energy market consulting associates

Evoenergy 2024 to 2029 Regulatory Proposal

REVIEW OF PROPOSED EXPENDITURE ON DER AND AUGEX

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

August 2023

Preface

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be allowed for the prescribed distribution services of Evoenergy from 1st July 2024 to 30th June 2029. The AER's determination is conducted in accordance with its responsibilities under the National Electricity Rules (NER).

This report covers a particular and limited scope as defined by the AER and should not be read as a comprehensive assessment of proposed expenditure that has been conducted making use of all available assessment methods nor all available inputs to the regulatory determination process. This report relies on information provided to EMCa by Evoenergy. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AER and for the use of this report for any purpose other than the intended purpose. In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as an interpretation of the application of the NER or other legal instruments.

EMCa's opinions in this report include considerations of materiality to the requirements of the AER and opinions stated or inferred in this report should be read in relation to this over-arching purpose.

Except where specifically noted, this report was prepared based on information provided by to us prior to 16th June 2023 and any information provided subsequent to this time may not have been taken into account. Some numbers in this report may differ from those shown in Evoenergy's regulatory submission or other documents due to rounding.

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ABBREVIATIONS

Term	Definition
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
Augex	Augmentation (capital) Expenditure
BAU	Business as Usual
BESS	Battery Energy Storage Systems
CBA	Cost Benefit Analysis
CECV	Customer Export Curtailment Value
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DSO	Distribution System Operators
EMS	Energy Management Systems
ESB	Energy Security Board
EV	Electric Vehicles
IES	Inverter connected generation and storage systems
LV	Low Voltage
MVA	megavolt-amperes
NDP	Network Development Plan
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSPs	Network Service Provider's
NZM	Net Zero Modelling
POE	Probability of Exceedance
PV	Photovoltaic (i.e. typically 'rooftop' solar)
RCP	Regulatory Control Period
RIT-D	Regulatory Investment Test for Distribution
RP	Regulatory Proposal
STATCOMs	Static Synchronous Compensator
USE	Unserved Energy

Term	Definition
WACC	Weighted Average Cost of Capital
ZEV	Zero Emissions Vehicles (While we recognise the distinction, for practical purposes in this report and given the timeframe of the next RCP, we equate these with EVa.)
ZS	Zone Substation

1 INTRODUCTION

AER has asked us to review and provide advice on Evoenergy's proposed allowances over the next Regulatory Control Period for expenditure to facilitate increasing Distributed Energy Resources (DER) and for augmentation-related capex. Our review is based on information that Evoenergy provided and on aspects of the National Electricity Rules relevant to assessment of expenditure allowances.

1.1 Objective of this report

1. The purpose of this report is to provide the AER with a technical review of aspects of the expenditure that Evoenergy has proposed to facilitate Distributed Energy Resources (DER) and of its proposed augmentation capital expenditure (augex). These items form part of its revenue proposal for the 2024-29 regulatory control period (next RCP).
2. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed capex allowance as an input to its Draft Determination on Evoenergy's revenue requirements for the next RCP.

1.2 Our scope and approach

1.2.1 Scope of requested work

3. Our scope of work is as defined by AER. Relevant aspects of this are as summarised in Figure 1.1 below.

Figure 1.1: Scope of work

Requested scope for Evoenergy reviews covered in this report

The scope of this review covers components of the proposed ex-ante capex forecast and proposed opex step changes consistent with the AER's expenditure forecast assessment guideline. This comprises the review of expenditure relating to the following aspects:

- Evoenergy's forecast for augmentation including the non-demand and demand driven augmentation related to the electricity transformation arising from the ACT Government's 'Net Zero by 2045' policy (Electric Vehicles (EVs) and the phase out of the use of natural gas)
- Evoenergy's capex and opex forecast for DER/CER.

Further scope requirements for review of DER

The consultant is required to provide advice to the AER on whether the DNSP has sufficiently demonstrated the need for network investment to accommodate forecast levels of DER. The advice should consider the DNSP's approach to assessing network hosting capacity, including its level of network visibility and use of data (such as data provided by smart meters) to identify and forecast DER export constraints on its low voltage networks.

1.2.2 Our review approach

4. In conducting this review, we first reviewed the regulatory proposal documents that Evoenergy had submitted to AER. This includes a range of appendices to Evoenergy's regulatory proposal and certain Excel models, and which are relevant to our scope.

5. We next collated some information requests. The AER combined these with information request topics from its own review and sent these to Evoenergy.

6. In conjunction with AER staff, our review team met with Evoenergy at its office in Canberra on 20th April 2023. Evoenergy presented to our team on the scoped topics and we had the opportunity to engage with Evoenergy to consolidate our understanding of its proposal.

7. Evoenergy provided the AER with responses to information requests and, where it added relevant information, these responses are referenced within this review.

8. We have subjected the findings presented in this report to our peer review and QA processes and we presented summaries of our findings to AER prior to finalising this report.

9. As we refer to in section 4, the AER reviewed Evoenergy's demand forecasts, which were not part of EMCa's scope. The AER has advised that it intends not to accept Evoenergy's demand forecast and on 6th July advised us of an alternative demand forecast. The AER has asked us to assess Evoenergy's proposed augex consistent with that alternative demand forecast.

10. The limited nature of our review does not extend to advising on all options and alternatives that may be reasonably considered by Evoenergy, or on all parts of the proposed forecast. We have included additional observations in some areas that we trust may assist the AER with its own assessment.

1.2.3 Conformance with NER requirements

11. In undertaking our review, we have been cognisant of the relevant aspects of the NER under which the AER is required to make its determination.

Capex Objectives and Criteria

12. The most relevant aspects of the NER in this regard are the 'capital expenditure criteria' and the 'capital expenditure objectives.' Specifically, the AER must accept the Network Service Provider's (NSP's) capex proposal if it is satisfied that the capex proposal reasonably reflects the capital expenditure criteria, and these in turn reference the capital expenditure objectives.

13. The NER's capex criteria and capex objectives are reproduced below.

Figure 1.2: NER capital expenditure criteria

NER capital expenditure criteria

The AER must:

*(1) subject to subparagraph (c)(2), accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (**the capital expenditure criteria**):*

(i) the efficient costs of achieving the capital expenditure objectives;

(ii) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(iii) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Source: NER 6.5.7(c) Forecast capital expenditure, v200

Figure 1.3: NER capital expenditure objectives

NER capital expenditure objectives

*A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (**the capital expenditure objectives**):*

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Source: NER 6.5.7(a) Forecast capital expenditure, v200

Opex Objectives and Criteria

14. The most relevant aspects of the NER in this regard are the ‘operating expenditure criteria’ and the ‘operating expenditure objectives.’ The NER’s opex criteria and opex objectives are reproduced below.

Figure 1.4: NER operating expenditure criteria

NER operating expenditure criteria

*(c) The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (**the operating expenditure criteria**):*

(1) the efficient costs of achieving the operating expenditure objectives;

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Source: NER 6.5.6(c) Forecast operating expenditure, v200

Figure 1.5: NER operating expenditure objectives

NER operating expenditure objectives

*(a) A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (**the operating expenditure objectives**):*

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Source: NER 6.5.6(a) Forecast operating expenditure, v200

How we have interpreted the capex and opex criteria and objectives in our assessment

15. We have taken particular note of the following aspects of the capex and opex criteria and objectives:

- Drawing on the wording of the first and second criteria, our findings refer to efficient and prudent expenditure. We interpret this as encompassing the extent to which the need for a project or program or opex item has been prudently established and the extent to which the proposed solution can be considered to be an appropriately justified and efficient means for meeting that need;

- The criteria require that the forecast '*reasonably reflects'* the expenditure criteria and in the third criterion, we note the wording of a '*realistic expectation'* (emphasis added). In our review we have sought to allow for a margin as to what is considered reasonable and realistic, and we have formulated negative findings where we consider that a particular aspect is outside of those bounds;
- We note the wording '*meet or manage'* in the first objective (emphasis added), encompassing the need for the NSP to show that it has properly considered demand management and non-network options;
- We tend towards a strict interpretation of compliance (under the second objective), with the onus on the NSP to evidence specific compliance requirements rather than to infer them; and
- We note the word '*maintain'* in objectives 3 and 4 and, accordingly, we have sought evidence that the NSP has demonstrated that it has properly assessed the proposed expenditure as being required to reasonably maintain, as opposed to enhancing or diminishing, the aspects referred to in those objectives.

16. The DNSPs subject to our review have applied a Base Step Trend approach in forecasting their aggregate opex requirements. Since our review scope encompasses only proposed expenditure for certain purposes, we have sought to identify where the DNSP has proposed an opex step change that is relevant to a component that we have been asked to review. Where the DNSP has not proposed a relevant opex step change, then we assume that any opex referred to in documentation that the DNSP has provided is effectively absorbed and need not be considered in our assessment.

1.2.4 Technical review

17. Our assessments comprise a technical review. While we are aware of stakeholder inputs on aspects of what Evoenergy has proposed, our technical assessment framework is based on engineering considerations and economics.

18. We have sought to assess Evoenergy's expenditure proposal based on Evoenergy's analysis and Evoenergy's own assessment of technical requirements and economics and the analysis that it has provided to support its proposal. Our findings are therefore based on this supporting information and, to the extent that Evoenergy may subsequently provide additional information or a varied proposal, our assessment may differ from the findings presented in the current report.

19. We have been provided with a range of reports, internal documents, responses to information requests and modelling in support of what Evoenergy has proposed and our assessment takes account of this range of information provided. To the extent that we found discrepancies in this information, our default position is to revert to Evoenergy's regulatory submission documents as provided on its submission date, as the 'source of record' in respect of what we have assessed.

1.3 This report

1.3.1 Report structure

20. In section 2, we provide context information on considerations in our assessment, including our perspective on the energy transition and its implications and relevant aspects of the regulatory framework.

21. The substance of our review is contained in sections 3 and 4, which cover respectively our review of Evoenergy's proposed DER-related expenditure and our review of its proposed augex. In each section, we have presented:

- An overview of the proposed expenditure;
- An overview of the nature of the proposed works or projects and the justifications that Evoenergy has submitted; and
- Our assessment of the elements of what Evoenergy has proposed.

22. In accordance with our scope, we provide at the end of section 4 our assessment of an alternative augex forecast.

23. We have taken as read the considerable volume of material and analysis that Evoenergy provided, and we have not sought to replicate this in our report except where we consider it to be directly relevant to our findings.

1.3.2 Reference documents

24. We have examined relevant documents that Evoenergy has published and/or provided to the AER in support of the areas of focus and projects that the AER has designated for review. This included further information at virtual meetings and further documents in response to our information requests. These documents are referenced directly where they are relevant to our findings.

25. Except where specifically noted, this report was prepared based on information provided to us prior to 16th June 2023 and any information provided subsequent to this time may not have been taken into account. As noted in section 1.2.2, the AER provided us with an alternative peak demand forecast on 6th July and our assessment incorporates this updated information.

26. Unless otherwise stated, documents that we reference in this report are Evoenergy documents comprising its regulatory proposal and including the various appendices and annexures to that proposal.

27. We also reference information responses, using the format IR#XX being the reference numbering applied by the AER. Noting the wider scope of the AER's determination, it has provided us with Information Request documents that it considered to be relevant to our review.

1.3.3 Presentation of expenditure amounts

28. Expenditure is presented in this report in $2024 real terms, to be consistent with Evoenergy's Regulatory Proposal (RP) unless stated otherwise. In some cases, we have converted to this basis from information provided by the business in other terms.

29. While we have endeavoured to reconcile expenditure amounts presented in this report to source information, in some cases there may be discrepancies in source information provided to us and minor differences due to rounding. Any such discrepancies do not affect our findings.

2 RELEVANT CONTEXT

Our review is conducted in the context of an accelerating transition of the energy sector towards a lower carbon future. Aspects of this that are most relevant to DNSPs such as Evoenergy include further increases in consumer energy resources, such as PV and increased electrification including for transport (such as EVs) and within homes (e.g. through the phase out of gas).

This transition creates a prima facie potential case for increased network augmentation capex, where this satisfies the NER criteria. However, it also provides the opportunity for non-network 'DER' initiatives that can help to moderate the levels of network augmentation capex that might otherwise be required. For example, this can be through improving 'visibility' of the LV network and through dynamic services, including potentially dynamic tariffs and dynamic controls that may 'orchestrate' distributed electricity production, storage and demand, thereby minimising the net impact on the distribution network.

Changes in the regulatory landscape are taking place, to accommodate the changed and changing roles of DNSPs such as Evoenergy. This includes changes to the NER and AER guidelines, which we have considered in our assessment.

An overarching consideration in assessing both network augex and non-network DER-related expenditure, is uncertainty on the specifics of the energy transition over investment assessment timeframes of the order of 15 to 20 years. The energy transition and its impact on electricity networks will be driven by and leverage off technologies that will evolve and likely assist both technically and economically. Consumer behaviours as they adopt DER will also evolve. In our assessments we are therefore particularly cognisant of future uncertainties, the consequent value of retaining options to adapt as uncertainties resolve, and the potential regret that could arise from over-investment if based on a false perspective of future certainty.

2.1 Energy transition

2.1.1 Network investments and the transition to renewables and storage

30. The NEM is experiencing a significant transition away from reliance on thermal generation towards renewable generation and storage. This is supported by the Powering Australia Plan including reducing emissions by boosting renewable energy.

31. As a result, the location of these larger renewable energy sources is also shifting to be more geographically distributed and diverse. This will require a substantial investment in transmission infrastructure to enable connection of these new technologies and to facilitate benefits for consumers by way of a lower cost of electricity.

32. At the same time, there has been significant growth in distributed energy resources led by roof-top solar. Customers are now more engaged with their energy system, which is demanding different services in terms of their ability to supply, consume and trade energy. This has implications for investments in energy infrastructure, and digital applications and infrastructure to support changes in how the energy system is used.

33. The transition is being driven by a number of forces, including decarbonisation and 'net zero' emissions policies. Not only will this result in investments in new technologies, but there is also likely to be significant changes in the costs of such technologies, consumers'

interactions with these technologies and the services provided to consumers by DNSPs, by electricity retailers, and potentially by other parties (including 'aggregators').

34. We have necessarily undertaken our review in accordance with the current planning and regulatory framework. Nevertheless, to the extent that benefits are based on an assessment of future energy systems, or a projection of a future climate scenario, it is necessary to consider the likelihood of continuing changes to technologies and also changes to the regulatory and planning framework that may affect justification for projects of this type.

2.1.2 Definition of CER/DER

35. Distributed energy resources (DER) encompass a range of consumer level technologies used by households and businesses, such as inverter connected generation and storage systems (IES) which include solar photovoltaic (PV) and battery energy storage systems (BESS), energy management systems (EMS), controllable loads, and electric vehicles (EV) and their charging points.[1]

36. Consumer energy resources (CER) is often used interchangeably with DER although we note that AEMO considers that DER encompasses both CER (behind the meter resources at a consumer's premise) and distribution connected energy resources, including for example, neighbourhood batteries.'[2] Although Evoenergy tends to use DER in its relevant documentation, we refer to CER and DER interchangeably in this document.

2.1.3 DER developments and the regulatory landscape

37. In its Post-2025 Market Design Review, the Energy Security Board (ESB) developed a DER Implementation Plan ('Plan') to support the effective integration of DER and flexible demand. Three horizons were included in the Plan, with phasing in of dynamic operating envelopes (DOE) over 2022-2025 included as a long-term feature of the NEM DER 'ecosystem' among other things.[3] As shown in the figure below, development of a two-way or two-sided electricity market is recognised by the ESB. The figure below shows pertinent quotes from the ESB report regarding coordination of CER.

Figure 2.1: Recognition of the need for transition to a 'two-sided market'

Energy Security Board, Clean and Smart Power in the New Energy System:

'Coordination or management of distributed energy resources is important to keep the system safe and stable so everyone can use energy as they wish to do so.'

'Now more consumers are buying and producing their own power. They might choose to produce to use; they might want to sell back to the grid.

All this is made possible by renewables technology – with people putting solar PV on their rooftops, and turning on smarter home devices like air conditioning, hot water systems and pool pumps.

We are seeing the start of a two-way market. With all the right technical and security settings under the hood, advances in technology digital technology can enable appliances and systems to talk to each other securely.'

Source: Energy Security Board, Clean and smart power in the new energy system, final report (July 2021), page 3

1 Based on AEMO 2019, Technical Integration of Distributed Energy Resources, p10

2 AEMO, submission to AEMC regarding the draft report *Consumer Energy Resources Technical Standards Review (EMO0045)*, 25 May 2023, p2

3 ESB 2021, DER Implementation Plan – Three Year Horizon

38. The Australian Energy Market Commission (AEMC) made a rule determination in 2021 to introduce technical standards that will enable DNSPs and AEMO to better manage the growing number of micro-embedded generators connecting across the national electricity market (NEM).

39. In making this final rule determination, the AEMC stated that '*…[it] recognises the importance of promptly addressing the concerns of AEMO and the Energy Security Board (ESB) about the impact significant growth in distributed solar PV connections can have on networks and the electricity grid. In particular the final rule focuses on the ability and role DER in managing voltage disturbances.*'[4]

40. Throughout this report, the term 'compliance' is used to capture the technical settings requirements across the supply chain. This broad term is intended to encapsulate the requirements at manufacture to Standard, setting selection at install, and ongoing behaviour after install. Primarily, compliance is in respect of AS/NZS4777.2, which is a standard for the grid-connection of small-scale inverters. AEMO put forward a review to raise the performance requirements, with a major focus on improving the inverter's disturbance ride-through capabilities. The new Standard AS/NZS4777.2:2020 was published on 18 December 2020, and became mandatory for all new installations in Australia one year later.[5]

41. The key features of the final rule are:[6]

- *'The creation of DER Technical Standards which embedded generating units connecting to a distribution network by way of a micro EG connection service must comply with*
- *DER Technical Standards that include the requirements set out in AS 4777.2:2020 as updated from time to time*
- *A requirement that model standing offers for basic connection services for embedded generating units include that embedded generating units the subject of the basic micro EG connection service must be compliant with the DER Technical Standards*
- *An obligation on DNSPs that the information to be provided to connection applicants in order for them to negotiate a connection contract must include the requirement that if the connection applicant is proposing to connect a new or replacement embedded generating unit by way of a basic micro EG connection service, that the micro embedded generating unit must be compliant with the requirements of the DER Technical Standards*
- *A requirement that the minimum content requirements of connection offers under Schedule 5A.1 to the NER must include the requirement that if the connection applicant is proposing to connect a new or replacement embedded generating unit by way of a basic micro EG connection service, that the embedded generating unit the subject of the connection application is compliant with the DER Technical Standards.*
- *The DER Technical Standards will apply only to new connections and replacement inverters and connection alterations (including upgrade, extension, expansion or augmentation)*
- *The rule [commenced] on 18 December 2021, approximately 10 months after it [was] made, to allow for the implementation of the new requirements*
- *Transitional provisions have been included so that if before the commencement date of the rule:*
  - *a connection applicant in relation to a basic micro EG connection service has made a connection application but not received a connection offer, the new Chapter 5A will apply to that connection offer and connection contract*
  - *if a connection applicant in relation to a basic micro EG connection service has received a connection offer from the relevant DNSP but has not yet entered into a*

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4 AEMC 2021, Rule determination Technical Standards for DER, pi

5 AEMO 2023, Compliance of DER with technical settings, p3

6 AEMC 2021, Rule determination Technical Standards for DER, pi, ii

connection contract, the old Chapter 5A will apply to that connection offer and connection contract.'

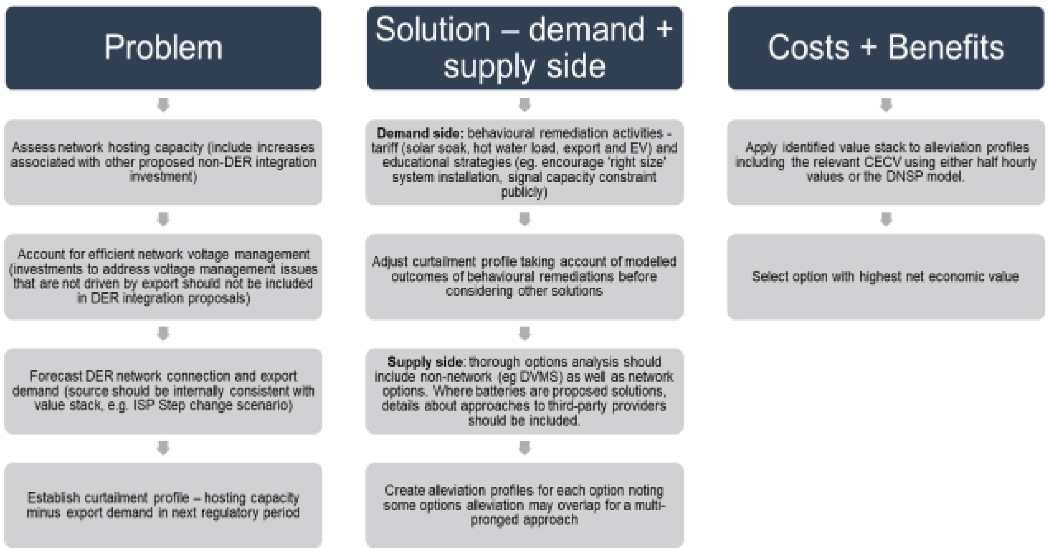
2.2 Our framework for assessing proposed DER-related expenditure

2.2.1 Relevant AER Guidelines

42. The AER has noted that as '*DER penetration levels increase and customer expectations with respect to DER use evolve, [DNSPs] are responding by investing in projects aimed at increasing DER hosting capacity and supporting a broadening range of DER services.*'[7]

43. The AER published a 'DER integration expenditure guidance note' in mid-2022. It is designed to help DNSPs work through the process of developing DER integration plans and expenditure proposals. The figure below summarises the process.

Figure 2.2: AER's process for developing DER integration investment proposals



Source: AER 2022, DER Integration Guidance Note, Figure 1.1

44. Our assessment follows this sequence in that we have first assessed Evoenergy's problem definition, then its proposed solutions and finally its cost benefit analysis.

45. The following AER and industry rules and guidelines are also particularly relevant to our assessment:

- CECV methodology, Oakley Greenwood, report to AER (June 2022). This includes our consideration of matters raised by Houston Kemp in its submission on behalf of Energy Networks Australia, and Oakley Greenwood's response to that submission in its report; and
- Rule determination on National Electricity Amendment (Technical Standards for Distributed Energy Resources) Rule 2021, AEMC, (25 February 2021).

2.2.2 Taking account of uncertainty in considering network investments

46. Given the factors described above, and the reality that network investments tend to be both capital-intensive and attract long technical / economic lives, it is particularly necessary to consider option value in assessing deep investments into the electricity network.

7 AER, DER integration guidance note, June 2022, page 4

47. Considerations of option value and the timeframe over which benefits are adequately able to be modelled, can help to ensure that any network investment is prudent and efficient in accordance with the regulatory objectives. This in turn helps in meeting the objective of ensuring that consumers do not end up paying the risk costs of projects that are developed earlier than required or which become stranded or 'regretted' due to changes in the electricity market, energy system, climate and the technologies deployed there.

2.2.3 Taking account of uncertainty in considering non-network CER-related investments

48. In considering economic business cases for CER-related expenditure, we are particularly cognisant of two factors:

- For the most part, the required investments are relatively short-lived, involving the development and integration of information systems and obtaining the information from those systems to enable the provision of new services to customers and the continuing prudent and efficient provision of existing services; and
- CER and the use of electricity in residential premises will both be strongly influenced by technological and consumer changes. While the pace and exact nature of such changes is a matter for conjecture, it is likely to involve reducing costs and increasing capacities for local storage, increasing uptake of EVs, increased electrification within households, and increased capability to integrate between and to orchestrate CER with in-home usage.

49. These factors, and their uncertainties emphasise the value of agility and optionality in considering CER 'solutions' and the disadvantage of solutions that may result in material regret through over-investment based on an unrealistic view of future certainty. While it is important to undertake a degree of preparation for the future, the nature of non-network solutions to CER lends itself to taking a relatively agile approach that can leverage off technological and consumer behavioural changes as they become evident. An example of this is likely to be the way in which some combination of increasing EV uptake (with or without the addition of V2H and V2G capabilities), more cost-effective options for higher capacity home batteries and increased controlled electrification of storage hot water, may significantly reduce the incidence of PV exports and their impact on DNSPs' LV systems.

50. In undertaking our assessments in this report, our consideration of these factors has led us to be wary of business cases that involve significant investments over the next regulatory period on the basis that they will solve supposed issues that will become evident or significant in 10 to 20 years' time. There is a balance to be struck between prudent preparation and the potential for over-investment that may burden consumers with costs that turn out to be excessive or not to be needed for a cost-effective energy transition.

3 REVIEW OF PROPOSED DER EXPENDITURE

Evoenergy has proposed a 'readiness'-based DER program, with a capex allowance of $5.5m and an opex step change allowance of the $11.6m over the period, for a total cost of $17.1m. The largest single element of this is a proposed community battery, costing [redacted] totex over the period. The remainder of the proposed expenditure is largely for ICT and data requirements that will provide increased visibility of the LV network and the ability to offer dynamic services, including 'integration' of VPPs.

We consider that Evoenergy's proposed DER Readiness program represents a prudent and proportionate approach to introducing DER management capabilities in the next regulatory period. With the exception of the proposed community battery, we consider that Evoenergy's proposed expenditure allowance is reasonable.

3.1 What Evoenergy has proposed

3.1.1 Overview and summary of proposed expenditure

51. Evoenergy has proposed DER-related capex of $5.5m and a DER-related opex step change of $11.6m, as shown in Table 3.1.

Table 3.1: Evoenergy proposed CER related expenditures - $million, real FY2024

Description	2025	2026	2027	2028	2029	Total
DER capex	5.3	0.1	0.0	0.0	0.1	**5.5**
DER integration – opex step change	2.6	2.2	2.2	2.2	2.3	**11.6**
DER TOTEX	**7.9**	**2.3**	**2.2**	**2.2**	**2.4**	17.1

Source: Derived from Appendix 2.5 Table 2 and 12

52. On a 'totex' basis, Evoenergy has presented its proposed expenditure as shown in Table 3.2. In our assessment, we review each of these items.

Table 3.2: Cost breakdown for proposed CER expenditure ($m, real FY24)

Investments	2025	2026	2027	2028	2029	Total
Data from network monitors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Procure LV smart meter data	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Procure data from 3rd parties	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Modelling and forecasting uplift	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IT systems for DOE / VPP integration	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Community battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Voltage management (STATCOMs)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Augmentation to increase hosting capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total opex and capex	**8.0**	**2.3**	**2.2**	**2.2**	**2.3**	**17.1**
Minus opex step changes	*-2.6*	*-2.2*	*-2.2*	*-2.2*	*-2.3*	***-11.6***
DER capex	*5.3*	*0.1*	*0.0*	*0.0*	*0.0*	***5.5***

Source: Appendix 2.5 - Table 12 Total cost breakdown for Option 2

3.1.2 Summary of the basis for Evoenergy's proposed expenditure

DER developments and the regulatory landscape

53. Evoenergy has presented the basis for its proposed DER expenditure in its Distributed Energy Resources (DER) integration Strategy.[8] The regulatory framework for Evoenergy's proposal derives from amendments made in 2021 to the NER and which were designed to allow for DNSPs' provision of services to facilitate increased DER, and which include provisions regarding export services. Evoenergy states that its proposal is consistent with this regulatory framework, and that it has taken account of relevant guidance on this framework.[9]

Summary of relevant context

54. The ACT government has a target of achieving a net zero emissions level by 2045. Its plan for achieving this includes, amongst other measures, a Zero Emissions Vehicles (ZEV) strategy, a gas transition strategy and measures to encourage further DER investments such as in rooftop solar and battery storage. Evoenergy has experienced a significant increase in DER uptake and expects this to continue.

55. Network visibility can play an important role in helping a DNSP to manage its capacity to host DER. Evoenergy states that it currently has a '*…comprehensive level of visibility at the 132kV level, operational level of visibility at the 11kV level and limited visibility on the low voltage network*.'[10] Currently Evoenergy states that it manages DER penetration in greenfields suburbs through negotiations with developers, and in brownfields suburbs it allows exports of up to 5kW per phase as a default (i.e. without specific network assessment).

8 Appendix 1.5 to Evoenergy's Regulatory proposal

9 This includes AER's DER Integration Expenditure Guidance Note (2022), Export Tariff Guidelines and Explanatory Statement (2022), Customer Export Curtailment Value (CECV) Methodology (2022) and Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance (DMIA) and their application now to export services.

10 Appendix 1.5, page 17

Evoenergy's stated DER strategy

56. Evoenergy presents its stated objectives and goals in Table 5 of its DER Strategy document. In summary, these are to:

- Manage the integration of increasing levels of DER (objective DER1), and to
- Leverage DER to support network functions (objective DER2).

57. To support these objectives, Evoenergy defines six goals which we reproduce in Figure 3.1.

Figure 3.1: Evoenergy's DER integration goals

Evoenergy's stated DER goals

DER1.1 – Analyse, monitor, and optimise Hosting Capacity

DER1.2 – Develop DER forecasts and increase network visibility, and utilise these in uplifting network planning and network operation functions

DER1.3 – Maintain network quality of supply and thermal issues attributed to DER within required limits

DER1.4 – Deliver value and equitable outcomes for all customers

DER2.1 – Develop feasible non-network options to defer or remove the requirement for network expenditure

DER2.2 – Utilise DER to reduce network safety risk, increase network reliability and to inform asset health and utilisation

Evoenergy Appendix 1.5, table 5

58. Evoenergy presents its proposed DER-related initiatives for the next regulatory period as an 'implementation' phase, involving the *'…establishment of systems, processes or technology to perform essential* DSO *functions.*'[11]

3.2 Assessment of Evoenergy's DER problem definition

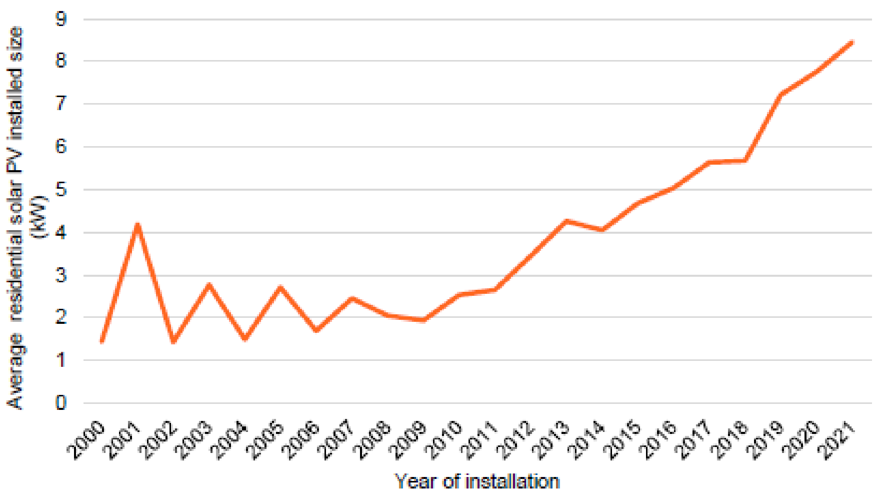
3.2.1 Power quality issues and increasing size of PV systems

Increasing power quality issues are reasonable indicators of a current and increasing need for DER-related interventions

59. Evoenergy is seeing a continuing increase in the penetration of PV and provides evidence of the increasing size of PV installations in its area of supply, as shown in Figure 3.2.

[11] Appendix 1.5, Table 5

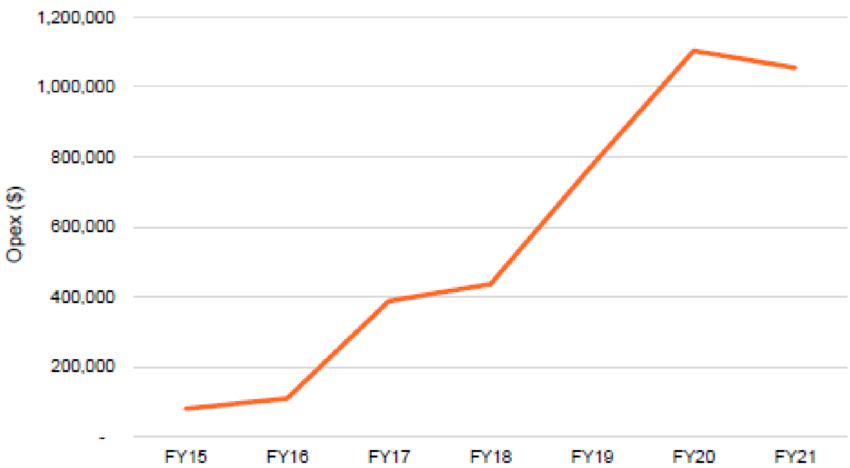
Figure 3.2: Historical average size of residential solar PV installed by year of installation



Source: Evoenergy appendix 2.5, page 13

60. In parallel with this, Evoenergy reports a significant and growing number of PQ incidents on the LV network, which it attributes to DER and considers that that there is growing inequality between DER and non-DER customers. The increasing cost of overvoltage issues is shown in Figure 3.3.

Figure 3.3: Historical yearly opex for DER-related overvoltage complaint management ($nominal)



Source: Evoenergy appendix 2.5, DER step change business case (page 13)

61. Both trends evidence a current and increasing need for interventions to facilitate DER.

3.2.2 Assessment of hosting capacity

Evoenergy's analysis of its future hosting capacity appears reasonable

62. Evoenergy states that it has completed intrinsic hosting capacity analysis but that it does not have readily accessible hosting capacity information on all parts of the LV network and has limited visibility of directional power flows on the HV network. Evoenergy reports a significant number of PQ incidents on the LV network, which it attributes to DER and considers that that there is growing inequality between DER and non-DER customers.

63. Evoenergy employed Zepben to undertake its hosting capacity analysis. While the hosting capacity analysis is only briefly described in Evoenergy's information, it appears to follow the process that we would expect and which Evoenergy describes as follows:

- *'Understanding the existing state of the network regarding the potential thermal and voltage ranges that the network can accommodate.*
- *Incrementally applying PV penetration uniformly across each feeder.*
- *Running load flow analysis to understand whether there are network violations at the LV level, distribution transformer, or the HV level.'*[12]

3.2.3 Assessment of future cost of curtailment

Evoenergy has presented a reasonable analysis of the future cost of curtailment

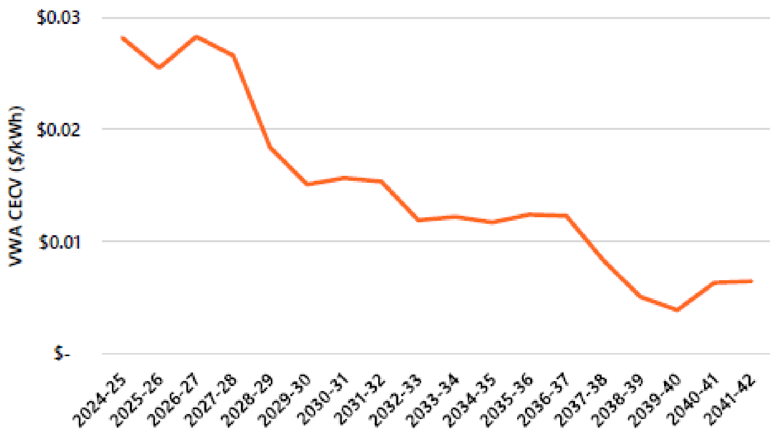
64. Evoenergy has calculated future curtailments based both on inverter tripping (due to overvoltage) and on an assumed reduction in static export limits.

65. Evoenergy has assumed a reduction in static export limits for new customers of 0.1kW per year, starting from the current level of 5.0kW in 2024-25. Therefore, for example, Evoenergy has assumed static export limits of 4.3kW would apply to new PV customers connecting in 2029-30 and 2.9kW for new PV customer connecting in 2039-40.

66. Evoenergy has not explained the rationale for its assumed 0.1kW per year reduction in new PV static export limits. However, from inspection of its modelling of CECV, we observe that its assumed curtailments from this source are much less than assumed inverter-related curtailments, as is shown in Figure 3.5.

67. Evoenergy has applied the AER's CECV, which has a declining trend, as shown in Figure 3.4.

Figure 3.4: Volume weighted average CECV

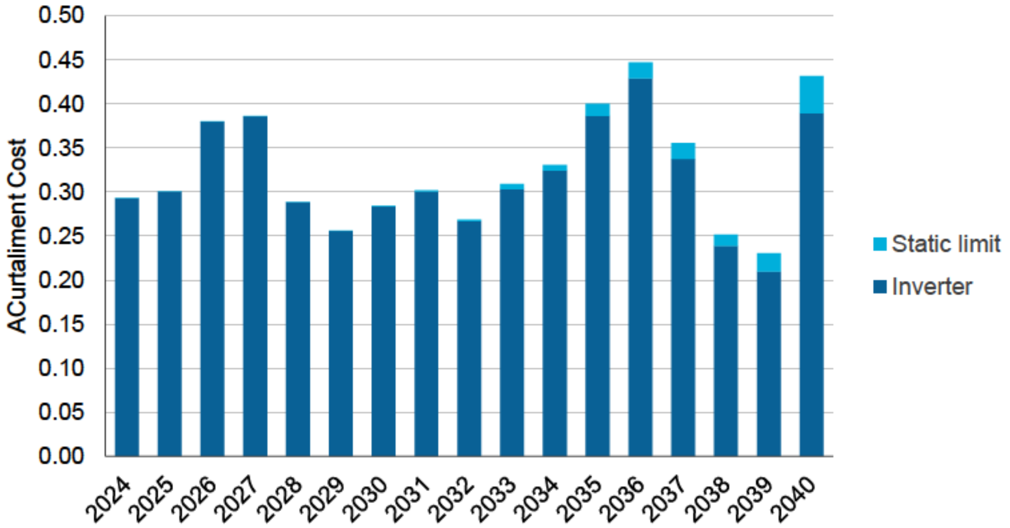


Source: Evoenergy appendix 2.5, page 47

68. The product of Evoenergy's forecast of curtailment volumes and the CECV is shown in Figure 3.5. While there is annual variability, the overall trend for this cost is relatively flat. To the extent that Evoenergy's need relies on its assessment of future curtailment costs, this indicates that its analysis is largely driven by current and near-term forecasts and not by speculative assumptions regarding circumstances in the distant future.

12 Evoenergy appendix 2.5, page 46

Figure 3.5: Forecast cost of curtailment $m, real FY24



Source: EMCa analysis from CECV sheet in Evoenergy CBA (response to IR#10)

3.2.4 Definition of base case

Evoenergy's base case counterfactual is consistent with the AER Guidelines

69. Evoenergy's base case appropriately reflects its current policy practice of '*enabling DER through reactively addressing network constraints…*' This is consistent with the AER's Guideline and provides a reasonable counterfactual against which to assess the intervention options that it has considered.

70. Evoenergy states that, while it has completed intrinsic hosting capacity analysis, it does not have readily accessible hosting capacity information on all parts of the LV network and has limited visibility of directional power flows on the HV network. This appears to be a reasonable acknowledgment of its current state and forms a basis from which to consider the value of enhancing this information.

3.3 Assessment of Evoenergy's proposed solutions

3.3.1 Options that Evoenergy considered

71. Evoenergy presents its assessment of options and the case for its proposal in Appendix 2.5 to its regulatory proposal.[13] In this document Evoenergy presents three options as follows:[14]

- Option 1: A base case of reactively addressing network constraints and limiting export capacity for new DER customers ($3.81m);
- Option 2: A '***DER Readiness'*** option, to develop a base level of Distribution System Operator (DSO) capability to handle bi-directional flows, improve customer access to dynamic exports and improve network utilisation ($17.1m); and
- Option 3: A '***Rapid Transition'*** option that would provide capability to enable high DER penetration, within the regulatory period ($31.1m).

[13] Appendix 2.5: Distributed energy resource integration step change

[14] Costs shown here are 'totex' in real $2023/24 over the 5-years of the regulatory period, as shown in Evoenergy's DER business case (Appendix 2.5 to its regulatory submission)

3.3.2 Our assessment of Evoenergy's proposed solutions

72. With 'Option 1' representing a 'reactive'-based counterfactual, Evoenergy has considered two intervention options. Both involve the following enabling capabilities:

- Increasing LV network visibility through obtaining and utilising increased LV data;
- Network operations including IT systems for DOE/ VPP integration;
- Enabling projects, including a community battery and voltage management (STATCOMS) to increase hosting capacity, as well as continuing to reactively address voltage issues through network measures as and where required.

73. We consider that these represent reasonable interventions for consideration, though it is notable that Evoenergy's business case does not include tariff reform[15].

74. The differences between options 2 and 3 revolve around timing and scale. For example:

- Option 2 targets obtaining data to provide visibility of 20% of its LV network, whereas Option 3 targets 50% data coverage;
- Under Option 2, Evoenergy will offer DOE to customers with standalone batteries and customers installing new PV and will scale solutions as required whereas under Option 3 Evoenergy will develop capability to offer DOE to all DER customers;
- Under Option 3, Evoenergy will proactively target and resolve power quality issues, including with a larger rollout of community batteries and STATCOMS than under Option 2.

75. We consider that Evoenergy's Options 2 and 3 provide reasonable 'bookend' options.

3.4 Assessment of Evoenergy's cost benefit analysis

3.4.1 Evoenergy's CBA

Overview

76. Evoenergy engaged Cutler Merz to undertake a CBA, and which takes the form of an economic analysis projecting costs and benefits over 20 years. Benefits considered in the analysis include:

- Alleviated curtailment, which is valued using the AER's CECV;
- Avoided opex, such as managing complaints and applying tap changes to manage voltage; and
- Avoided augmentation capex, to the extent that this would otherwise be required to increase hosting capacity or network capacity.

77. Evoenergy notes that the proposed DER investment (i.e. Options 2 and 3) will also provide a number of other benefits, but which were not included in the quantitative analysis.

78. From this analysis, Evoenergy identifies DER Readiness (Option 2) as its preferred option, on the basis that it assesses it to have a higher NPV than either the base case (Option 1) or Option 3. Evoenergy states that Option 2 also had the greatest support through Evoenergy's community consultation.

Evoenergy's CBA results

79. The overall results from Evoenergy's CBA ae summarised in Table 3.3, showing that Option 2 has a positive NPV and Option 3 a negative NPV, relative to Option 1 (the base case counterfactual).

[15] Evoenergy appendix 2.5, page 55. This is despite such reforms being covered in its Tariff Structure Statement.

Table 3.3: Evoenergy's cost benefit analysis (with medium DER adoption)

Option	Cost over 5-years (FY24 $m)	PV 20-year cost ($m)	PV 20-year benefit ($m)	20-year net present value (NPV $m)	20-year NPV relative to Base Case ($m)
1 - Base Case	$3.81	$13.29	$0.07	-$13.22	$0.00
2 - DER Readiness	**$17.08**	**$25.23**	**$15.10**	**-$10.13**	**$3.10**
3 - Rapid Transition	$31.09	$44.77	$27.95	-$18.22	-$5.00

Source: Evoenergy's response to IR#010 (confidential workbook, sheet 'Output Figures'

3.4.2 Assessment of CBA modelling

PV and NPV calculations in Evoenergy's CBA apply an incorrect WACC

80. In reviewing Evoenergy's CBA model, we found that an input of 7.80% that is intended to represent inflation from 2023 to 2024, has incorrectly been applied as the WACC. Evoenergy's intended WACC, as given in the relevant sheet of the model, is 3.0%. The incorrect WACC has the effect of producing lower present values, and a lower NPV by over-discounting costs and benefits.

81. In Table 3.4 (and in subsequent tables) we present the core CBA results after correcting for this misapplication of the WACC. With this correction, we derive a positive NPV of $13.9m for Option 2, compared with the NPV of $3.1m that Evoenergy presents in its analysis.

82. While the PV and NPV results differ from those in Evoenergy's analysis, the relativities between the options do not change and the DER readiness option remains the option with the highest NPV relative to the base case.

Table 3.4: Evoenergy's cost benefit analysis – with corrections to PV and NPV calculations

Option	Cost over 5-years (FY24 $m)	PV 20-year cost ($m)	PV 20-year benefit ($m)	20-year net present value (NPV $m)	20-year NPV relative to Base Case ($m)
1 - Base Case	$3.81	$22.81	$0.09	-$22.72	$0.00
2 - DER Readiness	**$17.08**	**$35.73**	**$26.92**	**-$8.82**	**$13.90**
3 - Rapid Transition	$31.09	$62.43	$47.51	-$14.92	$7.79

Source: EMCa corrections to Evoenergy's IR#010 CBA model

Factual and counterfactual definition in Evoenergy's CBA could be reconsidered

83. In presenting the NPVs of Options 2 and 3 compared to its 'base case', Evoenergy has implicitly defined the base case as its counterfactual. If the CBA had been formally specified in this way (i.e. with the base case as the counterfactual) then the avoidance of base case costs would have been treated as benefits for Options 2 and 3 and Option 2 would then present as having a positive NPV, as is shown when these options are compared with the base case.

84. In assessing the CBA, we prefer a rework of the economics of Option 2 in which the base case (Option 1) is explicitly defined as the counterfactual and the costs and benefits for Option 2 are presented by reference to this. In doing so, we also refer to the avoided opex cost relating to complaints and PQ-related tap changing, as a benefit to Option 2 (rather than a reduced cost).

85. The NPV remains the same as is shown by comparing Table 3.5 with Table 3.4. However, we consider that this presentation better shows the net benefits and costs of the proposed DER Readiness option (Option 2) and guides towards the components that warrant further assessment.

The activity/investment-level analysis of costs and benefits is useful, but requires interpretation of causality

86. In interpreting the implications of the CBA results, it is useful to be able to identify the individual costs of the various activities and investments proposed. However, there is a need for care in interpreting the benefits at this level of granularity, as there is a degree of interdependency between them. This is a presentational challenge in all such analyses. Our interpretation, for example, is that:

- While 'network visibility' on a stand-alone basis appears to have a negative NPV, it is a required enabler for DOE and therefore, for interpretive purposes, the two activities can be considered to be combined. On this basis, there is a positive overall NPV to these investments.
- We commonly see network visibility as contributing more strongly to augex-related benefits than is evident here, through the ability to better target augex to where it is needed. In section 3.4.3, we describe indications that the augex deferment benefits of the proposed DER program may be understated and that this has contributed to an overstatement of augex requirements, which is a conclusion that we come to in section 4.

Table 3.5: EMCa rework of NPV of proposed Option 2 relative to counterfactual (base case)

Activity/investment, categorised by 'enabling capability'	PV of benefits (Option 2 relative to base case)	PV of costs (Option 2 relative to base case)	NPV (Option 2 relative to base case)
Enabling projects:	**17.61**	**-5.62**	**11.99**
Augmentation to increase hosting capacity	[redacted]	[redacted]	[redacted]
Community battery	[redacted]	[redacted]	[redacted]
Voltage management (STATCOMs)	[redacted]	[redacted]	[redacted]
Change in BAU DER-related opex (complaints and tap changes)	[redacted]	[redacted]	[redacted]
Network operations:	**22.44**	**-6.73**	**15.71**
DOEs	22.44	-6.73	15.71
Network visibility:	**0.49**	**-14.30**	**-13.80**
Analytics	[redacted]	[redacted]	[redacted]
Data Collection and Storage	[redacted]	[redacted]	[redacted]
Grand Total	**40.55**	**-26.65**	**13.90**

Source: EMCa assessment from Evoenergy DER cost benefit model provided in response to IR#010, with corrected WACC

3.4.3 Assessment of benefit streams

87. As is shown in Table 3.5, the majority of Evoenergy's PV of net benefits arises from the DOE that is to be enabled. Table 3.6 further shows that the main source of net benefit is

from deferred or avoided augmentation capex, and from Evoenergy's CBA model, we find that this benefit is assumed to arise almost entirely from implementing DOE.

88. As is shown in Table 3.6, avoided DER-related opex from complaints and tap changes is also a significant contributor to the assessed net benefit of the proposed DER program. On the other hand, avoided curtailment (as represented by the CECV benefit) is only a minor contributor to the DER economics.

Table 3.6: NPV of benefits, by source of benefit (Option 2)

Nature of benefits	NPV of benefits (real $m)
Additional avoided OPEX	5.37
CECV	2.62
Avoidance of DER-related opex (complaints and tap changes)	13.72
Deferred/ avoided hosting capacity augmentation benefit	0.18
Deferred/ avoided network capacity augmentation benefit	18.67
VCR	0.00
Grand Total	**40.55**

Source: EMCa analysis from Evoenergy CBA confidential workbook provided in response to IR#010, with corrected WACC

The benefit of augex deferral is likely understated and inconsistent with assumptions Evoenergy has used for its augex forecast

89. Given its dominance, we further investigated the calculation of the augmentation network capacity deferment benefit within the CBA model. We find that it is derived from an assumed deferment of a projected amount of augex, which in turn is driven by an assumed increase in peak demand from EVs, together with an assumed LRMC of network expansion.

90. There are material inconsistencies between the augex deferment assumptions in Evoenergy's DER CBA and assumptions in its justification of proposed augex. For example, in support of its augex proposal, Evoenergy has assumed that EVs contribute a peak load increase of 64.6MW by 2030,[16] whereas the DOE impact analysis in its DER CBA is based on deferring network capacity augex that is derived from an assumed increase in peak demand from EVs of only 9.44MW in 2029-30, and which is multiplied by an assumed augex LRMC to give network capacity augex of only $1m in that year.[17] This is well short of the EV-driven augex that Evoenergy has proposed, and which we assess in section 4.

91. Moreover, in its DER analysis, Evoenergy appears to have assumed that only EV-related augex can be deferred by its proposed DER initiatives.

92. A further augex benefit anomaly appears to be present in the calculation of the deferred/avoided hosting capacity augmentation benefit and which is minimal (as shown in Table 3.6). Within the CBA model, the 2024/25 '*justified LV line augmentation*' for 2024-25 traces to a single historical augex amount for '*overvoltage violation*' in 2021-22. All other justified overvoltage violation augex is zero for the remainder of the analysis period.[18] This would appear to be driving Evoenergy's conclusion (as shown in Table 3.5) that no augex is required over the next RCP, to increase hosting capacity. While this may be the case, the derivation of this result appears to be erroneous.

93. In combination, we consider that these factors appear to understate the benefits of DER integration expenditure or, alternatively, suggest an overstatement of the proposed augex. We discuss the latter hypothesis in Section 4, but for the purpose of considering

[16] From response to IR#014

[17] Evoenergy workbook provided in response to IR#010, DOE, *Augex* and *LP* sheets

[18] Evoenergy IR#010 workbook, sheet *IHC and current EG*, cells JT109 to KU110

Evoenergy's proposed DER CBA our observation is only that the two forecasts appear to be inconsistent.

Avoided opex benefit is likely overstated

94. In its CBA Evoenergy treats the assumed increase in opex arising from customer complaints and the need for PQ-related tap changes, as a cost in its Option 1 base case. In its assessment of Options 2 and 3, Evoenergy assumes that its proposed DER initiatives entirely avoid the increase in such costs. In comparing Option 2 with the base case counterfactual, the assumed avoidance of the increase in complaint and tap changing costs presents as a benefit with a $13.7m PV.[19]

95. We consider that this likely represents a significant overstatement of the benefit, noting that:

- It is based on limited analysis of actual costs, with an 'average cost per complaint' of $5,891 that is heavily influenced by an unexplained almost-doubling of per-complaint costs between 2019 and 2020;
- It assumes that increased complaint costs and increased tap change costs can be entirely avoided with DER and increased network visibility, and which has not been adequately justified;
- The PV of this avoided cost derives from an assumed incremental cost that rises from around $120,000 in 2025-26 to close to $1.2m by 2035-36 and then to $2.9m by 2044-45. In other words, the PV of this avoided cost is strongly driven by costs assumed in a counterfactual 15 to 20 years out. While a CBA requires assumptions to be made, there are considerable but inevitable challenges to extrapolate from limited historical data to what will be a radically different future.

3.4.4 Assessment of the proposed DER costs

Line-item costs are reasonable

96. At a line-item level, we consider that the costs that Evoenergy has proposed are reasonable. Other than the proposed community battery (which we discuss below), we observe that the only material capex item is just over [redacted] for IT systems for DOE/VPP integration. Evoenergy makes provision for opex for '*modelling and forecasting uplift*', consistent with the focus on network visibility and associated analytics.

97. Evoenergy's proposal involves utilising existing network data that it has available to it, augmented with smart meter data from 8% of its customers. We consider this level is not unreasonably high and reflects a reasonable judgment by Evoenergy of requirements for DER readiness as opposed to a full DOE implementation.

Evoenergy has provided insufficient evidence to support the proposed community battery

98. The proposed community battery has a totex cost of [redacted] Evoenergy's proposed DER-related expenditure.

99. As shown in Table 3.5, this investment has a negative NPV. We consider that it is separable from the remainder of Evoenergy's proposed DER investment and that the remainder of the proposed DER program remains justified without it.

There is insufficient evidence to confirm that the entire proposed opex represents a step change

100. Evoenergy has proposed a step change that is equivalent to the entire level of opex that it has included for its DER program, commencing with an amount of $2.63m in 2024-25, and which is comprised of six line-items. To the extent that Evoenergy was already incurring some of these costs in the base year that it has used in projecting its overall opex forecast,

19 With WACC corrected, as descr bed above. From further review in the CBA, this benefit appears to be derived from improvements in network vis bility. An 'additional avoided opex' benefit of $5.33m appears to be derived based on assumed uptake of DER, however the same issues listed below apply to both components.

these would need to be deducted from its proposed step change. Assessment of Evoenergy's overall opex forecast is not within our scope and we therefore bring this to AER's attention to consider as part of its overall determination.

3.4.5 Assessment of the preferred option

Selection of the DER Readiness option is justified

101. Apart from the community battery, we consider that the other aspects of the DER Readiness option (Option 2) that Evoenergy has proposed are justified and that this option is preferrable to the base case (Option 1) and the Rapid Transition option (Option 3).

102. We consider that Evoenergy's DER Readiness option is a proportionate initiative that provides a reasonable path towards enabling 'DSO' type services where it is economic to do so and supporting increased DER during and beyond the next regulatory period. We form this view having considered Evoenergy's current and forecast levels of DER, information disclosed in its proposal regarding its ability to host DER as well as the implications for Evoenergy's network of the ACT government's Net Zero 2045 policy (mainly through EV uptake).

103. We observe that Evoenergy's DER Readiness strategy has relatively modest ambitions, and which we assume to be reflective of current needs. However, we also observe that Evoenergy has proposed a significant augex program, which we review in section 4. We consider that the proposed DER-related investments can potentially provide Evoenergy with greater opportunities than it has proposed, to test and deploy services including dynamic tariffs and 'orchestrated' behind-the-meter controls that will allow Evoenergy to meet future needs with materially less traditional network augmentation than would otherwise be required.

3.5 Our findings and implications

3.5.1 Summary of our findings

The majority of the proposed DER expenditure represents a prudent and efficient allowance

104. With the exception of the proposed community battery, we consider that Evoenergy's proposed DER Readiness expenditure represents a prudent and proportionate approach to introducing DER management capabilities in the next regulatory period. Other than in this regard, we consider that the proposed expenditure is reasonable. The proposed community battery involves capex and also a component of Evoenergy's proposed opex.

3.5.2 Implications for Evoenergy's proposed expenditure allowances

105. The proposed community battery contributes [redacted] to Evoenergy's proposed capex and [redacted] to its proposed opex step change.

106. If any of Evoenergy's proposed opex line items were represented by expenditure in its base year, then this would need to be deducted in accordance with AER's base step trend methodology, in deriving a step change allowance from the overall opex requirement.

4 REVIEW OF PROPOSED AUGMENTATION EXPENDITURE

Evoenergy has proposed augex totalling $181.6m, the majority of which is demand-driven with smaller components for secondary systems and for reliability and quality-related augex. Evoenergy claims that $76.3m of its proposed demand-driven augex is required to meet the ACT government's policy of achieving Net Zero by 2045.

AER asked us to assess Evoenergy's proposed augex on the basis of an alternative (and somewhat lower) peak demand forecast that AER provided to us. On this basis, we consider that Evoenergy's demand-driven augex presents as a considerable overstatement of its requirements and that a lesser amount will still be consistent with Evoenergy's role in facilitating achievement of the ACT government's carbon-reduction policy. A considerable proportion of Evoenergy's proposed augex is for some major projects at the end of the next RCP and, with the lower demand forecast provided to us, we consider that these will not be required within this timeframe.

We consider that one project proposed within the category of reliability and quality will not be required, while we consider that the proposed secondary systems expenditure is reasonable.

In aggregate, we propose an alternative forecast of $103.9 million, which is more than double Evoenergy's estimate of its augex in the current RCP.

4.1 What Evoenergy has proposed

4.1.1 Overview and summary of proposed expenditure

107. Evoenergy has proposed $181.6 million of 'augex', as shown in Table 4.1.

Table 4.1: Evoenergy Augex forecast for next RCP - $millions, real FY2024

Description	2025	2026	2027	2028	2029	Total
Demand Driven	22.3	23.3	32.4	39.9	43.7	**161.5**
Secondary systems	1.5	1.5	1.2	1.5	2.1	**7.8**
Reliability and quality	3.6	2.1	2.0	2.4	2.2	**12.3**
Total	**27.4**	**26.8**	**35.5**	**43.8**	**48.0**	**181.6**

Source: Evoenergy RP document Table 11, with additional information from Evoenergy Attachment 1, table 8[20]

108. The proposed demand driven expenditure is largely for zone substation and distribution feeder projects, together with some provisions for LV upgrades. The secondary systems expenditure is for zone substation controls and SCADA communications control, while the proposed expenditure on reliability and quality is for projects including distribution network

[20] In Attachment 1: Capital expenditure, Evoenergy refers to its augex program as $169.3m, which comprises its proposed demand -driven and secondary systems expenditure (section 1.7, page 41). In the same section, however, it also presents a proposed reliability and quality program of $12.3m (labelled as section 1.7.2 but presumably intended to be 1.7.3). For our assessment, we have considered all three components as proposed 'augex'.

monitoring, a grid-scale community battery, UG feeder reliability improvements and replacing some uncovered HV conductor in bushfire prone areas.

109. Included in the demand-driven expenditure is $76.3 million for projects that Evoenergy proposes as being required in order to support ACT Net Zero targets.

110. Evoenergy states that it has developed its demand-driven augex forecast from a combination of top-down and bottom-up approaches[21] with the top-down approach coming from its 'Net Zero Model' (NZM). Evoenergy states that the NZM *'…provided a provisional guide for the levels of demand-driven augex required'* and that *'(t)he top-down forecast has then been validated through bottom-up forecasts which reflect Evoenergy's well-established network planning process…'*.[22] We provide observations on the role of these top-down and bottom-up approaches in section 4.2.3.

111. The projects which comprise the demand-driven expenditure amount listed in Table 4.1 are assessed in sections as shown in Table 4.2. We assess proposed expenditure on secondary systems in section 4.6 and for reliability and quality in section 4.7.

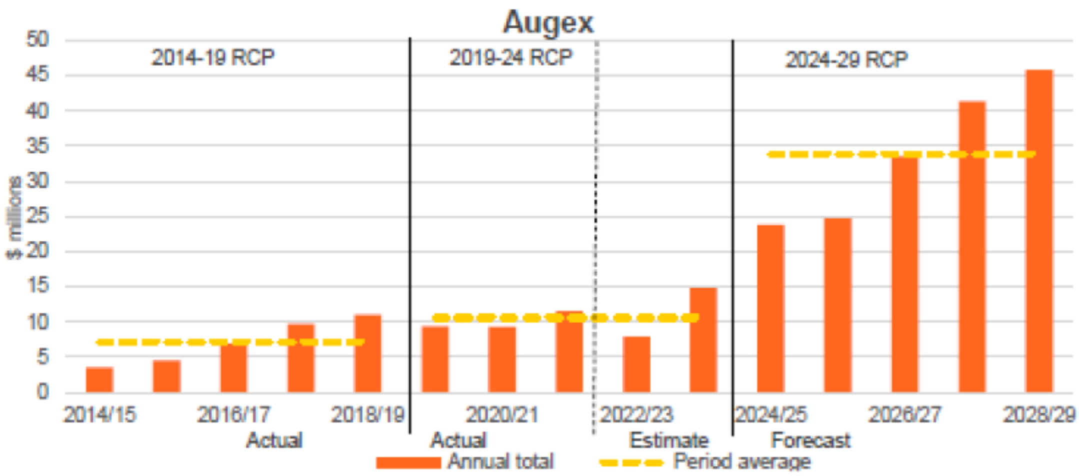
Table 4.2: Categorisation of demand-driven expenditure and reference to assessment sections

Category	Amount ($m)	Assessment section
Demand driven: Zone substations	$75.3	Section 4.3
Demand driven: Upgrades and ZS reactive plant	$10.1	Section 4.4.2
Demand driven: Net Zero supply projects	$34.7	Section 4.4.3
Demand driven: Other supply projects	$41.4	Section 4.5
Subtotal: Demand-driven augex	**$161.5**	

Source: EMCa analysis from Evoenergy Attachment 1, Capital Expenditure, table 8

112. For the combination of demand-driven and secondary systems expenditure, Evoenergy presents its augex trend as shown in Figure 4.1.

Figure 4.1: Actual/forecast augmentation capex across regulatory periods ($m, $2023/24)



Source: Evoenergy Attachment 1: Capital expenditure, page 41

21 Evoenergy Appendix 1.16, section 3.1 and in its RP (page 25)

22 Evoenergy Attachment 1, page 42.

4.1.2 Evoenergy information provided

113. Evoenergy has provided a listing of its proposed augex projects and their timings, together with information on drivers and its justification assessments. The main relevant documents are:

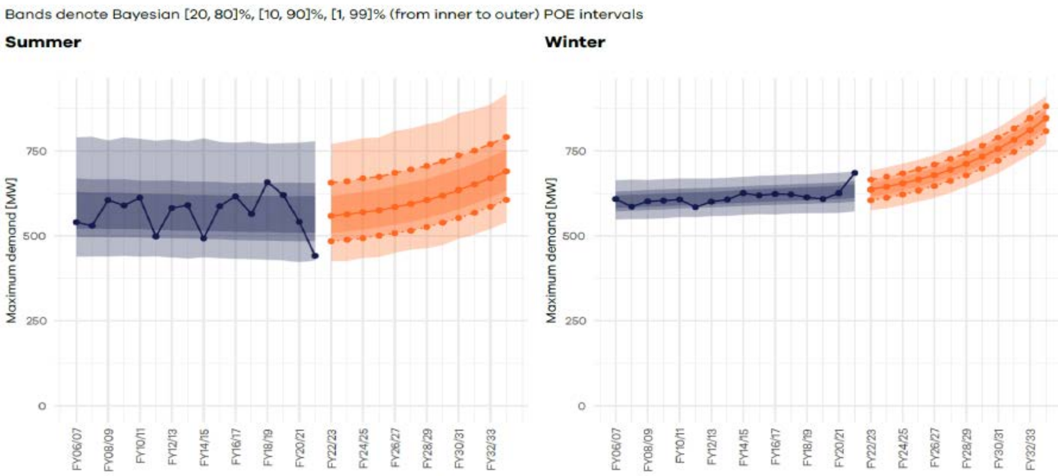
- Attachment 1: Capital expenditure
- Appendix 1.15: Demand driven capital expenditure
- Appendix 1.16: Network Development Plan
- Appendix 1.17: Augmentation to achieve Net Zero 2045
- Specific appendix documents and NPV analyses for proposed zone substation developments
- Appendix 1.8: Capital expenditure deliverability
- Appendix 1.4: Evoenergy Net Zero Modelling Journey (which comprises a report by Marsden Jacobs)
- Evoenergy SCS capex model
- Addendum 7.1.3: Draft 5-year electricity network plan 2024 (EN24)
- Annual Planning Report 2022

114. Evoenergy also provided further information in response to AER information requests.

4.1.3 Evoenergy's peak demand forecasts

115. Evoenergy developed a peak demand forecast as key inputs to assessing the need for demand-driven augex, as shown in Figure 4.2.

Figure 4.2: System historical and 12-year maximum demand forecasts



Source: Evoenergy appendix 1.16: Network Development Plan, figure 22

116. Evoenergy provided peak demand information at the zone substation level though, as we describe in section 4.2.1, our point of reference for our assessment of its proposed demand -driven augex is an alternative peak demand forecast provided to us by AER.

4.1.4 Evoenergy's Net Zero modelling (NZM)

117. Evoenergy has provided a considerable amount of information on the NZM that it commissioned, and which includes long-term forecasting of the impact of various 'Net Zero' emissions scenarios to 2045. Evoenergy states that its NZM indicates that to achieve net

zero by 2045, would require expenditure of the order of $743m over the 2024-29 regulatory period.[23]

118. Evoenergy separately states that, from the NZM scenarios considered, it has adopted '*Scenario B: Realistic Electrification Ad Hoc'* as best representing its future requirements. We provide observations on the NZM information provided and its role in Evoenergy's augex forecast, in section 4.2.3.

4.2 Observations on augex demand drivers and Evoenergy's augex forecasting inputs

4.2.1 Peak demand forecast assumptions

AER provided us with an alternative peak demand forecast to apply in our augex assessment and which is lower than Evoenergy's forecast

119. Evoenergy's peak demand forecasts that it used as the basis for its proposed demand-driven augex were provided in response to information request IR#07.

120. Consistent with our terms of reference, EMCa was not asked to review Evoenergy's demand forecast. EMCa was, however, asked to advise AER on the implications for Evoenergy's augex forecast if AER was to not accept Evoenergy's demand forecast and to substitute an alternative forecast.

121. At the time of drafting this report, AER has advised that it intends not to accept Evoenergy's demand forecast and has asked us to assess Evoenergy's proposed augex based on an alternative demand forecast that it has provided to us.[24] We understand that AER's alternative forecast makes adjustments for the peak demand impact of EV charging and removes or reduces residential/commercial/mixed development blockloads, other than a proposed Fyshwick to East Lake transfer.

122. Both Evoenergy's demand forecasts and AER's alternative forecasts have been provided to us at a zone substation level, and comprise 10%, 50% and 90% POE summer and winter peak demand forecasts. Evoenergy's forecasts are to 2034, while AER's alternative forecast is to 2032. In both cases, this allows us to take account of the lead time for projects in our assessment to meet the forecast peak demands beyond the end of the next RCP.

123. Accordingly, we have considered the AER alternative peak demand zone substation forecasts in assessing the justification for Evoenergy's proposed augex. In Figure 4.3 we show Evoenergy's historical peak demand, together with the peak demand forecast that it has used as the basis for its demand-driven augex proposal, and AER's alternative forecast.[25] In the historical graphs and tables that follow, the Evoenergy demand forecast refers to that provided under IR#07 as above, and the AER ALT forecasts are the alternative forecasts provided to us by AER as defined above.

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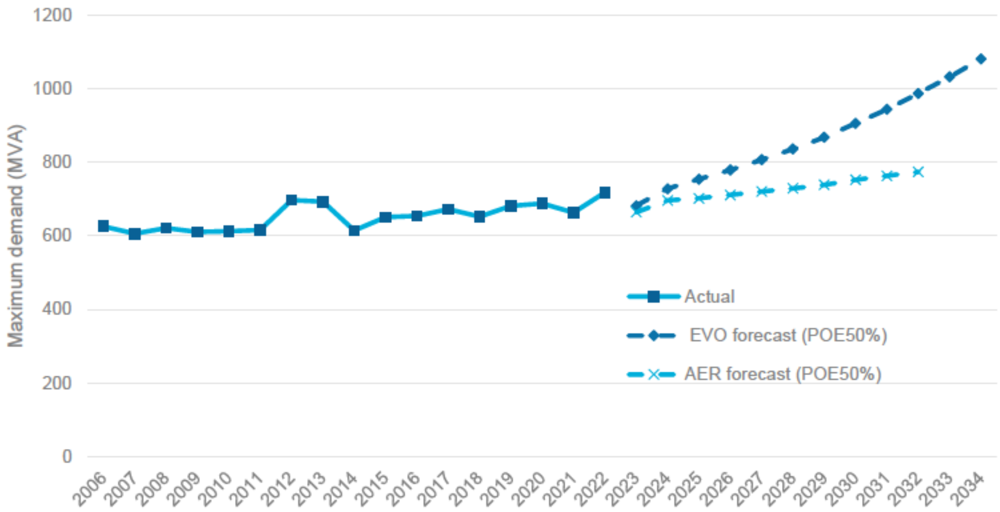
23 Evoenergy Attachment 1, Capital Expenditure, page 15

24 AER provided its alternative peak demand forecast in a spreadsheet labelled as '*REU Alternative Blockloads*' provided by email on 6th July 2023.

25 The Evoenergy demand forecast refers to that provided under IR#07 as above, and the AER ALT forecasts are the alternative forecasts provided to us by AER as defined above. The winter 50% POE forecast is shown, since this drives capacity augmentation requirements for the majority of demand-driven augex that Evoenergy has proposed.

Figure 4.3: Evoenergy and alternative non-coincident sum of ZS peak demand forecasts (Winter 50% PoE)



Source: EMCa analysis from AER workbook Forecasts_ZSandSystem_REU review.....(15467204.1), provided 3d July 2023

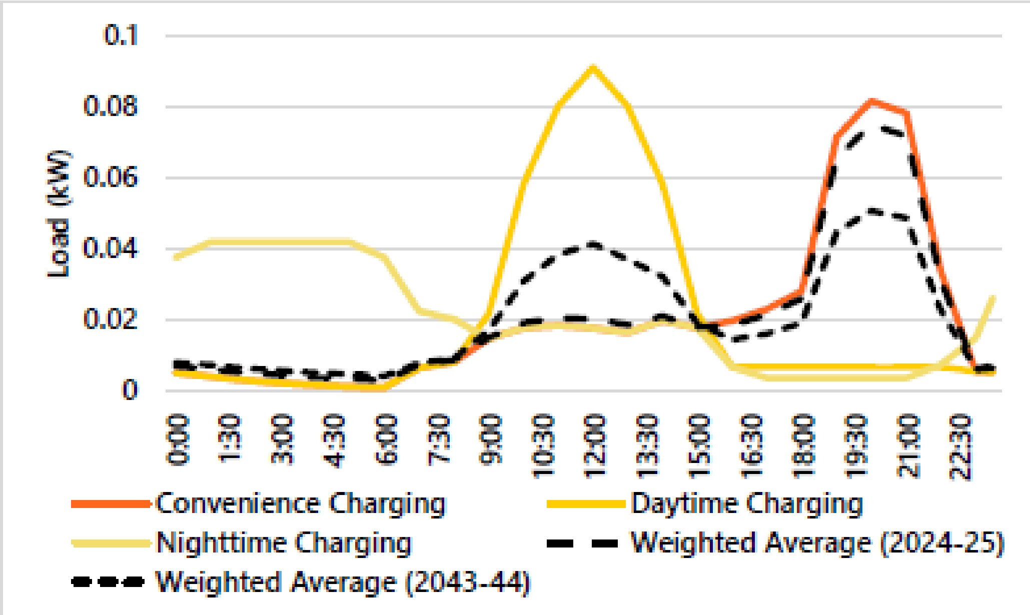
4.2.2 Consideration of assumed EV charging profiles

Evoenergy's forecast of the peak demand impact due to EV charging that it used for its proposed augex, was overstated but Evoenergy provided a reduced EV forecast that AER has taken into account in its alternative demand forecast

124. We have considered the specific implications of Evoenergy's assumptions regarding the future profiles of EV charging. Evoenergy's peak demand forecast incorporates the assumed charging impact from 50,000 EVs, by 2030. The need to be able to meet the charging requirements for these vehicles is the main implication that Evoenergy draws from the ACT Net Zero policy. This is a function of the number of vehicles, and their assumed charging profile and, in particular, the assumed contribution of EV charging to increases in demand at peak time.

125. From Evoenergy's description of the basis that it has adopted in forecasting the peak demand impact of EVs, it appears that it is based on an EV charging profile as shown below. As stated in Evoenergy's Attachment 1.4, the assumption is that *'…BEV charging will gradually move from convenience charging (charging in the evening peak) in the early years of the study period to increased daytime charging…'*

Figure 4.4: Daily EV charging profile (assumed for 'realistic electrification' scenario)

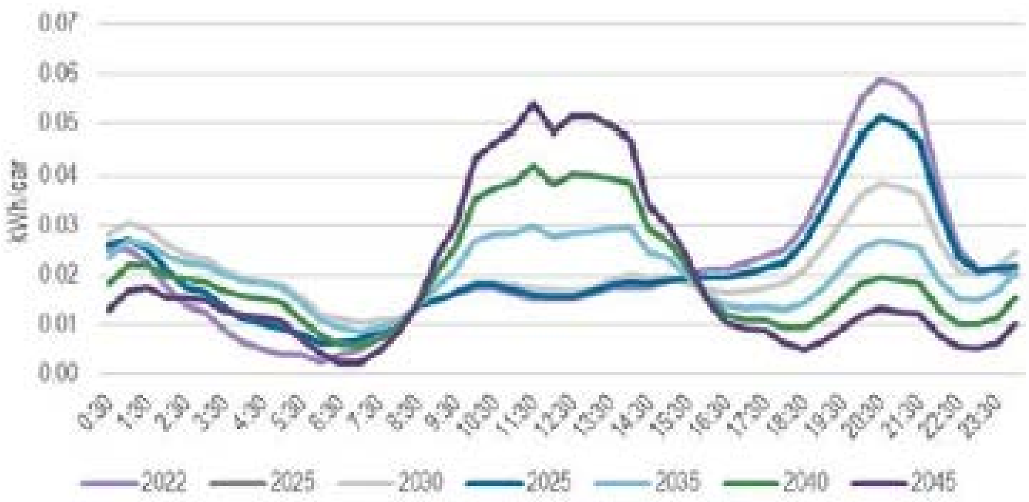


Source: Evoenergy Appendix 1.17, Augmentation to achieve net zero 2045

126. Evoenergy's assumed charging profile reflects a considerably slower moderation of EV charging profiles than is evident, for example, in ACIL Allen and GHD's advice to the ACT government, and which is reproduced in Figure 4.5. By a similar end-point (i.e. 2045 versus 2043-44) the ACIL Allen and GHD forecast suggests that there will be minimal charging during the convenience evening winter system peak window and considerable use being made of the ability to charge through 'solar soaking' during the middle of the day.

127. We further observe that moderation of this profile is to a considerable extent linked to Evoenergy's proposed DER initiatives that we have assessed in section 3.

Figure 4.5: Weighted average combined time of day ZEV charging profile (kW/car)



Source: ACIL Allen and GHD: Economic and technical modelling pf the ACT electricity network (April 2022) figure 140

128. From inspection of these graphs, and also through reference to information that is provided in the ACIL Allen report to the ACT government on the projected contribution of EVs to peak demand,[26] we consider that Evoenergy's assumptions on the peak demand contribution of

[26] For example, figure 106 in the ACIL Allen/GHD report

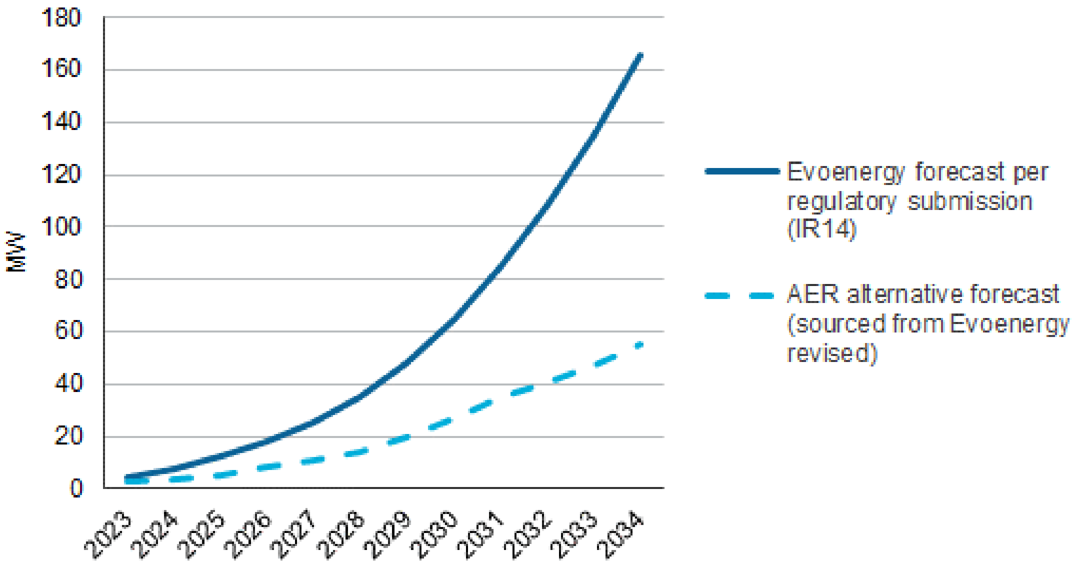
EVs was considerably overstated. In communication with the AER, Evoenergy subsequently provided a revised and considerably reduced EV peak demand forecast.

129. We understand that Evoenergy's reduced EV peak demand forecast is based on the same forecast of EV uptake in the ACT as it used for its regulatory submission augex forecast; therefore, we assume that the reduced forecast reflects a greater extent and rate of moderation of EV charging profiles, for reasons such as we have observed from our assessment as described above. Such moderation implies measures including tariff-driven behavioural change in charging patterns and perhaps a degree of control and orchestration; in other words, this will be enabled by programs that are broadly described under the heading of DER and/or DSO initiatives, which Evoenergy has proposed and which we largely accept as reasonable, as we describe in section 3. The potential to moderate EV charging impacts to the extent that Evoenergy now indicates, further demonstrates the benefits that can be obtained from a well-focused DER program.

130. In short, we consider that Evoenergy's revised EV peak demand forecasts reflect the same degree of support to ACT government's Net Zero policy that Evoenergy identified as a significant driver in its regulatory proposal; specifically, Evoenergy would be able to support the same level of EV uptake over the period and the extent to which gas churn occurs. The reduced peak demand forecast suggests that Evoenergy has determined that it can accommodate changes in usage resulting from ACT government's Net Zero policy in ways that result in less impact on its network and therefore less cost to consumers.

131. In Figure 4.6 we present Evoenergy's original and revised EV peak demand forecasts. We understand from AER that the 'AER ALT' alternative non-coincident aggregate peak demand forecast (as shown in Figure 4.3) incorporates Evoenergy's revised EV peak demand forecast which is (by 2030) 54% less than the original forecast that it provided.[27]

Figure 4.6: Evoenergy's original and revised forecasts of EV contribution to peak demand



Source: EMCa analysis workbook Forecasts_ZSandsystem_REUreview_withALTBlockLoadForecasts 15467204 *(EV Block loads sheet, winter)*

132. Consideration of the EV load forecast information above in conjunction with the alternative demand forecast presented in Figure 4.3 also raises doubt over Evoenergy's assertions that its proposed significant increase in augex in the next regulatory period is in response to ACT government's Net Zero policy. As can be seen in comparing the scale of Figure 4.3 with that shown in Figure 4.6 above, the impact of the 54% (by 2030) lower revised EV-driven

[27] The adjustments have been made at the zone substation level and reflect individual ZS geographic differences in EV uptake that Evoenergy expects.

peak demand forecast is small relative to the impact on the demand forecast of AER's alternative assumptions regarding non-EV block loads.

4.2.3 Consideration of Evoenergy's Net Zero Modelling

Evoenergy's augex forecast is based on a traditional bottom-up approach in defining specific projects, and we have assessed its forecast on the same basis

133. Evoenergy states that its augex forecast is from a combination of its 'top-down' NZM and bottom-up forecasting. Its forecasting approach is described in its Network Development Plan[28] and in the submission document describing derivation of its proposed demand-driven capex,[29] both of which provide evidence of planning at a zone substation level and of feeder and LV planning that we would tend to describe as applications of a traditional bottom-up approach. This is also consistent with the statement in its RP that *'(o)ur proposed 2024-29 capex program has been informed by, not based on, the net zero model….'*[30]

134. We have assessed Evoenergy's augex forecast on the basis of the 'traditional' approach that Evoenergy has applied, and which we consider to be appropriate.

The role of the NZM in informing Evoenergy's augex forecast for the next RCP is less clear but we consider that it has led Evoenergy to overstate the implications of its proposal for its longer-term augex requirements

135. The NZM that Evoenergy commissioned provides potential insights into the scenarios that could eventuate. This includes:

- Potential EV uptake scenarios;
- Assumptions regarding EV charging profiles; and
- Assumptions regarding the implications of gas churn, and which is assumed to have minimal net impact over the next regulatory period.

136. It is not clear what Net Zero-related augex implications for the next RCP Evoenergy deduced from the NZM. The NZM suggests total electricity capex requirements for Evoenergy of $607.5m in 2024-29[31], though in the RP a figure of $0.75 billion is referred to.[32] We understand that this is an estimate of total capex for which Evoenergy has proposed $577.5m in the next RCP and it is presumably from this comparison that Evoenergy states that its NZM '*suggests that to achieve net zero by 2045, we will require in the order of an additional $220 million in the 2024-29 period.*'[33]

137. However, we consider that some of the implications suggested by the NZM are misleading. For example:

- We would expect that the NZM would primarily encompass demand-driven augex requirements, with some implications for power quality-driven augex. However, Evoenergy does not seek to reconcile between the $76.3m of its proposed augex that it designates as being driven by 'Net Zero', or the $161.5m that it proposes as 'demand-driven', and the forecasts of aggregate capex requirements in its NZM. For example, section 6.3 of Evoenergy's Network Development Plan (NDP)[34] describes its '*validation and context'* of its cross-check against the outcomes of the NZM but does not include

28 RP Appendix 1.16

29 RP Appendix 1.15

30 RP, page 25

31 Evoenergy Appendix 1.4, page 50 (table 10)

32 RP, page 25

33 RP page 26. This appears to be an approximation of the difference between $0.75 billion and $521m, though we note that the latter figure is net of capital contributions. The gross capex of $577.5m is shown on page 55 of the RP.

34 Evoenergy Appendix 1.16, Network Development Plan (January 2023)

any quantitative comparison other than to note that its total proposed capex is less than 'scenario B' of its NZM.[35]

- Evoenergy states that the difference in winter peak demand from NZM is within 8% of its own bottom-up forecasting, by 2033/34.[36] However, we note that this represents around two years of proposed growth, and which therefore materially affects the required timing of projects proposed within a 5-year regulatory period;
- In its NZM, Evoenergy provides cost benefit analysis which includes a VCR-based value of unserved energy (USE) for what is assumed to be an inability to provide for load growth, for which it posits that the dominant cause is EVs. The NZM estimates these USE costs as rising steeply to $16.7m in 2032 under the medium EV uptake scenario that forms the basis of Evoenergy's submission, and $542m in 2032 under the high EV scenario. We consider that VCRs are inappropriate measures in this instance, because of the relative ease with which timing of EV charging can be shifted; that is, an inability to charge an EV at a particular time will for the most part (and assuming that it can be charged at an alternative time) have a much lower cost to a consumer than complete loss of supply to a household.
- From NZM estimates of a need for between $1.8bn and $2.4bn of expenditure above BAU levels up to 2045,[37] Evoenergy raises concerns about risks to planning, deliverability and operations if it was to undertake a lesser amount of augex than it has proposed in the next regulatory period.[38] Whilst future deliverability and the uncertainty of future requirements beyond the next regulatory period are undoubtedly factors to consider, the spectre of risks of this magnitude is weakened by the relatively poor calibration of the NZM against Evoenergy's bottom-up NZM-driven assessed augex requirements.
- The impact of EVs on augex requirements is heavily dependent on assumptions regarding charging profiles, and there is a strong interaction between these assumptions and assumptions regarding 'DER/DSO' mechanisms and also technology assumptions (such as with regard to behind the meter battery costs and vehicle-to-home and vehicle-to-grid capability of EVs). While there is no definitive path for these, especially when forecasting over periods of 20 to 25 years, we consider it likely on balance that a range of innovations will allow Net Zero policies to be achieved with lower levels of traditional network augex investment than might currently be apparent. In the NZM, we searched for, but did not find, any reference to the dynamic services / DSO / DER initiatives that Evoenergy is proposing to ready itself for during the next RCP. As is intended by its DSO/DER strategy, these should significantly moderate the level investment that it may need to incur in accommodating increased electrification within the territory in the subsequent years.

138. In summary therefore we consider that, while it is useful to have mapped out 'scenario' considerations in the NZM analysis, it is appropriate that Evoenergy has in this case relied on traditional assessments of its augex requirements.

4.3 Our assessment of proposed Zone Substation projects

4.3.1 Evoenergy's proposed zone substation and related projects

139. Evoenergy has proposed expenditure totalling $75.33m on zone substations and including works associated with those substations. The projects are shown in Table 4.3 and our assessment of these substation projects follows.

35 This refers to a figure of $0.61 billion, in table 2 of Evoenergy's NDP

36 Evoenergy appendix 1.14, page 5

37 Evoenergy appendix 1.17, page 7

38 Evoenergy appendix 1.16, page 26

Table 4.3: Evoenergy's proposed expenditure on substations and related augmentation

Description	Total Cost for next RCP ($m FY23-24)	Date needed
Molonglo Zone Substation Stages 2 & 3	11.16	2028/29
Strathnairn Zone Substation	19.04	2026/27
Curtin Zone Substation Stage 1	19.31	2030/31
Mitchell Zone Substation	2.20	2031/32
Gold Creek Zone Substation Third Tx	7.94	2025/26
Woden to Curtin 132kV UG Cable	8.52	2030/31
Supply from Molonglo ZS	3.33	2028/29
Supply to Strathnairn from Latham ZS	2.12	2024/25
Supply from Strathnairn ZS	1.71	2027/28
Total	**75.33**	

Source: EMCa analysis from Evoenergy Appendix 1.15 Demand driven augmentation capital expenditure, Table 1

4.3.2 Evoenergy's method for assessing the need for and timing of zone substation augmentation

140. In its Annual Planning Report[39], its demand-driven augex business case report[40] and in individual project business case documents Evoenergy describes the methodology it has used to determine the type and timing of its proposed zone substation and feeder augmentation projects.

141. The methodology can be summarised as follows:

1. Evoenergy applies its demand forecasts for 10%, 50% and 90% Probability of Exceedance (POE) levels to the zone substations and feeders to establish a 10-year projection of the assets' MVA loading;
2. For zone substations, Evoenergy compares the projected asset MVA values against the continuous and emergency 2-hour ratings (summer and winter) for the relevant asset;
3. For feeders, Evoenergy compares the projected asset MVA values against the firm and thermal ratings for the relevant asset;
4. Exceedance of an asset's rating indicates the need for and timing of an intervention; and
5. Options assessments are used to determine the lowest cost and highest NPV alternative.

142. Evoenergy establishes the forecast demand through an assessment of the likelihood of proposed developments proceeding. To do this Evoenergy establishes probability factors to represent the likelihood of a forecast load materialising in the current regulatory period. Evoenergy considers this to be a probabilistic methodology. The outputs from this process form the demand forecast input to the deterministic bottom-up methodology described in steps 2, 3, and 4 above.

143. Evoenergy applies its POE demand forecasts to determine an economic value/cost when considering options to address the identified network constraints.

[39] Evoenergy Annual Planning Report 2022, Version 1.1. Effective Date: 31.12.2022

[40] Evoenergy Appendix 1.15, Demand Driven Augmentation Capital Expenditure Business Case, section 5.1

144. The emergency 2-hour rating is set at the MVA level that, following an N-1 contingency event,[41] would allow remaining assets to be loaded to their 2-hour emergency rating for that limited time. Therefore, the emergency 2-hour rating is a higher value than the continuous rating allowing time for the event to be managed. We consider that the use of Evoenergy's ratings is appropriate for establishing the timing and level of emerging constraints on network assets. We have used this method for testing the results under the alternative forecast that AER provided to us.

145. To support its proposal, Evoenergy identified several drivers for the need and timing of investment in specific zone substations and feeders. These drivers include the forecast exceedance of loading on existing zone substations and feeders, and the timing of residential, commercial and public greenfield developments, which will require new feeders to be installed.

146. The timing for the commencement of new zone substation and feeder investment can be triggered by a single new greenfield development, if it cannot be supplied from an existing zone substation and feeder, or if it is uneconomic to do so.

147. Whilst use of alternative demand forecasts may indicate that the timing of augmentation could be deferred, full confirmation of the appropriateness of such deferral would need to be considered through network engineering assessments. For example, deferring commissioning of a new zone substation could lead to unmanageable constraints at a feeder level. While we have sought to understand implications to the extent that they are evident in Evoenergy's information provided, our assessment does not include engineering assessment at this level of granularity, therefore implications of alternative demand forecasts for feeders are necessarily indicative only.

4.3.3 Additional transformers at Molonglo substation and associated Molonglo ZS feeder works

Evoenergy's proposal

148. The proposed augex in the 2024-2029 RP includes two 132/11kV 30/55 MVA transformers that will be installed at the existing Molonglo ZS site which has been prepared for the transformer installation during the current regulatory period. This project forms part of a planned multi-stage development for the supply to loads in the Molonglo Valley. The transformers are to be installed in stages 2 and 3 of the overarching zone substation development:

- Stage 2 – first transformer installation has commenced in the current RP with completion targeted for winter 2025;
- Stage 3 – second transformer to be installed in 2029.

149. Evoenergy has undertaken several related feeder projects to support the Molonglo Valley load during the current RCP. However, Evoenergy considers that further extensions to the 11 kV feeder network will not provide feasible solutions to meet the forecast load. The final stage (stage 3) includes a second transformer installation in 2029.

150. The completion of Stage 2 is estimated to cost $7.1 million, with the balance of $4.1 million being for Stage 3.

151. Evoenergy has determined that: [42]

'..the remaining capacity of the existing zone substations and 11 kV feeder network supporting the Molonglo Valley District is significantly below the level required to meet

[41] To meet N-1 requires that peak demand can be met with an appropriate level of backup should a credible contingency event occur. A cred ble contingency event is the loss of a single network element that occurs sufficiently frequently, and has such consequences, as to justify the DNSP to take prudent precautions to mitigate. This is commonly referred to as an N-1 event.

[42] Evoenergy Appendix 1.18 Molonglo Zone Substation Project Justification Report, page 3

the forecast load during the 2024-2029 regulatory period, which is expected to reach 36.4MVA by 2029.'

152. The additional capacity at Molonglo ZS will allow load to be transferred from the Woden substation which Evoenergy's ZS data[43] indicates could exceed its summer emergency 2-hour rating in 2033 and winter emergency 2-hour rating in 2031.

153. Evoenergy has also determined that by 2027 the installed transformer capacity at Molonglo ZS will be insufficient to meet demand under an N-1 scenario (e.g., failure of the first transformer). At this point Evoenergy considers that the Stage 3 investment will be required to provide N-1 contingency for the first 55MVA transformer.

Our assessment

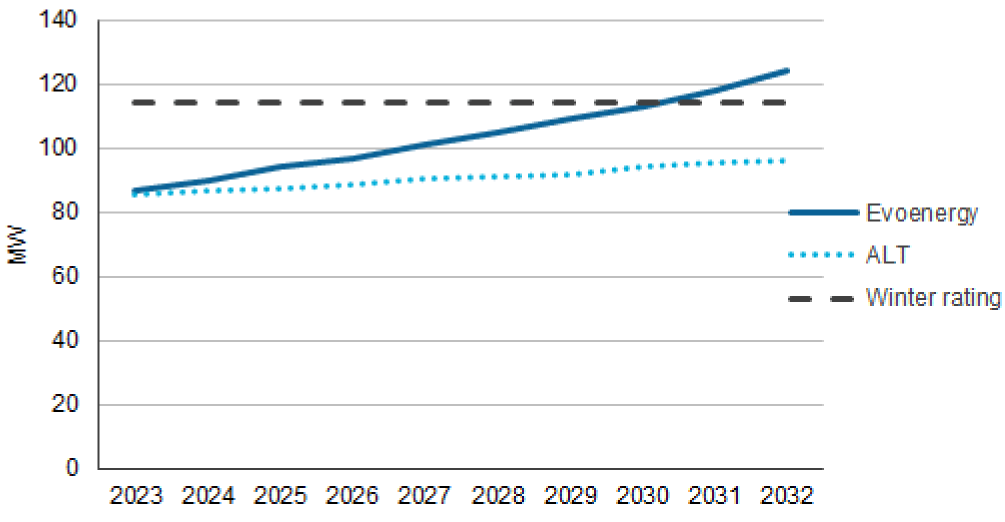
With the alternative demand forecasts, the second transformer at Molonglo will not be required in the next RCP

154. We consider that Evoenergy has demonstrated that:

- The modifications to its existing feeder network have enabled it to defer augex during the current RCP;
- Through a RIT-D process, it has extended the need for completion of Stage 2;
- It has reasonably identified that a staged transformer option is appropriate to meet future demand growth in the Molonglo Valley.

155. However, the timing of the need for the transformer installations is determined by the demand forecast that is applied. When the AER's alternative demand forecasts are applied to the load area (as indicated by the Woden ZS loading) we consider that the need for the installation of the second transformer (stage 3) can be deferred beyond 2030, as is illustrated in Figure 4.7.[44]

Figure 4.7: Woden substation capacity assessment – winter period



Source: Forecasts ZSand System REU review with ALTBlockLoadForecasts.

156. Feeder loadings in Evoenergy's Base Case assessment for Molonglo ZS are shown in Figure 4.8. Note that following the completion of Stage 2, Evoenergy concludes that there

43 EMCa analysis of Evoenergy ZS data, forecasts_ZSandSystem_REUreview_withALTBlockLoadForecasts (EMCa summary) v2 (final AER DF)

44 The demand forecast labelled as ALT is the AER's alternative forecast

will be sufficient capacity to delay the installation of Stage 3 to 2029. Therefore, the shortfall in capacity identified in the table below would change with completion of Stage 2.

Figure 4.8: Evoenergy's existing feeder capacity assessment in Evoenergy's base case option for Molonglo ZS investment

Feeder	Summer		Winter		2021		2022		2023		2024		2025		2026		2027		2028		2029	
	Firm	Thermal	Firm	Thermal	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Streeton	5.5	7.3	6.2	8.2	6.1	7.3	6.5	7.8	7.5	8.9	8.8	10.5	9.0	10.9	9.0	10.9	9.0	10.9	9.6	11.5	9.9	11.9
Black Mtn	4.9	7.6	5.5	7.3	3.0	7.1	3.7	8.8	4.3	10.4	5.1	12.2	5.4	13.0	6.0	14.6	6.6	16.0	7.1	17.1	7.5	18.2
Hilder	5.2	7.0	5.9	7.8	3.7	6.2	4.5	7.5	5.7	9.5	5.9	9.9	5.9	9.9	5.9	9.9	5.9	9.9	5.9	9.9	5.9	9.9
Bel Way	5.4	7.1	6.1	8.1	3.3	5.0	3.6	5.5	2.6	4.0	3.1	4.8	4.9	7.4	6.5	9.9	7.7	11.6	10.3	15.6	12.8	19.4
Expected Unserved Energy (kWh)									153615		437078		569244		1070067		2094595		6691476		13851530	
Value of Expected Unserved Energy									$5,062,389		$14,403,892		$18,759,423		$35,264,062		$69,027,376		$220,517,584		$456,477,173	

Source: Evoenergy Appendix 1.18, Page 8

157. We considered whether the changes in feeder loadings in Figure 4.8 could provide an indication of the level of demand increase that, post the completion of stage 2, could trigger the required timing of Stage 3. To do this we calculated the difference between 2027 and 2029 combined feeder demand values. This identified the step change in feeder loadings occurring between 2027 and 2029 under Evoenergy's demand forecast. The calculation gives an increase of 6.9 MVA (summer) and 11 MVA (winter) as the potential trigger for Stage 3.

158. The level of decreases in demand that we calculated by applying the AER's alternate demand forecast to the Woden zone substation suggest that a similar proportional reduction applied to the four feeders, would be sufficient to defer Stage 3 expenditure to beyond the 2024 – 29 RCP.

159. The above analysis is based on the limited information provided by Evoenergy. This includes the lack of information available to us on specific feeders and their associated loadings supplying the Molonglo area post the commissioning of stage 2. While the information above provides a first-pass indication, detailed network analysis would be needed to definitively establish the stage 3 need date under the AER's alternative demand forecast.

160. In addition to the installation of the two transformers, Evoenergy has included $3.3 million expenditure for the installation of new 11kV feeders in its proposed augex for the next RCP. The feeders will connect new growing suburbs to the Molonglo substation. Due to the limited granularity of the demand forecasts available to us, and limited information of the loads intended to be serviced by the new feeders, we are unable to determine the potential for deferral of the feeder installation dates under the AER's alternative demand forecast.

4.3.4 Proposed Strathnairn substation and associated Strathnairn supply works

Evoenergy's proposal

161. Evoenergy has proposed the establishment of a new zone substation at Strathnairn and associated feeders (Strathnairn to Latham), to be constructed in two stages commencing in 2024 with completion in 2032. Estimated cost for completion of the works is $20.75m with $19.04m for the zone substation and $1.17m for 11kV assets being incurred in the 2024-29 RCP.

162. The Strathnairn ZS is claimed to be needed to meet the forecast demand related to major development areas of Ginninderry, Strathnairn and Macnamara and two additional suburbs in the ACT and NSW.

163. The existing 11kV feeder network, the Latham and Belconnen Zone Substations, and a demand management scheme, have been used to meet current load over the 2019/24 RCP. Evoenergy has determined that the current network capacity, including demand management, will be insufficient to stay within feeder thermal limits at N-1 beyond mid-2027.

164. Through its options analysis Evoenergy concludes that continuing to use feeder extensions to meet the forecast increase in demand is no longer viable and has determined that the proposed new zone substation development option at Strathnairn has the lowest cost and highest NPV. A grid battery option that Evoenergy considered, was relatively close on both cost and NPV and Evoenergy intends to test a battery ZS deferral option through a RIT-D.

Our assessment

It is reasonable to assume that the Strathnairn zone substation and associated feeders will be required in the next RCP

165. The need for additional capacity was based on Evoenergy's demand forecast. We have assessed the potential under the AER's alternative demand forecast for movement in the timing date for completion of the Strathnairn ZS, and to defer the associated expenditure.

166. We consider that the application of the AER's alternative demand forecast to the Latham and Belconnen zone substations has no implications for the need or timing for this project. This is because the primary driver is the forecast exceedance of emergency 2-hour ratings on existing feeders.

167. Based on our assessment of the feeder loading forecasts at Strathnairn provided by Evoenergy and which we reproduce in Figure 4.9, the alternative demand forecast would need to result in deferral of the project by at least four years. This would require a reduced feeder demand to defer a material proportion of the proposed expenditure beyond the next RCP.

Figure 4.9: Evoenergy's feeder capacity assessment for Strathnairn ZS

	Summer		Winter		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
Feeder	Firm	Thermal	Firm	Thermal	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Macr'n	4.4	5.9	5.0	6.7	2.9	4.0	3.3	4.6	3.9	5.4	4.7	6.6	4.7	6.6	4.7	6.6	4.7	6.6	4.7	6.6	4.7	6.6	4.7	6.6	4.7	6.6	4.7	6.6
Latham	4.4	5.9	5.0	6.7	2.1	2.9	2.5	3.5	3.4	4.6	5.0	6.8	5.7	7.8	5.7	7.8	5.7	7.8	6.1	8.3	6.4	8.8	7.0	9.6	7.2	9.8	7.5	10.3
Weir	4.4	5.9	4.9	6.6	2.1	3.4	2.1	3.4	2.1	3.4	2.8	4.4	3.8	5.9	3.8	5.9	4.8	7.3	5.1	7.7	5.4	8.2	6.0	9.0	6.1	9.2	6.5	9.7
Expected Unserved Energy (kWh)									0		23		21584		21584		21584		75595		210100		636216		760550		1212397	
Value of Unserved Energy									$3		$755		$711,308		$711,308		$711,308		$2,491,229		$6,923,853		$20,966,488		$25,063,938		$39,954,551	

Source: Evoenergy Appendix 1.19, Page 10

168. Given that the bulk of the expenditure on this project is expected to be incurred in the first three years of the next RCP it is unlikely that changes in the demand forecast would move material sums to the next RCP. We also note that Evoenergy has indicated that the need for the ZS and feeder investment is primarily to accommodate greenfield growth.

169. Given the above, the proposed expenditure on the feeder supply projects *20009665 Supply to Strathnairn feeder* and *20001961 Supply to Strathnairn from Latham ZS*, would also be required.

170. The alternative demand forecast could change the options analysis outcome e.g., making the battery the lowest cost and highest NPV option. Also, we note that Evoenergy considered an option to transfer load from Weir to O'Loghlen feeder to potentially defer the need date for Strathnairn ZS. This option was dismissed due to the expected 'other projects', demand associated with Net Zero initiatives, and EV charging load. A lower demand forecast could potentially make this option viable but would be unlikely to defer expenditure to beyond the 2024-2029 RCP.

4.3.5 Proposed Curtin substation and associated 132kV cable

Evoenergy's proposal

171. Evoenergy proposes to construct the Curtin substation and a 132kV interconnecting underground cable between Curtin ZS and Woden ZS. The proposed expenditure in the

next RCP for Curtin substation is $19.31 million with a date needed for completion in 2030/31.

172. The Curtin to Woden 132kV cable has proposed expenditure in the next RCP of $8.52 with a need date of 2030/31. Proposed new feeder installations are also linked to the Curtin ZS development.

173. Evoenergy attributes the need for and timing of the Curtin ZS development to:

- The next stage of the Light Rail 2B to Woden;
- Conversion of horse paddocks in Curtin to an embassy precinct;
- Net Zero related demand requiring future load transfers from Woden and Telopea Park Zone Substations;
- The need to accommodate load growth due to significant forecast electric vehicle load growth; and
- Urban infill and gas transition.

174. Evoenergy identifies[45] the primary need for and timing of the Curtin zone substation as supply to the Woden Valley area and easing the expected constraints on the Woden Valley ZS.

175. To maintain the necessary aesthetic at this location for the transmission and distribution equipment associated with the Curtin ZS, Evoenergy considers that the zone substation would require indoor 132kV Gas Insulated Switchgear and indoor 11kV switch rooms and power transformers. This is to reduce noise and visual impact, but substantially increases costs.

176. Evoenergy evaluated the Curtin ZS project by applying three EV uptake scenarios (low, medium and high). Evoenergy adopted the expenditure profile under medium EV uptake in its Augex forecast. This results in $25.85m of the combined $27.83m cost of the proposed Curtin substation and the Woden to Curtin cable, being incurred in 2028 and 2029. The timing of expenditure under each option is provided in Table 4.4.

Table 4.4: Evoenergy's option analysis for the Curtin ZS

Option Analysis	FY25	FY26	FY27	FY28	FY29	Total
Option 1						
Curtin Zone Substation	0	0	0.48	1.28	10.00	**11.76**
Woden to Curtin 132kV UG Cable	0	0	0	0.88	5.64	**6.52**
Combined	**0**	**0**	**0.48**	**2.16**	**15.64**	**18.28**
Option 2						
Curtin Zone Substation	0	0.48	1.28	10.00	7.55	**19.31**
Woden to Curtin 132kV UG Cable	0	0	0.22	0.66	7.64	**8.52**
Combined	**0**	**0.48**	**1.5**	**10.66**	**15.19**	**27.83**
Option 3						
Curtin Zone Substation	0.48	1.28	10.00	7.55	20.49	**39.8**
Woden to Curtin 132kV UG Cable	0	0.22	0.66	7.64	9.28	**17.8**
Combined	**0.48**	**1.5**	**10.66**	**15.19**	**29.77**	**57.6**

Source: EMCa table derived from Evoenergy Appendix 1.17, Pages 26 - 30

45 Evoenergy Appendix 1.17, Page 22

Our assessment

With the alternative demand forecasts, the proposed Curtin substation and associated underground cable from Woden will not be required in the next RCP

177. The need for additional capacity was established based on Evoenergy's demand forecast for Woden ZS and its medium EV scenario in Option 2. Changes in the EV uptake profile and the Woden ZS demand forecast have the potential to move the timing date for completion of the Curtin ZS under all options.

178. The options tables indicate that, had Evoenergy adopted the low EV uptake option it would have resulted in a reduction in total expenditure in the next RCP to $11.7m with $10m being incurred in 2029. As we have explained in section 4.2, we consider that Evoenergy's regulatory submission forecast of EV peak demand was overstated, and Evoenergy has now provided a lower EV peak demand forecast and which is incorporated in AER's alternative peak demand forecast.

179. Whilst the Curtin ZS project is included as a Net Zero project it is primarily driven by the need to reduce demand on the Woden ZS. Therefore, any reduction in the forecast demand at the Woden ZS should result in the deferral of the need date of the Curtin ZS and the associated 132kV underground cable and feeders.

180. Deferral of the planned offload of the Woden ZS could raise issues for the resolution of emerging constraints on the feeders from Woden ZS. However, a lower demand forecast could also reduce the level of constraints seen on the feeders.

181. As for our evaluation of the Molonglo ZS, which is also driven by constraints at the Woden ZS, we consider the implications of the AER's alternative demand forecasts for Woden substation, as shown in Figure 4.7, as these inform our assessment of the required timing for the Curtin ZS development.[46] Applying the AER's demand forecasts to the Woden substation reduces constraints at Woden ZS and would therefore defer the timing of the Curtin ZS. Under the AER's alternative demand forecast, the Woden ZS would not exceed its Emergency 2-hour rating (at 10% POE) before 2032.

182. Based on our analysis, we consider that under the AER's POE 10% alternative demand forecasts the commencement of the Curtin ZS development could be deferred entirely beyond the next RCP. Alternatively, if a 2-year deferral was applied, expenditure in the next RCP could be reduced to $1.76m.

183. A deferral of Curtin ZS would imply a similar deferral of the proposed expenditure of the Wooden to Curtin 132kV cable. However, we note that our assessment does not take into consideration any broader risks associated with this deferral, but which were not evident from documentation that we reviewed.

Table 4.5: Alternative expenditure profile under a 2-year deferral of commencement

Description	FY25	FY26	FY27	FY28	FY29	Total
Curtin Zone Substation	$0	$0	$0	$0.48	$1.28	**$1.76**
Woden to Curtin 132kV UG Cable	$0	$0	$0	$0	$0	**$0**
Combined	**$0**	**$0**	**$0**	**$0.48**	**$1.28**	**$1.76**

Source: EMCa table derived from Evoenergy Appendix 1.17, Page 26

184. The above adjustments would also lead to a deferral of the associated Curtin feeder projects. However, constraints that may emerge on existing feeders would need to be

46 Appendix 1.17 page 22, states that the Curtin ZS will primarily supply the Woden Valley area and ease the expected constraints on the Woden Valley ZS in Woden Valley

addressed if the Curtin development is deferred and on balance we consider that a similar portfolio of feeder projects would likely be required.

4.3.6 Proposed Mitchell substation early works

Evoenergy's proposal

185. Evoenergy proposes to commence preliminary work during the next RCP to allow it to subsequently construct a new ZS at Mitchell. The proposed expenditure in the next RCP is $2.20m covering *early works* for the project.

186. Evoenergy considers that the project is required to meet growth in Mitchell and North Canberra, including Net Zero-related demand on its network. It is intended that the Mitchell ZS will allow future load transfers that relieve future constraints at the City East ZS.

187. This project will require subtransmission augmentation to connect the zone substation. However, expenditure for this is not included in the proposed augex.

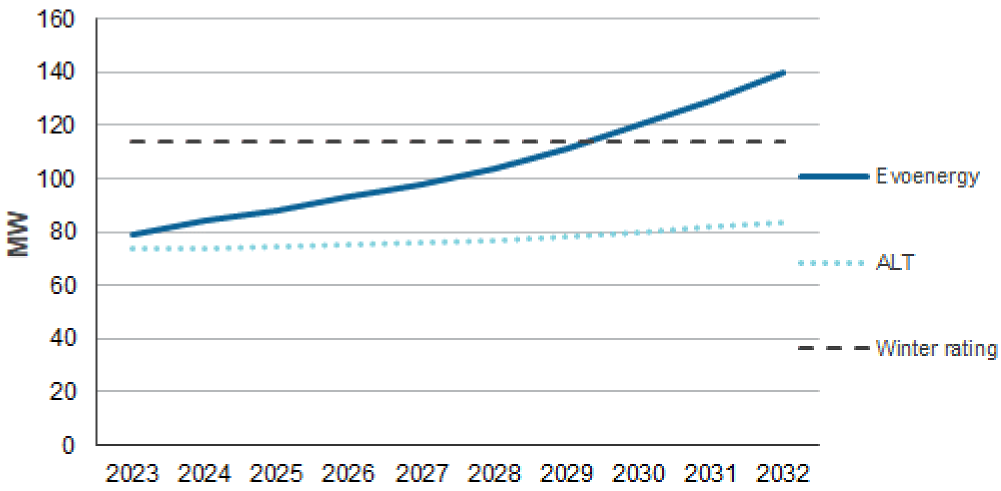
Our assessment

With the alternative demand forecasts, the proposed early works for Mitchell substation will not be required in the next RCP

188. The need and timing for additional capacity was established by Evoenergy based on its demand forecast. As for other zone substation augex projects we have considered, changes in the demand forecast have the potential to move the timing date for completion of the Mitchell ZS.

189. Under Evoenergy's demand forecast the rating of the City East ZS would be exceeded in 2030. However, when we apply the AER's alternative demand forecast to the City East ZS, we find that the load would not exceed its Emergency 2-hour rating until sometime beyond 2032 (being the limit of AER's alternative demand forecast).

Figure 4.10: City East rating assessment – Winter period



Source: Forecasts ZSand System REU review with ALTBlockLoadForecasts

190. We conclude that adoption of the AERs alternative demand forecast as the basis for determining the commencement date would defer the necessary commencement of this project and associated expenditure beyond the next RCP.

191. We note an error in Evoenergy's Options 1 and 2 in the table provided on pages 26 and 27 of Appendix 1.17. A corrected table is provided in Table 4.6, which shows the correct total for Option 1 if the contributing yearly values are correct as $1.77 million, and not $2.20 million.

Table 4.6: Correction of error in Evoenergy's proposed Augex for Mitchell ZS

	FY25	FY26	FY27	FY28	FY29	Total
Option 1	$0	$0	$0	$0	$1.77	**$1.77**
Option 2	$0	$0	$0	$0.44	$1.77	**$2.20**
Option 3	$0	$0.44	$4.77	$11.56	$17.33	**$34.10**

Source: EMCa table derived from Evoenergy Appendix 1.17, Pages 26 - 27

192. However, we consider it is likely that Evoenergy's intention was to defer the Mitchell ZS project by one year between Options 1 and 2. In that case the value for Option 1 in FY29 should be $0.44 million and not $1.77 million. The resulting total for Option 1 for the next RCP would also be $0.44 million.

193. We also note that deferral of the Gold Creek ZS development may bring forward the need date for Mitchell ZS. Our evaluation for the Gold Creek substation is provided in the following subsection.

4.3.7 Proposed third transformer at Gold Creek substation

Evoenergy's proposal

The proposed expenditure for Gold Creek zone substation is justified

194. Evoenergy has proposed installing a third 132/11 kV 55 MVA transformer at the existing Gold Creek zone substation, at an estimated cost of $7.9m.

195. The driver for this project is the connection of increased load from new developments, urban infill, gas transition and electric vehicle growth. Evoenergy describes the area supplied as currently being dependent on the gas network, which will be under transition from gas to electricity.

196. Currently there are periods when the N-1 requirement is not met and a RIT-D process in late 2022 did not reveal any demand management options. Evoenergy's Annual Planning Report identifies that, based on its winter 50% POE demand forecast the Gold Creek ZS is expected to continue to exceed two-hour emergency ratings on an ongoing basis.

197. Evoenergy's analysis indicates that deferral of this project would likely drive the earlier need for Mitchell ZS development or the installation of three new feeders from Latham ZS (see 2022 Annual Planning Report).

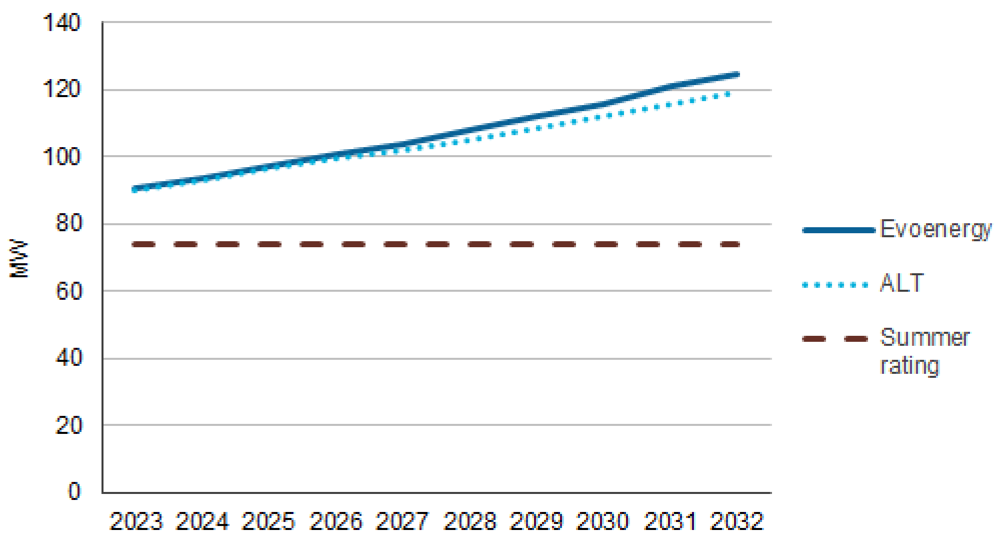
198. Evoenergy's options analysis indicates that installing the third transformer in the next RCP has the lowest negative NPV of the four options that it assessed.

Our assessment

199. The information provided by Evoenergy indicates that the installation of the third Gold Creek ZS transformer has rolled over from the current RCP.

200. The need for and timing of the third transformer installation is driven by the emergence of constraints against the zone substation emergency 2-hour ratings. In Figure 4.11, we show that the emergency 2-hour rating for Gold Creek ZS was already exceeded in 2023. Our analysis of the implications of the AERs alternative demand forecasts on the timing of the need for the third transformer can be seen in Figure 4.11 below.

Figure 4.11: Gold Creek loading assessment – Summer peak demand



Source: Forecasts ZSand System REU review with ALTBlockLoadForecasts

201. All demand forecasts and loading assessments indicate the current need to install the third transformer. Also, the RIT-D that was undertaken by Evoenergy indicated that non-network options are unavailable to manage any further delay.

202. We note that accepting the need for the Gold Creek ZS expenditure removes the need to bring forward commencement of the Mitchell ZS project.

4.4 Our assessment of projects that Evoenergy identifies as driven by ACT's Net Zero policy

4.4.1 Proposed zone substation projects that Evoenergy links to ACT government's Net Zero policy

Proposed Net Zero projects

203. Evoenergy has designated the Curtin and Mitchell zone substations ($19.31m and $2.20m respectively) and the Woden to Curtin underground cable project ($8.52m) as being required to support ACT government's Net Zero policy. We have discussed our assessment of these projects in section 4.3.

204. Evoenergy has also listed three upgrade programs and a number of supply projects as being required to support the Net Zero policy. Taking the zone substation projects above, together with the upgrade projects listed in Table 4.7 and the supply projects listed in Table 4.8) these proposed Net Zero policy projects sum to $76.3m capex over the period.

205. Evoenergy provides information that is relevant to our assessment of the zone substation and upgrade projects, and which reasonably aligns with our assessment of these projects. We present this information below.

Evoenergy's assessment of implications for zone substation projects of a lower EV peak demand forecast

Evoenergy's assessment of the implications of a lower EV peak demand forecast for zone substations reasonably aligns with our assessment of the impact of lower overall peak demand forecasts

206. From comparison of Evoenergy's Net Zero related augex forecasts for its option 1 and option 2 EV peak demand forecasts, it identifies the following consequences of adopting a lower EV forecast:[47]

- Deferral by one year of Curtin ZS, with a consequent reduction of $7.55m within the period;
- Deferral of Mitchell substation. Tables 3 and 4 suggest no change, however inspection of tables 7 and 8 suggests (from an addition error in table 7) an intention to defer by one year, reducing the cost within the period by $1.77m;
- Deferral of the Woden to Curtin UG cable, with a consequent reduction of $2m.

207. These zone substation and UG cable deferrals and reductions in Net Zero-related expenditure are those identified by Evoenergy and are solely resulting from the forecast lower impact of EV demand. Our assessment of the need and timing for the three projects above is covered in sections 4.3.5 (for Curtin substation and related UG cable) and 4.3.6 (for the proposed early works for Mitchell substation). Our assessment is directionally consistent with Evoenergy's own forecast with lower EV demand; however, our assessment extends the deferrals to beyond the next RCP, once we take account not only of a lower EV charging demand forecast but also the other reductions inherent in AER's alternative demand forecast.

4.4.2 Net Zero-related upgrade programs and ZS reactive plant

Evoenergy's proposal

208. Evoenergy has designated proposed expenditure allowances for zone substation reactive plant, a distribution substation upgrade program and an LV circuits upgrade program as also being required to support the Net Zero Policy, as shown in Table 4.7.

Table 4.7: Other demand driven projects

Description	Total Cost for next RCP ($m FY23-24)	Date needed
Zone Substation Reactive Plant	2.06	2028/29
Distribution Substation Upgrade Program	5.13	Ongoing
LV Circuits Upgrade Program	2.87	Ongoing
Total	**10.06**	

Source: EMCa, from Evoenergy Appendix 1.15 to regulatory submission, table 1

Our assessment

Evoenergy states that the LV circuits upgrade and distribution substation upgrades programs are not required under a 'low EV' demand forecast scenario

209. From comparison of Evoenergy's Net Zero related augex forecasts for its option 1 and option 2 EV peak demand forecasts[48], it identifies that it can prudently defer all of the

[47] Refer to tables 3, 4, 7 and 8 in Evoenergy appendix 1.17

[48] Refer to tables 3, 4, 7 and 8 in Evoenergy appendix 1.17

proposed works for distribution substation upgrades and LV circuit upgrades (with cost reductions of $5.13m and $2.87m respectively) with a lower EV peak demand forecast.

With the lower EV peak demand forecast inherent in AER's alternative demand forecast, the LV and distribution substation upgrade programs are not required in the next RCP

210. Evoenergy proposes targeted upgrades to distribution substations in areas aligned with the medium and high EV uptake. Evoenergy states that the requirement varies significantly in scope and scale (and therefore cost) between each scenario.[49]

211. In its Appendix 1.15 Evoenergy states that further information on this program is given in App 1.17, however we were unable to find additional information of relevance in that document. In several places the documents supplied by Evoenergy explain that the need for distribution substation augmentation and low voltage circuit augmentations are identified due to the likely impact of EV chargers and growing gas conversions. However no further detail on the types and locations for these projects has been provided.

212. We identified no information demonstrating how Evoenergy determined its $5.13m forecast. The proposed expenditure is not identified against any specific work that could be subject to evaluation and appears to be a contingency allowance. The expenditure on the distribution substation upgrade program would change, for example if assumptions on the EV demand related to charging profiles changes. As Evoenergy's low EV uptake scenario has no expenditure for distribution substation upgrades and as this scenario is inherent in AER's alternative peak demand forecast, this augex item is not required.

213. For similar reasons, and consistent with Evoenergy's own analysis of a 'low EV' demand forecast scenario, the LV upgrade allowance is also not required in the next RCP.

The proposed allowance for zone substation reactive plant appears to be a contingency provision that Evoenergy has not adequately justified

214. Evoenergy is expecting to experience deterioration of power quality at zone substations due to the forecast penetration of DER (primarily rooftop solar). Evoenergy states that the Gold Creek Zone Substation has already experienced this issue and anticipates that reactive plant may be needed at other zone substations. However, this has yet to be subjected to detailed analysis and no details were provided on the specific investments needed or locations.

215. The proposed expenditure appears to be a contingency for issues that could arise from increasing rooftop solar. Assumptions underpinning the magnitude of this issue would be needed to support inclusion in the proposed augex. Absent justification of this nature, the proposed generic allowance does not meet the requirements of the NER.

4.4.3 Net Zero-related supply projects

Evoenergy's proposal

216. Evoenergy has proposed the supply projects shown in Table 4.8, and which it has designated as being required in order to support the ACT government's policy of Net Zero by 2045. Evoenergy explains these projects as being largely driven by the need to cater for increasing EV uptake.

[49] Evoenergy Appendix 1.15, page 23

Table 4.8: Supply projects that Evoenergy designates as being driven by Net Zero 2045 policy

Description	Total Cost for next RCP ($m FY23-24)	Date needed
Supply to Braddon	3.87	2028/29
Supply to Watson	2.97	2029/30
Supply to Ainslie	4.77	2027/28
Supply to Campbell	5.04	2028/29
Supply to Franklin	4.98	2028/29
Supply to Garran and Red Hill	2.54	2029/30
Supply to Phillip	4.50	2028/29
Supply to Canberra CBD feeder 1	3.16	2027/28
Supply to Canberra CBD feeder 2	2.61	2028/29
Supply to Canberra CBD feeder 3	0.28	2030/31
Total	**34.72**	

Source: EMCa, from Evoenergy Appendix 1.15 to regulatory submission, table 1

Our assessment

With the alternative demand forecasts, and in particular with Evoenergy's reassessment of the peak demand impact of EVs, most if not nearly all of the proposed supply projects are not required within the next regulatory period

217. As we have discussed in section 4.2.2, Evoenergy has now provided an EV peak demand forecast that is 54% lower in 2030 than the forecast that it used in determining its augex requirements for its regulatory submission. We understand that AER has taken account of this reduction in its alternative peak demand forecast, which our assessment is based on.

218. In its appendix describing augmentations driven by the ACT government's Net Zero policy[50], Evoenergy describes the augmentations that would be required for a 'low EV uptake', being 50% of the medium uptake. On the basis that a 50% lower uptake (in terms of vehicle numbers) results in a 50% lower peak demand than the medium EV uptake that Evoenergy has assumed for its augex proposal, this can therefore provide a guide to the augex impact of the 54% lower EV-related peak demand forecast that Evoenergy has now provided for its medium EV uptake scenario.

219. Comparing Evoenergy's augmentation works required under its 'option 1' (low EV uptake) scenario with the proposed augmentations in Table 4.8 shows that Evoenergy's assessment is that the following are not required during the next RCP:

- Supply to Watson
- Supply to Ainslie
- Supply to Garran and Red Hill
- Supply to Phillip
- Supply to Canberra CBD feeder 3.

220. Of the remainder of supply projects listed in Table 4.8, the Braddon, Campbell, Franklin and Canberra CBD 2 feeders are each designated as required in 2028/29. Whilst Evoenergy did

50 Evoenergy appendix 1.17

not provide feeder-level forecasts, we expect that the combination of a lower EV-related forecast in conjunction with AER's lower non-EV block load forecasts would likely allow for the prudent deferral of some if not all of these remaining end-of-period supply feeder projects into the next RCP. If all such projects were able to be deferred, this would leave only the Canberra CBD 1 project required.

4.5 Our assessment of supply projects to meet general load growth including non-EV block loads

Evoenergy's proposal

221. Evoenergy proposes the following supply projects, which it designates as being driven by its forecast load growth, based on factors other than the ACT government's Net Zero policy.

Table 4.9: Supply projects that Evoenergy driven by factors other than the Net Zero by 2045 policy

Description	Total Cost for next RCP ($m FY23-24)	Date needed
Supply to Belconnen Town Centre	0.41	2024/25
Supply to Donaldson St	3.41	2024/25
Gungahlin Feeder Ties	0.63	2024/25
Supply to Kingston	0.99	2025/26
Supply to CBD S63	3.69	2024/25
Supply to Fyshwick Sec 38	0.68	2025/26
Supply to Lyneham- Canberra Racing Club	5.28	2027/28
Supply to Diplomatic Development – Curtin	5.30	2027/28
Supply to Woden Town Centre	4.14	2026/27
Supply to Fairbairn South	1.57	2028/29
Supply to Hume West	2.33	2026/27
Supply to Greenway / Tuggeranong	2.81	2026/27
Supply to Canberra CBD S3 & S37	4.98	2028/29
Supply to Gungahlin	5.22	2027/28
Total	**41.44**	

Source: EMCa, from Evoenergy Appendix 1.15 to regulatory submission, table 1

222. The primary drivers of the need for the supply projects is Evoenergy's assumed demand assessment for the respected locations. Evoenergy provided brief descriptions of each project including the perceived need and timing. Information was given on the options that

had been considered to meet the need for the investment. Evoenergy also discussed a selection of the projects during the onsite meeting.

Our assessment

To the extent that we are able to determine for projects at 'feeder' level, Evoenergy's process for determining the need and timing for the proposed projects is reasonable

223. The information provided by Evoenergy demonstrates that it has reasonably justified the need and considered reasonable alternative options for each project, based on its demand forecast. A summary for each supply project and our assessment of the need for the expenditure is provided in Table 4.10 below.

Table 4.10: A summary for each supply project and our views on the need for the expenditure.

Project	Drivers	EMCa assessment summary
Supply to Belconnen Town Centre	This is a delayed 2019-24 RCP project, with delays are attributed to the developer.	*Probable that this project will be undertaken in the next RCP*
Supply to Donaldson St	Expected growth in demand from planned high density redevelopment of a car parking site in Canberra CBD. The construction of two underground cable feeders from Civic Zone Substation to supply new demand associated with the high-density redevelopment of a car parking site situated on the corner of Donaldson Street and Cooyong Street, Canberra CBD.	*Construction is scheduled to commence during the current regulatory period. Project completion and commissioning is targeted for winter 2025. Canberra CBD load forecasting indicates 9.4MVA of new demand coming online between 2023 and 2026.*
Gungahlin Feeder Ties	Required to improve network reliability in the Gungahlin area, reducing STIPS costs and risk cost of a prolonged outage.	*This project will be partially delivered in the current RCP. So likely to continue into the next RCP*
Supply to Kingston	Planned to meet expected demand from high density commercial and residential developments in the Kingston foreshore area and the redevelopment of a former switching station. The sites will be converted into a mix of residential and commercial uses, generating up to 15.9MVA	*Construction is scheduled to commence in 2026/27 and be completed in 2027/28. Slower development timing may move the project schedule.*
Supply to CBD S63	New underground cable feeder to supply a cumulative incremental load increase of approximately 20.4MVA by 2027. Construction is scheduled to commence during the current regulatory period. Project completion and commissioning is targeted for 2024/25.	*The 2024 – 25 commissioning date suggests that this project will have been mostly completed during the current RCP. Not a candidate for Augex deferral.*
Supply to Fyshwick Sec 38	East Lake ZS to Fyshwick Sec 38 New 11kV feeder - increase in load from the planned high-density redevelopment of the Section 38 site on Dairy Road, Fyshwick. Load growth from these developments is forecast to reach 13.3 MVA in 2026, rising to 16 MVA in 2028.	*The need for this project is driven by the planned development's construction commencement date and construction timeframe. Evoenergy has assumed commencement at 2024/25 with load growth forecast to reach 13.3 MVA in 2026.*
Supply to Lyneham-Canberra Racing Club	Civic Zone Substation to Lyneham 11kV feeder providing capacity to supply anticipated load growth in Lyneham area, including from conversion of the existing	*Construction is scheduled to commence in 2026/27. Commissioning planned for 2027/28. Possible adjustment in timing under alternative demand forecasts.*

Project	Drivers	EMCa assessment summary
	Canberra racing club to commercial and residential precincts.	
Supply to Diplomatic Development – Curtin	Proposed underground cable from Woden Zone Substation to support load growth in Curtin. Includes planned development for 32 different embassies, combined with a range of nearby developments.	*Timing of project completion is scheduled for 2027/28. Changes to assumed timing of the developments and the level of associated loads likely to affect the required construction time.*
Supply to Woden Town Centre	Planned extension of an existing feeder supplying Woden Bus Depot combined with construction of a new underground cable feeder from Wanniassa Zone Substation. Supports planned residential developments and a new bus depot at Woden.	*Project commencement 2024/25 and completion 2026/27. The timing of dates could be moved if the developments move sufficiently.*
Supply to Fairbairn South	New 11kV feeder required to meet expected load growth from several commercial developments in the Fairbairn area near Canberra Airport. Full load is expected to come online by 2029.	*Construction is scheduled to commence in 2027/28. Completion and commissioning is planned for 2028/29. Possible for adjustment in timing under alternative demand forecasts.*
Supply to Hume West	Planned new 11kV feeder to meet growing demand from an industrial precinct at Hume, including the New West Industry Park.	*Construction scheduled to commence in 2026/27 with completion in the same year. To defer expenditure from the next RCP the alternative demand assumptions would need to move the requirement back by two years.*
Supply to Greenway / Tuggeranong	New feeder to meet expected new demand from mixed residential and commercial developments	*Construction is due to commence in 2023/24 with completion in 2025/26. Given the advanced timeframe this project does not appear to be a deferral candidate under an alternative demand forecast.*
Supply to Canberra CBD S3 & S37	Proposed new feeder to supply the proposed new University of New South Wales (UNSW) Canberra City Campus. Evoenergy has scheduled construction to commence in 2026/27. Project completion is scheduled for 2028/29	*This is a proposed development, suggesting that timeframes may move. The assumed demand associated with this development may change if the ACT net zero actions include measures to improve the energy footprint of new developments.*
Supply to Gungahlin	New 11kV feeder from the Gold Creek ZS proposed to meet increased 24.4 MVA demand growth attributed to high density residential and commercial development.	*This expected load will be contributing to the constraint issues at the Gold Creek ZS. Construction is scheduled to commence in 2026/27. Possible for adjustment in timing under alternative demand forecasts.*

Source: Drivers summarised from Evoenergy documentation, with needs assessment commentaries added by EMCa.

The AER's lower alternative peak demand forecast is likely to affect the need and timing for some projects, but impacts for specific projects cannot be determined from the information provided

The scale of the difference between the demand forecast applied by Evoenergy and the alternative AER demand forecast would likely have an impact on the need for, and timing of some of the identified projects.

For projects with a current need date towards the end of the next RCP, application of the AER's alternative demand forecast could defer some expenditure out of the next RCP. However, we are unable to determine the impact of the AER's alternative demand forecast at the feeder project level. Such granular analysis would need to be undertaken through network modelling, and detailed assessment of the probability of demand and probable timing of individual developments.

Option selection is reasonably justified

224. The information provided demonstrates that Evoenergy has reasonably considered alternative options for each project. The options considered include grid batteries and, where available, supplying from an alternative zone substation. Whilst it is difficult to fully assess the comprehensiveness of the options considered for individual projects, the available information indicates that Evoenergy has adequately applied its options assessment methodology for each of the proposed projects and the selected option for each project appears to be technically sound.

225. The selected option and project timing of related expenditure is dependent on demand growth assumptions in specific locations. Under alternative demand assumptions the timing of a selected project and the option selected could change.

226. An example of the potential sensitivity of options analysis to changes in the demand forecast can be seen in the Supply to Canberra CBD S3 & S37 project, which we summarise in Table 4.11. However, we also observe that there are only relatively small cost differences between the options.

227. The closeness of the calculated NPV for the options evaluated for this project suggests that changes in input assumptions, such as the energy at risk and timing, could change the selection of the preferred option, corresponding to the highest NPV. However, we also observe that there are only relatively small differences in cost between the options.

Table 4.11: Supply to Canberra CBD S3 & S37 Options assessment

Ref	Option	Cost (millions)	NPV (millions)	Evaluation Summary
0	Utilise existing network infrastructure	$0	$0	Not selected as not technically feasible
1	Grid battery	$5.65	$31.27	Not selected due to lower NPV
2	New 11kV feeder from City East Zone Substation to Sections 3 and 37	$5.24	$31.29	Not selected due to lower NPV
3	**New 11kV feeder from Civic Zone Substation to Sections 3 and 37**	**$4.98**	**$31.49**	**Recommended – Highest NPV technically feasible option**

Source: Information from Evoenergy Appendix 1.15 to regulatory submission, Page 20

4.6 Our assessment of proposed secondary systems expenditure

Evoenergy's proposal

228. Evoenergy has included $7.8m in its proposed Augex for secondary systems. The project breakdown is provided in Table 4.12. The projects listed reflect Evoenergy's bottom-up forecasting method for secondary systems described in its Draft Portfolio Strategy – Secondary Systems Assets.

229. Evoenergy states that the proposed expenditure is similar to its allowance for the current RCP, of $7.2m (in $2023/24).[51]

Table 4.12: Secondary Systems projects - $m, real 2024

Project	Category	TOTAL RCP
20009634 - Automation Systems Lab Development and Integration	Secondary	0.1
20009635 - City East ZSS Station Control	Secondary	0.7
20009636 - Theodore ZSS Station Control	Secondary	0.4
20009637 - Latham ZSS Station Control	Secondary	0.7
20009638 - Wanniassa ZSS Station Control	Secondary	0.7
20009639 - Gilmore ZSS Station Control	Secondary	0.4
20009629 - Vermin Protection for Comm Infrast	Secondary	0.1
20009630 - Fibre UG Kings Av to National Library	Secondary	0.6
20009631 - Fibre UG Canberra Metro Stage 2A Civic to Commonwealth Av	Secondary	0.8
20009632 - Fibre UG Canberra Metro Stage 2B Commonwealth Av to Woden	Secondary	1.1
20009633 - ZSS Cyber Security Gateways	Secondary	0.4
ANTICIPATED - SCADA Communications Upgrade - Others	Secondary	1.4
20008513 - QR Codes for Asset Management	Secondary	0.0
20008881 - Network Monitors Comms Pilot	Secondary	0.1
20009299 - Communications Test Lab	Secondary	0.3
Total		**7.8**

Source: EMCa analysis from Evoenergy capex model,

Our assessment

The proposed expenditure on secondary systems is reasonable

230. Comparison with the project list in Evoenergy's 2022 APR (Table 11) indicates that the proposed $7.78m on 15 projects is considerably less than the $25.74m for the 19 projects listed in the APR for the 2020/25 period. The proposed expenditure is similar to AER's $7.2m allowance for the current regulatory period.

231. The key driver of secondary systems augex in the 2024/29 RCP is the continued investment in zone substation control and the development of its SCADA and Communication Systems. Evoenergy aims to continue its strategy to increase SCADA penetration at the distribution substation level to improve its ability to obtain accurate information for improved management of network load, power quality, and DER penetration on its low voltage

[51] Attachment 1 Capital expenditure, page 47

network. This aligns with the strategies presented in Evoenergy's Annual Planning Report and its Draft Portfolio Strategy for Secondary Systems.

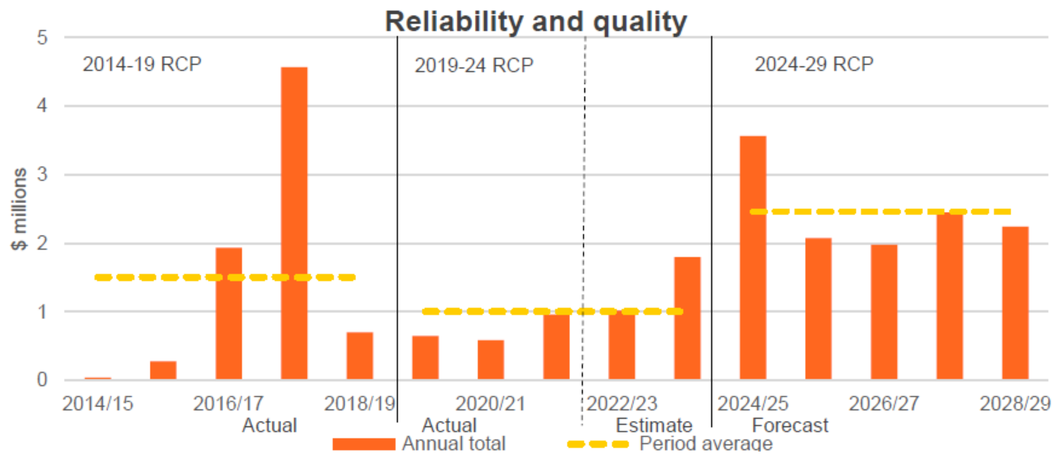
232. The proposed projects indicate the continuation of an established strategy. The proposed expenditure does not appear out of step with historical spend indicated in the APR and appears to be consistent with the established strategic approach.

4.7 Our assessment of proposed reliability and quality expenditure

Evoenergy's proposal

233. Evoenergy proposes $12.31m reliability and quality capex for the 2024 – 29 RCP. This is $5.31m above the regulatory allowance for the 2019 – 24 RCP, as is shown in Figure 4.12.

Figure 4.12: Actual and forecast reliability and quality capex ($m2023/24)



Source: Insert-source-details ,Evoenergy Attachment 1, to regulatory submission, Figure 19, Page 48

234. A list of the proposed reliability and quality projects is provided in Table 4.13.

Table 4.13: Evoenergy proposed reliability and quality projects

Project	TOTAL RCP
20007851 - Power Transformer DGA Devices	0.4
20004380 - UG Feeder Reliability Improvements	2.2
EN24 Intelliruper Reliability Program	0.9
20009871 - QoS Network Augex	1.7
20009872 - Grid scale community battery	2.0
20010493 - Resilience - Covered HV conductor	1.5
20009624 - City East ZSS Voltage Regulation Upgrade	0.3
20009625 - Theodore ZSS Voltage Regulation Upgrade	0.2
20009626 - Wanniassa ZSS Voltage Regulation Upgrade	0.3
20009627 - Latham ZSS Voltage Regulation Upgrade	0.3
20009628 - Gilmore ZSS Voltage Regulation Upgrade	0.2
20007713 - Telopea ZSS Voltage Regulation Upgrade	0.2
20005014 - Distribution Network Monitoring	2.0
Total	**12.3**

Source: EMCa analysis from Evoenergy capex model,

235. Evoenergy describes the need for the increased expenditure as reflecting *'the rapid uptake of DER on our network'*.[52] The inclusion of distribution network monitoring and several zone substation level voltage regulation upgrade projects, reflects Evoenergy's DER penetration concerns. Evoenergy investigations have identified over voltage complaints as one of the dominant drivers of increasing customer complaints.

Our assessment

Other than the grid scale battery, the proposed expenditure is reasonable

236. The proposed projects align with Evoenergy's APR, QoS strategy and onsite discussions however, more information would be needed for specific assessment of each project. For example:

- The proposed $1.53m proposed for the installation of covered HV conductor appears to be reasonable if this is applied to demand driven and not replacement work.
- The proposed feeder reliability improvements expenditure appears to be consistent with Evoenergy's quality of supply (QoS) strategy. The need identified is to maintain unplanned outage performance and price quality (PQ compliance).

237. At a general level, we consider that the modest increase in voltage regulation expenditure that is proposed is a reasonable response to address the impacts of increasing PV exports and EV charging loads, on power quality.

238. However, we consider that the inclusion of expenditure for a grid scale battery is questionable. Whilst the driver is related to the management of increasing DER, there are also linkages with the Net Zero projects and interrelationships with the broader DER initiatives across Evoenergy divisions. We consider that the inclusion of expenditure for a grid scale battery has not been sufficiently supported. This item may also be a duplication of the community battery included in the DER category projects but, even if it's not, we see no reason why the CBA would not result in the same negative result that we identified in section 3.4.4.

52 Appendix 1.13

4.8 Deliverability

Evoenergy's proposal

239. Evoenergy provides information on its capex deliverability approach in Appendix 1.8 to its RP. In summary, Evoenergy's approach relies on:

- Optimising its end-to-end works planning processes;
- Attracting and retaining key staff;
- Flexible sourcing approaches;
- A refined procurement approach;
- Leveraging technology to facilitate delivery efficiency; and
- Effective stakeholder engagement to maintain 'social licence' for its works program.

Our assessment

Evoenergy did not provide compelling evidence that it would be able to scale up its delivery capability sufficiently to be able to deliver its proposed augex program

240. We consider that Evoenergy's deliverability approach contains the appropriate elements for works delivery. However, our discussions with Evoenergy at our onsite meeting exposed the challenges that Evoenergy already faces, and which would be magnified if it needed to scale up its augex program to the level that it has proposed. For example, Evoenergy referred us to the significant challenges that it faces in attracting and retaining both staff and the contractor pool that it requires, given its location and the relatively small size and lack of continuity of its works program, compared with neighbouring DNSPs.

241. We concur with these concerns. Both from review of its deliverability approach documentation and from discussions with Evoenergy at our onsite meeting, we consider that Evoenergy did not provided sufficiently compelling evidence of its ability to implement the suite of changes that would be required to deliver an augex program that, by the end of the next RCP, would be over four times greater than its current annual spend.

A lower augex investment will ameliorate deliverability risks

242. With the lower augex requirement that we have assessed in the current section, Evoenergy's deliverability challenges will clearly be much reduced, though we consider them to be still significant and the projects challenging to complete.

4.9 Our findings and implications for Evoenergy's proposed augex

4.9.1 Summary of our findings

Based largely on our consideration of AER's (lower) alternative peak demand forecast, Evoenergy's proposed augex is overstated

243. After taking into account the lower demand forecasts that AER has asked us to assume, Evoenergy's required augex within the next RCP will be considerably less than it has proposed. The lower demand forecast will allow it to defer to the following RCP the significant amount of expenditure that it proposed in the final years of the regulatory period, some of which was to meet expected further demand growth in the years immediately following.

244. Our assessment of a lower augex requirement is directionally consistent with Evoenergy's own assessment of the impact on its requirements based on a lower peak demand impact

from EV charging. However, our assessment indicates further project deferments based on the still-lower aggregate demand forecast that AER asked us to base our assessment on.

Evoenergy provides sufficient evidence to support its choice of augex options

245. Evoenergy has provided adequate evidence to support its choice of augmentation options for a given peak demand forecast, for regulatory allowance purposes. The processes demonstrated in Evoenergy's documentation give us reasonable confidence that Evoenergy will select appropriate options at the time when it makes investment decisions, and that this will take account of any improvement opportunities that may be available at that time.

The level of augex that Evoenergy has proposed for the next RCP is more than is required to contribute to ACT government's policy of Net Zero by 2045

246. We do not see evidence to support Evoenergy's claim that it requires an increase in augex of the extent that it has proposed, in order to support the ACT government's Net Zero policy. We see little evidence to suggest that Evoenergy has taken account of the opportunities that its proposed DER investment will provide and which, if properly harnessed, can allow it to accommodate the impact of the ACT Net Zero policy without undertaking unnecessary expansion of its distribution network. This includes assumptions that overstate the peak demand impact that EV charging should have, if properly managed, and which we understand are accounted for in AER's alternative peak demand forecast.

A lower level of augex than Evoenergy has proposed should not jeopardise its role beyond the next RCP in supporting the ACT government's Net Zero policy

247. Based on an overstatement of requirements in the Net Zero modelling, which does not calibrate well to Evoenergy's traditional planning assessment, we consider that Evoenergy has overstated the risk of a potential bow wave of expenditure if augex to the level that it has proposed, is not undertaken in the next RCP. Experience of increasing EV uptake, PV uptake and electrification and experience of ways to manage and moderate their respective impacts, will provide a firmer base of knowledge from which Evoenergy will be able to better assess its subsequent requirements in order to provide the necessary network support to the ACT government's Net Zero 2045 target.

4.9.2 Implications of our findings for proposed expenditure

Summary of implications

248. We summarise the implications of our findings as follows:

- We consider it unlikely that Molonglo stage 3, Curtin substation or the early works on Mitchell substation will be required within the next RCP. Consequently, we consider it unlikely that the proposed Woden to Curtin underground cable will be required or the new feeder to supply from Molonglo substation.
- We consider that few, if any, of the proposed Net Zero projects are required within the regulatory period. This includes the Net Zero supply projects (with the probable exception of Canberra CBD feeder 1) and the proposed provisions for distribution substation upgrades and LV circuit upgrades.
- Evoenergy has not adequately justified the proposed allowance for ZS reactive plant.

249. Based on AER's alternative demand forecast, allowance for some remaining (i.e. non-Net Zero driven) supply projects may not be required. However, identifying these would require consideration of specific block loads, feeder loadings and network planning-level consideration of switching opportunities. On balance we consider that it is reasonable to retain this element of the proposed allowance and we have not made such adjustment in our alternative forecast.

250. We consider that the community battery (under power quality and reliability) is not required.

251. We have not proposed adjustment to secondary systems expenditure.

Alternative forecast

252. In Table 4.14 we present our proposed alternative forecast. The categories of expenditure for the proposed alternative forecast align with those of Evoenergy's forecast, which we presented in Table 4.1. We have derived this alternative forecast by making adjustments to specific projects, as described in sections 4.3 to 4.7 and consistent with the bottom-up approach that Evoenergy applied.

Table 4.14: EMCa proposed alternative augex forecast ($m 2023/24)

	2024-25	2025-26	2026-27	2027-28	2028-29	RCP TOTAL ($000)
Demand-driven:						
Evoenergy proposed	22.3	23.3	32.4	39.9	43.7	161.5
EMCa adjustments	-0.6	-2.9	-8.6	-25.2	-38.4	-75.7
EMCa proposed alternative	**21.7**	**20.4**	**23.8**	**14.7**	**5.2**	**85.8**
Secondary systems:						
Evoenergy proposed	1.5	1.5	1.2	1.5	2.1	7.8
EMCa adjustments	0.0	0.0	0.0	0.0	0.0	0.0
EMCa proposed alternative	**1.5**	**1.5**	**1.2**	**1.5**	**2.1**	**7.8**
Power quality and reliability:						
Evoenergy proposed	3.6	2.1	2.0	2.4	2.2	12.3
EMCa adjustments	-2.0	0.0	0.0	0.0	0.0	-2.0
EMCa proposed alternative	**1.6**	**2.1**	**2.0**	**2.4**	**2.2**	**10.3**
Total AUGEX:						
Evoenergy proposed	27.4	26.8	35.5	43.8	48.1	181.6
EMCa adjustments	-2.6	-2.9	-8.6	-25.2	-38.4	-77.7
EMCa proposed alternative	**24.8**	**23.9**	**26.9**	**18.7**	**9.6**	**103.9**

Source: EMCa analysis, derived from information in Evoenergy SCS capex model

253. While this alternative forecast is less than Evoenergy has proposed, it is double Evoenergy's current RCP allowance of $57m, and more than double its forecast spend of $49m in this period.[53]

Deliverability implications

254. While it will be challenging for Evoenergy to deliver the alternative augex program above, and which still represents essentially a doubling of its current program, we do not consider that any further adjustment for deliverability is required.

[53] Evoenergy Attachment 1, Capital expenditure, page 41. We note that Evoenergy's figures for the current period do not include PQ-related expenditure of around $5m.