energy market consulting associates

Energergex and Ergon Energy 2025/26 to 2029/30 Regulatory Proposals

REVIEW OF NETWORK VISIBILITY OPEX STEP CHANGE

Public Version

Report prepared for:

AUSTRALIAN ENERGY REGULATOR

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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 Energex and Ergon Energy from 1st July 2025 to 30th June 2030. 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 Energex and Ergon Energy. 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 21 June 2024 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 Energex and Ergon Energy's regulatory submissions or other documents due to rounding.

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ABBREVIATIONS

Term	Definition
AEMC	Australian Energy Market Commission
AMI	Advanced Metering Infrastructure
CBA	Cost Benefit Analysis
DER	Distributed Energy Resource
DOE	Dynamic Operating Envelope
EQ	Energy Queensland
LV	Low Voltage
NER	National Electricity Rules
NPV	Net Present Value
PQ	Power Quality
RCP	Regulatory Control Period
RP	Regulatory Proposal

EXECUTIVE SUMMARY

Introduction

1. The AER has engaged EMCa to undertake a technical review of aspects of the expenditure that Ergon Energy (Ergon) and Energex have proposed in their regulatory proposals (RPs) for 2025-30 Regulatory Control Period (next RCP). The scope of our review, covered by this report, comprises opex step changes proposed by both businesses, for a network visibility program.

2. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed opex allowance as an input to its draft determination on EQ's revenue requirements for the next RCP.

Proposed network visibility opex step changes

Proposed opex step changes are primarily to enable purchase of live power quality (PQ) data to augment 'basic' PQ data that is likely to be made available at no cost

3. Ergon and Energex have proposed opex step changes of $6.9 million and $14.5 million respectively, for proposed programs to enhance the visibility of their LV networks in the next RCP.

4. EQ assumes that power quality data will be made available at no cost, and this is in line with a rule change that is in progress following recommendations in AEMC's review of metering services.[1] The rule change would provide 'basic' data, which for working purposes EQ assumes would be provided 6-hourly.

5. Part of the EQ proposal is to provide for the analytical capability to utilise this data. However, the majority of the opex that EQ proposes would be to purchase 'live' Power Quality (PQ) data to supplement the basic data.

EQ asserts that live data will enable it to achieve greater safety benefits than it can with basic data alone

6. The main benefit that EQ considers is the ability to detect service line integrity faults, and thereby to improve safety. EQ also considers that the data will provide reliability and DER integration-related benefits, though it quantifies these at an order of magnitude less than the safety benefits. EQ asserts that the live data that it proposes to purchase will enable it to achieve considerably greater safety benefits than the 6-hourly 'basic' data that will be made available under the proposed rule change.

Our assessment

EQ provided a business case that was not compelling

7. In the business case that EQ provided with its RP, it claimed an NPV for this program of $554 million for Ergon and $377 million for Energex. EQ subsequently provided revised models, which reduced the claimed net benefits to $74 million for Ergon and $22 million for Energex. The magnitude of the corrections that EQ made, considerably undermine confidence in its analyses.

8. Taking account of the assumptions in EQ's update CBA however, our primary concern was with EQ's assumption that it would achieve a markedly greater safety benefit by purchasing

[1] AEMC, 30 August 2023

live data. This assumption is not consistent with AEMC's assessment that safety benefits from access to AMI PQ data can be achieved by utilising the 'basic' data that is to be provided at no cost.

The network visibility program is justified, but purchase of live data is not justified

9. When we modified the CBA models that EQ provided to equate the assumed service line defect detection rate from 6-hourly data to that for live data, we confirmed that there is a net benefit to utilising the basic 6-hourly data. However, we found that the additional cost of purchasing live data was not justified.

Implications

10. After removing the proposed cost for purchasing live data, we find that:

- Ergon's proposed step change of $6.9 million is not justified
- Energex's proposed step change of $14.5 million is not justified, but that a step change of $3.31 million would be a reasonable alternative allowance to provide for the additional costs required to process and utilise the data.

1 INTRODUCTION

The AER has asked us to review and provide advice on Energex and Ergon Energy's (Ergon) proposed allowances over the next Regulatory Control Period (RCP) relating to their Network Visibility program. Our review is based on information that Energex and Ergon provided and on aspects of the National Electricity Rules (NER) relevant to assessment of expenditure allowances.

1.1 Purpose of this report

11. The purpose of this report is to provide the AER with a technical review of aspects of the expenditure that Energex and Ergon have proposed in their respective regulatory proposals (RP) for the 2025-30 Regulatory Control Period (next RCP).

12. Energex and Ergon are owned and managed by Energy Queensland (EQ).

13. The assessment contained in this report is intended to assist the AER in its own analysis of the proposed capex and opex allowances as an input to its Draft Determination on Energex and Ergon's revenue requirements for the next RCP.

14. Energex and Ergon have a common network visibility strategy, under the structure of parent company EQ. Furthermore, the business cases that each business has submitted for the proposed expenditure allowances are identical in structure and justification logic and differ only with regard to input data and resulting amounts. For expediency, we have therefore undertaken a common assessment in this report, with our findings nevertheless reflecting differences in the numerical information provided.

15. For this report, we will refer to 'EQ' rather than 'Energex and Ergon Energy' when referring to the common network visibility strategy or other common elements of network visibility plans.

1.2 Scope of requested work

16. Our scope of work, covered by this report, is as defined by the AER. The AER initially asked us to advise on Energex and Ergon's proposed Distributed Energy Resources (DER) capex and opex. However, following a reprioritisation assessment, the AER asked us to advise only on the respective businesses' proposals for an opex step change for network visibility. As we discuss in our assessment, EQ's business case for this step change is only partly predicated on DER and EQ identifies safety benefits as the dominant driver.

17. The scope of the assessment in this report is therefore to advise on Energex and Ergon's proposed opex step changes to enable network visibility. Our assessment considers the various benefits that EQ has claimed in seeking to justify this expenditure.

1.3 This report

1.3.1 Report structure

18. In Section 2 we present the opex step change amounts that EQ proposes for Ergon and Energex.

19. In Section 3 we present our assessment of the proposed expenditure allowances. Our assessment is based on review of the Ergon and Energex business cases that EQ provided, together with their associated cost benefit analysis (CBA) models. The business cases and CBA models for each business are based on similar premises, involving the same use

cases and assessment of similar options. We review the common aspects of these business cases, then consider the implications for the business cases presented for each business.

20. We present our conclusions on the proposed allowances in Section 4.

1.3.2 Information sources

21. We have examined relevant documents that EQ has published and/or provided to the AER in support of the areas of focus and projects that the AER has designated for review. This included further information at onsite 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 21 June 2024 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 EQ documents comprising the Ergon and Energex's RPs and including the various appendices and annexures to the RPs.

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

1.3.3 Presentation of expenditure amounts

25. Consistent with the EQ RPs for the next RCP, expenditure is presented in this report in $FY25 real terms, 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 EQ PROPOSALS FOR NETWORK VISIBILITY STEP CHANGE

In its RPs for the next RCP, EQ proposes step change opex allowances totalling $6.8 million for Ergon and $14.6 million for Energex.

EQ provided business cases, based mainly on improved customer safety but also including improvements to customer reliability, DER benefits, service line replacement deferral benefits and some benefits from reduced theft and improved network planning. In its business cases, EQ presents its assessment of four options for each business, involving different levels of assumed live smart meter data purchase and differentiating between overhead and underground service customers.

The Ergon proposed option would involve purchasing live smart meter data for 25% of its customers. The Energex proposal is to purchase live data for 25% of overhead service customers but only 10% of underground service customers. For remaining customers, the businesses would obtain smart meter data on an assumed 6-hourly cycle, for which there is assumed to be no data acquisition cost.

In the course of our review, EQ provided updated business cases with modified expenditures and significantly modified assessments of benefits. As is our policy, we take the view that the subject of our assessment is the expenditures that the business proposed in its regulatory proposal. Our findings on the proposed step changes are therefore based on the amounts that Ergon and Energex proposed in their regulatory submissions, regardless that EQ provided different figures subsequently.

2.1 Introduction

27. In this section we provide an overview of what Ergon and Energex have each proposed, and relevant information that they provided in support of their proposals.

2.2 Overview of EQ's Network Visibility opex step change

2.2.1 Relevant information

28. Energex and Ergon have each proposed an opex step change for network visibility in their RPs. They have each provided a business case document and associated CBA model for this program.[2]

29. The EQ proposals also reference a DER Integration Strategy, that provides further information on the source of assumed DER-related benefits.[3]

2 6.05A – Business Case – Smart Meter Data Acquisition and 6.05B – NPV Model – Smart Meter Data Acquisition. Documents of the same name are provided separately for Energex and Ergon.

3 5.6.01 DER Integration Strategy. Documents of the same name are provided separately for Energex and Ergon.

2.2.2 EQ's opex forecast for a Network Visibility program

Proposed step change information

EQ proposed step changes of $6.8 million and $14.6 million respectively for Ergon and Energex

30. In its RP, Ergon proposes an opex step change of $6.8 million and Energex proposes a step change of $14.6 million for the acquisition and processing of data to facilitate enhanced network visibility at the LV level.[4]

31. Both businesses provided business cases to support the proposed expenditure. The original business cases that were provided with the RPs indicated costs that aligned with the amounts proposed in the RPs (noting that the RP amounts are in $FY25, whereas the business case amounts are expressed in $FY23).[5]

EQ provided updated business cases in May 2024 that were based on different opex amounts than had been proposed

32. In May 2024 EQ provided us with revised business cases in response to an information request in which we had queried certain information in the original business cases. The revised business cases are based on different expenditure, with Energex's proposed opex being less than in its original business case. The revised Ergon opex is more, with the main reason being a considerably greater amount in FY30 which is due to an assumption that there is a cost of $0.86 million that commences in that year, for 'ongoing LV monitor data costs', whereas Ergon's original business case had no expenditure in that year for this item.[6]

33. In Table 2.1 and Table 2.2, we show the amounts that each business proposed in its RP and the opex amounts in its original and revised business cases (noting that the business case expenditure is expressed in $FY23).

Table 2.1: Ergon's opex forecasts for its Network Visibility program - $million, real FY2025

Opex forecast	FY26	FY27	FY28	FY29	FY30	TOTAL
Proposed step change ($ FY25)	1.0	1.2	1.4	1.6	1.7	**6.8**
Original business case ($ FY23)	*0.9*	*1.1*	*1.3*	*1.5*	*1.6*	***6.4***
Revised business case ($FY23)	*1.2*	*1.4*	*1.6*	*1.8*	*2.8*	***8.8***

Source: Proposed step change is from Ergon's regulatory proposal, Table 54. Business case information is from the summary page of each business case

Table 2.2: Energex's opex forecasts for its Network Visibility program - $million, real FY2025

Opex forecast	FY26	FY27	FY28	FY29	FY30	TOTAL
Proposed step change ($ FY25)	2.1	2.5	2.9	3.3	3.7	**14.6**
Original business case ($ FY23)	*2.0*	*2.4*	*2.8*	*3.1*	*3.5*	***13.8***
Revised business case ($FY23)	*1.7*	*2.0*	*2.2*	*2.4*	*3.2*	***11.5***

Source: Proposed step change is from Energex's regulatory proposal, Table 56. Business case information is from the summary page of each business case

34. We also observe a discrepancy between the expenditure referred to in the tables above and the expenditure assumed in the DER integration business cases provided to us:

4 $ realFY25.

5 Slight differences in these tables from the source data are due to rounding.

6 Ergon model 6.05 NPV model, updated 08052025 (sic), DCF sheet.

- For Energex, the DER Integration business case presents Network Monitoring (Grid Visibility) expenditure of $2.28 million per year, or $11.40 million in total, for its preferred option 2c, which is described as 'DOE with High Grid Visibility' and which we understand is intended to reflect its preferred option for providing network visibility.[7]
- For Ergon, the proposed Network Monitoring expenditure in its DER Integration business case is similarly for 'option 2c'. For this business, the proposed expenditure rises over the period and totals $13.67 million, compared with amounts of $6.4 million and $6.8 million provided in the two instances of its Network Visibility business case.[8]

35. For the purpose of forming a view based on the requirements of the NER, we have assessed the step change opex that each business has proposed in its RPs and have disregarded the differing expenditure information provided.

Composition of proposed costs

The majority of the proposed costs are for the assumed purchase of live data

36. The composition of the opex that EQ proposes is provided only in its cost benefit models. In Table 2.3 and Table 2.4 we provide the cost composition for EQ's proposed option for each business , which it denotes as Option 4. Noting that this information is in $FY23 terms, the annual and aggregate costs reconcile to the January versions of the business cases.

37. As is shown in the tables, the dominant cost is the assumed cost for purchasing 'live' PQ data.

Table 2.3: Ergon: Composition of proposed opex - $ million, real FY23

Cost (Option 4)	FY26	FY27	FY28	FY29	FY30	TOTAL
Data acquisition	0.77	0.95	1.10	1.26	1.42	**5.50**
Data analytics	0.20	0.22	0.23	0.25	0.26	**1.16**
LV Monitor data cost	0.00	0.00	0.00	0.00	0.00	**0.00**
Total opex	0.98	1.17	1.34	1.51	1.68	6.67

Source: EMCa table derived from Ergon 6.05B – NPV model (January 2024).

Table 2.4: Energex: Composition of proposed opex - $ million, real FY23

Cost (Option 4)	FY26	FY27	FY28	FY29	FY30	TOTAL
Data acquisition	1.69	2.06	2.40	2.74	3.11	**12.00**
Data analytics	0.36	0.39	0.43	0.46	0.42	**2.05**
LV Monitor data cost	0.00	0.00	0.00	0.00	0.00	**0.00**
Total opex	2.05	2.46	2.82	3.19	3.53	14.05

Source: EMCa table derived from Energex 6.05B – NPV model (January 2024)

2.2.3 Overview of EQ's justification for it Network Visibility opex step change

EQ has sought to justify its proposed program based primarily on assumed safety benefits, but also including reliability, DER integration and some other minor benefits

38. In their business cases EQ has undertaken a CBA in which it has considered several use cases for network visibility data and several deployment options. In summary, the use cases involve:

[7] Energex 5.6.01 DER integration Strategy. Table 18.

[8] Ergon 5.6.01 DER Integration Strategy. Table 18.

- The potential to provide improved customer safety and improved customer reliability by detecting service line defects and failures
- The potential to provide improved customer reliability by early detection of LV transformer faults
- The ability to defer replacement of some service lines that would otherwise be proactively replaced earlier than necessary
- Benefits to DER integration
- A reduction in theft and improvements in grid planning.

EQ assumes that it will be provided basic PQ data 6-hourly, and that it will need to purchase any live data

39. In line with an assumed rule change from the AEMC, EQ assumes that 'base' smart meter data will in the future be provided at no cost and that this will comprise 6-hourly data. To the extent that it requires live (or near real-time) data, EQ assumes that this will need to be purchased.

EQ considers four options, which differ in the extent of live data assumed to be purchased

40. EQ has considered four deployment options, which differ with respect to the amount of 'live' smart meter data that it purchases as follows:

- Option 1: EQ does not purchase any live data and obtains 6-hourly data only for customers with overhead services
- Option 2: EQ purchases live data for 25% for all its customers and obtains 6-hourly data for 75% of its overhead service customers
- Option 3: EQ purchases live data for 25% of its overhead service customers and 6-hourly data for 75% of its overhead service customers, but no data for its underground service customers
- Option 4:
  - For Ergon, this option assumes purchase of live data for 25% of all its customers and obtaining 6-hourly data for the remaining 75%. (Ergon obtains this across its entire customer base, whether serviced overhead or underground)
  - For Energex, this option assumes purchasing 25% live data for overhead service customers and 10% live data for underground service customers, with 6-hourly data for the remainder (i.e. for 75% of overhead service and 90% of underground service customers).

41. For both businesses, EQ prefers option 4, claiming the highest NPV for this option.

3 ASSESSMENT OF NETWORK VISIBILITY OPEX STEP CHANGE

Ergon and Energex each propose an LV network visibility program that utilises data from smart meters and from LV transformer monitoring. They propose to utilise '6-hourly' smart metering data that, under a likely change to the NER, will be provided at no charge. They propose to augment this with a proportion of 'live' or 'near real-time' data which they would need to purchase from meter data providers.

EQ provided business cases in which the businesses claim that their proposed option involving purchase of some real-time data is supported by cost benefit analysis. As we noted in section 2, EQ provided two versions of a CBA, but the originally provided versions (and associated Business Case documentation) were based on illogical calculations that led to a massively overstated benefit. To the extent that we have based our findings on economic analysis, we have chosen to set aside the originally provided versions and to conduct our assessment utilising the updated versions that EQ subsequently provided.

On the basis that basic PQ data is provided at no cost pursuant to the proposed rule change, we consider that the business cases do support a network visibility program with the main benefit being that it will provide significant safety benefits through detecting service line defects. However, we consider that essentially the same safety benefits as EQ has assumed from purchasing 'live' data can be provided by utilising this 6-hourly basic data. The information provided by EQ does not indicate sufficient additional benefit to justify the cost of purchasing the proposed live data.

3.1 Introduction

42. In this section we present our assessment of the network visibility opex step changes that each business has proposed.

43. Our assessment is based on our review of the Ergon and Energex business cases that were provided to us, together with CBA modelling that formed the basis of each business case. The structure of the Ergon and Energex business cases, the methodologies applied, costing assumptions and benefit use cases are the same for each business and we refer to these as the EQ analyses. The results of the EQ analyses differ only to the extent of inherent differences between the businesses, and we therefore present these (together with our conclusions) separately for each business.

3.2 EQ cost benefit analysis

3.2.1 Overview of EQ analysis

EQ initially presented business cases with a hugely overstated assessment of benefits

44. EQ seeks to justify the proposed network visibility expenditure based on its CBA of the four options referred to in section 2.2.3.

45. In its original versions of its business cases, EQ presented an NPV of $554 million for Ergon and $377 million for Energex, for its preferred option. In its revised business case, its NPVs

were substantially lower, but still positive, at $74 million for Ergon and $22 million for Energex.

46. We consider it an indictment on EQ quality controls in its assessment processes that it released the original business cases to AER as part of its regulatory proposal. The benefit assessments in its original CBA were clearly erroneous with illogical calculations that resulted in claimed safety benefits, for example, for Ergon of the order of $30 million per year rising to over $60 million per year. In its reissued cost benefit analysis, EQ revised its calculations, and this reduced claimed benefits to around one-tenth of what had previously been proposed.

We have used updated analyses that EQ provided, as the basis for our assessment

47. We consider that the revised CBAs at least provided plausible values from which we could conduct an assessment though, as we describe in section 3.3, we consider that these updated analyses too have led EQ to an incorrect option selection. Our assessment of the justification for the proposed expenditure and option selection, including the PV of costs and benefits referred to in this section, is based on the revised business cases. We have taken this approach because the originally provided business cases were erroneous and resulted in massively overstated benefits, such that they were not amenable to any plausible assessment.

3.2.2 PV of costs

Ergon

In its CBA, the main difference in costs between the options is the assumed cost of purchasing live PQ data

48. The PV of Ergon's assessment of the costs for each option is shown in Table 3.1. The LV Monitor Capital Cost is the only capex, and the other line items all represent the PV of opex, which Ergon has assessed over 15 years. We observe that:

- The capex is the same for each option
- The ongoing LV monitor data and support system and infrastructure opex are also the same and there are only minor differences in the PV of opex for ongoing data analytics
- The substantial cost difference is therefore between option 1, which does not involve purchase of live data, and each of the other options which do - the lower cost for option 3 is because this involves purchasing live data only for customers with an overhead service.

Table 3.1: Ergon PV of costs for each option ($m FY23)

Costs	Option 1	Option 2	Option 3	Option 4
Data acquisition	0.00	-14.97	-8.51	-14.97
LV Monitor Capital Cost	-14.51	-14.51	-14.51	-14.51
Ongoing LV Monitor data	-6.60	-6.60	-6.60	-6.60
Support System & Infrastructure	-1.30	-1.30	-1.30	-1.30
Ongoing data analytics	-3.39	-3.23	-3.39	-3.05
TOTAL PV of COST	**-25.79**	**-40.60**	**-34.30**	**-40.42**

Source: EMCa analysis, using data from Ergon 6.05B – NPV model (08052025) (sic)

Energex

As with Ergon, the main cost difference between the options assessed is the cost of purchasing live data

49. The PV of Energex's assessment of costs for each option is shown in Table 3.2. As the larger of two businesses, these costs are higher than Ergon's.

50. As is the case for Ergon, the LV Monitor Data and Support System and Infrastructure costs are the same for all four options and, of the opex cost items, Data Acquisition is the highest cost for all except options 1.

51. In its updated business case for Energex, EQ has proposed a different 'option 4', with live data for 25% of its overhead services but only for 10% of its underground services, rather than 25% for all services as it assumed for Ergon (and as it proposed in its original business case).

Table 3.2: Energex PV of costs for each option ($m FY23)

Costs	Option 1	Option 2	Option 3	Option 4
Data acquisition	0.00	-30.49	-11.46	-19.07
LV Monitor Capital Cost	-24.69	-24.69	-24.69	-24.69
Ongoing LV Monitor data	-4.60	-4.60	-4.60	-4.60
Support System & Infrastructure	-1.30	-1.30	-1.30	-1.30
Ongoing data analytics	-4.57	-5.18	-4.57	-6.21
TOTAL PV of COST	**-35.15**	**-66.25**	**-46.61**	**-55.87**

Source: EMCa analysis, using data from Energex 6.05B – NPV model (09052024)

EQ's assumed costs for live data may be understated

52. In response to our information request, EQ provided background information comprising contracts for provision of 'live' meter data and associated analytics. [redacted].[9] We observe also that in its business cases, EQ describes its assumed cost per meter as being the current differential between the rates for 6-hourly versus real-time data.[10] Therefore it is not entirely clear that it would be able to obtain 'live' data at this rate, and a higher cost would clearly worsen the economics of purchasing live data.

53. Energex's information on the cost assumed for data analytics is reasonably supported by its evidence, which comprises quotations from a provider.

9 Information is from two confidential contracts provided in response to IR017. A monthly fee has been converted to annual by multiplying by 12.

10 For example in Energex 6.05A business case. Page 6.

3.2.3 EQ's PV of benefits

Ergon

The main benefit is from service line safety and reliability, which EQ estimates to be higher for options in which it purchases live data

54. The PV of Ergon's assessment of the benefits for each option is shown in Table 3.3.

55. Benefits from reduced theft and improved grid planning are low. The main benefit is, as we would expect, from service line safety and reliability. For this, we observe that for options 2, 3 and 4 the benefit comprises the sum of the 6-hourly and live data benefit streams. This benefit is the same for each of these three options which is logical because it applies only to those customers with overhead services and, for these customers, each of these three options involves 25% live and 75% 6-hourly data.

56. While EQ combines 'service line safety and reliability' in its benefits presentation, we find on inspection in the models that EQ's estimated safety benefits considerably exceed the estimated reliability benefits

57. Benefits from improvement in distribution transformer reliability are around $4 million greater for options 2, 3 and 4, arising from the application of live data.

58. In response to our information request, EQ advised that there is a DER integration benefit from utilising 6-hourly data, and which it refers to as 'basic grid visibility'. EQ advises that with this level of grid visibility it expects to be able to allow Dynamic Operating Envelopes (DOE) levels to match customer export levels to utilise 80% of distribution transformer capacity. EQ has captured this benefit in its DER integration business case and has therefore not duplicated this benefit in 'option 1' for its network visibility business case.

59. EQ explains in its response that the DER benefits shown for the 'live data' options in Table 3.3 (i.e. options 2 and 4) therefore reflect only the incremental benefit (relative to basic grid visibility) by allowing close to full utilisation of export capacity.[11]

Table 3.3: Ergon PV of benefits for each option ($m FY23)

Item	Option 1	Option 2	Option 3	Option 4
Theft & Grid Planning	0.20	0.41	0.20	0.82
Service line safety and reliability – 6-hour data	84.24	63.18	63.18	63.18
Service line safety and reliability – live data	0.00	32.20	32.20	32.20
Distribution transformer reliability - 6 hour data	1.16	0.00	0.00	0.00
Distribution transformer reliability - near real time data	0.00	5.23	5.23	5.23
Service line replacement deferral	6.30	6.30	6.30	6.30
DER Integration	0.00	6.80	0.00	6.80
TOTAL PV of BENEFITS	**91.90**	**114.12**	**107.11**	**114.53**

Source: EMCa analysis, using data from Ergon 6.05B – NPV model (08052025) (sic)

Energex

The main benefit is from service line safety and reliability, which EQ estimates to be higher for options in which it purchases live data

60. The PV of Ergon's assessment of the benefits for each option is shown in Table 3.4. The pattern of relative benefits is similar to that for Ergon, with service line safety and reliability

11 The zero DER benefit for option 3 appears counterintuitive since it does not seem to ascribe any benefit to the use of live data for the 25% of overhead service customers. However we have not relied on consideration of option 3 in our assessment.

the dominant benefit. However, the aggregate PV of benefits is considerably less than for Ergon, for all options.

Table 3.4: Energex PV of benefits for each option ($m FY23)

Item	Option 1	Option 2	Option 3	Option 4
Theft & Grid Planning	0.20	0.89	0.29	0.89
Service line safety and reliability – 6-hour data	42.33	31.75	31.75	31.75
Service line safety and reliability – live data	0.00	16.47	16.47	16.47
Distribution transformer reliability - 6 hour data	2.43	0.00	0.00	0.00
Distribution transformer reliability - near real time data	0.00	11.14	11.09	11.11
Service line replacement deferral	8.49	8.49	8.49	8.49
DER Integration	0.00	14.83	0.00	9.28
TOTAL PV of BENEFITS	**53.46**	**83.57**	**68.08**	**77.99**

Source: EMCa analysis, using data from Energex 6.05B – NPV model (09052024)

3.2.4 EQ's NPV

61. Given that the main opex cost for network visibility is from purchase of live data, and the business cases are defined as being specifically to support the case for data acquisition, the main options of interest are option 1 (which involves no purchase of live data) and option 4, which for both businesses is presented as the preferred option.

62. For Ergon, option 4 provides the most comprehensive coverage of live data. For Energex, option 4 involves less live data (since it assumes only 10% coverage for underground services) but is nevertheless presented as having the highest NPV.

Ergon

EQ's CBA for Ergon suggests a net benefit from the purchase of live data

63. In Table 3.5 we show a derived calculation from Ergon's assessment, of the relative benefit of purchasing 25% live data. With Ergon's assumptions (regarding costs and benefits of each option, there is a net benefit of $7.99 million (in PV terms) in favour of option 4 and it is on this basis that Ergon proposes to purchase this level of live data.

Table 3.5: Ergon - Relative NPV for purchase of live data ($m FY23)

Item	NPV ($m)
NPV of option 4 (Purchase of live data)	74.10
Less NPV of option 1 (no purchase of live data)	66.11
Net benefit ascribed to purchase of live data	**7.99**

Source: EMCa analysis, using data from Ergon 6.05B – NPV model (08052025) (sic)

Energex

As with Ergon, EQ's CBA for Energex suggests a net benefit from the purchase of live data

64. In Table 3.6 we show a similarly derived calculation from Energex's assessment, of the relative benefit of purchasing live data which, for its option 4, comprises 25% for overhead service customers and 10% for underground service customers.

65. With Energex's assumptions (regarding costs and benefits of each option, there is a net benefit of $4.81 million (in PV terms) in favour of option 4, and it is on this basis that Energex proposes to acquire this level of live data.

Table 3.6: Energex - Relative NPV for purchase of live data ($m FY23)

Item	NPV ($m)
NPV of option 4 (Purchase of live data)	22.12
Less NPV of option 1 (no purchase of live data)	18.31
Net benefit ascribed to purchase of live data	**3.81**

Source: EMCa analysis, using data from Energex 6.05B – NPV model (09052024)

3.3 Our assessment of the EQ Cost Benefit Analyses

3.3.1 Working assumption for our assessment

66. We have examined the EQ NPV models and, as a working assumption, we accepted the cost and benefit inputs that are incorporated in them. While we did not conduct a model review or model audit, we did not observe errors in the EQ modelling or cost benefit approach that would thwart our alternative analysis using these models.

67. While noting that the models contain some assumptions that are not consistent with the original business cases provided in conjunction with the EQ RPs, and therefore with the opex step change that each business has proposed, we consider that they provide an adequate means for assessing the impact of the main alternative assumption that we describe below.

3.3.2 Assumed service line safety benefit

Assumed higher safety benefit from live data compared with 6-hourly data

We consider that both 6-hourly and live PQ data will provide a materially similar safety benefit

68. Our primary concern with the EQ assessments is EQ's assumption that 6-hourly data will lead to a 60% reduction in safety incidents, whereas live data will reduce safety incidents by 90%. Neither of these assumptions is supported by evidence, with Ergon stating that the 60% safety incident improvement with 6-hourly metering *'…is difficult to quantify and has been determined through engineering judgment'*.[12]

69. Through an information request, we sought further explanation from EQ of any basis for its assumption that that the safety benefits of live data are additive to the benefits obtained from 6-hour data. The EQ responses reasserted their assumption but did not provide evidence for it.[13]

70. Regardless of which percentage is justified, we are not convinced by EQ's assumption that a lower safety incident reduction percentage is ascribed to 6-hourly data compared with live data. In our experience, service line defects may exist for a significant period before they are either identified and rectified or result in a safety incident. Six-hourly data is sufficient to identify these defects and there is minimal likelihood of a safety incident occurring within a 6-hour window after a defect emerges.

[12] Ergon 6.05A Business case. Page 12.

[13] Ergon response to IR019 and Energex response to IR017. Question 3a.

71. Our opinion on data requirements to deliver service line safety benefits is consistent with the AEMC's finding in its metering review.[14] The AEMC describes the use case for service line safety through loss of neutral detection and states that '*DNSPs are expected to use 'basic' power quality data for detecting loss of neutral*'.[15]

72. Both businesses also acknowledge this in their business cases, where they state:

> *'For those with 6-hour data capture, 60% of our incidents will be captured. This is likely understating the number of incidents that we would capture as a result of this capability.'*[16]

73. We consider that a realistic assumption is that both 6-hourly and live data will provide a materially similar safety benefit and that detection of 90% of service line safety issues is a plausible assumption.[17]

3.3.3 Assumed transformer outage reductions

Reduction in outages arising from transformer failures

EQ has overstated reliability benefits from reduced transformer failures, and these will be substantially the same with 6-hourly or live data

74. EQ's assessment of improved transformer reliability from detecting failures assumes that failure-based outage durations, which average 8 hours for Ergon and 3 hours for Energex, can be reduced by 90% with live data and 10% with 6-hourly data.

75. From our experience, DNSPs tend to become aware of a distribution transformer failure relatively quickly. While smart meter data can reduce the time to identify the specific failure that has occurred and therefore to be able to mobilise crew to address that failure, there will be little reduction in the time then required for crew to travel and restore supply. It does not seem plausible that this time can be reduced by 90%, which would imply that (for Energex) supply can be restored in 0.3 hours.

76. We consider that any reduction in outage times will be materially the same whether utilising transformer information obtained 6-hourly, or live. EQ has assessed this reduction as 10% utilising 6-hourly data and we therefore consider this would also be a plausible assumption to apply to utilisation of live data.

Reduction in outages arising from transformer defects

We consider that reliability benefits from detection of transformer defects will also be substantially the same with 6-hourly or live data

77. We consider that there is a benefit from being able to detect transformer defects before failure occurs. However, we do not consider that this can be reduced by 90%, which would imply that a transformer repair or replacement can be undertaken with an outage that is only 10% of duration otherwise required.

78. We consider that a more plausible assumption might be a reduction in the number of failures that arise from defects, and this could be represented by the difference in outage duration arising from a failure compared with the outage required for a planned repair or planned replacement. Moreover, we consider that there would not be a material difference in the benefit obtainable by using 6-hourly data compared with live data, as with service line

14 Review of the regulatory framework for metering services. AEMC. 30 August 2023.

15 AEMC review as above. P.118. AEMC defines basic metering data as being provided between 6-hourly and daily.

16 Ergon 6.05A and Energex 6.05A Business cases. Page 14.

17 AusNet is a similar size to Ergon (of the order of 750,000 to 800,000 customers) and reported that it identified and remediated 1500 loss of neutral situations and reduced reported electric shocks by 75%. (refer to AEMC Metering Review, August 2023, page 119).However not all reported electric shocks would be from service line defects and we consider it likely that Ami power quality data will identify a higher proportion of safety defects.

safety benefits as described above, we consider that either data will allow defects to be identified.

Alternative assumptions for transformer reliability benefits

While we sought to model alternative transformer reliability assumptions, the result was counter-intuitive, and we do not place reliance on it

79. Within the EQ models, we sought to model an alternative scenario in which we:
    - Assumed that live data reduces failure-based outages by 10%, rather than 90%
    - Assumed that live data and 6-hourly data equally provide for identification of defects, and that the benefit of being able to proactively address those defects is to reduce the outage time by the difference between the failure restoration time and the defect restoration time (based on each business' values for these).

80. Whereas we would expect the model to produce transformer reliability benefits for a live data option that are slightly higher than for 6-hourly data, the model produced a reverse result in which the benefit from 6-hourly data was approximately twice that for live data. We consider that this is likely an erroneous result and it's unclear whether this exposes a logic fault in the model or is a result of invalid modifications that we made in seeking to model this scenario. However, rather than pursue this quantitatively, we take account of this aspect of our finding qualitatively in our revised assessments for each business in the following subsections.

3.4 Revised assessment result for Ergon

3.4.1 Revised assessment result

81. Using Ergon's NPV model, we modified the safety benefit assumption so that it is the same for 6-hourly data as for live data – that is, 90%.

With equivalent safety benefits to those that can be obtained from 6-hourly data, the purchase of live data has a negative NPV

82. With a revised assumption that 6-hourly data provides the same safety benefit as live data, the overall NPV of a proposed network visibility program presents as being considerably greater than in Ergon's business case. However, the ranking of the options reverses, with Option 1 having a higher NPV than Option 4.

83. We show the results of this revised assessment in Table 3.7. Comparing this with the information in Table 3.1, the costs for options 1 and 4 remain the same and, comparing with Table 3.3, the benefits other than for service line safety and reliability also remain the same.

84. The safety benefits are almost the same for these two options. However, despite DER and transformer reliability benefits being greater for option 4, these benefits are not sufficient to justify the cost of acquiring the live data. The NPV would be more negative still, if the purchase cost for the live data was greater than the cost of [redacted] that EQ has assumed.

Table 3.7: EMCa revised assessment of Ergon NPV for network visibility program ($m FY23)

	Option 1	Option 4
Net Present Cost:		
Data acquisition	0.00	-14.97
LV Monitor Capital	-14.51	-14.51
Ongoing LV Monitor data	-6.60	-6.60
Support System & Infrastructure	-1.30	-1.30
Ongoing data analytics	-3.39	-3.05
PV of cost	**-25.79**	**-40.42**
Net Present Benefit:		
Theft & Grid Planning	0.20	0.82
Service line safety and reliability	126.19	126.84
Distribution transformer reliability	1.16	5.23
Service line replacement deferral	6.30	6.30
DER Integration	0.00	6.80
PV of benefit	**133.86**	**145.99**
NPV	**108.07**	**105.57**

Source: EMCa analysis, using data from Ergon NPV model, with assumed benefit of 6-hourly data modified

85. As we show in Table 3.8, with the modified assumption equating the safety benefits of 6-hourly data with those for live data, the proposed investment in purchasing live data returns a negative NPV.

Table 3.8: Relative NPV for purchase of live data ($m FY23)

Item	NPV
NPV of option 4 (Purchase of live data)	105.57
Less NPV of option 1 (no purchase of live data)	108.07
Net benefit (cost) ascribed to purchase of live data	**-2.50**

Source: EMCa analysis, using data from Ergon 6.05B – NPV model (08052025) (sic)

The NPV of the option to purchase live data is more negative than shown in Table 3.8, because Ergon's assumed higher transformer reliability benefit from live data is overstated

86. Consistent with our finding in Section 3.3.3, we consider that the result above understates the difference between scenarios 1 and 4 because it overstates the extent to which live data provides higher transformer reliability benefits than 6-hourly data. Noting that there is a distribution reliability benefit difference of around $4 million in favour of option 4 in our alternative quantitative analysis (as shown in Table 3.7), a reduced differential between the options would drive a more negative NPV to the purchase of live data than is shown in Table 3.8 further reinforcing our negative finding for the proposed purchase of live data.

3.4.2 Justification for a step change

An opex step change is not justified for Ergon

87. In our information request, we asked Ergon to provide information on its current purchase costs for meter data. The cost information that Ergon provided for FY24 is shown in Table 3.9.

Table 3.9: Ergon's current year opex for network visibility

Item	Amount ($)
Meter data cost	$429,300
Analytics licence cost	$140,000
Total opex	**$569,300**

Source: Ergon response to IR019, Q.4. We assume the amounts to be $nominal.

88. FY24 is the base year that Ergon has adopted for its base step trend opex forecast. The response above suggests that there is implicitly $2.8 million[18] included in Ergon's opex forecast for network visibility opex, absent a step change.

89. In Table 3.10 we show the opex that Ergon has assumed in its revised business case. We observe that this cost includes $0.87 million in FY30 for LV Monitor data costs, that were not included in Ergon's original business case that accompanied its RP. We also note that this cost is in $FY23, whereas Ergon's RP is in $FY25.

Table 3.10: Ergon opex for network visibility program – Option 1 (utilising 6-hourly meter data) ($m FY23)

Cost	FY26	FY27	FY28	FY29	FY30	TOTAL
Data acquisition	0.00	0.00	0.00	0.00	0.00	**0.00**
Data analytics	0.26	0.28	0.30	0.32	0.34	**1.50**
LV Monitor data cost	0.00	0.00	0.00	0.00	0.87	**0.87**
System support and infrastructure cost	0.13	0.13	0.13	0.13	0.13	**0.63**
Total opex	**0.39**	**0.41**	**0.43**	**0.44**	**1.33**	**2.99**

Source: EMCa analysis, using data from Ergon 6.05B – NPV model (08052025) (sic)

90. At a reasonable level of materiality, we consider that the opex required to enable Ergon's data visibility program, making use of the forthcoming access to 6-hourly data, is covered by the $2.8 million that results from application of the base step trend forecast. On Ergon's information, this is sufficient to allow for the necessary data analytics capacity and system support and infrastructure costs. Ergon's information suggests that such a program will have a significantly positive NPV. However, we find that no step change is required.

3.5 Revised assessment result for Energex

91. Using Energex's NPV model, we modified the safety benefit assumption so that it is the same for 6-hourly data as for live data – that is, 90%.

3.5.1 Revised assessment result

As with Ergon, with equivalent safety benefits to those that can be obtained from 6-hourly data, the purchase of live data has a negative NPV

92. With a revised assumption that 6-hourly data provides the same safety benefit as live data, the overall NPV of a proposed network visibility program increases considerably. However, the ranking of the options reverses, with Option 1 having a higher NPV than Option 4.

93. We show the results of this revised assessment in Table 3.11. Comparing this with the information in Table 3.2, the costs for options 1 and 4 remain the same and, comparing with Table 3.4, the benefits other than for service line safety and reliability also remain the same.

94. The safety benefits are almost the same for these two options and, despite DER and transformer reliability benefits being greater for option 4, these benefits do not appear to be

18 $569,300 x 5.

sufficient to justify the cost of acquiring the level of live data that Energex has assumed. The NPV would be more negative still, if the purchase cost for the live data was greater than the cost of [redacted] that EQ has assumed.

Table 3.11: EMCa revised assessment of Energex NPV for network visibility program

	Option 1	Option 4
Cost:		
Data acquisition	0.00	-19.07
LV Monitor Capital	-24.69	-24.69
Ongoing LV Monitor data	-4.60	-4.60
Support System & Infrastructure	-1.30	-1.30
Ongoing data analytics	-4.57	-6.21
PV of cost	**-35.15**	**-55.87**
Benefit:		
Theft & Grid Planning	0.20	0.89
Service line safety and reliability	63.34	63.97
Distribution transformer reliability	2.43	11.11
Service line replacement deferral	8.49	8.49
DER Integration	0.00	9.28
PV of benefit	**74.46**	**93.74**
NPV	**39.31**	**37.87**

Source: EMCa analysis, using data from Energex NPV model, with assumed benefit of 6-hourly data modified

95. As we show in Table 3.12, with the modified assumption equating the safety benefits of 6-hourly data with those for live data, the proposed investment in purchasing live data would return a negative NPV.[19]

Table 3.12: Relative NPV for purchase of live data

	NPV
NPV of option 4 (purchase of live data)	37.87
Less NPV of option 1 (no purchase of live data)	39.31
Net benefit (cost) ascribed to purchase of live data	**-1.44**

Source: EMCa analysis, using data from Energex 6.05B – NPV model (09052024)

3.5.2 Justification for a step change

A smaller opex step change would be justified for Energex

96. In response to our information request, Energex advised that it has no historical expenditure for meter data acquisition and that it made no base year adjustment because its FY24 forecast costs for meter data expenditure were considered to be immaterial.

97. In Table 3.13 we show the opex that Energex has assumed for 'option 1' in its revised business case. This option provides for the LV network visibility program based on utilising the 6-hourly data that is assumed to be obtainable without a data acquisition cost.

[19] We did not explicitly consider EQ's quantification of reliability benefits. However, from inspection of the EQ CBAs, we observe that while 'safety and reliability' benefits are aggregated, this grouping is dominated by the safety benefits and the reliability benefits are small by comparison.

98. On Energex's information that there was no expenditure relating to this program in its FY24 base year opex, there appears to be justification for a step change though we observe that the amount involved is small relative to Energex's overall opex. Consistent with Energex's RP, we have converted this to FY25 real terms, and it would amount to a total of $3.31 million.

Table 3.13: Energex opex for network visibility program – Option 1 (utilising 6-hourly meter data) ($m FY23)

Option 1:	FY26	FY27	FY28	FY29	FY30	TOTAL
Data acquisition	0.00	0.00	0.00	0.00	0.00	0.00
Data analytics	0.36	0.38	0.40	0.43	0.45	2.02
LV Monitor data cost	0.00	0.00	0.00	0.00	0.51	0.51
System support and infrastructure cost	0.13	0.13	0.13	0.13	0.13	0.63
Total opex ($m FY23)	**0.48**	**0.51**	**0.53**	**0.55**	**1.08**	**3.15**
Potential step change ($m FY25)	***0.50***	***0.53***	***0.56***	***0.58***	***1.14***	***3.31***

Source: EMCa analysis, using data from Energex 6.05B – NPV model (09052024)

3.6 Other observations on use cases for basic smart meter data

99. While our finding that neither Ergon nor Energex has presented sufficient justification for its proposed purchase of live data, we observe that the AEMC identifies use cases consistent with those that EQ has proposed, and which are supported by basic meter data. In addition to the service line safety benefit that EQ has demonstrated, AEMC's use case list includes:

- Theft detection
- Improved ability to connect DER via a greater understanding of local hosting capacity
- Improved visibility, DER hosting capacity and investment planning
- Dynamic export limits (dynamic operating envelopes)
- LV network optimisation – static tuning of voltage management
- Cross-referencing error correction.[20]

100. AEMC's assessment reinforces the position that a range of network visibility benefits can be realised from a network visibility program utilising basic smart meter data. The EQ business cases demonstrate that this net benefit can be substantial.

[20] AEMC smart metering review (August 2023). Table E.1.

4 CONCLUSIONS

4.1 Our findings

A network visibility program would provide significant safety benefits, but EQ information does not support the proposed purchase of live data

101. The EQ business cases provide strong support for an LV network visibility program and demonstrate the significant service line safety benefits that would result from it. A program based on improving network visibility is justified for both businesses.

102. On the information provided, neither business case provides sufficient justification for the purchase of live data from smart meter data providers. We consider that essentially the same safety benefits can be provided by utilising 6-hourly data that is assumed to soon be available at no charge to DNSPs, under a NER rule change.

The business cases overstate the benefits of live data to transformer reliability

103. In the EQ business cases, we consider that the reliability benefits of live data (as opposed to 6-hourly data) from improved transformer reliability are considerably overstated. We consider that 6-hourly data will facilitate detection of transformer defects and we do not consider it realistic to assume that live data will allow transformer failure and defect-based outages to be reduced by 90%, as the EQ business cases assume.

Live data provides DER benefits but EQ information in the network visibility business cases indicates that these are not sufficient to support the purchase of live data

104. For DER, we consider it reasonable to assume that live data will provide a higher level of benefit than DER utilising only ‘basic’ 6-hourly data. However, on the information that EQ provides in its network visibility business cases, this is not sufficient to justify the proposed purchase of live data.

105. EQ has provided separate business cases for DER integration, which show significant net benefits for DER integration strategies. EQ’s proposed option in these business cases assumes utilisation of live smart meter data. We have taken account of the DER benefits of live data relative to utilising basic data, as presented by EQ in its network visibility business cases. While it is not within our scope to review the DER integration business cases, from the EQ analyses presented there it would appear that these too would nevertheless be strongly positive based on utilising only basic (6-hourly) smart meter data.

4.2 Implications for proposed step changes

Ergon’s proposed step change not justified

106. We consider that Ergon has not justified the proposed step change for network visibility.

We propose a reduced step change for Energex

107. We consider that Energex has not justified the step change that it has proposed for network visibility, because it has not justified the proposed purchase of live smart meter data. We consider that there is justification for an alternative step change, as shown in Table 4.1. As shown in Table 3.13, this would be to cover the additional costs required for data analytics, data costs for LV monitoring and system support and infrastructure costs.

Table 4.1: EMCa proposed alternative opex step change for Energex network visibility program ($m FY25)

	FY26	FY27	FY28	FY29	FY30	TOTAL
Alternative step change	**0.50**	**0.53**	**0.56**	**0.58**	**1.14**	**3.31**

Source: EMCa analysis, using data from Energex 6.05B – NPV model (09052024)