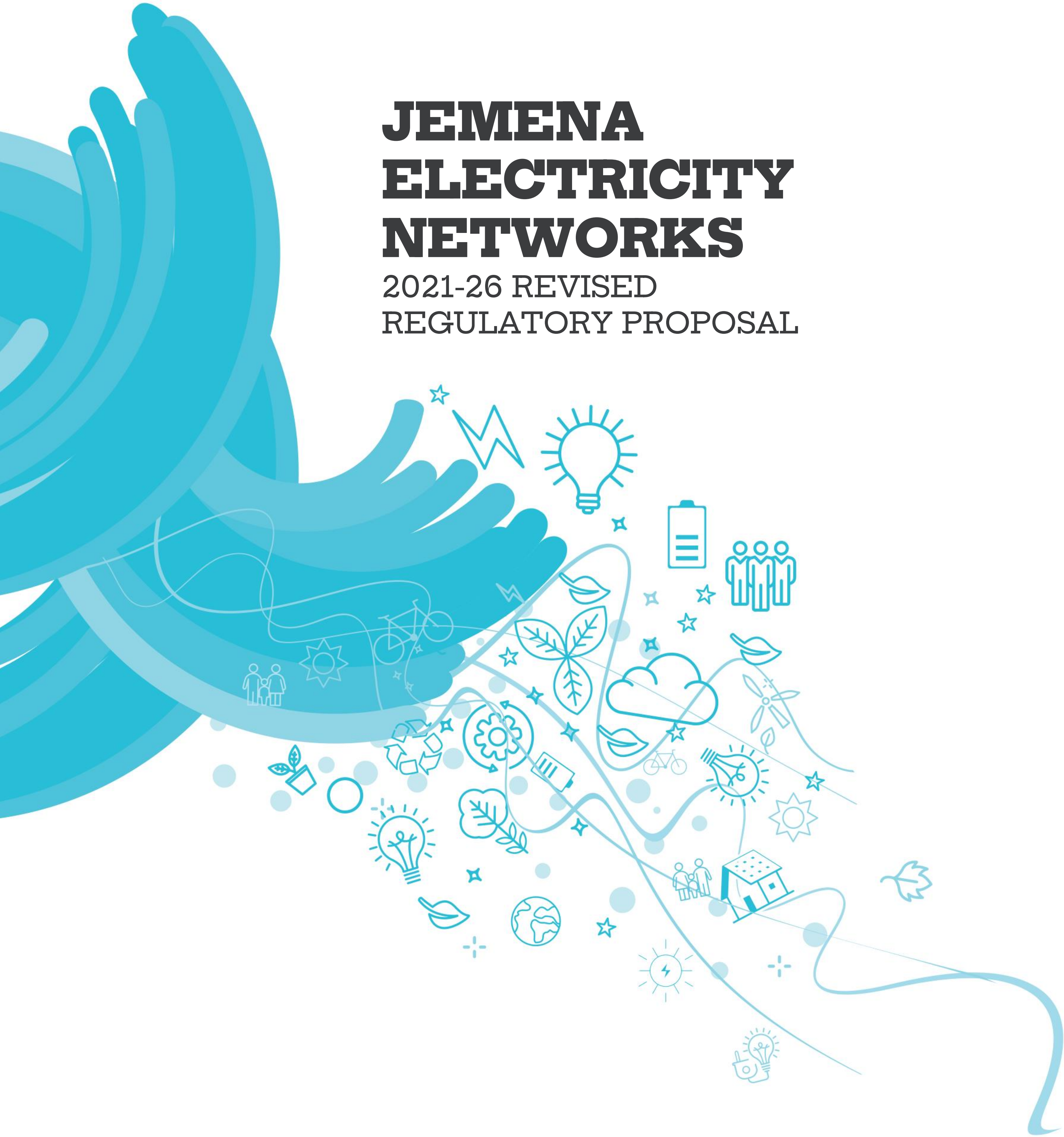
JEMENA ELECTRICITY NETWORKS

2021-26 REVISED REGULATORY PROPOSAL



DECEMBER 2020


“Jemena”
is an Aboriginal
word that means
“to hear, to listen
and to think”

Contents

Glossary

alternative control services	A distribution service that is a direct control service but not a standard control service. It includes smart metering services, public lighting OM&R services and ancillary services.
current regulatory period	The regulatory control period covering 1 January 2016 to 31 December 2020
draft decision	The draft decision on the determination that will apply to setting JEN's distribution prices for the next regulatory period
F&A paper	Framework and approach paper[1,2]
initial proposal	The initial proposal to the AER for the setting of regulated pricing for JEN for the next regulatory period
next regulatory period	The regulatory control period covering 1 July 2021 to 30 June 2026
revised proposal	The revised regulatory proposal to the AER for the setting of regulated pricing for JEN for the next regulatory period
smart metering services	Type 5 & 6 metering provision (including smart meters)
standard control services	The electricity distribution services provided using JEN's shared electricity network. Per the NER definition, a standard controls service is a direct control service that is subject to a control mechanism based on a DNSP's total revenue requirement

1 AER, *Final framework and approach, Victorian distributors, Regulatory control period commencing 1 January 2021*, January 2019.

2 Since finalisation of the F&A paper, the Victorian Government deferred the commencement date of the next regulatory period to 1 July 2021. The F&A paper was not updated with this change, and the substantive positions in that paper have not changed.

Abbreviations

AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
CCP17	Consumer Challenge Panel (sub panel 17)
CESS	Capital Expenditure Sharing Scheme
CSIS	Customer Service Incentive Scheme
DER	Distributed Energy Resources
DMIAM	Demand Management Incentive Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefits Sharing Scheme
ECA	Energy Consumers Australia
ESCV	Essential Service Commission of Victoria
ESV	Energy Safe Victoria
F&A	Framework and Approach
FY	Financial year[3]
GDP	Gross Domestic Product
HY	Half Year
ICC	Individually Calculated Customer
IAP2	International Association of Public Participation
JEN	Jemena Electricity Networks (Vic) Ltd
LRMC	Long Run Marginal Cost
NEL	National Electricity Law
NER	National Electricity Rules
OIC	Order In Council
OECD	Organisation for Economic Co-operation and Development
OEF	Operating Environment Factor
OM&R	Operation Maintenance and Replacement
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
REFCL	Rapid Earth Fault Current Limiter
SDIC	Summer Demand Incentive Charge
STPIS	Service Target Performance Incentive Scheme
TSS	Tariff Structure Statement

3 When expressing the financial year, in this document we follow the initials with a two year digit code. The two digits represent the latest year of that straddled annual period. For example, the financial year 1 July 2021 to 30 Jun 2022 is represented as FY22.

Overview

Every five years, the Australian Energy Regulator (**AER**) undertakes an electricity distribution price review (**price review**) to determine the revenue which our business can recover for the services it provides. The review involves a comprehensive assessment of our plans and consideration of our customers' preferences. Given the nature and extent of the review, multiple submissions are made by stakeholders and us to inform the AER in making its decision.

This document—Jemena Electricity Networks (Vic) Ltd's (**JEN**) revised regulatory proposal (**revised proposal**)—outlines the revenue we require to deliver the services our customers expect over the 2021-26 regulatory control period (**next regulatory period**). It is an update to our initial proposal of 31 January 2020 (**initial proposal**), focusing on providing updated or new information and addressing material issues outlined in the AER 2021-26 draft decision on our initial proposal(**draft decision**). It also examines and incorporates the effects of changes arising since the submission of our initial proposal, such as the COVID-19 pandemic, updates from our customers and changes to legal and regulatory requirements.

To the extent that our initial proposal has not been updated, amended or otherwise changed by this document, it remains applicable (and for those elements should be read together with this document). For simplicity and ease of understanding, we have not restated those elements in this document.

Table OV.1 sets out a summary of the standard control services and smart metering services revenue we require to provide the electricity distribution services to our customers safely, efficiently, and to a level expected of us.

Table OV.1: standard control services and smart metering services smoothed revenue forecasts [5-year totals] – ($Nominal, $M)

Service Type	Initial Proposal	Draft Decision	Revised Proposal
Standard control services	1,379.6	1,273.3	1,305.0
Smart metering services	128.2	112.1	112.9
Total	**1,507.8**	**1,385.3**	**1,417.9**

The revised proposal revenue amount of $1,418M ($nominal) is 6 per cent lower than our initial proposal amount of $1,508M ($nominal). The revenue now being proposed is greater than the $1,385M ($nominal) approved in the AER's draft decision by 2.3 per cent. In this revised proposal, we outline the reasons why the revenue assessment in the draft decision is insufficient and why the revenue we seek in the revised proposal is the minimum necessary to provide our services safely and efficiently.

Our customers' preferences

In developing our initial proposal, we set out to make our customers the centre of our plan. We did this by involving our customers in the development of our plan and making sure that we reflected their preferences in every aspect of our initial proposal. By reaching out widely, we were able to capture the broadest range of voices possible. Given the insights gained and success of this approach when developing our initial proposal, we have re-engaged with a number of our key stakeholders, including our People's Panel and Customer Council when developing this revised proposal.

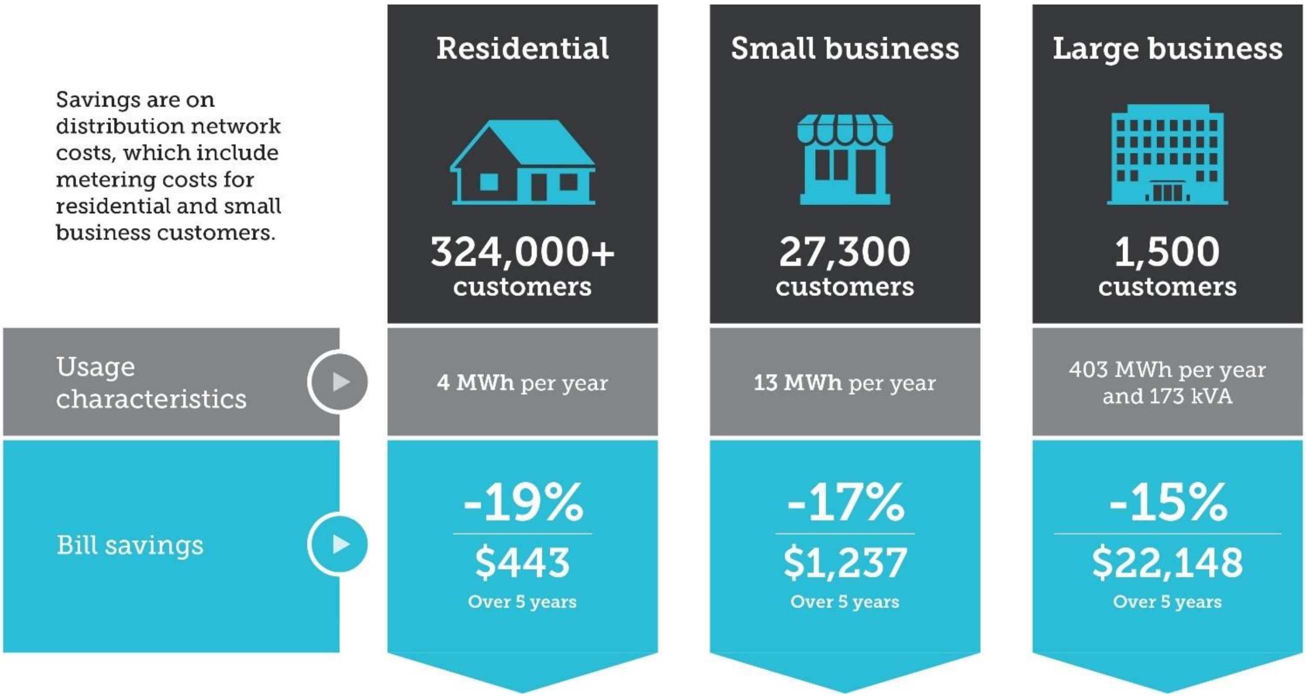
Through our Customer Council, we obtained comprehensive feedback on the draft decision and our initial proposal. We have also sought the views of our People's Panel to understand what has changed for them since we last met, whether their preferences have changed as a result, as well as to discuss some of the more material issues raised by the AER in the draft decision.

Our People's Panel members—representing the voice of our broader customer base—affirmed their preferences, and particularly emphasised their desire for affordable electricity. Our revised proposal responds to the feedback we've heard by:

- providing even greater bill savings than our initial proposal for all of our customers
- offering a range of network tariffs that give our customers more choices, empowering them to manage their electricity usage in a way that better suits them
- reflecting the efficient expenditure required to maintain the current reliability of our services over the long-term
- incorporating our Future Grid program to facilitate the efficient connection of a growing amount of Distributed Energy Resources (**DER**) to our network.

The bill savings for our customers are outlined in Figure OV.1 below, with more than five per cent extra savings across each customer type compared to our initial proposal.

Figure OV.1: Bill savings our revised proposal will deliver for customers ($2021)



The AER's draft decision

On 30 September, the AER released its draft decision relating to our initial proposal. The draft decision is a formal draft of the decision that will set out the revenues and prices the AER considers are prudent and efficient for us to provide our services in the long-term interests of customers. The AER's draft decision considered that our smoothed revenues for standard control services should be $1,273M (nominal) for the next regulatory period.

Similarly, for our smart metering services we proposed $128M (nominal) of smoothed revenue for the next regulatory period, however, the draft decision considered $112M (nominal) of smoothed revenue is required.

In making its draft decision, the AER has outlined its reasoning and invited JEN and other stakeholders to make submissions to better inform its final decision. We have prepared this revised proposal to inform the AER's final decision and demonstrate why our revised proposal revenue requirement is in the long-term interests of our customers.

What has changed since submitting our initial proposal?

There have been several changes since submitting our initial proposal in January 2020 which impact our forecast expenditures, and therefore, our revenue requirements. Changes include movements in the risk free rate and the AER's consultation on forecast inflation. Additionally, the COVID-19 pandemic has impacted on the way our society interacts and changed the way our customers use and rely on our electricity network.

In preparing this revised proposal, we have undertaken a comprehensive analysis of the impacts of the pandemic on JEN and is services, including on our capital and operating expenditures, and adopted a balanced approach when factoring these changes into our revised proposal. We elaborate on the pandemic, its economic impacts and our revised proposal's response to it in Appendix A.

We have also continued to focus on the efficient deployment of Rapid Earth Fault Current Limiter (**REFCL**) devices to meet our bushfire mitigation obligations. As indicated in our initial proposal, we have refined our program and reduced our forecast expenditure required to achieve compliance in the Coolaroo area. Our revised proposal also incorporates expenditure required to comply with bushfire mitigation obligations in the Kalkallo area, in light of changes outlined by Energy Safe Victoria (**ESV**).

These changes are new, and aside from the refinement of our REFCL program, were not contemplated when we developed our initial proposal. Given this, we consider it is prudent to raise these issues in this revised proposal, so that these matters are appropriately assessed and considered by the AER to afford JEN a reasonable opportunity to recover its efficient costs related to these changes.

Ensuring we have sufficient revenue to deliver services

JEN must recover its efficient costs through regulated revenue to provide standard control services and smart metering services in line with our customers' preferences and in accordance with our regulatory obligations.

Application of benchmarking techniques to operating expenditure

We have examined the draft decision in detail and how the AER's assessment tools have been applied. For our base year operating expenditure, we have significant concerns with the approach the AER has adopted to determine an alternative operating expenditure base year amount, including:

- the deterministic application of benchmarking techniques to assess base year operating expenditure efficiency, despite there being known shortcomings associated with these benchmarking techniques
- making no adjustment to account for differences in capitalisation policies between Distribution Network Service Providers (**DNSP**s)
- making reductions to our newly expensed corporate overheads, when these expenses were not subject to a similar assessment methodology under their former classification as capital expenditure
- the existence and acknowledgement of significant errors between 2014 and 2018 by AER's consultant about the calculation of output weights as part of this analysis.

These concerns are material, and similar concerns have been raised by other stakeholders and industry participants previously. Left unaddressed, we consider the AER's approach to determining an alternative operating expenditure base year amount will not provide JEN with a sufficient revenue allowance for the next regulatory period and could have long term consequences to our customers.

Inflation Forecast

We note that the AER has recently made its draft decision on forecasting inflation[4] and is scheduled to release its final position paper after submission of this revised proposal. We have provided our views on this

[4] AER, *Draft position, Regulatory treatment of inflation,* October 2020.

consultation through a separate submission to the AER and have summarised our submission in Attachment 03-01. We note that, although we cannot incorporate the outcomes of the inflation forecasting final decision into this revised proposal, there is sufficient time for the AER to include it in JEN's price reset final decision.

Our revised proposal

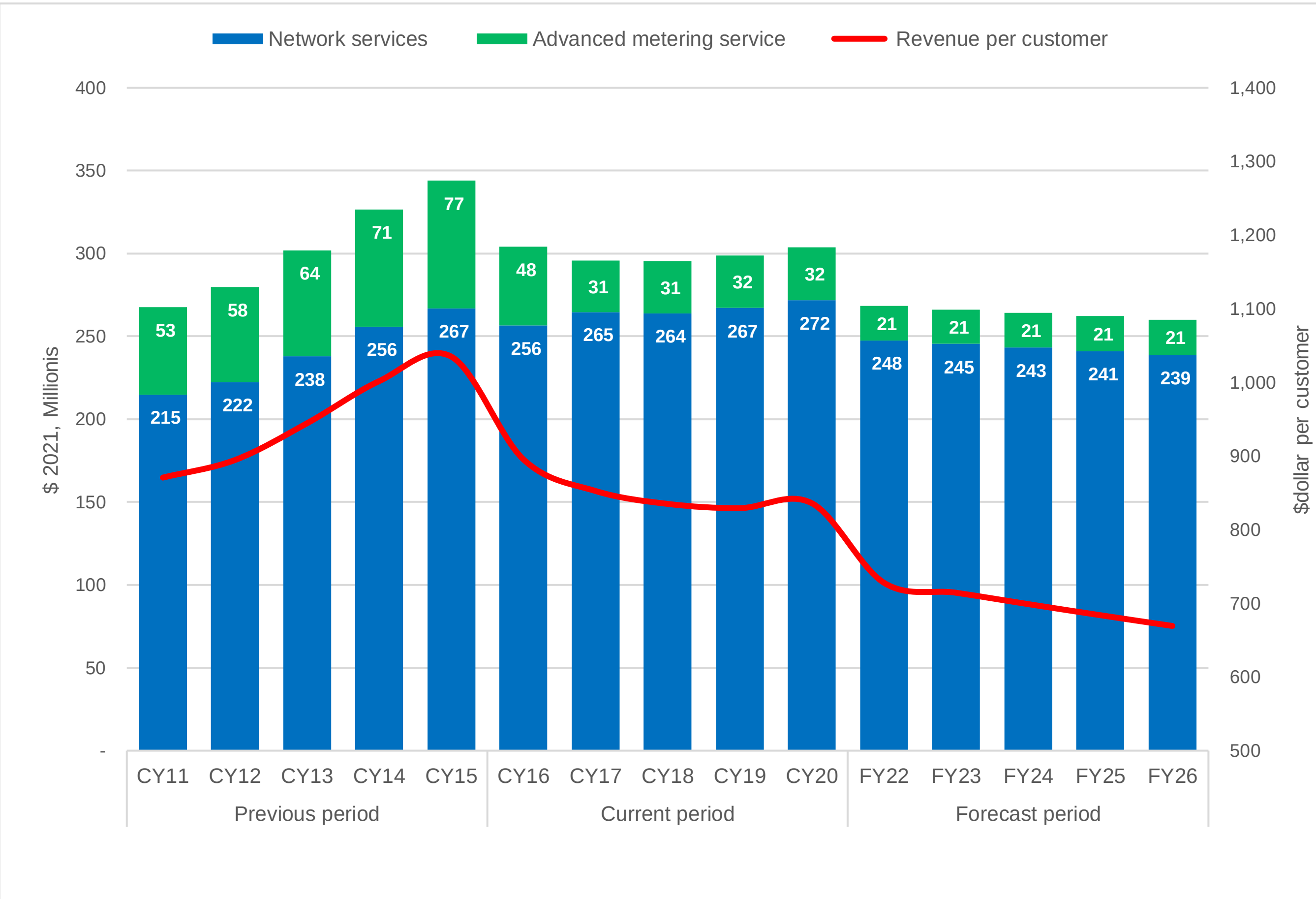
We have considered a broad range of factors when thinking about how we operate and invest in the future, and have reflected these in our revised proposal. We have also addressed other key areas of the draft decision in which the AER sought further information.

Our revised proposal revenue forecast reflects the updates we have made to our key drivers of building block revenue, most notably:

- a revised operating expenditure forecast which incorporates changes to our base year, step changes, forecast output growth and real labour price escalation
- a revised capital expenditure forecast which incorporates updates to our REFCL program, real price escalation and responding to the COVID-19 pandemic
- updates to the rate of return to account for market movements.

Our revised proposal continues the long-term trend of falling network prices for our customers. As can be observed in Figure OV.2, our revenues are forecast to reduce substantially at the start of the next regulatory period and then decline at a slower rate, despite our network and customer base growing—meaning that our customers will continue to benefit through lower bills over time. The revenue per customer is declining at an even faster rate when the revenue reductions are spread across a growing customer base.

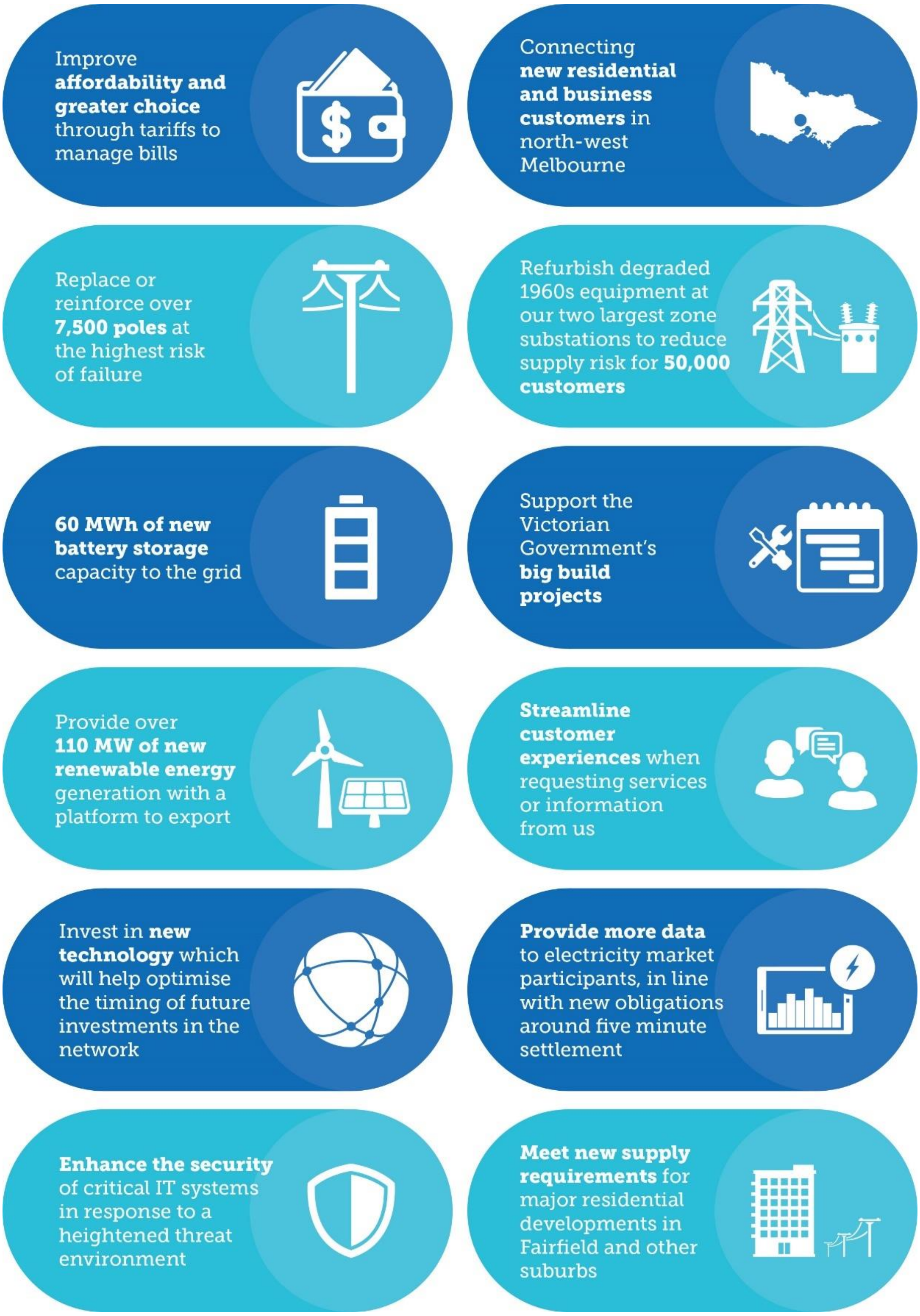
Figure OV.2: Long term revenue requirements ($2021, $M)



What our revised proposal delivers for customers

Through our revised proposal, we can deliver on the commitments we have made to our customers to provide safe and reliable electricity distribution services, efficiently, affordably and sustainably. Figure OV.3 outlines the initiatives and benefits that our revised proposal allows us to deliver.

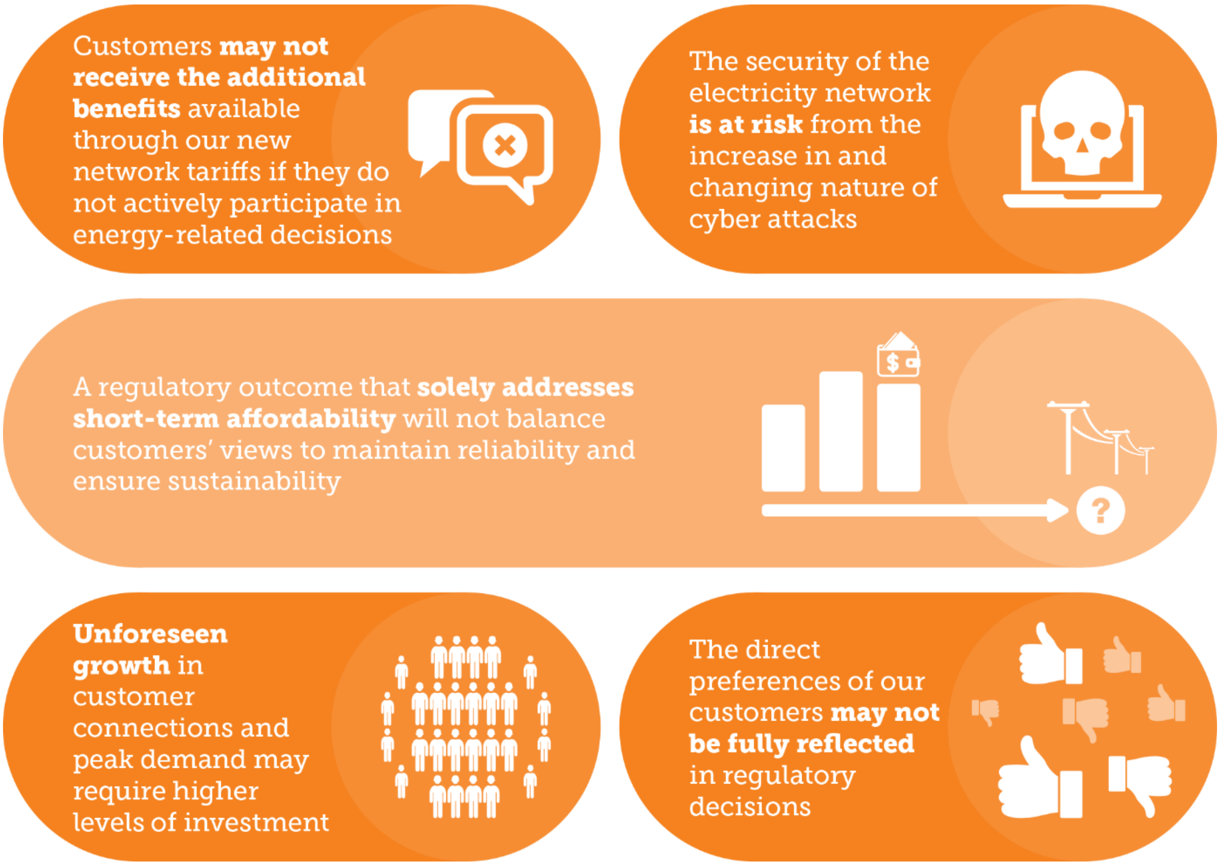
Figure OV.3: What our revised proposal delivers for our customers



Our revised proposal identifies several risks

Our proposal also identifies several risks, including revenue sufficiency, to ensure we can deliver safe and reliable distribution services to our customers. We outline these risks in Figure OV.4 below.

Figure OV.4: Risks of our proposal to our customers

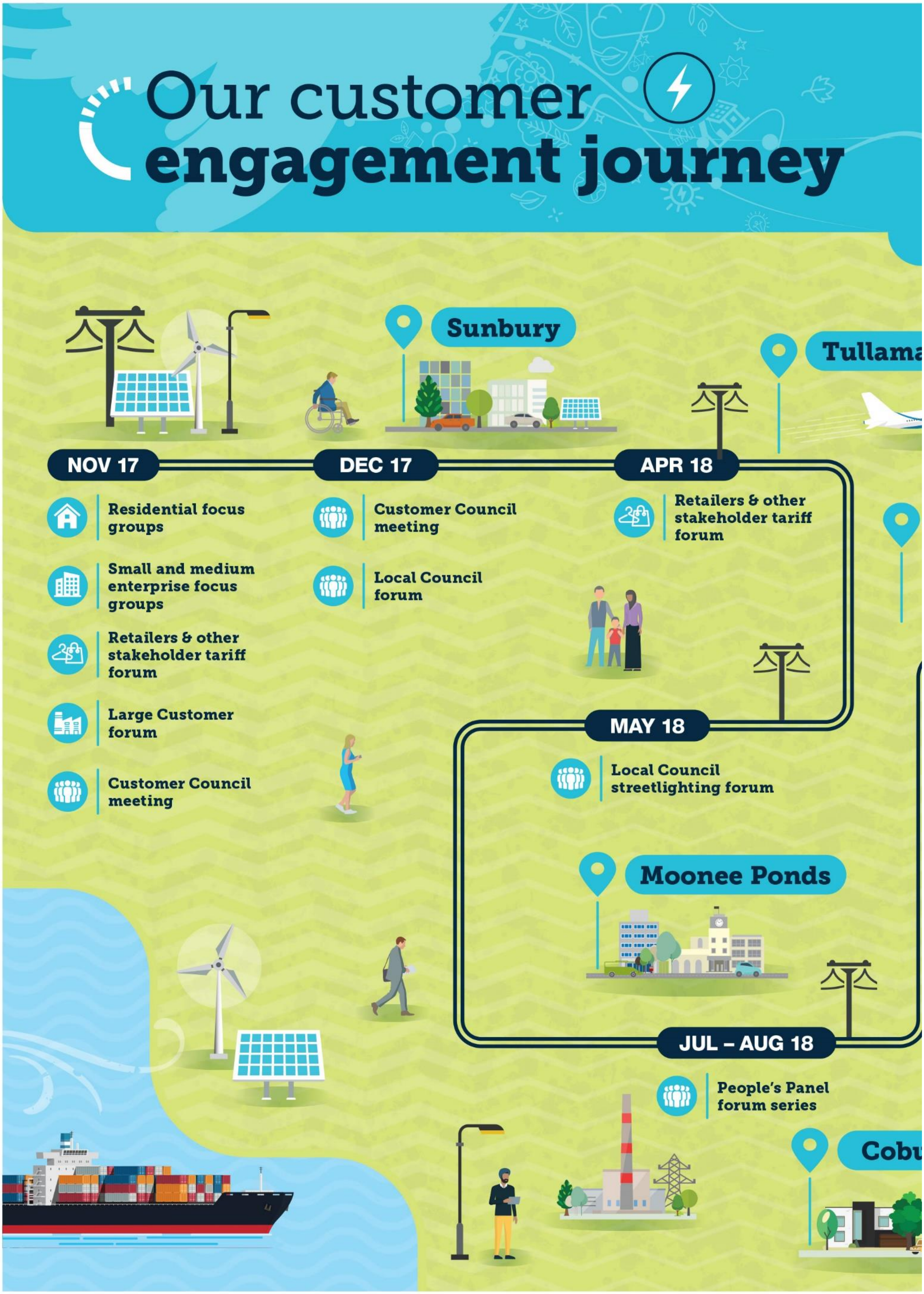


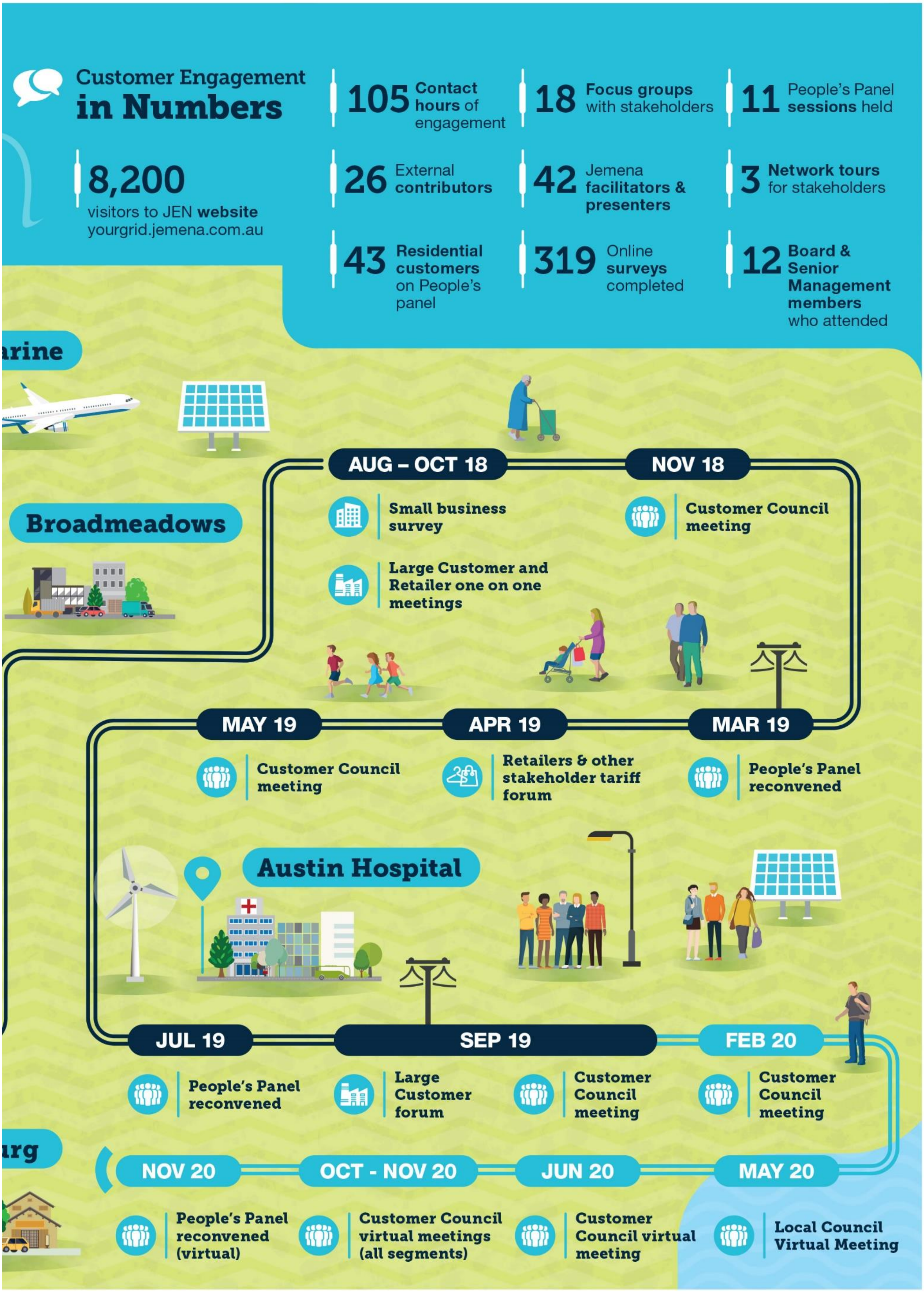
Additional documents

We have developed a range of additional materials to support the positions outlined in this revised proposal, at the end of each section of this overview document we note the reference to each of these documents. In addition, we include the following further supporting documents:

- Attachment OV-01 – A document map to assist navigating the supporting materials
- Attachment OV-02 – Claims for confidentiality.

1. Including our Customers' Preferences


Our customer engagement journey
Sunbury
Tullama
NOV 17
Residential focus groups
Small and medium enterprise focus groups
Retailers & other stakeholder tariff forum
Large Customer forum
Customer Council meeting
DEC 17
Customer Council meeting
Local Council forum
APR 18
Retailers & other stakeholder tariff forum
MAY 18
Local Council streetlighting forum
Moonee Ponds
JUL – AUG 18
People's Panel forum series
Cobu


Customer Engagement
in Numbers
105 Contact hours of engagement
18 Focus groups with stakeholders
11 People's Panel sessions held
8,200 visitors to JEN website yourgrid.jemena.com.au
26 External contributors
42 Jemena facilitators & presenters
3 Network tours for stakeholders
43 Residential customers on People's panel
319 Online surveys completed
12 Board & Senior Management members who attended
arine
Broadmeadows
AUG – OCT 18
Small business survey
Large Customer and Retailer one on one meetings
NOV 18
Customer Council meeting
MAR 19
People's Panel reconvened
APR 19
Retailers & other stakeholder tariff forum
MAY 19
Customer Council meeting
Austin Hospital
JUL 19
People's Panel reconvened
SEP 19
Large Customer forum
Customer Council meeting
FEB 20
Customer Council meeting
urg
MAY 20
Local Council Virtual Meeting
JUN 20
Customer Council virtual meeting
OCT - NOV 20
Customer Council virtual meetings (all segments)
NOV 20
People's Panel reconvened (virtual)

1.1 Continuing our strong customer engagement

When we first set out to develop our initial proposal, we identified three objectives to achieve in our customer engagement journey, outlined in Figure 1.1. We sought our customers' views and preferences and committed to embedding them in our regulatory proposal and in shaping the culture of our business.

Figure 1.1: Our customer engagement objectives

The approach we have taken to engaging with our customers has been recognised as leading amongst our peers and customer groups, achieving the combined Energy Networks Australian and Energy Consumers Australia customer engagement award in 2019. We were also shortlisted for the International Association for Public Participation (**IAP2**) planning category award, the only Australian DNSP to achieve such recognition of our engagement. The AER has acknowledged this, stating that 'Jemena has often been a leader in consumer engagement approaches and its regulatory proposal reflects the feedback it received through this engagement.'[5]

We have continued our emphasis on customer engagement in shaping this revised proposal. Through our Customer Council, we obtained comprehensive feedback on the draft decision and our initial proposal. We also engaged with our People's Panel to understand what has changed for them since we last met (noting the far-reaching impacts of the COVID-19 pandemic on our customers), whether their preferences have changed as a result, and to discuss some of the key issues raised in the draft decision.

1.2 Re-engaging with our customers

In developing this revised proposal, we reached out to our customers and customer representatives to seek their views on issues raised in the draft decision and how our revised proposal should respond to these. What became evident when re-engaging with our customers was that our objective of building trust underpinned a commitment by them to participate and contribute to discussions with us at short notice. Knowing that their views mattered to us and that we were committed to implementing their recommendations to the maximum extent possible emboldened our customers to express those views freely and without boundaries on the topics important to them.

5 AER, *Overview, Draft decision – Jemena 2021–26*, 30 September 2020, pg. 4.

1.2.1 Customer Council

Our Customer Council is a key sounding board for us to hear from those who represent a broad cross-section of our customers and stakeholders and have special interests in renewable energy and assisting the vulnerable.

Figure 1.2: JEN's Customer Council is made up of a broad range of customer representatives

- Renew
- Kildonan Uniting Care
- Energy Consumers Australia (ECA)
- St Vincent de Paul
- Brotherhood of St Laurence

- Victorian Chamber of Commerce and Industry (VCCI)

- Energy Users Association of Australia (EUAA)
- Australian Industry Group (Ai Group)
- CSL Behring

- Australian Energy Council (AEC)

- Energy & Water Ombudsman - Victoria (EWOV)
- Australian Energy Foundation
- Northern Alliance for Greenhouse Action (NAGA)
- Emerging Technologies Research Lab at Monash University
- Clean Energy Council (CEC)
- Western Alliance for Greenhouse Action
- NORTH Link

From time to time, we have guests attend our Customer Council meetings. At our October 2020 meeting, the Consumer Challenge Panel – sub-panel 17 (**CCP17**)[6] attended to observe our processes, and we also had some of our large customers attend the meeting allowing them to express their views—specifically to discuss tariff design in our revised proposal.

Our Customer Council has assisted the shaping of our revised proposal, providing advice on how to engage with customers and on which topics. Our Customer Council also provided input on tariff designs for both small and large customers, and this has been factored into our revised proposal (see section 12).

1.2.2 People's Panel

Our People's Panel is a key contributor to helping shape JEN's customer culture and—in the present case—our revised proposal. Over a sustained period since 2018, we have built a relationship with our panel members, helped build their understanding and capabilities to engage better in the energy sector and the regulatory process, as well as giving them an opportunity to speak directly to us on issues that matter most to them. Through our engagements and their contributions, we were able to develop the energy trilemma of sustainability, affordability and reliability, to capture their key preferences.

Following the release of the draft decision, we held meetings with our People's Panel to re-engage on the topics they focussed on during the development of our initial proposal, which can be summarised within the energy

6 The Consumer Challenge Panel sub-panel 17 was formed to undertake a review of the Victorian electricity distribution price reviews for the next regulatory period.

trilemma. Our engagement during the development of our revised proposal was aligned to the key issues raised in the draft decision, and include:

- **Reliability** – The capital investment needed to maintain current levels of reliability
- **Sustainability** – Focusing on the Panel's recommendation to 'green the grid' and aligned to our Future Grid program
- **Affordability** – Focusing on general affordability issues, especially addressing the AER's base year operating expenditure decision.

We also wanted to seek our Panel members' views on the question around the depth to which they wish to engage on certain topics. Whilst the AER found our People's Panel process was an effective form of customer engagement, covering a broad range of topics, they questioned the depth we achieved on specific engagement topics such as our operating expenditure proposal.

When we first set out to engage with our customers, we recognised that their capacity and interest in engaging on a very wide range of topics in electricity distribution services could be limited in some circumstances, especially given the significant knowledge gap in the broader community about the role DNSPs play in the electricity supply chain. This set us a challenge in how we designed our customer engagement and was a key influence on our decision to establish the People's Panel to help build customers' capacity to engage and provide informed input, helping us to hear broadly representative views from a range of our customers.

"I think long-term is what needs to be considered. Balance over the long term to reduce individual costs"

A People's Panel member

We are also cognisant of the time and commitment given by our customers to engage, particularly in relation to the detail on some of the highly complex issues involved in the price review process. Being respectful of our customers' time, there is a limit in how much we can ask of them, and also, how much they are willing to contribute. This is a balance which must be evaluated in all forms of customer engagement, and one of the key reasons we chose to focus on breadth.

Nevertheless, the question of depth in the draft decision[7] is relevant as it has been raised by the AER. We tested this with the Panel members themselves, asking them whether they felt the depth we reached on various topics was sufficient. We asked this question by way of example, walking them through more detailed aspects of operating expenditure base year efficiency. The outcomes of this engagement and our Panel members' views on the depth of our engagement are outlined in section 1.3.

1.2.3 Other customer representative groups

We also met with other customer representative groups directly to seek their views on matters raised in the draft decision. These groups included Energy Consumers Australia, Brotherhood of St Lawrence and St Vincent De Paul.

Following on our commitment to ensure our customers' voices are captured in this revised proposal, we have reflected feedback obtained from these groups throughout this revised proposal.[8]

[7] AER, *Draft Decision, Jemena Distribution Determination, 2021 to 2026, Overview*, September 2020, p. 45.

[8] More detail on other customer representative feedback is outlined in Attachment 01-01.

1.3 An update from our People's Panel

We checked in with our People's Panel to test their views on our revised proposal, and in particular, to consider the AER's draft decision. Table 1.1 outlines their feedback from our discussions.

Table 1.1: Feedback from our People's Panel

Discussion topic	What our panel members told us	How we have incorporated the panel member feedback into this revised proposal
Reliability	Our panel members told us they relied on their electricity supply more than when we met with them earlier in the process. They told us: - They depended on communications equipment (mostly internet access) for work, school and to keeping in touch socially, particularly during the isolation period in 2020. They acknowledged their equipment could only operate if there is a reliable electricity supply - That the way we managed outages was very effective during the COVID-19 lock-down, having received multiple outage notifications through letters, SMS and phone calls - They accepted outages were a necessary part of our work, and that the inconvenience was understandable.	Whilst our panel members expressed a heightened dependence on the electricity supply, and were acutely more aware of outages when they did arise, none expressed a desire to increase the levels of reliability. Additionally, there was no discussion around reducing reliability levels. Based on this outcome, we have maintained our reliability related capital and operating forecasts in our revised proposal.
Sustainability	Our People's Panel members told us that 'greening the grid' continued to be important to them. They valued the benefits of more renewable generation. - They valued greener generation, more for its environmental benefits, they see this as extremely important - They believed having the option to put energy into the electricity network is important, but wanted to make sure the benefits of having a PV system stacked up - When presented with the benefits case—and breakeven point for our future grid strategy—the panel members were still keen to support the initiative.	We have mostly maintained our future grid strategy originally presented in our initial proposal. - We have removed our DER settings initiative ($1.8M) as the benefits lacked certainty - We reclassified two other initiatives as capital expenditure ($2M) These changes are relatively minor and do not materially affect our delivery of the future grid program.
Affordability	We presented the bill impacts for residential customers in: - our initial proposal (~$64 per annum) - the draft decision (~$73 per annum) - our updated initial proposal (~$70 per annum)[9] and focused our discussions on JEN's base year operating expenditure.	Our revised proposal continues the operating expenditure reduction of $4M per annum resulting. This approach strikes this middle ground in terms of bill impacts and addresses the concerns we raise around the AER's benchmarking approach.[10]

9 See section 5.3.2 for an explanation of an updated initial proposal we put to the AER for their consideration, prior to the release of the draft decision.

10 ibid

Discussion topic	What our panel members told us	How we have incorporated the panel member feedback into this revised proposal
	Our panel members recognised there are some vulnerable members in our community where the bill impacts are important; the panel members were sympathetic to them.	
Depth of engagement	We asked our panel members whether they felt they had been engaged to a sufficient level of depth on price reset matters. We did this by presenting an example of a complex issue—namely, the operating expenditure adjustment made to our base year amount using benchmarking techniques. Whilst concerned about their capabilities to understand the issues; we have over 60% of attendees signing up to participate in a workshop series to get a better understanding of the issues.	We are running a series of workshops to elaborate on benchmarking practices—including, having subject matter experts attending.. Our People's Panel members will make their own submission to the price reset process based on their findings. Our panel members are taking their own initiative to deep dive on complex topics; in this case, operating expenditure efficiency.

Our People's Panel continued to engage on a broad range of topics, their views have not changed materially during the course of the pricing review process, rather, their views have galvanised more so due to the COVID-19 pandemic.

1.4 The customer engagement assessment framework

In the draft decision, the AER set out a draft *framework for considering consumer engagement* which outlines how it will take customer feedback into account when assessing the DNSPs' regulatory proposals. We consider having a framework for considering consumer engagement is an important part of the price review process, as it gives DNSPs further guidance around how the AER will assess their approach to engaging with customers and gives assurance that the AER will consider a variety of engagement methods.

In developing our customer engagement program, we commenced with the IAP2 core values and evaluated its design through the IAP2's quality assurance standard.[11] This step gave us the assurance that our approach would stand up to scrutiny; including the approach that the AER would undertake to evaluate how we have incorporated our customers' preferences into our proposal. With the *framework for considering consumer engagement* now released, we are confident that the evaluation we undertook against internationally recognised engagement standards will meet the AER's objectives.

1.5 Attachments

In Attachment 01-01 we provide further details on our customer engagement that helped to shape this revised proposal, and we also respond to the AER's customer engagement assessment framework.

11 IAP2, *Quality assurance standard for community and stakeholder engagement*, May 2015.

2. Classification of Services

2.1 Classification of services

A key part of the AER's price review process is to identify and classify the services provided by DNSPs. Classification is important to customers as it determines which network services are included in our network charges, the basis on which the other user-requested services are charged and those services that are not regulated by the AER. As a part of the price review process, we proposed to the AER the services we want to provide our customers and how they should be classified.

Importantly, when speaking to our customers about the services we provide, they told us they wanted to see further integration of renewable energy with our network—in their words, 'greening the grid.' Whilst this does not change the services we propose per se, it does indicate that our customers want to see more products and services—including market-based options—in the future. This will see JEN's role moving more and more towards an energy 'facilitator' and services being classified differently as technology and products become more and more prevalent, most likely in future regulatory periods.

2.2 Draft decision

In the draft decision,[12] the AER considered a range of services and their classification proposed by JEN. The AER:

- largely accepted the services JEN proposed and their classifications; however, some minor changes were identified. In the draft decision, the AER largely stated its approach to service classifications as set out in the AER's final Framework & Approach (**F&A**) paper[13]
- made minor amendments to clarify that the service description of temporary connections includes temporary disconnection and reconnection services
- added a new metrology service to the auxiliary metering services for types 5-7 metering group
- made minor changes to reflect delineation of alternative control services between fee-based and quoted services; and the distinction between basic and non-basic connections is contained in JEN's pricing schedule.

The AER accepted all other aspects of our proposed services and their classification.

2.3 JEN's response to the draft decision

We have accepted the AER's draft decision[14] on service classification without change. We acknowledge the AER's explanation that the appropriate place to:

- delineate alternative control services between fee-based and quoted services, and
- distinguish between basic connection and non-basic connection services,

is in the pricing proposal for these services.

We also re-tested our customers' preferences when developing this revised proposal to see if there was any material change required, including in the services and service levels we provide. We found that our customers

12 AER, *Draft Decision, Jemena Distribution Determination 2021 to 2026, Attachment 13, Classification of services*, September 2020.

13 AER, *Final framework and approach, Victorian distributors, Regulatory control period commencing 1 January 2021*, January 2019.

14 AER, *Draft Decision, Jemena Distribution Determination 2021 to 2026, Attachment 13, Classification of services*, September 2020.

were more galvanised in their views about the future of electricity distribution and the services we should provide.[15] In line with this feedback, we consider our services should be retained, however, as new products and services come to market and as customers become more engaged in the electricity market, the services we provide will change.

2.4 Supporting attachments

Further details of our approach to classifying services in this revised proposal can be found in Attachment 02-02.

15 See section 1.3.

3. Annual Revenue Requirement

3.1 Annual revenue requirement

Our Annual Revenue Requirement (**ARR**) outlines the revenues we require to provide standard control services to our customers to the level expected of us. The ARR outlined in this revised proposal is an update to the ARR we sought in our initial proposal and is provided to the AER in response to the draft decision to assist with setting the revenue allowance for the next regulatory period.

Using the AER's Post Tax Revenue Model (**PTRM**), we calculate the unsmoothed revenue, smoothed revenue and X-factors over the next regulatory period. It is our smoothed revenue which we recover from our customers.[16]

A summary of the smoothed revenue we initially proposed, the level determined by the AER in its draft decision, and now included as a part of this revised proposal, is outlined in Table 3.1.

Table 3.1: Summary of the standard control services forecasts [5-year totals] – ($Nominal $M)

Service Type	Initial Proposal	Draft Decision	Revised Proposal
Smoothed revenue	1,379.6	1,273.3	1,305.0

The smoothed review sought in this revised proposal is 5.4 per cent lower than the amount sought in our initial proposal and 2.5 per cent higher than the draft decision amount. It is the minimum that JEN requires to provide standard control services to our customers and at the level they expect.

3.2 Draft decision

The draft decision smoothed revenue for JEN was $1,273.3M ($nominal), which is 7.7 per cent lower than the smoothed revenue we proposed in our initial proposal. A summary of the AER's smoothed revenue draft decision by year is outlined in Table 3.2.

Table 3.2: AER draft decision smoothed revenue and real price changes - ($Nominal, $M)

	FY22	FY23	FY24	FY25	FY26	Total
Building block (unsmoothed) revenue requirement	247.0	252.1	255.2	259.0	261.7	1,274.9
X-factors	10.58%	2.45%	2.45%	2.45%	2.45%	N/A
Total smoothed revenue	255.3	255.0	254.7	254.3	254.0	1,273.3

The lower smoothed revenue requirement reflects the impact of changes made on each of the building block items. We outline the implications of each of the building block elements in Table 3.3.

16 We have prepared these forecasts in accordance with the JEN Cost Allocation Methodology [JEN, *Cost Allocation Methodology, Public*, 29 March 2019].

Table 3.3: Overview of why the draft decision is different to the initial proposal - Building block standard control services revenue, unsmoothed [5 years] ($Nominal, $M)

Building block item	Initial proposal	Draft decision	Comments
Return on capital	399.2	368.8	The draft decision applied the 2018 rate of return guideline and updated the placeholder return on debt and return on equity parameters for latest market observables
Regulatory depreciation	279.0	274.1	The AER largely accepted the JEN's approach to forecasting regulatory deprecation, making minor corrections and updating for changes in other parts of the building block model
Operating expenditure	619.4	536.1	The draft decision made several revisions to JEN's proposed operating expenditure, most notably a 15% reduction to the base year amount and newly expensed corporate overheads, 91% reduction to real escalation, and 48% reduction in step changes. (See section 5.2 for further details of the operating expenditure draft decision).
Revenue adjustments	53.0	68.0	The draft decision updated for actual 2019 costs and uplifted the Efficiency Benefits Sharing Scheme (**EBSS**) and Capital Expenditure Sharing Scheme (**CESS**) amounts (see section 6). The AER made minor changes to the Demand Management Incentive Allowance Mechanism (**DMIAM**).
Corporate income tax	30.6	27.8	The draft decision made minor changes such as updating for 2019 and HY21 capital expenditure, rate of return and CPI.
Revenue requirement (unsmoothed)	**1,381.2**	**1,274.9**	

The most significant change between our initial proposal and the draft decision is the reduction in base year operating expenditure allowance, which makes up 40% of the overall reduction in smoothed revenue.[17]

3.3 JEN's response to the draft decision

We have considered the AER's ARR draft decision, and have identified that the elements of the building block model require further consideration and therefore revised our proposal to account for these. After accounting for these factors, we propose smoothed revenue in this revised proposal 5.4 per cent lower than the amount sought in our initial proposal and 2.5 per cent higher than the draft decision amount. We believe this is the minimum revenue required to provide standard control services safely and efficiently to our customers.

We summarise this revised smoothed ARR in Table 3.4.

17 The adjustment to the operating expenditure base year amount is paired with the removal of the EBSS.

Table 3.4: Revised proposal smoothed revenue and real price changes - ($Nominal, $M)

	FY22	FY23	FY24	FY25	FY26	Total
Building Block (unsmoothed) Revenue Requirement	245.8	254.3	261.1	268.5	276.9	1,306.5
X-factors	11.22%	0.90%	0.90%	0.90%	0.90%	N/A
Total Smoothed Revenue	253.5	257.2	260.9	264.7	268.6	1,305.0

As noted above, there are several reasons for proposing higher smoothed revenue compared with the draft decision. We outline our reasoning for these changes to the draft decision for each building block in Table 3.5.

Table 3.5: JEN's response to the Draft Decision - building block for standard control services revenue, unsmoothed [5 years] ($Nominal, $M)

Building block item	Draft Decision	Revised Proposal	Comments
Return on capital	368.8	362.2	We **accept** the AER's draft decision. However, JEN is concerned about the Reserve Bank of Australia's (**RBA**'s) intervention in the bond market that will artificially suppress the risk free rate over the next 6 months.
Regulatory depreciation	274.1	276.8	JEN **accepts** AER's draft decision on method for estimating this component. In our revised proposal, JEN has amended components which affect the forecast regulatory depreciation, including changes to the opening RAB and capital expenditure forecasts.
Operating expenditure	536.1	571.9	JEN **does not accept** AER's efficiency assessment and reduction of our forecast operating expenditure. Our response contains an updated operating expenditure model which includes offering a $20 million ($2021) reduction in our operating expenditure forecast relative to our initial proposal. We have also updated some of our step changes and trend components. We elaborate on these issues in section 5.
Revenue adjustments	68.0	67.9	We **accept** the draft decision with minor updates for CPI and rate of return.
Corporate income tax	27.8	27.7	We **accept** the draft decision and make minor updates for changes in other elements of the building block model.
Revenue requirement (unsmoothed)	**1,274.9**	**1,306.5**	

3.4 Attachments

Refer to attachment 03-01 for further details on our revenue requirement.

4. Capital Expenditure

4.1 Capital expenditure

To provide services which meet our customers' expectations—such as maintaining our current levels of network reliability and efficiently integrating more DER with our network—we must invest in our distribution network and in other supporting assets. In our initial proposal submitted to the AER, we outlined several areas of capital expenditure for standard control services that require continued investment. In total, our proposed capital expenditure was in line with the level of investment we have undertaken during the current regulatory period.

Our capital expenditure forecast for the next regulatory period has sought to address the following overarching objectives, which themselves reflect the feedback we heard from customers:

- Meet customers' expectations that we should maintain our current levels of network reliability (including the frequency and duration of outages) at the most efficient cost over the long term
- Manage safety, environmental, physical security and cybersecurity risks to as low as practicable and comply with all applicable regulatory obligations at the most efficient cost over the long term
- Connect new customers to our network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers at the least cost over the long term
- Efficiently minimise any constraints on grid exports from DER to the extent possible.

To meet these objectives, we proposed $627M ($2021) of net capital expenditure ($781M in gross terms) in our initial proposal.

4.2 Draft decision

The AER evaluated our proposed capital expenditure by applying a range of assessment tools, considered feedback from our customers and addressed the capital expenditure criteria contained in the NER. The AER was generally satisfied that our forecast reflected the capital expenditure criteria. The AER's top-down and bottom-up category analysis, taken together, found our proposed capital expenditure in aggregate to be prudent and efficient, except for three areas where it made adjustments:

- connections and cost escalation due to the unforeseen impacts of the COVID-19 pandemic
- an adjustment to our REFCL program.[18]

These adjustments resulted in our capital expenditure allowance for the next regulatory period reducing by 4.0 per cent to $602M ($2021) for net capital expenditure ($745M in gross terms).

A summary of the AER's draft decision on our capital expenditure proposal, by item, is outlined in Table 4.1.

Table 4.1: Summary of the AER's draft decision on our capital expenditure proposal by category

Item	AER position
Replacement expenditure	Accepted.
Connections expenditure	Accepted, with adjustment for COVID-19 impacts.
Augmentation expenditure	Traditional augmentation expenditure – accepted, with COVID-19 impacts to be reconsidered in the final decision. REFCL augmentation expenditure – project information to be updated.

[18] AER, *Draft decision: Jemena Distribution Determination 2021 to 2026, Overview*, September 2020, p. 8.

Item	AER position
DER integration expenditure[19]	Accepted, noting some stakeholders' concerns around how DER is valued.
Non-network expenditure	Accepted, noting one non-network IT project was excluded from our initial proposal's forecast.
Capitalised overheads	Accepted our methodology, and forecast updated for changes in direct capital expenditure.
Real cost escalation	Modelling adjustments consistent with the AER's operating expenditure draft decision. Final decision to adopt AER's standard approach (average of two consultant forecasts).

4.3 JEN's response to the draft decision

Our revised capital expenditure forecast substantially adopts the draft decision's amounts in most areas, while also incorporating new information for a small number of specific matters. Our forecast capital expenditure for the next regulatory period is $626M ($2021) net ($769M gross), which represents a 3.9 per cent increase in net capital expenditure from the draft decision and a 0.2 per cent decrease from our initial proposal.

We prepared our initial proposal before COVID-19 emerged as a global pandemic, and as such, our initial proposal's capital expenditure forecast did not factor in the effects of COVID-19. We have considered the potential effects of COVID-19 on our connections and (demand-driven) augmentation capital expenditure. Aside from the reduction to connections expenditure reflected in the draft decision, COVID-19 is unlikely to lead to any further material changes in aggregate to our forecast connections or augmentation expenditure, relative to the reductions observed in the AER's draft decision.

4.3.1 Our customers' views considered

Aside from our own assessment, we recognised that our customers' evaluation of the impacts of the COVID-19 pandemic may be different and that their expectations and preferences may have changed since we met them some time earlier. Over October and November, we met with our customers—through our Customer Council and People's Panel—to ask them whether their expectations and preferences have changed as a result of COVID-19. They told us:

- Their need for a reliable electricity supply at home has increased, particularly with an increase in people working from home
- They continued to be concerned about affordability and the impacts on vulnerable customers
- Greening the grid and efficiently integrating DER was still important to them, although some stakeholders have raised questions about how DER should be valued when assessing our Future Grid program.

The outcomes of our engagement are summarised in section 1.2.

Our recent engagement demonstrates that our customers continue to maintain similar views, in comparison to their feedback given to us ahead of the initial proposal, in terms of how we should balance the elements of the energy trilemma.

Based on this feedback, our revised proposal's capital expenditure forecast reflects only minimal changes to

> "My reliance on the network was even more critical at this time as I was unable to attend the office to perform my work"
>
> *A People's Panel member*

[19] This category represents our Future Grid program.

our initial proposal and the AER's draft decision and therefore keeps us well-placed to deliver on the recommendations our Panel made and other feedback our customers have provided.

> "The last year has demonstrated how important it is to move quickly now to greener energy"
>
> *A People's Panel member*

In particular, our revised capital expenditure forecast recognises customer views on affordability by reflecting a lower-cost approach to meeting our bushfire mitigation obligations in the Coolaroo area. Our forecast also continues to incorporate our Future Grid program, and we have examined the impacts of various DER valuations on our proposed activities.

4.3.2 Our revised proposal

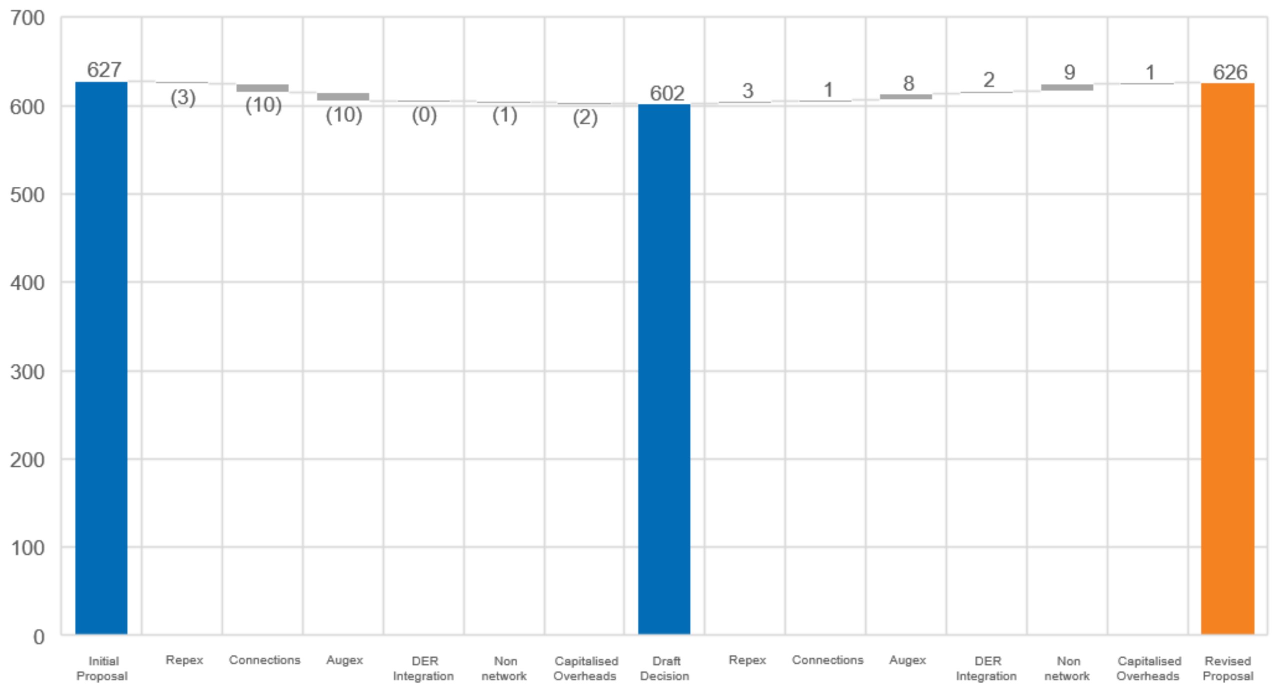
Our revised proposal largely accepts the AER's draft decision. We have considered the impacts of the COVID-19 pandemic, our customers' preferences and regulatory obligations, and developed this revised capital expenditure proposal taking these factors into account. We summarise the key elements of our revised capital expenditure forecast by key issue in Table 4.2 below.

Table 4.2: Summary of our revised capital expenditure forecast

Item	JEN response	Comment
Replacement expenditure	Accept	For this item, we accept the forecast from the draft decision
Connections expenditure	Accept, with updates to be made	Accept the draft decision's forecast, however the AER should update its adjustment to reflect latest Housing Industry Association forecasts; no further material downward impacts on net expenditure
Augmentation expenditure	Accept	Traditional augmentation expenditure – we consider likely aggregate impacts of COVID-19 on our forecast are not material, and therefore accept the forecast from draft decision
	Accept with updates	REFCL augmentation expenditure – new information and forecasts are provided in this revised proposal
DER integration expenditure	Accept with updates	We have considered the impacts of a wide range of DER values, and consider that our proposed program remains in customers' long-term interests. We maintain the forecast from the draft decision
Non-network expenditure	Accept with an updates	We accept the forecast from the draft decision, subject to the addition of one previously omitted non-network IT project
Capitalised overheads	Accept	Accept the methodology. Our forecast was updated for changes in direct capital expenditure
Real cost escalation	Accept with updates	Updated to reflect AER's standard approach, consistent with our approach used in our operating expenditure forecast

The net outcome from the above responses is outlined in Figure 4.1.

Figure 4.1: Outline of our revised capital expenditure forecast by category ($2021, $M)



In Table 4.3 we outline our revised capital expenditure by category for each year of the next regulatory period.

Table 4.3: Our revised proposal capital expenditure forecast by category ($2021, $M)[20]

Capital expenditure category	FY22	FY23	FY24	FY25	FY26	Total
Replacement	46.1	41.1	40.3	41.1	42.5	**211.1**
Connections	26.9	41.6	43.9	45.3	41.4	**199.1**
Augmentation	35.4	49.6	24.8	15.0	6.9	**131.8**
DER integration	5.6	4.0	8.5	7.1	5.2	**30.4**
Non-network	34.0	22.8	19.6	19.7	10.4	**106.6**
Capitalised overheads	17.8	19.1	18.1	17.8	17.3	**90.1**
Gross capital expenditure	**165.8**	**178.2**	**155.2**	**146.0**	**123.9**	**769.1**
Capital contributions	(22.0)	(29.8)	(30.7)	(30.6)	(29.5)	**(142.6)**
Asset disposals	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	**(0.5)**
Net capital expenditure	**143.6**	**148.4**	**124.4**	**115.3**	**94.3**	**625.9**

4.4 Attachments

Further details on our revised capital expenditure forecast are outlined in Attachment 04-01.

20 Equity raising costs are not shown in this table. Equity raising costs are transaction costs that we incur when we raise equity. JEN recognises equity raising costs as capital expenditure within the PTRM and amortises these costs over the life of the assets that they are used to fund. The AER has applied a benchmark approach in its recent regulatory decisions for determining costs for raising equity through dividend reinvestment plans and seasoned equity offerings. These costs have been forecast using the AER's approach contained in the PTRM included in our revised proposal.

5. Operating Expenditure

5.1 Operating expenditure

We incur operating expenditure to operate and maintain our network, a key aspect of providing standard control services. Our operating expenditure reflects the costs of activities such as clearing vegetation around electricity infrastructure, responding to faults and emergencies, providing a range of customer services, inspecting our assets to ensure they remain safe and the administrative activities which support our provision of services.

As a part of the price reset process, we must develop a forecast of our operating expenditure for the next regulatory period. In our initial proposal, we adopted the AER's preferred approach to forecasting operating expenditure, known as the 'base, step and trend' method, as outlined in the AER's Expenditure Forecast Assessment Guideline.

Taking this approach, we established:

- Base year – using the 2018 calendar year (**CY**) as the efficient base year, noting this year had the lowest operating expenditure of any year during JEN's current regulatory period
- Step changes (including specific forecasts) – we identified several step positive changes relating to changing external obligations and factors, including public liability insurance premiums (attributed to bushfires), cyber security and debt raising costs
- Trend – we incorporated forecasts of real price escalation, increases in the scale of our network and productivity improvements.

In total, our initial proposal forecast was $577M ($2021) for standard control services operating expenditure during the next regulatory period.

Subsequent to submitting our initial proposal—and prior to the draft decision being released—JEN was able to confirm the realisation of further efficiency improvements, stemming from a business transformation program. In light of our customers' continued concerns around energy affordability, we proposed an update to our initial proposal (updated initial proposal), offering an additional $20M reduction for our expected savings over the next five years relative to our initial proposal.

Through our transformation program in 2019, we expect to realise $20M over the next regulatory control period. We proposed to pass these savings through to our customers by reducing our operating expenditure forecast.

5.2 Draft decision

In the draft decision, the AER adopted an alternative operating expenditure forecast of $500M ($2021) (including debt raising costs). This amount is 10.6 per cent lower than the $559M ($2021) of operating expenditure we proposed in our updated initial proposal.

The draft decision's operating expenditure was lower than our updated initial proposal primarily due to concerns with:

- our base year efficiency, driven by the AER's benchmarking analysis
- changes to real price escalation, driven by the expected effect of the COVID-19 pandemic on labour prices
- scale escalation, driven by a range of factors, including the weights coming from the AER's benchmarking models.

The draft decision's positions on key components of our operating expenditure forecast are outlined in Table 5.1.

Table 5.1: Key components of the draft decision operating expenditure

Draft decision item	AER position
Base year	
Selection of base year	The AER accepted the use of CY18 as an appropriate base year.
Efficiency adjustment to base year	The draft decision made a 15 per cent negative adjustment to JEN's estimated final year operating expenditure, informed by the AER's benchmarking analysis. This adjustment was also applied to JEN's newly expensed corporate overheads that were previously capitalised. Partially offsetting this adjustment is a step change glide path designed to provide a ramp down in operating expenditure to meet the FY26 target.
Trend	
Input cost trend	The draft decision departed from the AER's standard approach of utilising an average of two labour price forecasts. The AER opted instead to using a single forecast from a consultant engaged by the AER. The reasoning for this change in approach is that the JEN's forecast did not incorporate the expected economic impacts of the COVID-19 pandemic on future labour prices. The AER stated in the draft decision that it would consider our revised proposal real escalator forecast once submitted.[21]
Output growth trend	The draft decision relied on output weights from multilateral total factor productivity analysis and the four econometric models based on its latest economic modelling. This analysis used 2018 data to determine output growth trend, with the AER then applying updates for forecast residential dwelling construction growth, ratcheted maximum demand and energy throughput.
Productivity	The AER applied an 0.37 per cent productivity rate in FY22 to reflect 9 months of escalation, then a 0.5 per cent productivity rate per annum for each subsequent year of the next regulatory period. This is consistent with the AER's standard approach to forecasting productivity improvements.
Specific forecasts	
Guaranteed service level payments	The AER approved our specific forecast, albeit slightly higher than the amount in our initial proposal due to methodological variances.
ESV distributor levy	The AER acknowledged that this levy payable by JEN would increase in the next regulatory period and is not within our ability to control. However, the draft decision did not provide any allowance or consider alternative mechanisms for recovery of this efficient cost.
Debt raising costs	The AER accepted JEN's estimation approach to determine allowed debt raising costs.
Step changes	
Accepted	The AER accepted our forecast step changes for insurance premiums ($28.2M), REFCL testing and maintenance ($1.3M) and cyber-security ($2.9M).
Not accepted	The AER did not accept our forecast step changes for our Future Grid program ($3.8M), Environment Protection Act changes ($4.2M) and additional regulatory reporting ($0.5M).
Withdrawn	JEN withdrew its forecast step change for transitional return on debt alignment costs ($0.9M) prior to the publication of the draft decision.

21 AER, Draft decision, Jemena Distribution Determination 2021 to 2026, Attachment 6, Operating expenditure, September 2020, p. 6-53.

5.3 JEN's response to the draft decision

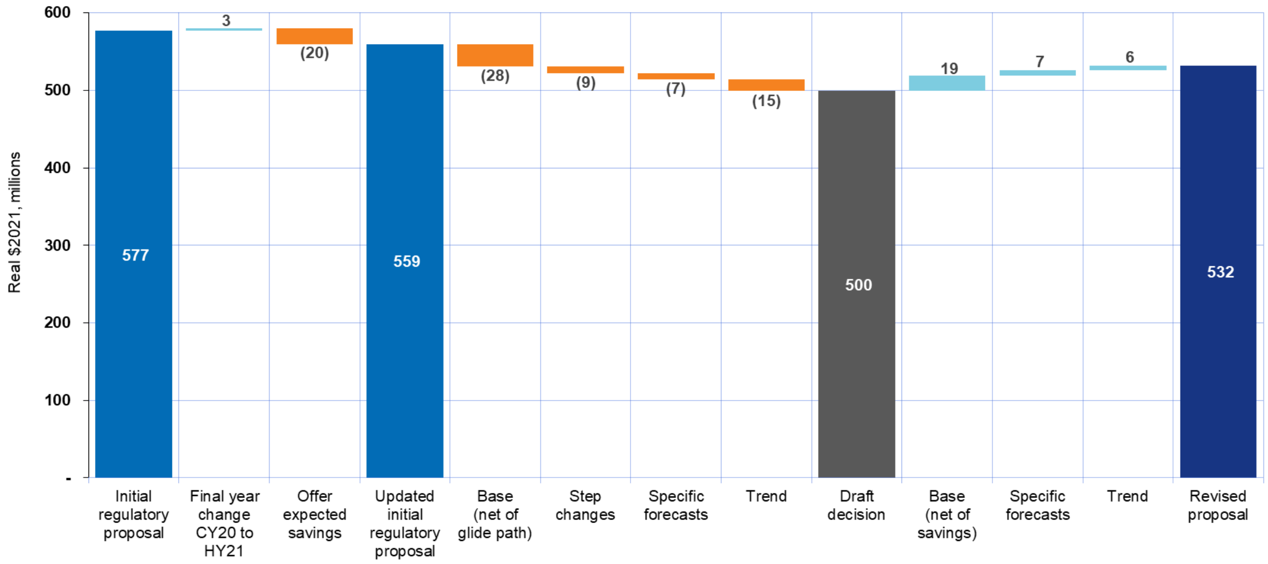
In our view, the AER's draft decision to not accept our operating expenditure forecast for the next regulatory period will result in JEN not being provided with a reasonable opportunity to recover its efficient costs. We are especially concerned that the largest driver of the draft decision's reduction to our forecast—the AER's benchmarking efficiency assessment on our base year—does not take into account significant differences in capitalisation policies between DNSPs and this has negatively impacted the AER's assessment of JEN's base year efficiency.

5.3.1 Developing a revised operating expenditure forecast

We have developed a revised operating expenditure forecast which further addresses the affordability concerns of our customers, but which also provides JEN with a reasonable opportunity to recover our efficient costs. Our revised operating expenditure forecast of $532M ($2021) is a further $27M (five per cent) lower than our updated initial proposal amount ($559M). Our revised proposal operating expenditure forecast also incorporates updates relating to the impacts of COVID-19, as well as updates to some of our step changes and specific forecasts in response to issues raised in the draft decision and external developments.

We outline key changes to our operating expenditure forecast in Figure 5.1.

Figure 5.1: Changes from initial proposal, draft decision and revised proposal ($2021, $M, incl. debt raising costs)



Our revised proposal operating expenditure forecast reflects:

- the AER's draft decision to accept CY18 as the base year—although we have not applied the AER's efficiency adjustment to our base year, we have included a $20M negative step change to reflect our projected efficiency gains from our transformation program (as reflected in our updated initial proposal)
- the AER's standard approach to forecasting input cost growth (which is averaging two available labour price forecasts), factoring in the expected impacts of COVID-19 and the increase in the superannuation guarantee
- the AER's output growth rates on customer numbers, maximum demand and circuit length
- our specific forecast for increases in annual ESV levies, which the draft decision acknowledges represented an unavoidable cost increase

- the AER's draft decision on allowed debt raising costs
- the AER's draft decision on step changes, with an updated forecast for REFCL testing and maintenance to reflect the changes in our approach to complying with these bushfire mitigation obligations.

We have decided *not* to pursue the following step changes, and will seek to absorb these costs or manage their recovery through alternative means:

- Future Grid program – we will instead pursue cost recovery for a portion of these activities through our capital expenditure forecast
- Environment Protection Act changes – we address cost recovery associated with compliance with this new legislative requirement through a nominated cost pass through mechanism
- Additional RIN reporting – we are unable to pursue cost recovery for this cost through any regulatory mechanism and will instead absorb these costs.

5.3.2 Setting base year operating expenditure

Establishing an efficient base year amount is important because it plays the most significant role in setting the operating expenditure allowance over the next regulatory period. In our initial proposal, we used our actual 2018 operating expenditure for establishing the proposed base year amount of $86M ($2021). Our operating expenditure for 2018 was the lowest expenditure for any year of the current regulatory period, meaning it provides the lowest revealed costs for setting operating expenditure in the next regulatory period.

During 2019, we ran a transformation program which identified an annual operating expenditure savings of $4M ($2021) per annum. After submission of our initial proposal (and before making this revised proposal), we offered this additional reduction in our base year to the AER as part of an updated proposal. If accepted, this further adjustment reduces our base year operating expenditure to $82M ($2021) per annum.

In its draft decision, the AER considered our base year operating expenditure proposal[22] and decided that it is inefficient. The AER decided a 15% reduction of our proposed base year amount is an efficient level expected of JEN; this results in our base year amount being adjusted down to $75M ($2021). We understand the AER predominantly relied on its benchmarking analysis to reach this conclusion.

We do not agree with the AER's draft decision, particularly because of the shortcomings in the benchmarking analysis.[23] We have identified several issues with the AER's benchmarking method, , including:

- the benchmarking models do not account for differences in capitalisation policies of all DNSPs
- it relies on the translog models that are prone to significant statistical issues
- it incorporates a vegetation management operating environment factor (**OEF**) adjustment that is calculated using significantly allowance data instead of actual data.

We also note that the most recent 2020 draft benchmarking report has identified errors in the benchmarking modelling spanning back to 2014[24].

Given these issues we do not have confidence that the benchmarking models can be relied upon deterministically as the AER has done in its draft decision for JEN.

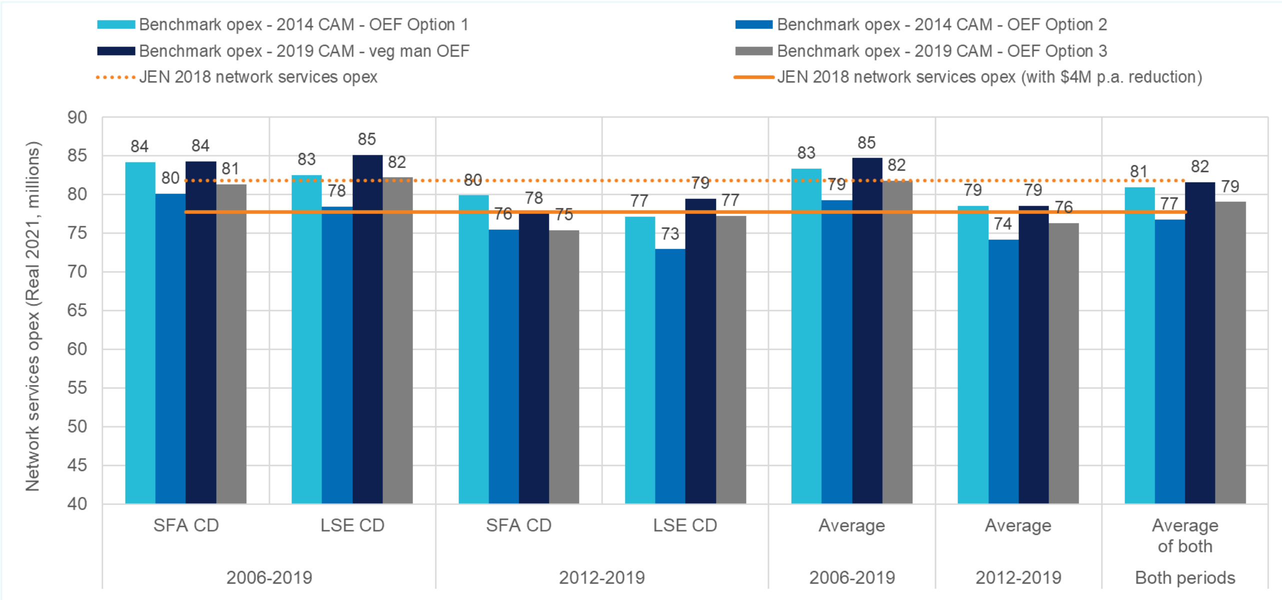
22 Referencing the original base year amount of $86M.

23 We elaborate on our reasoning in Attachment 05-01 and Attachment 05-07.

24 AER, *2020 distribution network service provider benchmarking report (draft)*, November 2020, p. 71-72

We also engaged economic experts CEPA to consider the reasonableness of AER's approach in assessing our base year operating expenditure efficiency. CEPA pointed to several deficiencies in the draft decision analysis and concluded that an OEF must be applied for JEN to take into account capitalisation policy differences between DNSPs. Both CEPA and our analysis demonstrates that our updated base year operating expenditure proposal of $82M ($2021) is an efficient base year amount. In Figure 5.2, we demonstrate this by showing JEN's updated operating expenditure is in line with the broad range of benchmarking models used in the AER's processes to assess efficiency once capitalisation differences are accounted for.

Figure 5.2: JEN's base year operating expenditure compared to AER benchmark



Given this analysis, we maintain that $82M ($2021) is an efficient level of operating expenditure for our base year, and this should be adopted in the AER's final decision.

5.4 Attachments

Further details of our revised operating expenditure proposal are outlined in Attachment 05-01.

6. Incentive Schemes

6.1 Incentive schemes

Incentive schemes are included in the regulatory regime to provide a continuous incentive for DNSPs to reduce costs whilst maintaining the quality of service, and to provide for a fair sharing of resulting benefits between DNSPs and customers. This approach is in keeping with the regulatory regime set out in the National Electricity Law (**NEL**),[25] which seeks to promote economic efficiency with respect to direct control services.

The incentive schemes identified in the F&A paper that could apply to JEN in the next regulatory period are outlined in Table 6.1 below.

Table 6.1: Incentive schemes available to a DNSP in providing standard control services

Incentive mechanism	Included in the building block model	Operate outside of the building block model
Efficiency Benefit Sharing Scheme	✓	
Capital Expenditure Sharing Scheme	✓	
Service Target Performance Incentive Scheme (**STPIS**)		✓
Demand Management Incentive Scheme (**DMIS**)		✓
Demand Management Incentive Allowance Mechanism	✓	
Small Scale Incentive Scheme / Customer Service Incentive Scheme	n/a	n/a

Historically JEN has responded well to these incentives achieving positive results, which in turn delivers positive outcomes for our customers through lower long term costs. JEN continues to support the use of incentive schemes as a means to achieve the intent of the incentive regime. We consider having all of the available schemes balance competing interests between costs and services, and therefore achieve the best outcomes for customers.

Incentive mechanisms work for the long term interest of customers. In this revised proposal, our customer's benefit by $124M under the CESS and more than double JEN's portion ($25.1M) of the EBSS

In our initial proposal, we sought to include revenue adjustments for the EBSS, CESS and DMIAM schemes in the PTRM for the next regulatory period. The revenue adjustments are outlined in Table 6.2 below.

Table 6.2: Proposed incentive mechanism revenue adjustments in initial proposal [5 year totals] - ($2021, $M)

Incentive mechanism	Revenue adjustment(1)
EBSS	23.6
CESS	25.6
DMIAM	2.0
Total	**51.2**

(1) Positive values represent an increase in the revenue requirement.

We also sought to include the same incentive schemes that were applied in the current regulatory period, into the next regulatory period.[26]

25 NEL, section 7A(3).

26 We chose not to include the new Customer Service Incentive Scheme (**CSIS**) on the basis that our customers did not support the approach. Despite the absence of the CSIS, we will continue our focus on providing customer services as is expected.

6.2 Draft decision

In its draft decision, the AER considers the various incentive schemes available to JEN. It considered:

- The revenue adjustments applicable in the building block model for the next regulatory period which is attributed to JEN's performance in the current regulatory period (these include the EBSS, CESS and DMIAM incentive schemes), and
- Whether a particular incentive mechanism should apply to JEN in the next regulatory period.

For those schemes in operation during the current regulatory period that provide revenue adjustments outside of the building block model—that is, revenue is adjusted through the annual pricing proposal—then those adjustments have already been captured within the actual revenues recovered.

6.2.1 Revenue adjustments in the building block model

In its draft decision, the AER considered the materials submitted to make a decision on the revenue adjustments in the building block model for standard control services.

- EBSS - The AER approved EBSS carryover amounts accrued over the current regulatory period. The amount of revenue adjustment in the draft decision was higher than in the initial proposal due to updates of actual CY19 data and due to other changes in WACC
- CESS – The AER had several inquiries of JEN to obtain a better understanding the capital efficiency. This, combined with updates to CY19 data, resulted in an increase of CESS revenue adjustment in the building block model
- DMIAM – The AER accepted our proposed allowance. With the introduction of the AER's amended demand management incentive allowance mechanism,[27] the allowance afforded to JEN effectively doubles the allowance in the current regulatory period.

We summarise the outcomes of the revenue adjustments in the building block model in Table 6.3 below.

Table 6.3: Proposed incentive mechanism revenue adjustments [5 year totals] - ($2021, $M)

Incentive mechanism	Initial proposal	Draft decision
EBSS	23.6	25.1
CESS	25.6	38.3
DMIAM	2.0	2.0
Total	**51.2**	**65.3**

6.2.2 Application of incentives in the next regulatory period

The AER considered the range of incentive mechanism and whether they should apply in the next regulatory period. A summary of the applicable incentive schemes and the draft decision outcomes are listed in Table 6.4.

Table 6.4: Draft decision - incentive schemes for the next regulatory period

Incentive mechanism	Applicable during the next regulatory period
EBSS	The AER set aside EBSS for the next regulatory period because it did not utilise JEN's revealed operating expenditure for setting operating expenditure allowance in next period

27 AER, *Demand Management Innovation Allowance Mechanism, Electricity distribution network service providers*, December2017.

Incentive mechanism	Applicable during the next regulatory period
CESS	AER accepted our proposal to apply the CESS in the next regulatory period
STPIS	AER accepted our proposal to apply the STPIS in the next regulatory period
DMIS	AER accepted our proposal to apply the DMIS in the next regulatory period
DMIAM	AER accepted our proposal to continue to DMIAM in the next regulatory period
Small Scale Incentive Scheme / CSIS	Draft decision acknowledged our approach to not adopting the CSIS on the basis of feedback from our customers

6.3 JEN response to the draft decision

Below, we outline our response to the AER's draft decision with regards to the incentive schemes.

6.3.1 Revenue adjustments in the building block model

We accept the draft decision outcomes for the revenue adjustments in the next regulatory period for performance achieved in the current regulatory period. In our revised proposal, some relatively minor amendments have arisen to the incentive adjustment amounts because of the interaction with updates to WACC parameters.

A summary of our revised proposal revenue adjustments is outlined in Table 6.5 below.

Table 6.5: Proposed incentive mechanism revenue adjustments [5 year totals] - ($2021, $M)

Incentive mechanism	Draft decision	Revised proposal
EBSS	25.1	25.1
CESS	38.3	38.2
DMIAM	2.0	2.0
Total	**65.3**	**65.2**

Our revised incentive forecast for the next regulatory period is $65M, which is approximately $0.07M lower than the AER's draft decision, and $14M higher than our initial proposal.

6.3.2 Application of incentives in the next regulatory period

Regarding incentive mechanisms, we agree with the approach adopted, other than the approach on the EBSS. EBSS should apply during the next regulatory period as this gives balance to the range of incentives and aligns with expectations our customers. We do, however, understand the AER's practice of not applying an EBBS and instead implementing ab operating expenditure glide path approach in circumstances where the AER has not used a revealed cost approach to setting the base year operating expenditure allowance.

6.4 Attachments

Further details on our revised approach to incentive schemes are outlined in attachment 06-01 of this revised proposal.

7. Control Mechanisms

7.1 Control mechanisms

As a regulated entity, JEN's prices and revenues are subject to strict controls to ensure the revenues we earn are not more than is approved in the price reset process. We apply these controls for each year during the next regulatory period and demonstrate to the AER—through the annual pricing process—how we comply with these controls.

The control mechanisms themselves give us a degree of freedom to change our tariffs to allow us the opportunity to respond to incentives—as is permissible under the incentive framework. They also allow us to adapt our tariffs dynamically, to respond to evolving market conditions and send more efficient price signals to our customers over time.

Having a rigorous framework for setting prices helps our customers. Our customers have told us that they value consistency and certainty in their bills.[28] They told us they manage budgets and that they could do this better if they knew what was coming up. Whilst most of the bill impacts are driven by x-factors, the revenue and price control formula also contributes to the stability in prices and bills from year to year. Having these formulae prescribed at the commencement of the next regulatory period gives our customers confidence and certainty around the process for setting prices.

7.2 Draft decision

The AER's draft decision outlined its approach to setting allowable revenues and prices for the next regulatory period. As a part of this decision, the AER outlined how it would implement the controls for setting prices and revenues. The draft decision largely adopts the previous practices for setting revenues in the current regulatory period.

7.3 JEN response to the draft decision

We agree with most positions taken in the AER's draft decision. However, we made two changes as part of this revised proposal. These are:

- expanding the items within the B factor to account for the likelihood that market participant fees will be imposed by the Australian Energy Market Operator during the next regulatory period on DNSPs and metering participants including JEN
- the inclusion of a margin component in the price cap formula for quoted services given the identical circumstances that led to this allowance being approved for other DNSPs.

The price cap formula we propose to apply to our quoted services as set out a below.

$$Price = Labour + Contractor\ Services + Materials + Margin$$

We note that the F&A paper is binding on the price reset process, and deviations can only be adopted if there is a material change in circumstances. Concerning the two issues noted above, we believe the materiality threshold is satisfied for these items.

Other than these adjustments, we have adopted (i) the control mechanisms and (ii) the unders and overs account approaches to setting prices, as set out in the AER's draft decision.

[28] JEN, *2021-26 Electricity Distribution Price Review, Regulatory Proposal, Attachment 02-04, Reconvening the Jemena People's panel*, 31 January 2020. Section 3.1

7.4 Attachments

Further details on our approach to establishing revenue and price controls, including managing:

- side constraints from standard control services and smart metering services, and
- our approach to trueing up revenues for standard control services, smart metering designated pricing proposal charges and jurisdictional cost recovery charges

are outlined in Attachment 07-01 of this revised proposal.

8. Pass Through Events

8.1 Pass through events

Cost pass-through events are specific activities or events which, if they occur, could cause significant disruption to a DNSP. The cost pass through regime in the National Electricity Rules (**NER**) allows a DNSP to apply to the AER to recover the consequential costs incurred, or expected to be incurred, in managing the DNSP's response to a relevant event.

The cost pass through regime is a balanced way to share the risk of low frequency / high impact events between DNSPs and customers. A clearly defined cost pass through framework improves customer understanding of how risk allocation operates. Also, with our customers telling us affordability is essential to them, using the cost pass through regime to displace capital and operating expenditure is effective in lowering costs to customers most of the time.

The cost pass through events that apply in a regulatory control period are:

- the events specifically outlined in the NER, and
- if nominated by the DNSP, other events approved within the relevant price reset determination.

In our initial proposal, we outlined our approach to managing risk and uncertainty.[29] We did this to demonstrate that we are a prudent business and to show that we take these matters very seriously—especially because of the high-risk exposure that JEN faces every day. While risk management is a broad business activity, we placed a particular emphasis on the nominated cost pass-through events.

With the growing uncertainly brought about with the summer bushfires of 2019/20, the COVID-19 pandemic and a growing rate of change in legislative requirements, managing risk and uncertainty through the appropriate mix of management practices, insurance and the cost pass through mechanism, is more critical now than ever before.

8.2 Draft decision

In its draft decision, the AER considered the pass-through events we nominated along with the conditions attached to them. The draft decision accepted some of our nominated events, either without amendment or subject to amendments and rejected others. For the most part, we agree with the AER's draft decision findings. However, in some specific areas, we seek further changes as outlined in this response proposal.

We summarise the AER's draft decision on cost pass through events, and JEN's response, in Table 8.1.

8.3 JEN response to the draft decision

In this response to the AER's draft decision, we:

- seek some relatively minor further refinements to clarify the intent of particular events
- propose an additional cost pass through event, in response to an emerging area of risk, arising from the commencement of new environmental protection legislation in Victoria[30]

[29] JEN, *Attachment 07-08, Managing Risk and Uncertainty*, 31 January 2020.

[30] We also seek to nominate this event because our alternative approach to managing part of the cost rise through an operating expenditure step change has been rejected in the draft decision.

- withdraw our proposed insurance premium cost pass through event, subject to the AER confirming in its final decision the draft decision position on our insurance premium operating expenditure step change.

In Table 8.1 we outline each of the nominated pass through events we proposed in our initial proposal and the additional environment protection event. We also provide a summary of the draft decision on each of these nominated events and our response in this revised proposal.

Table 8.1: Summary of the AER's draft decision on JEN's nominated cost pass-through events

Nominated Pass-through event	AER position	JEN response
Insurance coverage event (replaces JEN's 'insurance cap event')	The AER has adopted the approach it took for defining an *insurance coverage event* in its recent determination for South Australian Power Networks. The method largely continues the predecessor insurance cap event, however now addresses gaps in insurance cover, as well as the insurance cap	**Accept** – we accept the AER's decision to implement an *insurance coverage event.* However, we consider that some minor drafting amendments will give greater clarity for Victorian electricity distribution businesses
Insurer credit risk event	The draft decision accepts our nominated pass through event without modification	**Accept** – no modifications
Natural disaster event	The draft decision accepts the intent of our natural disaster event and outlines some amendments	**Accept** – with some drafting amendments
Terrorism event	The draft decision accepts our nominated pass through event without modification	**Accept** – no modifications
Retailer insolvency event	The draft decision accepts the intent of our proposed drafting and outlines some minor amendments	**Accept** – with one minor drafting amendment
Insurance premium event	The AER rejects our proposed insurance premium event	**Accept** – pending no change to the insurance premium operating expenditure step change; we will not pursue this cost pass through event
Environment protection event	N/A	This is a new cost pass through event proposed in this revised proposal. This is being raised in response to impending changes to Victorian environment protection laws and regulations.

We have proposed some relatively minor wording changes to previously nominated events. In broad terms, these are intended to improve clarity and therefore go towards creating greater confidence in the application of the regulatory framework.

8.4 Attachments

A detailed explanation of our nominated cost pass through events is outlined in attachment 08-01 of this revised proposal.

9. Alternative Control Services

9.1 Alternative control services

As outlined in section 2 above, the AER undertakes a process of classifying services as part of the price review process. This involves considering that nature of a service provided and the degree of competitiveness or the likelihood of competition. One such service classification is alternative control services. Within this service classification, there are various groups of services that JEN provides, including:

- Smart metering services
- Ancillary services – made up of:
  - fee-based services – where the activities involved are relatively consistent, and
  - quoted services – where activities involved vary from job to job, and
- Public lighting services.

In this revised proposal, we outline the services we seek to classify as alternative control services (see section 2) and the form of price control (see section 7). This chapter focuses on the prices for alternative control services. In putting forward this revised proposal, we respond to the decisions in the AER's draft decision concerning alternative control services and respond to new alternative control services -related issues that have arisen since submitting our initial proposal.

9.2 Smart metering services

In its draft decision the AER accepted various elements that we put forward in our initial proposal, however, did not accept them all. We outline the various issues across each of the sub-types of alternative control services below.

9.2.1 Draft decision

The AER used the standard PTRM model to determine a revenue allowance for smart metering services. This approach is consistent with the method we put forward in our initial proposal and also with the approach used in the current regulatory period. This approach takes various inputs and models a revenue outcome. The AER used the PTRM model in our initial proposal as a starting point and made several adjustments to determine its view on a revenue requirement for the next regulatory period. The key changes are outlined in Table 9.1 below.

Table 9.1: Draft decision outcomes on our smart metering services

Initial proposal	Draft decision
Service types and pricing structure – We proposed to adopt a revenue cap as the form of control in our initial proposal.	The AER accepted the use of a revenue cap as the form of control.
Labour escalation – we used the average of the forecasts from the 2019 DAE and BIS reports in our initial proposal.	The AER used an updated DAE forecast only noting that the BIS 2020 report that included the impact of COVID-19 was not available when the AER prepared its draft decision.
CPI and rate of return	The AER includes an estimate of expected inflation of 2.37%. The AER also noted that it is reviewing the approach to estimating expected inflation in its draft decision. The AER has also accepted our approach for return on debt and equity but updated placeholder inputs to reflect the latest market information

Initial proposal	Draft decision
Customer growth	The AER has updated customer growth to reflect the impact of COVID-19.
Base year operating expenditure	The AER has also replaced the estimate for CY19 operating expenditure with actual as reported in our annual RIN.

As a consequence of these changes in the draft decision, JEN's smoothed revenue for the next regulatory period reduces from $128M ($nominal) to $112M ($nominal).

We note that one of the more significant changes since submitting our initial proposal is the advent of the COVID-19 pandemic. The AER has also identified this issue and has considered the impacts on determining a revenue allowance. In its assessment, the AER has identified the customer growth rates as an area that has been significantly impacted, which is the main reason for making adjustments to this area of our initial proposal.

9.2.2 JEN response to the draft decision

JEN has reviewed the AER's draft decision on smart metering services and accepts many of the changes made by the AER to our initial proposal for smart metering services. There are, however, several updates that we have introduced into this revised proposal. Our position on the changes is outlined in Table 9.2 below.

Table 9.2: Our response to the draft decision on our smart metering services

Draft decision	JEN response
Labour escalation	We **partially accept** the AER's decision. Our revised proposal calculates labour escalation using the average of both DAE and updated BIS forecasts.
CPI and rate of return	We **partially accept** the AER's draft decision. We adopted the same placeholder value for inflation in our revised proposal, which will be updated by the AER in the final decision. Refer to Section 3.4 of Attachment 03-01 for our response to the AER's review into the treatment of inflation. We note that AER will update return on debt annually with our nominated averaging period. We also note that the AER will update our return on equity in the final decision with our nominated averaging period.
Customer growth	We **accept** the AER's draft decision.
Base year operating expenditure	We **accept** the AER's draft decision to update CY19 with actual data.

As a consequence of these changes, the smoothed revenue for smart metering services over the next regulatory period in our revised proposal is $113M ($nominal).

When considering the AER's draft decision for smart metering services, we also undertook a review of the economic and social impacts of the COVID-19 pandemic. We undertook this review in response to our customers' focus on affordability, and also to consider whether the approach the AER took in its draft decision was materially the right approach. Having undertaken a detailed analysis (see Appendix A), we consider the approach to adjusting customer numbers is reasonable. We have also obtained updated information that underpins the approach and note that there has not been any material decrease in those forecasts—in fact, there have been modest increases—and therefore, we do not consider any further adjustments are required.

Our proposed prices for smart metering services are outlined in Table 9.3 below.

Table 9.3: Prices for smart metering services in FY22 - ($Nominal, per meter)

Meter type	CY20 Actual	FY22 Initial proposal	FY22 Revised proposal
Single Phase	79.64	66.39	56.21
Single Phase, Two Element	79.55	66.39	56.21
Three Phase DC	96.60	80.49	68.81
Three Phase CT	107.67	89.77	76.41

9.3 Ancillary services

Ancillary services are those services provided to a particular customer on request. These services can be:

- fee-based – where the activities involved in providing the services are standard in nature, and therefore can be priced using a standard schedule of rates, or
- quoted – where the activities involved can vary significantly from job to job, and therefore, the price for the service can also vary.

Labour rates used in setting prices for both fee-based and quoted services can be the same for the first year of the next regulatory period, however, all other aspects of pricing will vary between fee-based and quoted services.

In our initial proposal we also included a mechanism to increase real labour rates and incorporate these increases in our fee-based and quoted services. We proposed adjusting for these real cost increases annually in accordance with the price control mechanism using a percentage escalator known as an x-factor.

9.3.1 Draft decision

The AER largely accepted JEN's initial proposal fees and labour rates for ancillary services. A summary of the AER's draft decision is outlined in Table 9.4 below.

Table 9.4: Draft decision outcomes on our ancillary services

Initial proposal	Draft decision
We proposed fees for 20 ancillary services, including wasted site visit fees for when we are unable to fulfil the request for reasons beyond our control. Remote special meter read, energisation, and de-energisation services are offered free of charge.	The AER accepted JEN's proposed fees for fee-based ancillary services except for certain connection services fees, customer access to data charge, and requiring JEN to offer a separate price for testing additional meters.
We proposed labour rates for labour categories, including: – Administrative employee – Fieldworker – Technical Specialist – Engineer – Senior Engineer.	The AER accepted JEN's proposed labour rates for Administrative employee, Fieldworker and Technical Specialist, but rejected the proposed labour rates for Engineer and Senior Engineer. For the Engineer and Senior Engineer labour types, the AER replaced the labour rates with estimates of their maximum recommended hourly rates from Marsden Jacob, escalated by the draft decision real labour escalation in FY22.

9.3.1.1 Real price escalation

In terms of escalating prices in subsequent regulatory years of the next price regulatory period, we initially set out to apply the real labour rate escalation used in the standard control services modelling as the basis for increasing prices in real terms. This is the same approach adopted in the current regulatory period and was accepted by the AER in its draft decision, albeit, the actual escalation rates differ to those in our initial proposal.

9.3.2 JEN response to the draft decision

JEN has reviewed the AER's draft decision on ancillary services and accepts many of the changes made by the AER to our initial proposal. There are, however, several updates that we have introduced into this revised proposal. Our positions on the changes are outlined in Table 9.5 below.

Table 9.5: Our response to the draft decision on our ancillary services

Initial proposal	JEN response
We proposed fees for 20 ancillary services, including wasted site visit fees.	We **accept** all of the AER's draft decision fees for our proposed fee-based ancillary services. Further, we clarify 'customer access to data' service is free of charge; and the meter test fee will apply only once.
We proposed labour rates for labour categories, including: – Administrative employee – Fieldworker – Technical Specialist – Engineer – Senior Engineer.	We **partially accept** the AER's labour rates of all the labour categories in the draft decision (noting minor updates for real labour escalation), except for the hourly rate of Technical Specialist. We have included a vehicle allowance in the hourly rate of a Technical Specialist.

In this revised proposal, we have included a vehicle allowance in the hourly rate of a Technical Specialist, as their role requires them to carry out inspection and auditing services in the field. Not including a vehicle allowance to the hourly rate of a Technical Specialist would not allow JEN to recover its efficient costs. This cost treatment is consistent with the way JEN allocates cost in its approved Cost Allocation Methodology document.[31]

A summary of the labour rates we propose in this revised proposal is outlined in Table 9.6.

Table 9.6: Comparison of draft decision labour rates and JEN's revised proposal - ($2021)

Labour category[(1)]	AER's draft decision maximum total hourly labour rates	JEN's revised proposal total hourly labour rates[(2)]
Administration	91.05	90.75
Field worker[(3)]	155.06	154.55
Technical specialist[(4)]	142.39	163.61
Engineer	150.69	151.50
Senior engineer	197.05	198.11
Field worker (*after hours*) [(3)]	236.00	235.23

(1) Maximum total hourly labour rates, including on-costs and overheads for FY22.

[31] JEN, *Cost Allocation Methodology*, 29 March 2019, see Table3-2, fleet operating costs.

(2) Our rates are different from the AER's draft decisions following updates to labour rate escalation between CY19 and FY22.[32]
(3) In our initial proposal we included a vehicle allowance in the labour rates for 'Field worker'. The AER accepted the vehicle allowance in the draft decision.
(4) JEN's revised proposal hourly labour rate for 'Technical specialist' includes a vehicle allowance (the allowance was not included in our initial proposal or in the AER's draft decision).

A summary of the prices we propose for the connection services we provide are outlined in Table 9.7 below.

Table 9.7: Revised proposal fee-based ancillary network services prices FY22 - ($2021)

Proposed fee-based services	Business Hours (B/H)	After Hours (A/H)	Wasted site attendance (B/H)	Wasted site attendance (A/H)
New basic connection, single-phase (up to 100 Amps)	555.73	735.53	464.96	642.19
New basic connection, three-phase (up to 100 Amps)	684.55	864.35	464.96	642.19

Source: *JEN – 09-11M ACS Fee Based Services Model – 20201203 – Public*

Refer to Attachment 09-01 for a full list of alternative control services and our revised proposed prices.

9.3.2.1 Real price escalation

We accept the draft decision methodology for escalating prices in real terms by using a real escalator. However, for reasons set out in section 5, we propose a different set of escalators to those used by the AER in its draft decision. Our revised proposal real escalators for ancillary services is outlined in Table 9.8.

Table 9.8: Revised proposal X-factors for ancillary network services FY23 to FY26 (per cent)

Factor	FY23	FY24	FY25	FY26
X-factor(1)	-0.4961	-0.6513	-0.9935	-1.3075

Source: *JEN – 09-10M ACS Quoted Services Model – 20201203 – Public*

(1) A negative value represents a real *increase* in prices.

9.4 Public lighting services

Public lighting services include:

- New public lighting installation – for these services we apply charges under the ancillary quoted charges approach. (Refer to section 9.3)
- Operation Maintenance and Replacement (**OM&R**) services – for these services, we calculate a set of prices based on a limited building block model. Prices are determined based on the light type installed and are charged to local councils and VicRoads.

9.4.1 Operation Maintenance and Repair services

In our initial proposal we applied the limited building block model used in setting price for the current regulatory period and updated the model inputs based on:

[32] The AER retained the labour escalation rates from our initial proposal to escalate hourly labour rates from CY18 to FY22 in *AER - Draft decision - Jemena distribution determination - 2021–26 - ACS Quoted Services Model - September 2020* for all labour categories apart from 'Engineer' and 'Senior engineer'. In this revised proposal we have replaced these with updated labour rates, see Table 9.1.

- feedback from our customers
- changes in technology
- introduction of the Minamata standard, which seeks to reduce the amount of mercury imported into Australia
- general updates to labour and material costs

9.4.2 Draft decision

The AER made several adjustments to the public lighting limited building block model. These adjustments include:

- minor changes to the initial proposal public lighting model itself
- updating the WACC, CPI and wage growth assumptions
- the unit cost of LED luminaires
- labour rates
- the number of repairs performed in a day

9.4.3 JEN response to the draft decision

We partially accept the draft decision. We accept the changes made to the modelling inputs for LED unit costs and labour rates, however, we do not agree with the estimate for the number of repairs performed in a day, nor the approach to deriving the amount.

We have also made updates to WACC, CPI and wage growth based on more current information as outlined in section 3.

JEN has undertaken a comprehensive analysis on the number of lights that can be repaired each day, and found that the amount substituted by the AER into JEN's public lightning model is at around 50% more than can be safely and efficiently replaced each day (we elaborate on this in Attachment 09-01).

A summary of the prices in this revised proposal for the main light types are outlined in Table 9.9 below.

Table 9.9: Price for the most common light type for FY22 ($Nominal, dollars)

Light type	Price per light
Mercury Vapour 80 watt	$57.43
Sodium High Pressure 150 watt	$120.92
Sodium High Pressure 250 watt	$123.74
Sodium High Pressure 100 watt	$165.66
T5 (2 x 14 W)	$61.36
LED 18W (incl. other standard Category P LED variants)	$28.13
Compact Fluoro 32W	$58.18
L1 - LED 70W	$53.26
L2 - LED 118W, 155W, 162W	$53.80
L4 - LED 275W	$58.62

See Attachment 09-01 for a full list of light types.

9.5 Attachments

Further details on our revised proposal approach for setting prices for alternative control services is provided at Attachment 09-01.

10. Negotiated Services

10.1 What is the negotiating framework?

The negotiating framework applies to distribution services which are classified as negotiated distribution services for which JEN must negotiate in good faith with the person requesting the service. JEN has no such services in the next regulatory period. However, the NER requires it to have a negotiating framework, nonetheless.

The framework sets out the timeframes for negotiations by the service applicant and JEN, pricing principles, payment of our costs incurred in the provision of the service, confidentiality treatments of the commercial information exchanged, the publication of negotiation results, dispute resolution and giving of notices.

10.2 Draft decision

In the draft decision on negotiated distribution services framework and criteria,[33] the AER noted that the NER requires the AER to make decisions on the negotiating framework to apply to JEN[34] and a decision on the negotiated distribution service criteria.[35]

Further, the AER noted that while the draft decision does not include any services to be classified as a negotiated distribution service, these constituent decisions are required regardless of our classification decisions.

The AER's draft decision is to accept JEN's proposed negotiated distribution services framework[36] outlined in the initial proposal and apply the negotiated services criteria published for consultation in February 2020[37] to JEN.

10.3 JEN response to the draft decision

We accept the AER's draft decision on negotiated services framework and criteria. We did not consult customers about this element of our revised proposal because it is of no consequence to them during the next regulatory period in light of there being no negotiated distribution services.

10.4 Attachments

Our negotiated distribution services framework is provided in Attachment 10-01 of this revised proposal. For the avoidance of doubt, this document is the same as submitted in the initial proposal.

33 AER, *Draft Decision, Jemena Distribution Determination 2021 to 2026, Attachment 17 Negotiated services framework and criteria,* September 2020.

34 NER, cl. 6.12.1(15).

35 NER, cl. 6.12.1(16).

36 JEN, *2021-26 Electricity Distribution Price Review, Regulatory proposal, Attachment 07-10 Negotiating Framework*, 31 January 2020.

37 AER, *Proposed Negotiated Distribution Service Criteria for Victorian Electricity Distributors, Regulatory Control Period 1 July 2021,* February 2020.

11. Connection Policy

11.1 Connecting to JEN's distribution network

JEN's connection policy assists our customers by outlining a clear process for making a connection to our shared distribution network. The connection policy outlines:

- our connection services
- the circumstances in which a retail customer or real estate developer may be required to pay a connection charge to Jemena in respect of connection services, and
- how those charges are calculated.

Under the NER,[38] JEN is required to submit a connection policy in its regulatory proposal for the next regulatory period. Accordingly, JEN submitted a connection policy in the initial proposal, which is to apply from 1 July 2021 to all new or modified connections.

We prepared the connection policy in accordance with Part DA of chapter 6 of the NER.[39] It has also been prepared in accordance with the:

- connection charge principles set out in Part E of Chapter 5A of the NER, as applied in Victoria
- connection charge guidelines[40] for electricity retail customers published by the AER, and
- consistent with the AER's classification of connection services in final F&A for the Victorian DNSPs for the next regulatory control period.

11.2 Draft decision

In the draft decision, the AER did not approve JEN's connection policy, noting that it did not contain all the necessary information and contains some conditions that are inconsistent with the AER's connection charge guidelines. In the draft decision, the AER amended our proposed connection policy and included an approved marked-up version of our connection policy.[41] However, the AER did approve our upstream augmentation unit rates noting that our marginal cost for shared network augmentation is reasonable.

11.3 JEN response to the draft decision

We accept the AER's amendments to our connection policy as outlined in Appendix A of the AER's draft decision. In this revised proposal, we submit a connection policy consistent with the version amended in the draft decision, with one minor modification. We no longer propose to add tax to the charge for connection and connection related services that are classified as alternative control services.

11.4 Attachments

Our revised connection policy is provided at Attachment 11-01 of this revised proposal.

38 NER, Chapter 6, Part DA.

39 As applied in Victoria through the *National Electricity (Victoria) Act 2005*, and as amended by the *National Electricity (Victoria) Further Amendment Act 2016*

40 AER, *Connection charge guidelines for electricity retail customers – Under chapter 5A of the National Electricity Rules*, Version 1.0, June 2012.

41 AER, *Draft Decision, Jemena Distribution Determination 2021 to 2026, Attachment 18 Connection policy*, September 2020, p. 9.

12. Tariff Structure Statement

12.1 Tariff structure statement

When submitting a regulatory proposal to the AER as a part of the price review process, we must also submit a tariff structure statement (**TSS**). To develop our TSS we undertook a comprehensive engagement programme with our customers and a broad range of interested stakeholders, including the other four Victorian DNSPs electricity retailers, the Victorian Government and its departments and customer representative groups.

We sought to actively involve our customers and stakeholders in decision making on tariff structures for the next regulatory period. Our role has included framing discussion and providing analysis to explore tariff structure options that meet our customers' preferences and expectations. Our engagement began in November 2017 and covered multiple pricing forums, consultation documents, a vulnerable customer study, research on community perceptions of electric vehicles and customer impact analysis. JEN also discussed tariffs with our People's Panel, who provide a recommendation to move to more cost reflective tariffs.

JEN's TSS explains our proposed tariff structures to apply for the next regulatory period. It is accompanied by our TSS explanatory document (**explanatory document**[42]), which provides the reasons behind why we have proposed the tariff structures and the tariff assignment and reassignment policy we have. The explanatory document includes how we have relied on the feedback we have received from our customers and stakeholders.

Our TSS provides which tariffs are our default tariffs, which tariff options are available, and how we assign and reassign customers. Table 12.1 provides our range of default tariff structures for each tariff class.

Table 12.1: JEN's default tariffs during the next regulatory period

Tariff class	Default tariff structure	Components	Unit	Charging parameter (local time)
Residential	Time of use	Standing charge	$ pa	
		Peak rate	c/kWh	3pm-9pm every day
		Off peak rate	c/kWh	All other times
Small business	Under 40MWh pa - Time of use	Standing charge	$ pa	
		Peak rate	c/kWh	9am-9pm weekdays
		Off peak rate	c/kWh	All other times
	Over 40MWh pa - Time of use Demand	Standing charge	$ pa	
		Peak rate	c/kWh	7am-11pm weekdays
		Off peak rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set at any time using the maximum level of the last 12 months where data is available.
Large business	Summer demand incentive charge - transition[43]	Standing charge	$ pa	
		Peak rate	c/kWh	8am-8pm weekdays
		Off peak rate	c/kWh	All other times

42 See Attachment 12-02.

43 The transition will move the SDIC charge toward cost reflective levels at 0%, 25%, 50%, 75% and 100% over the 5 years of the regulatory period.

Tariff class	Default tariff structure	Components	Unit	Charging parameter (local time)
		Demand charge	$/kVA pa	Subject to minimum chargeable demands as set out in our tariff schedule.[44]
		SDIC	c/kVA/day	4pm-7pm workdays December to March[45]

12.2 Our initial proposal

When submitting our initial proposal for the next regulatory period we sought to provide a balanced position based on the varying views of our stakeholders, but which we also considered best advanced the pricing principles in the NER. Our TSS submitted with our initial proposal outlined:

- for **household customers**, to create a new two-rate time of use (**ToU**) tariff for households with a 3pm-9pm every-day peak period. From 1 July 2021:
  - any household can choose this network tariff via their retailer
  - new connections, customers who upgrade to a three-phase power supply and customers who install solar PV and customers on our legacy ToU tariffs will be assigned to this network tariff by default
  - any customer who chose or has been assigned to this network tariff can move to a single rate or demand network tariff
  - there will be an increase to the fixed charges within our indicative prices as the best means to recover our residual costs without distorting price signals
  - that new ToU tariff would be priced more attractively than our single rate tariff for a typical household customer.

- for our **small business customers consuming less than 40MWh per year**, from 1 July 2021, update our current ToU tariff will be updated to:
  - have a shorter peak window of 9am to 9pm
  - be the default tariff for small business customers consuming less than 40MWh per year.

  We also proposed reassigning small business customers from our legacy ToU tariff onto the new default ToU tariff.

- for our **small business customers consuming over 40MWh per year and our large business customers**, we did not propose any changes to our tariff structures or assignment criteria. However, we indicated we would:
  - change how we measure demand from an ongoing ratcheting approach to a 12 month rolling average
  - for simplicity, move all our peak periods from AEST to local time
  - introduce a new tariff for sub-transmission customers with multiple feeders
  - change how reserve feeder prices are charged, from $/kW to $/kVA.

[44] Maximum demand for the demand charge set 8am-8pm Monday to Friday (local time) using the maximum level of the last 12 months where data is available. Minimum's in customer contract and in tariff schedule apply.

[45] Maximum demand for the SDIC set 4pm-7pm workdays (local time) each month in December to March and reset monthly.

12.3 Draft decision

After careful consideration of our initial TSS and taking on board the feedback of other stakeholders, the AER accepted many elements of JEN's TSS proposal, however they:

- required JEN to introduce tariff choice for large business customers in addition to the proposed default tariff in the form of individually calculated customer (**ICC**) tariffs
- suggested JEN consider:
  - closing the legacy residential ToU tariffs and reassigning those customers to the new ToU and demand tariffs
  - amending peak charging windows for business customers to make these more targeted
  - including a statement on how tariff proposals are integrated with demand management and other initiatives
  - continuing to explore including replacement capital expenditure into estimates of long run marginal cost (**LRMC**)
  - our approach to assigning tariffs for grid-scale batteries.

We have considered these items further within the window available for submitting our revised proposal.

12.4 JEN response to the draft decision

12.4.1 Further stakeholder engagement for the revised proposal

JEN continued to be led by our stakeholder engagement when responding to this aspect of the draft decision.

For our household and small business customers consuming less than 40MWh per year, JEN continued our collaborative engagement with the four other Victorian DNSPs, and following numerous discussions, our positions remain aligned. We updated our analysis for legacy residential customers to understand the bill impacts from CY20 to FY22 under the draft decision and engaged on this with our Customer Council, who recognised the low level of year-on-year customer impacts. We also engaged stakeholders on our approach to recovery of residual revenue from fixed charges and adjusted our position from our initial proposal as a result.

For our large business customers we undertook further engagement on new options for our large business tariff structures with both our Customer Council and via a large business customer survey. We consider our revised TSS reflects a balanced position on what we heard, but perhaps also caters for the fact that we had limited time to reach more customers before submitting this proposal

Finally, we understand that the Victorian Government is re-considering the AMI order in council (**OIC**), which may constrain the tariff options available to some customers. For example, customers who purchase electric vehicle fast chargers may be prevented from being assigned to a single rate network tariff. JEN will comply with any OIC requirements once gazetted, but cannot confirm them as part of this revised proposal.

12.4.2 Outcome

Based on our previous stakeholder engagements and the additional work since the AER's draft decision, our revised proposal includes the following amendments to those described in section 12.2 of this document:

- For household customers:
  - given the small number of customers with bill increases between CY20 and RY22 (around 1% of legacy ToU customers) and the expected low level of the majority of those bill increases, we will assign all legacy ToU tariffs to the new ToU tariff on 1 July 2021. The legacy ToU tariffs will then be removed (see section 3.5.6 of our explanatory document)
  - the assignment criteria have been updated to recognise the need to comply with the yet to be determined OIC (see section 3 of our TSS)
  - we have tempered expected increases in annual fixed charges based on consultation with our Customer Council (see section 3.5.5 of our explanatory document)

- For our large business customers (those consuming over 400MWh per year), we are:
  - changing how we measure demand to a twelve month rolling average and shifting our peak periods to local time
  - reducing our peak window for our usage charges and for setting maximum demand for our demand charge to 8am-8pm weekdays
  - introducing a new tariff component—the summer demand incentive charge (SDIC) with a 4pm-7pm workday peak window over summer months—to better target our summer peaks
  - transitioning to cost reflective SDIC price levels over 5 years to mitigate relative customer impacts, especially given the current economic situation faced by customers due to the pandemic
  - providing the option for customers to immediately choose a tariff with cost reflective SDIC price levels.

The amendments to large business tariffs are detailed in section 5 of our explanatory document, with the new tariff structures stated in section 3 of our TSS.

We have also addressed the following additional items raised by the AER in its draft decision:

- Section 3.4.5 of our explanatory document provides additional explanation of the interaction of tariffs, demand management and DER

- Attachment E of our explanatory document sets out how we incorporate replacement expenditure into our LRMC estimates, noting that this is appropriate under an average incremental approach where the expenditure results in additional capacity on the network

- Section 3 of our TSS outlines that we will offer network tariff exemptions for grid-scale batteries in certain circumstances.

JEN tested the concept of ICCs and potentially passing through location TUoS signals with our Customer Council. Section 5.4.8 of our explanatory document details why we are not proposing ICCs as part of this revised proposal. In summary:

- the improvements proposed to the peak window, and new SDIC tariff component are a substantial step that better targets our peak—and we consider these tariff structures meet the pricing principles within the NER

- the general threshold for other distribution networks with ICC tariffs is consumption greater than 40MWh per year or demand greater than 10MVA per year. We have eight customers who meet these criteria across five tariffs meaning we already have a high degree of targeted tariffs

- there are practical and administrative difficulties to commit to ICCs for the revised proposal, including appropriate consultation, building/licensing/running a new locational pricing model, developing a negotiating framework and increasing internal resources to administer
- we have concerns about making this optional, leading to customers self-selecting the cheapest tariff, which has no associated behavioural change benefit
- our Customer Council was not convinced that passing through TUoS was an appropriate mid-point.

12.5 Attachments

In our attachments, we provide a comprehensive explanation on the journey we have undertaken to finalise our TSS for the next regulatory period and outline the tariff designs.

Our revised:

- TSS is provided at Attachment 12-01
- TSS explanatory document is provided at Attachment 12-02
- TSS indicative prices in Excel format is provided at Attachment 12-03.

Appendix A
COVID-19 pandemic

Forecasting considerations

A.1 COVID-19

Since submitting our initial proposal on 31 January 2020, the world has come to experience a global COVID-19 pandemic. The purpose of this appendix is to outline the impacts of the COVID-19 pandemic on JEN's regulatory proposal and to explain how we assessed its consequences when developing our revised proposal.

Through our detailed analysis, we have identified that the most likely economic scenario occurring since submitting our initial proposal through to the end of the next regulatory period is one with a decline in economic conditions in FY20, the commencement of a recovery in FY21 and then a strong recovery in FY22. This scenario—outlined in Table A.1—is supported by a range of independent economic forecasts.

Table A.1: Forecast economic growth

Economic forecasts	2019-20	2020-21	2021-22	2022-23	2023-24
Victorian Gross State Product	-1.30	-0.80	5.50	3.80	3.00
Australian Gross Domestic Product	-2.35	1.07	4.07	2.80	2.90

Source: See Table A.4

In broad terms, we consider this profile of economic conditions aligns with the implied profile adopted in the draft decision where adjustments were made to our proposed operating expenditure and capital expenditure in FY22 to account for this type of economic profile.[46] Given this, we consider the approach to adjusting connections and metering capital expenditure and real labour rate escalation made in the draft decision for the impacts of the COVID-19 pandemic are reasonable.

A.1.1 Background

The implications of COVID-19 are wide-reaching, stretching the Australian health system and economy. It has disrupted our community, the way our staff and contractors work, and the customers that we serve. In response, the Australian and State Governments have instituted measures to mitigate the harms caused to our community and the economy.

Lockdowns and other measures designed to slow the spread of the virus have been initiated across Australia (including with extended effect here in Victoria), and economic support packages were introduced to help those most impacted by these measures. The Australian Federal Government has introduced a range of policy measures, such as JobSeeker and JobKeeper packages, to help those affected by job losses. Similarly, the Victorian State Government has introduced policy measures to stem the spread of COVID-19 and reduce the negative economic impacts, including a suite of economic recovery measures announced as part of its 2020-21 budget.

Regulators and market operators have also considered the response required by the electricity industry, focusing on:

- Protecting the vulnerable and those impacted by job losses by ensuring the right measures are in place to put customers on hardship programs to reduce disconnection for non-payment.
- In Victoria, the Essential Service Commission of Victoria (**ESCV**) undertook a review "Supporting energy customers through coronavirus pandemic",[47] which put measures in place—focusing on electricity retailer obligations—to bring about these protections.

46 Albeit, using a different technique.

47 ESCV, *Supporting energy customers through coronavirus pandemic, Final Decision*, 24 August 2020.

- The AER released a Statement of Expectations of energy businesses: Protecting customers and the market during COVID-19 also outlining expectations on protecting vulnerable customers.[48]
- Ensuring the electricity system is protected and stable, through market reviews and monitoring.[49]
- Ensuring the competitiveness of the retail electricity market by putting measures in place to provide relief to smaller retailers for potential credit stress arising when their customers are under financial pressure themselves.[50,51]
- Adapting current rule changes to account for market and timing risks. Noteworthy is the deferral of the five-minute settlement rule change[52] and realigning other market reforms.

Our industry has also responded. Through a series of network relief packages, we and other DNSPs have voluntarily provided credit relief—and in some cases debt relief—to our customers via electricity retailers. The relief started with a package coordinated through Energy Networks Australia that carried through the second quarter of 2020. Since then, a voluntary relief package was provided by the Victorian DNSPs that run through until February 2021. This package was disclosed to the ESCV as a part of their consultation process. It was welcomed as a part of that review to play our part in the electricity supply chain.[53]

JEN is also minded to the impacts of our end customers and we have undertaken a range of initiatives to support those impacted by the pandemic:

- In collaboration with our community partners and continuing the theme of strong customer and stakeholder engagement, we hosted the COVID-19 customer hardship forum in June 2020, where we explored the impacts of COVID-19 on customers. Stemming from this program, we developed a range of support measures targeted at doing our part in supporting our customers through the COVID-19 pandemic.
- We are sensitive to the needs of our customers relying on electricity as a part of their daily needs staying at home during lockdown periods or working from home more. Operationally, we have made changes to the way we undertake planned outages. We are only undertaking essential works and communicating more through card drops, SMS notifications and making phone calls to those who are impacted by planned outages. For those who are particularly vulnerable and have critical needs for continuous electricity supply, for example, those with medical equipment in their homes, we offer batteries to ensure a continuity of electricity supply.
- We have introduced a range of more general measures, including bill payment support, no disconnections for customers experiencing financial distress, assistance for life support customers, free over-the-phone home energy advice and energy-saving tips.[54]
- JEN has been transparent with reporting the impacts on the changes in energy usage, reporting to regulatory bodies every week—particularly during the height of the lockdown periods—to inform them of the changes arising.

A.1.2 Government and Economic Stimulus

During recessions, private demand often drops dramatically. However, this may be compensated for, at least in part, by increases in government spending. Since the emergence of COVID-19, Australia's federal and state

48 AER, *Statement of Expectations of energy businesses: Protecting customers and the market during COVID-19*, April 2020, July 2020, and November 2020.

49 https://aemo.com.au/newsroom/news-updates/latest-covid19-demand-impact-summary

50 AEMC, *Rule determination, National electricity amendment (deferral of network charges) rule 2020*, 6 August 2020.

51 This rule change does not apply in Victoria.

52 AEMC, *Rule determination, National electricity amendment (delayed implementation of five minute and global settlement) rule 2020*, 9 July 2020.

53 ESCV, *Supporting energy customers through coronavirus pandemic, Final Decision*, 24 August 2020. pg. 49.

54 https://jemena.com.au/help-and-advice/covid-19

governments have announced significant spending programs that will soften the economic impact of a decrease in private spending.

Government stimulus takes two forms—one is through increased spending, and the other is through reduced revenues (i.e. reductions in taxes). Increases in spending create demand for goods and services while reduced revenues leave more funds in the private sector, enabling an increase in private demand relative to what it would have been if taxation levels were retained. The net fiscal position summarises this.

The green recovery

The coronavirus pandemic has had significant consequences for lives and livelihoods around the world, while also dramatically cutting carbon emissions. In many countries, governments are looking towards recovery, with plans for economic stimulus. The International Energy Agency is among those that have called for a “green recovery” that “builds back better”, by cutting carbon emissions as well as boosting the economy.

Relevantly for JEN, the Victorian government has demonstrated a strong commitment to using existing programs, such as Solar Homes, as a means of delivery economic stimulus, with this expected to continue to drive strong take-up of solar PV by our customers over the next decade.

A.1.2.1 Australian Government

The Federal Government has been responsible for most of the economic stimulus announced up to this date. This includes many programs aimed at softening the impact of COVID-19 induced shutdowns and more recently, economic stimulus to help the Australian economy recover.

Table A.2 shows the impact of the Federal budget response. Fiscal stimulus during FY22 will be $216.1B relative to the fiscal balance forecast in the 2019 budget. This equates to approximately 11.1 per cent of Australia’s Gross Domestic Product (**GDP**).

Table A.2: Impact of the Australian Government’s response to COVID-19 ($B)

	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Fiscal balance (2020 budget)			-96.3	-205.7	-113.3	-94.5	-69.3
Fiscal balance (2019 budget)	-5.3	2.0	8.1	10.4	19.1	9.8	
Fiscal stimulus			104.4	216.1	132.4	104.3	

A selection of the key programs contained in the Federal budget was identified as being driven by COVID-19 and these are shown in Table A.3. Note the periods covered by the expenditure varies between programs.

Table A.3: Federal government key COVID-19 programs

Type	Program	Expenditure
Response	Job Keeper Payment (2020-21 federal budget)	$101B
	Supporting Apprentices and Trainees	$2.8B
	Income Support for Individuals (2020-21 federal budget)	$16.8B
	Boosting Cash Flow for Employers	$20,000-$100,000 / business
	Small and Medium Enterprises Guarantee Scheme	$40B
	Early Release of Superannuation	Up to $20,000/applicant

Type	Program	Expenditure
	Supporting Pensioners	$12B
	Home Builder	$25,000/house
Recovery	Job Maker Hiring Credit	$4B
	Job Trainer Fund	$1B
	Accelerating Personal Income Tax Cuts	$17.8B
	Supporting Business Investment	$31.6B
	Infrastructure Stimulus	$14B

These initiatives will provide broad support across the Australian economy. Some of these programs are also likely to have a direct impact on our customers and how they use our services—for example, the Home Builder program will support the construction of new residential dwellings, which will, in turn, support new connections and alterations volumes. JEN's distribution area covers some of Melbourne's urban growth corridors where many of these new dwellings may be located.

Home Builder will provide eligible owner-occupiers (including first home buyers) with a grant of $25,000 to build a new home or substantially renovate an existing home where the contract is signed between 4 June 2020 and 31 December 2020, and was recently extended until 31 March 2021.[55] Construction must commence within three months of the contract date, helping increase connections volumes in the coming years. Home Builder will complement existing state first homeowner grant programs, stamp duty concessions and other grant schemes, as well as the Commonwealth's First Home Loan Deposit Scheme and First Home Super Saver Scheme.

More recently, the Australian Government released its Modern Manufacturing Strategy,[56] involving a commitment of $1.3B of funding to reinvigorate the domestic manufacturing sector. This is particularly relevant to JEN because the northern and western suburbs of Melbourne have traditionally been the manufacturing belt of Victoria, and investment in an area that has established infrastructure will be the most economic place to spend the funding. Along with direct investment in these industries comes indirect benefits, including benefits to surrounding commercial enterprises and household investment spurred by enhanced employment prospects. Additionally, the Australian Government has announced direct support for the critical local medical and pharmaceuticals sector, entering into a long-term contract commitment with Seqirus (a CSL company) for the domestic supply of influenza and other vaccines. This will lead to Seqirus investing $800M in new vaccine manufacturing plant at Tullamarine Airport business park within JEN's network area by 2026.[57]

A.1.2.2 Victorian Government

In its 2020-21 budget announcement on 24 November 2020, the Victorian Government announced a significant package of expenditures designed to promote growth in Victoria's economy, particularly following the state's second wave of COVID-19 infections. The total package is expected to add $43.9B to gross state product[58] through significant direct investment, incentivising private demand and enhancing the productive capacity of the state's economy via initiatives such as education and skill development.

In addition to the broader impacts of the Victorian Government's support on the state economy, key initiatives and programs announced to date which will directly support the households, businesses and projects within our distribution area include:

55 Australian Government, *Economic Response to the Coronavirus, Homebuilder extension*, 29 November, 2020.

56 Australian Government, *Make it happen, Modern Manufacturing Strategy*, November 2020.

57 https://www.seqirus.com/news/seqirus-will-build-world-class-vaccine-manufacturing-facility

58 Department of Treasury and Finance, Victorian Budget 2020/21, Overview, pg. 4.

- A $191M expansion to the Solar Homes program including, demonstrating the Victorian Government's continued commitment to meeting renewable energy targets. This includes 42,000 additional solar rebates to enable a total of 140,000 households to install solar panels on their roof at no upfront cost over next two years, 15,000 solar rebates for businesses (for the first time) and 17,500 household battery rebates over the next three years. Additionally, the Government will spend $25M to accelerate the adoption of zero emissions vehicles, including rolling out of a fast-charging network for electric vehicles.[59]
- The $5.3B Big Housing Build program for new social and affordable housing, which will commence over 12,000 new dwellings (including 9,300 new social housing dwellings) over the next four years.[60]
- $5B funding (in addition to $5B from the Federal Government) for the construction of the Melbourne Airport Rail link with construction to begin in 2022.[61]
- Facilitating private investment in property developments by identifying priority projects and streamlining planning and approval processes through the Development Facilitation Program.[62]

We expect the economic impacts on JEN's distribution area of some of these initiatives to be above average, particularly due to:

- the opportunities for social and affordable housing construction under the Big Housing Build program are likely to be targeted at our network area, which has higher levels of socio-economic disadvantage. Three of the program's six 'fast-start' sites are located in our distribution network area
- the opportunities for road, rail and other infrastructure projects in this area
- programs such as Solar Homes which have an emphasis on targeting demographic segments, such as rental tenants, which are strong in JEN's distribution area.
- significant parts of the Melbourne Airport Rail link will be located within JEN's network area.

A.1.3 Economic Forecasts

Due to the uncertainty caused by the COVID-19 pandemic, there is a high level of forecast uncertainty for key economic variables. It is also unknown if or when a vaccine will become available, whether new virus outbreaks will require additional lockdowns and what the long-term economic implications of lockdowns may be. Therefore, there are higher than the usual differences between forecasts from different organisations. In comparison, series such as GDP growth rate forecasts in normal times usually differ by less than 0.5 percentage points, and often forecasts are near identical.

The sophistication of forecasting methodologies differs between each forecasting organisation. Simpler models are often linear, and trend based. These approaches are extremely unreliable in the current economic environment. For example, the Australian Bureau of Statistics has suspended publishing trend estimates for all series in the National Accounts as underlying trends cannot currently be calculated.

Table A.4 shows a selection of forecasts for key economic indicators. All values are percentage growth rates.

59 https://www.budget.vic.gov.au/clean-energy-power-our-recovery
60 https://www.vic.gov.au/homes-victoria-delivering
61 https://bigbuild.vic.gov.au/newsfeed/melbourne-airport-rail-to-create-jobs-for-years-to-come
62 https://www.planning.vic.gov.au/policy-and-strategy/development-facilitation-program

Table A.4: Forecasts for key economic indicators

Variable	Source	Date	2019-20	2020-21	2021-22	2022-23	2023-24
Victorian Gross State Product	2020-21 state budget[63]	Nov 2020	-0.25	-4.00	7.75	3.25	3.00
	BIS Oxford Economics[64]	Sep 2020	-4.30	3.10	2.80	3.40	3.30
	Deloitte Access Economics[65]	Aug 2020	0.80	-1.60	6.00	4.70	2.70
	Average		**-1.30**	**-0.80**	**5.50**	**3.80**	**3.00**
Australian Gross Domestic Product	Federal budget[66]	Oct 2020	-0.20	-1.50	4.75	2.75	3.00
	RBA May 2020[67]	May 2020	-1.00	-3.00	6.00		
	IMF[68]	Oct 2020	-4.16^	2.95^	2.80^	2.58^	2.61^
	OECD[69]	Dec 2020	-3.80	3.20	3.10		
	BIS Oxford Economics	Sep 2020	-2.60	3.70	3.70	3.20	3.20
	Average		**-2.35**	**1.07**	**4.07**	**2.80**	**2.90**

^ Calendar year (i.e. 2019-20 = 2020)

Notes:

- The Federal budget GDP forecasts are produced alongside the budget expenditure forecasts so include the expected effect of government stimulus on GDP. The other sources of GDP forecasts may include the effect of government stimulus to varying degrees depending on the methodologies applied by the forecasters.
- The OECD produced two GDP scenarios due to the uncertainty of COVID-19 on economic growth. These are a scenario where a second outbreak is avoided (single-hit scenario) and an alternative scenario in which a second outbreak occurs in most economies towards the end of 2020 (double-hit scenario).

A.1.4 Notes on Economic Recoveries

There are several economic recovery scenarios that may play out for the Australian and Victorian economies.

The COVID-19 recession is different from the typical recessions Australia has experienced over the past century. There is no underlying economic harm; however, there has been a large, temporary forced reduction on both the supply side (forced shutdowns preventing businesses from operating) and demand (international travel ban, stay-at-home orders).

These supply and demand reductions are likely to be temporary. After COVID-19 has been managed or a vaccine developed, the forced shutdowns and stay-at-home orders will be lifted. There may be no fundamental destruction of economic capacity or demand for the products Australia produces.

This is in contrast to a typical recession where, in the period leading up to the recession, capital and labour are typically invested into industries that had fundamental issues, and those resources were often wasted as demand collapsed and were difficult to redeploy, causing a long return to ‘normal’.

63 https://www.dtf.vic.gov.au/2020-21-state-budget/2020-21-budget-overview

64 See attachment 05-02.

65 https://www.aer.gov.au/system/files/Deloitte%20Access%20Economics%20-%20Wage%20Price%20Index%20forecasts%20-%2011%20August%202020_6.pdf

66 https://budget.gov.au/2020-21/content/overview.htm

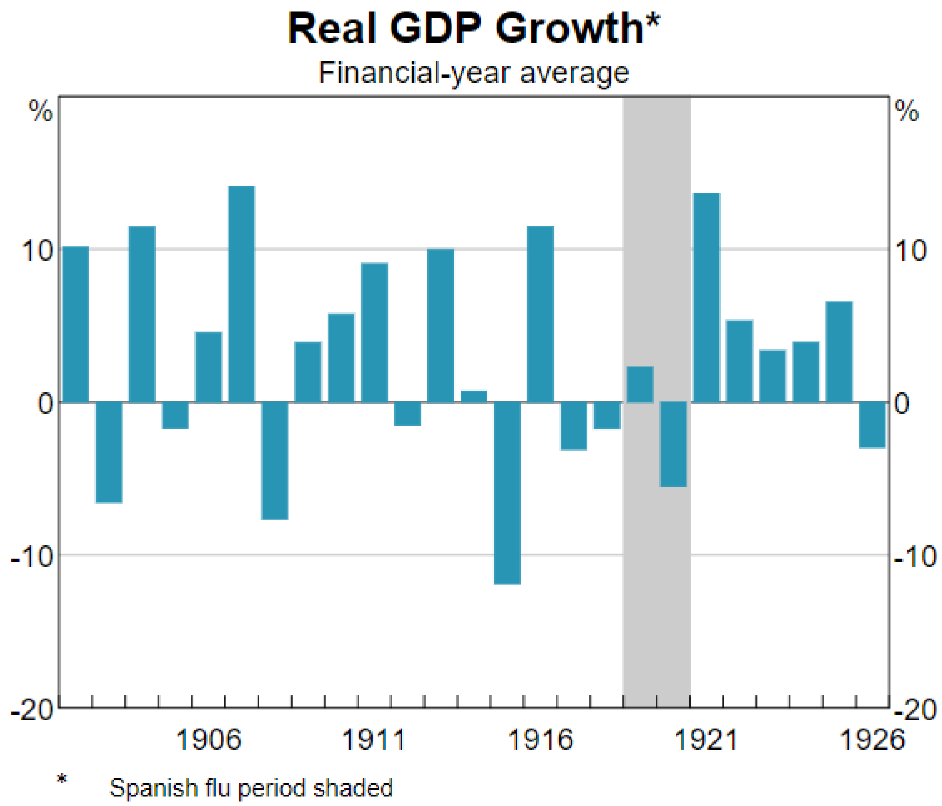
67 https://www.rba.gov.au/publications/smp/2020/may/economic-outlook.html

68 https://www.imf.org/en/Publications/WEO/Issues/2020/09/30/world-economic-outlook-october-2020

69 https://read.oecd-ilibrary.org/economics/oecd-economic-outlook/volume-2020/issue-1_34ffc900-en

The strong economic recovery that has been seen in NSW since the lifting of most lockdown restrictions following the initial 'wave' indicates that a strong rebound is a likely scenario. Rebounds have also been strong in other states although most did not have as significant restrictions as those in place in Victoria and NSW.

The RBA looked at the Australian recovery from the Spanish Flu for signs of what may happen over the coming years. Although challenging to extract the effect of that pandemic from other events such as the end of World War I, the data indicates that GDP recovered strongly.



Source: RBA[70]

The recovery timeline is likely to be directly related to the occurrence of domestic COVID-19 outbreaks and the length of time until a vaccine becomes available and widely distributed. Therefore, the occurrence of further waves may cause a saw-tooth shaped recovery, while slower vaccine availability may cause GDP to recover only partially.

As with any recovery from a major economic shock, there is a possibility that the Australian and global economies partially recover following the development of a vaccine only to collapse shortly afterwards due to the withdrawal of government stimulus, misallocated capital and resources caused by government stimulus or other economic factors that have been hidden by the pandemic and the large government interventions—such as a preponderance of 'zombie' businesses or a property price collapse.

A.1.5 What our customers say about COVID-19

Customers and customer representatives involved in the price review process are acutely aware of the impacts of COVID-19, as many have interactions with our customers on a day to day basis. Through our Customer Council and People's Panel, we heard a range of stories about how COVID-19 is impacting customers; some stories are about hardship and others about prosperity.

70 https://www.rba.gov.au/publications/bulletin/2020/jun/economic-effects-of-the-spanish-flu.html

We also heard customer views through the submissions made to our initial proposal and at the AER's pre-determination conference. For example, at AER's pre-determination conference:

- Energy Consumers Australia (**ECA**) noted the "dramatic impact on the economy."[71]
- the CCP17 sought that we "keep engaging"[72] our customers and that we "embrace uncertainty." [73]
- Brotherhood of St. Laurence, Renew, Victorian Council of Social Services collectively stated that the prior "findings on 'willingness to pay' can't be assumed to necessarily hold"[74] because of the COVID-19 pandemic.

Noteworthy is the timing of these submissions and the level of information contained in them on how to address the impacts of COVID-19 in the price review process. These submissions were received soon after the pandemic emerged, meaning there was little information on which to form robust views on how to implement changes into a draft decision.

Other noteworthy observations are that all customer representatives recognised the COVID-19 pandemic would impact JEN's business; no customer group was silent on this issue.

Most of the feedback from customers and customer representatives recognises that COVID-19 is significant, and that due consideration and adjustment should be made across all aspects of the building block model in JEN's revised proposal.

We have heard the message that we cannot ignore the impacts of COVID-19 in our revised proposal and that we must consider the issues across all aspects of our proposal. We also heard that we must keep engaging with our customers on this particular issue. In response, we reconvened our People's Panel to hear first-hand, the pandemic's impacts on our customers to better shape our revised proposal.

Below, we outline how we have factored in aspects of the COVID-19 pandemic aspects into this revised proposal.

A.1.6 Developing this Revised Proposal

There are many challenges in developing a revised proposal that must consider the economic effects of the COVID-19 pandemic, and the associated risks and uncertainty. To approach this exercise, we have collated information that has become available from a range of sources—albeit, much of it relatively recent—and considered its implications in the building block development process. For example, as discussed further in Attachment 04-01 in relation to our connections capital expenditure, we considered the construction forecasts released by the Housing Industry Association (a key source of information used by the AER in making its draft decision), which appear to show a moderate softening in their view of the negative economic impacts of COVID-19 in updates to the information used by the AER in the draft decision. We also considered forecasts from the Australian Construction Industry Forum and leading indicators from the Australian Bureau of Statistics.

We have also developed several economic scenarios—recognising the uncertainty in the outcomes to identify a plausible, acceptable forecast. This approach means our revised proposal does not reflect any over-investment to account for uncertainty, and instead demonstrates a balanced approach of not asking customers to bear all costs associated with uncertainty.

We bring all this information together to develop a revised building block model to incorporate into this revised proposal.

[71] ECA, *ECA insights on the Victorian Electricity Network Distributor revenue proposals & AER Draft Determination AER pre-determination conference*, 15 October 2020, pg. 17.

[72] CCP17, *Victorian Electricity Distribution Draft Decisions Public Forum*,15 October 2020, pg. 3.

[73] CCP17, *Victorian Electricity Distribution Draft Decisions Public Forum*, 15 October 2020, pg. 3.

[74] Brotherhood of St. Laurence, Renew, Victorian Council of Social Services, *Consumer advocates 2022-2027 EDPR Response to draft determination Electricity Distribution Price Reset*, 15 October 2020, pg. 4.

A.1.6.1 Economic scenarios

The current conditions make developing a forecast for the next regulatory period difficult, economic data that shows the effect of the pandemic is still being collated, and the impact of stimulus packages appears to be highly positive. Nevertheless, we need to establish a forecast based on the best information available to us.

To determine the best set of conditions on which to base the forecasts in this revised proposal, we have identified a range of plausible scenarios that could shape the outcomes on our network. These scenarios are informed by current observations—including observations from the forecasts released in November 2020—and current our understanding of what is happening on the ground based on feedback from our Customer Council and People's Panel.

We outline the plausible scenarios in Table A.5.

Table A.5: Scenario analysis

Scenario	Possible outcome	Implications for our network
Optimistic	Vaccine development is highly effective with accelerated trials, highly effective testing rates (90% effective or greater) and wide distribution.[75, 76] Stimulus packages are effective and create confidence beyond their implementation, which buoys the economy in the medium to long term. Immigration booms. Globally, Australia's handling of the pandemic and strong health care system is seen as leading and attracts strong immigration from overseas. The structural changes have accelerated because of the new ways of working; this introduces new productivity and efficiency while also empowering people to make new choices in seeking work-life balance. The economy grows at an even faster pace than before the pandemic. High levels of general investment are required to keep up with growing demand.	Growth on the distribution network accelerates. The structural changes see a resurgence in local manufacturing as distribution channels are diversified; locally sourced resources reinvigorate the industrial belt that is present in JEN's distribution network, which saw a structural decline throughout the previous decade. Increased interest in people relocating to semi-rural areas (empowered by flexible and remote working arrangements) combined with new commercial and industrial demand sees changes in usage patterns across our network, driving increased investment in new areas not previously anticipated. Migration into JEN's distribution area is strong, particularly in the designated Melbourne growth corridor and the State Government construction of social housing.
Neutral	The stimulus packages achieve their objectives and safe vaccines are distributed globally in 2021, first to wealthy nations, and then to the remaining countries. The economy has taken a hit because of the lockdown programs through 2020 and a continuance of some public health restrictions in 2021. Overall, however, the economy has avoided a deepening and protracted slowdown.	The labour force returns to operating on-premises over an extended time frame, and there continues to be many people working from home. The disruption has created structural changes in the way people live and work, and investments in our network are required to meet these changes. The locations on our network where we need to invest changes as we adapt to evolving customer expectations, trends and behaviours. Immigration recommences in the second half of 2021 with strict health screening protocols in place.

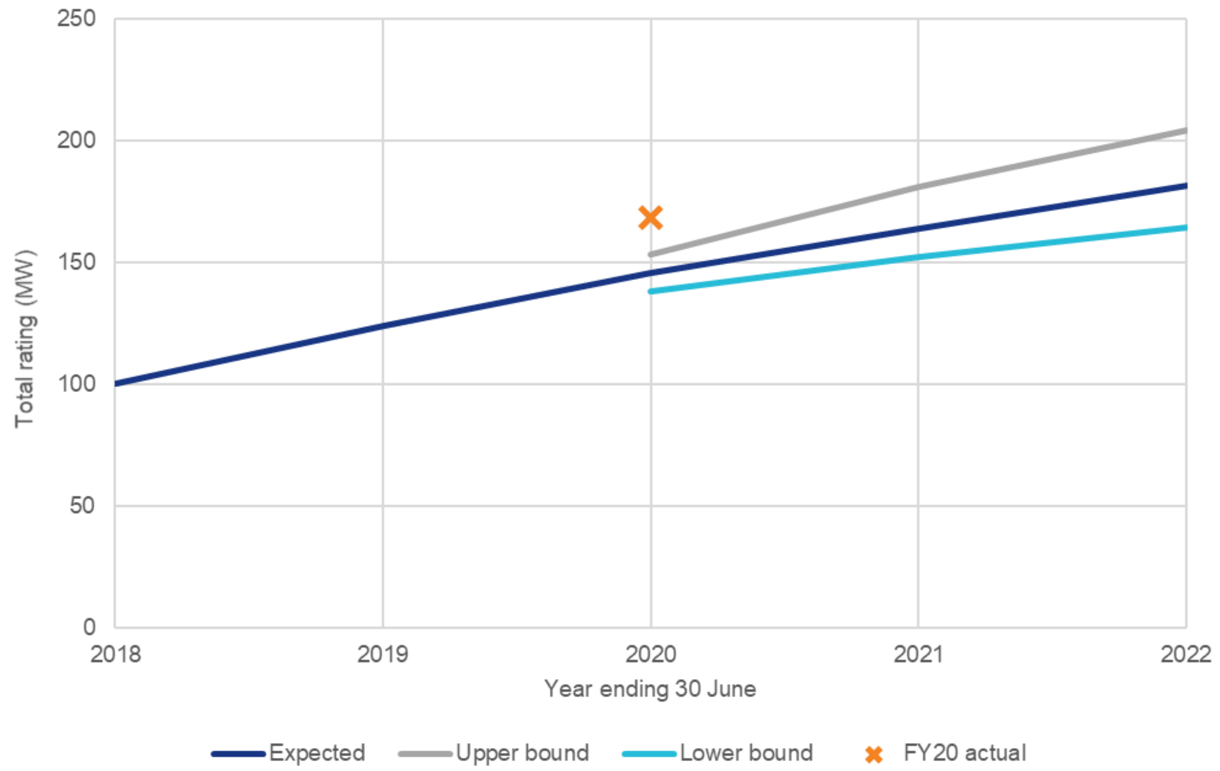
[75] Pfizer, *Pfizer and BioNTech Announce Vaccine Candidate Against COVID-19 Achieved Success in First Interim Analysis from Phase 3 Study*, November 2020.

[76] Moderna, *Moderna's COVID-19 Vaccine Candidate Meets its Primary Efficacy Endpoint in the First Interim Analysis of the Phase 3 COVE Study*, 16 November, 2020.

Scenario	Possible outcome	Implications for our network
Pessimistic	The pandemic has a deeper impact than first thought, and whilst stimulus packages[77] have a strong short-term fix, the effectiveness over the medium term is less than expected. The identification of an effective vaccine is protracted, and the vaccine distribution takes longer than expected; this causes delays to the local and global economic recoveries. Australia's international borders stay closed for longer.	For the most part, the existing network continues to operate as is. Demand across the network varies with businesses operating at reduced levels. With electricity being an essential service, we see net utilisation remain relatively flat across the network. Households may still seek higher levels of reliability as they now depend on electricity for their home-based work activities. We anticipate businesses will also require high levels of reliability. Growth on the network slows – new connections, particularly for businesses, slows and stimulus packages prop up household connections.

In regard to DER we continue to see a strong growth, irrespective of the scenario being considered as customers continue to take their energy needs into their own hands. The population of Photo Voltaic generation, for example, is above our forecasts from just twelve months earlier (See Figure A.1 below). This, combined with strong policy initiatives announced recently, we expect DER penetration to be even higher than outlined in our initial proposal and this outcome will persist across all scenarios.

Figure A.1 Installed residential solar capacity



A.1.6.2 Economic profile adopted in this revised proposal

Predicting the impact on our revised proposal is difficult. When considering the economic data, Government incentive and our customer feedback in determining which of the scenarios would be more plausible, we find that the optimistic and pessimistic options become more like 'guard rails', and that the neutral scenario is the

[77] Stimulus packages support private investment; however, Governments also invest directly into infrastructure projects.

more likely candidate for the future. This does not mean that the neutral scenario is the only way out of the pandemic, it is more that within the guard rails of more extreme cases, it reflects a more balanced view to adopt when developing our revised proposal forecast.

With the information before us, we consider that a scenario that shows a decline in economic conditions in FY20, the commencement of a recovery in FY21 and then a strong recovery in FY22 to be the most plausible scenario. This view is generally aligned to the numerous economic forecasts noted above, and by the strong support issued by various levels of Government to recover as quickly as possible (see Table A.4).

A.1.6.3 Developing this Revised Proposal

We have developed this revised proposal in line with the economic activity and recovery profile noted above. We do this by adopting the approach used by the AER in developing the draft decision, in particular we have focussed on the COVID-19 pandemic impacts. The draft decision has made adjustments to the following areas within our initial proposal that are impacted by the pandemic:

- real escalators in operating and capital expenditure
- connections capital expenditure
- metering capital expenditure.

With some of our investment activity indirectly related to underlying macroeconomic conditions, we need to consider the potential impacts of COVID-19 on the investment in our network. Many stakeholders—for example, the CCP17[78]— make this point in their submissions to the Victorian electricity distribution price reviews, seeking for revised proposals of the Victorian DNSPs to address these changes specifically. The AER has also recognised the implications COVID-19 has on our business, noting “[t]hese forecasts may need to be revisited in light of the impacts of COVID-19 on the economy.”[79]

We have considered the impacts from the COVID-19 pandemic on our business and have factored these into our revised proposal. In some areas of our expenditure forecast, costs are expected to decline marginally, however, in other areas they will increase marginally. In summary, we note the following impacts which are the most significant to our building block proposal:

- **Augmentation capital expenditure** – over time, electricity maximum demand is influenced by economic growth. We have tested our proposed demand-driven augmentation program using revised economic estimates to account for the economic impacts of the COVID-19 pandemic and found that there is no material impact on our augmentation expenditure in aggregate.
- **Connections capital expenditure** – Prior to COVID-19, our connections capital expenditure was growing strongly. We expect that COVID-19 will impact the construction sector (and therefore required connections to our network). Having analysed multiple data sources, we consider that the draft decision’s negative adjustment to our connections expenditure may reflect a more significant slowdown in connections activity than could eventuate. However, we have accepted the draft decision amount as an update to our forecast in this area may not represent a material change in our net capital expenditure.

Other areas impacted include labour price escalation (capital expenditure and operating expenditure), scale escalation (operating expenditure) and smart metering services (capital expenditure).

[78] CCP17, *Advice to the AER on the Victorian Electricity Distributors’ Regulatory Proposals for the Regulatory Determination 2021-26, 10 Jun 2020*, Section 14.

[79] AER, *Issues Paper, Victorian electricity distribution determination, 2021 to 2026*, April 2020, pg. 15.