DRAFT DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Attachment 1
Annual revenue requirement

October 2019

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Ergon Energy for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	annual revenue requirement
CPI	consumer price index
DMIAM	demand management innovation allowance mechanism
distributor	distribution network service provider
NER or the rules	national electricity rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RIN	regulatory information notice
SCS	standard control services

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 revenue 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 (SCS) for each year of the regulatory control period. This attachment sets out our draft decision on Ergon Energy's ARRs and expected revenues for the 2020–25 regulatory control period.

1.1 Draft decision

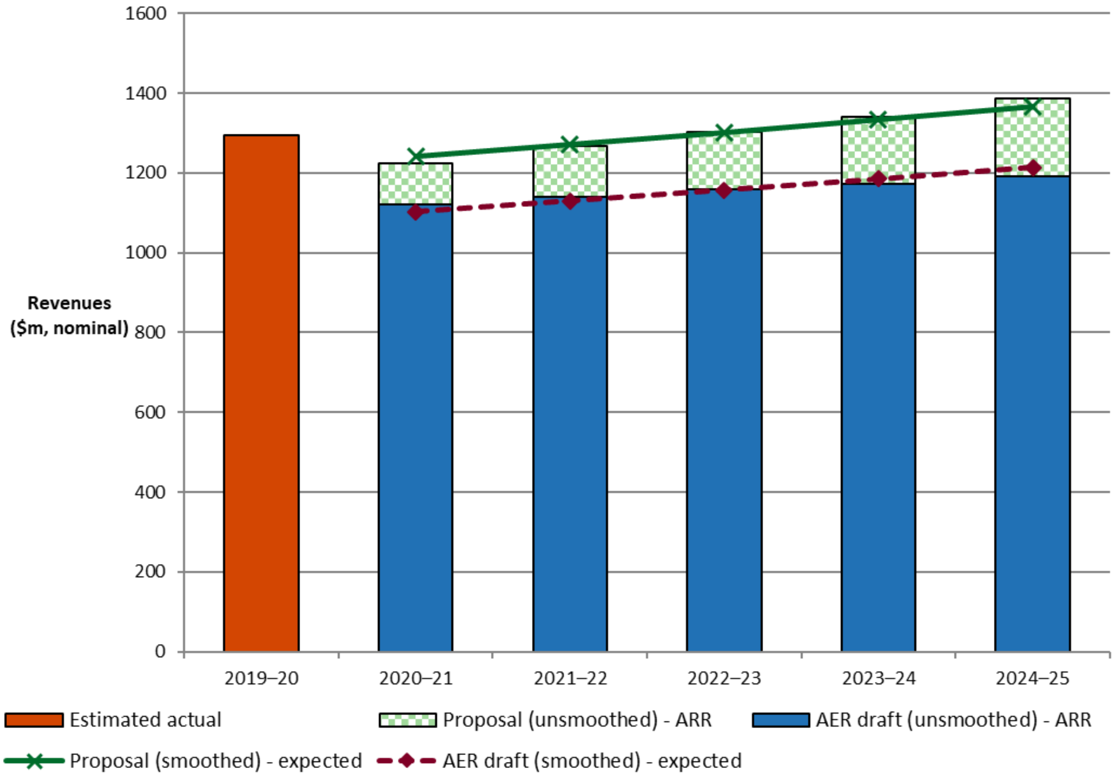
We do not accept Ergon Energy's proposed total ARR of $6520.5 million ($ nominal) over the 2020–25 regulatory control period. This is because we have not accepted the building block costs in Ergon Energy's proposal. We determine a total ARR of $5783.1 million ($ nominal) for Ergon Energy for the 2020–25 regulatory control period, reflecting our draft decision on the various building block costs. This is a reduction of $737.4 million ($ nominal) or 11.3 per cent to Ergon Energy's proposal.

We determine the annual expected revenue (smoothed) and X factor for each regulatory year of the 2020–25 regulatory control period by smoothing the ARR. Our draft decision is to approve total expected revenues (smoothed) of $5787.9 million ($ nominal) for Ergon Energy for the 2020–25 regulatory control period.

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

Table 1.1 shows our draft decision on the building block costs, the ARR, annual expected revenue and X factor for the 2020–25 regulatory control period.

Figure 1.1 AER's draft decision on Ergon Energy's revenue for the 2020–25 regulatory control period ($ million, nominal)



Source: AER analysis; Ergon Energy, *8.004 PTRM - SCS,* 31 January 2019.

Table 1.1 AER's draft decision on Ergon Energy's revenues for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Return on capital	562.3	562.3	562.0	561.1	559.2	2806.9
Regulatory depreciation[a]	170.8	187.8	200.3	210.3	228.3	997.4
Operating expenditure[b]	386.1	390.0	394.6	398.9	403.1	1972.7
Revenue adjustments[c]	1.1	1.1	1.1	1.1	1.1	5.5
Net tax allowance	0.6	0.0	0.0	0.0	0.0	0.6
Annual revenue requirement (unsmoothed)	1120.8	1141.2	1158.0	1171.4	1191.7	5783.1
Annual expected revenue (smoothed)	**1102.2**	**1129.2**	**1156.9**	**1185.2**	**1214.3**	**5787.9**
X factor[d]	n/a[e]	0.00%	0.00%	0.00%	0.00%	n/a

Source: AER analysis.

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

(b) Includes debt raising costs.

(c) Includes revenue adjustments from demand management innovation allowance mechanism (DMIAM).

(d) The X factors 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.

(e) Ergon Energy is not required to apply an X factor for 2020–21 because we set the 2020–21 expected revenue in this decision. The expected revenue for 2020–21 is around 16.8 per cent lower than the approved total annual revenue for 2019–20 in real terms, or 14.8 per cent lower in nominal terms.

1.2 Ergon Energy's proposal

Ergon Energy proposed a total revenue requirement of $6520.5 million ($ nominal) for the 2020–25 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 2020–25 regulatory control period.

Table 1.2 Ergon Energy's proposed revenues for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Return on capital	635.1	652.1	669.0	686.7	703.4	3346.3
Regulatory depreciation[a]	172.5	195.1	211.2	225.2	248.4	1052.3
Operating expenditure[b]	386.9	389.8	394.3	398.4	402.5	1971.9
Revenue adjustments[c]	1.1	1.2	1.2	1.2	1.3	6.0
Net tax allowance	27.8	28.2	27.7	28.8	31.4	144.0
Annual revenue requirement (unsmoothed)	1223.4	1266.3	1303.4	1340.4	1387.0	6520.5
Annual expected revenue (smoothed)	**1241.6**	**1271.6**	**1302.4**	**1333.9**	**1366.2**	**6515.8**
X factor	n/a[d]	0.00%	0.00%	0.00%	0.00%	n/a

Source: Ergon Energy, *8.004 PTRM - SCS,* 31 January 2019.

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

(b) Includes debt raising costs.

(c) Includes revenue adjustments from DMIAM.

(d) Ergon Energy is not required to apply an X factor for 2020–21 because we set the 2020–21 expected revenue in this decision.

1.3 Assessment approach

In this section, we describe the approach used to determine the ARR and expected revenue for Ergon Energy for each year of the 2020–25 regulatory control period.[1]

[1] NER, cll. 6.3.2(a)(1), 6.5.9(b)(2).

In this determination we first calculate the ARR for each year of the 2020–25 regulatory control period. To do this we consider the various costs facing the distributor and the trade-offs and interactions between these costs, service quality and across years. This reflects our holistic assessment of the distributor'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 draft decision and are reflected in the calculations made in the PTRM.[2] Such understanding allows us to exercise judgement in determining the final inputs into the PTRM and the ARRs that result from this modelling.

Having calculated the total revenue requirement for the 2020–25 regulatory control period, we smooth the ARRs for each regulatory year across that period. This step reduces revenue variations between years, and calculates the expected revenue and X factor for each year.[3] The X factors equalise (in net present value terms) the total expected revenues to be earned by the distributor with the total revenue requirement for the 2020–25 regulatory control period.[4] They 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] By minimising this divergence, it helps to manage the prospect of a significant revenue change (and consequently prices) between the last year of the 2020–25 regulatory control period, and first year of the following 2025–30 regulatory control period. 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.

The building block costs (and the elements that drive those costs) used to determine the unsmoothed ARR are set out in section 1.3.1.

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 capital expenditure and operating expenditure 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(b)(3)(i). The X factors represent the real revenue path over the 2020–25 regulatory control period under the CPI–X framework.

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

1.3.1 The building block costs

The efficient costs to be recovered by a distributor can be thought of as being made up of various building block costs. Our draft 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 1.3 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 draft decision.

Table 1.3 Building block costs

Building block costs	Attachments where elements are discussed
Return on capital	Regulatory asset base (attachment 2) Rate of return (attachment 3) Capital expenditure (attachment 5)
Regulatory depreciation (return of capital)	Regulatory asset base (attachment 2) Regulatory depreciation (attachment 4) Capital expenditure (attachment 5)
Operating expenditure	Operating expenditure (attachment 6)
Estimated cost of corporate tax	Corporate income tax (attachment 7)
Other revenue adjustments	
Adjustment for shared assets	Annual revenue requirement (attachment 1)
Operating efficiency benefits/penalties	Efficiency benefit sharing scheme (attachment 8)
Capital efficiency benefits/penalties	Capital expenditure sharing scheme (attachment 9)
Demand management innovation allowance	Demand management incentive scheme (attachment 11)

1.4 Reasons for draft decision

We determine a total ARR of $5783.1 million ($ nominal) for Ergon Energy over the 2020–25 regulatory control period. This is a reduction of $737.4 million ($ nominal) or 11.3 per cent to Ergon Energy's proposed total ARR of $6520.5 million ($ nominal) for this period. This reflects the impact of our draft decision on the various building block costs.

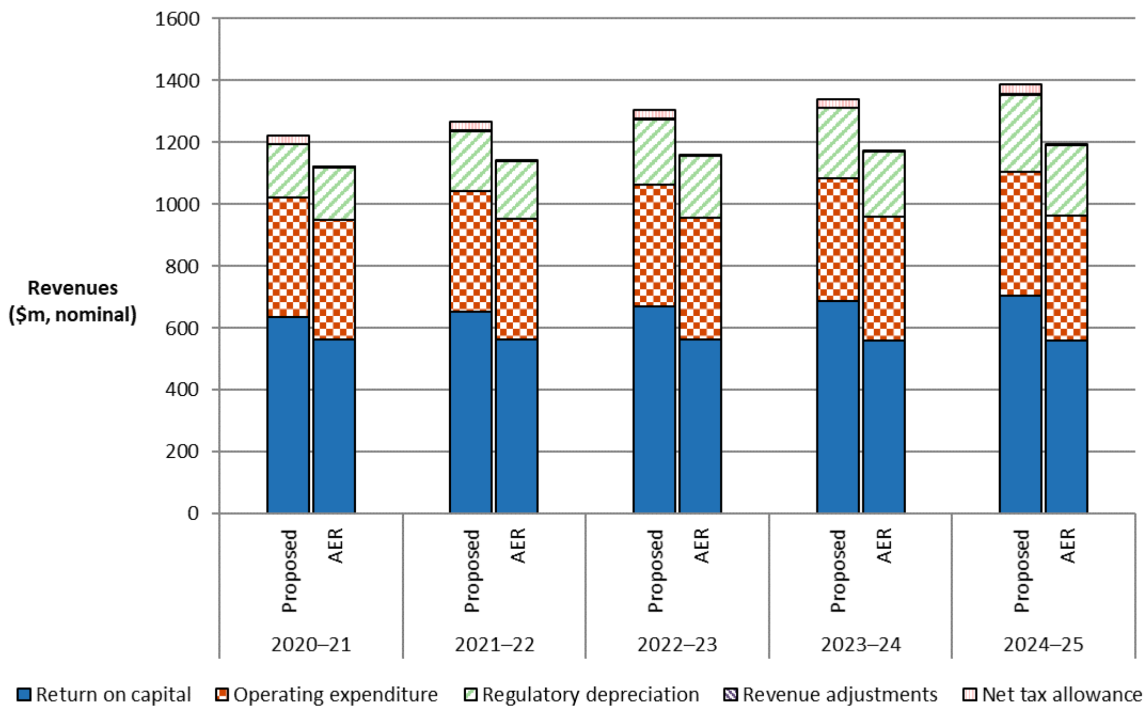
The changes we made to Ergon Energy's proposed building blocks include (in nominal terms):

- a reduction in the return on capital allowance of $539.4 million or 16.1 per cent (attachments 2, 3 and 5).
- a reduction in the regulatory depreciation allowance of $54.9 million or 5.2 per cent (attachments 2, 4 and 5).

- an increase in the operating expenditure (opex) allowance of $0.8 million (attachment 6).[6]
- a reduction in the cost of corporate income tax of $143.4 million or 99.6 per cent (attachment 7).
- a reduction in the revenue adjustments of $0.5 million or 8.6 per cent arising from changes to DMIAM (attachment 11).

Figure 1.2 shows the building block components from our determination that make up the ARR for Ergon Energy, and the corresponding components from its proposal.

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



Source: Ergon Energy, *8.004 PTRM - SCS,* 31 January 2019; AER analysis.

Note: Revenue adjustments are from DMIAM. Opex includes debt raising costs.

1.4.1 Revenue smoothing

We have taken into account the building block costs determined in this decision when smoothing the expected revenues for Ergon Energy over the 2020–25 regulatory control period. In doing so, we first set the expected revenue for the first regulatory year (2020–21) at $1102.2 million ($ nominal). This is lower than the 2020–21 ARR

[6] Although we have accepted the opex proposal, there were some updates including for expected inflation which results in this small difference in nominal dollar terms.

(unsmoothed) of $1120.8 million we determined. It is also $191.1 million lower than the expected revenue for 2019–20. We then applied a profile of X factors to determine the expected revenue in subsequent years.

To smooth the revenue movements from the second regulatory year (2021–22) onwards, we have applied X factors of zero as proposed by Ergon Energy. This allows for a relatively predictable price movement over the regulatory control period. This approach smooths the revenues by allowing for a path for revenues over the 2020–25 regulatory control period that match the rate of actual inflation.

Based on the X factors we have determined for Ergon Energy, the difference between the expected revenue and ARR for 2024–25 is 1.9 per cent. This divergence lies within our target band of 3 per cent. Therefore, we consider 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.[7] We will review this smoothing for the final decision.

1.4.2 Shared assets

Distributors, such as Ergon Energy, may use assets to provide both the SCS we regulate and unregulated services. These assets are called 'shared assets'.[8] If the revenue from shared assets is material, ten per cent of the unregulated revenues that a distributor earns from shared assets will be used to reduce the distributor's revenue for SCS.[9]

The shared asset principles establish that use of shared assets should be material before cost reductions are applied.[10] The NER does not define materiality in this context. Our approach to what constitutes a material use of shared assets is that unregulated use of shared assets in a specific regulatory year is material when a distributor's annual average unregulated revenue from shared assets is expected to be greater than one per cent of its expected revenue for that regulatory year.[11]

Ergon Energy submitted that its total revenue requirement is not subject to a shared asset adjustment because its forecast annual unregulated revenue from shared assets does not exceed the AER's materiality threshold.[12]

We consider Ergon Energy's forecast unregulated revenues from shared assets for the 2020–25 regulatory control period are reasonable. However, Ergon Energy's forecast unregulated revenues must be compared to the regulated revenues we determine, rather than those proposed by Ergon Energy. While our draft decision sets lower expected revenues than Ergon Energy's proposal, we estimate that the unregulated

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

8 NER, cl. 6.4.4.

9 AER, *Shared asset guideline*, November 2013, p.11.

10 NER, cl. 6.4.4(c)(3).

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

12 Ergon Energy, *1.004 Ergon Energy Regulatory Proposal 2020-25*, 31 January 2019, p. 115.

revenues will be less than one per cent of its expected revenues in each year of the 2020–25 regulatory control period. Hence, the materiality threshold is not met in any year of the 2020–25 regulatory control period and we do not apply a shared asset revenue adjustment.[13]

Unregulated revenues from shared assets may in future become material. We note the recent announcement that Powerlink Queensland and Energy Queensland will jointly operate a new business, FibreCo Queensland. Queensland Electricity Users Network questioned whether the shared assets revenue from this operation should be included in Ergon Energy's regulatory proposal.[14] We have discussed with Energex and Ergon Energy the potential for any increase to unregulated revenues from shared assets. Ergon Energy noted the current use of shared assets will not substantially increase for the distribution business over the 2020–25 regulatory control period.[15] We will continue to monitor the use of shared assets by FibreCo Queensland in future regulatory control periods. We expect Ergon Energy to provide updates on any changes to its forecast unregulated revenue from shared assets in its revised proposal.

1.4.3 Indicative average distribution price impact

Our draft 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 into indicative distribution price impact.

We regulate Ergon Energy's SCS under a revenue cap form of control. This means our draft decision on Ergon Energy's expected revenues does 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 within the 2020–25 regulatory control period. In each assessment we will administer the pricing requirements set in this distribution determination.

For this draft decision, we have estimated some indicative average distribution price impacts flowing from our determination on the expected revenues for Ergon Energy over the 2020–25 regulatory control period. In this section, our estimates only relate to SCS (that is, the core electricity distribution charges), not alternative control services (such as metering charges). These indicative price impacts assume that actual energy consumption across the 2020–25 regulatory control period matches Ergon Energy's forecast energy consumption, which we have adopted for this draft decision.

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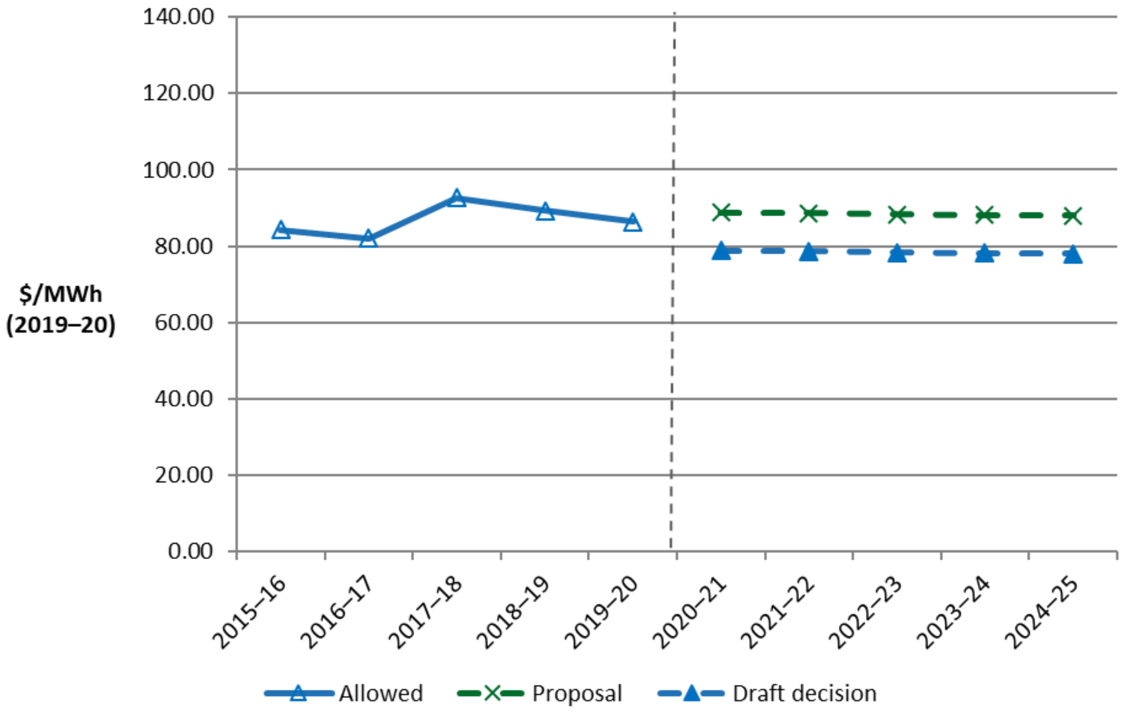
13 We will reassess the materiality of the forecast shared asset unregulated revenues for our final decision.

14 Queensland Electricity Users Network, *Ergon Energy and FibreCo and 2020-25 Regulatory Proposal*, 04 July 2019.

15 Ergon Energy, *Information request 055 - FibreCo Queensland and shared assets*, 05 July 2019.

Figure 1.3 shows Ergon Energy's indicative average price path over the period 2015–16 to 2024–25 in real 2019–20 dollar terms based on the expected revenues established in our draft decision compared to Ergon Energy's proposed revenue requirement.

Figure 1.3 Indicative distribution price path for Ergon Energy ($/MWh, 2019–20)



Source: AER analysis.

Note: The relatively lower allowed revenues in 2015–16 and 2016–17 is largely explained by costs associated with solar feed-in tariffs that were passed through separately in annual pricing for those years. By anticipating these pass through costs during its final decision in 2015, the AER helped smooth the overall revenues customers ultimately faced over the entire 2015–20 regulatory control period.

We estimate that our draft decision on Ergon Energy's annual expected revenue will result in a decrease to average distribution charges by about 3.8 per cent per annum over the 2020–25 regulatory control period in real 2019–20 dollar terms.[16] This compares to the real average decrease of approximately 1.5 per cent per annum proposed by Ergon Energy over the 2020–25 regulatory control period.[17] These high-level estimates reflect the aggregate change across the entire network and do not reflect the particular tariff components for specific end users.

[16] In nominal terms we estimate average distribution charges to decrease by 1.5 per cent per annum. This amount reflects an expected inflation rate of 2.45 per cent per annum as determined in this draft decision.

[17] In nominal terms Ergon Energy's proposal would increase distribution charges by 0.9 per cent per annum. This amount reflects an expected inflation rate of 2.42 per cent per annum as proposed by Ergon Energy in its proposal.

Table 1.4 displays in nominal terms the comparison of the revenue and price impacts of Ergon Energy's proposal and our draft decision.

Table 1.4 Comparison of revenue and price impacts of Ergon Energy's proposal and the AER's draft decision ($ nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25
AER draft decision						
Revenue ($ million)	1293.4	1102.2	1129.2	1156.9	1185.2	1214.3
Price path ($/MWh)[a]	94.93	80.73	82.52	84.32	86.22	88.11
Revenue (change)		–14.8%	2.4%	2.4%	2.4%	2.4%
Price path (change		–15.0%	2.2%	2.2%	2.2%	2.2%
Ergon Energy's proposal						
Revenue ($ million)	1293.4	1241.6	1271.6	1302.4	1333.9	1366.2
Price path ($/MWh)[a]	94.93	90.94	92.92	94.93	97.03	99.14
Revenue (change)		–4.0%	2.4%	2.4%	2.4%	2.4%
Price path (change)		–4.2%	2.2%	2.2%	2.2%	2.2%

Source: AER analysis; Ergon Energy, *8.004 PTRM - SCS,* 31 January 2019; Ergon Energy, *17.059 2020-25 Indicative Bill Impact RIN template,* 31 January 2019.

(a) The price path is in nominal terms and is constructed by dividing nominal expected revenue for SCS by forecast energy consumption for each year of the regulatory control period.

1.4.4 Expected impact of decision on electricity bills

Our bill impact calculations for Ergon Energy adopt the network charges in our draft 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.[18]

The annual electricity bill for customers in Ergon Energy's network reflects the combined cost of all the electricity supply chain components—wholesale energy generation, transmission, distribution, metering, and retail costs. This draft decision primarily relates to the distribution charges for SCS, which represent approximately

[18] Queensland Competition Authority, *Final Determination–Regulated retail electricity prices for* 2019–20, May 2019, p.iii.

34.9 per cent on average for residential customers' and 30.0 per cent on average for small business customers' annual electricity bill in Ergon Energy's network area.[19]

We estimate the expected bill impact by varying the distribution charges in accordance with our draft decision, while holding all other components—including the metering component—constant. This approach isolates the effect of our draft decision on the core distribution charges only. However, this does not imply that other components will remain unchanged across the regulatory control period.[20]

Based on this approach in our draft decision, we expect that the distribution component of the average annual residential electricity bill in 2020–21 to increase by about $102 ($ nominal) from the 2019–20 total bill level, followed by average annual increases of $9 ($ nominal) over the remaining years of the 2020–25 regulatory control period (2021–25).[21] By comparison, had we accepted the proposal, the expected distribution component of the average annual residential electricity bill in 2020–21 would decrease by about $48 ($ nominal) from the 2019–20 total bill level, followed by average annual increases of $10 ($ nominal) over the remaining years of the 2020–25 regulatory control period (2021–25).[22]

Similarly, for an average small business customer, we expect that the distribution component of the average annual small business electricity bill in 2020–21 to increase by about $131 ($ nominal) from the 2019–20 total bill level, followed by average annual increases of $12 ($ nominal) over the remaining years of the 2020–25 regulatory control period (2021–25).[23] By comparison, had we accepted the proposal, the expected distribution component of the average annual small business electricity bill in 2020–21 would decrease by about $62 ($ nominal) from the 2019–20 total bill level, followed by average annual increases of $13 ($ nominal) over the remaining years of the 2020–25 regulatory control period (2021–25).[24]

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[19] Ergon Energy, *17.059 2020-25 Indicative Bill Impact RIN template,* 31 January 2019; Energex, *17.052 Indicative Bill Impact RIN template,* 31 January 2019; *Australian Energy Market Commission, Databook–2018 Residential electricity price trends*, December 2018

[20] It also assumes that actual energy consumption will equal the forecast adopted in our draft decision. Since Ergon Energy operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2020–25 regulatory control period.

[21] This equates to a 6.5 per cent decrease in the average residential customer's total electricity bill in 2020–21, followed by average annual increases of 0.6 per cent in the remaining years of the 2020–25 regulatory control period.

[22] This equates to a 3.1 per cent decrease in the average residential customer's total electricity bill in 2020–21, followed by average annual increases of 0.7 per cent in the remaining years of the 2020–25 regulatory control period.

[23] This equates to a 5.6 per cent decrease in the average small business customer's total electricity bill in 2020–21, followed by average annual increases of 0.5 per cent in the remaining years of the 2020–25 regulatory control period.

[24] This equates to a 2.6 per cent decrease in the average small business customer's total electricity bill in 2020–21, followed by average annual increases of 0.6 per cent in the remaining years of the 2020–25 regulatory control period.

Our estimated impact is based on an average annual electricity usage of around 4600 kWh per annum for residential households[25] and 6866 kWh per annum for small businesses.[26] Therefore, customers with different usage will experience different changes in their bills. We also note that there are other factors, such as metering, wholesale and retail costs, which affect electricity bills.

Table 1.5 shows our estimated impact of our draft decision and Ergon Energy's proposal on the average annual electricity bills for residential and small business customers in its network over the 2020–25 regulatory control period.

Table 1.5 Estimated impact of Ergon Energy's proposal and AER's draft decision on annual electricity bills for the 2020–25 regulatory control period ($ nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25
AER draft decision						
Residential annual bill	1570[b]	1468	1477	1489	1497	1506
Annual change[d]		–102 (–6.5%)	9 (0.6%)	12 (0.8%)	8 (0.5%)	9 (0.6%)
Small business annual bill	2347[c]	2216	2228	2243	2253	2265
Annual change[d]		–131 (–5.6%)	12 (0.5%)	15 (0.7%)	10 (0.5%)	11 (0.5%)
Ergon Energy proposal						
Residential annual bill	1570[b]	1522	1532	1545	1554	1564
Annual change[d]		–48 (–3.1%)	10 (0.7%)	13 (0.8%)	9 (0.6%)	10 (0.6%)
Small business annual bill	2347[c]	2285	2298	2315	2326	2339
Annual change[d]		–62 (–2.6%)	13 (0.6%)	17 (0.7%)	12 (0.5%)	13 (0.5%)

Source: AER analysis; AER, AER, *Final determination, Default Market Offer Prices 2019–20*, April 2019, p.8, Queensland Competition Authority, *Final Determination–Regulated retail electricity prices for 2019–20*, May 2019, p. vi; Energex, *17.052 Indicative Bill Impact RIN template,* 31 January 2019.

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

(b) Annual bill for 2019–20 is sourced from AER, Final determination, Default Market Offer Prices 2019–20, and reflects the average consumption of 4600 kWh for residential customers in Queensland.

(c) Annual bill for 2019–20 is sourced from Queensland Competition Authority, Final Determination–Regulated retail electricity prices for 2019–20, and reflects the average consumption of 6866 kWh for small business customers in Queensland.

(d) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2019–20 bill amounts in proportion to yearly expected revenue divided by forecast energy. Actual bill impacts will vary depending on electricity consumption and tariff class.

25 AER, *Final determination, Default Market Offer Prices 2019–20*, April 2019, p. 8.

26 Queensland Competition Authority, *Final Determination–Regulated retail electricity prices for 2019–20*, May 2019, p. 130.