Revised regulatory proposal

ACT electricity distribution network 2019–24

November 2018

evoenergy

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1 Introduction

1.1 Background

Evoenergy owns and operates the electricity distribution network in the ACT. This network is the poles, wires, cables, substations and other infrastructure that deliver electrical energy safely and reliably to ACT homes and businesses. Evoenergy is part of the ActewAGL Distribution partnership owned equally by Icon Water Limited and Jemena Limited via subsidiary companies.

As a distribution network service provider (DNSP), the prices charged by Evoenergy to electricity retailers for the carriage of energy are regulated by the Australian Energy Regulator (AER) under the National Electricity Law[1] and the associated National Electricity Rules (Rules).

In January 2018, Evoenergy submitted to the Australian Energy Regulator (AER) its regulatory proposal – its detailed plan for operating, maintaining and investing in its Australian Capital Territory (ACT) electricity distribution network over the five years beginning 1 July 2019.

On 27 September 2018, the AER published its draft decision on Evoenergy's regulatory proposal. Evoenergy, in addition to written submissions, may within 45 business days submit to the AER a revised proposal setting out revisions to its regulatory proposal to incorporate changes required or to address matters raised in the draft decision or the AER's reasons.[2]

Evoenergy's key objective for the 2019–24 regulatory period is to strike the right balance between cost and reliability of supply for the long-term interests of consumers. As part of the process of developing its regulatory proposal, and in the time since, Evoenergy has engaged extensively with consumer groups and the feedback received has been important in shaping its proposals.[3] In its draft decision, the AER acknowledges that Evoenergy has undertaken genuine efforts to engage with consumers.[4] The AER's Consumer Challenge Panel (CCP10) considered that Evoenergy's regulatory proposal was reasonable, and tends to address the contemporary concerns of customers.[5]

1.2 Key issues

The AER's draft decision would allow Evoenergy to collect revenue of $871 million (nominal) over the 2019–24 regulatory period to fund the elements of its plan, $80 million or 8 per cent lower than proposed by Evoenergy. The largest contributor to this reduction is the lower rate of return that Evoenergy would earn on network assets.

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[1] Adopted in the ACT as the National Electricity (ACT) Law by the Electricity (National Scheme) Act 1997 (ACT)

[2] Rules, clause 6.10.3

[3] This includes consumer engagement in the lead up to submitting the RP and follow-up engagement since submitting the RP, including deep dive workshops on technical issues, an Energy Matters workshop on tariff structure and ongoing ECRC engagement.

[4] AER 2018, Overview | Draft decision – Evoenergy distribution determination 2019–24, p.8.

[5] CCP10, Presentation to public forum on Issues paper, 13 April 2018.

Evoenergy's revised proposal takes account of the AER's draft decision, revising forecasts where possible and providing more information to support forecasts where expenditure cannot be reduced or deferred.

- For operating expenditure (opex), Evoenergy has adopted the changes from AER's draft decision, and revised its base efficient year expenditure from an estimated to actual basis. This results in a proposed opex allowance 2 per cent higher than that of the draft decision, and 3 per cent below Evoenergy's January regulatory proposal.
- For capex, Evoenergy has maintained most of its original proposal, refining forecast load growth in new and rapidly developing existing areas and providing requested further information for some projects.
- Evoenergy does not agree with elements of the AER's draft decision on the rate of return Evoenergy should receive on its asset base. Evoenergy's revised proposal uses a rate of return consistent with its submission to the separate process the AER is running on developing a new rate of return guideline.[6]

Evoenergy's revised proposal would allow it to collect standard control service charges totalling $928 million (nominal) over the five year period, 6 per cent higher than the AER's draft decision. Some of the increase reflects updates of expenditure from estimates to actual since January 2018, which flow through to forecasts for the 2019–24 period, and adjustments for the AER's November 2018 final decision on the remaking of the 2015 determination for the 2014–19 period.

Evoenergy estimates that its revised proposal, if accepted in full by the AER, would result in an average annual retail electricity bill increase of 0.3 per cent (or $6 per year for an average residential customer) in real terms for the five years, compared with an annual average decline of 0.01 per cent under the AER's draft decision.

The AER has a number of concurrent processes in train (in addition to the rate of return review mentioned above), notably reviews of opex productivity and the regulatory tax allowance. Evoenergy has had limited opportunity to review the AER's November 2018 papers on these reviews in time for providing a response in this revised regulatory proposal. Given the AER's intention to reflect the outcome of these reviews in its final determination for Evoenergy's network for 2019–24 and the potential for these reviews to significantly impact Evoenergy's revenue requirement, Evoenergy expects that the AER will provide the opportunity for meaningful consultation on these important issues.

The AER's draft decision recognises that Evoenergy is relatively advanced in tariff reform, with consumer engagement identified as a key enabler. Evoenergy's revised proposed tariff structure statement aligns with the AER's draft decision which required clarification on some aspects of Evoenergy's tariff design and assignment policies.

1.3 Consumer engagement

In developing the regulatory proposal, Evoenergy has extensively consulted with our customers to understand what they want, focussing on reliability, adoption of new technologies and tariff reform.

Over the period of more than twelve months before submitting the regulatory proposal for 2019–24, Evoenergy provided information and sought input on the areas under consideration through issues and discussion papers. We then sought and received views

[6] Evoenergy 2018, Submission to the review of rate of return guideline – draft decision, 25 September.

of consumers, through forums and surveys, on issues including their attitudes to new technologies and considerations of future reliability, cost and pricing. The information and views received have been taken into account in developing our proposal and these are set out in detail in chapter 2 of Evoenergy's regulatory proposal.

In the lead up to and since the AER's draft decision, Evoenergy has undertaken further consumer engagement in the form of 'deep dives' on its proposals on information and communication technologies (ICT) and system monitoring in August and November, respectively.[7] The outcomes of this engagement are included in discussion of non-network and reliability capex and the information supporting the relevant projects, particularly in discussion of their benefit to consumers.

1.4 Updated forecasts

The regulatory proposal for the 2019–24 regulatory period is supported by three forecasts which are discussed in this attachment:

- energy sales—an input into the Tariff Structure Statement, including formulating the indicative pricing schedule and opex forecasts;
- customer numbers—an input into forecasting connections related capex and opex; and
- peak demand—an input into forecasting augmentation expenditure.

The above forecasts are referenced in various parts of the regulatory proposal including proposed capex, opex and pricing.

Evoenergy engaged consultants Jacobs to identify key factors influencing electricity sales in the ACT and to prepare an independent sales forecast for the ACT electricity network for the 2019–24 regulatory control period. Jacobs has expertise in developing energy sales forecasts and advising on energy forecasting methods.

Since the regulatory proposal in January 2018, Evoenergy has updated the forecasts of energy sales, customer numbers and demand with the latest sales data up to September 2018. This update has resulted in the latest forecasts being slightly different from the forecasts presented in the January 2018 regulatory proposal. These differences and the reasons underpinning them are presented in detail in Attachment 3. Further detail on the methods, processes and assumptions used to determine the forecast was provided in appendix 3.1 of the January 2018 regulatory proposal.

1.5 Content of the revised proposal

This document addresses the AER's draft decisions and reasoning and provides proposed revisions to its Evoenergy's regulatory proposal.

Attachments comprise revised versions of Evoenergy's proposed Tariff Structure Statement and Connection Policy. Appendixes contain detailed supporting material, including business cases and models.

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[7] Due to AER drafting deadlines, the outcomes of the August deep dive engagements could not be taken into account in the draft decision.

Following this Chapter 1 Introduction:

- Chapter 2 addresses revisions to Evoenergy's building block proposal for standard control services, including the annual revenue requirement to fund network services;
- Chapter 3 addresses revisions to forecast operating and maintenance expenditure;
- Chapter 4 addresses revisions to forecast capital expenditure to provide growth and renewal of the network as well as maintaining reliability and quality;
- Chapter 5 addresses revisions to the rate of return that Evoenergy's owners receive for investing in network assets;
- Chapter 6 address the starting value of Evoenergy's regulatory asset base (RAB), and provides information on RAB growth over the period, an important determinant of future network charges;
- Chapter 7 addresses the cost of corporate income tax to Evoenergy;
- Chapter 8 addresses the cost of depreciation of regulated assets;
- Chapter 9 addresses the proposed application of the AER's regulatory incentive schemes to Evoenergy. These include incentives to make savings on operating and capital expenditures, to maintain and improve service standards, and to evaluate and undertake demand management initiatives;
- Chapter 10 addresses the operation of control mechanisms to apply to the recovery of regulated charges;
- Chapter 11 addresses the pricing of alternative control services – special services provided at a customer's request;
- Chapter 12 addresses revisions to Evoenergy's proposed Tariff Structure Statement which forms Attachment 1 to the revised proposal;
- Chapter 13 addresses required revisions to Evoenergy's Connection Policy. The revised proposed policy forms Attachment 2 to the revised proposal.
- Chapter 14 comprises a table of AER's draft constituent decisions and where and how they are addressed in the revised proposal.

Confidential material included in the regulatory proposal is identified in the template completed in accordance with the AER's confidentiality guideline which forms Attachment 4.

2 Building block proposal

2.1 Rules requirements

The AER is required to make a decision on the DNSP's current building block proposal in which the AER either approves or refuses to approve:[8]

i. the annual revenue requirement for the DNSP, as set out in the building block proposal, for each regulatory year of the regulatory control period; and

ii. the commencement and length of the regulatory control period as proposed in the building block proposal.

The Rules also specify that:

- with regard to (i), the AER must approve the total revenue requirement for a DNSP for a regulatory control period, and the annual revenue requirement for each regulatory year of the regulatory control period, as set out in the DNSP's current building block proposal, if the AER is satisfied that those amounts have been properly calculated using the post-tax revenue model on the basis of amounts calculated, determined or forecast in accordance with the requirements of Part C of Chapter 6 of the Rules (Building Block Determinations for standard control services);[9]
- with regard to (ii), the AER must approve a proposed regulatory control period if the proposed period consists of 5 regulatory years.[10]

2.2 Regulatory proposal

Evoenergy proposed a total revenue requirement of $952 million[11] for the 2019–24 regulatory control period. The building blocks that make up Evoenergy's proposed revenue requirement are set out in Table 2.1 for distribution and Table 2.2 for transmission.

Table 2.1 Regulatory proposal: distribution building blocks

$ million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Return on capital	50.80	52.34	54.14	55.86	57.29
Return of capital (regulatory depreciation)	35.06	38.06	41.25	45.43	48.86
Operating expenditure	52.89	55.30	57.92	60.57	63.20
Revenue adjustments	0.66	0.32	0.33	0.34	0.35
Net tax allowance	5.97	6.33	6.66	7.18	7.42
Annual revenue requirement (unsmoothed)	**145.38**	**152.36**	**160.30**	**169.38**	**177.12**

[8] Rules, clause 6.12.1(2)
[9] Rules, clause 6.12.3(d)
[10] Rules, clause 6.12.3(e)
[11] All figures in this section are presented in nominal terms unless otherwise stated.

Table 2.2 Regulatory proposal: transmission building blocks

$ million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Return on capital	11.19	11.18	10.97	11.45	11.29
Return of capital (regulatory depreciation)	6.40	7.05	7.75	8.62	9.39
Operating expenditure	8.37	8.76	9.18	9.62	10.05
Revenue adjustments	0.07	0.00	0.00	0.00	0.00
Net tax allowance	0.92	0.97	1.03	1.13	1.19
Annual revenue requirement (unsmoothed)	**26.95**	**27.97**	**28.93**	**30.83**	**31.91**

Evoenergy proposed smoothing the revenue requirement over the regulatory period by setting the X-factors to be equal in each year. This approach is consistent with the requirement in the Rules (clause 6.5.9(b)(2)) to limit the difference between smoothed and unsmoothed revenue in the last year of the regulatory control period. Evoenergy's proposed smoothed revenues and X-factors are presented in Table 2.3.

Table 2.3 Regulatory proposal: smoothed revenue and X-factors

$million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Smoothed revenue: distribution	143.78	151.92	160.52	169.61	179.21
X-factors: distribution	-3.08%	-3.08%	-3.08%	-3.08%	-3.08%
Smoothed revenue: transmission	26.30	27.75	29.27	30.88	32.57
X-factors: transmission	-2.92%	-2.92%	-2.92%	-2.92%	-2.92%

Evoenergy estimated the expected retail bill impacts of its proposal by adjusting the distribution and transmission components of the bill, while holding all other elements of the bill constant in real terms. Evoenergy adopted the average usage categories for residential and non-residential customers from the Independent Competition and Regulatory Commission's final report on retail electricity prices from 1 July 2017.[12]

As shown in Table 2.4 below, the estimated real bill impacts associated with Evoenergy's regulatory proposal are minimal, increasing the bill of an average residential and non-residential customer by less than one per cent a year over the 2019–24 regulatory period.

[12] ICRC 2017, Report 6 of 2017: Final report – Standing offer prices for the supply of electricity to small customers from 1 July 2017, p. 57.

Table 2.4 Estimated real indicative bill impacts associated with Evoenergy's regulatory proposal

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Average residential annual electricity bill, ($2018/19)	1,935	1,954	1,973	1,985	2,000	2,016
Annual change, ($2018/19)		18	19	12	16	15
Annual change, %		0.94	0.98	0.62	0.79	0.76
Average non-residential annual electricity bill, ($2018/19)	6,703	6,766	6,832	6,874	6,928	6,981
Annual change, ($2018/19)		63	66	42	54	53
Annual change, %		0.94	0.98	0.62	0.79	0.76

2.3 Draft decision

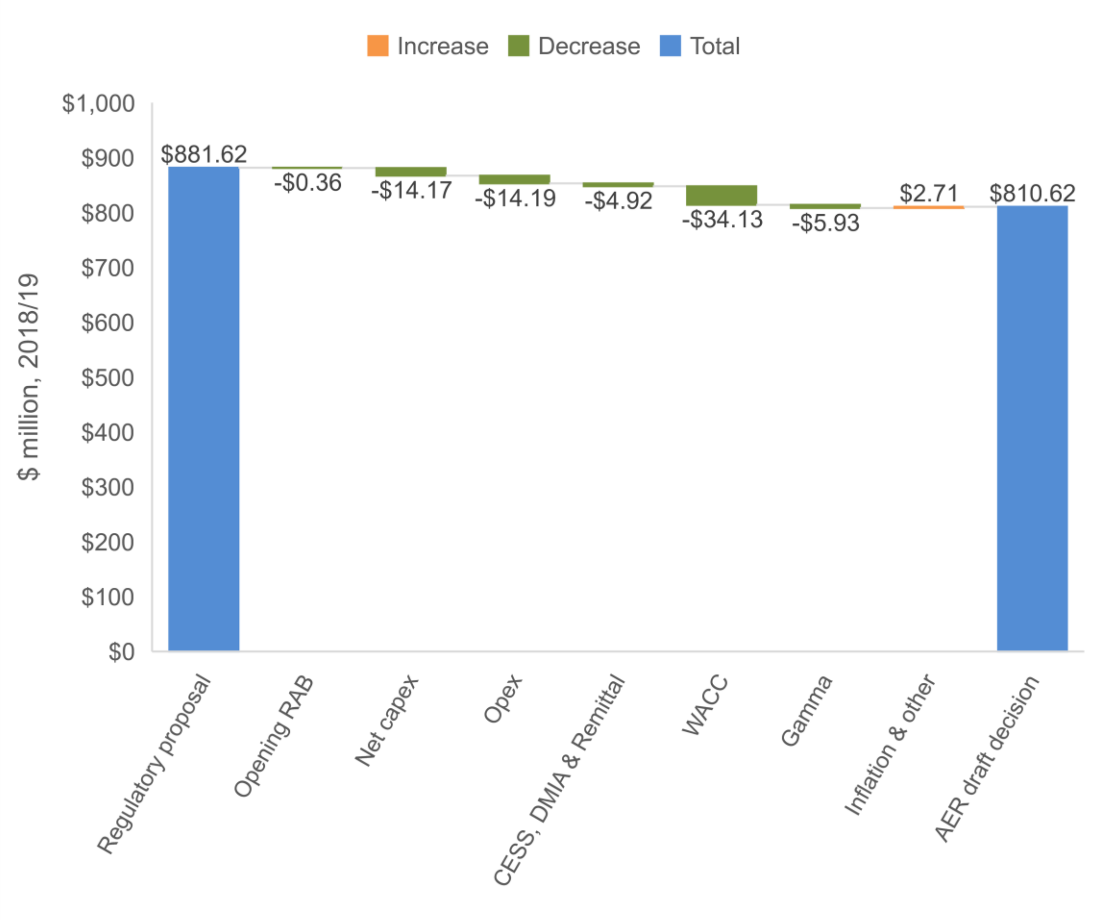
The AER's draft decision does not accept Evoenergy's proposed revenue requirement for the 2019–24 regulatory control period because it does not accept the building block costs in Evoenergy's proposal. The AER's draft decision on the building blocks results in a total revenue requirement of $871 million comprised of $732 million for distribution and $139 million for transmission. The revenue requirement in the AER's draft decision is 8 per cent lower than Evoenergy's regulatory proposal, driven largely by the AER's draft decision on the rate of return as shown in Figure 2.1 below.

The AER's draft decision smoothed revenue over the regulatory period by using a P_0 adjustment with X-factors in years 2 to 5 set as close as possible to zero while maintaining a difference of no more than 3 per cent between the final year smoothed and unsmoothed revenue. The AER's draft decision annual revenue requirements and X-factors are shown in Table 2.5.

Table 2.5 AER draft decision: smoothed revenue and X-factors

$million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Smoothed revenue: distribution	137.71	141.93	146.28	150.77	155.39
X-factors: distribution	2.19%	-0.60%	-0.60%	-0.60%	-0.60%
Smoothed revenue: transmission	26.55	27.20	27.87	28.55	29.25
X-factors: transmission	-2.73%	0.00%	0.00%	0.00%	0.00%

Figure 2.1 Drivers of difference between Evoenergy proposal and AER draft determination



The AER estimates that under its draft decision, the average electricity bill will increase by a total of 3 per cent in nominal terms between 2018/19 and 2023/24.[13]

In its draft decision, the AER included the distribution remittal value for the 2014–19 regulatory period in the distribution building blocks but excluded the transmission remittal value from the transmission building blocks. In its final remade decision for the 2014–19 regulatory period, the AER has specified that it will utilise the X-factors for both transmission and distribution standard control services (SCS) in the 2019–24 regulatory control period to effect the required outcome for the 2014–19 regulatory control period.[14] The AER published the distribution and transmission variation amounts for inclusion in Evoenergy's building block revenue requirement as - $4.7 million for distribution SCS and $3.8 million for transmission SCS (both in 2018/19 dollars).[15]

[13] AER 2018, Attachment 1: Annual revenue requirement | *Draft decision – Evoenergy distribution determination 2019–24*, p.1-20.

[14] AER 2018, Final decision, Evoenergy 2014–19 electricity distribution determination, November, p.33.

[15] AER 2018, Final decision, Evoenergy adjustment determination, November, p. 6.

2.4 Revised proposal

In its revised proposal, Evoenergy proposes a total revenue requirement of $928 million, comprised of $773 million for distribution and $155 million for transmission. The revised proposal reflects Evoenergy's position on each of the building blocks, which are set out in the following chapters:

- Chapter 3: Operating expenditure
- Chapter 4: Capital expenditure
- Chapter 5: Rate of return
- Chapter 6: Regulatory asset base
- Chapter 7: Corporate income tax
- Chapter 8: Regulatory depreciation
- Chapter 9: Incentive schemes

The building blocks that make up Evoenergy's proposed revenue requirement are set out in Table 2.6 for distribution and Table 2.7 for transmission.

The revenue adjustments building block includes the remittal variation amounts for distribution and transmission as set out in the AER's final decision adjustment determination.[16] The revenue adjustments building block excludes any shared asset revenue. As noted in response to the AER's information request in relation to shared asset revenue, Evoenergy has been in preliminary discussions in relation to the shared use of Evoenergy's infrastructure.[17] Evoenergy estimates that the shared revenue from these arrangements would not exceed the AER's materiality threshold.[18] Therefore, Evoenergy has not included any revenue adjustment for shared assets in its revised proposal.

Table 2.6 Revised regulatory proposal: distribution building blocks

$ million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Return on capital	49.06	50.38	51.30	53.29	54.57
Return of capital (regulatory depreciation)	35.70	38.60	41.87	45.83	48.73
Operating expenditure	51.89	53.89	56.03	58.28	60.58
Revenue adjustments	-5.29	-0.44	-0.45	-0.45	-0.46
Net tax allowance	5.71	6.30	6.26	6.73	6.98
Annual revenue requirement (unsmoothed)	**137.07**	**148.72**	**155.01**	**163.68**	**170.40**

[16] Ibid
[17] Evoenergy 2018, Response to AER information request IR16,18 April
[18] AER 2013, *Shared Asset Guideline*, November, p.8

Table 2.7 Revised regulatory proposal: transmission building blocks

$ million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Return on capital	10.94	10.74	10.96	10.91	10.75
Return of capital (regulatory depreciation)	6.53	7.13	7.80	8.59	9.20
Operating expenditure	8.22	8.54	8.88	9.25	9.61
Revenue adjustments	4.47	0.55	0.57	0.58	0.60
Net tax allowance	2.50	4.29	0.83	0.91	0.97
Annual revenue requirement (unsmoothed)	**32.67**	**31.25**	**29.04**	**30.24**	**31.13**

Evoenergy has adopted the AER's approach to smoothing revenue over the regulatory period by using a P_0 adjustment and setting the X-factors in years 2 to 5 as close as possible to zero subject to the final year constraint of limiting the difference between the smoothed and unsmoothed revenue to 3 per cent. Evoenergy's smoothed revenue and X-factors are set out in Table 2.8.

Table 2.8 Regulatory proposal: smoothed revenue and X-factors

$million nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Smoothed revenue: distribution	144.31	149.29	154.45	159.78	165.30
X-factors: distribution	-2.49%	-0.98%	-0.98%	-0.98%	-0.98%
Smoothed revenue: transmission	29.91	30.44	30.97	31.51	32.07
X-factors: transmission	-15.75%	0.68%	0.68%	0.68%	0.68%

The revenue requirement in Evoenergy's RRP is 6 per cent higher than the AER's draft decision, driven primarily by the difference in the rate of return.

Evoenergy has estimated the retail bill impacts associated with its RRP using the same methodology as its original proposal with the exception of:

- the starting retail bill in 2018/19, which has been set at $2,012 for an average residential customer and $6,993 for an average small business customer, consistent with the approach used by the AER's in its draft decision;
- the share of the retail bill made up by distribution and transmission has been determined using the AEMC's residential electricity price trends analysis which finds that, in the ACT in 2018/19, distribution and transmission account for 29.1 per cent of the retail bill;
- the share of the total bill accounted for by distribution is calculated by multiplying the AEMC's 29.1 per cent by the distribution share of total distribution and transmission revenue. This results in 21.7 per cent of the bill being accounted for by distribution;
- the remaining transmission share of the bill (7.5 per cent) accounted for by Evoenergy's dual function assets is determined by multiplying the transmission share of the bill by the dual function asset share of total transmission revenue (53 per cent) to arrive at a figure of 4.0 per cent.

The resulting estimated bill impact associated with Evoenergy's revised proposal is an average increase of 0.3 per cent per year in real terms (equivalent to $6 per year for residential customers and $20 per year for small business customers). Evoenergy's estimate of indicative retail bill impacts are set out in Table 2.9.

Table 2.9 Indicative retail bill impacts

Real $2018/19	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Residential annual bill	$2,012	$2,027	$2,019	$2,025	$2,032	$2,041	$29*
Small business annual bill	$6,993	$7,044	$7,017	$7,038	$7,062	$7,095	$102*
Residential annual change		$15	-$8	$6	$7	$10	$6#
Small business annual change		$51	-$27	$21	$24	$34	$20#
Annual change, %		0.73%	-0.39%	0.30%	0.34%	0.48%	0.29%#

* Total change in the annual bill between 2018/19 and 2023/24.

Average annual change in the residential bill over the 2019–24 regulatory control period.

3 Operating expenditure

3.1 Rules requirements

The AER is required to make a decision on whether it accepts or does not accept the total of the forecast operating expenditure for the regulatory control period that is included in the current building block proposal.[19] The AER must accept the DNSP's forecast if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the operating expenditure criteria.[20]

3.2 Regulatory proposal

Evoenergy's regulatory proposal included forecast operating expenditure (opex) of $308.9 million[21] for the 2019–24 regulatory control period (excluding debt raising costs).

Evoenergy adopted a base-step-trend approach to forecasting opex as follows:

- **base**: 2017/18 was adopted as the base year, reflecting an efficient level of opex;
- **step**: two step-changes were included in the opex forecast: the first reflecting changes to vegetation clearance responsibilities in the ACT; and the second being an efficient trade-off between capital expenditure and opex for demand management in a new urban development; and
- **trend**: Evoenergy trended the base year forward to reflect forecasts in output and input costs. Evoenergy set the productivity trend to zero given that the AER's benchmarking results revealed negative productivity growth.

This approach resulted in an opex forecast of $298 per customer, which represents no increase per customer from the current period, despite the substantial increase in vegetation management obligations.

3.3 Draft decision

The AER did not accept the forecast opex in Evoenergy's proposal and substituted its alternative estimate of $294.7 million (excluding debt raising costs). The AER made the following changes to Evoenergy's proposed forecast:

- reduction in the efficient and prudent costs of complying with Evoenergy's expanded vegetation management responsibilities (-$6.8 million);
- lower forecast of expected increases in real labour prices in the ACT (-$3.4 million)
- lower forecast of expected output growth (-$4.5 million).

The AER's opex forecast for 2019–24 results in an opex estimate of $285 per customer.

[19] Rules, clause 6.12.1(4)
[20] Rules, clause 6.5.6(c)
[21] All values in this section are reported in 2018/19 dollars.

3.4 Revised proposal

Evoenergy's revised proposal includes a revised forecast for SCS opex of $299.5 million (excluding debt raising costs). This is $9.3 million (or 3.0 per cent) below Evoenergy's original proposal and $4.9 million (or 1.6 per cent) above the AER's draft decision.

Evoenergy has adopted the AER's draft decision for opex and has updated the base year. Given the timing of Evoenergy's original proposal, the base year of 2017/18 was determined using actual expenditure to October 2017 and forecast expenditure for the remainder of the year. In the revised proposal, Evoenergy has updated the 2017/18 base year for actual expenditure for the full year. The adjustments to the base year for Power of Choice and ring-fencing expenditure have also been updated. These updates are consistent with the approach set out in the AER's draft decision.[22]

This gives an adjusted base year opex of $53.8 million, compared with $52.5 million in the AER's draft decision. The revised base year opex is in line with the AER's estimate of efficient opex for 2017/18 in its remade final decision for 2014–19 (remittal)[23] and is only marginally outside the AER's revised range of efficient opex for 2017/18.[24]

Since the draft decision, the AER has also updated its benchmarking analysis. This reports that Evoenergy remains one of the middle performing businesses in terms of opex (see Figure 3.1 below):

> *Evoenergy also significantly improved its opex productivity between 2014-15 and 2015-16. In 2016-17, Evoenergy increased its opex and this reduced its opex MPFP score, partially in response to concerns about its network reliability. Notwithstanding this reduction, Evoenergy remains amongst the middle group of efficient firms.*[25]

Given the substantial reduction in opex that Evoenergy has achieved over the 2014–19 regulatory period and the AER's benchmarking results, it is Evoenergy's view that its revealed opex for 2017/18 cannot be considered materially inefficient. Consequently, it is appropriate to adopt revealed opex for 2017/18 as the base opex for the purpose of the base-step-trend calculation.

Evoenergy's forecast opex per customer is below that of Evoenergy's January 2018 regulatory proposal and actual operating expenditure per customer for the current regulatory period. As shown in Figure 3.2, this is significantly below the per customer operating expenditure incurred in the 2009-14 period and only slightly above that of the AER's draft decision.

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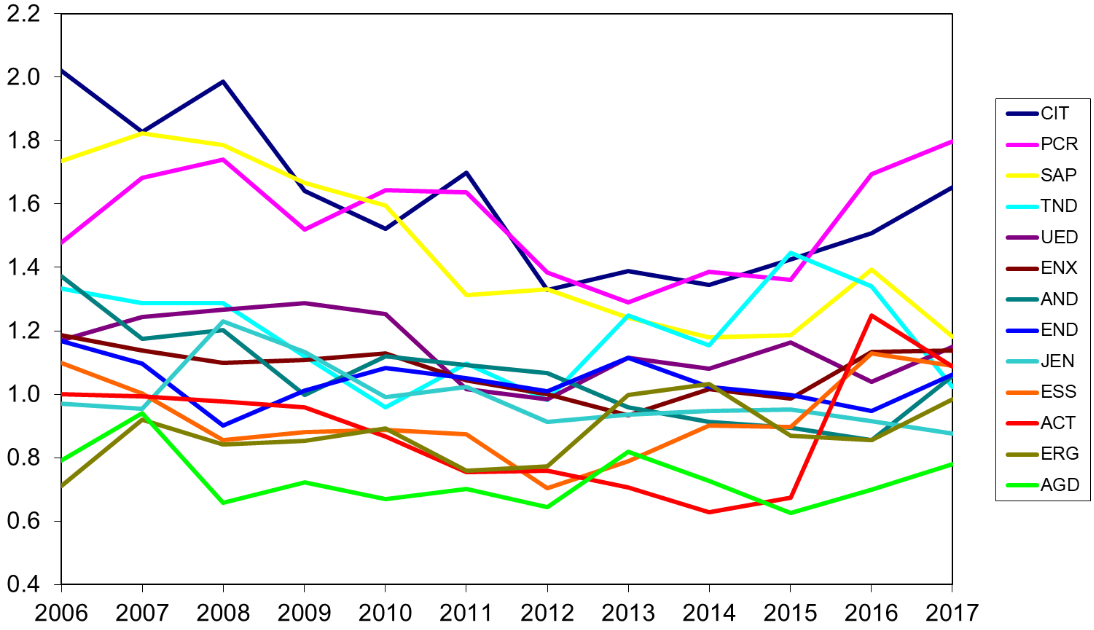
[22] AER, 2018, Attachment 6: Operating expenditure | *Draft decision – Evoenergy distribution determination 2019–24*, p.6-8, footnote 5.

[23] AER 2018, Final decision, Evoenergy 2014–19 electricity distribution determination, November, p.19.

[24] AER 2018 – Evoenergy 2019–24 – Draft decision – Opex econometric modelling – October.

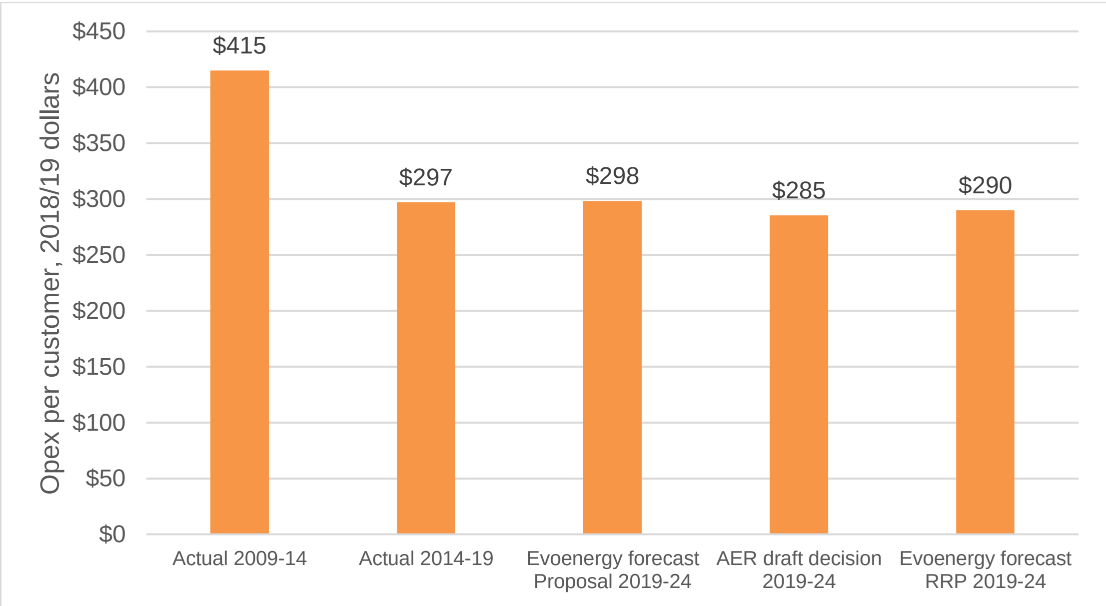
[25] AER 2018, Annual Benchmarking Report, Electricity distribution network service providers, September, p.10.

Figure 3.1 Opex multilateral partial factor productivity, 2006/17



Source: AER 2018, *Annual Benchmarking Report, Electricity distribution network service providers*, September

Figure 3.2 Evoenergy opex per customer 2009–14 to 2019–24



3.5 AER review of approach to forecasting productivity growth

On 9 November 2018, the AER published a draft decision paper on forecasting productivity growth for electricity distributors.[26] The AER invites submissions on its draft decision paper by 21 December 2018.

In the paper, the AER indicates its intention to apply the productivity growth forecast it arrives at through this consultation process to the opex estimates of electricity distribution businesses, including Evoenergy, for whom the AER will publish a final distribution determination in April 2019.

Given the timing of the publication of the draft decision paper, Evoenergy has not yet had the opportunity to consider and respond to that paper, including in particular the proposed application of the productivity growth forecast arrived at through consultation on the draft decision paper to Evoenergy's distribution network determination for 2019–24, in this revised regulatory proposal. Evoenergy welcomes the opportunity to make a submission in response to the draft decision paper and the additional opportunity, foreshadowed by the AER in the draft decision paper, to submit its views on how the AER should apply its final decision on productivity growth to its specific circumstances in making its final determination for Evoenergy for 2019–24. Evoenergy intends to make submissions in each of those processes, and foreshadows its intention to rely on those submissions in the present reset process for 2019–24.

[26] AER 2018, Draft decision paper, Forecasting productivity growth for electricity distributors, November

4 Capital expenditure

4.1 Introduction

In its January 2018 regulatory proposal, Evoenergy set out a capital expenditure (capex) program for the 2019–24 period of $330 million.[27] The program continues and builds upon the key initiatives of the current period aimed at ensuring the ongoing reliability of the network, the ability to connect new customers, and augmenting the network to meet the forecast peak demand in growth areas.

This forecast expenditure is largely driven by the need to address the rapidly changing electricity market, manage the ageing asset base to meet safety and reliability standards, accommodate major urban developments in the Canberra metropolitan area, and meet increasing requirements of the Australian Capital Territory (ACT) Government's planning and system security regulations.

The regulatory proposal was informed by significant engagement with consumer and industry groups. The AER's Consumer Challenge Panel (CCP10) judged that Evoenergy's proposal is "reasonable, and tends to address the contemporary concerns of customers"[28] as well as recognising Evoenergy's efforts to ensure that the total proposed capex envelope is a relatively stable compared with both the AER's capex allowance for 2014–19 and Evoenergy's actual spend during the same period.[29]

The AER recognised that Evoenergy's capex proposal for 2019–24 reflects considerable efforts made to engage more thoroughly with its stakeholders, particularly on ICT expenditure.[30]

Evoenergy's revised proposal reflects a continuation of this approach, informed by further engagement and feedback from the AER and other stakeholders through public engagement. The outcomes of this are discussed in section 4.2. Under the Rules, the AER is required to make a decision on whether it accepts or does not accept the total of the forecast capital expenditure for the regulatory control period included in current DNSP's building block proposal.[31] The AER must accept the forecast where it is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the capital expenditure criteria in the Rules.[32]

In its draft decision, the AER was satisfied with substantial aspects of Evoenergy's regulatory proposal such as its proposed connections expenditure, rationale for changing the asset mix towards ICT, forecasting methodology, demand forecasts, and replacement capex (repex) forecasting methodology. However, the AER also found that it needs further supporting information in some areas of Evoenergy's proposed capex before it can be satisfied that the proposal as a whole meets the capex criteria. As a result, the AER substituted an alternative estimate of $261.4 million for total forecast capex over the 2019–24 regulatory period: a 21 per cent reduction from Evoenergy's proposed capex program.

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[27] Unless otherwise specified, all financial information in this chapter is stated in real 2018/19 dollar terms.
[28] CCP10 presentation, AER pre-determination conference for Evoenergy draft decision, 10 October 2018
[29] Ibid.
[30] AER 2018, Draft Decision Evoenergy Determination: Evoenergy Determination: Attachment 5, p.5-11.
[31] Rules, clause 6.12.1(3)
[32] Rules, clause 6.5.7(c)

Evoenergy's revised proposal aims primarily to address issues identified in the AER's draft decision. Evoenergy's revised proposal for capex reflects the minimum that would enable Evoenergy to continue to provide a safe, reliable and secure network in accordance with customer needs and regulatory obligations. It is a modest program, significantly less than both the AER's allowance and the historical spend for the 2014–19 regulatory period by $22 and $12 million, respectively.

In the revised proposal Evoenergy provides further information to demonstrate more strongly that:

- its proposed primary systems augmentation capex (augex) is necessary to achieve the capex objectives. Since preparing its regulatory proposal, Evoenergy has received further information (subsequently shared with the AER) that provides a clearer justification of the proposed projects and has clarified and improved its probabilistic modelling to address concerns of the AER. Moreover, the proposed expenditure is reasonable historically in total and as a proportion of total capex.
- its proposed repex is found to be reasonable when benchmarked through the AER's repex model when the correct inputs are used. In accordance with AER and consumer expectations, Evoenergy provides more information on the inputs and the risk calculations for underground cables.
- it has engaged with consumers and listened to feedback in revising business cases for a number of non-network, reliability, and secondary systems augex projects, in particular the proposed Advanced Distribution Management System (ADMS) upgrade, to further establish that the proposed expenditure is supported.
- its revised proposal for capitalised overheads represents an efficient approach that incorporates elements of the AER's decision, and corrects for inconsistencies in the implementation of Evoenergy's approved cost allocation method (CAM)
- it has considered feedback and viewpoints from the AER and consumers in taking a holistic approach that ensures the capex proposal best addresses the long term interests of consumers in tackling the changing electricity network landscape.

A summary of Evoenergy's response to the key elements of the AER's draft decision is provided in Table 4.4.

4.2 Consumer engagement and feedback

After submitting its regulatory proposal to the AER in January 2018, Evoenergy engaged further with stakeholders in 'deep dive' workshops and in other forums prior to the submission of this revised proposal Major such engagements are described below.

4.2.1 ICT deep dive workshops

Across August and November 2018, Evoenergy ran a well-received series of 'deep dive' workshop stakeholder engagement sessions on ICT projects proposed for the 2019–24 period. At their conclusion, there was a better understanding by consumers of Evoenergy's proposal and of stakeholders' views by Evoenergy on topics set out in Table 4.1.

Table 4.1 Outcomes of Deep Dive workshops

AER draft decision	Evoenergy's response
Evoenergy's ICT vision and approach to technological innovation	Stakeholders supported the establishment of an overarching ICT vision for Evoenergy, which would be centred on a 'smaller, lighter, faster and cheaper' approach to network management. Stakeholders recognised the importance of undertaking future-proofing operations. Key elements of the capex proposal include constraining augex, meter data and billing, as well as corporate ICT extension capabilities (such as mobility and business intelligence) to cope with the exponential rise in data requirements.
Smart Network	Stakeholders advised that Evoenergy's transformation into a smart network should take into consideration the participation of different consumers and the benefits it entails for the distributor and consumers. Evoenergy proposed a number of projects that leverage consumer data and can better target consumers' diverse levels of market engagement, especially with Distributed Energy Resources (DER). These include projects that can increase the granularity of data provided (ADMS upgrade and the distribution substation monitoring) and projects that enable better data management (Business Intelligence analytic capabilities and Digital Content Management system).
ADMS	Stakeholders were supportive of Evoenergy's investment proposal in the ADMS upgrade and considered the forecast expenditure reasonable. They recognised the various benefits of the upgraded ADMS and acknowledged risks associated with not upgrading the ADMS including for data security. Participants wanted to see the benefits of the upgraded ADMS better explained in Evoenergy's revised proposal. Evoenergy notes the concerns with the existing business case and submits a revised version that better explains the main drivers of the ADMS Upgrade and the avoided risks.
Distribution Substation Monitoring	General support for this project given that Evoenergy is facing unique challenges in managing DER uptake, with large customers already experiencing power quality issues. Consumers noted that the project represented an affordable and attractive option for consumers, especially compared to spending on smart meters. Consumers note and agree with the benefits presented for this project, such as more effective network monitoring, supporting consumer choice, and maintaining reliability.

4.2.2 AER Predetermination conference

The AER convened its public predetermination conference[33] on its draft decision for Evoenergy on 10 October 2018. The AER, consumer groups and Evoenergy all presented. CCP10 acknowledged Evoenergy's genuine efforts to engage with consumers on its proposal and the efforts made to significantly continuously improve the quality of its consumer engagement, and the importance of capex to support the progressive energy policies of the ACT. It also recognised that Evoenergy's capex has stabilised over the past few years. Points raised by CCP10 were taken into account into forming Evoenergy's revised proposal, including:

[33] As required under the Rules, Clause 6.10.2.

- For some areas of non-network capex, there should be a more thorough consideration of a ‘deferral’ or ‘do nothing’ option and the consumer benefits and avoided risks associated with this. This has been implemented in several ICT business cases, such as for the ADMS upgrade and Business Intelligence proposals;
- Evoenergy notes the CCP10’s view that Evoenergy’s revised proposal should account for opex productivity benefits associated with the significant non-network ICT expenditure. Evoenergy’s revised proposal aims to make it clear that the proposed ICT expenditure reflects the replacement of existing systems or the need to maintain the existing quality and reliability of power supply in an increasingly complex operating environment, rather than reducing current levels of opex;
- that Evoenergy’s proposed inclusion of ICT project contingencies reflects a conservative approach to project planning. Evoenergy has accepted this and excluded such contingencies in its revised proposal;
- that Evoenergy’s proposed capitalised overheads are relatively high in historical terms, that is, they exceed the allowance for the 2014–19 regulatory period.[34] Evoenergy has noted this and has adopted the AER’s decision to use the 4-year average approach to forecasting its Fixed Price Service Charge (FPSC) for corporate services; and
- that the CCP10 was generally satisfied with Evoenergy’s repex estimate despite this being the largest capex category[35] since it reflects a robust bottom up and top down methodology developed by Evoenergy as explained in the initial proposal.

4.3 Draft decision

4.3.1 Overview

The AER’s draft decision highlights concerns with Evoenergy’s proposed total forecast capex, concluding that, given the information available, it was not satisfied that the forecast capex reasonably reflects the capex criteria. The AER removed from the forecast 21 per cent ($68 million) of Evoenergy’s proposed capex program to form an alternative net capex forecast of $261 million.

The majority of the AER’s capex reduction was in the areas of augex, capitalised overheads, reliability, and non-network capex. Augex was subject to the largest reduction of 47.5 per cent ($23 million) while the second largest area of spending, repex, was subject to an 8.7 per cent ($8 million) reduction. The AER, however, stated in the draft decision that it was open to further consultation on the issues identified and also pointed to assessments which would benefit from further stakeholders engagement by Evoenergy.

Table 4.2 summarises the AER's draft decision on capex.

[34] CCP10 Response to Evoenergy regulatory Proposal 2019–24 and AER Issues Paper: May 2018, p.7.
[35] AER draft decision, 5-50.

Table 4.2 Impact of AER draft decision – capital expenditure 2019–24

$ million (2018/19)	2019–24 regulatory proposal	2019–24 draft decision	Variance	
Augmentation	47.2	24.8	(48%)	(22.5)
Connections	85.9	85.7	(0%)	(0.2)
Replacement	91.6	83.6	(9%)	(8.1)
Reliability and quality Improvements	6.2	-	(100%)	(6.2)
Non-network	58.3	46.0	(21%)	(12.4)
Capitalised overheads	75.6	58.0	(23%)	(17.6)
Less capital contributions	(34.2)	(35.6)	4%	(1.4)
Less disposals	(1.1)	(1.1)	-	-
Net capital expenditure	**329.8**	**261.4**	**(21%)**	**(68.4)**

Note: Totals may not add due to rounding

The AER's draft decisions on individual capex categories can be summarised as follows:

- **Connections capex:** the AER largely accepted Evoenergy's proposed connections capex, which comprises the largest proportion of total proposed capex.
- **Replacement capex:** the AER approved the majority of Evoenergy's proposed repex with the exception of the proposed replacement of high voltage (HV) underground cables. The AER's repex modelling identified HV underground cables as an area for further investigation, which necessitates that Evoenergy provide more information on the risk-based calculations and cost benefit analysis underpinning the forecast. Pending the outcome of this assessment, the AER's draft decision allocated no expenditure for HV underground cables.
- **Augmentation capex:** The large reduction in Evoenergy's augex stems from the AER's concerns with a number of demand-driven augmentation projects. Specifically, the AER considered that the results of Evoenergy's probabilistic analysis did not support the inclusion of these projects. The result was that the AER's draft decision did not allow the $7m proposed for Molonglo Valley project and $13m proposed for feeder augmentation to address supply in high growth areas. However, the AER is aware of updated information since the proposal and considers it more appropriate to review the efficiency and prudency of the affected projects following the revised proposal.

  The AER also took issue with some non-demand-driven secondary systems augex, whereby it perceived that the benefits identified in the business cases were operational efficiencies and should be taken into account in the overall proposal and/or the projects can be self-funded. The projects impacted include the distribution substation monitoring and chamber substation remote thermal units (RTUs).
- **Capitalised overheads:** Reductions in capitalised overheads are primarily in proportion to the reduction in direct capex, albeit with a secondary effect from the AER applying a slightly lower rate of capitalised overheads by substituting a 4-year average of corporate costs over Evoenergy's proposed base year approach.
- **Non-network capex:** The AER considered that the supporting information submitted by Evoenergy did not demonstrate that the proposed ADMS upgrade was efficient

and prudent. The AER's concerns lie mostly in the fact that consumer benefits were not quantified, as well as insufficient support for the proposed timing of the project.

The AER rejected contingencies that were included in all ICT expenditure, due to Evoenergy's sufficient experience in delivering ICT projects and that the estimates were based on tendered quotes.

The AER also considered that Evoenergy's assumptions in forecasting vehicle fleet expenditure were conservative.

- **Reliability capex:** The AER's draft decision examined Evoenergy's reliability capex under the augex category, classifying the expenditure as secondary systems or non-demand-driven augex. Refer to summary of AER's draft decision for augex above.

4.4 Revised proposal

Evoenergy's revised capex proposal provides additional supporting documentation and updates in inputs since the submission of the regulatory proposal. It also takes into account the outcomes of consumer engagement activities and matters raised by the AER and its consultants. Table 4.3 compares the AER's draft decision and Evoenergy's revised proposal on the capex components.

Table 4.3 Impact of Evoenergy's revised capex proposal for 2019–24

$ million (2018/19)	2019–24 AER draft decision	2019–24 revised proposal	Variance %	Variance $m
Augmentation	24.8	48.6	96%	23.8
Connections	85.7	106.2	24%	20.5
Replacement	83.6	91.8	10%	8.3
Reliability and quality Improvements	-	6.2	-	6.2
Non-network	46.0	56.0	22%	10.0
Capitalised overheads	58.0	66.6	15%	8.6
Less capital contributions	(35.6)	(57.7)	62%	(22.1)
Less disposals/materials escalation adjustment	(1.1)	(1.2)	9%	(0.1)
Net Capital Expenditure	**261.4**	**316.5**	**21%**	**55.2**

Evoenergy proposes a revised capex allowance of $316.5 million, which is 21 per cent higher than the substitute estimate from the AER's draft decision and a $13 million reduction from Evoenergy's January 2018 regulatory proposal capex of $329.8 million.

Most of the difference between the revised proposal and the draft decision is due to demand-driven augex. This is the area of the AER's assessment where it found that a number of demand-driven projects were not able to be justified under a purely probabilistic planning approach.

The other notable areas of difference are the increases in connections and capital contributions (which together net to zero). This relates to a customer-initiated project for construction of a zone substation mandated by the Commonwealth Government which was proposed subsequent to the regulatory proposal. This project is discussed further in section 4.5.4.1.

Table 4.4 gives an overview of Evoenergy's revised proposal in relation to the AER's draft decision in each of the key capex categories. The following sections (4.5 to 4.8) give a detailed explanation of context, the AER's draft decision, and Evoenergy's response to the AER's assessments for each category.

Table 4.4 Overview of Evoenergy's response to the AER draft decision on forecast capex

Forecast capex category	AER draft decision	Evoenergy's response
Forecasting method and key assumptions	Evoenergy's key assumptions and forecasting methodology are generally reasonable. The AER has identified some specific areas of concern, notably Evoenergy's application of materials costs escalators, and substituted them with CPI in its draft decision.	Evoenergy accepts the AER's assessment.
Augmentation capex	The AER has substituted $24.8 million ($2018-19) augex forecast, which reflects that: • Based on the information available, Evoenergy has not demonstrated that its use of deterministic planning standards for augmentation is justified. We consider this practice is overly conservative, with Evoenergy proposing augmentation measures when the risk of unserved energy remains minimal. • Evoenergy has not demonstrated how it has incorporated the forecast benefits of its Chamber Substation SCADA Program and Distribution Monitoring Program into its overall proposal.	Evoenergy acknowledges issues identified by the AER in its augmentation planning methodology, and that the probabilistic approach should be applied consistently to justify all projects. Evoenergy is providing new load forecast information related to the Molonglo Valley project and other demand-driven feeder projects. Evoenergy stresses that there are substantial social and economic risks if this investment is not adequately funded.
Connection capex	The AER considered that Evoenergy's forecast customer connections capex is justified and reasonably reflects the capex criteria.	Evoenergy accepts the AER's assessment.
Replacement capex	The AER did not accept Evoenergy's repex. The AER notes that Evoenergy's modelled repex lies slightly above their predictive modelling threshold, which compares distributors' asset categories on both unit costs and expected replacement lives. The AER also undertook a bottom-up review of a sample of Evoenergy's repex The AER accepts that some of Evoenergy's repex forecast reasonably reflects the required expenditure for this driver but argues that Evoenergy has not justified that its repex forecast for the underground cable asset category is prudent and efficient.	In relation to HV underground cables, Evoenergy's revised proposal clarifies a number of inconsistent assumptions in the AER's repex modelling, and provides more detail on the underlying cost benefit calculations to in response to the AER's concerns. Evoenergy's revised forecast for repex is unchanged from original proposal.

Forecast capex category	AER draft decision	Evoenergy’s response
Reliability capex (Non-demand-driven augmentation capex)	The AER believed that Evoenergy has not justified that its proposed capex for chamber substation SCADA and distribution substation monitoring (reliability capex) is reasonably likely to reflect prudent and efficient costs. Evoenergy has not demonstrated how the forecast benefits were incorporated into its overall proposal.	Evoenergy considers that the benefits identified are not the result of delivering operational efficiencies and reliability improvements. They relate to avoiding increased costs and reliability deterioration. Evoenergy will submit revised business cases that will further clarify the drivers of the projects and their benefits.
Non-network capex	The AER did not accept Evoenergy’s non-network capex. Their revised forecast reflects that: • the AER has removed contingency costs from ICT program forecasts; • the AER does not consider that Evoenergy has demonstrated that the proposed ADMS and information and communications technology (ICT) asset extension programs are prudent and efficient or that Evoenergy has accounted for the benefits of these programs within its overall proposal; • Evoenergy's forecast assumed a target replacement age for elevated work platforms and heavy commercial vehicles lower than industry standard benchmarks.	Evoenergy: • accepts the AER’s decision on contingency costs • is submitting a revised business case and clarification of the drivers for the ADMS upgrade and ICT extension projects more clearly in terms of regulatory obligations and benefits to consumers • Accepts the AER’s decision on fleet expenditure
Capitalised overheads	The AER considers that Evoenergy’s estimate of capitalised overheads is not warranted. The AER’s alternative forecasts reflects a lower forecast for corporate costs.	Evoenergy has adopted the AER’s draft decision on corporate costs, but notes aspects of AER’s implementation are not consistent.

4.5 Augmentation capex

4.5.1 Overview

Augex relates to demand-driven expenditure expanding or upgrading the network to address increases in demand or network utilisation, or non-demand-driven expenditure that addresses changes in network requirements in relation to quality, reliability, safety, and security of power supply.

Evoenergy’s proposed augex reflects an approach that considers both deterministic and probabilistic planning criteria to arrive at a forecast. This approach takes into account consumer benefits in terms of the avoided risks of customer outages and Unserved Energy (USE). This represents a significant development since Evoenergy’s proposal for the 2014–19 regulatory review, which did not explicitly draw upon economic studies of consumer benefits through USE analysis.

Evoenergy proposed augex of $47.2 million, excluding overheads, for the 2019–24 regulatory period reflects expenditure to address key growth areas in the ACT region, as well as augmentation projects that were commenced in the 2009–14 regulatory period following a sustained period of very low investment.

The proposed augex forecast aims to ensure that Evoenergy can continue to comply with reliability standards and efficiently meet anticipated customer demand in new urban areas. Major augmentation projects expected to be undertaken during the 2019–24 regulatory period include:

- Relocation of a mobile zone substation[36] into the Molonglo district for the provision of power to new suburbs in the Molonglo Valley and North Weston;
- Construction of three new feeders from the East Lake Zone Substation to enable retirement of the Fyshwick Zone Substation and to service its existing load. East Lake Zone Substation was established in 2013, in part to enable the retirement of Fyshwick Zone Substation, thus avoiding substantial associated repex;
- The construction of a double-circuit 132 kV transmission line from the new Stockdill Substation to connect into and out of Evoenergy's existing Canberra–Woden 132 kV transmission line, and installation of 11 kV capacitor banks at four zone substations, known as the Second Supply to the ACT Project—Stage 2. This is a network security project aimed at meeting the requirements of the *Electricity Transmission Supply Code 2016 (ACT)* which will increase security of supply to the ACT;
- Installation of several augmentation-related secondary systems, which includes expenditure on projects including downstream communications infrastructure and cybersecurity measures;
- Construction of several feeders addressing supply to high growth areas, which include:
  - Supply to Whitlam, to serve a new suburb in the Molonglo Valley region;
  - Supply to Strathnairn, to serve a new suburb in the West Belconnen region;
  - Supply to Canberra CBD, to serve a high growth commercial precinct – in particular multi-story developments to be situated on or adjacent to London Circuit;
  - Supply to Canberra City North, Lyneham and Dickson, to address significant commercial growth around these areas;
  - Supply to Gungahlin Town Centre – to serve expansion of Gungahlin Town Centre precinct as well as the new suburbs of Throsby and Kenny;
  - Supply to Kingston – to serve high residential and commercial growth in the Kingston Foreshore area;
  - Supply to Pialligo – to meet further development around Pialligo/Brindabella Business and Industrial Park area located adjacent to Canberra Airport;
  - Supply to Griffith – to serve new residential developments in the Griffith/Red Hill/Forrest/Narrabundah area;
  - Supply to Mitchell – to serve a significant number of new industrial customers in the Mitchell area, including a number of critical data centres;

[36] Construction of the Molonglo Zone Substation was originally planned for the 2014–19 period but was deferred due to delayed urban development in the area.

- Supply to Belconnen – to serve new residential and commercial developments in Belconnen, particularly around the Belconnen Town Centre area.

4.5.2 Draft decision

In its draft decision, the AER did not accept Evoenergy's proposed augmentation capex of $47.2 million excluding overheads.[37] The AER instead included capex in the amount of $24.8 million (excluding overheads) in its alternative estimate of total capex, representing a reduction of 47.5 per cent.

The AER concluded that Evoenergy's proposed forecast of augmentation capex exceeded the augmentation capex required to achieve the capex objectives.[38] The AER decision to require further information on a number of projects proposed by Evoenergy was primarily due to an assessment of Evoenergy's augmentation planning criteria and examination of economic analysis provided by Evoenergy.[39] The AER's draft decision reflects a view where projects should be justified on the basis of probabilistic planning models, which is substantially different from the approach used by Evoenergy in its regulatory proposal.

The AER's draft decision on augex was based on a desktop review comprising of trend analysis, an examination of utilisation and capacity on Evoenergy's network, an assessment of Evoenergy's augmentation planning criteria, the outcomes of consumer engagement processes, and stakeholder submissions.

The AER's trend analysis compared Evoenergy's proposed augex to historical expenditure, taking into account changes in demand, network capacity, and design and planning standards.[40] The AER concluded that the analysis shows that Evoenergy has proposed an increase in augex for 2019–24 compared to that incurred during the 2014–19 regulatory control period.

Following the trend analysis, the AER examined the utilisation of Evoenergy's network during 2014–19 and found that there was no significant shift in network utilisation. Taken together with Evoenergy's forecast of system wide declining demand growth, the AER concluded that there is likely to be excess capacity in the network that could be utilised ahead of additional augmentation investment.

In respect of the planning criteria used by Evoenergy in making augmentation decisions, the AER concludes:[41]

> *We recognise that Evoenergy does not apply a purely deterministic approach to network augmentation. However, Evoenergy has not demonstrated that its application of deterministic standards would result in augmentation proposals that are prudent and efficient and which would form part of a total capex allowance that reasonably reflects the capex criteria. Deterministic planning relies on a pre-determined set of triggers for initiating augmentation works. The advantage of deterministic standards is that they are easy to understand and relatively easy to apply. However, they are intrinsically less efficient as they do not consider the*

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[37] AER 2018, draft decision Evoenergy determination: Attachment 5, p. 6-10 and *Appendix A*, p. 6-30
[38] AER 2018, draft decision Evoenergy determination: Attachment 5, p. 6-10 and *Appendix A*, p. 6-30
[39] AER 2018, draft decision Evoenergy determination: Attachment 5*: Appendix A*, pp. 6-30 to 6-31
[40] AER 2018, draft decision Evoenergy determination: Attachment 5*: Appendix A*, pp. 6-30 to 6-34
[41] AER 2018, draft decision Evoenergy determination: Attachment 5, p. 5-32

individual circumstance (cost, benefit and risk) of the project or program in question.

In addition, deterministic standards must also be designed to accommodate all foreseeable contingencies. This means that they must be sufficiently conservative so as to cater for a wide range of circumstances. This conservatism results in increased overall costs when compared to individual project evaluations. A useful example is with CitiPower where, in defining deterministic standards in its Distribution Annual Planning Report, notes that a strict use of the approach may lead to inefficient outcomes:

The AER conducted an internal desktop review of a sample of Evoenergy's major augmentation projects, which included the Molonglo Valley Supply project, the deferral of Strathnairn Zone Substation project, and various demand-driven feeder augmentation projects.

The Molonglo Valley Supply project, which comprises relocation of a mobile zone substation and construction of associated new feeders, represents the largest project within Evoenergy's proposed augex program. In its draft decision, the AER concludes that Evoenergy did not provide sufficient evidence that its proposed Molonglo Valley Zone Substation is an efficient solution, referring to the outcomes of Evoenergy's economic analysis that indicate an insufficient value of USE within the 2019–24 regulatory period.

However, the AER acknowledges that the potential growth in the Molonglo Valley area and that the demand forecasts for the area are "subject to considerable change". This was informed by the knowledge that, since the Evoenergy's January 2018 regulatory proposal, further information has become available that has significantly impacted the forecasts, and hence the USE results of the economic analysis. In its recommendations, the AER has stated that it considers it:[42]

… more appropriate to consider the prudency and efficiency of the proposed augmentation measure once there is greater certainty on the load that would need to be supplied.

In place of the proposed expenditure for the Molonglo Valley, the AER draft decision substituted an estimate of $4 million, which Evoenergy considers an interim measure that more truly reflects the "do nothing" option in the Molonglo Project Justification Report (PJR). This option reflects the cost of extending the Hilder feeder to supply the Molonglo greenfield development. In the absence of this spending, the USE outcomes would be sufficiently large to justify the proposed measure. The AER acknowledged that this reflects the absolute minimum required to service the Molonglo greenfield development. However, updated load forecast information means that even this option will not meet minimum requirements beyond 2021 (see section 4.5.3.1).

The AER's draft decision also identified a number of demand-driven projects (relating to various feeders for specific high growth regions) that it considers could be deferred to the 2024–29 regulatory period. This appears to be the outcome of an approach where all

[42] AER 2018, draft decision Evoenergy determination: Attachment 5, p. 5-16

projects with a very low annual USE value (within the 2019–24 regulatory period) were identified for deferral. These include the following projects:

- Supply to Canberra City and Dickson ($2.9 million);[43]
- Supply to Kingston ($712,950);[44]
- Supply to Canberra CBD ($892,600);[45]
- Supply to Pialligo ($3.0 million);[46]
- Supply to Gungahlin Town Centre ($2.8 million); and [47]
- Supply to Belconnen ($2.4 million).[48]

The AER allowed the proposed spending for the Strathnairn deferral project and the associated opex step change for demand management activities. Initially, the AER reviewed the associated PJR and supporting demand forecast information and identified that there was available capacity of 23.6 MW (summer) and 21.1 MW (winter) on feeders surrounding the Strathnairn area which on face value would be sufficient to manage the increase in load. However, the AER noted further information from Evoenergy (subsequent to the regulatory proposal) that, due to geographical and network constraints, not all feeders surrounding the Strathnairn area are available to supply the area. In practice only two (Latham and Macrossan) have this capability.

The AER has largely accepted two non-demand-driven projects proposed by Evoenergy, which are:

- the decommissioning of Fyshwick Zone Substation: the AER has conducted an extensive enquiry into the nature of the Fyshwick Zone Substation assets, and also of the three proposed feeders. In conclusion, the AER is satisfied with Evoenergy's proposed repex-augex trade-off (three new feeders in place of avoided costs of repex associated with refurbishment of the ageing zone substation) as the most efficient outcome.
- the Second Supply to the ACT: The AER has reviewed the proposed unit rates of key components of the projects, such as capacitor banks and circuit breakers, and is satisfied that the assumptions are reasonable. In terms of the prudence of the project, it has been mandated through the ACT Transmission Supply Code.

The AER has allowed the majority of Evoenergy's proposed secondary systems augex, with the remaining disallowed expenditure relating to distribution zone substation monitoring and chamber substation supervisory control and data acquisition (SCADA) equipment. This was a result of the AER's review of the relevant business cases, which identified benefits of avoided costs relating to reliability, opex, and capex. The AER is of the view that these benefits relate to operational efficiencies and reliability improvements, rather than avoided costs. In its draft decision, the AER notes that Evoenergy has incentives to self-fund this and similar programs through the two incentives schemes (EBSS and CESS) discussed in more detail in chapter 9 of this document.

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[43] Evoenergy 2018, Appendix 5.27 - Regulatory proposal for the ACT electricity distribution network 2019–24, January, pp. 1, 13.
[44] Evoenergy 2018, Appendix 5.28 - Regulatory proposal, pp. 1, 16.
[45] Evoenergy 2018, Appendix 5.31 - Regulatory proposal, pp. 1, 12
[46] Evoenergy 2018, Appendix 5.32 - Regulatory proposal, pp. 1, 13.
[47] Evoenergy 2018, Appendix 5.33 - Regulatory proposal, pp. 1, 12
[48] Evoenergy 2018, Appendix 5.35 - Regulatory proposal, pp. 1, 12.

Despite this, the AER acknowledges the evidence put forward by Evoenergy on the increased prevalence of power quality complaints relating to voltage issues. The AER recommends that Evoenergy, as part of its revised regulatory proposal, provide more analysis surrounding the counterfactual and the consumer benefits that would justify the project.

4.5.3 Evoenergy response

Evoenergy notes the AER's concerns with respect to a number of proposed augex projects, and that the AER is open to considering new information that demonstrates the efficiency and prudency of these projects as part of the revised proposal. The AER has pointed out instances where application of deterministic standards was used to justify the projects, in spite of probabilistic analysis indicating a low USE value. Evoenergy recognises that the strict application of deterministic standards can lead to inefficient outcomes, despite the benefits of being a simple and robust approach that accounts for all contingencies.

During the 2014–19 regulatory determination review for Evoenergy (then ActewAGL Distribution), the AER expressed concern with Evoenergy's application of deterministic standards. In its regulatory proposal for the 2019–24 period, Evoenergy responded to these concerns by adopting a more risk based approach that involved probabilistic analysis in justifying expenditure. In its draft decision, the AER notes and commends this significant development, but considers that for some projects the implementation does not sufficiently satisfy the approach required:[49]

> *Evoenergy has identified that it is certified to ISO 55001 for asset management. As part of its submission documentation, Evoenergy identified that it has significantly reduced reliance on deterministic planning criteria in recent years. This reduced reliance on deterministic planning is consistent with the continual improvement processes contained within ISO 55001. We commend Evoenergy for reducing reliance on deterministic standards, and recognise that Evoenergy does apply risk-based probabilistic methods. However, we note that Evoenergy's major augmentation projects are often proposed because the 'do nothing' option breaches its Distribution Network Augmentation standards, which incorporate deterministic standards. They do not appear to be primarily driven by the risk based assessments that are intrinsic to ISO 55001 or ISO 31000.*

Since its January 2018 regulatory proposal, Evoenergy has further reviewed its planning approaches and the projects identified by the AER that required stronger justification under a probabilistic approach. In particular, Evoenergy has accounted for updated and more granular information and has consulted the AER on this information during the regulatory determination process.[50] As a result, Evoenergy has instigated a two-step process on which it is basing this revised proposal:

- as a first step, Evoenergy applies deterministic planning criteria to identify where existing or emerging constraints exist on the network. Further analysis is then performed to confirm whether the investment proposal is justified economically; and

[49] AER 2018, Draft Decision Evoenergy Determination: Evoenergy Determination: Attachment 5, p.5-35.
[50] Evoenergy, Response to Information Request 039, 29 August 2018.

- in a second step, Evoenergy applies probabilistic assessment of risk to determine whether network investment is justified. The value of avoided risk is estimated using probabilistic methodology.

As a result, Evoenergy can demonstrate that the proposed demand-driven augex is justified on a probabilistic basis, with deterministic planning playing a role only in identifying areas of capacity constraint. The results of this approach are incorporated in revised Project Justification Reports that clearly set out the efficiency and optimal timing of the relevant projects submitted as part of Evoenergy's revised proposal.

In Evoenergy's probabilistic methodology, benefit is expressed as avoided risk. If avoided risk exceeds the cost of the proposed augmentation, the investment is considered economic. The assessment of risk is predominantly based on the probability of an outage occurring sufficiently frequently. The probability of an outage occurring at a time when load exceeds firm capacity is then used to calculate USE. Investment is triggered when the value of USE exceeds the annualised cost of the investment for any year of the 2019–24 regulatory period. This determines the optimal timing, and hence the prudency of the augmentation.

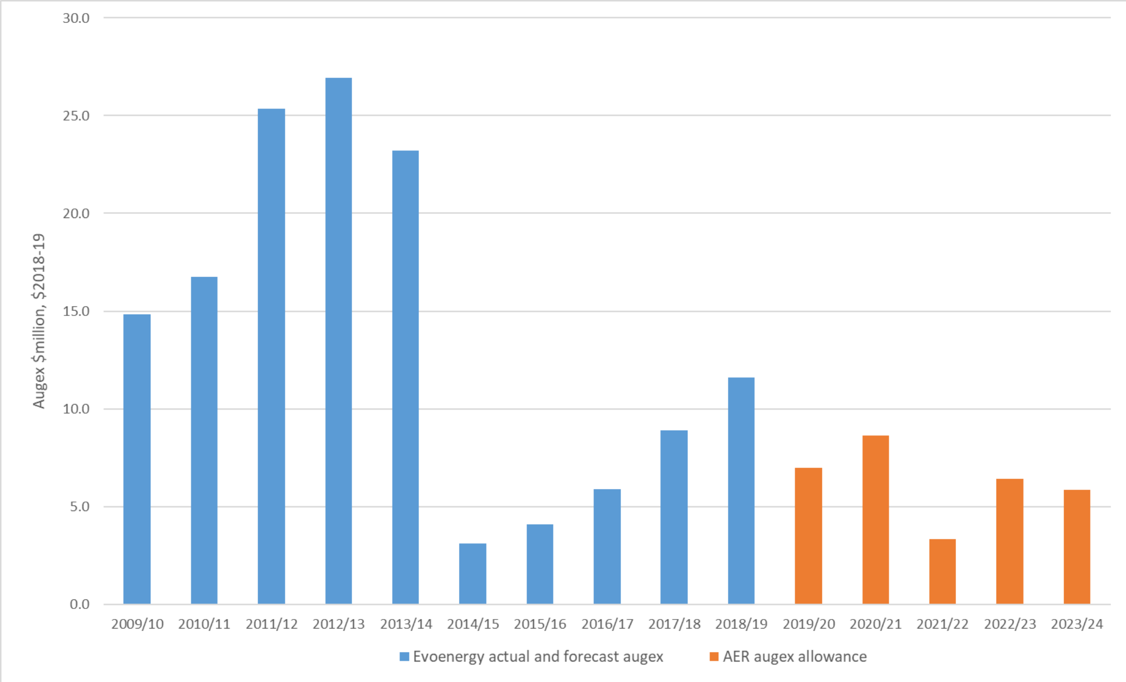
USE modelling involves assumptions, as historical data to accurately calibrate all parameters is not always available. Evoenergy's approach reflects assumptions that tend to result in lower capex. They include the following:

- the probability of failure for any given time interval is constant until thermal limit is reached (at which time the probability will become 100 per cent). In reality the probability should increase as the thermal limit is approached;
- the age of the particular assets involved does not impact the modelling even though, in practice, older assets such as zone substations are more likely to experience longer outages; and
- the value of customer reliability (VCR), based on the NSW NEM region, is subject to estimation error and differs considerably depending on the customer type (e.g. residential, commercial).

While acknowledging the AER's concerns with Evoenergy's planning approach, Evoenergy's revised proposal demonstrates that the AER's draft decision augex will not cover the efficient costs of meeting demand from new suburbs in the Molonglo district, or to address high growth areas in the ACT region to meet regulatory obligations in respect of safety and reliability.

The AER's trend analysis shows that Evoenergy's proposed forecast of augex for the 2019–24 regulatory period is higher than incurred in 2014–19. Evoenergy notes that its proposed augex is not particularly high by historical standards and overall reflects declining system-wide demand and industry change. However, the AER did not explicitly compare its allowed augex within the trend analysis. If this were to be included, it would clearly show that the AER's draft decision augex for 2019–24 period would be at historically low levels, as Figure 4.1 shows.

Figure 4.1 Evoenergy historical and AER draft decision augex 2009–2024



Source: Evoenergy analysis, Evoenergy's Reset RIN.

Evoenergy notes the AER's observations in relation to peak load forecasts and asset utilisation to support its position to reject some augex projects, specifically:

- available information on zone substation utilisation trends does not provide evidence for increasing utilisation between 2013 and 2024;
- the utilisation trend is that some zone substations increase utilisation to 50 to 60 per cent capacity, but fewer operate at 60 to 70 per cent capacity; and
- a reduction in peak system demand is projected over the next regulatory control period. In particular, the AER observes:

> *We consider that Evoenergy's forecast of negative system peak demand growth indicates that forecast demand-driven augmentation should be minimal, addressing only localised peak demand pressures that are forecast to arise.*

Evoenergy explains that while some of the AER's arguments are valid in general, they do not justify its conclusions in relation to Evoenergy's proposed augex program.

In particular, there is no direct causal link between the system peak demand and a need for augmentation of zone substations. Evoenergy's experience is that, for many network growth and development scenarios, system peak demand forecast trends and zone substation utilisation are poor indicators of the need for augmentation investment. Similarly, the link between the utilisation of distribution substations and the need for new substation capacity is unclear. The reasons for the lack of causality include:

- The need for extending or augmenting distribution feeders is usually driven by localised network constraints (e.g. due to localised load growth, significant point loads and/or seasonal summer/winter constraints) or a geographically separate load.

- The ACT network comprises of a small number of high capacity substations located relatively long distances apart. Such a network configuration has some advantages, but it limits opportunity to service areas of high load growth from the existing network.

Augmentation of existing substations cannot address capacity requirements of the Molonglo Valley area (see section 4.5.3.1 below for more details). This is a large, new greenfield area open for development by the ACT government and Evoenergy's solution involves relocation of a mobile substation to this area. In this context, the utilisation of existing zone substations is largely irrelevant due to their geographical location and distance. Regardless of their existing capacity and utilisation, these zone substations are not in a position to sustain the medium to long term Molonglo load.

Evoenergy agrees that individual utilisation of zone substations can be used in the assessment of the need to augment these specific substations. However, high level zone substation utilisation figures should be treated with extreme caution. Evoenergy considers that drawing overall conclusions on the proposed programs on the basis of two high level parameters is not appropriate.

For example, an outage consequence and risk associated with a single contingency network event for a two-transformer zone substation with 60 per cent utilisation is higher than for a three-transformer substation with the same level of utilisation. Furthermore, Evoenergy's practice is to assess the adequacy of zone substation capacity with reference to a two-hour transformer emergency rating, rather than to their installed capacity. Evoenergy considers that without these considerations, the AERs analysis will not draw meaningful conclusions.

Evoenergy's methodology also allows for higher zone substation loading limits (relative to many other DNSPs). This is reflected in Evoenergy not proposing additional zone substation capacity for the next regulatory control period, despite the need to service a new geographical area (Molonglo). For Molonglo, Evoenergy has opted to relocate an existing mobile zone station instead (see section 4.5.3.1).

Lastly, Evoenergy notes that updated information since Evoenergy's initial proposal shows material increases in the maximum demand forecast and utilisation of zone substations. As a result, for Evoenergy's revised proposal the projected demand in several substations and for the system has been revised upwards.

The sections below outline Evoenergy's specific responses and details its revised business case with respect to the AER's assessment of particular projects.

4.5.3.1 MOLONGLO ZONE SUBSTATION

Evoenergy expects that over the next 20 years, land releases will result in new suburbs being built in the Molonglo Valley region. It is expected that these developments will result in a total population of 55,000, with current development proceeding at approximately 1000 dwellings per annum. This development has significant socioeconomic and political ramifications for the ACT, and it is important that it is not hindered by inadequate provision of the necessary infrastructure.

To service the new development, Evoenergy proposed a cost-effective approach by installing a mobile substation (rated 132/11 kV 14 MVA) in Molonglo by June 2023. When demand exceeds the power capacity of the mobile substation, a permanent zone substation will be provisioned with the installation of one 132/11 kV 30/55 MVA transformer and one 11 kV switchboard, with space provided for a future two additional transformers and two additional 11 kV switchboards. This represents a flexible, cost-effective approach that minimises the risk of stranded assets and ensures that consumers pay only for the capacity they need.

The AER's draft decision was to defer Evoenergy's proposed Molonglo Valley project until the 2024–29 regulatory period as its efficiency and prudency was not sufficiently supported by results from a probabilistic approach. In particular, the AER found that the value of USE did not outweigh the annual costs in any year during the 2019–24 regulatory period. This is chiefly because, under the 'do nothing' option, none of the feeders in the area (Black Mountain, Streeton and Hilder) will breach their thermal ratings during the 2019–24 regulatory period.

Evoenergy considers that there is sufficient evidence to demonstrate the efficiency and prudency of the project. This includes that:

- the AER's draft decision leaves little margin for error, even under the original demand forecasts;
- The 'do nothing' option is not the least cost option over the longer term (beyond the 2019–24 regulatory period), and under revised forecasts all feeders will breach thermal ratings within the 2019–24 regulatory period; and
- new updated demand forecasts since the original proposal in January 2018 result in a much higher cost of unserved energy.

The sections below set out Evoenergy's reasoning with respect to the issues above.

New demand forecasts and point loads

The AER has acknowledged the dynamic nature of the demand forecast, and that Evoenergy's regulatory proposal reflects only a snapshot of the information available as at Evoenergy's regulatory proposal in January 2018. Since then, the pace of expected development has accelerated considerably, suggesting USE that is much higher than originally considered. Evoenergy has received an updated development program from the developers of Whitlam Estate, Molonglo Valley which shows full development of Whitlam (all 4 stages) by mid-2021, ahead of the schedule assumed in Evoenergy's regulatory proposal. The result of this is that the combined thermal ratings for the relevant feeders will be exceeded as early as 2022: four years ahead of the previous forecast of 2026. In particular, the solution of extending the Hilder Feeder only defers a need for subsequent augmentation investment to 2021.

As a result of this updated information, Evoenergy does not consider the AER's draft decision, Evoenergy's interim 'do nothing' option (to simply extend existing feeders), to be a prudent or efficient approach. Table 4.5 shows the revised USE forecasts for this option. It shows that the preferred option is the only acceptable option that avoids a very high value of USE.

Appendices 4.3 to 4.10 provide more detail on the new point loads and development applications received by Evoenergy since its regulatory proposal in January 2018, and how these has been factored into the revised USE calculations.

Table 4.5 Molonglo Valley project unserved energy – original and updated forecasts

Option	Original demand forecasts		Updated demand forecasts	
	Net Present Cost	Present Value of Unserved Energy	Net Present Cost	Present Value of Unserved Energy
Do Nothing	$0	$535,000,000	$0	$1,001,944,000
Do Something (connect to existing feeders)	$11,425,000	$2,375	$11,425,000	$240,758,000
Preferred Option (Molonglo ZS and feeder project)	$10,336,000	$0	$10,336,000	$130,656,000

Source: Evoenergy Revised Regulatory Proposal, Appendix 4.

AER's decision leaves little margin for error

Even without taking into account the updated information since the January 2018 regulatory proposal, the USE of the "doing nothing" option will be unacceptably high one year after the 2019–24 regulatory period. This is because the demand forecast has already exceeded the firm rating and is approaching the thermal rating for the feeders. This is reflected in the USE being predicted to rise rapidly after 2024.

As a result, the AER's draft decision is premised on an assumed one-year timing difference which increases the risk that developers would become commercially exposed and ultimately impact ACT consumers.

As discussed previously, the circumstances surrounding this project are dynamic and the direction of change is overwhelmingly upwards. Growth in the ACT is outpacing almost all other jurisdictions by a significant margin.[51] It is important that the AER's decision reflects a reasonable assessment that accounts for the inherent risks of mistiming infrastructure provision in relation to an important development in a high growth jurisdiction.

Long term inefficiency of the 'Do nothing' option

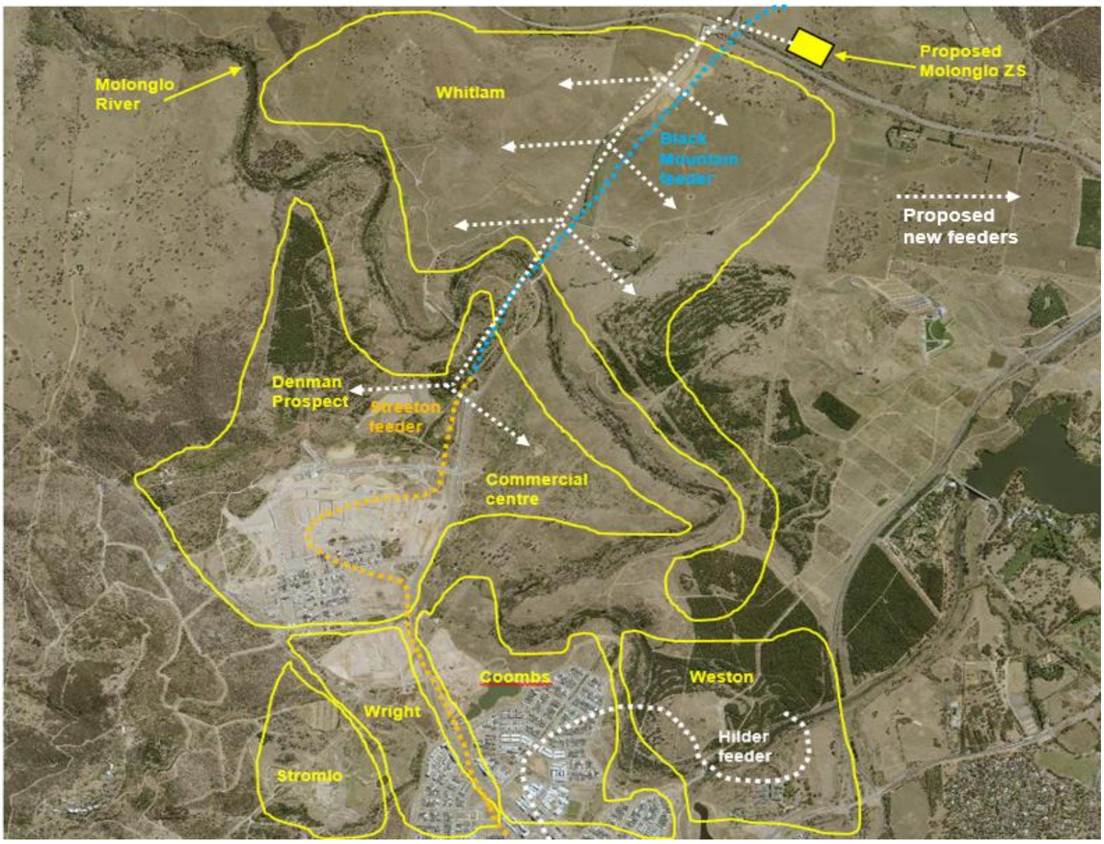
The AER's draft decision forecast of $4.1 million for the Molonglo Valley project reflects the minimum required (under the load forecasts as at January 2018) to service the area without resulting in excessive USE during the 2019–24 regulatory period. While this reflects the least cost option during the 2019–24 regulatory period, it is not the most efficient option in the longer term, even disregarding the new demand forecasts received since the regulatory proposal. This is because:

- relying on extending the three existing feeders is essentially an interim solution that results in an inefficient feeder configuration in the longer term as the Molonglo Valley area develops. The extension of feeders without a zone substation requires considerably more cables running in all directions, north and south of Molonglo River, and east and west of John Gorton Drive;
- as the suburb of Whitlam develops, the Black Mountain Feeder will need to be relocated. This is because the Black Mountain Feeder is currently an overhead line

[51] Australia Bureau of Statistics, 3101.0 - Australian Demographic Statistics, Mar 2018, http://www.abs.gov.au/ausstats/abs@.nsf/mf/3101.0, Accessed 14 November 2018.

that cuts through the middle of the planned suburb (see Figure 4.2). Thus, extending this feeder results in significant expenditure on an asset soon to be retired.

Figure 4.2 Molonglo Valley project, outline of feeder and precinct locations



Source: Evoenergy Revised Regulatory Proposal, Appendix 4.

4.5.3.2 FEEDERS TO SUPPLY CANBERRA CITY, DICKSON, GUNGAHLIN, AND PIALLIGO

In its draft decision, the AER has not allowed funding for six feeder projects, as described in section 4.5.2 above. Evoenergy considers that in doing so, the AER has not taken adequate account of the critical nature of the developments to be served by these feeders. Some of the developments to be served include critical customers such as hospitals, data centres, and Canberra Airport. Consumer engagement conducted by Evoenergy indicates consumers recognise that very high reliability should be maintained for critical customers (Appendix 4.1). Other feeders serve very high growth residential and commercial developments such as the Gungahlin district, the second highest population growth area in Australia.[52] Table 4.6 summarises the nature of development relating to the feeders.

[52] Canberra Times, "*Census 2016: ACT has nation's largest population growth, Gungahlin the driver*." 27 June 2017. https://www.canberratimes.com.au/national/act/census-2016-act-has-nations-largest-population-growth-gungahlin-the-driver-20170627-gwz5bq.html, Accessed 14 November 2018.

Table 4.6 Outline of proposed feeders to high growth precincts disallowed in AER draft decision (excluding Molonglo Valley)

Feeder	Nature of development
Supply to Canberra CBD	Numerous high-rise commercial and residential buildings, Canberra Metro Stage 2, City to the Lake project, National War Memorial expansion.
Supply to Canberra North	Major expansion including business and shopping centre, numerous high-rise commercial and residential buildings in Braddon, Lyneham and Dickson areas.
Supply to Belconnen Town Centre	Expansion of Calvary Hospital, University of Canberra Hospital, University of Canberra residential buildings, Belconnen Trades Centre, and major high-rise commercial and residential buildings in town centre.
Supply to Gungahlin	Numerous high-rise commercial and residential buildings in Gungahlin Town centre East area, Throsby Estate, Canberra Metro TPS, Kenny Estate.
Supply to Pialligo	Commercial and light industrial developments at Brindabella Park, Fairbairn Park, Majura Defence facility and Canberra Airport.
Supply to Kingston	Numerous high-rise commercial and residential buildings, Kingston Arts Precinct, and proposed school.

Importantly, as with the Molonglo Valley, revised demand forecasts and point load connection applications have resulted in dramatically revised USE values for all feeders. This is summarised in Table 4.7. As a result, even with a purely probabilistic approach applied, each of these feeder projects is strongly justified after accounting for the latest available information. Also contributing to this are network alteration proposals received by Evoenergy, which could significantly increase the loads forecast.

Table 4.7 Increase in unserved energy for proposed feeder projects (excluding Molonglo Valley)

Project	Energy at Risk 2024 – regulatory proposal (kWh)	Energy at Risk 2024 – revised proposal (kWh)
Molonglo Zone Substation	861,758	24,720,930
Molonglo Valley Feeders	861,758	24,720,930
Supply to CBD	283,749	15,120,430
Supply to Canberra North	537,020	11,646,010
Supply to Belconnen	725,450	2,842,330
Supply to Gungahlin	2,737	1,348,151
Supply to Pialligo	237,964	4,648,192
Supply to Kingston	193,436	611,840

Table 4.8 outlines the additional point load connection requests and network alteration proposals for each relevant feeder project since Evoenergy's regulatory proposal. This illustrates the very dynamic nature of demand-driven augex and the growth in the ACT. Project Justification Reports submitted for each feeder (Appendices 4.3 to 4.10) outline

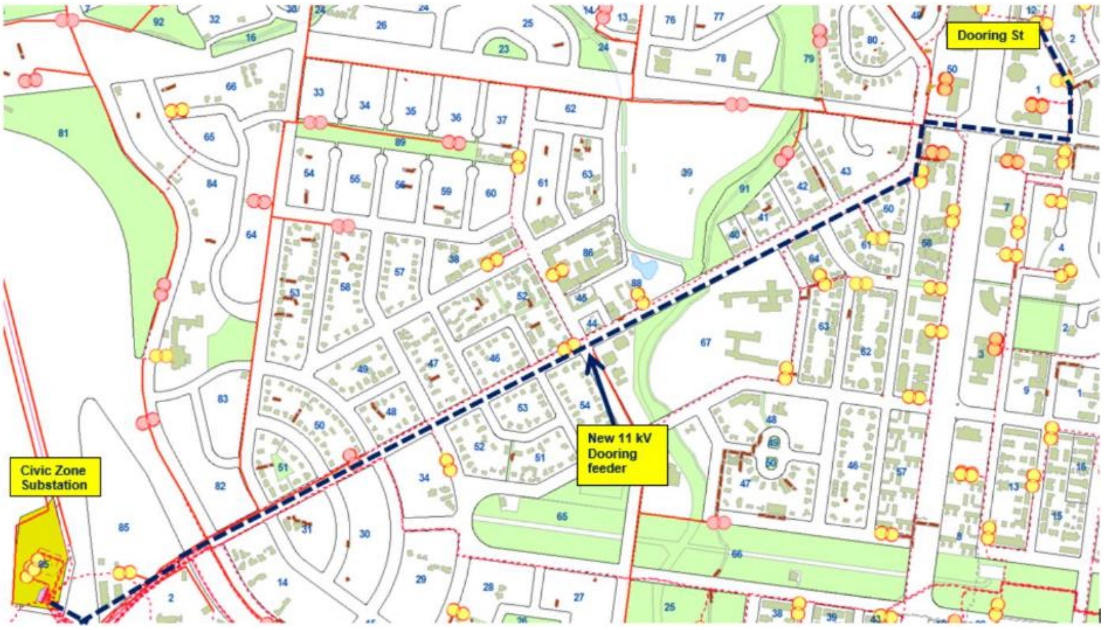
in detail the new proposed loads and how they are factored into the revised USE values in Table 4.7.

Table 4.8 Updated load forecasts vs original load forecasts for demand-driven augex projects

Project	Forecast Additional Max Demand by 2024 (MVA) – calculated Jan 2018	Forecast Additional Max Demand by 2024 (MVA) calculated Nov 2018
Molonglo Zone Substation	21.6	23.6
Molonglo Valley Feeders	21.6	23.6
Supply to Canberra CBD	24.8	48.2
Supply to Canberra North, Lyneham & Dickson	30.9	34.1
Supply to Belconnen	20.4	25.1
Supply to Gungahlin	16.6	22.6
Supply to Pialligo	8.2	11.2
Supply to Kingston	12.5	18.4

The updated information not only justifies Evoenergy's originally proposed expenditure, but also requires Evoenergy to further revise expenditure upwards by $2.6 million for the cost of the Supply to Canberra North project. This increase relates to a proposed major residential development at Dooring St, Lyneham. There is a need to construct an 11 kV feeder from Civic Zone Substation to Dooring St by June 2021 to supply new developments in the Lyneham area. Without the new feeder, the projected maximum demand (summer 2024) for the relevant area is 6.3 MVA which will exceed the spare thermal capacity of existing feeders in the area. Civic Zone Substation is nearest to the proposed residential development at Dooring St, Lyneham and there are no spare conduits available along this route. It is proposed to install three conduits (including two spares for future needs) from Civic Zone Substation to this site. Figure 4.3 shows the location of the feeder with respect to the Civic zone substation.

Figure 4.3 Proposed layout of Dooring Street feeder



Source: Evoenergy Revised Regulatory Proposal, Appendix 8.

4.5.3.3 SECONDARY SYSTEMS AUGEX AND RELIABILITY CAPEX

4.5.3.3.1 Overview and AER draft decision

Evoenergy proposed expenditure of $6.2 million to install monitoring devices in 200 distribution substations per year over the 2019–24 regulatory period with the expectation that substation monitoring would be extended to 20 per cent of substations by 2025. This program is to address the significant challenges in managing the low voltage network due to growth in residential rooftop solar photovoltaic (PV) generation in the ACT. The presence of solar PV has already been shown to have direct impacts such as excessive voltage rise, thermal overload of low voltage feeders, harmonic excursion and load balancing on distribution feeders on electricity networks.

The primary benefits of the proposed program come from avoided costs of asset replacement and avoided power quality complaint investigation costs. Without this program, and in the absence of any alternative solutions, these costs will increase from current levels. An extensive options analysis was conducted as part of developing the business case which included a ‘do nothing’ option, a smart meter rollout, and extending the existing SCADA network. The benefits of the program in terms of avoided costs were extensively assessed and further demonstrate the efficiency and prudency of the program.

Evoenergy has proposed $1.5 million for the installation of SCADA RTUs at selected chamber substations. This program is to be delivered in conjunction with HV and LV switchboard replacements at selected sites where SCADA is required for asset management and safety with operation. Recent changes to the ACT Utilities (Management of Electricity Network Assets) Code requires ENA NENS 09 to be implemented for arc flash hazards. This program offers an engineering control for managing arc flash hazards at chamber substations.

In its assessment of Evoenergy’s secondary systems program, the AER identified distribution substation monitoring and chamber substation RTUs as areas where it did not have sufficient evidence to allow the proposed expenditure. As part of its assessment, the AER requested that Evoenergy identify and provide modelling showing the expected costs and benefits of both programs. Evoenergy provided modelling indicating benefits in relation to reliability (reduction in USE), replacement and augmentation (better utilisation of existing assets), and safety and opex (avoidance of manual network monitoring). In response, the AER appears to have assumed that the benefits relate to operational efficiencies and reductions from the existing cost base. The AER therefore expected the benefits to be accounted elsewhere in Evoenergy's proposal, or self-funded through the incentive schemes:[53]

> *Evoenergy has not demonstrated that it has accounted for the benefits of this expenditure in the overall proposal. This is because it has not shown quantitatively how its overall regulatory proposal is lower than it otherwise would be in the absence of these projects.*
>
> *We note that Evoenergy has incentives to undertake these programs under the EBSS, CESS and STPIS due to the reduced expenditures it expects to incur elsewhere. These programs would provide Evoenergy with enhanced network capability to manage the operation and planning of the network in addition to ensuring compliance with regulations. We consider that, in the absence of evidence that Evoenergy has factored these programs into the proposal, Evoenergy could appropriately fund these programs through the respective incentive schemes.*

4.5.3.3.2 Evoenergy Response

While the AER's draft decision appears to assume that the benefits all relate to identifying existing efficiencies, the main driver of the proposed programs is the impact of technological change and not existing cost drivers. In correspondence with the AER, Evoenergy has clarified that the benefits mostly relate to avoided costs and has provided modelling showing the costs and benefits of these programs. [54]

In its draft decision, the AER accepted the purpose behind the programs is to maintain the quality of power supply:[55]

> *Evoenergy explained that it has obligations to maintain and control the quality of supply through the distribution and transmission networks under its control projects. It has explained that with the increasing penetration of micro-generators such as PVs, fixed batteries and electric vehicle batteries, there will be an increasing need to extend network monitoring to lower levels of the distribution network. The substation monitors would provide Evoenergy with a permanent site solution that delivers real time data that Evoenergy will use to address power quality issues on a more proactive basis than current methods*

Given that the benefits are mostly avoided increases in future operating costs (and given Evoenergy has not included this opex in its forecasts), it would be inappropriate to adjust Evoenergy's opex forecasts for these benefits. Evoenergy's regulatory proposal and

[53] AER 2018, Draft Decision Evoenergy Determination: Evoenergy Determination: Attachment 5, p. 5-40, 5-41

[54] Evoenergy, Response to Information Request 028, 1 June 2018.

[55] AER 2018, Draft Decision Evoenergy Determination: Attachment 5, p 5-40.

accompanying business cases clearly set out why the projects are required. It is clear that their purpose is not to realise efficiencies from current activities, and that the cost benefit analysis submitted subsequent to the proposal at the request of the AER[56] should be assessed in this context.

The key driver for the projects is to address power flow issues from increasing DER uptake. Traditionally, distribution networks were designed to accommodate the flow of power in one direction – from substation to customer. The Evoenergy network currently has a 12 per cent penetration of embedded generation; this is expected to increase to 23 per cent over the next five years. This increase will create significant reverse power flows through the LV network and through existing distribution transformers. Voltages exceeding the V99% high voltage limit at customer connection points for extended periods of time will become the norm if action is not taken.

To make effective use of its capabilities with respect to managing the impact of DER, Evoenergy's ADMS requires information from either smart meters or from low voltage distribution substation monitoring. Compared to purchasing data from meter data providers, the proposed distribution substation monitoring is the least cost option that will provide real-time load-flow data and enable voltage profiling functionality. With this visibility in the ADMS, network performance can be managed, and voltage compliance assured.

Overall, the distribution substation monitoring project will enable sensors to provide feedback to dynamically adjust zone substation voltage regulation, ensuring voltage compliance across the entire LV network. This will also unlock a major capability of ADMS. Specifically, the benefits include:

- A number of Evoenergy distribution substations do not have the tapping adjustment required to maintain LV voltage compliance. Without the proposed program distribution substations that are unable to maintain compliant voltage would need to be replaced at a cost of $6.3 million during the 2019–24 period. This program avoids these costs.
- This project avoids increasing requirement to use mobile 'poly-logging' of the LV network. This is a manual process that is opex intensive and provides only quality of supply data over the period of installation.
- The installation of distribution substation monitoring is targeted to areas expected to be impacted by quality of supply issues on the basis of observed measurements and modelling. This will mitigate risk to customer assets, and increased costs of investigating additional customer complaints and reactive monitoring.

The chamber substation SCADA project is necessary to ensure effective asset management and operational safety as follows:

- The switchgear being installed in switchboard replacement projects incorporates numerical protection and requires supporting DC auxiliary supplies. It is critical for the safe and reliable operation of the primary equipment that the protection and DC systems have remote SCADA monitoring to detect failures that would otherwise be undetectable. Potentially having primary systems in service without operable protection presents an unacceptable safety risk, and would degrade network reliability.

[56] Evoenergy, Response to AER Information Request 024, 18 May 2018.

- Recent changes to the ACT Utilities (Management of Electricity Network Assets) Code requires ENA NENS 09 to be implemented for arc flash hazards. Remote control of switchgear via SCADA will eliminate arc flash hazards by engineering out the need for manual switching at high risk sites.

Subsequent to the AER's draft decision, Evoenergy has undertaken consumer engagement specifically to address the issue of power quality and distribution substation monitoring (see Appendix 4.2). Evoenergy wanted to understand consumers' views on the importance and value of distribution substation monitoring as a means to delivering better power quality and reliability. Workshop participants included members of Evoenergy's Energy Consumer Reference Council (ECRC) and major customers. Representatives of ACT Utilities Technical Regulator also attended.

One of the main findings of the workshop was that the $6 million proposed for the distribution monitoring project was justified on the basis that:

- it represented an affordable option for consumers;
- the expenditure compares favourably with investment in smart meters to achieve the same outcome; and
- ACT residential customers place a sufficiently high value on power quality and reliability to justify the investment in distribution substation monitoring.

In particular, consumers accepted that the benefits identified by Evoenergy are real and significant, in terms of greater network monitoring and improved response, greater potential for demand management in lieu of augmentation, maintaining the reliability and quality of power supply, and supporting consumer choice.

Appendices 4.14 to 4.17 provides further information on the distribution substation monitoring and Chamber substation SCADA projects, including the cost benefit analyses.

4.5.4 Revised proposal

Evoenergy's revised forecast augex for each year of the 2019–24 regulatory period is set out in Table 4.9. Key elements that are different from the AER's draft decision are inclusion of:

- all expenditure relating the Molonglo Valley Project as per the original proposal;
- all other demand-driven augmentation projects, with some adjustments; and
- all reliability and secondary systems augmentation projects, as per the original proposal.

The reasons behind this revised proposal are explained in the preceding sections. Evoenergy also notes that in relation to certain disallowed projects (in particular Molonglo Valley) the AER has stated that it would be in a better position to assess efficiency and prudency in the revised proposal.

Overall, total augex in Evoenergy's revised proposal remains at similar levels to that of Evoenergy's January 2018 regulatory proposal. However, Evoenergy has made significant improvements to relevant supporting information due to the AER's draft decision, feedback from consumer engagement since the original proposal, and external developments that have arisen since the original proposal.

Evoenergy is proposing the following revisions in relation to its January 2018 regulatory proposal:

- the addition of a feeder to Dooring Street to service a new development (see section 4.5.3.2);
- removal of a feeder in the Supply to Kingston project as a result of updated demand forecast information;
- minor adjustments made to other projects;
- the inclusion of the Commonwealth Government capital contribution (which has a zero impact on net capex as it is fully contributed by the customer but which impacts the recovery of tax expenditure as explained below).

Table 4.9 Evoenergy revised augex proposal 2019–24

$ million (2018/19)	Total
Evoenergy regulatory proposal	**53.5**
Add:	
Commonwealth Government project	0.0*
Dooring St Feeder (part of Supply to Canberra City and Dickson project)	2.7
Remove:	
Minor adjustments to other projects and cost escalation	(1.0)#
Downward adjustment to Kingston Feeder	(0.4)
Evoenergy revised proposal	**54.7**
AER draft decision	24.8
Variance from draft decision	*29.9*

***** Capital contribution.

This includes a reduction of $0.7m that Evoenergy has inadvertently proposed for Mitchell zone substation. This has since been clarified as a transcription error in the original model submitted by Evoenergy and has been corrected for in Evoenergy's revised capex proposal.

4.5.4.1 COMMONWEALTH GOVERNMENT CAPITAL CONTRIBUTION

A Commonwealth Government department is currently in the early stages of planning for a new data centre in Canberra. The expected increase in load on Evoenergy's network (19.3 MVA by 2024) requires the construction of a new 132/11 kV zone substation and sections of the 132 kV transmission line. These works are estimated to cost $27 million, to be fully funded by the department involved.

In relation to the estimation of tax expenses in Evoenergy's 2019–24 regulatory determination, Evoenergy is particularly concerned about the potential treatment of the project. While it would be funded by the department, the tax implications are significant given the mismatch between the timing of when revenues and costs are recognised for tax purposes.

At this time, planning for the project is in preliminary stages and Evoenergy would not expect to be able to satisfy requirements for an efficiency and prudency test. However, the delivery and timing of the project are mandated by government and are outside of Evoenergy's control. If the AER were to exclude this project from the 2019–24 regulatory determination, then Evoenergy has no ability to recover the relevant tax expenses. Rather, tax expenses in future regulatory periods would be reduced as the tax asset base will be rolled-forward in the subsequent regulatory period using actual capex. For these reasons, Evoenergy has included the zone substation project in its revised proposal.

4.6 Replacement and renewal capex

4.6.1 Overview

Asset replacement and renewal capex (repex) relates to expenditure on the existing network to ensure compliance with regulatory obligations, particularly in respect of network reliability and safety. In its regulatory proposal, Evoenergy proposed repex of $91.6 million (excluding overheads) for the 2019–24 regulatory period.

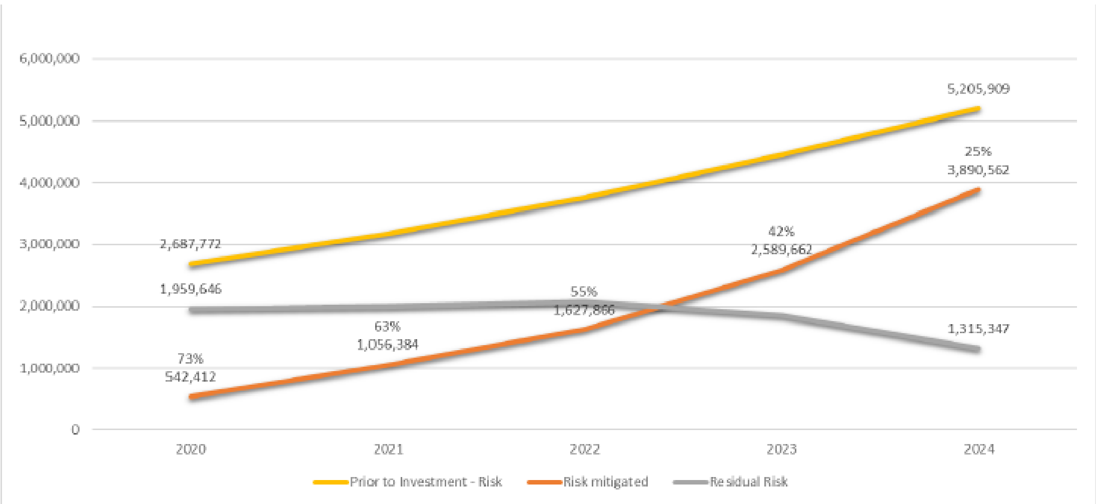
To forecast repex, Evoenergy uses a two-step approach that combines bottom up and top down risk-based methodologies:

- Evoenergy develops a bottom-up forecast, using RIVA. RIVA is a decision support system (DSS) comprising of a series of algorithms that provide for an optimal repex program and maintenance work schedule. RIVA uses a risk-based approach to prioritise capex based on key asset attributes including age, condition, probability of failure, consequence of failure and replacement cost.
- The bottom-up estimate is optimised and tempered by applying top down calculations to account for interrelationships between asset classes in addressing risk. The top-down assessment considers how repex can be optimised across asset categories to achieve the same level of risk at a lesser cost than the bottom-up approach.

For a number of assets, the probability of failure and risk data were used to determine probability of failure and cost of consequence curves, which then form the basis for the risk curves. These curves were produced for 'do nothing' and proposed investment scenarios. The difference between the 'do nothing' and the investment risk represents the risk that is mitigated.

Figure 4.4 shows the results of this approach for the HV underground cable asset class, which was identified by the AER as an area requiring further justification (section 4.6.2 further details the AER's position). Figure 4.4 shows that 73 per cent of the risk associated with the 'do nothing' option at the start of the regulatory period has been mitigated by the investment proposed.

Figure 4.4 HV underground cable unit cost comparison



Source: Evoenergy analysis

4.6.2 Draft decision

In its draft decision, the AER did not accept Evoenergy's proposed repex of $91.8 million (excluding overheads). The draft decision substituted repex of $83.6 million excluding overheads in its estimate of total capex, representing a reduction to Evoenergy's repex proposal of 10 per cent attributable to proposed expenditure relating to HV underground cables.

Table 4.10 Evoenergy revised proposal 2019–24

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Evoenergy regulatory proposal	17.3	17.7	16.4	17.1	23.1	91.6
AER draft decision	15.8	16.0	15.2	15.8	20.7	83.6
Variance from draft decision						*(9.8)*

The AER's draft decision on repex was based on a desktop review comprising of trend analysis; a deterministic forecast using the AER's repex model given past submitted RIN information; an assessment of Evoenergy's repex planning criteria for each asset class; and stakeholder submissions.

In its trend analysis, the AER noted that total proposed repex was consistent with past trends. In particular, the AER noted the CCP10 was "generally satisfied with the repex forecast", and that, despite being Evoenergy's largest capex item, repex as a proportion of total capex was lower for Evoenergy than for other DNSPs. The AER's repex modelling also showed that for almost all modelled asset classes, Evoenergy's proposal is broadly consistent with the repex model prediction.

The AER's assessment of Evoenergy's bottom-up and top-down considerations also concluded that Evoenergy's repex planning processes were generally sound. In particular, the AER was satisfied with the scenario analysis used in the top-down approach and Evoenergy's assessment of the cost effective repex–augex trade-off that underpins the bottom-up forecasts for the Fyshwick Zone Substation decommissioning project.

However, the AER calculated that Evoenergy's proposal for HV underground cable replacement is 102 per cent higher than predicted by the repex model. The AER conducts a detailed assessment of Evoenergy's engineering and cost benefit analyses in the areas identified for further investigation in its repex modelling.

Accordingly, the AER requested that Evoenergy submit the risk based calculations behind the RIVA DSS system and also examined the input parameters, in particular for underground cables.[57] From examining the input parameters submitted by Evoenergy, the AER's assessment is that they appear conservative. As an example, the AER outlined Evoenergy's proposed value for employee safety risk. The AER compared this to other DNSPs and found that the value used by Evoenergy is much higher than the industry average.

57 Evoenergy, Response to Information Request 012, 11 April 2018.

As a result of both the repex modelling and its detailed economic assessment, the AER concluded that there was insufficient justification for the $8.3m of HV underground cable spend, and adjusted Evoenergy's proposed repex accordingly.

4.6.3 Revised proposal

In response to the AER's draft decision, Evoenergy undertook a detailed review of the HV cable replacement program, which included examining the AER's repex modelling and Evoenergy's risk assessment methodology. Evoenergy notes the AER's concerns with the outcomes of its repex modelling, that it has insufficient information on the risk assessment and cost benefit analysis, and that some assumptions appeared to be conservative.

Evoenergy considers that the matters raised by AER are addressed appropriately in this revised proposal. Further detail on Evoenergy's review process and its findings is provided in Appendix 4.12. In addition, Appendix 4.13 includes the risk valuation model and revised repex model.

With respect to repex modelling, Evoenergy identified two issues which should be addressed in its approach: These are that:

- The unit cost used in the AER's repex model is considerably lower than the industry average. Evoenergy acknowledges that the historical RIN data provided by Evoenergy to AER contributed to the use of the lower unit costs in the repex model;
- The 100-year calibrated asset life in the repex model appears unreasonable in light of industry practice. This appears to have arisen from the fact that the methodology assumes that there has been a history of replacement across a large population of assets that are distributed randomly with age.

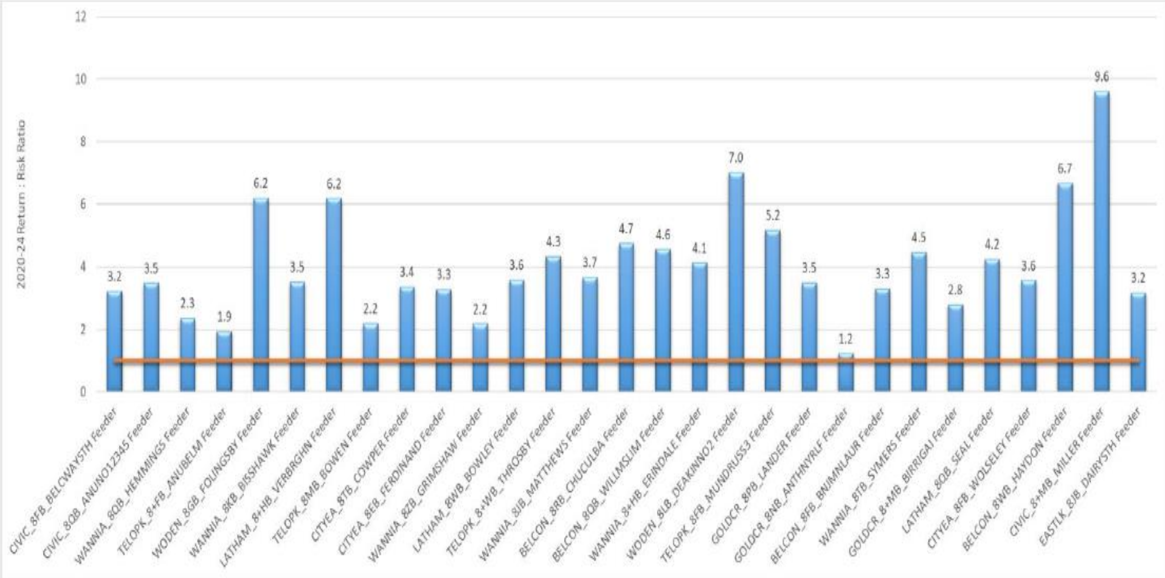
If these assumptions were corrected, the repex modelling would show that Evoenergy has adopted a very reasonable approach to forecasting HV underground cable expenditure.

With respect to Evoenergy's risk assessment and cost benefit analysis, Evoenergy's revised proposal addresses the AER's concerns by:

- Providing detailed supporting information on the cost benefit analysis. This sets out how key elements (such as the probability of failure, consequence of failure, and deterioration curves) are calculated. Evoenergy welcomes further engagement with the AER on this matter.
- Reviewing the input assumptions, which found that they are generally in line with the industry norms. In particular, it shows that the safety risk assumption with which AER had concerns with has a very minor impact on the calculation of HV cable risk. Detailed discussion of Evoenergy's input assumptions is presented in Appendix 4.12.

Figure 4.5 presents the overall outcome of Evoenergy's RIVA based cost benefit analysis of HV underground cables. It shows that for almost all the feeders the mitigated risk is higher than the investment, with an average cost benefit ratio of 3.4.

Figure 4.5 HV underground cable unit cost comparison



Source: Evoenergy analysis, Evoenergy reset RIN.

4.7 Non-network capex

4.7.1 Overview

Non-network capex relates to ICT, facilities, non-system assets, finance lease arrangements and corporate services business support. Investments in ICT assets typically comprise the largest proportion of Evoenergy's non-network costs.

Non-network capex is forecast to be $58.3 million, excluding overheads, for the 2019–24 regulatory period. This reflects a transition from a period of technological investment growth and innovation, to one of agile innovation and realisation of benefits to support the continual and rapid changes expected to occur in the electricity distribution industry.

The ICT forecast has been developed utilising a risk-based approach to ensure the activities are prudent to operations. The forecast reflects a number of regulatory and industry changes, such as the transition to five-minute data settlements in the National Electricity Market, software refreshes to maintain acceptable cybersecurity, and to address voltage and power flow issues from DER uptake.

Evoenergy proposed only minor expenditure to broaden the functionality of existing ICT assets.

4.7.2 Draft decision

In its draft decision, the AER did not accept Evoenergy's proposed non-network capex of $58.3 million. It instead included non-network capex of $46 million in its alternative estimate of total non-network capex, representing a reduction to Evoenergy's proposal of 21 per cent.

The reduction arises from:

- Disallowing the $12 million proposed for an upgrade of Evoenergy's Advanced Distribution Management System (ADMS) and substituting in its place the $6.6m required to implement the 'do nothing' option in the business case.
- Disallowing all Corporate ICT extension projects, which include
  - Business Intelligence
  - ICT Platforms such as mobility and custom resource management
- Excluding the allowance for contingencies identified for all ICT projects.
- A small downward adjustment for proposed fleet expenditure.

Table 4.11 AER draft decision 2019–24

$ million (2018/19)	Total
Evoenergy Original Proposal	58.3
Remove:	
ADMS	(5.0)
Contingency costs	(5.1)
Corporate ICT projects	(2)
Fleet	(0.3)
AER draft decision	**46.0**
Variance from draft decision	*(12.4)*

Note: Differences may not add due to rounding.

The AER's draft decision on non-network capex was based on a number of assessments of particular elements of proposed non-network expenditure. These include:

- category analysis, in particular for fleet expenditure;
- an assessment of what and how consumer benefits were identified in Evoenergy's regulatory proposal and further information provided by Evoenergy;
- assessment of business cases and other supporting information submitted by Evoenergy; and
- stakeholder submissions.

The AER's findings in support of its reduction to Evoenergy's proposal are that it has found no rigorous evidence of clear consumer benefits with respect to the disallowed projects, and that the benefits identified in the business cases have not been accounted for in the overall proposal. In the process of reviewing Evoenergy's submission, the AER has sought information from Evoenergy to understand how it had incorporated consumer benefits into its proposal, and how Evoenergy has consulted its consumers on such benefits. In its draft decision the AER disallowed all projects where consumer benefits were not quantified.

The AER appears to require all consumer benefits to be quantified in a cost benefit analysis, regardless of their nature. Except for the Distribution Monitoring and Chamber Substation SCADA projects, Evoenergy did not submit cost benefit analyses as part of business cases. However, even for these projects, the AER disallowed the expenditure on the basis that it considers the benefits identified to be operational efficiencies. As a result, the AER has rejected a substantial portion of proposed ICT replacement expenditure, and all proposed ICT extension expenditure.

The AER has excluded contingencies included in ICT projects on the basis that Evoenergy has sufficient experience in delivering such projects and tendering information to negate the need for contingencies, and that CCP10 considered the amounts excessive.

4.7.3 Evoenergy response

Evoenergy notes the concerns of the AER with respect to historical and proposed level of ICT costs. It is on this basis that the AER considered it necessary to review in detail the relevant business cases and other supporting information. In particular, the AER noted that:[58]

> *we have concerns with Evoenergy's historical expenditure for this category, given that over the past five years Evoenergy has spent the highest total IT expenditure (capex and opex) per customer of all distributors in the NEM.*

However, it is important to note that, on a customer basis, Evoenergy has one of the smallest energy networks in the NEM. ICT implementation costs generally do not scale with customer numbers, and that there are few economies of scale with implementing systems like Schneider ADMS.

The following sections outline Evoenergy's response within each substantive expenditure area in which the AER has identified significant issues in its review.

4.7.3.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The ADMS is a software platform that allows Evoenergy's network to be managed centrally by drawing on the capabilities provided by smart metering, distributed network sensors, and DER. The ADMS provides for automated outage identification, restoration, and performance optimisation of the network to drive efficiencies that benefit customers through a reliable supply of electricity.

Evoenergy proposed upgrading the system and associated hardware to resolve a number of challenges with the existing system, and because the new system will provide more functionality than before. From the consumer perspective, this allows Evoenergy to:

- Implement the least cost option to maintain the ADMS – the proposed solution is more cost effective than doing nothing or deferring the project to the next regulatory period.
- Avoid considerable risks and cost from trying to operate an outdated legacy system into the future. Such costs range from risks such as increased server failure rates, to catastrophic cybersecurity events.
- Transition its augmentation planning to a more accurate probabilistic system that optimises augmentation requirements and aligns with AER preferred approach. The ADMS upgrade provides Evoenergy with modelling tools to facilitate real time operation and control of the network when required. This can then provide the real time data that is necessary to develop more accurate probabilistic planning models. Without this data, it would be difficult to ensure that probabilistic planning will lead to good long term outcomes for consumers.

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[58] AER 2018, *Draft Decision Evoenergy Determination:* Attachment 5, p. 5-40, 5-63.

- Support consumer uptake of DER, with its associated benefits of independence, avoided reliability deterioration, and environmental goals. To this end, it is essential that Evoenergy has visibility of DER that is connected to Evoenergy's electricity supply network along with scenario analysis of likely future DER connections.

Evoenergy's ADMS solution incorporates SCADA, the Outage Management System, the Work Order Management System for management of planned and unplanned outages, the User Interface for Control Room and Web-based users, Field Mobility and a broad set of Distribution Management System (DMS) applications. While the Evoenergy Control Room is the main user of the ADMS for network operations, the ADMS is also used throughout Evoenergy for day to day tasks (e.g. planning for network augmentation, design, SCADA, primary assets, commissioning, and works delivery).

To be effective, ADMS should maintain a secure and effective interface between the key components in an evolving software and hardware technology environment. In addressing this, the key challenges facing Evoenergy's existing systems include:

- operating system platforms reaching end of extended operational life, introducing cyber security risks;
- current hardware platforms reaching end of extended operational life, with the potential of a total ADMS outage;
- limited capabilities (including power flow modelling) for DER capacity and minimising DER driven network augmentation;
- lack of real time data for probabilistic planning; and
- that the system is four versions or 5 years behind the current solution.

The current version of the ADMS uses hardware that is now obsolete and difficult to maintain, as well as operating systems that are approaching the end of extended support during the 2019–24 regulatory control period. The ADMS software is also ageing and support and maintenance contract costs for the currently installed version will increase over time as the specialist skills required to maintain these systems become scarcer.

In its draft decision, the AER disallowed expenditure for the proposed ADMS upgrade as the options analysis did not provide evidence on the risks associated with the deferral option. In particular, Evoenergy's initial business case only provides a 'do nothing' and an upgrade option. Evoenergy submits a revised business case (Appendix 4.18) which sets out the risks associated with the deferral option. The deferral option involves operating the existing ADMS until the end of 2026/27, with the upgraded ADMS taking over from 2027/28. This is due to the three-year lead time to implement a new ADMS.

In the draft decision, the AER quoted Evoenergy's response to an information request that vendor support can be obtained under the deferral option:[59]

> *Therefore, even though extended support can be obtained, albeit with a higher level of risk, the organisation will be limited in its response to the move to demand management and leveraging distributed energy resources.*

Evoenergy wishes to clarify that full vendor support cannot be obtained throughout the 2019–24 regulatory period. Maintenance and support for the Windows operating system will not be provided by Microsoft after January 2023 and it will become extremely difficult to maintain the level of security expected for a sensitive system such as the ADMS without this support. Evoenergy's statement relates to the fact that partial vendor support

[59] Evoenergy, Response to information request 004 - part 2, 05 March 2018, p.5.

for the ADMS itself can be obtained through Schneider electric, but this is expected to lead to large and uncertain cost increases due to scarcity of expertise.

Evoenergy's revised business case conducts a lifecycle costing of the deferral option and compares this with the preferred options. This includes quantifying both the direct costs and indirect risks to consumers of the different options and comparing these to the corresponding benefits. These costs are then discounted to the present to arrive at a net present cost (NPC) for each option.

Figure 4.6 shows both the costs, benefits, and the net movements between the different options considered. Note that the preferred option (option 3) implies significant benefits relative to the deferred option. The difference between the lifecycle costs relative to the deferral option includes the level of quantified risk that has been avoided by pursuing the preferred option.

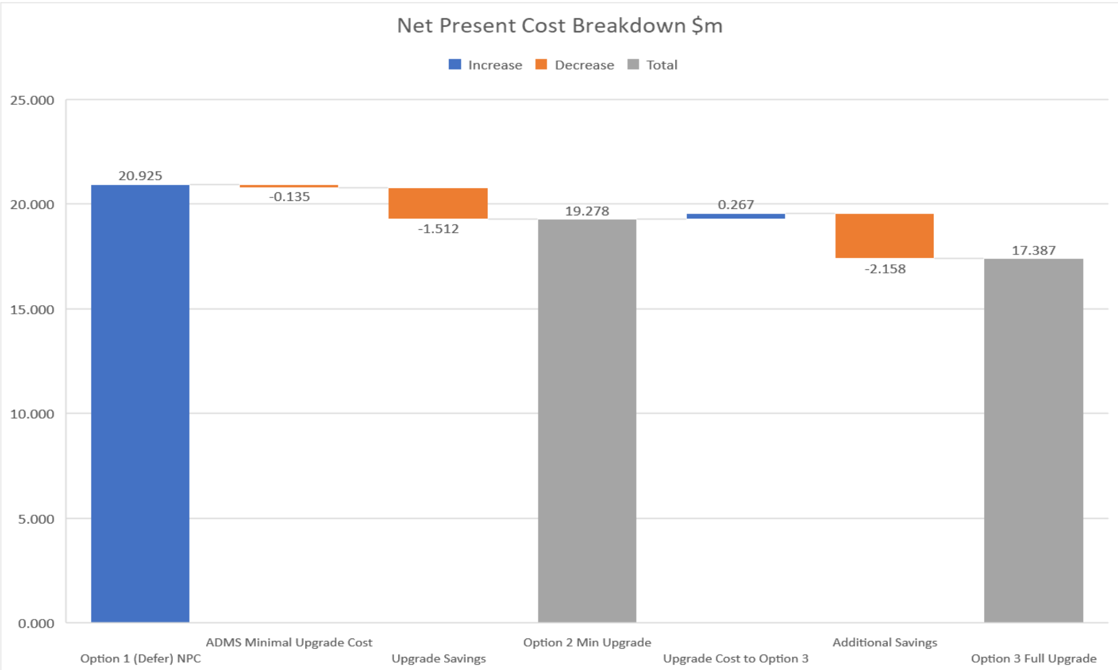
Table 4.12 below outlines the NPC of each option and shows that option 3 has the lowest NPC of all the other options.

Table 4.12 Evoenergy ADMS options analysis results

Option	Net Present Cost	Net Present Cost Reduction	2019–24 Capital Expenditure
Option 1: Defer upgrade	20.92	-	6.62
Option 2: Minimal upgrade	19.28	1.65	11.30
Option 3: Full upgrade	17.39	3.54	11.21

Source: Evoenergy Revised Regulatory Proposal, Appendix 4.18.

Figure 4.6 Comparison of ADMS options based on NPC analysis



Source: Evoenergy Revised Regulatory Proposal, Appendix 4.18.

It is important to note that the options analysis conducted by Evoenergy does not quantify the full range of risks inherent in the deferral option. It represents only cost increases that are predictable at the time of this submission. There are a number of risks that are potentially extremely high but that are unable to be captured due to their intangible nature and/or a lack of forward looking quantifiable information available. They include:

- obsolete, 14-year old hardware;
- software and operating systems used for up to 6 years beyond extended support, and;
- cybersecurity implications.

More details about the cost drivers, the options analysis, and the risks addressed by the expenditure are in the ADMS Business case attached to this proposal (Appendix 4.18).

The AER's reasoning on deferring the ADMS upgrade also appears to underestimate the impact that DER will have in the ACT region. In particular, the AER notes:[60]

> *Evoenergy (and ActewAGL before it) has been connecting solar PV installations for up to 15 years and more recently a number of storage devices have also been connected to the Evoenergy network. It therefore appears that Evoenergy is currently managing the impact of existing DER using its current system. We also note that the current levels of PV penetration in the ACT are quite modest and almost half of the penetration rates of Queensland and SA. These distributors have not implemented advanced DSO functionality to manage these high levels of DER penetration.*

While the ACT has had a relatively modest PV penetration rate in recent years compared to other jurisdictions, this is expected to change rapidly and in a way that is especially difficult to manage. The results of the Energy Consumer Sentiment Survey[61] show that, compared to other jurisdictions, the ACT has by a large margin the highest proportion of consumers who are considering installing PV and battery storage systems in the near future. This strongly indicates that future growth in DER uptake for the ACT region will accelerate in the near future.

Notwithstanding this, the main matter for Evoenergy to address is the *nature* of the DER uptake where several current developments mandate a 100 per cent DER penetration rate.[62] This trend is expected to include all new sub-divisions within the ACT in the near future. These estates vary in size from 1,000 dwellings (Jacka 2) to the two largest, Denman Prospect (21,000 dwellings) and Ginninderry (10,500 dwellings). These are significant estate developments that will be connected to the Evoenergy network and will require a radically different approach than adopted historically. It is also expected that the developers of these estates will mandate residential battery storage in the immediate future.

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[60] AER 2018, *Draft Decision Evoenergy Determination:* Attachment 5, p. 5-40, 5-70.

[61] Energy Consumers Australia 2017, *Energy Consumer Sentiment Survey*, December, p. 9. http://energyconsumersaustralia.com.au/wp-content/uploads/Energy-Consumer-Sentiment-Survey-December-2017.pdf.

[62] For example, Ginninderry and Denman Prospect developments: https://denmanprospect.com.au/building-guide/; https://ginninderry.com/environment-and-people/sustainability/#governance

This emergence of major pockets of 100 per cent DER penetration represents a major technical challenge for Evoenergy in constructing and operating the network. As an example, the Ginninderry development will be the equivalent of a 40 MW solar farm embedded directly in one suburb of the Evoenergy distribution network, and Denman Prospect will be a 60 to 80 MW solar farm equivalent. This is substantially above the 30 per cent penetration level commonly experienced at which technical problems usually become evident. Technical studies indicate that limitations should be imposed on PV connections when they exceed 26 per cent of normal network topology.[63]

Moreover, although it is true that DNSPs in South Australia and Queensland have not yet made formal proposals to the AER that reflect a move to a Distribution Service Operator (DSO) functionality, their most recent regulatory proposals would reflect circumstances that are several years old.[64] Given this, any assumption that they are not presently considering moving to a DSO functionality in the current rapidly changing electricity market is premature.

In recent years, extensive analysis of major industry developments in both the technical and policy space has occurred. Key examples include the development of the CSIRO/ENA ENTR as described in Evoenergy's initial proposal, and recent work from the AEMO responding to DSO drivers; both of which suggest an understanding reached across the industry of the immediacy of moving to DSO functionality.[65] Evoenergy understands that many DNSPs around the country, including in SA and Queensland, have moved or are considering moving to a DSO functionality, and this will likely be reflected in future regulatory proposals to the AER.

To further support its position, the AER referred to the broader industry trend (as per the findings of the AEMO National Electricity Forecast Report) that future DER uptake will be moderate, and infers that DER penetration in the ACT will remain significantly below that of Queensland and SA:[66]

> *Given that the AEMO National Electricity Forecast Report is forecasting the take-up rate of solar PV to slow and for only a very moderate uptake of DER storage, it would appear that over the forthcoming regulatory period PV penetration will remain below that already managed by the respective distributors in Qld and SA.*

Evoenergy cannot see how the AER has arrived at its position from the findings of the AEMO report. In particular, the latest Electricity Forecasting Insight published by the AEMO indicates that PV and battery storage rates will almost double (from around 6000 MW installed capacity presently to about 11000 MW by the 2024 calendar year, the end of the Evoenergy's upcoming regulatory period).[67]

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63 Integrating PV systems into distribution networks with Battery Energy Storage Systems, Tara M. Jackson, University of Queensland, September 2014.

64 Ergon Energy's and SA Power Networks' initial and revised regulatory proposals were submitted to the AER in December 2013 and July 2015, respectively.

65 AEMO and Energy Networks Australia 2018, *Open Energy Networks, consultation paper*. https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2018/OEN-Final.pdf

66 AER 2018, *Draft Decision Evoenergy Determination*: Attachment 5, p. 5-40, 5-70.

67 AEMO 2017, *Electricity Forecasting Insights, Key component consumption forecasts, rooftop PV and battery storage*. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-

Given the rapid changes specific to the ACT and that the AEMO report did not include a separate ACT forecast, Evoenergy considers that broad NEM trends are of limited value in identifying ACT-specific outcomes, particularly as the sentiment and behaviour of ACT consumers are significantly different from the average NSW consumer.[68]

4.7.3.2 BUSINESS INTELLIGENCE

Business intelligence (BI) is a business capability that can transform raw data into meaningful and useful information to help identify and develop new opportunities for further optimising business efficiency and other value creation. When coupled with artificial intelligence, predictive analytics and machine learning, BI will generate insights into customer behaviour at a granular level; make predictions and recommendations around assets; and drive improvements in performance through the automation of processes.

The AER disallowed $1 million allocated to this project on the basis that Evoenergy was not able to quantify the consumer benefits involved. Evoenergy notes that the vast majority of the benefits included are inherently intangible. Such benefits identified by Evoenergy and submitted to the AER included the following:

- the ability to analyse demand response patterns to ensure desired outcomes and benefits are optimally achieved (e.g. peak shift versus peak reduction);
- increased customer satisfaction across channels through predictive network service complaints management and proactive responses;
- the ability to maintain and improve reporting and decision support tools that will support sustainable and cost effective network management; and
- greater visibility of business challenges and effective actions to respond to those challenges.

Quantifying these benefits is an inherently difficult process. Nevertheless, it is clear that these benefits are supported by consumers, given that a major learning from Evoenergy's consumer engagement was that it should foster a smarter nimbler network that is able to effectively utilise large increases in digital information. Given this, Evoenergy seeks advice from the AER on the quantification of consumer benefits on this and similar projects, where the benefits are well understood and supported, but difficult to quantify.

In addition, some of the benefits relate to maintaining existing obligations. The proposed BI includes consolidating existing reporting obligations, despite the project's primary status as ICT extension expenditure. These obligations relate to financial and statutory, human resources, and health and safety reporting. In its revised proposal, Evoenergy has revised the business case to include a 'do nothing' option which accounts for this compliance driven expenditure which is necessary in the absence of BI.

Evoenergy's Business Intelligence business case is Appendix 4.19 to the revised proposal.

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forecasting/Electricity-Forecasting-Insights/2017-Electricity-Forecasting-Insights/Key-component-consumption-forecasts/PV-and-storage

[68] Refer to section 3 of Appendix 4.12. Also refer to Energy Consumers Australia 2017, *Energy Consumer Sentiment Survey*, December, p. 9. http://energyconsumersaustralia.com.au/wp-content/uploads/Energy-Consumer-Sentiment-Survey-December-2017.pdf.

4.7.3.3 ICT PLATFORMS

Evoenergy is proposing capex on a number of ICT platform initiatives to improve cybersecurity and workforce capabilities using mobile infrastructure. The draft decision disallowed $1 million allocated to ICT Platforms due to issues with quantification of consumer benefits. As with BI, the vast majority of the benefits included are inherently intangible.

The project is driven by an assessment of Evoenergy's ICT Security conducted by Energy Networks Australia against the Electricity Subsector Cybersecurity Capability Maturity Model and, more recently, by AEMO against the Australian Energy Sector Cyber Security Frameworks (AESCSF). It reflects a revised ICT Security Strategy which seeks to mature security controls to be in line with the industry average'. It also addresses the recent Finkel Review, which recommends that cyber security maturity against the newly introduced AESCSF be reported annually.[69]

Platforms and capabilities included within this program are as follows:

- Security analytics;
- Security incident and event management expansion;
- Extended intrusion detection/prevention capabilities;
- Network monitoring sensors;
- Memory acquisition/analysis and hard drive forensics capability;
- Cyber threat intelligence platform;
- Additional capacity to support enterprise log management; and
- Identity management solution.

Evoenergy's assets classification as Critical Infrastructure justifies the need for a robust ICT security capability (see section 4.7.3.6 for further context). In addition, changes to the *Electricity Supply Act* require Evoenergy to maintain a level of ICT security at a higher standard than in previous regulatory periods. As such prudent investments are required to ensure these standards are met.

Key drivers and benefits include:

- ICT security capability will be maintained in line with industry peers to ensure Evoenergy is able to maintain the security of critical network infrastructure;
- Increased capability to detect and respond to cyber security incidents in a timely manner, minimising the likelihood and consequence of incidents;
- The necessary threat intelligence to enable ICT Security Capability to understand and respond to emerging threats to the industry;
- Reduced liability: insurance providers and legal departments are increasingly wary of cybersecurity risks. Proactive, comprehensive cybersecurity can help mitigate their concerns and avoid increases in associated costs or losses,
- Improved security integration and management reducing the risk of security solution gaps.

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[69] Commonwealth of Australia 2017, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, p. 69.

Evoenergy's ICT Platforms business case is Appendix 4.20 of the revised proposal.

4.7.3.4 MOTOR VEHICLE FLEET

Evoenergy's proposal of $12.9 million for motor vehicles for the 2019–24 regulatory period is 10 per cent higher than total actual/estimated motor vehicle capex of the current period. The AER considers that the information Evoenergy has presented to date suggests that the proposed motor vehicle capex does not reflect prudent and efficient costs. The draft decision pointed out that Evoenergy's forecast assumed a target replacement age of 8 years for elevated work platforms and heavy commercial vehicles is lower than the replacement ages adopted by NSW distributors, which for similar fleet components is 10 years.

Evoenergy accepts the AER's view that a target replacement age of 8 years should be used for elevated work platforms and heavy commercial vehicles, and revises its proposal to $11.9 million for motor vehicle capex. This estimate is based on the same modelling as submitted by Evoenergy.

4.7.3.5 PROJECT CONTINGENCIES

Evoenergy has included $5.7 million in contingency costs within the cost forecasts for ICT replacement projects. These contingency amounts were not explicitly detailed in Evoenergy's submission and were outlined in subsequent correspondence with the AER in April 2018. [70] Table 4.13 outlines the contingency costs included in Evoenergy's proposed ICT expenditure.

Table 4.13 Components of Evoenergy's proposed base year direct opex

Program	Total Capex Cost	Contingency Cost
Works and Asset Management	$4,981,654	$530,000
Meter Data and Billing	$15,697,762	$4,475,371
GIS, ArcFM and Designer	$1,252,917	$76,250
Riva DS	$389,146	$25,000
Outsystems	$518,860	$80,000
ADMS	$11,794,712	$560,000
Business Intelligence	$978,253	$127,598
IT Platforms	$987,564	$128,813
Hardware & Software Refresh	$2,134,779	-
Total	**$38,735,647**	**$6,003,032**

In its draft decision, the AER did not accept Evoenergy's proposed non-system capex and recommended that no contingency costs be included.

Evoenergy accepts the AER's decision in principle. Evoenergy has reviewed the costings and found that some costs were included in error as contingencies. In particular, $4.5 million allocated to the largest contingency component, the meter data and billing project, does not represent 35 per cent of the total direct costs as specified by the

[70] Evoenergy, Response to Information Request 011, 17 April 2018.

business case. Evoenergy considers that an adjusted contingency of $3.5m properly represents 35 per cent of the direct costs of the project.

In addition, for a number of other smaller projects with minor contingencies allocated, it was found that these were actually not included in the proposed expenditure in the business cases. Table 4.14 outlines the adjustments Evoenergy has made and accordingly deducts from its costs in the revised proposal.

Table 4.14 Components of Evoenergy's proposed base year direct opex

Program	Proposed contingency	Revised contingency
Works and Asset Management	$530,000	-
Meter Data and Billing	$4,475,371	$3,475,371
GIS, ArcFM and Designer	$76,250	-
Riva DS	$25,000	-
Outsystems	$80,000	-
ADMS	$560,000	$530,000
Business Intelligence	$127,598	-
IT Platforms	$128,813	-
Hardware & Software Refresh	-	-
Total	**$6,003,032**	**$4,005,371**

4.7.3.6 PHYSICAL SECURITY MEASURES

Evoenergy's network serves a number of high profile consumers in the ACT, including:

- the Australian Parliament House;
- the Australian Federal Police national headquarters;
- federal security agencies; and
- Tidbinbilla Deep Space Tracking Station.

Maintaining and protecting the network from specific security related events is a core function of Evoenergy. Evoenergy's Fyshwick Control Room, zone substations and 132kV switching stations have been deemed as Critical Infrastructure, defined by the Australian Government Critical Infrastructure Centre in the following terms:[71]

> *Critical infrastructure underpins the functioning of Australia's society and economy and is integral to the prosperity of the nation. It enables the provision of essential services such as food, water, health, energy, communications, transportation and banking. Secure and resilient infrastructure supports productivity and helps to drive the business activity that underpins economic growth. The availability of reliable critical*

[71] Critical Infrastructure Centre 2018, *Safeguarding Critical Infrastructure,* https://cicentre.gov.au/infrastructure, accessed 19 November.

infrastructure promotes market confidence and economic stability, and increases the attractiveness of Australia as a place to invest.

The Protective Security Policy Framework (PSPF) as detailed by the Australian Government Attorney-General's Department recommends that entities protect their resources by using a combination of physical and procedural security measures. In particular the PSPF requires that security measures be implemented that minimise or remove the risk of:[72]

- harm to people; and
- information and physical asset resources being made inoperable or inaccessible, or being accessed, used or removed without appropriate authorisation.

In the context of critical infrastructure, these risks have potentially serious consequences not only to ACT consumers, but to the nation as a whole.

In addition, the National Critical Infrastructure Guidelines advise that:

- all Critical Infrastructure sites require risk assessment;[73]
- a risk-based approach should be applied when considering security treatments in the protection of assets;[74] and
- defence in depth principles need to be applied when considering security management of any site.[75]

A revision of Evoenergy's Security Management Plan (Appendix 4.23) was recently completed, and an internal risk assessment was undertaken in accordance with the Guidelines and relevant standards. The risk assessment recommended that Evoenergy undertake further appropriate physical security measures to safeguard and improve the overall resilience of certain electrical network sites.

Based on the recommendations, Evoenergy proposed physical security expenditure of $2 million over the 2019–24 regulatory period. This comprises of a number of measures, which include the following:

- Network Upgrades and Control Room G-Sim upgrade;
- Signage upgrade;
- CCTV Earthing;
- Electronic access control where none is currently deployed;
- Intruder alarms where none is currently deployed;
- CCTV where none is currently deployed;
- Lighting upgrades;

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[72] Australian Government Attorney-General's Department 2018, *Protective Security Policy Framework, 15 Physical security for entity resources*, https://www.protectivesecurity.gov.au/physical/physical-security-entity-resources/Pages/default.aspx, accessed 19 November.

[73] Australian Government Attorney General's Department, *National Guidelines for Protecting Critical Infrastructure,* https://www.nationalsecurity.gov.au/Media-and-publications/Publications/Documents/national-guidelines-protection-critical-infrastructure-from-terrorism.pdf, Accessed 19 November 2018.

[74] Standards Australia 2006, *HB167:2006 Security risk management*, Standards Australia International Ltd.

[75] Ibid.

- Electronic access control upgrade to replace legacy systems;
- Intruder alarm upgrade to replace legacy systems;
- Mechanical keying upgrades.

Expenditure to meet the list of measures above with align Evoenergy's security management with industry practice as well as the relevant standards. By extension, it will be compliant with the PSPF, as well as a number of national security concepts and standards. These include Defence in Depth (deter, detect, delay, respond, recover) and Crime Prevention through Environmental Design (CPTED). More detail about Evoenergy's proposed expenditure in relation to its updated Security Management Plan is detailed in Appendices 4.11 and 4.22.

4.7.4 Revised proposal

Table 4.15 sets out Evoenergy's revised forecast non-network capex for each year of the 2019–24 regulatory period, compares this with Evoenergy's initial proposal and the AER's draft decision. Key elements of this in relation to the AER's draft decision are:

- Retention of proposed expenditure on the ADMS Upgrade, but with a considerably revised business case to address concerns raised by the AER and consumers (section 4.7.3.1).
- Retention of proposed expenditure on corporate ICT assets extensions, again with revised businesses cases to address concerns raised in the draft decision. See sections 4.7.3.2 and 4.7.3.3 above.
- Acceptance of the AER's reduction to contingency, with some adjustments (section 4.7.3.5).
- Acceptance of the AER's allowed fleet expenditure to reflect benchmark target replacement age for elevated work platforms (section 4.7.3.4)

Table 4.15 Evoenergy revised proposal 2019–24 for non-network capex

$ million (2018/19)	Total
Evoenergy regulatory proposal	58.3
Add:	
Physical security measures	2.0
Remove:	
Contingency costs and cost escalation	(4.3)
Evoenergy revised proposal	56.0
AER draft decision	46.0
Variance from draft decision	(12.4)

Note: Differences may not add due to rounding.

4.8 Capitalised overheads

Capitalised overheads are costs associated with capital works that have been appropriately capitalised in accordance with Evoenergy's capitalisation policy and Cost Allocation Methodology (CAM). They are generally costs shared across different assets and cost centres. The amount of capitalised overheads incurred is a function of:

- the amount of corporate costs to be allocated;

- the amount of capital costs to be allocated; and
- the relative proportion of totex that is capex.

It is important for Evoenergy to be provided the opportunity to recover the overhead costs necessary for delivering its capital program as well as operating and maintaining its network in the provision of regulated distribution services.

4.8.1 Regulatory proposal

Evoenergy proposed $75.6 million in capitalised overheads expenditure for the 2019–24 regulatory period. This represents a significant increase from $58 million and $68 million for allowed and actual expenditure for 2014–19 respectively. This increase is largely due to significant decreases in opex made in response to the 2015 final determination which result in more overhead expenditure being allocated to capex. A further contributor is significant increases in required corporate ICT investments, in particular, ICT security obligations (cybersecurity).

Evoenergy uses a simple methodology that allocates its overheads uniformly, as a fixed percentage, across its proposed total expenditure (totex). This is represented by the formula in Figure 4.7, which calculates Evoenergy's expected corporate overhead costs, referred to as the Fixed Price Service Charge (FPSC), as a percentage of totex. Note that the opex and capex on which overheads are to be applied exclude indirect costs.

Figure 4.7 Capitalised overheads allocation formula

$$Capitalised\ Overhead\ \% = \frac{Fixed\ Price\ Service\ Charge_{Base\ Year} \times 5}{Direct\ Totex_{Reg\ Period}}$$

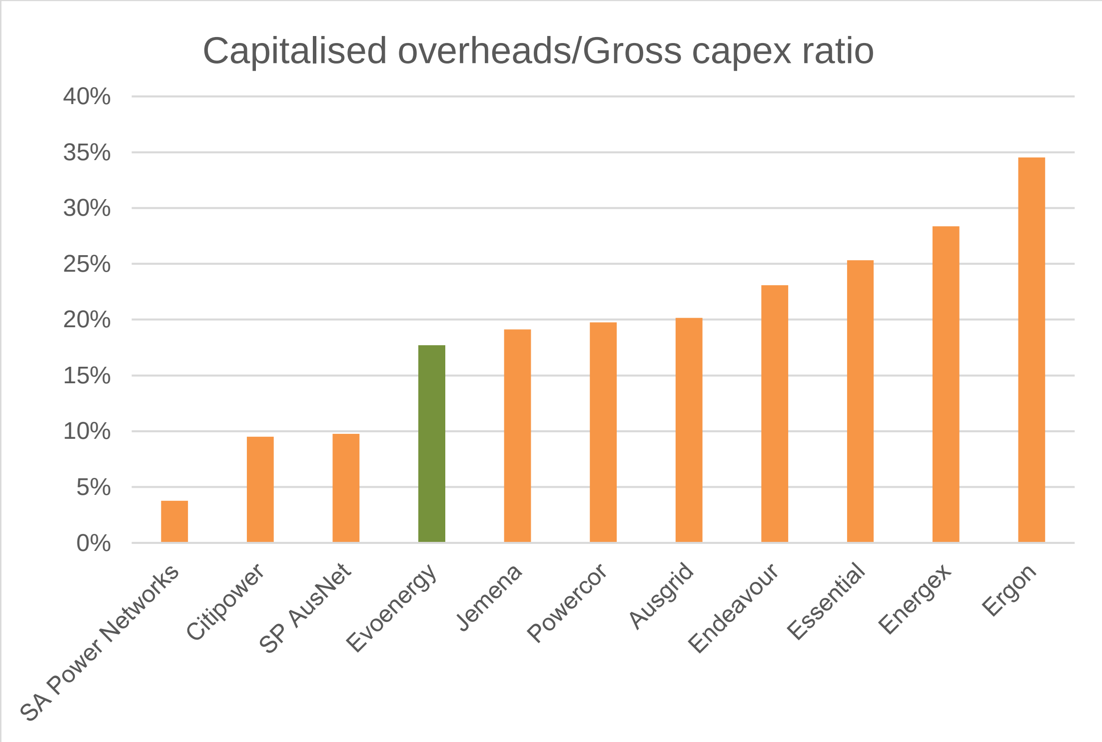
$Where$:

$$Direct\ Totex_{Reg\ Period} = Total\ Forecast\ Capex_{Reg\ Period} + Direct\ Opex_{Base\ Year} \times 5$$

To forecast the total FPSC for the 2019–24 regulatory period, Evoenergy used a base year approach (as with opex). The 2017/18 base year was selected as it best represented Evoenergy's overhead costs going forward, given the rapid pace of industry change. This is then multiplied by five (years in the regulatory period) to arrive at the best estimate of the expected FPSC for the 2019–24 regulatory period.

Figure 4.8 shows that Evoenergy's proposed capitalised overheads percentage as a proportion of gross capex is at the lower end of historical allowed expenditure for most electricity DNSPs for the past five years.

Figure 4.8 Capitalised overheads as a percentage of gross capex allowance



Source: Evoenergy calculations, capex models in AER final decisions distribution determination.

4.8.2 Draft decision

The AER's draft decision did not accept Evoenergy's proposed forecasts of $75.6 million for capitalised overheads and instead included an amount of $58.0 million. Most of this reduction was due to the reduction of direct capex in the AER's decision, with a minor downward adjustment to the overhead rate having a secondary impact.

The AER accepted the general approach of Evoenergy's methodology for forecasting capitalised overheads but has disagreed with Evoenergy's base year approach to forecasting the FPSC. The AER considers that using the FPSC in the single 2017/18 year to forecast total overheads for the 2019–24 regulatory period would overestimate costs. The CCP10 has also expressed concerns about the recent trends in the growth of actual capitalised overheads during the current regulatory control period.

In its draft decision, the AER deviated from Evoenergy's base year regulatory proposal methodology to use a four year average estimate of the FPSC in the current regulatory period (from 2014-15 to 2017-18) for its FPSC forecasts. In addition, the AER's calculations substituted a significantly higher direct opex estimate that included some indirect costs. This resulted in significantly higher total estimated totex, which further reduced the AER's estimated overheads rate.

As a result of these adjustments, the AER arrived at a slightly lower capitalisation rate of 26 per cent to derive its capitalised overheads. This, combined with a significant decrease in the AER's allowed capex in its draft decision, resulted in a significant decrease in allowed capitalised overheads (see Table 4.16).

Table 4.16 AER draft decision - Capitalised overheads

	Evoenergy regulatory proposal	AER draft decision
FPSC	$27.8m	25.7m
Total Direct Totex	$503m	$503m
Capitalised Overheads %	28%	26%
Total capitalised overheads	**$75.6m**	**$58.0m**

Note: Total Direct totex is calculated as per Figure 4.7.

4.8.3 Evoenergy's response

Evoenergy agrees in principle with the AER's draft decision which retained Evoenergy's overall methodology for allocating overheads, and the AER's approach of using the four-year average to forecast the FPSC. However, Evoenergy considers the use of a higher opex estimate that includes indirect costs is not an appropriate approach, nor does it correctly reflect Evoenergy's CAM.

In particular, the AER assumed an opex estimate of $52 million (including indirect costs), while Evoenergy's proposed opex assumption was $42 million. Under Evoenergy's CAM, the opex assumption applied in the overheads methodology should include only direct costs (i.e. exclude indirect costs such as business overheads). The result of not following this practice would essentially be to apply overheads on overheads. Evoenergy acknowledges that the AER's variation from the CAM approach is due to an erroneous response provided to the AER in correspondence subsequent to the proposal.[76]

Table 4.17 shows the correct direct cost components of Evoenergy's $43 million proposed base year opex (as sourced from the RIN data) that were included for the purposes of calculating overheads in Evoenergy's initial proposal.

[76] Evoenergy, Correspondence with AER, 23 October 2018.

Table 4.17 Components of Evoenergy's proposed base year direct opex

Cost Component	2017/18 Forecast ($ million)	Source in Annual RIN
Add:		
Vegetation management	2.3	Tables 2.1.2 & 2.1.6
Maintenance	8.8	Tables 2.1.2 & 2.1.6
Emergency response	2.1	Tables 2.1.2 & 2.1.6
Non-network	5.9	Tables 2.1.2 & 2.1.6
Network Overheads	21.9	Tables 2.1.2 & 2.1.6
Metering	3.0	Table 2.1.4
Fee & Quoted Services	3.2	Table 2.1.4
Less:		
Network Overheads (not included in Program of work)	(4.4)	Table 2.10.1
Total Direct Opex Cost	**42.8**	

4.8.4 Revised proposal

Evoenergy does not propose to change its general approach to capitalised overheads in the revised proposal. There are, however, substantial changes compared to its initial proposal as follows:

- An increase in the base year opex compared to the regulatory proposal means that a smaller proportion of the FPSC is allocated to capex. This increase is explained in chapter 0;
- Acceptance of the AER's decision to use the four-year average to forecast the FPSC. Evoenergy assumes an FPSC that is lower than that determined by the AER, as the AER has included alternative control services in its estimate of FPSC.
- A reduction in direct capex ($316.5 million vs $329.1 million) compared to the regulatory proposal.

Table 4.18 shows Evoenergy's forecast capitalised overheads included in its revised proposal and compares it to the AER's draft decision and Evoenergy's initial Proposal.

Table 4.18 Evoenergy revised proposal - capitalised overheads

	2019–24 regulatory proposal	2019–24 draft decision	2019–24 revised proposal
FPSC	$27.8m	$25.7m	$25.1m
Total direct totex*	$503m	$503m#	$539m†
Capitalised overheads	28%	26%	23%
Total capitalised overheads	**$75.6m**	**$58.0m**	**$66.4m**

Notes: * Total direct totex is calculated as per Figure 4.7. # The AER included some indirect opex costs that Evoenergy considers should be excluded. † The revised proposal gross capex is higher than that in the January 2018 regulatory proposal primarily because the revised proposal includes an additional capital contribution for a major Commonwealth Government project.

5 Rate of return

5.1 Rules requirements

The AER is required to make a decision on the allowed rate of return for each regulatory year of the regulatory control period in accordance with clause 6.5.2.[77] Separately, the AER must make a decision on whether the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) and, if that is the case, the formula that is to be applied in accordance with clause 6.5.2(l).[78] The AER must also make a decision on the value of imputation credits as referred to in clause 6.5.3.[79]

5.2 Regulatory proposal

Consistent with the transitional provisions set out in the Rules, Evoenergy adopted the AER's 2013 rate of return guideline (2013 Guideline) to estimate the rate of return and the value of imputation credits, updating estimates where appropriate and taking into account the most recently available evidence. This approach resulted in a rate of return estimate of 6.42 per cent (nominal vanilla) and a value for gamma of 0.4. In Evoenergy's view, this approach is consistent with the appeal decisions of the Australian Competition Tribunal and the Federal Court, which provide important guidance to the AER and industry on the approach that should be adopted going forward.

Evoenergy adopted the AER's approach to estimating debt and equity raising costs and forecast inflation.

The rate of return and forecast inflation in Evoenergy's regulatory proposal were necessarily placeholders given that the averaging periods for the risk free rate and cost of debt had not yet occurred and the information on which the AER's forecast inflation methodology is based was not yet available.

5.3 Draft decision

Since Evoenergy submitted its regulatory proposal, the Council of Australian Governments (COAG) Energy Council has determined that the 2018 rate of return guideline (2018 Guideline) will be binding and will apply to the businesses currently under review.

While the legislation to create a binding guideline has not yet been passed, the AER's draft decision applies its draft 2018 Guideline to determine the rate of return for Evoenergy, noting that this is a departure from the 2013 Guideline. Based on this approach, the AER's draft decision is to reject Evoenergy's proposed rate of return and estimate of gamma and instead adopt an allowed rate of return of 5.80 per cent (nominal vanilla) and a value of 0.5 for gamma.

As with Evoenergy's proposal, the AER's draft determination rate of return is a placeholder and will be updated to reflect the appropriate averaging periods in the final determination. Similarly, the AER estimated forecast inflation of 2.45 per cent, which is

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[77] Rules, clause 6.12.1(5)
[78] Rules, clause 6.12.1(5A)
[79] Rules, clause 6.12.1(5B)

slightly below Evoenergy's proposal estimate of 2.50 per cent, will be updated in the AER's final determination.

5.4 Revised proposal

The rate of return and gamma estimates adopted in the RRP reflect Evoenergy's position in relation to the AER's draft 2018 Guideline. As set out in Evoenergy's submission on the AER's 2018 Guideline draft decision, Evoenergy has serious concerns about the review process and outcomes proposed in the draft decision[80]. The AER's draft decision proposes a significant departure from the foundation model approach used to estimate the return on equity in the 2013 Guideline, despite the Tribunal accepting the 2013 Guideline approach. Evoenergy considers that the AER's draft decision on the 2108 Guideline does not properly reflect market evidence commensurate with prevailing market conditions nor does it reflect a balanced, evidence-based and consistent approach. Consequently, the draft decision is inconsistent with the NEO and undermines the principles of stability and predictability.

In Evoenergy's view, a balanced assessment of the relevant evidence supports an equity beta of at least 0.7 and a market risk premium (MRP) of at least 6.5 per cent in the prevailing market conditions. Evoenergy also considers that the relevant evidence does not support any increase in the value of imputation credits from 0.4. These parameter values are consistent with the AER's 2013 Guideline, which were accepted by the Tribunal against an assessment of the NEO and the Rules.

For other parameter values, namely the risk free rate, cost of debt and gearing, Evoenergy has adopted the AER's draft decision values, although it is important to note that the risk free rate and cost of debt estimates are placeholders. The resulting rate of return adopted in the RRP is 6.16 per cent (nominal vanilla). The individual parameter values adopted in the RRP are presented in Table 5.1 below together with the values used in Evoenergy's regulatory proposal and the AER's draft decision.

Table 5.1 Rate of return parameters

	Evoenergy regulatory proposal	AER draft decision	Evoenergy revised proposal
Risk free rate	2.78%	2.66%	2.66%
Equity beta	0.7	0.6	0.7
MRP	7.0%	6.0%	6.5%
Return on equity	7.7%	6.3%	7.2%
Return on debt	5.57%	5.46%	5.46%
Gearing	60%	60%	60%
Nominal vanilla WACC	**6.42%**	**5.80%**	**6.16%**
Gamma	0.4	0.5	0.4

[80] Evoenergy 2018, Submission to the review of rate of return guideline – draft decision, 25 September.

6 Regulatory asset base

6.1 Rules requirements

The AER is required to make a decision on the regulatory asset base (RAB) as at the commencement of the regulatory control period in accordance with clause 6.5.1 and schedule 6.2.[81] The AER must also make a decision on whether depreciation for establishing the regulatory asset base as at the commencement of the following regulatory control period is to be based on actual or forecast capital expenditure.[82]

6.2 Regulatory proposal

Evoenergy calculated the opening RAB for the 2019–24 regulatory control period using the AER's roll-forward model (RFM). For each subsequent year of the 2019–24 regulatory control period, Evoenergy estimated the RAB using the AER's post-tax revenue model (PTRM), adopting the AER's methodology for calculating forecast depreciation, forecast inflation and asset lives. Consistent with the AER's Framework and Approach decision, Evoenergy split the RAB between distribution and transmission (dual function assets). Given the timing of the regulatory proposal, a number of the inputs were placeholders, including capital expenditure for 2017/18, inflation and changes due to the AER's remittal decision for the 2014–19 regulatory period.

Based on this methodology and forecasts for net capex, depreciation and inflation, Evoenergy proposed an opening RAB of $791.4 million for distribution and $174.2 million for transmission. Over the 2019–24 regulatory control period, Evoenergy's total proposed RAB increased below the level of inflation (see Table 6.1 below). On a per customer basis, Evoenergy's proposed RAB declined in real terms by 7.5 per cent over the 2019–24 regulatory period.

For the purposes of clause 6.12.1(18) of the Rules, Evoenergy proposed to use forecast depreciation to establish the RAB at the commencement of the 2024-29 regulatory control period.

Table 6.1 Regulatory proposal: RAB

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution opening RAB	791.43	815.39	843.39	870.19	892.50
Transmission opening RAB	174.24	174.16	170.90	178.43	175.83
Total opening RAB	965.67	989.54	1014.30	1048.62	1068.32

6.3 Draft decision

The AER's draft determination accepted Evoenergy's proposed opening RAB with revisions to update 2017/18 forecast inflation for actual inflation and to update the RFM for changes made to the 2014–19 PTRMs in the AER's draft decision for the remittal.

However, the AER determined a significantly lower RAB over the 2019–24 regulatory period, largely reflecting the AER's draft decision to reduce Evoenergy's forecast capex

[81] Rules, clause 6.12.1(6)
[82] Rules, clause 6.12.1(18)

(see chapter 0). The AER's draft decision results in the value of the RAB per customer declining by 13.5 per cent in real terms over the 2019–24 regulatory period.

Table 6.2 AER draft decision: RAB

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution opening RAB	790.95	803.22	815.15	821.48	840.02
Transmission opening RAB	174.07	172.58	168.50	164.84	162.21
Total opening RAB	965.02	975.79	983.65	986.31	1,002.23

The AER accepted Evoenergy's proposal that the forecast depreciation approach is to be used to establish the opening RAB values at the commencement of the 2024-29 regulatory control period.

6.4 Revised proposal

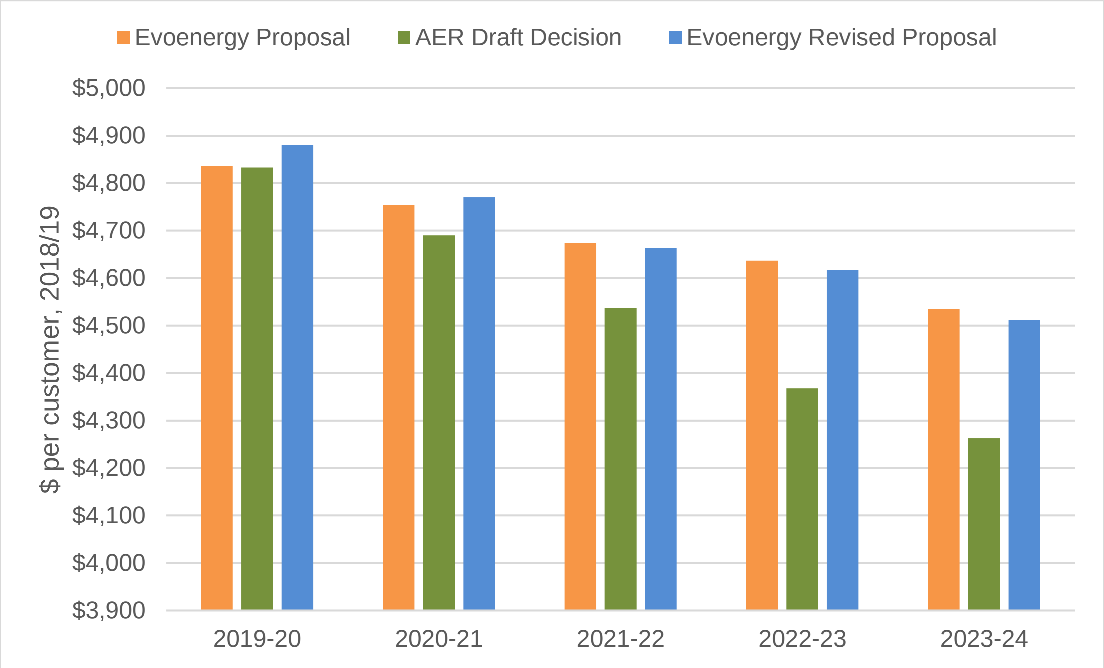
The opening RAB in Evoenergy's revised proposal reflects changes made to update the RFM for actual capex for 2017/18 and forecast capex for 2018/19. Evoenergy has also adopted the AER's updates to the RFM for actual inflation and the AER's final decision on the 2014–19 remittal. The resulting opening RAB for the 2019–24 regulatory period is $796.7 million for distribution and $177.7 million for transmission. The value of the RAB over the 2019–24 period is determined by Evoenergy's net capex forecasts (see chapter 0). By the end of the 2019–24 regulatory period, Evoenergy forecasts a real decline in the total RAB of 2.6 per cent. On a per customer basis, the RAB is forecast to decline by 9 per cent in real terms over the 2019–24 period, slightly below Evoenergy's regulatory proposal but higher than the AER's draft decision (see Figure 6.1).

Table 6.3 Regulatory proposal: RAB

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution opening RAB	796.69	818.07	833.04	865.47	886.22
Transmission opening RAB	177.71	174.41	178.00	177.19	174.62
Total opening RAB	974.41	992.49	1,011.03	1,042.66	1,060.84

Consistent with the AER's draft decision to accept Evoenergy's proposal, Evoenergy proposes that forecast depreciation be used to establish the opening RAB values at the commencement of the 2024-29 regulatory control period.

Figure 6.1 RAB per customer, 2019–24



7 Corporate income tax

7.1 Rules requirements

The AER is required to make a decision on the estimated cost of corporate income tax to the Distribution Network Service Provider for each regulatory year of the regulatory control period in accordance with clause 6.5.3.[83]

7.2 Regulatory proposal

Evoenergy adopted the AER's PTRM for the calculation of corporate tax expenses. Based on Evoenergy's PTRM input values, including a value for gamma of 0.4 (see chapter 0), Evoenergy estimated a net corporate income tax expense of $38.8 million[84] (see Table 7.1) for the 2019–24 regulatory period.

Table 7.1 Regulatory proposal: corporate income tax

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution	5.97	6.33	6.66	7.18	7.42
Transmission	0.92	0.97	1.03	1.13	1.19
Total	6.90	7.30	7.69	8.31	8.61

7.3 Draft decision

The AER's draft decision resulted in a corporate income tax expense of $26.6 million (see Table 7.2) reflecting a number of amendments to Evoenergy's proposed PTRM inputs, including:

- The opening tax asset base: while the AER accepted Evoenergy's proposed method to establish the opening tax asset base, it adjusted the equity raising cost input to reflect the 2014–19 remittal decision models;
- Remaining tax asset lives: the AER accepted Evoenergy's proposed standard tax asset lives because they are broadly consistent with the values prescribed by the Commissioner of Taxation and the same as the approved standard tax asset lives over the 2014–19 regulatory period. The AER assigned a value of 'n/a' to the 'Opening distribution assets' asset class, reflecting the fact that it will no longer have any allocated capex going forward.
- Proposed tax treatment of revenue adjustments associated with the capital expenditure sharing scheme: the AER changed the tax treatment of the CESS to be consistent with the incentives developed for the scheme; and
- The value of imputation credits – gamma: the AER adopted a value for gamma of 0.5, consistent with its draft decision on the 2018 rate of return guideline (see chapter 0).[85]

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[83] Rules, clause 6.12.1(7)
[84] All values in this section are in nominal dollars.
[85] AER 2018, Attachment 7: Corporate income tax | *Draft decision – Evoenergy distribution determination 2019–24*, September, pp.7-11 to 7-15.

Table 7.2 AER draft decision: corporate income tax

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution	4.08	4.38	4.62	4.99	5.15
Transmission	0.57	0.62	0.67	0.74	0.78
Total	4.65	5.01	5.28	5.73	5.93

7.4 Revised proposal

Evoenergy's revised proposal adopts the AER's PTRM for estimating corporate tax expenses. Evoenergy has accepted the first three changes made by the AER listed in section 7.3 above which impact the estimation of corporate income tax. Evoenergy has maintained a value of 0.4 for gamma for the reasons discussed in chapter 0.

Evoenergy's revised proposal also reflects updates for actual capex for 2017/18 and forecast capex for 2018/19 and the 2019–24 regulatory period. Other revisions to some PTRM inputs also flow through to the calculation of corporate income tax in Evoenergy's revised proposal.

Evoenergy's revised estimate of corporate income tax is $41.5 million (see Table 7.3).

Table 7.3 Revised regulatory proposal: corporate income tax

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution	5.71	6.30	6.26	6.73	6.98
Transmission	2.50	4.29	0.83	0.91	0.97
Total	8.21	10.59	7.09	7.63	7.95

7.5 AER review of regulatory tax approach

On 2 November 2018, the AER released a discussion paper identifying possible changes to its regulatory tax approach based on voluntary information provided by distribution businesses. The AER's discussion paper does not consider additional tax information collected via RIN responses. The AER states that if the RIN data is consistent with the voluntary information tranche on the matters relevant to the AER's proposed changes then the AER intends to apply those model changes to the group of revenue determinations with final reset decisions due in April 2019. Under such circumstances, the AER would consult with the affected businesses on the specific implementation of the model changes for their network. The AER states that this consultation could be done simultaneously with the general model changes.[86]

Alternatively, if the AER were to recommend changes to the Rules in its final report then there would be further opportunities for stakeholder consultation as part of the Australian Energy Market Commission (AEMC) led rule change process. Details of this process would be at the discretion of the AEMC, including the scope for applying the rule change to upcoming or ongoing regulatory determinations[87].

[86] AER 2018, Discussion paper, Review of regulatory tax approach, November, p.7
[87] Ibid, p.7

If the new material arising in the RIN responses leads to changes in the proposals put forward in the AER's discussion paper or identifies new possible changes to its approach, the AER does not consider those changes could be implemented in time for the April 2019 reset determinations. Instead, the AER would consider any relevant model and rule changes after March 2019.[88]

Evoenergy submitted a response to the AER's discussion paper on 23 November 2018.[89] Evoenergy also intends to engage in the ongoing consultation process set out in the AER's November discussion paper.

[88] Ibid, pp.7-8

[89] Evoenergy 2018, Submission in response to AER discussion paper on review of regulatory tax approach, 23 November.

8 Regulatory depreciation

8.1 Rules requirements

The AER is required to make a decision on whether or not to approve the depreciation schedules submitted by the Distribution Network Service Provider and, if the AER decides against approving them, a decision determining depreciation schedules in accordance with clause 6.5.5(b).[90]

8.2 Regulatory proposal

The AER defines regulatory depreciation as the sum of straight-line depreciation less the indexation adjustment made to remove the double-counting of inflation.

In the regulatory proposal, Evoenergy calculated straight-line depreciation using the AER's PTRM and Evoenergy's forecast RAB and capex. Evoenergy also used the PTRM to calculate the indexation adjustment, adopting a placeholder value for forecast inflation of 2.5 per cent given the information used by the AER to forecast inflation for the 2019–24 regulatory control period was not yet available. The resulting estimate of regulatory depreciation is presented in Table 8.1 for distribution and Table 8.2 for transmission.

Table 8.1 Regulatory proposal: regulatory depreciation distribution

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Straight-line depreciation	54.84	58.45	62.34	67.19	71.17
Indexation adjustment	-19.79	-20.38	-21.08	-21.75	-22.31
Regulatory depreciation	35.06	38.06	41.25	45.43	48.86

Table 8.2 Regulatory proposal: regulatory depreciation transmission

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Straight-line depreciation	10.76	11.41	12.02	13.08	13.78
Indexation adjustment	-4.36	-4.35	-4.27	-4.46	-4.40
Regulatory depreciation	6.40	7.05	7.75	8.62	9.39

8.3 Draft decision

The AER's draft decision estimated a regulatory depreciation allowance of $206.1 million for distribution and $38.5 million for transmission, a total reduction of 1.3 per cent compared with Evoenergy's proposal.

The AER accepted Evoenergy's proposed asset classes, straight-line depreciation method, standard asset lives[91] and weighted average method to calculate the remaining

[90] Rules, clause 6.12.1(8)

[91] Subject to an update to the standard asset life for equity raising costs for the transmission network. See AER 2018, Attachment 4: Regulatory depreciation | *Draft decision – Evoenergy distribution determination 2019–24*, September, p.4-6. Evoenergy has adopted this revision in its revised regulatory proposal.

asset lives as a 1 July 2019. The reduction in the AER's estimate of regulatory depreciation is a consequence of the AER's draft decision on other components of Evoenergy's proposal including the opening RAB and forecast capex. In addition, the AER used a placeholder forecast inflation rate of 2.45 per cent compared with the placeholder rate of 2.50 per cent used by Evoenergy.

Table 8.3 and Table 8.4 present the AER's draft decision estimates of regulatory depreciation for distribution and transmission, respectively.

Table 8.3 AER draft decision: regulatory depreciation distribution

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Straight-line depreciation	54.78	57.95	61.10	64.13	67.90
Indexation adjustment	-19.38	-19.68	-19.97	-20.13	-20.58
Regulatory depreciation	35.41	38.27	41.13	44.01	47.32

Table 8.4 AER draft decision: regulatory depreciation transmission

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Straight-line depreciation	10.74	11.31	11.81	12.30	12.97
Indexation adjustment	-4.26	-4.23	-4.13	-4.04	-3.97
Regulatory depreciation	6.48	7.08	7.68	8.27	9.00

8.4 Revised proposal

In the revised proposal, Evoenergy has maintained the same approach to estimating regulatory depreciation as its regulatory proposal with the exception of adopting the AER's draft decision placeholder for forecast inflation of 2.45 per cent. The AER will update this value in its final determination. Evoenergy estimates a total regulatory depreciation allowance of $250 million for the 2019–24 regulatory control period, which is 0.8 per cent higher than in the regulatory proposal, reflecting changes to the opening RAB (see chapter 6), forecast capex (see chapter 0) and the use of a slightly lower forecast inflation rate. Evoenergy's estimates of regulatory depreciation are presented in Table 8.5 for distribution and Table 8.6 for transmission.

Table 8.5 Revised regulatory proposal: regulatory depreciation distribution

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Straight-line depreciation	55.22	58.64	62.28	67.03	70.44
Indexation adjustment	-19.52	-20.04	-20.41	-21.20	-21.71
Regulatory depreciation	35.70	38.60	41.87	45.83	48.73

Table 8.6 Revised regulatory proposal: regulatory depreciation transmission

$million, nominal	2019/20	2020/21	2021/22	2022/23	2023/24
Straight-line depreciation	10.88	11.40	12.16	12.93	13.48
Indexation adjustment	-4.35	-4.27	-4.36	-4.34	-4.28
Regulatory depreciation	6.53	7.13	7.80	8.59	9.20

9 Incentive schemes

9.1 Introduction

Evoenergy supports the AER's draft decision to apply each of the following incentive schemes for the 2019–24 regulatory control period:

- 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);

Together with the incentive-based regulatory framework, these schemes provide balanced incentives to improve expenditure efficiency and service performance, and to optimise the use of non-network options related to demand management, thereby contributing to the long-term interests of consumers. Decisions on how these schemes will apply to Evoenergy are constituent decisions that the AER must make in its determinations under clause 6.12.1(9) of the Rules.

This chapter discusses each of the applicable schemes in turn.

9.2 Rules requirements

The AER is required to make a decision on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply to the DNSP.[92]

The Rules require Evoenergy to indicate how these incentive schemes should apply to its services for the 2019–24 regulatory control period, taking account of how the AER intends to apply these schemes as set out in its F&A paper.

Clause 6.4.3 of the Rules provides for the Annual Revenue Requirement for each regulatory year of a regulatory control period to be determined using a building block approach, under which the constituent building blocks include the revenue increments or decrements (if any) for that year arising relevantly from the application of the EBSS, CESS, STPIS, DMIS and DMIA as referred to, respectively, in clauses 6.5.8, 6.5.8A, 6.6.2 and 6.6.3 of the Rules.

As the EBSS did not apply to Evoenergy in the 2014–19 regulatory control period, there are no revenue increments or decrements for the subsequent regulatory period arising from the application of the EBSS during a previous regulatory control period.

Evoenergy set out its positions on the application of the EBSS, CESS, STPIS, DMIS and DMIAM in Attachment 10 to its January 2018 regulatory proposal.

[92] Rules, clause 6.12.1(9)

9.3 Efficiency benefit sharing scheme

9.3.1 Introduction

The EBSS provides electricity distributors with a continuous incentive to achieve efficiencies in opex throughout the regulatory control period. Under the scheme, any efficiency gains (or losses) are retained by the distributor for a fixed period of time (the 'carryover period'), regardless of the year in which the gain (or loss) was made.

In its regulatory proposal, Evoenergy proposed the reinstatement of the EBSS for the 2019–24 regulatory control period, consistent with the November 2013 version of the EBSS guideline.[93]

Evoenergy proposed that the carryover period to apply for the 2019–24 regulatory control period be set to five years, which corresponds to the length of the regulatory control period. This is also aligned to the carryover period for the CESS and ensures an approximate '30:70' sharing ratio of efficiency gains or losses between Evoenergy and its customers (as per the EBSS guideline).

Evoenergy's proposal supported the method for calculating incremental efficiency gains and losses as set out in the November 2013 version of the AER's EBSS guideline.

As per section 1.4 of the EBSS guideline, the AER's final determination will list any opex adjustments or exclusions relevant for the purposes of calculating efficiency gains or losses. Evoenergy proposed that the following cost categories be excluded:

- debt-raising costs;
- costs of any approved pass through events and new regulatory obligations introduced after the final determination;
- insurance and self-insurance costs;
- superannuation costs for defined benefits fund members;
- operating costs associated with projects funded under the DMIA mechanism;
- operating costs associated with non-network demand management initiatives (under the DMIS mechanism) as they are not forecast using a single-year revealed forecast; and
- costs for any services that will not be classified as Standard Control Services in the 2024-29 regulatory control period

9.3.2 Draft determination

The AER's draft decision is to reinstate the EBSS for Evoenergy in the 2019–24 regulatory control period. Consistent with Evoenergy's proposal, the AER will apply the EBSS as set out in the November 2013 EBSS guideline. The AER accepted Evoenergy's proposal to set a five year carryover period for incremental gains or losses.

Consistent with Evoenergy's proposal, the AER's draft decision is to make the following adjustments in the calculation of efficiency gains and losses:

- exclude debt-raising costs (as a pre-defined 'excluded category' because they have not been forecast on a revealed costs basis as part of base year opex);

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[93] AER 2013, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November.

- adjust the forecast opex to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination, such as approved pass-through amounts;
- adjust actual opex to remove demand management innovation allowance (DMIA) operating expenditure since it is not included in the opex forecast (but is typically reported by service providers as part of their standard control opex);
- adjust actual opex to add capitalised opex that has been excluded from the RAB;
- exclude costs of any services that will not be classified as Standard Control Services in the 2024-29 regulatory control period, to the extent that excluding these costs better achieves the requirements of clauses 6.5.8 and 6A.6.5 of the NER.

The AER did not accept Evoenergy's proposal to exclude the following cost categories from calculations of efficiency gains or losses:

- insurance and self-insurance costs, because these have been forecast using a revealed cost approach and hence are within the scope of the EBSS;
- superannuation costs, because these have been forecast using a revealed cost approach and hence are within the scope of the EBSS;
- costs associated with demand management (non-network initiatives), because specific exclusions are generally not made for costs that may be 'one-off' or 'lumpy' in the base year opex used to forecast opex for the next regulatory control period.[94]

9.3.3 Revised proposal

Evoenergy welcomes the AER's draft determination to reinstate the EBSS for the 2019–24 regulatory control period, consistent with the November 2013 version of the EBSS guideline. The EBSS provides an ongoing incentive to pursue efficiency improvements in opex and allows for a fair sharing of efficiency gains and losses between Evoenergy and its customers. We also note that the Consumer Challenge Panel (CCP10) supports the application of the EBSS to Evoenergy in the 2019–24 regulatory control period.[95]

Evoenergy agrees with the AER's draft decision to set the carryover period to five years (equal to the length of the regulatory control period) because this ensures that there is a continuous incentive to pursue efficiency improvements across the regulatory control period.

Evoenergy also accepts the AER's draft decision to make the following adjustments to opex when calculating carryover amounts:

- exclude debt-raising costs, because these are not forecast on a revealed cost basis
- adjust forecast opex to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination, such as approved pass-through amounts;
- adjust actual opex to remove demand management innovation allowance (DMIA) operating expenditure;

[94] AER 2013, Explanatory Statement – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November, pp. 14-17, 21-22.
[95] CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER issues paper, May 2018, p.17.

- adjust actual opex to add capitalised opex that has been excluded from the RAB; and
- exclude costs for any services that will not be classified as Standard Control Services in the 2024-29 regulatory control period.

9.4 Capital expenditure sharing scheme

9.4.1 Introduction

This section responds to the AER's draft decision on the CESS as set out in Attachment 9 to its draft decision.[96] The CESS applied to Evoenergy in the 2014–19 regulatory control period for the regulatory years 2015/16 to 2018/19. The CESS did not apply during the transitional regulatory period 2014/15 because the Rules precluded its application.

In its regulatory proposal, Evoenergy proposed to continue to apply CESS for the 2019–24 regulatory control period as per the Capital Expenditure Incentive Guideline (the CESS Guideline).[97] Evoenergy sought clarification from the AER regarding the treatment of asset disposals in the calculation of net capex. Evoenergy also calculated the revenue increments from the application of CESS during 2014–19 based on the AER's original CESS model published in 2013.

9.4.2 Draft decision

The AER's draft decision accepted Evoenergy's proposal to apply the CESS in the 2019–24 regulatory control period in accordance with the CESS Guideline. To calculate the revenue increments or decrements from the 2014–19 regulatory control period, the AER updated their CESS model as follows:

- the financing benefit is now calculated using the real, not nominal, rate of return. This gives a lower financing benefit, and hence higher CESS payment;
- the AER has applied an unlagged CPI (consistent with the RFM) in calculating the rate of return adjustment, rather than lagged inflation as previously;
- rather than including the financing benefit from the six-month rate of return adjustment as a direct cash flow received for the underspend or overspend, the updated model adjusts asset values, in effect capitalising the changes (consistent with the PTRM).

According to the AER, the updated CESS model better accounts for the distribution of the financial benefits across regulatory periods and also reflects the capitalisation approach applied in the PTRM.

In addition to updates to the CESS model, the AER's calculation of CESS revenue increments differs from Evoenergy's proposal in the following ways:

- In its regulatory proposal, Evoenergy calculated a total capex CESS and then split the increments as per the distribution and transmission assets mix, whereas the AER has estimated CESS revenue impacts on distribution and transmission capex separately;

[96] AER 2018, Attachment 9 – Draft Decision, Evoenergy Distribution Determination 2019 to 2024, Capital expenditure sharing scheme, September.

[97] AER 2013, Better Regulation – Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November.

- the AER used an updated inflation rate for 2017-18, based on actuals.
- the AER used a time varying WACC, as per the AER's draft decision for Evoenergy's 2014–19 remittal determination, whereas Evoenergy used the AER's 2014 final decision WACC as a placeholder.
- the AER has confirmed that forecast net capex figures are adjusted for asset disposals.

The AER also proposes to update the CESS revenue increment calculations in the final decision to account for Evoenergy's actual 2017/18 capex, updated inflation data, and Evoenergy's capex to reflect the outcome of its proposed cost pass through application related to Power of Choice obligations.[98]

9.4.3 Revised proposal

Evoenergy welcomes the AER's decision to apply the CESS for the 2019–24 regulatory control period. Evoenergy accepts the modifications made to the CESS model and the clarifications of the net capex definition for the purposes of calculating the revenue increments or decrements from the 2014–19 regulatory control period**.**

Evoenergy has applied the updated model in calculating the CESS revenue increments in the revised proposal. This results in a net CESS revenue decrement of $1.12 million ($2018/19) from the application of CESS in the 2014–19 regulatory control period. The net CESS decrement consists of a total distribution CESS decrement of -$3.76 million ($2018/19) over the regulatory control period and a total transmission CESS increment of $2.64 million ($2018/19) over the regulatory control period. The proposed CESS revenue increments for 2019–24 are summarised in Table 9.1.

Table 9.1 Evoenergy's revised proposal CESS revenue increments

$million, 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Distribution	-0.75	-0.75	-0.75	-0.75	-0.75	-3.76
Transmission	0.53	0.53	0.53	0.53	0.53	2.64
Total						**-1.12**

The calculation of Evoenergy's revised CESS revenue increments differs from the AER's draft decision as follows:

- Actual 2017/18 capex and revised 2018/19 capex have been included, instead of estimates used in the regulatory proposal. The main driver of the difference between expected and actual 2017/18 capex has been a strong growth in customer initiated works due to the ACT government's accelerated strategy in the growth of the reticulation of new estates as well as commercial and urban infill.[99] The higher revised 2018/19 capex has been driven by higher revised augmentation and replacement capex.

[98] AER 2018, Attachment 9: Capital Expenditure Sharing Scheme: Draft Decision Evoenergy distribution determination 2019–24, September, page 6.
[99] ACT Government 2018, Indicative land release program 2017-18 to 2020-21

- Excludable capex in the distribution CESS model includes direct capex related to Evoenergy's forthcoming pass through application. Evoenergy expects that the CESS revenue increments ought to reflect this cost pass through application.

Details of the revenue increment calculations are included in the CESS models[100] accompanying Evoenergy's revised proposal. Evoenergy acknowledges that the AER will make further adjustments to the CESS revenue increments during the 2024-29 revenue determination when actual 2018/19 capex figures are known.

9.5 Service target performance incentive scheme

9.5.1 Introduction

This section responds to the AER's draft decision in respect of the STPIS as set out in Attachment 10 to its draft decision. The STPIS applied to Evoenergy in the 2014–19 regulatory control period for the regulatory years 2015/16 to 2018/19. The STPIS did not apply during the transitional regulatory period 2014-15 because the Rules precluded its application.

Evoenergy's proposal supported the AER's position in in its Framework and approach paper to continue to apply the 2009 National STPIS[101] for the 2019–24 regulatory control period with two variations:

- To maintain the current revenue at risk of ±2.5 per cent instead of the higher ±5 per cent as proposed by the AER. This was supported by an analysis of Evoenergy's historical reliability performance, and customer engagement supporting the current reliability arrangements.[102] CCP10 supported maintaining the current revenue at risk level, adding that "Evoenergy has a strong focus on reliability, which could be over-emphasised with a higher revenue of risk level."[103]
- To reclassify 44 urban feeders as short rural feeders based on the feeders' 2016/17 maximum load and route length.

Evoenergy's regulatory proposal also provided reliability of supply targets based on the revised feeder classification, customer service targets and estimates of the incentive rates by feeder type for unplanned SAIDI and unplanned SAIFI.

Following the AER's draft decision applying the 2009 National STPIS, the AER in November 2018, published a revised STPIS.[104] Evoenergy's response regarding the application of the revised STPIS is set out in sections 9.5.4 and 9.5.5. Given the short timeframe between the release of the revised STPIS and the submission date for Evoenergy's revised proposal, the methodology in the revised proposal is based on the earlier 2009 National STPIS consistent with the AER's draft determination.

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[100] Evoenergy 2018, 2019–24 – revised proposal – CESS model – Distribution – November and Evoenergy 2018, 2019–24 – revised proposal – CESS model – Transmission – November

[101] AER, Electricity distribution network service providers—Service target performance incentive scheme, November 2009.

[102] Evoenergy 2018, Attachment 10 Incentive Schemes, pp. 9-11.

[103] CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER Issues Paper, May 208, p.17.

[104] AER 2018, Electricity distribution network service providers, Service target performance incentive scheme Version 2.0, November.

Evoenergy would welcome working with the AER to further consider the application of the revised STPIS in advance of the AER's final determination for the 2019–24 regulatory control period. This would allow the additional time required to gather some of the inputs needed under the revised STPIS, and assess the potential for application of the scheme to Evoenergy.

9.5.2 Draft decision

The AER draft decision supported Evoenergy's proposal to continue to apply the 2009 National STPIS for the 2019–24 regulatory control period.[105] The AER responded to Evoenergy's regulatory proposal on STPIS as summarised in Table 9.2.

Table 9.2 Regulatory proposal and draft decision STPIS parameters

	Evoenergy proposal	AER draft decision
Revenue at risk	± 2.5%	± 5%
Supply reliability areas	Urban and Short rural	Accepted
Reliability measures	Unplanned SAIDI Unplanned SAIFI	Accepted
Customer service measure	Telephone answering	Accepted
Feeder classification	Updated based on 2016/17 RIN data. This results in 44 urban feeders being reclassified as short rural.	Accepted
Performance targets	Based on 5 regulatory year historical average	Accepted
Specific event exclusions from annual performance and performance targets	As per AER's F&A position/STPIS guideline	Accepted
VCR used	AEMO's 2014 VCR	Accepted

Revenue at risk

The AER's draft decision was consistent with its position in its final framework and approach, which was set the revenue at risk within the range of ±5 per cent, in contrast to Evoenergy's proposal to maintain the revenue at risk at ±2.5 per cent. The AER reasons include that:

- the ±2.5 per cent revenue at risk during the 2014–19 regulatory control period was a transitional arrangement when STPIS was first applied to Evoenergy. The AER further claimed that "reduction of the revenue at risk will change the balance of the suite of incentive schemes."[106]
- the proposed ±5 per cent revenue at risk, together with the application of CESS and EBSS, would provide the right balance across incentive schemes to ensure that cost efficiencies will not be delivered at the expense of service levels to customers.

[105] AER 2018, Attachment 10 – Draft Decision Evoenergy Distribution Determination 2019 to 2024, Service target performance incentive scheme, September, p. 6.
[106] AER 2018, *Draft Decision Evoenergy Distribution Determination 2019 to 2024*: Attachment 10 Service target performance incentive scheme, September, p .10

- The risk of Evoenergy achieving a reward or penalty higher than 2.5 per cent of revenue is fully within Evoenergy's control and Evoenergy consumers should be fully compensated if Evoenergy's actual reliability performance leads to a STPIS penalty exceeding 2.5 per cent of its annual revenue.

9.5.3 Revised proposal

Evoenergy welcomes the AER's draft decision to accept most of the elements of STPIS in Evoenergy's regulatory proposal, including the revision of feeder classification used to set reliability of supply targets for the next five years.

Evoenergy will adopt the AER's draft decision to increase the revenue at risk to ±5 per cent from its current level of ±2.5 per cent despite the following reservations:

- in its draft decision, the AER contends that preventing a penalty higher than 2.5 per cent of revenue is fully within Evoenergy's control. However, the annual variation in reliability performance is largely the result of unusual weather events and other events beyond Evoenergy's control.[107]
- Evoenergy has undertaken analysis showing that, because it is one of the most reliable distribution networks in the NEM, it would take about a 40 per cent decrease in both SAIDI and SAIFI to reach the 2.5 per cent revenue at risk limit in any given year. Evoenergy acknowledges the AER's concern that consumers should receive compensation for service levels that reduce beyond the level that the 2.5 per cent revenue at risk provides for. However, Evoenergy believes that this eventuality is highly unlikely based on its historical standards of service performance, and the current configuration and condition of its network assets.

9.5.3.1 REVISED PROPOSED TARGETS

For the purpose of this revised proposal, the STPIS targets have been updated to reflect the latest five-year average performance over the period 2013/14 to 2017/18, as shown in Table 9.3. This corresponds to the preferred approach outlined in the AER's Framework and Approach paper and draft decision. Evoenergy has not proposed capex that would improve reliability above historical levels and therefore the targets do not need to be adjusted.

Table 9.3 Historical reliability performance after removing excluded events and Major Event Days

Financial year ending	2014	2015	2016	2017	2018
Unplanned SAIDI (minutes/customer/year)					
Urban	25.10	37.17	35.75	40.34	27.61
Short Rural	35.16	23.30	33.67	37.77	39.90
Unplanned SAIFI (number/customer/year)					
Urban	0.465	0.679	0.742	0.673	0.430
Short Rural	0.602	0.442	0.531	0.726	0.640
Telephone answering (%)	82.7	79.7	74.3	74.4	81.5

[107] Evoenergy 2018, Regulatory Proposal Attachment 10: Incentive Schemes, p. 11.

Proposed reliability of supply and customer service targets for 2019–24 are provided in Table 9.4.

Table 9.4 Proposed reliability of supply targets for the 2019–24 regulatory control period

Measure	2019–24
Unplanned SAIDI	
Urban	33.19
Short rural	33.96
Unplanned SAIFI	
Urban	0.598
Short rural	0.588
Telephone answering	78.5%

9.5.3.2 INCENTIVE RATES

Evoenergy has updated its incentive rates for SAIDI and SAIFI by feeder types to reflect performance targets that are based on the last five-year historical averages, the revised expected smoothed revenues, and revised energy throughput forecasts used in its revised proposal. The inputs used in these calculations are set out in Table 9.5.

Table 9.5 Specific inputs into the calculation of Evoenergy's incentive rates

Item		Amount
Average annual (smoothed) distribution revenue requirement ($000, 2019/20) *		147,162
Average annual energy consumption: forecast for 2019/20 – 2023/24 (MWh)		2,964,994
Feeder type	**Urban**	**Short rural**
VCR ($2019-20/MWh) #	$41,726	$41,726
Urban/short rural weighting	68.7%	31.3%
Average unplanned SAIDI target	33.19	33.96
Average unplanned SAIFI target	0.598	0.588

*Smoothed revenue requirement (in real $2018/19) from the Distribution PTRM has been converted to real $2019/20 as per Section 3.2.2 (h)(2) of the STPIS Guideline.

#VCR value has been inflated to the start of 2018/19 using actual CPI data and up to 2019/20 using the expected inflation rate of 2.45 per cent

The incentive rate for unplanned SAIDI is expressed as a percentage per unit of unplanned SAIDI (where unplanned SAIDI is measured as the difference in minutes from the target). Similarly, the incentive rate for unplanned SAIFI is expressed as a percentage per unit of unplanned SAIFI (where unplanned SAIFI is measured in 0.01 interruptions away from the target).

Table 9.6 presents Evoenergy's proposed incentive rates for reliability and customer service targets based on the above inputs.

The incentive rate for unplanned SAIDI is expressed as a percentage per unit of unplanned SAIDI (where unplanned SAIDI is measured as the difference in minutes from the target). Similarly, the incentive rate for unplanned SAIFI is expressed as a percentage per unit of unplanned SAIFI (where unplanned SAIFI is measured in 0.01 interruptions away from the target).

Table 9.6 Proposed incentive rates for Evoenergy's STPIS targets

	Urban	Short rural
Unplanned SAIDI	0.05405%	0.02400%
Unplanned SAIFI	3.09399%	1.50559%
Telephone answering	-0.040%	

9.5.4 AER's revised STPIS and DRMG

On 14 November 2018, the AER published its revised STPIS.[108] The revised STPIS contains the following key amendments that could impact Evoenergy's application of STPIS in the 2019–24 regulatory period:

- Momentary Average Interruption Frequency Index event (MAIFIe) is included as a new and preferred reliability of supply parameter (clause 3.1 (a)(3) of the revised STPIS).
- All three reliability of supply parameters would apply to Evoenergy except where the AER determines otherwise in its final determination (clause 3.1 (b) of the revised STPIS). However, where a DNSP is unable to measure MAIFIe or MAIFI, it may propose a variation to exclude MAIFI or MAIFIe (clause 3.1(f) of the revised STPIS).
- There is a change in the weighting ratio for the incentive rates from the existing 50% SAIFI / 50% SAIDI to 40% SAIFI / 60% SAIDI, as shown in Table 1 of the revised STPIS.
- There are amended and new exclusion conditions that may impact the calculation of STPIS revenue increments/decrements (clause 3.2.2(f) of the revised STPIS).
- There is a change in the definition of the reliability of supply component, in particular the momentary interruption threshold (from less than 1 minute to less than 3 minutes) which also affects the definition of unplanned SAIDI, unplanned SAIFI and MAIFI/MAIFIe. (Table A1 of the revised STPIS).
- DNSPs would be required to backcast historical reliability data using the new momentary interruption threshold.

The AER also published their final Distribution Reliability Measures Guideline (DRMG)[109] in accordance with the AEMC final rule change on the Review of Distribution Reliability Measures.[110] The key changes that may impact Evoenergy's revised proposal are:

- the change in the definition of a momentary interruption threshold level of less than one minute to less than three minutes.

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[108] AER 2018, Electricity distribution network service providers Service target performance incentive scheme Version 2.0, November.
[109] AER 2018, Distribution Reliability Measures Guideline, November.
[110] AEMC 2014, Review of Distribution Reliability Measures, Final Report, September.

- the change in the threshold of an urban feeder would now be based on an average demand over a three year period and over the average length of that feeder for three years.

9.5.5 Impact of the revised STPIS on Evoenergy's revised proposal

In its final Framework and Approach[111] for Evoenergy, the AER noted that, during the revenue determination process, it would consider the application of the revised STPIS to Evoenergy for the 2019–24 regulatory control period if the STPIS review was completed in time. Since the STPIS review was still in progress at the time, Evoenergy's regulatory proposal was based on the 2009 National STPIS. The AER's subsequent draft determination for Evoenergy accepted the application of the 2009 National STPIS, with the AER stating it would apply the STPIS 'as is'.[112] Following this, on 14 November 2018, the AER published its revised STPIS.

In its explanatory statement for the revised STPIS, the AER states its intention is to be flexible in implementing the revised scheme for Evoenergy, given the current revenue determination is still in progress.[113] In particular, AER notes that flexibility will be exercised in the application of the revised definitions for SAIDI, SAIFI, and MAIFI, which would require backcasting of historical data.

The compressed timeframe between the release of the revised STPIS and the imminent deadline for the submission of the revised proposal has not provided Evoenergy sufficient time to consider how the revised STPIS should apply for the 2019–24 regulatory control period. Due to these constraints, Evoenergy's revised proposal is based on the 2009 National STPIS (as outlined in the sections above), consistent with the AER's draft determination.

Evoenergy welcomes the AER's flexibility on introducing the revised STPIS. Evoenergy notes that, in making its constituent decision on STPIS in its final distribution determination, the AER is required to determine all the performance targets, incentive rates, revenue at risk, and other parameters under the STPIS.[114] Evoenergy proposes to work with the AER to consider the implementation of the revised scheme, including the relevant performance parameters, in advance of the AER's final determination for the 2019–24 regulatory control period.

Evoenergy is generally supportive of the application of the revised STPIS for the 2019–24 regulatory control period.[115] In particular, Evoenergy wishes to retain several elements of Evoenergy's initial revised proposal pertaining to the 2009 national STPIS that have been unchanged in the revised STPIS, namely:

- the level of revenue at risk;
- supply reliability areas to determine network segmentation;

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111 AER 2017, Framework and approach, ActewAGL, Regulatory control period commencing 1 July *2019*, July, p. 52.
112 AER 2018, Attachment 10 – Draft Decision Evoenergy Distribution Determination 2019 to 2024, Service target performance incentive scheme, September, p 6.
113 AER 2018, Explanatory statement – Final decision, Amendment to the Service Target Performance Incentive Scheme (STPIS) Establishing a new Distribution Reliability Measures Guideline (DRMG), November, p. 37.
114 AER 2018, STPIS Version 2, Section 2.1 (d)
115 AER 2018, Electricity distribution network service providers Service target performance incentive scheme Version 2.0, November 2018, Section 1.5

- the exclusion of the GSL component of STPIS since Evoenergy is subject to an ACT jurisdictional scheme; and
- the Value of Customer Reliability used to calculate incentive rates.

While Evoenergy looks forward to working with the AER to implement the revised STPIS, we wish to raise some initial concerns about the introduction of several new elements in the revised scheme. In particular,

- there is insufficient time to allow Evoenergy to consider the implication of reclassifying Evoenergy's feeders based on the updated definition of urban and short rural feeders. This prevents Evoenergy from proposing, at this stage a revised feeder classification to set reliability of supply performance targets for 2019–24.
- there is insufficient time for Evoenergy to backcast historical performance data pertaining to unplanned SAIDI and unplanned SAIFI under the new measurement method. As a result, Evoenergy is unable, at this stage, to propose reliability of supply targets based on the average of the last five years
- as previously highlighted in Evoenergy's submission to the draft STPIS,[116] Evoenergy is unable to provide sufficient historical MAIFIe/MAIFI data that would allow the AER to set a performance target for MAIFIe/MAIFI for 2019–24.
- there is a lack of clarity in the revised STPIS and the accompanying explanatory statement regarding the transitional arrangements in place to ensure consistency and continuity of reported reliability data.

Evoenergy looks forward to working with the AER to resolve these issues in advance of the AER's final determination.

9.6 Demand Management Incentive Scheme

9.6.1 Introduction

The DMIS provides distributors with an incentive to undertake efficient expenditure on non-network options relating to demand management. Specifically, the DMIS provides networks with a cost-uplift for eligible efficient demand management projects, subject to a net-benefit constraint, and an overall limit on the incentive in any regulatory year.

Evoenergy proposed it would participate in the new DMIS during the 2019–24 regulatory control period, as per the December 2017 version of the scheme.[117] Evoenergy noted it would consider eligible projects over time as part of its network planning processes.

9.6.2 Draft decision

The AER's draft decision is to apply the new DMIS without any modification, as outlined in the December 2017 scheme. The AER will set the cost multiplier (uplift) for eligible projects equal to the cost multiplier specified in the version of the DMIS that is in effect at the time an eligible project becomes a committed project.

[116] Evoenergy 2018, Response to AER's draft STPIS- 2017 amendment, February

[117] AER 2017, Demand Management Incentive Scheme, Electricity distribution network service providers, December.

9.6.3 Revised proposal

Evoenergy accepts the AER's draft determination to apply the new DMIS for the 2019–24 regulatory control period. This is consistent with Evoenergy's proposal. Evoenergy believes the new DMIS will provide incentives for distributors and consumers to adopt efficient demand management measures in the long-term interests of the network and its users.

9.7 Demand Management Innovation Allowance Mechanism

9.7.1 Introduction

The DMIAM provides funding to distributors to undertake demand management research and development projects that have the potential to reduce long-term network costs. The current version of the scheme was published by the AER in December 2017.[118]

The DMIAM provides an ex-ante allowance in each year of the regulatory control period to undertake eligible demand management projects. The allowance comprises an annual funding amount equivalent to $200,000 (in 2016/17 dollars) plus 0.075 per cent of the unsmoothed annual revenue requirement, excluding adjustments for shared assets and other factors.

Evoenergy's proposal supported the application of the DMIAM in the 2019–24 regulatory control period, as set out in the December 2017 version of the scheme. Evoenergy noted it would consider eligible projects during the 2019–24 regulatory control period.

9.7.2 Draft decision

The AER's draft decision is to apply the DMIAM to Evoenergy for the 2019–24 regulatory control period, without any modification, as per the December 2017 version of the scheme. The AER stated that it will determine the allowance for Evoenergy based on its annual revenue requirement in the AER's final distribution determination.

9.7.3 Revised proposal

Evoenergy accepts the AER's draft decision to apply the DMIAM for the 2019–24 regulatory period, as per the December 2017 version of the scheme.

Table 9.7 provides Evoenergy's calculation of DMIAM funding over the 2019–24 regulatory control period. The total DMIAM funding is equal to $1.69m (in 2018/19 dollars) over the five years. The calculation is based on the unsmoothed annual revenue requirement from Evoenergy's revised proposal, and an estimate of inflation for 2018-19 (consistent with the RFM). The worksheet accompanying this proposal provides details of the calculations.

Table 9.7 Evoenergy's calculation of the allowance under the DMIAM

$ million (2018/19)	2019/20	2020/21	2021/22	2022/23	2023/24
DMIAM	0.336	0.336	0.336	0.340	0.342

[118] AER 2017, Demand Management Innovation Allowance Mechanism, Electricity distribution network service providers, December.

As stated in our draft proposal, Evoenergy will consider eligible projects during the 2019–24 regulatory control period and will submit supporting documentation to the AER as required under the DMIAM.

10 Control mechanisms

In this section Evoenergy responds to the AER's draft decision on the control mechanisms to apply to the recovery of distribution charges, designated pricing proposal charges, jurisdictional scheme charges, metering charges and ancillary services charges.

10.1 Rules requirements

The AER is required to make a decision on the form of the control mechanisms (including the X-factor) for Standard Control Services and on the formulae that give effect to those control mechanisms.[119] Similarly, the AER must make a decision on the form of the control mechanisms for Alternative Control Services and on the formulae that give effect to those control mechanisms.[120] In addition, the AER must make a decision on how compliance with a relevant control mechanism is to be demonstrated.[121]

The form of the control mechanisms must be as set out in the relevant Framework and Approach paper.[122] The formulae that give effect to the control mechanisms must be as set out in the relevant Framework and Approach paper unless the AER considers that unforeseen circumstances justify departing from the formulae as set out in that paper.[123]

10.2 Draft decision

The AER's draft decision confirmed the revenue cap form of control for Evoenergy's Standard Control Services (distribution and transmission), and price cap for Alternative Control Services. This is a departure from the 2014–19 regulatory control period where an average revenue cap applied to Evoenergy's distribution services.

10.3 Revised proposal

Evoenergy's response to the draft decision can be summarised as below:

- Evoenergy accepts the AER's draft decision to apply the revenue cap form of control with an unders and overs account, to distribution services. Evoenergy proposes a revision to the form of control formula to enable the true-up of the distribution variation amount for the difference between actual and forecast volumes for 2018/19[124].
- Evoenergy accepts the AER's draft decision to apply the revenue cap form of control with an unders and overs account, to Designated Pricing Proposal Charges. Evoenergy proposes a revision to the form of control formula to enable the true-up of the transmission variation amount for the difference between actual and forecast volumes for 2018/19.

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119 Rules, clause 6.12.1(11)
120 Rules, clause 6.12.1(12)
121 Rules, clause 6.12.1(13)
122 Rules, clause 6.12.3(c)
123 Rules, clause 6.12.3(c1)
124 AER 2018, Final Decision, Evoenergy 2014-19 electricity distribution determination, November, p.33

- Evoenergy accepts the AER's draft decision to apply an unders and overs mechanism for the recovery of Jurisdictional Scheme charges. The amount of revenue Evoenergy can recover through the Jurisdictional Scheme charges for the large scale Feed-in tariff is governed by the *Electricity Feed-in (Large-scale Renewable Energy Generation) Amendment Bill 2017*.
- Evoenergy accepts the AER's draft decision to apply price caps to Type 5 and Type 6 regulated metering services.
- Evoenergy accepts the AER's draft decision to apply a specific formula to quoted ancillary services.

10.3.1 Distribution charges

Evoenergy accepts the AER's draft decision to apply a revenue cap form of control with an unders and overs account, to distribution services. Evoenergy will demonstrate compliance with a revenue cap form of control in the annual Pricing Proposal and associated compliance models. Evoenergy will include adjustments for DUoS revenue under or over recovery in accordance with appendix A of the AER's draft decision.[125]

Evoenergy notes that the AER's draft decision is for the revenue cap for any given regulatory year to be the total annual revenue (TAR) calculated using the formula in Figure 13.1 of Attachment 13 of the draft decision. The side constraints applying to price movements for each of Evoenergy's tariff classes are outlined in the formula in Figure 13.2 of the AER's draft decision.

However, Evoenergy notes the AER's revenue cap formulas include no provision for the true-up of the distribution variation amount for the difference between actual and forecast volumes for 2018/19. Evoenergy proposes an additional $\mathrm{RV_t}$ factor which would allow for this true-up (adjusted for the time value of money) in the 2020–21 regulatory year. For all other regulatory years, $\mathrm{RV_t}$ would take a value of zero.

Evoenergy notes the AER's proposed methodology for intra-period adjustments to the weighted average cost of capital. Changes to the TAR resulting from the trailing average cost of debt update will be implemented through annual revisions to the X-factors. This is effectively a continuation of the procedure for updating the rate of return that has occurred during the current regulatory control period.

10.3.2 Designated pricing proposal charges

Evoenergy accepts the AER's draft decision to apply a revenue cap form of control with an unders and overs account to Designated Pricing Proposal Charges (DPPC). Evoenergy notes there was no formula in the AER's draft decision for Evoenergy to demonstrate compliance with the revenue cap form of control. However, Evoenergy understands that the revenue cap formulae for prescribed (transmission) services for 2019–24 will be similar to that for the current regulatory control period.[126] These are set

[125] AER 2018, Draft Decision Evoenergy Distribution determination – Attachment 13 – Control Mechanism, September, pp 14-12 to 14-13.

[126] The revenue cap formulae for prescribed (transmission) services for 2019–24 may, however, incorporate a term or terms that operate to address the under-recovery of 2014–19 prescribed (transmission) services revenues arising from the AER's remade final decision for that period.

out in the AER's 2015 final determination for the current regulatory control period[127], and are as follows:

$$MAR_t = AR_t \pm PT_t$$
$$AR_t = AR_{t-1}(1 + \Delta CPI_t)(1 - X_t)$$

However, to be Consistent with the AER's Final Decision on remittal, Evoenergy proposes to demonstrate compliance with the revenue cap for each year of the 2019–24 regulatory control period in accordance with the following formula:

$$MAR_t = AR_t \pm PT_t \pm RV_t$$
$$AR_t = AR_{t-1}(1 + \Delta CPI_t)(1 - X_t)$$

Compared to the formula used in the 2014–19 regulatory control period, this formula includes an additional component, RV_t. This additional component facilitates the true-up of the transmission variation amount, representing the difference between the transmission variation amount calculated using actual versus forecast volumes for 2018/19. This true-up is required to ensure Evoenergy recovers no more for the 2014–19 regulatory control period than it is entitled to recover under the AER's remade final decision for the period. This RV_t factor is proposed to be activated in the 2020–21 financial year. For all other regulatory years, RV_t takes a value of zero.

Evoenergy's compliance with the revenue cap form of control will be presented to the AER in the annual Pricing Proposal document and associated compliance models. This will include a record of the amount of revenue recovered from DPPC and associated payments in accordance with appendix B of the AER's draft decision on control mechanisms.

Evoenergy notes the AER's proposed methodology for intra-period adjustments to the weighted average cost of capital. Changes to the TAR resulting from the trailing average cost of debt update will be implemented through annual revisions to the X-factors. This is effectively a continuation of the procedure for updating the WACC that has occurred in the current regulatory control period.

10.3.3 Jurisdictional scheme amounts

Evoenergy accepts the AER's draft decision to apply an unders and overs mechanism for the recovery of Jurisdictional Scheme amounts. The amount of revenue Evoenergy can recover through the jurisdictional scheme amounts for the large scale Feed-in tariff is governed by the *Electricity Feed-in (Large-scale Renewable Energy Generation) Amendment Bill 2017*. Evoenergy will submit as part of its annual Pricing Proposal a record of any jurisdictional scheme amounts it recovers and associated payments in accordance with Appendix C of the AER's draft decision on control mechanisms.

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[127] AER 2015, Final Decision ActewAGL Distribution determination – Attachment 14 – Control Mechanism, April, pp 14-15 to 14-16.

10.3.4 Metering and fee based ancillary services

Evoenergy accepts the AER's draft decision to apply price caps to Type 5 and Type 6 metering serviced and fee based ancillary services. Evoenergy will demonstrate compliance with the relevant formula (Figure 13.3 in the AER's draft decision on Control Mechanisms) in the annual Pricing Proposal and associated compliance spreadsheets.

10.3.5 Ancillary quoted services

Evoenergy accepts the AER's draft decision to apply the formula outlined in Figure 13.4 of the AER's draft decision on control mechanisms.

11 Alternative control services

11.1 Introduction

In this chapter Evoenergy responds to the AER's draft decision on Alternative Control Services (ACS) set out in Attachment 15 of its draft decision. Evoenergy's response to the draft decision can be summarised as:

- Evoenergy accepts the AER's draft decision to classify metering and ancillary network services as ACS, as set out in the final Framework and Approach. Evoenergy agrees with the AER's position to apply caps on the prices of individual services in the next regulatory period to ACS.
- Evoenergy has revised the elements of the metering proposal that were not accepted by the AER in its draft decision. The remaining elements that were accepted in the draft decision have remained unchanged. Updated X-factors and indicative prices have been calculated.
- Evoenergy has accepted the revised labour rates recommended by the AER's consultant, and incorporated these into a revised ancillary services cost build-up model. Updated X-factors and indicative prices have been calculated.
- Following the AER's draft decision to reduce some of Evoenergy's proposed labour rates, Evoenergy no longer proposes gradually transitioning some ancillary services to cost-reflectivity. Instead, all ancillary services are proposed to be priced to be cost-reflective from 1 July 2019.

11.2 Metering services (Types 5 and 6)

For the 2014–19 regulatory period, the AER classified Evoenergy's Type 5 and Type 6 metering services as ACS and applied individual price caps to each of the metering and ancillary services. For the 2019–24 regulatory period, the AER has retained the ACS classification and the individual price cap form of control.

Evoenergy accepts the AER's classification of metering services and notes that there are no unforeseen circumstances which could justify a departure from the classification[128] of the following services as ACS:

- Types 5 and 6 metering data services, which includes collection, processing, storage and delivery;
- scheduled meter reads;
- maintaining and repairing meters and load-control equipment;
- meter testing during business hours (refunded to customer if meter proves faulty); and
- special meter reading or check (refunded to customer if original reading was incorrect).

For consistency with the Australian Energy Market Commission's (AEMC's) Power of Choice reforms, services relating to meter installation do not form part of Evoenergy's ACS proposal, and will be removed from its pricing schedule.

[128] As permitted under clause 6.12.3(b) of the Rules.

11.2.1 Forecast metering operating expenditure

In its draft decision the AER did not approve the proposed amounts for operational expenditure (opex) because it did not consider them efficient. The AER did not consider the forecast base year opex on condition monitoring to be efficient, and proposed a revised amount. Evoenergy has revised the proposed condition monitoring costs based on actual 2017–18 data. In its draft decision the AER accepted the amounts proposed by Evoenergy for strategy and planning, meter reading and meter data services in the 2017–18 base year. Evoenergy's revised proposed opex for metering is depicted in Table 11.1.

Table 11.1 Forecast metering operating expenditure, 2019–24

$ million (2017/18)	2019/20	2020/21	2021/22	2022/23	2023/24	Total
Condition monitoring	0.54	0.54	0.54	0.54	0.54	0.54
Strategy and planning	0.14	0.14	0.14	0.14	0.14	0.14
Meter reading	1.55	1.54	1.54	1.55	1.55	1.55
Meter data services	1.64	1.64	1.64	1.64	1.64	1.64
Total	**3.87**	**3.86**	**3.86**	**3.87**	**3.87**	**3.87**

11.2.2 Building blocks and revenue requirement

Evoenergy's proposed building blocks and revenue requirement for metering are shown in Table 11.2. Evoenergy's metering PTRM and RFM have been used to derive the revenue requirement and the X-factors. The X-factors represent the average annual price adjustment (in addition to the forecast CPI) necessary for Evoenergy to recover the forecast revenue requirement, based on a forecast of the number of meters in the PTRM. This forecast of the number of meters is based on the Jacobs forecast of customer numbers and estimates of the number of Type 5 and Type 6 meters to be replaced with Type 4 meters during the 2019–24 regulatory period. The revenue requirement also reflects additional revenue of $0.88 per year arising from the 2014–19 remittal final decision.

Table 11.2 Proposed metering revenue building blocks

$ million (nominal)	2019/20	2020/21	2021/22	2022/23	2023/24
Return on capital	2.75	2.58	2.40	2.21	2.01
Regulatory depreciation	2.77	2.93	3.10	3.28	3.46
Operating expenditure	4.12	4.21	4.31	4.42	4.53
Revenue adjustments	0.88	0.88	0.88	0.88	0.88
Net tax allowance	0.50	0.52	0.53	0.55	0.57
Total revenue building block (unsmoothed)	11.02	11.12	11.23	11.34	11.45
Smoothed revenue requirement	10.91	11.07	11.24	11.41	11.57
X-factor	**-20.50%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**

Source: Evoenergy metering PTRM.

11.2.3 Proposed price caps and price path for metering services

The proposed price path for each of Evoenergy's metering services is depicted in Table 11.3, and an indicative pricing schedule (as per the format in the PTRM) is shown in Table 11.4.

Table 11.3 Proposed X-factors for metering for each year of the 2019–24 regulatory control period

	2019/20	2020/21	2021/22	2022/23	2023/24
Metering X-factor	-20.50%	0.00%	0.00%	0.00%	0.00%

Table 11.4 Proposed prices for metering for each year of the 2019–24 regulatory control period

$/NMI/year Code	2019/20	2020/21	2021/22	2022/23	2023/24
MP1	17.5	17.9	18.4	18.8	19.3
MP2	30.7	31.4	32.2	33.0	33.8
MP3	30.7	31.4	32.2	33.0	33.8
MP4	248.2	254.3	260.5	266.9	273.4
MP6	70.6	72.4	74.1	76.0	77.8
MP7	35.6	36.5	37.3	38.3	39.2
MP8	62.2	63.8	65.3	66.9	68.6
MP9	62.2	63.8	65.3	66.9	68.6
MP10	502.3	514.6	527.2	540.1	553.3

* Prices based on a forecast CPI of 2.45 per cent per year

Ancillary metering services (e.g. special meter reads) are treated the same way as other ancillary services, and are subject to the cost build-up approach instead of the building block approach. Metering ancillary services are included in the fee-based ancillary services in section 11.3.

11.2.4 Compliance with the control mechanism

Under clause 6.8.2(c)(3)) of the Rules, Evoenergy is required to include in its regulatory proposal 'for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information.'

Evoenergy will demonstrate compliance with the control mechanism by multiplying the price for each service in the previous year by CPI–X (rounded to the same number of decimal places as currently applied) and comparing that to the proposed price. Prices equal to or less than equal to the calculated price are compliant. Evoenergy will demonstrate this compliance in the network pricing proposal to be submitted to the AER in May 2019.

11.3 Ancillary services

Evoenergy has revised its cost-build up approach to determining price caps for individual ancillary services to take into account the AER's draft decision in September 2018.

11.3.1 Fee-based ancillary services

Evoenergy proposed 123 fee based ancillary services in the January 2018 regulatory proposal, 70 more than offered in 2018–19. This reflects a large number of services being changed from being quoted to being fee-based.

The cost of ancillary services is largely made up of labour. Evoenergy's proposed labour rates can be compared with the AER's draft decision in Table 11.5. The AER's draft decision rates are lower than Evoenergy's proposed rates for four of the six types of labour. The AER accepted Evoenergy's estimates of the number of hours needed to complete ancillary services, as well as Evoenergy's proposed overhead rate of 61 per cent. Evoenergy accepts the revisions made to the proposed labour rates in the draft decision. These revised labour rates have been used to price the services in Table 11.5.

Table 11.5 Comparison of Evoenergy's proposed and the AER's draft decision on hourly labour rates (base rates excluding overheads)

Evoenergy labour category	Evoenergy proposed ($2019–20)	AER draft decision ($2019–20)
Office support service delivery	89.42	68.96
Electrical apprentice	87.44	81.44
Electrical worker	109.66	97.36
Electrical worker - labourer	80.41	81.44
Project officer design section	116.70	121.70
Senior technical officer/engineer design section	146.93	133.87

Note: The revised ancillary services costing model is based on the labour rates highlighted in orange in Table 11.5

Evoenergy made an error in the publication of proposed prices in the January 2018 regulatory proposal. Code 523 – *new underground service connection* – was published at a price of $734.68. Evoenergy does not currently charge for a new underground service, and proposes to continue not to do so in the next regulatory period. As a result, Evoenergy includes a price of $0.00 for this service in the ACS pricing schedules (Appendix 11.1).

Some of Evoenergy's ancillary services have not been priced to be cost-reflective in the 2014–19 regulatory control period, and Evoenergy proposed to correct this in the draft proposal. Evoenergy proposed a transition path to cost-reflectivity for some ancillary services, where an immediate move to cost-reflectivity from 2018–19 to 2019–20 produced a high percentage change in the price.

However, following the AER's draft decision to reduce five of Evoenergy's six proposed labour rates, the price increases that come about as a result of moving to full cost-reflectivity are no longer as considerable as in the January 2018 regulatory proposal. As a result, Evoenergy has abandoned the idea of a transition path to cost reflectivity, and instead propose pricing all ancillary services to be cost-reflective from 2019–20 based on the AER draft decision labour rates in Table 11.5. Ancillary services prices affected by this change are indicated in the ACS pricing schedules (Appendix 11.1).

Evoenergy has calculated X-factors to apply to each ancillary service during the next regulatory period as shown in the ACS pricing schedules appendix (Appendix 11.1). These X-factors are in the form of the prescribed CPI – X method, and are proposed to be applied to the 2019–20 charges.

The full list of proposed ancillary services, and indicative prices, is provided in the Ancillary Services Cost Build-Up Model in the modelling appendix. A detailed description of each of these services is provided in the Connection Policy. The proposed prices are based on a cost build-up model, which is provided in the modelling appendix to the regulatory submission.

11.3.2 Quoted ancillary services

Evoenergy proposes to set prices on a quoted basis for those ancillary services where the service is not typical or standard, or the scope of the service is specific to a particular customer's needs.

Evoenergy proposes to set the prices for quoted services using the following formula from the AER's Framework and Approach paper.

> ***Price = Labour + Contractor services + Materials***
>
> *where:*
>
> - *Labour (including on-costs and overheads)—consists of all labour costs directly incurred in the provision of the service which may include but it is not limited to labour on-costs, fleet on-costs and overheads, and other associated delivery costs including overheads. The labour cost for each service is dependent on the skill level and experience of the employees involved, time of day the service is undertaken, travel time, number of site visits, and crew size required to complete the service.*
> - *Contractor services—reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted service charge applies the rates under existing contractual arrangements. Direct costs are passed on to the consumer.*
> - *Materials (including overheads)—reflects the cost of materials directly incurred in the provision of the service, material storage and logistics and overheads.*

Price caps will apply to the labour rates used in this formula. Evoenergy proposes to demonstrate compliance with the formula by providing its annual calculation of labour rates to the AER in its annual pricing proposal. The rates are to be approved by the AER in its annual network pricing approval process.

The application of price caps to labour costs only, rather than to all cost inputs, helps to reduce administrative costs, as Evoenergy will not be required to identify, for AER approval, every input cost that may be required in performing a quoted service. This approach will also result in cost-reflective charges.

12 Proposed tariff structure statement

12.1 Rules requirements

The AER is required to make a decision on the DNSP's proposed tariff structure statement, in which the AER either approves or refuses to approve that statement.[129] The AER must also make a decision on the policies and procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another (including any applicable restrictions).[130]

The AER must approve a DNSP's proposed tariff structure statement unless the AER is reasonably satisfied that the proposed tariff structure statement does not comply with the pricing principles for direct control services or other applicable requirements of the Rules.[131]

If, in making a distribution determination in relation to a DNSP, the AER refuses to approve the DNSP's proposed tariff structure statement, the AER must include in that distribution determination an amended tariff structure statement which is:[132]

- determined on the basis of the DNSP's proposed tariff structure statement; and
- amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

12.2 Regulatory proposal

Evoenergy's Proposed TSS (submitted as Attachment 17 of the regulatory proposal) was focused on tariffs offered to large commercial customers. To continue Evoenergy's journey towards its long-term vision of more cost-reflective tariffs, the focus of the Proposed TSS was refining the existing commercial tariff structure to increase cost reflectivity and thereby sharpen price signals to encourage more efficient use of the network. This included the following proposed changes, designed to build on the recent tariff reforms implemented as a result of the first TSS:

- Refining the tariff structure for large LV commercial and HV commercial consumers by changing the anytime maximum demand charges to peak period maximum demand charges.
- Refining the residential and LV commercial peak demand tariffs.
- Closing one of the controlled load tariffs to new LV commercial connections from 1 July 2019 as it currently sends a contradictory message to commercial customers about the commercial peak window (which currently coincides with the off-peak window in this controlled load tariff).
- Simplifying the tariff structure by offering one version of each tariff from 1 July 2019, rather than the current approach of offering two versions (one with a metering capital charge applied to the access charge and another without it applied). Metering

[129] Rules, clause 6.12.1(14A)
[130] Rules, clause 6.12.1(17)
[131] Rules, clause 6.12.3(k)
[132] Rules, clause 6.12.3(l)

charges will be added separately when customers are billed, depending on the circumstances of each customer.

In preparation for the Proposed TSS, Evoenergy undertook a comprehensive review of its network costs and existing tariff structures, and consulted widely with the ACT community, large consumers and retailers.

12.3 Draft decision

A summary of the AER's draft decision on key elements of Evoenergy's proposed TSS is shown in Table 12.1.

Table 12.1 AER draft decision for network tariff reform 2019–24

<table>
<tr><th>Tariff</th><th>Proposed change*</th><th>AER draft decision</th><th>Revised change[#]</th></tr>
<tr><td>25 -Residential KW Demand</td><td>Replace the flat energy charge with a TOU energy charge</td><td>Not approved</td><td>Evoenergy will retain flat energy charge</td></tr>
<tr><td>106 - LV KW Demand</td><td>Replace the flat energy charge with a TOU energy charge</td><td>Not approved</td><td>Evoenergy will retain flat energy charge</td></tr>
<tr><td>101 - LV TOU kVA Demand</td><td rowspan="5">Replace the anytime kVA maximum demand charge with a peak kVA maximum demand charge</td><td rowspan="5">Approved</td><td rowspan="5">Evoenergy will replace the anytime kVA maximum demand charge with a peak kVA maximum demand charge from 1 July 2019</td></tr>
<tr><td>103 - LV TOU kVA Capacity</td></tr>
<tr><td>111 - HV TOU Demand</td></tr>
<tr><td>121 - HV TOU Demand – Customer LV</td></tr>
<tr><td>122 - HV TOU Demand – Customer HV and LV</td></tr>
</table>

* As per Attachment 17 of regulatory proposal
[#] As per Attachment 1 of revised proposal

The AER's draft decision also requires specific changes to the tariff assignment policy, as outlined below.

1. Removal of references to assigning LV commercial customers with embedded generators to the LV Capacity tariff.
2. Customers who receive a Type 4 meter as a replacement meter remain on their existing network tariff for 12 months before moving to a cost-reflective network tariff.

12.4 Revised proposal

Evoenergy accepts the AER's draft decision and, in response, submits a revised TSS (Attachment 1 to the RRP) that addresses the AER's draft decision. A summary of the key proposed tariff and assignment policy changes from the current regulatory period to the upcoming regulatory period are outlined in Table 12.2 and Table 12.3.

Table 12.2 Key proposed tariff changes 2019–24

	Change in 2019–24 regulatory period
101 - LV TOU kVA Demand 103 - LV TOU kVA Capacity 111 - HV TOU Demand 121 - HV TOU Demand – Customer LV 122 - HV TOU Demand – Customer HV and LV	Evoenergy will replace the anytime kVA maximum demand charge with a peak kVA maximum demand charge
070 – Of-peak (3) Day & Night	Closing this controlled load tariff to new LV commercial connections as it currently sends a contradictory message to commercial customers about the commercial peak window (which currently coincides with the off-peak window in this controlled load tariff).
All residential and LV commercial tariffs	Simplifying the tariff structure by offering one version of each tariff, rather than the current approach of offering two versions (one with a metering capital charge applied to the access charge and another without it applied). Metering charges will be added separately when customers are billed, depending on the circumstances of each customer.

Table 12.3 Network tariff assignment 2019–24

	Default	Opt-out
Residential		
Residential (new connection or customer initiated)	Residential kW demand	Residential Time-of-Use
LV commercial		
LV commercial without a CT meter	LV kW Demand	1. LV kVA TOU Demand 2. LV kVA TOU Capacity 3. General TOU
LV commercial with a CT meter	LV kVA TOU Demand	1. LV TOU kVA Capacity 2. General TOU
HV commercial		
HV commercial	HV TOU Demand (code 122)	n/a (mandatory default)

Note: As per the AER draft decision, from 1 July 2019 a residential or commercial customer who receives a replacement meter will not be assigned to the default tariff for 12 months. However, these customers can opt in to the default tariff.

The revised indicative pricing schedule, required by Rules clause 6.10.3(b1) forms Appendix 1.2.

13 Connection policy

13.1 Rules requirements

The Rules require that a regulatory proposal includes a proposed connection policy.[133]

The AER is required to make a decision on the connection policy that is to apply to the DNSP for the regulatory control period (which may be the connection policy as proposed by the DNSP, some variant of it, or a policy substituted by the AER).[134]

Evoenergy's proposed connection policy was submitted to the AER in January 2018 in compliance with:

- 5A.A1 of the Rules which defines the connection policy;
- clause 6.8.29(c)(5A) which requires that the proposal includes the connection policy; and
- the AER's Connection Charge Guidelines.

13.2 Regulatory proposal

The policy submitted to the AER in January 2018 was prepared with full consideration of the connection policy requirements specified in clause 6.7A.1 of the Rules.

The policy did not propose major changes to the existing approved connection policy which applies to the current regulatory control period. However, the proposed policy included changes reflecting commencement of metering contestability from 1 December 2017 as well as several other minor changes. The reasons for the proposed changes were explained in more detail in the Attachment 16 to the regulatory proposal.

13.3 Draft decision

The AER assessed the policy proposed by Evoenergy against the requirements of Part DA of chapter 6 of the Rules. In the draft decision, the AER stated that "… the majority of the connection policy meets Rules requirements. "[135] The AER confirmed consistency of the proposed connection with:

- Chapter 5A of the Rules
- Connection Charge Guidelines published under the Chapter 5A of the Rules
- Part DA, Chapter 6 of the Rules

However, the AER noted three minor issues which must be rectified in the proposed policy. The three issues related to:

- inclusion of difficult ground conditions in the Least Cost Technically Acceptable Solution (LCTAS) (connection policy, page 7)

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[133] Rules, clause 6.8.2(c)(5A)
[134] Rules, clause 6.12.1(21)
[135] AER 2018 Evoenergy draft decision, section 17.5

- changing some existing references from an accredited meter installer to a retailer (connection policy, section 4.13.1)
- clarification that the upstream shared network asset augmentation charge is approved by AER (connection policy, section 3.5)

The AER modified the proposed Connection Policy to address the above three issues and attached to the draft decision the modified policy approved for the 2019–24 regulatory control period. For avoidance of doubt, Evoenergy agrees with changes made by the AER to the Connection Policy.

13.4 Revised proposal

After careful consideration, Evoenergy decided to propose several additional amendments to the policy. The amended policy is attached to this revised regulatory proposal. This section summarises amendments and reasons for these amendments.

For clarity, Evoenergy does not propose major changes to the policy or the principles on which the policy is based. Evoenergy considers that the revised policy proposed for the 2019–24 period is consistent with the Rules and AER's Connection Charge Guidelines for Electricity Retail Customers. Evoenergy considers that these amendments merely assist in consistent interpretation of the policy, address identified ambiguities and correct minor discrepancies.

Brief descriptions of changes and summary of reasons for these changes are as follows:

- **Least Cost Acceptable Solution (LCTAS) (Connection Policy, table 3).** Under the existing connection policy, the customer is required to pay for the cost of above standard or special requirements. The amendment clarifies that if a customer pays for the above LCTAS assets, the connection agreement may include a requirement for that customer to pay for the ongoing operations and maintenance costs related to these assets.
- **HV commercial connections (Connection Policy, section 4.7).** Additional comments were added to clarify that HV connection is not mandatory regardless of the level of demand estimated for the connection. Thus, even if a capacity of a connection is high, that connection may be an HV connection or an LV connection.
- **Subdivision estate reticulation (Connection Policy, section 4.8).** The terminology relating to the subdivision estate reticulation was changed. The "typical" estates (for which capital contributions are calculated using published per block charges) have been renamed to "Category 1" estates. The reason is that "traditional" subdivisions are no longer "typical" due to dynamic changes in planning requirements, PV penetration rates and other factors. Therefore, Evoenergy considers that referring to these estates as "typical" is confusing and no longer appropriate. Most new residential estates do not meet the criteria for a typical estate. For greater clarity, the description of the Category 1 estate (previously a typical estate) was amended to include criteria for Category 1 estates.

  In addition, Evoenergy explained some advantages of per block capital contributions which currently apply to Category 1 estates only. Per block contributions assist in efficient processing of estate connections and provide upfront certainty to the developers in relation to charges. The amended policy clarifies that in the future, Evoenergy may define other categories of estates (e.g. Category 2) with specified characteristics. For the defined additional categories of estates, Evoenergy may calculate and apply per block capital contributions. However, prior to the commencement of the 2019–24 regulatory period, due to dynamic changes in estate reticulation requirements, there is insufficient cost data for Evoenergy to define additional categories and calculate per block contributions. For estates which do not belong to any of the defined categories, the capital contribution will continue to be assessed using Incremental Cost Revenue Test (ICRT).

- **Pioneer scheme (Connection Policy, section 6).** The description of a pioneer scheme was expanded and improved. The amended section includes a more detailed description of the scheme and a number of clarifying comments. There are no changes to the principles on which the scheme is based. Table 6.1 was added to provide a guidance on the application of the pioneer scheme to different types of connections. An explanation was added (connection policy, page 25) to clarify that a pioneer scheme may be applied to urban as well as rural connections. Additional comments were added to explain the link between the pioneer scheme refunds and application of the ICRT employed to calculate capital contribution. Additional clarifying comments were added to section 6.3 in relation to calculation of pioneer scheme refunds. The materiality threshold for pioneer scheme refunds was increased from $1000 to $1500. The formula for the depreciation factor (connection policy, section 6.4) was amended and the application of the formula further clarified.

14 References to constituent decisions

Table 14.1 provides a reference to constituent decisions in the Rules with the corresponding AER draft decisions and responses in Evoenergy's revised proposal.

Table 14.1 Cross-reference of constituent decisions in the Rules, the AER's draft decision and Evoenergy's revised regulatory proposal

Constituent decision	AER draft decision	Evoenergy RRP
6.12.1(1) Classification of services	The classification of services set out in Attachment 12 of the DD will apply to Evoenergy for the 2019–24 regulatory control period.	Evoenergy accepts the AER's draft decision on classification of services as being in accordance with its regulatory proposal.
6.12.1(2)(i) Annual revenue requirement	Not to approve the annual revenue requirement set out in Evoenergy's building block proposal. Evoenergy's annual revenue requirement for each year of the 2019–24 regulatory control period is set out in attachment 1 of the draft decision.	Evoenergy proposes a revised total revenue requirement of $928 million (nominal), as set out in chapter 2 of the RRP. The revised proposal reflects Evoenergy's position on each of the building blocks, as set out in the following chapters of the RRP: • chapter 3: Operating expenditure • chapter 4: Capital expenditure chapter 5: Rate of return • chapter 6: Regulatory asset base • chapter 7: Corporate income tax • chapter 8: Regulatory depreciation • chapter 9: Incentive schemes
6.12.1(2)(ii) Commencement and length of the regulatory control period	To approve Evoenergy's proposal that the regulatory control period will commence on 1 July 2019. To approve Evoenergy's proposal that the length of the regulatory control period will be 5 years from 1 July 2019 to 30 June 2024.	Evoenergy accepts the AER's draft decision on the commencement and length of the regulatory control period as being in accordance with its regulatory proposal.
6.12.1(3) Forecast capital expenditure	Not to accept Evoenergy's proposed total net forecast capital expenditure of $329.8 million ($2018–19). Draft decision therefore includes a substitute estimate of Evoenergy's total net forecast capex for the 2019–24 regulatory control period of $261.4 million ($2017–18).	Evoenergy proposes a revised capex forecast of $316.5 million ($2018/19) as set out in Chapter 4 of the RRP.

Constituent decision	AER draft decision	Evoenergy RRP
6.12.1(4) Forecast operating expenditure	Not to accept Evoenergy's proposed total forecast operating expenditure of $308.9m ($2018-19, excluding debt raising costs). AER draft decision includes a substitute estimate of Evoenergy's total forecast opex for the 2019–24 regulatory control period of $294.7million ($2018–19, excluding debt raising costs)	Evoenergy's proposes a revised opex forecast of $299.5 million ($2018/19, excluding debt raising costs) as set out in Chapter 3 of the RRP. Evoenergy has adopted the AER's draft decision opex and has updated the base year for actual opex as set out in the draft decision.
6.12.1(4A) Contingent project	Evoenergy did not propose a contingent project for the 2019–24 regulatory control period.	Evoenergy has not proposed a contingent project for the 2019–24 regulatory control period.
6.12.1(5) Allowed rate of return	The allowed rate or return for the 2019–20 regulatory year is 5.80 per cent (nominal vanilla), as set out in Attachment 3 of the draft decision, and that the rate of return for the remaining regulatory years 2020–24 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.	Evoenergy estimates an allowed rate of return of 6.16 per cent (nominal vanilla) as set out in Chapter 5 of the RRP. This estimate reflects Evoenergy's position in relation to the AER's draft 2018 Guideline.
6.12.1(5A) Return on debt estimation methodology	The return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) and using the formula to be applied in accordance with clause 6.5.2(l). The methodology and formula are set out in Attachment 3 of the draft decision.	Evoenergy has adopted the AER's draft decision values and methodology for estimating the return on debt as set out in Chapter 5 of the RRP.
6.12.1(5B) Value of imputation credits	To adopt a value of 0.5.	Evoenergy considers that the relevant evidence does not support an increase in the value of imputation credits from 0.4, which reflects Evoenergy's position in relation to the AER's draft 2018 Guideline.
6.12.1(6) Regulatory asset base	The opening regulatory asset base as at 1 July 2019 set in accordance with clause 6.5.1 and schedule 6.2 is $790.9 million and $174.1 million ($ nominal) for its distribution and transmission networks respectively.	Evoenergy proposes an opening RAB for the 2019–24 regulatory period of $796.7 million ($ nominal) for distribution and $177.7 million ($ nominal) for transmission, as set out in Chapter 6 of the RRP.
6.12.1(7) Corporate income tax	Not to accept Evoenergy's proposed corporate income tax of $38.8 million ($ nominal). The AER's draft decision on Evoenergy's corporate income tax is $26.6 million ($ nominal).	Evoenergy's revised estimate of corporate income tax is $41.5 million ($ nominal), as set out in Chapter 7 of the RRP.

Constituent decision	AER draft decision	Evoenergy RRP
6.12.2(8) Depreciation schedules	To not approve Evoenergy's regulatory depreciation forecasts but adopts an alternative estimate of regulatory depreciation of $206.1 million (nominal) for distribution and $38.5 million (nominal) for transmission..	Evoenergy estimates a regulatory depreciation allowance of $210.7 million ($nominal) for distribution and $39.3 million ($nominal) for transmission as set out in Chapter 8 of the RRP. This reflects changes to the opening RAB (see chapter 6 of the RRP), forecast capex (see chapter 4) and the use of a marginally lower forecast inflation rate.
6.12.1(9) Application of regulatory incentive schemes	The AER will apply to Evoenergy in the 2019–24 regulatory control period: • version two of the EBSS • the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline • its Service Target Performance Incentive Scheme (STPIS) • the DMIS and DMIAM	Evoenergy accepts the AER's draft decision to apply each of the incentive schemes for the 2019–24 regulatory control period, as set out in chapter 9 of the RRP.
6.12.1(10) Other appropriate amounts, values or inputs	All appropriate amounts, values and inputs are as set out in the draft determination including attachments.	Evoenergy seeks amendment to relevant amounts, values and inputs of the AER's draft decision in accordance with its RRP.
6.12.1(11) Form of the control mechanisms for standard control services	The form of control mechanisms (including the X-factor) for standard control services is a revenue cap. The revenue cap for Evoenergy 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.	Evoenergy accepts the AER's draft decision to apply a revenue cap form of control with an unders and overs account, to distribution standard control services. Evoenergy notes that the AER has not included any mechanism to allow for the true-up of the remittal variation amounts. Evoenergy has proposed an adjustment to the formula that would allow for this true-up when setting prices for the 2020–21 regulatory year in chapter 10 of the RRP.
6.12.1(12) Form of the control mechanisms for alternative control services	The form of the control mechanism for alternative control services is to apply price caps for all services.	As set out in chapter 10 of the RRP: • Evoenergy accepts the AER's draft decision to apply price caps to Type 5 and Type 6 regulated metering services, and fee-based ancillary services. • Evoenergy accepts the AER's draft decision to apply a specific formula to quoted ancillary services.

Constituent decision	AER draft decision	Evoenergy RRP
6.12.1(13) Demonstration of compliance with a relevant control mechanism	To demonstrate compliance with its distribution determination, the AER's draft decision is Evoenergy must maintain a DUoS unders and overs account. It must provide information on this account to the AER in its annual pricing proposal.	Evoenergy will maintain unders and overs accounts for DUOS, Designated Pricing Proposal Charges and Jurisdictional Scheme charges. These will be presented in Evoenergy's annual pricing proposal.
6.12.1(14) Additional pass through events	Apply the following nominated pass through events for the 2019–24 regulatory control period in accordance with clause 6.6.1(a1)(5): • Terrorism event • Natural Disaster event • Insurance Cap event • Insurer Credit Risk event These events have the definitions set out in Attachment 14 of the draft decision.	Evoenergy accepts the AER's draft decision on additional pass through events as being in accordance with its regulatory proposal.
6.12.1(14A) Proposed tariff structure statement	To not approve the tariff structure statement proposed by Evoenergy.	Evoenergy submits a revised proposed TSS as Attachment 1 to the RRP that addresses the AER's draft decision as set out in chapter 12 of the RRP.
6.12.1(15) Negotiating framework	Approve Evoenergy's proposed negotiating framework.	Evoenergy accepts the AER's draft decision on the proposed negotiating framework as being in accordance with its regulatory proposal.
6.12.1(16) Negotiated Distribution Service Criteria	Apply the negotiated distribution services criteria published in February 2018 to Evoenergy.	Evoenergy accepts the AER's draft decision on Negotiated Distribution Service Criteria as being in accordance with its regulatory proposal.
6.12.1(17) Procedures for assigning retail customers to tariff classes	The procedures for assigning retail customers to tariff classes for Evoenergy is set out in attachment 13 of the draft decision.	Evoenergy submits a revised proposed TSS as Attachment 1 to the RRP that addresses the AER's draft decision as set out in chapter 12 of the RRP.
6.12.1(17A) Proposed pricing methodology for transmission standard control services		Evoenergy notes that the AER has not published a draft decision on the proposed pricing methodology for transmission standard control services.
6.12.1(18) Depreciation for establishing regulatory asset base in subsequent period	The depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of Evoenergy's regulatory control period as at 1 July 2024.	Evoenergy accepts the AER's draft decision on depreciation for establishing regulatory asset base in subsequent period as being in accordance with its regulatory proposal.

Constituent decision	AER draft decision	Evoenergy RRP
6.12.1(19) Recovery of designated pricing proposal charges	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.	As set out in chapter 10 of its RRP: • Evoenergy accepts the AER's draft decision to apply a revenue cap form of control with an unders and overs account, to Designated Pricing Proposal Charges. • Evoenergy proposes a revision to the form of control formula to enable the recovery of revenue from the final decision of the remittal for the 2014–19 regulatory control period.
6.12.1(20) Recovery of jurisdictional scheme amounts	To require Evoenergy 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.	As set out in chapter 10 of the RRP, Evoenergy accepts the AER's draft decision to apply an unders and overs mechanism for the recovery of Jurisdictional Scheme charges. Evoenergy will present the Jurisdictional Scheme unders and overs account to the AER in the annual pricing proposal.
6.12.1(21) Connection policy	To not approve the connection policy proposed by Evoenergy. The draft decision is to amend Evoenergy's proposed connection policy as set out in attachment 17 of the draft decision.	Evoenergy proposes to amend its connection policy in accordance the AER's draft decision as set out in chapter 13 of the RRP. Evoenergy submits a revised proposed Connection Policy as Attachment 2 to the RRP.

* Rules clause

Shortened forms

Term	Meaning
ACS	Alternative Control Services
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
CAM	cost allocation methodology
capex	capital expenditure
CBD	central business district
CCP, CCP10	The AER's Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Securities
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	distributed energy resources
DMIA	Demand Management Innovation Allowance
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DPPC	Designated Pricing Proposal charges
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Australia
FPSC	fixed price service charge
GW	gigawatt
HV	high voltage
ICRC	Independent Competition and Regulatory Commission
ICRT	Incremental Cost Revenue Test
ICT	information and communication technology
km	kilometre
kV	kilovolt
LCTAS	Least Cost Acceptable Solution
LV	low voltage
MEFM	Monash Electricity Forecasting Model

Term	Meaning
MRP	market risk premium
MWh	megawatt-hour
NEM	National Energy Market
NSW	New South Wales
NUOS	network use of system
opex	operating expenditure
PTRM	post-tax revenue model
PV	photovoltaic
RAB	regulatory asset base
repex	renewals expenditure
RFM	roll-forward model
RIN	Regulatory Information Notice
RRP	revised regulatory proposal
RTU	remote thermal unit
Rules	National Electricity Rules
SCADA	supervisory control and data acquisition
SCS	Standard Control Services
SL-CAPM	Sharpe-Lintner capital asset pricing model
STPIS	Service Target Performance Incentive Scheme
TAB	tax asset base
TAR	total average revenue
totex	total expenditure
TOU	time of use
TSS	Tariff Structure Statement
WACC	weighted average cost of capital