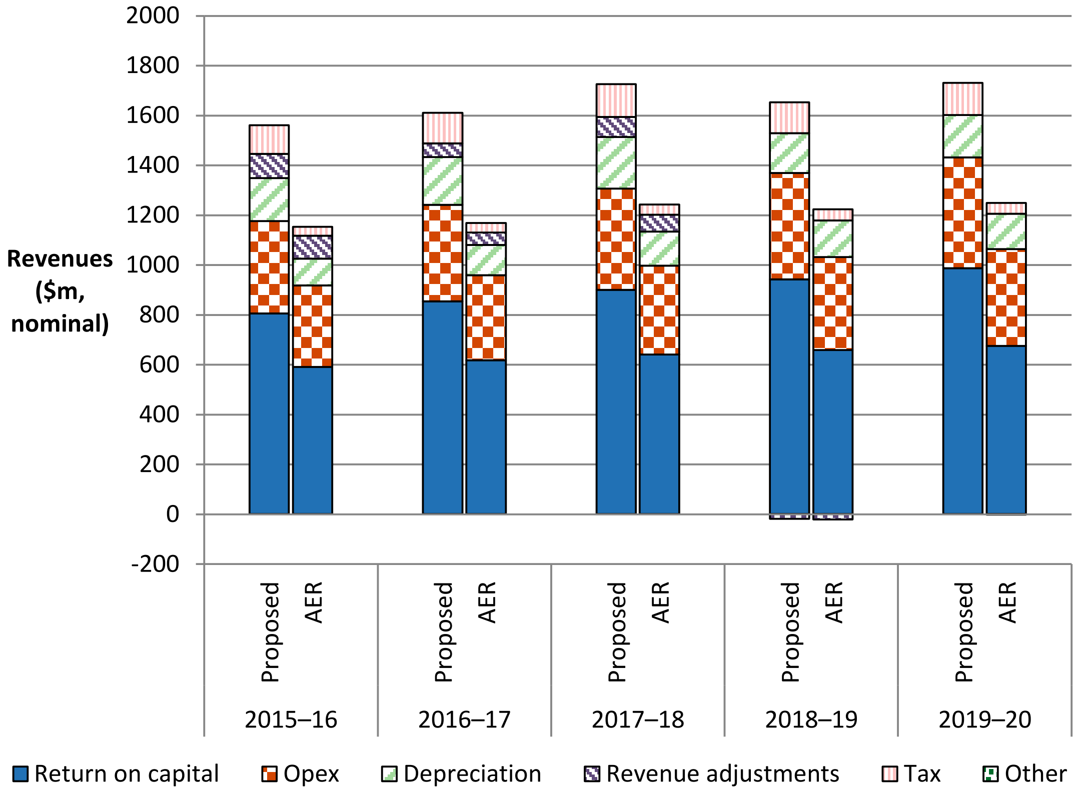
Table 1.4 Building block costs

Building block costs	Attachments where elements are discussed
Return on capital	Regulatory asset base (attachment 2) Capex (attachment 6) Rate of return (attachment 3)
Regulatory depreciation (return of capital)	Regulatory asset base (attachment 2) Capex (attachment 6) Rate of return (attachment 3)
Operating expenditure (opex)	Opex (attachment 7)
Efficiency benefits/penalties	Efficiency benefit sharing scheme (attachment 9)
Estimated cost of corporate tax	Corporate income tax (attachment 8) Rate of return (attachment 4)
Closing balance of DUoS unders/overs account	Annual revenue requirement (attachment 1)
Adjustment for shared assets	Annual revenue requirement (attachment 1)
Demand management innovation allowance	Demand management incentive scheme (attachment 12)

1.4 Reasons for preliminary decision

For this preliminary decision, we determine a total revenue requirement of $6012.6 million ($ nominal) over the 2015–20 period for Ergon Energy. This is $2216.1 million ($ nominal) or 26.9 per cent below Ergon Energy's proposal. This reflects the impact of our preliminary decision on the various building block costs. Figure 1.2 shows the difference between Ergon Energy's proposed ARRs and our preliminary decision.

Figure 1.2 AER's preliminary decision and Ergon Energy's proposed annual revenue requirements ($million, nominal)



Source: AER analysis; Ergon Energy, *Regulatory proposal*, October 2014, p 27.

The most significant changes to Ergon Energy's proposal include: a reduction to the rate of return of 2.2 per cent (attachment 3), a reduction in the capex allowance of 29.1 per cent (attachment 6), and a reduction in the opex allowance of 10.5 per cent (attachment 7).

1.4.1 Revenue smoothing

We have determined our smoothed revenue path having regard to major drivers of total network revenues (distribution use of system—DUoS—charges), including elements that do not fit in the building blocks as set out in Table 1.3. In particular, Ergon Energy has forecast large revenue recovery associated with the under-recovery of the solar bonus scheme (feed-in tariffs) in 2013–15. It has also forecast solar bonus scheme payments throughout the 2015–20 regulatory control period. In the determination for the 2010–15 regulatory control period, we included the forecast solar bonus scheme payments in the opex allowance. We included a pass-through mechanism for any difference to be applied two years later during the annual pricing proposal processes. As a result of this mechanism, the expected under-recoveries from 2013–14 and 2014–15 will be recovered in 2015–16 and 2016–17. Based on Ergon's proposal, these amount to $135.0 million and $124.4 million ($ nominal) respectively. Then, in the 2015–20 regulatory control period, there is no solar bonus scheme forecasts included in the opex allowance. Instead, these amounts will be recovered through a jurisdictional scheme obligation, which will feed into DUoS as part of the annual pricing approval process.[8]

Accordingly, we have smoothed the building block revenue for standard control services over the 2015–20 regulatory control period by allowing for these additional forecast revenue impacts. This approach was initially proposed by Energex. We have consulted on the approach with Ergon Energy, and have adopted it in this preliminary decision. Overall, we are satisfied this will contribute to a smoother final revenue path for customers and the service providers.

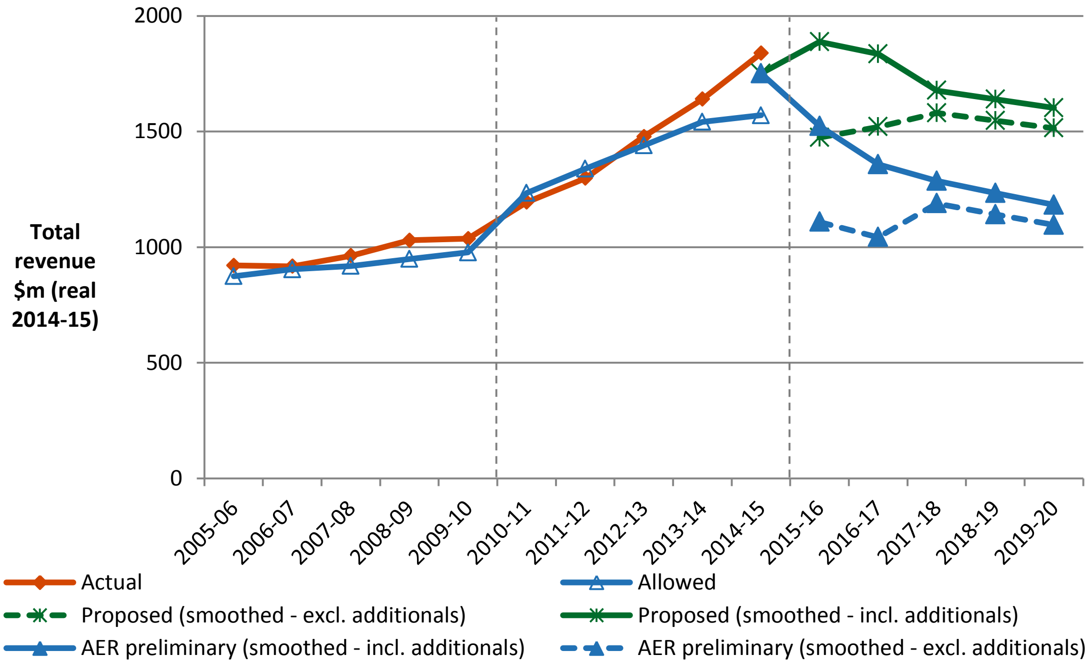
In practice, we would normally set the path of X factors to result in a smooth building block revenue path. That is, these X factors would result in the desired smoothed path of the annual expected revenues through the regulatory control period. However, due to the sizeable factors outside of the building blocks that will affect total DUoS revenue, we have adopted a different approach. Specifically, when determining the X factors that set the path for smoothed building block revenue, we have considered the additional impact of these additional factors. As a result, the smoothed building block revenue does not produce a desirable path for revenue in isolation. However, the total DUoS revenue to be faced by customers including the additional factors will be smoothed overall. Further, we note that our profile of X factors results in an expected revenue in the last year of the regulatory control period that is as close as reasonably possible to the ARR for that year.[9]

Figure 1.3 sets out the revenue path of our preliminary decision smoothed revenues both including and excluding the additional revenue impacts.

8 Ergon Energy forecast these costs to be $110.4 million in 2015–16 to $99.2 million in 2019–20 ($ nominal).

9 In the present circumstances, based on the X factors we have determined for Ergon Energy, this divergence is around 0.3 per cent.

Figure 1.3 Smoothed revenue path including and excluding jurisdictional scheme amounts



Source: AER analysis.

Notes: 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.

1.4.2 Revenue increments or decrements

Revenue increments or decrements arising from the operation of a control mechanism or schemes, also known as 'carry-overs', may have a sizeable impact in addition to our approved annual revenue requirements for the 2015–20 regulatory control period.[10] The revenue increment and decrement amounts are shown in Table 1.5.

10 NER, cls 6.4.3(a)(5), (6), (6A).

Table 1.5 Revenue increments or decrements ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
EBSS	35.4	51.3	69.2	–19.2	0.0	136.7
DMIA	1.0	1.1	1.1	1.1	1.1	5.4
Closing balance of DUoS unders/overs account as at 30 June 2015.	58.6	n/a	n/a	n/a	n/a	58.6
Shared assets	–3.1	–3.2	–3.3	–3.4	–3.5	–16.5
Total	**91.9**	**49.1**	**66.9**	**–21.4**	**–2.3**	**184.2**

Source: AER analysis.

This section explains how these revenue increments or decrements arose.

Over the 2010–15 regulatory control period, we regulated Ergon Energy under a revenue cap form of control. Under this form of control, service providers recover no more or less than the total allowed revenue, which usually includes:

- Building block expected revenue set in the determination.
- Under or over-recovery in the expected revenue from two years prior—these amounts are for two years prior because the full amount of any under/over-recovery is not known until the end of a pricing year, but the pricing approval process must take place in advance of the pricing year. Therefore, there is a two year lag between when the pricing year finishes and when revenue under/over recoveries can be included in the future revenue target.
- Jurisdictional scheme obligation amounts—these are amounts that the service provider is required to collect under legislation and which we are not required to assess.
- Pass through amounts—these are amounts that the service provider has applied for under the pass through provisions in its determination and we have subsequently approved. Often, this relates to events with unforeseeable likelihood and or timing, such as damage due to storms or regulatory changes.
- Other factors—this category includes applicable incentive scheme amounts, such as the S-factor for STPIS, and transitional capital contributions and shared asset amounts.

Ergon Energy has accumulated a large under-recovery balance due to:

- revenue cap under-recoveries
- pass through of feed-in tariffs under-recoveries.

These are amounts that Ergon Energy was allowed to recover as revenues over the 2010–15 regulatory control period, but did not do so. In particular, these amounts accumulated due to three main factors:

- Throughout the 2010–15 regulatory control period, consumption of electricity on Ergon Energy's network decreased at a faster rate than was projected in pricing forecasts. Approved prices are set annually to recover the target revenue based on estimated units of consumption, customer numbers and other factors where relevant. Holding all else constant, if any of these units is overestimated:
    - prices are relatively lower than they should have been, since the same revenue amount is shared across a larger number of units
    - revenue is therefore lower than it should have been, since it is the product of a lower-than-forecast actual number of units multiplied by a relatively lower price.
- Uptake of the solar bonus scheme (feed-in tariffs) was greater than forecast. Annual estimates of the feed-in tariffs were included in Ergon Energy's opex allowance over the 2010–15 regulatory control period. However, since this was a new jurisdictional policy and hence difficult to forecast, we approved a specific overs/unders factor to account for the difference between forecast and actual. As the take-up of the scheme was much greater than forecast, this led to a large under-recovery balance.

These in combination led to a triggering of the under-recovery threshold. In the 2010 determination, we set a 5 per cent over/under threshold for accumulated under or over-recovery balances. On meeting this threshold, Ergon Energy submitted a plan to clear the balance over several years. Part of this plan included the recovery of some of the revenue in the 2015–20 regulatory control period. This was designed to prevent larger increase in prices over the 2010–15 regulatory control period.

1.4.3 Shared assets

Service providers, such as Ergon Energy, may use assets to provide both standard control services we regulate and unregulated services. These assets are called 'shared assets'.[11] Of the unregulated revenues a service provider earns from shared assets, 10 per cent will be used to reduce the service provider's prices for standard control services.[12]

Shared asset price reductions are subject to a materiality threshold. Unregulated use of shared assets is material when a service provider's unregulated revenues from shared assets in a specific regulatory year are expected to be greater than 1 per cent of its total expected revenue for that regulatory year.[13]

Ergon Energy submitted that its shared asset unregulated revenues are forecast to be around 20 per cent of its total revenues in each year of the 2015–20 regulatory

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11 NER, cl. 6.4.4.

12 AER, *Shared asset guideline*, November 2013.

13 AER, *Shared asset guideline*, November 2013, p. 8.

period.[14] Ergon Energy therefore proposed reductions in its total revenues for each year of that period.

Our Shared Asset Guideline caps the value of annual shared asset revenue adjustments, to prevent them exceeding the value of the regulated assets generating the unregulated revenue. The cap means distributors retain incentives to allow their regulated assets to provide unregulated services. Without the cap, society would risk losing the benefits of having unregulated services provided in conjunction with electricity network assets. It would also risk electricity customers losing altogether the price benefits of shared asset revenue reductions.

Ergon Energy calculated annual caps and applied those to its annual shared asset revenue adjustments.[15] Ergon Energy's updated proposed revenue adjustments are set out in Table 1.6.

Table 1.6 Ergon Energy's proposed shared asset revenue adjustments ($ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Adjustment for shared assets	–3.1	–3.1	–3.1	–3.1	–3.1	–15.3

Source: Ergon Energy, *Response to Information Request 'AER Ergon 060'*, 23 February 2015, Revised SCPTRM Data Model.

Our preliminary decision is to accept Ergon Energy's updated proposed shared asset revenue adjustments.

Ergon Energy also proposed to adjust its total revenue for alternative control service assets that it retained in its RAB for standard control services.[16] Ergon Energy noted that this is the approach applied for the 2010 determination, consistent with that determined by the Queensland Competition Authority. Under transitional provisions of the NER, Ergon Energy was permitted to continue this approach during the 2010–15 regulatory control period. These transitional arrangements cease at the end of the 2010–15 regulatory control period. From the beginning of the 2015–20 regulatory control period, Ergon Energy's RAB must be determined under the NER.

We consider that, under the NER, Ergon Energy's RAB should reflect only the value of assets providing standard control services.[17] We indicated our position to Ergon Energy. In turn, Ergon Energy agreed to remove from its RAB the value of assets providing alternative control services.[18] Ergon Energy subsequently submitted revised

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14 Ergon Energy, *Regulatory proposal*, *attachment 3.01.02 Other revenue adjustments*, October 2014, p. 8.

15 Ergon Energy, *Regulatory proposal*, *attachment 3.01.02 Other revenue adjustments*, October 2014, p. 11.

16 Ergon Energy, *Regulatory proposal*, *attachment 3.01.02 Other revenue adjustments*, October 2014, p. 12.

17 NER, cl. 6.5.1(a).

18 Ergon Energy, email to AER, 7 February 2015.

RAB values providing these services.[19] This means standard control service revenues will decline by the full value of the assets providing alternative control services.

On the basis of the above, our preliminary position is to not accept Ergon Energy's proposed revenue reductions for alternative control services provided by assets retained in its RAB. This is because we have removed these assets providing alternative control services from the RAB for standard control services.

1.4.4 Indicative average distribution price impact

Our preliminary decision on Ergon Energy's expected revenues ultimately affects the prices consumers pay for electricity. There are several steps required in translating our revenue decision to a price impact.

We regulate Ergon Energy's standard control services under a revenue cap form of control. This means our preliminary decision on Ergon Energy's expected revenues do not directly translate to price impacts. This is because Ergon Energy's revenue is fixed under the revenue cap form of control, so changes in the consumption of electricity will affect the prices ultimately charged to consumers. We are not required to establish the distribution prices for Ergon Energy as part of this determination. However, we will assess Ergon Energy's annual pricing proposals before the commencement of each regulatory year for the 2015–20 regulatory control period to administer the pricing requirements in this distribution determination.

For this preliminary decision, we have estimated some indicative average distribution price impacts flowing from our determination on the expected revenues and jurisdictional scheme obligation amounts for Ergon Energy over the 2015–20 regulatory control period. Figure 1.4 shows Ergon Energy's indicative price path based on the expected revenues established in our preliminary decision compared to its proposal. We used the data on average price changes Ergon provided in its proposal. We estimated average prices by dividing expected revenue by total forecast energy consumed (MWh) in Ergon's distribution network to determine the movement in overall prices. For presentational purposes, the prices are scaled so that the price index begins at 1.0 in 2014–15. The index provides a simple overall measure of the relative movement in expected distribution prices over the 2015–20 regulatory control period.

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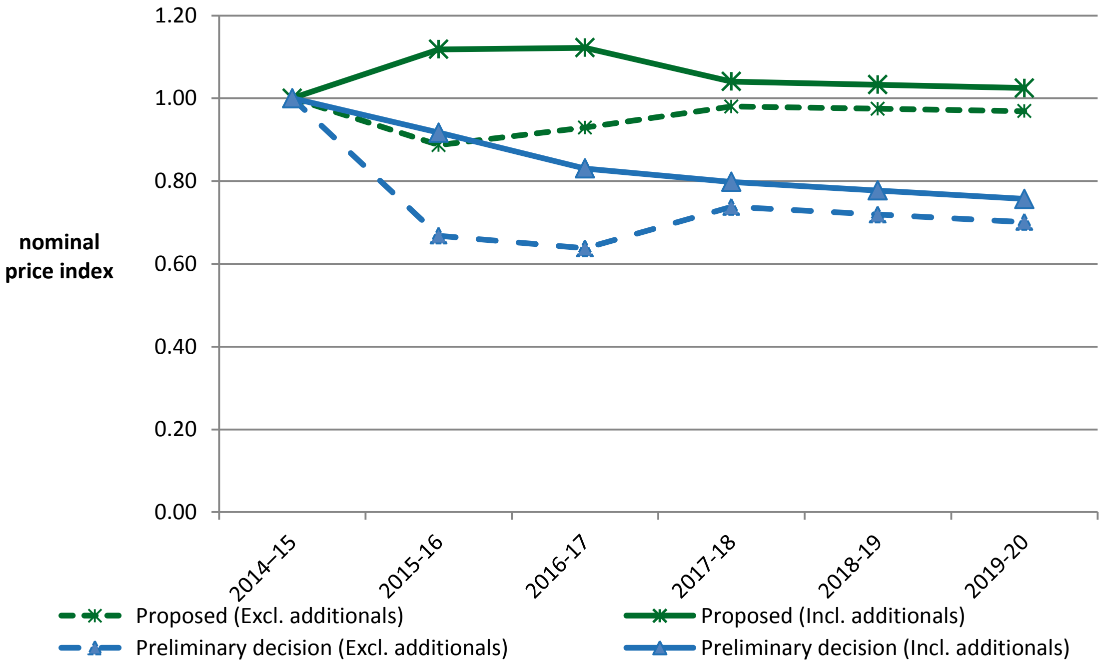
[19] Ergon Energy, *Response to Information Request 'AER Ergon 060'*, 23 February 2015.

Figure 1.4 AER's preliminary decision and Ergon Energy's proposed indicative price paths (nominal price index)



Source: AER analysis.

Notes: The nominal price index is calculated by the AER based on the indicative average price changes submitted by Ergon Energy in its proposal, and adjusting for the change in overall revenue substituted by the AER.

We estimate that our preliminary decision on Ergon Energy's annual expected revenue will result in a decrease to average distribution charges (including additionals) by about 5.4 per cent per annum over the 2015–20 regulatory control period in nominal terms. This amount includes a forecast inflation rate of 2.55 per cent per annum. In real terms we estimate average distribution charges to decline by 7.5 per cent per annum, compared to a decline of 2.0 per cent proposed by Ergon Energy. This compares to the nominal average increase of approximately 0.5 per cent per annum proposed by Ergon Energy (including additionals) over the 2015–20 regulatory control period.

Table 1.7 displays the comparison of the price impacts of Ergon Energy's proposal and our preliminary decision revenue allowance.

Table 1.7 Comparison of revenue and price impacts of Ergon Energy's proposal and the AER's preliminary decision

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Ergon Energy proposal						
Revenue ($m, nominal)[a]	1751	1935	1930	1809	1813	1817
Price path (nominal index)	1.00	1.12	1.12	1.04	1.03	1.02
Revenue (change %)		10.5%	–0.3%	–6.3%	0.2%	0.2%
Price path (change %)		11.9%	–0.3%	–7.3%	–0.7%	–0.8%
AER preliminary decision						
Revenue ($m, nominal)[a]	1751	1562	1428	1387	1364	1342
Price path (nominal index)	1.00	0.92	0.83	0.80	0.78	0.76
Revenue (change %)		–10.8%	–8.6%	–2.9%	–1.6%	–1.6%
Price path (change %)		–8.3%	–9.5%	–3.9%	–2.6%	–2.6%

Source: AER analysis.

(a) This includes the additional amounts in DUoS, which are outside of the building block revenue determination.

Distribution charges represent approximately 42 per cent on average of Ergon Energy's typical customer's annual electricity bill.[20] We expect that our preliminary decision, holding all other components of the bill constant, will reduce the average annual electricity bills for residential customers in Ergon Energy's network. This is because we estimate that our preliminary decision will result in lower distribution charges on average over the 2015–20 regulatory control period compared to Ergon Energy's proposal. 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.

We estimate that based on the distribution charges from our preliminary decision passing through to customers, we would expect the average annual electricity bill for residential customers to reduce by $34 or 1.8 per cent in 2015–16. This would be followed by reductions of, on average, $25 or 1.3 per cent ($ nominal) per annum from 2016–17 to 2019–20. By comparison, had we accepted the proposal, the average annual electricity bill for residential customers would increase by $21 or 1.1 per cent in 2015–16. This would be followed by increases of approximately $17 (0.9 per cent) per annum between 2016–17 and 2019–20.

20 QCA, *Final determination: Regulated retail electricity prices 2014–15* , May 2014, p. 116; AEMC,*2014 Residential electricity price trends report*, 5 December 2014, p. 33.

Our estimate of the potential impact our preliminary decision will have for Ergon Energy's residential customers is based on the typical annual electricity usage of 4100 kWh per annum for a residential customer in Queensland.[21] Therefore customers with different usage will experience different changes in their bills. We also note that there are other factors, such as transmission network costs, wholesale and retail costs, which affect electricity bills.

Similarly, for an average small business customer in Queensland that uses approximately 10 MWh of electricity per annum, our preliminary decision for Ergon Energy is expected to lead to lower average annual electricity bills. We estimate that based on the distribution charges from our preliminary decision passing through to customers, we would expect the average annual electricity bill for small business customers to reduce by $53 or 1.8 per cent in 2015–16. This would be followed by decreases of about $38 or 1.3 per cent ($ nominal) per annum from 2016–17 to 2019–20. By comparison, had we accepted the proposal, the average annual electricity bill for small business customers would increase by $32 or 1.1 per cent in 2015–16. This would be followed by increases of approximately $26 (0.9 per cent) per annum between 2016–17 and 2019–20.

Table 1.8 shows the estimated annual average impact of our preliminary decision for the 2015–20 regulatory control period and Ergon Energy's proposal on the average residential and small business customers' annual electricity bills.

Table 1.8 Estimated impact of Ergon Energy's proposal and AER's preliminary decision on annual electricity bills for the 2015–20 regulatory control 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%)

21 QCA, *Final determination: Regulated retail electricity prices2014-15*, May 2014, p. 116.

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.