Jemena Electricity Networks (Vic) Ltd

JEN 2026-31 Regulatory proposal reset RIN

RIN Support

Grid Stability and Flexible Services Program

Table of contents

List of tables

List of figures

Glossary

Capital expenditure	Commonly abbreviated as capex, this expenditure is related to investment of funds to acquire or upgrade a long-term asset. Examples of capital expenditure include investment in infrastructure such as poles, wires and meters.
Distribution feeders	A set of radial 22 kV, 11 kV or 6.6 kV powerlines that emanate from zone substations to supply distribution substations.
Distribution substation	Commonly abbreviated as DSS, this is a type of facility which receives electricity from zone substations and transforms voltage to low voltage levels to facilitate the electrical supply to a particular low voltage network in the JEN network.
Jemena	Refers to the parent company of Jemena Electricity Networks.
Jemena Electricity Networks	An electricity distribution network service provider wholly-owned by Jemena and licensed to distribute and supply electricity to customers in a distribution area covering the northwest region of greater Melbourne.
Network	JEN's regulated electricity distribution network assets.
Non-network	A solution to a network need that does not involve a network asset solution.
Operating expenditure	Commonly abbreviated as opex, this expenditure is related to investing funds in ongoing, day-to-day expenses to run a business, including operating, servicing, and maintaining the network.
Reliability of supply	The measure of the ability of the distribution system to supply to customers.
Zone substation	A type of facility that receives electricity from high-voltage transmission or sub-transmission networks and transforms voltage to lower voltage levels to facilitate the electrical supply to distribution substations.

Abbreviations

ADMS	Advanced Distribution Management System
AEMO	Australian Energy Market Operator
ACR	Automatic Circuit Recloser
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
API	Application Programming Interface
ARENA	Australian Renewable Energy Agency
Capex	Capital Expenditure
CBAM	Costs and Benefits Analysis Model
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resources (a subset of DER)
CSIP-AUS	Common Smart Inverter Profile (Australia)
CT	Current Transformer
DAPR	Distribution Annual Planning Report
DEECA	Department of Environment, Energy and Climate Action
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DMO	Distribution Market Operator
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DPV	Distributed Solar PV
DSO	Distribution System Operator
DSS	Distribution Substation
DVM	Dynamic Voltage Management
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FLISR	Fault Location Identification and Supply Restoration
GMM	Generation Monitoring Meter (AMI CT Meter)
HV	High Voltage
IED	Intelligent Electronic Device (Digital Relay)
IT	Information Technology
JEN	Jemena Electricity Networks (Vic) Ltd
PKI	Public Key Infrastructure
kV	Kilo Volt
LV	Low Voltage

MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Mega Watt hour
NEM	National Electricity Market
NER	National Electricity Rules
NMS	Network Management System (AMI Itron backend)
NPV	Net Present Value
NSP	Network Service Provider
Opex	Operations and Maintenance Expenditure
OSII	Open Systems International Incorporated
OT	Operational Technology
PQ	Power Quality
PV	Photovoltaic
PVR	Present Value Ratio
SCADA	Supervisory Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme
TS	Terminal Station
UFLS	Under Frequency Load Shedding
UIQ	UtilityIQ ® Itron
VCR	Value of Customer Reliability
V2G	Vehicle to Grid
VER	Value of Emissions Reduction
VPP	Virtual Power Plant
ZSS	Zone Substation

Executive summary

This Grid Stability and Flexible Services Program delivers part of Jemena Electricity Network's (**JEN**) Consumer Energy Resources Integration Strategy (**CER Integration Strategy**). It supports JEN's strategic objective of connecting our customers to a renewable energy future by facilitating the integration of Consumer Energy Resources (**CER**), including Distributed Solar PV (**DPV**), into the network.

Australian Energy Market Operator (**AEMO**) forecasts[1] net minimum demand in Victoria to fall below its minimum acceptable operating threshold by late 2024. This poses the following challenges for maintaining power system security:

- **Supply-Demand Balance** – an oversupply of DPV generation that cannot be curtailed or interrupted, leading to a collapse of the power system following the unexpected disconnection of an interconnector; and
- **Under Frequency Load Shedding (UFLS)** – a scheme that disconnects load to mitigate power system collapse from a sudden drop in system frequency (triggered by a loss-of-generation event), becoming ineffective due to the presence of reverse power flows from DPV.

To support AEMO in addressing both of these emerging power system security needs, JEN requires grid stability applications to fulfil its power system security regulatory obligations. Furthermore, flexible services applications will enable JEN to respond strategically to the challenges and opportunities associated with increasing CER penetration and relevant impacts on our own network and support legislated emission reduction targets.

This Grid Stability and Flexible Services Program articulates the need for JEN to develop a DPV Backstop Capability,[2] a Distributed Under-Frequency Load Shedding (**Distributed UFLS**) Scheme, and Flexible Import and Export Services (**Flexible Services**). It sets out a least-regrets investment roadmap, providing a prudent balance between risk, expenditure and uncertainty to meet the identified needs. The program is a subset of JEN's broader CER Integration Strategy and is the pragmatic outcome to realise JEN's strategic objective. The applications developed are supported by a new and staged Low-Voltage Distributed Energy Resource Management System (**LV-DERMS**) platform.

The Grid Stability and Flexible Services Program:

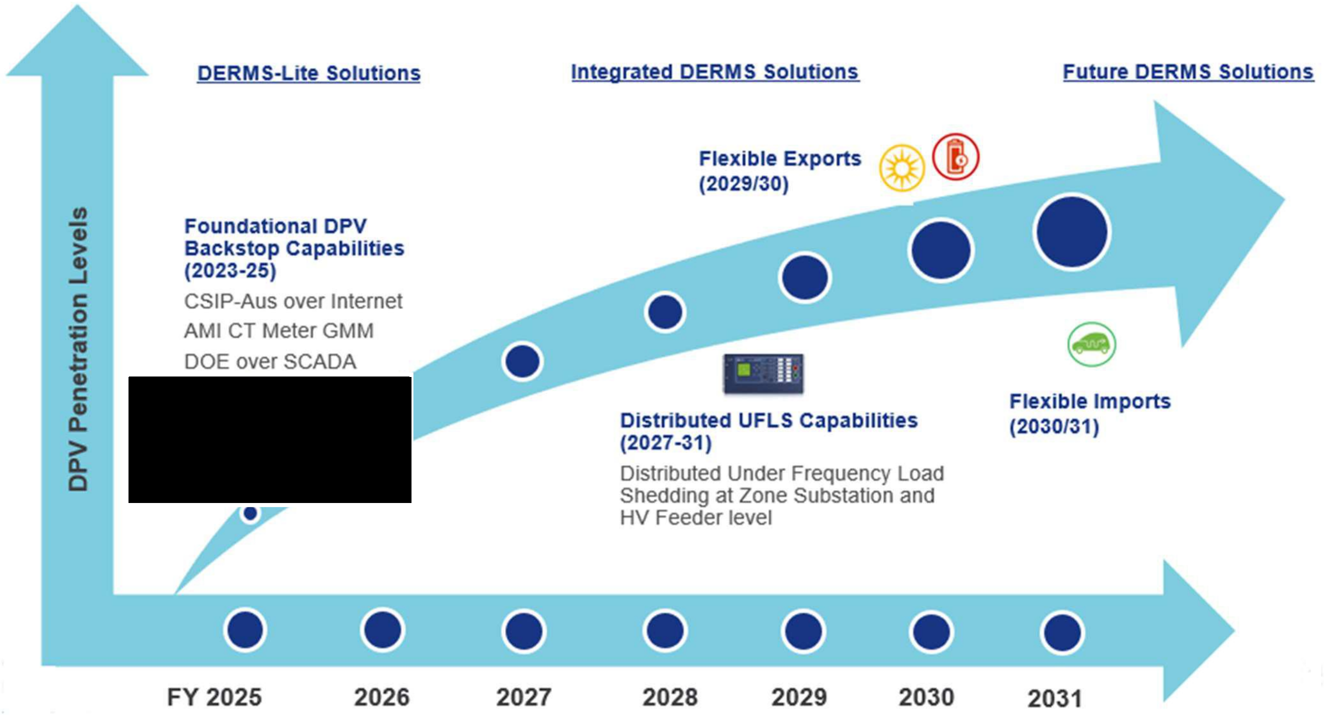
- seeks to achieve power system security compliance with AEMO's requirements across JEN's network to enable CER uptake and then maintain compliance in an environment of increasing CER penetration;
- identifies and implements DPV Backstop[2] and Distributed UFLS capabilities required to address the identified needs of the power system on a least-regrets basis and to comply with JEN's regulatory obligations;
- provides a foundation on which JEN plans to establish flexible services (flexible exports and flexible imports) for our customers;
- optimises the sequence of capability investment to provide the highest net benefit, considering compliance risk, performance, cost, timing and uncertainty;
- complements and supports other CER Integration Strategy initiatives and programs;
- is scalable for the future; and
- ensures total lifecycle costs are minimised for customers.

The proposed roadmap for developing JEN's Grid Stability and Flexible Services capabilities to meet our business needs for the next ten years is illustrated in Figure **1**.

[1] As at early November 2024.

[2] This capability is deployed in 2024 with further improved automation work in early 2025.

Figure 1 **– JEN's Grid Stability and Flexible Services Capability Roadmap**



The proposed concept diagram for developing JEN's Grid Stability and Flexible Services capabilities to meet our business needs for the next ten years is illustrated in Figure **2**.

Figure 2 **– JEN's Grid Stability & Flexible Services Concept Diagram**

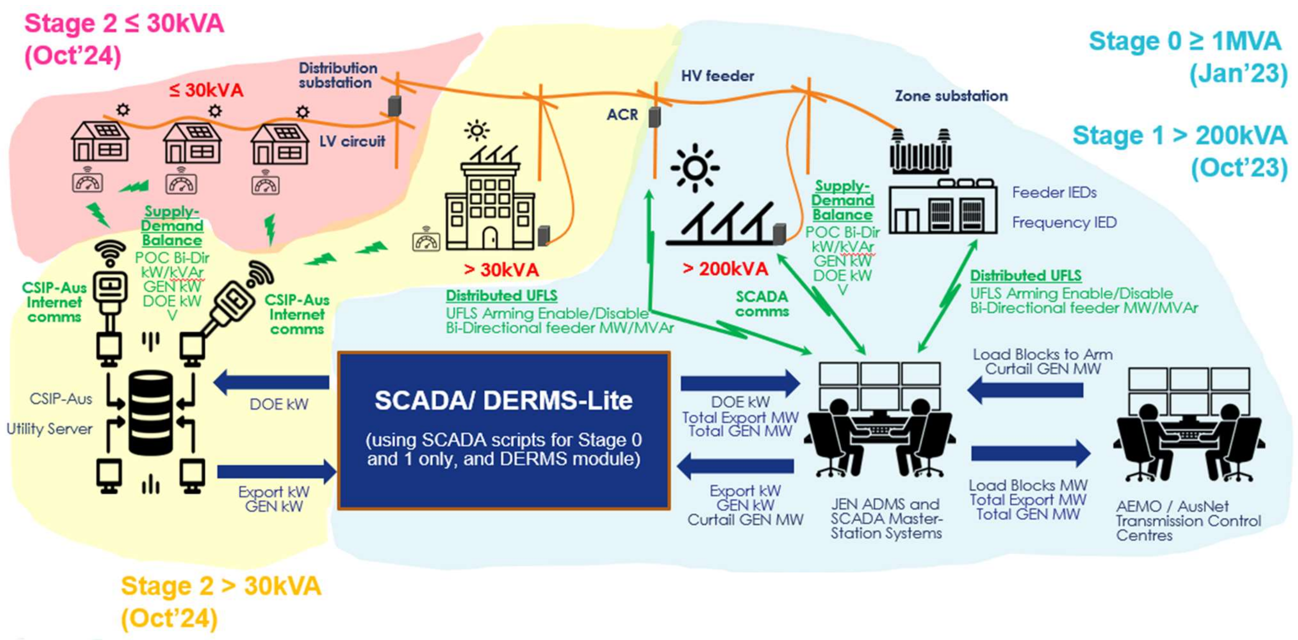


Table 0-1 presents the net economic value of the Grid Stability and Flexible Services Program roadmap for various development options. Table 0-2 presents the total costs for the recommended option by year over the next regulatory period 2026-31.

Table 0-1 – Flexible Services Program Roadmap Economic Evaluation by Option ($k, June 2024)[3]

Economic Evaluation Results	Option 1 Do Nothing	Option 2 Flexible Services by 2028-29 without Augex Deferral	Option 3 Flexible Services by 2028-29 with Augex Deferral	Option 4 Flexible Services by 2030-31 with Augex Deferral	Option 5 Flexible Services by 2030-31 without Augex Deferral
Present Value Capex	0	21,168	21,168	20,093	20,093
Present Value Opex	0	11,966	11,966	10,723	10,723
Present Value Total Costs	**0**	**33,134**	**33,134**	**30,817**	**30,817**
Present Value Benefits	0	28,929	35,578	34,882	28,525
Net Present Value (NPV)	**0**	**(4,206)**	**2,444**	**4,066**	**(2,292)**

The economic analysis of the options indicates that Option 4 – "Flexible Services by 2030-31 with Augex Deferral" maximises the present value of net benefits and is therefore the recommended development path.

Table 0-2 details the costs breakdown by year for each initiative.

3 The dollars presented include capitalised overheads and escalations.

Table 0-2 – Grid Stability and Flexible Services Expenditure for Option 4 ($k, June $2024)[4]

Initiative	Expenditure type	FY2026/27	FY2027/28	FY2028/29	FY2029/30	FY2030/31
Grid Stability UFLS	Digital Capex	345	706	495	269	148
	Digital Opex	0	0	0	0	0
	Network Capex	314	710	1,380	1,986	1,103
	Network Opex	0	0	0	0	0
Flexible Export Services	Digital Capex	0	2,443	7,086	4,675	0
	Digital Opex	0	0	1,049	1,299	502
	Network Capex	0	0	0	0	0
	Network Opex	0	0	87	175	175
Flexible Import Services	Digital Capex	0	0	0	4,044	6,053
	Digital Opex	0	0	0	0	0
	Network Capex	0	0	0	0	0
	Network Opex	0	0	0	0	0
Total	**Capex**	**659**	**3,859**	**8,961**	**10,975**	**7,303**
	Opex	**0**	**0**	**1,136**	**1,474**	**677**
	Capex and Opex	**659**	**3,859**	**10,097**	**12,449**	**7,980**

4 The dollars presented include capitalised overheads and escalations.

1. Background

JEN has developed its CER Integration Strategy to meet the challenges posed by the rapid transformation of the Australian energy sector as the Australian economy transitions towards a decarbonised net-zero future. JEN's strategic response is to adopt a least-regrets scenario-based investment approach to manage a smooth transition for customers.

JEN operates in a rapidly changing energy landscape. Disruptive impacts on distribution networks, particularly those triggered by the distributed renewable energy transition, are changing the way customers use electricity networks.

CER uptake is continuing to increase and will be a crucial resource in the future to support and manage the distribution network and broader energy system. JEN has already seen strong growth in network-connected, passive distributed solar photovoltaic (**DPV**) system installations by our customers, and this is likely to continue. Other potentially more active CER technology is emerging, including customer and community storage and electric vehicles (**EVs**). This presents further challenges and opportunities for network integration of CER.

However, this trend is resulting in an increasing proportion of the overall power system generation being located within distribution networks rather than at large, transmission-connected plants. As a result, it is becoming increasingly complex for JEN to manage power system security to maintain standards of service to customers and maintain compliance with our regulatory obligations. Challenges of managing power system security will exacerbate as CER uptake continues to increase.

This Grid Stability and Flexible Services Program is one of three programs that will enable JEN to deliver its CER Integration Strategy.

2. Needs analysis

2.1 Identified need

AEMO forecasts[5] net minimum demand in Victoria to fall below its minimum acceptable operating threshold by late 2024. This poses the following challenges for maintaining power system security:

- **Supply-Demand Balance**[6] – an oversupply of DPV generation that cannot be curtailed or interrupted, leading to a collapse of the power system following the unexpected disconnection of an interconnector; and
- **Under Frequency Load Shedding (UFLS)** – a scheme that disconnects load to mitigate power system collapse from a sudden drop in system frequency (triggered by a loss-of-generation event), becoming ineffective due to the presence of reverse power flows from DPV.

Actions are required in the JEN network to address both of this emerging power system security needs through new grid stability applications to fulfil our power system security regulatory obligations. The risks associated with higher CER levels and the required actions are set out below.

2.1.1 Grid Stability

The inherent Grid Stability risks associated with higher CER levels in the network under the status quo include:

- **Power system security non-compliance** – There are increased risks that JEN may be unable to comply with AEMO directives under the NER regarding the supply-demand balance and standards for minimum levels of load under the control of the UFLS scheme. This could affect service delivery to our customers and result in JEN's non-compliance with regulatory obligations, as well as compliance and enforcement consequences. Improved power system security compliance can be achieved by adopting DPV Backstop and Distributed UFLS (Grid Stability capabilities). This would allow AEMO to meet its NER obligations regarding power system security and for JEN to meet its NER obligations regarding directives issued by AEMO to meet those obligations for minimum levels of load under control of the UFLS scheme. For JEN to maintain its Distribution License, it must comply with NER obligations to meet power system security directives issued by AEMO.
- **Power system collapse** – There may be an increased probability of state-wide blackouts occurring should AEMO be unable to control power system frequency, particularly under critical credible contingencies. This may further result in a power system collapse with catastrophic implications for our customer services. Power system collapse (system black) could be minimised by adopting Grid Stability capabilities.
- **Customer appliance damage** – Should voltage levels increase, for example, due to JEN needing to increase voltage above 258 V[7] To trip off DPV as a last resort in an energy emergency to maintain system stability, there is a risk of damage to customer appliances and safety implications from appliances overheating and deteriorating insulation.
- **Load shedding** – The reliability of JEN's service delivery to customers may deteriorate, as JEN would need to trip reverse power feeders and/or CER as a last resort in an emergency to maintain system stability. Deteriorating reliability also has public safety implications for customers and the community. We expect that the need for load-shedding will be minimised by adopting Grid Stability capabilities.

5 As at early November 2024.

6 This need is being addressed by the Backstop Mechanism. This project has been implemented and will progress to a fully automated solution with automation by early 2025.

7 Source: AS 4777.2.

- **Increased costs** – JEN may face increased complaints and claims from customer appliance damage and load shedding. Costs arising from insurance claims and penalties under JEN's service target performance incentive scheme (**STPIS**) may not be recoverable where JEN has incurred the costs in breach of the NER. JEN may also incur increased capex costs. Adopting DPV Backstop capability will avoid the need for JEN to apply intentional over-voltages to customers to trip off CER and, therefore, avoid the need for operational expenditure to fund complaints management and equipment damage claims. Adopting DPV Backstop capability will drive capital expenditure efficiencies by avoiding the need for (possibly) more expensive transmission solutions (such as interconnectors and resistor heat banks).

2.1.2 Flexible Services

The inherent network management risks associated with higher CER levels in the network (particularly DPV and EV) under the status quo include:

- **DER curtailment—**Increasing DPV will result in increasing curtailment for both customer exports through fixed export limiting being applied and gross generation from elevated network voltages in the absence of other control mechanisms. If fixed export limits could be avoided with the use of flexible export services, the power system could accommodate more CER exports at times other than minimum demand. Enabling DER contributes to greenhouse gas emissions reductions, displacing centralised fossil fuel generation sources.

- **Load shedding** – As JEN will need to shed load on assets that are overloaded, particularly from future EV charging at times of air-conditioning peak demand in the absence of other control mechanisms, this will deteriorate reliability of supply. Minimising the risk of network overload (and therefore forced load shedding to avoid the overload) by being able to reduce the magnitude of EV charging at times of maximum demand with the use of Flexible Import Services is possible with an investment in flexible services.

- **Increased costs** – Limitations in the network will result in increased capital expenditure costs to customers on traditional augmentation solutions to enable DER or increased costs to JEN of complaints from export limiting and load shedding in the absence of other control mechanisms. Avoiding the costs by limiting the times during the year that worst case export and import limiting is needed to be applied to manage the network is possible with an investment in flexible services. Flexible Services defer the need for network investment in DER enablement and peak demand capacity as it limits the times during the year that worst-case export and import limiting is needed to be applied to manage the network.

We continue to seek ways to improve the utilisation of our assets, to minimise network augmentation costs for our customers. Introducing flexible (import and export) services can facilitate us to achieve this outcome. The systems needed to enable our grid stability applications also provide us the foundation to introduce flexible services for our customers. Flexible services will enable us to strategically respond to the challenges and opportunities associated with increasing CER penetration (particularly DPV and EV growth) and relevant impacts on our own network and support legislated emission reduction targets.

2.2 Strategic alignment

2.2.1 Alignment with JEN's CER Integration Strategy

The Australian energy sector is transforming rapidly as the Australian economy transitions towards a decarbonised net-zero future. While many aspects of this transformation remain uncertain, the transformation is accelerating, and the energy system in 2040 will look vastly different from today.

The role of the electricity distribution system is also changing due to the transformation of the energy system. While traditionally a relatively simple link in the supply chain from large-scale fossil fuel generators to customer loads met the needs of customers, the distribution business of the future will need to serve a far more complex environment.

In this environment, a significant proportion of generation will originate from customers and flow back into the network, and many customer devices will seek to connect to and interact with the electricity system. This transition will be heavily influenced by customers, governments and regulators, as well as other changes in the external market environment.

CER connected to our network is continuing to increase and is becoming a crucial resource for supporting, managing, and utilizing the distribution network. JEN has already seen strong growth in network-connected, passive DPV system installations by our customers and this is likely to continue. Other emerging, potentially more active CER technology (including customer and community storage and EVs), present further challenges and opportunities for network integration.

These trends will cause an increasing proportion of the overall power system generation to be located within the distribution network. Therefore, power system security will become increasingly more important and complex for JEN to manage on behalf of AEMO as CER penetration continues to rise. Furthermore, low voltage (**LV**) network planning and operation will become increasingly more important and complex because most CERs are connected to customer premises within our LV networks. With the networks traditionally designed for one-way passive loads, this change has direct and profound implications on our customers' experience with the network and, therefore, on the way JEN manages this part of the network.

As a regulated electricity distribution network in Victoria, we play a key role in facilitating the transformation of this energy system. Given the uncertainty in the rate of change and direction of the transformation, a least-regrets scenario-based investment approach is needed to manage the transition for customers. We have, therefore, developed a CER Integration Strategy and associated programs of work to support the transition over the next decade. The CER Integration Strategy is the overarching strategy for JEN's asset management strategies, setting the basis for the strategic direction from which JEN's asset management strategies are informed. The CER Integration Strategy informs this Grid Stability and Flexible Services Program.

This Grid Stability and Flexible Services Program articulates the need for JEN to develop a DPV Backstop Capability, a Distributed Under-Frequency Load Shedding (Distributed UFLS) Scheme and Flexible Services for our customers. These applications will strategically respond to the challenges and opportunities associated with increasing CER penetration and the associated influence on power system security and network operating limits. The applications developed from this program are supported by a new and staged Low-Voltage Distributed Energy Resource Management System (LV-DERMS) platform to achieve near real-time optimised control of CER active power operating envelopes. These will deliver grid stability and flexible export and import distribution services using Dynamic Operating Envelopes (DOEs), facilitated by a CSIP-AUS[8] utility server.

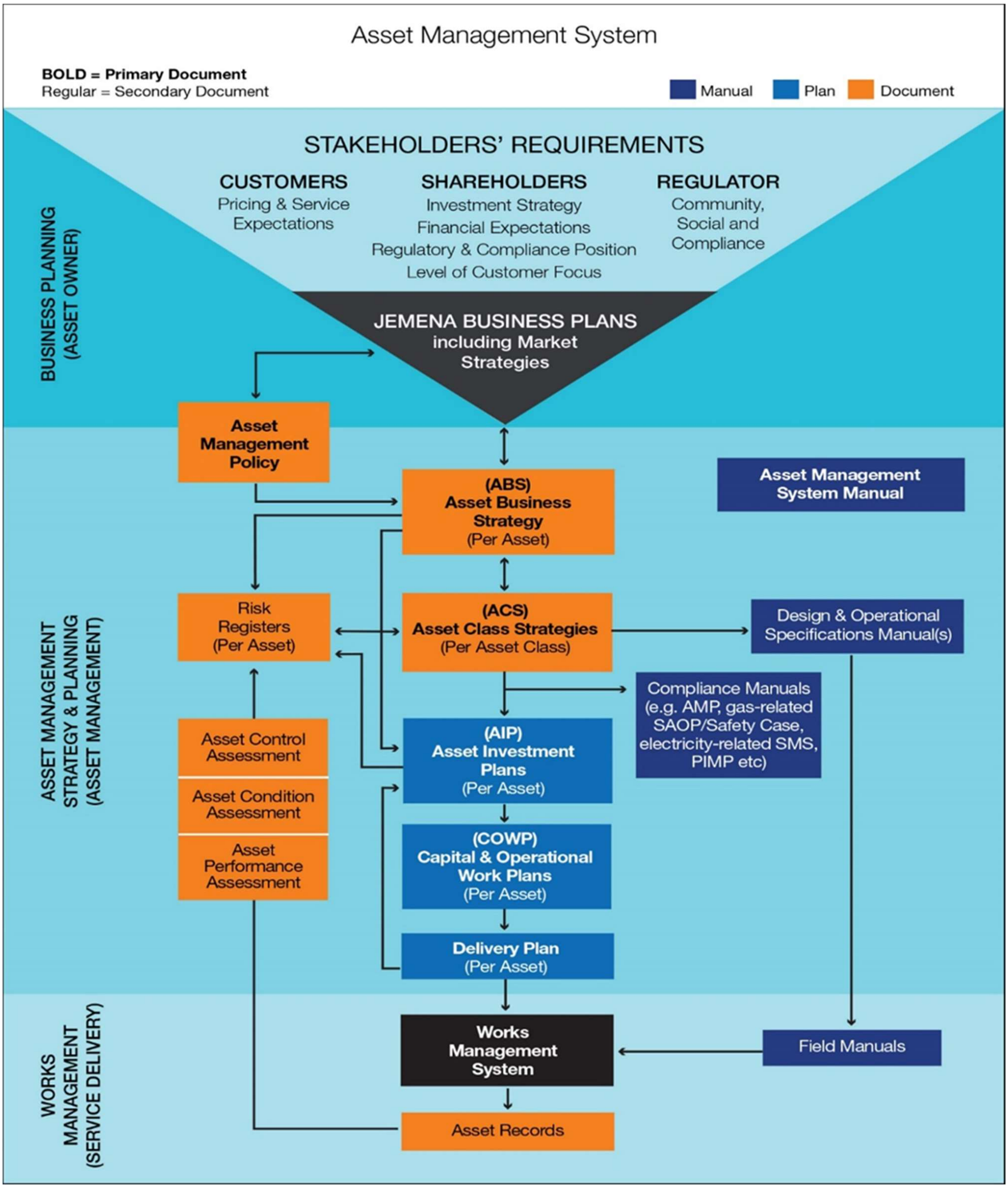
This Grid Stability and Flexible Services Program supports JEN's CER Integration Strategy and proposes a Grid Stability and Flexible Services program roadmap.

2.2.2 Alignment with JEN's Asset Management System

JEN's approach to managing the performance and safety of our network and our investment decision-making is set out in JEN's Asset Management System shown in Figure 2.1. 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 / investment briefs.

[8] CSIP – Common Smart Inverter Profile. Refer to: Common Smart Inverter Profile Australia (Arena.gov.au).

Figure 2.1 - JEN's Asset Management System



JEN's Asset Management System structure follows the high-level structure of ISO 55001. This Grid Stability and Flexible Services Program sits within and supports JEN's Asset Management System as an Asset Business Strategy (**ABS**). This strategy informs the development of Grid Stability and Flexible Services Program to support JEN and our customers during the renewable energy transition, consistent with JEN's strategic objectives and CER Integration Strategy.

2.3 Regulatory obligations

AEMO has a responsibility to maintain power system security under clause 4.3.1 of the National Electricity Rules (**NER**). Under clause 4.3.4 of the NER, DNSPs including JEN must use reasonable endeavours to exercise our rights and obligations in relation to networks so as to cooperate with and assist AEMO in the proper discharge of this responsibility.

In August 2021, AEMO issued a directive[9] to JEN and other Victorian electricity network service providers (**NSP**) to identify and implement measures to restore power system security from the threats caused by increasing levels of uncontrolled DPV within their respective networks.

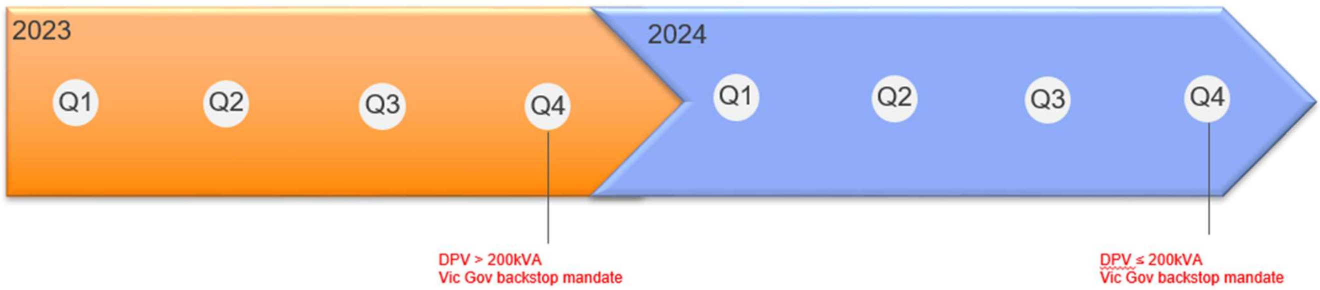
In October 2021, the Victorian Government's Department of Energy, Environment and Climate Action (**DEECA**), AEMO and the Victorian electricity DNSPs established a DER and System Security Working Group to address the issues associated with CER and system security collaboratively.

From 25 October 2023, new regulatory obligations took effect to require each Victorian DNSP to be satisfied that each new or modified DPV system of between 200 kVA and 30 MVA capacity connected to the DNSP's network has emergency DPV Backstop capability, meaning that its generation may be remotely curtailed or interrupted.[10] Moreover, from 1 January 2024, each DNSP must have the capability to remotely curtail or interrupt generation by these DPV systems where required by AEMO to manage minimum system load risks.

As shown on the timetable below at Figure 2.2, the Victorian Government has also imposed similar regulatory obligations through Stage 2 of the ministerial order from October 2024 in relation to DPV systems of 200 kVA capacity or less.[11] For these smaller systems, the government has prescribed the enabling of DPV Backstop capability by requiring each system to be capable of communicating via a channel that is compliant to the standard IEEE 2030.5 CSIP-AUS[12] and to be connected to the relevant DNSP's utility server via the internet. To do so, a system must have a compliant inverter, gateway device or a certified cloud connection. The government considers this option to be preferable for consistency with approaches in other jurisdictions including South Australia, and to enable future capabilities such as flexible exports through dynamic operating envelopes.

The regulatory obligations in relation to DPV Backstop capability are conditions of JEN's distribution licence. JEN must comply with the requirements, monitor compliance and self-report breaches or potential breaches of our obligations. There are a range of compliance and enforcement tools available to the Essential Services Commission to enforce compliance with the requirements, including civil penalties and enforcement orders.

Figure 2.2 – Regulatory Compliance Milestones for DPV Backstop



[9] in its letter dated 9 August 2021.

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

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

[12] CSIP – Common Smart Inverter Profile. Refer to: Common Smart Inverter Profile Australia (Arena.gov.au).

2.4 Customer expectations

Our customers' main concern continues to be affordability, but they also want us to focus on reliability, facilitating the energy transition, sustainability and quality customer service. These are all relevant to capital expenditure.

To meet these competing expectations, this Grid Stability and Flexible Services Program sets out clearly identified needs, the credible options to address those identified needs, and finally, applies the economic evaluation to those options to select the preferred option and optimum timing of each component of the program that delivers the net benefit for our customers. This approach ensures that we continue to deliver our services affordably while meeting other expectations.

2.5 Risks of doing nothing

Several risks need to be assessed and managed for the do-nothing option. These are quantified below in the context of grid stability and flexible services. Furthermore, by adopting strategic programs to address the risks, several benefits can be quantified and realised in the form of avoided risks.

Three benefit streams (mitigating do-nothing risks) have been quantified, being DER enablement, reduced emissions, and maintaining reliability of supply. These are summarised below.

2.5.1 DER enablement

Flexible exports contribute to DER enablement by allowing more CER exports at times other than minimum demand, with fixed worst-case import or export limits being relaxed at these times. The value of this to customers based on the AER's customer export curtailment value (**CECV**) methodology for the JEN network is estimated in Table 2-1 associated with the growth in DPV.

Table 2-1 – DER Enablement Benefit by Year ($k, June $2024)[13]

Benefit	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
DER Enablement	2	6	25	32	55	102	178	350	783	916

2.5.2 Reduced emissions

The DER enablement achieved above also contributes to reduced greenhouse gas emissions as it can displace centralised fossil fuel generation sources. The value of this to customers based on the AER's value of emissions reduction (**VER**) methodology for the JEN network is estimated in Table 2-2 associated with the enablement of DER.

Table 2-2 – Emission Reduction Benefit by Year ($k, June $2024)

Benefit	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Emissions Reduction	9	22	57	135	233	359	507	579	646	724

[13] Excluding DVM benefits already quantified in JEN's Voltage & PQ Management Strategy and including benefit uptake factors.

2.5.3 Maintain reliability of supply

Flexible Imports contribute to minimising the risk of network overload (and therefore forced load shedding to avoid the overload) by being able to reduce the magnitude of air-conditioning, pool pump and EV charging load at times of maximum demand. The value of this to customers based on the AER's value of customer reliability (**VCR**) methodology for the JEN service area is estimated in Table 2-3 associated predominantly with the growth in air-conditioning and EVs.

Table 2-3 – Reliability Benefit by Year ($k, June $2024)[14]

Benefit	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reliability	7	14	33	88	125	160	205	204	220	227

2.5.4 Reduced operational expenditure

The value of avoided cost to consumers of appliance damage from high voltages and cost of complaints and claims is not quantified, as it is assumed customers will be load shed in preference to raising voltages on the JEN network.

2.5.5 Reduced capital expenditure

The value of reduced capital expenditure is not quantified, as it is assumed based on our 20% reduction in JEN's Distribution Substation Augmentation Program capex forecast (in anticipation of introducing Flexible Services), that customers will be load shed in preference to augmenting the network in the absence of Flexible Services.

[14] Excluding DVM benefits quantified in the Voltage & PQ Management Strategy.

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. The credible options are considered for their commercial and technical feasibility, deliverability, economic and financial benefits, as well as legal and regulatory implications and customer expectations.

JEN has identified and considered the following options based on the identified need. These are described in Table 3-1.

Table 3-1 – Summary of Options

Option	Description	Benefits	Risks
Option 1 **'Do Nothing'**	No additional capital works are considered under this option (i.e., continue as per status quo).	Nil.	Risks will not be mitigated.
Option 2 **Grid Stability and Flexible Services by 2028-29 without Augex Deferral**	Grid Stability applications including DPV Backstop and Distributed UFLS to meet compliance requirements. Flexible Import and Export Services for more efficient network management and flexible DER operation for customers.	Allows JEN to meet its system security regulatory obligations in full now for the next 10 years. Provides flexible import and export services for customers as early as possible.	Risks will be mitigated as early as possible. No augmentation demand capex reductions compared to Option 3.
Option 3 **Grid Stability and Flexible Services by 2028-29 with Augex Deferral**	Option 2 plus deferring approximately 20% of our Distribution Substation Augmentation Program.	As per Option 2. Reduced costs for customers from deferred or avoided capital expenditure on network augmentation.	Risks will be mitigated as early as possible.
Option 4 **Grid Stability and Flexible Services by 2030-31 with Augex Deferral**	Option 3 deferred by two years.	As per Option 3. Reduced costs for customers from deferred or avoided capital expenditure on network augmentation.	Risks will be mitigated with a delay of two years.
Option 5 **Grid Stability and Flexible Services by 2030-31 without Augex Deferral**	Option 2 deferred by two years.	Allows JEN to meet its system security regulatory obligations in full now for the next 10 years. Provides flexible import and export services for customers with timing based on JEN's network need.	Risks will be mitigated with a delay of two years. No augmentation demand capex reductions compared to Option 4.

3.2 Option 1 – 'Do Nothing'

3.2.1 Description

Under Option 1, no additional capital works are considered that address the identified needs. That is, it assumes a business-as-usual or status quo position.

3.2.2 Costs

The risk cost profile of this option is presented in Section 2.5.

3.2.3 Benefits

There are no benefits of adopting this option.

3.3 Option 2 – Grid Stability and Flexible Services by 2028-29 without Augex Deferral

3.3.1 Description

Grid Stability applications are established with this option including:

- Foundational DPV Backstop, which is a committed project and are deployed in different stages in 2024 and 2025 to integrate with JEN's existing backend systems to enable the required automation
- CSIP-AUS Utility Server and Itron NMS Integration
- GMM alternative control system (e.g. in the absence of an internet connection)
- DERMS Lite
- Foundational Distributed UFLS
- Zone substation and distribution feeder dynamically armed Distributed UFLS system
- Flexible Exports & Flexible Imports
- Integrated LV DERMS
- CSIP-AUS DOE capability.

3.3.2 Costs

The present value capital cost of this option is $21.2 million ($, June 2024) and a present value operational cost of $12.0 million ($, June 2024).

3.3.3 Benefits

The present value of avoided risks (benefits) of this option is $28.9 million ($, June 2024).

3.4 Option 3 – Grid Stability and Flexible Services by 2028-29 with Augex Deferral

3.4.1 Description

This option includes Option 2 plus a reduction in the Distribution Substation Augmentation Program by approximately 20%.

3.4.2 Costs

The present value capital cost of this option is $21.2 million ($, June 2024) and a present value operational cost of $12.0 million ($, June 2024).

The reduction in capex for the Distribution Substation Augmentation Program has already been applied.

3.4.3 Benefits

The present value of avoided risks (benefits) of this option is $35.6 million ($, June 2024).

3.5 Option 4 – Grid Stability and Flexible Services by 2030-31 with Augex Deferral

3.5.1 Description

This option is Option 3 deferred by two-years to better align with our network needs.

3.5.2 Costs

The present value capital cost of this option is $20.1 million ($, June 2024) and a present value operational cost of $10.7 million ($, June 2024).

The reduction in capex for the Distribution Substation Augmentation Program has already been applied.

3.5.3 Benefits

The present value of avoided risks (benefits) of this option is $34.9 million ($, June 2024).

3.6 Option 5 – Grid Stability and Flexible Services by 2030-31 without Augex Deferral

3.6.1 Description

This option is Option 2 deferred by two-years to better align with our network needs.

3.6.2 Costs

The present value capital cost of this option is $20.1 million ($, June 2024) and a present value operational cost of $10.7 million ($, June 2024).

3.6.3 Benefits

The present value of avoided risks (benefits) of this option is $28.5 million ($, June 2024).

4. Economic evaluation

The key assessment used to compare the merits of the options considered is the present value of the net benefits (**NPV**). 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 value stack are presented in Table 4-1.

Table 4-1 – Flexible Services Program Roadmap Economic Evaluation by Option ($k, June 2024) [15]

Economic Evaluation Results	Option 1 Do Nothing	Option 2 Flexible Services by 2028-29 without Augex Deferral	Option 3 Flexible Services by 2028-29 with Augex Deferral	Option 4 Flexible Services by 2030-31 with Augex Deferral	Option 5 Flexible Services by 2030-31 without Augex Deferral
Present Value Capex	0	21,168	21,168	20,093	20,093
Present Value Opex	0	11,966	11,966	10,723	10,723
Present Value Total Costs	**0**	**33,134**	**33,134**	**30,817**	**30,817**
Present Value Benefits	0	28,929	35,578	34,882	28,525
Net Present Value (NPV)	**0**	**(4,206)**	**2,444**	**4,066**	**(2,292)**

The economic analysis of the options indicates that Option 4 – "Flexible Services by 2030-31 with Augex Deferral" maximises the present value of net benefits and is therefore the recommended development path.

The benefits have been quantified by identifying the forecast network limitations and applying the CECV methodology for CER enablement, the AER's VER methodology for emissions reduction, and the VCR methodology for reliability of supply. Refer to the attached CBAM for details for how those benefits have been applied in the cost-benefit analysis model.

Table 4-2 details the costs breakdown by year for each initiative.

[15] The dollars presented in Table 4-1 includes capitalised overheads and escalations.

Table 4-2 – Flexible Services and Grid Stability Expenditure for Option 4 ($k, June $2024)

Initiative	Expenditure type	FY2026/27	FY2027/28	FY2028/29	FY2029/30	FY2030/31
Grid Stability UFLS	Digital Capex	345	706	495	269	148
	Digital Opex	0	0	0	0	0
	Network Capex	314	710	1,380	1,986	1,103
	Network Opex	0	0	0	0	0
Flexible Export Services	Digital Capex	0	2,443	7,086	4,675	0
	Digital Opex	0	0	1,049	1,299	502
	Network Capex	0	0	0	0	0
	Network Opex	0	0	87	175	175
Flexible Import Services	Digital Capex	0	0	0	4,044	6,053
	Digital Opex	0	0	0	0	0
	Network Capex	0	0	0	0	0
	Network Opex	0	0	0	0	0
Total	**Capex**	**659**	**3,859**	**8,961**	**10,975**	**7,303**
	Opex	**0**	**0**	**1,136**	**1,474**	**677**
	Capex and Opex	**659**	**3,859**	**10,097**	**12,449**	**7,980**

4.1 Preferred option

The preferred option builds capabilities for:

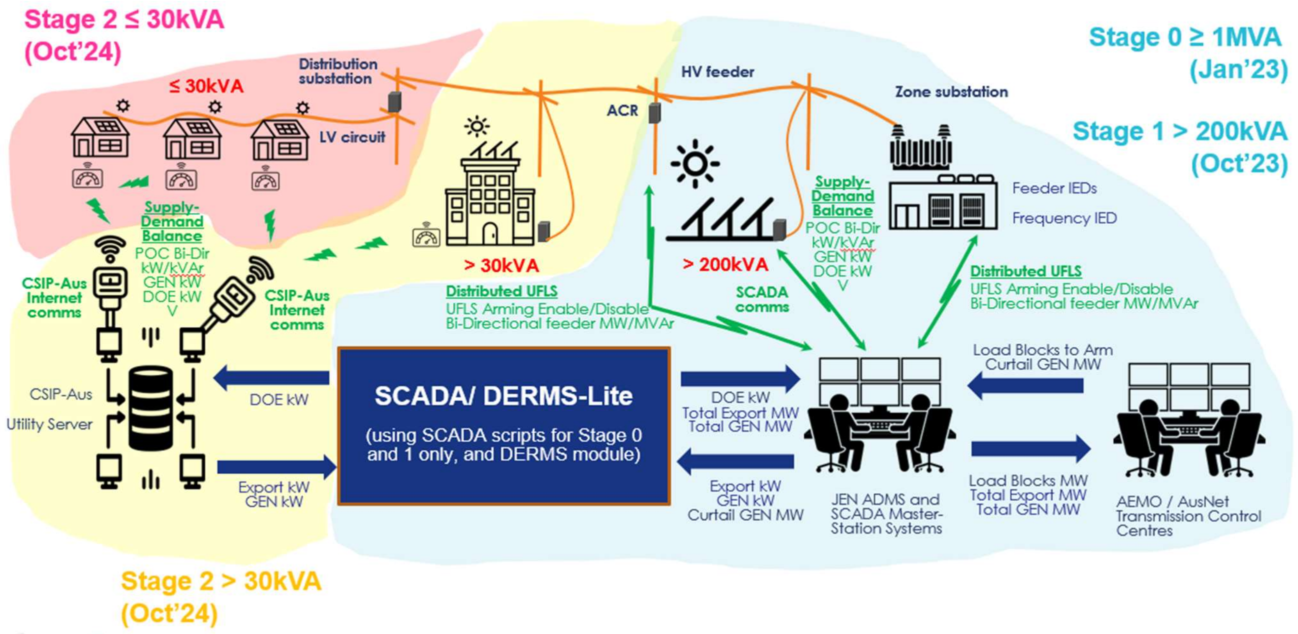
1. Grid Stability to address emerging power system security-related issues stemming from the distribution network, including:
   a) maintaining the supply-demand balance by using DPV backstop control to keep the power system stable and decrease net minimum demand
   b) maintaining the UFLS scheme effectiveness by using a more granular distributed UFLS scheme architecture, to keep the power system stable for a major loss-of-generation contingency
2. Network Management that responds to increasing CER challenges associated with continuing to manage loading levels on JEN's network assets to within their ratings, including:
   a) enabling participation in Flexible Export services by applying DOEs to minimise DER curtailment while network assets remain operating within their ratings; and
   b) enabling participation in Flexible Import services such as for EVs to minimise the risk of asset overload during peak demand.

4.2 Optimum timing

The optimum timing of each component of the program is driven by various factors including:

- **DPV Backstop** – DEECA has mandated 1 October 2024 for when the DPV Backstop capability must be implemented for all new or altered DPV customers. Therefore, this capability is committed and deployed in different stages over 2023 to 2025.
- **Distributed UFLS** – AEMO expects system security to be compromised in Victoria for UFLS in late 2025. Hence the capability should be developed starting from 2024.
- **Flexible Exports** – JEN's network limitations associated with DPV are material in its service area now. However, the systems required to support flexible exports (established by the foundational DPV Backstop capability), particularly for the smaller systems, need to be put into place first. Furthermore, deploying JEN's dynamic voltage management system over the next few years will defer the need for flexible export services from 2027/28 to 2029/30.
- **Flexible Imports** – JEN expects network limitations associated with EVs to become material in its service area from 2028 to 2031.

5. Proposed Grid Stability Program



5.1 Program development

The systems needed to support the Grid Stability and Flexible Services capabilities are shown in Figure 5.1.

Figure 5.1 – JEN's systems needed to support Grid Stability and Flexible Services capabilities[16]

[redacted]

Core components for the operational system needed to support capabilities are the establishment of a new CSIP-AUS Utility Server and the establishment and evolution of an LV DERMS. The key drivers of the need for an LV DERMS and Utility Server are to:

[16] The solution architecture is being reviewed regularly by JEN to ensure the investments are on a least-regrets basis, considering the rapidly changing nature of the energy landscape including roles and responsibilities within the NEM

- manage minimum system demand to allow JEN to continue to maintain its NER compliance obligations to AEMO for power system security;
- provide Flexible Export services for the continued efficient management of the network to ensure JEN continues to support customers to harness their renewable generation while ensuring the distribution network export operating limits are maintained; and
- provide Flexible Import services for the continued efficient management of the network to ensure JEN continues to support customers' uptake of CER such as electric vehicles while ensuring the distribution network import operating limits are maintained.

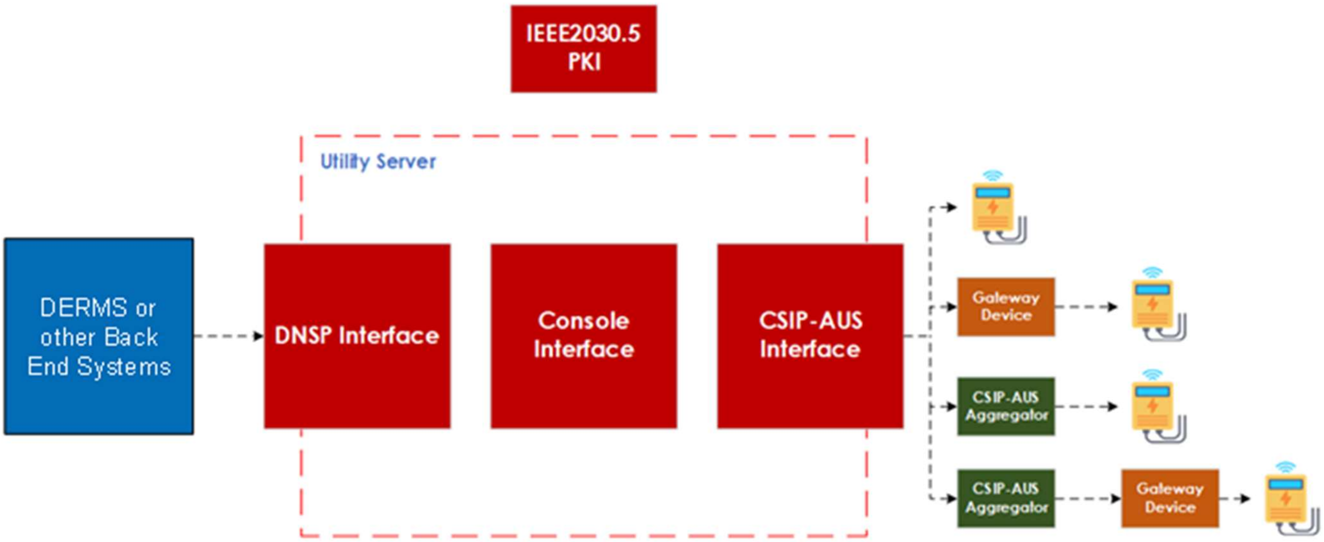
The Grid Stability program will be reviewed periodically to continue to ensure the investments are on a least-regrets basis, considering the rapidly changing nature of the energy landscape.

It is envisaged that the LV DERMS and Utility Server will be delivered over three phases:

5.1.1 Phase 1 – DPV Backstop Capability

Phase 1 (shown in Section 8 Figure 8.1) will establish a DERMS-Lite (a minimally functional version of an LV DERMS) and the CSIP-AUS Utility Server. The need to adopt CSIP-AUS as the primary means of communicating with CER requires the development of a CSIP-AUS Utility Server to interface with the LV DERMS, as illustrated in Figure 5.2.

Figure 5.2 – LV DERMS to Utility Server to DER Interfacing



The required Utility Server interface components are:

- DNSP Interface: APIs to integrate with JEN's backend systems;
- Console Interface: GUI to support administrative and configuration functions of the Utility Server;
- CSIP-AUS Interface: APIs to integrate with DER software clients; and
- IEEE 2030.5 PKI: PKI to support secure server/client communications.

The focus of Phase 1 will be on DPV customers where systems will be developed to embed capabilities to manage minimum demand and provide the foundation for future flexible export services, with an expected volume of approximately 6,000 new and altered connections per annum.

5.1.2 Phase 2 – Flexible Export

Phase 2 is an enhancement from DERMS-Lite to LV DERMS and backend systems, but not Utility Server[17], to incorporate flexible export services including DOEs. This is shown in Section 8 Figure 8.2 – Phase 2 – Flexible Export.

5.1.3 Phase 3 – Flexible Import

Phase 3 (shown in Section 8 Figure 8.3) is an enhancement to LV DERMS and backend systems, but not Utility Server[18], to incorporate other CER and flexible import services such as customer batteries and EVs, as well as network-owned CER. The system will be able to support an additional approximately 6,000 devices per annum.

5.2 Implementation risks

The implementation risks for UFLS would be low as JEN is progressively implementing the new requirement over a 5-year period.

For Flexible Services, JEN is proposing to implement it over a three-year period (2028-2031). By then, the technology would be more mature and adoption by other DNSPs across the NEM would likely open up more competition and availability of the Utility Server and LV DERMS products. As such, the implementation risks for flexible services are considered low.

[17] Whilst the Utility Server capability remains broadly unchanged, however its capacity will need to be expanded to cater for additional monitoring and control points under Flexible Export.

[18] Whilst the Utility Server capability remains broadly unchanged, however its capacity will need to be expanded to cater for additional monitoring and control points under Flexible Import.

6. Findings and recommendation

This program recommends building capabilities for:

- **Grid Stability** – to address emerging power system security-related issues stemming from the distribution network including:
  - maintaining the supply-demand balance by using DPV backstop control to keep the power system stable for decreasing net minimum demand[19]
  - maintaining the UFLS scheme effectiveness by using a more granular distributed UFLS scheme architecture to keep the power system stable during a major loss-of-generation contingency.
- **Flexible Services** – network management that responds to increasing CER challenges associated with continuing to manage loading levels on JEN's network assets to within their ratings including:
  - adopting Flexible Services by applying DOEs to minimise CER curtailment while network assets remain operating within their ratings and enable participation of flexible import services for CER such as EVs.

The program has identified that there is an economic case to further invest in Grid Stability and Flexible Services capabilities to address the need.

The Grid Stability and Flexible Services 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.

The economic analysis of the options indicates that Option 4 – "Flexible Services by 2030-31 with Augex Deferral" maximises the present value of net benefits and is therefore the recommended development path for both the benefit of JEN and its customers.

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

7. Implementation timetable

7.1 Foundational DPV Backstop Capability (2023-2025)

- DOE Over SCADA for DPV > 200kVA as primary solution.
- CSIP-AUS for DPV 0-200kVA:
    - Utility Server deployment, 1 October 2024, and
    - LV DERMS deployment, by 31 March 2025.
- GMM for DPV >30-200kVA, as an alternative solution to CSIP-AUS where the internet connectivity is not available, 1 October 2024.

7.2 Flexible Exports (2028-2029)

- Implementation duration from January 2028 to December 2029.
- Expand DOE of SCADA and GMM using LV DERMS platform.

7.3 Flexible Imports (2030-2031)

- Implementation from January 2030 to March 2031.

7.4 Foundational Distributed UFLS Capabilities (2027-2031)

- Implementation of 7 terminal stations, from 2027 to 2031.

8. Appendix A: High-Level Overview of Flexible Services Initiative Development

Figure 8.1 – Phase 1 – DPV Backstop Capability

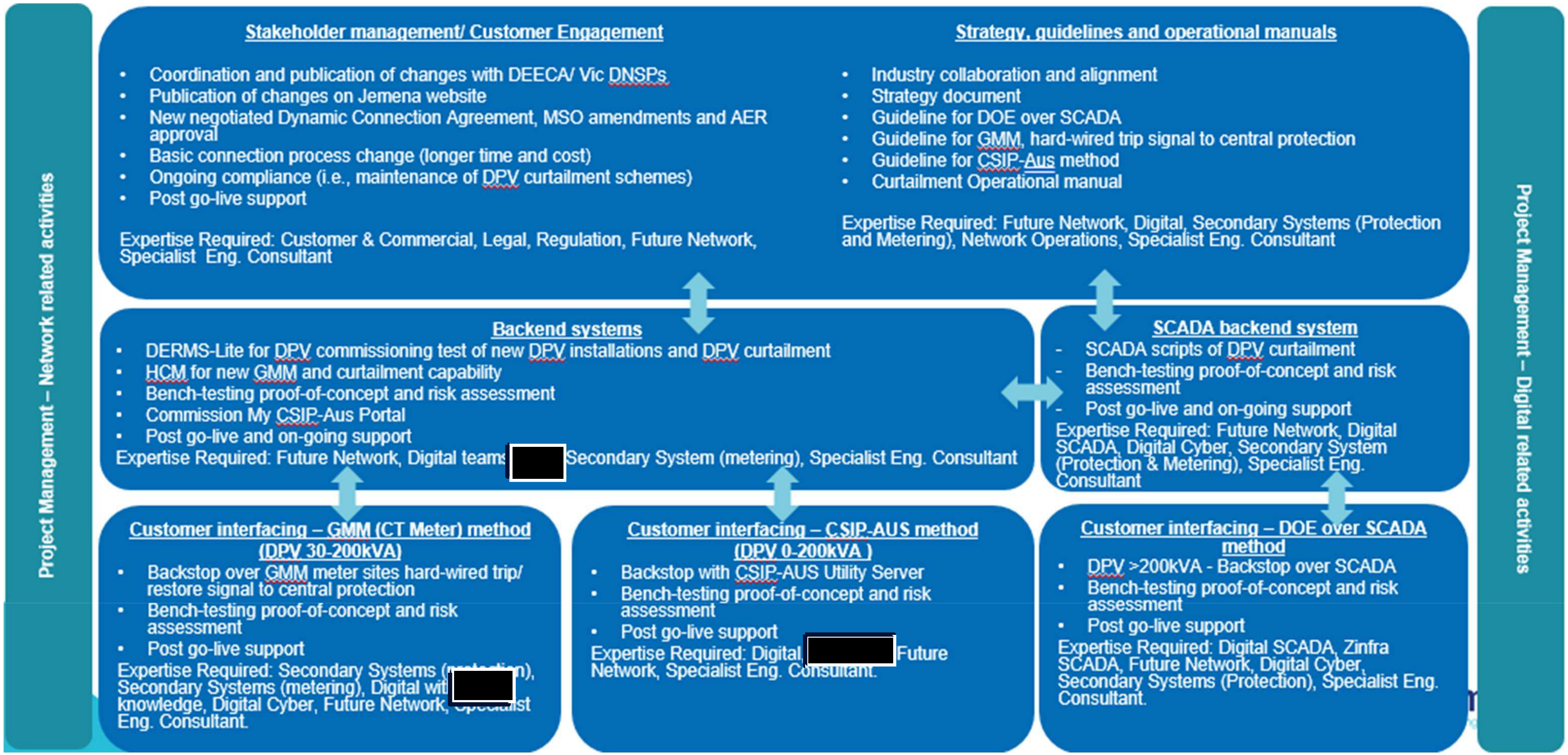


Figure 8.2 – Phase 2 – Flexible Export

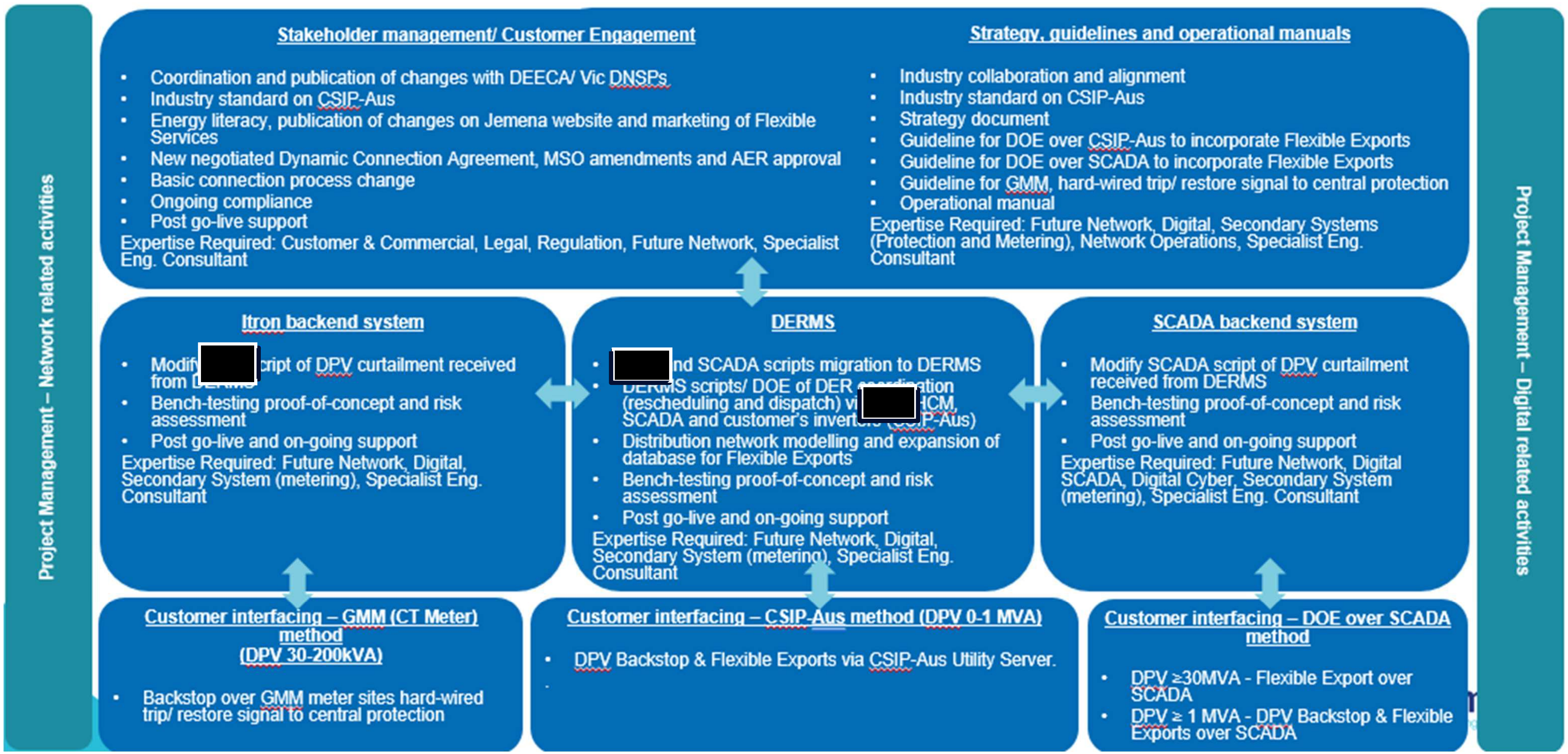
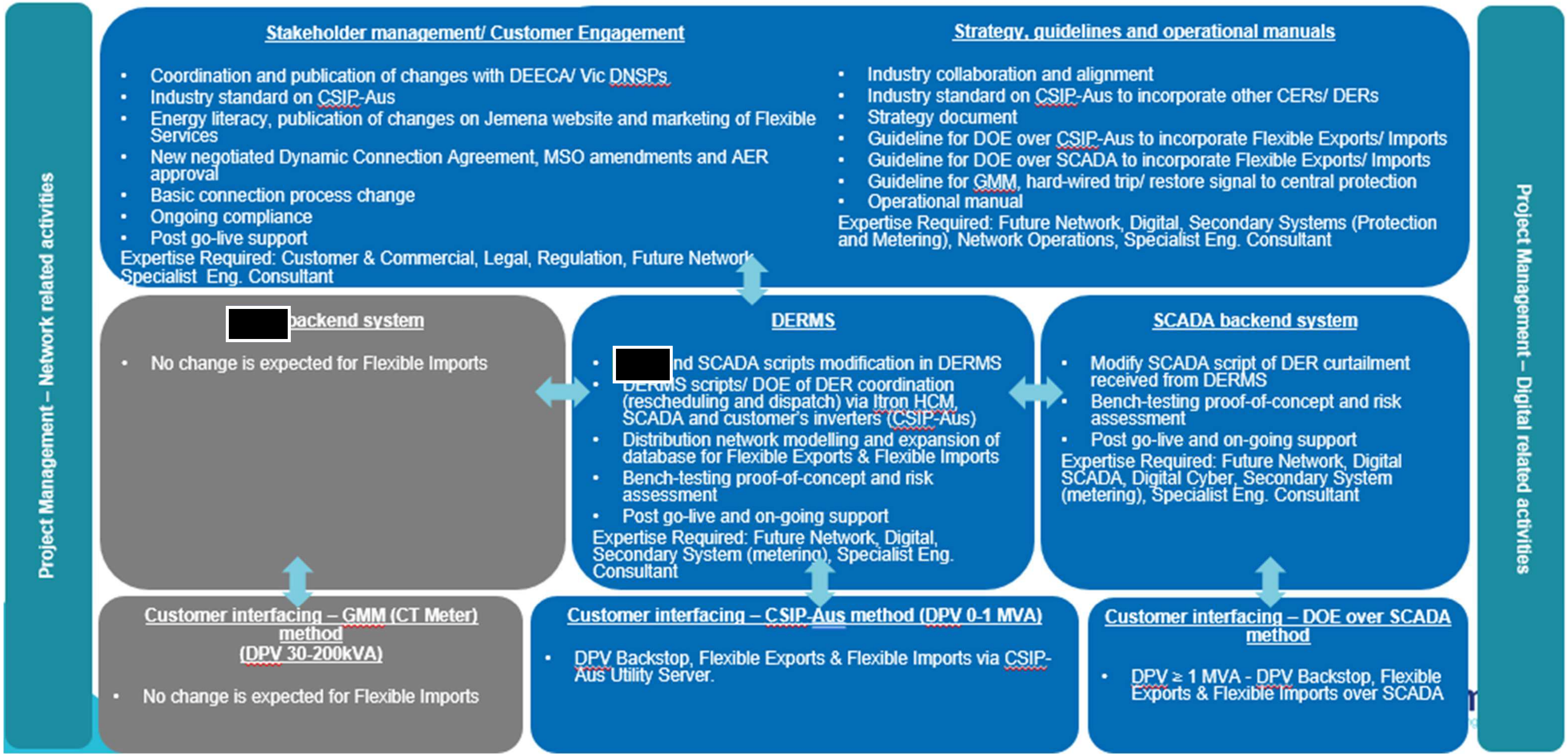


Figure 8.3 – Phase 3 – Flexible Import

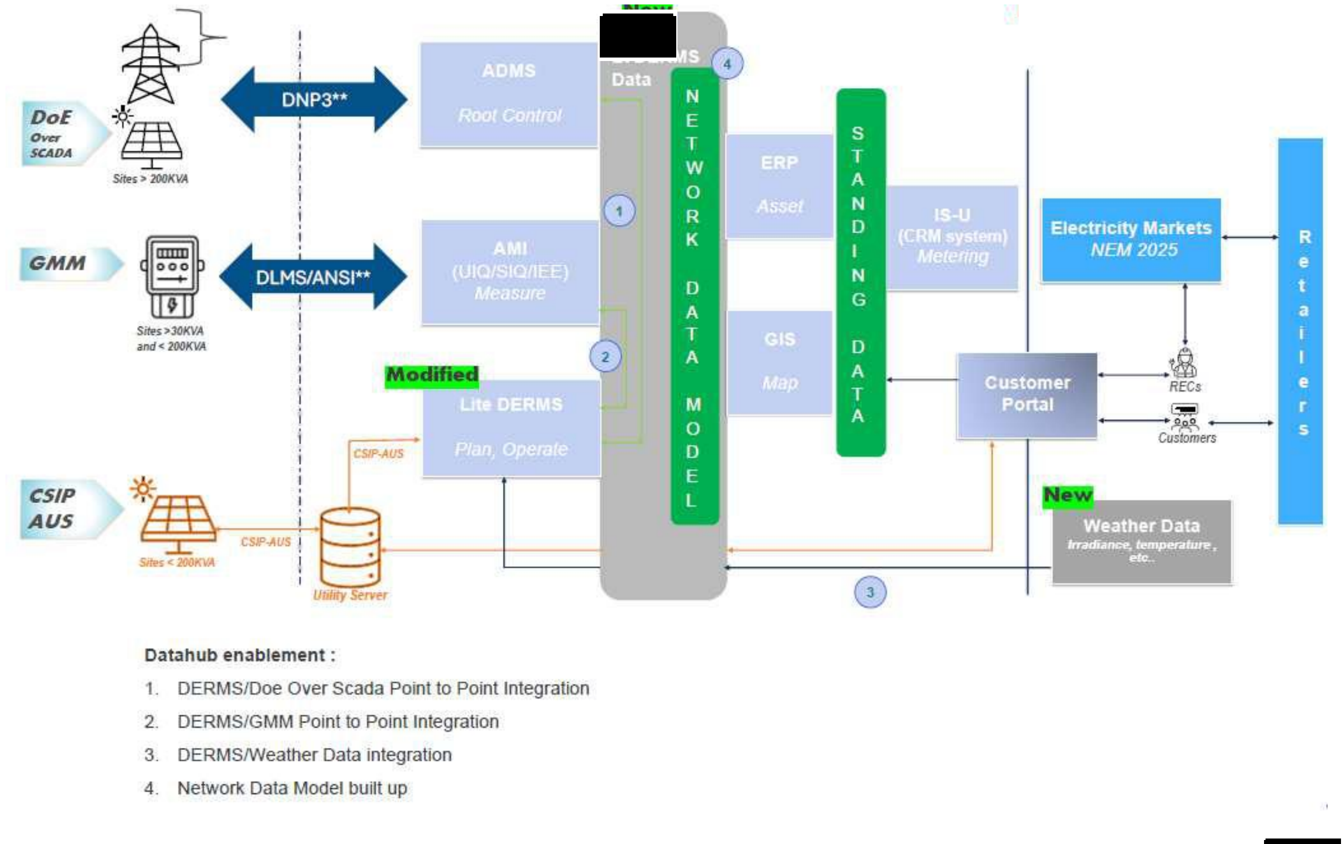


9. Appendix B: Grid Stability and Flexible Services Program

9.1 Implementing a DPV Backstop solution

For DPV systems (greater than 200kVA) connected to JEN's existing SCADA, JEN is applying the mandated DPV Backstop capability via SCADA. For all other DPV systems, the architecture that JEN has adopted is illustrated in Figure 9.1 – Architecture for JEN DPV Backstop, showing two additional options to minimise cost and performance burden on our SCADA system.

Figure 9.1 – Architecture for JEN DPV Backstop



Source: [redacted]

The two additional options include using:

- **Common Smart Inverter Profile (CSIP-AUS)** – using a Utility Server over the public internet (preferred method for all DPV sizes, as advised by DEECA); and
- **Generation Monitoring Meter (GMM)** – using a dedicated AMI CT meter with load contactor on the DPV circuit (JEN's alternative method for DPV sizes 30 kVA to 200 kVA, or for contestable meter customers, or for customers without an internet connection).

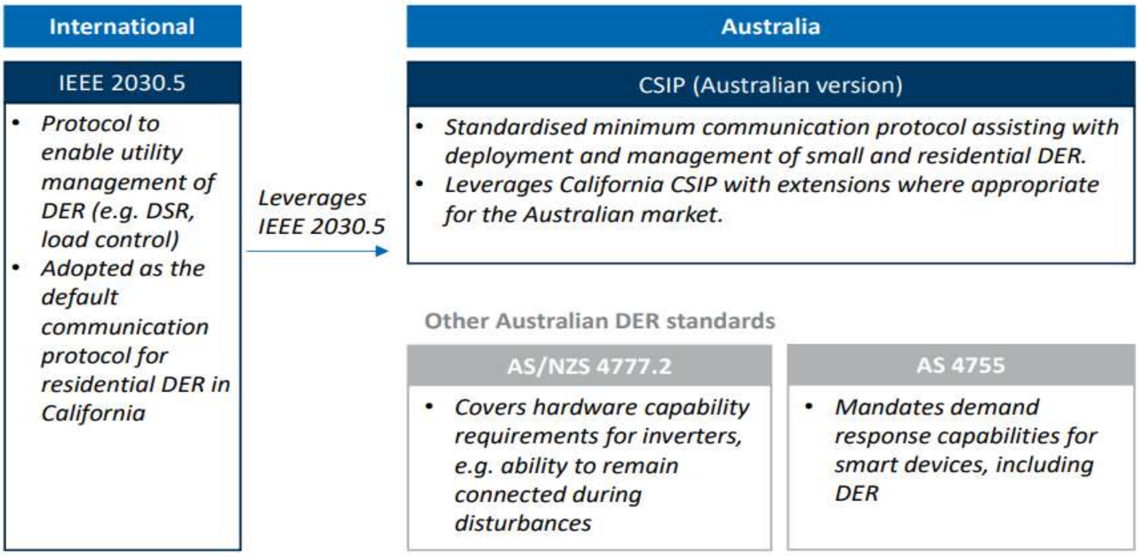
9.1.1 CSIP-AUS

Adopting the emerging CSIP-AUS[20] secure communications protocol is key to implementing DPV Backstop capability. Figure 9.2 – CSIP-AUS and IEEE 2030.5 shows that CSIP-AUS is an Australian implementation[21] of the IEEE 2030.5 protocol, which originated in the United States and is specifically designed for managing CER over the internet.

[20] CSIP – Common Smart Inverter Profile. Refer to: Common Smart Inverter Profile Australia (Arena.gov.au).

[21] CSIP Implementation Guide. Refer to: CSIP Implementation Guide v2.0 (Sunspec.org).

Figure 9.2 – CSIP-AUS and IEEE 2030.5

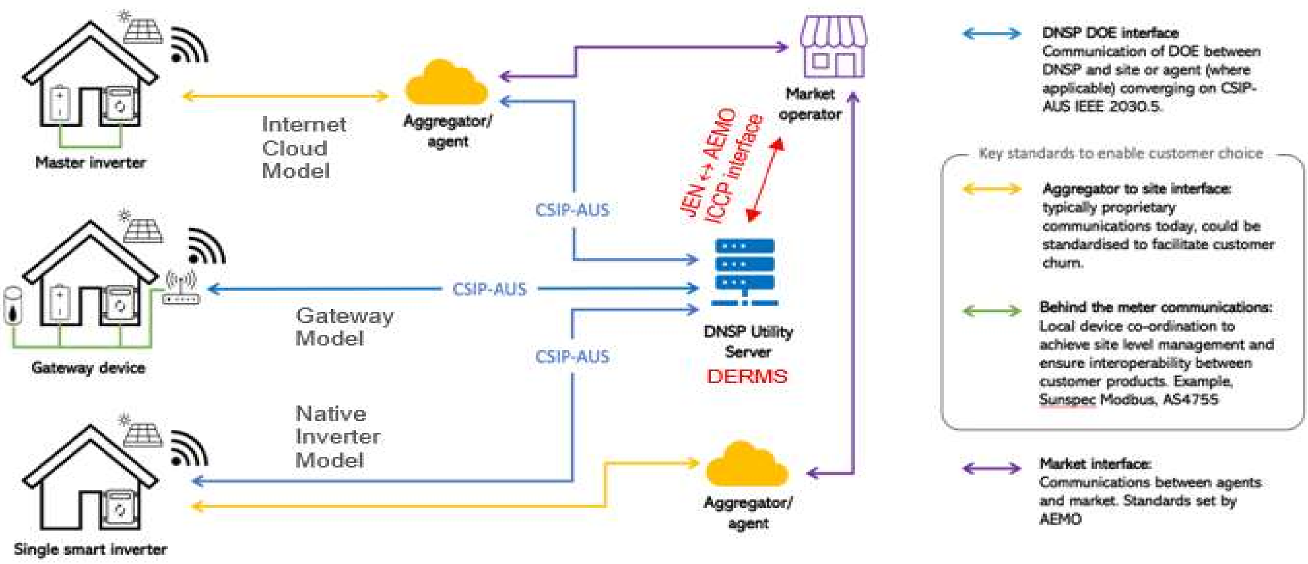


Source: FTI Consulting

CSIP-AUS is the mandated end-state solution for JEN to comply with the Victorian Government's new Ministerial Licence Condition[22] relating to establishing or altering a connection of a relevant embedded generating unit.

The use of the CSIP-AUS protocol is the basis for JEN's communication to small and medium DPV sites, and to Virtual Power Plant (VPP) Aggregators, via gateways, via third-party cloud platforms, or natively direct to the inverter. This is illustrated in Figure 9.3 – CSIP-AUS Implementation.

Figure 9.3 – CSIP-AUS Implementation



Source: SAPN (modified by JEN)

CSIP-AUS enables control (trip, restore, setpoint) and monitoring capabilities over the public internet, allowing JEN to directly or indirectly communicate with DPV inverters using a new JEN CSIP-AUS Utility Server and a lite version of a new LV DERMS.

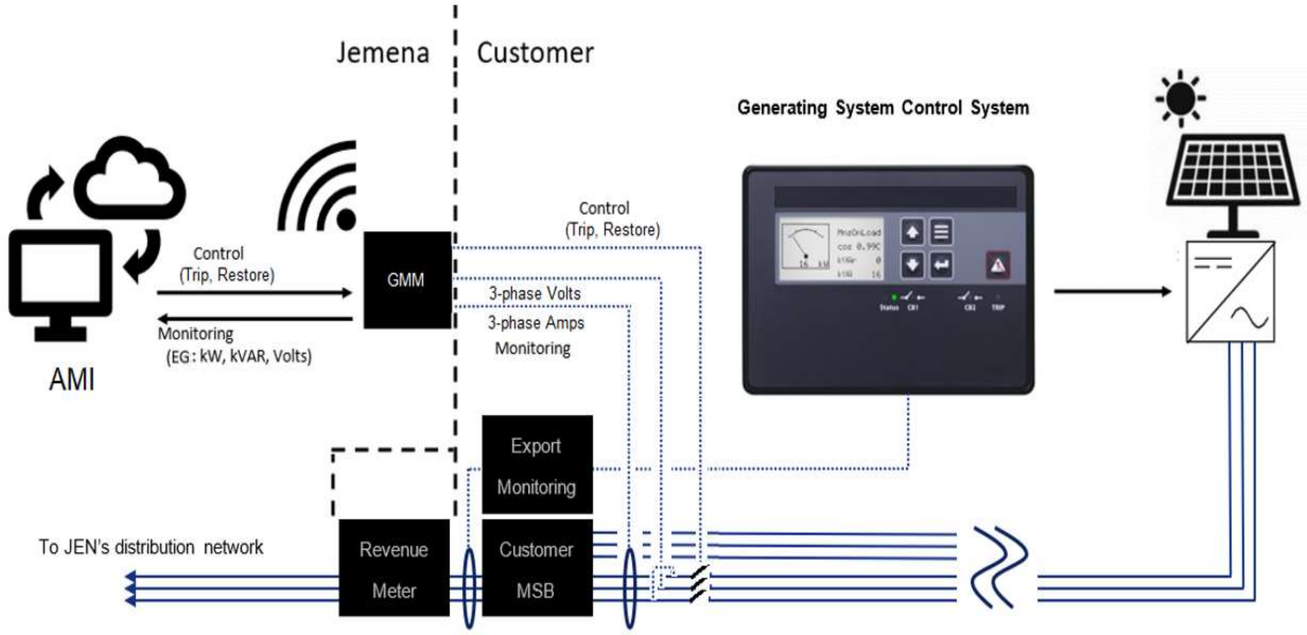
[22] Electricity Industry Act 2000 - Ministerial Order Specifying Licence Condition 2023 (No. 1).

9.1.2 Generation Monitoring Meter (GMM)

To manage the risks with customers' internet service not being available, the Generation Monitoring Meter (**GMM**) has been developed concurrently with CSIP-AUS and adopted as an alternative method for DPV sizes 30kVA to 200kVA for contestable revenue meter customers or customers without a reliable internet connection.

The GMM utilises a dedicated AMI CT Meter for the generating system a non-market meter. The GMM has control (trip and restore) capability and monitoring capability. As the GMM is a JEN-owned AMI meter, it interfaces directly into JEN's existing AMI GenX meshed radio communications network. The GMM's internal load contactor is used to trip and restore the main contactors of each DPV inverter, as illustrated in Figure 9.4.

Figure 9.4 – GMM Implementation



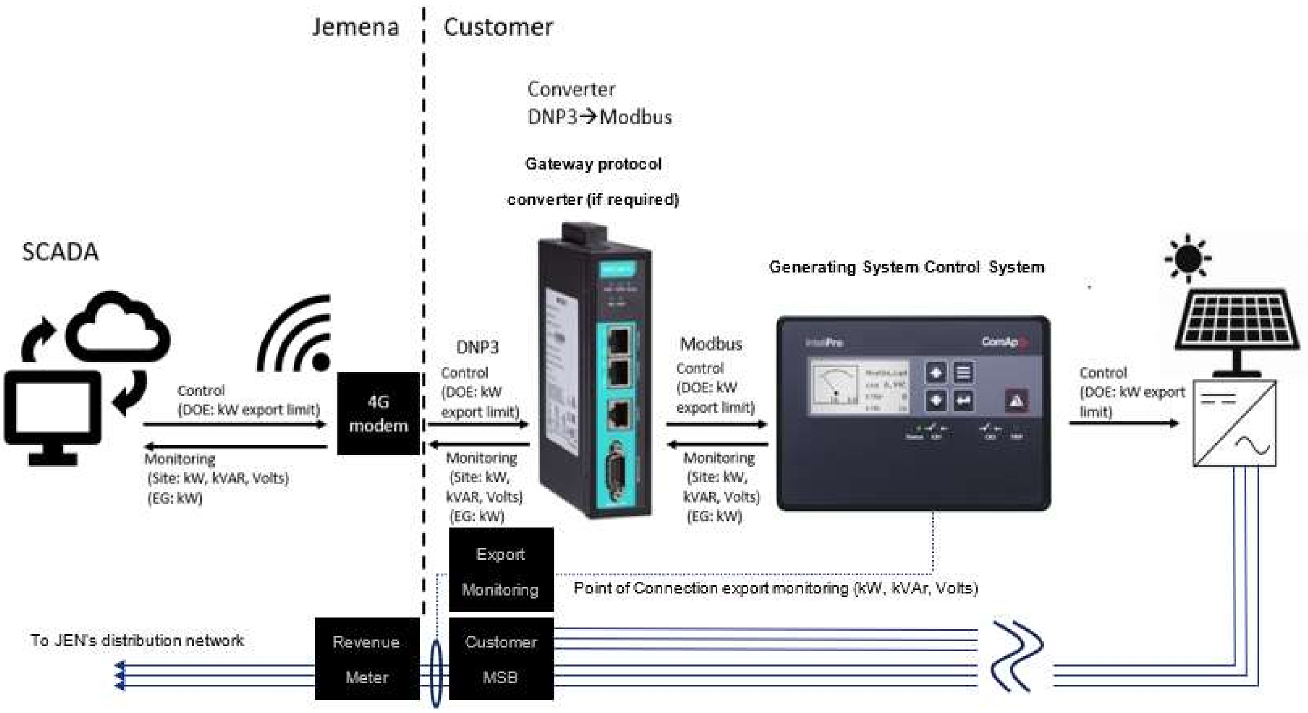
9.1.3 SCADA

The regulatory requirements that the Victorian Government has imposed for DPV systems greater than 200kVA do not specify a particular technology by which DPV Backstop capability must be implemented.[23]

JEN is adopting its existing SCADA communication system as the method for monitoring DPV generation and control for DPV Backstop for this tranche, using DNP3 over SCADA via gateways. This is illustrated in Figure 9.5 – SCADA Implementation.

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

Figure 9.5 – SCADA Implementation



9.2 Under frequency load shedding

Underfrequency Load Shedding (**UFLS**) schemes were originally designed on the assumption that they would shed blocks of load based on one-way power flow. With the uptake of DPV, there is an increasing risk of the load-shed blocks being net negative (i.e., generation) sources because of reverse power flows. Shedding such blocks could risk a state-wide collapse of the power system from under-frequency.

Under clause S5.1.10.1 of the NER, NSPs, including JEN, in consultation with AEMO, must ensure sufficient load is under control using under-frequency relays and other technologies to guard against potential risks, including underfrequency load events. NSPs may also require installation of load shedding arrangements to manage abnormal operating conditions. Further, under clause 4.3.1(k) of the NER, AEMO has power system security responsibilities including to ensure that appropriate levels of contingency capacity reserves and reactive power reserves are available to arrest the impacts of significant multiple contingency events (including underfrequency load events) which affect up to 60 per cent of the total power system load. On this basis, AEMO requires NSPs including JEN to ensure that 60 per cent of underlying load is under the control of UFLS schemes.

Meeting this required standard will become increasingly difficult for JEN as DPV uptake continues to increase and the net demand as measured by the UFLS schemes reduces. Load blocks with reverse power flow and the reduced numbers of available block loads are a threat to the effectiveness of the UFLS schemes in responding to a widespread loss of larger, transmission-connected generation sources.

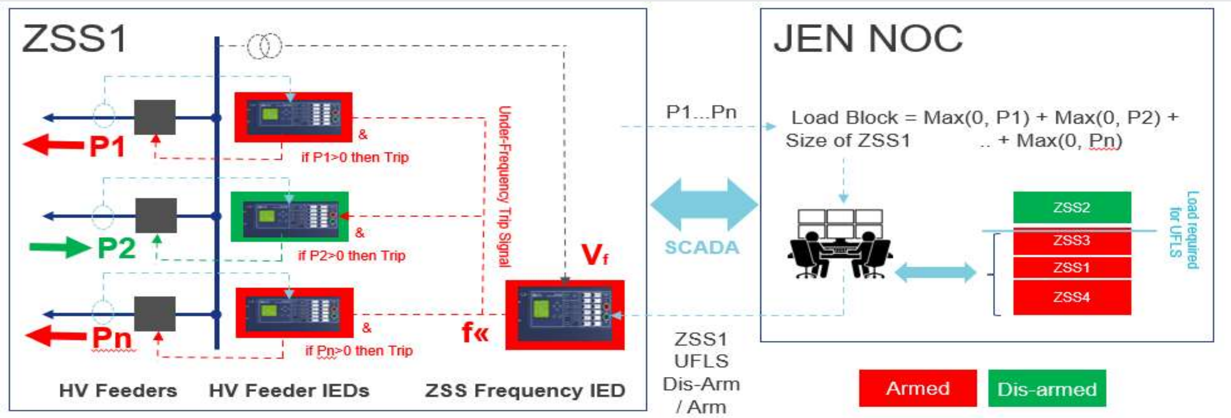
AEMO requires DNSPs to implement a distributed, granular UFLS control scheme that involves the automatic disconnection of dynamic load blocks through the ability to apply settings remotely (i.e., frequency and trip time), monitor, arm and disarm of UFLS, disconnect (in 0.2-0.5s response time), and restore load within the distribution network.

Load-shed blocks

A load-shed block comprises dynamically-armed distribution feeders that are available to be shed by the associated zone substation's dedicated under-frequency relay. Any distribution feeder relay is self-armed locally when it self-senses to become a net load (i.e. forward active power flow down the feeder) and it is not supplying critical customers (pre-determined). Otherwise, it remains disarmed.

The load-shed block size is the aggregate net load on all armed distribution feeders. JEN sends relevant information to AEMO aggregated by zone substation. The dedicated zone substation under-frequency relay trips all armed distribution feeders based on AEMO-defined under-frequency threshold and time delay settings. JEN manually restores distribution feeders after a load shed based on advice from AEMO. This is illustrated in Figure 9.6 – Foundational Distributed UFLS Implementation.

Figure 9.6 – Foundational Distributed UFLS Implementation



Options to address the effectiveness of the UFLS scheme include a combination of:

- utilising more granular load blocks (e.g. zone substation, feeder, ACR[24]; and/or possibly customer level); or
- increasing the load within a load block by curtailing the DPV (i.e. utilising dynamic operating envelopes (**DOE**s)),
- dynamically excluding all load blocks with reverse power flow using the list of armed load blocks in UFLS scheme.

Combined, these options provide a distributed UFLS capability.

9.2.1 More granular load blocks

Using more granular load blocks at the zone substation, feeder, ACR and/or possibly customer/CER level is likely to enable JEN to identify a greater amount of net load in aggregate than the net load measured at the sub-transmission level.

A foundational distributed UFLS would involve JEN adopting granular load blocks at the zone substation and distribution feeder levels. JEN would establish load-shed blocks on a per zone substation basis using a dedicated under-frequency relay per zone substation. JEN would arm and disarm each block as instructed by AEMO.

Adopting granular load blocks at the ACR and/or customer/DER level is a much more difficult proposition, given the performance requirements needed by the UFLS in terms of speed and the complexities needed to manage

[24] ACR – Automatic Circuit Recloser, used to sectionalise a distribution feeder.

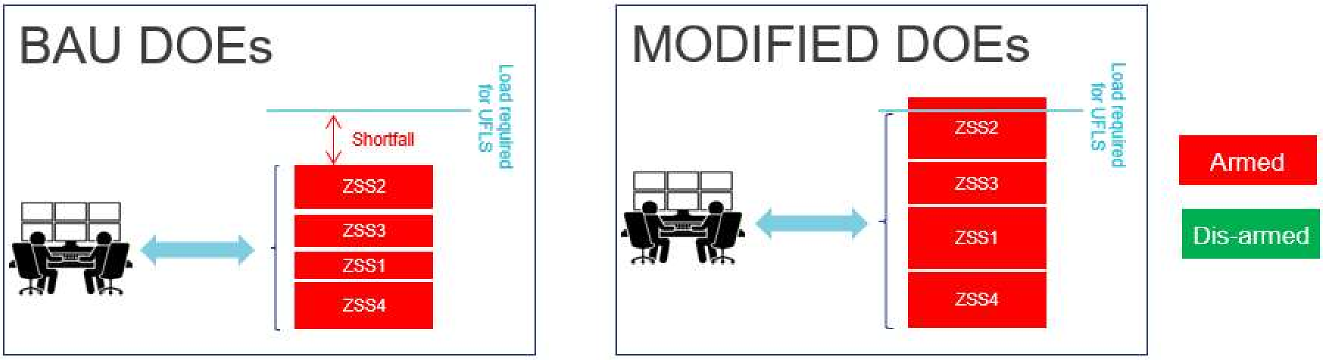
the coordination of the number of load blocks involved. Instead, an enhanced form of distributed UFLS could be provided by curtailing DPV using modified DOEs as discussed below.

9.2.2 Curtailing DPV using modified DOEs or the backstop mechanism

If there is insufficient demand in the load blocks available for operating the distributed UFLS solution, then DOEs could be used as an enhanced way to increase the amount of underlying load available to the UFLS scheme. A DOE is an export limit that varies in time according to an allocation of the actual available network capability at the time, on the premise that zero export limiting may only be needed for a small fraction of the year.

As shown in Figure 9.7 – Enhanced Distributed UFLS Implementation, JEN could modify the typical DOE value normally used for flexible services applications so that the block load size is sufficient in aggregate to meet 60 per cent of underlying demand.

Figure 9.7 – Enhanced Distributed UFLS Implementation



If the DOE is designed to be bidirectional, it could be used to curtail generation further to force an import condition at a site. This would offset the export contribution of legacy DPV sites that do not have such control mandated or to compensate for non-compliant DPV sites. As a last resort, the backstop mechanism could be used as an alternative to a modified DOE.

9.3 Flexible services

New distribution network management adaptations are centred around flexible services, which include flexible exports and flexible imports.

9.3.1 Flexible exports

JEN is already responding to voltage limitations on our network caused by DPV exporting electricity, including by:

- using Dynamic Voltage Management (**DVM**) (covered by the Voltage and PQ management strategy) to optimise use of existing assets and avoid unnecessary capex investment in the near-term; and
- setting fixed (zero) export limits, subject to Chapter 7A of the AER's Connection Charge Guideline[25].

However, further adaptations are needed for thermal limitations triggered by CER and any residual voltage limitations imposed by CER that are not addressed by these measures.

As CER uptake and electricity exports increase, JEN will incur increased costs for maintaining regulatory voltage compliance, managing assets within thermal ratings, and managing complaints and claims. We also anticipate increased need for JEN to curtail CER electricity exports and for zero export limits needing to be imposed more often so that JEN can manage network thermal and voltage limitations. Similar challenges are likely to apply in

[25] Connection charge guidelines for electricity customers, v3, April 2023 (aer.gov.au).

relation to electricity exports from increased storage and vehicle-to-grid (**V2G**) uptake, as a result of more CER customers starting to participate in Virtual Power Plant (**VPP**) programs and market services.

Adopting flexible exports using DOE control will be important to minimise further network investment and DER curtailment. Flexible exports are required to minimise CER electricity export curtailment while ensuring JEN's network operates within its export ratings. This is important to ensure that reverse power loading on network assets and customer voltage rises remain within technical and regulatory limits.

Implementing flexible export capabilities for all new and upgraded DPV systems by dynamically controlling export limits using DOEs is best aligned to follow the Grid Stability (Supply-Demand Balance) strategic need and targeted in areas of the network where export-related thermal and voltage limitations exist so that some augmentation expenditure can be deferred. To implement flexible exports for DPV systems of up to 200kVA capacity, JEN would utilise CSIP-AUS to DPV inverters and AMI meter export monitoring to enforce the DOE, with DOE and setpoint values calculated by an Integrated LV DERMS system.

We also intend to allocate hosting capacity between customers based on the AER's Export Limit Guidance Note[26]. The proposed timing of this work is as follows:

- Determine export capacity allocation (or intrinsic hosting capacity) by April 2025.
- Engage customers on static export limit and dynamic export limit by August 2025.
- Develop and communicate customer offers for opt-in flexible services including connection agreements (e.g. model standing offers) by June 2029.
- Set up a compliance and monitoring framework by June 2029.
- Set up a complaints and disputes resolution process by June 2029.
- Set up systems for reporting by December 2029.

9.3.2 Flexible imports

Maximum demand challenges are also likely to arise particularly as EV uptake and gas electrification accelerates. For example, maximum demand may reach new high levels where peak EV charging times coincide with peak demand for other purposes such as air conditioning. There is an emerging opportunity to use flexible imports to manage EV charging at times of maximum network demand in an environment with high EV penetration. JEN could use flexible imports to help ensure our network operates within its import ratings. This is important to ensure that forward power loading on network assets and customer voltage level remain within technical and regulatory limits.

Implementing flexible import capabilities for all new EV supply equipment (**EVSE**) by dynamically controlling import limits using DOEs is best aligned to follow the implementation of flexible exports in those areas of the network where network limitations associated with EV charging begin to materialise later this decade. To implement flexible imports, JEN would utilise CSIP-AUS to EV chargers and AMI meter import monitoring.

[26] Final export limit guidance note, October 2024.

10. Appendix C: Cost Estimates of Recommended Program

Cost estimates provided in this section for Flexible Export and Flexible Import initiatives are based on an in-depth understanding of key requirements and likely implementation duration from Jemena's Solar PV Emergency Backstop project. The implementation duration for Flexible Export and Flexible Import initiatives are likely to be at least 18 months and 15 months, respectively. Refer to Table 10-1 and Table 10-2 for the cost breakdown.

For the gid stability distributed UFLS initiative, the cost estimates summary is based on estimates derived from the scope of work prepared for each terminal station and is presented in Table 10-3.

Note that cost estimates presented in Table 10-1, Table 10-2 and Table 10-3 are direct cost in $'000, June 2024, which excludes capitalised overheads and escalations.

Table 10-1: Flexible Export Cost Estimates FY2026/27-2030/31 (Direct Cost, $k, June 2024)

			Direct Cost ($k, June 2024)	Effort (human-days)	Comments
Digital	Capex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Internal hardware	[redacted]	[redacted]	[redacted]
		Internal software	[redacted]	[redacted]	[redacted]
		External labour	[redacted]	[redacted]	[redacted]
		External hardware	[redacted]	[redacted]	[redacted]
		External software	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
	Opex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Internal hardware	[redacted]	[redacted]	[redacted]
		Internal software	[redacted]	[redacted]	[redacted]
		External labour	[redacted]	[redacted]	[redacted]
		External hardware	[redacted]	[redacted]	[redacted]
		External software	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
Network	Capex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Subcontract	[redacted]	[redacted]	[redacted]
		Materials, plant and equipment	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
	Opex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Subcontract	[redacted]	[redacted]	[redacted]
		Materials, plant and equipment	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
Total	**Capex**		[redacted]	[redacted]	[redacted]
	Opex		[redacted]	[redacted]	[redacted]

Table 10-2: Flexible Import Cost Estimates FY2026/27-2030/31 (Direct Cost, $k, June 2024)

			Direct Cost ($k, June 2024)	**Effort (human-days)**	**Comments**
Digital	Capex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Internal hardware	[redacted]	[redacted]	[redacted]
		Internal software	[redacted]	[redacted]	[redacted]
		External labour	[redacted]	[redacted]	[redacted]
		External hardware	[redacted]	[redacted]	[redacted]
		External software	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
	Opex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Internal hardware	[redacted]	[redacted]	[redacted]
		Internal software	[redacted]	[redacted]	[redacted]
		External labour	[redacted]	[redacted]	[redacted]
		External hardware	[redacted]	[redacted]	[redacted]
		External software	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
Network	Capex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Subcontract	[redacted]	[redacted]	[redacted]
		Materials, plant and equipment	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
	Opex	Internal labour	[redacted]	[redacted]	[redacted]
		Contract labour	[redacted]	[redacted]	[redacted]
		Subcontract	[redacted]	[redacted]	[redacted]
		Materials, plant and equipment	[redacted]	[redacted]	[redacted]
		Subtotal	[redacted]	[redacted]	[redacted]
Total	**Capex**		[redacted]	[redacted]	[redacted]
	Opex		[redacted]	[redacted]	[redacted]

Table 10-3: Foundation UFLS Cost Estimates FY2026/27-2030/31 (Direct Cost, $k, June 2024)

			Direct Cost ($k, June 2024)								Effort (human-days)								Comments
			Initial set up	**BLTS**	**BTS**	**KTS**	**SMTS**	**TSTS**	**TTS**	**WMTS**	**Initial set up**	**BLTS**	**BTS**	**KTS**	**SMTS**	**TSTS**	**TTS**	**WMTS**	
Digital	Capex	Internal labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Contract labour		[redacted]															
		Internal hardware	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Internal software	1,167	-	-	-	-	-	-	-	Not Applicable								
		External labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		External hardware	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		External software	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Subtotal	***1,167***	***102***	***82***	***201***	***27***	***11***	***224***	***52***	**-**	***94***	***76***	***185***	***25***	***10***	***206***	***48***	
	Opex	Internal labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Contract labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Internal hardware	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Internal software	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		External labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		External hardware	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		External software	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	SCADA System Modification - Open LSR Implementation
		Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			Direct Cost ($k, June 2024)								Effort (human-days)								Comments
			Initial set up	LTS	TS	TS	MTS	STS	TS	MTS	Initial set up	LTS	TS	TS	MTS	STS	TS	MTS	
Network	Capex	Internal labour	-	[redacted]															[redacted]
		Contract labour		[redacted]															[redacted]
		Subcontract	-	[redacted]															
		Materials, plant and equipment	-	[redacted]															
		Subtotal	**-**	***680***	***547***	***1,339***	***182***	***74***	***1,490***	***346***	**-**	***442***	***408***	***950***	***122***	***48***	***942***	***223***	
	Opex	Internal labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Contract labour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Subcontract	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Materials, plant and equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
		Subtotal	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Total	**Capex**		**1,167**	**782**	**629**	**1,540**	**209**	**85**	**1,714**	**398**	**-**	**535**	**484**	**1,134**	**147**	**59**	**1,148**	**270**	
	Opex		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	