



Jemena Electricity Networks (Vic) Ltd

2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 06-05

Operating expenditure step changes



Table of contents

| | |
|---|-----------|
| Glossary | iv |
| Abbreviations | v |
| Overview | vi |
| 1. Insurance premiums | 1 |
| 1.1 Background | 1 |
| 1.2 Step change forecast | 5 |
| 1.3 Options assessment | 5 |
| 2. Annual REFCL testing and maintenance | 7 |
| 2.1 Reason for a step change | 7 |
| 2.2 Step change forecast | 8 |
| 2.3 Options analysis | 9 |
| 3. Future Grid program | 11 |
| 3.1 Reason for a step-change | 11 |
| 3.2 Step change forecast | 12 |
| 3.3 Options assessment | 13 |
| 4. Transitional return on debt alignment costs | 16 |
| 4.1 Reason for a step-change | 16 |
| 4.2 Step change forecast | 16 |
| 4.3 Reasoning for the step change | 16 |
| 5. Environment Protection Act changes | 19 |
| 5.1 Reason for a step change | 19 |
| 5.2 Step change forecast | 20 |
| 5.3 Options analysis | 20 |
| 6. Cybersecurity | 22 |
| 6.1 Reason for a step-change | 22 |
| 6.2 Step change forecast | 23 |
| 6.3 Options assessment | 23 |
| 7. Additional RIN reporting | 27 |
| 7.1 Reason for a step-change | 27 |
| 7.2 Step change forecast | 28 |
| 7.3 Options analysis | 28 |

List of tables

| | |
|---|-----|
| Table OV-1: JEN's proposed operating expenditure step changes summary 2021-26 (\$ June 2021, millions) | vii |
| Table OV-2: JEN's operating expenditure step changes – recurrence and operating expenditure categories | vii |
| Table 1-1: Operating expenditure step change for insurance premiums (\$ June 2021, millions) | 5 |
| Table 2-1: Operating expenditure step change for REFCL testing and maintenance (\$ June 2021, millions) | 9 |
| Table 2-2: Operating expenditure for in-house REFCL testing and maintenance (\$ June 2021, millions) | 10 |
| Table 3-1: Proposed Future Grid operating expenditure step change (\$ June 2021, millions) | 12 |
| Table 4-1: Operating expenditure step changes for return of debt alignment (\$ June 2021, millions) | 16 |
| Table 4-2: Transitional return of debt alignment costs options assessment | 17 |
| Table 4-3: [REDACTED] | 17 |
| Table 4-4: Cost impact over the next regulatory period - 6bpps (\$ June 2021, millions) | 18 |

| | |
|--|----|
| Table 5–1: Proposed operating expenditure step change for Environment Protection Act changes (\$ June 2021, millions)..... | 20 |
| Table 5–2: Additional environmental risk management activities (\$ June 2021, millions)..... | 21 |
| Table 6–1: Proposed 2021-26 operating expenditure step change for cybersecurity (\$ June 2021, millions)..... | 23 |
| Table 6–2: Cybersecurity options assessment..... | 24 |
| Table 6–3: Options 1 – Strengthening internal capability – cost analysis (\$ June 2021, dollars) | 24 |
| Table 6–4: Option 2 – Outsourced – cost analysis (\$ June 2021, dollars) | 25 |
| Table 6–5: Option 2 – Hybrid automation with automation – cost analysis (\$ June 2021, dollars)..... | 25 |
| Table 7–1: Proposed operating expenditure step change for additional RIN reporting (\$ June 2021, millions) | 28 |

List of figures

| | |
|--|----|
| Figure 1–1: HBRA and LBRA areas overlapping JEN distribution areas..... | 2 |
| Figure 3–1: Results of options analysis to address the future trend in energy distribution | 13 |

Glossary

| | |
|---------------------------|---|
| Aon | Aon Risk Services |
| Act | Environment Protection Amendment Act 2018 (Vic) |
| Current regulatory period | The regulatory control period covering 1 January 2016 to 31 December 2020 |
| Intervening period | The six months between the end of the current regulatory period and beginning of the next regulatory period covering 1 Jan 2021 to 30 Jun 2021 |
| Minister | Victorian Minister for Energy, Environment and Climate Change |
| Next regulatory period | The regulatory control period covering 1 July 2021 to 30 June 2026 |
| Regulations | Victoria's Electricity Safety (Bushfire Mitigation) Regulations 2013 (including subsequent amendments made in 2016 and 2017) |
| RIN response | Our response to information sought by the AER in the Regulatory Information Notice served 4 Oct 2019 |
| Required Capacity | Technical performance standards (referred to as the Required Capacity) for 45 zone substations throughout Victoria's most bushfire-prone areas set by the Regulations |

Abbreviations

| | |
|--------|---|
| AER | Australian Energy Regulator |
| AESCSF | Australian Energy Sector Cyber Security Framework |
| AMI | Advanced Metering Infrastructure |
| AR | Annual Reporting |
| BMP | Bushfire Mitigation Plan |
| CA | Category Analysis |
| COO | Coolaroo zone substation |
| CY | Calendar year |
| DELWP | Department of Environment, Land, Water and Planning |
| DNSP | Distribution Network Service Provider |
| EB | Economic Benchmarking |
| EBSS | Efficiency Benefits Sharing Scheme |
| EDC | Electricity Distribution Code |
| EPA | Environmental Protection Authority (Victoria) |
| ESV | Electrical Safety Victoria |
| EV | Electric Vehicle |
| FY | Financial year |
| GEN | General Environment Duty |
| HBRA | Hazardous Bushfire Risk Areas |
| JEN | Jemena Electricity Networks (Vic) Ltd |
| LBRA | Low Bushfire Risk Areas |
| MIL | Maturity Indicator Levels |
| NEL | National Electricity Law |
| NER | National Electricity Rules |
| OHS | Occupational Health and Safety |
| OT | Operational Technology |
| PCB | Poly-Chlorinated Bisphenols |
| PTRM | Post Tax Revenue Model |
| RBA | Reserve Bank of Australia |
| REFCL | Rapid Earth Fault Current Limiter |
| RIN | Regulatory Information Notice |
| SGSPAA | SGSP (Australia) Assets Pty Ltd |

Overview

Jemena Electricity Networks (Vic) Ltd (**JEN**) has adopted a base, step and trend approach to forecasting operating expenditure for the regulatory control period covering 1 July 2021 to 30 June 2026 (**next regulatory period**). The proposed operating expenditure base year is the regulatory year 2018 (i.e. calendar year). From time to time increases in operating expenditure—not captured in the base year and not captured by the rate of change—arise, and these can be reasonably forecast. When this occurs, we seek recovery of these costs through an operating expenditure step change.

In this document, we propose prudent and efficient operating expenditure step changes consistent with the operating expenditure objectives in the National Electricity Rules (**NER**).¹ We have also taken into account the matters outlined in the AER's expenditure assessment guideline² when identifying and proposing operating expenditure step changes.

Operating expenditure step changes are in the long term interests of customers

Several factors drive costs that a network business incurs, these include:

- Inputs that are procured to deliver services – through a range of mechanisms such as negotiations, volume discounts (scale) and market tenders, etc., inputs into providing distribution services can be purchased efficiently.
- The ability of a business to recover efficient costs – if regulatory frameworks allows for the recovery of efficient costs, then investors recognise the lower investment risk and therefore provide financing at a lower cost.
- Regulatory stability – ensuring the assessment framework does not change materially from one regulatory period to the next, also signals to investors that risks can be managed, and therefore, also contributes towards lower financing costs.

By having these features built into the regulatory framework—in particular, the AER's preferred approach to forecasting operating expenditure using the base, step and trend approach—over the past four regulatory periods, signals stability. Maintaining a regulatory framework where efficient procurement is encouraged and where investors can manage financial risks by recovering its efficient costs, customers can receive lower-cost services in the long term.

Based on this, and by allowing network businesses to recover efficient step change costs, customer's long term interests can be met.

Consistent with the approach to modelling step changes in the post-tax revenue model (**PTRM**), we include two types of uplift in costs, these are:

- Step changes – forecast expenditure that will become part of our recurrent base year operating expenditure in the subsequent regulatory period and is *included* in an adjustment under the Efficiency Benefits Sharing Scheme (**EBSS**).
- Category-specific forecasts – a forecast expenditure that is not always recurrent may require bespoke forecasting methods based on its cost driver. This category of expenditure will be *excluded* from both our base year operating expenditure as well as in the subsequent regulatory period EBSS calculations.

This document details the operating expenditure step changes we propose in our Regulatory Proposal; details of the category-specific forecasts are outlined in Attachment 06-01.

¹ NER, clause 6.5.6(a).

² AER, *Better Regulation - Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

Table OV–1 lists the operating expenditure step changes we propose and the annualised cost we expect to incur during the next regulatory period.

Table OV–1: JEN’s proposed operating expenditure step changes summary 2021-26 (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|------------------------------------|------------|------------|------------|------------|-------------|-------------|
| Insurance premiums | 3.9 | 5.1 | 6.1 | 6.6 | 7.1 | 28.8 |
| Inspection of REFCL equipment | - | 0.1 | 0.4 | 0.4 | 0.4 | 1.3 |
| Future Grid program | 0.7 | 0.7 | 0.8 | 0.8 | 0.8 | 3.8 |
| Transitional hedging costs | 0.1 | 0.1 | 0.2 | 0.2 | 0.3 | 0.9 |
| Environment Protection Act changes | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 4.2 |
| Cybersecurity | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 2.9 |
| Additional RIN reporting | 0.5 | - | - | - | - | 0.5 |
| Total | 6.7 | 7.5 | 8.9 | 9.4 | 10.0 | 42.4 |

Source: Attachment 07-15 SCS PTRM FY22-26.

Note: Total amounts may not reconcile to the total due to rounding, refer to Attachment 07-15 SCS PTRM FY22-26.

Table OV–2 sets out, for each of the step changes we propose in this Regulatory Proposal, whether the expenditure is recurrent and the relevant operating expenditure category.

Table OV–2: JEN’s operating expenditure step changes – recurrence and operating expenditure categories

| Step change | Recurrence | Operating expenditure category ³ |
|------------------------------------|---------------|---|
| Insurance premiums | Recurrent | Network overheads and corporate overheads |
| Inspection of REFCL equipment | Recurrent | Maintenance |
| Future Grid program | Recurrent | Network overheads and corporate overheads |
| Transitional hedging costs | Recurrent | Network overheads and corporate overheads |
| Environment Protection Act changes | Recurrent | Network overheads and corporate overheads |
| Cybersecurity | Recurrent | Non-network expenditures |
| Additional RIN reporting | Non-recurrent | Network overheads and corporate overheads |

Based on previous experience, we anticipate a high likelihood that further operating expenditure step changes will arise following submission of this Regulatory Proposal. This situation occurs due to the timing differences between submitting a five-yearly proposal and identifying the need to incur additional expenditure. This has also been our experience in this current round of price reviews where we did not identify any step changes in our draft plan⁴ (issued on 31 January 2019), but those noted above have since arisen.

On some occasions, further step changes arise after submitting a Regulatory Proposal, but before submitting a revised proposal. To the extent that this situation arises, JEN may raise additional step change activities in its revised regulatory proposal. Already, we are aware of several events—mostly driven by Government policy developments—that fall into this category, these include:

³ These categorisations are consistent with the way we categorise operating expenditure in our Regulatory Information Notice reporting requirements.

⁴ JEN, *Jemena Electricity Networks, Draft 2021-25 Plan*, January 2019.

- the impending Victorian Government policy announcements, including tariff reform, advanced metering infrastructure (**AMI**) roadmap and Electric Vehicle (**EV**) policy, the outcomes from the Grimes review,^{5,6} outcomes from the Energy Safety Legislation Amendment (Victorian Energy Safety Commission and Other Matters) Bill 2019, along with other state-based policy announcements.
- Changes in Federal Government policy, including a potential uplift in the superannuation payment rate from 9.5% to 10%.

We will know more about these, and other step changes, following submission of this Regulatory Proposal. We will inform the Australian Energy Regulator (**AER**) of these as they arise, and no later than in our revised regulatory proposal. We will also keep other stakeholders informed on these developments, including, the Customer Challenge Panel and JEN's customer council.

The remainder of this document details each proposed operating expenditure step change that forms a part of our Regulatory Proposal.

⁵ Dr Paul Grimes, *Independent review of Victoria's electricity and gas network safety framework, Final Report*, December, 2017.

⁶ Department of Environment, Land, Water and Planning, *Government Response to the Independent Review of Victoria's Electricity and Gas Network Safety Framework*, August 2018.

1. Insurance premiums

1.1 Background

Insurance is a form of financial risk management, primarily used to hedge against the risk of a contingent or uncertain losses and usually associated with low frequency, high impact events (although the relationship of frequency and magnitude can vary depending on the type of event being insured). JEN procures insurance for public liability; the policies we obtain cover a range of events, including—and most significantly—bushfire events associated with the electricity distribution network.

Currently, the insurance market is undergoing significant change, primarily driven by an increase in the number of insurable events and a substantial increase in the magnitude of payouts associated with those events experienced on a global scale. The extreme wildfire events in California in recent years have contributed to these changes. Locally, the bushfire events that fall into this category of extreme events are the Ash-Wednesday event in 1983 and the black-Saturday events in 2009 and numerous other events⁷ and these also impacted the insurance market at the time.

Australia is the most bushfire prone country in the world, and Victoria is regarded as one of the most fire-prone states.⁸ This, combined with the global trend in the insurance market, has implications on the public liability insurance we procure to manage bushfire risks.

What regulations say about the prudence and efficiency of insurance

When considering whether to approve a nominated pass-through event,⁹ the AER must take into account the *nominated pass-through event considerations*.¹⁰ These considerations, outline several factors including the extent to which an event can be insured, thus indicating insurance is a prudent and efficient tool in managing the financial risks of an electricity distribution business.

If insurance is not obtained to mitigate JEN's bushfire liability exposure, JEN would be required to retain significant capital funds to facilitate payment to potential claimants in the event of a bushfire incident, leading to a higher cost to serve. This outcome would not be a prudent nor efficient use of capital for JEN's customers when considered against the alternative of insuring at an appropriate level.

Given these factors, we consider it is both prudent and efficient for a distribution business to manage financial risks by obtaining a suitable level of insurance coverage.

Legislative requirements concerning bushfire risks

As a part of the Victorian State Government's fire management plans, regions within Victoria are classified into hazardous bushfire risk areas (**HBRA**) and low bushfire risk areas (**LBRA**) by the Country Fire Authority. JEN's electricity distribution area covers both categories of bushfire risk ratings.

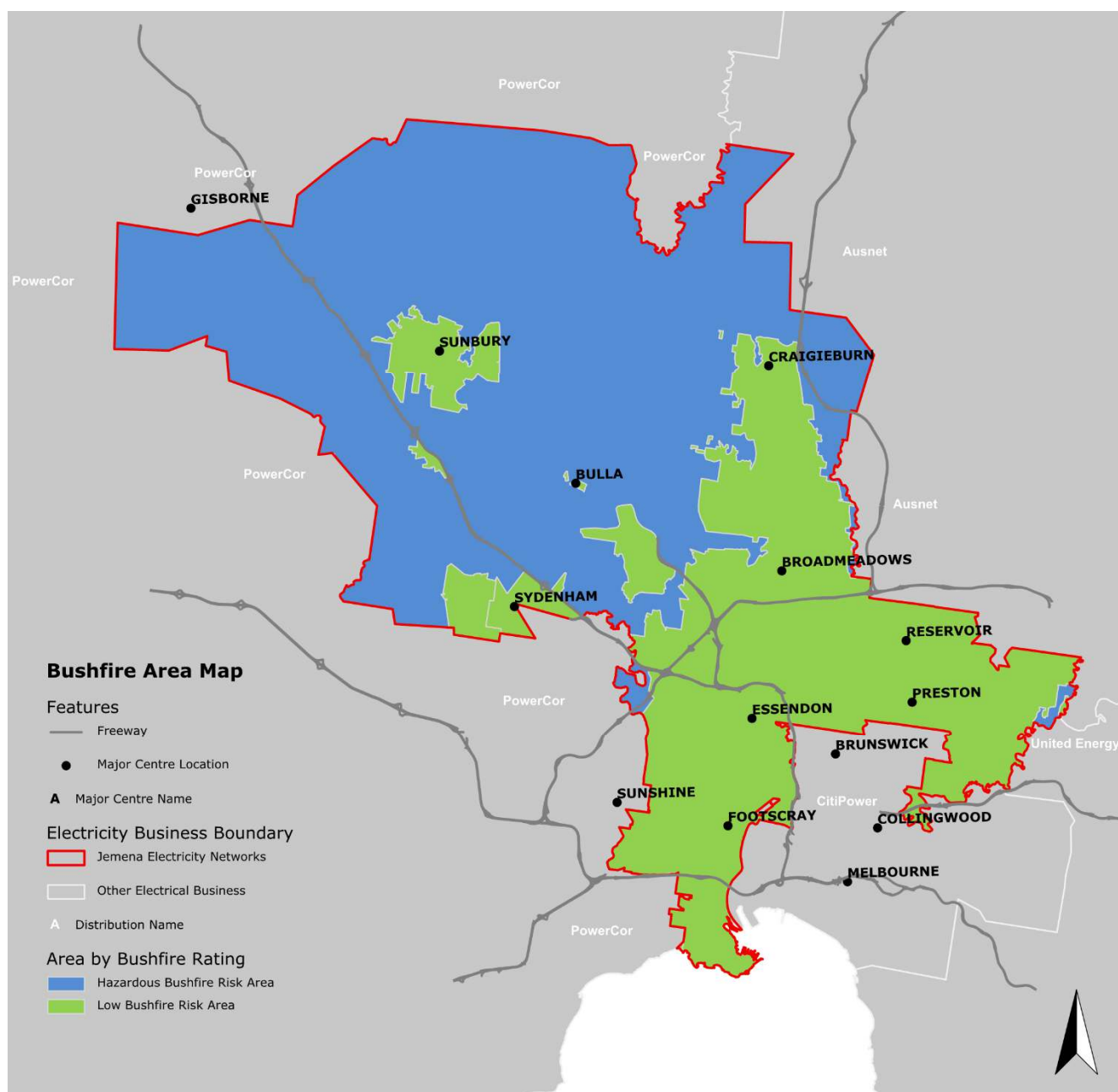
⁷ <https://www.cfa.vic.gov.au/about/major-fires> (cited, 23 Sep, 2019).

⁸ <https://www.cfa.vic.gov.au/plan-prepare/am-i-at-risk> (cited 23 Sep, 2019).

⁹ NER, cl 6.5.10(a).

¹⁰ NER, cl6.5.10(b).

Figure 1–1: HBRA and LBRA areas overlapping JEN distribution areas



As can be observed in Figure 1–1, more than half (in fact 63%) of JEN’s distribution area is classified as HBRA, this means that our business is susceptible to high levels of bushfire risk and contributes to the level of and premiums for public liability insurance.

In addition, the Victorian Government has put in place legislative requirements on electricity distribution businesses to mitigate against bushfires, some of these include:

- the F-Factor incentive scheme, which rewards or penalises businesses for taking action to reduce the number of fire-starts caused by electrical equipment

- the legislated (1 May 2016) requirement to install 45 Rapid Earth Fault Current Limiter (**REFCL**) devices in specified HBRA areas. These measures require JEN to install one REFCL device at Coolaroo Zone Substation by 30 June 2023.

There are many other legislative requirements required of electricity distribution businesses to manage bushfire risk including *Electrical Safety Act 1998*, the *Electricity Safety (Bushfire Mitigation) Regulations 2013* and *Electricity Safety (Electric Line Clearance) Regulations 2015*, and we must adhere to these.

Our response to addressing bushfires

JEN has developed a bushfire mitigation plan (**BMP**),¹¹ in compliance with legislative requirements (note above) to demonstrate how we manage and respond to bushfire risks. Also, JEN has developed other policies and procedures (including vegetation management and asset inspection) that are designed to reduce the potential impact of bushfire events; irrespective of whether the event is caused by JEN's asset or some other trigger such as arson or lightning strikes.

JEN has an extensive risk management policy¹² in place—developed under ISO 31000:2018, *Risk management – Guidelines*—which provides the principles, framework and processes for managing risk. This policy identifies, measures and mitigates risks prudently and efficiently as outlined in our risk management framework.¹³ The risk management framework is managed through the SGSP (Australia) Assets Pty Ltd (**SGSPAA**) Risk, Health, Safety & Environment Committee (that is, the Jemena group of companies).

As a part of risk management policy, JEN has determined that any consequences of bushfire events are most suitably managed through credible and market-sourced insurance providers.

Market for insurance

Public liability insurance in a bushfire prone area is a specialised product with few providers prepared to offer coverage. No one insurer, and not even the Australian insurance market as a whole, can afford to provide the levels of public liability insurance coverage required by electricity networks in Australia. The underwriting of bushfire liability requires specialist knowledge and understanding of the risks, issues and appropriate risk mitigation by the insurer. Given the magnitude of the consequences of a catastrophic bushfire event, there are very few providers within Australia who can provide coverage efficiently. These insurance providers will have reinsurance in place internationally—which attracts a further premium and additional compliance requirements by insurers—to mitigate their financial exposure. Therefore, to obtain access to the most efficient insurance, we must obtain coverage from the global market and through multiple insurance providers.

To ensure JEN identifies the best insurance opportunities, the SGSPAA Group appointed an insurance broker that has the experience, depth and access to a broad range of insurance products and global providers. By drawing on our broker's comprehensive industry expertise, we can identify and obtain the most efficient insurance coverage available.

Insurers' response to changing circumstances

Despite the implementation of extensive measures to mitigate risks (both legal and internally developed through risk management practices), the public liability insurance premiums are forecast by JEN's insurance broker, Aon Risk Services (**Aon**), to rise significantly—well above the expected general increase in costs—in the next regulatory period, primarily driven by the risks and consequences of a bushfire event occurring both in Australia and internationally.¹⁴ The factors driving insurance premiums are not those that drive general Australian consumer price increases, and therefore, expenditure operates outside of local trend factors.

¹¹ JEN, *JEN PL 0100, Bushfire Mitigation Plan – 2019-2024*, June 2019.

¹² Jemena, *JAA PO 0050, Risk Management Policy*, 6 June, 2018.

¹³ Refer to Attachment 07-08 *Managing risk and uncertainty*.

¹⁴ See Attachment 06-06 *Insurance premium forecast report*.

In addition to the direct impacts of going through a significant wildfire event in 2017 and again in 2018, the Pacific Gas & Electric Company (PG&E) filed for bankruptcy in the face of massive potential uninsured liability allegedly caused by PG&E assets. Other investor-owned and public utilities have experienced recent credit rating downgrades, with San Diego Gas & Electric (SDG&E) and Southern California Edison Company (SCE) (collectively, the Californian electricity businesses) now precipitously hovering just above junk status.¹⁵ This level of risk inevitably results in increased costs—be it through:

- rising insurance premiums, because insurers seek to recover their payouts over time
- cost of capital attributed to the perceived increase in risk observed by debt and equity holders.

The credit rating of insured businesses also impacts the premium paid for insurance—a deteriorating credit rating will cause insurance premiums (and other costs) to rise.

Following the California fires in 2018 a report on the events was commissioned by Governor of California. The report¹⁶ found that the frequency and intensity of “Wildfires are not only more frequent but far more devastating. Fifteen of the 20 most destructive wildfires in the state’s history have occurred since 2000; ten of the most destructive fires have occurred since 2015”¹⁷ and that these events are attributed to climate change – “Climate change has created a new wildfire reality for California. The state’s fire season is now almost year round.”¹⁸

While the Californian electricity businesses operate in the American energy market—subject to different a different legal and regulatory framework—there are indirect consequences to JEN, namely:

- the California wildfires are particularly relevant to informing our thinking on insurable events given the similarities in climatic conditions, topography and magnitude of an insurable event.
- the global insurance market that JEN accesses is impacted because of them—and are expected to have adverse impacts on the insurance premiums and coverage for the Australian electricity distribution businesses.

Equivalent experience of earlier, more significant and more devastating fires is playing out across Australia and Victoria too. Victoria’s 2019/20 fire season started early with Gippsland fires started in November still burning as at late December. The Australian Seasonal Bushfire Outlook: December 2019 states:

The 2019/20 fire season is well underway with multiple large bushfires occurring since the release of the previous Outlook in August. Queensland and New South Wales in particular have experienced severe fires, but all states have had challenging fire conditions. Catastrophic fire danger ratings have been issued in NSW, Western Australia, South Australia and Victoria, and there has been loss of human lives and animals, and damage to property and the environment.

*2019 has seen the second warmest January to November period on record for Australia, 0.01°C behind 2013, coupled with the second-driest on record for the same period. Looking forward into the Outlook period, it is these conditions that lead to the continued above normal fire potential across most states and territories into 2020. A long and challenging fire season is expected, and all states and the ACT are warning of increased fire danger as the fire season progresses.*¹⁹

This situation is not lost on other Australian financial institutions, including the Reserve Banks of Australia (**RBA**), who have identified “inflation-adjusted insurance claims for natural disasters in the current decade have been more than doubling those in the previous decade. This impact is likely to grow over time.”²⁰ The RBA also notes

¹⁵ Ibid, Pg. 3.

¹⁶ *Wildfires and Climate Change: California’s Energy Future, A Report from Governor Newsom’s Strike Force*, 12 April, 2019.

¹⁷ Ibid, Pg. 1.

¹⁸ Ibid, Pg. 1.

¹⁹ Australian Bushfire and Natural Hazard Cooperative Research Centre, *Australian seasonal bushfire outlook*: December 2019, p.1.

²⁰ Reserve Bank of Australia. *Financial Stability Review*, October, 2019, p. 57.

that insurance premiums are likely to rise, stating “[i]nsurers are most directly exposed to the physical impacts of climate change. This can arise through natural disaster claims, crop insurance, and health and life insurance”.²¹

In all of these changes, the insurance industry has responded to the increase in frequency and magnitude of global claim payments and class actions by charging higher premiums, increasing deductibles, and in several cases, reducing or withdrawing the availability of insurance capacity.^{22,23} It can, therefore, reasonably be concluded that procuring public liability insurance coverage for bushfire risks is a prudent decision that is in the best interest of customers.

1.2 Step change forecast

JEN has investigated the likely forecasts in insurance premiums and sought advice from our insurance broker.²⁴ Following this process, we have identified that insurance premiums will rise significantly over the next regulatory period, and the timing of those premium increase will mean they are not included in our operating expenditure base year. Based on the analysis undertaken, we have considered a range of options and conclude that a step change is the most efficient approach to addressing this increase in operating expenditure. The amount of increase in operating costs takes into account a base level of insurance premium included in the operating expenditure base year and the rate of change with the additional amount being outlined in Table 1–1.

Table 1–1: Operating expenditure step change for insurance premiums (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|---|------|------|------|------|------|-------|
| Insurance premiums not accounted for in base year or rate of change | 3.9 | 5.1 | 6.1 | 6.6 | 7.1 | 28.8 |

Source: Attachment 07-15 SCS PTRM FY22-26.

Note: (1) Total amounts may not reconcile to the total due to rounding, refer to Attachment 07-15 SCS PTRM FY22-26 for full details.

(2) The step change represents the increase in insurance premium expenditure above the base and trend amount that would otherwise be expected.

It is noteworthy that, commencing in September 2019, the rate of change in insurance premiums is significant—in the order of 20% p.a. over the current regulatory period—which is well above the rate of change component in AER’s final decision for JEN’s over the current regulatory period.²⁵

Given the method adopted by the AER to develop the rate of change component in the next regulatory period does not take into account the significant increase in public liability insurance premiums, then a step change is a way to be afforded a reasonable opportunity to recover efficient costs, consistent with the NEL.²⁶

To determine cost efficiency, we outline our approach below.

1.3 Options assessment

Below, we outline several options that we considered to identify ways to manage the increases in public liability insurance premiums. Based on an assessment of the relative risks and costs of each option, we recommend procuring insurance through a broker as being the most prudent and efficient approach to managing public liability insurance risk.

²¹ Ibid, p. 58.

²² Coverage due extreme weather events is being withdrawn <https://www.afr.com/companies/financial-services/northern-insurance-crisis-requires-action-apra-20191007-p52y9o> (sited 5 Nov, 2019).

²³ Whilst the article demonstrates the withdrawal of insurance coverage in some circumstances, it does not mean withdrawal will occur in our circumstance, rather, it demonstrates the extent of change and complexity across the insurance industry.

²⁴ AON, *Insurance Premium Forecast, Jemena Electricity Networks (VIC) Ltd.*, October 2019; (Attachment 06-06).

²⁵ Between 1.74% and 2.16% per annum; AER, *Final Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure*, May 2016, Table 7.1.

²⁶ NEL, s 7A(2).

1.3.1 Do nothing

It is possible not to take out public liability insurance; however, this presents an unacceptable risk. This approach would operate outside of the board approved risk management policy and contrary to the risk management approach that is adopted by SGSPAA.

Should a material bushfire event arise, then JEN would find itself in a similar situation to the Californian electricity utilities where credit ratings would be materially impacted (at best) and insolvent (at worse). Even without a bushfire event, JEN's credit rating would suffer—because of the credit risks perceived by suppliers and ratings agencies—and this would lead to increase costs.

Based on this, doing nothing—that is, not insuring—is not considered a viable option.

1.3.2 Seek out prudent and efficient insurances

As is our usual practice, and as set out in our risk management policy, we seek out efficient insurance products from the global insurance market as demonstrated above. The consequence of this approach is that our public liability insurance premiums are expected to rise. Even with these increased costs—and when considered in the context of the increasing risks and costs of the alternative options—taking an appropriate level of insurance coverages remains the most prudent and efficient approach to managing insurable risk events.

1.3.3 Self-insurance

Self-insurance is an approach to insuring whereby a large business allocates a portion of funds to cover events; by doing this, the business avoids the costs charged by the insurance markets. This product is best suited where events are *relatively* minor and frequent; the self-insurance is more of a means of smoothing *somewhat* volatile expenditure. This product is less suited to significant events such as bushfire events, by externalising the insurable event, there is a more substantial opportunity to diversify the cost and risks.

1.3.4 Seek alternative quote

The process of obtaining insurance through a broker is in itself, the most efficient way to competitively seek out the most efficient insurance products from insurance markets. Through the broker, negotiations with insurance providers in a range of international markets take place annually to identify a portfolio of insurance coverage at the most efficient cost.

In selecting a broker, we do so after a competitive tender process based on a demonstrated ability to secure prudent and efficient policies to ensure we are getting the best coverage for bushfire risk.

2. Annual REFCL testing and maintenance

2.1 Reason for a step change

Victoria's Electricity Safety (Bushfire Mitigation) Regulations 2013 (including subsequent amendments made in 2016 and 2017) (**Regulations**) set out mandatory standards for electricity companies to reduce bushfire risks.²⁷ The Regulations set technical performance standards (referred to as the **Required Capacity**) for 45 zone substations throughout Victoria's most bushfire-prone areas, including JEN's Coolaroo zone substation (**COO**).

The Required Capacity can only be met by installing devices known as Rapid Earth Fault Current Limiters (**REFCL**) in the respective zone substations. REFCLs are designed to limit the current that is released in a phase-to-ground fault on a high voltage line originating from the zone substation, thus reducing the risk of a bushfire caused by a fallen conductor. Under the Regulations, JEN must ensure that COO meets the Required Capacity by 1 May 2023.²⁸ The *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017* (Vic) provides for significant financial penalties in cases where a zone substation does not meet the Required Capacity by its relevant compliance date.²⁹

In addition to requiring that REFCL equipment be installed at COO by 1 May 2023, the Regulations also require that testing be undertaken before the commencement of each specified bushfire risk period³⁰ to ensure that lines originating from COO continue to meet the Required Capacity.³¹

Two types of testing activities will be required before November 2023, and then each type of testing is conducted each subsequent year:

- **Primary earth fault testing** – each of the eight feeders at COO will be tested in the presence of Electrical Safety Victoria (**ESV**) representatives to demonstrate they meet the Required Capacity before each specified bushfire risk period. This testing involves creating high impedance and low impedance tests on each phase, thereby carrying out six tests per feeder. Testing will require one team located at the point on the feeder where the fault is created and one team situated in the zone substation, and we estimate that each feeder will take one day to test. Some pre-testing activities will be required on one phase (not all three) for each feeder before the final tests in the presence of ESV.
- **Insulation testing** – this is annual testing to check the capability of network assets to withstand over-voltage on other phases after a REFCL operation.³² We need to undertake such tests to ensure all network equipment is expected to remain safe under a REFCL operation, consistent with our obligations under the Electricity Distribution Code (**EDC**) to minimise the risks associated with the failure or reduced performance of assets.³³

REFCLs are a new class of asset which have only recently been deployed in Victoria, and although they have been installed in other countries, it is only in Victoria where they are deployed to achieve the high level of performance as prescribed by the Regulations. The mandatory installation of REFCL equipment at COO represents a new development that will cause JEN to incur additional operational expenditure in relation to the following REFCL operational support activities:

²⁷ Regulations, Cl. 7(1)(ha).

²⁸ Regulations, Cl. 7(3).

²⁹ Cl. 120M(3).

³⁰ The period commencing 1 November and ending 31 March the following year.

³¹ Electricity Safety (Bushfire Mitigation) Regulations 2013, s 7(1)(hb).

³² When a REFCL device operates, other phases of the network experience a voltage increase which can cause other equipment downstream of the REFCL device to fail.

³³ Essential Services Commission, Electricity Distribution Code, s 3.1(b).

- **Data analysis and reporting** – this involves the analysis of data from annual testing and normal REFCL operation activities to understand network behaviour with these devices, and the development of detailed compliance reports for ESV in accordance with the Regulations.³⁴ A higher level of activity will be required during the summer months and around the time the annual testing activities are undertaken. This activity will recur annually from financial year (FY)24.
- **Network balancing** – this work includes monitoring capacitive balance on the distribution network, day-to-day capacitance analysis and forecasting and initiating corrective actions to ensure that REFCL devices can operate correctly. This activity will recur annually from FY24.
- **Equipment maintenance** – additional maintenance on the REFCL equipment installed at COO, including inspection and maintenance of associated network hardening and balancing equipment which is installed subsequently. This activity will recur annually from FY24.
- **Change management** – the introduction of REFCL equipment represents a new type of asset for JEN's distribution network and will require us to make changes to work instructions, safety procedures and asset management policies and strategies. This work will primarily occur in FY23 and will require minor updates annually.
- **Training** – the installation of the REFCL at COO will require us to develop and deploy additional training for field staff working on the COO zone substation and its feeders. Training will predominately occur in FY23 with additional training undertaken annually.
- **Development of test equipment specifications** – primary earth fault testing requires a specialised truck or trailer-mounted equipment to generate the fault. This equipment is not available in a standard configuration and we have therefore included once-off operational expenditure to develop specifications for this test equipment to meet our network needs and coordination of fabrication with a vendor. Our capital expenditure forecast includes expenditure for the purchase of this equipment.

Since the regulatory obligations identified above are entirely new, and the REFCLs deployed to meet this requirement are not in place, the costs associated with testing and maintenance of these assets is not accounted for in base year operating expenditure or any trend factors. A step change is required to ensure that JEN is able to recover the efficient costs of complying with these new regulatory obligations.

2.2 Step change forecast

We are proposing a step change in relation to REFCL testing and maintenance activities as:

- JEN is mandated to install a REFCL at COO by the Regulations and the testing and maintenance activities described above are necessary to ensure JEN remains compliant with the Regulations each year
- the expenditure required to perform the required testing and maintenance activities is not captured in JEN's operating expenditure base year.

Table 2–1 sets out our forecast operating expenditure for REFCL testing and maintenance during the next regulatory period. As can be seen from Table 2-1, the step change is expected to occur from FY23 onwards. This timing is driven by the timing of JEN's new regulatory obligations, as outlined above. Expenditure associated with the purchase of the specialist tools and equipment required for us to undertake these annual testing and maintenance activities has been included in our capital expenditure forecast, described in Attachment 05-01 to our Regulatory Proposal.

³⁴ Electricity Safety (Bushfire Mitigation) Regulations 2013, s 7(1)(n)(vii).

Table 2–1: Operating expenditure step change for REFCL testing and maintenance (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|-----------------------------------|------|------|------|------|------|------------|
| REFCL testing and maintenance | 0.0 | 0.1 | 0.4 | 0.4 | 0.4 | 1.3 |

Source: Attachment 07-15 SCS PTRM FY22-26.

2.3 Options analysis

We assessed three options to address the identified need in developing our step change forecast and summarise each of them below. Our assessment of these options demonstrated that undertaking testing and maintenance activities in-house is the only feasible option; hence this option forms the basis of our step change forecast.

2.3.1 Do nothing

This option would involve not carrying out the annual testing and maintenance activities for the COO REFCL equipment. JEN considers that this option is not feasible because:

- if JEN does not undertake Primary Earth Fault Testing or Insulation Testing before the commencement of each declared bushfire season and develop reports to ESV, it will be in breach of the Regulations³⁵
- not undertaking the network balancing and equipment maintenance activities described in section 2.1 would put JEN at risk of breaching the Regulations. A failure to perform necessary operational activities associated with the REFCL or to properly maintain the REFCL equipment would increase the likelihood that the equipment may break down, deteriorate prematurely or otherwise not operate as intended, which may, therefore, fail to ensure that all feeders originating from COO meet the Required Capacity
- not undertaking the change management and training activities described in section 2.1 would pose safety risks to JEN personnel working around COO assets or feeders once the REFCL is commissioned, as safety procedures would not be updated to reflect the additional risks introduced by the new equipment.

2.3.2 Procure testing and maintenance services

This option involves JEN contracting a third party to undertake significant REFCL testing activities. These are specialised activities which need to be performed on sophisticated equipment which JEN has limited prior experience working with. Given JEN will only have a single REFCL zone substation during the next regulatory period—far fewer than the number that the Regulations require of other Victorian distribution network services providers (DNSPs) to install—we have considered outsourcing the annual testing and maintenance activities to a third party who already possesses the necessary skills, experience and equipment. Under this option, if JEN were able to outsource the testing and maintenance activities, JEN would still be required to carry out the REFCL operational support activities³⁶ (e.g. data analysis and reporting, network balancing, change management etc.) described in section 2.1 itself.

We sought quotes from other DNSPs which are more experienced with the operations of REFCL devices to undertake the annual testing activities. However, we consider that ring-fencing constraints may prevent them from providing such a service. We also explored whether any external service providers—other than DNSPs—would be able to provide these services. However, we considered that, due to the highly specialised nature of REFCL equipment and its minimal deployment internationally to the Victorian specifications, there would be no third parties who would be in a position to provide suitable services.

As we have not been able to obtain any offers from the market for the provision of these services, we consider this option is not feasible.

³⁵ Electricity Safety (Bushfire Mitigation) Regulations 2013 s 7(1)(hb).

³⁶ JEN would be required to undertake the first five REFCL operational support activities listed in section 2.1, however the development of test equipment specifications would not be required as a contractor would be expected to provide their own test equipment.

2.3.3 Undertake testing and maintenance activities in-house

This option involves JEN undertaking the significant REFCL testing and maintenance activities itself using in-house resources. This approach is feasible; however it does require JEN to develop new skills and capabilities. This option also requires capital expenditure to purchase specialist tools and equipment needed to perform the REFCL testing and maintenance activities.³⁷

We have developed our cost estimates under this option on a bottom-up basis which reflects the mix of labour resources required to undertake the activities. Given JEN does not have prior experience conducting the testing and maintenance activities on REFCL equipment, we sought information from other Victorian DNSPs (those who have already installed REFCLs in their networks and whose staff have more experience with this equipment) to assist in developing the scope of these cost estimates. JEN's proposed expenditures under this option for key activities such as primary earth fault testing and insulation testing are in line—on a per-REFCL basis—with those approved by the AER its final decision on AusNet Services' contingent project application for tranche 1 of its REFCL program. In its final decision, the AER stated that it considered these costs to reasonably reflect the operating expenditure criteria, having regard to the expenditure that would be incurred in respect of a contingent project by an efficient and prudent DNSP under NER clause 6.6A.2(g)(4).³⁸ The composition of our expenditure estimate is outlined in Table 2–2.

Table 2–2: Operating expenditure for in-house REFCL testing and maintenance (\$ June 2021, millions)

| Activity | FY22 | FY23 | FY24 | FY25 | FY26 |
|--|-------------|-------------|-------------|-------------|-------------|
| Primary earth fault testing | 0.00 | 0.00 | 0.24 | 0.25 | 0.25 |
| Insulation testing | 0.00 | 0.00 | 0.04 | 0.04 | 0.05 |
| Data analysis and reporting | 0.00 | 0.00 | 0.05 | 0.05 | 0.05 |
| Network balancing | 0.00 | 0.00 | 0.03 | 0.03 | 0.03 |
| Equipment maintenance | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 |
| Change management | 0.00 | 0.04 | 0.00 | 0.01 | 0.01 |
| Training | 0.00 | 0.04 | 0.00 | 0.01 | 0.01 |
| Development of test equipment specifications | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 |
| Total | 0.00 | 0.11 | 0.38 | 0.39 | 0.39 |

(1) Totals may not add due to rounding.

As Option 3 is the only feasible option; undertaking these activities in-house is the recommended option.

³⁷ As this is the recommended option, our capital expenditure forecast incorporates the expenditure required to purchase the necessary tools and equipment to perform these activities in-house. Our capital expenditure forecast is detailed in Attachment 05-01 to our Regulatory Proposal.

³⁸ AER, Final decision AusNet Services Contingent Project: Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche 1, August 2017, p. 64.

3. Future Grid program

3.1 Reason for a step-change

Our forecast operating expenditure and capital expenditure reflects our Future Grid program, which represents a set of least-regrets initiatives in response to changes we know will continue to occur in our energy market over the coming decades, particularly as the customer take-up of distributed energy resources (**DER**) continues to accelerate. The majority of expenditure proposed as part of our Future Grid program is capital expenditure. However, we have also included an operating expenditure step change which forms part of our 'Enabling DER' portfolio.

During the next regulatory period, we propose to undertake a series of initiatives referred to as our **Future Grid program**. We have designed this program in response to changes we know will continue to occur in our energy market over the coming decades. Our *Future Grid investment proposal* (Attachment 05-04 to this regulatory proposal) provides a full explanation of the drivers, options analysis (including cost-benefit analysis) and proposed expenditures (capital and operating) of our Future Grid program.

A key part of our stakeholder engagement activities during the development of this proposal included seeking customers' views on how they expect to use energy in the future, what they expect the role of network service providers should be and what actions we should take to facilitate customers' energy futures. Through our engagement, customers told us that affordability, efficiency and 'future-proofing' the grid were crucial to them, and also that there was a wide range of potential future energy scenarios that they considered may eventuate. Our People's Panel also made a specific recommendation which we have designed the 'Enabling DER' portfolio in response to:

Jemena should enable increased feed in of solar (and other renewables) into the grid, by improving performance of the grid through new technologies.

We have designed our Future Grid program to future-proof our network in a way that contributes to our customers' long-term interests under multiple future scenarios. Despite uncertainty around changes in customer expectations and behaviour, technological developments and policy and regulatory responses, our Future Grid program will ensure we are best placed to deliver services in the long-term interests of our customers by building a strong and adaptable foundation during the next regulatory period.

Our Enabling DER portfolio will build a foundation for the network to support increased two-way flows and energy trading by customers in future. It involves expenditure on network monitoring and power quality, particularly to improve visibility on the LV network to improve 'hosting capacity'³⁹ for DER. This approach is necessary in the context of our network's limited ability to accommodate the forecast increase in DER penetration without augmentation, as two-way power flows will—absent correction—cause the distribution network to operate outside safe and reliable limits (including power quality obligations set out in the EDC) and result in adverse outcomes for customers, such as solar PV inverters tripping. Without augmenting the network or taking other actions to address these technical challenges, it would be increasingly necessary to place limits on new DER connections in areas of the low voltage (**LV**) network where there is insufficient spare hosting capacity.

The process of developing our Enabling DER portfolio in our Future Grid program involved first quantifying the cost to customers of a counterfactual scenario where we take no investment action and are therefore required to constrain the exports of new PV systems installed in some areas over the next 20 years—resulting in the potential value of some DER exports being 'lost'. We then developed and analysed options which involved capital expenditure and operating expenditures to address the technical challenges and prevent the loss of this value to customers, and analysed all options through a cost-benefit analysis. Each of these options resulted in a higher net benefit to customers than the counterfactual scenario where exports were constrained in the future. These options and our development and analysis process are detailed in Attachment 05-04 *Future grid investment proposal*.

³⁹ The capacity of the distribution network to accommodate bi-directional power flows due to exports from distributed energy resources.

The option which we have incorporated into our regulatory proposal provides the highest net benefit to customers, and represents a mix of network and non-network capital expenditure and operating expenditure which, broadly, will enable us to:

- Develop an LV Network Model – improve data capture processes to capture DER information, implement LV network modelling tools, trial LV network monitoring and implement a new DER website and connection portal
- Enable dynamic DER export control – install LV network monitoring devices to enable dynamic export limits and enable new Distribution Management System modules in our SCADA system to allow for the control and management of DER
- Increase DER hosting capacity – augment distribution substations and LV circuits to increase LV network hosting capacity and install LV voltage regulation devices to mitigate power quality impacts from increased DER.

The specific activities which form part of this operating expenditure step change are explained in the section below.

We have included this step change in our forecast operating expenditure as these form part of a portfolio of works which, together with our proposed capital expenditure, represents the most prudent and efficient means of addressing an identified customer need. This is demonstrated through the cost-benefit analysis presented in Attachment 05-04. Additionally, as these expenditures relate to new activities which JEN has not yet undertaken, they are not captured in JEN's operating expenditure base year or any forecast trend factors.

3.2 Step change forecast

As outlined above, JEN has considered a range of options and proposes operating expenditure required to implement the most efficient means of avoiding DER constraints. Our proposed Future Grid operating expenditure step change is outlined in Table 3–1. As can be seen, the step change expenditure is expected to occur from FY22 onwards. This timing is driven by the need for this operating expenditure to support the implementation of other activities (for which our proposal includes forecast capital expenditure) within our Future Grid program. The timing of our overall Future Grid program reflects a balance between uncertainty in Australia's energy landscape and the need to improve the visibility of our LV network hosting capacity in the near term to determine the most efficient long-term response to increasing DER uptake under a range of future scenarios.

Table 3–1: Proposed Future Grid operating expenditure step change (\$ June 2021, millions)

| | FY22 | FY23 | FY24 | FY25 | FY26 |
|---|-------------|-------------|-------------|-------------|-------------|
| Low voltage network asset inspection | 0.17 | 0.17 | 0.17 | 0.18 | 0.18 |
| Enabling DER portfolio preparatory work packages | 0.21 | 0.21 | 0.22 | 0.22 | 0.22 |
| Increase hosting capacity by modifying customers' DER inverter settings | 0.36 | 0.36 | 0.36 | 0.36 | 0.36 |
| Future Grid operating expenditure step change total | 0.75 | 0.75 | 0.75 | 0.76 | 0.76 |

Source: Attachment 07-15 SCS PTRM FY22-26.

Note: Total amounts may not reconcile to the total due to rounding, refer to Attachment 07-15 SCS PTRM FY22-26 for full details.

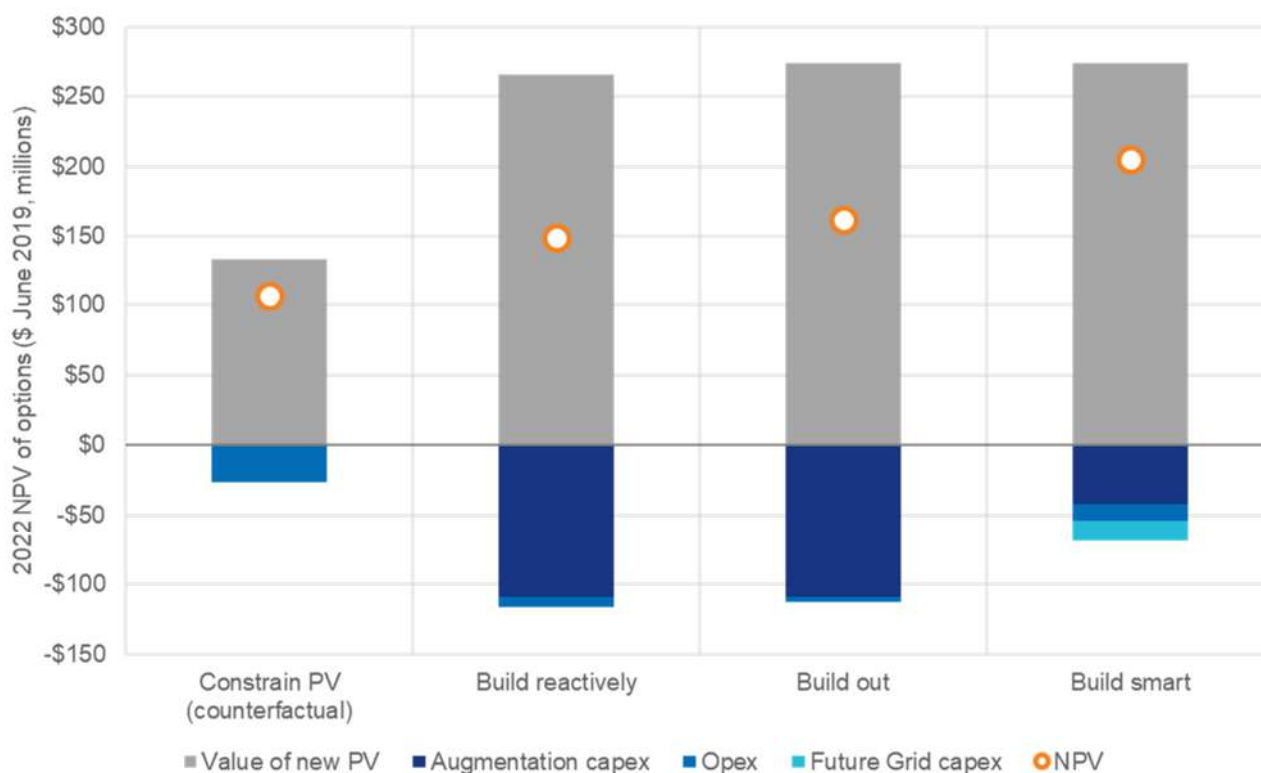
Below, we outline the considerations undertaken for determining the efficient step change operating expenditure.

3.3 Options assessment

Our Future Grid investment proposal (Attachment 05-04 *Future Grid investment proposal*) details the cost-benefit analysis we undertook to determine the most efficient course of action in response to the network and customer implications of the forecast increase in DER take-up. Each of the four options we considered (including the counterfactual of constraining DER exports) involved a mix of capital expenditure and operating expenditures, and our cost-benefit analysis determined the most beneficial option on a total cost (capital expenditure and operating expenditure) basis. The options we considered, and our approach to the cost-benefit analysis, are discussed in detail in Attachment 05-04 *Future Grid investment proposal*.

The results of our cost-benefit analysis are summarised in Figure 3–1, which shows that the ‘Build Smart’ option results in the highest net benefit to customers. Additionally, even though we undertook our options analysis on a total cost basis, we note that our proposed option requires less operating expenditure than the counterfactual. Accordingly, our operating expenditure step change reflects the operating expenditure portion of the total expenditures under the ‘Build Smart’ option.

Figure 3–1: Results of options analysis to address the future trend in energy distribution



Source: JEN Future Grid investment proposal (Attachment 05-04)

The section below explains the specific initiatives which form part of this operating expenditure step change, and how they relate to our Enabling DER portfolio.

3.3.1 Recommended option

Our operating expenditure step change for Future Grid is comprised of three components which support the capital expenditure we have proposed under this program.

1. Low voltage network asset inspection

This initiative requires operating expenditure to collect information necessary to enable the development of a low voltage (LV) network model. In contrast to the subtransmission and high voltage parts of our distribution network, we have little ‘visibility’ of our LV network. Specifically, our ability to monitor and control individual assets within the LV network is limited, as most equipment within this network is not capable of active monitoring and control.

In the past, where most power flows were one-way, this approach to investment and control generally represented an efficient way of designing, building and operating the network. However, with increasing DER penetration this lack of visibility can present a barrier to the optimising LV network planning, design and operations.

As DER export congestion on our network increases and more power quality issues arise on the network, we therefore first need to gather LV network data (including information about LV network configuration, LV asset data and LV customer connection arrangements) to determine the most cost-effective solutions to address network problems that will arise. The incremental cost of this activity has been forecast at an additional cost of one full-time asset inspector to gather this data and record it into our asset and customer and network management systems.

2. Enabling DER portfolio preparatory work packages

This initiative requires operating expenditure in advance of capital works which increase the hosting capacity of the network. As explained in Attachment 05-04, the Enabling DER portfolio in our Future Grid program includes several activities to enhance our systems and solve network and customer power quality issues through investments which increase the hosting capacity of our network for DER. Before commencing to these capital works, we need to undertake several activities to establish methods, processes and explore options for these investments. During the next regulatory period, these planned activities include:

- developing the data architecture for the LV network model, which will consist of network management and customer systems (SAP and GIS), as well as operational technology and network simulation and modelling tools
- developing a method to accurately calculate the hosting capacity of various network assets, including LV circuits, distribution substations, high voltage feeders and zone substations
- developing a model which utilises AML data to optimise the planning, operation and maintenance of network assets to improve two-way power flows
- developing an ‘Increase Hosting Capacity Solution’ model to determine the optimal mix of technical solutions and drive the annual program of capital investments that will increase hosting capacity on the LV network
- revising our customer connections process for DER to provide customers with the option of dynamic hosting capacity limits in cases where it is not economically feasible to remove an export constraint.

3. Increase hosting capacity by modifying customers’ DER inverter settings

This initiative requires operating expenditure which represents payments to customers to incentivise them to make changes to their DER installations. More than 35,000 solar inverters had already connected to our network before 1 December 2019, the date from which all inverters must be set up with the Victorian mandated unified inverter settings. These unified inverter settings require voltage regulation (volt-var and volt-watt control) to be enabled, both of which can have a materially positive impact in addressing localised power quality issues (which can cause inverters to trip off) in some cases. On some LV circuits, the most economic option to solve power quality issues will be to enable voltage regulation in some of these 35,000 older inverters.

We, therefore, propose to make payments to customers to incentivise them to update their inverter settings and enable voltage regulation (noting that customers would need to engage a Clean Energy Council-accredited person

to undertake this task). We have assumed a modest rate of 2 per cent per year of these systems being updated each year (700 customer systems) and a payment of \$500 per system (June 2019 dollars).

4. Transitional return on debt alignment costs

4.1 Reason for a step-change

The Victorian Government has required a change from calendar to financial regulatory years (CY to FY). This shift in regulatory year impacts the return on debt trailing average approach. Specifically, it poses a misalignment issue for JEN because the proposed return on debt averaging periods and regulatory years will commence six months earlier than previously anticipated under the ten year return on debt transition to trailing average approach.

JEN's existing debt portfolio is designed such that the maturity of debt instruments (interest rate swaps/hedges) is aligned to the beginning of CY regulatory years. That is, existing debt instruments (each for around 10% of the portfolio) are designed to mature in January each year and must be contracted during the return on debt averaging period that occur sometime prior to January. The move from a CY to a FY regulatory year means that future averaging periods must end 6 months earlier. Consequently, the minimum gap between the maturity of our existing debt instruments and the return on debt averaging periods is 6 months longer than it otherwise would have been. This will require JEN to enter into debt instruments that start at least 6 months further forward than would have been the case under CY regulatory years.

The requirement to enter into debt instruments 6 months earlier will lead to an increase in our debt financing costs which are not currently captured in the base year operating expenditure. The larger time gap between entering into these instruments and the maturity dates of our existing debt instruments means that providers of debt finance will require greater compensation for risk.

4.2 Step change forecast

This step-change covers the expenditure for \$0.9M that is not captured in the base year costs—and are not treated as a capital expense.

JEN has considered two options to address the operating expenditure associated with transitioning the return on debt through the alignment process and finds the most efficient approach to addressing this challenge is by seeking an allowance, as outlined in Table 4–1.

Table 4–1: Operating expenditure step changes for return of debt alignment (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|---|------|------|------|------|------|-------|
| Transitional return of debt alignment costs | 0.06 | 0.12 | 0.18 | 0.25 | 0.31 | 0.92 |

Source: Attachment 06-04 – SCS Opex model FY22-26.

Below, we outline the considerations undertaken for determining efficient step-change expenditure.

4.3 Reasoning for the step change

Options analysis

In evaluating the available options, cost considerations and risk have been used as criteria to identify the option that is most likely to minimise financing cost impact on the business. Table 4–2 summaries the assessment of each option against cost and risk criteria. The options include adjusting debt instruments to FY regulatory years (transitional arrangements) or to not change the debt instruments (Do Nothing).

Table 4–2: Transitional return of debt alignment costs options assessment

| Criteria | Option 1 – Transitional arrangements | Option 2 – Do Nothing |
|---------------|--|---|
| Cost (\$2020) | 0.9M but removes interest rate risk for JEN | Misalignment between return on debt allowance and JEN's cost of debt creating interest rate risk and result in significant costs that are much higher than Option 1 |
| Risk | Low – JEN can enter into new swap arrangements | Extreme – JEN cannot reverse the change to regulatory year. |

Recommended option

Option 1 is the recommended option. This option recognises the efficient cost—derived from market sources—for procuring changes in financing arrangements and is necessarily incurred to comply with the policy change to move the regulatory year from a calendar to financial year. JEN's current Treasury Management Framework requires that *"Treasury seeks, at a minimum, to mirror the actual cost of debt against the cost of debt assumed by the regulator, thereby minimising interest rate risk in the regulatory period concerned."* Option 2 is likely to result in a mismatch between JEN's actual cost of debt and regulatory return on debt allowance creating interest rate risks for the business as well as non-compliance with its Treasury Management Framework. Under Option 2, there could be increased floating rate exposure resulting in higher than allowed financing costs impacting JEN's liquidity and credit rating.

Below we outline the detailed assessment of each option considered.

4.3.1 Transitional arrangements

Under the status quo of a continuation of CY regulatory years, the averaging period would have

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For any given tenor, forward swaps are typically more expensive (higher fixed rate) than spot swaps. This increase arises because banks face more significant interest rate uncertainty when offering a more distant start date. The move from a CY to an FY regulatory year means that future averaging periods must end 6 months earlier. However, the maturity of our existing debt instruments is. Consequently, the minimum gap between the maturity of our existing debt instruments and the return on debt averaging periods is six months longer than it otherwise would have been.

This situation requires JEN to enter into debt instruments that start at least six months further forward than would have been the case under the status quo.

We have asked to provide an estimate of the incremental cost of a ten-year swap contract starting six months further forward. They provided estimates of for each of the past four years as outlined in

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⁴⁰ Clause 24(d) of the rate of return instrument.

⁴¹ A forward swap is an interest rate swap that is contracted on one date but with payments only starting at a future date.

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It can be observed that the incremental cost of a six month further forward swap ranges from between [REDACTED] over the period.

JEN proposes to take the lowest of these values (6bps). However, this is only incurred on 10% of the portfolio each year. Consequently, in year one of the regulatory period, the cost will only be around \$0.06m ($0.06\% \times 10\% \times 60\% \times \text{Opening RAB}$) rising to approximately \$0.31m in the final year of the regulatory period. This results in an average cost of \$0.18m pa over the regulatory period.

We summarise the cost impact in Table 4-4 below.

Table 4-4: Cost impact over the next regulatory period - 6bps (\$ June 2021, millions)

| | FY22 | FY23 | FY24 | FY25 | FY26 |
|---|------|------|-------|-------|-------|
| Hedging requirement p.a. (\$m=10% of 60% of RAB) | 92.9 | 99.6 | 106.3 | 111.1 | 114.7 |
| Incremental cost of 6mth forward contract per hedge (\$m) | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 |
| Cumulative cost (\$m) | 0.06 | 0.12 | 0.18 | 0.25 | 0.31 |

4.3.2 Do nothing

This option is not consistent with JEN's Treasury Management Framework and creates more volatility in its funding arrangements. While under this option, we would not incur additional costs relating to ten-year swap contract starting six months earlier, we do not see this as a viable option because it could result in higher financing risk and costs and potentially expose JEN to adverse movements in interest rates resulting in liquidity issues.

5. Environment Protection Act changes

5.1 Reason for a step change

The *Environment Protection Amendment Act 2018* (Vic) (**Act**) introduces several significant changes to Victoria's environment protection framework from 1 July 2020 under the *Environment Protection Act 2017* (Vic) and two subordinate instruments—the Environment Protection Regulations and Environment Reference Standard. The primary objective of these reforms is to reduce harm, and the risk of harm, to human health and the environment from pollution and waste,⁴² including shifting from a 'reactive' to a 'preventative' framework. The changes include:

- the introduction of a General Environmental Duty (**GED**) requiring any person (including an organisation) conducting an activity which poses risks to human health and the environment to understand those risks and minimise them so far as is reasonably practicable⁴³
- the introduction of duties to notify the Environment Protection Authority Victoria (**EPA Victoria**) of pollution incidents⁴⁴
- the introduction of new obligations relating to contaminated land, including duties to notify EPA Victoria of significant contamination and to manage contaminated land by undertaking activities to minimise the risk of harm to human health and the environment so far as is reasonably practicable⁴⁵
- changes to the existing permissions framework by introducing a tiered system of registrations, permits and licences⁴⁶
- strengthened enforcement powers for EPA Victoria, including increased penalties and changes to civil penalties for various offences under the Act.⁴⁷

EPA Victoria and the Department of Environment, Land, Water and Planning (**DELWP**) published drafts of the Environment Protection Regulations and Environment Reference Standard for consultation in September 2019, and are expected to finalise these subordinate instruments in early-mid 2020, after the submission of our Regulatory Proposal. Details contained in the subordinate instruments inform forecasts of the activities required to comply with the Act.

Based on an assessment of the Act and the draft subordinate instruments, we consider that the introduction of the GED and the specific obligations relating to land contamination are the main drivers of additional operational activities and expenditure for JEN in relation to the Act during the next regulatory period.

The GED concept is modelled on existing occupational health and safety (**OHS**) legislation. Risk measurement and management are central to the GED and critical parts of the revised framework—under the Act, all persons are required to have a reasonable state of knowledge about the risks their activities pose and how to address those risks. Although we currently consider environmental risk consequences and appropriate mitigations in our asset management and operational planning, we expect to undertake additional activities (incremental to those conducted during the base year) to assess and monitor environmental risk during the next regulatory period to ensure full compliance with GED under the Act.

Specifically, we expect that the new obligations relating to contaminated land will require us to carry out additional activities during the next regulatory period. Based on limited environmental risk review activities undertaken during

⁴² Department of Environment, Land, Water and Planning and Environment Protection Authority Victoria, *Regulatory Impact Statement: Proposed Environment Protection Regulations*, August 2019, p. 8.

⁴³ Environment Protection Amendment Act 2018, s 7, which inserts relevantly part 3.2 (General Environmental Duty) into the Environment Protection Act 2017 (**Principal Act**).

⁴⁴ Environment Protection Amendment Act 2018, s 7, which inserts relevantly part 3.4 (duties relating to pollution incidents) into the Principal Act, and Environment Protection Regulations Exposure Draft, chapter 2 (contaminated land).

⁴⁵ Environment Protection Amendment Act 2018, s 7, which inserts relevantly part 3.4 (duties relating to pollution incidents) and 3.5 (duties relating to contaminated land) into the Principal Act, and Environment Protection Regulations Exposure Draft, chapter 3 (permissions).

⁴⁶ Environment Protection Amendment Act 2018, s 7, which inserts relevantly chapter 4 (permissions) into the Principal Act.

⁴⁷ Environment Protection Amendment Act 2018, s 7, which inserts relevantly chapter 11 (enforcement and proceedings) into the Principal Act.

the previous regulatory period, we understand that soil contamination resulting from transformer oil (potentially containing polychlorinated biphenyls (**PCBs**), underground cable insulation oil or asbestos could require assessment, reporting and management under the Act. We anticipate that sites covered by these requirements could range from zone substations and current or former depot sites to land below or around distribution substations located throughout our network.

5.2 Step change forecast

We are proposing an operating expenditure step change caused by changes in the Environment Protection Act changes as:

- JEN must comply with the Act
- the operating expenditure required to perform the activities necessary to enable compliance with the Act are not captured in JEN's operating expenditure base year or any forecast trend factors, since the relevant obligations only commence from 1 July 2020.

Table 5–1 sets out our forecast operating expenditure for the Environment Protection Act changes during the next regulatory period. This expenditure reflects the incremental operating activities listed in section 5.3.2. At this stage, JEN has not included expenditure within its operating expenditure or capital expenditure forecasts which relates to the remediation of contaminated sites.

Table 5–1: Proposed operating expenditure step change for Environment Protection Act changes (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|------------------------------------|------|------|------|------|------|-------|
| Environment Protection Act changes | 0.81 | 0.82 | 0.83 | 0.84 | 0.85 | 4.15 |

Source: Attachment 09-05 Post-tax revenue model - standard control services.

5.3 Options analysis

We assessed two options to address the identified need in developing our step change forecast, both of which are summarised below. Our assessment of these options demonstrated that undertaking the additional compliance activities is the only feasible option; hence this option forms the basis of our step change forecast.

5.3.1 Do nothing

This option would involve not undertaking the additional environmental risk assessment and management activities which are necessary to comply with the Act. JEN considers that this option is not feasible because this would likely lead to JEN failing to comply with the requirements of the Act, and therefore causing JEN to not comply with clause 3.1(b) of the EDC which requires JEN—as a licenced DNSP—“to comply with the laws and other performance obligations which apply to the provision of distribution service”. We also consider that such an outcome would be inconsistent with our customers’ and the broader community’s expectations regarding the protection of the natural environment in which we operate.

5.3.2 Undertake additional environmental risk management activities

This option involves undertaking the additional operational activities to understand better, measure and manage the environmental risks associated with our operations. We consider that these activities are necessary to enable us to comply with the new requirements introduced under the changes to the Act, particularly concerning the GED

and contaminated land obligations. Our forecast operating expenditure under this option reflects the following activities to comply with the Act:

- a desktop study to assess and quantify JEN's environmental risk profile, including identification of sites requiring investigation⁴⁸
- site environmental risk assessments of five zone substation or depot ('large') sites per annum
- site environmental risk assessments of 20 distribution asset sites (predominately a sample of distribution substations) per annum
- the production of a specific Environmental Management Plan for each large site (30) and common Environmental Management Plans for different asset types (20)
- the ongoing annual monitoring of sites identified through risk assessments as posing an elevated risk
- one internal full-time equivalent resource to manage the above activities on an ongoing basis, including increased liaison with EPA Victoria.

The composition of our forecast expenditure estimate is shown in Table 5–2.

Table 5–2: Additional environmental risk management activities (\$ June 2021, millions)

| Activity | FY22 | FY23 | FY24 | FY25 | FY26 |
|--|-------------|-------------|-------------|-------------|-------------|
| Large site risk assessments | 0.21 | 0.21 | 0.22 | 0.22 | 0.22 |
| Small site risk assessments | 0.32 | 0.32 | 0.33 | 0.33 | 0.33 |
| Production of Environmental Management Plans | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 |
| Ongoing monitoring of elevated risk sites | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| Internal resource – Senior Environmental Advisor | 0.16 | 0.16 | 0.16 | 0.16 | 0.17 |
| Total | 0.81 | 0.82 | 0.83 | 0.84 | 0.85 |

As Option 2 is the only feasible option, this is the recommended option.

⁴⁸ As the Act commences on 1 July 2020, we expect to undertake this activity during CY20, therefore it does not form part of the forecast operating expenditure for this step change.

6. Cybersecurity

6.1 Reason for a step-change

Our customers expect that the energy they consume is delivered safely and securely and that their data is treated confidentially, and in most cases, there are legal obligations aligned to these expectations. With the increase in cyber-threats to our industry and the monetisation of private information by cybercriminals, both the motivation and the means to disrupt our energy supply and steal private or confidential data is increasing. To ensure we continue to protect our customers, staff and data against these evolving risks, we need to increase investment in our corresponding cybersecurity controls.

JEN operates in an increasingly digitally threatened environment, which means that the effort required to identify, protect, detect, respond and recover from cyber-attacks is increasing; consequently, merely maintaining the historical level of cybersecurity effort will result in a decrease in protection levels. JEN must adapt to the challenges and invest in cybersecurity to create a stronger and faster response to cyber threats to protect the network, personal customer information and the safety of the community. To address these growing security issues, an increase in cybersecurity effort and expenditure is required to keep pace with existing security levels (in essence, doing more to maintain performance levels). Without continued investment in cybersecurity, JEN will not keep pace with the increasing sophistication of cyber-attackers.

In 2018, AEMO released the Australian Energy Sector Cyber Security Framework (**AESCSF**)⁴⁹ as a best practice guide for organisations operating in the National Electricity Market. As part of this framework, maturity indicator levels (**MIL**) were developed as a set of graded standards to demonstrate a businesses' cybersecurity capabilities. More recently, updates to the AESCSF framework (version 2019-8) incorporated "Security Profiles" (SP). Based on the AESCSF standards—JEN, being a DNSP, is categorised as 'moderately critical' per the Critical Assessment Tool (CAT)⁵⁰ "should achieve"⁵¹ SP-2 level of security (this is akin to the MIL2 standards).

There are a several statistics available to show how long it takes for an adversary to move from initiating a security incident to achieving a compromise of a system, [REDACTED]

In attempting to set relevant targets for industry, one of the leading organisations in this space, CrowdStrike, have defined best practice metrics⁵² to (i) detect an intrusion on average within one minute, (ii) investigate it within 10 minutes, and (iii) isolate or remediate the problem within one hour. [REDACTED]

⁴⁹ <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Cyber-Security>.

⁵⁰ 2019 AESCSF Criticality Assessment Tool (CAT), Pg. 2.

⁵¹ AESCSF, version 2019-8, Table 1.

⁵² CrowdStrike CTO Explains "Breakout Time" — A Critical Metric in Stopping Breaches, <https://www.crowdstrike.com/blog/crowdstrike-cto-explains-breakout-time-a-critical-metric-in-stopping-breaches/>, retrieved on 10/09/2019.

6.2 Step change forecast

This step-change covers the expenditure for managing cybersecurity activities that are not incurred until after the operating expenditure base year and are not treated as capital expenditure.⁵³

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Table 6–1: Proposed 2021-26 operating expenditure step change for cybersecurity (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|---|------|------|------|------|------|-------|
| Cybersecurity spend ⁵⁴ | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 9.1 |
| Apportionment attributed to JEN ⁵⁵ | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 2.9 |

Source: Attachment 07-15 – SCS PTRM FY22-26.

Note: Total amounts and percentages may not reconcile to the total due to rounding, refer to Attachment 07-15 SCS PTRM FY22-26 for full details.

Below, we outline the considerations undertaken for determining efficient step-change expenditure.

6.3 Options assessment

Jemena has assessed a range of options to manage cybersecurity issues by investigating several different approaches to security monitoring and response. Expert research from Gartner has been used to develop the options, particularly in comparing the ability to execute each of the options. This research was based on the cyber-defence activities that similar organisations around the world are undertaking to achieve the same goal.

In developing these models, standard industry models have been used and adapted for the JEN environment. Each of these options has been developed to complement JEN's forecast capital expenditure on cybersecurity enhancements, which is presented in Attachment 05-01 - *Forecast capital expenditure report*.

The options considered include: (i) strengthening internal capability, (ii) outsourced, (iii) hybrid sourcing, and (iv) do nothing.

Options analysis

In evaluating the available options, several criteria have been used to identify the option that is most likely to succeed and be efficient expenditure. Table 6–2 summaries the assessment criteria for each option.

⁵³ Note, however, that JEN's capital expenditure forecast does include expenditure on separate items and activities related to cybersecurity, as explained in Attachment 05-01 - *Forecast capital expenditure report*.

⁵⁴ This amount relates to the operating expenditure across the whole Jemena group, not just JEN.

⁵⁵ Per our RIN Response *Technology plan*; Jemena attributes 35% of IT costs to JEN.

Table 6–2: Cybersecurity options assessment

| Criteria | Option 1 | Option 2 | Option 3 | Option 4 |
|--|----------|----------|----------|----------|
| Skills and Capability | Moderate | High | High | Low |
| Ability to attract trained staff | Moderate | High | High | Low |
| Access to broader threat intelligence | Low | High | High | Low |
| Ability to scale to increasing threat levels | Low | Moderate | High | Low |
| Knowledge of JEN systems & network | High | Moderate | High | High |
| Ongoing cost (\$RY21) | \$11.4m | \$9.6m | \$8.8m | N/A |

Recommended option

Option 3 is the recommended option. [REDACTED]
[REDACTED]. The use of key internal staff with a good understanding of the business, augmented by experienced external vendors provides a good level of coverage, while automation allows for increasing threat levels.

Below we outline the detailed assessment of each option considered.

6.3.1 Option 1 – Strengthening the internal capability

[REDACTED] A level 1 security analyst and a level 2 security analyst [REDACTED], with allowance for leave and sickness. By using a standard 24x7, 8-hour shift pattern, [REDACTED] this approach also complies with health and safety rules such as not working alone [REDACTED]
[REDACTED]

Conversely, the critical issue with this option is that there is a large number of security operations staff required, [REDACTED], with significant problems of staff retention due to the dedicated nature of the environment and high demand for this skill set. This option also does not offer the ability to manage a higher level of threat in the future, other than by adding more staff.

Table 6–3 outlines the anticipated expenditures of this option.

Table 6–3: Options 1 – Strengthening internal capability – cost analysis (\$ June 2021, dollars)

| Option 1 | [REDACTED] | Annual charge |
|---------------------------|------------|-------------------------|
| Level 1 staff | [REDACTED] | \$ 1,304,800.00 |
| Level 2 staff | [REDACTED] | \$ 990,250.00 |
| Total Over 5 Years | | \$ 11,475,250.00 |

6.3.2 Option 2 – Outsourced

Several organisations can provide an outsourced 24x7 detection and response service that would meet the needs of the JEN IT ecosystem. However, there are several limitations in the use of external parties [REDACTED]

⁵⁶ Refer to our RIN Response - *Investment brief non-recurrent - compliance - Cyber-Security*

while adhering to health and safety standard and working hours, as well as for leave and training.

An outsourced cybersecurity service provider is more likely to recruit and retain qualified staff due to the attraction of specialisation and diversity of employment, and therefore, is expected to be more successful in operation. This option also has the advantage of increased access to threat intelligence via a large number of customers.

Table 6–4 outlines the anticipated expenditures of this option.

Table 6–4: Option 2 – Outsourced – cost analysis (\$ June 2021, dollars)

| Option 2 – Outsourced | Annual Cost |
|--|---------------------|
| External Cyber Security Monitoring and Detection Service (per annum) | \$ 1,600,000 |
| 2 additional L1 staff for Operational Technology | \$ 326,200 |
| Total Over 5 Years | \$ 9,631,000 |

6.3.3 Option 3 – Hybrid sourcing with automation

This approach is inherently more efficient, both in terms of cost and ability to execute. This option is also highly scalable

Of the three options considered, this option provides the best value and highest ability to execute.

Table 6–5 outlines the anticipated expenditures of this option.

Table 6–5: Option 2 – Hybrid automation with automation – cost analysis (\$ June 2021, dollars)

| Option 3 – Hybrid automation with automation | Annual Cost |
|--|-------------|
| | \$600,000 |
| | \$180,000 |
| | \$285,000 |
| | \$300,000 |
| 2 staff members | \$396,100 |

| Option 3 – Hybrid automation with automation | Annual Cost |
|--|--------------------|
| Total over 5 years | \$8,805,500 |

6.3.4 Option 4 – Do nothing

In this option, we must accept the risk of a cybersecurity incident occurring without being detected. As noted above, this approach does not meet standard cybersecurity practices such as AESCSF and puts JEN [REDACTED]. Doing nothing—in an environment of increasing risk—results in a degradation of cybersecurity performance. This option is not considered viable for the safe and secure operation of JEN's business, nor the services provided to our customers and the security of their data.

7. Additional RIN reporting

7.1 Reason for a step-change

In April 2019, the Victorian Minister for Energy, Environment and Climate Change (**Minister**) advised JEN of their intention to make changes to the timing of Victorian electricity network regulatory years. The Minister's communication to JEN stated that the timing of annual price changes over the Christmas period meant consumers may miss notification of any price changes, resulting in a missed opportunity for these customers to engage with the energy market and consider whether they are on the best retail offer, particularly in cases where retail prices increase.

Accordingly, the Minister has advised of their intention to make changes to the *National Electricity (Victoria) Act 2005* to implement a change to financial years (ending 30 June) for Victoria's electricity network businesses. This will align Victoria with the regulatory year used in other National Electricity Market states and is intended to take effect on prices from 1 July 2021.

The Victorian Government carried out an initial consultation with their staff from the AER and Victorian network business before making this decision, during which network businesses advised that a change to the timing of the regulatory year would cause them to incur additional costs in moving to these new arrangements. The response from the Minister noted this, and also said these would be in the long term interest of Victorian customers.

Since receiving this advice, JEN has worked collaboratively with the Victorian Government, AER and other network businesses to understand the detail of the arrangements associated with the change in the regulatory year, including regulatory information reporting requirements. The AER has provided JEN with its future Regulatory Information Notice (**RIN**) reporting requirements in light of the regulatory year change, which involves:

- The continued reporting against the existing Annual Reporting (**AR**), Economic Benchmarking (**EB**) and Category Analysis (**CA**) RINs for calendar years 2019 and 2020
- The introduction of a new reporting requirement to collect AR, EB and CA RIN data for the six months between 1 January 2021 to 30 June 2021⁵⁷
- The introduction of new AR, EB and CA RINs to collect data on a financial year basis throughout the next regulatory period.⁵⁸

These reporting requirements and timeframes are reflected in the new Annual RIN issued by the AER to JEN on 7 November 2019.

On the basis that RIN responses for a regulatory year (or six month period) will continue to be due to the AER at the end of the fourth month following the reporting period, the change in regulatory year timing and the introduction of the six-month intervening period will require JEN to prepare, obtain external assurance over and submit two sets of RIN responses within 12 months. This requirement represents more work to develop and obtain external assurance over RIN responses compared to the single set of RINs every twelve months which we are currently required to respond to—with this being the level of activity reflected in our operating expenditure base year. The changes to the *National Electricity (Victoria) Act*⁵⁹ to change JEN's regulatory year and the subsequent RINs will, therefore, result in JEN incurring costs to comply with a new regulatory obligation which is not reflected in its base year operating expenditure.

⁵⁷ This six month period represents the 'gap' between the conclusion of the current regulatory period on a calendar year basis and the commencement of the next regulatory period on a financial year basis.

⁵⁸ A new Annual RIN was issued to JEN on 7 November 2019. For the EB and CA RINs (the current versions of which will remain in force until 2024), JEN has assumed that these would either be replaced or modified so that information is only collected on a financial year basis from 1 July 2021 onward, and that calendar year information would no longer be collected.

⁵⁹ And changes to any other regulatory instruments which may yet be made in respect of the Minister's announcement.

7.2 Step change forecast

JEN has considered the impacts of the change in its regulatory year and the associated reporting requirements in the context of its annual RIN reporting plan. As explained above, the Victorian Government's changes to the regulatory year for Victorian networks will require JEN to undertake an additional round of RIN reporting in FY22 to provide information for the six months 1 January 2021 to 30 June 2021. In the absence of us including a step change in our operating expenditure forecast to reflect this additional level of compliance activity, we would not be provided with a reasonable opportunity to recover at least our efficient costs incurred in complying with a regulatory obligation or requirement.⁶⁰

We have, therefore included a step change in our operating expenditure forecast for additional RIN reporting. We have developed our forecast for this step change on a bottom-up basis, comprising:

- Estimates of the incremental staff time required to prepare the necessary information to a reporting period in the current AR, EB and CA RINs (based on our experience with the current RINs),⁶¹ multiplied by a daily labour rate. Undertaking this additional reporting would require us to recruit temporary staff or engage contractors to ensure we could continue to deliver our annual work program.
- An estimate of the external assurance fees for an audit of six months of RIN data, which reflects our most recent RIN audit fees reduced by [REDACTED] to account for the lower volume of information.

Our forecast expenditure for this operating expenditure step change is shown in Table 7–1. This expenditure is necessary for us to achieve compliance with an applicable regulatory obligation or requirement associated with the provision of standard control services.⁶² Our forecast reflects the costs a prudent operator would expect to incur as it relates to the activities required to comply with a regulatory information instrument issued by the AER under the National Electricity Law (NEL). JEN would be unable to comply with the RIN if it did not undertake these activities, and the AER would expect a prudent operator would comply with the RIN. Furthermore, our forecast costs are efficient as they are our best estimate of the costs we expect to incur in complying with the obligation and reflect our revealed costs of complying with similar obligations during the current period—noting that the Efficiency Benefit Sharing Scheme provides us with an incentive to ensure our operating costs are efficient.

Table 7–1: Proposed operating expenditure step change for additional RIN reporting (\$ June 2021, millions)

| Operating expenditure step change | FY22 | FY23 | FY24 | FY25 | FY26 | Total |
|-----------------------------------|------|------|------|------|------|-------|
| Additional RIN reporting | 0.5 | - | - | - | - | 0.5 |

Source: Attachment 07-15 SCS PTRM FY22-26.

7.3 Options analysis

We have considered two options in relation to the additional RIN reporting arising from the change in JEN's regulatory year, which are set out below.

7.3.1 Option 1 – Do nothing

RINs issued by the AER under the NEL require a DNSP to provide, prepare and maintain information in the manner and form specified by the notice. It is an offence under the NEL for a person to fail to comply with a RIN without a reasonable excuse. Under the NEL, the AER may issue an infringement notice and institute civil proceedings seeking orders including a civil penalty where it believes a DNSP has not complied with a RIN. As set out in the sections above, JEN would be unable to comply with this additional RIN without undertaking the

⁶⁰ National Electricity Law, section 7A.

⁶¹ This includes data extraction, data validation against source systems, production of the basis of preparation and other written materials required by the RIN, internal quality assurance reviews and project management. Based on our experience preparing RIN data within a regulatory year for internal analysis purposes, we consider the workload required to respond to a RIN will be substantially the same for a 6 month period as for a 12 month period.

⁶² Consistent with the requirements of NER cl. 6.5.6(a)(2).

reporting activities reflected in our step change forecast. We do not consider it reasonable that a prudent operator would fail to comply with a RIN and therefore do not find that 'do nothing' represents a credible option which could be reflected in our operating expenditure forecast.

7.3.2 Option 2 – Undertake additional RIN reporting

JEN is required to comply with the requirements of a RIN under the NEL. Our operating expenditure base year contains revealed efficient expenditure which reflects the preparation of a single set (AR, EB and CA) of RIN information in 12 months. This option indicates the incremental reporting and external assurance activities required as a result of the change to the regulatory year, enabling us to recover our costs associated with complying with a change in regulatory obligations.