



# Jemena Electricity Networks (Vic) Ltd

## 2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 05-04

Future Grid investment proposal



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## Abbreviations

AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure
AUGEX	Augmentation expenditure
CAPEX	Capital Expenditure
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DMS	Distribution Management System
DNSP	Distribution Network Service Providers
DSS	Distribution Substation
DPF	Distribution Power Flow
EDPR	Electricity Distribution Price Review
ENA	Energy Networks Australia
ESC	Essential Service Commission
FiT	Feed-in-Tariff
GIS	Geographic Information System
HV	High Voltage, above 1000 volts
JEN	Jemena Electricity Networks (Vic) Ltd
kWh / MWh	KiloWatt-hour / MegaWatt-hour
kW <sub>p</sub> / MW <sub>p</sub>	KiloWatt-peak / MegaWatt-peak
LV	Low Voltage, at or below 1000 volts
NPV	Net Present Value
OMS	Outage Management System
OPEX	Operational Expenditure
PI	Programming Interface
REPEX	Replacement Expenditure
SCADA	Supervisory Control And Data Acquisition
VVC	Volt-VAr Control
WMR	Wholesale Meter Reporting

## Executive summary

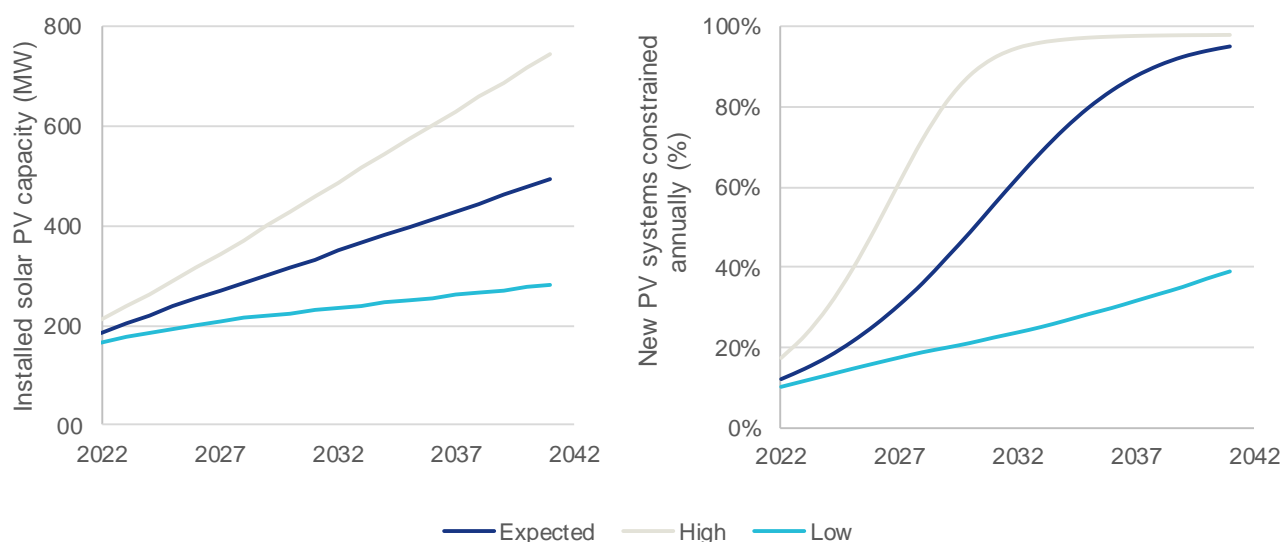
### Expected DER take-up requires a network response to meet customer expectations

Australia's energy landscape is undergoing a significant transformation characterised by the decentralisation, decarbonisation and digitisation of the power system. Australia's electricity distribution networks are at the forefront of this transformation, with traditional operations being challenged by increasing distributed energy resource (DER) – and photovoltaic (PV) generation in particular – penetration and the emergence of bi-directional power flows. However, the pace and scale of this transformation are still subject to significant uncertainties related to technology costs decrease, regulatory and policy response, and customer response and engagement.

One of the critical drivers changing Australia's energy landscape is an increase in customer participation and engagement. This increased 'awareness' is best exhibited by the rise in PV generation uptake as both residential and commercial and industrial (C&I) customers are looking for more reliable, affordable and sustainable energy solutions. In addition to this, customers are becoming more active in their desire to benefit from the opportunities available in electricity markets. Jemena Electricity Networks (Vic) Ltd's (JEN) customers have put forward clear views about the vital role they think Distributed Energy Resources (DER) should play in Australia's future energy system, including that they value (and expect) DER exports to be facilitated by distribution networks.

With limited visibility of our DER hosting capacities today, we are left with little choice other than increasingly constraining customer DER exports to ensure such electricity exports remain within safe and reliable operating limits of the electricity grid. The rate at which customer DER will be constrained is uncertain and varies significantly. Figure 1 shows different forecasts of installed PV capacity and the correspondingly potential for exports to the grid to be constrained. This is resulting in poor outcomes for customers—who expect to be able export excess PV capacity to the grid—as well operation of the efficient electricity market.

**Figure 1: Impact of PV generation forecasts on constrained customer PV systems on JEN's network**



In light of the uncertainty ahead for Australia's energy landscape, key industry bodies have worked collaboratively through distinct initiatives to identify actions that will support efficient investments in electricity networks to allow for increased customer participation. The initiatives include (i) Energy Networks Australia (ENA) and the CSIRO's Electricity Network Transformation Roadmap and (ii) ENA's and the Australian Energy market Operator's (AEMO's) Open Energy Networks consultation work that detail 'no regret' actions to 'enable balanced, long term outcomes for customers, enable the maximum value of customer DER and position Australia's networks for resilience in uncertain futures'.<sup>1</sup>

<sup>1</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.



Combining the industry work with our own analysis—and taking account of our customer preferences—we have developed a Future Network Strategy to meet customer expectations and futureproof our network by undertaking several ‘least-regret’ activities, in line with these initiatives. The ‘Future Grid’ proposal presented in this paper is a direct translation of this strategy, feeding into JEN’s regulatory proposal for the 2021-26 regulatory period.

## Our Future Grid initiatives aim to invest on a least-regrets basis and cater for a range of outcomes

As JEN prepares its plans, including its regulatory proposal for the 2021-26 regulatory period, it recognises the importance of properly preparing its network for Australia’s ongoing energy transformation. Regardless of the future state of its network and the potential changes to the way the National Electricity Market (**NEM**) operates, JEN has identified several ‘least-regret’ activities that will address aspects common to all future scenarios to unlock benefits for its customers. The implementation of these activities will ultimately benefit all of JEN’s customers by allowing them to maximise the opportunities available from increasing DER and optimise the utilisation of existing network assets. JEN’s Future Grid program can be separated into two overarching initiatives:

- The **Enabling DER** initiative – will benefit JEN’s customers through activities that maximise the value realised from their systems. JEN acknowledges the need for Distribution Network Service Providers (**DNSPs**) to significantly increase the visibility, control and availability of accurate data to facilitate increasing DER penetration on its network. Activities contained in the ‘Enabling DER’ initiative will therefore ultimately serve to increase DER value on JEN’s network through improved visibility of the Low-voltage (**LV**) network and the establishment of its network constraints and hosting capacity.
- The **Optimised Asset Investments** initiative – will deliver value to JEN’s customers by managing and utilising network assets more efficiently. In an environment where there remain strong expectations from JEN’s customers around energy affordability, JEN’s ‘Optimised Asset Investments’ initiative will aim to reduce system costs over the long-term by optimising existing network assets. This will be facilitated by activities that will improve JEN’s decision-making processes for network utilisation and investment, leveraging real-time condition monitoring techniques – rather than purely relying on inspection-based condition assessments – and advanced asset management lifecycle systems that are increasingly available.

## Robust analysis of options shows that building smart is efficient and best-choice to maximise consumer benefits

Our Future Grid proposal highlights the prudent and efficient timing of its proposed expenditure through quantified cost-benefit analyses. When considering the expected improvements from the implementation of both Future Grid initiatives, the following benefits are anticipated for JEN’s customers:

- increased exports from new PV installations,
- reduction of augmentation and replacement expenditures, and
- reduction of operational expenditure .

Given the ongoing and long-term benefits that each Future Grid initiative will deliver, the cost-benefit analyses were conducted over the next four regulatory control periods (i.e. FY 2022-2041), by testing different assumptions. Unless otherwise noted, all dollars shown in this document are presented in real mid-2019 dollars.

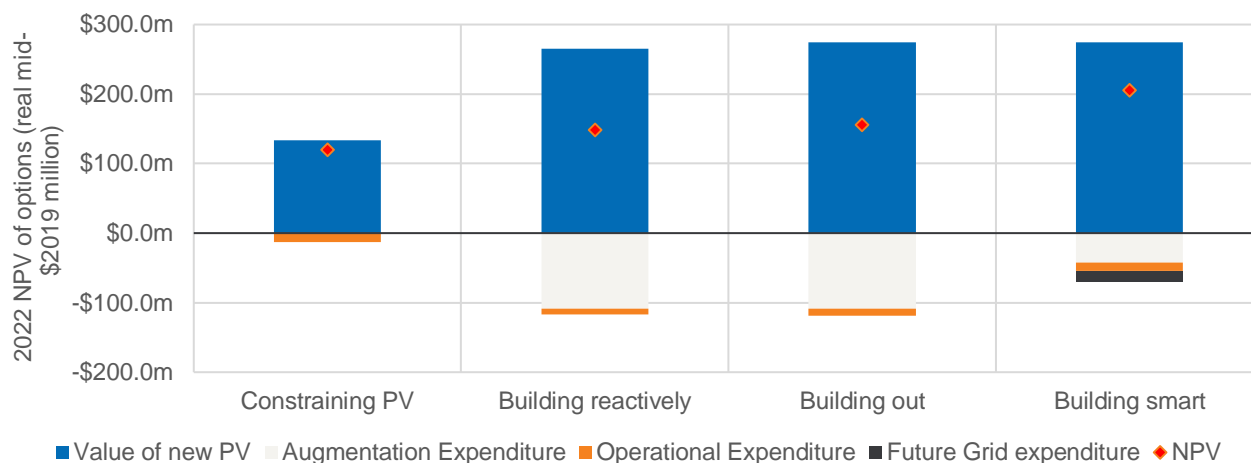
Under JEN’s ‘Enabling DER’ initiative, three investment options were compared against a counterfactual:

- The counterfactual considered that exports of PV systems exceeding a penetration rate commonly agreed as being a lower bound of networks’ hosting capacity will be constrained (‘Constraining PV’)
- A first investment option considered traditional, reactive network augmentation (‘Building reactively’)

- A second investment option considered traditional, proactive network augmentation ('Building out')
- A third investment option considered smart, proactive network augmentation supported by increased visibility on LV network hosting capacity ('Building smart')

The results of this cost-benefit analysis found that JEN's 'Building smart' investment option has the highest net present value of the four options (see Figure 2).

**Figure 2: Enabling DER cost-benefit analysis results**



Investment options 'Building out' and 'Building smart' both maximised the value of additional PV exports as proactive investment meant that no generation was constrained to export to the grid. However, investing in all 'Building smart' activities improved network visibility and decision-making, which reduced the cost of facilitating additional PV installation connections and exports.

JEN's 'Optimised Asset Investments' initiative has been compared to conducting business-as-usual. The 'Optimised Asset Investments' initiative results in a positive NPV of \$6.5m for an investment of \$5m in the FY2022-2026 period. Of this, replacement expenditure reductions account for close to 70% of the total benefits, driven by the higher share of replacement expenditure in JEN's replacement expenditure forecasts.

These cost-benefit analyses demonstrate that JEN's Future Grid expenditure is both prudent and efficient in light of the uncertainty facing future electricity networks, and is therefore in the long-term interests of JEN's customers. In addition to this, it is argued that JEN's Future Grid initiatives are in-line with its customers' expectations to allow them to have the right and benefit from emerging electricity market opportunities and to reduce overall network costs.

# 1. Expected DER take-up requires a network response to meet customer expectations

## 1.1 What is driving a change in Australia's electricity system

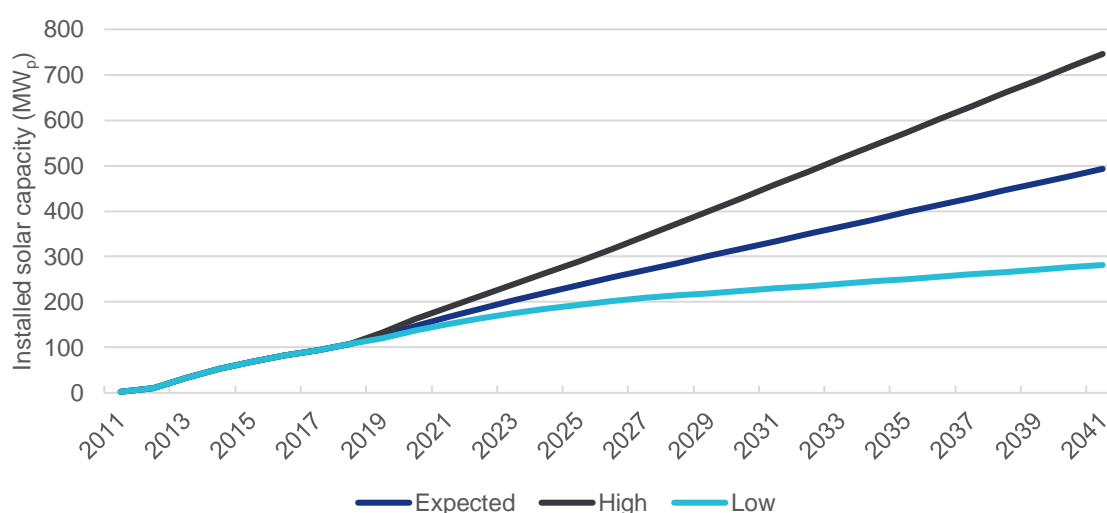
Australia's energy landscape is undergoing a significant transformation characterised by the decentralisation, decarbonisation and digitisation of the power system and driven by an increase in customer participation and engagement. This increased 'awareness' is best exhibited by the rapid increase in PV generation uptake as both residential and C&I customers looking for more reliable, affordable and sustainable energy solutions. In addition to this, customers are becoming more active in their desire to benefit from the opportunities available in electricity markets. As shown in Table 1, customers expect to be able to install and utilise PV generation for own use—evidenced from the increase in installed generation capacity from 83MW in 2016/17 to just under 109MW in 2018/19—and also to export to the electricity grid which have increased nearly 30MWh over the same period.

**Table 1: Historical residential PV generation capacity and generation on JEN's network**

Financial year	Installed residential PV generation capacity (MW)	Estimated 'gross' residential PV generation (GWh)	Residential PV generation exported to the grid (MWh)	Percentage of residential PV generation exported to the grid
2016/17	83.3	92.6	59.6	64%
2017/18	93.5	103.9	68.5	66%
2018/19	108.7	121.7	87.2	72%

However, the pace and scale of this transformation is still subject to uncertainties related to technology costs decrease, regulatory and policy response to the environmental issues and electricity market reforms, and customer response and engagement. This is best illustrated by the full range of PV generation uptake forecasts on JEN's network (see Figure 3).

**Figure 3: Forecast installed PV generation capacity on JEN's network<sup>2</sup>**



<sup>2</sup> Based on ACIL Allen's independent expert forecast to 2028.



## 1.2 What are the resulting challenges for electricity distribution networks

Australia's electricity distribution networks are at the forefront of this transformation. Indeed, electricity distribution networks have traditionally been built for one-way power flows, from sub-transmission assets down to customers' premises. As a consequence, there is extensive planning, operations and skills and capabilities of the sub-transmission, zone substations and High-Voltage (HV) feeder network assets. This allows DNSPs to model the impact of changes in customer behaviour and undertake assessments where large customers add embedded generation systems connected at the HV level of their networks.

In contrast, for LV networks, the part of the network from distribution substations down to customers' premises connections, planning, operations, control and more generally visibility on asset capability is more limited. This is because these assets have been designed and built for one-way flows and given the relatively criticality for this part of the network at a time when we invested in an energy system before the advent of bidirectional flows.

With the increasing penetration of DER, bidirectional power flows are emerging on electricity distribution networks, and this happens first at the LV level due to the nature of these resources. This translates into power quality – mainly voltage – issues, not seen at these levels in traditional one-way flow networks. This also causes customers' PV inverters tripping off, thereby limiting the availability of these resources for the wider community.

The limited visibility of DER hosting capacities on their LV networks' means that DNSPs will need to constrain customer DER exports to ensure the network remains within safe and reliable operating limits. The rate at which customer DER will be constrained is uncertain. This is resulting in poor outcomes for both customers and the operation of the NEM.

The increasing availability of AMI data, however, creates a unique opportunity for DNSPs to improve their understanding of the LV level of their networks and the impacts of increasing DER penetration. For instance, the use of AMI data now allows us to map customer connectivity and identify voltage problems across our distribution networks. Yet, without detailed asset data (network configuration and physical asset parameters) and more information about the DER systems that customers are connecting to the network, we are unable to effectively model the LV network and determine how much DER our network can accommodate, when and where to invest to ensure that we meet customer expectations for their PV exports to remain unconstrained.

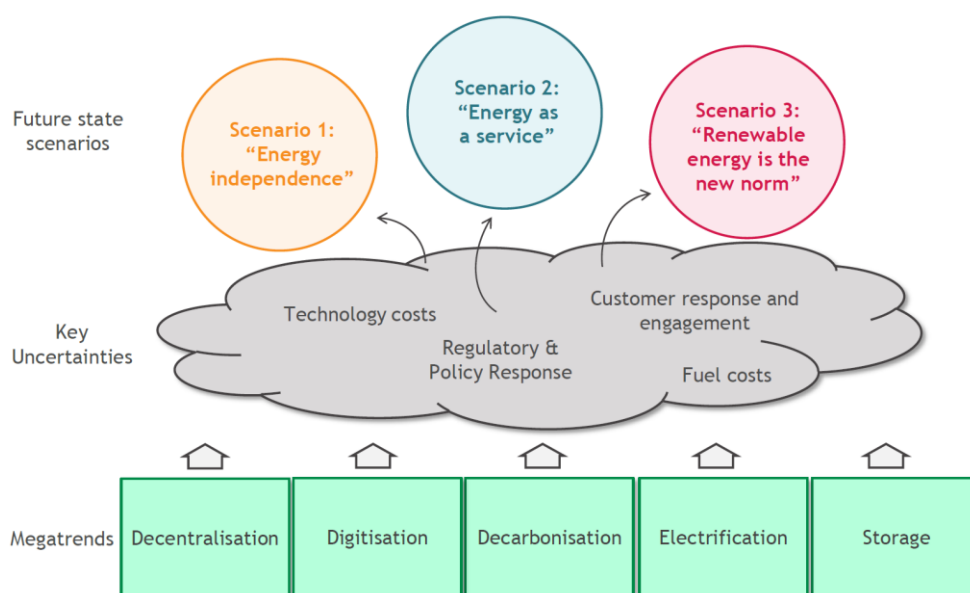
## 1.3 Our Future Network Strategy is aligned with customer expectations

In light of the uncertain future of Australia's energy landscape, several key industry stakeholders have worked collaboratively to identify actions that will support efficient investments in electricity networks allowing for increased customer participation. Such initiatives include ENA and the CSIRO's Electricity Network Transformation Roadmap and ENA and AEMO's Open Energy Networks consultation work that details 'no regret' actions to 'enable balanced, long term outcomes for customers, enable the maximum value of customer DER and position Australia's networks for resilience in uncertain and divergent futures'.<sup>3</sup>

In line with this, JEN has developed its Future Network Strategy to meet customer expectations and futureproof its network by undertaking several 'least-regret' activities of its own. This strategy recognises the importance of JEN of being adequately prepared to navigate this transformation and deliver cost-efficient electricity supply in different future network scenarios (see Figure 4).

<sup>3</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.

**Figure 4: Future state scenarios considered in JEN's Future Network Strategy**



When considering the combination of divergent outcomes of the industry's megatrends and key areas of uncertainties, JEN has arrived at three possible future state scenarios for Australia's distribution networks (see Figure 4), these are:

1. Energy independence – characterised by uncertainty in key policy drivers and reform, and fuel prices remaining high. This scenario predicts customer mistrust in the electricity system that prompts them to leave the grid.
2. Energy as a service – characterised by regulators adopting a market-based approach to the electricity system. There is a rapid increase in DER uptake, and customers benefit from an increased focus on digital capabilities.
3. Renewable energy is the new norm – characterised by a cost reduction in renewables and increase in grid-connected storage. This scenario anticipates a focus on digital technology and solutions.

With the likely future state being a combination of the elements in each scenario, JEN has identified common themes representative of Australia's probable future network state:

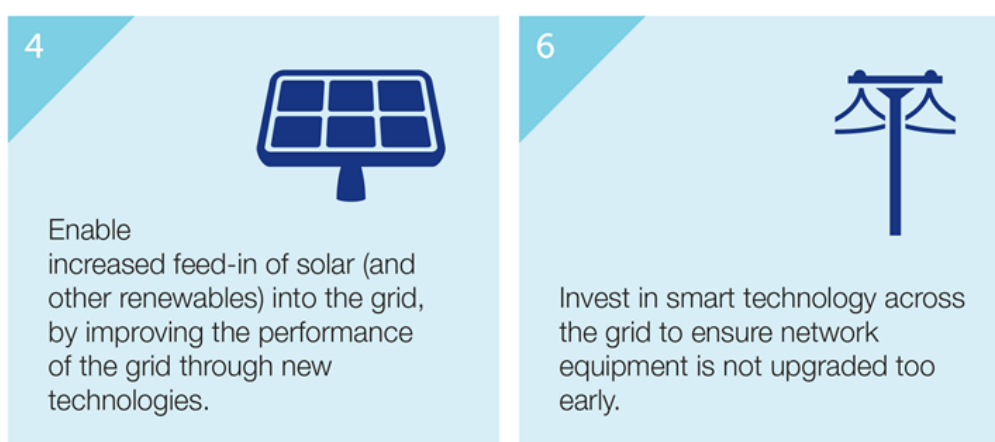
- A significant increase in large-scale (probably renewable), centralised renewable generation and DER.
- The need to significantly increase visibility, control and data relating to the low voltage network to maintain grid reliability and security.
- The importance of reducing system costs and optimising network utilisation to maintain the relevance of the network and avoid potentially detrimental impacts from regulatory and policy changes.
- The need to leverage the functionality of DER to support an efficient network.
- The capability for networks to implement cost-reflective price signals, to understand customer behaviour and the benefits of DER to the system.

When considering these themes, JEN has noted that an unwavering focus on delivering value for customers will ultimately be rewarded. As such, JEN has identified several high-level activity categories that will address themes common to the probable future states for the benefit of its customers:

- Optimising the performance of existing assets
- Modernising the Grid
- Seeding the market
- Building organisational capacity.

JEN received positive customer feedback on its Future Network Strategy through its People's Panel in July 2018.<sup>4</sup> Based on trade-off price options for different initiatives, 97% of participants to this panel agreed that JEN needs to modernise the grid to allow for excess PV generation from residential, commercial and industrial customers to be made available to the community. In addition to that, 100% agreed to step up smart network investments, at the right time, in intelligent systems and assets to reduce costs in the future (see Figure 5). These strong agreement levels came along with a recommendation for JEN to maintain the level of reliability of its network.

**Figure 5: JEN's People's Panel recommendations related to its Future Network Strategy**



## 1.4 Future Grid proposal

The Future Grid proposal presented in this paper has built upon JEN's Future Network Strategy and integral part of our capex proposal for the 2021-26 regulatory period. This proposal includes what we consider to be least-regret activities that address two of the high-level activity categories described in its Future Network Strategy, namely optimising the performance of existing assets and modernising the grid.

As such, JEN's Future Grid proposal does not include activities targeting uncertain outcomes, most notably the transition to a Distribution System Operator or Distribution Market Operator model as contemplated in the Open Network strategy. Rather, the expected results from JEN's Future Grid initiatives are in line with ENA and CSIRO's Electricity Network Transformation Roadmap, in that they will provide the foundation for intelligent networks and markets.<sup>5</sup>

In developing our Future Grid proposal, we have taken into account:

- the least-regret actions identified in AEMO and ENA's Open Energy Networks consultation work on the transition to a two-way grid<sup>6</sup>
- the future network activities included in the recent EDPR submissions of DNSPs in other states.

<sup>4</sup> Capire, Community Consultation Report (Attachment 02-02 to JEN's Regulatory Proposal), 2019.

<sup>5</sup> Energy Networks Australia and CSIRO, *Electricity Network Transformation Roadmap: Final Report*, 2017.

<sup>6</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.

The rest of this attachment is structured as follows: :

- In Section 2, an overview of the options available to enable increased PV generation into the grid and to optimise asset investments
- In Section 3, a comparison of the costs and benefits associated with these options.
- In Section 4, we outline the recommendation.

Appendices A to C provide further detail about the cost-benefit analysis and detailed expenditures associated with the recommendation.

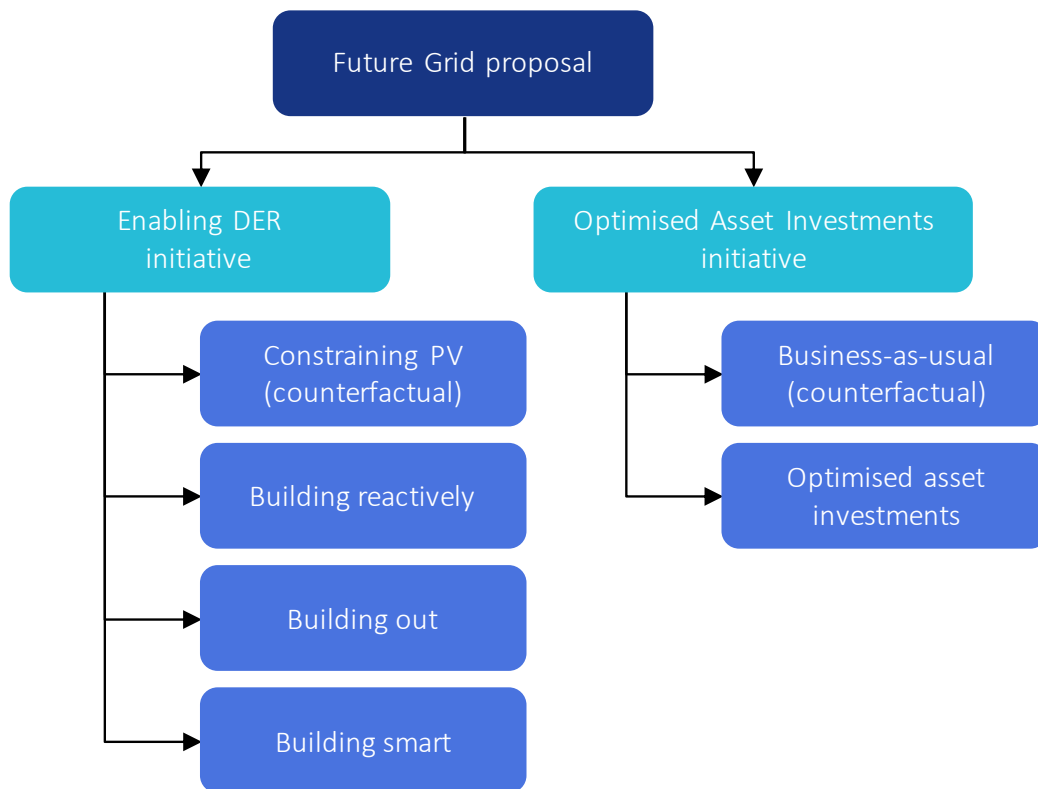
## 2. Robust set of options developed

JEN's Future Grid proposal details least-regret activities that address themes common to possible future network states identified in its Future Network Strategy. As articulated in Section 1, the implementation of these activities will ultimately benefit JEN's customers through the optimisation of existing network assets and the modernisation of its grid. JEN's Future Grid proposal can be separated into two overarching initiatives:

- The **Enabling DER** initiative – this is directed towards ensuring that JEN's customers benefit from activities that maximise the value realised from their DER installations.
- The **Optimised Asset Investments** initiative – this is focused on delivering deliver value to JEN's customers by managing and utilising network assets more efficiently.

For each of these initiatives, JEN has outlined different market benefits and investment options, including a counterfactual (see Figure 6), which are described in this section.

**Figure 6: Overview of Future Grid initiatives and investment options**



### 2.1 Market benefits

The expected improvements from the implementation of Future Grid initiatives have been translated into anticipated benefits. These benefits were identified through internal analysis, stakeholder discussions, and the review of recent Electricity Distribution Price Reset submissions of DNSPs in other states. Eight long-term benefits were identified for further consideration and short-listing:

1. Increased PV generation exports – improved visibility of network hosting capacity will facilitate increased PV penetration and avoid the unnecessary constraining of PV exports.

2. Reduction of augmentation and replacement expenditures – improved understanding of network hosting capacity and the optimisation of existing assets results in reduced expenditures.
3. Reduction of operational expenditure – improved visibility of the network will allow for an increase in the efficiency of connection processes and reduce reactive operational expenditure (operational expenditure) associated with the resolution of network issues.
4. Reduced maintenance expenditure – improved asset maintenance and decision-making processes result in reduced maintenance and material costs.
5. Maintaining voltages within the limits prescribed in the Electricity Distribution Code – improved network power quality and voltage profile allows for greater adherence to regulatory voltage limits.
6. Improved customer safety – improved power quality and network management reduces potential exposure to harmful network operating conditions.
7. Reduced liability risk – improved monitoring of the LV network allows for a better understanding of network operating conditions.
8. Reduced damage to customer appliances – improved network power quality and voltage profile reduces damage to customer appliances.

To determine which of these benefits should be included in each initiative cost-benefit analysis, JEN assessed the materiality of each. This, in turn, is based on whether the benefit was considered to be tangible, quantifiable, and whether the anticipated benefit could be passed onto JEN's customers. The inclusion of these benefits in regulatory proposals of other DNSPs' was also considered. Of the eight market benefits initially identified, three were considered to be material for inclusion in the cost benefit analyses, with each option comparing PV generation exports, capital expenditure and operational expenditure. Table 2 summarises the outcomes of the analysis.

**Table 2: Materiality of Future Grid benefits**

Benefit	Materiality
Increased PV generation exports	● Value of PV-generated energy exported to the network
Augmentation / replacement expenditure reduction	● Value of augmentation and replacement expenditure avoided
Reduction of operational expenditure	● Reduction in future full-time equivalents ( <b>FTE</b> ) required to conduct connection assessments and / or to resolve network issues as DER penetration increases
Improved network maintenance	● Uncertainty regarding materiality
Voltage compliance	● Uncertainty regarding materiality
Improved customer safety	● Uncertainty regarding materiality
Reduced liability risk	● Uncertainty regarding materiality
Reduced damage to customer appliances	● Uncertainty regarding materiality



## 2.2 Options considered as part of the ‘Enabling DER’ initiative

The four different options were compared in the ‘Enabling DER’ initiative:

### 1. ‘Constraining PV’ (counterfactual)

In this option PV generation exports from additional installations are constrained after an assumed 30% penetration threshold is reached at the distribution substation level. This penetration threshold may be lower or higher than the actual hosting capacity of the network due to limited visibility regarding the network hosting capacity and the point where issues are experienced. Practically, PV generation systems are allowed to connect unconstrained until the threshold is reached.

After the threshold is reached, PV generation systems are assigned a ‘zero export’ constraint to prevent network issues<sup>7</sup>.

This would mean that all new PV generation connections need to be assessed by JEN, and this would include incurring operating expenditure required to assess each customer connection. .

This option is the counterfactual against which other options are compared.

### 2. ‘Building reactively’

In this option, PV generation exports are unconstrained, with PV generation installations increasing in line with JEN’s expected PV generation capacity forecast.

This occurs up until the actual network hosting capacity is reached, with DER-enabling augmentation expenditure occurring reactively to alleviate PV export constraints after the issue is identified and alerted to JEN.

It is assumed that there is some lost value in PV generation exports before constraints are relieved through network augmentation. In parallel, reactive operational expenditure is required to rectify issues where PV generation penetration is higher than the network hosting capacity.

Our incremental operating expenditure required to assess requests from new customer connections is not considered in this option. This is because it is assumed that all customers can connect PV generation systems to the network.

### 3. ‘Building out.’

PV generation exports are unconstrained in this option, with PV installations increasing in line with JEN’s expected solar capacity forecast. This occurs until the network hosting capacity is reached, with DER-enabling augmentation expenditure occurring proactively to facilitate the forecast increase in PV penetration.

Reactive operational expenditure is avoided in this option, and customer connection operational expenditure occurs to facilitate customer PV generation uptake until the network hosting saturation limit is reached.

### 4. ‘Building smart’

In this option PV generation exports are unconstrained, with PV installations increasing in line with JEN’s expected solar capacity forecast. This occurs until the network hosting capacity is reached, with DER-enabling augmentation expenditure occurring proactively to facilitate the increase in PV penetration.

<sup>7</sup> PV has been considered as a priority in this analysis as the uptake – and thus impact – of other distributed energy resources (e.g. behind-the-meter batteries) will remain limited over the next regulatory period. In addition, customers are at present not allowed to export the combined capacity of their PV and battery systems, their exports being limited to the size of their PV system.

In this option, the costs associated with DER-enabling augmentation expenditure are expected to be less than the 'Building out' option due to improved visibility of LV network limits and solutions to accommodate increase PV generation export.

Additional Future Grid capital and operational expenditure is undertaken to facilitate this improved visibility, as well as to provide JEN with more significant insights of its LV network. This expenditure includes the following, considered capital expenditure:

- The development of an LV network model, through the upgrade of JEN's data capture processes to capture DER and LV-related information and unlock additional smart meter data extraction and analysis capabilities, the implementation of new LV network modelling tools and a new DER website and connection portal
- Enabling dynamic DER export control, through the installation of LV network monitoring devices to allow dynamic export limits and dynamic phase connection, the implementation of additional Distribution Management System (**DMS**) modules and the upgrade of the existing SCADA being upgraded to increase JEN's operational functionality for the control and management of DER and retrofitting in-situ PV generation inverters to allow for voltage regulation
- Increasing DER hosting capacity, through the augmentation of LV network assets to increase LV network hosting capacity and the installation of LV voltage regulation devices to mitigate power quality impacts from increased DER penetration.

These activities and associated projects are detailed in Appendix B1.1.

## 2.3 'Optimised Asset Investments' initiative

The cost-benefit analysis of the 'Optimised Asset Investments' initiative is computed against employing business as usual (**BAU**) decision-making processes, which serves as the counterfactual for this initiative.

The material benefits that have been considered for the analysis of the initiative are augmentation expenditure and replacement expenditure reductions.

The 'Optimised Asset Investments' initiative includes activities that will allow for smarter asset investment and utilisation. This will be achieved through the real-time monitoring of network assets and asset lifecycle and rating solutions. In implementing this initiative, JEN will be in a position to optimise asset investment decisions through the optimisation of aging assets replacements and better utilisation of existing asset capacity.

These activities and associated projects are detailed in Appendix B1.2.

## 3. Cost-benefit analysis

For both JEN's Future Grid initiatives, a cost-benefit analysis was conducted, focusing on the market benefits and investment options described in the previous section. This section describes the methodologies employed for these analyses, the results and the scenario analysis performed.

### 3.1 'Enabling DER' initiative

#### 3.1.1 Cost-benefit methodology

The cost-benefit analysis conducted for the 'Enabling DER' initiative relies on the assessment of the value of PV generation exports to the grid as well as option-specific assumptions, which are described in this section.

##### 3.1.1.1 Cost-benefit analysis - estimating constrained PV installations

Given the ongoing benefits that the Future Grid initiative proposes to offer in enabling DER on JEN's network and the need to ensure that JEN's investments are in the long-term interests of customers, the cost-benefit analysis of each option is conducted over the next four regulatory control periods (i.e. FY 2022-2041).

With value and expenditure streams in each cost-benefit analysis driven by the constraining of customer PV installations, it was first necessary to develop a model describing the rate at which PV systems would be constrained. To do this, a baseline of constrained PV and distribution substation (**DSS**) was first derived.

A key input required to develop the cost-benefit analysis baseline is our expected forecast of PV installations on its network. With the cost-benefit analysis looking to assess the value of each option over the next four regulatory control periods, and a forecast for JEN's network available up until 2028 only<sup>8</sup>, it was necessary to extrapolate this forecast to 2041. To achieve this, it was assumed that both PV installations and JEN's solar capacity increased at the same rate each year after 2029, equal to the number added in the previous year (i.e. between 2028-2029). Doing so allows for exploring a wide range of potential uptake rates, with an expected uptake forecast following a linear trend.

It should be noted that saturation has not been considered in this long-term forecast, but the expected forecast in 2041 results in a total of 111,000 PV systems being installed on JEN's network in 2041, equivalent to around 32% of its total number of customers.

Figure 7 illustrates JEN's forecast installed PV capacity to 2041 for low, expected and high scenarios. JEN's installed PV capacity is forecast to increase from 126 MW<sub>p</sub> (2019) to 493 MW<sub>p</sub> in 2041, sitting approximately halfway between the installed capacity forecast in the low and high scenarios (281 and 746 MW<sub>p</sub> respectively). Given the range between forecasts, the expected scenario was used for the cost-benefit analysis of the four investment options.

<sup>8</sup> This forecast was undertaken by independent experts ACIL Allen, and is described further in Attachment 05-03 to JEN's 2021-26 Regulatory Proposal.

Figure 7: Forecast installed PV generation capacity on JEN's network

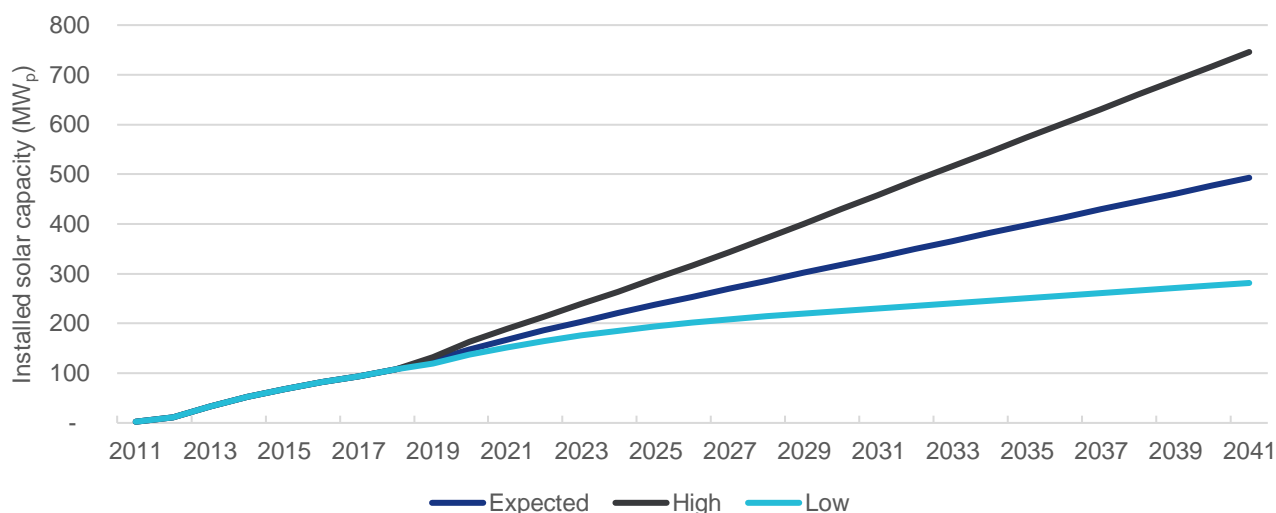
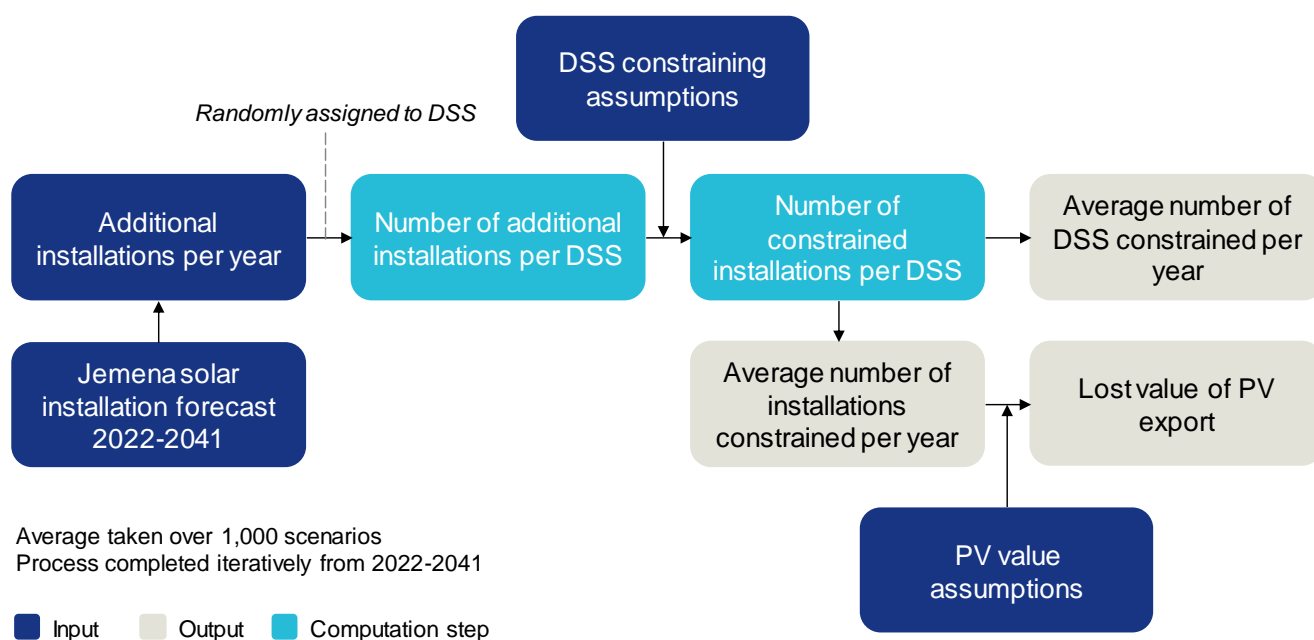


Figure 8 presents the approach adopted to calculate constrained PV exports.

Figure 8: Approach to estimating constrained PV installations



Once forecast for the number of additional PV installations on JEN's network is developed, installations were randomly assigned to distribution substations weighted by the number of remaining customers without PV systems. This was completed for each year between 2022-2041 in 1,000 scenarios to compute the average number of installations added to each DSS. To determine the number of installations that would be constrained, the following assumptions were employed:

- For distribution substations with ten or more customers: it was assumed that installations would be constrained once 30% of the customer base had PV systems installed. This is assumed to be the lower limit of the actual network hosting capacity which, when enforced, would ensure that JEN would remain inside its operating limits<sup>9</sup>.

<sup>9</sup> Analysis from SAPN suggests that voltage problems could start appearing at penetration rates between 1 and 2 kWp/customer depending on the LV network type. This would correspond to 20 to 40% penetration assuming PV systems have an average size of 5Wp. SA Power Networks, *LV Management Business Case*, 2019.

- For distribution substations with less than ten customers: it was assumed that installations would be constrained only when the installed PV capacity exceeded that of the distribution substation rating.

In addition to the number of constrained PV installations, another output of the model was the number of DSS where installations exceeded the threshold. This figure was then used to assess the scale of the issue across JEN's network, and ultimately the level of expenditures needed to allow PV installations constrained under the 'Constraining PV' option to actually export to the grid.

To quantify the market value of PV generation export from new installations on JEN's network, the share of PV-generated energy exported into the network was assumed to be 50%<sup>10</sup>. A feed-in tariff of 10c/kWh was used, in line with the Essential Services Commission's (ESC's) draft proposed minimum single rate feed-in tariff from 1 July 2020 (Essential Services Commission, 2019), in conjunction with an assumed average daily production of 3.6 kWh/kW<sub>p</sub>. Using a real discount rate of 2.50%, the value of each installation over a 20-year life was calculated as being \$1,050/kW<sub>p</sub>.

### 3.1.1.2 Investment options

Knowing the rate at which customer PV generation installations and DSS would be constrained on JEN's network, a cost-benefit analysis for each investment option was conducted. The outcome of each cost-benefit analysis was presented as the net present value (NPV) of each option over the next four regulatory periods (i.e. FY 2022-2041). These NPVs are presented as the value of the option in 2022 shown in real mid-2019 dollars and using a discount rate of 2.5% (approximates JEN's proposed real WACC for the next regulatory period).

When considering the material future benefits and option descriptions in section 2.2, the following value streams were considered in each cost-benefit analysis:

- Value of PV exports from additional customer installations
- Augmentation expenditure to facilitate increased DER penetration
- Operational expenditure associated with assessing and connecting additional PV installations, reacting to PV-related issues on JEN's network, and 'Building smart' activities (including proactively gathering LV network data, designing and maintaining enhanced IT and OT systems and modifying existing inverter settings)
- Activities under the 'Building smart' option, reflecting network and non-network capital expenditures (see Appendix C for detailed expenditures).

Assumptions specific to each options' cost-benefit analysis can be found in Appendix A1.1.

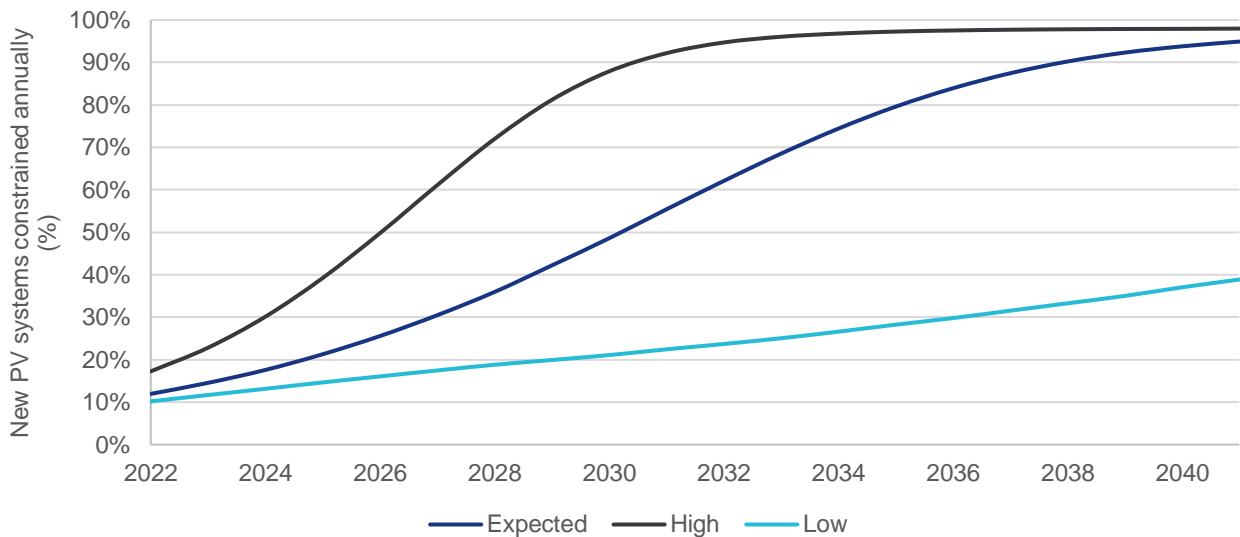
<sup>10</sup> This is expected to be conservative as today's export figures are in the order of 60% (see Table 1)

### 3.1.2 Results

#### 3.1.2.1 Cost-Benefit Analysis (PV and DSS constraints)

The proportion of new PV generation systems connection applications which would require constraining under each forecast scenario is presented in Figure 9.

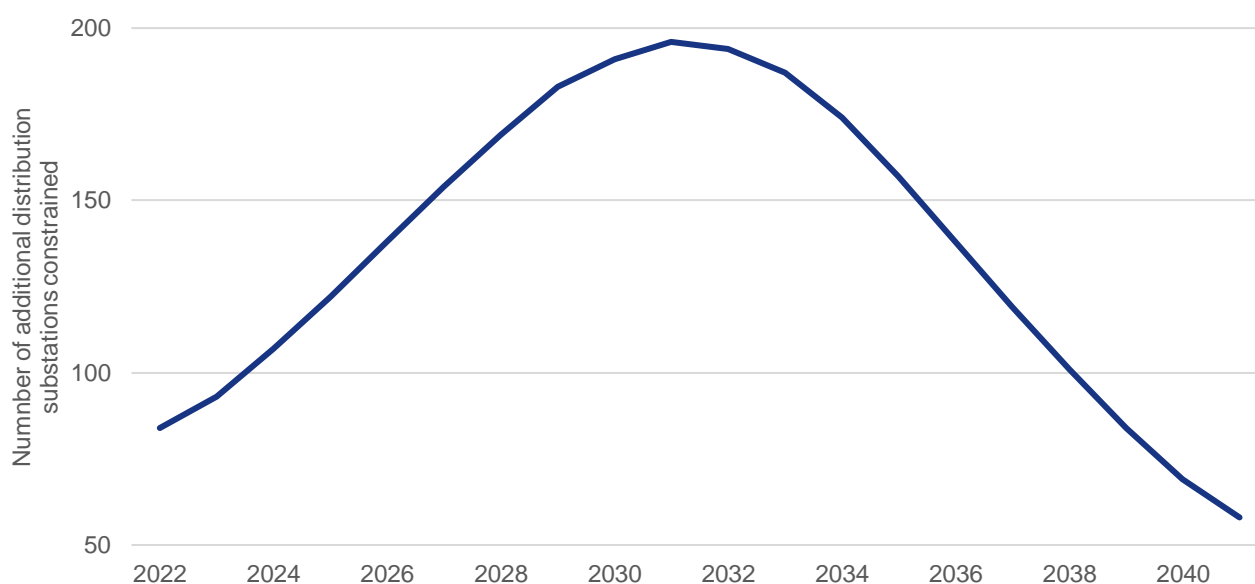
**Figure 9: Proportion of new PV system connections constrained**



The rate at which new PV systems are constrained under JEN's expected PV forecast steadily increases until network saturation is reached around 2040. In JEN's high uptake scenario, PV installations are constrained more rapidly, with approximately 90% of new PV systems constrained each year by 2030. The rate at which installation is constrained in the low scenario steadily increases over the period investigated, with 39% of additional new PV systems constrained in 2041.

Similar to the rate at which additional PV systems are constrained, the rate at which DSS are forecast to have additional PV systems exceed their capacity threshold under JEN's expected PV forecast increases before reaching saturation by 2041 (see Figure 10). It can be seen that the number of DSS constrained increases before peaking around 2030.

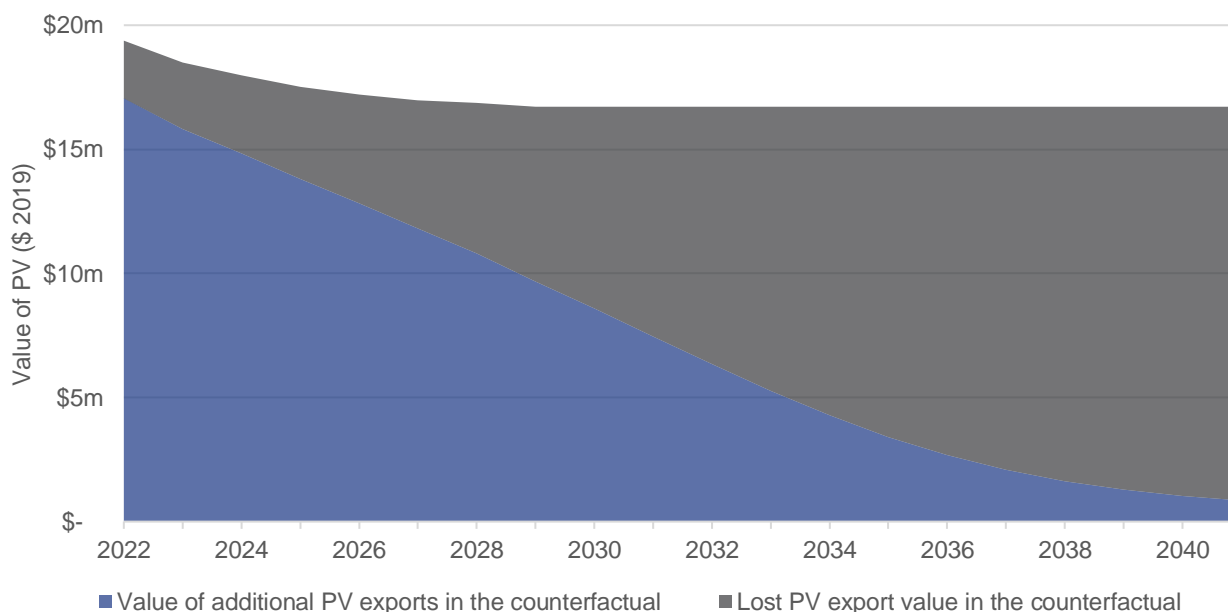


**Figure 10: Number of additional distribution substations constrained due to DER connections per annum**

### 3.1.2.2 Investment options

#### Constraining PV (counterfactual)

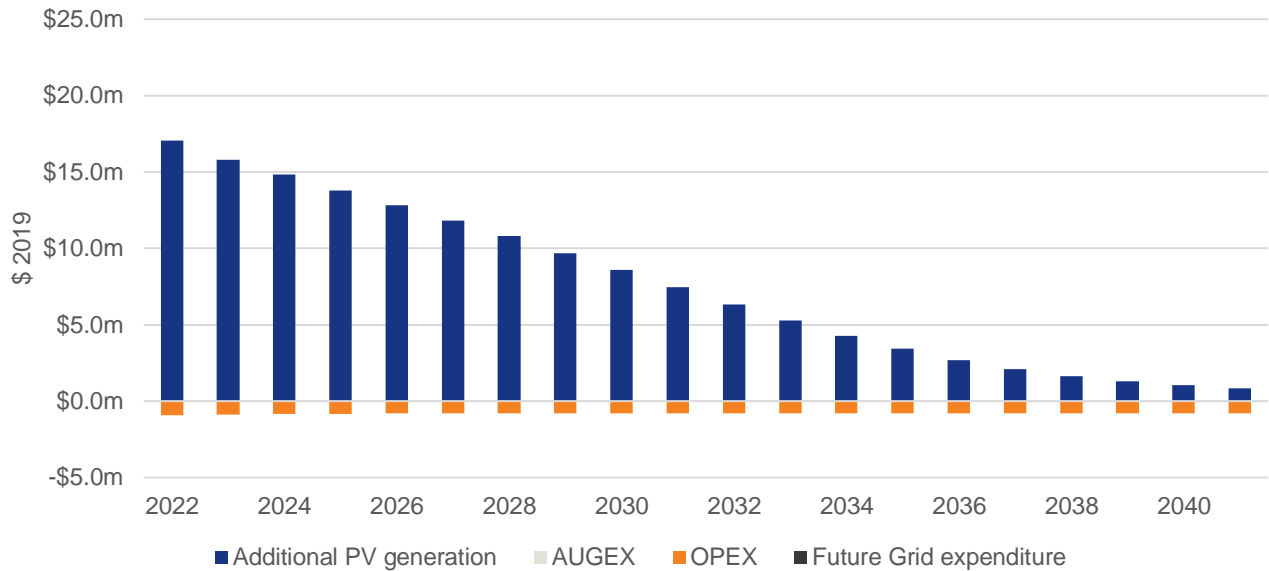
The 'Constraining PV' option assumes that additional PV generation installations are constrained once the threshold of their respective DSS is exceeded. As such, there is a significant value lost as the number of installations constrained increases over time.

**Figure 11: PV value realised and PV value lost under the 'Constraining PV' option (counterfactual)**

This lost PV export value is evident in the 'Constraining PV' value stream in Figure 11, as new PV export benefits decrease from 2021 to 2040. With operational expenditure in this option relating to the cost of connection

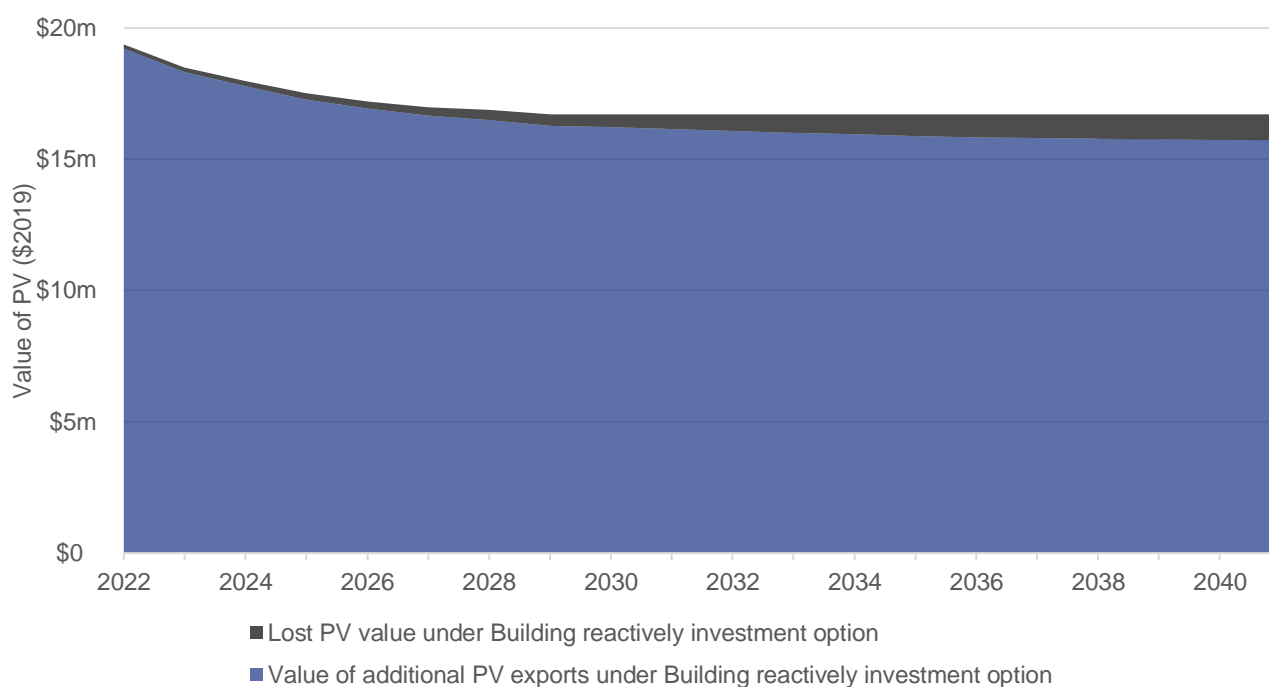
applications, the cashflow for this evolves in-line with new PV generation systems installed on JEN's network. There is no DER-enabling augmentation expenditure or reactive operational expenditure in this option as all forecast PV installations are permitted to connect to the network and export is constrained (where necessary) before issues arising.

**Figure 12: Value and expenditure cashflows for Constraining PV option**



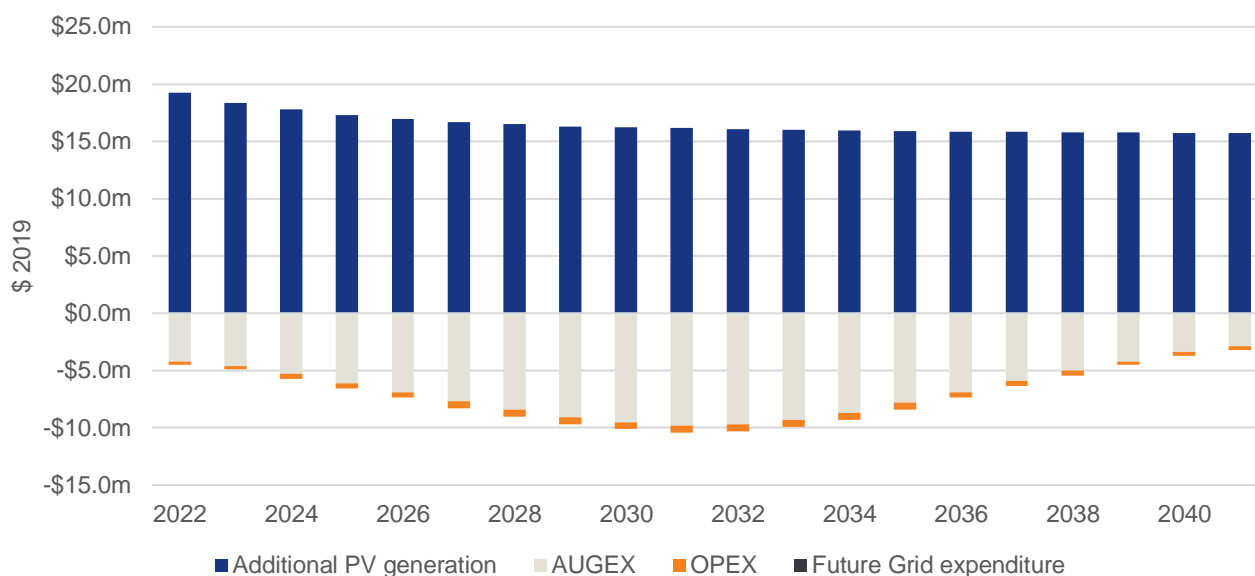
### Building reactively

The 'Building reactively' option assumes that PV installations forecast to exceed their DSS threshold are constrained for one year until relieved by DER-enabling augmentation expenditure. This results in some PV-generation value being lost, as seen in Figure 13.

**Figure 13: Lost PV value over time under Building reactively**

Under this option, augmentation expenditure is incurred in line with the number of new DSS on which PV installations are constrained. As can be seen in Figure 14, this increases up until 2031 after which the number of DSS constrained each year decreases as the network becomes saturated. To manage this augmentation work, the cost-benefit also considers an operational expenditure associated with four power quality engineers whose role will be to address network performance issues as they arise and coordinate network augmentation works.

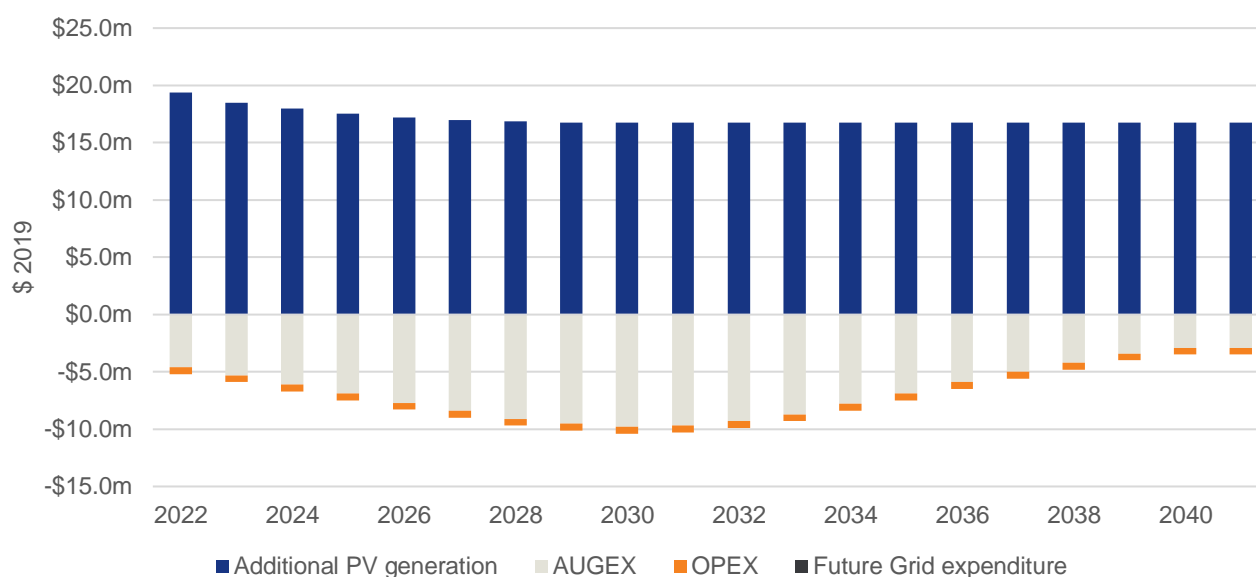
Figure 14: Value and expenditure cashflows for Building reactively



### Building out

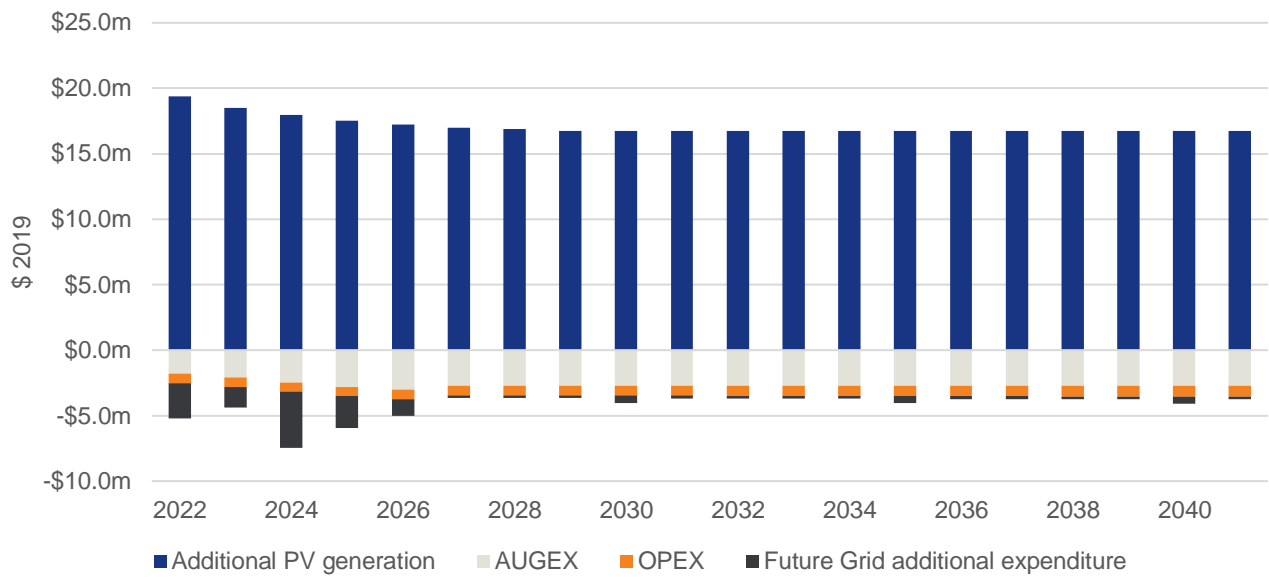
The 'Building out' option assumes that DER-enabling augmentation expenditure is undertaken proactively as opposed to reactively. The spending profile for this augmentation expenditure is assumed to be equal to that in the 'Building reactively' option brought one year forward. This assumes that JEN is in a position to identify coming constraints on its network and address them before any issues arising. Thus, in this option, it is assumed that PV-generation export is not constrained, allowing for the full benefit from additional PV generation installations to be realised. The cashflow for additional PV generation in this option, therefore, represents the total amount available in line with JEN's expected solar capacity forecast.

The cost-benefit analysis for this option also includes some operational expenditure associated with power quality engineers proactively identifying network constraints and augmentation requirements to facilitate unconstrained customer connection.

**Figure 15: Value and expenditure cashflows for Building Out**

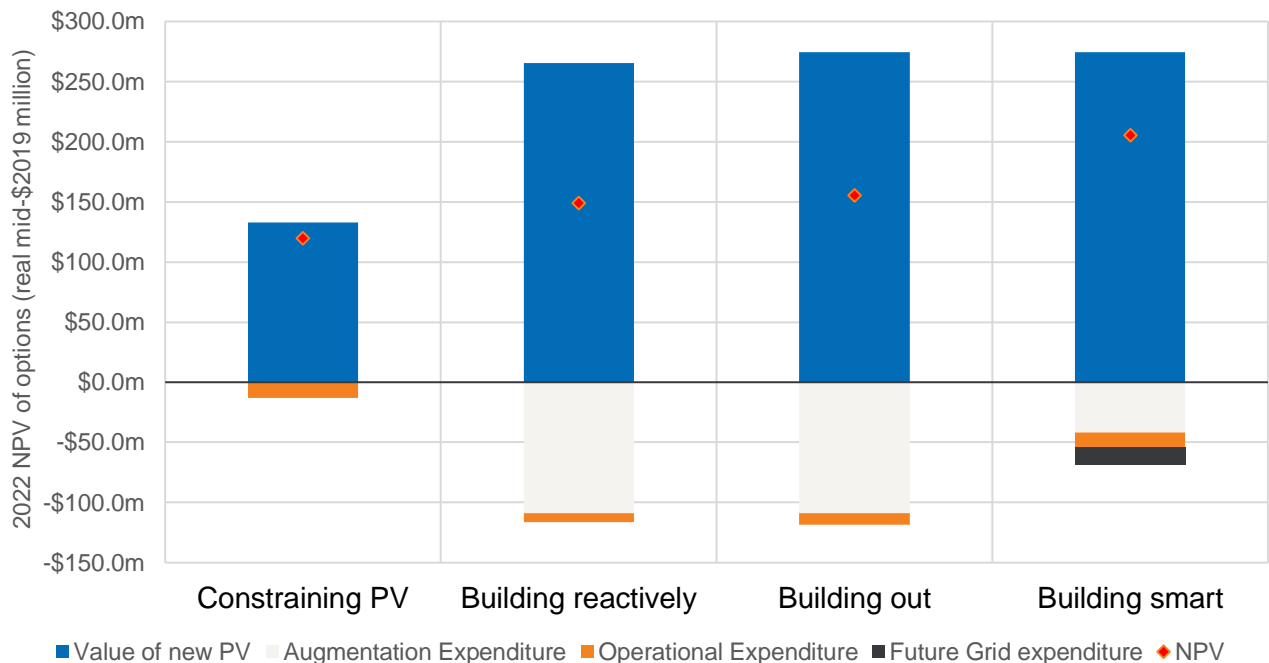
### Building smart

The 'Building smart' option considers a suite of activities that employ a mix of new technologies and methods to allow for the maximisation of the value available from additional PV installations. This option still encompasses DER-enabling augmentation expenditure that occurs proactively to facilitate unbridled connection of PV generation. Also, additional Future Grid capital expenditure and operational expenditure are required to improve LV network visibility and solutions to accommodate increased PV generation. Minor customer connection operational expenditure still occurs for the assessment and connection of PV installations.

**Figure 16: Value and expenditure cashflows for Building smart**

### 3.1.2.3 Comparison of the net present value of investment options

Each investment option was then compared using the cashflows presented in their own cost-benefit analysis. Figure 17 compares the value and expenditure streams for each option, as well as their NPV over the 2022 to 2041 period.

**Figure 17: Enabling DER initiative investment option comparison**

The comparison shows that while the Constraining PV investment option has the lowest expenditure, it also has the lowest value of additional PV generation. Constraining PV exports as opposed to investing in upgrading the network results in this option having the lowest NPV.



By comparison, the Building reactively investment option has a higher NPV than Constraining PV. Like the first investment option, each additional PV installation that is forecast to exceed the threshold of its distribution substation is constrained. These installations are only constrained for one year; however, after which it is assumed that DER-enabling augmentation expenditure allows for the systems to export excess PV generation to JEN's network. Although this option has higher expenditure, it results in a higher value of additional PV generation that results in a higher NPV than the base case of constraining PV.

Investment options Building out and Building smart both maximise PV export value as their proactive investment approach allows for unconstrained PV exports. In comparison to the Building reactively option, DER-enabling augmentation expenditure is incurred one-year prior through an increase in operational expenditure. In this instance, the benefit of not constraining new installations is less than the increase in operational expenditure benefit resulting in a more favourable option.

The Building smart investment was found to be the most favourable option with the highest NPV. This is due to a combination of timely DER-enabling augmentation expenditure and Future Grid expenditure that allows for improved visibility of the network hosting capacity. With the expenditures in this option being less than the other options while still allowing for the full value of additional PV installations to be realised, the Future Grid 'Building smart' activities represent the most beneficial option and outcome for customers over the long-term.

### 3.1.3 Sensitivity analysis

An accurate cost-benefit analysis for Future Grid investment relies on both the visibility of intricate network characteristics and the future of Australia's energy market. As this remains unclear at this point, it was necessary to make several assumptions to assess the merit of each investment option against one another.

The key assumptions influencing cashflows in this cost-benefit analysis relate to actual PV uptake, the actual hosting capacity of the LV network and changes in the feed-in tariff. While such assumptions will result in sensitivities in the cost-benefit analyses, it is considered that the above approach is reasonable.

Although changing assumptions may adjust the cashflows of each cost-benefit analysis, the favourability of each investment option is not expected to differ. This is evidenced by a sensitivity analysis on the feed-in tariff employed to compute the value of new PV. This analysis does not consider the evolution of the feed-in tariff over time, meaning that the value of additional PV generation may be over- or under-valued. The cost-benefit analysis assumed a feed-in tariff of 10c/kWh of exported PV generation. While employing a lower feed-in tariff of 7c/kWh – corresponding approximately to only the energy component of the draft 2020-2021 feed-in tariff<sup>11</sup> – reduces the value of additional PV generation, the Building smart investment option is still the most valuable option.

**Table 3: Sensitivity of NPV to different feed-in tariff values**

Option	NPV (12c/kWh feed-in tariff)	NPV (10c/kWh feed-in tariff)	NPV (7c/kWh feed-in tariff)
Option 1 – Constraining PV (base case)	\$147m	\$120m	\$80m
Option 2 – Building reactively	\$202m	\$149m	\$69m
Option 3 – Building out	\$211m	\$156m	\$73m
Option 4 – Building smart	\$260m	\$205m	\$123m

As the hosting capacity of LV networks is also not understood in detail at this time, it was necessary to make an assumption about distribution substation thresholds which determine the point at which new PV installations would be constrained. This assumption relies on an estimate that around 50% of the DSS that will exceed the commonly

<sup>11</sup> The energy component of the feed-in tariff includes wholesale electricity prices, avoided market fees and ancillary service charges and the value of avoided distribution and transmission losses. This component is 7.55c/kWh for the draft 2020–21 minimum FIT. It excludes the avoided social cost of carbon emissions and avoided human health costs. Essential Services Commission, *Minimum electricity feed-in tariff to apply from 1 July 2020*, 2019.

agreed threshold used in the counterfactual will see their hosting capacity exceeded and, hence, will require augmentation. This assumption is considered reasonable.

Lastly, while this cost-benefit analysis has employed JEN's expected PV forecast, the high and low PV uptake forecasts show the significant uncertainty surrounding actual uptake rates. It should be noted that any increase above the predicted forecast, will result in PV installations being constrained earlier, making the 'Building smart' investment option even more relevant. Beyond this, the 'Building smart' option will increase JEN's visibility on its network hosting capacity, which is a prerequisite to facilitate any uptake scenario.

## 3.2 ‘Optimised Asset Investments’ initiative

### 3.2.1 Cost-benefit methodology

Through the implementation of ‘Optimised Asset Investments’ activities, augmentation expenditure will be reduced due to an increase in asset load capacity from the formulation of dynamic ratings. Similarly, it is anticipated that replacement expenditure will be reduced due to an extension in asset life from real-time conditioning monitoring and asset life-cycle management solutions.

These reductions will materialise from FY 2027, i.e. not in this regulatory reset period, assuming that this period will be used to ramp up JEN’s capacity to deliver these benefits.

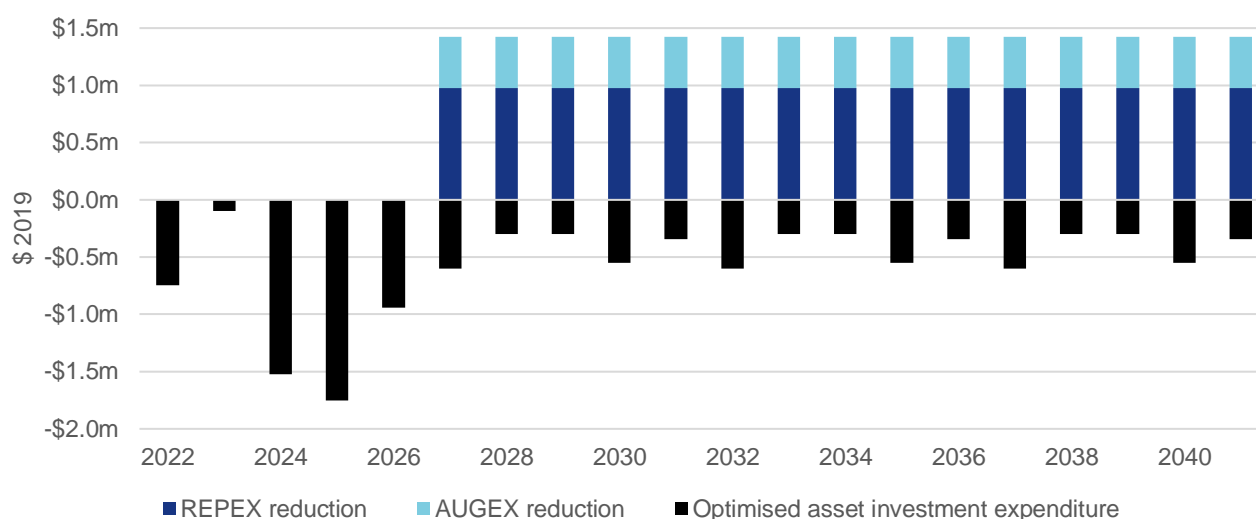
In computing the cost-benefit analysis, the following assumptions have been made:

**Table 4: Assumption summary for the ‘Optimised Asset Investment’ initiative cost-benefit analysis**

Assumption	Value	Comment
Discount rate (real)	2.5%	Approximates JEN’s proposed real WACC for the next regulatory period (FY 2022-2026)
Annual replacement expenditure	\$32.5m/yr	JEN’s proposed average replacement expenditure for the next regulatory period (FY 2022-2026) is ~\$32.5m/yr, once customer-initiated works are excluded
Annual augmentation expenditure	\$15m/yr	JEN’s proposed average augmentation expenditure for the next regulatory period (FY 2022-2026) is ~\$15m/yr, once REFCL compliance and Preston conversion program costs are excluded
Capital expenditure reduction potential	3%	Based on vendor claims

### 3.2.2 Results

The Optimised Asset Investments initiative results in a positive NPV of \$6.5m for an investment of \$5m in the FY2022-2026 period. Replacement expenditure reductions account for close to 70% of the total benefits, driven by the higher share of replacement expenditure in JEN’s capital expenditure forecasts.

**Figure 18: Value and expenditure streams for the 'Optimised Asset Investments' initiative**

### 3.2.3 Sensitivity analysis

These results are highly sensitive to the achievable capital expenditure reductions in next four regulatory control periods as well as to both augmentation expenditure and replacement expenditure forecasts for these periods.

As such, any capital expenditure reduction above 1.8% of JEN's replacement and augmentation capital expenditure would result in an NPV-positive cost-benefit analysis. As current industry estimates of the performance of such initiatives are well above this figure<sup>12</sup>, it is estimated that this benefit is mostly achievable.

Also, augmentation expenditure and replacement expenditure forecast estimates for the next regulatory periods are based on JEN's proposed average forecasts for regulatory period FY 2022-2026. It is anticipated that the replacement expenditure forecast for the subsequent regulatory periods will increase compared to FY 2022-2026 period as JEN's assets age and approach their end of life.

As a consequence, we consider that this cost-benefit analysis is conservative for all investment options.

<sup>12</sup> Initial interactions with vendors indicate reduction claims of up to 30%

## 4. Recommendation

JEN's Future Grid initiatives will position it to unlock benefits for its customers, lower long-term augmentation and replacement expenditure, while responding to uncertainties inherent in future electricity network planning. It will achieve this through several activities that, when implemented, will allow for it to maximise the opportunities available from increasing customers' DER exports and optimising the utilisation of existing network assets.

When assessing the 'Enabling DER' initiative, our option of 'Building smart' has the most favourable net present value while also ensuring that new PV systems installed on its network will not be constrained. This recommended option is aligned with JEN's People's Panel recommendation that JEN should enable increased feed-in of PV generation into the grid<sup>13</sup>.

Further, the 'Building smart' option is also consistent with the Australian Energy Regulator's recent comments in its Assessing DER integration expenditure consultation paper that "the offer of zero-export or significant augmentation do not represent a long-term sustainable solution to the continuing deployment of consumer DER"<sup>14</sup>. An overview of the proposed expenditures for the recommended option is shown in Table 5.

**Table 5: Future Grid 'Enabling DER' initiative expenditures for the next four regulatory periods (real mid-2019 \$m)**

Activities	Expenditure type	FY 2022-2026	FY 2027-2031	FY 2032-2036	FY 2037-2041
Developing an LV Network Model	IT Asset	\$5.9m	\$1.4m	\$1.4m	\$1.4m
	OPEX	\$0.8m	\$0.8m	\$0.9m	\$0.9m
Enabling dynamic DER export control	Network Asset Augmentation	\$2.7m	\$1.4m	\$1.4m	\$1.4m
	IT Asset	\$6.4m	-	-	-
	OPEX	\$1.0m	\$1.0m	\$1.1m	\$1.2m
Increasing DER hosting capacity	Network Asset Augmentation	\$9.4m	\$12.2m	\$12.2m	\$12.2m
	OPEX	\$1.8m	\$1.8m	\$1.9m	\$2.0m
<b>Total capital expenditure</b>		<b>\$24.5m</b>	<b>\$15.0m</b>	<b>\$15.0m</b>	<b>\$15.0m</b>
<b>Total operational expenditure</b>		<b>\$3.6m</b>	<b>\$3.7m</b>	<b>\$3.9m</b>	<b>\$4.1m</b>

JEN's 'Optimised Asset Investments' initiatives will position it to invest in and utilise its network in a more informed manner. This will lead to a reduction in augmentation and replacement expenditure which will allow for cost savings to be passed on to its customers. The cost-benefit analysis for this initiative was found to have a positive net present value when compared to continuing with business-as-usual. In addition to this, these activities are well aligned with JEN's People's Panel recommendation that JEN should employ smart technology to ensure network equipment is not upgraded too early<sup>15</sup>. An overview of the proposed expenditures for this initiative is shown in Table 6.

<sup>13</sup> Capire, Community Consultation Report (Attachment 02-02 to JEN's Regulatory Proposal), 2019, p. 4.

<sup>14</sup> Australian Energy Regulator, *Assessing Distributed Energy Resources Integration Expenditure*, 2019.

<sup>15</sup> Capire, Community Consultation Report (Attachment 02-02 to JEN's Regulatory Proposal), 2019, p. 4.

**Table 6: Future Grid ‘Optimised Asset Investment’ initiative expenditures for the next four regulatory periods (real mid-2019 \$m)**

Activities	Expenditure type	FY 2022-2026	FY 2027-2031	FY 2032-2036	FY 2037-2041
Condition Monitoring	Network Asset Augmentation	\$0.4m	\$0.5m	\$0.5m	\$0.5m
	IT Asset	\$0.2m	-	-	-
Dynamic Network Ratings	Network Asset Augmentation	\$1.8m	\$1.0m	\$1.0m	\$1.0m
	IT Asset	\$0.7m	-	-	-
Integrated asset investments	IT Asset	\$0.6m	\$0.3m	\$0.3m	\$0.0m
Integrated network design tool	IT Asset	\$1.3m	\$0.3m	\$0.3m	\$0.3m
<b>Total capital expenditure</b>		<b>\$5.1m</b>	<b>\$2.1m</b>	<b>\$2.1m</b>	<b>\$2.1m</b>

These cost-benefit analyses demonstrate that JEN’s Future Grid expenditure is both prudent and efficient as a set of foundational activities in light of the uncertainty facing future electricity networks, and is therefore in the long-term interests of customers. It is also noted that some additional benefits would be unlocked by the implementation of JEN’s Future Grid initiatives – most importantly voltage benefits allowing JEN to maintain the quality of supply (in line with obligations under the Electricity Distribution Code) under the ‘Enabling DER’ initiative. Furthermore, JEN’s Future Grid initiatives are in line with customers’ expectations – and specifically, respond to recommendations of the People’s Panel – by enabling customers to participate in emerging energy market opportunities actively and to reduce overall network costs in the long-term.



# Appendix A

## Cost-benefit analysis assumptions

## A1. Cost-benefit analysis assumptions

### A1.1 Cost-benefit analysis assumptions

This Appendix outlines the assumptions employed in the cost-benefit analysis of each investment option.

#### A1.1.1 Option 1 – ‘Constraining PV’

The following assumptions were employed in the ‘Constraining PV’ cost-benefit analysis:

##### Additional PV export

- Each PV installation forecast to exceed the threshold of its respective DSS is refused from exporting to the network, with the value lost from this assumed to be equal to the amount of energy that it would export over its lifetime. Our analysis has assumed that PV installations export 50% of the energy generated into the grid, which is below the observed rate over the last 3 years (see Table 1).
- A feed-in tariff of 10c/kWh was used, in line with the Essential Services Commission’s proposed minimum single rate feed-in tariff from 1 July 2020 (Essential Services Commission, 2019).
- A daily PV production of 3.6 kWh/KW-peak was assumed.

##### Augmentation expenditure

- There is assumed to be no DER-enabling augmentation expenditure.

##### Operational expenditure

- A connection application is completed for each additional forecast PV installation. To value this operational expenditure, it was assumed that the end-to-end process to costs JEN \$250/application.
- There is no reactive operational expenditure as PV installations are constrained before issues arise on the network.

##### Future Grid expenditure

- There is no Future Grid expenditure.

#### A1.1.2 Option 2 – ‘Building reactively’

The following assumptions were employed in the ‘Constraining PV’ cost-benefit analysis:

##### Additional PV export

- Each PV installation forecast to exceed the threshold of its respective DSS is constrained for one year. It is assumed that after this point, DER-enabling augmentation expenditure, initiated after identifying such constraints, would allow for it to export unconstrained into JEN’s network.

##### Augmentation expenditure

- DER-enabling augmentation expenditure is undertaken to alleviate network constraints once they have been identified. This augmentation is specifically the upgrade of constrained DSS, valued at \$100,000 per unit.

- It has been assumed that 50% of the DSS identified as having constrained PV are replaced. Given the uncertainty around the actual penetration threshold when issues will arise, this has been used as a conservative estimate knowing that not all DSS will be required to be upgraded.
- There is no operational expenditure associated with assessing and connecting PV installations as it is assumed that all customers can connect their system to JEN's network.

#### Operational expenditure

- Reactive operational expenditure is incurred as a number of power quality (**PQ**) engineers are required to address network issues associated with increasing DER penetration and coordinate the replacement of DSS augmentation. It is assumed that one PQ engineer is required for each 50 DSS constrained at the cost of \$150,000 per annum.

#### Future Grid expenditure

- There is no Future Grid expenditure.

### A1.1.3 Option 3 – 'Building out'

The following assumptions were employed in the 'Building out' cost-benefit analysis:

#### Additional PV export

- Additional forecast PV installations are not constrained due to DER-enabling augmentation expenditure being conducted proactively before network issues are realised. The value of PV in this scenario is, therefore maximised.

#### Augmentation expenditure

- DER-enabling augmentation expenditure occurs proactively to prevent network issues associated with additional PV from occurring and to prevent the constraining of systems. To value this, it is assumed that the augmentation expenditure profile in the 'Building reactively' option is brought forward by one year.

#### Operational expenditure

- The connection operational expenditure for this option relates to the number of PQ engineers required to forecast PV installations and proactively initiate and coordinate DSS augmentation. It is assumed that this will require four PQ engineers between 2022-2041, assuming that one PQ engineer will be able to manage 1,000 additional PQ installations each year. The cost of these employees is assumed to be \$150,000 per annum.
- There is no reactive expenditure for this option, as it is assumed that network issues do not arise due to proactive network augmentation.

#### Future Grid expenditure

- There is no Future Grid expenditure.

### A1.1.4 Option 4 – 'Building smart'

The following assumptions were employed in the 'Building smart' cost-benefit analysis:

### Additional PV exports

- Additional forecast PV installations are not constrained due to Future Grid 'Building smart' activities being conducted. The value of PV in this scenario is, therefore maximised.

### Augmentation expenditure

- Several DER-enabling augmentation expenditure activities are conducted to prevent additional forecast PV installations from being constrained. This includes activities such as upgrade of network assets to allow for dynamic export limits; voltage regulation to facilitate higher levels of DER, and the augmentation of LV assets to allow for an increase in network hosting capacity. A breakdown of this spend is detailed in Appendix C.

### Operational expenditure

- There is no reactive expenditure for this option as it is assumed that network issues do not arise
- It is assumed that there will be some operational expenditure associated with assessing and connecting PV installations as well as preparing for the Future Grid activities each year:
  - Additional LV network asset inspection to enable development of a LV network model: it has been assumed that one full-time asset inspector would be required to work through gathering LV network data (e.g. LV network configuration, LV asset data, LV customer connection arrangement and data) and ensuring it is loaded into our asset and customer systems (SAP and GIS). A basis of \$160k has been assumed for FY 2022
  - Preparatory work packages to allow for IT and OT system enhancements: a cost of \$200k has been assumed for FY 2022
  - Modifications of customers' PV inverter settings: as more than 35,000 PV generation inverters had already connected to JEN's network before December 2019 (the date from which all inverters must be set up with the Victorian mandated unified inverter settings, including the requirement for voltage regulation (i.e.. Volt-VAr and Volt-Watt control) to be enabled), some of these inverters may need to be modified to address power quality issues by enabling voltage regulation. Customers would need to engage a qualified person to allow this setting on their system, and JEN, therefore, proposes to make direct payments to customers to incentivise them to take this action. It has been assumed that a modest rate of 2% per year of these systems would require an update (i.e. 700 per year) to address inverters tripping off, and we have assumed a payment per system updated of \$500, resulting in a cost of \$350k for FY 2022
  - A 1% real cost growth per year has been assumed from FY2027.

### Future Grid expenditure

Future Grid expenditures are incurred. An overview of this spend is presented in Appendix B and expenditures are detailed in Appendix C.

## **Appendix B**

### **Detailed activities and projects**

## B1. Detailed activities and projects

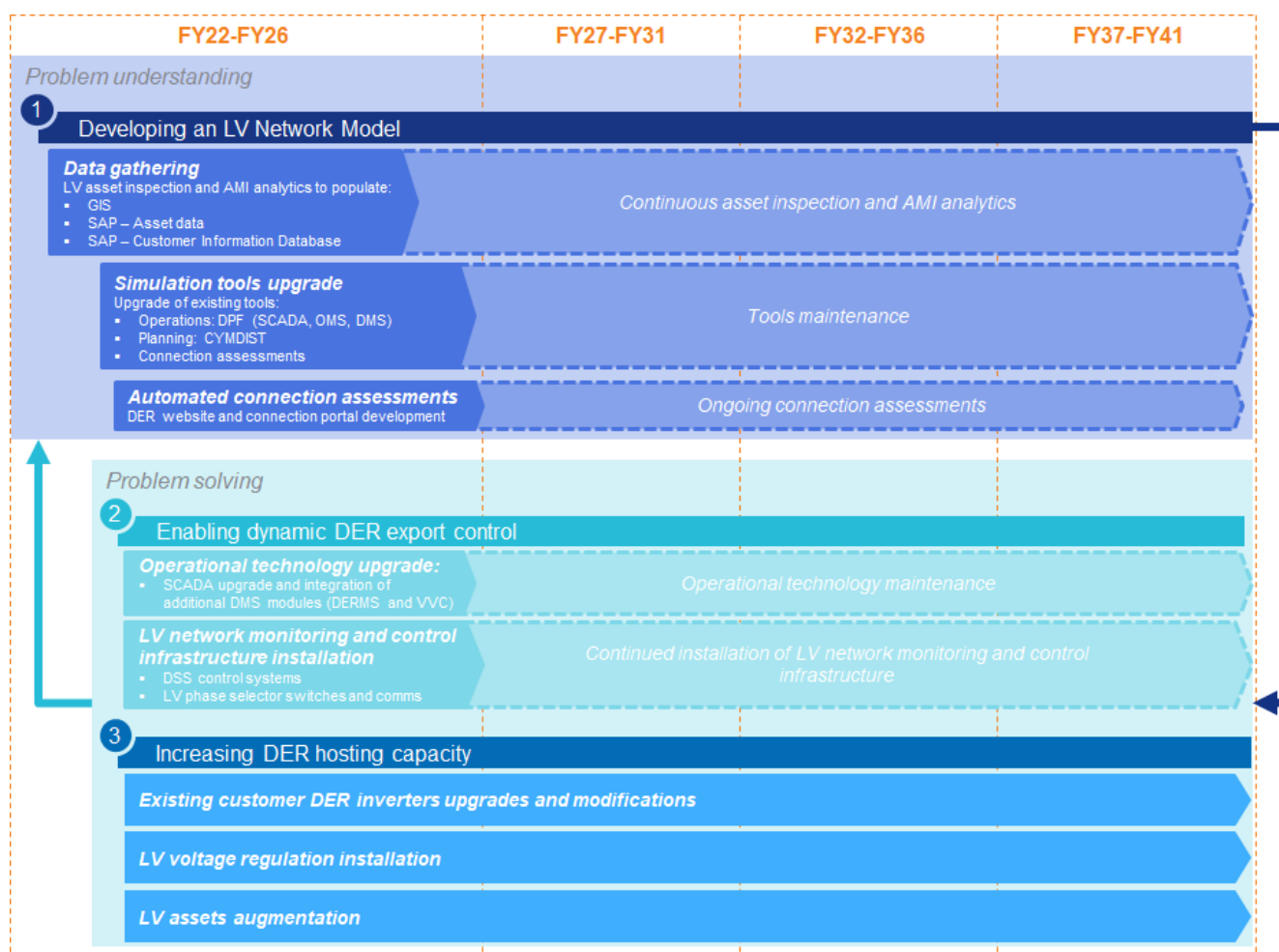
This appendix provides a detailed view of the activities and projects under the 'Building smart' option of the 'Enabling DER' initiative (section B1.1) and the 'Optimised Asset Investments' initiative (section B1.2).

### B1.1 'Enabling DER' initiative

The 'Building smart' option of the 'Enabling DER' initiative features three complementary activities aimed at understanding network DER hosting capacity and addressing hosting capacity limitations (see Figure 19):

- The development of a full LV network model will allow for the understanding of LV network hosting capacity and proactive assessment of new DER connections. This activity will first require the collection of both LV and DER data to overcome JEN's limited visibility of this part of the network (as opposed to the HV and sub-transmission network, see section 1.2). This data will then feed into simulation tools used by JEN's operation, planning and connection teams, that will effectively allow for the assessment of network hosting capacity. Finally, JEN will leverage these tools to implement automated connection assessments and thus streamline and facilitate the connection of new DER systems.
- Having visibility of network hosting capacity limits will facilitate the implementation of activities to overcome this issue. The two main activities that will facilitate this are:
  - The enablement of dynamic DER export control on JEN's network, in order to mitigate the adverse impacts of DER generation when and where they arise (as opposed to time and spatially static limits assumed in the counterfactual where no such visibility is available). This activity will require an improved monitoring and control infrastructure at the LV level, which entails LV monitoring and control infrastructure (DSS control systems and LV phase selector switches and comms) as well as operational technology upgrade (SCADA and DMS)
  - The increase in DER hosting capacity, in order to unlock exports from DER once (and where) network hosting capacity is reached. This will involve a range of projects, including the upgrade and modifications of existing DER inverters, the installation of LV voltage regulation devices and ultimately the augmentation of LV assets (both DSS and LV network).

Figure 19: 'Building smart' workflow



The following sub-sections provide more details on each main activity of the 'Building smart' option.

### B1.1.1 Developing an LV Network Model

This activity entails a range of individual projects that will improve JEN's visibility and understanding on its DER hosting capacity.

First, improved data capture processes for DER and LV network information need to be in place to feed into any LV network model. This involves one full-time asset inspector to gather this information (including LV network configuration, LV asset data, LV customer connection arrangement and data) and modifications to existing asset and customer systems (SAP, GIS and CIC). Then, the expansion of LV network modelling capabilities – power flow modelling at the LV level, planning tools and connection assessments – will provide JEN with an improved understanding of its network hosting capacity, enabling more accurate indications as to where customers can readily connect DER to the network. The establishment of factors influencing network hosting capacities will also allow for improved system coordination of the future network. This will ultimately materialise through the implementation of a DER website and connection portal to streamline and facilitate DER connections.

These projects are well aligned with least-regret activities outlined in the Open Energy Networks consultation paper.<sup>16</sup>

<sup>16</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.

Table 7: Detailed project list for the development of an LV network model

Project	High-level description
<i>Data gathering</i>	
LV network asset inspection	Gathering of LV network data (incl. LV network configuration, LV asset data, LV customer connection arrangement and data, etc.)
Integration of LV network asset data into existing systems	Addition of GIS/SAP fields to capture gathered LV network assets and DER data
Customer demand and generation data extraction tools	DER analysis reporting tools (PI, WMR, AMI) using consolidated customer Demand Data Set (incl. DER generation, exports, etc. analysed through AMI data)
Additional DER information gathering through AMI data	Data analytics projects using AMI data to gather additional DER system characteristics (e.g. capacity, phase identification, etc.) to inform the Future Grid program of work
Integration of DER data into existing systems	Integration of gathered DER data into SAP
<i>Simulation tools upgrade</i>	
Distribution Power Flow ( <b>DPF</b> )	Enabling 'LV network modelling' with DPF model of OMS/DMS platform
LV network modelling tool	Upgrade of Network Planning Powerflow Simulation software to accommodate LV network data in GIS/SAP
Template connection assessment tool	Development of a template-based, simple connection assessment tool validated by a State Estimation Trial
<i>Automated DER connection assessments</i>	
DER website and connection portal	Update of customer-facing platforms, automating DER connection assessment processes

### B1.1.2 Enabling dynamic DER export control

This activity entails a range of individual projects that will ensure JEN is in a position to effectively manage and dynamically control DER exports on its network. Upgrades to existing Distribution Management System (**DMS**) and SCADA will complement the installation of LV monitoring devices to JEN's SCADA, OMS and DMS to allow for these devices to effectively communicate with existing systems:

- Additional Distribution Management System (**DMS**) modules will be implemented and the existing SCADA will be upgraded to increase JEN's operational functionality for the control and management of DER. Such modules include Distributed Energy Resource Management System (**DERMS**) and Volt/Var Control (**VVC**) modules.
- LV network monitoring and control devices will be installed to allow real-time, dynamic export limits and dynamic phase connection. These will include communication infrastructure and Distribution Substations meters.

In its consultation response, Open Energy Networks considers DMS to be a key enabler for DER integration, through the provision of static and real-time network data.<sup>17</sup>

<sup>17</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.



**Table 8: Detailed project list for the enablement of dynamic DER export control**

Project	High-level description
<i>LV network monitoring and control infrastructure</i>	
LV phase selector switches and comms	Network Assets (communication) to enable dynamic DER export limits and phase connection
Distribution Substations control systems	Network Assets (Distribution Substations) to enable dynamic export limits and dynamic phase connection
<i>Operational technology upgrade</i>	
Distributed Energy Resource Management System (DERMS)	Integration of a DERMS component in the new OMS/DMS platform
Volt-VAr Control (VVC)	Enabling of the VVC component of the new OMS/DMS platform
SCADA upgrade	OT Assets to enable dynamic export limits and dynamic phase connection (integration into DMS-DERMS)
IT and OT system enhancement OPEX	Preparatory work packages to allow for IT and OT system enhancements

### B1.1.3 Increasing DER hosting capacity

This activity entails a range of individual projects that will go beyond the effective control of DER exports (see previous section) to unlock additional hosting capacity on JEN's network:

- A portion of existing customer PV generation inverters will be upgraded and modified to allow for voltage regulation (see estimated number of inverter modifications in section 0).
- LV voltage regulation devices (in-line voltage regulators, static VAR compensators, and VAR-controlled devices) will be installed to mitigate power quality impacts from increased DER penetration
- LV network assets (LV circuits and Distribution Substations) will be augmented to increase LV network hosting capacity

In particular, LV network voltage regulation was identified as the least regret action in the Open Energy Networks consultation response, addressing the function of system security and restoration through the ability to regulate system voltage.<sup>18</sup>

<sup>18</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.

**Table 9: Detailed project list for increasing DER hosting capacity**

Project	High-level description
<i>Existing customer DER inverters upgrades and modifications</i>	
Existing customer DER inverters upgrades and modifications	Modifications of existing customer PV inverters' functionalities to allow for voltage regulation (i.e. volt-var and volt-watt control)
<i>LV voltage regulation installation</i>	
LV voltage regulation	New Network Assets to enable the mitigation of adverse voltage impacts of increased DER penetration: in-line voltage regulators, static VAR compensators and VAR-controlled devices
<i>LV assets augmentation</i>	
Distribution Substations augmentation	Augmentation of Distribution Substations to increase hosting capacity (e.g. on-load tap changer)
LV network assets augmentation	Augmentation of LV networks assets to increase hosting capacity (e.g. high impedance joints/phase balancing)

## B1.2 'Optimised Asset Investments' initiative

the 'Optimised Asset Investments' initiative includes four activities, detailed in this section, that will result in reduced augmentation and replacement expenditures:

- Improved condition monitoring will target for JEN's zone substation approaching end-of-life to reduce replacement expenditures
- The implementation of Dynamic Network Ratings across JEN's heavily loaded assets will help optimise asset utilisation, reducing augmentation expenditures
- The deployment of an integrated asset investment software will allow for a better understanding of risks at both an asset and asset portfolio level, resulting in reduced augmentation and replacement expenditures
- The deployment of integrated network design tool will streamline augmentation and replacement design tasks, thus reducing the associated expenditures

### B1.2.1 Condition monitoring

In this activity, real-time condition monitoring equipment will be added to zone substation assets approaching their end-of-life. Along with this monitoring equipment, a condition monitoring software package will be deployed for use by JEN's Asset Management team.

It is anticipated that this activity will result in improved decision-making processes for asset replacements, ultimately reducing replacement expenditures. Real-time conditioning monitoring is a least-regret action identified by stakeholders in the Open Energy Networks consultation response, allowing for the improved operation of future electricity networks.<sup>19</sup>

<sup>19</sup> AEMO and Energy Networks Australia, *Open Energy Networks, consultation paper*, 2018.

### B1.2.2 Dynamic Network Ratings

This activity entails three projects that will see:

- Climate and asset monitors being installed for use in the real-time calculation of dynamic asset ratings
- Several software packages being deployed to calculate dynamic asset ratings using real-time monitors
- Modifications to Operational Technology (OMS, DMS, etc.) to take account of dynamic network ratings

The development of dynamic ratings on heavily loaded assets will allow for their optimised utilisation. Potential assets on which this will be deployed include heavily loaded sub-transmission lines, zone substations, and high-voltage feeders. The expected improvement of this activity will be optimised utilisation of existing assets, allowing for the reduction of network augmentation expenditures.

### B1.2.3 Integrated asset investments

This activity aims to integrate a holistic asset life-cycle management software into JEN's asset management processes. This software will allow for a better understanding of consolidated asset risks both at an asset and asset portfolio level, thereby improving the decision-making processes for asset replacements.

### B1.2.4 Integrated network design tool

This activity aims to develop and deploy a single integrated electricity network design tool. This tool would be used across the business for High-Level Design, Detailed Design and Construction Drawings. It would thus result in increased efficiency in network augmentation and replacement design tasks across JEN's network.

**Table 10: Future Grid 'Optimised Asset Investment' activities and projects**

Activity and project	High-level description
<i>Condition Monitoring</i>	
Condition Monitoring Software	Condition monitoring equipment software package for use by the Asset Management team
Primary Plant Condition Monitoring Equipment	Real-time condition monitoring equipment added to zone substation assets approaching end-of-life
<i>Dynamic Network Ratings</i>	
Climate and asset monitors	Climate and asset monitors for use in the real-time calculation of dynamic asset ratings
Software package	Several software packages to calculate dynamic asset ratings using real-time monitors
Modifications to Operational Technology	Changes to Operational Technology (OMS, DMS, SCADA) to take account of dynamic network ratings
<i>Integrated asset investments</i>	
Network Asset Management Lifecycle System	Integrated asset investment software for the Asset Management team to predict investment needs
<i>Integrated network design tool</i>	
Integrated network design tool	A single integrated electricity network design tool used across the business for High-Level Design, Detailed Design and Construction Drawings

## Appendix C

### Future Grid detailed expenditures

## C1. Future Grid detailed expenditures

This appendix outlines the Future Grid expenditure for both the 'Enabling DER' and 'Optimised asset investment' initiatives. All expenditures shown in this section are displayed in real mid-2019 dollars.

While developing expenditures estimates presented in this section, the following sources have been used:

- JEN's IT Project Estimation Tool, based on a top-down methodology (i.e. project size and complexity) was used to create long-term capital forecasts for project IDs ITEG04 to ITEG09<sup>20</sup>
- Enhancements to the recently commissioned Operational Technology platform (SCADA / OMS / DMS) have been estimated by the existing SCADA replacement project team based on estimated internal effort to develop these modules on the new platform (project IDs A558, A560 to A562, A565)
- Estimates of new types of network assets and associated software were estimated based on recent trials and information obtained via other Network Service Providers and Suppliers (project IDs A172, A11, A556, A557, A559, A563, A564, A566). The DER congestion modelling has been used to determine the number of issues which would need to be addressed, and then estimate the volume of each option undertaken to increase DER hosting capacity.

Estimation of 2020 / 2021 project costs carrying over into the next regulatory period (i.e. post 1 July 2021) was used where the project is predominantly being carried out prior to that date (project IDs A945 to A948).

<sup>20</sup> This top-down methodology for estimating individual project costs is consistent with the approach Jemena applied to develop its forecast IT capital expenditure for the Jemena Gas Network's 2020-25 Access Arrangement Proposal, which the AER found to be a reasonable approach in its November 2019 Draft Decision for JGN's 2020-25 Access Arrangement Proposal (Attachment 5 Capital Expenditure, p. 5-39).

## C1.1 'Enabling DER' initiative

### C1.1.1 Developing an LV Network Model

Project	LV network asset inspection	Integration of LV network asset data into existing systems	Customer demand data extraction tools	Additional DER information gathering through AMI data	Integration of DER data into existing systems	Distribution Power Flow (DPF)	LV network modelling tool	Template connection assessment tool	DER website and portal
Project ID	-	ITEG04	A946	ITEG09	A945	A560	ITEG06	ITEG05	A947
Service code	-	GID	GID	GID	GID	GID	GID	GID	GID
Grouping	OPEX	IT Asset	IT Asset	IT Asset	IT Asset	IT Asset	IT Asset	IT Asset	IT Asset
Expenditures									
FY22	\$159,263	\$344,388	\$309,368	\$413,266	\$103,123	\$618,735	\$0	\$112,709	\$515,613
FY23	\$160,099	\$0	\$0	\$414,742	\$0	\$517,455	\$0	\$113,111	\$0
FY24	\$160,983	\$0	\$0	\$208,146	\$0	\$0	\$908,272	\$0	\$0
FY25	\$161,881	\$0	\$0	\$208,929	\$0	\$0	\$911,688	\$0	\$0
FY26	\$162,794	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY27	\$164,422	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY28	\$166,066	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY29	\$167,727	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY30	\$169,404	\$0	\$0	\$209,718	\$0	\$0	\$350,000	\$0	\$0
FY31	\$171,098	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY32	\$172,809	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0

Project	LV network asset inspection	Integration of LV network asset data into existing systems	Customer demand data extraction tools	Additional DER information gathering through AMI data	Integration of DER data into existing systems	Distribution Power Flow (DPF)	LV network modelling tool	Template connection assessment tool	DER website and portal
FY33	\$174,537	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY34	\$176,282	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY35	\$178,045	\$0	\$0	\$209,718	\$0	\$0	\$350,000	\$0	\$0
FY36	\$179,826	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY37	\$181,624	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY38	\$183,440	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY39	\$185,275	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY40	\$187,127	\$0	\$0	\$209,718	\$0	\$0	\$350,000	\$0	\$0
FY41	\$188,999	\$0	\$0	\$209,718	\$0	\$0	\$0	\$0	\$0
FY27-FY42 assumption	1% growth per year	Zero (one off development cost)	Zero (one off development cost)	Zero (one off development cost)	Constant at FY26 value	Zero (one off development cost)	Zero (part of OMS/ DMS lifecycle costs)	IT lifecycle costs - \$350k in FY30, 35, 40	Zero (one off development cost)
<b>Total FY22-FY26</b>	<b>\$0.8m</b>	<b>\$0.3m</b>	<b>\$0.3m</b>	<b>\$1.5m</b>	<b>\$0.1m</b>	<b>\$1.1m</b>	<b>\$1.8m</b>	<b>\$0.2m</b>	<b>\$0.5m</b>
<b>Total FY22-FY41</b>	<b>\$3.5m</b>	<b>\$0.3m</b>	<b>\$0.3m</b>	<b>\$4.6m</b>	<b>\$0.1m</b>	<b>\$1.1m</b>	<b>\$2.9m</b>	<b>\$0.2m</b>	<b>\$0.5m</b>

### C1.1.2 Enabling dynamic DER export control

Project name	LV phase selector switches and comms	Distribution Substations control systems	SCADA upgrade	Distributed Energy Resource Management System (DERMS)	Volt-VAr Control (VVC)	IT and OT system enhancement OPEX
Project ID	A556	A557	A558	A561	A562	-
Service code	PRA	PQA	GID	GID	GID	-
Grouping	Network Asset Augmentation	Network Asset Augmentation	IT Asset	IT Asset	IT Asset	OPEX
Expenditures						
FY22	\$297,677	\$238,816	\$283,587	\$0	\$0	\$199,079
FY23	\$296,914	\$238,386	\$51,745	\$465,709	\$0	\$200,124
FY24	\$304,204	\$244,433	\$51,939	\$3,116,326	\$0	\$201,228
FY25	\$307,617	\$247,375	\$52,134	\$0	\$1,251,219	\$202,352
FY26	\$313,329	\$252,171	\$52,331	\$0	\$1,046,621	\$203,492
FY27	\$150,000	\$125,000	\$0	\$0	\$0	\$205,527
FY28	\$150,000	\$125,000	\$0	\$0	\$0	\$207,583
FY29	\$150,000	\$125,000	\$0	\$0	\$0	\$209,658
FY30	\$150,000	\$125,000	\$0	\$0	\$0	\$211,755
FY31	\$150,000	\$125,000	\$0	\$0	\$0	\$213,873
FY32	\$150,000	\$125,000	\$0	\$0	\$0	\$216,011
FY33	\$150,000	\$125,000	\$0	\$0	\$0	\$218,171
FY34	\$150,000	\$125,000	\$0	\$0	\$0	\$220,353
FY35	\$150,000	\$125,000	\$0	\$0	\$0	\$222,557
FY36	\$150,000	\$125,000	\$0	\$0	\$0	\$224,782



Project name	LV phase selector switches and comms	Distribution Substations control systems	SCADA upgrade	Distributed Energy Resource Management System (DERMS)	Volt-VAR Control (VVC)	IT and OT system enhancement OPEX
FY37	\$150,000	\$125,000	\$0	\$0	\$0	\$227,030
FY38	\$150,000	\$125,000	\$0	\$0	\$0	\$229,300
FY39	\$150,000	\$125,000	\$0	\$0	\$0	\$231,593
FY40	\$150,000	\$125,000	\$0	\$0	\$0	\$233,909
FY41	\$150,000	\$125,000	\$0	\$0	\$0	\$236,248
FY27-FY42 assumption	Constant \$150k from FY27 onwards	Constant \$125k from FY27 onwards	Zero: part of OMS/DMS lifecycle costs	Zero: part of OMS/DMS lifecycle costs	Zero: part of OMS/DMS lifecycle costs	1% growth per year
<b>Total FY22-FY26</b>	<b>\$1.5m</b>	<b>\$1.2m</b>	<b>\$0.5m</b>	<b>\$3.6m</b>	<b>\$2.3m</b>	<b>\$1m</b>
<b>Total FY22-FY41</b>	<b>\$3.8m</b>	<b>\$3.1m</b>	<b>\$0.5m</b>	<b>\$3.6m</b>	<b>\$2.3m</b>	<b>\$4.3m</b>

### C1.1.3 Increasing DER hosting capacity

Project name	LV voltage regulation	Distribution substation augmentation	LV network assets augmentation	Existing customer DER inverters upgrades and modifications
Project ID	A559	A563	A564	-
Service code	DSL	PQA	PQB	-
Grouping	Network Asset Augmentation	Network Asset Augmentation	Network Asset Augmentation	OPEX
Expenditures				
FY22	\$409,516	\$746,097	\$118,181	\$348,388
FY23	\$406,543	\$1,043,966	\$117,641	\$350,217
FY24	\$414,476	\$1,376,459	\$120,275	\$352,149
FY25	\$417,050	\$1,701,090	\$121,366	\$354,116
FY26	\$422,680	\$1,891,283	\$123,355	\$356,112
FY27	\$422,680	\$1,891,283	\$123,355	\$359,673
FY28	\$422,680	\$1,891,283	\$123,355	\$363,270
FY29	\$422,680	\$1,891,283	\$123,355	\$366,902
FY30	\$422,680	\$1,891,283	\$123,355	\$370,571
FY31	\$422,680	\$1,891,283	\$123,355	\$374,277
FY32	\$422,680	\$1,891,283	\$123,355	\$378,020
FY33	\$422,680	\$1,891,283	\$123,355	\$381,800
FY34	\$422,680	\$1,891,283	\$123,355	\$385,618
FY35	\$422,680	\$1,891,283	\$123,355	\$389,474
FY36	\$422,680	\$1,891,283	\$123,355	\$393,369
FY37	\$422,680	\$1,891,283	\$123,355	\$397,303

Project name	LV voltage regulation	Distribution substation augmentation	LV network assets augmentation	Existing customer DER inverters upgrades and modifications
FY38	\$422,680	\$1,891,283	\$123,355	\$401,276
FY39	\$422,680	\$1,891,283	\$123,355	\$405,288
FY40	\$422,680	\$1,891,283	\$123,355	\$409,341
FY41	\$422,680	\$1,891,283	\$123,355	\$413,435
FY27-FY42 assumption	Constant at FY26 value	Constant at FY26 value	Constant at FY26 value	1% growth per year
<b>Total FY22-FY26</b>	<b>\$2.1m</b>	<b>\$6.8m</b>	<b>\$0.6m</b>	<b>\$1.8m</b>
<b>Total FY22-FY41</b>	<b>\$8.4m</b>	<b>\$35.1m</b>	<b>\$2.5m</b>	<b>\$7.6m</b>

## C1.2 'Optimised Asset Investments' initiative

Activity	Condition Monitoring		Dynamic Network Ratings			Integrated design tool	Integrated Asset Investments
Project name	Primary Plant Monitoring Equipment	Condition Monitoring Software	Modifications to Operational Technology	Climate and asset monitors	Software package	Integrated network design tool	Network Asset Management Lifecycle System
Project ID	A172	A11	A565	A566	ITEG08	A948	ITEG07
Service code	DZB	GID	GID	DZB	GID	GID	GID
Grouping	Network Asset Augmentation	IT Asset	IT Asset	Network Asset Augmentation	IT Asset	IT Asset	IT Asset
Expenditures							
FY22	\$128,783	\$0	\$0	\$0	\$0	\$618,735	\$0
FY23	\$0	\$99,843	\$0	\$0	\$0	\$0	\$0
FY24	\$147,060	\$100,216	\$51,939	\$601,373	\$0	\$0	\$624,437
FY25	\$146,562	\$0	\$260,671	\$606,829	\$113,961	\$0	\$626,786
FY26	\$0	\$0	\$209,324	\$616,777	\$114,391	\$0	\$0
FY27	\$100,000	\$0	\$0	\$200,000	\$0	\$300,000	\$0
FY28	\$100,000	\$0	\$0	\$200,000	\$0	\$0	\$0
FY29	\$100,000	\$40,000	\$0	\$200,000	\$0	\$0	\$0
FY30	\$100,000	\$0	\$0	\$200,000	\$0	\$0	\$250,000
FY31	\$100,000	\$0	\$0	\$200,000	\$45,000	\$0	\$0
FY32	\$100,000	\$0	\$0	\$200,000	\$0	\$300,000	\$0
FY33	\$100,000	\$0	\$0	\$200,000	\$0	\$0	\$0
FY34	\$100,000	\$40,000	\$0	\$200,000	\$0	\$0	\$0

Activity	Condition Monitoring		Dynamic Network Ratings			Integrated design tool	Integrated Asset Investments
FY35	\$100,000	\$0	\$0	\$200,000	\$0	\$0	\$250,000
FY36	\$100,000	\$0	\$0	\$200,000	\$45,000	\$0	\$0
FY37	\$100,000	\$0	\$0	\$200,000	\$0	\$300,000	\$0
FY38	\$100,000	\$0	\$0	\$200,000	\$0	\$0	\$0
FY39	\$100,000	\$40,000	\$0	\$200,000	\$0	\$0	\$0
FY40	\$100,000	\$0	\$0	\$200,000	\$0	\$0	\$250,000
FY41	\$100,000	\$0	\$0	\$200,000	\$45,000	\$0	\$0
FY27-FY42 assumption	Constant \$100k from FY27 onwards	IT lifecycle costs - \$40k in FY29, FY34, FY39	Zero: will form part of OMS/DMS lifecycle costs	Constant \$200k from FY27 onwards	IT lifecycle costs - \$45k in FY31, FY36, FY41	IT lifecycle - \$300k in FY27, FY32, FY37	IT lifecycle costs - \$250k in FY30, FY35, FY40
<b>Total FY22-FY26</b>	<b>\$0.4m</b>	<b>\$0.2m</b>	<b>\$0.5m</b>	<b>\$1.8m</b>	<b>\$0.2m</b>	<b>\$0.6m</b>	<b>\$1.3m</b>
<b>Total FY22-FY41</b>	<b>\$1.9m</b>	<b>\$0.3m</b>	<b>\$0.5m</b>	<b>\$4.8m</b>	<b>\$0.4m</b>	<b>\$1.5m</b>	<b>\$2.0m</b>