

Essential Energy

10.05 Future Network Business Case Overview



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1. Executive summary

Business Case	10.05 Future Network Business Case Overview						
Description	Essential Energy is proposing to introduce a range of investments broadly categorised under a future network business case. These investments span assets, systems, data and tariffs to address the growing decentralisation of generation and uptake of Consumer Energy Resources (CER).						
Drivers for Program	<p>Large scale uptake of CER technologies such as rooftop PV, storage and electric vehicles (EV) has occurred at a rapid rate and is forecast to continue. Without investment this would lead to system constraints and ultimately customer curtailment and/or drive less economic 'traditional' Capex/Opex solutions. System constraints are generally categorised into voltage or thermal capacity constraints.</p> <p>Customers have identified that the adoption of CER technology is a fundamental requirement for standard electricity connections.</p>						
Risk & Value Benefits	<p>Following an AEMC determination and update to the National Electricity Rules (NER), the AER, in June 2022 published a valuation methodology and rate for DNSPs to evaluate a customer export curtailment value (CECV).</p> <p>This business case has adopted an alternative CECV rate to calculate the benefits of reducing curtailment through the interventions detailed in this document.</p> <p>In addition to curtailment alleviation, other benefits for this business case include:</p> <ul style="list-style-type: none"> - deferred augex - reliability improvement - reduced losses - opex reductions - safety improvement - voltage regulation 						
Options	<p>Options analysed in the development of this business case included:</p> <ul style="list-style-type: none"> - implementation of Dynamic Operating Envelopes (DOEs) - traditional network solutions including; HV/LV reinforcement, distribution transformer upgrades, voltage control and regulation settings and community Battery Energy Storage Systems (BESS) <p>With three timing options explored in particular for DOEs, being:</p> <ol style="list-style-type: none"> 1. Basic DOE implementation 2025-2029. Advanced DOE trial and implementation 2030-2035 2. Basic DOE implementation 2025-2029. Advanced DOE trial in 2026 and implementation in 2031 3. Full DOE capability by 2029 <p>Recommend Option 1 at a total cost of \$296M¹ with NPV of \$159M and a combination of traditional network solutions and DOE.</p>						
Estimated expenditure FY\$24 ²		2024/25	2025/26	2026/27	2027/28	2028/29	
	CAPEX	\$28.2M	\$17.8M	\$10.9M	\$12.6M	\$23.1M	
	OPEX	\$10.6M	\$9.4M	\$9.4M	\$13M	\$12M	

All values are in full year 2023-24 real dollar terms

¹ Full expenditure over multiple regulatory periods

² Expenditure for 2024-29 period only shown

2. Introduction and the identified need

The Australian energy system is embarking on a period of significant change, as it moves towards greater decentralisation, decarbonisation and digitisation³. The integration of CER including solar rooftop PV, residential scale storage, electric vehicle (EV) uptake and alternative energy management systems into the electricity system, is crucial in supporting this transition and increases the need to consider investment that facilitates a greater uptake of CER while maintaining affordability and security of supply.

Several changes to the way our customers and stakeholders interact with our network now and into the future is driving the need for grid modernisation: continuing to transition a network traditionally designed to support one way energy flow, into a more dynamic, two-way system with the optimal amount of capacity available to ensure Essential Energy can meet both stakeholder requirements and technical standards around voltage, safety and performance.

The below table outlines several parameters reflecting changes in network, customer and third-party requirements that are and will continue to shape future network developments and operations.

Drivers		Enablers	
Factors to which we need to respond		Prerequisites to allow us to respond	
Reverse flow management (voltage and thermal)	Finely balanced demand and CER generation leading to low load demand and reverse flows on the network, with resulting voltage and thermal issues. Reaches a level where point interventions are unfeasible or not cost-effective.	Widespread smart metering	The availability of smart metering allows Essential Energy (EE) to build data-driven analytical tools that can help us understand the state of the current and future network.
Peak load exceeding capacity	Peak demand exceeds transformer or line capacity at multiple sites such that they cannot be managed quickly enough or cost-effectively through traditional auxex solutions.	Availability of customer data	Increasing levels of access to customer data from smart devices reduces the costs and time for data acquisition. Increases overall network visibility close to real-time (e.g. IEEE2030.5).
Customer expecting access to services	Connected customers expect to be able to access sufficient network capacity for their needs (import and export) – including PV export, EV charging, battery services etc.	Sufficient flex market liquidity	Enough CER exists in an area to run a viable tender and to ensure that individual participants cannot exert undue market power.
Increasing levels of export constraints for new and existing connections	Increasing network voltages, emerging thermal constraints, and minimum demand risk reduce the amount of energy consumers can export. Also driving increased costs associated with voltage management and customer complaints.	Customer acceptance/produce maturity	Customers are willing to participate, and/or their agents have developed customer propositions that facilitate their participation (this includes both 'market' based and fringe of grid solutions).
Peak demand timing shifting	More interconnected devices such as EVs, batteries etc, result in more coordinated behaviours. This means less diversification of	Institutional arrangements & capabilities	Existing (and potentially new) agencies (e.g. AEMO → DMO) develop and implement new capabilities providing us and our

³ World Economic Forum - *The Future of Electricity New Technologies Transforming the Grid Edge*, [Online](#).

Drivers		Enablers	
Factors to which we need to respond		Prerequisites to allow us to respond	
and becoming unpredictable	peak demand, and a decreased ability to forecast system needs.		customers/suppliers to develop and offer new services.
Reliability/ security of supply (including resilience) – fringe of grid	Decreasing levels of reliability and increasing total expenditure to maintain fringe of grid assets. Reducing CER costs.	Third party capabilities	Existing and new service providers (e.g. IT, asset, human resource) develop capabilities ahead of or at pace with EE to support trialling; procurement; and operationalisation of new services.

Forecasting studies anticipate that without proactive intervention, the volume of curtailed energy generation in our area will increase significantly (Figure 1). While diversified peak demand and consumption are forecast to remain relatively flat over the next regulatory period, rapid shifts in customer behaviour driven by technology change, economic and environmental conditions and, government incentives impose increasing demand variability at specific locations and time periods across the Essential Energy distribution network. These changes would result in voltage and power quality issues, increased export curtailment, higher augmentation expenditure, and poor customer, market and stakeholder outcomes.

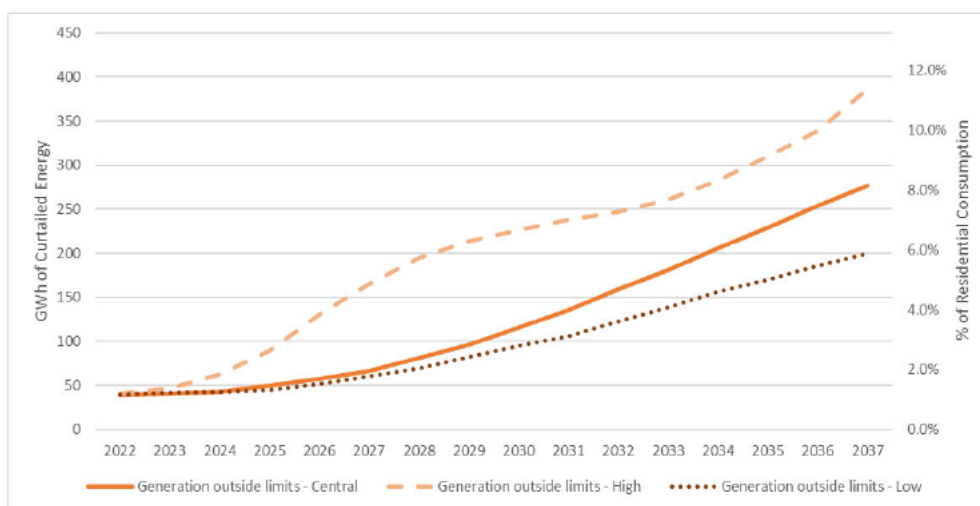


Figure 1: Forecast Generation Curtailment (7.01.01 Hosting Capacity Study - Zepben)

To enable the transition towards widespread CER, Essential Energy must continue to plan and act on how to integrate these systems into the distribution network in an economically efficient manner, that maximises long-term value for all customers.

The future network program aims to ensure the Essential Energy network is capable of safely managing a diversity of energy demand and supply now and into the future, utilising a range of traditional and new non-traditional interventions. As new conditions and increased data emerge, we will continue to review and adjust our future network program to remain aligned with customer, stakeholder and market values.

In June 2022, the AER published its final guidance note to DNSPs on CER integration expenditure⁴. The guidance note included the AER's expectations on what should be considered through the process of developing CER integration plans and investment proposals.

⁴ AER DER integration expenditure guidance note, AER, June 2022

Additionally, a rule change through the AEMC, published in August 2021 on access, pricing and incentive arrangements for distributed energy resources (DER)⁵, formalised the requirement for DNSPs to support more CER connecting to the grid and to provide efficient options to support the provision of export services.

Both the AER's guidance and the AEMC requirements have been carefully considered in the development of this Future Network Business Case⁶ which assesses the net economic benefits of a range of credible options for Essential Energy to increase hosting capacity and support increased CER integration, proposing an optimal package of planned interventions under current forecast conditions.

Essential Energy recognises the pace of change in and around the energy industry is rapid, and as such, the future network program and subsequent investment plans must remain agile to accommodate any future shifts, ensuring optimal outcomes for our customer, stakeholder, and market beneficiaries.

3. Our customer appetite for a smarter network

In preparing the 2024-2029 Regulatory Proposal, we engaged with customers over four phases (refer **Attachment 4.02**). During the first phase conducted in October/November 2021, customers were polled on risks in operating the distribution network and how these are valued. Customers supported our risk metrics and placed a high level of importance on reliability, bushfire, and safety.

During the second phase of engagement in February 2022, the challenges for power quality relating to the energy system transition were discussed.

In the third phase of engagement, customers were offered four options⁷ from a 'change nothing' to large expenditure alternatives to avoid the problems from occurring with investment in a smarter grid as shown in the figure below. The concepts of automation, real-time monitoring (network visibility) and dynamic network assets were introduced with options for uplift and the expected effects. The outcome of this phase of engagement resulted in broad support across the two most expensive options, 27% and 66% respectively. Customers overwhelmingly supported option 4 (66%) which included full automation, a high level of real-time network monitoring and a significant increase in the use of dynamic network assets to target current and all potential problem areas.









		Option 1 – Do nothing more	Option 2 – Mitigate existing problems over time	Option 3 – Mitigate existing problems and pre-empt some	Option 4 – Avoid the problems from occurring
METHODS	Level of manual intervention	Entirely manual – based on customer complaints	Mostly manual, with some automation	Some manual intervention, but mostly automated	Fully automated
	Level of real-time monitoring	Next to none	Minimal – target only current problem areas	Some – a basic level of real-time network monitoring	Significant – a high level of real-time network monitoring
	Use of dynamic network assets	Next to none	Minimal – target only current problem areas	Some – target current and some potential problem areas	Significant – target current and all potential problem areas
OUTCOMES	Power quality	Will decline	About the same	Improved	Greatly improved
	Export limits	Significant	Some	Reduced – some dynamic management*	Greatly reduced – higher level of dynamic management*
	Number of export connections denied	Many	Some	Minimal	Next to none
	Cost	\$21M over 2024-29	\$45M over 2024-29	\$81M over 2024-29	\$164M over 2024-29
	Bill Impact increase per annum Residential	 \$1.56	 \$1.80	 \$2.15	 \$5.54
	Small business	 \$6.77	 \$7.83	 \$9.37	 \$24.12

Figure 2: Customer engagement on a smarter grid (phase 3).

During the fourth phase of engagement, an increased bill impact was tested due to price increases in delivering on the outcomes engaged on in the previous phases. Customers accepted the increase in costs and elected to not review the options.

⁵ AEMC, [Access Pricing and incentive arrangements for distributed energy resources, Rule determination](#), AEMC, 12 August 2021

⁶ Draft Future Networks Business Case, Baringa, January 2023

⁷ Option numbers from customer engagement are unrelated to the option numbering in this business case

4. Key inputs and assumptions

Essential Energy has undertaken analysis of our network's current and forecast hosting capacity, current CER penetration and forecast uptake over the succeeding 15-year period.

The modelling, forecasting and analysis inputs used to inform the development of the future network investment proposal are summarised below. More detailed information is available in the associated reports and reference documents mentioned below.

4.1 Constraint modelling

4.1.1 CER uptake and demand forecasts – Frontier Economics

A 15-year forecast (2022-2037) of consumption and minimum and maximum demand on the Essential Energy network was developed by Frontier Economics (Frontier)⁸ (**Attachment 11.01**). This modelling projected maximum demand will increase towards approximately 2,500MW, while minimum demand decreases below 500MW by 2037.

Frontier's modelling considered various CER and electrification forecasts, in line with the AER's guidance to DNSPs² and projected the impacts on consumption for each Essential Energy zone substation (ZS). Step change scenarios in line with AEMOs guidance for low, central and high were modelled for each factor. The central scenario, or most likely step change, as identified by AEMO, forms the basis of the future network program. The AER's CECV methodology also adopted the central step change scenario as the basis of its CECV estimations.

With consideration of the increasing impact of solar PV penetration and embedded generation, Frontier showed baseline consumption has already begun declining with the trend to continue over the succeeding 15-year forecast period. In contrast, the decline in baseline consumption is offset by the significant increase in consumption associated with electrification, EVs and batteries expected to result in a net increase of 6.0% by 2037 compared to 2021 (Figure 3).

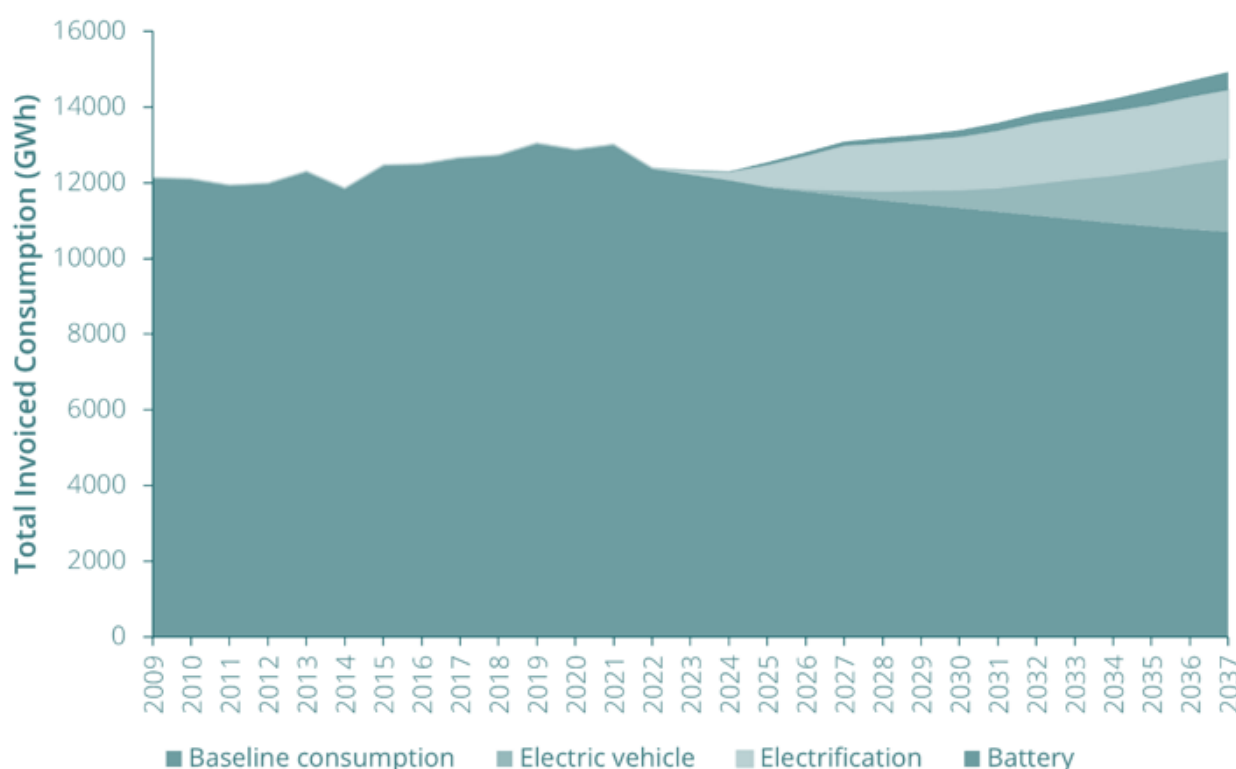


Figure 3 - Forecast ZS consumption (Attachment 11.01 Non Financial Forecasts - Frontier Economics)

⁸ Forecasts of customer numbers, energy consumption and demand, Frontier Economics (Attachment 11.01).

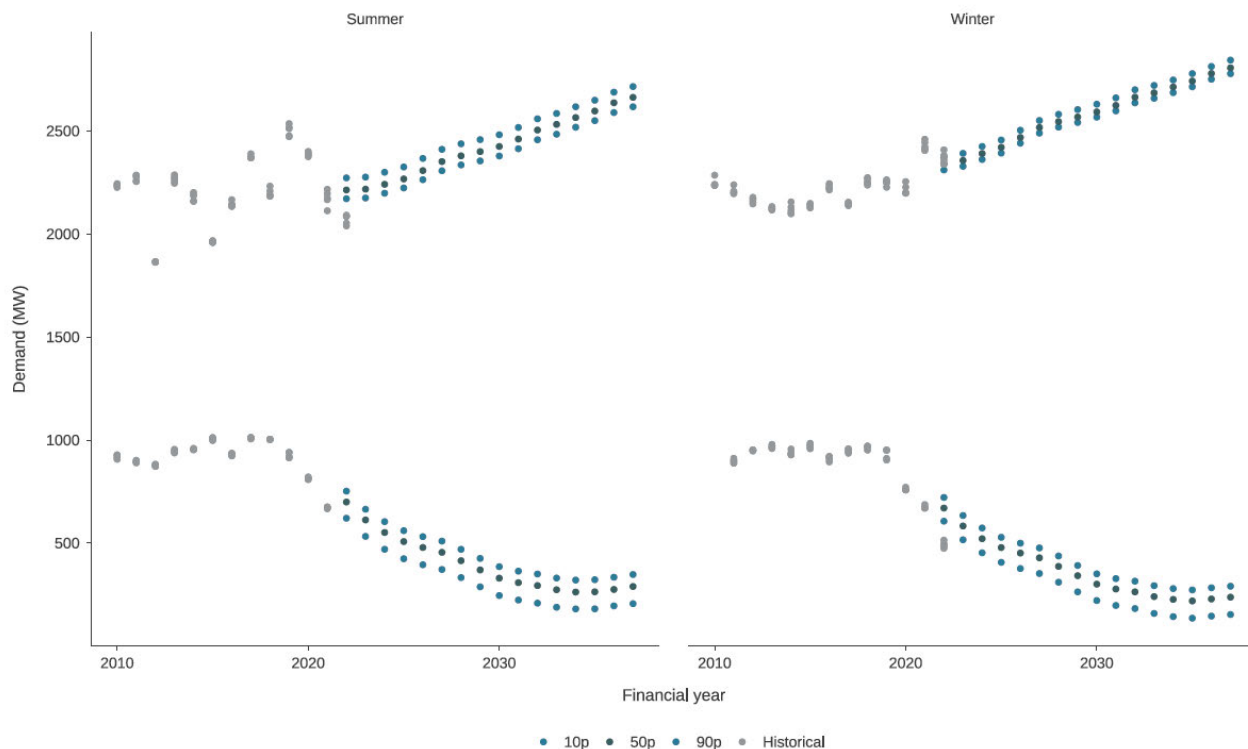


Figure 4 - Minimum and maximum total network consumption forecast for 2022-2037 (Attachment 11.01 Non Financial Forecasts - Frontier Economics)

Also considered were the contribution of CER factors to forecasted maximum and minimum demand including rooftop PV, batteries, EVs, and electrification. The impact of each factor on forecast demand is summarised below and the detailed analysis is available in Frontier's final report⁹:

- > Rooftop PV – expected to increase significantly as relates to minimum demand. Over the forecast period, rooftop PV is expected to increase its impact on minimum demand from 500MW of demand, with the POE 10 nearing 2,000MW. This large and increasing role of rooftop PV is consistent with the expected change in time of minimum and maximum demand, as maximum demand is pushed later into the day, and minimum towards the middle of the day by the emergence of rooftop PV generation⁶.
- > Batteries (behind the meter) – expected to reduce forecasted maximum demand in the near term, and as uptake rates increase over time, will have an increasing role in offsetting the fall in minimum demand over the forecast period.
- > EV – contribution to maximum demand increases towards the end of the period while EVs have significant and rapidly increasing scope to offset minimum demand in both summer and winter.
- > Electrification from gas and LPG – mostly attributed to business rather than residential customers. Contribution to maximum demand is consistent with growth rates forecast in electrification, while playing a significant and increasing role in offsetting minimum demand.

Frontier's forecast was further extrapolated to a 20-year forecast and used to inform the future network program and associated cost benefit analysis.

4.1.2 Hosting capacity analysis

Hosting capacity refers to the ability of a power system to accept DER generation without adversely impacting power quality such that the network continues to operate within defined operational limits.

Electrical network modelling was undertaken in conjunction with Zepben to confirm the existing and projected hosting capacity of the Essential Energy network around forecasted CER and demand changes to extend strategic network

⁹ Forecasts of customer numbers, energy consumption and demand, Frontier Economics (Attachment 11.01)

planning from a focus on enabling peak demand to include power flow considerations such as voltage impacts (**Attachment 7.021.01**).

The hosting capacity analysis¹⁰ involved a comprehensive set of digital asset information inputs that represent Essential Energy's physical network and baseline consumer behaviour. A detailed set of underlying load data, electrification and DER forecasts, in partnership with Frontier Economics discussed in the above section were also included in the forecast hosting capacity model. DER technology forecasts for the period 2022-2037 at the ZS level covered:

- > PV panel capacity (MW)
- > Battery storage capacity (MW)
- > Electric vehicle numbers by type.

With limited penetration of smart metering infrastructure on our network (limited network visibility), synthetic load synthesis capability was used to substitute availability of interval data that would ordinarily provide 30-minute energy consumption. The synthetic profiles were validated against available transformer monitoring, and coupled with feeder level SCADA data, deemed a suitable representation for network loading analysis.

A base year model was developed, representing the current network performance around existing solar, battery and EV penetration. Three forecast scenarios for future CER uptake were then applied to the base case, these were in line with the AEMO ISP scenarios and are as follows:

1. Low, progressive change – Net zero by 2050 where investment in renewable generation and storage starts more slowly and picks up pace in the 2030s and 2040s.
2. Central, step change – Net zero by 2035 where rapid transformation takes place with significant investment in renewable generation, storage and firming generation as coal plants exit.
3. High, strong electrification – Net zero by 2035 with stronger and faster electrification of transport and heavy industry (but with limited hydrogen uptake) supported by investment in renewable generation and storage.

The central scenario forms the basis of the future network business case.

The modelled performance of the network is illustrated below for pre-intervention or 'do nothing' scenarios under the input forecasts for CER uptake and demonstrates how over voltage events change geospatially and over the forecast period.

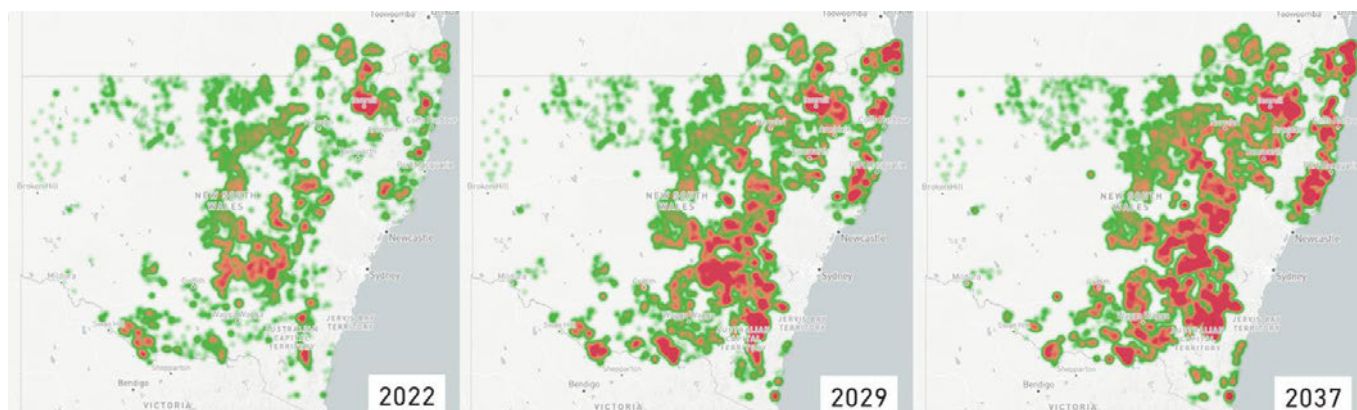


Figure 5¹¹: Heatmap of the change in pre-intervention over voltage events geospatially and over the forecast period

Identified emerging issues associated with CER integration

The hosting capacity analysis showed the progressive impact of increased CER integration on voltage and thermal constraints over the forecast period and concluded, that without intervention:

- > Capacity of the network to host increased generation is primarily limited by voltage constraints, with overhead substations showing lower hosting capacity and the capacity of the network to host generation is not uniformly distributed.

¹⁰ Essential Energy Hosting Capacity Study, Zepben (Attachment 7.01.01)

¹¹ Essential Energy Hosting Capacity Study, Zepben, p.53 (Attachment 7.01.01)

- > The increased trend in daytime constraints indicate solar generation will continue having a significant impact on network constraints and the need for customer curtailment will increase.
- > Increase in EV demand and thermal load electrification are not likely to offset the minimum demand increase from increasing PV.
- > EV charging behaviour is a critical assumption – Uncontrolled convenience charging, or EV load would result in significant overload of assets by 2034 through increase in afternoon peak demand.
- > Close to 25% of customers are likely to experience over voltage constraints/power quality issues (greater than 1% of the time) by 2037.
- > Undervoltage issues are expected to see an increase from 2030 as increase in electric vehicle demand offsets the reduction in demand from PV and batteries.
- > Increasing demand variability will challenge voltage regulation with an increasing number of substations facing voltage swings greater than the approved limits.
- > Voltage regulation issues unable to be solved by tap changes are likely to increase from 7% in 2030 to 20% by 2037 and extremities of rural feeders may experience over-voltages of up to 270V during minimum demand periods.

4.1.3 Essential Energy base case assumption

To compare new alternative options for expanding hosting capacity for CER growth, a base case scenario representing the existing business as usual (BAU) approach was considered; a justifiable set of actions that take place in the absence of other credible options and can be used to trade-off investment expenditure decisions.

The base case for Essential Energy is represented through an approach where export limits are static or fixed and are set around maintaining network integrity under all conditions, including peak net export times (a relatively conservative or restrictive approach that can lead to unnecessary curtailment). As the future network program aims to employ more advanced techniques that understand network behaviour and increase CER hosting capacity, maximising benefit to customers, stakeholders and the market, the base case physical export limits form the baseline to compare the impact of credible options to export limits.

4.2 Valuation approach

4.2.1 CECV benefit valuation approach

Aligned to the AER DER integration expenditure guidance, value streams from DER integration must be considered by DNSPs and how to quantify them using consumer export curtailment values (CECV) was included in the preparation of the cost-benefit analysis (CBA) for the future network program.

CECV measure the benefits of increasing CER hosting capacity in DNSP networks, quantifying the disadvantages suffered by customers and the market when CER exports are curtailed. This approach differs from the value for customers of having reliable export or consumption services.

To support prudent investment decision making on expenditure to increase CER hosting capacity, the CECV methodology considers benefits pertaining to the wholesale market, network sector, environment, and customer DER value streams.

The CECV methodology calculates how CER integration can provide:

- > Wholesale market benefits which include reductions in costs of electricity dispatch through decreased requirements for fuel and operations maintenance costs, investment in generation, storage and transmission infrastructure and the costs to provide ancillary services. These are segmented into:
 - Avoided marginal generator short run marginal costs (SRMC): Increased CER generation substitutes for generation by marginal centralised generators, which may have higher short-run marginal costs pertaining to fuel and maintenance.
 - Avoided generation capacity investment: Increased CER generation reduces investment in new and/or replacement generators.
 - Essential system services (including frequency control ancillary services): Increased CER capacity enables more CER participation in ESS markets, reducing investment in new/replacement centralised ESS suppliers.
- > Network sector benefits which represent the avoided costs of augmenting or replacing assets in the distribution network, or through improved reliability outcomes for customers.

- > Environmental benefits, implicitly captured in the wholesale market benefits given the absence of jurisdictional legislation requiring DNSPs to consider these externalities.
- > Customer benefits are generally relating to the expectation that CER integration investments will facilitate more exports from existing sources rather than stimulating an increased uptake of CER.

Three CECV approaches were critically analysed in the development of the future network program; the AER's approach established by Oakley Greenwood¹² and two alternative approaches proposed by HoustonKemp¹³.

The below table summarises the distinguishing features of each approach used as the determining factors considered when selecting the HoustonKemp Avoided Dispatch approach as the most suitable CECV input into the CBA for the future network program.

Oakley Greenwood	HoustonKemp Avoided Dispatch	HoustonKemp Avoid Dispatch & Avoided Investment
<p>Does not quantify the impact of incremental DER export on possible changes to generation or transmission system investment costs, that is, it does not capture all the wholesale market benefit categories under the DER value streams (Baringa, 2022, p. 70).</p> <p>Includes greater penetration of variable renewable energy/high curtailment/high utilisation of transmission when considering an optimal capacity mix.</p> <p>Intraday prices pertaining to wholesale market benefit are very low with a decreasing trend (refer graph below).</p>	<p>Includes an estimation of marginal avoided dispatch costs for each 30-minute period over a 20-year modelling horizon allowing for the estimation of the dispatch benefits of any profile of avoided curtailment of DER.</p> <p>Driven from a market equilibrium lens which considers profitability of new market entrants.</p> <p>Avoided cost estimates adjusted by Distribution Loss Factors (DLFs) to capture benefits from avoided distribution network losses.</p> <p>Intraday prices pertaining to wholesale market benefits forecast prices to increase overtime (refer graph below).</p>	<p>Estimation of investment benefits for an indicative set of profiles of avoided DER curtailment by calculating the difference between the changes in total system costs arising from avoided curtailment, using with-and-without analysis, and the dispatch benefit estimates for the same profile estimated using the HK dispatch method.</p> <p>Driven from a market equilibrium lens which considers profitability of new market entrants.</p> <p>Avoided cost estimates adjusted by DLFs to capture benefits from avoided distribution network losses.</p> <p>Intraday prices pertaining to wholesale market benefits forecast prices to increase overtime (refer graph below).</p>

¹² AER CECV Methodology, Final Report, Oakley Greenwood, April 2022

¹³ Value of DER and customer export curtailment value, *A report for Ausgrid, Endeavour Energy, Essential Energy, Evoenergy and TasNetworks*, HoustonKemp, 5 April 2022

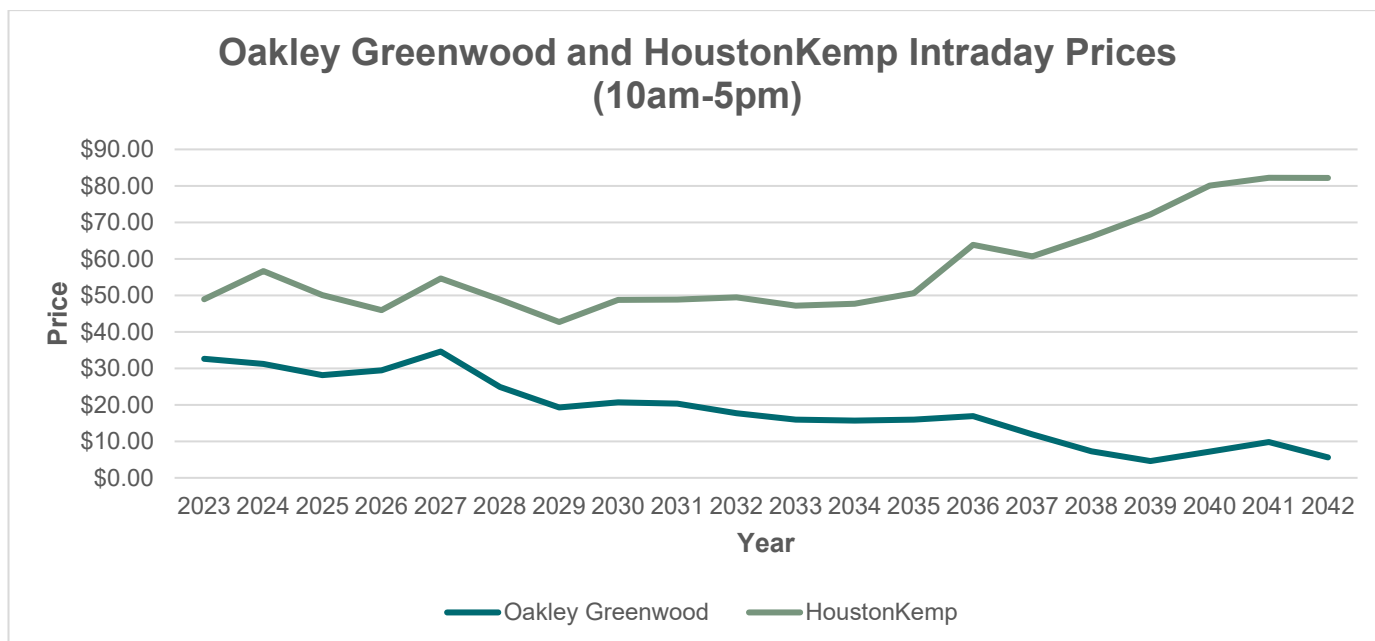


Figure 6 - Oakley Greenwood and HoustonKemp Intraday Prices

Following the AER's final decision on CECV methodology and discussion in the explanatory statement¹⁴, Essential Energy has elected to not include avoided generation investment from the proposed CECV rates of the HoustonKemp method (despite the ability for DNSPs to nominate these values). However, Essential Energy believes that the modelling conducted by HoustonKemp more accurately reflects the long-term generation capacity mix under the ISP step change scenario given a requirement for profitability of new renewable generation installations and thus has adopted its use in the justification of this business case.

4.2.2 Non-CECV benefit valuation approach

Utilising Essential Energy's Appraisal Value Frameworks (**Attachment 6.03.03**), reflecting reliability, bushfire, safety, environment and financial benefits per unit, network interventions were modelled to determine any non-CECV benefits attributable to increasing DER hosting capacity (e.g., value of improved bushfire). A robust process is followed based on analysis of the NPV of options and a range of sensitivity analyses that explicitly trade off alternative investment options.

¹⁴ Explanatory statement: Final Customer export curtailment value methodology June 2022

4.2.3 CBA optimisation approach

1. Identify the value of curtailment alleviation value for each intervention



2. Calculate the 20-year Intervention NPV to determine best options



5. Options analysis

5.1 Identified options

Our customers have told us they expect us to proactively plan for and integrate renewable energy and new technologies, but they realise this needs to be done in a sustainable manner, to avoid over-investment and maintain affordability.

Network interventions are the traditional means by which Essential Energy strengthens the network and/or increases its hosting capacity while non-network interventions describe investment in people, process, data and system related uplifts.

Customers have given us a clear indication of their desired DER integration outcomes and their willingness to pay for the associated investments. They support us introducing flexible connection agreements, for new and upgraded connections, so we can be ready for the future and more efficiently manage power quality on the network until such time that a network intervention investment 'stacks up'.

Both network and non-network interventions were considered in the options analysis and only those that showed a positive NPV were included in the overall program. A combination of both network and non-network interventions is considered most effective.

5.1.1 Network interventions – 'building up' the network

Under network interventions, where network assets are proposed to be used to release and/or improve CER export hosting capacity and power flows, these were included in the FNBC for assessment. Alternatively, where network assets are used to meet peak demand (underlying demand and DER imports), these were excluded as they are included in Essential Energy's wider regulatory submission for augmentation and replacement forecasts, aligning with the capex objectives.

The below network interventions were assessed under the low, central, and high case forecast scenarios. The central case scenario was selected as the most likely outcome.

LV & HV reinforcement:

- > Reconductoring sections of the network with conductors that have a minimum of 80% increase in thermal capacity.

Transformers:

- > Replacing distribution transformers with the next standard distribution transformer size that will increase capacity by at least 50%.

- > Add on-load tap changers (OLTC) as part of a minimum 50% upgrade to transformer capacity.
- > Transformers added in new locations to share customers across transformers.

Voltage control and regulation settings:

- > Closed loop voltage control (CLVC)
- > Line drop compensation

Community BESS:

- > The addition of community BESS to LV network sections.

Table 1, under the central case scenario, summarises the network interventions pertaining to the FY24-29 regulatory period.

Table 1: Total network interventions proposed FY24-29 regulatory period under the central demand scenario (HK dispatch only) benefits

Intervention Type	Number of Interventions	CECV benefits 20yr PV	Non-CECV benefits 20yr PV	Costs 20yr PV	20yr NPV
ZS & HV interventions					
CLCV	50	\$111.73M	Non-CECV benefits allocated to LV interventions		
RLDC (Revised Line Drop Compensation)	Nil in FY25-29 regulatory period under chosen scenario. Becomes preferred method from 2033 onwards	N/A	N/A	N/A	N/A
LV interventions					
Additional transformers with LV upgrades	100	\$11.48M	\$4.57M		

Source: Baringa CBA 2022

HV reconductor was shown to have high capital cost with low voltage uplift, small-scale LV connected community BESS (100 kW/200 kWh) and RLDC interventions were shown to be NPV negative and therefore have not been included for this regulatory period.

Analysis of network interventions was based on network wide average investment costs and benefits (per type). Detailed valuation of investments will be undertaken in locations where these interventions may show higher benefit. If increased benefit can be realised, Essential Energy may elect to utilise varying intervention rates to the above whilst ensuring total costs remain within regulated expenditure.

A complete view of the number of network interventions considered across the low, central, and high demand scenarios and the associated costs and benefits over the 20-year period to 2043 is available in the Baringa CBA¹⁵.

¹⁵ Future Network CBA Model - Baringa, January 2023

5.1.2 Non-network interventions – investing in a smarter network

Non-network interventions considered in the future network program include dynamic operating envelopes (DOEs), increased network visibility and tariffs to influence demand side behaviour.

Dynamic operating envelopes (DOE)

A DOE represents an allocation of available hosting capacity to an individual or aggregate CER or connection point within a segment of an electricity distribution network at a given time interval. DOEs are both expected to provide a more efficient approach to managing network capacity through dynamically varying customer export limits as agreed and allowing customers to export more electricity based on periodically monitored network conditions: limiting only when necessary.

Basic DOEs target specific areas where hosting capacity is most constrained and require minimal investment uplifts to enact. Advanced DOEs require a full network model with complex and dynamic systems as the supporting infrastructure to operate effectively and efficiently.

Network visibility

Network visibility describes remote access to network performance data and enables improved decision making around network operations. Network visibility data is a key input requirement to enabling other non-network interventions including DOEs and has therefore been considered as a parallel requirement, complementing, and increasing the benefit attributed to other non-network and network interventions. Investment to improve visibility include:

- > Installation of distribution substation meters on brownfield sites – 600 meters p.a from FY24-29
- > Upgrade feeders with MV & HV data – 400 feeders
- > Acquire and utilise advanced metering infrastructure data – increase to 30% network coverage from 0% (excluding trial data)
- > Upgrade SCADA historian database to capture historical data.

Tariff incentives

In terms of customers' priorities, whilst safety, reliability and affordability remain the top three concerns in relation to their electricity supply, the importance of resilience has emerged, along with the importance of collective benefit – to ensure that the benefits of the energy transition are fairly shared between our customers.

To improve fairness in the respective prices customers' pay, two-way price tariffs (those that charge for both consumption and exports) are under trial and are proposed to be introduced in the 2024-29 regulatory period.

The results of these trials run in conjunction with customers and stakeholders will be considered as part of the customer engagement program for our Revised Proposal and TSS in the second half of 2023. The results will inform the success of different tariffs and the final structure of our respective tariffs.

Further detail can be found for:

- > Tariff trials and the design of our trial tariffs in [Attachment 4.02](#) to our Proposal
- > Our proposed tariffs in [Chapter 12](#) of our Proposal as well as our [TSS](#)
- > How we derived our export price in our [TSES – Attachment 12.01](#)

The non-network interventions considered for the future network program comprised of three DOE based alternatives and assumes we will evolve our DOE service over time from a targeted trial stage delivering basic DOEs, transitioning to a more advanced DOE capability as deemed necessary. The differentiating factor in the options considered was the pace in which technology change is implemented.

In parallel, investment to allow for improved visibility of the network down to the LV level is a key enabler in expanding any DOE implementation and improving our understanding of what exists on the network, how it is performing and how operations could be managed to improve investment decision making. In line with customer preferences for a smarter grid, options presented below, assume network visibility uplifts will be enacted.

The three DOE implementation options are outlined below as described in the FNBC¹⁶.

¹⁶ Draft Future Networks Business Case, Baringa, January 2023, p.25

Option 1 - Basic DOE implementation 2025-2029. Advanced DOE trial and implementation 2030-2035

Essential Energy will offer a dynamic export limit option to new DER customers. This would enable us to signal the true capacity of the network on a locational and time-varying basis, so that customers' exports would only be limited at times and in places where there is a capacity constraint. This requires expenditure on new systems to improve visibility of network performance and capability uplifts to deliver DOEs on a larger scale. Development would begin in 2024 with the trial DOE commencing in 2026. Essential Energy commences advanced DOE design work at the start of 2030-35 regulatory period and begin trials in 2030 with a view to rollout in 2033.

Option 2 - Basic DOE implementation FY24-29. Advanced DOE trial in 2026 and implementation in 2031

A faster paced rollout of Advanced DOEs with DOE development beginning in 2024 and the trial DOE commencing in 2026. Advanced DOEs begin trials in 2026 with view to rollout in 2031.

Option 3 – Full DOE capability by 2029

Development of both Basic and Advanced DOEs begin in 2024. Full DOE capability expected by 2029.

A complete view of the non-network intervention considered across the low, central and high demand scenarios and the associated costs and benefits over the 20-year period to 2043 is available in the Baringa CBA¹⁷.

¹⁷ Future Network CBA Model – Baringa, January 2023

6. Cost-benefit analysis

Network and non-network interventions were assessed separately as detailed above and collectively over a 20-year period, and against the low, central and high demand scenarios, using the HK dispatch only approach to select an optimised program.

Option 1 includes the combination of NPV positive network interventions and the non-network interventions presented in alternative 1.

Table 2: Option 1 - Net 20-yr values

Option 1	Central Demand Scenario	High Demand Scenario	Low Demand Scenario
Total DOE (CECV)	\$214,584,440	\$211,043,305	\$183,069,840
Total DOE & network visibility (non-CECV)	\$122,272,829	\$122,272,829	\$122,272,829
Total network intervention benefit	\$105,917,107	\$115,175,943	\$101,569,309
Total tariff benefit calculation	\$16,212,145	\$16,212,145	\$16,212,145
Total benefits*	\$442,774,376	\$448,492,076	\$406,911,977
Total non-network intervention capex	-\$102,248,482	-\$102,248,482	-\$102,248,482
Total non-network intervention opex	-\$167,629,974	-\$167,629,974	-\$167,629,974
Total network intervention opex	-\$34,409,855	-\$36,044,521	-\$35,176,068
Total costs	-\$304,288,311	-\$305,922,976	-\$305,054,524
Total NPV	\$138,486,064.55	\$142,569,099.96	\$101,857,453.84

Option 2 includes the combination of NPV positive network interventions and the non-network interventions presented in alternative 2 above.

Table 3: Option 2 - Net 20-yr values

Option 2	Central Demand Scenario	High Demand Scenario	Low Demand Scenario
Total DOE (CECV)	\$215,702,471	\$212,129,740	\$183,943,769
Total DOE & network visibility (non-CECV)	\$122,272,829	\$122,272,829	\$122,272,829
Total network intervention benefit	\$105,917,107	\$115,175,943	\$101,569,309
Total tariff benefit calculation	\$15,683,507	\$15,683,507	\$15,683,507
Total benefits	\$443,892,407	\$449,578,512	\$407,785,906
Total non-network intervention capex	-\$102,235,536	-\$102,235,536	-\$102,235,536
Total non-network intervention opex	-\$178,735,263	-\$178,735,263	-\$178,735,263
Total network intervention opex	-\$34,409,855	-\$36,044,521	-\$35,176,068
Total costs	-\$315,380,654	-\$317,015,320	-\$316,146,867
Total NPV	\$128,511,752.35	\$132,563,192.14	\$91,639,039.45

Option 3 includes the combination of NPV positive network interventions and the non-network interventions presented in alternative 3 above.

Table 4: Option 3 - Net 20-yr values

Option 3	Central Demand Scenario	High Demand Scenario	Low Demand Scenario
Total DOE (CECV)	\$215,870,220	\$212,295,891	\$184,080,024
Total DOE & network visibility (non-CECV)	\$122,272,829	\$122,272,829	\$122,272,829
Total network intervention benefit	\$105,917,107	\$115,175,943	\$101,569,309
Total tariff benefit calculation	\$15,266,517	\$15,266,517	\$15,266,517
Total benefits	\$444,060,155	\$449,744,662	\$407,922,162
Total non-network intervention capex	-\$102,717,758	-\$102,717,758	-\$102,717,758
Total non-network intervention opex	-\$206,862,057	-\$206,862,057	-\$206,862,057
Total network intervention opex	-\$34,409,855	-\$36,044,521	-\$35,176,068
Total Costs	-\$343,989,671	-\$345,624,336	-\$344,755,883
Total NPV	\$100,070,484.23	\$104,120,326.02	\$63,166,278.80

Table 5: Summary of combined option performance

20yr NPV (\$M)*	Cost	Benefit	Net Benefit
Option 1	304	455	138
Option 2	315	443	129
Option 3	343	444	121
Network-only option	35.12	111.02	75.85

*Weighted Average Cost of Capital (WACC) and 22/24 Inflation Rate input at time of development: 3.54% and 13.3% respectively.

6.1 Sensitivity analysis

In developing the FNBC, sensitivity analysis was conducted on the options outlined in Section 5.1 including:

- > CER uptake and demand forecasts
- > Assumed CECV rate
- > WACC rate
- > Inflation

The impact of CER uptake and future demand forecasts were conducted over three scenarios (discussed in Section 5.1.2) with the results presented in Table 6. As demonstrated in Table 6 the impact on NPV for Option 1 is largest between the low to central demand scenario with a \$38M reduction in value when considering the lower demand/CER uptake. However, Option 1 still retains a positive NPV (\$121M) irrespective of the low demand scenario.

Table 6: Demand sensitivities for highest NPV option (\$M)

Cost-benefit Category	Low Demand Scenario (Option 1)	Central Demand Scenario (Option 1)	High Demand Scenario (Option 1)	High Demand Scenario (Option 2)
DOE: CECV benefit	\$183	\$215	\$211	\$212
DOE: non-CECV benefit	\$122	\$122	\$122	\$122
Network intervention benefits	\$102	\$106	\$115	\$115
Tariff: CECV benefit	\$16	\$16	\$16	\$16
Total benefits	\$407	\$443	\$448	\$450
Total costs	-\$306	-\$305	-\$307	-\$318
Total NPV	\$101	\$138	\$142	\$132

As a primary input to the CBA, the selection of a CECV rate for adoption is a key variable on which to conduct sensitivity analysis. This is due to Essential Energy utilising HK CECV over Oakley Greenwood CECV (AER proposed), further discussed in Section 4.2.1. Sensitivity analysis was completed for the preferred Option 1 by varying the CECV rate between HK and Oakley Greenwood. Utilisation of the lower Oakley Greenwood CECV rate greatly eroded the benefits for the preferred option resulting in a negative NPV (see Table 7). Of note, the total costs between each analysis differs as the NPV positive network interventions are reduced under Oakley Greenwood, DOE implementation costs remain static.

Table 7: Sensitivity analysis based on CECV selection (\$M)

Cost-benefit Category	Houston Kemp CECV (SRMC only)	Oakley Greenwood CECV
DOE: CECV benefit	\$215	\$101
DOE: non-CECV benefit	\$122	\$122
Network intervention benefits	\$106	\$49
Tariff: CECV benefit	\$16	\$7
Total benefits	\$443	\$272
Total costs	-\$305	-\$295
Total NPV	\$138	-\$22

As inflation is undergoing rapid fluctuations over the short term it is important to analyse the impact of short term inflation escalation unit rates from FY22 to FY24 dollars. Currently, inflation is expected to escalate costs from the base FY22 year by 13.3% however a range of NPV benefits over varying CPI rates are included in Table 8. These have been calculated assuming a 3.54% WACC rate for Option 1.

Table 8: Impact of inflation to FY24 (NPV benefit \$M)

Scenario	2.5%	5%	7.5%	10%	12.5%	13.3%	15%
Low demand	\$114	\$111	\$108	\$105	\$103	\$102	\$100
Central demand	\$151	\$148	\$145	\$142	\$139	\$	\$137
High demand	\$154	\$151	\$149	\$146	\$143	\$143	\$141

Currently the regulated industry is coming off a period of low WACC rates which is expected to change into the next regulatory period. It is expected that this rate of return will be approximately 3.54% however this investment is highly sensitive to changes in WACC rate. Utilising an initial inflation rate of 13.3% and analysing Option 1 with Houston Kemp CECV rates show that even at rates upwards of 4.2% this business case still shows positive benefit (refer Table 9).

Table 9: Impact of WACC rate¹⁸ (NPV benefit \$M)

Scenario	3.2%	3.54%	3.6%	3.8%	4%	4.2%
Low demand	\$112	\$101	\$100	\$94	\$89	\$83
Central demand	\$151	\$138	\$136	\$130	\$123	\$117
High demand	\$155	\$143	\$140	\$134	\$127	\$120

7. Recommendation

Option 1, the central demand scenario, is recommended as the optimal approach to realise the network and customer needs associated with smartening the grid, building up the network and enabling increased CER integration in the forthcoming regulatory period:

- > CLVC showed both positive NPVs and cost-benefit ratios to reduce curtailment at network limits across a zone substation.
- > RLDC provides a low-cost solution with the second highest cost-benefit ratio to reduce curtailment at network limits and operates well in conjunction with CLVC to lift the hosting capacity of the network. Noting these are planned for implementation in the following regulatory period.
- > Additional transformers with LV upgrades will also be suitable at targeted network sections and reduce curtailment from DOEs and inverters.
- > DOEs were best placed to increase customer export connection limits, have the highest overall NPV, and are applied consistently across the network but follow the implementation of the above network interventions due to the comparative speed at which they can be deployed.

Option 1 results in the highest net economic benefit and forecast the optimum NPV of \$175M in benefits over the 20-year timeframe. Table 10 summarises Option 1 expenditure requirements for the forthcoming regulatory period. A description of the expenditure categories can be found in the key terms and definitions.

¹⁸ Pre-tax vanilla WACC rate

Table 11: 5-year estimates for the regulatory period FY25-29 - (Real FY24,\$m)¹⁹

Category	FY25	FY26	FY27	FY28	FY29	TOTAL
ICT & Pgm. management						
Network visibility						
Network						
Capex Subtotal	28.17	17.76	10.86	12.56	23.08	92.43
Non-network						
Network overhead						
Corporate overhead						
Opex Subtotal	10.57	9.37	9.28	11.01	11.52	51.75
GRAND TOTAL	38.76	27.21	20.27	25.58	35.04	146.87

Investment in non-network interventions presented in Option 1 also supports a suite of additional network benefits as summarised in the table below and aligned with our customer preferences around safety, reliability and affordability.

Table 12: Network benefits related to non-network activities

Category	Example inclusions	\$m (20yr PV)
Deferred augex	> 5yr deferral of % of Augex forecast	75.65
Reliability	> Reduced unplanned outage rectification times > Reduced planned outage duration	17.31
Losses	> Reduced theft	4.81
OPEX Reduction	> Reduced power quality complaints > 2 nd crew call out reductions	7.29
Safety	> Reduced risk of broken neutrals	13.78
Voltage regulation	> Reduced inverter tripping	1.26
TOTAL		120.11

¹⁹ Draft Future Networks Business Case, Baringa, January 2023, p.99 (\$FY22)

References

Doc No.	Document Name	Relevance
1	7.01 DER Integration Strategy	Reference material
2	7.01.01 Hosting Capacity Study - Zepben	Hosting capacity analysis
3	10.01.02 Demand Management Plan	Reference material
4	10.05.01.01 Draft Future Networks Business Case – Baringa	Reference material
5	10.05.01.02 Future Network CBA Model – Baringa	Financial analysis
6	11.01 Forecasts of customer numbers, energy consumption and demand - Frontier Economics	Reference material

Key terms and definitions

Term	Definition
\$M	Dollars expressed in millions
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
CER	Consumer Energy Resources
CLVC	Closed Loop Voltage Control
DER	Distributed Energy Resources
DLF	Distribution Loss Factors
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
FY	Financial Year
NPV	Net Present Value
RLDC	Revised Line Drop Compensation
SCADA	Supervisory Control and Data Acquisition
VUE	Value of Unserved Energy
WACC	Weighted Average Cost of Capital
ICT & Pgm. management	Capital investment in IT infrastructure to support dynamic asset operations
Network visibility	Capital investment in data to derive network performance and operations
Network	Capital investment in network assets to replace/augment the network
Non-network	Opex investment in non-system
Network overhead	Operating costs to maintain the network
Corporate overhead	Operating costs to implement and maintain network capabilities