DRAFT DECISION

Ergon Energy Distribution Determination 2020 to 2025

Overview

October 2019

AUSTRALIAN ENERGY REGULATOR

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AER reference: 62728

About our decision

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set a maximum revenue that network businesses are allowed to recover from customers in providing network services.

The National Electricity Law and Rules (NEL and NER) provide the regulatory framework governing electricity transmission and distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[1]

> …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—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Ergon Energy is the electricity distribution network service provider in regional Queensland and submitted its revenue proposal on 31 January 2019 for the five year regulatory period commencing 1 July 2020.

Following the release of this draft decision, Ergon Energy will now have the opportunity to submit a revised proposal by 10 December 2019. Submissions from stakeholders on both the draft decision and revised proposal are invited by 15 January 2020.

The table below sets out the key milestones for our review of Ergon Energy's proposal:

Milestone	Date
Ergon Energy submitted its proposal	31 January 2019
AER issues paper published	28 March 2019
Public forum on Ergon Energy's proposal held in Brisbane	9 April 2019
Submissions on AER's issues paper and Ergon Energy's proposal closed	31 May 2019
AER draft decision published	8 October 2019
Public forum on draft decision	24 October 2019
Ergon Energy submits revised proposal	10 December 2019
Submissions on draft decision and revised proposal due	15 January 2020
AER final decision to be published	30 April 2020

1 NEL, s. 7.

Invitation for submissions

In response to our draft decision, Ergon Energy now has the opportunity to submit a revised proposal for its next regulatory control period (2020-25) by 10 December 2019. Submissions on our draft decision and Ergon Energy's revised proposal are invited from interested stakeholders by 15 January 2020. We will consider and respond to all submissions received by that date in our final determination.

Submissions should be sent to: EnergyQueensland2020@aer.gov.au

Alternatively, submissions can be sent to:

Warwick Anderson
General Manager
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process.

Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) provide a non-confidential version of the submission in a form suitable for publication.

(3) all non-confidential submissions will be placed on our website.[2]

[2] For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy* (June 2014), which is available on our website: https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information.

Note

This overview forms part of the AER's draft decision on the distribution determination that will apply to Ergon Energy for the 2020–25 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

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATO	Australian Tax Office
augex	augmentation expenditure
CAM	cost allocation method
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP 14	Consumer Challenge Panel, sub-panel 14
CESS	capital expenditure sharing scheme
CoS	classification of service
CPI	consumer price index
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DSO	distribution system operator
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NSP	network service provider

Shortened form	Extended form
opex	operating expenditure
Pricing Order	electricity pricing order
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
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

Executive summary

The Australian Energy Regulator (AER) regulates electricity transmission and distribution networks in all Australian jurisdictions except Western Australia.

As part of this process, regulated electricity network businesses must periodically apply to us to us for a ruling on the amount of money they can collect from their customers to run their business.

We use our insights and expertise to determine how much money the businesses can recover from consumers for using their networks.

We are currently doing this for Ergon Energy for the 2020–25 regulatory control period.

This draft decision allows Ergon Energy to recover $5787.9 million from its customers for the 2020–25 period.

This is $727.9 million less than the $6515.8 million Ergon Energy proposed.

The revenue we allow forms the distribution network component of electricity bills. Other components of the electricity bill include generation, transmission environmental policy and retail costs.

We estimate that if this draft decision is implemented, on average residential customers and small business customers in Queensland will save $64 and $82, respectively by 2024–25 via reduced network distribution charges.[3]

In making this draft decision we took three key factors into account:

- Ensuring that consumers pay no more than they need for safe and reliable services
- Ergon Energy's engagement with consumers
- Recognition that an evolving electricity system requires investment.

Ergon Energy has submitted a proposal with targeted actions to reduce prices. Whilst we see these actions as a positive step, there is still a material difference between what Ergon Energy proposes and what we consider efficient spending on capital expenditure (capex). In order to accept Ergon Energy's proposal we will need further justification and supporting material with its revised proposal. We will carefully consider additional material provided before making our final decision.

Ergon Energy has demonstrated timely and effective engagement with its consumers but stakeholders have expressed concern over Ergon Energy's engagement over pricing changes, requiring further work in this regard.

3 Our bill impact calculations for Ergon Energy adopt the network charges in our draft decision for Energex as retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy.

Our draft decision also recognises that the way Queenslanders engage with electricity is changing, and the rapid uptake in rooftop solar is having an increasing impact on Ergon Energy's network. But Ergon Energy must provide us with suitable information to justify its proposed spending for us to include it in allowed revenues.

What are the next steps?

Ergon Energy now has the opportunity to consider our draft decision and submit its revised proposal and supporting material in December 2019.[4]

We will make the final determination by 30 April 2020.

Detailed explanations of other factors informing our draft decision can be found in the overview section and attachments to this draft determination.

What does this draft decision mean for consumers?

We estimate that if this draft decision is implemented, network charges in 2024–25 would be:

- $64 lower for average residential customers in Ergon Energy's zone
- $82 lower for average small business customers in Ergon Energy's zone.

The average annual electricity bill for a residential or small business customer is estimated to be around 4.1 and 3.5 per cent lower in 2025, respectively, compared to the current level.[5]

What does this mean for Ergon Energy?

- The total allowed revenue provides for Ergon Energy's operating and capital expenditure.
- It also provides a rate of return of 4.87 per cent consistent with current market conditions.
- Tax allowance has been reduced in line with our recent review of the regulatory tax approach and the 2018 rate of return instrument resulting in a reduction of $181.6 million compared to the 2015–20 regulatory period.

Ensuring that consumers pay no more than they need for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a cornerstone of the regulatory determination process. This involves us assessing whether a business' proposal is a reasonable and realistic forecast of how much money it needs for the safe and reliable operation of the network.

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[4] The numbers in this draft determination may change in the final determination.

[5] Compared to the current level, holding all other components of the bill constant.

To do this we use a range of materials including Ergon Energy's formal regulatory proposal, submissions from stakeholders and our own analysis. Additionally we met with Ergon Energy representatives to discuss the proposal.

Ergon Energy has submitted a proposal with targeted actions to reduce prices and we have accepted these whilst evaluating the required expenditure to provide safe and reliable electricity into the future. Nevertheless, this draft decision finds a significant difference between what Ergon Energy proposes and what we consider efficient spending on capex, especially regarding the need for future investment.

Ergon Energy now has the opportunity to consider our draft decision and put forward further supporting material to support its capex proposals.

Ergon Energy's engagement with consumers

Ergon Energy has demonstrated timely and effective engagement with its consumers, but stakeholders have expressed concern over Ergon Energy's engagement over pricing changes, requiring further work in this regard.

Consumers were appreciative of Ergon Energy's proactive engagement noting the numerous opportunities provided and participation of senior Ergon Energy management in community meetings. Consumers were also appreciative that Ergon Energy took on their feedback and adjusted its proposal to address their affordability concerns

Ergon Energy's engagement has been positive overall but stakeholders were unhappy with Ergon Energy's consultation on pricing changes. There has subsequently been significant engagement in this area by Ergon Energy.

Ergon Energy must clearly communicate to customers how changes to tariffs or other pricing structures will affect their circumstances so they can be fully informed when trying to make further savings on their bills. Our draft decision sets out in detail the amendments we require Ergon Energy to make to its proposed tariff changes before they can be approved

Recognition that an evolving electricity system requires investment

The way Queenslanders engage with electricity is changing, and the rapid uptake in rooftop solar is having an increasing impact on networks. This draft decision reflects Ergon Energy's need to engage with technologies like Distributed Energy Resources (DER) to address the evolving needs of consumers.

Ergon Energy (and Energex) proposed to spend for an Intelligent Grid Enablement Program that would provide a framework to manage the data of its low voltage (LV) network. However, Ergon Energy has not supplied project scoping, a business case or cost benefit analysis.

As a result, we are not able to assess this program and have not included it in our draft decision. Ergon Energy needs to provide us with the relevant information if it is to be approved in the final decision.

The AER understands the need for investment to deal with the impact of these technologies, but we must ensure that any spending is cost-efficient and in the long term interest of consumers.

1 Our draft decision

Our draft decision would allow Ergon Energy to recover a total revenue of $5787.9 million ($ nominal) from its customers from 1 July 2020 to 30 June 2025.

Ergon Energy is regulated using a revenue cap. Incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

Our draft decision for Ergon Energy determines the total revenue it can recover from customers for the provision of common distribution services (standard control services (SCS)). This forms the basis of Ergon Energy's distribution tariffs for the 2020–25 regulatory control period. Ergon Energy's Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from customers.

Ergon Energy also provides alternative control services (ACS), the costs of which are recovered only from users of those services, through a capped price on the individual service. These costs are considered separately to our building block determination.[6] Ergon Energy has not proposed to provide any services on a negotiated basis in the 2020–25 regulatory control period.[7]

1.1 What is driving revenue?

The changing impact of inflation over time makes it difficult to compare revenue from one period to the next on a like-for-like basis. To do this, we use 'real' values based on a common year (in this case, 2019–20),[8] which have been adjusted for the impact of inflation. Figures in this section are presented in real $2019–20 terms unless otherwise stated.

The total revenue allowance in this 2020–25 draft decision is 15.6 per cent lower than the allowed revenue provided for in our 2015–20 final decision. Figure 1 shows an initial real revenues decrease from 2019–20 levels by 16.8 per cent in 2020–21, then staying constant over 2021–25.

Figure 1 shows our draft decision for Ergon Energy's smoothed revenue for the 2020–25 regulatory control period, and its allowed revenues over the 2010–2020 regulatory control periods.

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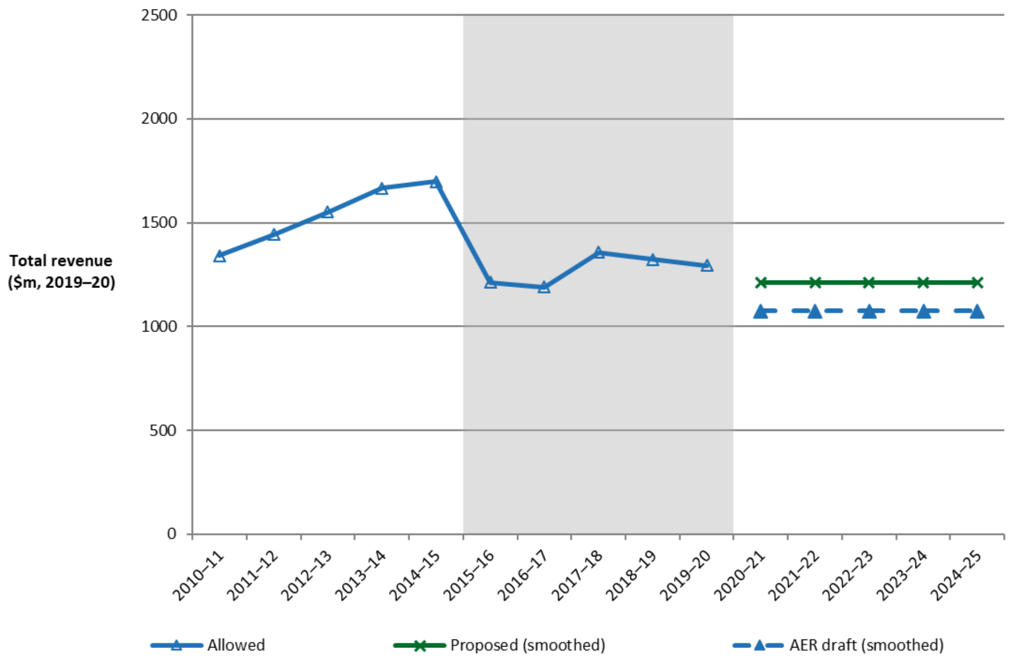
6 We discuss alternative control services in Attachment 15 to this draft decision.

7 Our distribution determination for Ergon Energy includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because Ergon Energy has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2020–25 regulatory control period.

8 That is, 30 June 2020 dollar terms, based on Ergon Energy's estimated actual revenue for 2019–20.

Figure 1 Revenue over time ($ million, 2019–20)



Source: AER analysis, smoothed revenue.

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.

Figure 2 highlights the key drivers of the change in Ergon Energy's allowed revenue from the 2015–20 regulatory control period compared to what we expect in the 2020–25 regulatory control period. It illustrates that the largest driver is the return on capital building block. The nominal WACC has decreased from around 6.0 per cent in the 2015–20 regulatory control period to 4.87 per cent for the 2020–25 regulatory control period.[9] Other reductions include:

- opex, due to lower proposed opex compared to the 2015–20 regulatory control period[10]
- the net tax allowance, due to changes in our regulatory tax approach following from our recent tax review and the 2018 rate of return instrument[11]
- the revenue adjustment building block due to no DUoS under recovery and no incentive scheme payments in the 2020–25 regulatory control period compared to the 2015–20 regulatory control period[12]

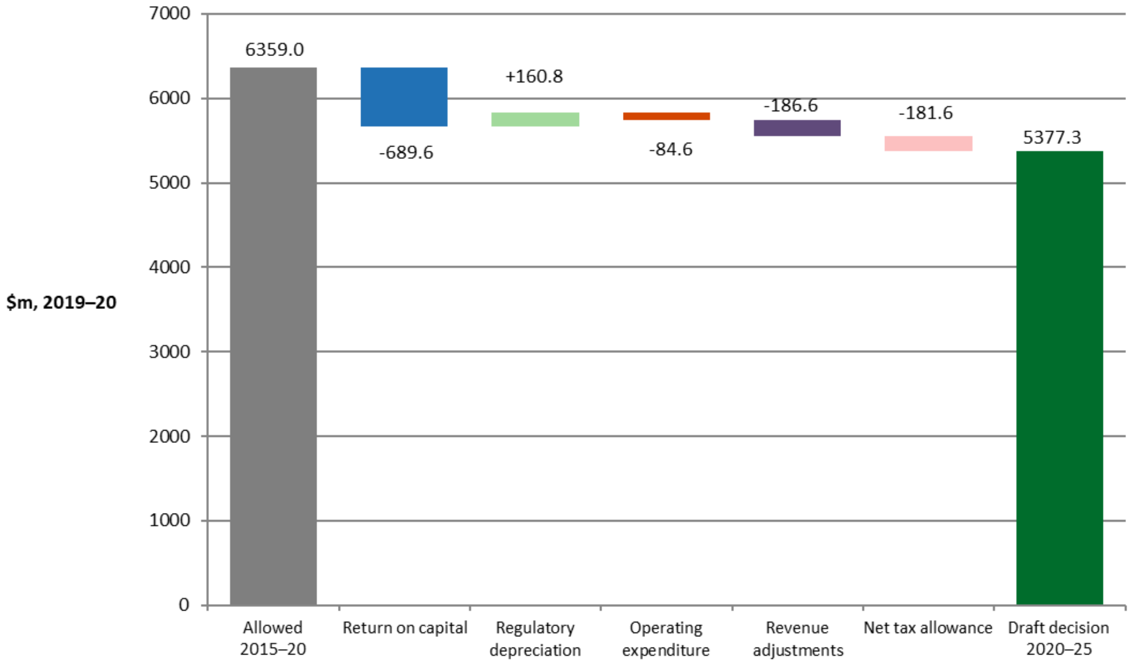
[9] The reference to the WACC is a nominal WACC unless stated otherwise. The real WACC is impacted to a similar degree. Please see section 2.2 for further details.

[10] Please see section 2.5 for further details.

[11] Please see section 2.6 for further details.

The increase in the regulatory depreciation building block is largely driven by a rising RAB over the 2015–20 regulatory control period and forecast capex over the 2020–25 regulatory control period.[13]

Figure 2 Change in revenue from 2015–20 to 2020–25 ($ million, 2019–20)



Source: AER analysis, building block revenue.

Note: Revenue adjustments include increments or decrements accrued under incentives schemes such as the CESS, EBSS and DMIAM.

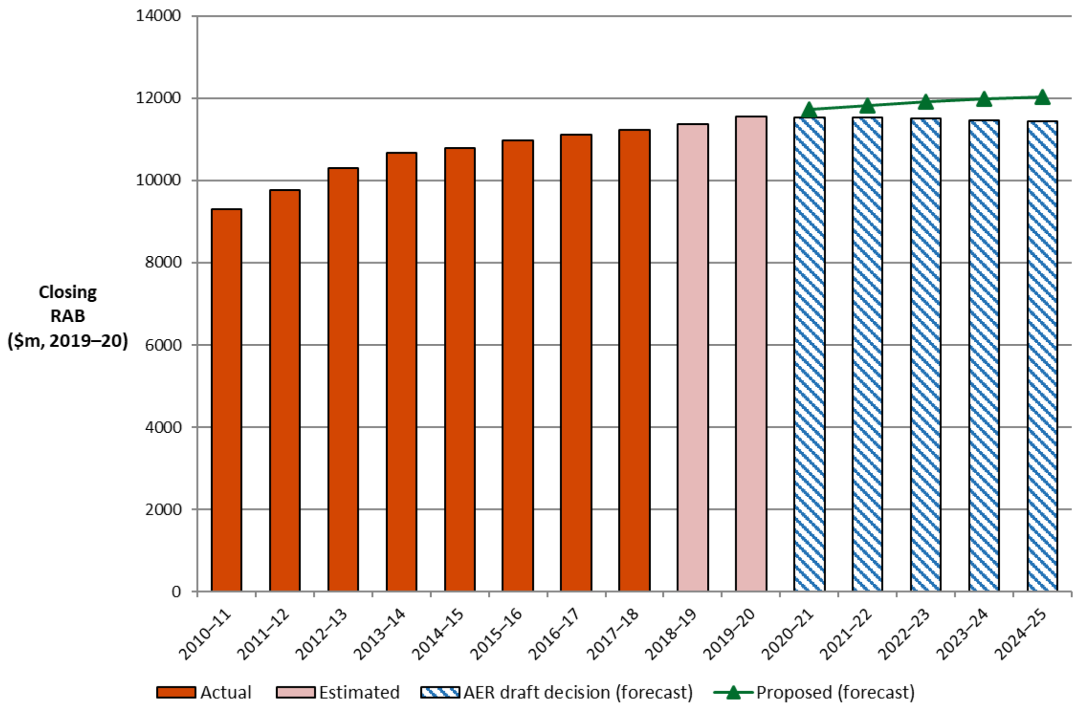
Figure 3 compares our draft decision forecast RAB to Ergon Energy's proposed and actual RAB. This shows that Ergon Energy's RAB is forecast to decrease by around 1.1 per cent in value over the 2020–25 regulatory control period, following a 7.2 per cent increase in the current 2015–20 regulatory control period.[14] This change is mainly driven by lower forecast capex for the 2020–25 regulatory control period compared to capex incurred (and estimated) in the 2015–20 regulatory period.

12 Please see section 2.6 for further details.

13 Please see section 2.3 for further details.

14 Please see section 2.1 for further details.

Figure 3 Value of Ergon Energy's RAB over time ($ million, 2019–20)



Source: AER analysis.

1.2 Key differences between our draft decision and Ergon Energy's proposal

Our draft decision provides for a lower revenue allowance than that proposed by Ergon Energy. The total revenue in this draft decision for the 2020–25 regulatory period is $5787.9 million ($ nominal), which is 11.2 per cent lower than Ergon Energy's proposed $6515.8 million ($ nominal).

The biggest contributor to the difference between our draft decision revenue and Ergon Energy's proposal is the current rate of return (and therefore the return on capital). Whist Ergon Energy applied the 2018 rate of return instrument to propose a 5.46 per cent rate of return, currently the risk free rate and cost of debt is lower than at the time of its proposal, leading to a rate of return of 4.87 per cent. Consequently, the revenue for the cost of capital component is lower by $539 million ($ nominal) compared to Ergon Energy's proposal.

Applying our new regulatory tax approach following from our recent tax review, along with the 2018 rate of return instrument, has also reduced the tax allowance in this draft decision compared to Ergon Energy's proposal by $143 million ($ nominal).

Ergon Energy has not sufficiently justified the prudency or efficiency of its proposed forecast capex of $2724.2 million ($2019–20). Our substitute capex forecast is $573 million ($2019–20) or 21.0 per cent lower than the proposal. This leads to a lower forecast RAB than Ergon Energy's proposal. The lower forecast RAB also contributes to our lower draft decision revenues through a lower regulatory depreciation allowance.

1.3 Expected impact of our draft decision on electricity bills

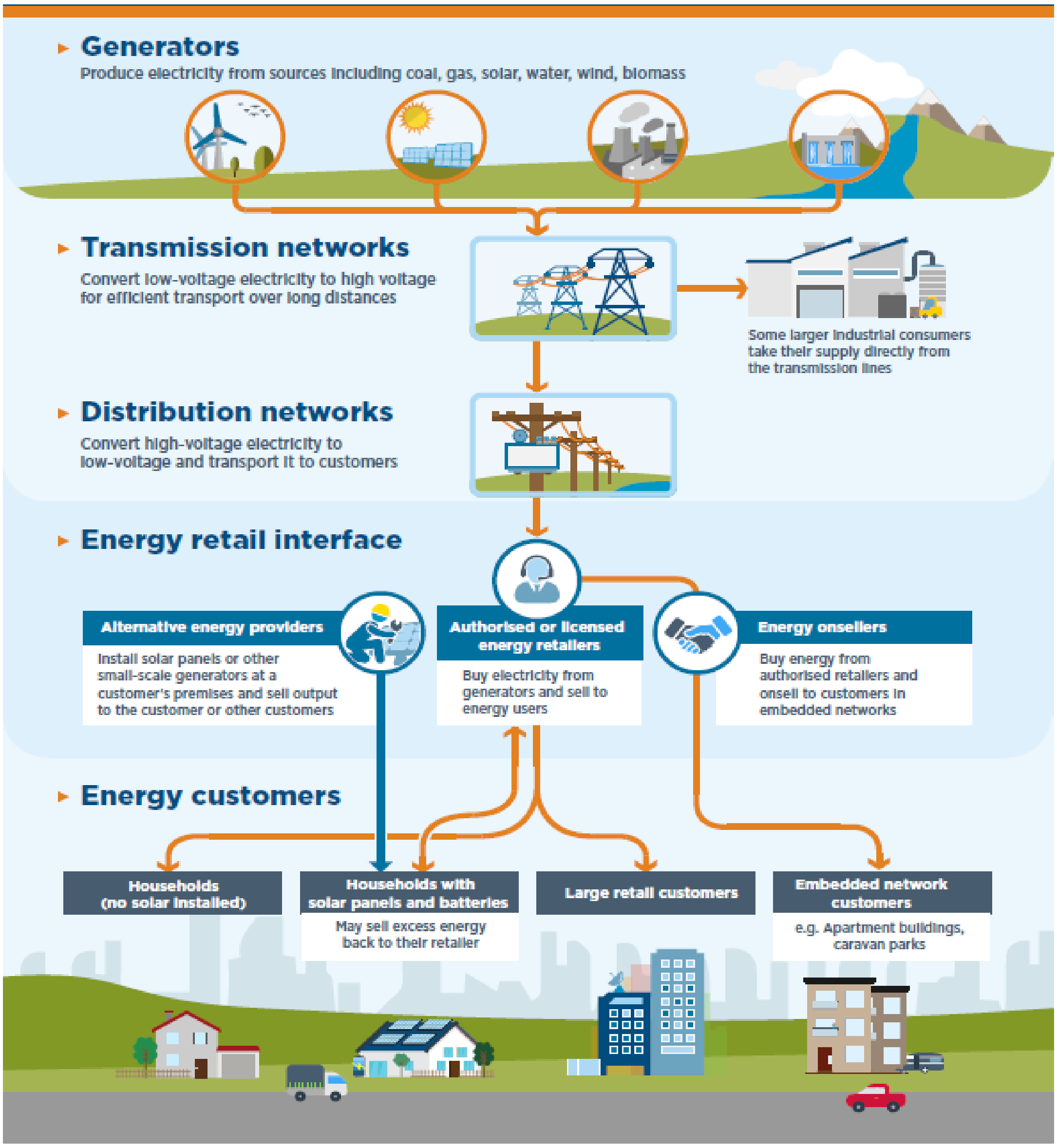
Our bill impact calculations for Ergon Energy adopt the network charges in our draft decision for Energex. This is because retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. The policy results in regulated retail electricity prices in Ergon Energy's distribution area being matched to those in Energex's area.[15]

The distribution network charges make up around 35 per cent of the total residential and 30 per cent of the total small business retail electricity bills Ergon Energy's customers pay.[16] Other components of the electricity bill include environmental policy costs, wholesale electricity costs and retail costs. Figure 4 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to customers by their chosen electricity retailer.

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

[16] Ergon Energy, *17.059 Indicative Bill Impact RIN template,* January 2019*,* January 2019; AEMC, *Databook–2018 Residential electricity price trend*s, December 2018.

Figure 4 Electricity supply chain



Source: AER, *State of the Energy Market*, December 2018, p. 28.

Table 1 shows the estimated average annual impact of our draft decision for the 2020–25 regulatory control period on electricity bills for residential and small business customers. These estimates suggest a 4.1 per cent ($ nominal) decrease for residential customers, and a 3.5 per cent ($ nominal) decrease for small business customers over the five-year 2020–25 regulatory control period. The impact of distribution network charges on the retail bill is dependent on how retailers structure their standing or market offers to customers.

We estimate the expected bill impact by varying the distribution charges in accordance with our 2020–25 draft decision, while holding all other components constant. This approach isolates the effect of our draft decision on distribution network tariffs from other parts of the bill. However, this does not imply that other components will remain unchanged across the regulatory control period.[17]

We estimate that were this draft decision to be implemented, then on 30 June 2025 distribution network charges ($ nominal) in Ergon Energy's area would be:

- $64 lower for an average residential customer[18]
- $82 lower for an average small business customer[19]

than what we expect them to be on 30 June 2020.

This compares to Ergon Energy's proposal of $6 and $8 decreases for the average residential and small business customers, respectively.[20] [21]

[17] It also assumes that actual energy consumption will equal the forecast adopted in our final 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.

[18] This equates to a 4.1 per cent decrease in the average residential customer's total electricity bill over five years.

[19] This equates to a 3.5 per cent decrease in the average small business customer's total electricity bill over five years.

[20] This equates to a 0.4 per cent decrease in the average residential customer's total electricity bill over five years.

[21] This equates to a 0.3 per cent decrease in the average small business customer's total electricity bill over five years.

Table 1 Estimated contribution to 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[a]						
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[a]						
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*, p.8, Queensland Competition Authority, *Final Determination–Regulated retail electricity prices for 2019–20*, p. vi; Energex, *17.052 2020-25 Indicative Bill Impact RIN template,* 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.

Further detail on our draft decision impact on overall bills is set out in attachment 1.

1.4 Ergon Energy's consumer engagement

The NEO puts the long term interests of consumers at the centre of our decisions as a regulator and the way Ergon Energy operates its network. An important part of this is ensuring the regulatory proposal Ergon Energy puts to us for approval reflects the NEO, and that Ergon Energy has engaged with its consumers to determine how best to provide services that align with their long term interests.

Consumer engagement in this context is about Ergon Energy working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence Ergon Energy’s decisions. In the regulatory process, stronger consumer engagement can help us test service providers' expenditure proposals, and can raise alternative views on matters such as service priorities, capex and opex proposals and tariff structures.

While both Ergon Energy Network and Energex have submitted individual regulatory proposals to the AER, a joint engagement approach has been undertaken by Energy Queensland.[22] As a result, except where indicated otherwise, references to Energy Queensland's engagement process includes that undertaken for both entities.

Submissions to our issues paper and the regulatory proposal acknowledged Energy Queensland's engagement process. The submissions by Queensland Council of Social Service (QCOSS) and CCP14, in particular acknowledged the quality of the process.[23]

Through its engagement program, Energy Queensland identified the following four key themes, which were used to develop the draft plan: safety; affordability; security; and sustainability.[24] Energy Queensland then sought stakeholder feedback on the draft plan before finalising its regulatory proposal.[25]

In response to these themes, National Seniors Australia submitted that safety, security and sustainability are issues which consumers should be able to take for granted. They conclude that the focus should be on affordability and "fairness/equity".[26] In other submissions, stakeholders identified affordability as the most critical issue facing consumers. For example the ECA submission highlighted findings from its latest Energy Consumer Sentiment Survey which found that consumers are much more satisfied with reliability than they are with value for money.[27] The National Farmers Federation, Queensland Canegrowers, and Queenslanders with Disability Network all submitted that price is the primary concern.[28]

In response to the key stakeholder concern of affordability, Energy Queensland proposed a further $364 million (in nominal terms) reduction in its revenue requirement for Ergon Energy from that presented in its Draft Plan.[29] Stakeholder feedback recognised that Energy Queensland had taken into account areas of concern raised by stakeholders in the development of the regulatory proposals from the draft plan.[30]

In their submission the Consumer Challenge Panel's sub-panel for the Queensland reset, CCP14, acknowledged the changes made to the regulatory proposal and noted the positive approach to engagement including attendance by key executives at most

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22 Energex and Ergon Energy, *2020 and beyond community and customer engagement report*, *Regulatory proposals*, January 2019.

23 QCOSS, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019; CCP14, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019, p. 15.

24 Energy Queensland, *2.001 Customer Engagement Strategy - Regulatory Proposal 2020-25*, January 2019, p. 22.

25 Energy Queensland, *2.001 Customer Engagement Strategy - Regulatory Proposal 2020-25*, January 2019, p. 13.

26 National Seniors Australia, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019.

27 ECA, *Submission on Ergon Energy's Regulatory Proposal 2020-25*, 5 June 2019.

28 QFF, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019; Queensland Canegrowers, *Submission on Ergon Energy's Regulatory Proposal 2020-25 – TSS,* 14 June 2019; Queenslanders with a Disability Network, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 25 April 2019.

29 Ergon Energy, *1.005 Overview Regulatory Proposal 2020-25*, January 2019, p. 19.

30 Origin Energy, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019, p. 1; QCOSS, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019, p. 21; CCP14, *Submission on Ergon Energy's Regulatory Proposal 2020-25*, 31 May 2019, p. 15.

of the community engagement events.[31] On the engagement process, CCP14 made the observation that customer engagement in Ergon Energy's distribution area was not as effective due in part to the wide range of industries that needed to be involved. [32]

While the proposed price reductions were welcomed by consumers, CCP14 also questioned the sustainability of the one-off cut, driven by merger savings, lower WACC and handing back the EBSS and CESS benefits from the current period.[33] Similarly, Energy Consumers Australia (ECA) requested that we closely scrutinise key elements of Energy Queensland's proposal to ensure that investment is both prudent and efficient.[34] Queensland Canegrowers submitted that the proposal should be rejected, based on flaws and we should require Energex and Ergon Energy to reduce the revenue request and develop more appropriate network tariffs suitable for food and fibre production.[35]

Energy Queensland's engagement with its stakeholders continued after the submission of the regulatory proposal. The focus of further engagement was targeted to the further development of the Tariff Structure Statement (TSS) proposal, which was considered incomplete at the time of submission. On 14 February, Energy Queensland submitted a letter outlining the further engagement process along with a timeline for the submission of the required details to complete the TSS proposal.[36]

Stakeholders have been critical of this later process and the ongoing development of the TSS since the submission of the regulatory proposal. For example, Red and Lumo Energy expressed concern that we accepted– what was in their view– a non-compliant TSS. They were more positive about some of the changes made in respect of further engagement, in particular the decision not to proceed with the lifestyle tariff. However, they requested that we allow for additional time for consultation once a fully compliant TSS has been received.[37]

On the TSS proposal submitted with the regulatory proposal the QCOSS submission observed that the proposals submitted do not adequately reflect the key issues that were raised in the consultation process.[38]

Energy Consumers Australia (ECA) also expressed disappointment that the engagement process has been at the inform end of the International Association for Public Participation (IAP2) spectrum, rather than consult, involve or collaborate.[39]

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31 CCP14, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019, p. 15.

32 CCP14, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019, p. 15.

33 CCP14, *Submission on Ergon Energy's Regulatory Proposal 2020-25,* 31 May 2019, p. 5.

34 ECA, *Submission on Ergon Energy's Regulatory Proposal 2020-25 - Attachment A - Dynamic Analysis*, p. 4.

35 Queensland Canegrowers, *Submission on Ergon Energy's Regulatory Proposal 2020-25 – TSS,* 14 June 2019 p. 3.

36 Ergon Energy, *14 February tariff structure statement further explanation,* February 2019.

37 Red and Lumo Energy*, Submission on Ergon Energy's Regulatory Proposal 2020-25*, 13 June 2019.

38 QCOSS, *Submission on Ergon Energy's Regulatory Proposal 2020-25 – TSS*, 31 May 2019, p. 2; Etrog Consulting, *Report for QCOSS, Submission on Ergon Energy's Regulatory Proposal 2020-25*, 31 May 2019, p. 3.

39 Energy Consumers Australia, *Submission on Ergon Energy's Regulatory Proposal 2020-25*, 5 June 2019, p. 21.

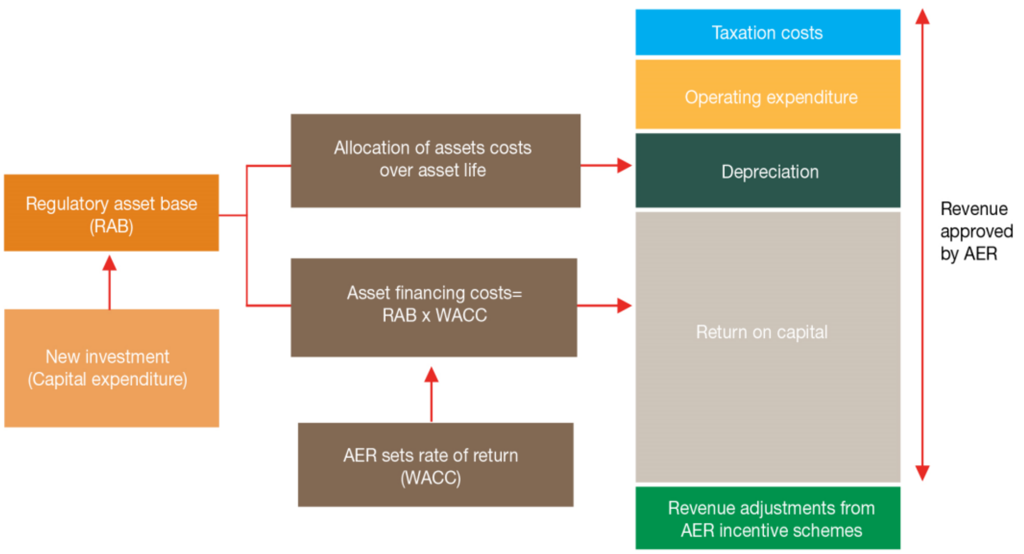
This draft decision is the half-way mark in our review of Ergon Energy's regulatory proposal. Ergon Energy now has the opportunity to respond to our draft decision in a revised proposal, a process that we consider would benefit from further consideration of consumer views.

2 Key components of our draft decision on revenue

The total revenue Ergon Energy has proposed reflects its forecast of the efficient cost of providing network services over the 2020–25 regulatory control period. Ergon Energy's proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach to determining a total revenue allowance (see Figure 5) which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of incentive schemes, such as the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) that applied to Ergon Energy for the 2015–20 regulatory control period and the Demand Management Innovation Allowance Mechanism (DMIAM) allowance for 2020–25 (section 2.7).

Figure 5 The building block approach for determining total revenue



We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework which aims to promote the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our draft decision on Ergon Energy's distribution revenues for the 2020–25 regulatory control period is set out in Table 2.

Table 2 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. In this draft decision, a 0.00% X factor means that the revenue will stay constant in real terms and forecast to vary in line with expected inflation.

(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.

In the sections below we discuss each component of our draft decision on Ergon Energy's revenue for 2020–25 in turn.

2.1 Regulatory asset base

The RAB is the value of assets used by Ergon Energy to provide regulated distribution services. The value of the RAB substantially impacts Ergon Energy's revenue requirement, and the price consumers ultimately pay. This makes it a key issue for many stakeholders. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

As part of our decision on Ergon Energy's revenue for 2020–25, we make a decision on Ergon Energy's opening RAB as at 1 July 2020. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block allowances.

We have determined an opening RAB value of $11552.8 million ($ nominal) as at 1 July 2020 for Ergon Energy. This value is $81.3 million (or 0.7 per cent) lower than Ergon Energy's proposed opening RAB of $11634.1 million ($ nominal) as at 1 July 2020.[40] While we largely accept the proposed methodology for calculating the opening RAB, we made the following revisions to Ergon Energy's proposed inputs to the roll forward model (RFM):

- Updated inputs as newer information has become available since Ergon Energy submitted its proposal. These updates include:
    - actual CPI for 2018–19 and updated inflation estimate for 2019–20
    - WACC input for 2019–20 following the return on debt update for that year in the 2015–20 post-tax revenue model (PTRM)
    - forecast straight-line depreciation for 2019–20 following the return on debt update for that year in the 2015–20 PTRM.
- Used March to March quarter actual CPI for 2014–15 consistent with that used for annual pricing purposes.
- Corrected the adjustments for movements in capitalised provisions over the 2015–20 period.[41]
- Reduced the value of legacy ICT assets as at 1 July 2020. ICT services that were previously provided for a fee by a subsidiary are now being provided in-house.[42]

Table 3 sets out the roll forward of the RAB to the end of the 2015–20 regulatory control period.

40 Ergon Energy, *Regulatory proposal, attachment ERG 8.008 RFM - SCS JAN19 PUBLIC*, 31 January 2019.

41 This amendment reduced the closing RAB value as at 1 July 2020 by around $27.8 million.

42 Our draft decision allows $121.2 million of legacy ICT assets to be included in the opening RAB as at 1 July 2020. This is $32.8 million less than Ergon Energy's proposed amount of $154.0 million

Table 3 AER's draft decision on Ergon Energy's RAB for the 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19[a]	2019–20[b]
Opening RAB	9873.0	10217.0	10489.8	10803.3	11149.8
Capital expenditure[c]	611.4	509.7	506.9	563.6	552.5
Inflation indexation on opening RAB [d]	166.7	150.8	200.3	192.7	223.0
Less: straight-line depreciation[e]	434.1	387.7	393.6	409.8	423.7
Interim closing RAB	10217.0	10489.8	10803.3	11149.8	11501.7
Difference between estimated and actual capex in 2014–15					–54.2
Return on difference for 2014–15 capex					–15.9
Roll-in of legacy ICT assets					121.2
Closing RAB as at 30 June 2020					**11552.8**

Source: AER analysis.

(a) Based on estimated capex. We will update the RAB roll forward for actual capex in the final decision.

(b) Based on estimated capex provided by Ergon Energy. We expect to update the RAB roll forward with a revised capex estimate in the final decision, and true-up the RAB for actual capex at the next reset.

(c) Net of disposals and capital contributions, and adjusted for actual CPI.

(d) We will update the RAB roll forward for actual CPI for 2019–20 in the final decision.

(e) Adjusted for actual CPI. Based on forecast capex.

We have determined a forecast closing RAB value of $12894.9 million ($ nominal) as at 30 June 2025 for Ergon Energy. This is $659.6 million lower than Ergon Energy's proposed closing RAB value of $13554.5 million ($ nominal).[43] Our draft decision on the forecast closing RAB value reflects the updated opening RAB as at 1 July 2020, and our draft decisions on the expected inflation rate (attachment 3), forecast depreciation (attachment 4) and forecast capex (attachment 5).

Table 4 sets out our draft decision on the forecast RAB values for Ergon Energy over the 2020–25 regulatory control period.

43 Ergon Energy, *Regulatory proposal, attachment ERG 8.004 PTRM - SCS JAN19 PUBLIC,* 31 January 2019.

Table 4 AER's draft decision on Ergon Energy's RAB for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25
Opening RAB	11552.8	11819.0	12090.4	12362.0	12623.7
Capital expenditure[a]	437.0	459.2	471.8	472.0	499.5
Inflation indexation on opening RAB	283.0	289.6	296.2	302.9	309.3
Less: straight-line depreciation	453.8	477.3	496.5	513.1	537.5
Closing RAB	**11819.0**	**12090.4**	**12362.0**	**12623.7**	**12894.9**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the PTRM, the capex includes a half-year WACC allowance to compensate for the six month period before capex is added to the RAB for revenue modelling.

We accept Ergon Energy's proposal that the forecast depreciation approach is to be used to establish the opening RAB at the commencement of the 2025–30 regulatory control period.[44] This approach is consistent with our Framework and approach (F&A).[45]

Further detail on our draft decision regarding the RAB is set out in attachment 2.

2.2 Rate of return and value of imputation credits

The return each business is to receive on its RAB (the 'return on capital') is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.

An accurate estimate of the rate of return is necessary to promote efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

44 NER, cl. 6.12.1(18). Ergon Energy, *Regulatory proposal*, January 2019, p. 32.

45 AER, *Final framework and approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2020,* July 2018, p. 12.

As required under the NER, we have applied the 2018 rate of return instrument (2018 instrument) and estimate a placeholder allowed rate of return of 4.87 per cent (nominal vanilla) which will be updated for our final decision on the averaging periods.[46] Ergon Energy's regulatory proposal has adopted the 2018 instrument, however made an error in the assumption of a 6.0 per cent MRP, when it was finalised at 6.1 per cent.[47]

Our calculated rate of return, in Table 5, will apply to the first year of the 2020–25 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with the 2018 instrument to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Our draft decision is to accept Ergon Energy's proposed risk free rate[48] and debt averaging periods because they satisfied the 2018 instrument.[49]

Table 5 Final decision on Ergon Energy's rate of return (% nominal)

	Previous Regulatory Period (2015–20)	Ergon Energy's Proposal (2020–25)	AER draft decision (2020–25)	Allowed return over regulatory control period
Nominal risk free rate	2.96%	2.60%	1.32%[a]	
Market risk premium	6.5%	6.0%	6.1%	
Equity beta	0.7	0.6	0.6	
Return on equity (nominal post–tax)	7.5%	6.26%	4.98%	Constant (%)
Return on debt (nominal pre–tax)	5.01%	4.92%	4.79%	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.01%	5.46%	4.87%	Updated annually for return on debt
Forecast inflation	2.5%	2.42%	2.45%	Constant (%)

Source: AER analysis.

[a] Calculated using a placeholder averaging period of 20 business days ending 31 July 2019.

46 See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision. The legislative amendments to replace the (previous) non-binding Rate of Return Guidelines with a binding legislative instrument were passed by the South Australian Parliament in December 2018. See, Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018 (SA). NGL, Chapter 2, Part 1, division 1A; NEL, Part 3, division 1B.

47 Ergon Energy, *Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 95.

48 This is also known as the return on equity averaging period.

49 AER, *Rate of return instrument*, December 2018, cll.7–8, 23–25; AER, *Draft Rate of return guidelines*, July 2018, p. 5.

Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

Ergon Energy has proposed to use our standard approach to estimating debt and equity raising costs.[50] We have set total debt raising costs of $28.5 million ($2019–20) and zero equity raising costs.

Imputation credits

Our draft decision applies a gamma of 0.585 as per the binding 2018 instrument.[51] Ergon Energy's proposal has adopted the 2018 Instrument for gamma.[52]

2.3 Regulatory depreciation (return of capital)

Regulatory depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). Ergon Energy invests capital in large assets to provide electricity network services to its customers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from customers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance. The regulatory depreciation allowance is the net total of the straight-line depreciation less the inflation indexation adjustment of the RAB.

Our draft decision on Ergon Energy's revenue for 2020–25 includes a regulatory depreciation allowance of $997.4 million ($ nominal). This is $54.9 million (5.2 per cent) lower than Ergon Energy's proposal. We adopt the same approach to regulatory depreciation as Ergon Energy, including its proposed standard asset lives which determine how quickly an asset class is removed from the RAB. We also accept its proposed year-by-year tracking approach, subject to minor changes to its depreciation tracking model. The difference in our draft decision and the proposed regulatory depreciation allowance is largely due to the following determinations on related parts of our decision:

- a lower opening RAB at 1 July 2020 due mainly to a lower amount of legacy ICT assets (attachment 2)
- expected inflation over the 2020–25 regulatory control period (attachment 3)

50 Ergon Energy, *An Overview Our Regulatory Proposals 2020–25*, January 2019, p. 41.

51 AER, *Rate of return instrument*, December 2018, cl. 27.

52 Ergon Energy, *Ergon Energy Regulatory Proposal 2020-25*, January 2019, p.100.

- forecast capex (attachment 5) including its effect on the projected RAB over the 2020–25 regulatory control period.[53]

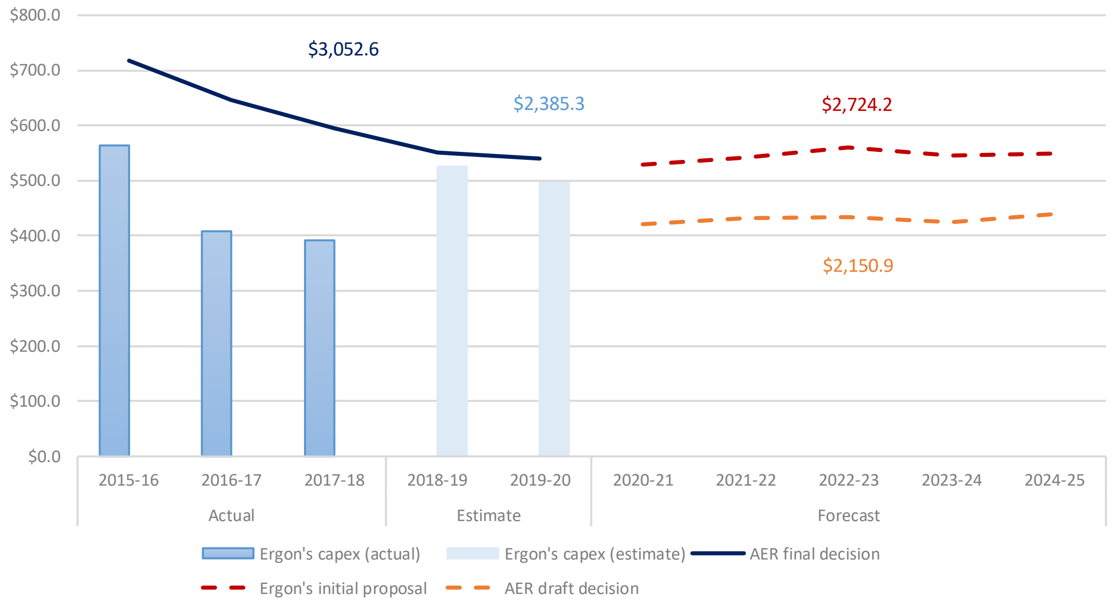
Further detail on our draft decision regarding depreciation is set out in attachment 4.

2.4 Capital expenditure

Capex—the capital costs and expenditure incurred to provide network services—mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. Capex is added to Ergon Energy's RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our draft decision on Ergon Energy's revenue includes total forecast capex of $2150.9 million ($2019–20) for 2020–25. This is 10 per cent lower than Ergon Energy's actual and estimated capex of $2385.3 million ($2019–20) over the current period. Figure 6 shows Ergon Energy’s proposed capex and our draft decision compared with historical expenditure.

Figure 6 Ergon Energy's capex over time ($ million, 2019–20)



Source: AER analysis.

Notes: Net of capital contributions and disposals. Ergon Energy's historical allowance is not directly comparable to its recast data, initial capex forecast and the AER draft decision due to its CAM and CoS changes.

[53] Capex enters the RAB net of forecast disposals and capital contributions. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our draft decision on the RAB (attachment 2) also reflects our updates to the WACC for the 2020–25 regulatory control period.

Our draft decision substitutes a capex forecast that is 21 per cent lower than Ergon Energy's proposal.[54] Several factors contribute to this lower substitute estimate:

- Overall, we observed a lack of necessary material in Ergon Energy's capex proposal.
- Ergon Energy did not provide quantitative cost-benefit analysis. We are typically provided this analysis from the regulated businesses in support of its proposals In particular, its proposal for a step up in capex due to increased network risk has not been sufficiently supported through quantitative evidence. We therefore consider that a business-as-usual amount—as revealed in its actual spend—and comparison with other businesses through the repex model provide a reasonable and appropriate substitute estimate for repex in the circumstances. As mentioned in our previous decisions we expect businesses to provide risk-based cost-benefit analysis, including a comparison with the status quo and an exploration of all feasible options, to support its forecast capex. This is consistent with good business practice.
- While we note that Ergon Energy provided businesses cases to support some projects and programs, these were generally presented as least-cost options analyses and did not demonstrate the need for the program. In this regard, we observe that Ergon Energy continues to maintain a deterministic approach to forecasting which is inconsistent with good industry practice, where industry has moved to a probabilistic framework.
- We acknowledge the importance of addressing safety risks, as reflected in our acceptance of proposed capex for safety reasons in other decisions. However, at this stage, Ergon Energy has not demonstrated that its proposed new low-voltage safety capex program is prudent and efficient. The information currently before us is insufficient to demonstrate that the costs will not be grossly disproportionate to the benefits. We invite Ergon Energy to support its forecasts with more robust risk-based cost-benefit analysis.
- Ergon Energy was not able to show how it had derived its forecast or why it was prudent and efficient for many projects and programs. Examples of this include the forecasts for communications augmentation capex (augex), modelled repex and non-network capex. We encourage Ergon Energy to address the issues identified in this draft decision in its revised proposal.
- Our substitute estimate for ICT capex reflects our concerns that some elements of Ergon Energy's non-recurrent ICT programs cannot be delivered within the 2020–25 regulatory control period and therefore likely to be deferred. Ergon Energy is currently behind schedule delivering the ICT program in the current period.
- Finally, our assessment and our consultant EMCa highlighted concerns with Ergon Energy's governance, noting that it does not consistently apply its investment and

54 NER, cl. 6.12.1(3)(ii).

management framework, and forecasting processes with a clear focus on achieving a total capex forecast that is prudent and efficient.

The differences between the total capex forecast proposed by Ergon Energy and the forecast we have substituted in our draft decision are summarised in Table 6.

Table 6 Assessment of required capex by driver 2020–25 ($ million, 2019–20)

Category	Ergon Energy's proposal	AER draft decision	$ million	Per cent
Repex	$1094.4	$842.0	-$252.4	-23%
Augex	$248.5	$170.5	-$78.0	-31%
Gross connections	$375.9	$375.9	$0.0	0%
ICT	$210.1	$159.7	-$50.4	-24%
Property	$128.6	$56.5	-$72.0	-56%
Fleet	$135.8	$115.2	-$20.6	-15%
Other non-network	$24.9	$22.4	-$2.5	-10%
Overheads	$686.5	$613.9	-$72.6	-11%
Gross capex	**$2904.7**	**$2356.1**	**-$548.6**	**-19%**
less capcons	$169.9	$169.9	$0.0	0%
less disposals	$10.6	$19.3	$8.7	82%
less modelling adjustments		$16.1		
Net capex	**$2724.2**	**$2150.9**	**-$573.3**	**-21%**

Source: AER analysis.

Note: Table excludes equity raising costs. Numbers may not add due to rounding. Modelling adjustments relating to Ergon Energy's CPI and real price escalation assumptions.

Ergon Energy will now have the opportunity to respond to the concerns we have raised with its capex forecast in its revised proposal. As it does so, we encourage Ergon Energy to have particular regard to our detailed observations in attachment 5 to this draft decision, particularly where we have noted a lack of supporting material to justify the prudency and efficiency of its forecast. Consistent with our recent decisions, we expect Ergon Energy to provide risk quantification where necessary in support of its revised proposal. We will carefully consider additional material before making our final decision.

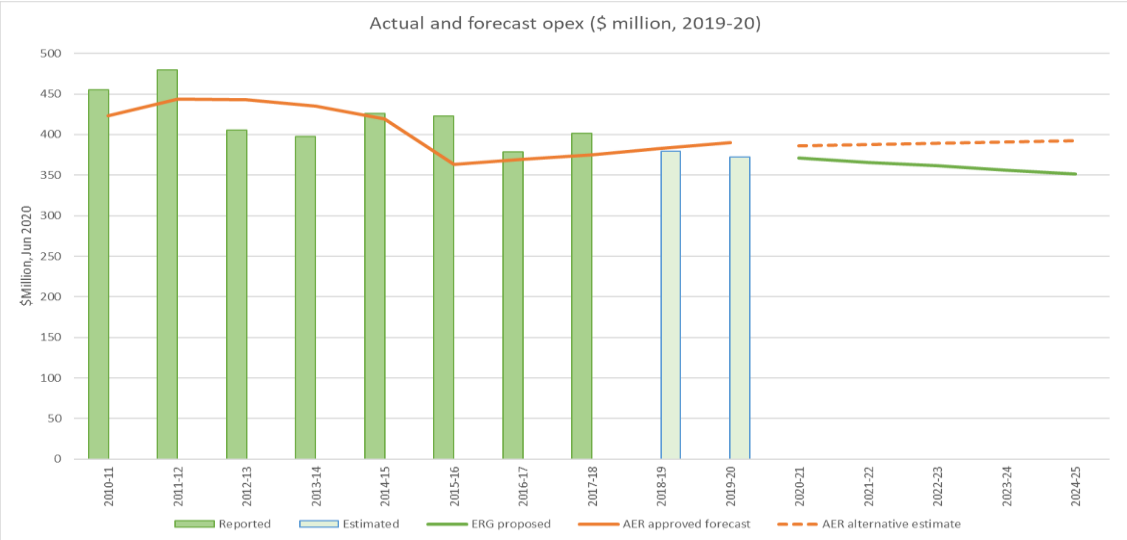
2.5 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of prescribed transmission services and distribution standard control services. Forecast opex is one of the building blocks we use to determine Ergon Energy's total regulated revenue requirement.

Our draft decision is to include Ergon Energy's proposed total opex forecast of $1834.6 million ($2019–20) [55] in its allowed revenue for the 2020–25 period. This is $129.5 million (or 7.1 per cent) lower than our alternative total opex estimate of $1964.2 million ($2019-20).[56]

Figure 7 shows Ergon Energy's actual opex, our previous forecast, proposed opex for the next five years and our draft decision.

Figure 7 Ergon Energy's opex over time ($ million, 2019–20)



Source: AER analysis.

Note: Excludes debt-raising costs.

Table 7 sets out the differences between Ergon Energy's proposed total opex and our alternative estimate.

55 Includes debt-raising costs.

56 Includes debt-raising costs.

Table 7 AER's alternative estimate compared to Ergon Energy's proposal ($ million, 2019–20)

	Ergon Energy's proposal	AER alternative estimate	Difference
Based on reported opex in 2018-19	1898.9	1884.9	-14.0
Base adjustment: Negative base adjustments	-127.0	0.0	127.0
Base adjustment: CAM adjustments	78.7	0.0	-78.7
Base adjustment: Service classification change	0.4	1.3	0.9
2018-19 to 2019-20 increment	36.6	36.2	-0.3
Trend: Output growth	56.5	33.2	-23.3
Trend: Price growth	3.5	18.3	14.8
Trend: Productivity growth	-141.4	-28.6	112.7
Step changes	0.0	0.0	0.0
Total opex (excluding debt raising costs)	1806.1	1945.3	139.1
Debt raising costs	28.5	18.9	-9.6
Total opex (including debt raising costs)	1834.6	1964.2	129.5

Source: Ergon Energy, Revenue proposal, 6.008 Opex forecast - SCS - January 2019; AER analysis.

Note: Numbers may not add up to total due to rounding.

Similar to Ergon Energy we start with the 2018–19 base year opex of $379.8 million ($2019–20). Our assessment of revealed cost data and a range of benchmarking techniques show that historically, Ergon Energy has performed poorly against our benchmarking metrics. It has had high operating costs compared to other networks, even after accounting for its status as a rural, low density network. Ergon Energy has achieved some limited reductions in operating expenditure over the first three years of the current period (relative to the previous period) and is forecasting to achieve a further reduction in 2018-19, its proposed base year. Only after taking into account this forecast cost reduction in its base year opex and its unique operating environmental factors (OEFs), does Ergon Energy's benchmarking performance improve to the point where we do not consider it's estimated base year opex to be materially inefficient.[57] However, we note that Ergon Energy currently remains a relatively poor performer in the NEM and that our position on the efficiency of its base year opex is a finely balanced assessment. We will review this position after updating our benchmarking analysis, taking into account the actual base year opex included in Ergon Energy's revised proposal and the results of our 2019 Annual Benchmarking Report.

[57] See Attachment 6 for a fuller description of our economic benchmarking and base opex assessment.

Whilst we accept Ergon Energy's proposed total opex, we set out the factors that contribute to our higher alternative forecast:

- Our alternative estimate does not include the removal of the negative base adjustments from base opex as proposed by Ergon Energy. This is because information provided by Ergon Energy indicate that while it is not seeking to recover these costs from consumers, it has incurred these costs in the base year and will continue to incur these costs at some level over the forecast period.[58] Our standard approach is to set opex based on a revealed cost approach of actual costs incurred.
- Our alternative estimate does not include the additional costs proposed by Ergon Energy that have resulted from changes in its cost allocation method (CAM). Ergon Energy has not been able to adequately explain and justify this proposed increase in opex. However, we seek further information on these costs in its revised proposal.
- We have applied a lower forecast output growth rate compared to that proposed by Ergon Energy. Our estimate of output growth uses Ergon Energy's forecasts of growth in customer numbers, circuit line length, maximum demand and energy throughput from its regulatory determination RIN response rather than its opex model. We believe the regulatory determination RIN numbers, which are more recent, reflect Ergon Energy's best available forecast output growth.
- We have used a higher forecast input price growth rate compared to that proposed by Ergon Energy. We have forecast labour price growth using the Deloitte Access Economics (DAE) forecasts prepared for the AER. This is a change in our standard approach of averaging the forecasts from DAE and the business's consultant (generally BIS Oxford). It reflects analysis that over the period 2007 to 2018 DAE's real Wage Price Index growth forecasts have been more accurate. We have not included Ergon Energy's 0.59 per cent average annual unit rate efficiency' discount to our input price growth forecast.
- We have applied our standard 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision.[59] This is lower than Ergon Energy's 2.58 per cent forecast average annual productivity growth forecast,[60] and is in line with our standard practice of applying a sector-wide productivity forecast that reflects improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.

We have set out the reasons for our final decision on opex in more detail in attachment 6. Our opex model, which calculates our alternative estimate of opex, is available on our website.

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[58] Energy Queensland, *Response to AER information request #47 Ergon Energy,* 25 June 2019, p. 9, Energy Queensland, *Response to AER information request #048 – Energex & Ergon Energy*, 17 July 2019, pp.14-15.

[59] AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019.

[60] While some of these benefits may be delivered via Ergon Energy's ICT capex, this is not substantiated via its ICT business cases, and this draft decision includes a lower ICT capex forecast than Ergon Energy proposed.

2.6 Corporate income tax

The building block approach to the calculation of revenue includes an allowance for the estimated cost of corporate income tax payable by Ergon Energy. Our draft decision is to include a corporate income tax allowance of $0.6 million ($ nominal) in Ergon Energy's revenue for 2020–25. This represents a decrease of $143.4 million ($ nominal) compared to Ergon Energy's proposal of $144.0 million ($ nominal).

The key reasons for the reduction are:

- Application of the latest version of the PTRM (version 4) released in April 2019 which implements the findings in our final report on the review of the regulatory tax approach (the tax review). Specifically, for this draft decision, we have recognised immediate expensing of some forecast capex for the calculation of tax depreciation. We also applied the diminishing value (DV) method for tax depreciation to all new depreciable assets except for forecast capex associated with buildings and in-house software.[61] These changes have reduced Ergon Energy's proposed corporate income tax allowance by about $106.7 million (or 74.1 per cent).
- Adjusted the proposed opening tax asset base as at 1 July 2020, which follows our draft decision to reduce the value of legacy ICT assets to be rolled into the RAB and other input amendments.[62] We also reduced the tax remaining asset life of the 'Legacy ICT' asset class from 10 years to 4 years to better reflect the life of these assets under tax law.

We accept Ergon Energy's proposed standard tax asset lives for all of its existing asset classes. Further, we determine standard tax asset lives of 40 years and 4 years respectively for the two new asset classes of 'Buildings - capital works' and 'In-house software' that are subject to the straight-line method of tax depreciation.

We also accept the proposed remaining tax asset lives as at 1 July 2020 for all asset classes (with the exception of the 'Legacy ICT' asset class) because they are calculated based on the weighted average method as set out in our RFM.

Our adjustments to the return on capital (attachments 2, 3 and 5) and the regulatory depreciation (attachment 4) building blocks affect revenues, in turn impact the tax calculation. The changes affecting revenues are discussed in attachment 1.

Table 8 sets out our draft decision on the estimated cost of corporate income tax for Ergon Energy over the 2020–25 regulatory control period.

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61 All assets acquired prior to 30 June 2020 will continue to be depreciated using the straight-line depreciation method for tax purposes, until these assets are fully depreciated.

62 This is discussed in section 2.4.1, attachment 2 of this draft decision.

Table 8 AER's draft decision on Ergon Energy's cost of corporate income tax for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Tax payable	1.4	0.0	0.0	0.0	0.0	1.4
Less: value of imputation credits	0.8	0.0	0.0	0.0	0.0	0.8
Net corporate income tax	**0.6**	**0.0**	**0.0**	**0.0**	**0.0**	**0.6**

Source: AER analysis.

Further detail on our draft decision regarding corporate income tax is set out in attachment 7.

2.7 Revenue adjustments

Ergon Energy elected not to claim the rewards it accrued from the operation of the efficiency benefit sharing mechanism (EBSS) and capital expenditure sharing scheme (CESS) during the current regulatory control period (2015–20), subject to us accepting its regulatory proposal. For the purpose of this draft decision we have not included any EBSS or CESS increments or decrements in Ergon Energy's allowed revenues.

Ergon Energy accrued EBSS carryover amounts totalling $157.6 million ($ 2019–20) during the current regulatory control period. Our calculation of the EBSS carryover amounts Ergon Energy has accrued is $110.9 million ($2019–20) lower than the $268.5 million ($2019–20) it calculated. This is primarily due to Ergon Energy assuming its opex in 2019–20 will be significantly lower than what it is likely to spend (the negative base adjustments Ergon Energy proposed in its opex forecast, as outlined in section 2.5). We do not consider Ergon Energy should receive EBSS rewards for costs that it will incur but chooses not to recover from customers.

Ergon Energy accrued CESS rewards totalling $45.1 million ($2019–20). Our calculation of the CESS increment is $5.8 million ($2019–20) higher than the $39.3 million ($2019–20) it calculated. This is to reflect updated actual data consistent with the roll forward model.

If, in its revised proposal, Ergon Energy elects to claim its EBSS and CESS rewards, then we will adjust the total revenue for the next regulatory control period in our final decision by adding the EBSS and/or CESS rewards it has accrued in the current period. The above amounts will need to be updated to reflect audited actual opex and capex in 2018–19 and the latest forecast of inflation for 2019–20 from the RBA.

Our draft decision on Ergon Energy's total revenue included an adjustment for the demand management innovation allowance mechanism (DMIAM) which aims to encourage distribution businesses to find investments that are lower cost alternatives to investing in network solutions. An allowance of $5.09 million ($2019–20) has been applied to Ergon Energy over the 2020–25 regulatory control period.

Following section 3 sets out our draft decision on incentive schemes.

3 Incentive schemes to apply for 2020–25

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination we've discussed in section 2 above, to encourage Ergon Energy to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

The incentive schemes that might apply to an electricity distribution network as part of our decision are:

- the opex efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS)
- the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM).

Once we make our decision on Ergon Energy's revenue cap, it has an incentive to provide services at the lowest possible cost, because its returns are determined by its actual costs of providing services. Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. If networks reduce their costs to below our forecast of efficient costs, the savings are shared with its customers in future regulatory periods through a lower opex allowance and a lower RAB.

The DMIS and the DMIAM provide businesses an incentive to undertake efficient expenditure on non-network options relating to demand management research and development in demand management projects that have the potential to reduce long term network costs.

The STPIS balances a business' incentive to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to businesses to maintain and improve service performance and not simply cutting costs at the expense of service quality. Once improvements are made, the benchmark performance targets will be tightened in future years.

Our draft decision is that each of the EBSS, CESS, STPIS, DMIS and DMIAM should apply to Ergon Energy for the 2020–25 regulatory control period.

We discuss our draft decisions on each incentive scheme further in attachments 8 to 11.

4 Tariff structure statement

The requirement on distributors to prepare a tariff structure statement arises following significant reforms to the Rules governing distribution network pricing. These reforms to the Rules aim to:

- provide better price signals to retailers—underlying network tariffs that reflect what it costs to use electricity at different times
- transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for the entire duration of the regulatory control period.

It is important to note that distributors charge retailers for the network services provided to end-customers and there is no obligation on retailers to pass the network tariff structure through to their end-customers. In Ergon Energy's distribution network area, the majority of customers are on regulated retail offers, though they can also choose a market offer. The retail tariff structure for those regulated retail offers is determined by the Queensland Competition Authority, and may not necessarily reflect the same structure as the underlying network tariff structure.

The purpose of network tariff reform is to improve the cost reflectivity of the price signals that distributors charge retailers for the cost of providing electricity network capacity for their end customers.

Among other matters, Ergon Energy's proposed tariff structure statement must set out its tariff classes, proposed tariffs, the structures and charging parameters for each proposed tariff, the policies and procedures it will use to assigning customers to tariffs, or reassigning customers from one tariff to another and a description of the approach that Ergon Energy will take in setting tariff levels in each pricing proposal during the 2020–25 regulatory control period.[63]

In this determination we decide the structure of tariffs that will form the basis of annual pricing proposals throughout the regulatory control period.[64] We are also required to decide the policies and procedures for assigning or reassigning customers to tariff classes.[65] While an indicative pricing schedule must accompany the tariff structure

[63] NER, cl. 6.18.5.

[64] NER, cl. 6.12.1(14A).

[65] NER, cl. 6.12.1(17).

statement, Ergon Energy's tariff levels for each tariff for each year of the 2020–25 regulatory control period are not set as part of this determination.[66]

Tariffs for the regulatory year commencing 1 July 2020 will be subject to a separate approval process that takes place in May 2020, after we have made our final revenue determination in April 2020. In turn, tariffs for the following four years will also be approved on an annual basis.[67]

The Queensland electricity distributors are at the forefront of the customer driven and technology enabled transformation of the energy sector in Australia. They are leading the industry in the use of automated load control in the residential and small business customer segment. We support their efforts to expand the use of controlled load products to assist customers to improve the utilisation of their electricity distribution network. We note that the presence of the excess capacity means that peak demand growth is not expected to create significant upward cost pressures in the foreseeable future.

Ergon Energy submitted an initial tariff structure statement in January 2019. In the months that followed, Ergon Energy provided several partial updates to its tariff structure statement proposal, before providing a consolidated updated proposal in June 2019. Between the January and June versions of its proposal, Ergon Energy make several significant changes to its proposal as well as submitting information that was missing from the early versions of its proposal. In this decision, we assess the June 2019 version of Ergon Energy's tariff structure statement proposal.

Ergon Energy has proposed some significant changes to its tariffs and tariff structures for the 2020–25 regulatory control period, including

- The introduction of an inclining block tariff structure for existing residential and small business customers.
- The introduction of a default demand tariff for new residential and small business customers and existing customers that have a smart meter installed after 30 June 2020.
- The introduction of a capacity tariff that is available on an opt-in basis to residential and small business customers with a smart meter installed.
- The introduction of additional controlled load tariffs to assist customers to improve their network capacity utilisation.
- To allow hardship customers on the inclining block tariff and more cost reflective tariffs to opt-in to a legacy anytime energy tariff.

Although we are satisfied that parts of Ergon Energy's tariff structure statement contribute to compliance with the distribution pricing principles and to the achievement

66 NER, cl. 6.8.2(d)(1).

67 NER, cll. 6.18.2 and 6.18.8.

of the network pricing objective, some elements of the tariff structure statement require amendment and further detail.

Our draft decision is to not approve Ergon Energy's proposed tariff structure statement, as we are not satisfied that it complies with the distribution pricing principles.[68] In summary, and among other matters, we are not satisfied with the following elements of Ergon Energy's proposal:

- We consider the proposed inclining block tariff structure is not an efficient tariff structure and it is overly complex.
- We approve Ergon Energy's proposal to use a demand tariff as the default tariff for new residential and small business customers and existing customers who receive a smart meter in the future. However, we consider the specific design of this tariff is not efficient. We also consider this tariff should apply to existing customers with a smart meter.
- We consider more research and stakeholder engagement is required before Ergon Energy introduces opt-in capacity tariffs. The current design of Ergon Energy's proposed capacity tariff does not have better efficiency properties to its demand tariff, but it introduces additional complexity and transaction costs. We encourage Ergon Energy to instead trial different capacity tariff designs during the 2020-25 period. The learnings from these trials and additional consultation can then be reflected in Ergon Energy's tariff structure statement proposal for the 2025-30 period.
- We consider Ergon Energy's proposed application of its long run marginal cost methodology is not appropriate for its economic circumstances given the presence of excess capacity and expectations of minimal peak demand growth in the foreseeable future. Instead, we consider Ergon Energy should transition its tariffs towards its long run marginal cost estimates.
- We do not approve Ergon Energy's proposal to allow customers on retail hardship programs to opt-in to the existing legacy anytime tariff as Ergon Energy has not demonstrated these customers will be worse off on a cost reflective network tariff and Ergon Energy has not provided a plan to eventually transition these customers to cost reflective network tariffs.

Attachment 18 sets out in detail our assessment of Ergon Energy's proposed tariff structure statement.

68 NER, cl. 6.18.5(d).

5 The National Electricity Law and Rules

The (NEL and NER) provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[69]

> "…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—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[70] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long term interests of consumers.[71] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[72]

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. [73]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[74] These are set out in appendix A and the relevant attachments. In coming to a decision that contribute to the achievement of the NEO, we have considered interrelationships of the constituent components of our draft decision in the relevant attachments. Examples include:

- 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 5 and 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

[69] NEL, s. 7.

[70] NEL, s. 16(1)(a).

[71] This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

[72] Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

[73] NEL, s. 16(1)(d).

[74] NER, cl. 6.12.1.

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 and 7).

- 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 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[75] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account.[76]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long term interests of consumers.[77] A particular economically efficient outcome may nevertheless not be in the long term interests of consumers, depending on how prices are structured and risks allocated within the market.[78] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree than others would. For example, we consider that:

- the long term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[79]
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable leading to safety, security and reliability concerns.[80]

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

76 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

77 Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].

78 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

79 NEL, s. 7A(7).

80 NEL, s. 7A(6).

A Constituent decisions

Our draft decision on Ergon Energy's distribution determination for the 2020–25 regulatory control period includes the following constituent components:

Constituent decisions
In accordance with clause 6.12.1(1) of the NER, the AER's draft decision is that the classification of services set out in Attachment 12 will apply to Ergon Energy for the 2020–25 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's draft decision is not to approve the annual revenue requirement set out in Ergon Energy's building block proposal. Our draft decision on Ergon Energy's annual revenue requirement for each year of the 2020–25 regulatory control period is set out in attachment 1 of the draft decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve Ergon Energy's proposal that the regulatory control period will commence on 1 July 2020. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's draft decision is to approve Ergon Energy's proposal that the length of the regulatory control period will be 5 years from 1 July 2020 to 30 June 2025.
The AER did not receive a request for an asset exemption under clause 6.4.B.1 (a)(1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(i) and acting in accordance with clause 6.5.7(d) of the NER, the AER's draft decision is not to accept Ergon Energy's proposed total net forecast capital expenditure of $2724.2 million ($2019–20). Our draft decision therefore includes a substitute estimate of Ergon Energy's total net forecast capex for the 2020–25 regulatory control period of $2150.9 million ($2019–20). The reasons for our draft decision are set out in attachment 5 of the draft decision.
In accordance with clause 6.12.1(4) and acting in accordance with clause 6.5.6(c) of the NER, the AER's draft decision is to accept Ergon Energy's proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $1834.6 million ($2019–20). This is discussed in attachment 6 of the draft decision.
Ergon Energy did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the 2018 Rate of Return Instrument, the AER's draft decision is that the allowed rate or return for the 2020–21 regulatory year is 4.87 per cent (nominal vanilla), as set out in attachment 3 of the draft decision. The rate of return for the remaining regulatory years 2021–25 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) of the NER and the 2018 Rate of Return Instrument, the AER's draft decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in section 2.2 of this draft decision overview.

Constituent decisions

In accordance with clause 6.12.1(6) of the NER, the AER's draft decision on Ergon Energy's regulatory asset base as at 1 July 2020 in accordance with clause 6.5.1 and schedule 6.2 is $11,552.8 ($ nominal). This is discussed in attachment 2 of the draft decision.

In accordance with clause 6.12.1(7) of the NER, the AER's draft decision is not to accept Ergon Energy's proposed corporate income tax of $144.0 million ($ nominal). Our draft decision on Ergon Energy's corporate income tax is $0.6 million ($ nominal). This is discussed in attachment 7 of the draft decision.

In accordance with clause 6.12.1(8) of the NER, the AER's draft decision is not to approve the depreciation schedules submitted by Ergon Energy. Our draft decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in attachment 4 of the draft decision.

In accordance with clause 6.12.1(9) of the NER, the AER makes the following draft decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme(DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme is to apply:

- We will apply version 2 of the EBSS to Ergon Energy in the 2020–25 regulatory control period. This is discussed in attachment 8 of the draft decision.
- We will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Ergon Energy in the 2020–25 regulatory control period. This is discussed in attachment 9 of the draft decision.
- We will apply our STPIS to Ergon Energy for the 2020–25 regulatory control period. This is set out in attachment 10 of the draft decision.
- We will apply the DMIS and DMIAM to Ergon Energy for the 2020–25 regulatory control period. This is discussed in attachment 11 of the draft decision.

In accordance with clause 6.12.1(10) of the NER, the AER's draft decision is that all other appropriate amounts, values and inputs are as set out in this draft determination including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper the AER's draft 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 annual revenue calculated using the formula in attachment 13 plus any adjustment required to move the DUoS unders and overs account to zero. This is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's draft decision on the form of the control mechanism for alternative control services is to apply price caps for all services. This is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's draft decision is that Ergon Energy must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing

Constituent decisions

proposal. This is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(14) of the NER, the AER's draft decision is to apply the following nominated pass through events to Ergon Energy for the 2020–25 regulatory control period in accordance with clause 6.5.10:

- Terrorism event
- Insurance cap event
- Natural disaster event
- Insurer credit risk event

These events have the definitions set out in Attachment 14 of the draft decision.

In accordance with clause 6.12.1(14A) of the NER, the AER's draft decision is to not approve the tariff structure statement proposed by Ergon Energy. This is discussed in attachment 18 of the draft decision.

In accordance with clause 6.12.1(15) of the NER, the AER's draft decision is that the negotiating framework as proposed by Ergon Energy will apply for the 2020–25 regulatory control period. This is discussed in attachment 16 of the draft decision.

In accordance with clause 6.12.1(16) of the NER, the AER's draft decision is to apply the negotiated distribution services criteria published in February 2019 to Ergon Energy. This is discussed in attachment 16 of the draft decision.

In accordance with clause 6.12.1(17) of the NER, the AER's draft decision on the procedures for assigning retail customers to tariff classes for Ergon Energy is set out in attachment 18 of the draft decision.

In accordance with clause 6.12.1(18) of the NER the AER's draft decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of Ergon Energy's regulatory control period as at 1 July 2025. This is discussed in attachment 2 of the draft decision.

In accordance with clause 6.12.1(19) of the NER, the AER's draft 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 method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 13 of the draft decision.

In accordance with clause 6.12.1(20) of the NER the AER's draft decision is to 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 13 of the draft decision.

In accordance with clause 6.12.1(21) of the NER the AER's draft decision is to not approve the connection policy proposed by Ergon Energy. Our draft decision is to amend Ergon Energy's proposed connection policy as set out in attachment 17 of the draft decision.

B List of submissions

We received 12 submissions in response to Ergon Energy's revenue proposal. These are listed below.

Submission from	Date received
CCP14	03/06/2019
Electrical Safety Office	24/07/2019
Energy Consumers Australia	06/06/2019
EnergyAustralia	03/06/2019
National Seniors Australia	31/05/2019
Origin Energy	31/05/2019
QCOSS	31/05/2019
Queensland Farmers' Federation	03/06/2019
Queensland Canegrowers	14/06/2019
Queenslanders with Disability Network	31/05/2019
Red & Lumo Energy	13/06/2019
Total Environment Centre	17/05/2019