energy market consulting associates

Ausgrid 2024 to 2029 Regulatory Proposal

REVIEW OF PROPOSED EXPENDITURE ON CER AND FOR ERP SYSTEM

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 Ausgrid 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 Ausgrid. 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 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 Ausgrid's regulatory submission or other documents due to rounding.

Enquiries about this report should be directed to:

Paul Sell

Managing Director
psell@emca.com.au

Prepared by

Mark de Laeter and Paul Sell with input from Eddie Syadan

Date saved

26/09/2023 12:43 PM

Version

Final v4

Energy Market Consulting associates

ABN 75 102 418 020

Sydney Office

L25, 100 Mount Street, North Sydney NSW 2060
PO Box 592, North Sydney NSW 2059
+(61) 2 8923 2599
contact@emca.com.au
www.emca.com.au

Perth Office

Level 1, 2 Mill Street, Perth WA 6000
contact@emca.com.au
www.emca.com.au

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABBREVIATIONS

Term	Definition
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BAU	Business as Usual
BESS	Battery Energy Storage Systems
BTM	Behind-the-meter
CBA	Cost Benefit Analysis
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resources
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelopes
DSC	Dynamic Service Capabilities
EAM	Enterprise Asset Management
EBSS	Efficiency benefit sharing scheme
EMS	Energy Management Systems
ERP	Enterprise Resource Planning
ESB	Energy Security Board
EV	Electric Vehicles
HCM	Hosting Capacity Model
ICT	Information and Communication Technology
IES	Inverter Energy System
LV	Low Voltage
MBS	Metering Business System
MCS	Meter Configuration System
MDM/B	Meter Data Management and Billing
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Meter Identifier
NPV	Net Present Value

Term	Definition
NSP	Network Service Provider
NSW	New South Wales
PQ	Power Quality
PV	Photovoltaic
RCP	Regulatory Control period
RIT-D	Regulatory Investment Test for Distribution
RP	Regulatory Period
STATCOMS	Static Synchronous Compensator
VCR	Values of Customer Reliability
VPP	Voluntary Protection Program

1 INTRODUCTION

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 Ausgrid has proposed to facilitate Consumer Energy Resources and of a specific program within its proposed Non-recurrent ICT expenditure. 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 Ausgrid's revenue requirements for the next RCP.

1.2 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.

Figure 1.1: Scope of work

Requested scope for Ausgrid review 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:

- Ausgrid's capex and opex forecast for:
  - Distributed Energy Resources (DER)/CER; and
  - ICT non-recurrent programs

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.

Scope - Non-recurrent ICT expenditure

The consultant is required to assess and advise on whether the NSW DNSP's forecast expenditure for non-recurrent ICT programs is prudent and efficient, consistent with clauses 6.5.6 and 6.5.7 of the NER. In particular, the consultant is required to provide an alternative forecast in the event that the findings are that the DNSP's forecast is not prudent and efficient.

1.3 Our review approach

1.3.1 Approach overview

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

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

6. In conjunction with AER staff, our review team met with Ausgrid at its offices on 17th April 2023. Ausgrid presented to our team on the scoped topics and we had the opportunity to engage with Ausgrid to consolidate our understanding of its proposal.

7. Ausgrid provided AER with responses to information requests and, where they 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. The limited nature of our review does not extend to advising on all options and alternatives that may be reasonably considered by Ausgrid, 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.

1.3.2 Conformance with NER requirements

10. 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

11. 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) 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.

12. 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

13. 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

14. 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.

15. The Distribution NSPs (DNSP) 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.

1.3.3 Technical review

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

17. We have sought to assess Ausgrid's expenditure proposal based on Ausgrid's analysis and Ausgrid'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 Ausgrid may subsequently provide additional information or a varied proposal, our assessment may differ from the findings presented in the current report.

18. We have been provided with a range of reports, internal documents, responses to information requests and modelling in support of what Ausgrid 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 Ausgrid's regulatory submission documents as provided on its submission date, as the 'source of record' in respect of what we have assessed.

1.4 This report

1.4.1 Report structure

19. The substance of our review is contained in the following sections, which cover respectively our review of Ausgrid's proposed DER integration expenditure and our review of its proposed non-recurrent ICT. 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 Ausgrid has submitted; and
- Our assessment of each of the elements of what Ausgrid has proposed.

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

1.4.2 Information sources

21. We have examined relevant documents that Ausgrid has published and/or provided to 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.

22. Except where specifically noted, this report was prepared based on information provided by AER staff prior to 16th June 2023 and any information provided subsequent to this time may not have been taken into account.

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

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

1.4.3 Presentation of expenditure amounts

25. Expenditure is presented in this report in $2024 real terms, to be consistent with each NSW DNSP's RP unless stated otherwise. In some cases, we have converted to this basis from information provided by the business in other terms.

26. 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 TO OUR CER ASSESSMENT

2.1 Energy transition

2.1.1 Network investments and the transition to renewables and storage

27. 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.

28. 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.

29. 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.

30. 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').

31. 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

32. 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]

33. 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 Ausgrid tends to use CER in its relevant documentation, we refer to CER and DER interchangeably in this document.

2.1.3 CER developments and the regulatory landscape

34. 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

---

[1] Based on AEMO 2019, *Technical Integration of Distributed Energy Resources*, page 10

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

demand. Three horizons were included in the Plan, with phasing in of dynamic operating enveloped (DOE) over 2022-2025 included as a long-term feature of the NEM DER 'ecosystem' among other things.[3] 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

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

36. 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]

37. 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]

38. 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*

[3] ESB 2021, DER Implementation Plan – Three Year Horizon

[4] AEMC 2021, *Rule determination Technical Standards for DER*, page i

[5] AEMO 2023, *Compliance of DER with technical settings,* page 3

[6] AEMC 2021, Rule determination Technical Standards for DER, pages i, ii

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

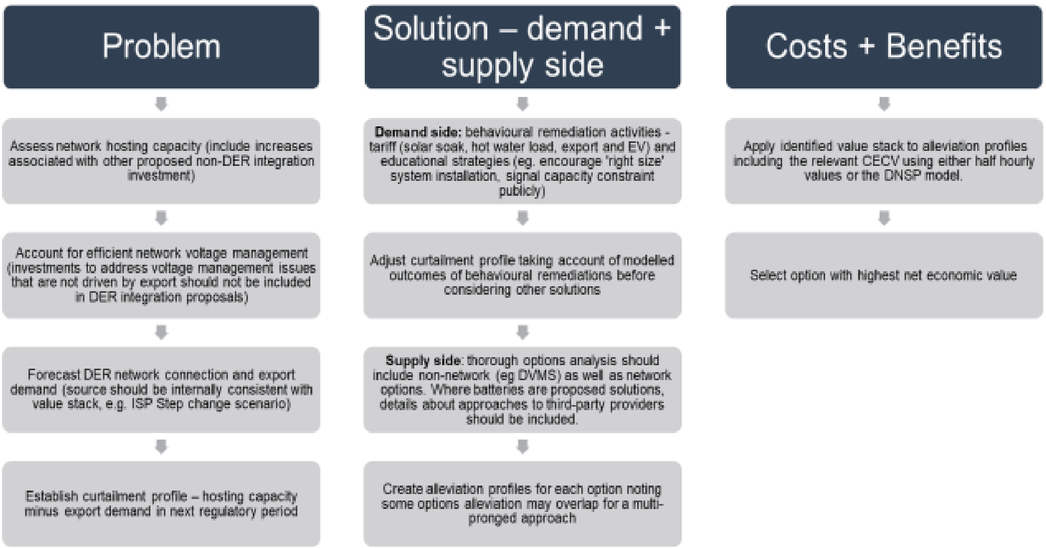
2.2 Our framework for assessing proposed CER-related expenditure

2.2.1 Relevant AER Guidelines

39. 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.'

40. 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

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

42. 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

43. 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.

44. 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

45. 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.

46. 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.

47. 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 CER EXPENDITURE

3.1 What Ausgrid has proposed

3.1.1 Overview and summary of proposed expenditure

48. Ausgrid has proposed CER-related expenditure of $105.2m over the next regulatory period as shown in Table 3.1.[7] This is comprised of:

- Capex of $70m (comprising $47m network capex, $20m ICT non-network capex and $3m ICT SaaS opex); and
- Opex step changes of $24.9m (for smart meter data) and $10.4m (for ICT integration).

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

Description	2025	2026	2027	2028	2029	TOTAL
CER Non-network:						
CER ICT capex	7.0	7.0	2.0	2.0	1.0	**20.0**[8]
CER ICT – SaaS opex	0.0	1.0	0.0	1.0	1.0	**3.0**
Smart meter data (opex step change)	3.6	4.3	5.0	5.6	6.3	**24.9**
ICT for CER integration (opex step change)	0.9	2.1	2.2	2.5	2.6	**10.4**
TOTAL CER - Non network	**11.5**	**14.4**	**9.2**	**11.1**	**10.9**	**58.2**
CER – Network capex	9.5	9.5	9.5	9.5	9.5	**47.3**
TOTAL CER	**21.0**	**23.9**	**18.7**	**20.6**	**20.4**	**105.2**

Source: Ausgrid RP document, Figure 5.1.1, Attachment 5.7 (CER Integration Table 15) and Opex model (attachment 6.1.b)[9]. There are discrepancies between different source of information that Ausgrid provided, though these are not material to our assessment

3.1.2 Ausgrid's proposed CER integration program

49. Ausgrid proposes investment in the following categories to increase its capacity to enable customers to leverage their investments in CER and to deliver net economic benefits:[10]

- Network visibility and modelling uplift;
- Dynamic service capabilities, including dynamic pricing and DOE;
- Connections process improvement (including for improving connections compliance) and customer education regarding CER-related choices;
- Innovation pilots and trials to investigate further alternatives for CER integration;
- Network augmentation using a combination of traditional and newer technologies; and
- Community batteries as an alternative to network augmentation.

7 This total is derived from the sum of the total amounts proposed. However, there are reconciliation discrepancies in Ausgrid's proposal information, and which are likely due to rounding, such that year-by-year amounts add to different totals.

8 We have shown the sum as shown in table 5.9.2 in Ausgrid's RP. We assume that the summation discrepancy is due to rounding

9 Because of reconciliation discrepancies as noted in the footnote above, row and column totals do not reconcile.

10 Ausgrid 2023, Att 5.7 CER Integration Program, pages 4-5

3.1.3 Summary of the drivers for Ausgrid's proposed CER program

Ausgrid forecasts both increasing rooftop solar export curtailment and peak load impacts from electrification of transport and heating

Rooftop solar penetration is forecast to rapidly increase causing network voltages to rise

50. Ausgrid's network currently contains about 250,000 residential rooftop solar installations, or 10% of the connected residential customers.[11] The number of rooftop solar installations is expected to double by 2029 with increasing unit sizes. When rooftop solar systems export power to the local distribution network, network voltages rise. Inverters are (or should be) set to respond to excessive voltage rise in accordance with Australian Standard 4777 by progressively reducing their export to the network and/or trip-off. Ausgrid forecasts 11% of CER installed by the end of 2029 will experience curtailment without intervention.[12] This represents foregone zero emissions energy and depending on the tariff arrangements, lost income for households.

Electrification of transport including the rapid uptake of EVs is expected to dramatically contribute to peak demand if not managed effectively

51. Ausgrid forecasts that 2 million EVs will connect to its network by 2039. Uncoordinated charging of EVs has the potential to increase load at traditional peak times or create new peak loads in local sections of the network. Traditional corrective action would be to increase network augmentation, with the cost passed on to all customers.

Electrification of heating can also drive peak demand

52. Electrification of residential and other heating involves changing heating loads from gas to electricity by converting hot water services, space heating, and cooking. Like EV's, unconstrained heating loads would potentially exacerbate peak loads.

Ausgrid identifies significant challenges with managing the forecast impact of CER on its LV network

Inadequate low voltage visibility

53. Ausgrid, like most other DNSPs, cites poor understanding of the performance of and connections to its LV network as reducing its ability to accurately identify and act on constraints and behind-the-meter (BTM) compliance. Ausgrid advises that the complexity of the dynamic two-way power flows from CER makes it difficult to respond prudently and efficiently to maintain voltage control in particular.[13]

Inadequate connection systems

54. Ausgrid's advises that its '*network connection systems lack the capacity and adaptability to meet future CER connection requests*'[14] with a limit of approx. 45,000 CER connections p.a. without exponential operational investment and only able to manage solar and storage requests. With the forecast rate of increase in CER connections over the next decade, Ausgrid advises that it will not be able to cope without investing in improving capability.

Low levels of compliance of CER BTM to technical standards

55. Ausgrid refers to low levels of compliance of BTM CER to technical standards with increasing difficulty of monitoring compliance:

---

11 Ausgrid 2023, Att 5.7 CER Integration Program, Figure 2 and page 8

12 Ausgrid 2023, Att 5.7 CER Integration Program, page 8

13 Ausgrid 2023, Att 5.7 CER Integration Program, page 26

14 Ausgrid 2023, Att 5.7 CER Integration Program, page 26

As further CER penetration grows in our network, monitoring of compliance against connection agreements will become increasingly important. Particularly once control is taken over by customer agents… and complexity of agreements increases.'[15]

Inadequate pricing and billing system

56. Ausgrid advises that its pricing and billing systems are not equipped to support more dynamic and complex network pricing structures and tariffs which are required to help incentivise customers to modify their behaviour for mutual benefit in managing CER integration.[16]

Customer and stakeholder feedbacks supports investing in CER integration

57. Ausgrid advises that its customers and stakeholders have provided feedback that they are supportive of Ausgrid investing in people, process, and systems to enhance CER integration, and which it has incorporated in developing its CER integration plan. We provide an extract from this in Figure 3.1 below.

Figure 3.1: Extract from stakeholder feedback on CER options

'We have heard through customer engagement that customers have consistently been looking for:

- *Improved access to the benefits of CER for customers, which include;*
    - *A greater choice of lower cost energy options that reduce bills, and*
    - *Zero emissions renewables to realise their net-zero emissions ambitions.*
- *A greater understanding of their role in the energy transition and opportunities to engage with Ausgrid around the choices available to them; and*
- *Rewards for supporting lower network costs and clean energy investments.'*

Source: Ausgrid 2023, Att 5.7 CER Integration Program, p21

3.2 Assessment of Ausgrid's CER problem definition

58. The potential drivers for investments to accommodate increased CER relate to voltage management issues and the ability to host customer exports. These are functions of the network's inherent hosting capacity, assumptions regarding the future increases in CER and other factors that might mitigate the effects of such increases, and the way in which the network is managed to accommodate these. A key outcome from this aspect of the assessment is the extent to which exports may be curtailed as part of such voltage management.

59. In this section we consider the steps Ausgrid has taken to establish its future export curtailment profile, being the hosting capacity[17] less the export demand over time. Of particular focus is the next regulatory period, but as discussed in section 3.4, Ausgrid has conducted a cost-benefit analysis over a 20-year period.

15 Ausgrid 2023, Att 5.7 CER Integration Program, pages 26, 27

16 Ausgrid 2023, Att 5.7 CER Integration Program, pages 27, 28

17 Defined by the AER as *the ability of a power system to accept DER generation without adversely impacting power quality such that the network continues to operate within defined operational limits (without experiencing voltage or thermal violations)*

3.2.1 Ausgrid's CER integration challenges

Ausgrid has a looming CER integration challenge but not currently at the same level as some peers due to relatively low CER penetration in its network

60. The information provided by Ausgrid overall in its CER Integration Program document echoes the issues that are recognised and increasingly manifesting throughout the NEM and NSW.

61. Ausgrid's rooftop solar penetration is significantly less than its peers at 10% - other NSW DNSPs report approximately 25% rooftop solar coverage. This difference is not surprising given '*38% of Ausgrid's customers live in apartment blocks with limited access to useable rooftop space for adoption of rooftop solar.*'[18]

62. As discussed in section 2.2.4, Ausgrid has an ongoing Power Quality program to reactively respond to customer complaints. CER-driven overvoltage correction averaged $1.1m over the FY18-FY22 period, with the FY22 spend the highest of the period at $1.6m. The quantum of expenditure is again indicative of the relatively low penetration of rooftop solar and EVs within its network and perhaps of increasing CER-driven issues.[19]

63. With forecast increases in CER penetration, it is likely that Ausgrid will eventually experience the level of DER-driven overvoltage constraints that other DNSPs are experiencing, but not for 5-7 years.

64. In our view, these changes mean Ausgrid needs to prudently adapt its services to better suit customers' needs, wants and address additional compliance requirements. The orientation we take into our assessment is that Ausgrid needs to prepare for looming CER issues rather than immediate issues.

65. We have used the AER's process (per the figure above) as the basis for our assessment of Ausgrid's proposed CER integration investment.

3.2.2 Overview of Ausgrid's CER integration model

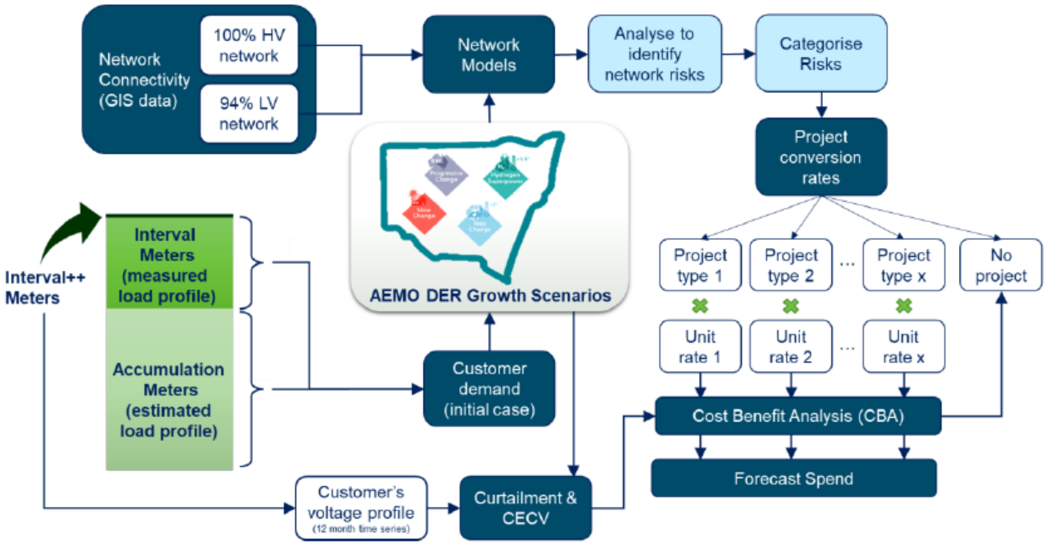
66. The figure below illustrates Ausgrid's process of, firstly, determining the curtailment and then determining the means of alleviation of curtailment via a cost benefit analysis of its identified options.

67. In this section we focus on assessment of the suitability of the model in determining the curtailment energy (base case and scenarios), focusing on the inputs and the development of the network model. In section 3.3 we consider the Options (solutions) modelling and the proposed hierarchy of solutions derived from Ausgrid's cost-benefit analyses.

[18] Ausgrid 2023, Att 5.7 CER Integration Program, pages 7

[19] FY2023 data was not available

Figure 3.2: Ausgrid's CER integration modelling process



Source: Ausgrid 2023, Att 5.7 CER Integration program, Figure 7

3.2.3 Derivation of hosting capacity

Ausgrid's hosting capacity modelling methodology is sound

68. Ausgrid has provided a detailed description of its forecasting approach and modelling methodology in Appendix B of its CER Integration Program. Conceptually Ausgrid's model follows three steps:

- Model the CER impacts on the network by incorporating technology load models and technology uptake models, and then
- Determine the hosting capacity prior to any interventions beyond BAU by assessing the voltage and load constraints from load flow analysis, and then
- Quantify the curtailment over time from the forecast hosting capacity constraints.

69. Ausgrid's CER hosting capacity model incorporates the same network electrical models used for its BAU purposes, which include HV and LV networks for each zone substation.[20] The model identifies the network response to the adoption of CER technologies by considering the incremental effect from each connection and simulating the network for various load and CER uptake scenarios. For the purposes of modelling, Ausgrid classifies each customer as being one of seven customer strata based on their consumption (e.g. apartment, small residential, large business).

70. Ausgrid's CER integration model is designed to identify the probable extremes of network conditions within the distribution network connected to a zone substation – *'[i]n a model run the network behaviour in each zone is simulated at three moments only each model year—the times the zone substation has historically experienced its annual maximum, minimum, and daytime minimum total load. These times are chosen as they are likely to be the times of maximum and minimum voltages on most connections in the zone.'*[21]

71. A curtailed energy profile, giving the energy curtailed on every interval in a year is calculated for each zone for the years 2024, 2029, 2034 and 2039. Estimates of energy lost to curtailment in intervening years are derived by Ausgrid by interpolation.

72. Based on the information provided, we consider the simulation tool to be adequate for the purposes of supporting the CER integration business case. It provides an approximate picture of network response to CER and the alleviation profiles of the interventions.

20 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 6

21 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 6

3.2.4 Other modelling assumptions

Existing and proposed tariffs

73. Ausgrid's base case scenario assumes CER integration is addressed with its current static network settings and capabilities including;

- The 'solar soak' controlled load tariff, which is a modified version of the existing OP1 tariff, reducing the price of electricity in the middle of the day; in Ausgrid's model '*it is assumed that half of current OP1 customers would adopt the new tariff when introduced. Remaining customers will transition gradually as ripple and time clocks are replaced with smart meters, and retailers respond to the new opportunities.*'[22]
- Off-peak hot water (controlled load via smart meters).

CER uptake forecasts

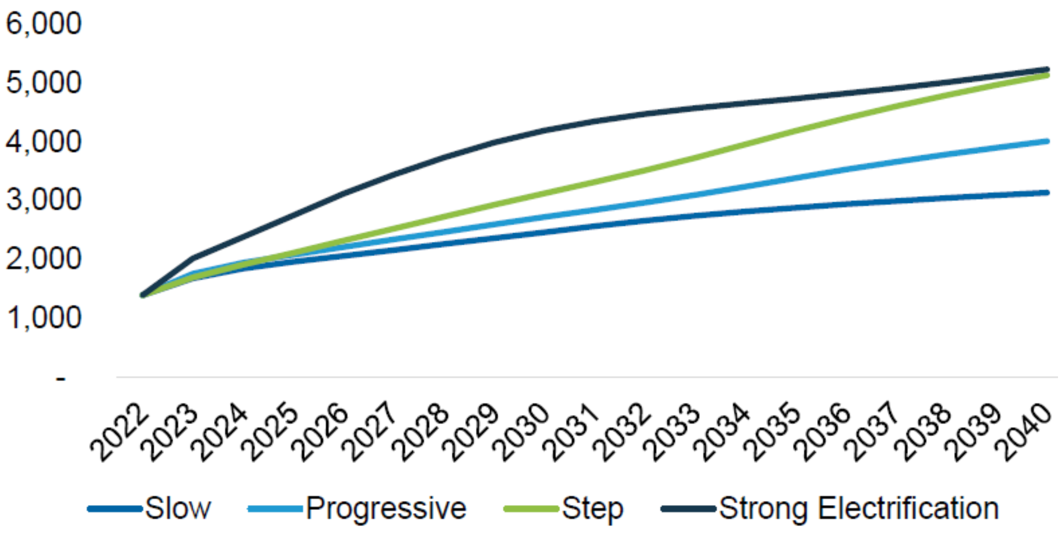
74. Ausgrid has applied the ISP Step Change Scenario to forecast DER penetration for PV, EV, and Batteries through to 2040 with *'inputs from internal and commissioned studies to translate these to locational differences within the Ausgrid service area.'*[23] Use of the ISP Step Change Scenario is consistent with the AER's DER Integration Guideline.

Rooftop solar and batteries forecast uptake

75. Ausgrid's model examines the uptake of rooftop solar installations both with and without batteries. The effects of tariffs are considered against different models of customer charging behaviour.

76. Ausgrid's forecast rooftop solar capacity and battery capacity are shown in the figures below which align with *'AEMO's projections for NSW* (d*ownscaled to Ausgrid's network, based on Ausgrid representing 32% of installed NSW capacity).*'[24]

Figure 3.3: Ausgrid's forecast rooftop solar capacity (MW)



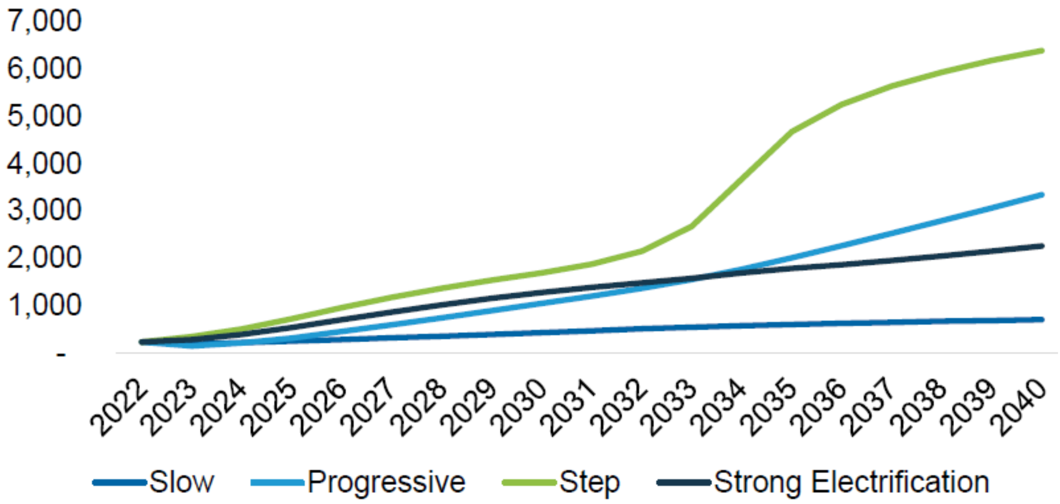
Source: Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 2

22 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 1

23 Ausgrid 2023, Att 5.7 CER Integration Program, page 14

24 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 2

Figure 3.4: Ausgrid's forecast battery capacity (MWh)

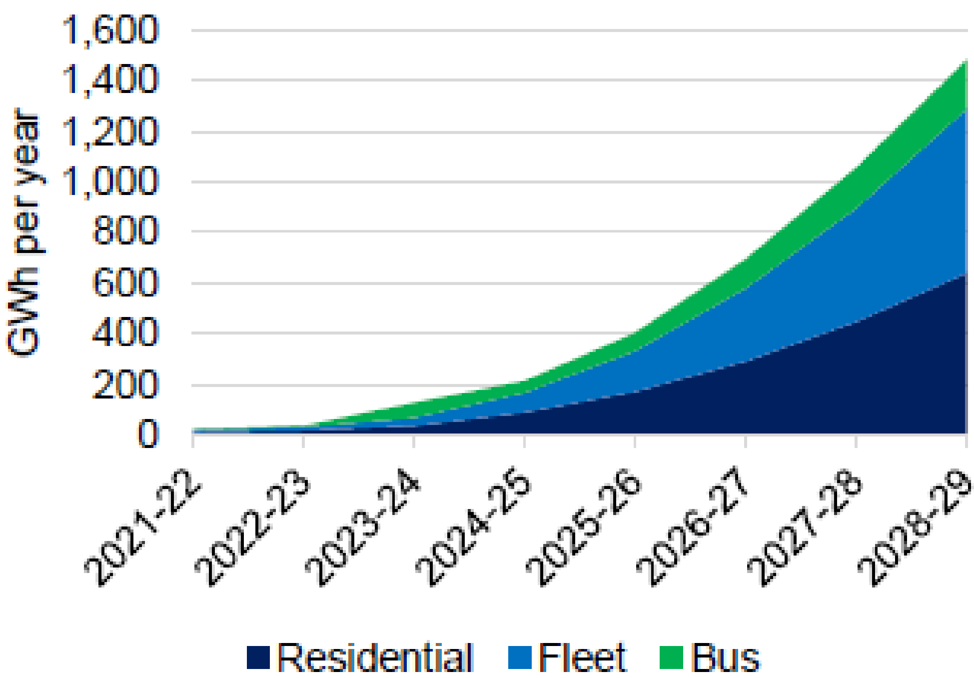


Source: Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 3

Electric vehicle charging behaviour and forecast uptake

77. EV uptake for Ausgrid is derived from the scenario projections in AEMO's 2022 ISP for NSW based on: 2021-25: 70% of NSW; 2026-30: 60% of NSW; 2031-40: 46% of NSW. The result through to FY29 is shown in the figure below.

Figure 3.5: Ausgrid's forecast EV consumption



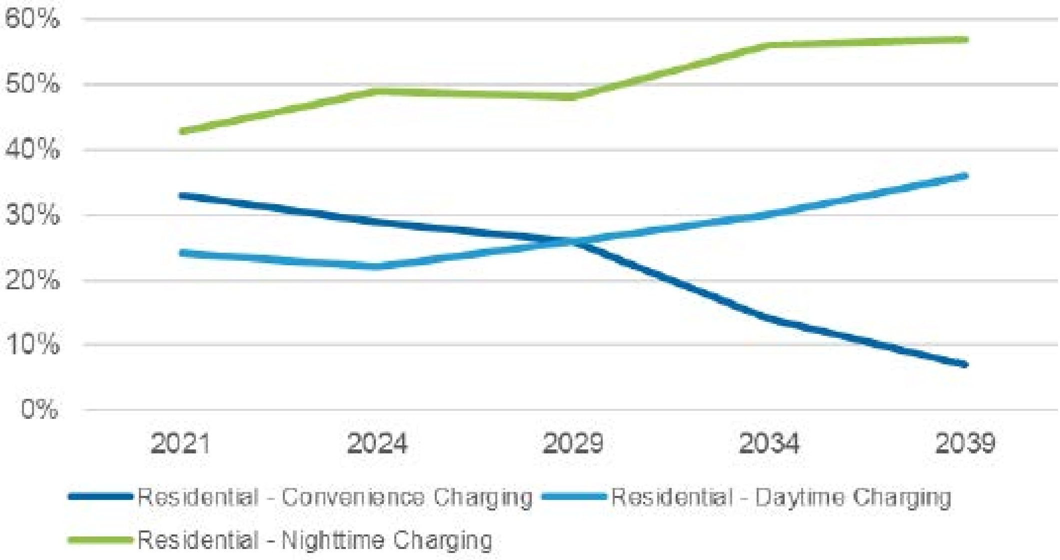
Source: Ausgrid 2023, Att 5.7 CER Integration Program, page 9

Ausgrid's CER and non-CER behaviour and load profile inputs are reasonable

78. The models consider 3 charging patterns, associated with possible tariff settings as shown in the figure below. Ausgrid based its modelled EV charging behaviour on its 'Charge Together' project, with the change over time depicted in the figure below. Assumptions about the magnitude of EV charging loads are based on AEMO forecasts for the number of EVs and the average contribution of an EV to peak load. Base peak load (before applying

EV loads) on a LV distributor is taken to be its maximum historically observed load. AEMO's standard charging profiles per vehicle type were applied.[25]

Figure 3.6: Ausgrid's forecast EV charging behaviour



Source: Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 4

Ausgrid's approach to applying the CER forecasts at the customer level is fit for purpose

79. Ausgrid's hosting capacity model combines the uptake rate and the load model for each technology, selecting '*random samples of existing connections as technology adopters and examine the effects of their loads on the network. Multiple simulations are conducted with different* NMI *allocations to understand the possible range of variation'*.[26] The randomised aspects of the CER types are:

- Location of new rooftop solar;
- EV charger sizes (3), location, charge profile (tariff response);
- Battery location and tariff response; and
- % solar soak volume (new tariff).

80. Elsewhere in Ausgrid's documentation it advises that its model examines clustering of EVs due to household income (i.e. higher amongst higher income households) and clustering due to 'neighbourhood effects' (EV uptake will be greater in neighbourhoods that have also adopted other CER technologies).[27] Both of these 'scenarios' are reasonable – probably more realistic than the randomised locational allocation described in the preceding paragraph.

81. We assume that all three approaches were run through the model and that this will help identify areas where focussed efforts on managing network constraints as EV penetration levels build toward the latter part of the next RCP.

25 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 5

26 Ausgrid 2023, Att 5.7 CER Integration Program, page 15

27 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, pages 10-11

Voltage-related assumptions

Ausgrid has undertaken steps towards efficient voltage management in the current RCP

82. Ausgrid's current capabilities for voltage regulation include '…*Distribution substation tap changes, LV phase balancing, LV DC, LV distributor augmentation, upgrades, HV feeder augmentation and voltage regulation changes of a variety of scale as justified.*'[28]

83. Ausgrid is also completing or extending network management and control enhancement projects in the current period, including 'advanced LV voltage regulation' pilots, distribution automation schemes, VPP trials, community batteries and STATCOMS.[29]

84. As discussed in section 2.2.4, Ausgrid has a Power Quality Compliance capital program which responds reactively to customer PQ complaints, mainly addressing over voltages linked to CER integration issues by implementing traditional supply-side solutions.

Ausgrid's voltage constraint settings appear to be too conservative leading to overestimating solar curtailment

85. Ausgrid models the energy in kWh that could potentially be generated by a rooftop solar installation in 30 minute intervals as:

    0.5hr x 6.6kW x *f*

    - Where, 0.5 corrects for 30-minute intervals; 6.6kW is the average capacity of rooftop solar installations, and '*f is an environmental factor depending on the interval, to represent the proportion of total capacity achievable given the time of day and the season.*'[30]

86. Ausgrid further advises that the curtailment models assume '*that all inverters installed before 2022 operate according to the 2015 standard, and all inverters installed thereafter operate according to the 2020 standard.*'[31]

87. Ausgrid has set the voltage threshold for calculating solar export energy curtailment due to overvoltage at 250V.[32] This is lower than the default of 253V volt-watt setting under AS 4777.2:2020, noting that at:[33]

    - 253V: volt-watt responses initiate and ramp down output (kW) with increasing voltages through to 265V;
    - 258V: trips the inverter if the 258V is sustained on average for 10 minutes;
    - 260V: trips the inverter if 260V is sustained for more than 1 second; and
    - 265V or more: instantaneous inverter trip.

88. AS 4777.2:2020 applies to solar inverters installed from December 2021. Prior to that inverters were required to comply with AS4777.2:2015 for which 255V was the default setting for the 10-minute average trip[34] with the other two higher voltage settings the same as for the 2020 standard.

89. We asked Ausgrid to explain the rationale for its 250V threshold. Its response was that modelling a 250V limit on the Ausgrid mains is equivalent to modelling a 253V limit at the inverter/switchboard.[35]

90. We do not agree with Ausgrid's explanation, noting that AS3000 specifies that voltage rise within an installation must not exceed 2%. We consider that 253V is a conservative trigger

[28] Ausgrid 2023, Att 5.7 CER Integration Program, page 14

[29] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix C, page 2

[30] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, page 13

[31] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix B, pages 12-13

[32] Ausgrid – IR032 – CER Integration Program – 20230609 – Confidential, page 2

[33] Also, at 240V, var absorption commences, which assists with reducing local voltage rise)

[34] The selectable range was 244V – 258V

[35] Ausgrid – IR017 – Part C – CER (consolidated) – 202330516 - Public

for assuming curtailment for inverters installed under AS 4777.2:2020 given the volt-var and volt-watt settings described above. This would have the effect over over-estimating the extent of curtailment. We consider 258V is a more appropriate setting to be used for curtailment modelling purposes for inverters that are required to be compliant with AS4777.2:2020.

Ausgrid's approach to load flow simulation to determine the forecast BAU curtailment energy is reasonable

91. New PVs, EVs and batteries within each year of the HCM are allocated '*to customers according to the Ausgrid LV Network forecast scenarios*.'[36] Based on the description of the allocation approach, Ausgrid follows an acceptable approach but we consider that it could be improved somewhat by allocating EVs in accordance with higher income areas, at least for the next decade to give a more likely geographical concentration of the uptake.

92. Ausgrid's Simulation Tool runs load flow simulations for each customer based on its LV network model and the DER scenario builder as illustrated in the figure below. Load and voltage profiles are analysed to measure constraints arising from either voltage excursion above or below prescribed limits or line or transformer capacity overloads.

Ausgrid's forecast curtailment profile and number of customers curtailed

Ausgrid's assumptions of curtailed energy is likely to be overstated

93. Ausgrid's Base Case (or BAU) scenario was developed with inputs as described above, with no intervention actions. As shown in the figure below, Ausgrid's forecast modelled curtailment energy profile builds relatively slowly from FY25 to FY34, noting that: [37]

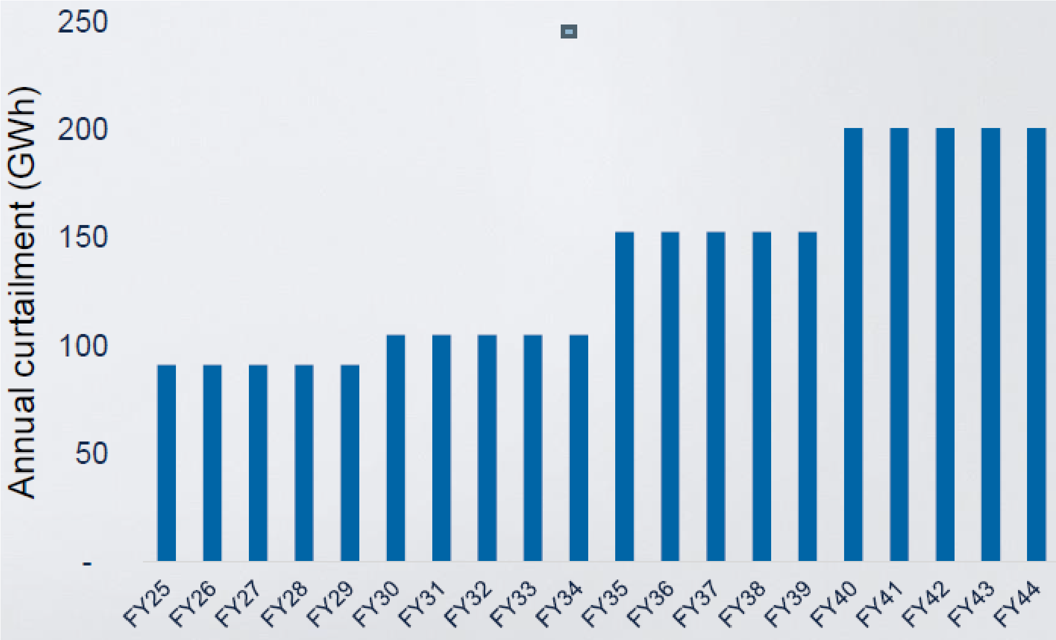
- Only four years are modelled: FY25, FY29, FY34, and FY39, with the intervening results interpolated;
- By the end of the next RCP, the curtailment energy is expected to be 93GWhr from 81GWh in FY24 (+15%); and
- The forecast increase in curtailment energy from FY29 to FY34 and from FY34 to FY39 is a more substantial 46% and 32%, respectively.

94. In our view, the curtailed energy is likely to be somewhat overstated due to the conservative AS4777 inverter settings and AS61000 steady state overvoltage setting that Ausgrid has adopted in its modelling.

[36] Ausgrid 2023, Att 5.7 CER Integration Program, page 22

[37] Ausgrid, IR008 response – Ausgrid – IR008 – CER integration program – 20230404 – public, question 3

Figure 3.7: Annual curtailment energy forecast for Step Change Scenario without intervention

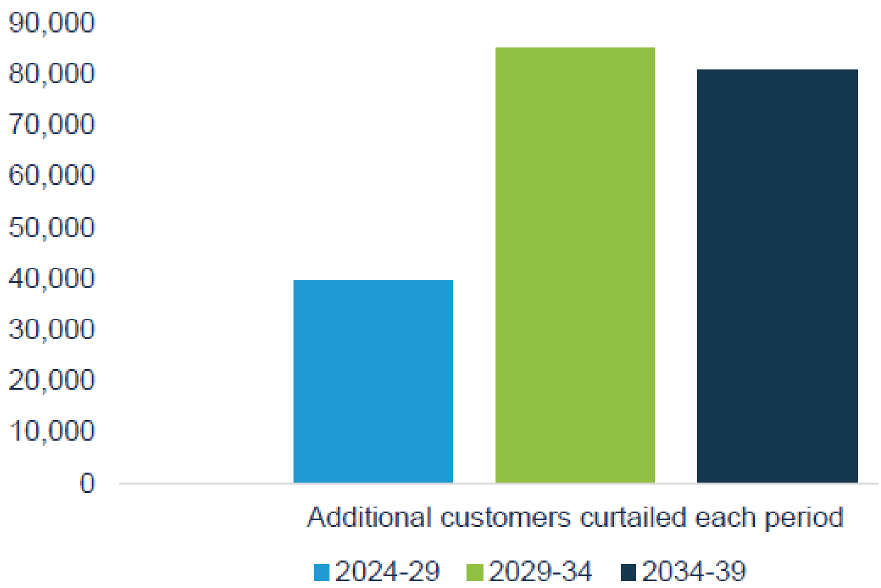


Source: Ausgrid, On-site presentation, slide 37

2% of Ausgrid's customers are expected to experience curtailment in the next RCP

95. The figure below shows the results of Ausgrid's modelling in terms of the additional number of customers expected to be curtailed under the ISP Step Change Scenario. As an indication of the impact, 40k customers represents about 2% of Ausgrid's customer base[38] and about 11% of Ausgrid's forecast rooftop solar customers.[39]

Figure 3.8: Ausgrid's estimation of the number of customers experiencing curtailment (ISP Step Change Scenario) without further intervention



Source: Ausgrid 2023, Att 5.7 CER Integration Program, Figure 9

[38] Assuming approximately 2m customers by 2029

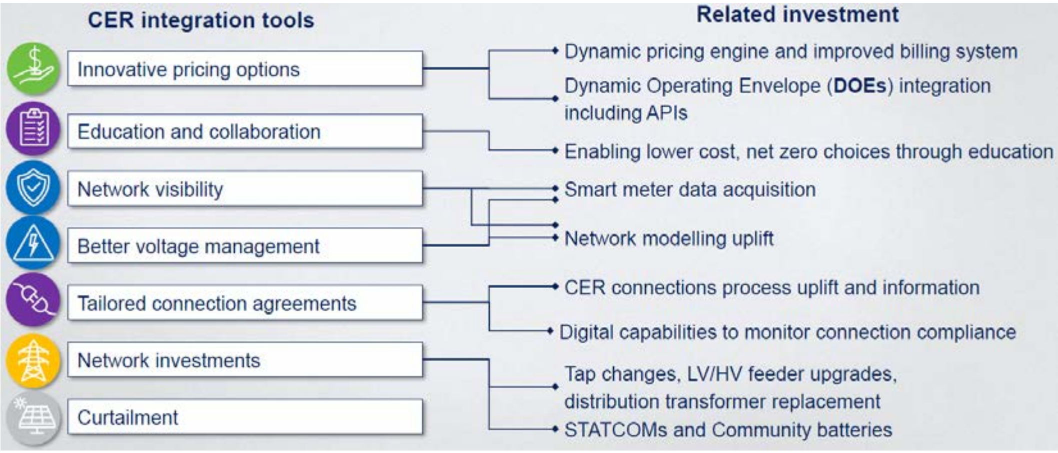
[39] Assuming approximately 450,000 PV customers by 2029

3.3 Assessment of Ausgrid's proposed solutions

3.3.1 Overview of proposed solutions

96. Ausgrid has identified seven solutions for deployment in the next RCP, as shown in the figure below. We discuss the solutions and the costs and benefits attributed to them in this section after first considering the DER-related investments Ausgrid has made or is making in the current RCP.

Figure 3.9: Ausgrid CER Integration plan



Source: Ausgrid, On-site presentation, slide 49

3.3.2 Proposed options

97. An outline of each option is provided below, with our assessment of the solutions which are included in the various options included in this section. Our assessment of Ausgrid's cost benefit analysis (CBA) is discussed in section 2.2.5.

Option 1 is the base Case and addresses CER with current capabilities only

98. Option 1 includes only traditional network augmentation as its investment activity in the next RCP. Assumptions and inputs include:[40]

- *Implementation of Ausgrid's 2024-29 TSS, specifically opt-in export pricing tariffs for small customers, changes to switching times for controlled load devices and peak charging windows as outlined Ausgrid's 2024-29 TSS compliance paper.*
- *Timings are based on the years that related market changes are forecast to occur...*
- *Historical costing accurately informs investment types and volumes specific to network constraints identified because of network modelling; and*
- *All investments will occur in the 2024-29 period.*

Option 2 is referred to by Ausgrid as 'preparatory investment'

99. Option 2 incorporates three investment activities:

- Traditional augmentation;
- Network visibility and modelling uplift; and
- CER connection process uplift and compliance.

[40] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, page 15

100. Assumptions and inputs for Option 2 are as for Option 1 with one addition: *ICT investments will leverage our Big Insights Platform data and analytics, as well as integration capabilities to drive economies of scale and re-use.'*[41]

Option 3 is the preferred option and is referred to be Ausgrid as 'proactive investment'

101. Option 3 incorporates five investment activities:

- Network visibility and modelling uplift;
- CER connection process uplift and compliance;
- Dynamic service capabilities (incorporating billing, dynamic pricing, and integration of VPP/DOE platforms);
- Traditional network augmentation and STATCOMs; and
- Community batteries.

102. Assumptions and inputs for Option 3 are as for Option 2 plus *'[t]he Billing and Pricing initiative will occur in alignment and considering delivery risk and interdependencies with the Meter Data Management and Billing (MDM/B) program.'*[42]

3.3.3 Ausgrid's Network Innovation Program

103. Three CER-related Network Innovation Program projects support the CER integration program:[43]

- CER and Net Zero - trialling of new, untested technology;
- Intelligent devices – developing and testing new field assets; and
- Intelligent systems - Developing technology and capability to better plan, maintain and operate the network.

104. The $20.9m cost and benefits are incorporated into Ausgrid's CBA, but the cost is not included in Ausgrid's CER integration program expenditure.

105. EMCa has not reviewed the Network Innovation Program as it is excluded from our scope of work.

3.3.4 CER-related investments in the current RCP

Investments in CER-related power quality (PQ) impacts

106. Ausgrid has an established a Power Quality Compliance capital program to reactively address power quality complaints where network non-compliance to AS61000.3.100 and Network Standard 238 (supply quality) is the issue. Ausgrid advise that *'[in] recent years most of these reactive investments have targeted addressing overvoltage complaints and as such are aligned to CER integration*.'[44]

107. Ausgrid's proposed CER integration program should offset the major proportion of the reactive PQ program if investment is directed to the network zones with the more acute constraints.

Project Edith is trialling 'DSO capabilities', otherwise referred to as Dynamic Service Capabilities

108. Project Edith is primarily an '*ICT based demonstration of dynamic network services including dynamic pricing and DOEs on a pilot scale*…'[45] to '…*signal the availability of*

---

[41] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, page 17

[42] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, page 20

[43] Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, page 16

[44] Ausgrid 2023, Att 5.7 CER Integration Program, page 29

[45] Ausgrid 2023, Att 5.7 CER Integration Program, page 19

unused network capacity to CER and manage local constraints.'[46] Dynamic pricing is seen by Ausgrid as a more efficient signal of network capacity than DOEs, with the possibility of DOEs being used as a backstop. Ausgrid's dynamic pricing is intended to be offered as an opt-in tariff and anticipate that customer agents will offer dynamic pricing products to customers.

109. Given the importance of Project Edith in trialling solutions for the next RCP, we asked Ausgrid for a description of the status of the project. In summary, Ausgrid advised that:

- The 'demonstration phase' was successful enough to warrant transitioning to an 'expansion phase';
- The expansion phase is planned to operate until June 2024 and its primary objective is to include more customer agents and thereby reach 500-1000 customers to help validate pricing and DOE algorithms and customer responses; and
- It intends to continue operating the project into the next RCP, growing customer participation and working with industry to support dynamic pricing.

CER integration-related pilots and trials are valuable in informing the investment in the next RCP and proposed pricing structures (via tariff reform) should help with network utilisation

110. Ausgrid advise that throughout the current RCP it will build CER-related capabilities, including by:[47]

- Implementing an ADMS, advanced LV voltage regulation pilots, distribution automation pilots, VPP trials, community batteries, and distribution monitoring and control;
- Increasing network visibility; and
- Developing/testing tariff reform (including dynamic pricing), innovative network and non-network solutions, and flexible load offerings.

111. Whilst not all the CER-related work in the current RCP has been completed, we consider that Ausgrid's pilots, trials can inform the scope, cost, and timing of the CER integration options identified for the next RCP. We note also that Ausgrid references collaboration with industry/DNSPs regarding similar programs underway in the NEM and other jurisdictions[48] which should also help shape its approaches.

112. Ausgrid has provided a summary of its proposed pricing structures and positions them as an enabling capability in its CER Integration Program document.[49] Whilst it is beyond our scope of work to assess Ausgrid's TSS for 2024-29, we consider that cost- and time-reflective tariffs[50] have the potential to support the integration of CER whilst also reducing the need for network investment through managing demand by constructively influencing customer behaviour.

113. Therefore, by extension we consider that the proposed expansion of Project Edith, including the requisite capabilities required to enable development of dynamic pricing, has merit as long as the associated costs are efficient. To this end:

- A 'staged' (or gated approval) approach to pilots/trials in which further expenditure is conditional on the success of the previous stage is appropriate - Ausgrid appears to be following this development path, as discussed further below; and
- Transitioning to full dynamic service capability from pilots/trials should be matched with benefits realisation – as discussed below, we have some concerns with the assumptions underpinning Ausgrid's benefits forecast.

---

46 IR008 – Ausgrid response – CER integration program – 20230404 – Public _final, Annexure 1.2, question 5

47 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix C, page 2

48 AEMO Project Edge, Western Power Project Symphony, Evoenergy Project Converge; DEIP 2022, DER Market Integration Trials Summary Report

49 Ausgrid 2023, Att 5.7 CER Integration Program, pages 25-27

50 Export pricing for small customers, utility scale storage tariffs, controlled load, charging window changes

3.3.5 Innovative Pricing Options (aka Dynamic service capabilities)

The proposed dynamic service capabilities require an interim billing engine to enable basic dynamic pricing capability

114. Ausgrid plans to spend $12.1m on establishing dynamic services capabilities in the next RCP, building off Project Edith to manage and incentivise two-way power flows, solving network constraints due to static limits. In summary, the initiative comprises:[51]

- Dynamic pricing and DOEs (incorporating pricing engine and aggregator APIs[52]) to be developed from FY26 to FY29 which:
  - enables dynamic pricing capability to be added to its billing system to unlock the value of price responsive CER in its network[53]
  - develops VPP/DOE platforms and integrates these with ADMS to support control systems to dynamically manage the network
  - enables standardised and interoperable APIs for DOEs and streamlining coordination with aggregators; and
- Upgrading the current billing engine over the period FY24-FY25 to be able to offer basic dynamic network pricing capability as an interim step to the proposed new Meter Data Management and Billing system (MDM/B) scheduled to be operational by FY27.

115. The MDM/B is part of the proposed ICT ERP Program and the cost and benefit is included in that Program, as discussed in Section 4 of this report. Ausgrid advise that the initial investment in upgrading its billing system will *'…support tariff demonstrations, dynamic pricing capability to bill retailers for these innovative tariff structures prior to Ausgrid's 2024-29 ERP upgrade.'*

Ausgrid's assumed take-up rate of DOE appears to start too early

116. Ausgrid's assumed DOE adoption rate is assumed to be from near zero in FY25 to about 9% in FY29, rising exponentially through to about 68% by FY44.[54] This assumption is based on expected Project Edith outcomes, but even Ausgrid's relatively low uptake rate in the early years of the next RCP appears to be inconsistent with the development of the 'dynamic service capability platform' which is required to deliver 'basic' dynamic pricing and DOE capability and which is not scheduled to be completed until FY26 at the earliest, with ongoing development through to FY29.

The cost estimating approach is fit-for-purpose at this stage of the project development lifecycle

117. Ausgrid advise that it has benchmarked costs against peers, coordinated with software vendors and incorporated consultants' independent cost benchmarks to establish its cost estimates. We consider this approach to be acceptable.

The development of dynamic service capabilities in the next RCP through pilots/trials is likely to be prudent despite the uncertainty of future benefit streams

118. The impact of dynamic service capability on alleviating CER curtailment will be relatively small in the next RCP, aligning with our view that much of Ausgrid's CER integration work in the next RCP is preparing for the likelihood of higher CER penetration levels in the following decade. Ausgrid assumes further market efficiency-based wholesale market arbitrage-

---

51 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, pages 19-20

52 Enables streamlining coordination with aggregators

53 Upgrades to the billing system are within the scope of this initiative; they support tariff demonstrations, dynamic pricing capability to bill retailers for the innovative tariff structures prior to Ausgrid's proposed 2024-29 ERP upgrade

54 Ausgrid – IR032 – Att A. CBA total program V1.2 – 20230609 – Confidential, Dynamic Services Capabilities worksheet

based benefits accruing to VPP participants and EV owners, however these too are forecast to become significant only late in the decade following the next RCP. Further, in worksheet 'Dynamic Services Capabilities' of the CBA in row 82, Ausgrid assumes that the '*incremental benefits unlocked from dynamic pricing* are 10%', however it does not provide evidence to support this assumption.

119. On this basis, we considered whether the proposed 'interim' upgrade to Ausgrid's existing billing system is warranted ahead of the planned full MDM/B upgrade to be delivered by FY27 as part of the separate ERP upgrade ICT project. As discussed in section 4, we recognise the need to upgrade the MDM/B in the next RCP, due primarily to technical obsolescence.

120. Ausgrid proposes spending $7.5m across FY24 and FY25 to *'improve existing billing and pricing systems to implement Project Edith and increasingly sophisticated and innovative trial tariffs in the FY25-29 period that benefit our customers*.'[55] It is not clear what proportion of the proposed $12.1m to deliver dynamic service capabilities in the next RCP is required to complete the billing system upgrade, but we assume that the upgrade would not be compatible with the planned cloud-based replacement for the current MDM/B. We note that without the billing system upgrade, development of dynamic pricing and DOEs via various phases of Project Edith would likely stall.

121. We consider dynamic pricing is likely to be an important component of CER orchestration, which is a means of minimising total CER integration costs and maximising benefits. Ausgrid's Project Edith, along with other trials across Australia,[56] is ongoing and whilst the benefits remain speculative at this time, investment in progressing dynamic service capability as envisioned by Ausgrid is likely to be prudent. Therefore, unless Ausgrid can cost effectively bring forward the investment in the new MDM/B to avoid the need for the proposed $7.5m investment in the 'interim' billing system upgrade, we consider the latter to be a reasonable step.

3.3.6 Network visibility and modelling uplift

The network visibility and modelling uplift initiative is reasonably positioned as an enabling capability for other DER projects

122. The initiative seeks to overcome the limitations described in section 3.1.3 by increased smart meter data acquisition and improved modelling. Ausgrid's premise is that leveraging network and customer data (including from smart meters) to help it pinpoint constraints on the network, will help ensure our solutions are as targeted as possible improved planning accuracy directed towards identifying and alleviating localised constraints/curtailment and manage network assets for controlling min and max loads more effectively.

123. The modelling uplift component of the initiative is planned to be completed from FY25 to FY26 inclusive with the data purchase spanning each year of the next period (stopping in FY29).[57, 58] We discuss the lack of recognition of costs beyond FY29 in our assessment of Ausgrid's cost-benefit analysis model in Section 3.4

124. Ausgrid presents a reasonable case for investing in some level of improved LV network visibility as a key to extracting benefits from the other initiatives.

125. We consider it prudent that Ausgrid invests in improved visibility of its LV network, and we support a prudent level of investment in upgrading its analytical capability.

---

55 IR008 response – Ausgrid – AGD IR008 – CER integration program – 20230404 – Public, page 1

56 Including for example, Project Symphony in Western Australia

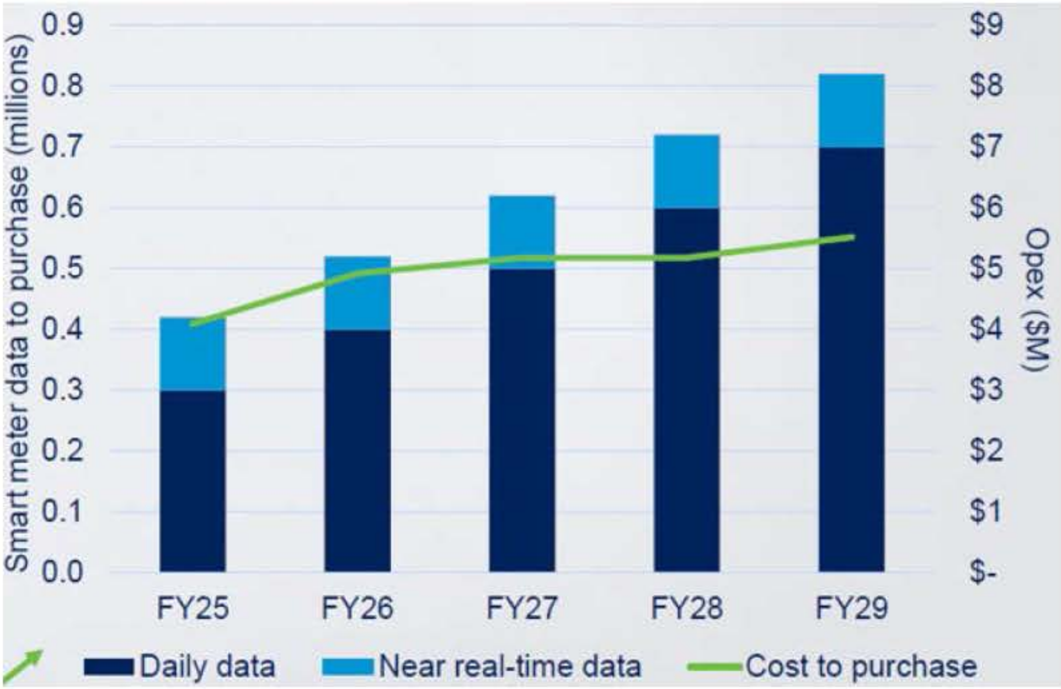
57 Ausgrid 2023, Att 5.7 CER Integration Program, page 32

58 In response to an Information Request, Ausgrid advised that '*The smart meter data purchased to 2029 will be used to improve the efficiency of capex and opex expenditure over that period (decisions which can only be made with the data available at the time). Ausgrid is planning on continuing investment in smart meter data beyond 2029 which will enable further use cases and benefits beyond what we have currently modelled*' *IR#032*

Ausgrid's intended smart meter data purchases in the next RCP are excessive

126. Ausgrid proposes a smart meter data acquisition program at an estimated operating cost of $24.9m over the next RCP. Whilst Ausgrid proposes that 85% of the data acquired will be daily data, which is able to be acquired at a lower cost than near-real time data, Ausgrid plans to acquire data from 820,000 NMIs by FY29,[59] which is 114% of the projected aggregate of c718,000 rooftop solar installations and EV's in Ausgrid's network in FY29.[60] This information is shown in Figure 3.10: .

Figure 3.10: Ausgrid proposed data purchase quantum and expenditure



Source: On-site meeting slide 49

127. In Ausgrid's CBA model, slightly different (but still very high) data requirements are assumed, as shown in Table 3.2:

[redacted]

---

[59] Vis bility and modelling worksheet in Ausgrid – IR014 – CBA total program v1.1 – 20230505 – Confidential, noting that information provided in Ausgrid – IR014 – EMCa model wa kthrough presentation – 20230505, slide 12 shows higher numbers of data purchases but the same total cost over the next RCP

[60] Ausgrid – IR014 – CBA total program v1.1 – 20230505 – Confidential, Customer experience; Ausgrid opex model Att 6.1.b

128. Whilst we envisage that a relatively small amount of real-time data may be useful, Ausgrid does not adequately explain why it is targeting such a high level of overall data capture given:

- It has not demonstrated that it has extensive constraints in its network caused by PV penetration;
- Its proposal is much higher than the 20-25% coverage of smart meter plus distribution transformer meter data which we have observed in other DNSPs' proposals and which is consistent with ARENA's 'Solar Enablement Initiative' and 'Project Shield' findings;[61]
- Ausgrid has invested in distribution monitoring and control devices in the current RCP[62] and which provide power flow and power quality information to supplement the smart meter data;
- It is not clear why real-time data to the extent proposed is required for modelling purposes, particularly in the early years of the next RCP;
- Whilst we consider it is reasonable to target 20-25% data coverage to design/set transformer tapping, phase balancing, and other voltage control measures, this level of coverage is only required for the feeders at which there are over-voltage constraints (or likely to be in the near future), not across the whole LV network;
  - Ausgrid can leverage off its LV network modelling and any customer complaints to target the areas of the network with the highest levels of over-voltage and then secure the minimum required LV visibility in those areas to identify the best solution(s);
  - A targeted approach is likely to maximise the cost-benefit of any intervention; and
- Similarly, our understanding is that whilst a degree of LV visibility is required to help design dynamic prices and DOEs, this is able to be done with targeted programs and which can be progressively refined over the next 5-10 years and are not scheduled to be offered in great numbers until the later years of the current RCP.

129. Therefore, at least for the duration of the next RCP, we do not consider that Ausgrid has adequately justified the proposed daily data or near real-time data volumes and the proposed cost of $24.9m for this. We expect that data visibility building over the next RCP towards 20-25% overall coverage by the end of the next RCP would be adequate for Ausgrid's constraint modelling, with a lower proportion of real-time data purchase than proposed.

Ausgrid's cost estimation methodology for data is reasonable

130. Ausgrid advises that it has used revealed costs, market testing and peer review to determine the applicable data costs. We consider this approach to be appropriate.

3.3.7 Connections, compliance, and education

The initiative will enable Ausgrid to manage 500k connections p.a. which is significantly more than the peak connections forecast of 122k connections in the next RCP

131. To address the challenges with managing the forecast volume and complexity of connections described in section 3.1.3, Ausgrid proposes '*using data, analytics and modelling tools to simplify connection of CER within required timeframes by increasing the proportion of automatically approved connections, streamlining those connections that require further assessment….*'[63] Ausgrid also advises that the initiative will enable monitoring of compliance to CER technical standards such as AS4777.

---

61 ARENA, Increasing Visibility of Distribution Networks 'Solar Enablement Initiative', 'Project results and lessons learnt' Report, 5 December 2019

62 Ausgrid 2023, Att 5.7 CER Integration Program, page 28

63 Ausgrid 2023, Att 5.7 CER Integration Program, page 5

132. Our understanding is that this will be achieved through a combination of process improvement and an ICT-based initiative to avoid adding staff.

133. Ausgrid advises that the proposed investment will enable it to assess up to 500k connections annually which is far in excess of the forecast peak of c175k connections in 2040 and the projected 122k connections in FY29. In its CBA, Ausgrid's assessment of benefits sums to only $3.3m within the next RCP. While Ausgrid forecasts benefits rising through the 2030s, this does not justify undertaking the proposed level of investment in the current RCP, particularly noting that Ausgrid proposes undertaking the majority of the investment in 2025 and 2026,

134. We therefore question whether the proposed $11.2m capex and associated opex of $2.7m over the next RCP is required instead of a staged investment at a lower cost in the next RCP that would still realise forecast benefits in this period and which could be scaled when required.

Improved compliance with AS4777 will equitably increase hosting capacity

135. As discussed in section 3.2.4, compliance with volt-var and overvoltage tripping settings under AS4777 is relatively poor.

136. With the planned increase in low voltage visibility and the concomitant analytical capability, and with the proposed connections process, Ausgrid will be able to progressively identify non-compliant inverter systems, with identification of non-compliance in hosting capacity constrained areas being more important than the rest.

137. Addressing non-compliant solar inverters would have the twin effect of increasing available hosting capacity and creating a more equitable distribution of the available hosting capacity. Our understanding is that Ausgrid does not have the jurisdictional role or authority to undertake a program of retrospective compliance action, however we expect that a prudent operator would seek to improve compliance levels for new installations in order to minimise or defer the need for new investments to achieve the same result.

The education component is supported by Ausgrid's customers

138. Ausgrid has bundled the cost of education within the $13.9m totex for this initiative. The intention is to raise awareness of the choices that remove barriers to accessing the benefits of CER by targeting '…*apartment residents, customers without direct access to CER, technology choices available, right-sizing investments and raising awareness around benefits including pricing options.*'[64]

139. Ausgrid advise that its customers support enhanced community engagement and communication.

140. The cost of this component of the initiative is not explicit in the information provided but is likely to be relatively modest. We consider that it is likely to provide assistance to the target customers.

Ausgrid's cost estimation methodology for connections compliance and education is reasonable

Ausgrid advises that costs have been benchmarked internally against the current CIS program, using relevant historic costs. We consider this approach to be acceptable at this point in the project development lifecycle.

3.3.8 Network investments

141. Ausgrid proposes three network capex solutions totalling $47.1m:[65, 66]

---

64 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, page 27

65 Ausgrid 2023, Att 5.7 CER Integration Program, Table 1 pages 5-6

66 In other sources, Network Capex is forecast to be $47.3m

- Augmentation – traditional ($27.3m): tap changing, LV phase balancing, LV DC, LV distributor augmentation, upgrades, HV feeder augmentation and voltage regulation changes;
- Augmentation – new technology ($10.0m): STATCOMs; and
- Community batteries ($9.8m).

142. Ausgrid describes its approach to prioritising network investments as follows:

> *Network augmentation is prioritised using an iterative approach to deliver the greatest economic benefit to customers, starting with the most cost-effective solutions. Our final prioritised portfolio is a diverse mix of tap changes, flexible technology solutions including STATCOMs and traditional augmentation.*[67]

143. We consider this approach to be appropriate. We discuss each of the proposed ‘technologies’ below.

Phase balancing is a relatively low-cost initiative to increase overall hosting capacity

144. Ausgrid’s proposal provides scant information about the scope/opportunity/cost of phase balancing in its LV network. However, based on our experience it is a relatively low cost means of releasing hosting capacity from existing assets by changing customer connection points to balance the connections across phases to balance loading on the network.

Distribution substation transformer tap changing is a relatively low cost initiative to increase overall hosting capacity

145. Similarly, Ausgrid’s proposal provides scant information about the opportunity for further changing tap settings on transformers in its network. However, based on our experience, it is a relatively low cost means of releasing hosting capacity from existing assets where the taps have been set to respond to undervoltages due to peak demand impacts and/or the superseded standard of 240V.

Ausgrid has combined its phase balancing and tap changing programs with traditional network augmentation in its costings

146. Ausgrid intends to use traditional network augmentation solutions such as transformer or mains upgrades where economically viable to manage loads and voltage levels in the network to relieve local network constraints. These solutions are more expensive than tap changing/phase balancing and costs vary depending on the local network characteristics.

147. To provide sufficient hosting capacity, Ausgrid proposes network capex in each of its three options: Option 1 (Base Case, $47.3m), Option 2 ($60.6m) and Option 3 ($47.1m)[68] in the next RCP. These amounts are significant, despite Ausgrid’s relatively low CER penetration starting point.

148. In our view, there is significant uncertainty about the medium to long term utilisation of the LV network given the potential for energy self-sufficiency through a combination of solar generation, energy storage (either BTM or in community battery energy storage systems), and home energy management systems. Therefore, we consider that investing in traditional LV network assets with technical lives of over 40 years should be avoided/deferred if practicable. Nonetheless, we consider that it is likely to be technically and economically prudent for Ausgrid to spend some capex on traditional augmentation in the next RCP.

STATCOMs may be an economically viable alternative to traditional augmentation

149. Ausgrid and other utilities have been trialling the deployment of STATCOMs to help regulate voltage in LV networks as an alternative to traditional network augmentation. LV-connected

[67] Ausgrid, On-site presentation, slide 46

[68] In other sources, Network Capex is forecast to be $47.3m

STATCOMs can either absorb or generate reactive power in synchronization with demand to help maintain LV voltages within statutory limits.

150. Ausgrid has included $10.0m in its preferred Option 3 for what it refers to as 'flexible technology augmentation.' We consider that there *may* be some locations at which STATCOMs are a viable alternative to traditional network augmentation during the course of the next RCP, however based on the economic analysis that Ausgrid has presented (as reviewed in the next section) these appear to be marginal at best.

Community batteries may be economically viable in some circumstances

151. Ausgrid positions STATCOMs and community batteries as '*flexible technology options to intelligently manage CER'* and states that '[*d]uring our extensive engagement with our customers we heard that they want innovative approaches to enabling CER in place of traditional network augmentation*'[69] Community batteries can facilitate orchestration of localised supply and demand and thereby increase hosting capacity, however they are currently relatively expensive. To offset the cost, Ausgrid proposes utilising a mixture of external and internal funding to deploy community storage beyond its 2019-24 trials.

152. Ausgrid has allowed $9.8m capex in its proposal for community batteries, with costs based on its recent trials.

153. We consider that community batteries may be a viable alternative in some circumstances with the cost curve likely to decline over time. However, as for STATCOMS and based on our review of its CBA in the next section, Ausgrid's economic analysis suggests that these options are at best marginal.

3.4 Assessment of Ausgrid's cost benefit analysis

3.4.1 AER base case guidelines

154. Consistent with the DER guidelines, the AER expects DNSPs to define a BAU base case against which to measure the net economic benefit of options. The guideline states that the BAU base case should have the following characteristics:

- DNSP continues its BAU activities which are 'ongoing, economically prudent activities that occur in the absence of a credible option being implemented'
- Comprises BAU operating expenditure associated with voltage management which are already in place
- Allow for inverter systems to trip at times where DER exports exceed hosting capacity
- Incorporate export curtailment assumptions based on existing static export limits.

155. The guideline states that the preferred option should be that which maximises the net economic benefit across the NEM, with the base case representing the best option if there is no option that yields a net economic benefit.

3.4.2 Ausgrid's cost benefit analysis (CBA)

156. Ausgrid has provided a CBA in which it has modelled the costs and benefits of its proposed program over 20 years (from 2025 to 2044). The model provides forecast costs and benefits year by year, for each of the five DER 'solutions' (as identified in section 3.3).

157. In Table 3.3 we summarise the costs in Ausgrid's CBA model for each of the five solutions that comprise its preferred option (option 3), as presented for the next regulatory period.

69 Ausgrid 2023, Att 5.7 CER Integration Program, Appendix A, pages 6, 11

Table 3.3: DER costs for each solution (option 3)

	2024	2025	2026	2027	2028	Total
Network visibility and modelling uplift	5.6	8.2	6.0	6.0	6.2	32.1
Dynamic service capabilities	2.5	2.0	2.6	2.6	2.3	12.1
Connections, compliance and education	5.1	5.5	0.8	1.3	1.3	13.9
CER - Non Network	**13.2**	**15.7**	**9.4**	**9.9**	**9.8**	**58.1**
Augmentation - Traditional	8.2	3.0	3.9	4.8	7.4	27.3
Augmentation - New technology	4.9	4.0	4.0	4.0	3.0	19.8
CER - Network	**13.2**	**6.9**	**7.9**	**8.8**	**10.4**	**47.1**
TOTAL CER	**26.4**	**22.6**	**17.3**	**18.7**	**20.2**	**105.2**

Source: EMCa, summarised from Ausgrid's CBA model

158. The costs in Ausgrid's CBA model reconcile in aggregate with its regulatory submission (as presented in Table 3.1. There are differences in the costs on a year-by-year basis, but we consider these are not so great as to invalidate the CBA.

159. The information in the CBA shows that the majority of proposed expenditure is for network augmentation, comprising both traditional solutions and 'new technology' which Ausgrid defines as Statcoms and community batteries.

3.4.3 Model review

Despite some discrepancies, Ausgrid's CBA model is suitably fit for purpose and is adequate in allowing confirmation of Ausgrid's choice of preferred option

160. For the most part the model provides a transparent view of Ausgrid's calculation of the costs, benefits and NPV of its proposed program. Cognisant of the challenges involved in forecasting costs and benefits, particularly for new initiatives for which there is no firm experience 'at full scale', we consider that there is a reasonable and balanced matching of assumed benefits against the costs assumed in delivering those benefits. We do however observe some formula errors, including in the NPVs summarised in the CBA option summary sheet.[70]

161. Ausgrid presents its summary of the costs and benefits of the three options that it assessed, in a table which we reproduce as Table 3.4. This table includes 'DER innovation projects' which Ausgrid has proposed in its submission as part of its proposed Network Innovation Program, and which we have not been asked to assess. This explains differences in costs relative to Table 3.3.

70 For example, the 5-year PVs of benefits are calculating PVs for 20 years but are set beside 5-year costs. Also the 5-year, 15-year and 20-year costs and benefits each incorporate the same PV of the 'DER innovation' projects. Another example of likely model error is in the Augmentation sheet, where the option 3 total cost appears not to include the 'community battery' costs. This error does not appear to affect the cost benefit summary, which appears to pick from the component cost rows rather than the total cost row. We note that augmentation deferral benefits calculated in the model are also not incorporated into the CBA for 2025-29 but are thereafter.

Table 3.4: Ausgrid's Investment options overview

<table>
<tr><th colspan="4">Investment Options (FY24 real $M)[71]</th></tr>
<tr><th>Capability</th><th>Option 1 Base Case</th><th>Option 2 Preparatory investment</th><th>Option 3 Proactive investment</th></tr>
<tr><td>Network visibility and modelling uplift</td><td>-</td><td>29.7</td><td>32.1</td></tr>
<tr><td>Dynamic service capabilities</td><td>-</td><td>-</td><td>12.1</td></tr>
<tr><td>Connections and compliance</td><td rowspan="2">3.0</td><td rowspan="2">13.9</td><td rowspan="2">13.9</td></tr>
<tr><td>Education</td></tr>
<tr><td>DER innovation projects^</td><td>-</td><td>20.9</td><td>20.9</td></tr>
<tr><td>Traditional network augmentation</td><td>47.3</td><td>60.6</td><td>27.3</td></tr>
<tr><td>Flexible technology augmentation</td><td></td><td></td><td>19.8</td></tr>
<tr><td>Total</td><td>50.3</td><td>125.0</td><td>126.1</td></tr>
<tr><td>Net Present Value</td><td>-2.9</td><td>48.8</td><td>169.4</td></tr>
</table>

Source: Ausgrid attachment 5.7, Table 9 (page 30)
^ Not within EMCa's scope for assessment

162. However, the NPVs shown in Ausgrid's table do not align with those that we find in its CBA model. For example, over a 20-year period, Ausgrid's model shows an NPV for option 3 of $157.8m. The footnote under Table 3.4 suggests that the NPVs are for 15 years (i.e. to 2039) in which case the equivalent NPV in Ausgrid's model is $68m. An interpretation of the footnote is that benefits have been modelled to 2039 but costs only to 2029; however any logic in presenting a misaligned analysis such as this is unclear and even if this was Ausgrid's intention, we are unable to reproduce its tabled results.

163. Nevertheless, our review of the model mechanics confirms that if the cost and benefit assumptions are taken as given, then Ausgrid's chosen option (option 3) provides the highest NPV.

The model results rely on assumptions regarding distant future benefit streams to justify the proposed near-term investment

164. In Table 3.5 we show the PVs that we derive directly from Ausgrid's CBA model, and which show the component NPVs for each proposed solution. The NPV of Dynamic Service Capabilities (DSC) contributes most to Ausgrid's economic assessment of the NPV of its proposed DER program, with traditional network augmentation also providing a significant NPV and both yielding a relatively high benefit/cost ratio.

165. The economics of Ausgrid's proposed 'new technology' investment in Statcoms and a community battery, appear marginal.

71 Costs include all costs from FY25 to FY29, Benefits look at all benefits out to 2044 from investments made out to 2029, NPV = Net Present Value of Benefits minus Costs out to 2039, with costs only modelled to 2029. ^ Included in the CER integration program for visibility but expenditure allocated in the Network Innovation Program (NIP)

*Table 3.5: PV of costs and benefits with **20**-year analysis period (option 3)*

CER solution	PV costs	PV benefits	NPV
Network visibility and modelling uplift	31.5	44.1	12.6
Dynamic service capabilities	39.6	130.0	90.4
Connections, compliance and education	18.0	29.7	11.6
Augmentation - Traditional	25.0	62.4	37.4
Augmentation - New technology	18.3	18.4	0.2
TOTAL	**132.4**	**284.6**	**152.3**

Source: EMCa analysis from Ausgrid CBA model

166. An economic assessment shortened to 15 years yields a markedly different result. While this still presents a positive NPV, it is notable that:

- The economics of 'network visibility and modelling uplift' now appear marginal; and
- The PV of benefits from DSC is over 50% lower and the NPV is 64% lower.

167. This illustrates how CBA modelling assumptions regarding future benefits in the period 2039 to 2044 are driving Ausgrid's assessment of the economics of its proposed near-term DER investment.

*Table 3.6: PV of costs and benefits with **15**-year analysis period (option 3)*

CER solution	PV costs	PV benefits	NPV
Network visibility and modelling uplift	30.9	32.5	1.6
Dynamic service capabilities	28.1	60.7	32.7
Connections, compliance and education	16.5	19.5	3.1
Augmentation - Traditional	25.0	50.0	25.0
Augmentation - New technology	18.3	18.4	0.2
TOTAL	**118.7**	**181.2**	**62.5**

Source: EMCa analysis from Ausgrid CBA model

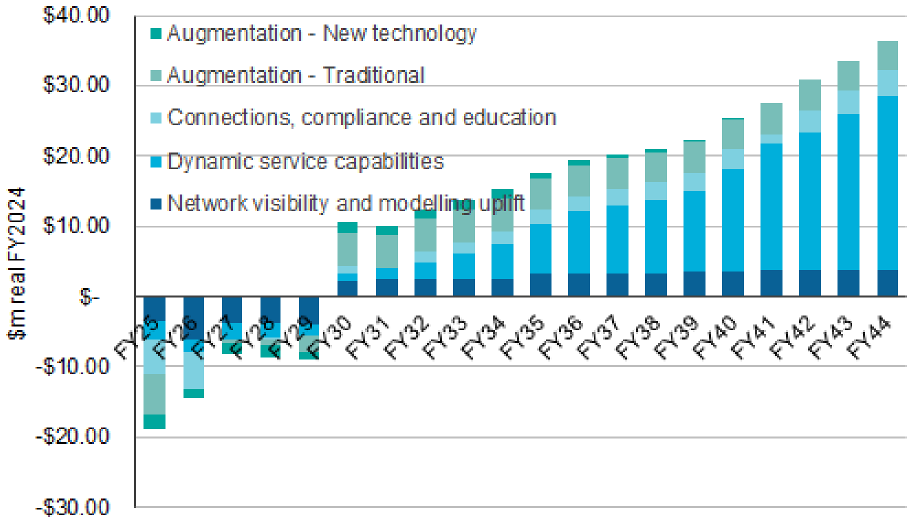
3.4.4 Assessment of net benefits

Costs and benefits by 'solution', over the assessment period

With Ausgrid's assumptions, DSC provides the dominant benefit

168. In Figure 3.11 we present Ausgrid's assessment of the costs and benefits of its proposed DER program, over the period of its analysis. The time trend illustrates the dependence of the economic assessment of the proposed five-year investment on net benefits that arise only beyond the regulatory period with the most prominent benefits arising in the late 2030s and early 2040s. The analysis also shows that the dominant assumed net benefit would results from DSC.

Figure 3.11: Annual net benefits for each proposed DER solution



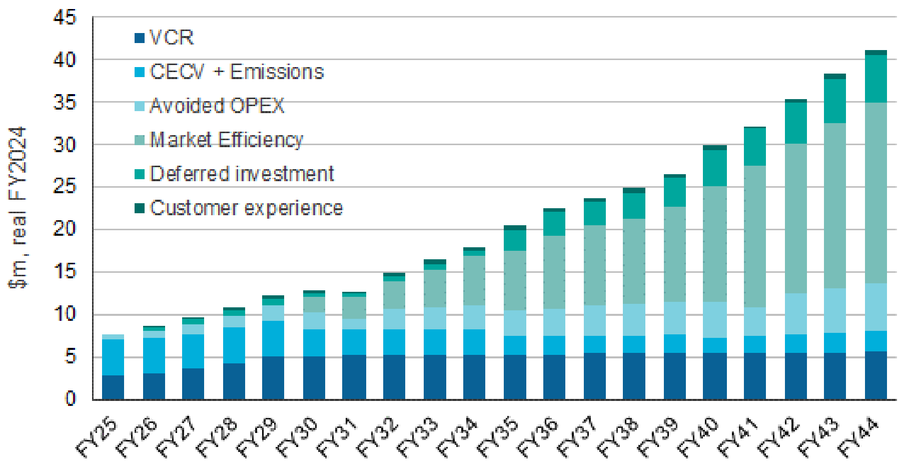
Source: EMCa analysis from Ausgrid CBA model

Nature and time trend of assumed benefits

The positive NPV is predicated on a strong and continuing increase in benefits, with Ausgrid's addition of a 'market efficiency' benefit being the dominating assumed benefit

169. Figure 3.12 illustrates the source of assumed benefits over the period of Ausgrid's analysis.[72] As with Figure 3.11, the continuing and significant increase in annual assumed benefits is evident. However, this analysis also shows that the dominant assumed benefit arises from the inclusion of estimated 'market efficiencies' over and above the estimated CECV-based curtailment value. The assumed market efficiency benefit is based on analysis undertaken for Ausgrid by Houston Kemp, of assumed wholesale market 'arbitrage' benefits of DOE to owners of virtual power plants (VPPs) and EVs.[73]

Figure 3.12: Annual assumed benefits, by source of benefit



Source: EMCa analysis from Ausgrid CBA model

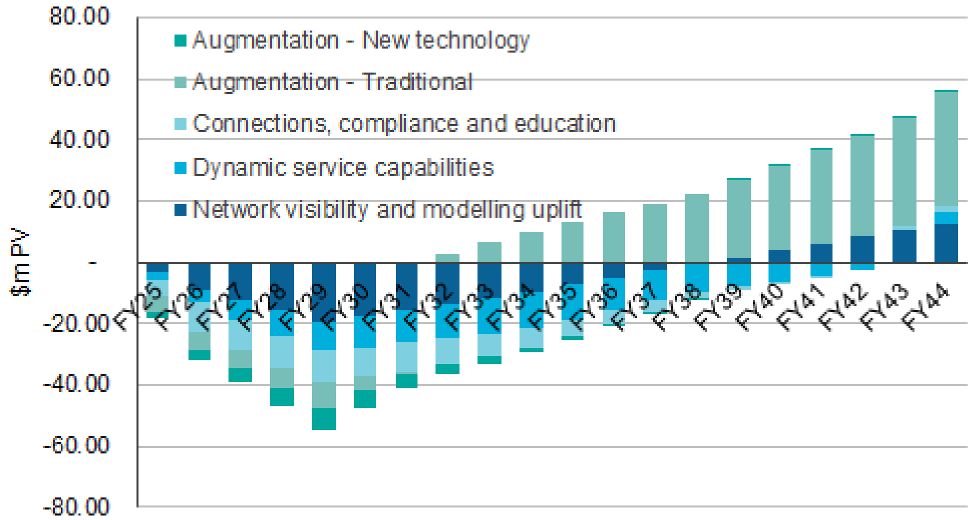
72 For clarity, we note that Figure 3.11: Annual net benefits for each proposed DER solutionFigure 3.11 shows net benefits (that is, benefits minus costs) while Figure 3.12 shows benefits only.

73 Ausgrid IR#002 response, attachment 5.7.A.2, Economic benefits of distribution system operator investments, Houston Kemp (February 2023)

170. The time profile of the assumed market efficiency benefits is particularly problematic in the analysis. No market efficiency benefit is assumed during the period 2025 to 2029. An assumed value of $1.73m benefit is assumed in 2030, but this then rises to $6.33m in 2035, $12.31m in 2040 and finally $19.02m in 2044. Whilst the fundamental economics of the assumed market efficiency benefit (as an addition to the curtailment value) is a consideration in itself, from a modelling perspective it is notable that this assumed benefit occurs entirely beyond the next regulatory period and its influence on the economics of the proposed next period investment derives almost entirely from its assumed steep increase over the period from 2030 to 2044.

171. We have undertaken a sensitivity assessment in which we have removed the assumed market efficiency benefit in the analysis. In Figure 3.13 we show the cumulative build-up of the NPV of the proposed program, without the assumed market efficiency benefit but with other benefits (being reduced unserved energy (USE), CECV-based avoided curtailment, avoided opex, deferred network investment and improved customer experience) as per Ausgrid's analysis. The positive NPV of $55m over a 20-year analysis period in this case would arise almost entirely from traditional augmentation and the DSC solution and network visibility components of the proposed program would not produce a positive NPV until around 2039 or the early 2040s.

Figure 3.13: Cumulative NPV of proposed DER program (by solution) – Excluding assumed market efficiency benefit



Source: EMCa analysis from Ausgrid CBA model

Network visibility

The lack of an ongoing cost for obtaining smart meter data beyond the regulatory period is not explained and does not seem plausible in an assessment based on economic costs

172. The network visibility component of Ausgrid's assessment is based on benefits from reduced unserved energy, reduced curtailment, avoided opex and deferred investment. In aggregate these benefits are of the order of $2m per year initially rising to $4m over the 20-year analysis period. The nature of these benefits appears plausible.

173. We observe that the costs for smart meter data are of the order of $4m to $5m per year, however in Ausgrid's CBA these costs cease in 2030. The basis for this is unclear and if smart meter data costs were to continue for the remainder of the period, the NPV for this component would be negative.

174. In section 3.3.6 we have questioned the extent of data that Ausgrid assumes it will require. Provided it can meet the needs of the service, a reduced data requirement would result in a lower cost and thereby improve the economics of this proposed service. We also observe

that other DNSPs have ascribed to network visibility a somewhat higher benefit from augmentation capex deferment. Our review of these elements in Ausgrid's CBA reinforces our view that at this stage Ausgrid may not have adequately aligned the costs of this component of its proposed program with a realistic assessment of the benefits that it should realise from it.

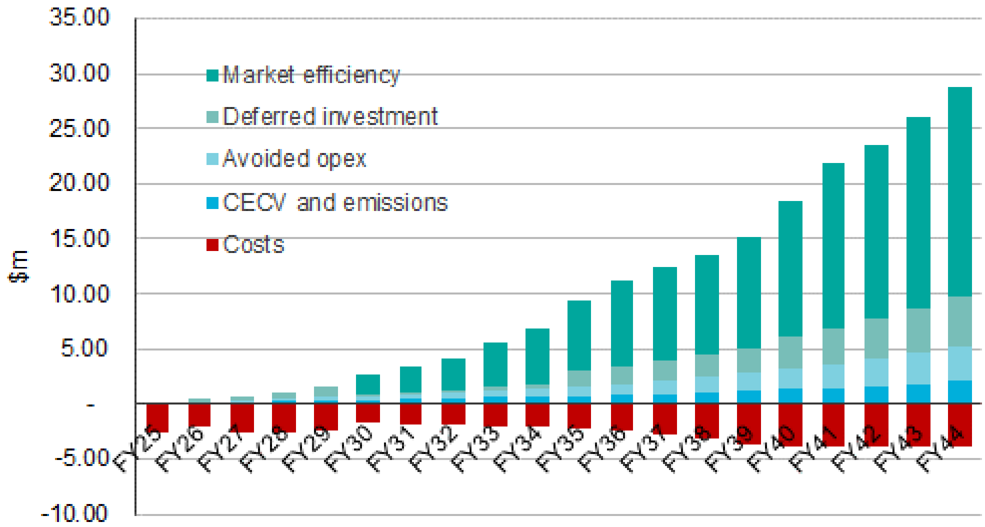
Dynamic Service Capabilities (DSC)

Absent other factors, the CBA suggests that the economics would be improved by better aligning the costs of establishing the DSC with the benefits to be derived from it.

175. The opportunity to provide DSC is the primary 'innovative' aspect of a DER program. In its CBA, Ausgrid has considered the benefits of reduced export curtailment, as we would expect. While Ausgrid states that it has applied a CECV value based on the AER's guideline values,[74] Ausgrid has (as we have noted above) also added in a 'market efficiency' benefit based on advice provided to it by Houston Kemp. The assumed market efficiency benefit dominates Ausgrid's analysis of DSC benefits over its 20-year analysis period, but only because of extremely high values in the latter years. For example, we observe from Ausgrid's model that the assumed 'CECV' value in 2040 of avoided curtailment ascribed to DSC is only $1.34m whereas Ausgrid's assumed 'market efficiency' benefit is $12.31m in that year.

176. The impact of the assumed market efficiency benefit for the DSC alone is evident in Figure 3.14. Noting that the annual costs of DSC in Ausgrid's analysis are relatively constant by comparison with the benefits, consideration only of the economics would suggest that it would be preferrable if the DSC expenditure was to be delayed until nearer the time when the benefits are assumed to be realised, or (if the opportunity exists) for services to be established such that benefits can be brought forward.

Figure 3.14: Ausgrid's assessment of annual costs and benefits for DSC



Source: EMCa analysis from Ausgrid CBA model

177. The considerable lag between costs and benefits in Ausgrid's analysis not only results in a sub-optimal economic outcome but also, due to the inherent uncertainties of modelling 15 to 20 years out in a rapidly changing sector, exposes the proposed investment to considerable risk of regret and fails to account for the option value of better aligning the timing of the proposed investment with realisable benefits.

74 From advice to AER from Oakley Greenwood

Augmentation and VCR

Modelling of VCR impact of EV charging considerably overstates the assumed benefit of augmentation

178. Reduced Unserved Energy (valued at VCR) is the dominant benefit assumed in Ausgrid's CBA for traditional augmentation. In the CBA this benefit is described as an outcome of separate analysis to address forecast EV constraints and the values were hard coded in the original CBA model provided.[75]

179. In an IR response, Ausgrid provided further information to explain how it had calculated the assumed VCR impact.[76] In summary, the relevant model comprises a weighted average of two methods:

- Method 1 assumes unmanaged convenience charging, which is assumed to cause outages to all customers on the same LV circuit;
- Method 2 assumes managed charging (e.g. through smart chargers) that would curtail EV charging that would otherwise trigger an outage. For this, the VCR is based on the EV charging load that is assumed to be curtailed.

180. Method 2 gives a value that is less than 1% of method 1 initially, rising only to 6% of the method 1 value by 2029. In its modelling, Ausgrid weights these two methods, with weighting of 90% given to method 1 initially and reducing to 82% by 2029.[77] The high VCR-based cost of Method 1, together with the high weighting given to this scenario, which assumes continuing high levels of unmanaged convenience charging, therefore dominate the resulting VCR-based benefit values.

181. There are two issues with this analysis:

- Firstly, the analysis relies on a questionable assumption that the prevalent EV regime will be for unmanaged convenience charging continuing over the next 20 years. We observe that Ausgrid's EV sheet in its CBA contains a forecast of decreasing convenience charging and increasing smart charging continuing to 2050, though the CBA itself overstates the benefits of augmentation by freezing these parameters at the 2029 values.
- Secondly, while considerably lower than method 1, method 2 overstates the impact on EVs by applying a current standardised VCR outage value to assumed avoidance of being unable to fully serve EV charging loads 'on demand'. We consider that this represents a misapplication of the currently-specified VCR value and a considerable overstatement of this assumed benefit, for reasons that we describe below.

182. By its nature, EV charging is one of the easier loads to time-shift, which is why it is recognised as an ideal candidate for (orchestrated) control. An inability to supply an EV charger load at a particular time will for the most part have a negligible cost to a consumer (and may even be unnoticed) provided the charging load can be supplied at a deferred time prior to when the consumer requires the EV to be charged to its desired level. In future consideration of VCR values, we consider that this is better recognised as 'deferred supply' of energy than as 'unserved' energy, and we would expect the per-kWh cost of such deferment to be considerably less than the current standardised VCR values.

75 Annotations to this effect are provided in the 'augmentation' sheet of the CBA model

76 Primarily this is provided by way of an 'EV' worksheet included in a resubmitted version of its CBA. (IR#032 Attachment A. CBA total program v1.2). A separate workbook (IR#032 Att B CBA EV analysis) was also provided, and which included values referred to as 'Total load from outage' and 'EV load above threshold from outage'. Attachment A refers to these values (in Attachment B) as being those descr bed as Method 1 and Method 2 in Attachment A, however the values (each of which is hard coded) differ, though in relative terms they are broadly similar.

77 EV sheet in IR#032 Attachment A updated CBA model, calculated from values in rows 19 to 23.

Augmentation by 'new technologies'

Ausgrid's CBA does not provide compelling evidence that these are viable

183. As presented in Ausgrid's CBA, the 'new technology' augmentation options essentially have a Benefit to Cost ratio of 1. Its analysis appears to rely on a proportionate allocation of overall CECV-related augmentation benefits, between 'traditional' and 'new technology' augmentations. On Ausgrid's assumptions, it would appear that the same benefits could be achieved through traditional augmentation, at lower cost.

184. While the cost of new technologies may well reduce and result in them being preferred in some circumstances at some time over the regulatory period, axiomatically this would imply that lower expenditure will be required than Ausgrid has proposed.

Connections, compliance and education

There are multiple issues with the assumed benefits, correction of any one of which is likely to result in a negative NPV for this work

185. The benefits of this component of the preferred Option 3 investment are derived from the following sources in Ausgrid's CBA:

- Avoided opex (for extra staff) that would otherwise be required for Ausgrid to cope with increased CER connection demand in lieu of an automated process – this assumes that a steady increase in FTEs is required from FY25 to FY44 and is the largest assumed benefit stream, again with the benefits accruing primarily in the next decade through to the end of the study period in FY44;
- Customer experience benefit from FY26 onwards – derived by Ausgrid from avoided customer wait times to process unserved customers at $0.665/min (i.e. if insufficient FTEs are available or in lieu of the automated/self-serve process)
- Market efficiency benefit from FY30 onward - this benefit stream is the second largest with the majority of the benefits accruing well beyond the end of the next RCP; consistent with our discussions above, if it were removed from the NPV calculation, the Connections, compliance, and education investment would have a negative NPV; and
- CECV unlocked by improved CER compliance from FY28 – this is valued by Ausgrid at 2% of the total potential CECV benefits available from alleviating curtailment, with 1% benefit attributed to the uplift in digital capabilities to monitor compliance and 1% to customer education; whilst the assumptions are not adequately justified, the assumed benefit is relatively small in the next RCP and declines through to FY44 in line with the declining CECV.

186. Overall, we consider that Ausgrid's proposed $13.9m investment in Connections, compliance and education is unjustified as presented.

3.4.5 ICT enablement opex step change

187. Following from our assessment of Ausgrid's CBA analysis, we turn to the implications for Ausgrid's proposed 'ICT enablement' opex step change.

188. Ausgrid has identified seven drivers of an 'ICT enablement' opex step change of $10.4m for Option 3, as summarised in Table 3.7.[78] The proposed ICT enablement opex step change is in addition to the data driven opex step change.

[78] Our understanding is that Option 2 would incur costs for drivers 1, 2b, 6, and a proportion of each of driver 8 and Ausgrid's support cost.

Table 3.7: Option 3 ICT enablement opex step change proposed by Ausgrid, $m real 2024)

Driver (with numbering from Ausgrid's spreadsheet)	Opex step change**
1. Customer connection performance and compliance	0.40
2b. Connection maps and modelling	1.12
3. VPP/DOE integration (+API, Utility server)	2.80
5. Billing Engine & basic DNP (prior to ERP upgrades)	0.06
6. Network modelling uplift (load flow/constraint analysis)	1.06
8. Hosting services for 1, 3 (partial), 4, 5, 6, 7)*	1.75
Ausgrid support costs (data cleansing, project management, system administration, etc)	2.16
Total $June 2022	**9.35**
Total $June 2024	**10.35**

*Source: Ausgrid – Att. 6.1b – Step changes model – 31 Jan 2023 – Public, Calc I ICT enablement for CER; *4 Is dynamic pricing and 7 is Multiple horizon forecasting, neither of which are forecast to require an opex step change ** escalated from $June 2022 to $June 2024 using Ausgrid's escalation factor of 11%*

It is reasonable for Ausgrid to forecast 'new opex' for the new functionality proposed for Option 3

189. Noting that we support Ausgrid's selection of Option 3 as the preferred set of solutions, the drivers of opex step change appear to reasonably follow from the introduction of new or enhanced functionality proposed under Option 3.

Overall Ausgrid's proposed costs are too high and we would expect it to reduce its ICT enablement opex costs to help achieve a prudent and efficient DER integration program

190. In sections 3.3 and 3.4 we have assessed directly or indirectly the technical and economic merits of all but the Ausgrid support costs. Overall, we conclude that Ausgrid's proposed ICT integration program is not economic.

191. Ausgrid's step changes model only includes hard coded cost estimates for the seven line items in Table 3.7. As we consider that Ausgrid's proposed costs are more likely than not to exceed the proposed benefits of its discretionary investment in Connections, compliance, and education, we would expect Ausgrid would seek to reduce the proposed capex and opex associated with the initiative, including the proposed opex step change of $1.52m (per drivers 1 and 2b in Table 3.7).

192. Given our expressed concerns with aspects of Ausgrid's costing methodology, we consider it likely that there are opportunities to reduce the ICT enablement opex step change forecast without compromising the enablement of a prudent DER integration program.

3.4.6 Conclusions on our assessment of Ausgrid's CBA

Ausgrid's model is an adequate vehicle for exploring the economics of its DER proposal and is sufficient to confirm its preferred choice of 'option 3'

193. Despite some anomalies (and some inputs that are unable to be verified), Ausgrid's CBA model provides a transparent representation of the costs and benefits that Ausgrid has assumed, and of the resulting economics of its proposed DER investment when based on those assumptions. While we consider that the net present value is overstated, we nevertheless find that Ausgrid's preferred option is the best of the three options that it considered.

Ausgrid's inclusion of an assumed 'market efficiency' benefit is a significant driver of the economic case as proposed, but does not support the proposed level of investment within the next RCP because of the significant time lag and uncertainty

194. We consider that the assumed market efficiency benefit does not support the proposed level of investment within the next RCP, given that it relies more heavily than is realistic (given future unknowns) on very high assumed benefits that are 15 to 20 years out, and which therefore lag the proposed investment by over 10 years. This especially drives and therefore overstates the economics of the level of DSC investment in the proposed program. A logical conclusion to draw from this analysis is that either the investment should be deferred closer to when the benefits will arise (and are better known) or, if feasible, that initiatives should be accelerated in order to realise earlier benefits from the proposed investment.

For other reasons, the economics of the network visibility, augmentation, and Customer connections, compliance, and education solutions are overstated

195. We consider that the network visibility solution economics within the overall business case are overstated by failing to include ongoing smart meter data purchase costs beyond the next regulatory period.

196. We also consider that an inappropriately high value has been applied to assumed USE impacts from EV charging, resulting in overstatement of the benefits of its proposed level of network augmentation.

197. On the face of it, Ausgrid's proposal to improve its capability to cope with forecast higher connections applications, improve the customer experience, and educate customers has merit. However, we consider that the economic benefit is overstated to the extent that costs are likely to significantly exceed benefits, or at best the payback period for the proposed investment is very long and dependent on uncertain benefits in 15-20 years' time.

3.5 Our findings and implications

3.5.1 Summary of our findings

Ausgrid's voltage constraint settings appear to be too conservative leading to overestimating solar curtailment

198. Ausgrid has set the voltage threshold for calculating solar export energy curtailment due to overvoltage at 250V. This is lower than the default of 253V volt-watt setting under AS 4777.2:2020 and leads to an overstatement of the curtailment energy forecast.

Ausgrid's intended smart meter data purchases in the next RCP are excessive

199. At least for the duration of the next RCP, we do not consider that the proposed cost of $24.9m data to support improved LV visibility of its network and is adequately justified.

Ausgrid's model is an adequate vehicle for exploring the economics of its DER proposal

200. While we consider that the net present value is overstated, we nevertheless find that Ausgrid's preferred option is the best of the three options that it considered

Ausgrid's inclusion of an assumed 'market efficiency' benefit in addition to the CECV should not be included

201. The market efficiency benefit is not consistent with AER's guideline, not adequately supported and is the primary factor leading to an overstatement of benefits. We consider that the assumed value does not represent a valid economic cost and leads to an overstatement of the economics of the DSC component of the proposed program.

The economics of the network visibility, augmentation, and Connections, compliance and education solutions are overstated

202. The network visibility costs in the CBA model are understated because the business case fails to include ongoing smart meter data purchase costs beyond the next regulatory period.

203. Secondly, we consider that an inappropriately high value has been applied to an assumed potential inability to always fully provide for EV charging 'on demand'. We consider that the generalised VCR, used for reliability assessment, is not appropriate for this purpose.

204. As presented in Ausgrid's CBA, the 'new technology' augmentation options essentially have a Benefit to Cost ratio of 1. On Ausgrid's assumptions, it would appear that the benefits could be achieved through traditional augmentation, at lower cost.

205. We also consider that the costs are too high relative to the benefits when we remove benefit duplication and assess the sensitivity of the results to uncertain (distant) future benefits. Ausgrid's CBA does not provide compelling evidence that augmentation by new technologies is viable.

Ausgrid's proposed ICT enablement opex step change is likely to be over-estimated

206. We have expressed concerns with aspects of Ausgrid's cost forecasting methodology (including the opaqueness of the opex step change estimates) and identified what we consider to be unjustifiably high costs for the Connections and Compliance initiative. Taking these factors into account we consider that the ICT enablement opex step change is likely to be higher than required to enable implementation of a prudent DER integration within the period.

3.5.2 Implications of our findings for proposed expenditure

Implication for CER ICT Capex

207. In Table 3.8 we show the breakdown of Ausgrid's proposed CER-related ICT spend.

208. In accordance with our findings, we consider that Ausgrid's proposed ICT expenditure on network visibility is reasonable and proportionate to need within the next RCP. While we consider that the economic case that Ausgrid has presented for DCS is overstated, we consider that this aspect of the proposed expenditure is also reasonable. However, we consider that the proposed expenditure of $11.2m on connections and compliance-related ICT is both excessive and premature, based on the benefit information that Ausgrid has provided.

Table 3.8: Breakdown of Ausgrid's proposed CER ICT expenditure

Description	FY25	FY26	FY27	FY28	FY29	RCP Total
Network visibility - network modelling uplift	0.6	1.7	0.3	0.3	0.2	3.1
Network visibility - multi horizon forecasting	0.3	0.8	0.2	0.2	0.1	1.6
Subtotal - Network visibility	**1.0**	**2.5**	**0.5**	**0.5**	**0.3**	**4.7**
DSC	2.3	1.2	1.2	1.2	0.9	6.7
Connections and compliance	4.9	4.9	0.3	0.6	0.5	11.2
TOTAL CER ICT	**8.2**	**8.6**	**2.0**	**2.2**	**1.7**	**22.7**

Source: Ausgrid CER CBA model, provided in response to IR#014

Implication for CER ICT – SaaS opex

209. Ausgrid proposed $3.0m SaaS opex in the next RCP for hosting services that were formerly capitalised. These are included in the ICT 'capex' amounts shown in Table 3.8 above, presented by Ausgrid in its CBA.

Implication for Smart meter data – opex step change

210. For reasons that we describe in section 3.3.6, we consider that Ausgrid has overstated its proposed $24.9m opex step change for smart meter data within the next RCP.

Implications for ICT enablement program for CER integration - opex step change

211. Ausgrid proposed $10.4m opex step change:

- For reasons stated in section 3.4.4, we consider that Ausgrid's proposed costs are more likely than not to exceed the proposed benefits of its discretionary investment in Connections, compliance, and education;
- Uplifting Ausgrid's modelling and forecasting capabilities is broadly supported; and
- Providing customers with more flexible network services via DSC is broadly supported, as is investing in dynamic operating envelopes and dynamic network pricing.

212. Given our comments regarding the costs and benefits of components of Ausgrid's DER Integration Program, we consider that it is likely there are opportunities to reduce the proposed opex step change.

Implication for CER – network capex

213. For reasons that we state in section 3.4.4, we consider that the costs that Ausgrid has proposed for 'new technology' augmentations are overstated.

4 REVIEW OF NON-RECURRENT ICT EXPENDITURE FOR 'ERP' PROGRAM

4.1 What Ausgrid has proposed

4.1.1 Overview and summary of proposed expenditure

214. Ausgrid has proposed ICT capex totalling $301m, comprising $161m 'BAU' ICT and a further $140m capex for three specific non-recurrent projects, as follows:

- CER-related ICT capex ($20m) and an associated $3m of SaaS opex, and which we reviewed in section 3;
- Expenditure on cyber security ($44m ICT capex and $47m opex, totalling $91m), which we have reviewed in a separate report.

215. Expenditure for ERP replacement ($76m ICT capex and $73m SaaS opex, totalling $149m), as shown in Table 4.1, which we review in the current section.

216. We were not asked to review other items of ICT expenditure.

Table 4.1: Ausgrid proposed ICT related capex for ERP replacement - $million, real FY2024

Description	2025	2026	2027	2028	2029	Total
Non-recurrent ICT- ERP capex	21.0	33.0	15.0	6.0	1.0	**76.0**
Non-recurrent ICT - SaaS opex	21.0	32.0	15.0	5.0	0.0	**73.0**
Total	**42.0**	**65.0**	**30.0**	**11.0**	**1.0**	**149.0**

Source: Ausgrid RP document, Figure 5.9.2 and Opex model (Attachment 6.1.b)

4.1.2 Summary of the basis for Ausgrid's proposed ERP upgrade expenditure

ERP Upgrade Program

217. Ausgrid's Enterprise Resource Planning Program (ERP Program) comprises of replacement and upgrade of three core systems and an 'ERP Transformation'. The three applications involved are:

- Enterprise Asset Management (EAM)
- Enterprise Resource Planning (ERP)
- Meter Data Management and Billing (MDM/B).

218. The drivers for change include:

- Ausgrid's current version of the platform on which the three relevant core systems operate is SAP ECC6[79] will not be supported by the vendor from 2027
- The three systems are inter-dependent and are utilised across a large number of Ausgrid's critical business processes
- The upgrade to applications on a supported software suite provides the opportunity to '*transform critical functions that these systems support, creating a step-change in*

[79] SAP ERP Central Component version 6 (ECC 6) was launched in 2005 and is a client/server business application software suite; since 2005 there have been eight major upgrades, with the last in 2016; SAP ECC6 was replaced by SAP S/4HANA in 2015

capabilities to respond to our changing energy landscape and future network providing significant benefits to customers.'[80]

219. Ausgrid's preferred option of the three considered is to:

- Replace the three core applications, migrating them to the contemporary cloud-based version SAP S/4HANA
- Simplify and standardise its technical landscape and end-to-end processes.

4.2 Our assessment approach and context

4.2.1 Our assessment approach

220. Our assessment approach is based on assessing Ausgrid's proposed non-recurrent ICT capex for the ERP Upgrade Program against the following project dimensions:[81]

- Regulatory expectation – is the business case (or equivalent, cognisant of the project development lifecycle) meets regulatory requirements set out in the NER and AER guidelines
- Strategic alignment – is the business case is aligned to the ICT strategy/strategic priorities
- Cost estimation methodology – are the project cost estimates based on a methodology that is likely to lead to a prudent and efficient delivered project cost
- Deliverability – the project and/or program of work is likely to be deliverable at an efficient cost.

4.2.2 Relevant context: AER Guidelines

221. The AER's Non-network ICT capex assessment approach[82] provides the following guidance on its approach to assessing non-recurrent ICT projects as part of its reviews of NSPs five-year revenue forecasts. We provide excerpts from this guideline in Figure 4.1.

80 Ausgrid, ERP Program Brief, page 9

81 We would normally consider benchmarking in our reviews of ICT expenditure, however this is not helpful in assessing non-recurrent ICT project or even programs of work due to the diverse timelines on which non-recurrent ICT operate

82 AER, Non-network ICT capex assessment approach, Nov 2019, pages 11-12

Figure 4.1: Excerpts from AER guideline on assessment of non-network ICT

Maintaining existing services, functionalities, capability and/or market benefits

'Given that these expenditures are related to maintaining existing service, we note that it will not always be the case that the investment will have a positive NPV. As such, it is reasonable to choose the least negative NPV option from a range of feasible options including the counterfactual. For such investments, we consider that they should be justified on the basis of the business case, where the business case considers possible multiple timing and scope options of the investments (to demonstrate prudency) and options for alternative systems and service providers (to demonstrate efficiency). The assessment methodology would also give regard to the past expenditure in this subcategory.'

Complying with new / altered regulatory obligations / requirements

'It is likely that for such investments, the costs will exceed the measurable benefits and as such, the least cost option will likely be reasonably acceptable in regard to the NER expenditure criteria. Therefore the assessment of these expenditures is similar to subcategory one. Should there be options to achieve compliance through the use of external service provides, the costs and merits of these should be compared.'

New or expanded ICT capability, functions and services

'We consider that these expenditures require justification through demonstrating benefits exceed costs (positive NPV). We will make our assessment therefore through assessing the cost-benefit analysis. Where benefits exceed costs consideration should also be given to self-funding of the investment.

For each subcategory of non-recurrent expenditure, we note that there may be cases where the highest NPV option is not chosen. In these cases, where either the chosen option achieves benefits that are qualitative or intangible, we would expect evidence to support the qualitative assumptions. We consider the evidence provided must be commensurate with the cost difference between the chosen and highest NPV option.

We also note that where non-recurrent projects either lead to or become recurrent expenditures in the future, this needs to be identified in the supporting business case and accounted for in any financial analysis undertaken to support the investment.'

222. Our assessment is based on these guidelines, in particular, the need to identify where, and the extent to which, proposed expenditure is to provide new or expanded capability and the need for economic justification of such expenditure.

4.3 Our assessment of Ausgrid's proposed ERP Upgrade Program

4.3.1 Ausgrid's case for action

It is reasonable for Ausgrid to replace SAP ECC 6 by 2027

223. SAP ECC version 6 (ECC 6) was launched in 2005 and since then there have been eight major upgrades, with the last in 2016. SAP ECC6 was replaced by SAP S/4HANA in 2015. Ausgrid is still running SAP ECC6 with ongoing support from SAP confirmed until 2027 at which time it will technically reach end-of-life.

224. There are significant business risks in running with an unsupported core system, as pointed out by Ausgrid:[83]

- There is a low but increasing risk of system failure with significant recovery costs and business interruption costs
- The systems become increasingly vulnerable to cyber attacks
  - Successful breaches could lead to outages and supply interruptions
- Licence obligations require all critical systems to remain secure at all times
- Not able to enable transition of applications to progressively meet the challenges in integrating CER over the next decade and beyond, which are discussed in Section 2.

The ERP, EAM, and MDM/B systems are core to Ausgrid's operations and it is reasonable for them to be replaced within the next RCP

ERP System

225. Ausgrid's ERP system is not unique in the industry, providing a means to '*help consolidate data/information from multiple business functions into one centralised database… [the] data is used for a wide variety of tasks by different business functions.'*[84] the core system of record for managing corporate information.

226. Ausgrid's ERP system is based on applications from a variety of vendors, including SAP software. Based on information in its Program Brief, its ERP landscape includes 26 applications from non-SAP vendors, and 16 SAP applications (including 4 SAP SaaS applications).[85] Ausgrid advises that its ERP system '*is functional, but it contains a number of legacy and duplicate applications…some are not properly integrated and several are approaching end of support/life*.'[86] Ausgrid further advises that this causes the following issues:[87]

- Inefficient and labour intensive multiple, manual steps
- Customised and inconsistent processes requiring use of 'off-system software'
- Systems not optimally integrated.

227. These issues are familiar to us with ERP systems in DNSPs – utilities select the cost-effective approach which is to defer the major upgrade to a new platform due to the business disruption during the transition until the cost of doing so is outweighed by the risk of not doing so. We are satisfied that Ausgrid will reach this point by 2027 or shortly thereafter (i.e. within the next RCP).

EAM System

228. Ausgrid's EAM system performs functions similar to those of EAMs at other NSPs, namely asset lifecycle management, supply chain management, maintenance planning and scheduling, monitoring, reporting and analytics. Ausgrid's EAM has seven SAP applications which interface with a number of other enterprise systems,[88] nonetheless Ausgrid advises that 'integration with other asset management tools for planning and analysis is limited.

229. Furthermore, Ausgrid advises that the issues with its current EAM are:

- Does not capture real-time information
- Unable to easily integrate customer asset information from CER

---

83 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 10

84 Ausgrid, Program Brief - ERP Program, p15

85 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, Figure 16

86 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 17

87 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 17

88 Including finance, human resources, procurement

- Asset system landscape is heavily fragmented
- Requires largely manual asset maintenance planning.

230. We are satisfied that Ausgrid has presented a satisfactory case for replacing Ausgrid's EAM system with a contemporary product within the next RCP.

MDM/B System

231. Ausgrid advises that it operates a suite of 44 third party and internally developed MDM/B applications and systems, with SAP ECC6 applications an integral part of its network billing process.[89] In addition to collecting, storing and validating meter and customer data they '*manage communications and data sharing with other market participants and billing with customers.* [90]

232. Ausgrid 's identified issues with its MDM/B include:

- Complex, relying on multiple systems and technologies to deliver services
- Legacy elements are increasingly difficult to maintain
- Incorrect/inconsistent data results in customer disputes and manual intervention.

233. We are satisfied that Ausgrid has presented a satisfactory case for replacing Ausgrid's MDM/B system with a contemporary product within the next RCP.

4.3.2 Assessment of options

Options considered by Ausgrid

234. Ausgrid considered four options:

- Do nothing
- Option 1: Base Case – technical upgrade of SAP ECC6 applications to SAP S/4HANA
- Option 2: Enhance - consolidate and simplify and add capabilities (preferred)
- Option 3: New – Migrate EAM and EAP SAP ECC6 applications to Oracle

The do-nothing option is not the prudent choice

235. Ausgrid concludes that the do-nothing option is unviable due to the application support for SAP ECC6 applications ceasing by 2027. For the reasons provided above, we consider that the 'do nothing' option would not be the prudent approach over the course of the next RCP.

Option 1 (technical upgrade) is the cheapest option and mitigates application support risks

236. This option is based on upgrading SAP-based applications to the current cloud-based SAP S/4HANA version but otherwise:

237. *'…business processes would remain the same, and there would be no changes to the integration and interoperability of SAP and non-SAP applications.* [91]

238. The Option 1 landscape is illustrated in the figure below, with the MDM/B applications continued to be hosted on-premise. The non-SAP applications will be retained.

---

89 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, Figure 7

90 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 17

91 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 11

[redacted]

239. The advantage of this option is the relatively low implementation cost of $19.8m (direct costs only, comprising $5.0m capex and $14.8m opex) including $1.6m (20%) contingency over the course of the next RCP. This option reduces the two key risks of system failure and cyber security breaches.

240. The disadvantage of this option is that it does not capture the potential efficiency gains from process transformation, retaining multiple legacy applications and the need for manual intervention.

241. This option is technically viable and is the counterfactual for Options 2 and 3. We assess Ausgrid's cost-benefit analysis in section 4.3.6.

Option 2 (upgrade and transform) is the most expensive option but does generate benefits

242. Option 2 is based on (i) upgrading existing SAP applications to S/4HANA, (ii) adoption of new SAP applications, and (iii) decommissioning bespoke and legacy systems to the extent practicable.

243. The new landscape under this option is summarised below. Objectively, this landscape is considerably more efficient and simpler than Ausgrid's current landscape.

[redacted]

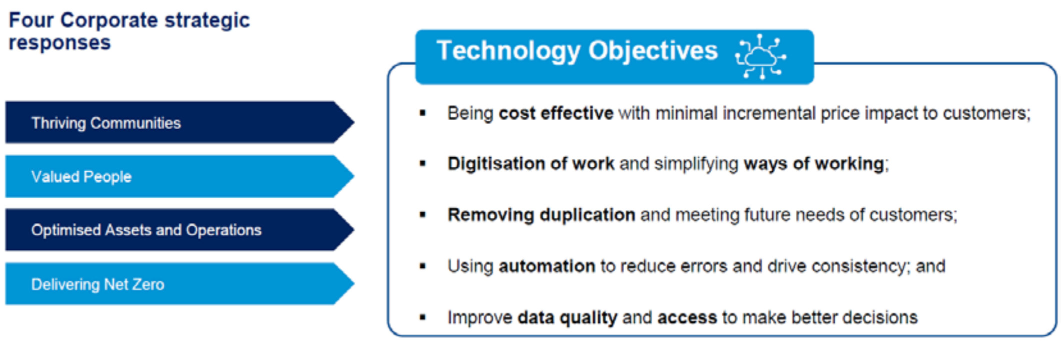
244. The advantage of this option compared to Option 1 is it '*enables increased integration and interoperability of systems, reduce the need for manual workarounds (e.g., for reconciliation of billing and invoicing data from multiple systems), increase the use of automation to*

reduce errors, and improve data quality. [92] As discussed below, Ausgrid has quantified several benefit streams which we consider in our assessment of Ausgrid's cost-benefit analysis, below.

245. Comparing Figure 4.3 and Figure 4.5, the simpler landscape resulting from the adoption of SAP applications in Option 2 is readily apparent, with Ausgrid planning on removing 43 legacy applications.

246. Figure 4.4 shows Ausgrid's technology objectives and, if Ausgrid's cost-benefit analysis was robust and demonstrated cost-effectiveness, then Option 2 would appear to be the prudent option.

Figure 4.4: Ausgrid's technology objectives



Source: Ausgrid on-site presentation, slide 8

247. The disadvantage of Option 2 compared to the counterfactual is the totex forecast of \$183.9m with a 50:50 capex:opex split and including \$24.6m (20%) contingency. This is a significant \$163.9m more than Option 1, to be spent on process improvements and purchase and integration of new applications to allow legacy systems to be retired.

248. We assess Ausgrid's cost-benefit analysis below.

Option 3 (migrate to Oracle applications) does not offer any advantages over the Base Case

249. Ausgrid assumed that the alternative to SAP S/4HANA is Oracle Cloud Applications because it is a mature enterprise application suite with a similar functionality coverage when compared with SAP and is considered to have the next best functionality. Only ECC6 will be decommissioned, all other related systems will be retained. The applications are hosted and managed in the public cloud by Oracle using "one solution for all". Ausgrid advises that '*[w]ith this option, our business processes will have to change to conform to the standard out-of-the-box processes that come defined within the Oracle Cloud Application Suite.*'[93]

250. The diagram below shows the landscape of the three core systems with selection of Option 3.

251. There are no clear advantages of Option 3 over either Option 1 or Option 2 other than the lower cost at \$138.2m, but at this cost, the simplification of the landscape and the majority of the benefits Ausgrid identifies for Option 2 would not be achieved despite spending an estimated \$118.2m more than Option 1.

252. Option 3 does not appear to be a prudent option.

[92] Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 11

[93] *Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential,* page 42

[redacted]

4.3.3 Program deliverability and dependencies

Ausgrid's preferred option 2 is a complex undertaking and won't be delivered by FY27 and there is some risk of delay beyond FY29

253. Ausgrid has presented an implementation roadmap for the preferred ERP Program Option 2, and we observe that:

- Ausgrid's core ERP, MDM/B and EAM systems are not scheduled to completed until Q3 of FY27/28 under Option 2:
  - Ausgrid's transformation roadmap for Option 2 shows that it intends to commence' integrated design' (ERP Program Phase 0) in Q1 of FY25
  - Replacement of the core systems not scheduled to be replaced until the end of Q3 of FY28
  - This implies some risk, albeit likely to be modest, is acceptable to Ausgrid given that SAP ECC6 will be unsupported from FY27
  - The implementation of the 'enhanced' or extended digital core program is not scheduled to be completed until the end of Q1 of FY29
  - A further six months work is then allowed for retiring superseded systems.
- There is considerable overlap in the implementation of the core ERP, EAM, MDM/B and enabling activities
- It is not clear from the roadmap whether Ausgrid has allowed sufficient time for hypercare between major tasks, particularly with the strong dependencies on completion of other Programs (see below) and interdependencies between the three EAP systems.

254. Ausgrid has recognised the significant Option 2 program delivery risks as follows, rating them all as 'medium' level:[94]

- Scarcity and availability of affordable resources with required skills within the required timeframes
- Complex digital transformation with many dependencies
- Ability to manage and govern third party services.

255. Ausgrid also identifies program dependencies with its Cyber Security, GIS Upgrade, ICT CER, and Data and Analytics Program, but denotes only potential delay to the ERP

94 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, section 6.1.1

Program from the GIS Upgrade Program. The bulk of the expenditure for the preferred GIS Upgrade option is scheduled to occur from FY25 – FY27[95] but it is not apparent from the information provided the timing of the work on which the ERP Program depends.

256. Ausgrid has denoted generic risk mitigation strategies and self-assessed the residual risk as 'Low' for all dimensions of risk. We remain unconvinced that the risk will be reduced to low from the information provided regarding planned mitigation actions.

Option 1 presents a low deliverability risk

257. Based on the narrow implementation window for Option 1 indicated in the CBA model of 1 year (FY25), it appears that there is negligible delivery risk presented by Option 1, regardless of the dependency on the GIS Upgrade Program.

4.3.4 Ausgrid's cost estimates for Options 1-3

The cost estimation methodology should not include contingency amounts but is otherwise fit-for-purpose

258. Ausgrid advises that *'[r]esourcing costs have been priced based on economies of scale achieved though delivering ERP, EAM and MDM/B as part of the same program over a four year delivery period.*'[96] Other costs are based on a combination of historic costs and vendor/supplier information for products and contract services have been used to forecast these costs.

259. Ausgrid has provided its CBA model which we used to check the application of Ausgrid's cost and benefit assumptions. For each option, the detail underpinning the costs estimate is indicative of a reasonable cost forecast. At this stage of the project lifecycle, we consider the cost estimating methodology to be reasonable.

260. As shown in the tables below Ausgrid has added 20% contingency to the project which we consider is not warranted at a project level in an RP proposal because over the entire portfolio such contingencies should balance out provided the cost estimation is not biased.

Table 4.2: Option 1 - Ausgrid proposed ICT ERP expenditures in next RCP - $million FY24

Description	Description	Capex/ opex	Cost
Program implementation	Contracted services and Ausgrid program costs for SIT and UAT support, UAT testing and project management	capex	2.03
		opex	2.03
Implementation initiatives	S/4HANA brownfield migration, technical services provided by third parties, functional support costs, application security modification and remediation and new UX experience implementation costs;	capex	2.14
		opex	2.14
Software and hosting fees	Additional SAP RISE[97] environment costs	capex	0.00
		opex	9.80
Contingency	20% allowance	capex	0.84
		opex	0.84
Total			**19.82**

Source: Based on Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, p30 and ERP upgrade CBA model – 31 Jan 20203 - Public

95 Ausgrid Att. 5.9.f - Data & Analytics Program – 31 Jan 2023 – Public, page 16

96 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 47

97 A new arrangement with SAP to enable Ausgrid's current ERP and EAM services to be managed in the cloud until 2027

261. In addition to the $175.3m totex in the next RCP to implement Option 2 as shown in Table 4.3 below, Option 2 requires an estimated $8.5m in the current RCP for 'customisation and preparation' (integrated business design and technical support costs). The total Option 2 cost is estimated to be $183.8m.

Table 4.3: Option 2 - Ausgrid proposed ICT ERP expenditures in next RCP - $million FY24

Description	Description	Totex[98]
Program implementation	Contracted services and Ausgrid program costs for business support, project management and training	51.0
Customisation & preparation	Integrated business design and technical support costs	0.0
Implementation initiatives	S/4HANA brownfield migration, technical services provided by third parties, functional support costs, application security modification and remediation and new UX experience implementation costs;	95.0
Contingency	20% allowance	29.2
Total		**175.3**

Source: EMCa pivot table derived from information in Ausgrid Att.5.9.h – ERP Upgrade CBA model – 31 Jan 2023 – Public

Option 3 cost estimate of $138.2m includes a 40% contingency amount

262. The estimated totex for option 3 is $138.2m in the next RCP, as shown in the table below.

263. Ausgrid state that

> *'The license and subscription cost estimates are based on Oracle's list price and does not represent a negotiated rate…and that '[t]he implementation is complex due to the change in product and vendor, the underpinning data models, and structures…The shift to a new product presents a significant risk and accordingly, the cost includes a 40% contingency.*[99]

264. Historic costs and vendor/supplier information have been used to estimate the costs. The level of detail in the CBA model is indicative of a reasonable level of cost analysis.

98 In Ausgrid's CBA model, all proposed totex is allocated 50% to capex and 50% to opex. The amount of $175.3m reconciles to the amounts in table on pages 39 to 41 of Ausgrid's Attachment 5.9.b, after deducting the $4.3m of capex and $4.3m of opex in FY24.

99 Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, page 42

Table 4.4: Option 3 - Ausgrid proposed ICT related expenditures in next RCP - $million FY24

Description	Description
Program implementation	Contracted services and Ausgrid program costs for business support, project management and training
Customisation & preparation	Integrated business design and technical support costs
Implementation initiatives	S/4HANA brownfield migration, technical services provided by third parties, functional support costs, application security modification and remediation and new UX experience implementation costs;
Contingency	20% allowance
Total	**$138.2m**

Source: Based on Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, pp42-43 and ERP upgrade CBA model – 31 Jan 20203 - Public

Summary of cost allocations between the three systems

265. The table below summarises the differences in costs between the three options for the replacement of the three core systems and, particularly, the difference between Options 1 and 2 due to the 'transformational work' to release benefits (compared to the counterfactual Option 1).

Table 4.5: Summary of Ausgrid proposed ERP program expenditures - $million FY24

Description	Option 1	Option 2*	Option 3
EAM	4.8	53.5	64.7
ERP	5.3	59.8	73.5
MDM/B	9.8	70.6	0.0
Total	**19.9**	**183.8**	**138.2**

*Source: Based on Ausgrid Att.5.9.b – ERP Upgrade Program – 31 Jan 2023 – Confidential, p30 and ERP upgrade CBA model – 31 Jan 20203 – Public * includes $8.5m in the current RCP*

4.3.5 Benefits

Ausgrid has identified 19 benefit sub-categories of benefits in its CBA model

266. Ausgrid has identified and quantified 19 benefit sub-categories of benefits in its CBA model with supporting descriptions and quantification approach. The benefits begin to accrue from FY28 (partial) with benefits either maximising the following year or several years later depending on the benefit sub-category. This appears to reflect the timing of systems implementation in the roadmap.

267. The largest benefit of $3.5m p.a. is attributed to a 10% reduction in outage duration/response time due to digital insights to manage condition-based maintenance related to extreme weather conditions and DER integration.

268. The second largest benefit is attributed to reduced repex:

- Various repex categories via better integrated visibility of different planned work types leading to identification of opportunities to respond to nearby work etc ($3.3m p.a.)
- Distributions mains:
  - Via better process compliance and system integration leading to better decision-making ($3.0m p.a.)

- Via access to dynamic unit rate forecasts (simulations as constructed data of similar components run by AI ($1.5m p.a.)

269. Two other cost reductions benefit streams average over $1m p.a. savings:

- Avoided network opex costs for non-maintenance / other operations through avoided FTE increases to network planning and support through automated planning processes provided through a modern EAM system
- ICT capex reduction for MSATS related ICT expenditure as a result of decommissioning MBS and MCS.

270. The other 13 benefit sources average $0.53m p.a. (cost reductions + customer time saved).

The calculations for the quantified savings in the CBA model are not provided

271. The derivation of the quantified savings are not provided in the CBA model which constrains our ability to assess the reasonableness of the claimed savings, however we make the following observations:

- It is plausible that savings from the sources identified may be made
- There appears to be some overlap in the benefits claimed for this program with the CER integration program.
- Confidence would be boosted if there was evidence of savings from similar programs of work, however we recognise that such benchmarking is challenging due to important differences between DNSPs.

4.3.6 Cost-benefit analysis

Ausgrid's CBA purports to show a positive NPV for its preferred option; however it assumes no costs beyond 2038 but benefits extend for 50 years. We consider that the economic assessment biases the economic analysis

272. Ausgrid's CBA model has been set up as a 'financial' model that attributes opex savings through the EBSS mechanism, between Ausgrid and its customers. As provided to us, the model is configured to assume that a customer EBSS benefit (from lower opex) continues for 50 years. On this basis, the NPV of its preferred option (S4Hana) is positive (+$18m) when compared with the 'base case' as an assumed counterfactual, as shown in Table 4.6. Against this same (base case) counterfactual, the NPV of the option to migrate to Oracle is significantly negative (-$44m).

Table 4.6: Ausgrid's representation of the NPV of the three options

Option name	Base Case	S/4Hana Transformation (preferred)	Migrate SAP ECC6 applications to Oracle
Option description	Technical upgrade of SAP ECC6 applications to S/4 HANA and maintain current legacy and bespoke MDM/B systems & perform technical upgrade of SAP ECC6	Full EAM/ERP transformation and upgrade and consolidate MDM/B systems in S/4HANA (Recommended)	Migrate SAP ECC6 applications to Oracle, no change to MDMB applications
Present value cost	(16,944,487)	(171,926,174)	(131,707,373)
Present value benefit	(1,657,991)	171,742,743	69,447,683
NPV [To market]	(18,602,478)	(183,432)	(62,259,690)
NPV relative to 'Base Case'		**18,419,046**	**(43,657,213)**

Source: EMCa analysis from Ausgrid CBA model

273. However, Ausgrid's analysis ignores any refresh or replacement costs that would be required if that benefit was to be provided to customers on an ongoing basis to 50 years. That is, the assumed EBSS benefit extends considerably beyond the assumed life of the ICT investment, which in the model is referred to as 15 years. The logic inherent in the relevant formula in the model takes the final year EBSS value (in this case, in year 11) and extrapolates that for the remainder of the 50 years analysis period.[100] This is effectively bestowing a 50-year opex benefit to the project, even though the 'life' of the ICT investment is considerably less.

274. When we undertake a resource-based economic analysis (as opposed to a financial analysis) and attribute the benefits to an assumed life of the proposed ICT asset of 15 years, the NPV is significantly negative as we show in Table 4.7. The analysis below demonstrates that the supposed positive NPV is a result of assuming an extrapolated benefit from years 16 to 50, without any associated ongoing cost.

Table 4.7: NPV of Ausgrid's preferred option relative to the Base Case, showing NPV disaggregated into years 1 to 15 and years 16 to 50

Description	AGD modelled costs and benefits over years 1 to 15 (2024 to 2038)	AGD modelled costs and benefits years 16 to 50 (2039 to 2074)	AGD's 50-year assessment (to 2074), as presented
Present value cost	(171,926,174)	-	(171,926,174)
Present value benefit	107,383,589	64,359,154	171,742,743
Net present value (NPV)	**(64,542,586)**	**64,359,154**	**(183,432)**
Add back Base case NPV (as shown in Table 4.6)	*18,602,478*		
NPV relative to 'Base case'	***(45,940,108)***	***82,961,632***	***18,419,046***

Source: EMCa analysis from Ausgrid CBA model

100 The 50-years' customer EBSS' benefit default may have been set with network capex investments in mind, but is not relevant to ICT investment

275. On this basis, we must conclude that Ausgrid has not demonstrated that its proposed ERP upgrade preferred option provides a net economic benefit.

4.4 Our findings and implications

4.4.1 Summary of our findings

The ERP, EAM, and MDM/B systems are core to Ausgrid's operations and it is reasonable for them to be replaced within the next RCP

276. Ausgrid's core applications which are the subject of this upgrade proposal are common to the industry and each perform critical functions. Based on the information provided about the obsolescence of the SAP ECC6 version that the applications are based, we are satisfied that they are justifiably in need of upgrade/replacement in the next RCP.

Option 1 (technical upgrade) is the cheapest option; it mitigates the risks satisfactorily and has the lowest Net Present Cost

277. Ausgrid has considered four options including 'Do nothing' and provided a CBA model which provides analyses for Options 1 – 3.

278. Ausgrid also refers to Option 1 as the Base Case, which involves a technical upgrade of the SAP ECC6 applications to SAP S/4HANA at a capital cost of $19.82m totex ($5.0m capex in the next RCP).

279. We consider that the 'Do-nothing' option is unlikely to be the prudent approach.

280. Ausgrid's CBA purports to show a positive NPV for its preferred Option 2, which is to spend $175.3m totex ($76m capex in the next RCP) on 'transforming its ERP, EAM, and MDM/B landscape'. However, the CBA assumes no costs beyond 2038, with benefits extending for 50 years. We consider that the economic assessment biases the economic analysis.

281. When we undertake a resource-based economic analysis perspective and attribute the benefits to an assumed life of the proposed ICT asset of 15 years, the NPV for Option 2 based on the information Ausgrid has provided, is significantly negative.

Contingency should be deducted from the project cost

282. Ausgrid has added 20% contingency to each of its Option costs which we consider is unwarranted.

4.4.2 Implications of our findings for proposed expenditure

283. Based on the information that Ausgrid has provided, we consider that the prudent option is Option 1 (also referred to as its Base Case) rather than Ausgrid's proposed Option 2 with a proposed totex of $149.0m.

284. After deducting the 20% contingency amounts included with Ausgrid's capex and opex forecasts, this would imply that a capital cost of $4.0m and SaaS opex of $11.8m would represent the prudent level of expenditure in the next RCP, as shown in the table below.

Table 4.8: EMCa adjustment table – ERP Program expenditure $m FY24

Description	FY25	FY26	FY27	FY28	FY29	Total
Capex:						
Option 2^ capex (Ausgrid preferred)	*21.0*	*33.0*	*15.0*	*6.0*	*0.0*	*76.0*
Option 1^ capex	5.0	0.0	0.0	0.0	0.0	5.0
Less 20% contingency	*-1.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-1.0*
EMCa adjustment	*-17.0*	*-33.0*	*-15.0*	*-6.0*	*0.0*	*-72.0*
EMCa proposed ERP capex	**4.0**	**0.0**	**0.0**	**0.0**	**0.0**	**4.0**
Opex:						
Option 2^ SaaS opex (Ausgrid preferred)	*21.0*	*32.0*	*15.0*	*5.0*	*0.0*	*73.0*
Option 1^ SaaS opex	7.0	2.0	2.0	2.0	2.0	14.8
Less 20% contingency	*-1.4*	*-0.4*	*-0.4*	*-0.4*	*-0.4*	*-3.0*
EMCa adjustment	*-15.4*	*-30.4*	*-13.4*	*-3.4*	*1.6*	*-61.2*
EMCa proposed ERP SaaS opex	**5.6**	**1.6**	**1.6**	**1.6**	**1.6**	**11.8**
Ausgrid proposed ERP totex^	42.0	65.0	21.0	11.0	0.0	149.0
EMCa proposed adjusted ERP totex	**9.6**	**1.6**	**1.6**	**1.6**	**1.6**	**15.8**

Source: EMCa analysis of Ausgrid RP, Figure 5.9.2 for Option 2; Ausgrid Att 5.9b – ERP upgrade program – 31 Jan 2023 – Confidential for Option 1; note rounding may lead to inconsistencies with totals; ^ includes contingency of 20%