Attachment 1 - Annual Revenue Requirements and Control Mechanism

2025–30 Regulatory Proposal

January 2024

Empowering South Australia

Company information

SA Power Networks is the registered Distribution Network Service Provider for South Australia. For information about SA Power Networks visit sapowernetworks.com.au

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Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal to the Australian Energy Regulator for the 1 July 2025 to 30 June 2030 regulatory control period. The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgement.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes and are therefore subject to ongoing change and development.

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Note

This attachment forms part of our Proposal for the 2025–30 Regulatory Control Period. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 20:

Document	Description
	Regulatory Proposal overview
Attachment 0	Customer and stakeholder engagement program
Attachment 1	**Annual revenue requirement and control mechanism**
Attachment 2	Regulatory Asset Base
Attachment 3	Rate of Return
Attachment 4	Regulatory Depreciation
Attachment 5	Capital expenditure
Attachment 6	Operating expenditure
Attachment 7	Corporate income tax
Attachment 8	Efficiency Benefit Sharing Scheme
Attachment 9	Capital Expenditure Sharing Scheme
Attachment 10	Service Target Performance Incentive Scheme
Attachment 11	Customer Service Incentive Scheme
Attachment 12	Demand management incentives and allowance
Attachment 13	Classification of services
Attachment 14	Pass through events
Attachment 15	Alternative Control Services
Attachment 16	Negotiated services framework and criteria
Attachment 17	Connection Policy
Attachment 17	Tariff Structure Statement Part A
Attachment 18	Tariff Structure Statement Part B - Explanatory Statement
Attachment 19	Legacy Metering
Attachment 20	List of Proposal documentation

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1 Overview

Annual revenue requirement

Our main standard control services (**SCS**) annual revenue requirement (**ARR**) reflects the sum of the revenue building blocks – namely the return on capital, return of capital (depreciation), operating expenditure, revenue adjustments, and corporate tax allowance, for services classified as SCS.

In accordance with the proposed reclassification of legacy metering services to SCS (refer to section 3), we will also have legacy metering SCS. The legacy metering services ARR is determined separately and reflects the return on capital, return of capital (depreciation) and the operating expenditure required to deliver these services in 2025–30.

Our total ARR will be a consolidation of the main SCS and legacy metering services ARR.

Our main SCS revenue requirement is calculated in accordance with the standard post-tax building block approach outlined in the National Electricity Rules (**NER**)[1], and the Australian Energy Regulator's (**AER**) Post-Tax Revenue Model (**PTRM**). The legacy metering services revenue requirement is calculated in accordance with the AER's standardised metering expenditure model and legacy metering services PTRM.

Regulatory control period

SA Power Networks proposes that the next regulatory control period (**RCP**) should be for the five years commencing on 1 July 2025 and ending on 30 June 2030. This is called the 2025–30 RCP in this Attachment.

Lodgement

In accordance with the NER, SA Power Networks is required to lodge its regulatory proposal by 31 January 2024, being 17 months prior to the expiry of the 2020–25 RCP (ie 30 June 2025)[2].

Cost Allocation

The ARR relates to distribution services classified as SCS. All costs in relation to the provision of SCS have been attributed and allocated in accordance with SA Power Networks' approved Cost Allocation Method (**CAM**)[3].

Presentation of numbers

In our Proposal, unless stated otherwise, forecast and historical expenditure is expressed in real terms in June 2025 dollars, while the regulatory asset base (**RAB**) and revenue building blocks are presented in nominal dollars consistent with the AER's PTRM.

We note that totals presented in table rows and columns throughout this Proposal may not necessarily add due to rounding.

1 NER Chapter 6 Part C.

2 NER 6.8.2(b).

3 Version 5, approved by the AER in June 2020; available at: https://www.sapowernetworks.com.au/public/download.jsp?id=309684.

2 Rule requirements

2.1 Control mechanism

Clause 6.2.6(a) of the NER provides that for SCS, the control mechanism must be of the prospective consumer price index (**CPI**) minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C of Chapter 6 of the NER.

The AER must set out its proposed approach to the form of control mechanism and formula that gives effect to the control mechanism in its Framework & Approach (**F&A**) paper for a forthcoming distribution determination[4]. The F&A is not binding on the AER or SA Power Networks[5]. However, clauses 6.12.3(c) and (c1) of the NER provide that the form of control mechanism must be as set out in the relevant F&A unless the AER:

- has departed from the classification of a particular distribution service as set out in the F&A in accordance with clause 6.12.3(b) of the NER and considers that no form of control mechanism set out in the F&A should apply to that distribution service; or
- considers that a material change in circumstances justifies departing from the formula that gives effect to the control mechanism set out in the F&A.

2.2 Annual revenue requirement

Clause 6.8.2(c)(3) of the NER provides that our Proposal must include a building block proposal for direct control services classified as SCS. Part C of Chapter 6 of the NER sets out the procedure and approach for making a building block proposal and determination.

Clause 6.3.2 of the NER provides that a building block determination is to specify (amongst other things) the ARR for each regulatory year of the relevant RCP. The building blocks are set out in clause 6.4.3 of the NER for each regulatory year of the RCP, as follows:

- indexation of the RAB;
- return on capital for that regulatory year;
- depreciation for that regulatory year;
- estimated cost of corporate income tax for the Distribution Network Service Provider (**DNSP**) for that regulatory year;
- revenue increments and decrements (if any) for that regulatory year arising from the application of the efficiency benefit sharing scheme (**EBSS**), capital expenditure sharing scheme (**CESS**), service target performance incentive scheme (**STPIS**), demand management incentive scheme (**DMIS**), the demand management innovation allowance mechanism (**DMIAM**) or small-scale incentive scheme;
- revenue decrements (if any) arising from use of shared assets;
- other revenue adjustments (if any) arising from the application of a control mechanism in the previous RCP; and
- forecast operating expenditure for that regulatory year.

Clause 6.5 of the NER contains the specific requirements for these building block components, which are used to establish an unsmoothed revenue requirement. The resulting price path to deliver this revenue is then smoothed with X factors, in accordance with the requirements of clause 6.5.9 of the NER.

4 NER 6.8.1(b)(1)(i) and (2)(ii).

5 NER 6.8.1(f).

This Attachment outlines the derivation of allowable annual revenues, prices and the associated X factors, to meet the requirements of clause S6.1.3(6) of the NER. The associated detail of all amounts, values and inputs relevant to the calculation is contained in other Attachments to this Proposal, its Supporting Documents and in the PTRM.

3 Reclassification of Legacy Metering Services

In August 2023, the Australian Energy Market Commission (**AEMC**) issued its final report on the review of the regulatory framework for metering services. Amongst other things, the AEMC report recommends accelerating the roll out of smart meters to all customers by 2030. The AEMC's final report is considered a material change in circumstances that allows for the departure from the service classification and the form of control detailed within the AER's final F&A for SA Power Networks in accordance with section 6.12.3 (b) of the NER.

To assist DNSPs in preparing their revised regulatory proposal and proposals, the AER released a 'Legacy metering services - guidance note' in November 2023. Noting the AEMC's final decision, the AER considers it would be more appropriate to reclassify legacy metering services as SCS for the 2025–30 RCP. In doing so, metering services expenditures will be treated as a sub-component of SCS.

Metering will be modelled separately and there will be a separate ARR output. This will maintain the transparency and assist with any 'true-ups' or adjustments (such as cost pass throughs) that may need to occur during the RCP.

The legacy metering component of SCS will be excluded from all incentive scheme considerations.

Refer to **Attachment 13 – Classification of Services** for further details on the proposal to reclassify Legacy Metering Services to SCS. **Attachment 19 – Legacy Metering** sets out our Legacy Metering Services Proposal for the 2025–30 RCP.

4 Control mechanism for SCS

4.1 Form of control mechanism

The AER decided in its final F&A for SA Power Networks for the 2025–30 RCP, that our SCS are to continue to be regulated via a revenue cap form of control[6].

Under a revenue cap form of control, the AER sets the total allowed revenue (or annual revenue requirement) for each regulatory year of the 2025–30 RCP. SA Power Networks must comply with the revenue cap by forecasting sales for the next regulatory year and setting prices so the expected revenue is equal to or less than the total revenue allowed. At the end of each regulatory year, SA Power Networks will report actual differences to the AER and any over or under recovery is deducted from or added to the total revenue in future regulatory years.

The main SCS annual revenue allowances will also be adjusted for outcomes of the various incentive schemes listed in clause 6.4.3 of the NER and may incorporate cost adjustments for pass through events. Our reasons for accepting this form of control were set out in our submissions to, and considered during, the F&A process. We also note that the South Australian solar feed-in tariff jurisdictional scheme will conclude in June 2028. This raises concerns about the ability for SA Power Networks to appropriately recover or return to customers any under or over recovery through the existing jurisdictional scheme following cessation of the scheme. Following consultation with the AER in developing the F&A, it was agreed that using the B-factor may be a pragmatic approach, with an appropriate materiality threshold. Once the true-up amounts are below this threshold, it may be appropriate to move these amounts to the B-factor to maintain transparency and accountability, where possible. The AER will define both the B-factor and the unders and overs accounts in its regulatory determination.

SA Power Networks is also proposing a revenue cap form of control for legacy metering services proposed to be reclassified as SCS for the 2025–30 RCP. A separate under or over recovery account is proposed to apply to the Legacy Metering Services to allow SA Power Networks to recover its reasonable costs and reduce the risks involved in the smart meter rollout.

Details in relation to our sales forecasts and pricing structure by which SA Power Networks proposes to recover the revenue allowed by the AER for the 2025–30 RCP are contained in **Attachment 18 – Tariff Structure Statement – Part A** and **Part B**.

4.2 Formula for control mechanism

The final F&A sets out the AER's proposed formula to give effect to the revenue cap form of control for SCS[7].

As detailed in section 3, the AEMC’s final report is considered a material change in circumstances that allows for the departure from the form of control detailed within the AER’s final F&A. We propose to amend the price control formulae for SCS to align with that contained within the AER’s Guidance note. The price control formulae for SCS is shown in Appendix A at the end of this document.

SA Power Networks will demonstrate compliance with the revenue cap control mechanism and formula for SCS by proposing tariffs that comply with this formula in its annual pricing proposal for each regulatory year of the 2025–30 RCP.

6 AER, *Final framework and approach, SA Power Networks 2025–30*, July 2023, page 13.

7 Ibid, page 15.

5 Annual revenue requirement

As discussed above, our ARR will be a consolidation of the main SCS and legacy metering services outputs outlined in sections 5.1 and 5.2.

5.1 Main SCS annual revenue requirement

The main SCS ARR, developed utilising the building block approach, comprises the sum of a number of components which are discussed in detail in other Attachments to this Proposal. The building block components and resulting ARR derived from the main SCS PTRM are set out in Table 1.

Table 1: Proposed main SCS Revenue for the 2025–30 RCP ($ million, nominal)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Return on capital	315.5	330.3	348.3	370.2	395.7	1,760.0
Regulatory depreciation	279.5	284.6	280.2	224.2	224.9	1,293.3
Operating expenditure	399.3	411.6	426.4	441.4	459.9	2,138.6
Revenue adjustments	(25.5)	(46.5)	(46.9)	40.7	11.0	(67.1)
Net tax allowance	11.1	11.2	7.2	0.4	-	29.9
Annual revenue requirement (unsmoothed)	979.9	991.3	1,015.2	1,077.0	1,091.5	5,154.8
Annual revenue requirement (smoothed)	**952.0**	**980.6**	**1,010.0**	**1,097.0**	**1,124.4**	**5,164.0**
Revenue P_0 and X-factors	(4.94%)	(0.52%)	(0.52%)	(6.02%)	0.00%	

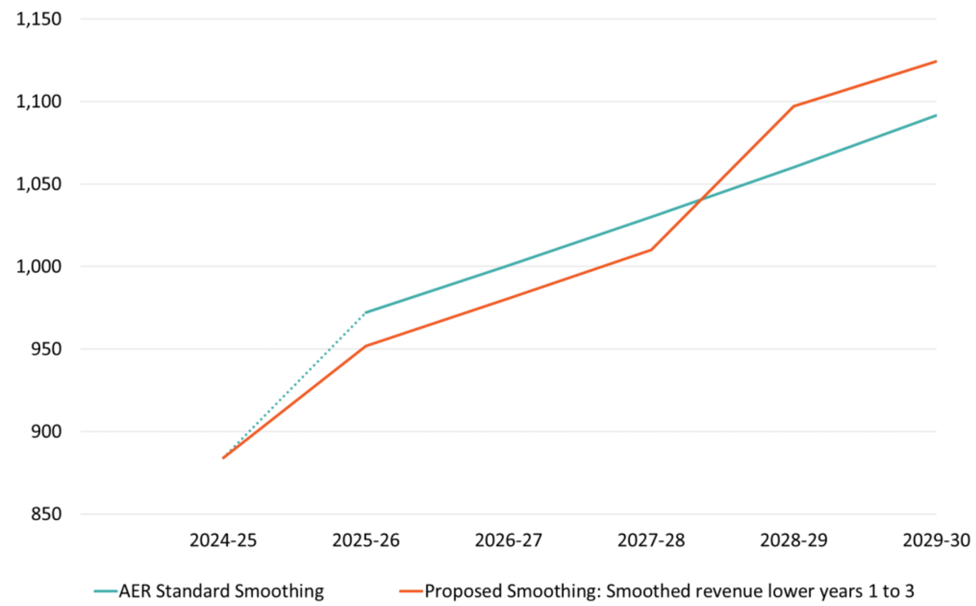
The P_0 revenue increase and X-factors proposed in Table 1 are SA Power Networks' preferred approach to reducing price volatility, in line with AEMC pricing policy objectives. This non-standard approach to distribution revenue smoothing will recover less revenue in years 1-3, lowering average customer bills in these years, in response to ongoing affordability and cost of living concerns. There will be a step increase in revenue recovery and average bills from year four but this increase will be offset by reductions in other network charges, specifically jurisdictional service obligation (**JSO**) charges, when the South Australian Government's solar 44c/kWh photo-voltaic feed-in tariff (**PV FiT**) scheme concludes in June 2028. This non-standard smoothing approach was endorsed by our Community Advisory Board on 21 November 2023.

The 44c/kWh PV FiT jurisdictional scheme obligation concludes on 30 June 2028, lowering network charges from 2028/29 for all customers. We have identified this as an opportunity to alleviate customer cost of living pressures in the first three years of the regulatory control period by proposing to delay a portion of revenue recovery until 2028/29 and 2029/30.

This smoothing approach would result in lower distribution revenues over the first three years of $65 million, to be collected after the 44c/kWh PV FiT scheme expires in June 2028. An average residential customer will have a combined Distribution Use of System (**DUoS**) and JSO annual bill which is lower in real and nominal terms in 2028/29 than 2023/24.

In the final regulatory year, the smoothed revenue will be three percent above the 2029/30 building block revenue, which is within the three percent target band that the AER has applied in other distribution network determinations[8]. The AER's standard smoothing approach would result in a P_0 reduction of 7.27 percent and subsequent annual real price increases of 0.43 percent, refer to Figure 1.

Figure 1: Comparison of price smoothed outcomes ($ million, nominal)



5.2 Legacy metering services annual revenue requirement

The legacy metering services ARR has been developed using the legacy metering services PTRM, as discussed in further detail in **Attachment 19**. Legacy metering services are proposed to be recovered across all customers, by way of a new fixed charge. If accepted, our legacy metering services ARR will deliver residential customers and small and medium businesses a five year annual average $13.75 increase (nominal) in their distribution charges from 1 July 2025.

The building block components and resulting ARR derived from the main SCS PTRM are set out in Table 2. Legacy metering services ARR will be smoothed separately however will have the same smoothing profile as the main SCS PTRM.

Table 2: Proposed legacy metering services SCS Revenue for the 2025–30 RCP ($ million, nominal)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Return on capital	0.05	-	-	-	-	0.05
Regulatory depreciation	0.80	0.01	-	-	-	0.81
Operating expenditure	12.13	12.66	13.08	13.51	13.48	64.86
Revenue adjustments	-	-	-	-	-	-
Net tax allowance	0.12	-	-	-	-	0.12
Annual revenue requirement (unsmoothed)	13.11	12.67	13.08	13.51	13.48	65.84
Annual revenue requirement (smoothed)	**12.68**	**12.83**	**12.99**	**13.55**	**13.89**	**65.93**

8 See, for example, AER, *Draft Decision: Ausgrid Electricity Distribution Determination 2024 to 2029, Attachment 1- Annual revenue requirement*, September 2023, page 13. Similarly referred to in AER, *Draft Decision: TasNetworks Distribution Determination 2024 to 2029, Attachment 1- Annual revenue requirement*, September 2023, page 5.

5.3 Total annual revenue requirement

Total annual revenue requirement comprises the main SCS ARR plus legacy metering services ARR, summarised in Table 3.

Table 3: Total SCS Revenue for the 2025–30 RCP ($ million, nominal)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Annual revenue requirement (smoothed) - Main SCS	951.98	980.57	1,009.99	1,097.02	1,124.44	5,164.00
Annual revenue requirement (smoothed) – Legacy Meters	12.68	12.83	12.99	13.55	13.89	65.93
Annual revenue requirement (smoothed) - Total	**964.66**	**993.40**	**1,022.98**	**1,110.57**	**1,138.33**	**5,229.93**

5.4 Revenue adjustments

Revenue adjustments for the 2025–30 RCP have been included for SA Power Networks' EBSS, CESS, DMIS, DMIAM (applicable for the 2025–30 RCP) and any shared asset cost reduction. A summary of adjustments is shown in Table 4.

Table 4: Revenue adjustments for the 2025–30 RCP ($ million, nominal)

	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
EBSS	5.3	(28.0)	(28.1)	30.0	-	(20.9)
CESS	(2.4)	(2.4)	(2.5)	(2.6)	(2.6)	(12.5)
CESS true-up for 2019/20	7.2	7.4	7.5	7.7	7.9	37.7
DMIS and DMIAM	1.0	1.0	1.1	1.2	1.2	5.5
Shared assets	(2.0)	(2.0)	(2.1)	(2.1)	(2.2)	(10.3)
Innovation Fund (Opex Component)	0.8	0.8	0.9	0.9	0.9	4.3
Cable and Conductor 2020–25 Adjustment	(35.4)	(23.2)	(23.8)	5.6	5.8	(71.0)
Total revenue adjustments	**(25.5)**	**(46.5)**	**(46.9)**	**40.7**	**11.0**	**(67.1)**

5.5 EBSS

The AER has developed and applied the latest version of the EBSS (Version 2) to SA Power Networks for the 2015–20 RCP in accordance with clause 6.5.8 of the NER. We forecast a carry-over EBSS loss of $20.9 million ($20.4 million in $ June 2025) as shown in Table 4. In accordance with the final F&A, we propose to continue to apply Version 2 of the EBSS for the 2025–30 RCP.

Full details in relation to the application of the EBSS to this Proposal and the 2025–30 RCP are contained in **Attachment 8 – Efficiency Benefit Sharing Scheme**. The legacy metering component of SCS will be excluded from the EBSS considerations, as per the AER's Guidance note for legacy metering services, released October 2023.

5.6 CESS

The AER has developed and applied its CESS (Version 1) to SA Power Networks for the 2020–25 RCP in accordance with clause 6.5.8A of the NER. We forecast a carry-over CESS payment of $25.2 million ($23.4 million in $June 2025) as shown in Table 4. In accordance with the final F&A, we propose to continue to apply Version 2 of the CESS for the 2025–30 RCP.

Full details in relation to the application of the CESS to this Proposal and the 2025–30 RCP are contained in **Attachment 9 – Capital expenditure sharing scheme**. The legacy metering component of SCS will be excluded from the CESS considerations, as per the AER's Guidance note for legacy metering services, released October 2023.

5.7 DMIS and DMIAM

The DMIS and DMIAM applying to SA Power Networks for the 2020–25 RCP is still in effect. We propose to continue to apply the DMIS and DMIAM for the 2025–30 RCP, consistent with the AER's proposed position as set out its final F&A.[9]

Full details in relation to the application of the DMIS and DMIAM to this Proposal and the 2025–30 RCP are contained in **Attachment 12 – Demand management incentives and allowances**.

5.8 Shared Assets

Where an asset is used to provide both SCS and unregulated services, clause 6.4.4 of the NER allows the AER to reduce SA Power Networks' SCS regulated revenue by an amount that the AER considers is reasonable to reflect such part of the cost of the asset that is being recovered through charging for unregulated services. Clause 6.4.4 of the NER requires the AER to have regard to the shared asset principles and the Shared Asset Guideline (**SAG**) in determining shared asset cost reductions.

Paragraph 2.4 of the SAG states that service providers may include in a regulatory proposal for an RCP proposed cost reductions for the AER's approval.

The shared asset cost reduction methodology set out in the SAG requires service providers to determine the forecast shared asset unregulated revenue (**SAUR**) for an RCP.

We have used the same methodology for estimating of our SAUR as accepted by the AER in our distribution determination for the 2020–25 RCP. This involves calculating the sum of:

- for unregulated services that rely on the use of shared assets, such as pole rental and other facilities access or asset rental services — the unregulated revenue earned from those services; and
- for each unregulated service that partially uses shared assets, such as unregulated construction and maintenance and where shared asset revenues are absorbed in overall project revenues — we have used the allocation apportioned by our approved CAM to derive those revenues.

Shared asset cost reductions are subject to a materiality threshold. Unregulated use of shared assets is material when the SAUR in a specific regulatory year is expected to be greater than one percent of its total ARR for that regulatory year. We expect our SAUR to exceed the materiality threshold for each regulatory year of the 2025–30 RCP and propose a shared asset cost reduction of $10.3 million ($ nominal) in accordance with the SAG as summarised in Table 5.

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9 AER, *Final framework and approach, SA Power Networks 2025–30*, page 20.

Table 5: Shared asset cost reduction for the 2025–30 RCP ($ million, nominal)

Shared Asset Cost Adjustment	2025/26	2026/27	2027/28	2028/29	2029/30	2025–30 RCP
Average SAUR	19.6	20.1	20.6	21.1	21.6	103.0
Smoothed ARR	952.0	980.6	1010.0	1097.0	1124.4	
Average SAUR as proportion of ARR	2.1%	2.0%	2.0%	1.9%	1.9%	
Material (Y/N)	Y	Y	Y	Y	Y	
Shared asset cost reduction	2.0	2.0	2.1	2.1	2.2	10.3

Detailed calculation of SA Power Networks' SAUR can be found in our Shared Asset Model set out in **Supporting Document 1.2 – Shared Asset Model**.

5.9 Innovation Fund

As a result of our engagement program, we have proposed a number of initiatives involving innovation into an explicit 'Innovation Fund'.

We propose that our Innovation Fund would be capped at $20 million for 2025–30, split 80 percent into capital expenditure and 20 percent into operating expenditure. The fund would have a scope targeting broad areas of innovation that collectively address the key focus areas we heard through our engagement.

The Innovation Fund is discussed further in **Supporting Document 5.7.7 – Innovation Fund – Business Case**.

5.10 Cable and Conductor Repairs Adjustment for 2020–25

In preparing our Proposal for 2025–30, we identified that an opex step change for Cable and Conductor repairs included in the 2020–25 Distribution Determination, was incorrect. This step change involved changing the regulatory treatment of this expenditure from capex to opex. We have discovered that this expenditure was already treated as opex in regulatory reporting.

We are liaising further with the AER on how to address this issue. In this Proposal we are assuming that this will be addressed by way of a revenue adjustment that would result in the same outcome as if there was a Revocation and Substitution Determination for the 2020–25 RCP, made in accordance with NER Clause 6.13.

The steps taken to calculate impacts as though a Revocation and Substitution Determination was done are:

1. Calculate an adjusted opex allowance for 2020–25 reversing Cable and Conductor repairs step change.
2. Calculate an adjusted capex allowance for 2020–25 reversing the reduction made associated with the Cable and Conductor repairs step change.
3. Calculate an adjusted EBSS for 2020–25 based on the adjusted opex allowance.
4. Calculate an adjusted CESS for 2020–25 based on the adjusted capex allowance.
5. Recalculate the 2020–25 Determination revenue with the adjusted opex and capex allowances, using the PTRM.
6. Calculate the revenue adjustment arising from the recalculated 2020–25 Determination revenue. The adjustment comprises:
    - Difference in EBSS and CESS between the original calculations and the adjusted calculations in steps 3 and 4 above; and
    - Difference in 2020–25 revenue in step 5 from the original determination revenue, including the time value of adjusting revenue over 2025/26 to 2027/28.

We have incorporated this revenue adjustment into the revenue adjustments for 2025–30, as per Table 4. This assumes the revenue adjustment is returned to customers over the first three years of the regulatory period and includes the impact of the time value of money.

These steps and calculations will be reviewed with the AER and adjusted based on AER guidance.

5.11 Export Service Incentive Scheme

In June 2023, the AER published a new optional export service incentive scheme. We are not proposing an export service incentive scheme for the 2025–30 RCP.

Appendix A: Price control formulae for SCS

Reproduced from the AER's Legacy metering services – Guidance note – October 2023

	Equation	where
1.	$TAR_t \geq \sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} q_t^{ij}$	i=1,…,n j=1,…,m t=1,2,3,4,5
2.	$TAR_t = TAR_t^{SCS} + TAR_t^{M}$	t=1,2,3,4,5
3.	$TAR_t^{SCS} = AAR_t^{SCS} + I_t^{SCS} + B_t^{SCS} + C_t^{SCS}$	t=1,2,3,4,5
4.	$AAR_t^{SCS} = AR_t^{SCS}$	t=1
5.	$AAR_t^{SCS} = AAR_{t-1}^{SCS} \times (1 + \Delta CPI_t) \times (1 - X_t^{SCS})$	t=2,3,4,5
6.	$TAR_t^{M} = AAR_t^{M} + I_t^{M} + B_t^{M} + C_t^{M}$	t=1,2,3,4,5
7.	$AAR_t^{M} = AR_t^{M}$	t=1
8.	$AAR_t^{M} = AAR_{t-1}^{M} \times (1 + \Delta CPI_t) \times (1 - X_t^{M})$	t=2,3,4,5
9.	$B_t = b_t + A_t$	t=1,2,3,4,5
10.	$b_t = -O_t \times (1 + WACC_t)^{0.5}$	t=1,2,3,4,5
11.	$A_t = a_{t-2}^{1} \times (1 + WACC_t) \times (1 + WACC_t) + a_{t-1}^{2} + (1 + WACC_t) + a_t^{3}$	t=1,2,3,4,5
12.	$WACC_t = (1 + rvWACC_t) \times (1 + CPI_t) - 1$	t=1,2,3,4,5

Variable	Represents
t	the regulatory year with t = 1 being the 2024–25 financial year.
TAR_t	the total annual revenue for year t, calculated as per formula 2 above.
TAR_t^{SCS}	the total annual revenue for main SCS for year t, calculated as per formula 3 above.
TAR_t^{M}	the total annual revenue for metering for year t, calculated as per formula 6 above.
p_t^{ij}	the price of component 'j' of tariff 'i' for year t.
q_t^{ij}	the forecast quantity of component 'j' of tariff 'i' for year t.
AR_t^{SCS}	the annual smoothed revenue requirement in the main SCS PTRM for year t.
AR_t^{M}	the annual smoothed revenue requirement in the metering PTRM for year t.
AAR_t^{SCS}	the adjusted annual smoothed revenue requirement for main SCS for year t., calculated as per formulae 4 and 5 above.
AAR_t^{M}	the adjusted annual smoothed revenue requirement for metering for year t, calculated as per formulae 7 and 8 above.
I_t^{SCS}	the sum of incentive scheme adjustments for year t. Where applicable, incorporates revenue adjustments relating to the outcomes of: • the STPIS (S-factor) in relation to regulatory year t-2 • the DMIS in relation to regulatory year t-2 the DMIAM relating to the 2019–24 regulatory control period to be applied in regulatory year t=2 only • the customer service incentive scheme (H-factor) in relation to regulatory year t-2 • the export service incentive scheme (E-factor) in relation to the regulatory year t-2 • any other related incentive schemes as applicable that are to be applied in year t.
B_t^{SCS}	the sum of annual adjustment factors to balance the unders and overs account for year t, calculated as per formula 9 above. It includes: • the true-up of any under or over recovery of actual revenue (b-factor) collected through DUoS charges calculated using the method outlined in formula 7. • Any other bespoke adjustments the AER deems necessary (A-factor). These include but are not limited to: residuals of jurisdictional scheme amounts upon cessation, applicable licence fee payments, or other true-ups not provided for elsewhere. These adjustments will apply the time value of money where appropriate, calculated as per formula 11 above.

C_t^{SCS}	the approved pass-through amounts (positive or negative) for year t, as determined by the AER. It will also include any annual or end of period adjustments for year t.
I_t^M	the sum of incentive scheme adjustments for metering services for year t. Currently no incentive schemes apply.
B_t^M	the sum of annual adjustment factors to balance the unders and overs account for year t, calculated as per formula 9 above. It includes: • the true-up of any under or over recovery of actual revenue (b-factor) collected through metering services charges calculated using the method outlined in formula 7. • Any other bespoke adjustments the AER deems necessary (A-factor). These include but are not limited to the true-up of operating expenditure explicitly related to variances from forecast metering volumes, or other true-ups not provided for elsewhere. These adjustments will apply the time value of money where appropriate, calculated as per formula 11 above.
C_t^M	the approved pass-through amounts (positive or negative) for metering services for year t, as determined by the AER. It will also include any annual or end of period adjustments for metering services for year t.
ΔCPI_t	the annual percentage change in the Australian Bureau of Statistics' Consumer Price Index All Groups, Weighted Average of Eight Capital Cities* from December in year t–2 to December in year t–1. For example, for the 2024–25 year, t–2 is December 2022 and t–1 is December 2023.
X_t^{SCS}	the X-factor in year t, incorporating annual adjustments to the main SCS PTRM for the trailing cost of debt.
X_t^M	the X-factor in year t, incorporating annual adjustments to the metering PTRM for the trailing cost of debt.
b_t	the true-up for the balance of the respective unders and overs account in year t, calculated as per formula 10 above.
O_t	the opening balance of the respective unders and overs account in year t as calculated by the method in Appendix A of the control mechanisms draft decision.
$WACC_t$	the approved weighted average cost of capital (**WACC**) used in regulatory year t in the DUoS unders and overs account in Appendix A. The WACC is updated annually to apply actual inflation, calculated as per formula 12 above. It also applied to true-up mechanisms to adjust for the time value of money.
A_t	the sum of bespoke adjustments, including the application of the time value of money where appropriate, calculated as per formula 11 above.
a_t^1	the bespoke adjustment '1' for year t. Formula 11 above demonstrates the application of the time value of money for different bespoke adjustments relating to different regulatory years.
$rvWACC_t$	the real vanilla WACC provided in the annually updated PTRM for year t.

Glossary

Acronym / term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
CAM	Cost Allocation Method
Capex	Capital expenditure
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution network service provider
DUoS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
F&A	Framework & Approach
JSO	Jurisdictional Service Obligation
NER	National Electricity Rules
Opex	Operating expenditure
PTRM	Post-Tax Revenue Model
PV FiT	Photo-voltaic feed-in tariff
RAB	Regulatory Asset Base
RCP	Regulatory Control Period
SAG	Shared Asset Guideline
SAUR	Shared asset unregulated revenue
SCS	Standard control services
SSIS	Small-Scale Incentive Scheme
STPIS	Service Target Performance Incentive Scheme
WACC	Weighted Average Cost of Capital