Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review - Revised Regulatory Proposal

Attachment 07-01

Response to the AER's draft decision - Incentive mechanisms

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Abbreviations

AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CESS	Capital Expenditure Sharing Scheme
CSIS	Customer Service Incentive Scheme
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
EBSS	Efficiency Benefit Sharing Scheme
EDCoP	Electricity Distribution Code of Practice
ERG	Energy Reference Group
ESIS	Export Service Incentive Scheme
ESV	Energy Safe Victoria
EV	Electric Vehicle
F&A	Framework and Approach Paper
FCAS	Frequency Control Ancillary Services
GSL	Guarantee Service Level
IRU	Ignition Risk Units
JEN	Jemena Electricity Networks (Vic) Ltd.
MAIFIe	Momentary Interruption Frequency Index Event
NBI	Neighbourhood Battery Initiative
NEL	National Electricity Law
NER	National Electricity Rules
R&D	Research and Development
RAB	Regulated Asset Base
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
VCR	Value of Customer Reliability
VEBM	Victorian Emergency Backstop Mechanism

Overview

An important element of the regulatory framework is the application of various incentive schemes that seek to ensure a Distribution Network Service Provider (**DNSP**) incurs efficient operating and capital expenditure across a regulatory control period, while also maintaining appropriate levels of reliability and customer service.

As part of the regulatory price determination process, the Australian Energy Regulator (**AER**) must make a decision on the outcome of the incentive schemes applied to Jemena Electricity Networks Vic Ltd (**JEN**) in the current regulatory control period (2021 – 2026), and also decide which schemes will apply in the next regulatory control period (2026 – 2031). Table 4-1 below outlines JEN's response to the AER's draft decision.

Table 4-1: JEN's response to the AER's draft decision

Incentive scheme	JEN response to AER draft decision
Capital Expenditure Sharing Scheme (CESS)	Partially accept.
Efficiency Benefit Sharing Scheme (EBSS)	Partially accept.
Customer Service Incentive Scheme (CSIS)	Do not accept.
Service Target Performance Incentive Scheme (STPIS)	Partially accept.
Demand Management Incentive Scheme (DMIS)	Accept.
Demand Management Allowance Mechanism (DMIAM)	Accept.
Victorian F-Factor Scheme	Accept.

Where JEN has not accepted the AER's draft determination, we have included our reasoning in sections 1 to 4 below.

List of incentive schemes attachments

Table 4–2: List of incentive scheme attachments

Reference	Document title	Author
07-01	Incentive schemes (this document)	JEN
06-01	Operating expenditure	JEN
06-05	Insurance operating expenditure	JEN
06-06	John Middleton Legal Opinion for Victorian DNSP Insurance Opex	DLA Piper
06-07	Victorian DNSP insurance premiums	Houston Kemp
06-08	Insurance premium forecast 2026-31 and retrospective forecast 2021-26	Lockton
08-09M	EBSS model	JEN
08-10M	CESS model	JEN
05-01	Capital expenditure	JEN
05-02M	SCS Capex Model	JEN
07-03M	STPIS model	JEN
07-02M	CSIS calculation model	JEN

Reference	Document title	Author
06-06	John Middleton Legal Opinion for Victorian DNSP Insurance Opex	DLA Piper
06-07	Victorian DNSP insurance premiums	Houston Kemp
06-08	Insurance premium forecast 2026-31 and retrospective forecast 2021-26	Lockton
Support	FTA pass through application	JEN
Support	FTA Appendix B pass through expenditure model	JEN
Support	MITE pass through application	JEN
Support	MITE Attachment A pass through expenditure model	JEN
Support	VEBM2 pass through application	JEN
Support	VEBM2 Appendix C pass through expenditure model	JEN
Support	ASMR pass through application - 20251113	JEN
Support	ASMR Attachment A pass through expenditure model - 20251113	JEN

1. Capital Expenditure Sharing Scheme

1.1 Outcome of CESS in the current regulatory period

In our initial regulatory proposal, we estimated a CESS revenue of $3M, based on actual capital expenditure data to 2023–24 and forecast data for 2024–25 and 2025–26. This estimate also assumed that our reopener application[1] for unforeseen data centre connections was successful.

The AER's draft decision instead calculated a CESS penalty of $26M. This reflects the withdrawal of our reopener application, along with updated inflation and weighted-average cost of capital (**WACC**) assumptions.

In this revised regulatory proposal, we have updated the CESS calculation to reflect:

- Audited actual capital expenditure for 2024–25
- Revised forecast capital expenditure for 2025–26
- Updates to capital contributions for 2021–22 to 2023–24, on an as-incurred basis
- Inclusion of four new cost pass-through applications.[2]

Table 1-1 below provides a comparison of CESS outcomes across the initial regulatory proposal, draft decision, and revised regulatory proposal.

Table 1-1: CESS revenue between initial regulatory proposal, draft decision and revised regulatory proposal ($2026, millions)

Description	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
CESS revenue	3.1	-25.5	-34.5

1.1.1 Capital contributions – Transition to 'as incurred' basis

JEN has historically reported capital contributions on an 'as commissioned' basis, consistent with the statutory auditing standards required under the Regulatory Information Notice (**RIN**). In contrast, the regulatory allowances are set on an 'as incurred' basis. This creates a timing misalignment between allowances and actual capital expenditure, potentially leading to misestimation of CESS outcomes.

In the current regulatory period, JEN is experiencing unprecedented growth in large connection infrastructure projects spanning multiple years which has skewed the portfolio, exacerbating the impacts of the timing misalignment.

In November 2024, the AER issued a guidance note clarifying the timing of recognising capital contributions (contributions guidance).[3] It requires cash contributions for connection projects exceeding $200,000 and spanning more than 12 months to be individually reported on an 'as incurred' basis.[4]

Given the limited time between the issuance of the guidance and our initial regulatory proposal submission, we were unable to retrospectively review and restate JEN's RINs from 2021–22 to 2023–24 before submitting our

1 JEN, *Application to reopen the 2021-26 Electricity Distribution Price Review Determination, Reopening JEN's distribution determination for capital expenditure*, 15 October 2024.

2 JEN – RP – Support – FTA pass through application – 20251104, JEN – RP – Support – MITE pass through application – 20251030, JEN – RP – Support – VEBM2 pass through application – 20251105, JEN – RP – Support – ASMR pass through application – 20251113

3 AER, *Reporting capital contributions AER Guidance Note for electricity distributors*, November 2024.

4 meaning qualifying connection projects are to recognise capital contributions in proportion to the connection project capital expenditure spent

initial regulatory proposal. As a transitional measure, the initial regulatory proposal applied a one-off catch-up adjustment in 2024–25 to estimate cumulative ‘as incurred’ contributions for those years.

In its draft decision, the AER requested that JEN back-cast capital contributions on an 'as incurred' basis for each year of the 2021-26 regulatory period in the revised regulatory proposal.

In response, JEN has now back-cast capital contributions for 2021–22 to 2023–24 on an 'as incurred' basis. These values are currently undergoing audit as part of the 2024–25 Annual Regulatory Information Order (**RIO**) process, due for submission to the AER on 30 November 2025. Actual 'as incurred' capital contributions for 2024–25 have also been included in our revised regulatory proposal.

As the revised regulatory proposal is due on 1 December 2025, we have used unaudited numbers as placeholders in our revised regulatory proposal. We note that the AER will update these values to reflect audited actuals in its final determination, once the RIO audit is complete.

Table 1-2 below presents the updated values for the revised regulatory proposal, alongside a comparison with the initial regulatory proposal.

Table 1-2: Capital contributions on ‘as incurred’ basis in revised regulatory proposal ($2026, millions)

Capital contributions	Unaudited actuals				Estimate
	FY22	FY23	FY24	FY25	FY26
Revised regulatory proposal – as incurred	80.2	84.3	100.9	75.8	143.0
Initial regulatory proposal – as commissioned + catch-up adjustment in FY25	48.2	74.1	96.2	162.8	180.6

1.1.2 Inclusion of new cost pass-through applications

Recently, new regulatory obligations have been imposed on JEN and other Victorian distribution network service providers (DNSPs) during the 2021–26 regulatory period, these include:

- Flexible trading arrangements (FTA) – An amendment to the National Electricity Rules (NER) which allows segregation of loads within a facility for retailing and market settlement along with the introduction of new meter types.
- Victorian Emergency Backstop Mechanism #2 (VEBM2) – A further amendment to the original Victorian Order in Council requiring DNSPs to manage export services when directed to do so by the Australian Energy Market Operator (AEMO).
- Market Interface Technology Enhancements (MITE) – A technology platform enhancement for AEMO’s market systems
- Accelerated meter rollout (ASMR) – A NER change to mandate the accelerated roll out of smart meters. Mostly directed at non-Victorian states, there are some obligations that continue to apply in Victoria.

In response, JEN submitted four cost pass-through applications in November 2025 to recover the efficient costs of meeting these obligations.

These costs, incurred in 2024–25 and 2025–26, have been included in our revised proposal capital expenditure forecasts. However, without a corresponding increase in the capital expenditure allowance, JEN would face an additional CESS penalty to meet these new regulatory obligations. To avoid this perverse outcome, we have adjusted the capital expenditure allowance used for CESS calculations to include the amounts submitted in our pass-through applications.

Table 1-3 below sets out the adjusted capital expenditure allowance for CESS purposes, including the breakdown of each pass-through item.

Table 1-3: Net Capital expenditure allowance for CESS purpose ($2026, millions)

Item	FY22	FY23	FY24	FY25	FY26	Total
Net Capital expenditure allowance in AER-approved PTRM	184.9	176.3	155.7	142.5	113.3	772.6
Cost passthrough 1: FTA	-	-	-	0.6	12.9	13.6
Cost passthrough 2: VEBM2	-	-	-	0.6	16.7	17.2
Cost passthrough 3: MITE	-	-	-	0.4	4.7	5.2
Cost passthrough 4: ASMR	-	-	-	-	2.1	2.1
Total	184.9	176.3	155.7	144.1	149.7	810.6

1.1.3 Our revised regulatory proposal

Following the updates outlined above, including adjustments for capital contributions, updates to actual and forecast capital expenditure, and cost passthrough applications, JEN's revised CESS outcome is summarised in Table 1-4 below.

Table 1-4: Proposed CESS outcomes for the next regulatory period ($2026, millions)

CESS	FY27	FY28	FY29	FY30	FY31	Total
Reward (+) / Penalty (-)	-6.9	-6.9	-6.9	-6.9	-6.9	-34.5

Details of the CESS calculations are provided in *JEN – RP - Att 08-10M CESS model – 20251201*.

1.2 CESS for the next regulatory period

The AER has accepted the continuation of CESS for the next regulatory period. In its draft decision, the AER noted that the updated CESS guideline,[5] published in August 2025, will apply to JEN. The revised guideline introduces two key changes:

- Volumetric adjustments for business-as-usual (**BAU**) connections
- Ex-post exclusions for large bespoke connection projects.

JEN accepts the AER's decision to apply the updated scheme but seeks further clarification on the volumetric and ex-post adjustments. We discuss these below.

1.2.1 Volumetric adjustment for business-as-usual connections

The AER's revised CESS guideline provides a broad definition for BAU connections. It draws the relationship between the forecast connection capital expenditure in the electricity distribution price review determination process and the volumetric adjustment:[6]

> *Business-as-usual connection refers to common connection types that may include simple or complex connections for residential, commercial & industrial, subdivision and embedded networks. In relation to these connection types, we expect DNSPs to propose capex based on socio-economic*

[5] AER, Capital Expenditure Incentives Guideline v4 – August 2025.

[6] AER, Capital Expenditure Incentives Guideline v4 – August 2025, p. 7.

characteristics expected in forecast period. ...In determining the volumetric adjustments we will consider a DNSP's forecasts for connection sub-categories in its revenue determination process.

While the guideline has not specified the detailed mechanism, it outlines the principle of how the adjustment should apply:[7]

In making the volumetric adjustment, we will consider changes in connections volume, for each business-as-usual connection type, so that a DNSP is not rewarded or penalised for changes in the volume of work it needs to undertake. In this scenario, we will exclude a portion of the connection capex related to the increases or decreases in volumes, for each business-as-usual connection type, from our CESS calculations when determining the relevant CESS payments.

To support the implementation of this adjustment in the updated CESS, we propose to address:

- the connection categories which are subject to adjustment
- the allowed unit rates under each subcategory
- the forecast volumes underpinning the approved connection capital expenditure.

As the draft decision does not provide further guidance, we propose the following connection categories, unit rates, and forecast volumes used in our proposed BAU connection capital expenditure in Table 1-5 below.

Table 1-5: Proposed BAU connection capital expenditure subject to volumetric adjustment ($2026, dollars)

Item	FY27	FY28	FY29	FY30	FY31
Residential (including subdivision)					
Total net capital expenditure ($)(1)	19,358,208	18,388,075	18,643,151	19,310,074	19,759,878
Forecast number of new connections(2)	5,676	5,517	5,501	5,502	5,501
Implied unit rate ($)	3,411	3,333	3,389	3,510	3,592
Low-voltage business (including small business and low-voltage large business)					
Total net capital expenditure ($)	12,483,668	16,314,363	11,392,490	11,557,149	11,672,214
Forecast number of new connections(2)	334	325	324	324	324
Implied unit rate ($)	37,357	50,237	35,177	35,685	36,040

Note:
(1) Total net capital expenditure is calculated as the gross capital expenditure net of capital contributions and inclusive of capitalised overheads. Source: *JEN - RP - Att 05-02M SCS Capex model - 20251201*
(2) Source: *JEN – Att 05-04 Customer numbers - 20250131*

We propose that these values serve as the baseline for volumetric adjustments at the 2031-36 Electricity Distribution Price Review. Once actual volumes are known, we will then be able to calculate the volumetric adjustment using this data. These categories exclude connections at 22 kv and above. We propose to classify all connections at 22 kv and above as large bespoke projects, which we discuss in further detail in section 2.2.2 below.

[7] AER, Capital Expenditure Incentives Guideline v4 – August 2025, p. 8.

1.2.2 Ex-post adjustment for large bespoke projects

The updated CESS guideline also allows for ex-post exclusions of capital expenditure associated with large bespoke connections and related network augmentation, where these were not included in forecast capital expenditure. It defines large bespoke connections as:[8]

> *Large bespoke connections refer to emerging commercial & industrial connection type, that were not accounted for as a business-as-usual connection type, including but not limited to grid connected batteries and data centres. These connection types will be based on the DNSP's proposal for the upcoming regulatory control period. We generally consider large bespoke connections relate to large connection applications.*

The guideline also places responsibility on DNSPs to identify these projects:[9]

> *DNSPs bear the onus of identifying the large bespoke connections in its proposal for the upcoming regulatory control period. In some circumstances, there may be an overlap between business-as-usual connections and large bespoke connections. Therefore, DNSPs must also justify why some large bespoke connections have not been accounted for in the volumetric adjustment.*

We propose that all connection projects at 22 kv and above be classified as large bespoke and excluded from volumetric adjustments. This threshold aligns with JEN's Connection Policy, submitted as part of our initial regulatory proposal.

We consider this to be an appropriate definition because:

- Assets deployed differ significantly above and below 22 kV, as assets on 22kV and above involve high voltage equipment and require specialised engineering knowledge to deploy and operate. This is quite different from low-voltage connections.
- This definition is clear, transparent, not subject to interpretation, and we are able to track it within the regulatory period.
- Our Connection Policy uses 22 kV as the threshold for recovering tax from connecting customers, rather than through the building block revenue allowance. Applying a consistent definition across both mechanisms supports a coherent approach to managing uncertainty from large bespoke connections.
- Some alternative definitions, such as 'data centres', lack clarity, as the term is not defined in the National Electricity Market (NEM) or industry practice voltage standards.

It is worth noting that in our revised regulatory proposal JEN is only proposing large data centre capital expenditure that are at stage 5 and above as per Figure 1–1, and to accept the AER's position to exclude data centre projects that are currently at earlier stages of development. Specifically, we have excluded all data centre projects from enquiry (stage 1) to firm offer requested (stage 4) per our standard connection process. Refer to more details in *JEN - RP - Att 05-01 Capital expenditure – 20251201*.

Figure 1–1: Connection process and stages for data centre projects

In this context, all data centre projects are bespoke, and none have been included in our capital expenditure forecasts up to and including stage 4.

8 AER, Capital Expenditure Incentives Guideline v4 – August 2025, p.11.

9 AER, Capital Expenditure Incentives Guideline v4 – August 2025, p. 10.

2. Efficiency Benefit Sharing Scheme

2.1 Outcome of EBSS in the current regulatory period

In our initial regulatory proposal, we estimated an EBSS carryover amount of $21M, based on actual operating expenditure data to 2023–24 and forecast data for 2024–25. The AER's draft decision calculated an EBSS of $4M, primarily due to its adjustment for a non-recurrent efficiency gain in relation to JEN's bushfire insurance step change in the current regulatory period. The AER stated this adjustment was necessary to meet the operating expenditure criteria, noting that without it, the EBSS would treat the underspend as a recurrent saving and provide JEN with a windfall gain unrelated to efficiency improvements. We do not agree with the AER's draft decision.

In this revised regulatory proposal, we have updated the EBSS to reflect:

- Actual operating expenditure for 2024–25, including adjustments such as SaaS implementation costs, movements in provisions, GSL payments and DMIA
- Corrections to GSL payments from 2021–22 to 2023–24 to remove double-counting, as noted in the AER's draft decision[10]
- Removal of the non-recurrent efficiency gain adjustment, as the insurance underspend reflects ongoing efficiencies JEN has achieved in the current regulatory period
- Inclusion of new cost pass-through applications, which increase the operating expenditure allowance.[11]

Table 2-1 below provides a comparison of EBSS outcomes across the initial regulatory proposal, draft decision, and revised regulatory proposal.

Table 2-1: EBSS revenue between initial proposal, draft decision and revised proposal ($2026, millions)

Description	Initial regulatory proposal	AER draft decision	Revised regulatory proposal
EBSS carryover amount	21.0	-4.4	13.2

Our calculation of the EBSS carryover amount relating to the current regulatory period are set out in *JEN – RP - Att 08-09M EBSS model – 20251201*.

2.1.1 Non-recurrent efficiency gain

In its draft decision, the AER applied an adjustment to the calculation of the carryover amounts arising from the application of the EBSS during the current regulatory period to remove any benefits from savings on insurance premium costs. This ex-post clawback is inconsistent with the ex-ante regulatory framework, under which DNSPs are encouraged to reduce costs to retain any difference between actual costs and forecast costs (or to wear the financial penalty when forecast costs are lower than actual costs).

Our revised regulatory proposal does not accept the AER's draft decision in respect of insurance premiums. Our revised proposal is informed by an independent expert report from Houston Kemp[12], a legal opinion from the Hon. John Middleton AM KC[13], and a report from our insurance broker[14]. Refer to *Attachment 06-05 Insurance operating expenditure* for more details.

10 AER, Draft Decision for JEN, Attachment 3 – Operating expenditure – September 2025, pp. 39-40.

11 JEN – RP – Support – FTA pass through application – 20251104, JEN – RP – Support – MITE pass through application – 20251030, JEN – RP – Support – VEBM2 pass through application – 20251105, JEN – RP – Support – ASMD pass through application – 20251113

12 Houston Kemp, *JEN - RP - Att 06-07 Houston Kemp Victorian DNSP insurance premiums - 20251128*

13 DLA Piper, *JEN - RP - Att 06-06 John Middleton Legal Opinion for Victorian DNSP Insurance Opex - 20251128*

14 Lockton, *JEN - RP - Att 06-08 Lockton Insurance premium forecast 2026-31 and retrospective forecast 2021-26 - 20251125*

2.1.2 Inclusion of new cost passthrough applications

Recently, new regulatory obligations have been imposed on JEN and other Victorian DNSPs. In response, JEN submitted four cost pass-through applications in November 2025 to recover prudent and efficient costs of meeting these obligations during the current regulatory period. Refer to section 1.1.2 for more details.

These costs, incurred in 2024–25 and 2025–26, have been included in our base year operating expenditure. However, without a corresponding uplift to the operating expenditure allowance, JEN would face an additional EBSS penalty for meeting the new regulatory obligations. To avoid this perverse outcome, we have adjusted the operating expenditure allowance used for EBSS calculations to include the amounts submitted in our pass-through applications.

Table 2-2 below sets out the adjusted operating expenditure allowance for EBSS purposes, including the breakdown of each pass-through item.

Table 2-2: Operating expenditure allowance for EBSS purpose ($2026, millions)

Item	FY22	FY23	FY24	FY25	FY26	Total
Operating expenditure allowance in AER-approved PTRM (excl. specific forecasts and DRC)	98.4	100.3	102.7	106.2	108.3	515.9
Cost passthrough 1: FTA	-	-	-	0.3	0.1	0.4
Cost passthrough 2: VEBM2	-	-	-	-	0.1	0.1
Cost passthrough 3: MITE	-	-	-	0.1	0.8	0.9
Cost passthrough 4: ASMR	-	-	-	0.0	0.4	0.4
Total (excl. specific forecasts and DRC)	98.4	100.3	102.7	106.6	109.7	517.8

2.1.3 Our revised regulatory proposal

Following the updates outlined above, JEN's revised EBSS outcome is summarised in Table 2-3.

We note that our actual 2024-25 operating expenditure are currently undergoing audit as part of the 2024–25 Annual Regulatory Information Order (**RIO**) process, due for submission to the AER on 30 November 2025. As this revised regulatory proposal is due on 1 December 2025, we have used unaudited numbers as placeholders. We expect the AER will update these values to reflect audited actuals in its final determination, once the RIO audit is complete.

Table 2-3: Proposed EBSS outcomes for the next regulatory period ($2026, millions)

EBSS	FY27	FY28	FY29	FY30	FY31	Total
Carryover Amounts	2.6	1.9	4.7	3.9	-	13.2

Details of the EBSS calculations are provided in *JEN – RP - Att 08-09M EBSS model – 20251201*.

2.2 EBSS in the next regulatory period

In its draft decision, the AER has accepted the continuation of EBSS for the next regulatory period. The AER has also accepted the exclusion of the following cost categories from EBSS, as they were not forecast using a single year revealed cost approach:

- Debt raising costs

- Guaranteed service level (GSL) payments
- Demand Management Innovation Allowance Mechanism (DMIAM)
- Any other costs treated as category specific forecast, such as any innovation fund operating expenditure that is included in the forecast.

In line with the scheme, the AER will also apply the following adjustments when calculating EBSS carryover amounts:

- Adjust forecast operating expenditure to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination, such as approved pass–through amounts or operating expenditure for contingent projects
- Adjust actual operating expenditure to add capitalised operating expenditure that has been excluded from the regulatory asset base
- Adjust forecast operating expenditure and actual operating expenditure for inflation
- Adjust actual operating expenditure to remove any movements in provisions
- Adjust operating expenditure for any services that will not be classified as standard control services in the 2031–36 regulatory control period, to the extent these costs are not forecast using a single year revealed cost approach and excluding these costs better achieves the requirements of clauses 6.5.8 of the NER

JEN accepts the AER's draft decision and the proposed application of EBSS for the next regulatory period.

3. Customer Service Incentive Scheme

3.1 The AER's feedback

The AER's draft decision does not accept JEN's proposed customer service incentive scheme (**CSIS**) and instead suggested we should retain and expand the customer service metrics included the Service Target Performance Incentive Scheme (**STPIS**). A comparison between the two has been included in Table 3-1.Table 3-1: JEN's proposed CSIS v STPIS customer service metrics

Table 3-1: JEN's proposed CSIS v STPIS customer service metrics

		JEN's proposed CSIS	STPIS customer service metrics
Fault-line telephone answering	Description	Percentage of telephone calls to JEN's fault-line that are answered within 30 seconds	Percentage of telephone calls to JEN's fault-line that are answered within 30 seconds
	Target Calculation	Average of JEN's five-year historical performance	Average of JEN's five-year historical performance
	Revenue at Risk	+/-0.125% of annual allowed revenue	+/- 0.5% of annual allowed revenue
New connections	Description	How satisfied customers are with their connections experience, derived from JEN's customer satisfaction survey (**CSAT**).	Percentage of standard control services connections connected on or before the day agreed. This metric would only reflect large customer connections and would exclude the forecasted ~45,000 basic residential connections as these connections are included in alternative control services
	Target Calculation	Average of JEN's five-year historical performance	Average of JEN's five-year historical performance
	Revenue at Risk	+/-0.125% of annual allowed revenue	+/- 0.5% of annual allowed revenue
Planned outages	Description	How satisfied customers are with their planned outage experience, derived from JEN's CSAT.	This metric is not included
	Target Calculation	Average of JEN's five-year historical performance	
	Revenue at Risk	+/-0.125% of annual allowed revenue	
SMS unplanned outage notification	Description	The average number of minutes between the start of an unplanned outage and when JEN's ICT systems sends an SMS message to impacted customers advising them of the outage. This measure excludes momentary interruptions (of three minutes or less), outages on Major Event Days	This metric is not included

		JEN's proposed CSIS	STPIS customer service metrics
	Target Calculation	Average of JEN's five-year historical performance	
	Revenue at Risk	+/-0.125% of annual allowed revenue	

This decision was made on the basis of:

- insufficient evidence that customers strongly support the adoption of the scheme or attribute value to the service improvements proposed, and
- JEN's limited application of its expert panel's feedback on additional CSIS parameters

3.2 Customer Response

In light of the AER's feedback, JEN re-tested the inclusion of the CSIS with the Energy Reference Group (**ERG**) on two occasions (15th October 2025 & 11th November 2025). On both occasions the panel confirmed its support for the scheme and encouraged JEN to advocate for its inclusion. While the ERG members noted there are additional CSIS metrics that they would like to see included in future regulatory control periods, they reiterated their support of the scheme despite any perceived limitations. In addition to their support for the CSIS, the ERG members also shared their views that relying on the STPIS, particularly the new connections metric would be 'a missed opportunity to foster engagement, build trust, and encourage positive behaviour across the network'.

3.3 Revised Proposal

Given strong customer support for JEN's proposed CSIS, we propose retaining the four metrics initially included. JEN has updated the associated targets to reflect the most recent data available.

3.3.1 Updated Targets

Fault-line telephone answering
Target: 76.5%
This measure is currently captured under the STPIS. JEN is proposing to include this metric under the CSIS. It will continue to reward or penalise JEN based on the number of calls to our fault-line which are answered within 30 seconds.

SMS unplanned outage notification
Target: 12.78 minutes
Number of minutes between the start of an unplanned outage and the customer receiving an SMS message advising them of the outage.

Planned outages
Target: 8.3
Measuring customers' satisfaction with their planned outage experience. This metric reflects overall satisfaction with JEN's management of the planned outage, including the timeliness and quality of information provided across all notification channels, the duration of the outage, and our ability to meet the forecasted restoration time.

New connections
Target: 7.8
Measuring customers' satisfaction with their connection journey. This metric reflects overall satisfaction with the end-to-end process, including the ease of application, the quality and timeliness of communications, the quality of the work completed, and the total time taken to complete the connection.

JEN has updated our proposed CSIS model to reflect these targets.

4. Service Target Performance Incentive Scheme

The STPIS provides a countervailing incentive to the EBSS and CESS. It encourages DNSPs to maintain and improve network reliability (to the extent customers are willing to pay for such improvements) and ensures networks do not pursue efficiency gains at the sake of service quality.

Table 4-1 Summary of the AER's draft decision and JEN's revised regulatory proposal

The AER's draft decision	JEN's revised regulatory proposal
Apply the system average interruption duration index (**SAIDI**), system average interruption frequency index (**SAIFI**), momentary interruption frequency index event (**MAIFI**), and customer service (telephone answering and new connections) parameters	Partially accept – as noted above JEN is reproposing our CSIS in lieu of the STPIS customer service parameters.
Segment the network according to the urban and short rural supply reliability categories	Accept.
Set revenue at risk at ±5% of the annual forecast revenue, 1% of revenue at risk will apply to the customer service component.	Do not accept – JEN reproposes that 4.5% of the annual forecast revenue is at risk under the reliability components of the STPIS.
Apply the 2024 values of customer reliability (**VCR**) adjusted to December 2024 CPI to set the incentive rates for SAIDI, SAIFI and MAIFI	Accept.
Set performance targets based on Jemena's average performance	Accept – JEN has updated our performance targets to account for our FY25 performance.[15]
Apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets	Accept.
Apply a major event day (**MED**) boundary of 2.5 standard deviations from the mean	Accept.
Not apply the Guaranteed Service Level (**GSL**) component of the STPIS to Jemena as it remains subject to a jurisdictional GSL scheme.	Accept.

15 JEN – RP - Att 07-03M – STPIS Model – 20251201 – Public

4.1.1 Reliability performance outcomes

JEN's reliability performance outcomes in the current regulatory period inform our STPIS targets for the next regulatory period. When submitting our initial regulatory proposal Table 4-2 shows these outcomes segmented by urban and short rural feeders.[16]

Table 4-2: reliability performance outcomes – exclusions removed (FY21 – FY24)

Reliability parameter	Current period target	FY21	FY22	FY23	FY24	FY25
Unplanned SAIDI		**46.710**	**46.404**	**39.119**	**44.779**	**47.746**
Urban	43.914	47.356	50.272	38.640	44.467	40.4372
Short rural	48.440	38.660	19.530	42.540	47.149	66.5794
Unplanned SAIFI		**0.710**	**0.701**	**0.684**	**0.727**	**0.696**
Urban	0.728	0.738	0.748	0.672	0.738	0.5856
Short rural	0.952	0.498	0.376	0.772	0.640	0.9929
MAIFI		**0.854**	**0.887**	**0.948**	**1.144**	**1.223**
Urban	0.952	0.877	0.859	0.921	1.177	1.2173
Short rural	1.416	0.302	10.84	1.141	0.894	1.2660

Source: Response to Annual Regulatory Information Notices.

4.1.2 Updated STPIS performance targets & incentive rates

At the time of submitting JEN's initial regulatory proposal, the FY25 year was not yet complete, and therefore, we were unable to finalise STPIS performance targets and incentive rates for the next regulatory period. As part of our revised regulatory proposal, we have updated targets to reflect JEN's FY25 performance. A comparison between the placeholder performance targets and incentive rates included in the draft decision, and these updated figures have been included in Table 4-3 and Table 4-4

Table 4-4: STPIS incentive rates for the next regulatory period below.

Table 4-3: STPIS performance targets for the next regulatory period

Feeder Type	SAIDI		SAIFI	
	Draft Decision	Revised Proposal	Draft Decision	Revised Proposal
Urban	45.518	44.2340	0.713	0.696
Rural Short	36.9697	42.8916	0.571	0.656

Source: AER Draft Decision and JEN Analysis

Table 4-4: STPIS incentive rates for the next regulatory period

Feeder Type	SAIDI	SAIFI	MAIFI

16 JEN's network does not include any feeders that meet the AER's 'CBD' or 'Long Rural' definitions.

	Draft Decision	Revised Proposal	Draft Decision	Revised Proposal	Draft Decision	Revised Proposal
Urban	0.0783	0.0670	3.2588	2.8340	0.2607	0.2272
Rural Short	0.0104	0.0090	0.4503	0.3897	0.0360	0.0312

Source: AER Draft Decision & JEN Analysis

The calculations underlying these tables are included in *JEN – RP – Att 07 – 03M – STPIS Model – 20251201 – Public.*