Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review
Regulatory Proposal

Attachment 06-04

Operating expenditure step changes

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Abbreviations

ICT	Information and Communication Technologies
EDCoP	Electricity Distribution Code of Practice
ESV	Energy Safe Victoria
LBRA	Low Bushfire Risk Areas
DNSPs	Distribution Network Service Providers
AI	Artificial Intelligence
SNAP	Strategic Network Analytics Platform
ESMSs	Electricity Safety Management Schemes
BMPs	Bushfire Mitigation Plans
REFCL	Rapid Earth Fault Current Limiters
ASC	Arc Suppression Coil
AVT	Annual Validation Testing
NEM	National Electricity Market

Overview

Most of our operating expenditure is recurrent, as it funds the regular operations necessary to deliver reliable network services. For the next regulatory period, we anticipate some step changes in our operating expenditure due to several factors:

- new regulatory obligations
- meeting community and regulatory expectations in operating our network into the future
- major external factors beyond our control, particularly those associated with our Information and Communication Technologies (**ICT**) spend, that reflects operating expenditure/capital expenditure trade-off opportunities, new reporting requirements and accepted good industry practice.

Our proposed opex step changes included in the next regulatory period total $41.4M as set out in Table OV–1.

Table OV–1: Summary of proposed opex step changes over FY2026-31 period ($2026, millions)

Step change	Description	AER category	Total
Customer communications and education	To develop and implement new and expanded ICT capability to deliver integrated customer education programs that have been requested by our customers	Supported by our customers through engagement and to meet accepted good industry practice	4.3
ICT services	To develop and implement new and expanded ICT capability to meet new regulatory obligations; new or expanded ICT capability, functions, and services to meet our customers' expectations; and for ongoing operational expenses associated with a non-recurrent project or initiative for new capacity that continue beyond its initial implementation phase (in the current regulatory period, the Australia Energy Regulator (**AER**) allowance generally treated these expenses as capital expenditure)	New regulatory obligations, supported by our customers through engagement, operating expenditure / capital expenditure trade off, and/or to meet accepted good industry practice that result in net benefits to customers	21.6
Consumer Energy Resources (**CER**) Integration Strategy initiatives	These costs are necessary to ensure that we meet community and regulatory expectations in operating our network, maintain compliance with the Electricity Distribution Code of Practice (**EDCoP**) standards during increased solar export to the network, maintain grid stability and connect our customers to renewables and accommodate more customer energy resources into our network without affecting its reliability	Reflects accepted good industry practice, operating expenditure / capital expenditure trade off, that result in net benefits to customers	3.0
Other regulatory obligations	These costs are necessary to improve our annual validation testing as part of new obligations under our bushfire mitigation plan and to comply with the Energy Safe Victoria (**ESV**) REFCL operations policy	New regulatory obligation	4.9
Network reliability initiatives	These costs are necessary to improve how we manage reliability when faced with extreme weather events and electrification of the energy system, and respond to recent Victorian government reviews in managing network resilience	Likely new regulatory obligations, supported by our customers through engagement and to meet accepted good industry practice	4.9
Safety initiative	These costs are necessary to meet customer expectations for communities in the management of hazardous trees in Low Bushfire Risk Areas (**LBRA**)	Supported by our customers through engagement and to meet accepted good industry practice	2.6
Total			**41.4**

Note: Adding each item may not align to the total due to rounding

Overall, we believe that our forecast operating expenditures step changes represent the level of funding necessary to achieve the requirements under the National Electricity Rules (**NER**), efficiently meet our obligations and customers' expectations, and promote their long-term interests. We consider our forecast step changes to be based on prudent and efficient solutions. They are based on detailed assessments of credible options that can address the need to provide reliable and safe services in a changing environment and meet customer expectations. In addition, our forecast step changes are consistent with our customers' recommendations, priorities and expectations that we:

- prioritise digitisation and automation to increase economic efficiency
- use the latest technology to provide ongoing customer service excellence
- undertake innovative approaches, use digitisation and automation technology and advanced monitoring equipment for determining replacement/upgrading of wires
- commit to environmentally sustainable operations
- champion the use of renewables and energy storage to help reduce network and customer costs
- prioritise investment in network resilience to recover from and withstand extreme weather events.

Unless stated otherwise, all $ are in 2026 basis.

Potential additional operating expenditure step changes

Australian Energy Market Operator's (**AEMO**) participant fee structures are currently set for the period 2021-26. In its 2021 review of its fees structures AEMO stated it will review the structure of future fees, including the level of involvement network service providers, based on the circumstances at the time. AEMO added that should the level of DNSP involvement increase materially during the next fee period (2026–31) as a result of a major change, (e.g. in response to regulatory changes), then a declared NEM project consultation process could be undertaken to determine future charging of distribution network service providers (**DNSPs**).[1]

Should AEMO change its 2026-31 fee structures between now and our revised regulatory proposal we will consider the impact on our operating expenditure and whether we require a step change for any additional costs.

Supporting attachments

Table OV–2: List of supporting attachments

Attachment	Name	Author
Customer engagement program	Chapter 2 of JEN 2026-31 Proposal	JEN
Operating expenditure forecast	JEN - Att 06-01 Operating expenditure - 20250131 - Public	JEN
CER Integration Strategy	JEN – Att 03-01 CER Integration Strategy – 20250131 - Public	JEN
Data Visibility and Analytics Strategy	JEN – RIN – Support – Data Visibility and Analytics Strategy – Investment Brief – 20250131 – Public	JEN
Voltage and PQ Management Program	JEN – RIN – Support – Voltage and PQ Management Program – Investment Brief – 20250131 – Public	JEN

1 AEMO, Electricity Fee Structures Final Report and Determination, March 2021, p. 16.

Attachment	Name	Author
Grid Stability and Flexible Services Program	JEN – RIN – Support – Grid Stability and Flexible Services Program – Investment Brief – 20250131 – Public	JEN
Outage Preparedness and Response	JEN – RIN – Support – Outage Preparedness and Community Response – Business Case – 20250131 - Public	JEN
ICT Outage Preparedness and Response	JEN – RIN – Support - ICT Investment Brief - Outage Preparedness and Response – 20250131 – Public	JEN
06-03M	JEN - Att 06-03M SCS Opex model - 20250131 - Public	JEN
Customer systems	JEN – RIN – Support - ICT Investment Brief – Customer systems – 20250131 – Public	JEN
Customer education	JEN – RIN – Support - ICT Investment Brief – Customer education -– 20250131 – Public	JEN
Technology plan	JEN - RIN – Support - Technology plan – 20250131 - Public	JEN
LBRA Hazard Tree Program	RIN – RIN - Support - LBRA Hazard Tree Management Program - Business Case - 20250131	JEN
LBRA Hazard Tree Program	JEN – RIN – Support – Draft Plan feedback response – Greening the west – 20241007 – Public	City of Moonee Valley
LBRA Hazard Tree Program	JEN – MVCC - RIN – Support – Draft Plan feedback – Electric Line Clearance Requirements – 20240916 – Public	JEN

1. Step changes

Table 1–1 sets out our forecast operating expenditure step changes over each year of the next regulatory period.

Table 1–1: Forecast operating expenditure step changes ($2026, millions)

Step change	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer systems and education	0.9	0.8	0.9	0.9	0.8	4.3
ICT services	1.5	3.7	5.3	6.0	5.1	21.6
CER Integration Strategy Initiatives	0.2	0.6	0.7	0.8	0.8	3.0
New REFCL obligations	1.0	1.0	1.0	1.0	1.0	4.9
Network reliability initiatives (resilience)	1.1	1.1	0.9	0.9	0.9	4.9
Safety initiatives	0.5	0.5	0.5	0.5	0.5	2.6
Total	**5.2**	**7.7**	**9.3**	**10.1**	**9.1**	**41.4**

Note: Adding each item may not align to the total due to rounding

These operating expenditure step changes, the drivers for them, and the basis of our estimate are discussed in detail in the following sections.

1.1 What we heard from our customers

In developing our operating expenditure step changes, we have been mindful of feedback during our engagement program from our customers.

Affordable electricity was a top priority for all customer groups, with a specific emphasis on stability to alleviate cost-of-living pressures and reduce financial anxiety. Customers told us that affordability should be viewed as a balance between cost reduction, consistent and reliable services and the need to prioritise digitisation, sustainability and implementing climate change mitigations.

With regards to our operating expenditure step changes, our customers told us that clear, transparent, and accessible communication channels are required from JEN to customers. Customers emphasised the need for communication tailored to diverse needs, including multiple languages and accommodations for disabilities. Multichannel approaches, such as online platforms, phone support, and chat options, were highly valued. Enhancing communication accessibility was seen as a way to reduce confusion, increase trust, and improve overall customer satisfaction.

Stakeholders also widely emphasised the importance of customer education to empower informed energy usage and investment decisions. Tailored campaigns, culturally relevant materials, and partnerships with community organisations were recommended to address diverse customer needs. First Nations groups advocated for culturally specific education, while seniors sought simplified resources. Across all groups, accessible and practical information was deemed essential for promoting sustainable energy behaviours.

Consequently, we have dedicated expenditure to enhance communications to all our customers by:

- Developing simple and accessible customer communications across all our channels and in multiple languages to support customer needs

- Increasing customer education through utilising ICT platforms and helping to engage customers in their energy usage
- Upgrading customer systems to allow for near real-time communications with customers using web chat and two-way SMS to meet their needs better
- Collaborating with local councils, community groups, the Victorian Government, and emergency services to improve customer communications, particularly on policy development and during major outages and emergencies.

Stakeholders supported investments in digital technologies to enhance network management, reduce operational costs, enhance data protection measures and prepare for future energy challenges. Seniors and multicultural customers stressed the importance of adopting advanced systems to improve efficiency and reliability. Digitisation was viewed as a vital step toward creating a smarter, more resilient network. Customers' expectations are continuously increasing in line with technology advancements and customers expect a dedicated online portal that provides tailored information based on their expressed preferences, language, and needs. As we face the energy transition, customers have told us we need to help build their energy capability and increase our ability to empower them and support their decision-making into the future. Our proposed ICT operating expenditure step changes support this stakeholder feedback.

Maintaining high levels of network reliability and power quality was a top priority for all stakeholders. Vulnerable groups stressed the importance of timely outage notifications and resilience planning to minimise disruptions. Investments in infrastructure to withstand extreme weather events and future demand were seen as crucial for ensuring consistent and reliable energy supply. Customers' preferred option was for us to enhance network resilience, including along the Maribyrnong River, and create equity of network resilience for our customers. They also supported improvements to our resilience preparation and response for all customers. Customers also want us to:

- Share data with stakeholders to support customers during extreme weather events (for example, mapping data on flood plan and wind flow)
- Update and expand the support we can offer customers if an outage does occur, including temporary generation to power a 'community hub' and targeted communications for particularly vulnerable customers.

Our proposed Network reliability initiatives address this stakeholder feedback.

More detail on our customer engagement program and feedback from our customers is set out in Chapter 2 of JEN 2026-31 Proposal.

2. Customer systems and education

As part of our price reset customer engagement program, we undertook extensive engagement with our customers to understand their energy needs, preferences and priorities over the next regulatory period.

Customers told us that we need to:

- **Reduce customer barriers** – JEN's existing ICT capability that provides customer communications and services no longer meets the needs and expectations of customers. Customers highlighted the lack of in-language information, difficulty finding information on the energy transition, and lack of education programs that can help build energy literacy and energy capability. They have expectations that are rapidly increasing and expect a dedicated online portal that provides tailored information based on their expressed preferences, language, and needs. Customers also expect us to utilise Artificial Intelligence (**AI**) technology to enhance our systems to drive tailored information to empower customers to make decisions about sustainable energy usage.
- **Build customer capability and energy literacy** – customers are increasingly concerned about the energy transition and find it difficult to engage with the energy system and understand how to access consumer energy resources or take control of their energy usage. They told us we need to help build their energy capability and increase our ability to empower them and support their decision-making into the future.

We plan to develop and implement new and expanded ICT capability, and deliver integrated customer education programs that:

- build energy literacy
- build customer capability to prepare for the energy transition
- increase and enhance customer experience and the accessibility of information
- support customers to take on a more active role in energy generation and management.

Further, as we enter the energy transition and face more impacts on network resilience from extreme weather events, customers expect us to play a leading role in being a trusted source of information and advice to empower customers and build energy capability.

To address these concerns, we will:

- Further integrate our customer applications and back-end customer knowledge management so that we can reduce customer barriers and provide customers with a seamless customer experience.
- Make significant improvements to our customer education and customer communications to successfully meet the needs and expectations of JEN customers. This requires us to increase customer education through existing ICT platforms and help to engage customers in their energy usage by:
    - developing integrated education programs to generate awareness of energy-saving tips, the energy supply chain, rooftop solar, energy-efficient appliances, pricing and tariffs, and understanding electricity bills.
    - tailoring and targeting customer education programs to JEN's diverse customers and customers who face greater barriers to navigating their way through the energy system. This includes ensuring educational material developed is tailored for multicultural communities, First Nations communities, customers with disability and seniors.

Our existing customer technology landscape includes disparate and ageing systems with limited integration and in-language customer facing capability. This results in a difficult-to-navigate customer experience that lacks accessibility and creates barriers for customers accessing our services or finding information. We must maintain our customer systems to ensure we continue to meet our operational and regulatory obligations and update them to meet customer expectations for accessible and timely information.

We have prepared the following two investment briefs to deal with the matters above:

- *JEN – RIN – Support - ICT Investment Brief – Customer systems – 20250131 – Public*, to continue to maintain existing systems that provide services to customers. This includes fault reporting tools, contact management systems, connection and application services, and communications.
- *JEN – RIN – Support - ICT Investment Brief – Customer education -– 20250131 – Public*, to develop and implement new and expanded ICT capability to deliver integrated customer education programs.

The preferred option for both investment briefs will develop:

- Customer system improvements including:
  - maintenance of our existing systems and completing necessary upgrades to sustain current service levels
  - enhancements to existing systems: upgrading core functionalities to improve reliability, efficiency, and overall service quality
  - extending system capabilities: expanding current systems to offer new features and better support evolving customer needs
  - accelerated customer improvements: fast-tracking initiatives to deliver enhanced customer benefits and experiences sooner
  - proactive adaptation to regulatory and market changes: preparing early for anticipated regulatory changes and innovations, ensuring systems are ready for unplanned developments
  - telephony-based integrations: expanding existing telephony solutions to further automate customer interactions.
- New and expanded ICT capabilities to deliver integrated customer education programs that will:
  - expand customer awareness on CERs to enable customers to make informed decisions on sustainability and decarbonisation.
  - simplify and streamline the process for customers to participate in the energy transition.
  - increase the customer experience and accessibility of information to customers on their electricity service
- AI driven personalisation of insights provided on the customer portal. This enhancement will allow JEN to combine AI with customer journey decision points to support customers and energy retailers with personalised insight. The enhancement will prioritise data privacy, security, and adherence to strict AI ethics guidelines.
- Enhancement of the customer portal to include personalised data on customers' export limits.
- Digital calculators to help customers understand bills, and the impacts of changes to tariffs and energy consumption on their bills.
- Renewables portal to support the understanding of CERs.

These initiatives will have a significant impact on customers and their engagement with energy. They will create a shift from being passive on customer education to proactively becoming a trusted source of information and advice for customers through education. By educating customers on energy topics, it will ultimately influence their behaviours to engage in their own energy usage and make informed decisions to drive electrification.

2.1 Nature of the step change

The proposed increase in customer education and empowerment spend is incremental to our 2024-25 base year, and recurrent in nature.

We consider that our proposed spend is prudent and efficient. It meets accepted good industry practice (as evidenced by other similar programs approved by the AER) and our customers energy needs, preferences and priorities over the next regulatory period. The allowance is necessary to meet the operating expenditure objective (cl. 6.5.6(a) of the NER) to reasonably reflect the operating expenditure criteria in cl. 6.5.6(c) of the NER.

We expect that the customer education and communication operating expenditure will be recorded as SCS[2] - Network overheads.

2.2 Quantification of the step change

Table 2–1 shows our total forecast operating expenditure step change over the next regulatory period for our customer system and customer education programs of work, and what will be incurred by our customer communications and by ICT.

Table 2–1: Forecast customer education and empowerment step changes over 2026-31 ($2026, millions)

Operating expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Customer systems – option 2						
Customer Comms	0.3	0.3	0.3	0.3	0.3	1.4
ICT (see section 3, Table 3–2)	0.0	0.1	0.1	0.1	0.1	0.3
Total customer systems	**0.3**	**0.4**	**0.4**	**0.4**	**0.4**	**1.8**
Customer education – option 3[3]						
Customer Comms	0.6	0.5	0.6	0.6	0.5	2.8
ICT (see section 3, Table 3–2)	0.0	0.2	0.2	0.2	0.2	0.7
Total customer education	**0.6**	**0.7**	**0.7**	**0.8**	**0.7**	**3.5**
Total Customer Comms	**0.9**	**0.8**	**0.9**	**0.9**	**0.8**	**4.3**
Total ICT customer systems and education (see section 3, Table 3–2)	0.0	0.3	0.3	0.3	0.3	1.0

2 Standard control services.

3 This option was one of two options supported at the Customer Deep Dive on Expenditure event. Of the two options, it is the lower cost option and therefore represents the most prudent expenditure.

Note: Totals might not add due to rounding

Investment Briefs *JEN – RIN – Support ICT Investment Brief – Customer systems – 20250131 – Public* and *JEN – RIN – Support - ICT Investment Brief – Customer education -– 20250131 – Public* establish and summarise the overarching objective and problem statements that will be addressed, as well as the high-level scope, and what options have been considered to deliver the most prudent and efficient technology solution. The options analysis provides a preliminary assessment of the options to implement an effective solution to achieve the objective of the Investment Brief. They demonstrate the need to incur the expenditure and that we are adopting the most efficient option in accordance with accepted good industry practice. We consider that the preferred option (maintenance of existing systems, and education and empowerment) will help us deliver services to our customers, consistent with the achievement of the National Electricity Objective and in meeting our customers' energy needs, preferences and priorities over the next regulatory period.

3. ICT Services

The AER defines ICT as all devices, applications, and systems that, together, allow interaction with the digital world.[4] ICT now makes up a significant portion of a distribution network service provider's expenditure, including ours.

Further, we expect that a large portion of the ICT services costs must be recorded as operating expenditure rather than capital expenditure. Whilst our operating expenditure base year includes costs for recurrent ICT commitments, we need to consider whether we need any additional ICT recurrent operating expenditure for ongoing operational expenses associated with a new project or initiative for new capability undertaken over the next regulatory period that continues beyond the initial implementation phase. This includes any operating expenditure associated with new regulatory obligations resulting from market reform.

Our ICT expenditure over the next regulatory period is predominantly driven by:

- **National Electricity Market (NEM) Reforms** – with a constantly evolving regulatory landscape, digital technologies will play a vital role in enabling JEN to meet new obligations. In alignment with ongoing NEM reforms, our Digital team is expanding its capability to manage the complex new market obligations associated with the energy transition. This increased capability will ensure we can meet regulatory requirements and support a smooth and effective transition to the future energy system, supporting a more modern, secure, and sustainable energy market.
- **Energy Transition** – as we move toward a more sustainable energy future, we are investing in new digital capabilities. This includes the development of machine learning models that will support critical areas such as asset health monitoring, grid stability, system flexibility, and market integration, ensuring our infrastructure can adapt to the demands of a renewable energy landscape. We have developed our CER Integration Strategy (discussed in section 4) and associated programs of work and initiatives to support the energy transition over the next decade. Our ICT costs associated with our CER Integration Strategy initiatives are included in Investment Briefs prepared to support our CER Integration, which is detailed in section 4 of this attachment.
- **Building customer capability and energy literacy** – customers have told us they are increasingly concerned about the energy transition and find it difficult to engage with the energy system and understand how to access CER or take control of their energy usage. Consequently, customers have told us we need to help build their energy capability and increase their ability to empower them and support their decision-making in the future.

To forecast expenditure in the next regulatory period, we have adopted the ICT expenditure treatment outlined in the AER's non-network ICT capex Guidance Note (Box 3.1).

Box 3.1: Treatment of ICT expenditure

We manage a wide range of ICT projects within regulatory frameworks and accounting standards. The expenditure treatment of these is determined by a range of factors, including the types of systems deployed and the expenditure cycles of each system. The diagram below summarises this.

Expenditure Cycle	Operating expenditure	Capital expenditure
Non-Recurrent	>5 years	>5 years
Recurrent	Annually	2 to 5 years

We classify our ICT operating expenditure as:

4 AER, Non-network ICT capex assessment approach, November 2019, p. 5.

- **Recurrent operating expenditure**—from regulatory period to regulatory period—comes from our base expenditure (see *JEN - Att 06-01 Operating expenditure*)
- **Non-recurrent operating expenditure** incurred in implementing non-recurrent projects, which is adjusted against the base year operating expenditure (see expenditure (see *JEN - Att 06-01 Operating expenditure*)
- **Recurrent operating expenditure step change** for the large non-recurrent projects to be completed in the next regulatory period—which may be new systems or long-cycle upgrades—we will incur additional ongoing recurrent expenditures to support those systems. Ongoing recurrent expenditure is treated as an operating expenditure step change over the next regulatory period (set out in this section 3 and section 4 of this attachment).

We are proposing ICT recurrent operating expenditure step changes for the 2026-31 regulatory period for several reasons:

- **Services shifting from on-premises to cloud-based**. There has been a recent significant shift by users and software vendors away from on-premises systems to cloud computing services. This means that systems and platforms are hosted and maintained by the vendor, and their customers access them via a subscription rather than purchasing a license. Along with the recent changes to interpreting International Financial Reporting Standards (**IFRS**)—which introduced changes that limit what ICT projects can be recognised as assets (capital expenditure) from the first financial reporting period beginning after 15 December 2020—this has generated a large increase in operating costs over the next regulatory period that used to be recorded as capital expenditure.
- **Integration of new digital capability into the network and dynamic operations**. When implementing new systems and/or capability, we often need to employ additional human resources and licencing to support the associated ongoing operational activities; this type of expenditure is known as incremental ICT recurrent operating expenditure. This is necessary to ensure that our systems remain fit for purpose in a constantly changing technology and network environment where our customers' requirements and expectations continue to evolve.
- **CER integration Strategy**. As an electricity DNSP operating in Victoria, JEN plays a key role in facilitating the energy market transformation to renewable energy. Given the uncertainty in the rate of change and direction of the transformation, a least-regrets scenario-based investment approach is needed to manage a smooth transition for customers. Furthermore, Jemena has its own ambitions to work towards net zero. We have therefore developed a CER Integration Strategy and associated programs of work and initiatives to support the energy transition over the next decade (see section 4).
- **National Electricity Market Reforms**. When the AEMO modifies its systems or the Australian Energy Market Commission (**AEMC**) issues changes to the NER, we need to invest in our ICT systems to comply with the changes. For example, we expect to incur operating expenditure step changes in implementing Flexible Trading Arrangements in the next regulatory periods.

3.1 Nature of the step change

Our ICT operating expenditure step change reflects incremental operating expenditure associated with initiatives that are deploying new or expanded ICT capabilities, functions, and services to deliver customer or business benefits and that are not reflected in our base year operating expenditure. They are recurrent in nature, i.e. occur annually. The incremental expenses may include costs related to maintenance, licensing fees, support, and ongoing operational activities required to sustain the benefits or functionality delivered by the project.

Our step changes reflect accepted good industry practice, and the allowance is necessary to meet the operating expenditure objective (cl. 6.5.6(a) of the NER) to reasonably reflect the operating expenditure criteria in cl. 6.5.6(c) of the NER.

We have classified our forecast non-recurrent operating expenditure step changes to reflect the underlying drivers of our specific initiatives, as detailed in the Guidance Note[5]:

- Maintaining existing services, functionalities, capability and/or market benefits
- Complying with new / altered regulatory obligations / requirements
- New or expanded ICT capability, functions and services.

The ICT operating expenditure step change is recorded as SCS - Non-network opex.

3.2 Quantification of the step change

Table 3–1 shows our forecast operating expenditure step change over the next regulatory period.

Table 3–1: Forecast ICT operating expenditure step changes over 2026-31 period ($2026, millions)

Operating expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Recurrent opex step change	1.5	3.7	5.3	6.0	5.1	21.6

5 AER, Non-network ICT capex assessment approach, November 2019.

Table 3–2 sets out our estimated ICT recurrent opex for the non-recurrent ICT projects that we plan to undertake over the next regulatory period. We have prepared Investment Briefs for each proposed program of work which establishes and summarises the overarching objective and problem statements that will be addressed, as well as the high-level scope, and what options have been considered to deliver the most prudent and efficient technology outcome. The options analysis provides a preliminary assessment of the options to implement an effective solution to achieve the objective of the Investment Brief. *JEN -RIN – Support -Technology plan – 20250131* provides more details on our proposed non-recurrent ICT projects over the next regulatory period.

Table 3–2: Forecast ICT recurrent opex step change for the 2026-31 regulatory period ($ millions)

ICT sub-categorisation	Project name	$2024M	$2026M
Maintaining existing services, functionalities, capability and/or market benefits	Customer Systems[6]	0.3	0.3
	Network Operations Geospatial Enhancements[7]	0.2	0.2
	Cyber Program[8]	2.2	2.3
	Digitising Network Switching[9]	0.5	0.5
	Cloud Capacity Growth[10]	2.5	2.6
Complying with new / altered regulatory obligations / requirements	Enterprise Content Management Uplift[11]	0.6	0.6
	Data Foundations and Governance[12]	0.4	0.4
	NEM Reform - Flexible Trading Arrangements[13]	4.0	4.2
	Outage Preparedness and Response[14]	0.6	0.6
	Contract Lifecycle Management[15]	0.7	0.7
New or expanded ICT capability, functions and services	Customer Education[16]	0.7	0.7
	Dynamic Network Planning with Automation[17]	0.4	0.4
	3D Digital Twin[18]	0.1	0.1
	CER Integration – Flexible Exports[19]	2.9	3.1
	CER Integration – Strategic Network Analytics Platform (SNAP) - Data Hub[20]	1.3	1.4
	CER Integration – VVC (Volt Var Control) rollout[21]	3.0	3.2
Total operating expenditure step change		**20.5**	**21.6**

Totals might not add due to rounding

We have demonstrated in the Investment Briefs the need to incur the expenditure and that we are adopting the most efficient option in accordance with accepted good industry practice. We consider that the above non-recurrent programs will help us deliver services to our customers consistent with the achievement of the National Electricity Objective. Each non-recurrent project is necessary to ensure that our systems remain fit for purpose in a constantly changing technology and network environment where our customers' requirements and expectations continue to evolve.

6 *JEN – RIN – Support - ICT Investment Brief - Customer systems.*

7 *JEN – RIN – Support - ICT Investment Brief - Network Operations Geospatial enhancements.*

8 *JEN – RIN – Support - ICT Investment Brief - Cyber Security Program.*

9 *JEN – RIN – Support - ICT Investment Brief - Digitising Network Switching.*

10 *JEN – RIN – Support - ICT Investment Brief - Capacity growth.*

11 *JEN – RIN – Support – ICT Investment Brief - Enterprise Content Management re-platforming.*

12 *JEN – RIN – Support – ICT Investment Brief - Data foundations and governance.*

13 *JEN – RIN – Support – ICT Investment Brief - Reform - Unlocking CER benefits - Flexible Trading arrangements.*

14 *JEN – RIN – Support – ICT Investment Brief - Outage Preparedness and Response.*

15 *JEN – RIN – Support – ICT Investment Brief - Contract lifecycle management.*

16 *JEN – RIN – Support – ICT Investment Brief – Customer education.*

17 *JEN – RIN – Support – ICT Investment Brief - Dynamic Network planning with automation.*

18 *JEN – RIN – Support – Network Assets Digital Twin Program – Investment Brief.*

19 *JEN – RIN – Support – Grid Stability and Flexible Services Program – Investment Brief.*

20 *JEN – RIN – Support – Data Visibility and Analytics Strategy – Investment Brief.*

21 *JEN – RIN – Support – Voltage and PQ Management Program – Investment Brief.*

Consistent with the methodology outlined in the Technology Plan,[22] we have:

- Removed ICT projects from the base year and added forecast projects (Non-recurrent projects) as a base year adjustment
- Added incremental opex for new capability required to support the non-recurrent projects moving forward (recurrent step opex) as an opex step change.

The resulting net adjustment to our opex forecast is illustrated in

Figure 3–1.**Error! Reference source not found.**

Figure 3–1: Regulatory forecast step opex stacked column chart over 2026-31, by year ($2026, millions)

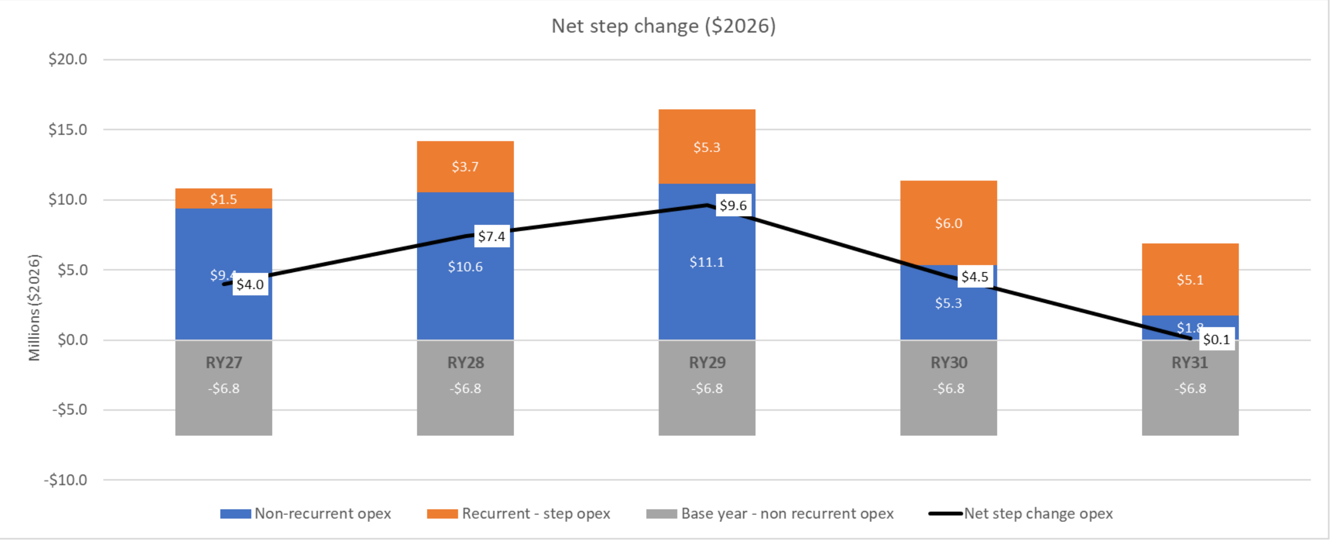
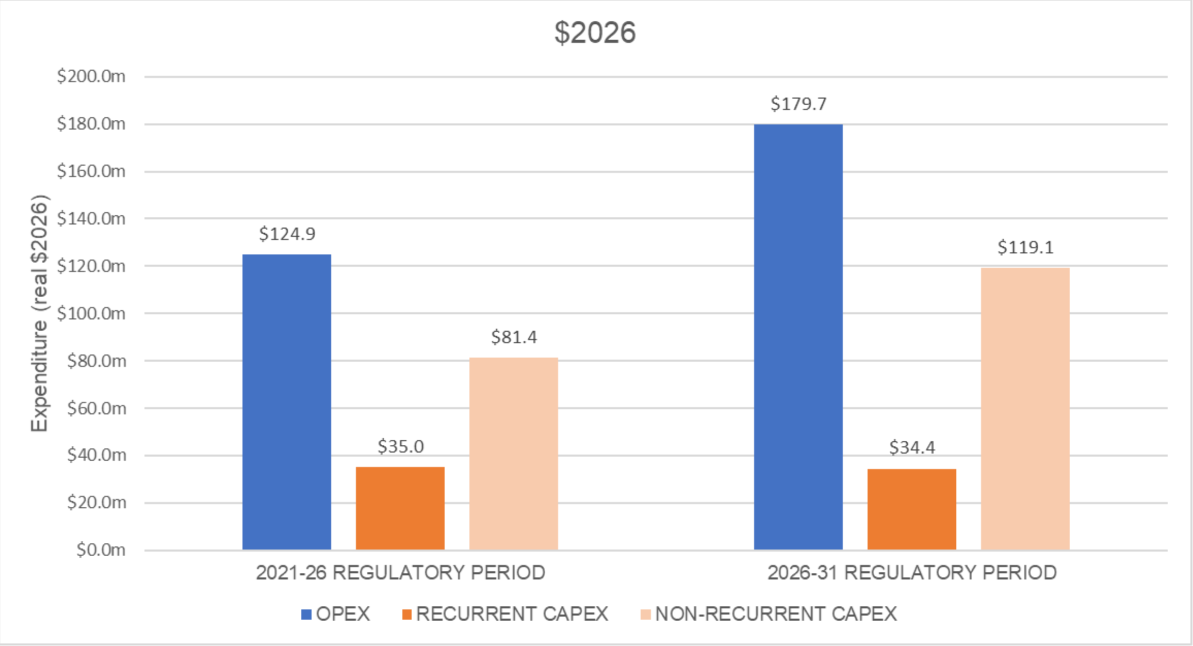


Figure 3–2 shows the current and next regulatory period ICT total capital and operating expenditure (totex).

Figure 3–2: Actual, estimated and forecast ICT totex ($2026 millions)



[22] *JEN - RIN –- Support –- Technology Plan – 20250131 – Public.*

Overall, we are forecasting a 38% increase in totex over the next regulatory period, comprising a 32% increase in capital expenditure and 44% increase in operating expenditure. This is largely driven by NEM Reform, CER Integration and Customer initiatives as follows:

- We forecast a total ICT capital expenditure of $154M for the next regulatory period, which is 32% higher than our estimated total ICT capital expenditure for the current regulatory period, driven by an uplift in capex required for projects across the NEM Reform, CER Integration and Customer initiatives.

We forecast a 44% increase in operating expenditure compared to the current period due to:

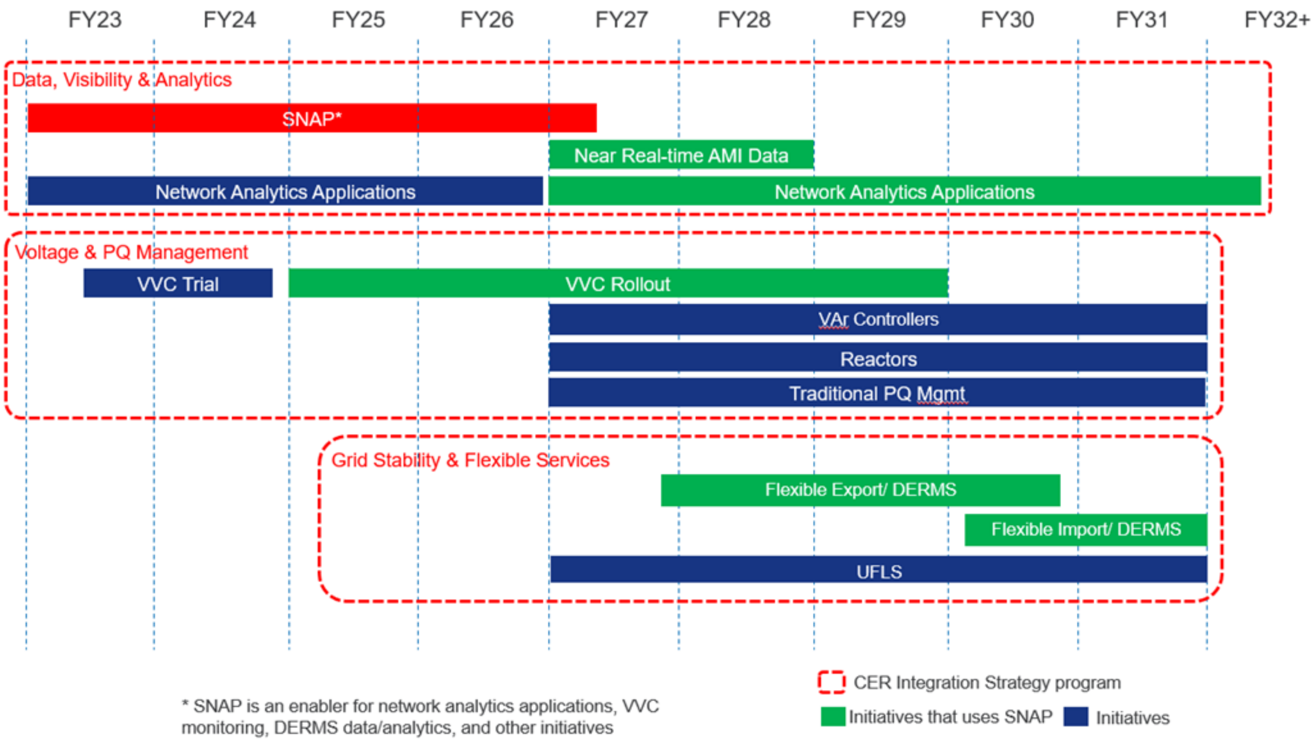
- Changes in the interpretation of the IFRS standards; a lot more of our project-related costs for SaaS are now treated as operating expenditure where once they were capital expenditure.
- Additional operating expenditure is required to run and maintain the new capability planned to be delivered in the next period; for example, additional licensing.
- Over the past six years, our analysis indicates increases averaging ~20% for storage usage and compute processing annually. In response to evolving business needs and technological advancements, we've embraced cloud computing as a strategic solution. As a result, our projection for cloud capacity growth stands at a conservative estimate of 15% per year, highlighting overall cost savings in our storage and compute processing. Despite this, operating expenditure is required to fund our cloud capacity rather than capital expenditure for more traditional on-premises storage and processing.

4. CER Integration Strategy programs and initiatives

JEN has a strategic objective of connecting its customers to a renewable energy future, by facilitating the integration of Distributed Energy Resources (**DER**) into the electricity distribution network and facilitating the electrification of the economy. The AER defines DER to include rooftop solar, batteries, electric vehicles and energy management systems, which are often located on the consumers' side of the electricity meter. We note that DER is now generally referred to as Consumer Energy Resources, or **CER**, noting that CER does not include front of meter batteries DER on our network. For the purposes of our CER Integration Strategy[23] we refer to CER to also include front of meter batteries.

We have developed our CER Integration Strategy which we plan to deliver through network operations (Asset Management) and new ICT (Digital) capability. Figure 4–1 shows our three proposed programs of work and supporting initiatives to deliver our CER Integration Strategy, and our indicative timing to implement them. Strategic Network Analytics Platform (**SNAP**) (in red) in the Data Visibility and Analytics program is an enabler for a number of initiatives (in green) in JEN's CER Integration Strategy.

Figure 4–1: JEN's CER Integration Strategy programs and initiatives



Key customer benefits of our CER Integration Strategy include:

- CER enablement – improved export capability and reduced CER curtailment, justified using the AER's Customer Export Curtailment Value (**CECV**) methodology.
- Reliability of supply – maintained reliability of supply, by managing and adapting to the changes in electricity demand from CER uptake and usage of the network, the electrification of the gas and transport sectors, and the change in new and existing customers' requirements for electricity, justified using the AER's Values of Customer Reliability (**VCR**) methodology.
- Regulatory compliance – improved appliance safety and reduced consumption by maintaining voltages within regulatory limits and satisfying system security through enabling grid stability by AEMO and power quality regulatory requirements using a least-cost approach to achieving our compliance obligations.

23 *JEN – RIN – Support – Att 03-01 – CER Integration Strategy.*

Our CER Integration Strategy programs are discussed below. Further detail on the need and scope of works for the program is available in the program documents and investment brief of each program.

Data Visibility and Analytics (**DVA**) program

Responds to the need for further digitalisation of network operations functions using network analytics applications.

JEN's existing prototyping platform is not of commercial grade, is not supported by Jemena Digital, and is reaching end-of-life. JEN currently has a backlog of prioritised analytics applications for development. JEN also needs the ability to adapt to emerging customer and regulatory needs. For example, providing data and analytics products to 3rd parties as part of the AER/DEECA Victorian Network Visibility data trials[24] in Victoria.

The DVA program of work aims to address the identified needs and existing analytics platform limitations, and improve the operational management of the network by:

- Implementing a SNAP to support a number of CER Integration Strategy initiatives, instead of building siloed platforms for each initiative. SNAP is an enabler to our other CER Integration Strategy initiatives such as the Volt-Var Control and Flexible Services.
- Facilitating the integration of more CER into our network in the future without compromising the safety and security of our network.
- Implementing a program of network analytics applications to improve operational efficiency and effectiveness, improve safety, and respond to emerging customer and regulatory needs over the next 10 years and beyond. Examples include simulating new and moved connections, connection approvals, detection of wrong connections, near real-time power quality data for field crews, detecting and predicting network faults, and regulatory data collection obligations.

These new data and analytics driven applications will reduce regulatory compliance risk (current and evolving), customer safety, and operational planning during the energy transition. The ongoing operating cost of VVC, SNAP Foundations and Network Analytics is a material change in our operating expenditure requirements.

It should also be noted that the following CER Integration Strategy initiatives will require data and analytics:

- In the Voltage & PQ Management program there is the need for a Dynamic Voltage Management (**DVM**) system. DVM requires data and analytics, including near real-time smart meter power quality data, a data streaming platform to process the power quality data, and analytics for performance monitoring.
- In the Grid Stability and Flexible Services Program there is the need for a DER Management System (**DERMS**). DERMS requires data and analytics, including near real-time data, including near real-time CER import/export data, a data streaming platform to compute Dynamic Operating Envelopes (**DOEs**), data storage, and analytics for performance monitoring.

Voltage and Power Quality (PQ) Management program

This program responds to the challenges and opportunities associated with increasing CER penetration and the associated influences on network voltage and power quality. JEN aims to do so by delivering an affordable, safe and reliable electricity supply that meets its customers' expectations, in a manner that is compliant with all regulatory compliance requirements and meets customer and community needs. This includes a focus on preparing the network for the future, leveraging new technologies and cost efficiencies where possible, and improving network competitiveness and customer outcomes.

The applications developed from this strategy are supported by a new and staged DVM system platform to achieve near real-time optimised control of network voltage and reactive power flow to maintain compliant voltages and reduce CER curtailment, using enhanced Volt-VAr control integrated with JEN's Advanced Metering Infrastructure (**AMI**) assets.

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24 https://www.aer.gov.au/industry/registers/resources/reviews/network-visibility

The growth of rooftop solar in the electricity network has significantly changed how network voltage needs to be managed to maintain compliance with EDCoP standards. With the uptake of distributed solar PV and other forms of CER, power can now flow in both directions, placing pressure on JEN to be able to maintain acceptable levels of voltage regulation. Whilst the network was designed for one-way power flow, our ability to cater for reverse power flows is limited due to the voltage-rise that can occur at the customer connection points. This is becoming increasingly problematic as CER penetrations rise, particularly at times of minimum daytime demand, when solar PV systems are most likely to be exporting into the network.

While JEN has remained functionally compliant with the EDCoP and maintained the level of compliance over the duration of the historical reporting period (following planned reductions in voltage in early 2022), there remains up to 3.9% of customers who are experiencing non-compliant over-voltages, and 3.6% of customers who are experiencing non-compliant under-voltages. These periods of non-compliance are greatest in the spring and summer periods for over-voltage when solar PV systems are operating at their maximum output, causing voltages to rise across the network, and during summer hot weather for under-voltages when demand for electricity from the grid is at its greatest.

To address non-compliant voltages for our worst-served customers and abate deteriorating potential excursions in voltage requirements, we plan to target expenditure through economically justified programs of work.

Grid Stability and Flexible Services program

This program addresses the need for JEN to develop a Distributed Solar PV (**DPV**) Backstop Capability[25] and a Distributed Under-Frequency Load Shedding (**Distributed UFLS**) Scheme as two distinct grid stability applications to strategically respond to the challenges and opportunities associated with increasing numbers of CER, and their associated influences on power system security and network operating limits. The applications developed from this strategy are supported by a new and staged Distributed Energy Resource Management System (**LV-DERMS**) platform to achieve near real-time optimised control of CER active power operating envelopes to keep the grid stable and to deliver flexible export and import distribution services using DOEs, facilitated by a CSIP-Aus utility server.

The need for the Grid Stability and Flexible Services program is expected to be largely driven by existing and new regulatory obligations:

- Clause 4.3.4 of the NER requires DNSPs to use reasonable endeavours to exercise their rights and obligations in relation to networks so as to cooperate with and assist AEMO in the proper discharge of this responsibility.
- In August 2021, AEMO issued a directive to Victorian electricity network service providers to identify and implement measures to restore power system security from the threats caused by increasing levels of uncontrolled DPV within their respective networks. Since then, the DER and System Security Working Group has also been established to address these challenges.
- From 25 October 2023, new regulatory obligations took effect to require emergency Backstop capabilities for certain DPV connections.[26] Moreover, from 1 January 2024, each DNSP must have the capability to remotely curtail or interrupt generation by these DPV systems where required by AEMO. The Victorian Government has also indicated its intention to impose similar regulatory obligations.[27]

The program aims to:

- achieve power system security compliance with AEMO requirements across JEN's network and then maintain this compliance in an environment of increasing CER penetration
- identify and implement DPV Backstop and Distributed UFLS capabilities required to address the identified needs of the power system on a least-regrets basis

[25] DPV Backstop Capability is a committed project and are deployed in different stages in 2024 and 2025 to integrate with JEN's existing system for the required automation.

[26] See Victoria Government Gazette, No. S 542, 11 October 2023.

[27] See also DEECA, Victoria's Emergency Backstop Mechanism for rooftop solar, accessed 8 November 2023.

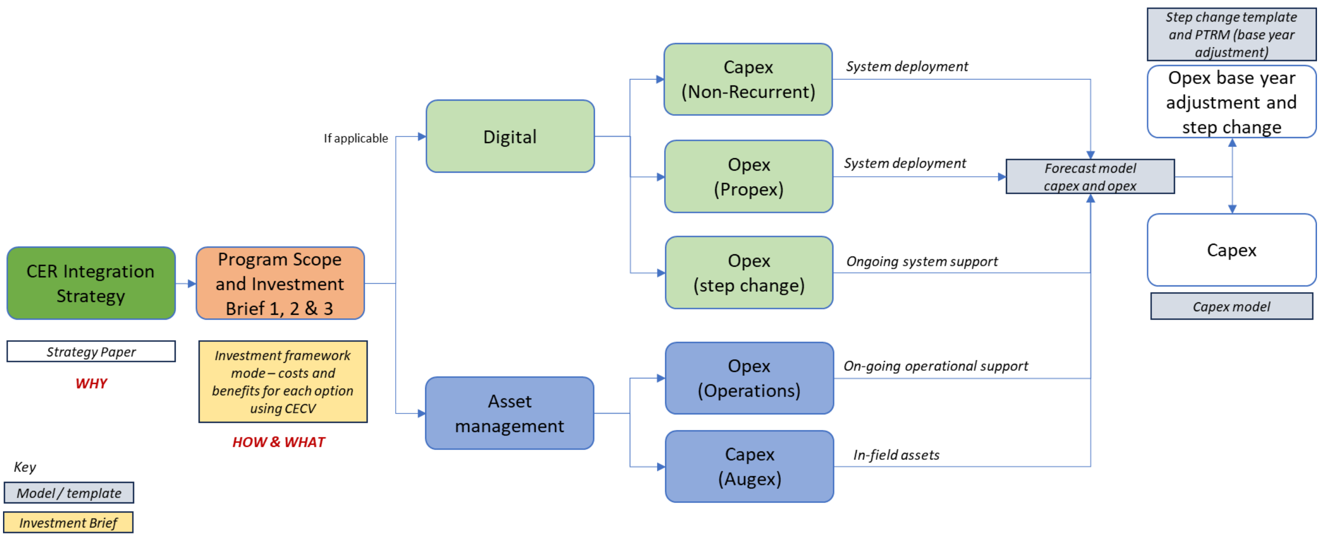
- provide a foundation on which JEN can establish Flexible Services for its customers
- optimise the sequence of Grid Stability capability investment to provide the highest net benefit, considering risk, performance, cost, timing and uncertainty
- complement and support other CER Integration Strategy initiatives and programs
- be scalable for the future
- ensure total lifecycle costs are minimised for JEN's customers.

4.1 CER Integration Strategy operating expenditure step change

Collaboration between the ICT and Asset Management (**AM**) teams is increasingly vital for JEN with the growing digitalisation and complexity of the energy landscape. As the grid modernises with smart technologies and automation, ICT provides the digital infrastructure needed for real-time data collection and analysis, while Asset Management manages the physical infrastructure. Together, they ensure a resilient and adaptable grid capable of accommodating the demands of renewable energy integration, which relies on advanced digital tools such as machine learning to monitor grid health and manage load fluctuations.

Therefore, expenditure is required on ICT activities (non-recurrent capital expenditure (capex) for system development, project operating expenditure (propex) for system deployment and ongoing recurrent (step) operating expenditure for ongoing system support) and Asset Management (non-recurrent capital expenditure on in-field assets and ongoing recurrent (step) operating expenditure for ongoing support) as shown in Figure 4–2.

Figure 4–2: Delivery of our CER Integration Strategy



We set out in Appendix B of our CER Integration Strategy the breakdown of the projects and associated costs which make up the programs of work supporting our CER Integration Strategy.

We have developed a detailed scope of work for each program which are supported by Investment Briefs. Our Investment Briefs for each CER Integration Strategy program of work sets out separately our ICT and AM forecast expenditure. Our ICT operating expenditure step changes are set out in section 3. This section only shows the forecast AM operating expenditure step changes associated with our CER Integration Strategy.

4.2 Nature of the step change

Our operating expenditure step change is spend incremental to our 2024-25 base year, and recurrent in nature. The operating expenditure is required to deliver our programs of work that support our CER Integration Strategy and deliver net present value (**NPV**) positive outcomes for our customers. We consider that our approach to developing our CER Integration Strategy and supporting programs of work reflect accepted good industry practice.

We expect that the CER Integration Strategy operating expenditure will be recorded as SCS - Export Services.

4.3 Quantification of the step change

We have completed economic analysis in the Investment Briefs of the available options, including do nothing. The preferred option for each program results in the most efficient option in accordance with accepted good industry practice that delivers expected net benefits to our customers. The description of the options considered and the supporting economic analysis for each option are set in the following Investment Briefs:

- JEN – RIN – Support – Data Visibility and Analytics Strategy – Investment Brief
- JEN – RIN – Support – Voltage and PQ Management Program – Investment Brief
- JEN – RIN – Support – Grid Stability and Flexible Services Program – Investment Brief.

The Investment Briefs for each CER Integration Strategy program of work sets out separately our ICT and AM forecast expenditure. Our ICT operating expenditure step changes are set out in section 3 (

Table 3–2). This section only shows the forecast AM operating expenditure step changes associated with our CER Integration Strategy associated with employment resources for ongoing monitoring and support.

Our estimated AM operating expenditure step changes for CER Integration Strategy programs incurred by the business SME / product owner for our preferred options based on maximum estimated net present value outcomes are shown in Table 4–1.

Table 4–1: CER Integration Strategy initiative AM operating expenditure step changes ($2026, million)

CER Integration Strategy program	Initiatives	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Data Visibility and analytics (option 3)	SNAP	-	0.4	0.4	0.4	0.4	1.5
Voltage and PQ management (option 4)	Voltage Var Control	0.2	0.2	0.2	0.2	0.2	1.1
Grid stability and flexible services (option 4)	Flexible exports	-	-	0.1	0.2	0.2	0.5
Total		**0.2**	**0.6**	**0.7**	**0.8**	**0.8**	**3.0**

Totals might not add due to rounding.

As noted above, our associated ICT operating expenditure step changes are set out in section 3.

We have demonstrated in the Investment Briefs the need to incur the expenditure and that we are adopting the most efficient option in accordance with accepted good industry practice. We consider that the above CER Integration Strategy programs of work and initiatives will help us deliver services to our customers consistent with the achievement of our obligations, the National Electricity Objective, and expectations of our customers and stakeholders in the transitioning energy market.

5. New REFCL obligations

Following the 2009 Black Saturday bushfires, in December 2011 the Victorian Government announced a package of initiatives to reduce the likelihood of power lines starting catastrophic bushfires in the future. Among these initiatives was a rollout of REFCLs in selected zone substations prone to bushfire start risk. At the time of implementing the changes, this was subject to further trials on a real network to confirm their effectiveness in reducing fire risk.

REFCLs have the ability to reduce the risk of bushfire starts from lines which experience a phase to earth fault (i.e. safety management). They reduce the current in any one phase which experiences an earth fault. As the devices act in milliseconds without the need for human intervention, they are designed to reduce customer supply interruptions and reduce the risk of starting a fire.

On 6 December 2024, ESV released its REFCL operations policy.[28] The policy sets out ESV's expectations for how REFCLs should operate. ESV has advised that it will consider the policy when assessing safety cases, including Electricity Safety Management Schemes (**ESMSs**) and Bushfire Mitigation Plans (**BMPs**) as a part of its usual functions. In particular, distribution businesses must regularly test and maintain REFCLs to ensure they are reliable and will function effectively when protection is needed, especially during high bushfire risk periods where REFCLs are installed to mitigate bushfire risk.

ESV's baseline expectations regarding the testing and maintenance of REFCLs—whether they are prescribed REFCLs or not—are as follows:

- Distribution businesses must have detailed forward plans to regularly test all components of REFCL systems, including high-voltage equipment and computer systems.
- All maintenance and network hardening related to REFCLs installed to mitigate bushfire risk should be completed before the declared Fire Danger Period each year.
- Testing and maintenance of REFCLs must be done efficiently, minimising out-of-service time as much as possible.
- Robust asset and vegetation inspection programs must also be in place to reduce the likelihood of faults that could trigger REFCLs, ensuring optimal performance and minimal supply disruptions.

Currently REFCL technologies deployed by JEN can be divided into two sub-categories:

- Base Level REFCL Technology (**BL REFCL**): This is the most common REFCL installations found around the world. It consists of an Arc Suppression Coil (**ASC**), an automatic ASC controller/tuning device and extremely sensitive earth fault detection devices.
- High Performance REFCL Technology (**HP REFCL**): This is currently the most advanced REFCL technology and can meet the performance requirements as prescribed in the Electricity Safety (Bushfire Mitigation) Regulations 2023. In addition to base level REFCL components, HP REFCL has an advanced power electronic component called Residual Current Compensator (**RCC**). The RCC helps to reduce the earth fault current even further and is used for diagnostic tests, as prescribed in the Electricity Safety (Bushfire Mitigation) Regulations 2023.

The Electricity Safety (Bushfire Mitigation) Regulations 2023 prescribe that (subject to exemptions) polyphase electric lines emanating from JEN's Coolaroo Zone Substation must have a REFCL installed and able to demonstrate the required capacity. In compliance with this mandate, JEN has installed two REFCLs at Coolaroo:

- A HP REFCL for all parts of the Coolaroo network that supply the Hazardous Bushfire Risk Area (i.e. and not exempt from the requirements of the regulations); and
- A BL REFCL for the remaining Coolaroo network.

28 ESV, *Operating rapid earth fault current limiters (REFCLs)*, 6 December 2024

Section 3 of JEN's Coolaroo REFCL Compliance Guideline ELE-999-GL-EL-005 [29] sets out the requirements for the Annual Required Capacity Testing for Coolaroo. The aim of the Annual Required Capacity Testing approach is to ensure a practical and efficient process has been adopted to demonstrate yearly compliance to the regulations. The Annual Required Capacity Testing results must be documented and submitted to ESV for review of compliance with the regulations.

The BL REFCL consisting of an Arc Suppression Coil (**ASC**), an automatic ASC controller/tuning device and extremely sensitive earth fault detection devices maintains customer reliability and safety outcomes. As such, we have installed an ASC at Sydenham (**SHM**) and Footscray West (**FW**) zone substations and will be installing these at all new and rebuilt zone substations in the future.

5.1 Nature of the step change

To meet the new regulatory obligations, we are proposing a step change for the Coolaroo HP REFCL annual validation testing (**AVT**). The REFCLs were installed and tested in 2023-24; this proposed step change is to cover the annual testing as part of a new obligation under JEN's Bushfire Mitigation Plan 2024-2029[30] which comes into effect from June 2024 with AVT to occur in August / September each year.

Whilst this obligation comes into effect from June 2024, the cost of AVT for summer 2024-25 has been included in the REFCL implementation project and therefore treated as capital expenditure.

In addition, this proposed step change is to cover the annual testing requirements for the SHM and FW ASC's.

As a result of this approach and timing, the step up in operating expenditure is not included in the base year and hence the need for a step change and they are not recovered in other operating or capital expenditure categories.

With this step change, and because of the approach taken, the allowance is necessary to meet the operating expenditure objective (cl. 6.5.6(a) of the NER) to reasonably reflect the operating expenditure criteria in cl. 6.5.6(c) of the NER.

We expect that the COO AVT and SHM and FW ASC testing operating expenditure will be recorded as SCS – Maintenance.

5.2 Quantification of the step change

We have quotations from third parties and estimates from our service provider to complete the annual program for the ESV REFCL validation testing on COO zone substation consistent with the testing requirements set out in Coolaroo REFCL Compliance Guideline. We have also estimated the cost for our service provider to complete the testing requirements associated with the ASC installations at two zone substations at Sydenham and Footscray West.

The annual fee estimate of $0.98M is set out in Table 5–1 and Table 5-2. We have firsthand experience of what is involved in performing the COO AVT as it was successfully completed prior to the 2024-25 summer period.

Table 5–1: Operating expenditure step change for Coolaroo HP REFCL AVT program ($2026)

Step change	Days / Hours	Rate	Annual cost
Overhead Line Crew	16 days	[redacted]	[redacted]
Driver of Test Truck and Trailer	160 hours		
Vegetation Management and Site Preparation	Quotation from contractor		
Truck Rental to Tow Test Trailer	Quotation from rental company		

[29] See Section 3 of the Coolaroo REFCL Compliance Guideline ELE-999-GL-EL-005 for further background on the requirements for the Annual Required Capacity Testing for COO.

[30] See section 19 of the JEN Bushfire Mitigation Plan 2024-2029 for further background and operational information on our REFCL obligations, and our annual Inspection and Testing of High Performance REFCL requirements for the Coolaroo HP REFCL.

Step change	Days / Hours	Rate	Annual cost
Protection Setting Review	Quotation from consultant		[redacted]
Engineering Consultant Engagement	25 days	[redacted]	
Relay Logic Testing	Quotation from consultant		
Project Management	300 hours	[redacted]	
Electrical Testers	810 hours		
Electrical Network Operator	170 hours		
Fleet and Plant	980 hours		
Total annual cost			**$644,045**

The rates in the above are based on actual 2024 rates based on testing completed as part of the REFCL implementation.

Table 5–2: Operating expenditure step change for Sydenham and Footscray West ASC program ($2026)

Step change	Days / Hours	Rate	Annual cost
Overhead Line Crew	8 days	[redacted]	[redacted]
Protection Setting Review	Quotation from consultant		
Project Management	150 hours	[redacted]	
Electrical Testers	405 hours		
Electrical Network Operator	85 hours		
Fleet and Plant	490 hours		
Total annual cost			**$338,709**

The rates in the above are based on learnings for the testing completed as part of the REFCL implementation and the capital project to upgrade the ASC at Sydenham zone substation. These have been applied to the testing requirements for the ASC's at Sydenham and Footscray West zone substations.

6. Network resilience initiatives

We set out in section 7 of *JEN - Att 05-01 Capital expenditure* how JEN plans to respond to community and government expectations in managing network resilience in an operating environment that has increasing frequency and severity of natural disasters on the electricity distribution system.

The industry expects that extreme weather damages (for example, caused by extreme wind, rainfall and heat days, and fires) will continue to disrupt the electricity network. At the same time, the energy transition is encouraging customers to electrify everything, which means that customers will be more reliant on the electricity network. These factors will place a higher priority on achieving network reliability that meets community and policy expectations in an operating environment that is expected to become more complex and challenging to manage over time.

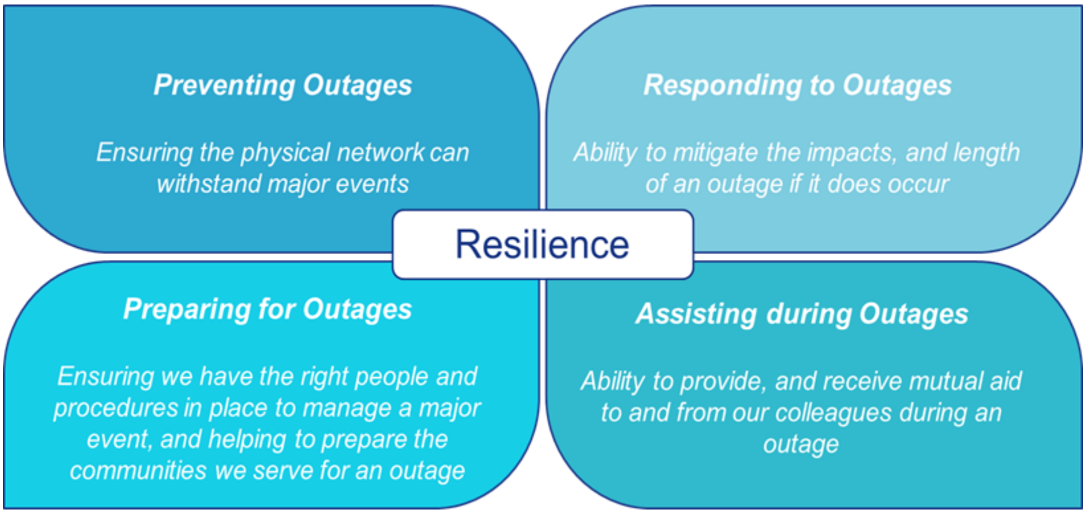
Given the increasing intensity and number of extreme weather events across Victoria and the National Electricity Market (**NEM**), as well as the resulting electricity outages, policymakers and regulators have begun investigating and developing adjustments to the regulatory framework to address this emerging challenge. Recent reviews include:

- The Victorian Government's Expert Panel Resilience Review (2021)
- The AER's Guidance Note on Resilience Issues (2022)
- The Victorian Government's Expert Panel Resilience Review (2024)
- The AER's Value of Network Resilience (VNR) Consultation & Draft Decision (2024).

The Victorian Government's Expert Panel Resilience Review recommendations call on electricity network service providers to improve network resilience, particularly through their restoration efforts. It is expected that some recommendations will result in regulatory obligations (for example, new Victorian electricity distribution network licence conditions). This is discussed further in section 6.1.

Figure 6–1 sets out JEN's approach to ensuring that it achieves network resilience that meet the community and government expectations.

Figure 6–1: JEN's key resilience tenets



JEN has identified several programs of work that addresses the key resilience tenets above to ensure that it achieves network resilience over the next regulatory period that meet community and government expectations.

JEN proposed the following programs of work that will require additional operating expenditure over the next regulatory period:

- **Resilience – outage preparation and response** which will uplift JEN's people and processes to meet the Recommendations from the 2024 Network Outage Review relating to planning and coordination, and mutual aid.
- **Mobile Emergency Response Vehicle** and two low voltage generators to enable JEN to provide support to customers during an outage.

These programs are discussed in sections 6.2 and 6.3.

6.1 Resilience – Outage preparation and response

The Victorian Government established two expert public reviews into electricity distribution network resilience for long-duration outages in the last three years. These were the:

- 2022 Electricity Distribution Network Resilience Review
- Independent review of transmission and distribution businesses operational response to the February 2024 storm and power outage event in Victoria (2024 network outage review).[31]

These are discussed below.

6.1.1 2022 electricity distribution network resilience review

Following the October 2021 storms, the Victorian Government convened an expert panel on electricity distribution network resilience. The expert panel suggested the following eight recommendations (see Table 6–1), comprising 35 sub-recommendations intended to increase network resilience.

[31] Network outage review expert panel, Independent review of transmission and distribution businesses operational response - February 2024 storm and power outage event - Final report, September 2024.

Table 6–1: Victorian Government's Expert Panel Resilience Review recommendations

Panel Recommendations
• *A Network Resilience Investment Strategy should be developed in the short term, with actions that can start immediately, to drive distributor investments in resilience solutions, informed by risk analysis and community needs. This should result in investments and solutions in the most high-risk locations by 2025.*
• *The distribution businesses should be required to take an all-hazards approach to risk mitigation for the purposes of safety, reliability, security and resilience of the electricity system. This should result in a regular assessment (at least every 5 years) of the need for investments and solutions in the-most high risk locations, from 2025 onwards*
• *The national legislative framework should be amended to drive distributor investments in resilience in the longer-term. To implement these changes, the Panel proposes that the Victorian Government should seek to amend the AER's framework, through working with the AER and through a series of proposed Rule changes, to embed resilience in the national framework from the next regulatory period (from 2026 onwards) and avoid the need for Victorian Government intervention in the longer term.*
• *The distribution businesses should be required to partner with communities and local councils in emergency planning and response*
• *The distribution businesses should have new obligations to improve the prioritisation of the restoration of power following an outage*
• *The distribution businesses should improve their communication with customers before and after prolonged power outages*
• *Improve delivery of relief to customers affected by prolonged power outages*
• *The distribution businesses should be required to conduct after action reviews (AARs) to improve outcomes for customers impacted by prolonged power outages*

We have begun to embed many of these recommendations into our business-as-usual practices including engagement with local councils and updates to our outage management processes.

A rule change request relating to this program of work was submitted by the Victorian Minister for Energy and Resources to the AEMC on 23rd August 2024[32], with a draft decision due on 13 February 2025 and the final determination expected in May 2025. The rule change request proposes to include resilience in the NER, however in a different way from that recommended by the Expert Panel. The Expert Panel recommended including resilience through the capital expenditure objectives in cl. 6.5.7 of the NER, while the Victorian Government in its rule change request has proposed to include resilience through the capital and operating expenditure factors in cl. 6.5.6(e) and cl. 6.5.7(e) of the NER.

6.1.2 2024 network outage review

In light of the February 2024 storms, the Victorian Government commissioned an independent panel (Victorian Government's Expert Panel Network Outage Review, or **2024 Review**) to review the operational response of electricity network service providers during long-duration outages and recommend ways in which this could be improved. A final report by the panel dated 30 August 2024 consists of 19 recommendations and 12 observations focused on delivering a clear pathway of improvements necessitating a step change in the operational response by transmission and distribution businesses during prolonged power outage events.

The recommendations and observations of the 2024 Review included how network service providers could improve their operational response to long-duration outages including:

[32] Including distribution network resilience in the National Electricity Rules | AEMC

- improving planning, coordination and accountability by clarifying roles and responsibilities in relation to emergency management
- recommending a new financial support mechanism, the Extended Loss of Supply Support payment, to support customers impacted by outages and put the onus on DNSPs to reduce restoration times for long-duration outages
- improve communication with customers by strengthening customer contact processes
- provide backup temporary generation within communities to support critical services and support a more reactive presence on the ground.

We understand that the Victorian Government is currently considering the 2024 Review report and its recommendations.[33]

The panel's identified improvements are reflected in and to a certain degree informed by the Energy Charter's #BetterTogether program of works.

Customer support

Our proposed programs of work addressing the recommendations from the two reviews (and draft rule change), have been informed by our customers' expectations on their energy priorities, preferences, and how we should prepare for a more sustainable energy future.

The proposed programs of work are aligned to recommendations from a Network Resilience Study JEN commissioned AECOM to undertake which included gathering insights on JEN's current capabilities and key gaps related to network resilience.[34] The purpose of the AECOM study was to assess the likely impact of the changing climate on the electricity network assets and to identify areas which could be classified as 'at risk.' Some of the findings from this study indicated that there are opportunities for JEN to expand the remit of our resilience team to capture broader aspects of resilience related to network resilience both upstream and downstream, including community resilience, and build the capability of the organisation to manage and respond to hazards such as wind and flooding. The study also found that JEN should enhance internal coordination across teams to support resilience efforts and prioritise community resilience planning to manage community expectations.

We note that the topic of resilience featured throughout our engagement program,[35] forming part of robust discussions in order to understand customers' expectations around the resilience of our network including how we respond to and recover from extreme weather events. Our customers, their representative groups and key stakeholders have given a strong endorsement to deliver network resilience and support the community during significant events.

JEN's proposed programs of work also align with the AER's note on network resilience key issues[36], by demonstrating a strategic approach to enhancing network resilience.

We expect that any future obligations on electricity network businesses resulting from the above two reviews will be consistent with the programs we plan to embed into our business-as-usual practices. Regardless of the form and nature of any regulatory obligations, we consider that our planned programs of work to achieve the community and government expectations on network reliability are consistent with acting as a prudent operator, and the operating criteria set out in cl. 6.5.6(c)(2).

[33] Network Outage Review.

[34] AECOM - Network Resilience Study Findings Report (2024)

[35] Further information on our engagement program can be found in Chapter 2 of our 2026-31 Proposal.

[36] AER – Network Resilience – A Note on Key Issues (2022).

6.2 Resilience – Outage preparation and response

The 2024 Review focussed on operational arrangements and preparedness to respond to extreme weather events. To meet the recommendations from the 2024 Review, JEN's emergency management capabilities, including planning, coordination, and communication with at-risk communities must be improved. The proposed expenditure increases will strengthen JEN's emergency preparedness, ensuring continuity of service and improved restoration times during prolonged outages. JEN will also need to implement the mutual aid arrangements stipulated in the 2024 Review, a proportion of the proposed operation expenditure will facilitate this.

JEN's is proposing investments that align recommendations 2 and 16 of the 2024 Review as follows:

- Mutual aid agreements: JEN is proposing to formalise mutual aid arrangements between other DNSPs before outages occur to facilitate quicker responses and reconnections during emergencies.
- Communication and engagement with customers and community: JEN has aligned with the community engagement recommendation by actively strengthening its connections with affected communities during outages. Following the February 2024 storms, JEN engaged customers through forums and feedback sessions to gather insights on their experiences and expectations. This input has been instrumental in informing strategies to improve network resilience and service reliability. By maintaining ongoing dialogue and outreach efforts, JEN demonstrates its commitment to incorporating community feedback into its planning and decision-making processes.

By addressing these key recommendations, JEN's proposed investments demonstrate a commitment to enhancing network resilience, improving emergency response capabilities, and better serving the community during extreme weather events. These initiatives also align with the AER's Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution, ensuring that investments are justified and demonstrate a net benefit to consumers by reducing outage frequency and duration.

6.2.1 Nature of the step change

We are proposing a total of $4.5M non-ICT operating expenditure over the next regulatory period, with the expenditure commencing from 2025-26.

The proposed increase in outage preparation and response spend is incremental to our 2024-25 base year, and recurrent in nature. We consider that our proposed spend is prudent and efficient. It meets accepted good industry practice and meets our regulatory (and likely future) obligations, and our customer and government expectations over the next regulatory period. The allowance is necessary to meet the operating expenditure objective (cl. 6.5.6(a) of the NER) to reasonably reflect the operating expenditure criteria in cl. 6.5.6(c) of the NER.

We expect that the operating expenditure associated with outage preparation and response will be recorded as SCS – Maintenance.

6.3 Resilience - deploying mobile emergency response vehicle

The 2022 Electricity Distribution Network Resilience Review focused on preparedness for, and response to, prolonged power outages arising from storms and other extreme weather events, it also considered ways to strengthen community resilience in the face of prolonged power outages.

We are proposing to invest in an emergency response vehicle consistent with recommendations of the review, which called for distribution businesses to introduce 'community hub' type locations and the review highlighted the necessity for the development of, and to maintain the capability to provide, on-the-ground support to communities during emergencies using trained staff with pre-established relationships with communities and local authorities. The purpose of the emergency response vehicle is to support JEN's emergency response capabilities by better serving communities during selected lengthy planned and unplanned outages.

The need for the emergency response vehicle has been reinforced by an incident in Pascoe Vale in December 2023 where 229 customers were without electricity supply for 3 days.

Our proposed emergency response vehicle is a community-centred information vehicle equipped with essential features including phone recharging stations, satellite Wi-Fi connectivity (Starlink), a water tank, two low voltage generators, tea/coffee facilities and designated points of contact for residents. The vehicle will enable JEN to provide effective, timely assistance to our customers during selected planned and unplanned outages.

6.3.1 Nature of the step change

We are proposing a total of $0.4M operating expenditure over the next regulatory period, with the expenditure commencing from RY26. Therefore, the expenditure is not included in our base year operating expenditure.

With this step change, and because of the approach taken, the allowance is necessary to meet the operating expenditure objective (cl. 6.5.6(a) of the NER) to reasonably reflect the operating expenditure criteria in cl. 6.5.6(c) of the NER.

We expect that the operating expenditure associated with deploying mobile response vehicles will be recorded as SCS - Emergency response.

6.4 Quantification of our network resilience initiatives step changes

Error! Reference source not found. sets out our estimated non-ICT operating expenditure that we plan to u ndertake over the next regulatory period to prepare and respond to community and government expectations on achieving network resilience, and our current and likely future regulatory obligations.

Table 6–2: Opex step change for resilience ($ June 2026, millions)

Opex category	2025-26	2026-27	2027-28	2028-29	2029-30	Total
JEN – RIN – Support - Outage Preparedness and Response – 20250131 – Public – option 2						
AM people uplift and processes	0.7	0.7	0.7	0.7	0.7	3.5
Emergency response vehicle	0.2	0.2	-	-	-	0.4
Total step change	0.9	0.9	0.7	0.7	0.7	3.9
JEN – RIN – Support - ICT Investment Brief - Outage Preparedness and Response – 20250131 – Public – option 2						
ICT (see section 3.2, Table 3–2)	-	0.2	0.2	0.2	0.2	0.7
Customer comms resilience support	0.2	0.2	0.2	0.2	0.2	1.0
Total step change	0.2	0.3	0.3	0.4	0.4	1.6
Outage preparation and response	**1.1**	**1.1**	**0.9**	**0.9**	**0.9**	**4.9**

Totals might not add due to rounding

We have prepared the *JEN – RIN – Support - Outage Preparedness and Response – 20250131 – Public* business case and *JEN – RIN – Support - ICT Investment Brief - Outage Preparedness and Response – 20250131 – Public* which establish and summarise the overarching objective and problem statements that will be addressed, as well as the high-level scope, and what options have been considered to deliver the most prudent and efficient solution.

We have been guided by feedback from our customers, who support us taking a balanced investment approach to resilience. Our balanced investment approach is focused on strengthening assets across the Maribyrnong River (an area with elevated risk), while investing in operational and response solutions which reduce the impact of the outage and its duration.

The options analysis in the business case and investment brief provide a preliminary assessment of the options to implement an effective solution to achieve the objective of the business case. The business case and ICT investment brief also set out how JEN's proposed investments align with the AER’s note on network resilience key issues. The preferred options are the least cost options that addresses key concerns of the Victorian government’s recent resilience reviews. The preferred options enhance JEN's ability to respond to emergency events and aims to ensure compliance with regulatory requirements and meet customer satisfaction.

We have demonstrated in the business case and ICT investment brief the need to incur the expenditure and that we are adopting the most efficient option in accordance with the costs that a prudent operator would incur, and that meets our customers’ expectations. We consider that the enhancing JEN’s outage preparedness and community response to meet the expectations of our customers and minimise disruption caused by network outages, and meet likely regulatory obligations, will help us deliver services to our customers consistent with the achievement of the National Electricity Objective.

The proposed opex increases will strengthen JEN’s emergency preparedness, ensuring continuity of service and improved restoration times during prolonged outages.

7. Low Bushfire Risk (LBRA) Hazard Tree Management Program

This strategic initiative is aimed at enhancing the operational safety of our network against increasingly frequent and damaging weather events, primarily strong winds and storms.

This program is to be implemented in addition to the existing Hazard Tree Management Program in the Hazardous Bushfire Risk Area (HBRA), a program that has proven to be highly effective. The LBRA program is designed to identify and mitigate the risk of hazard trees which are situated outside of the electric line clearance space and that has the potential to impact overhead lines.

7.1 Scope of LBRA Hazard Tree Management program

BMF20 Electric Line Clearance Management Procedure of the JEN Bushfire Mitigation Plan 2024-29 describes JEN's process for ensuring that adequate clearances are maintained between vegetation and network assets. It covers:

- The maintenance of programs for achieving statutory clearances between vegetation and network assets; and
- The development and implementation of an Electric Line Clearance Management Plan.

The Electric Line Clearance Management Procedure comprises:

- An annual pre-summer inspection on the JEN supply networks in the HBRA periodic audits carried out in the months before, and during, the fire danger period. For LBRA, a pre-summer inspection program within the LBRA is not undertaken. Rather vegetation in these areas is managed under the cyclic program contained within the JEN Electric Line Clearance Management Plan which includes audits on the Vegetation Management Contractor (**VMC**) to ensure compliance with JEN's obligations. The LBRA program is audited throughout the year. We refer to this as our Cyclic Vegetation Management Program.
- Hazard Tree Management Program – JEN manages hazard trees as a dedicated hazard tree management program in the HBRA. The biennial inspection cycle for the dedicated program has been designed to evaluate any potential tree hazards within the vicinity of JEN assets and action accordingly.

Hazard trees are defined as "...*trees that are likely to fall onto, or come into contact with, an electric line*..", typically trees in this category are dead or dying, located outside the electrical line clearance zone with a very weak connection to its root system, ground lifting around the roots or a major over balance towards network assets.

During extreme weather conditions such as high winds, these trees may fall onto network assets, disrupting supply to customers, hindering our crew's ability to restore power and potentially increasing the risk of a bushfire.

We are planning to extend our success HBRA Hazard Tree Management Program to the LBRA in response to customer expectations for communities in our network. The aim of the LBRA program is to thin out or clean out the hazard tree space that is/was traditionally performed by storms.

In response to our Draft Plan, the City of Moonee Valley raised concerns[37] about the potential impact on its urban forest resulting from our proposed LBRA program. Our LBRA program has been developed to identify trees that need pruning or removal by a qualified arborist. If a tree needs pruning or removal, with exception to emergencies, no tree will be pruned or removed without at least 14 days' notice provided to the local council and/or affected persons. If the local council and/or affected persons disagrees with an assessment, there is a negotiation process in place, with escalation options if necessary. In our experience, discussions over hazard trees are rare, as they typically involve dead or dying trees.

[37] Letter from Andrew Fox, Coordinator Trees and Urban Forest, City of Moonee Valley dated 16 September 2024.

If we target effort by the proposed program correctly, we will see better storm performance from a vegetation impact perspective. This increased program activity will result in additional operating expenditure.

7.2 Nature of the step change

JEN is proposing a step change in the coming period to extend the dedicated Hazard Tree Management Program beyond HBRA and to LBRA to account for the additional risks to the network due to the projected increase in extreme weather events.

The first year of expenditure will be 2025-26.

With this step change, and because of the approach taken, the allowance is necessary to meet the operating expenditure objective (cl. 6.5.6(a) of the NER) to reasonably reflect the operating expenditure criteria in cl. 6.5.6(c) of the NER.

We expect that the operating expenditure associated with the amended Hazard Tree Management Program for LBRAs will be recorded as SCS - Vegetation management.

7.3 Quantification of the step change

The Hazardous Tree Management Program in the LBRA will have the following elements:

- Two (2) year assessment cycle;
  - high Voltage and Sub transmission lines prioritised;
  - prioritising areas identified as previously poor performers in terms of vegetation related outages;
  - assessment to include both Jemena Responsible & Other Responsible Person (Council) vegetation;
- Targeted Assessment:
  - all trees which, in the event of a structural failure, will impact the overhead lines. This includes trees permitted to overhang
  - canopy density, species with propensity to shed limbs, deadwood, sail area in the direction of the line, and periods with unusual growth rates
  - assessment will be divided into 2 parts:
  - identify and categorise: an assessment conducted from a vehicle patrol or foot patrol to record all potential hazard tree locations and categorisation using hazard tree codes (priority rating scale from 1-5) to be adapted to the LBRA using the targeted assessment criteria
  - detailed assessment: when a tree is classified as 'Code 4' (Probable) & 'Code 5' (Imminent) by assessment then a detailed assessment by a suitably qualified arborist is organised. This results in confirmation of the assessment, or changes to a different priority. Assessment to identify follow up action required e.g. prune/remove/slashing/herbicide
- Notification and consultation with vegetation owners; and
- Coordination of remediation actions.

Our key assumptions, based on existing network data and Hazard Tree program evidence, are shown in Table 7–1.

Table 7–1: Key LBRA Hazard Tree Management Program assumptions

Assumptions	Parameters[38]
Inspection Program	
Inspection Cycle	2 years
Scope limited to HV & ST lines only	36,133 spans
Estimated HV/ST spans containing vegetation	16,508 spans
Estimated number of Hazard Trees (Rating 1-5) per vegetated span	0.20 (1 per 5 spans)
Percentage of JEN Responsible trees	70%
Percentage of Hazard Trees found requiring action (Rating 4-5) by JEN	15%
Cutting Program	
Ratio of Tree Cutting Requirement - Live Line vs. Shut Down	3:2
Live Line Cutting - Average cost per tree	$1,500
Planned Outage – Operational Costs	$4,000
Cutting Contractor - Hazard Tree Cutting Rate	$1,000

Based on these assumptions, for each cycle we expect 36,133 spans for inspection and the need to address 469 trees.

We have estimated the cost of our LBRA Hazard Tree Management Program by estimating costs associated with the following activities:

- program management, assessment and auditing (set out in Table 7–2: Forecast LBRA Hazard Tree Program Management, Assessment and Auditing ($2024, thousands))
- program cutting of identified risky trees:
- taking into consideration the various methods of cutting available depending on the circumstances, it was determined that a reasonable average cost estimate for the cutting of each tree is $2,000.
- at an expected 15% rate for all hazard trees found across the JEN network that will be actionable by cutting each cycle of the program, the total cost of cutting is forecast to be $360k ($2024) per annum (600 trees x 15% x 2 cycles x $2,000 per tree).

Table 7–2: Forecast LBRA Hazard Tree Program Management, Assessment and Auditing ($2024, thousands)

Activity	FTE	Estimated Investment per annum ($000)
Assessment – Identify & Categorise	[redacted]	[redacted]
Assessment – Detailed Assessment		
Notification – Customer		
Consultation – Customer		
Consultation & Reporting – Council		
Managing Program		
Coordinating Cutting Program - Live Line and Planned Outages		

[38] Based on existing network data and Hazard Tree program evidence.

Activity	FTE	Estimated Investment per annum ($000)
Auditing of Cutting	[redacted]	[redacted]
Total	**1.00**	**148**

The resulting annual forecast operating expenditure step change ($0.5M per annum 2026$) for LBRA Hazard Tree Management Program is shown in Table 7–3.

Table 7–3: Forecast LBRA Hazard Tree Management Program ($2024, thousands)

Program Component	Estimated Investment per annum ($000)
Program Management, Assessment and Auditing	148
Program Cutting	380
Total	**528**

Further details on the scope of our Hazard Tree Management Program and cost estimates are set out in *JEN - RIN - Support - LBRA Hazard Tree Program Business Case - 20250131*.