Jemena Asset Management Pty Ltd

JEN – RIN – Support – Voltage and PQ Management Program – 20250131

Table of contents

Abbreviations

Abbreviation	Description
ADMS	Advanced Distribution Management System
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
APVI	Australian PV Institute
ARENA	Australian Renewable Energy Agency
CAPEX	Capital Expenditure
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resources
CVR	Conservation Voltage Reduction
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DNSP	Distribution Network Service Provider
DPV	Distributed Solar PVNPV
DR	Demand Response
DVM	Dynamic Voltage Management
EDCOP	(Victorian) Electricity Distribution Code of Practice
ESC	Essential Services Commission
EV	Electric Vehicle
EWOV	Energy and Water Ombudsman of Victoria
HV	High Voltage
IASR	Inputs, Assumptions and Scenarios Report
IT	Information Technology
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo Volt
kVA	Kilo Volt - Ampere
LDC	Line Drop Compensation
LV	Low Voltage
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Mega Watt hour

Abbreviation	Description
NEM	National Electricity Market
NER	National Electricity Rules
NMS	Network Management System
NPV	Net Present Value
OLTC	On-Load Tap-Changer
OPEX	Operations and Maintenance Expenditure
OSII	Open Systems International Incorporated
OT	Operational Technology
PQ	Power Quality
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
TNSP	Transmission Network Service Provider
TS	Terminal Station
VER	Value of Emissions Reduction
VRR	Voltage Regulating Relay
VVC	Volt - VAr Control
ZSS	Zone Substation

Overview

This Voltage and Power Quality (PQ) Management program forms part of Jemena Electricity Network's (JEN's) Consumer Energy Resources Integration Strategy (CER Integration Strategy). It supports JEN's strategic objective of connecting its customers to a renewable energy future, by facilitating the integration of Distributed Energy Resources (DER) into the electricity distribution network and facilitating the electrification of the economy.

This Voltage and PQ Management program articulates the need for a voltage and power quality management program, to strategically respond to the network voltage and quality of supply compliance challenges associated with increasing numbers of DER, and the substitution of gas and transport sectors within the economy – all important in achieving legislated emission reductions targets and maintaining technical compliance with the Victorian Electricity Distribution Code of Practise (EDCOP)[1].

The voltage and quality of supply programs are optimised by a new Dynamic Voltage Management (DVM) system that achieves near real-time, optimised control of network voltage and reactive power flow, for the delivery of compliant voltages, reduced DER curtailment and avoiding the need to limit electricity being exported to the distribution network. Utilising an enhanced form of Volt-VAr control (VVC) that is integrated with JEN's Advanced Metering Infrastructure (AMI), DVM will act as a technology overlay over the physical network assets to minimise expenditure on more expensive forms of traditional network voltage and quality of supply investments.

The Voltage and PQ Management program aims to:

- ensure voltage and power quality compliance for our customers across the distribution network;
- reduce both the safety risk and the elevated energy consumption of customer appliances that are exposed to high network operating voltages;
- reduce the amount of voltage-induced DER curtailment of customer inverters that are exposed to high network operating voltages;
- enable greater levels of customer DER exporting, by alleviating over-voltage limitations within the network;
- enable greater levels of customer imports and reduce the risk of customer appliances from damage, by alleviating under-voltage limitations within the network.

Furthermore, the supporting programs:

- manage steady-state voltages at a holistic level in an environment of increasing numbers of DER, targeting a DVM rollout at the conclusion of our current trial[2] across the network on a least-regrets basis;
- complement this centralised DVM rollout program[3] with a subset of proactive, distributed program of works[4] to manage steady-state voltages and other quality of supply issues at a localised level, targeting our worst-served customers and those areas of the network that contribute to deteriorating the performance of the centralised DVM system;
- include ongoing (recurrent) expenditure needed to support urgent unforeseen quality of supply investments in response to customer complaints that are not addressed by our proactive programs. It is a continuation of the program within which projects addressing valid customer complaints on the quality of electricity supply can be raised and implemented. This reactive power quality management program has proven successful in resolving customer complaints on power quality within the current period to the satisfaction of our customers, and avoided escalation of their complaints to the Energy and Water Ombudsman of Victoria (EWOV);

1 Electricity Distribution Code of Practice – Essential Services Commission of Victoria, Version 2, 1st May 2023.

2 The current DVM trial at our Airport West (AW) and Coburg South (CS) zone substations is fully funded within the current regulatory period.

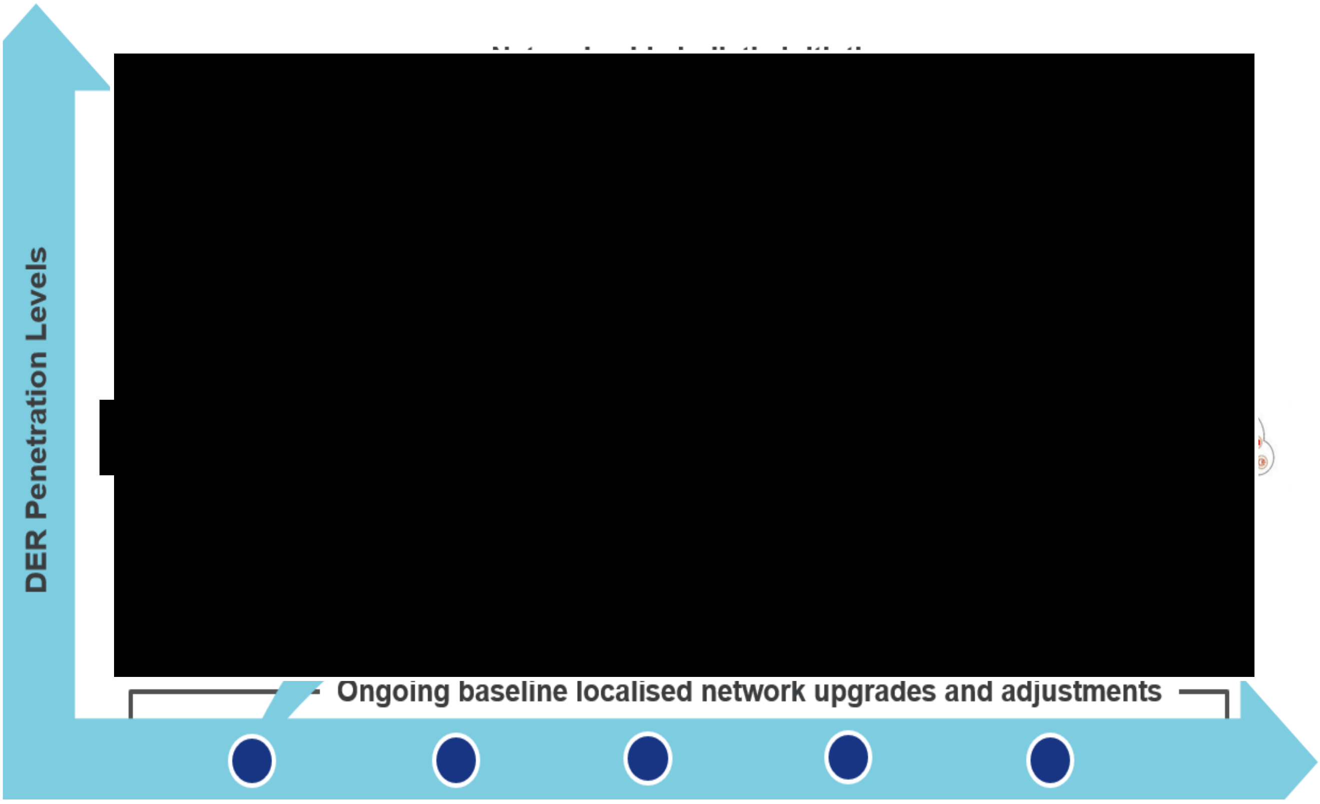
3 Option 2 in Table 1.

4 Subset of Option 3 in Table 1.

- optimise the blend of centralised and distributed solutions and the sequence of investment, to provide the highest net present value benefit, consider risk, performance, cost, timing and uncertainty - based on the emerging network need;
- complement and support other FNS initiatives and programs;
- are scalable for the future; and
- ensure the total lifecycle costs of the risk and investment is prudent and efficient in the long term.

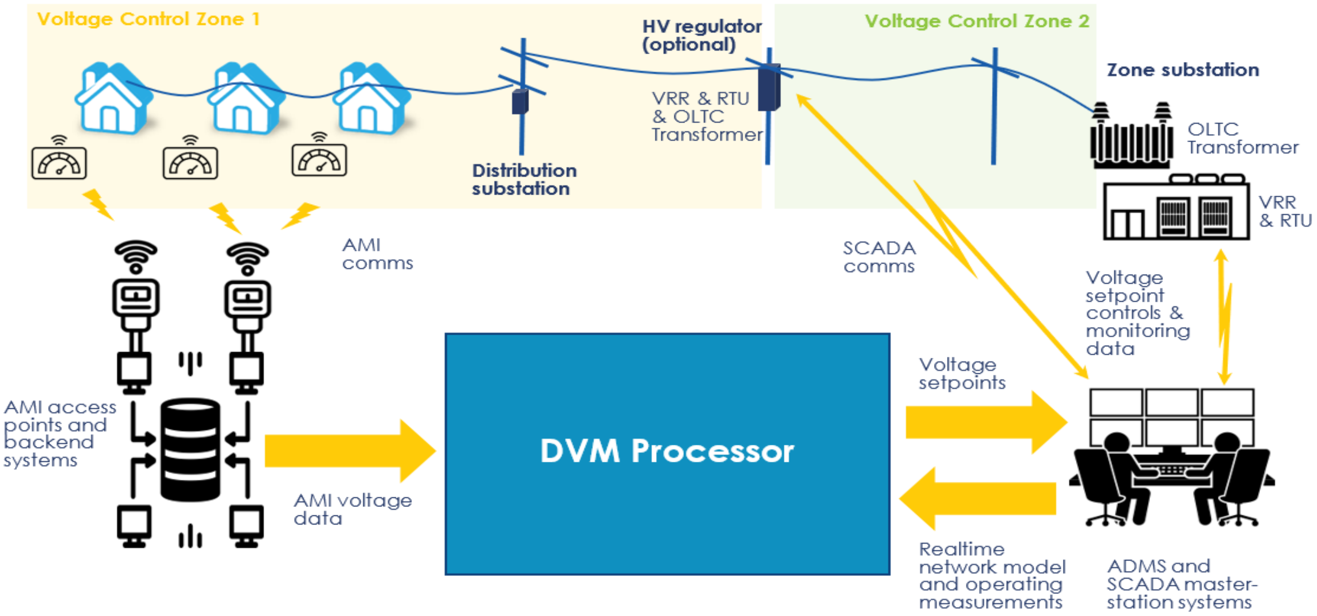
The proposed roadmap for the development of JEN's Voltage and PQ Management capabilities to meet emerging operational and customer needs over the next 10-years is illustrated in Figure 0.1.

Figure 0.1 – JEN's Voltage and PQ Management and Flexible Services Capability Roadmap



The proposed concept diagram for the establishment of JEN's new DVM capability to meet its business needs for the next 10-years is illustrated in Figure 0.2.

Figure 0.2 – JEN's Dynamic Voltage Management Concept Diagram



JEN has identified that there is an economic case to further invest in Voltage and PQ Management programs over the next 10 years to address the need with some investments starting now.

The Voltage and PQ Management program sets out a least-regrets investment roadmap providing an optimal balance between risk, performance, cost, timing and uncertainty to meet the identified needs in this paper and facilitate delivery of the FNS.

Table 1 presents the net economic value of the Voltage and PQ Management program roadmap for various development options for the next regulatory period, spanning 2026 to 2031.

Table 1 – Program Roadmap 20-Year Economic Evaluation by Option for 2026-2031 Regulatory Period[5]

Economic Evaluation Results	Option 1 - Do Nothing	Option 2 - Centralised DVM Program Only	Option 3 - Distributed Voltage & PQ Management Program Only	Option 4 - Centralised DVM & Optimised Distributed Voltage & PQ Management Programs
Total Costs ($m)	0.0	42.4	49.4	49.8
Present Value Costs ($m)	0.0	19.7	31.6	31.4
Present Value Benefits ($m)	0.0	16.6	33.6	33.6
Net Present Value (NPV) ($m)	**0.0**	**(3.0)**	**2.0**	**2.2**

The economic analysis of the options suggests that Option 4 – "Centralised DVM & Distributed Voltage & PQ Management Programs" maximises the present value of net benefits and is therefore the recommended development path. It includes proactive elements based on network performance data (particularly from AMI smart meters), and recurrent reactive elements based on customer complaints resolution.

It is recommended that JEN adopt the strategic roadmap detailed in this paper.

5 Direct escalated costs (including overheads), June 2024 dollars.

1. Strategic need

1.1 JEN's strategic vision

JEN's mission is to connect its customers to a renewable energy future. To deliver on this commitment, JEN's distribution network assets need to be capable of delivering an affordable, safe and reliable electricity supply that meets its customers' expectations, in a manner that is compliant with all regulatory compliance requirements and meets customer and community needs. This includes a focus on preparing the network for the future, leveraging new technologies and cost efficiencies where possible, and improving network competitiveness and customer outcomes.

1.2 A changing energy landscape

JEN is faced with operating in a rapidly changing energy landscape. Disruptive impacts on distribution networks, particularly those triggered by the distributed renewable energy transition, are changing the way electricity networks are used by customers as we know it today.

DERs continue to increase in numbers and will ultimately become a crucial resource to support, manage and utilise within the distribution network. Already JEN has seen strong growth in network-connected, passive distributed solar photovoltaic (DPV) system installations by its customers, and this is likely to continue well into the future. Other emerging, potentially more active DER technology (including customer and community storage and electric vehicles) present further challenges and opportunities for network integration of DER and the accelerating pace of electrification. This is expected to result in an increasing proportion of the overall power system generation being located within the distribution networks. Hence, voltage and PQ management will become increasingly more important and complex for JEN to manage as the penetration of DER rises, and as electrification of gas and transport sectors takes on momentum.

We will need to continue to adapt and strategically respond to this change, with a more proactive, technologically, data-driven approach to the management of our network (and in particular the low-voltage (LV) network), compared to the reactive approach historically taken at this level of the distribution network.

Many of the challenges for us will relate to voltage and other quality of supply compliance limitations, manifesting from reverse power flows driven by DER export. Improved voltage management (and the associated optimal management of reactive power) is a key element of a strategic response to this need.

While the emerging challenges lie in LV voltage management, the current operational real-time voltage control capability is predominantly[6] implemented at the high voltage (HV) level of the network using on-load tap changer (OLTC) transformers and the switching of reactive plant (capacitors). Currently these network devices are used on our network to regulate HV voltages only, with voltage drop[7] assumptions used to determine the HV float voltages needed to give rise to satisfactory LV voltages. This method of control is not optimal in a DER-rich environment for the bulk of customers and their DER connected at LV, as there is no direct measure and feedback into JEN's voltage control systems on how the LV voltages are performing.

We are ideally placed to respond to the emerging challenges of voltage management with our ubiquitous availability of AMI smart meters. Leveraging big data sets provides the visibility of DER behaviour and its impact on the network's operation, an essential element in addressing the challenges faced by DER. Data can facilitate the use of geospatial network analytics and machine-learning applications, advanced distribution management system applications, and other operational digital technologies to provide more efficient delivery of distribution services, particularly in a network with increasing penetrations of DER. Such technology overlays will allow us to optimise the use of its existing network assets, including for voltage management, to minimise network capital expenditure requirements needed to adapt to the changing energy landscape.

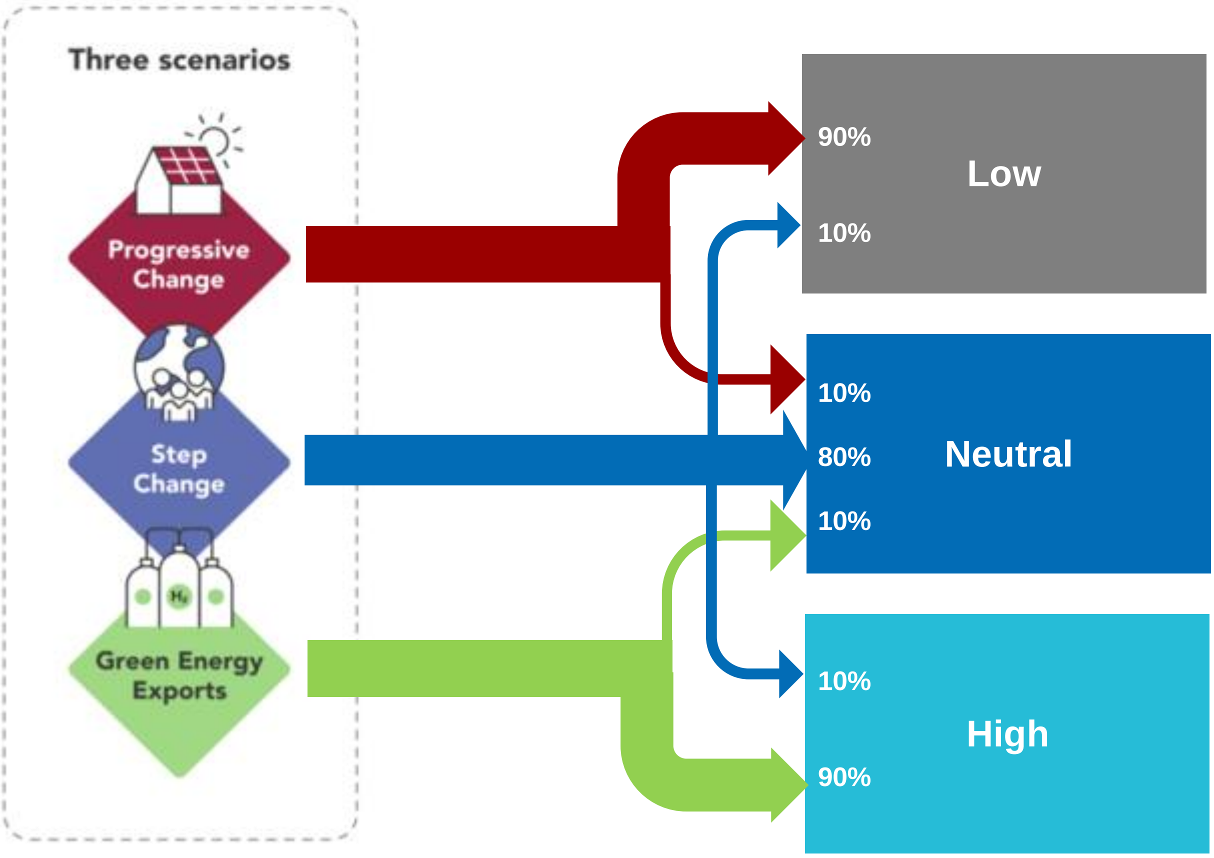
6 Distribution transformer off-load tap changers can be adjusted manually to adjust LV voltages. Furthermore, JEN has mandated standardised Victorian-wide smart inverter settings for all new household DER inverters, to improve LV network voltage profiles using inverters' Volt-VAr and Volt-Watt capability.

7 These are historic assumptions from pre-DER times when the network was less dynamic, and power flowed only in one direction.

1.3 Alignment with JEN's Future Network Strategy

As we plan our network investments, we recognise the importance of properly preparing our network for this changing energy landscape, in an environment of rapid change and uncertainty. Our FNS defines high, neutral and low future-state scenarios, and uses these to identify strategic responses to the challenges and opportunities posed by each scenario. These three future-state scenarios are a weighting of AEMO's three scenarios used in its Inputs, Assumptions and Scenarios Report (IASR)[8], as illustrated in Figure 1.1.

Figure 1.1 – JEN's Future Network Strategy – Future State Scenarios



Regardless of the future state of the network and the potential changes to the way the National Electricity Market (NEM) operates, JEN has identified several 'least-regret' activities as part of our FNS that will address the aspects common to all future scenarios to unlock benefits for our customers. Implementing these activities will ultimately benefit all of our customers in the long term, by allowing them to maximise the opportunities available from increasing DER while optimising the utilisation of our existing network assets.

The programs of work identified from these strategies set out least-regrets investment roadmaps, providing a prudent optimum balance between risk, expenditure and uncertainty, to meet the identified needs of the energy transformation, with key benefits being:

- **Regulatory compliance** – improved appliance safety and reduced consumption by maintaining our delivered voltages and quality of supply performance within regulatory limits; and
- **DER enablement** – improved export capability and reduced DER curtailment, determined using the Customer Export Curtailment (CECV)[9] methodology.

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8 2023 Inputs, Assumptions and Scenarios Report, AEMO.

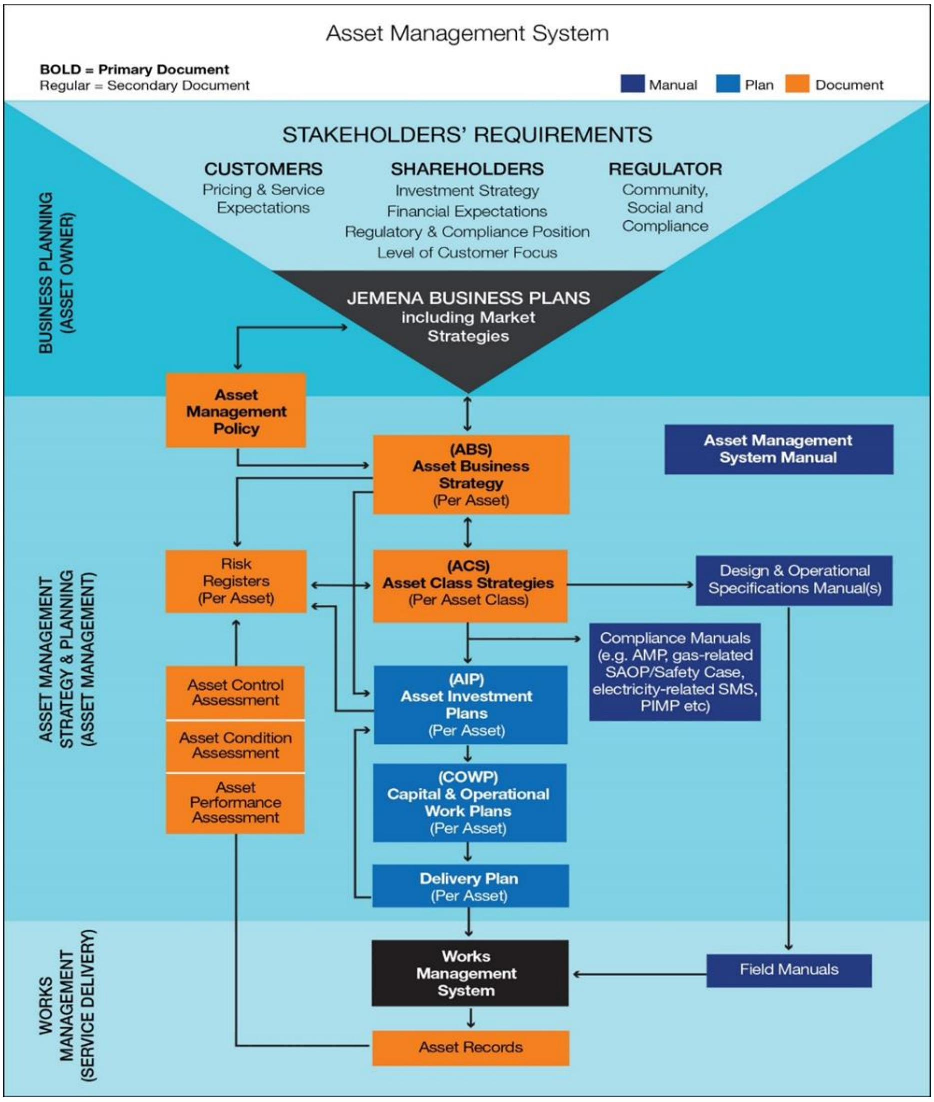
9 Customer Export Curtailment Value (CECV) methodology, AER.

This Voltage and PQ Management program supports JEN's CER Integration Strategy and proposes a Voltage and PQ Management roadmap aligned with those FNS themes.

1.4 Alignment with JEN's Asset Management System

JEN's approach to managing the performance and safety of our network and our network investment decision-making, is defined by our Asset Management System. Figure 1.2 outlines the JEN Asset Management System. This strategic framework facilitates the planning and identification of business needs that require network investment, justified through options assessments, economic evaluation, and documented in business cases.

Figure 1.2 – JEN's Asset Management System



Our Asset Management System structure operates in accordance with the high-level structure of AS 55001. This Voltage and PQ Management program sits within and supports our Asset Management System as an Asset Business Strategy (ABS). The Voltage and PQ Management program has been developed to allow us to embrace and prepare for a lower carbon future, consistent with the strategic objectives of our FNS.

2. Needs analysis

2.1 Our regulatory obligations

As a Victorian Distribution Network Service Provider (DNSP or distributor), we are required to comply with the Victorian Electricity Distribution Code of Practice (EDCOP)[10]. Part 3, Clause 20 details the regulatory obligations for the quality of supply for a number of parameters, including voltage.

Clause 20.4.2 of the EDCOP states that a distributor must maintain a nominal voltage level at the point of supply (POS) or meter to the customer's electrical installation in accordance with Table 1 (reproduced below).

Table 2 – EDCOP Nominal Voltages

Table 1

230 V	Meter
400 V	Meter
460 V	Meter
6.6 kV	POS
11 kV	POS
22 kV	POS
66 kV	POS

Source: EDCOP

The acceptable variation in those nominal voltages is documented by the EDCOP Clause 20.4.2 in its Table 2 (reproduced below).

Table 3 – EDCOP Voltage Variations

Table 2

STANDARD NOMINAL VOLTAGE VARIATIONS					
	Voltage Level in kV	Voltage Range for Time Periods			Impulse voltage
		Steady State	Less than 1 minute	Less than 10 seconds	
1	<1	*AS* 61000.3.100*	+ 13% - 10%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	6 kV peak
2**		+ 13% - 10%			
3	1 – 6.6	± 6% (± 10% Rural Areas)	± 10%	Phase to Earth +80%, -100% Phase to Phase +20%, -100%	60 kV peak
4	11				95 kV peak
5	22				150 kV peak
6	66	± 10%	± 15%	Phase to Earth +50%, -100% Phase to Phase +20%, -100%	325 kV peak

Notes for EDCOP Table 2:

** When examining network-wide compliance, functional compliance is met if the limits in Table 2 of AS 61000.3.100 (up to 1% of measurements below 216 V and up to 1% of measurements above 253 V) are maintained across at least 95% of a distributor's customers.*

*** Row 2 values (steady state, less than 1 minute, and less than 10 seconds) define the circumstances in which a distributor must compensate a person whose property is damaged due to voltage variations according to clause 20.4.8.*

Source: EDCOP

10 Electricity Distribution Code of Practice – Essential Services Commission of Victoria, Version 2, 1st May 2023.

For steady-state voltage variation, customer LV and HV voltages are subject to fixed limits, whereas customer LV voltages are also subject to duration-based limits as defined by AS61000.3.100 in its Table 2 (reproduced below).

Table 4 – EDCOP LV Steady-State Voltage Variations

TABLE 2

230 V NOMINAL STEADY STATE VOLTAGE LIMITS

Steady state voltage measure (10 minute r.m.s.)	Phase-to-neutral voltage limit		Phase-to-phase voltage limit		1 phase 3 wire centre neutral phase-to-phase voltage limit	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
$V_{1\%}$	216 V	—	376 V	—	432 V	—
$V_{99\%}$	—	253 V	—	440 V	—	506 V

Source: AS61000.3.100

$V_{x\%}$ is the value of the voltage below which ‘x’ percent of measurements fall over a survey period (using the measurement technique prescribed in AS61000.4.30) at a customer’s AMI meter.

2.2 Identified need

Our fleet of zone substation OLTC transformers and capacitor banks, are the key assets on our network that undertake the role of regulating network voltage and power factor. The function of the relays that control these assets is to locally regulate the voltage and reactive power on the HV buses at each of these zone substations. The regulation of customer voltages (the bulk of whom are connected in the LV networks), is only maintained through reviews and adjustments of distribution transformer taps manually on-site, infrequently on a case-by-case basis.

Maintaining customer voltages within acceptable limits has to date, been achieved by using voltage-drop assumptions, based on the expected maximum demand and the impedance of the network between the voltage regulation source and the customer. With power traditionally flowing in only one direction, the network was designed (and assets specified) to maintain voltages toward the top end of acceptable limits, to allow a margin down to the lower limits to cater for the voltage-drop through the network under maximum demand. The voltage-drop design assumptions have been necessary to manage customer voltages, because there is currently no capability on our network for directly regulating customer voltages in near real-time.

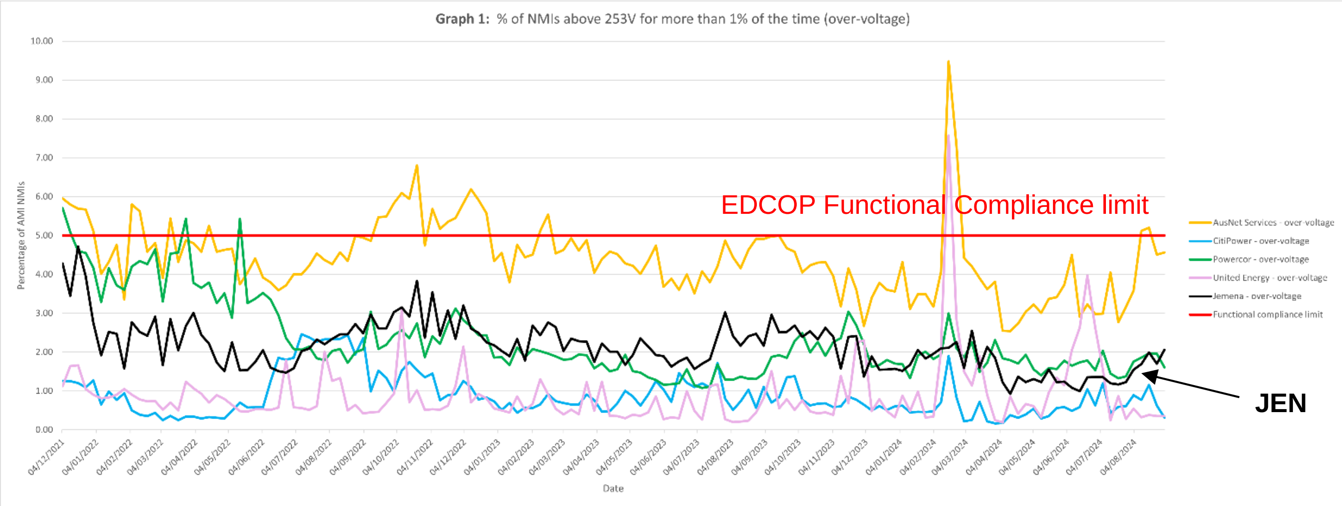
With the uptake of distributed solar PV and other forms of DER, power can now flow in both directions, placing pressure on JEN to be able to maintain acceptable levels of voltage regulation. Whilst the network was designed for one-way power flow, our ability to cater for reverse power flows is limited due to the voltage-rise that can occur at the customer connection points. This is becoming increasingly problematic as DER penetrations rise, particularly at times of minimum daytime demand, when solar PV systems are most likely to be exporting into the network. The following section presents the voltage-related challenges that are facing JEN as a result of higher DER levels in the network.

2.2.1 Voltage performance

We (and all other Victorian distributors) must report our steady-state voltage compliance levels to the Essential Services Commission (ESC)[11] of Victoria each quarter, a reporting mechanism enabled by the availability of smart meter voltage data from our AMI systems and capabilities. Since the reporting came into effect from late 2021, the steady-state voltage compliance results (network-wide) for JEN compared to the other distributors is presented in Figure 2.1 for over-voltages and Figure 2.2 for under-voltages.

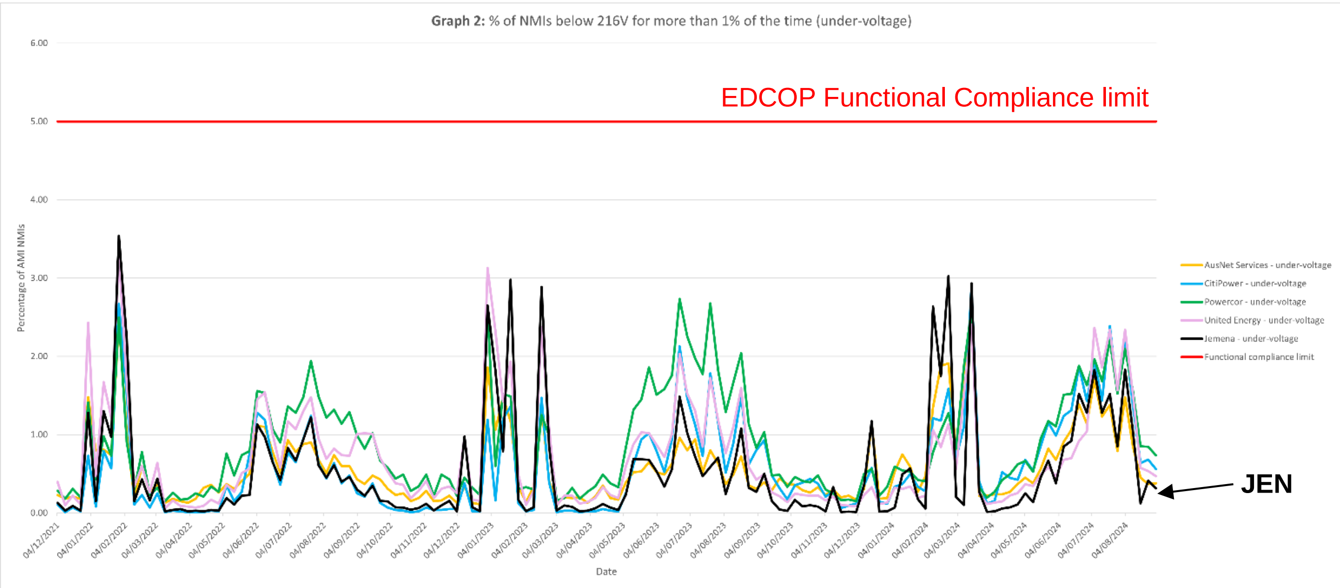
11 Voltage performance data – Essential Services Commission of Victoria, 2024.

Figure 2.1 – Steady-state over-voltage EDCOP non-compliance (by distributor)



Source: ESC

Figure 2.2 – Steady-state under-voltage EDCOP non-compliance (by distributor)



Source: ESC

The ESC only considers *functional compliance* is achieved for a distributor “if up to 1 per cent of measurements below 216 V and up to 1 per cent of measurements above 253 V are maintained across at least 95 per cent of a distributor's customers”[12].

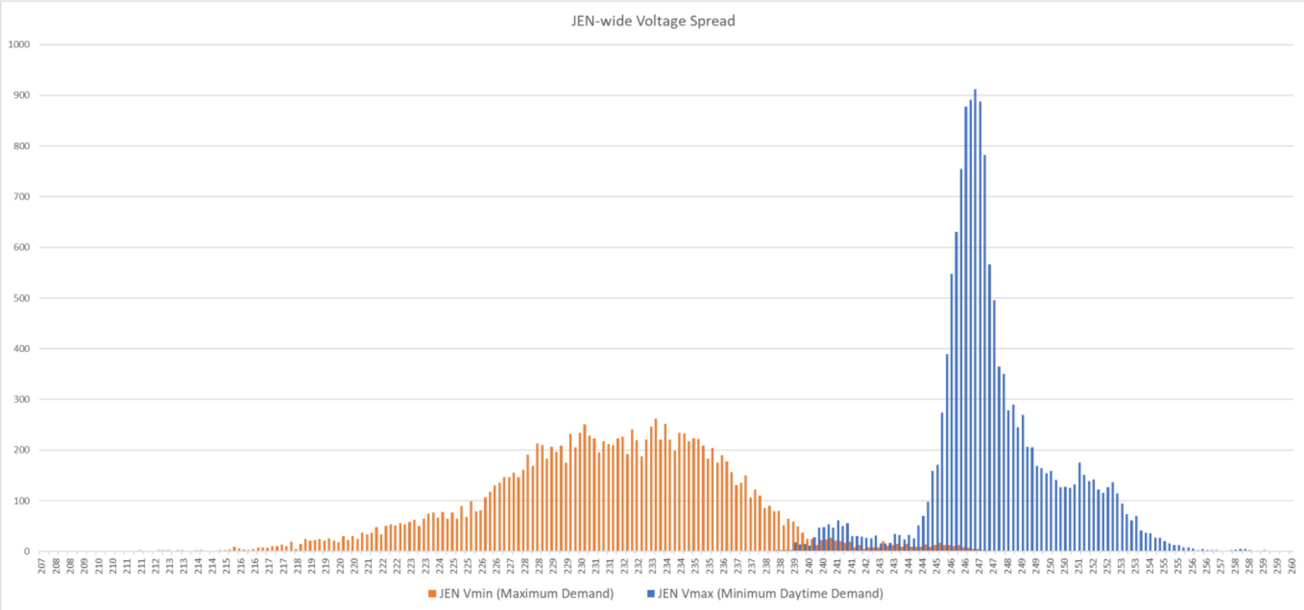
While JEN has remained functionally compliant with the EDCOP and maintained the level of compliance over the duration of the historical reporting period (following planned reductions in voltage in early 2022), there remains up to 3.9 per cent of customers who are experiencing non-compliant over-voltages,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

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

12 EDCOP Table 2, Note 1.

Figure 2.3 and Table 5 illustrate our actual network-wide LV voltage distribution across our population of AMI meters for two extreme network operating conditions - maximum demand (17th January 2023) and minimum demand (18th December 2023).

Figure 2.3 – JEN network-wide AMI LV steady-state voltage distribution at maximum and minimum demand



This chart highlights that JEN's LV steady-state voltage has some issues with respect to EDCOP compliance at the upper end of the regulatory limits for minimum demand, and at the lower end of the regulatory limits for maximum demand.

Table 5 – JEN network-wide AMI LV steady-state voltage distribution

Demand Condition	1st Percentile	50th Percentile	99th Percentile	Voltage Spread[13]	% Under[14]	% Over[15]
Maximum	218 V	231 V	244 V	26 V	**0.4%**	0.0%
Minimum	240 V	247 V	**254 V**	14 V	0.0%	**2.4%**

At both times of maximum and minimum demand there are material numbers of customers with voltages operating outside of the 216 V and 253 V EDCOP limits, being 0.4% below 216 V and 2.4% above 253 V respectively. Cross-referencing the time of the instantaneous values presented in Table 5 with the week of the compliance measurements taken in Figure 2.1 and Figure 2.2, this corresponds to EDCOP non-compliance values of 3.0% and 2.4% respectively.

Whilst presenting this data in this way is not an exact measure of compliance throughout the year, it does reflect the worst-case instantaneous operating conditions at the two extremes of network operation. Targeting mitigations at one or both of these extremes will deliver better compliance outcomes for JEN, as the operation of the network at any time of the year is expected to have voltages lying between the two extremes.

Structuring the data this way also highlights the significant offset between the median (50th percentile) values of customer voltages between minimum and maximum demand conditions, illustrating the fact that JEN has not yet deployed[16] a DVM capability to dynamically raise voltages at times of maximum demand, and to dynamically lower voltages at times of minimum demand, to keep the distributions centred within the regulatory limits as much as

13 Difference between the 99th percentile and 1st percentile voltage.

14 Percentage of AMI meters below 216 V.

15 Percentage of AMI meters above 253 V.

16 JEN is currently trialling DVM technology at two of our zone substations during 2024 – Airport West (AW) and Coburg South (CS).

practicable. With significant margins[17] available for doing this, DVM is a credible solution to consider when assessing the range of solutions available for addressing JEN's over-voltage (and under-voltage) compliance issues. DVM is one of the solutions that we have included in the options considered.

The levels of over-voltage and under-voltage vary substantially across different parts of our network. Worst performing sites for over-voltage include KLO, TH, PV, CS, EP, NT, BY, TT, FW and HB. For those zone substation with voltage spread in excess of 37 V, that is where the spread of the distribution is greater than the margin provided between the 253 V and 216 V EDCOP limits, then it is not possible to correct voltage regulation through adjustments in OLTC voltage settings alone, and more localised corrective actions are needed. Such sites include EPN, NT, BY, NH, ES, CN and EP.

With the projected growth in solar PV expected on to our network over the next several years, these results are forecast to deteriorate further.

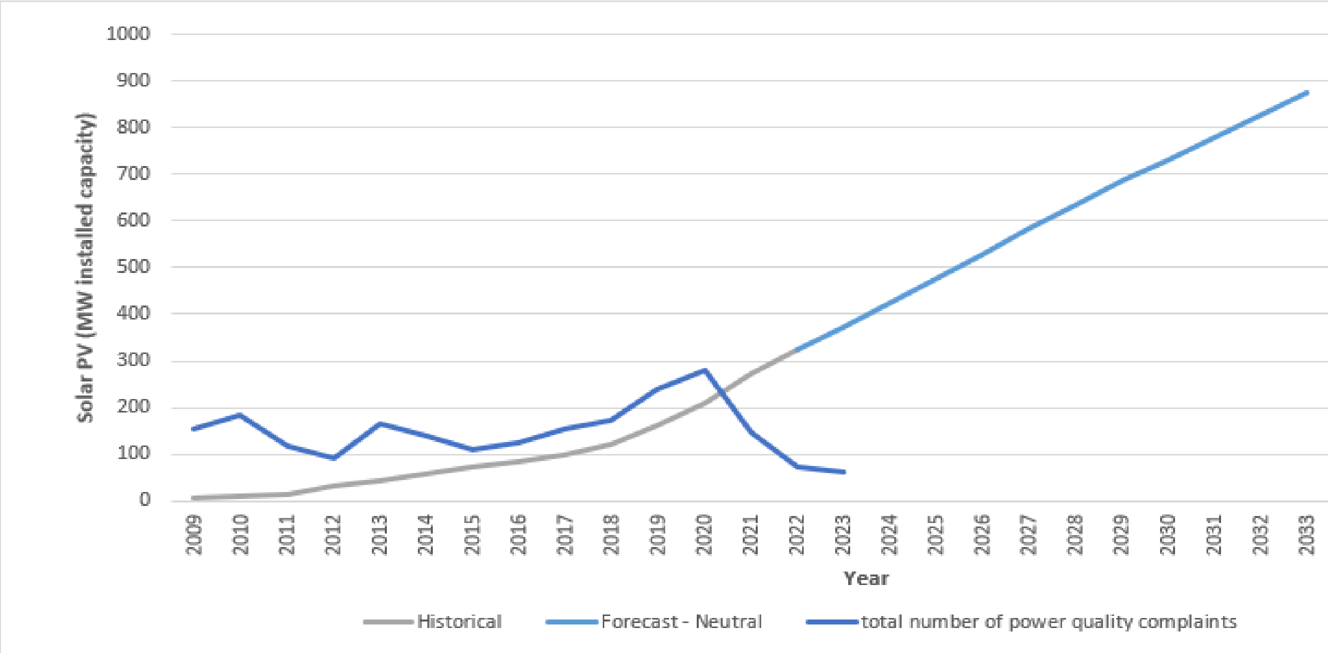
2.2.2 Quality of supply performance

JEN currently has a recurrent program that aims to resolve power supply issues raised by customers. This is predominantly a reactive program (mainly triggered by the urgency of customer complaints due to the lack of permanently installed quality of supply metering across the network[18]), to address quality of supply issues.

Each year we receive a significant number of customer complaints on quality of electricity supply. Complaints received by our call centre are referred to our technical staff who are tasked to investigate and identify the problem and develop a solution to address the issue based on least cost.

Figure 2.4 shows the historical growth of solar PV systems (grey), forecast (light blue) of solar PV systems up until 2033 and power quality (dark blue) complaints from 2009 to 2023.

Figure 2.4 – Voltage and quality of supply complaints



There is a distinct increase in the number of voltage complaints up until 2020. The bulk of the rise over this period was from complaints regarding solar inverter tripping due to over-voltages and identification of over-voltages by solar PV installers at customer premises during the installation process, as the numbers of connected solar PV

17 247 V – 231 V = 16 V.

18 While JEN uses AMI to measure steady-state voltage, it can only measure other power quality parameters at a limited scale—at the zone substation bus and at the end of the longest feeder of each zone substation. Customer complaints generally trigger JEN to temporarily install portable power quality meters at or near the customer's point of supply to confirm the issue and identify remedial action.

systems increased. Since 2020, the number of over-voltage complaints has significantly reduced due to active actions by JEN to reduce voltages across the distribution network. We intend to maintain this improved voltage performance through our planned proactive programs (particularly those that can be identified with AMI meters).

Nevertheless, there remains a base level of customer complaints that are not directly attributed to over-voltage, that require a response to other quality of supply issues such as harmonics, flicker, unbalance and sags or swells (for example). Hence, a level of zero customer complaints is unachievable, necessitating an ongoing reactive quality of supply program to support the management of these residual quality of supply issues that proactive programs do not identify or address. The forecast expenditure for this program is based on the annual average recent historical expenditure.

Failing to respond to and resolve customer complaints on power quality to the satisfaction of our customers, risks an escalation of their complaints to EWOV. As well as the need to resource the EWOV enquiry processes, there is a likelihood of more extensive and expansive corrective action being required because of the EWOV's investigations.

We do not expect an increase in complaints when this recurrent reactive program continues in parallel with proactive quality of support and voltage compliance programs.

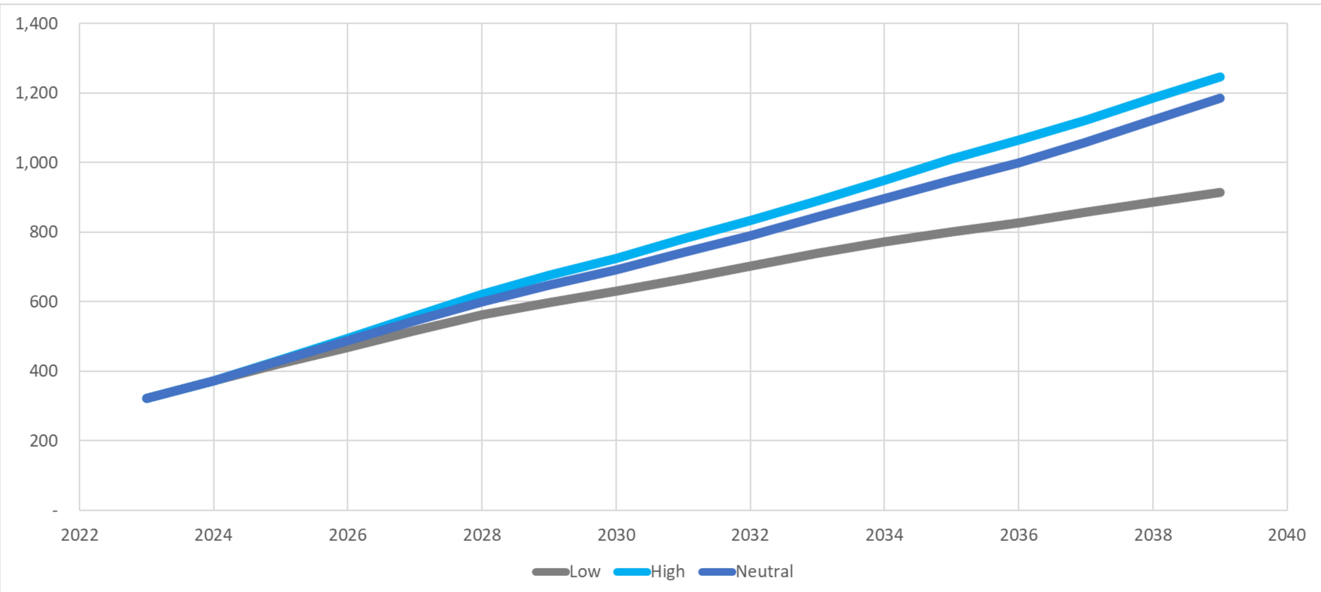
2.2.3 DPV forecasts

JEN has comparatively low levels of solar PV installations in our network compared to other DNSPs around Australia, with installed DPV capacity in 2023 being 322 MW across 16% of our customer base. Nevertheless, the growth in unconstrained solar PV on our network is expected to continue over the short, medium and long term, with increasing penetration levels having a material impact on increasing our network voltages.

We have consistently increased our forecast for solar PV installations year-by-year, in response to actual uptake exceeding expectations due to increasing system sizes, rapidly reducing system costs, and heavy subsidies and rebates (including the Victorian Government's Solar Homes Program[19] administered through Solar Victoria). With each re-forecast, this risks around managing voltages comes sooner, meaning we must act with an ever-increasing pace.

Figure 2.5 presents the latest 2023 forecast uptake of solar PV for our three future-state scenarios. In all three scenarios the growth in solar PV continues up until at least 2040.

Figure 2.5 – JEN's Forecast of Distributed Solar PV Installed Capacity (MW) - by Scenario



[19] https://www.solar.vic.gov.au/

The penetration levels of solar PV are not uniform across our network which much of the growth occurring in new residential underground subdivisions on the urban fringes of our network.

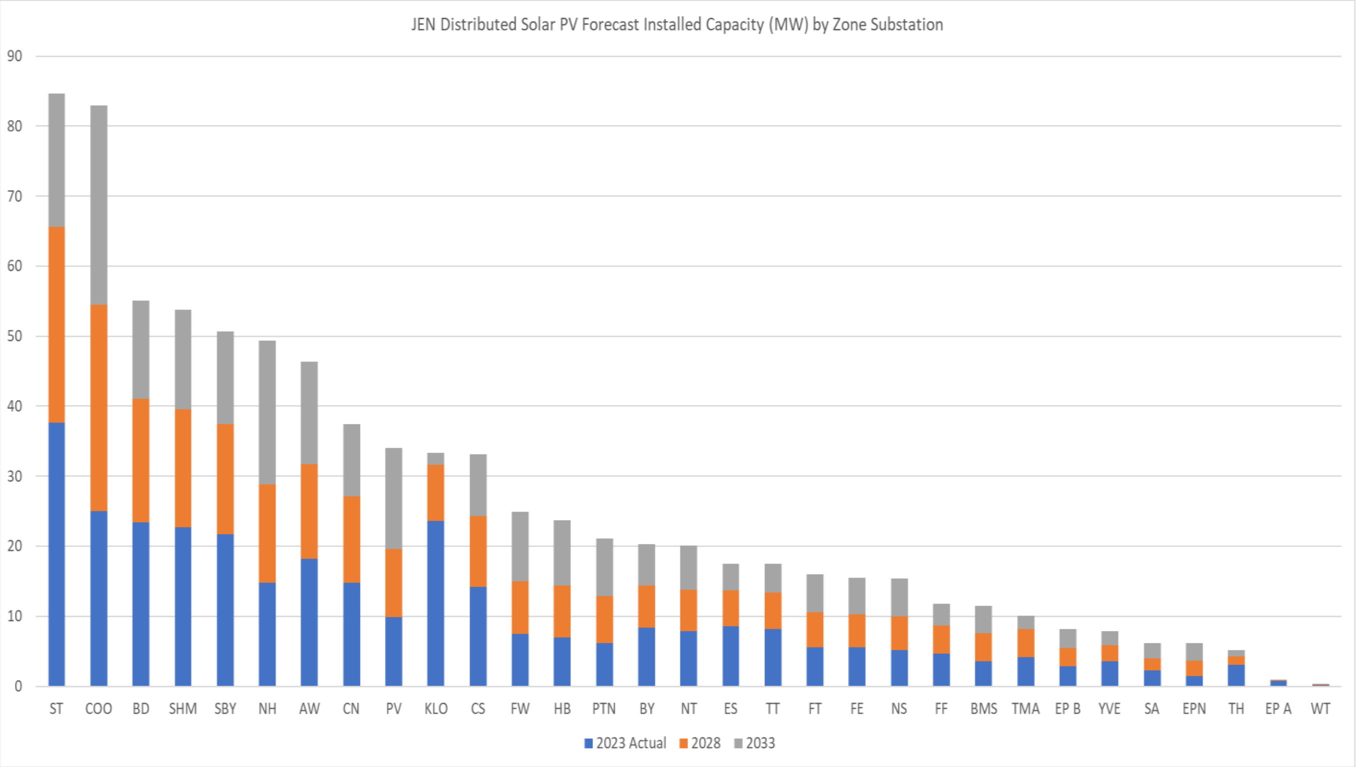
Figure 2.6 illustrates the distribution of solar PV systems across JEN's zone substations and the changes to that distribution over a five- and ten-year forecast period. The charts illustrates that the bulk of the systems and the absolute growth in those systems over a five- and ten-year period are located in the outer urban growth corridors in the new underground residential estates:

- ST, COO, BD, KLO form part of the Northern Growth Corridors including the developing suburbs of Mickleham, Craigieburn and Greenvale.
- SHM and SBY form part of the North-Western Growth Corridor including the developing areas of Sydenham, Hillside and Sunbury.

These are the areas likely to be prone to solar PV-induced reverse power voltage limitations with the effects most noticeable during spring, mild summer and autumn sunny days.

This is illustrated in Figure 2.6.

Figure 2.6 – JEN's Actual and Forecast Distributed Solar PV Installed Capacity (MW) - by Zone Substation



Whilst mandated Volt-VAr control inverter settings apply to the new systems being installed, a certain level of network investment will be required to maintain over-voltage compliance to avoid Volt-Watt-induced curtailment and export limiting of solar PV inverters. JEN assesses the economic balance between that investment, curtailment, and export limiting using the CECV methodology.

2.2.4 HV underground cable charging forecasts

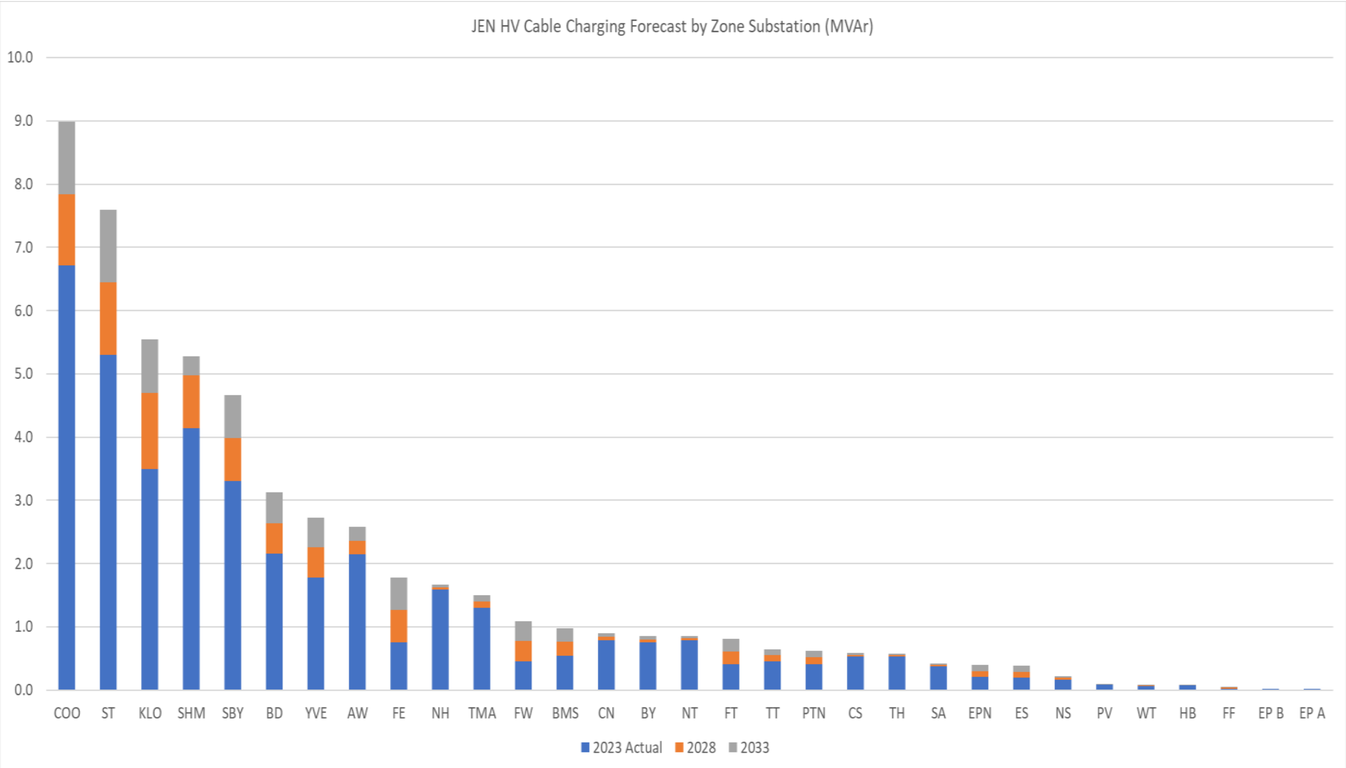
Apart from solar PV exports contributing to over-voltages on the distribution network, there is another cause of over-voltage limitation that will need to be managed, that being the growth in underground HV cable. 22 kV underground cable is a significant contributor of cable charging current which injects reactive power into the network, elevating network voltages. The effects are particularly noticeable at night when electricity demand is low, when solar PV inverters are off-line and not supporting network voltage through their Volt-VAr settings.

The locations with the highest amount of reactive power generated by HV cables and highest growth in cable charging are in the new 22 kV underground residential estates, which also coincide with the locations having the highest solar PV and growth:

- COO, ST, KLO, and BD form part of the Northern Growth Corridors including the developing suburbs of Mickleham, Craigieburn and Greenvale.
- SHM and SBY form part of the North-Western Growth Corridor including the developing areas of Sydenham, Hillside and Sunbury.

This is illustrated in Figure 2.7.

Figure 2.7 – JEN's Actual and Forecast HV underground cable charging (MVAr) - by Zone Substation



2.2.5 Available OLTC tap position forecasts

When over-voltage limitations materialise on the network, the control of voltage within regulatory limits can be aided by the tapping down of distribution transformers (for localised limitations) or zone substation transformers (for more widespread limitations). The limit to this being an effective means to mitigate the limitations is determined by the number of remaining available buck taps on the zone substation transformers.

As solar PV penetration levels increase and the amount of 22 kV underground cable increases, at times of low (or negative) net demand, some zone substation transformers will start to reach their extreme buck tap, after which point there is no further opportunity to maintain voltages.

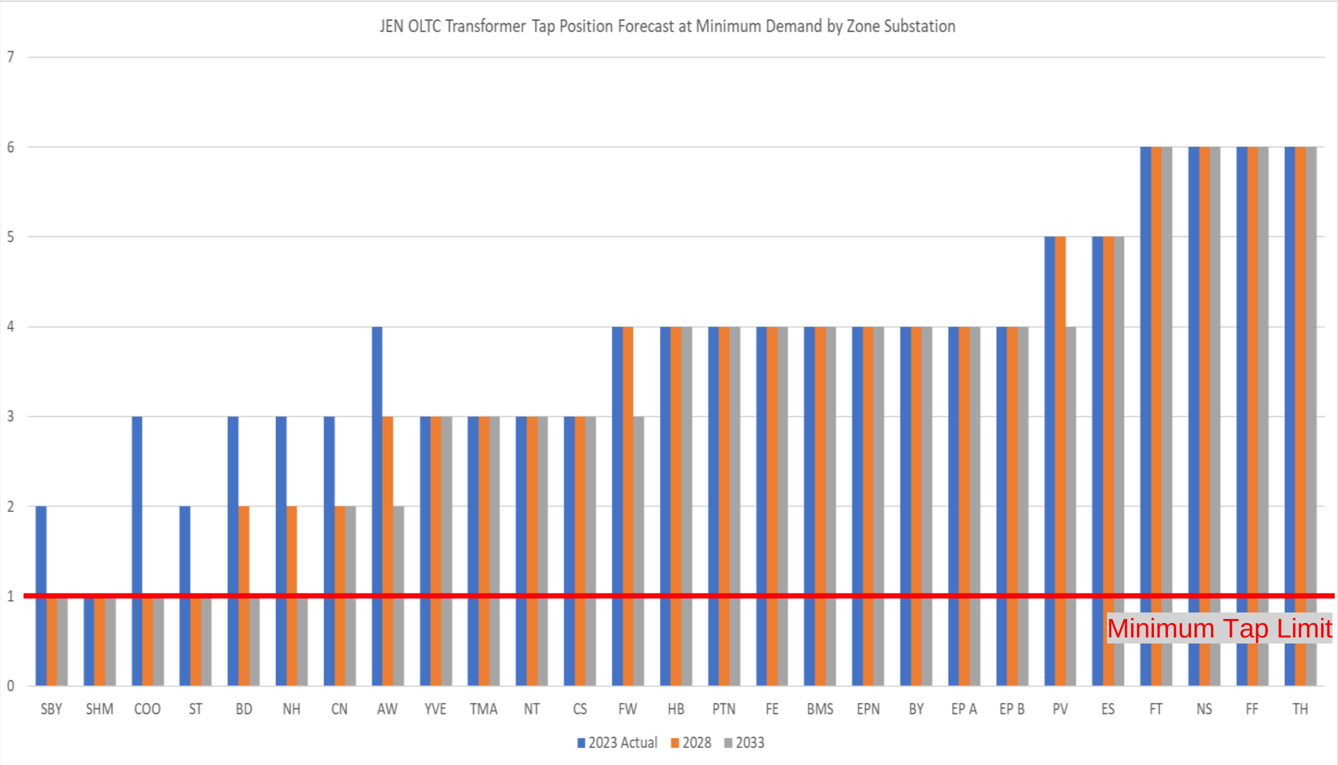
Figure 2.8 presents the actual transformer tap position (by zone substation) at JEN's minimum demand on 18th December 2023. Already three zone substations on our network, SBY, SHM and ST, are on the verge of no longer being able to satisfactorily regulate voltage at minimum demand, with their transformers effectively operating on the lowest tap during that time, with no remaining available tap positions in which to lower the voltage. This is equivalent to 10% of our zone substations and this level is expected to increase over time.

The locations with the lowest number of remaining OLTC taps are in the new 22 kV underground residential estates, which also coincide with the locations having the highest solar PV and growth:

- SHM and SBY form part of the North-Western Growth Corridor including the developing areas of Sydenham, Hillside and Sunbury.

- COO, ST, KLO, and BD form part of the Northern Growth Corridors including the developing suburbs of Mickleham, Craigieburn and Greenvale.

Figure 2.8 – JEN's Actual and Forecast Minimum Demand OLTC Transformer Tap Positions - by Zone Substation[20]



Options to increase the operating tap of zone substation transformers to provide additional tapping range for voltage control at times of minimum demand include:

- replacing transformers with transformers with additional buck taps;

- reducing float voltages at terminal stations and, if necessary, applying line drop compensation (LDC)[21]; or

- increasing the reactive power draw through the zone substation transformers to increase the voltage drop through the impedance of the transformer by switching off downstream capacitor banks, then if necessary, installing and switching on reactors.

20 Tap positions at EP, FW, ST and TH were unknown at the time of developing this strategy and are estimated.

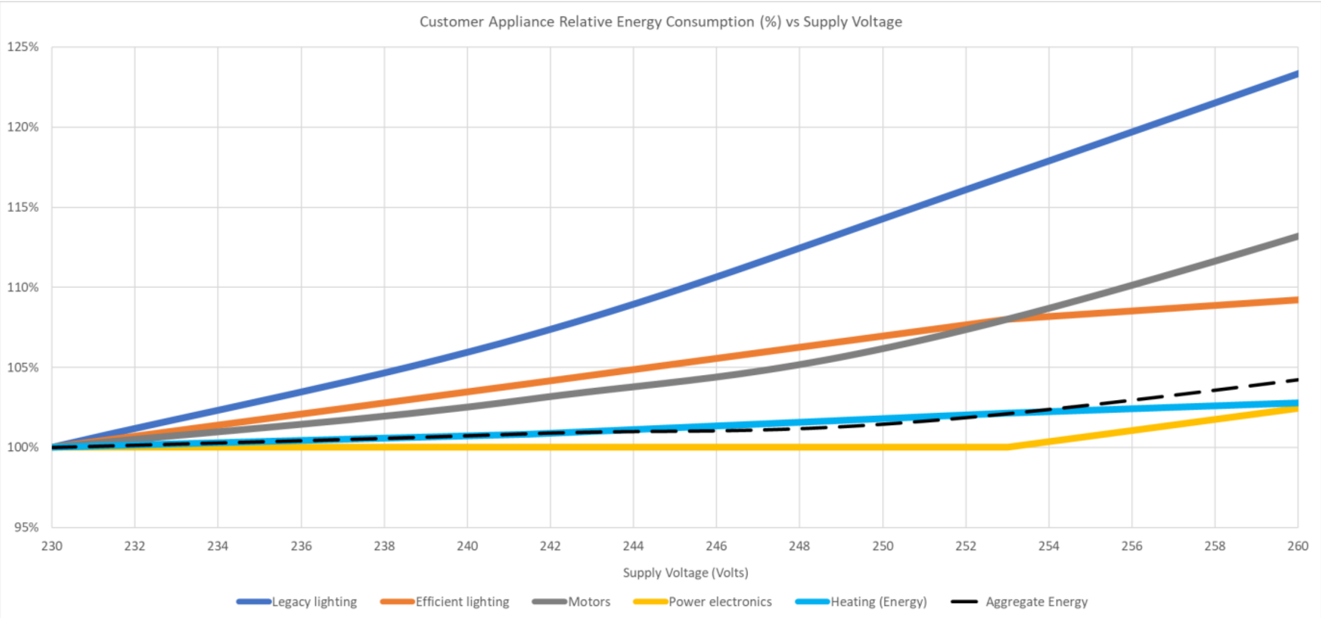
21 Most terminal station transformers are already operating at their extreme tap position; therefore, this option is no longer viable.

2.2.6 Voltage impact on consumption and safety

Over-voltages cause increased energy consumption by customers to levels higher than what would be the case if voltages were within the allowable operating range. Furthermore, voltages outside of EDCOP limits may cause customer equipment damage and reduced appliance lifespans, a potential safety risk for appliances overheating and catching on fire. A recognised approach to safety in the economic evaluation of investment is to apply a disproportionality factor to the quantified risk contributing materially to the safety risk – that being the over-voltage impact on customer appliances. JEN adopts the “As Far As Practicable” (AFAP) principle to safety which usually applies a disproportionality factor ranging between 1 and 6 that is commensurate with the safety risk, in this case being the operation of customer appliances beyond their technical design limits.

All Victorian DNSPs (including JEN) are operating with their average voltages towards the top end of the allowable EDCOP voltage range with the JEN median at 248 V at minimum demand. Higher supply voltages result in increased consumption of energy by customers. The amount of increase depends on the type of appliances used within the household, as illustrated in Figure 2.9.

Figure 2.9 – Relative energy consumption sensitivity to voltage (%) – by customer appliance type[22]



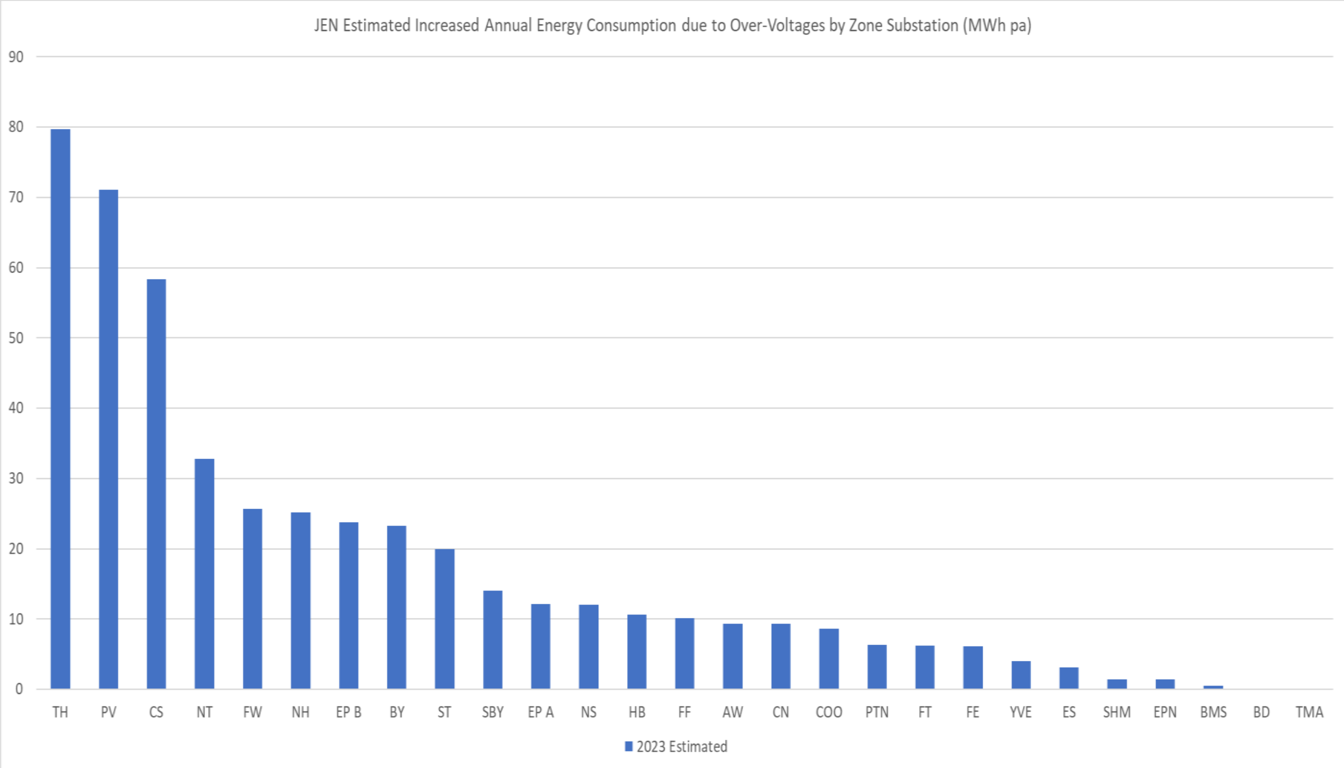
The aggregation[23] of all of these customer load types results in a rate of 0.33% increase in energy consumption for every 1 Volt above 253 V (the upper EDCOP limit).

Figure 2.10 This table presents the estimated annual increase in energy consumption at each zone substation due to current levels of customer over-voltages. Zone substations with significant proportions of their customers experiencing over-voltages have the highest levels of increased consumption, including TH, PV, CS, and NT. This totals approximately 475 MWh per annum across the JEN network.

22 Thermostat-controlled (cooking, heating and cooling) appliances have a much lower increase in energy compared to the instantaneous power (which has a square relationship with voltage), because the appliance is not needed to run as long to provide the same amount of heat when operating at higher voltages.

23 Aggregated by energy weighting as follows - 2% legacy lighting, 5% efficient lighting, 10% motors, 57% electronics, 25% heating elements.

Figure 2.10 – JEN’s Increased Annual Energy Consumption due to Over-Voltages (MWh pa) – by Zone Substation



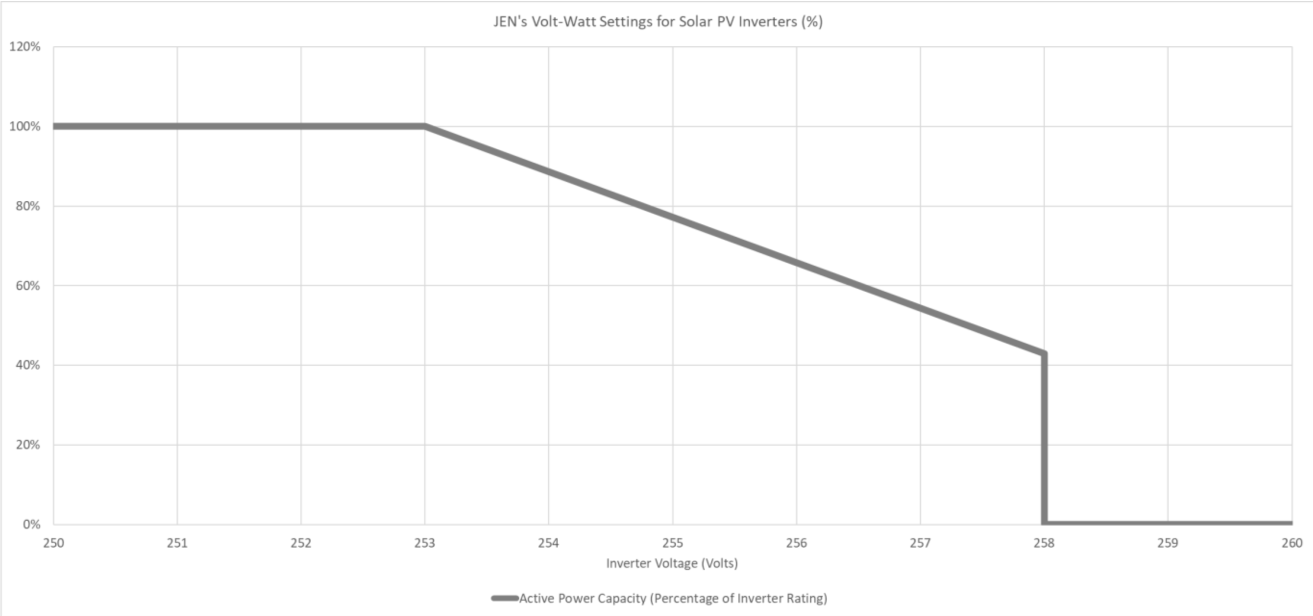
Under a ‘do nothing’ approach, more customers are expected to experience over-voltages and for longer, as the total amount of solar PV and 22 kV cable increases, and as the OLTC taps at zone substations reach the end of their buck tapping range. As a result, this increase in consumption is expected to rise over time.

2.2.7 Solar PV curtailment

High supply voltages above 253 V could result in curtailment of solar PV output (through the action of Volt-Watt inverter settings). The amount curtailed depends on the inverter size and level of solar PV generation. Furthermore, excessive over-voltages at or above 258 V (or legacy inverters at or above 255 V), results in inverter tripping.

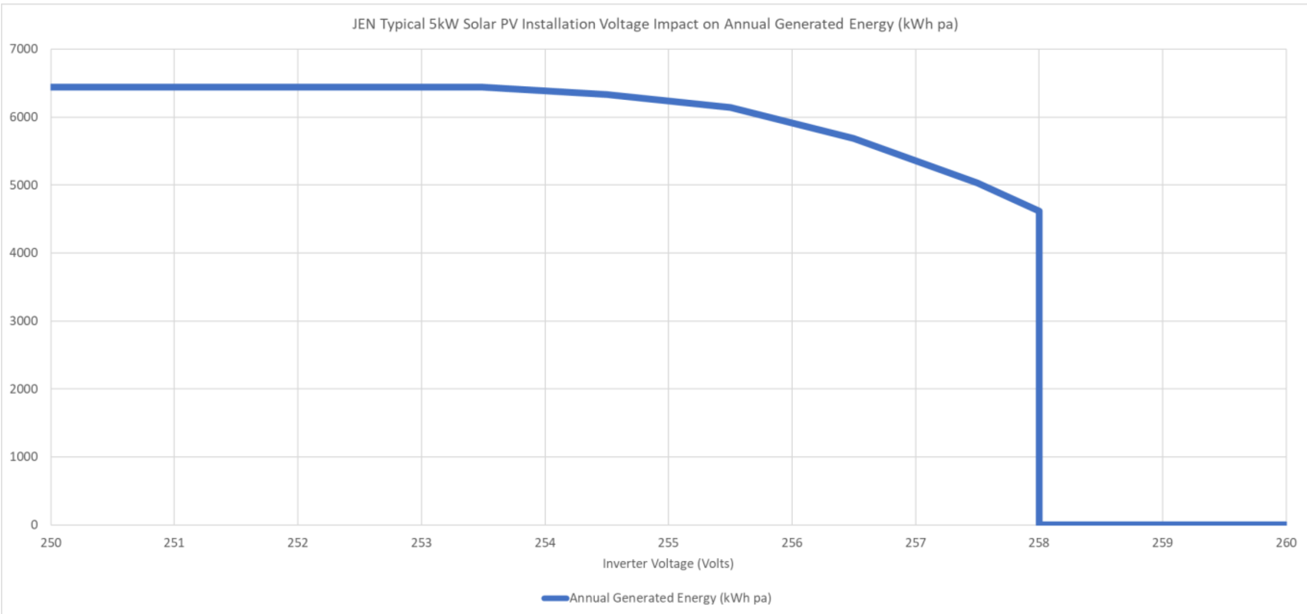
New solar customers exposed to voltages consistently above the upper limits of the EDCOP, will expect to be curtailing any solar power production higher than a percentage of the inverter’s nameplate rating as shown by the mandated Volt-Watt settings of Figure 2.11.

Figure 2.11 – Solar PV inverter power curtailment characteristic (% of inverter rating) vs voltage (Volts)



For example, applying this characteristic to a typical solar PV customer with a 5 kVA inverter and 5 kW of panels, generating 4kW, the solar PV generation will be curtailed down to a level of 3kW[24] if the voltage is raised to 256 V. Figure 2.12 illustrates that such a customer, potentially generating 6.4MWh pa, would be curtailed to 5.7MWh pa if the voltage is held at that level all year, an 11% annual energy production reduction. Most of the curtailment would be occurring during the summer period.

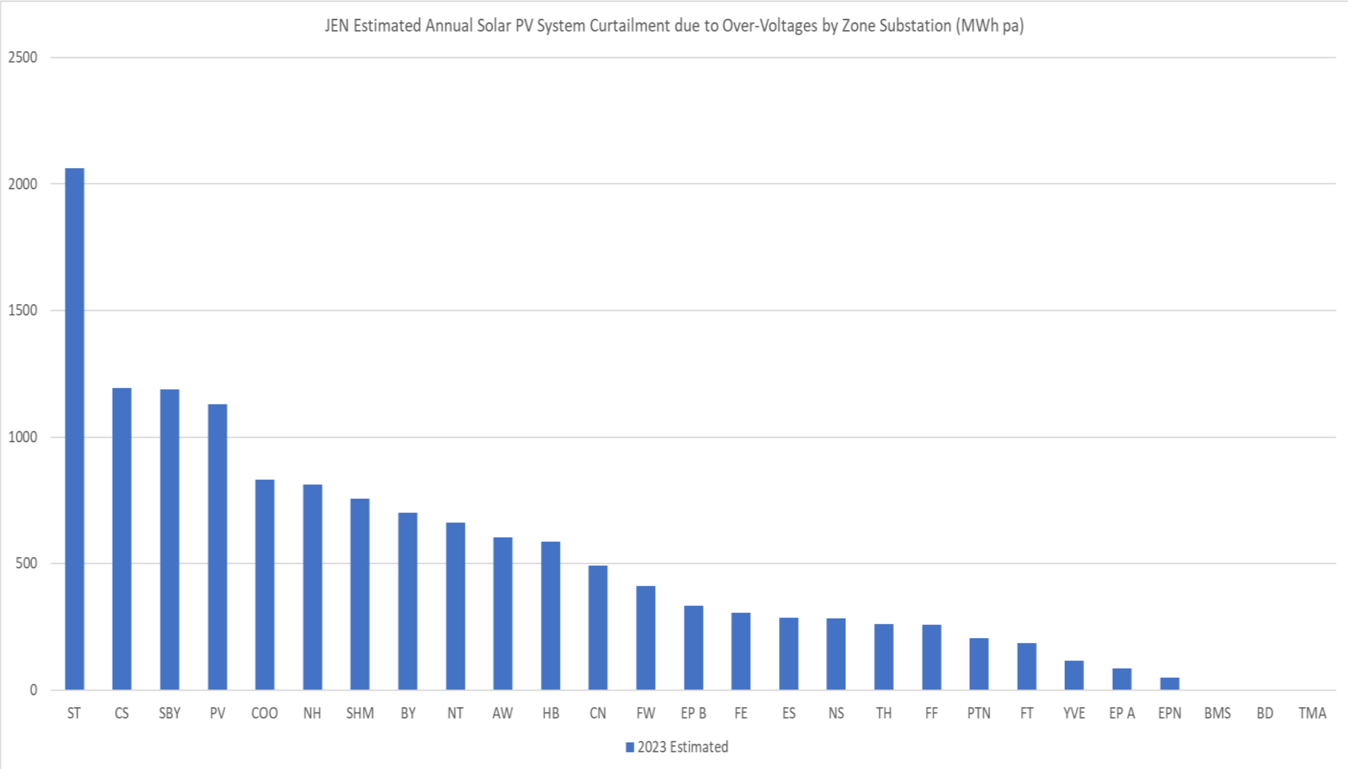
Figure 2.12 – Typical 5 kW solar PV system annual energy generation (kWh pa) vs operating voltage (Volts)



Applying this method to the over-voltages experienced on each zone substation gives the curtailment profile observed in Figure 2.13.

[24] Minimum of 4kW or 60% x 5kVA = 3kW.

Figure 2.13 – JEN's Solar PV System Annual Energy Over-Voltage Curtailment (MWh pa) – by Zone Substation



Under a 'do nothing' approach, more solar PV customers are expected to experience over-voltages and for longer, as the total amount of solar PV and 22 kV cable increases, and as the OLTC taps at zone substations reach the end of their buck tapping range. As a result, this increase in solar PV curtailment is expected to rise over time.

2.2.8 Greenhouse Gas Emissions

The increased customer energy consumption and curtailment of solar PV generation caused by high supply voltages on the distribution network, could result in higher emissions of greenhouse gasses if additional fossil fuel generation is dispatched to meet the increased demand.

The AER has released guidance on applying value of emissions reduction for network capital investments utilising a Value of Emission Reduction (VER)[25]. While JEN recognises this as a potential benefit for economically justifying capital expenditure to reduce emissions, we have not quantified this value stream in our economic valuation for each option for the Voltage and PQ Management program.

[25] Valuing emissions reduction final guidance - May 2024 | Australian Energy Regulator (AER), 19th July 2024.

2.3 Risks and opportunities

There are a number of risks that need to be assessed and managed for the do-nothing option. These are described below in the context of Voltage and PQ Management program. Furthermore, by adopting strategic programs to address the risks, a number of opportunities (benefits) can be quantified and realised.

The inherent Voltage and PQ Management program risks under the status-quo include:

- Exporting of power at customer connection points (from installed DER) and installation of HV underground cable (particularly 22 kV cable) causes voltages to rise in the network, more so at locations furthest from the HV voltage regulation point and at customer connection points where the exporting is occurring.
- HV voltage regulation equipment installed higher up in the network may not be able to detect such voltage rises (as they are designed to regulate the voltage on their local HV busbars, rather than the customer connection points). Hence, customer voltages may rise above the acceptable regulated voltage limits within the EDCOP.
- Whilst greater levels of export and/or cable charging, means this voltage rise can propagate further up into the network and ultimately be detected by the HV voltage regulation equipment, the OLTC transformers may not be able to bring down the voltage down to within regulatory limits if they run out of available taps (particularly as many legacy transformers have limited buck tap capability).
- Voltages above the EDCOP limit of 253 V (i.e., over-voltages), can trigger an increase in customer complaints and appliance damage or maloperation (due to accelerated loss-of-life from either the increase in energy consumption causing excessive internal heating, or from the over-voltage causing insulation deterioration).
- JEN measures and reports on its EDCOP steady-state voltage compliance to the ESC each quarter. While JEN is functionally compliant with the EDCOP, a residual level of non-compliance remains, requiring a proactive investment program to address this network compliance need.
- JEN also receives and acts on complaints relating to other power quality measures within the EDCOP that are not directly attributable to solar PV and cable charging issues (such as harmonics, flicker, under-voltage, etc.), which generally forms part of a recurrent reactive program of works each year to avoid customer complaints remaining unresolved and being escalated to the EWOV.
- Over-voltages in the proximity of DER, can cause DER inverters to either trip[26], curtail power output[27], or absorb reactive power[28] in response to those high LV network voltages. This can directly impact DER customers' bills, potentially increasing consumption costs and/or lower feed-in tariff payments and triggering an increase in DER customer complaints.
- JEN uses a 'solar reliability' measure to quantify and monitor solar PV curtailments. There remains material levels of over-voltage-induced curtailment and export limiting, and given the expected growth in solar PV connections, a proactive investment program is required to address this network limitation need.

The key needs for Voltage and Power Quality Management program can be summarised into:

- **Regulatory compliance** – improved appliance safety and reduced consumption by maintaining voltages and other quality of supply metrics within regulatory limits. We economically justify investments to address this need by quantifying the value of increased consumption from customer appliances being exposed to poor power quality and a safety disproportionality factor to achieve AFAP;
- **DER enablement** – improved export capability and reduced over-voltage-induced DER curtailment, by achieving an optimal balance between the value of DER to the market and the cost of reinforcing the

[26] 255V trip for legacy inverters, 258V for smart inverters.

[27] Output curtailed above 253V.

[28] Reactive power absorption commences above 241V for smart inverters only.

network to enable DER. We economically justify investments to address this need using the CECV[29] methodology;

- **Meeting customer expectations** – reduce customer solar-related complaints by managing supply voltages to enable more solar exports, and reducing all other quality of supply related complaints by addressing quality of supply issues for our worst-served customers; and

- **Emissions reduction** – emissions reduction from reduced consumption and increased renewable generation through reduced over-voltage-induced DER curtailment[30]. As mentioned above, we have not quantified values of emissions reduction in our economic valuations of the options in this paper.

2.3.1 Regulatory compliance

The approach to valuing regulatory compliance is based on the cost to customers of JEN not providing compliant voltages, being the value of increased consumption (based on a typical flat-rate residential retail energy consumption tariff) of customer appliances being exposed to over-voltages, and the associated safety risk of those appliances overheating and catching fire based on an applied AFAP disproportionality factor.

Taking into account the impact of mitigating the risk from projects planned over the remainder of the current regulatory period, the value of the residual risk applying this methodology for customers within the JEN service area is estimated to be worth approximately $0.9 million per annum by the end of FY2026, growing to $1.5 million per annum by the end of the 2026-2031 regulatory period. This growth in regulatory voltage compliance risk is associated with the growth in solar PV installations, and growth in HV underground cable length, raising network voltages.

2.3.2 DER enablement

Over-voltages cause tripping or a reduction of solar PV inverter power output, preventing DER customers from generating and exporting electricity.

The method applied to quantifying the value of DER enablement (reduced DER curtailment from the action of Volt-Watt control in AS4777.2 solar PV inverters, and export limiting due to upstream network voltage export limitations) utilises the CECV methodology and the AER assessment guideline.

On 30th June 2022, the AER made a final decision[31] on its CECV methodology and published an explanatory statement. Oakley Greenwood worked with the AER in developing the methodology and a model for calculating CECV. At this time, the AER published a set of CECV which it expected distributors utilise in justifying investments associated with alleviating CER export curtailment.

On 1st July 2024, the AER published updates to the CECV[32] values, including for the Victorian region. They cover every half hour period from 1/7/2024 to 30/6/2045 and are expressed in Australian dollars per MWh (Real, 2023). JEN has escalated the CECV value by also including the Consumer Price Index (CPI).

Taking into account the impact of mitigating the risk from projects planned over the remainder of the current regulatory period, the value of applying this methodology for customers within the JEN service area is estimated to be worth at least $0.6 million per annum by the end of FY2026, growing to $1.7 million per annum by the end of the 2026-2031 regulatory period. This growth in DER voltage curtailment risk is associated with the growth in solar PV installations, and growth in HV underground cable length, raising network voltages.

29 Customer Export Curtailment Value (CECV) methodology, AER.

30 Refer to 'Valuing Emissions Reduction, AER draft guidance'.

31 Final decision | Australian Energy Regulator (AER)

32 Update | Australian Energy Regulator (AER)

3. Credible options

3.1 Summary of network and non-network options

This section discusses how credible options are identified and developed into programs that can address the identified needs set out in Section 2 of this paper. The credible options are considered for their commercial and technical feasibility, deliverability, economic and financial benefits, as well as legal and regulatory implications. Options that do not have sufficient benefits to justify their cost, are not considered. JEN has identified and considered the following options based on the needs identified in Section 2. These are described in Table 6.

Table 6 – Summary of Options

Option	Description	Advantages/Benefits	Disadvantages/Risks	Residual Risk Rating
Option 1 **'Do Nothing'**	No additional capital works are considered under this option. (i.e., continue as per status quo).	Nil.	Risks and opportunities identified in Section 2.3 will not be mitigated and realised respectively.	High
Option 2 **'Centralised DVM Program'**	Proactive centralised Voltage and PQ Management investment (including DVM only) to meet compliance requirements and to enable DER. Reactive quality of supply recurrent program to resolve residual customer complaints.	Allows JEN to maintain our functional compliance obligations with the EDCOP. Allows JEN to improve quality of supply for our worst-served customers, that are experiencing non-compliant voltages and power quality. Enables DER through reduced over-voltage-induced curtailment and increased export capability, where it is economically prudent to do so. Improved emissions reduction through reduced consumption and reduced over-voltage-induced DER curtailment	Programs are only targeted at maintaining EDCOP compliance for the majority of our customers, only addressing issues for our worst-served customers if they make a complaint. Project risks related to implementation of a new technology solution, although the technology has been proven to work by way of JEN's trial sites implemented at AW and CS in 2023-24.	Medium
Option 3 **'Distributed Voltage & PQ Management Program'**	Proactive distributed (i.e. localised) Voltage and PQ Management investment (including traditional augmentations solutions, capacitor	This option has the same types of benefits as Option 2 (compliance, DER enablement) but achieves these on a larger scale e.g. compliance for more customers in areas of the	The most expensive program to address the needs. Lower cost solutions may exist to resolve the need.	Low

	controllers, and reactor installations) to meet compliance requirements and to enable DER. Reactive quality of supply recurrent program to resolve residual customer complaints.	network where DVM is less effective.	Project risks related to delivery in the field. Project risks related to constructability.	
Option 4 **'Centralised DVM & Distributed Voltage & PQ Management Programs'**	An economically optimum blend of the Option 2 and 3 proactive investments. A selection of projects from Option 2 and 3 that allow benefits to be maximised at minimum cost. Reactive quality of supply recurrent program to resolve residual customer complaints.	Exactly the same benefits as Option 3 but at a lower cost. Highest NPV.	Project risks related to implementation of a new technology solution, although the technology has been proven to work by way of JEN's trial sites implemented at AW and CS in 2023-24.	Low

3.2 Option 1 – 'Do Nothing'

Under Option 1, no additional capital works are considered that address the identified needs. That is, it assumes the status quo. The 10-year total capital cost of this option is zero.

The unrealised benefits associated with the do-nothing approach are summarised in Table 7 using a 20-year present value and a regulatory discount rate of 5.5%.

Table 7 – Quantification of unrealised value streams for Do Nothing[33]

Year	Regulatory Compliance ($m)[34]	DER Enablement ($m)[35]
2026	0.9	0.6
2027	0.9	0.6
2028	0.9	0.7
2029	1.0	0.8
2030	1.2	1.3
2031	1.5	1.7
2032	2.0	2.0

33 Note: Value of emissions reduction not included.

34 Refer to Section 2.3.1 for explanation.

35 Refer to Section 2.3.2 for explanation.

Year	Regulatory Compliance ($m)[34]	DER Enablement ($m)[35]
2033[36]	2.9	2.4
20-Year Present Value Total ($m)	18.2	15.5

3.3 Option 2 – Centralised DVM Program

Historically voltage and quality of supply network limitations have been addressed using traditional network augmentations and adjustments at the localised level, with centralised actions at the voltage regulation points (typically the zone substations) being limited adjustments of float voltage settings.

With the ubiquitous availability of AMI systems, JEN has the opportunity to incorporate the near-real-time voltage information from smart meters into our ADMS to provide more advanced centralised voltage regulation solutions. The use of this DVM capability is an option currently being trialled by JEN.

JEN is embarking on using the AMI smart meter voltage data for near real-time operational voltage control through a trial adopting DVM capability at two of our zone substations with high penetrations of DER in the current regulatory control period. We intend (at the conclusion of this trial) to transition to a more widespread use of DVM which provides a more advanced, data-driven way to manage both HV and LV voltages over traditional augmentations, eliminating the need for voltage drop assumptions and having the capability to dynamically respond to changes in DER operation in near-real-time.

The application of a DVM system on JEN's distribution network will act to try to maintain the AMI voltage distribution (across customers covered by the DVM system), within the EDCOP steady-state voltage limits, for all operating conditions between maximum demand and minimum demand, by operating continuously 24x7 (day and night) as an adjunct to our existing HV voltage regulation schemes.

Much of the foundational cost for establishing DVM has been incurred as part of the current trial in the current regulatory period. The additional costs to deploy the technology across the network following the trial is mainly associated with:

- field works at each zone substation to be enabled with DVM, including secondary control equipment, and reactors (if required to maintain the performance of the DVM by increasing the number of available OLTC buck taps).
- field works in the low voltage distribution network of those zone substations, including distribution transformer tap changes, phase balancing, and some low-voltage augmentations, to the extent that it is required to maintain the spread of the voltage distributions at maximum demand to within 37 V; and
- the AMI access points needed to accommodate the higher volume communications traffic from the smart meters, from the regular polling of customer voltages required for input into the ADMS.

The total cost of this option over the 2026-2031 regulatory period (for both the proactive and reactive programs) is $41.20 million (real 2024) as shown in Table 8.

[36] Year 10 to Year 20 values are held constant at Year 10 values.

Table 8 – Voltage and PQ Management Program Expenditure – Option 2

Voltage and PQ Management Program	Indicative Year	Cost ($M)[37]
DVM (VVC rollout) at 24 zone substations[38]	**2026-2031**	**18.5**
KLO, PV, FF, NS, COO, SA, ST, FT, YVE, EP/EPN	*2026-27*	[redacted]
TH, NT, TT, NH, CN, ES, SHM, EP/EPN	*2027-28*	[redacted]
BY, FW, BMS, BD, TMA, WT	*2028-29*	[redacted]
Nil	*2029-30*	[redacted]
Nil	*2030-31*	[redacted]
Digital capex	***2026-2031***	***0.1***
Reactive Power Quality Program Annual Cost	**2026-2031**	**16.7** (3.3 p.a.)
Total Capital Cost for 2026-2031 Regulatory Period	2026-2031	35.2
Digital opex	2026-2031	3.0
Network opex	2026-2031	1.0
Total Operational Cost for 2026-2031 Regulatory Period	2026-2031	4.0
Total Cost for 2026-2031 Regulatory Period	**2026-2031**	**39.2**

[37] Direct escalated costs (including overheads), June 2024 dollars.

[38] TT and KLO will integrate with AusNet's DVM and SA will integrate with Powercor's DVM.

3.4 Option 3 – Distributed Voltage & PQ Management Program

This option includes the range of solutions that are traditionally applied in localised areas of the distribution network to manage voltage and power quality limitations where there is an identified EDCOP compliance issue, as illustrated in Table 9. JEN already adopts many of these options as part of its business-as-usual management of the network, targeting specific areas of the network where there is an identified need and an economically viable solution, however it is a more expensive option than the other options being considered.

Table 9 – Distributed Voltage & PQ Management Solutions

No.	Description	Comment	Volt – Var Control		
			HV	LV	VAr
1	Smart inverters	Volt-VAr and Volt-Watt is already mandated for all new inverters. Opportunities for bespoke settings on a case-by-case basis may exist. The modes allow the voltage to be lowered by either drawing reactive power through the network impedance, or curtailing the generation output of the inverter, to the extent that the inverter is able to achieve this. It is expected that as more customers apply the settings, the reactive power support would enable more solar customers to be connected to the network with reduced levels of non-compliance.	×	✓	✓
2	Customer kVA tariffs	Customer kVA tariffs already in place to encourage close to unity power factor at peak demand.	×	×	✓
3	Power factor correction capacitors (shunt)	Already in place at most JEN zone substations.	×	×	✓
4	HV regulators	Used selectively by JEN on long rural feeders.	✓	×	×
5	HV OLTC transformers using VRRs	Standard used by JEN on all its zone substation transformers as the primary source of voltage control across the distribution network.	✓	×	×
6	Terminal station float voltage optimisation and Line Drop Compensation (LDC)	There may be opportunity to reduce terminal station voltages during minimum demand at sites that are not operating at their extreme tap. Either a fixed adjustment or augmented with a LDC setting. This has limited scope to apply because all terminal stations servicing JEN have no buck taps to substantially reduce the voltage.	✓	×	×
7	Zone substation and regulator station float voltage	JEN has already implemented this option at essentially all of its zone substations in recent years.	✓	×	×

No.	Description	Comment	Volt – Var Control		
	optimisation and LDC				
8	Increased buck taps on transformers, or lower impedance transformers.	JEN has already specified an increased buck range on its new and replaced distribution transformers. This opportunity could be explored for new and replaced zone substation transformers in lieu of reactors. They cater for voltage limitations that are caused by low short-circuit levels, or a lack of available buck taps during times of minimum demand.	✓	✓	×
9	Traditional opex reconfiguration options	JEN already adopts this option which includes tap changes, phase balancing, and transferring customers across open points. Many of our legacy transformers are operating at their extreme buck tap and cannot be tapped down any further without a transformer replacement. Phase balancing is effective at sites where there is significant unbalance at maximum demand causing a wide voltage to spread across phases and neutral. This option could be made more efficient with improved geospatial AMI analytics decision tools and automation.	×	✓	×
10	Traditional capex augmentation options	JEN already adopts this option as part of its demand-driven augmentation programs. It includes installing new and larger substations, and new (shorter or split) HV and LV circuits.	×	✓	×
11	VAr controllers on capacitor banks	This can be used to optimise reactive power flows on the network. It is installed on capacitor banks at many JEN zone substations already, however there are 14 banks across 10 zone substations that currently do not have VAr controllers. VAr control logic should also be interlocked against transformer tap position to prevent a capacitor bank from being in service when a zone substation transformer is on its extreme buck tap.	✓	×	✓
12	Tap position controlled switched reactors	JEN does not currently use this technology, however there is a growing need for this technology at zone substations operating at their extreme tap position, where a lower cost alternative is not available. These are used to draw more reactive power through the network to create a voltage drop which will result in transformers operating on more nominal taps during times of minimum demand, rather than at their extreme buck tap.	✓	×	✓

No.	Description	Comment	Volt – Var Control		
13	Storage	Insufficient levels of storage currently exist to provide efficient volt-VAr control. This could change over time as DER storage penetration increases. The opportunity lies with storage in being able to defer or displace a traditional augmentation by charging during minimum demand or discharging during maximum demand, and/or utilising its inverter for voltage support. The opportunity to adopt storage as a non-network alternative will be assessed on a case-by-case basis, since the business case for using storage for network support, requires value stacking with market benefits, given its current higher cost premium.	×	✓	✓
14	Series capacitors	Not used by JEN. Useful on sub-transmission lines that are limited by voltage constraints. No forecast need for this technology, as it is not suitable for use on HV or LV network due to highly distributed customers with isolation points along these assets, leading to complex design (such as resonance) and high cost.	✓	×	×
15	LV regulators	Not used by JEN. There may be opportunity to use this technology in niche areas of the network in future. Opportunity is currently limited by its high cost per customer served.	×	✓	×
16	HV Static compensators (Statcom or SVCs)	Not used by JEN. Opportunity is currently limited by its high cost per customer served.	✓	×	✓
17	LV OLTC transformers using VRRs	Not currently used by JEN. May be an opportunity to use on niche parts of the network. Opportunity is currently limited by its high cost per customer served.	×	✓	×

The relevance of each solution type to support this option are as follows:

- Solution types 1 through to 8 are largely being delivered by JEN through other business-as-usual programs and are not specifically included in this option.
- Solution types 9 and 10 are core to resolving the identified needs for this option.
- Solution types 11 and 12 are solutions JEN plans to apply to manage voltage through the use of reactive power to supplement the OLTCs, especially those that have reached the extent of their buck tap range.
- Solution types 13 through to 17 do not have an identified need for their application within the 10-year horizon of this strategy or are regarded as uneconomic solutions for JEN. Although solution type 13 is

likely to have opportunities for supporting voltage limitations in future as the level of DER storage (including EV) increases across the network or as a non-network solution.

The total cost of this option over the 2026-2031 regulatory period (for both the proactive and reactive programs) is $52.37 million (real 2024) as shown in Table 10.

Table 10 – Voltage and PQ Management Program Expenditure – Option 3

Voltage and PQ Management Program	Indicative Year	Cost ($M)[39]
Tap position-controlled reactors at 5 zone substations	**2026-2031**	**12.2**
SBY	*2028*	[redacted]
SHM	*2029*	[redacted]
COO	*2030*	[redacted]
ST	*2031*	[redacted]
BD	*2031*	[redacted]
Interlocked VAr controllers on 14 existing capacitor banks	**2026-2031**	**3.0**
CN No.1 and No.2	*2027*	[redacted]
CN No.3, CS	*2028*	[redacted]
FF, NH	*2029*	[redacted]
ST, TH No.1	*2030*	[redacted]
TH No.2	*2031*	[redacted]
Traditional investments to maintain voltage spread at 15 zone substations	**2026-2031**	**0.6**
EPN, NT, BY, NH, ES, CN, EP, TT	*2027*	[redacted]
YVE, AW	*2028*	[redacted]
NS, PTN, PV	*2029*	[redacted]
CS	*2030*	[redacted]
HB	*2031*	[redacted]
Traditional network investments for the worst-served under-voltage areas	**2026-2031**	**11.0**
CN, BY	*2027*	[redacted]
EP, AW	*2029*	[redacted]
PV, YVE	*2030*	[redacted]
CS, HB, FF, PTN	*2031*	[redacted]
Traditional network investments for the worst-served over-voltage areas	**2026-2031**	**14.3**
TH, CS, NT, BY, HB	*2027*	[redacted]
TT, FW, FF, NS, NH, KLO	*2028*	[redacted]
COO, PTN	*2029*	[redacted]
Reactive Power Quality Program Annual Cost	**2026-2031**	**8.3** (1.7 p.a.)
Total Capital Cost for 2026-2031 Regulatory Period	2026-2031	49.4
Total Operational Cost for 2026-2031 Regulatory Period	2026-2031	0.0

39 Direct escalated costs (including overheads), June 2024 dollars.

Total Cost for 2026-2031 Regulatory Period	**2026-2031**	**49.4**

3.5 Option 4 – Centralised DVM & Distributed Voltage & PQ Management Programs

Given that centralised and distributed control each on their own, can realise only a part of the total available value at least cost, it would make sense to blend the two, with each option supporting the other to maximise the overall benefits outcome. To achieve this optimal outcome, the sequence and timing of initiatives become important in a strategic roadmap that ensures costs are only incurred at a time when the need arises and that dependencies between initiatives are also considered.

By combining Options 2 and 3, Option 4 becomes a blend of distributed and centralised control initiatives which can be segmented into four key components for a strategic roadmap to address the identified need:

- A set of three **network-wide holistic solutions** which leverage capabilities to minimise the growth in traditional expenditure associated voltage and power quality management, and to realise new and additional revenue opportunities.
    - Firstly, to establish an **operational technology overlay** by enabling DVM across all of our zone substations as the need arises.
    - Secondly, to utilise **bridging network solutions** including tap-controlled switched-reactors interlocked with optimised capacitor VAr controllers such that the value from DVM can continue to be realised while there remains immaterial levels and a lag in the uptake of distributed storage compared to distributed solar PV.
    - Thirdly, to start to adopt **longer-term DER solutions** to provide ongoing value in place of potentially more expensive network solutions. It is envisaged that capability would be built in the next regulatory period through other elements of the FNS, although parts of Option 5 (below) could be used opportunistically in the next regulatory period if there is an identified economically viable alternative solution.
- An **ongoing baseline of localised network upgrades and adjustments** that can be used to assist the network-wide holistic solutions, to maintain their level of flexibility and effectiveness over time and address the worst-performing sites on the JEN network. These include a mix of traditional voltage and power quality network augmentation and reconfiguration solutions.

The total cost of this option over the 2026-2031 regulatory period (for both the proactive and reactive programs) is $50.19 million (real 2024) as shown in Table 11.

Table 11 – Voltage and PQ Management Program Expenditure – Option 4

Voltage and PQ Management Program	Indicative Year	Cost ($M)[40]
DVM (VVC rollout) at 24 zone substations[41]	**2026-2031**	**18.5**
KLO, PV, FF, NS, COO, SA, ST, FT, YVE, EP/EPN	*2026-27*	[redacted]
TH, NT, TT, NH, CN, ES, SHM, EP/EPN	*2027-28*	
BY, FW, BMS, BD, TMA, WT	*2028-29*	
Nil	*2029-30*	
Nil	*2030-31*	
Tap position-controlled reactors at 5 zone substations	**2026-2031**	**12.2**
SBY	*2028*	[redacted]
SHM	*2029*	
COO	*2030*	
ST	*2031*	
BD	*2031*	
Interlocked VAr controllers on 14 existing capacitor banks	**2026-2031**	**3.0**
CN No.1 and No.2	*2027*	[redacted]
CN No.3, CS	*2028*	
FF, NH	*2029*	
ST, TH No.1	*2030*	
TH No.2	*2031*	
Traditional investments to maintain voltage spread at 15 zone substations	**2026-2031**	**0.6**
EPN, NT, BY, NH, ES, CN, EP, TT,	*2027*	[redacted]
YVE, AW	*2028*	
NS, PTN, PV	*2029*	
CS	*2030*	
HB	*2031*	
Digital capex	***2026-2031***	***0.1***
Reactive Power Quality Program Annual Cost	**2026-2031**	**8.3** (1.7 p.a.)
Total Capital Cost for 2026-2031 Regulatory Period	2026-2031	42.6
Digital opex	2026-2031	3.0
Network opex	2026-2031	1.0
Total Operational Cost for 2026-2031 Regulatory Period	2026-2031	4.0
Total Cost for 2026-2031 Regulatory Period	**2026-2031**	**46.6**

40 Direct escalated costs (including overheads), June 2024 dollars.

41 TT and KLO will integrate with AusNet's DVM and SA will integrate with Powercor's DVM.

3.6 Option 5 – Non-network voltage and power quality management solutions

This option relies on third-party DER and demand response (DR) solutions to resolve the risks and take advantage of the opportunities, with benefits realised through contracting of non-network solutions. This option can open up a range of benefits not available from the other options and requires additional investments by JEN in DERMS and dynamic operating envelopes.

The benefits of this option increase when there is a significant penetration of controllable DER storage and DR resources. This option is not technically feasible to realise benefits for the short to medium term until the penetration of controllable storage and DR resources significantly increases in the JEN distribution network.

4. Economic evaluation

The key assessment used to compare the merits of the options considered is the NPV calculated for an unconstrained capex and opex assessment. This represents the present value of the avoided risks, minus the costs. The JEN economic evaluation results and the ability of the options to realise the benefits is presented in Table 12, spanning the 2026-2031 regulatory period only.

Table 12 – 20-Year Net Present Value of Options ($M, 2024)

Costs and Benefits ↓ / Options →	Option 1 - Do Nothing	Option 2 - Centralised DVM Program	Option 3 - Distributed Voltage & PQ Management Program	Option 4 - Centralised DVM & Distributed Voltage & PQ Management Programs
Total Cost	0.0	42.4	49.4	49.8
- Network Capex		*35.3*	*49.4*	*42.7*
- Network Opex		*1.0*	*0.0*	*1.0*
- Digital Capex		*0.1*	*0.0*	*0.1*
- Digital Opex		*6.0*	*0.0*	*6.0*
Present Value Cost [42]	0.0	19.7	31.6	31.4
Present Value Benefit	0.0	16.6	33.6	33.6
Net Present Value (NPV)	**0.0**	**(3.0)**	**2.0**	**2.2**
Regulatory Compliance	*0.0*	*8.3*	*18.2*	*18.2*
DER Enablement	*0.0*	*8.4*	*15.5*	*15.5*

The economic analysis of the options suggests that Option 4 – “Centralised DVM & Optimised Distributed Voltage & PQ Management Programs” maximises the present value of net benefits and is, therefore, the recommended development path.

[42] Reactive capex triggered by customer complaints is not included in the cost-benefit analysis as it is a compliance obligation.

4.1 Preferred option

This paper recommends developing:

- A set of three **network-wide holistic solutions** which leverage capabilities to minimise the growth in traditional expenditure associated voltage and power quality management, and to realise new and additional revenue opportunities by:
  - firstly, to establish an **operational technology overlay** by enabling DVM across all of our zone substations as the need arises.
  - secondly, to utilise **bridging network solutions** including tap-controlled switched-reactors interlocked with optimised capacitor VAr controllers such that the value from DVM can continue to be realised while there remains immaterial levels and a lag in the uptake of distributed storage compared to distributed solar PV.
  - thirdly, to start to adopt **longer-term DER solutions** to provide ongoing value in place of potentially more expensive network solutions. It is envisaged that capability would be built in the next regulatory control period through other elements of the FNS, although parts of Option 5 could be used opportunistically in the next regulatory period if there is an identified economically viable alternative solution.
- An **ongoing baseline of localised network upgrades and adjustments** that can be used to assist the network-wide holistic solutions, to maintain their level of flexibility and effectiveness over time and address the worst-performing sites on the JEN network. These include a mix of traditional voltage and power quality network augmentation and reconfiguration solutions.

The option that aligns with this strategic approach is Option 4 – “Centralised DVM & Optimised Distributed Voltage & PQ Management Programs”. Option 4 delivers maximum next customer benefit by adopting a DVM technology overlay to minimise traditional capital-intensive investment, coupled with least-regrets investments to address immediate needs while providing a pathway to pivot towards storage solutions in the future as the opportunity for distributed storage (including EV) to support network voltage is expected to increase over time.

4.2 Optimum timing

The optimum in-service timing of deploying the centralised DVM solution across the network is determined by the economic viability at each zone substation, which is driven by the size of the DER enablement and voltage compliance customer benefits at each site.

The optimum in-service timing of the distributed solutions applied at each network location is determined by the economic viability of the residual DER enablement and voltage compliance customer benefits after DVM has been applied.

Table 13 sets out the timing of implementation for this Program over the next regulatory period.

Table 13 – Voltage and PQ Management Program Expenditure Timing – Preferred Option 4

Cost ($k)[43]	26-27	27-28	28-29	29-30	30-31
Network Capex					
Install reactors at COO - 2 x 4MVAr	-	-	655	1,328	680
Reactors at BD - 4 x 4MVAr reactors, two of 2 x 4MVAr cap banks	-	-	-	-	2,424
Install reactors at ST - 2 x 4MVAr	-	-	-	708	1451
Install reactors at SBY - 2 x 4MVAr	575	1,158	584	-	-
Install reactors at SHM - 2 x 4MVAr	-	642	1295	657	-
Interlocked VAr controllers on 14 existing capacitor banks	322	648	653	663	679
VVC Roll-Out	7,065	7,003	4,434	-	-
Distribution substation augmentation - supply quality	1,378	1,708	1,720	1,743	1,784
Future Grid - Hosting Capacity (LV Network)	121	122	123	124	127
Network Opex					
Opex step change (Networks)	200	200	200	200	200
Digital Capex					
FN - VVC (Volt Var Control) rollout	124	-	-	-	-
Digital Opex					
Opex step change (Digital)	633	575	575	575	575

43 Direct escalated costs (including overheads), June 2024 dollars.

5. Voltage and PQ Management program

5.1 Program development

The Voltage PQ Management Program includes two key initiatives: centralised dynamic voltage management and Distributed voltage and power quality management.

5.1.1 Centralised dynamic voltage management

LV network planning and operation will become increasingly more important as the penetration of DER rises with the majority of DERs being connected within customer premises clustered deep within the LV networks. JEN will need to strategically respond to this challenge using a more proactive, technological, automated, data-driven approach to the management of the LV networks. The challenges for JEN from increasing DER relate predominantly to LV network voltage limitations, manifesting from reverse power flows driven by DER.

JEN has a capability gap in that current operational real-time voltage control capability is implemented at the HV level of the network only, using the on-load tap changer transformers at its zone substations and at some in-line HV regulator sites. There is currently no system in place across the JEN network that directly regulates LV voltages in near real-time and hence respond adequately to reverse power flows.

JEN is, however, ideally placed to respond to this challenge with its ubiquitous availability of AMI smart meters, which are able to measure LV customer voltages in near real-time. Utilising this data resource as a feedback loop into JEN's HV voltage control systems and ADMS, JEN can automate the regulation of LV voltages to respond to changes in DER output. This capability is referred to in the industry as DVM and if deployed across all JEN zone substation, will address much of the voltage compliance and DER enablement needs of this strategy.

JEN is currently trialling DVM technology at its Coburg South and Airport West zone substations using an augmented ADMS-VVC module to incorporate the near-real time AMI voltage feedback using an AMI data pre-processor, to dynamically inform HV float-voltage settings and enable DVM capability.

Having visibility to a randomised statistically significant number of smart meters every 5 minutes (grouped together for each separate HV voltage control zone) through increased AMI access points, will maximise the opportunity for customer voltages to be controlled within the EDCOP regulatory voltage limits by a DVM system, for a wide range of demand levels and DER exports. This centralised DVM capability, supported by targeted distribution network adjustments would be enabled continuously (24x7), realising improved voltage compliance, improved DER hosting capacity, and reduced network capital expenditure.

5.1.2 Distributed voltage and power quality management

The centralised DVM capabilities are limited only by the LV voltage spread, and the available tapping range on zone substation transformers, after which distributed solutions are required to complement the centralised system.

Distributed solutions (coupled with geospatial AMI analytics decision support and automation tools), are needed to maintain the level of flexibility and effectiveness of the centralised DVM system over time, by targeting worst performing sites.

The additional distributed options are:

- Tap position-controlled reactors at zone substations (if required) to provide available buck taps for DVM to reduce voltage at minimum demand;
- Interlocked VAr controllers on existing capacitor banks to correctly coordinate with those reactors;

- Traditional network investments to maintain the voltage spread per zone substation within 37 V at maximum demand;
- Traditional network investments for the worst-served areas that are not directly resolved by DVM; and
- Reactive recurrent program of works to respond to and resolve customer complaints (consistent with recent historical expenditure levels).

These are selected on the basis of relatively proven technology, being able to coexist with (and support) a centralised DVM system in maintaining its effectiveness to regulate customer voltages within regulatory limits.

5.2 Program investment costs

Table 14 lists the expenditures for the Voltage and PQ Management Program to support this roadmap.

Table 14 – Voltage and PQ Management Program Expenditure – Preferred Option 4

Cost ($k)[44]	26-27	27-28	28-29	29-30	30-31
Network Capex					
Install reactors at COO - 2 x 4MVAr	-	-	655	1,328	680
Reactors at BD - 4 x 4MVAr reactors, two of 2 x 4MVAr cap banks	-	-	-	-	2,424
Install reactors at ST - 2 x 4MVAr	-	-	-	708	1451
Install reactors at SBY - 2 x 4MVAr	575	1,158	584	-	-
Install reactors at SHM - 2 x 4MVAr	-	642	1295	657	-
Interlocked VAr controllers on 14 existing capacitor banks	322	648	653	663	679
VVC Roll-Out	7,065	7,003	4,434	-	-
Distribution substation augmentation - supply quality	1,378	1,708	1,720	1,743	1,784
Future Grid - Hosting Capacity (LV Network)	121	122	123	124	127
Network Opex					
Opex step change (Networks)	200	200	200	200	200
Digital Capex					
FN - VVC (Volt Var Control) rollout	124	-	-	-	-
Digital Opex					
Opex step change (Digital)	633	633	575	575	575

5.3 Implementation risks

Project implementation risks (which apply to any except the do-nothing option) include:

- Delivery risks – Dependency on availability of key resources (SMEs and field resources) is a risk. The mitigation is to have appropriate resourcing contingency and skills development plan in place, and to ensure that the project schedule is aligned with realistic resources availability;
- Delivery risks - Delays particularly due to complexities of implementing new technologies such as DVM. The mitigation is to derisk by undertaking proof-of-concept testing early in the project life-cycle to allow time to fix

[44] Direct escalated costs (including overheads), June 2024 dollars.

issues and minimise their impact on the overall project delivery timing. As such, the current trial at Coburg South and Airport West zone substations will feed important information into the future stages and mitigate this risk.

6. Findings and recommendation

This Voltage and PQ Management program articulates the need to strategically respond to the challenges and opportunities associated with voltage and power quality compliance, and DER enablement. It helps JEN deliver initiatives set out in its FNS. The needs can be best met through Option 4 which provides a blend of centralised and distributed investment solutions.

This program has identified that there is an economic case to further invest in Voltage and PQ Management programs over the next 10 years, to address the need with some investments starting now.

The Voltage and PQ Management program sets out a least-regrets investment roadmap providing a prudent optimum balance between risk, performance, cost, timing and uncertainty, to meet the identified needs in this strategy.

Table 15 presents the net economic value of the Voltage and PQ Management program roadmap for the next regulatory control period, spanning 2027 to 2031.

Table 15 – Program Roadmap Economic Evaluation by Option for 2027-2031 Regulatory Control Period

Economic Evaluation Results	Option 1 - Do Nothing	Option 2 - Centralised DVM Program Only	Option 3 - Distributed Voltage & PQ Management Program Only	Option 4 - Centralised DVM & Optimised Distributed Voltage & PQ Management Programs
Total Costs[45] ($m)	0.0	42.4	49.4	49.8
Present Value Costs[46] ($m)	0.0	19.7	31.6	31.4
Present Value Benefits ($m)	0.0	16.6	33.6	33.6
Net Present Value ($m)	**0.0**	**(3.0)**	**2.0**	**2.2**

The economic analysis of the options suggests that Option 4 – "Centralised DVM & Distributed Voltage & PQ Management Programs" maximises the present value of net benefits and is therefore the recommended development path. It includes proactive elements based on network performance data (particularly from AMI smart meters), and recurrent reactive elements based on customer complaints resolution.

It is recommended that JEN adopt the strategic roadmap detailed in this paper.

45 Direct escalated costs (including overheads), June 2024 dollars.

46 Direct escalated costs (including overheads), June 2024 dollars.

7. References

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