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Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses

Final decision – Reasons paper

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Associated documents

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1 October 2012	N/A	Electricity Distribution Information Disclosure Determination 2012 [2012] NZCC 22
1 October 2012	ISBN 978-1-869452-09-4	Information Disclosure for Electricity Distribution Businesses and Gas Pipeline Businesses: Final Reasons Paper
23 March 2022	ISBN 978-1-869459-96-3	Targeted Information Disclosure Review - Electricity Distribution Businesses – Process and Issues Paper
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27 March 2023	N/A	Targeted Information Disclosure Review – Tranche 2 – Technical Elements Workshop (Presentation)
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30 May 2023	ISBN 978-1-99-101296-8	Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Process paper
6 July 2023	ISBN 978-1-991085-23-8	Electricity Distribution Information Disclosure Determination 2012 (Consolidated)
17 August 2023	ISBN 979-1-99-101298-2	Part 4 Targeted Information Disclosure Review - Framework paper
17 August 2023	ISBN 978-1-99-101295-1	Targeted Information Disclosure Review (2024) - Electricity Distribution Businesses - Draft decision - Reasons paper
17 August 2023	ISBN 978-1-991085-8	[Draft] Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC [XX]

Commerce Commission
Wellington, New Zealand

Contents

Glossary

Acronyms	
AMP	Asset Management Plan
CPP	Customised price-quality path
DPP	Default price-quality path
DYE	Disclosure year ending
EA	Electricity Authority
EDBs	Electricity Distribution Businesses
EEA	Electricity Engineers' Association
EECA	Energy Efficiency and Conservation Authority
ENA	Electricity Networks Aotearoa
ID	Information Disclosure
IEGA NZ	Independent Electricity Generators Association
IMs	Part 4 input methodologies
IM Review	Input Methodologies Review
IPAG	Innovation and Participation Advisory Group
LV	Low voltage (in reference to network types)[1]
MBIE	Ministry of Business, Innovation and Employment
MEUG	Major Electricity Users' Group
MV	Medium voltage
Opex	Operational expenditure
Part 4	Part 4 of the Commerce Act 1986
PIP	Process and Issues Paper
PQ	Price-quality
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TIDR	Targeted Information Disclosure Review
ToU	Time of use

1 'Low voltage' is defined in the ID Determination as the nominal Alternating Current (AC) voltage of less than 1000 volts or the assets of the EDB that are directly associated with the transport or delivery of electricity at those voltages.

Executive summary

We are requiring electricity distribution businesses to disclose new and improved information about their performance

X1 We are reviewing the information disclosure (ID) requirements for electricity distribution businesses (EDBs) to ensure that sufficient information is available to enable stakeholders to assess EDBs' performance and to ensure the ID requirements remain fit for purpose in a changing environment.[2]

X2 As part of this targeted information disclosure review (TIDR), we are changing some ID requirements, adding some new requirements, and removing some requirements for EDBs. These changes will enable stakeholders (including consumers) to better understand how EDBs are performing now and in the future.

X3 This paper outlines our final decisions for TIDR (2024), including all changes we are making to the Electricity Distribution Information Disclosure Determination 2012 (ID determination), and our reasons for them.[3] The Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 (amendment determination) published alongside this paper gives effect to these decisions.[4] We have also published a separate document which summarises our final decisions for TIDR (2024).[5]

X4 The amended requirements will be implemented in a staged manner. We have published a compliance calendar in the *Summary of our Final Decisions* document, which sets out the key dates by which various categories of information must be disclosed.[6]

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2 Commerce Act 1986, Part 4, ss 52A and 53A. Unless stated otherwise, all references to statutory provisions are references to the provisions of the Commerce Act 1986.

3 *Electricity Distribution Information Disclosure determination 2012* [2012] NZCC 22. A copy of the current consolidated determination (eg, including subsequent amendment determinations for ease of reference), which is not the legal authority, can be accessed via our website: Commerce Commission, Electricity Distribution Information Disclosure Determination 2012, (6 July 2023).

4 *Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024* [2024] NZCC 2.

5 Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Summary of Final Decisions, (29 February 2024).

6 Ibid, at pages 6-7.

Our review of information disclosure requirements for electricity distribution businesses is ongoing

X5 We consider that our work on amending ID requirements for EDBs is better described as ongoing, rather than the targeted review in two tranches which we signalled in our March 2022 Process and Issues Paper (PIP).[7] We also note that we intend for the ongoing TIDR project to be broader, covering all sectors subject to ID regulation, and to not be limited only to electricity distribution.

X6 To reflect this amended approach to the TIDR, we have moved away from grouping and labelling issues into “tranches”. In any year in which we undertake a review, we will refer to the year in which the amendment determination is expected to be published. Therefore, we refer to the “Targeted Information Disclosure Review (2024)” – TIDR (2024) – rather than “Targeted Information Disclosure Review (Tranche 2)”.

Our final decisions will ensure stakeholders can access better information about electricity distribution business’ quality of service, asset management practices, and preparation for the future

X7 The key aspects of our final decisions are:

X7.1 **Decarbonisation**: We have expanded reporting requirements to capture more information on network constraints, non-traditional solutions, and pricing;

X7.2 **Asset management**: We have refined reporting requirements on vegetation management to capture more fulsome and consistent information on EDB practices and capability;

X7.3 **Quality of service**: We have extended reporting requirements on quality of service to capture more granular information on quality and reliability of EDB services; and

X7.4 **Other important changes**: We have clarified definitions, updated assurance standards, updated audit and director certification obligations, and made some additional amendments which were suggested by submitters on our draft decision.

X8 We have tailored the timing and format of our final decisions to ensure sufficient information on EDB performance is available to stakeholders, while accounting for EDB circumstances (for example, time required to prepare and deliver under new requirements) and uncertainty in the sector.

[7] Commerce Commission, Targeted Information Disclosure Review – Process and Issues paper, (23 March 2022).

Electricity distribution businesses continue to face a changing environment

X9 The energy sector is undergoing a period of significant change, particularly in relation to the transition to a low carbon economy, other impacts of climate change (including network resilience in the face of more frequent and severe adverse weather events), and the challenges and opportunities posed by new technology. We are carrying out this targeted review of ID requirements for EDBs because they are likely to be impacted significantly and in multiple ways.

Our final decisions reflect feedback from stakeholders and our analysis

X10 We have identified several ways we can improve our ID requirements for EDBs based on our observations since the requirements were set. Over time we have seen information disclosed by EDBs mature and improve. We have also seen trends emerge for key metrics through analysis we have completed using ID data.[8]

X11 Our final decisions are informed by feedback received from stakeholders, including feedback on our draft decisions for TIDR (2024), and other past engagement. We have received feedback on our draft decision from a wide group of stakeholders, including EDBs, retailers, third parties in the sector and consumer groups. We value the clarity, comprehensiveness, and depth of engagement in these submissions. Some of our final decisions are different to our draft decisions (informed by the feedback we received in submissions on our draft decisions). Key differences from our draft decisions are detailed in Table 1 below.

[8] Our public pieces of performance analysis using ID data are available on our website here.

Table 1: Key differences from draft decisions

Amendment number	Difference from draft decision	Determination clause/schedule affected
Various	Allowed greater lead-in time for EDBs to comply with multiple requirements.	Various
D3.1	Removed the requirement to disclose the approximate range of forecast available capacity in 20 years.	Schedule 12b(i)
D5.2	Renamed the term 'non-traditional solution' to 'non-network solution'.	Clause 1.4.3
D6.1	Amended the standardised connection type options in Schedules 8(i) and (ii).	Schedules 8(i) and (ii)
D6.2	Added and amended terms to the standardised price components in Schedules 8(i) and (ii).	Schedules 8(i) and (ii)
AM6.1	Removed the audit requirement for disaggregated vegetation operational expenditure (opex) information in Schedule 6b(i).	Clause 1.4.3, Schedule 6b(i)
AM6.1	Removed the requirement to disclose opex at a disaggregated level for 'routine and corrective maintenance and inspection' in Schedule 6b(i).	Schedule 6b(i)
AM6.2	Amended the disclosure of overhead circuit sites that are at high risk from vegetation damage (and associated definitions) in Schedule 9c.	Schedule 9c
AM6.3	Simplified the breakdown of vegetation interruptions in Schedule 10(ii).	Schedule 10(ii)
Q14.1	Relocated Schedule 10a to its own workbook and removed the director certification requirement for Schedule 10a.	Schedule 10a
Q14.2	Amended the criteria for reporting on worst-performing feeders within Schedule 10(vi) to be unplanned interruptions only.	Schedule 10(vi)
Q14.2	Added additional criteria for worst-performing feeders (unplanned) based on a customer impact ratio.	Clause 1.4.3, Schedule 10(vi)
Q14.2	Expanded the data collected on worst-performing feeders (unplanned).	Schedule 10(vi)

We set ID requirements to enable stakeholders to assess the performance of electricity distribution businesses

X12 We set ID requirements for EDBs to publicly disclose information regularly about how they are performing, including how they are responding to changing consumer demands and planning for the future.[9] The types of information that EDBs must disclose include data on prices, measures of quality, financial information and forward-looking information on managing and investing in the network (including expenditure forecasts).

X13 The purpose of this form of regulation is to ensure sufficient information is available to stakeholders (including consumers) to be able to assess EDBs' performance in terms of the outcomes listed in section 52A of the Act.[10] We produce a summary and analysis of this information to make it more accessible and understandable for stakeholders.[11]

These final decisions are the second package of material changes as part of ongoing targeted information disclosure reviews and our wider work programme

X14 These are our final decisions for TIDR (2024) which is the second package of material changes we are making to ID requirements for EDBs under the TIDR project. These changes come into force in a staggered timeline from 2024 to 2026.

X15 We are working on a broader range of issues as part of our wider work programme. This work includes a review of the 2023 asset management plans (AMPs) provided by the EDBs. Part of the review includes checking that the AMPs are fulfilling the purpose of ID regulation and to understand EDBs' approaches to significant issues such as resilience and climate change.[12]

X16 We also plan to continue to undertake periodic reviews for incremental minor improvements to the ID requirements, including error corrections and clarifications where appropriate. In April 2023 and June 2023, we made such changes by publishing non-material amendment determinations.[13] Our final decision for TIDR (2024) includes similar amendments.

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9 We regulate electricity distribution businesses under Part 4 of the Commerce Act 1986.

10 Sections 52A and 53A of the Act.

11 Our public pieces of performance analysis using ID data are available on our website here.

12 Further information on the work we are doing to review 2023 AMPs can be found on our website here.

13 Commerce Commission, Explanatory note for publication of non-material amendments to Electricity Distribution Information Disclosure Determination, (27 April 2023); *Electricity Distribution Information Disclosure (Non-material) Amendment Determination 2023* [2023] NZCC 6; Commerce Commission, Explanatory note for publication of non-material amendments to Electricity Distribution Information Disclosure Determination 2012, (28 June 2023); *Electricity Distribution Information Disclosure (Non-material) Amendment Determination - June 2023* [2023] NZCC 12.

X17 The EDB Information Disclosure Issues and guidance register (Issues Register) responds to stakeholder feedback that results in ID amendments, provides guidance and clarification on certain existing ID requirements, and lists outstanding issues that may be considered for future reviews.[14] We intend to keep stakeholders informed of any issues or potential changes identified through regular updates to our Issues Register.

[14] Commerce Commission, EDB Information Disclosure – Issues and guidance register, (27 April 2023).

Chapter 1 Introduction

We are requiring electricity distribution businesses to disclose new and improved information about their performance

1.1 We have made changes to the information disclosure (ID) requirements that apply to electricity distribution businesses (EDBs) under Part 4 of the Commerce Act 1986 (Part 4).

1.2 The amended ID requirements will be implemented in staged manner. We have published a compliance calendar in the *Summary of our Final Decisions* document, which sets out the key dates by which various categories of information must be disclosed.[15]

1.3 This paper outlines our final decisions for TIDR (2024), including all changes to ID requirements (for example new requirements and removed requirements), and our reasons. The Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2 (amendment determination) published alongside this paper gives effect to our final decisions.[16] References in this reasons paper to the ID determination are references to the Electricity Distribution Information Disclosure Determination 2012 [2012] NZCC 22 (principal determination) as amended by the amendment determination.

1.4 The *Part 4 Information Disclosure Reviews – Framework paper* summarises the legal framework we have applied in reaching our final decision on setting these ID requirements.[17]

We set information disclosure requirements to enable stakeholders to assess the performance of electricity distribution businesses

1.5 ID is a regulatory tool provided for under Part 4. We use it to regulate certain markets where there is little or no competition (and little prospect of future competition) by requiring suppliers in those markets to publicly disclose information about their performance.

1.6 The purpose of ID regulation is to ensure that sufficient information is readily available to interested persons (stakeholders) to assess whether the purpose of Part 4 is being met.[18] We also analyse and summarise that information into a form that is helpful and easier for consumers and other stakeholders to understand.

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15 Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Summary of Final Decisions, (29 February 2024), page 6-7.

16 *Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024* [2024] NZCC 2.

17 Commerce Commission, Part 4 Information Disclosure Reviews – Framework paper, (14 December 2023).

18 Commerce Commission, Part 4 Information Disclosure Reviews – Framework paper, (14 December 2023), paragraph 6-20.

1.7 An effective ID regime provides transparency to stakeholders on the performance of regulated suppliers. Information is disclosed regularly, to provide an ongoing source of information so that multi-year trends can be identified and monitored over time. This allows stakeholders to assess whether, in relation to a regulated supplier, outcomes are consistent with those produced in a competitive market.

1.8 Publishing our analysis of the information that a supplier publicly discloses can also promote incentives for the supplier to improve its performance, by highlighting performance levels, relative performance, and performance trends to stakeholders including other suppliers.

1.9 We also set price and quality controls for EDBs that are not 'consumer-owned' (referred to as non-exempt EDBs).[19] We set 'price-quality (PQ) paths' that restrict the revenue these EDBs can earn and impose minimum standards for the quality of service that consumers receive.

1.10 EDBs that are consumer-owned (currently 13 of the 29 EDBs) are exempt from PQ paths because Parliament has decided that their consumers have enough input into how the business is run, reducing the need for PQ paths. In exempt businesses, there is an alignment of interest between business owners and consumers which reduces the incentives of the owners to exercise market power at the expense of consumers.

We are reviewing our information disclosure requirements to ensure our regulation remains fit for purpose as the external context changes

1.11 We are undertaking this "targeted" review of ID requirements that apply to EDBs to ensure sufficient information is available for stakeholders to assess EDBs' performance and continue to do so in a changing environment. This is part of ensuring our regulation remains fit for purpose as the external context changes. It is important that our rules and processes ensure that EDBs have incentives to continue to invest and innovate to maintain reliable services, while responding to changing consumer preferences, technology, government policy and other environmental factors, including climate change.[20]

1.12 The energy sector is in a period of transition and change, particularly in relation to the transition to a low carbon economy and other impacts of climate change, and the challenges and opportunities posed by new technology. EDBs are likely to be impacted significantly and in multiple ways.

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19 'Consumer-owned' suppliers are defined in s 54D. Information disclosure is the only form of regulation to which consumer-owned EDBs ('exempt EDBs') are subject to under Part 4.

20 Commerce Commission, Ensuring our energy and airports regulation remains fit for purpose, (23 February 2022), paragraph 5.

1.13 Climate change will also pose other challenges to EDBs in the medium to long term, including network resilience to weather events.

1.14 We are continuing to work closely with the Electricity Authority (EA), especially on how decarbonisation affects EDBs.

Our final decisions reflect feedback from stakeholders, our analysis, and our increased experience of regulation

1.15 We have identified several ways in which we can improve our ID requirements for EDBs based on observations we have made in the period since the requirements were set. Over time we have seen information disclosed by EDBs mature and improve and trends emerge for key metrics. We have also undertaken several pieces of analysis using ID data.[21]

1.16 Our final decisions are also informed by our past engagement with stakeholders and the detailed and useful feedback they have provided us, including feedback in response to:

1.16.1 our resets of EDB price-quality paths;[22]

1.16.2 our open letter of April 2021;[23]

1.16.3 our March 2022 PIP for this review;[24]

1.16.4 our draft decisions for Tranche 1 of the TIDR;[25] and

1.16.5 our draft decisions for TIDR (2024).[26]

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21 Our public pieces of performance analysis using ID data are available on our website here.

22 We set "price-quality paths" that restrict the revenue these EDBs can earn and require them to deliver services at a quality that consumers would expect.

23 Commerce Commission, Ensuring our energy and airports regulation is fit for purpose, (29 April 2021). Commerce Commission, Summary of submissions received on letter published 29 April 2021, (12 October 2021).

24 Commerce Commission, Targeted Information Disclosure Review – Process and Issues paper, (23 March 2022).

25 Commerce Commission, Targeted Information Disclosure Review – Draft decisions paper – Tranche 1, (3 August 2022).

26 Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Draft decision – Reasons paper, (17 August 2023).

1.17 In March 2022, we published our PIP which detailed the process we plan to follow (including undertaking the review in two tranches), the scope of the review, and specific areas on which we wanted feedback.[27] Our draft decision for Tranche 1 was published in August 2022.[28]

1.18 We received submissions and cross-submissions on the 2022 PIP and Tranche 1 draft decision from a wide group of stakeholders, including EDBs, retailers, third parties in the sector and consumer groups. Our final decisions for Tranche 1 were published on 25 November 2022, alongside the ID amendment determination giving effect to our final decisions.[29]

1.19 In March 2023, we held a technical elements workshop to discuss issues raised by stakeholders in Tranche 1 submissions that we had excluded from Tranche 1 because we thought further consideration on these issues was required. We received valuable feedback from the workshop that has helped inform our priorities and our approach to developing ID requirements in the following areas:[30]

1.19.1 AMP requirements;

1.19.2 new connection measures;

1.19.3 breaking down System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) values;

1.19.4 network visibility and information; and

1.19.5 vegetation management.

1.20 In May 2023, we published a process paper, in which we noted that our work on amending the ID requirements for EDBs would be better described as ongoing, rather than as the targeted review in two tranches we noted in the March 2022 PIP.[31] This change in process is due to the impracticality of addressing the number of issues identified, and recognises that potential solutions may still be evolving.

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27 Commerce Commission, Targeted Information Disclosure Review – Process and Issues paper, (23 March 2022).

28 Commerce Commission, Targeted Information Disclosure Review – Draft decisions paper – Tranche 1, (3 August 2022).

29 Commerce Commission, Targeted Information Disclosure Review – Electricity Distribution Businesses – Final decision paper – Tranche 1, (25 November 2022); *Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022* [2022] NZCC 36.

30 Commerce Commission, Targeted Information Disclosure Review – Tranche 2 – Technical elements workshop presentation, (27 March 2023); Commerce Commission, Targeted Information Disclosure Review – Tranche 2 – Technical elements workshop notes, (27 March 2023).

31 Commerce Commission, Targeted Information Disclosure Review – Electricity Distribution Businesses – Process paper, (30 May 2023), paragraphs 17-22.

1.21 Our draft decisions for TIDR (2024) were published in August 2023.[32] We received submissions and cross-submissions on this paper from a wide group of stakeholders. As always, we value the clarity, comprehensiveness, and depth of engagement in these submissions.

We have refined existing requirements and added new ones to improve information on the quality of service and to prepare for future changes in the sector

1.22 This review focuses on EDBs in particular because of the increasing pace of change and potentially significant challenges EDBs are facing because of decarbonisation and new emerging technology.

1.23 For TIDR (2024), we have focussed on three key themes:

1.23.1 decarbonisation;

1.23.2 asset management; and

1.23.3 quality of service.

1.24 We have also made other important changes such as clarifying definitions, updating assurance standards, and removing redundancy in ID requirements where appropriate.

1.25 As appropriate, for each of the items in our final decision, we have added, amended, or removed definitions in the ID determination in clause 1.4.3 and Schedule 16. For new and amended definitions in Schedule 16, we have used capitalisation to indicate where a defined term is used.

1.26 Our TIDR (2024) final decision touches on some issues that we will continue to focus on in the longer term, for example:

1.26.1 issues that we considered in the Tranche 1 process but remain unresolved because we believe that the context and potential solutions may still be evolving, such as innovation; and

1.26.2 issues that we identified in the Tranche 1 process that whilst not in scope for TIDR (2024) have significant benefits to consumers and/or strategic importance for the industry, such as network resilience and contingency planning (which is being considered in our review of 2023 AMPs), and low voltage (LV) network information.

[32] Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Draft decision – Reasons paper, (17 August 2023).

1.27 Chapter 2 details our final decisions on the changes to ID requirements, and our reasoning. We have also published a supplementary paper which provides a summary of our final decisions.[33]

1.28 Amendments detailed in this paper are numbered in accordance with their category (for example, "Q14" relates to an amendment in the 'quality of service' category, "AM6" relates to an amendment in the 'asset management' category). This numbering carries on from numbering used in Tranche 1 of the TIDR.

1.29 We have slightly re-numbered the amendments in TIDR (2024), by splitting them out to sub-issues (for example, "D3" has become "D3.1", "D3.2", "D3.3", and "D3.4"). This re-numbering is to improve clarity within this paper.

1.30 Table 2 below details the numbering for all amendments within TIDR (2024).

Table 2: Numbering of amendments within TIDR (2024)

Amendment number	Amendment category	Amendment name
D3.1	Decarbonisation	Network constraints - Schedule 12b(i)
D3.2	Decarbonisation	Network constraints - Geospatial data requirements
D3.3	Decarbonisation	Network constraints - AMP requirements
D3.4	Decarbonisation	Network constraints - Schedule 9e(iii)
D5.1	Decarbonisation	Work and investment on flexibility resources (non-network solutions) – AMP requirements
D5.2	Decarbonisation	Work and investment on flexibility resources (non-network solutions) – Definition of 'Non-network solution'
D5.3	Decarbonisation	Work and investment on flexibility resources (non-network solutions) – Opex reporting requirements
D6.1	Decarbonisation	Standardised pricing components including transmission costs – Standardised connection types
D6.2	Decarbonisation	Standardised pricing components including transmission costs – Standardised pricing components
D6.3	Decarbonisation	Standardised pricing components including transmission costs – Transmission costs
D6.4	Decarbonisation	Standardised pricing components including transmission costs – Other items

[33] Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Summary of our Final Decisions, (29 February 2024).

Amendment number	Amendment category	Amendment name
AM6.1	Asset management	Vegetation management reporting - Schedule 6b(i)
AM6.2	Asset management	Vegetation management reporting – Schedule 9c
AM6.3	Asset management	Vegetation management reporting – Schedule 10
Q14.1	Quality of service	Raw interruption data
Q14.2	Quality of service	Worst-performing feeders
Q14.3	Quality of service	Removal of normalised SAIDI and SAIFI
A3	Other amendments	Definition of Gains/losses on asset disposals
N/A	Other amendments	Update of assurance standards
N/A	Other amendments	Aligning audit and director certification obligations with the verification framework
N/A	Other amendments	Submitter suggested changes
N/A	Other amendments	Other minor amendments

Chapter 2 Reasons for our final decisions

This chapter discusses the reasons for our final decisions, including how we have considered submissions on our draft decisions

2.1 The purpose of this chapter is to explain our final decisions to change ID requirements for EDBs.

2.2 In this chapter, we discuss the key considerations behind our final decisions and summarise for each amendment:

2.2.1 our final decisions;

2.2.2 the purpose of our final decisions;

2.2.3 stakeholders' views on our proposal based on submissions on draft decisions; and

2.2.4 any key changes (for the final decisions) from the draft decisions.

We have staggered compliance timing and amended assurance requirements for practicality

2.3 We received feedback from stakeholders about the timeframes we proposed in our draft decision. In response, we have made some changes to compliance timing and assurance obligations for some requirements, to allow EDBs more time to do their work. This is summarised in the calendar in the summary document for the TIDR (2024) final decisions, and discussed further at paragraph 2.11.[34]

2.4 We decided the timing of first disclosures under new and amended requirements based on the following considerations:

2.4.1 EDBs must have enough time to be able to comply with new requirements;

2.4.2 compliance with new requirements must not be delayed beyond what is necessary, as this delays stakeholders' access to the information; and

2.4.3 some requirements take more work to comply with than others, and some requirements take more time to prepare than others.

We have considered cost and complexity in making our final decisions

2.5 ID regulation is a statutory requirement. This means that in setting ID requirements that enable stakeholders to assess EDBs' performance, we are required to give effect to the purpose of ID in s 53A, and promote the Part 4 purpose in s 52A.

[34] Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Summary of our Final Decisions, (29 February 2024), page 6-7.

2.6 We recognise however that the information we require EDBs to disclose comes at a cost to EDBs, some of which is ultimately borne by consumers. In making our final decisions, we have considered the potential costs of new disclosure requirements for EDBs (and ultimately for consumers).

2.7 We have sought to balance the benefits from greater transparency that more comprehensive and detailed ID requirements would provide, against the costs of complying with the requirements. In our final decisions, we:

2.7.1 considered EDBs' existing practices and capability, including by looking at the scope and detail of their disclosures under existing ID requirements (such as what information EDBs already disclose voluntarily);

2.7.2 added new or expanded requirements only where we consider it valuable to meeting the ID purpose in s 53A;

2.7.3 aligned ID with other parts of the Part 4 regime;

2.7.4 sought technical input from electricity sector stakeholders on the design and implementation of our proposed requirements through public consultation;

2.7.5 considered relevant obligations imposed on EDBs by other agencies; and

2.7.6 deferred the timeframe for EDBs to comply with some requirements where more significant system changes may be required (eg, changes to vegetation management reporting requirements).

2.8 We recognise that the context for ID requirements can change over time, in which case there may be a need to re-consider the balance between benefits and costs. This may result in the Commission updating, simplifying, or removing existing requirements, in future.[35] In line with this, in TIDR (2024) we have removed some requirements that we deemed are no longer worthwhile.

[35] Commerce Commission, Part 4 Information Disclosure Reviews – Framework paper, (14 December 2023), paragraph 39.

Some submitters requested further consultation in advance of our final decisions

2.9 Some submitters requested that the Commission conduct further consultation (including requests for workshops) before making its final decisions, in order to work through any complex issues and ensure the timing and definitions in the final decisions are appropriate.[36] This was specifically in relation to components of reporting requirements in amendments D.3.1-3, D.5.1-3 and D6.1.

2.10 We do not consider that further consultation is required prior to our final decisions in relation to these amendments. We consider that stakeholder feedback is sufficiently addressed in the final decisions and reasons for the final decisions, detailed in the sections following.

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[36] Aurora Energy, Aurora Energy – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Aurora Energy submission**), paragraph 9; Electra, Electra – Cross-submission for Targeted ID Review (2024) draft decision -reasons paper for EDBs, (5 October 2023), (**Electra cross-submission**), page 1; IEGA, IEGA NZ– Cross-submission for Targeted ID Review (2024) draft decision -reasons paper for EDBs, (5 October 2023) (**IEGA cross-submission**), page 2; Orion, Orion – Cross-submission for Targeted ID Review (2024) draft decision - reasons paper for EDBs, (2 October 2023) (**Orion cross-submission**), page 1; Vector Limited, Vector – Cross-submission for Targeted ID Review (2024) draft decision - reasons paper for EDBs, (5 October 2023) (**Vector Limited cross-submission**), page 2; WEL Network, WEL Networks – Cross-submission for Targeted ID Review (2024) draft decision - reasons paper for EDBs, (5 October 2023) (**WEL Networks cross-submission**), paragraphs 3-6.

Some submitters expressed concern about the proposed implementation timing of new requirements

2.11 Some submitters noted that the proposed implementation timing did not allow enough time for EDBs and auditors to ensure the disclosed information meets the required standard.[37]

2.12 Having reviewed EDBs' concerns regarding the time required to prepare measurable data, we have decided to defer the relevant disclosure deadlines accordingly.

2.13 Some EDBs expressed concerns that proposed changes would amount to retrospective regulation.[38]

2.14 It was never our intention to require the disclosure of historical information that is not already available in the required form, or that relates to prior disclosure years. The requirement to disclose historical information for a disclosure year that is already underway would only apply where that information is already available, or can practically be made available, in the required form.

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[37] Alpine Energy, Alpine Energy's submission on the Commerce Commission's Targeted Information Disclosure Review (2024), (14 September 2023) (**Alpine Energy submission**), paragraph 5; Electra Electra submission, (14 September 2023), (**Electra submission**), page 1; Firstlight Network, Firstgas Group – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Firstlight Network submission**), page 1; Horizon Network, Horizon Networks – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Horizon Network submission**), paragraph 5; Horizon Network, Horizon Networks – Cross-submission for Targeted ID Review (2024) draft decision -reasons paper for EDBs, (5 October 2023) (**Horizon Network cross-submission**), paragraph 25; Network Waitaki, Network Waitaki – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Network Waitaki submission**), page 1; Northpower, Northpower – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Northpower submission**), paragraph 3; Northpower, Northpower – Cross-submission for Targeted ID Review (2024) draft decision -reasons paper for EDBs, (5 October 2023) (**Northpower cross-submission**), paragraph 2; Orion, Orion – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Orion submission**), paragraph 6; Powerco, Powerco – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Powerco submission**), page 6; The Lines, The Lines Company – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**The Lines Company submission**), page 3; Unison and Centralines, Unison and Centralines – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Unison and Centralines submission**), page 1; Vector Limited, Vector – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Vector Limited submission**), paragraph 2; WEL Networks cross-submission, paragraph 1.

[38] Aurora Energy submission , paragraph 31; Aurora Energy, Aurora Energy – Cross-submission for Targeted ID Review (2024) draft decision -reasons paper for EDBs , (5 October 2023) (**Aurora Energy cross-submission**), paragraph 3; Electra cross-submission, page 1; Horizon Networks submission, page 1; Vector Limited submission, paragraph 2; Vector Limited cross-submission, paragraph 2.

2.15 In making our final decisions we have further considered the overall implementation timeline for TIDR (2024) amendments. As a result, we have deferred the implementation timing for the following amendments:

2.15.1 some amendments relating to D3 network constraints;

2.15.2 some amendments relating to D5 work and investment on flexibility resources (non-network solutions);

2.15.3 all amendments relating to D6 standardised pricing components including transmission costs; and

2.15.4 all amendments relating to AM6 vegetation management reporting.

2.16 The compliance timing and assurance obligations for all amendments in TIDR (2024) are summarised in the calendar in the summary document for the TIDR (2024) final decisions.[39]

Some submitters noted the additional regulatory burden imposed by the proposed amendments

2.17 Submissions included comments on the additional regulatory burden imposed by the proposed amendments. Specifically, that the draft decision proposed the addition of many new disclosure requirements while only proposing the removal of one requirement. Submitters also recommended the removal of several specific schedules.[40]

2.18 We have detailed in paragraphs 2.5 to 2.8 how we have sought to balance the benefits from greater transparency that more comprehensive and detailed ID requirements would provide, against the costs of complying with the requirements.

2.19 We have reviewed the suggestions put forward in submissions for further amendments and as a result we have made some additional amendments which are detailed from paragraph 2.327 and summarised in the *Summary of our Final Decisions* document.[41]

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[39] Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Summary of our Final Decisions, (29 February 2024), pages 6-7.

[40] Alpine Energy submission , paragraph 3; Horizon Networks cross-submission, paragraph 6; Vector Limited submission, paragraphs 2-10.

[41] Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Summary of our Final Decisions, (29 February 2024).

Decarbonisation

2.20 EDBs face an increasing pace of change and potentially significant challenges from decarbonisation, for example:

2.20.1 increased load on the network caused by phasing out fossil fuels across the economy; and

2.20.2 new technology means there are more appliances connected to and using the network, two-way power flows and more participants (eg, non-network solutions).

2.21 An EDB's preparedness for such changes will affect its performance and ability to meet consumers' needs. An EDB must plan to ensure, especially in the context of these changes, that:

2.21.1 assets are maintained and replaced, as appropriate;

2.21.2 it innovates and invests in cost-efficient solutions (such as working with third parties to provide solutions);

2.21.3 it is prepared to manage potential future changes in demand; and

2.21.4 its ongoing operations enable it to deliver service at a quality that reflects consumer demand.

2.22 Submitters on the 2022 PIP and TIDR (2024) draft decision made some general points about ID requirements on decarbonisation:

2.22.1 broad engagement and coordination are required;

2.22.2 ID requirements should integrate and complement our regulation through PQ paths;

2.22.3 workshops would be a valuable method of engagement; and

2.22.4 there are several challenges to data access which is relevant to EDBs preparedness for decarbonisation.

2.23 We agree that broad engagement and coordination are required on the topic of decarbonisation given the complexity and the interconnected issues. Decarbonisation has been a focus of our recent stakeholder engagement including our April 2021 open letter and December 2021 workshop.[42] Decarbonisation continues to be a focus of our work and consultation in our current work programme, including beyond ID.

2.24 We engage regularly with other government agencies working in this area, such as the Electricity Authority (EA). For example, we have consulted the EA during the development of the TIDR (2024) draft and final decisions as this project has strong parallels to work the EA is undertaking around changes to regulatory requirements that may be needed in response to an evolving electricity sector.[43]

2.25 We also engage with the Energy Efficiency and Conservation Authority (EECA), Ministry of Business, Innovation and Employment (MBIE) and others. We recognise that it is important for different government regulators to work together effectively to support the best outcomes.

2.26 In the case of non-exempt EDBs, our ID requirements and PQ path regulations should work together in a complementary way. ID requirements support transparency of EDBs' performance, and both forms of regulation support the overarching purpose of our regulation—to promote the long-term benefit of consumers.[44]

2.27 We heard strong calls from submitters for the Commission to facilitate workshops on decarbonisation issues. As outlined in paragraph 1.19, we held a technical workshop in March 2023 to discuss some issues raised by submitters, which included the lack of visibility of EDBs' LV networks and network constraints.[45]

2.28 In feedback from submitters on the 2022 PIP and TIDR (2024) draft decision, and from stakeholders at the technical workshop, EDBs described significant and varying data access challenges they face, particularly in relation to LV network information. Recognising data access challenges, we have designed our decarbonisation requirements in a way that will allow EDBs to more easily comply by creating high-level narrative requirements, including in relation to data access. This gives EDBs the opportunity to qualify and contextualise the information they disclose.

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42 Commerce Commission, Ensuring our energy and airports regulation is fit for purpose, (29 April 2021); Commerce Commission, Workshop on the impact of decarbonization on electricity lines services, (February 2022).

43 The EA's work on updating regulatory settings for distribution networks can be found here.

44 Sections 52A and 53A.

45 Commerce Commission, Targeted Information Disclosure Review – Tranche 2 – Technical elements workshop presentation, (27 March 2023); Commerce Commission, Targeted Information Disclosure Review – Tranche 2 – Technical elements workshop notes, (27 March 2023).

2.29 We also consider data access to be an important topic for ID in many cases, especially in the context of decarbonisation. How EDBs plan and manage risk when it comes to data access challenges is very relevant to stakeholders trying to assess the purpose of Part 4. For example, data access challenges may affect EDBs' efficiency in innovating or their ability to respond to changing consumer demands in the context of new technology.

2.30 For constraints on LV networks, given the challenges with data that EDBs currently face, we have not added any quantitative requirements in the ID schedules at this time. We may add such requirements in the future as the sector overcomes those challenges, and we intend to monitor that process through:

2.30.1 the Tranche 1 narrative requirement for EDBs to report on LV network voltage quality; and

2.30.2 new narrative requirements for EDBs to report on their journey towards providing meaningful LV network constraint reporting.

D3.1 – Network constraints – Schedule 12b(i)

Final decision

2.31 Our final decision is to require EDBs to disclose more meaningful network constraint (and supporting) information, at a zone substation level, within Schedule 12b(i) of the ID determination.

2.32 We have added the following requirements:

2.32.1 the current peak load period for a zone substation (eg, the season current peak load occurred);

2.32.2 whether a zone substation is constrained or forecast to be constrained (eg, by selecting a ‘Current constraint type’ or ‘Forecast constraint type’);

2.32.3 if a zone substation is currently or forecast to be constrained – the type of constraint (capacity or security), the primary cause of the constraint, the type of solution (where known) to address a constraint (eg, through a demand response agreement with a large customer or aggregator), how long any temporary solution is expected to be in place (current constraints only), and for a forecast constraint, when the constraint is expected. The relevant year must be identified if the constraint falls within the period;[46]

2.32.4 if a zone substation is not currently constrained, the available capacity before it becomes constrained;

2.32.5 forecast available capacity in 5 years and an approximate range of forecast available capacity in 10 years; and

2.32.6 forecast peak load period and forecast security of supply classification in 5 and 10 years.

2.33 We have amended the following requirements:

2.33.1 changed ‘Installed Firm Capacity’ to ‘Installed operating capacity’ so zone substation operating capacity at its assigned security level (N, N-1, N-2, or N-1 switched) is reported; and

2.33.2 changed ‘Security of supply classification (type)’ to ‘Current security of supply classification (type)’ to differentiate it from the new forecast security of supply classification requirements.

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[46] For example, if an EDB is filling out Schedule 12b for the disclosure due 31 March 2025, and expects a constraint to occur from the winter of 2028, it would record this as a constraint in year 4 ('4' under 'year of constraint'). If the constraint is forecast to first occur after the asset management plan time horizon, then an EDB would record the constraint year as greater than 10 years (‘10+’ under 'year of constraint').

2.34 We have removed the following requirements, which we consider will be superseded by the new and/or amended requirements:

2.34.1 'Installed Firm Capacity + 5 years (MVA)';

2.34.2 'Installed Firm Capacity constraint + 5 years (cause)';

2.34.3 'Transfer capacity';

2.34.4 'Utilisation of Installed Firm Capacity %'; and

2.34.5 'Utilisation of Installed Firm Capacity + 5yrs %'.

2.35 We have also added, amended and removed definitions in relation to this amendment in Schedule 16 of the ID determination.

2.36 EDBs are first required to disclose the amended Schedule 12b(i) by 31 March 2025.

2.37 Consistent with existing assurance and certification requirements, Schedule 12b(i) is subject to only the director certification requirement.

Purpose of the amendment

2.38 The purpose of this amendment is to allow stakeholders to comprehend whether EDBs have visibility of current and forecast constraints on their network and if EDBs are planning for those constraints appropriately. This includes communicating constraint information to third parties to assist decision-making.

2.39 The information disclosed as a result of this amendment is intended to assist a stakeholder's assessment of whether EDBs are investing in their assets efficiently and providing services at a quality that reflects consumer demands.[47]

2.40 To help ensure consistency and limit confusion across EDBs, for Schedule 12b, current (or 'current year') information is forecast information for the year during which the report is prepared.[48] For example, current information for the Schedule 12b disclosure due by 31 March 2025 would be forecast information for the disclosure year-ending 31 March 2025. This approach also applies to zone substations when determining whether there is a current constraint.

47 Section 52A(1)(a)-(b).
48 Actuals may be used where known.

2.41 As Schedule 12b is required to be disclosed annually, constraint information will generally become less valuable and reliable over the course of a year (eg, a constraint that initially required a solution may have since been addressed). We recognise the value of timely constraint information for stakeholders and for that reason, we encourage EDBs to voluntarily disclose updated copies of Schedule 12b throughout a disclosure year (without director certification).

2.42 We consider the amendments to Schedule 12b will improve comparability across EDBs and provide clearer constraint information for stakeholders in a simpler form. Rather than adding separate reporting requirements for constraint data, we have prioritised improving the existing reporting requirement (eg, Schedule 12b) as we are mindful of the regulatory burden on EDBs.

Submitters generally supported the amendment

2.43 Overall, there was broad support to the proposed amendments to Schedule 12b.[49] Several submitters acknowledged the importance of disclosing capacity and constraints information. For example, Electricity Networks Aotearoa (ENA) said:[50]

> ENA welcomes the proposed changes to schedule 12b(i). ENA and its Information Disclosure Working Group (IDWG) suggested similar changes in its earlier submission to the Commission and is heartened that the Commission has acted upon its recommendations.

2.44 However, some submitters proposed changes and encouraged further consideration of the issue by the Commission.

2.45 Most submitters' concerns about this amendment related to the proposed inclusion of a 20-year time frame for an approximate range of forecast available capacity.[51] Some recommended limiting forecasts to the 10-year timeframe to align with the AMP.[52]

2.46 Having considered this feedback and recognising the difficulty of forecasting accurately to 20 years, we have decided to no longer include a 20-year time frame for an approximate range of forecast available capacity by not including the proposed fields for 'Max. available capacity +20 yr' and 'Min. available capacity +20 yrs' fields within Schedule 12b(i).

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[49] Alpine Energy submission, page 2; Electricity Networks Aotearoa, Electricity Networks Aotearoa – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**ENA submission**), page 4; Northpower submission, paragraph 4; Firstlight Network submission, page 4; Wellington Electricity, Wellington Electricity – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Wellington Electricity submission**), page 5.

[50] ENA submission, page 4.

[51] Horizon Networks submission, paragraph 65; ENA submission, page 4; Alpine Energy submission, paragraph 7; Northpower submission, paragraph 4; Network Waitaki submission, page 2; Vector Limited submission, paragraph 12.

[52] Alpine Energy submission, paragraph 7; ENA submission, page 4; Northpower submission, paragraph 4; Network Waitaki submission, page 2; Vector Limited submission, paragraph 12.

2.47 Some submissions recommended the Commission does not require disclosure of Transpower-caused constraints.[53]

2.48 We consider Transpower-caused constraints are important to collect and can clearly be distinguished and note that this is an existing requirement within Schedule 12b(i). There is also an 'Other' primary cause term as well as the 'explanation' section should EDBs want to clarify their selection.

2.49 Network Waitaki submitted that "terms be clearly defined so that there is no ambiguity, eg, "seasons" are not defined but using the month would avoid any vagueness."[54]

2.50 In Schedule 16 of the draft determination, 'Season' was defined which included a part for each of the four seasons (eg, spring – September, October, and November). This definition has remained unchanged from our draft decision.

2.51 Wellington Electricity recommended that the 'Year of any forecast constraint' field options should be changed to a range of years.

2.51.1 Given no other submitters raised issue with our proposed requirement (and no submissions supported Wellington Electricity's point in cross-submissions), we have decided to retain our draft decision. Greater specificity in forecast year of constraint will provide stakeholders increased certainty when planning for these constraints.

2.51.2 We note that the 'Explanation' field in Schedule 12b should allow EDBs to clarify, for example, if forecasts constraints cannot be accurately forecast to a specific year, or if the constraint duration is expected to be longer than one year.

2.52 Some submissions proposed removing the proposed 'Constraint solution' requirements from Schedule 12b, noting the AMP itself would be the best vehicle for disclosure of the solutions EDBs are considering (or employing) to resolve constraints.[55]

2.52.1 We consider there to be value in having constraint solution requirements in both Schedule 12b and the AMP due to variability in how different stakeholders use this information.

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53 Network Waitaki submission, page 2; Horizon Networks submission, paragraph 68.

54 Network Waitaki submission, page 2.

55 ENA submission, page 4; Wellington Electricity submission, page 5.

2.52.2 Constraints information disclosed in Schedule 12b provides a more accessible way for stakeholders to assess whether an EDB is adequately planning for their upcoming network constraints. This is in line with the primary purpose of ID.

2.52.3 Submitters on the 2022 PIP that potentially use this information (SolarZero and Trustpower) said that network constraints information is not very useful when embedded within descriptive information of the AMPs. Information in the ID schedules is more concise and data centric, while descriptive information in the AMP is useful to give context and detail to network constraints.

2.52.4 Alongside proposed geospatial requirements, constraint solution requirements in Schedule 12b will give important context to a national constraints map. This will be useful for stakeholders, who may see an area with a constraint that doesn't have a proposed solution where it can provide one (for example). This information would be much more difficult to align with a constraints map if embedded within the AMP.

2.53 Meridian Energy and Drive Electric proposed that network constraints disclosures be extended to lower voltage networks (as Schedule 12b(i) currently covers only aspects of medium voltage networks).[56] Meridian noted the following:[57]

> Meridian's view is that it is essential that this information is disclosed at the level of connection. EDBs are currently required to disclose information at the zone sub-station level. However, disclosing more granular data is key to enabling charge point operators to better identify suitable locations and understand the EDB work required to set up a charge point.

2.53.1 As outlined in the draft decision reasons paper, many EDBs currently do not have this information and we consider such a requirement would be too burdensome for EDBs to comply with at this time. As part of the new requirements in relation to amendment D3.3, EDBs must disclose qualitative information in their AMPs on their progress toward LV data access, which will help stakeholders monitor the EDBs' capabilities.

2.53.2 We may consider adding more quantitative requirements for LV network constraint reporting in the future.

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56 Meridian Energy, Meridian Energy – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Meridian Energy submission**), page 2; Drive Electric, Drive Electric – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs , (14 September 2023) (**Drive Electric submission**), paragraph 13.

57 Meridian Energy submission, page 2.

2.54 Orion raised the following points in their submission relating to the proposed network constraint requirements:[58]

> The inputs to a forecast 10 years out will naturally contain a high level of assumptions that flexibility providers would need to take into account in their decision making. Does the Commission envisage the information being accompanied by a high-level certainty rating?

2.55 We have taken this feedback on board but have not adopted a certainty rating and/or further commentary around disclosed forecasts. We note that EDBs can voluntarily do this in the 'explanation' field.

2.56 Orion asked for clarification on the use of 'anticipated' within the draft definition for the term 'Forecast available capacity' as the proposed definition required EDBs to take into account confirmed and anticipated changes in demand load. Orion indicated it would prefer to assign probabilities to the anticipated load increases as opposed to years.

2.57 We note that some EDBs may not have this information and so it would be difficult to implement a requirement like this at this stage. EDBs may use the 'explanation' field within Schedule 12b(i), or within the voluntary Explanatory Notes within Schedule 15 of the ID determination, if they would like to include a probability of anticipated load.

2.58 Finally, Orion also stated it required clarification on what the Commission meant by 'forecast security of supply classification'.[59]

2.58.1 Commission staff met with Orion to discuss some points raised in submissions, including clarifying forecast security of supply classification. It was established that our expectations for this requirement were consistent with Orion's interpretation.

2.58.2 We have also clarified the definitions of security of supply classifications at 5 and 10 years so that they must take into account confirmed and anticipated changes in demand load and confirmed capacity changes. For the purposes of this definition, 'confirmed' means the EDB has committed to implementing the changes by way of contract.

Our final decision considers the feedback from submissions

2.59 In response to stakeholder feedback, we have made the following key changes from the draft decision:

[58] Orion submission, page 2.
[59] Orion submission, page 3.

2.59.1 removed the proposed requirement to disclose in Schedule 12b(i) the approximate range of forecast available capacity in 20 years for each zone substation; and

2.59.2 amended the definitions of 'Security of supply classification +5 yrs' and 'Security of supply classification +10 yrs' in Schedule 16 of the ID determination to include that they must take into account confirmed and anticipated changes in demand load, and confirmed capacity changes.

D3.2 – Network constraints – Geospatial data requirements

Final decision

2.60 Our final decision is to require EDBs to disclose geographic information (including geospatial data) about their networks in a generic geospatial file format (such as Geopackage or Shapefile).

2.61 EDBs must disclose several attributes for each zone substation within a geospatial data file. This file must include the name of the substation, its location (in coordinates), the names of any feeders connected to it, the input and output voltages it primarily transforms, and the boundary of the area it serves.

2.62 EDBs are first required to disclose geographic information disclosed by 31 August 2025 for disclosure year 2025. However, we encourage EDBs who have this information available to voluntarily disclose it by 31 August 2024.

2.63 Geographic information is subject to only director certification (eg, no assurance report is required).

Purpose of the amendment

2.64 The purpose of this amendment is to allow stakeholders to comprehend whether EDBs have visibility of current and forecast constraints on their network and if EDBs are planning for those constraints appropriately. This includes communicating constraint information to third parties to assist decision-making.

2.65 Along with the amendments that have been made to Schedule 12b(i), geospatial information disclosure requirements are intended to better reveal the performance of EDBs in relation to their planning for and management of constraints at the medium voltage (MV) network level by:

2.65.1 significantly improving stakeholders' visibility of constraints occurring, and forecasted to occur; and

2.65.2 supporting the creation of a national constraints map in the future.

2.66 Maps are a useful tool to help stakeholders more easily understand the location and significance of current and likely future network constraints. Requiring EDBs to disclose geospatial information about their networks at a zone substation level will support any interested stakeholder to create a national constraints map in the future.

Most submitters were comfortable with the proposed geospatial requirements.

2.67 Three submitters suggested that these disclosures be pushed out to disclosure year 2025 (due 31 August 2025).[60]

2.67.1 Having considered this feedback, we have decided to defer the first disclosure of geographic information to 31 August 2025 (with respect to disclosure year 2025).

2.67.2 Deferring the first required disclosure of this information by one year will allow time for EDBs to establish processes and/or systems required to comply with the network geographic requirements. However, many EDBs will already have the required geospatial zone substation information available, and we encourage those EDBs to disclose this information alongside other disclosure year 2024 information.

2.68 Some submitters called for collaboration to establish appropriate data formats for disclosed geospatial information.[61]

2.68.1 EDBs will be able to collaborate and voluntarily use the same geospatial data formats over time, at first instance they may choose not to due to their existing technology. Delaying the start date of the requirement by a year will also help EDBs standardise their approach if they wish to.

2.68.2 While we are not defining a specific file format, our view is that it would take relatively little effort for a stakeholder (including the Commission) to combine the different EDBs' geospatial data, regardless of the file formats. This is provided the file is compatible with commercial GIS systems, which is part of the requirement. Therefore, we do not think it is necessary for EDBs to seek approval to use a file format other than Geopackage or Shapefile.

2.68.3 At this stage, we also do not want to be too specific with any technology/software requirements as this could lead to cost implications to EDBs and standards that we set now could change in future. Aurora Energy's submission on the EDB targeted ID PIP noted that "any form of prescribed geo-spatial reporting should be system agnostic and not impose material additional costs on EDB."[62]

2.68.4 No non-EDB stakeholders submitted about the approach to open file formats.

60 The Lines Company submission, page 6; Electra submission, page 4; Aurora Energy submission, paragraph 31.
61 ENA submission, page 4; Vector Limited cross-submission, paragraph 22.
62 Aurora Energy submission, page 17.

2.69 ENA, Network Waitaki, Aurora Energy, Electra, Wellington Electricity, Unison & Centralines, and PowerCo all questioned the potential usefulness of a static constraints map to consumers. Network Waitaki recommended the Commission consider making a requirement for EDBs to have a geospatial file available on request from an interested party to obtain a snapshot of a zone substation attributes at a point in time.[63]

2.69.1 We do not believe this is a sufficient reason to discard the requirement as there is still value to stakeholders in being able to access geospatial constraints information that is updated annually. Four submissions supported the proposed geospatial data requirements while a further two said that they had no issue with them.

2.69.2 While we acknowledge that a digital constraint map may be relatively static, it will still support the disclosure of up-to-date information for stakeholders. In future, this digital map could be updated annually without significant effort given the data-centric nature of this reporting in Schedule 12b(i) and geospatial systems.

2.69.3 Furthermore, this digital constraint map is intended to also contain forecast information, such as capacity and constraint data within the amended Schedule 12b(i). We consider this forecast information would still be useful for stakeholders in a more easily accessible and readable format.

2.69.4 We also encourage EDBs to voluntarily disclose geospatial data more frequently to help ensure sufficient information is readily available for stakeholders.

2.69.5 As noted in the draft reasons paper, most submissions on the 2022 PIP regarding issue D3 supported the introduction of this amendment. Several submitters suggested that heatmaps (eg, network constraint maps) would be a useful tool to present constraint information.

2.69.6 The geospatial information disclosures are intended to ultimately allow stakeholders to access and visualise network constraints information in a format that is more accessible compared with the AMP or ID Schedules.

[63] ENA submission, page 4; Network Waitaki submission, page 3; Aurora Energy submission, paragraph 32; Electra submission, page 4; Wellington Electricity submission, page 6; Unison and Centralines submission, pages 1-2; Powerco submission, page 1.

2.70 Wellington Electricity submitted that the definition of 'publicly disclose' under clause 1.4.3 of the ID determination needs to be adjusted so that any geospatial information is only required to be provided via the EBDs website or by email.[64]

2.71 We agree that due to the nature of geospatial data, it makes sense for this to only be required via the EDB's website or by email. We have adopted this feedback and amended the definition of publicly disclose to include the following "…Geospatial information is only required to be provided in a format commonly used by geographical, or equivalent, information systems mapping software via the EDB's usual publicly accessible website or by email."

2.72 ENA, Wellington Electricity, and Vector (via cross-submission) raised concerns about the security risks of identifying the specific location of their assets within geospatial data requirements (eg, zone substations).[65]

2.73 Substation locations can already be found using satellite maps and some EDBs already provide zone station geolocation data on their website.

2.74 Horizon Networks recommended that the Commission clarify two aspects of this requirement relating to LV and HV network boundaries:[66]

> Horizon Networks Recommends: The Commerce Commission clarify that the boundary referred to in clause 2.5.2A(4) is the HV boundary and not the LV boundary and specify the details required in the geospatial file are line features extending to the end of the HV network, identified by HV feeder and voltage.

2.74.1 For the time being, we do not want to be too prescriptive with the format requirements for geospatial information and whether the boundary provided is for HV or LV networks. Compared to a more prescriptive requirement, this is intended to reduce the compliance burden for EDBs as they can, to an extent, leverage existing systems and processes to comply with these new requirements.

2.74.2 Some EDBs may choose to provide a polygon shapefile of the LV boundary while others may choose to provide line features extending to the end of the HV network. Both formats could be combined in future for a national constraints map.

2.74.3 EDBs are free to collaborate with each other around which formats work best.

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64 Wellington Electricity submission, page 7.

65 ENA submission, page 4; Wellington Electricity submission, pages 6-7; Vector Limited submission, paragraph 21.

66 Horizon Networks submission, paragraph 76.

2.74.4 At some point in the future, once we have seen EDB and third party format preferences, we may consider being more prescriptive geographic network requirements.

2.75 Orion noted in their submission that they would have strict use case rules around disclosed geospatial data, and that more time would be required for Orion to comply with the requirement:[67]

> We also note that we would have strict use case rules around the data eg, it can only be used for the purpose we are sharing it for, and the data cannot be retained or used for other purposes such as connection decisions, asset location assessments, etc. In order to comply with this requirement Orion would require extra resources in order to provide the data. Depending on the final decision it could take 2-4 months of 1 FTE and we don't have bandwidth to include it in our existing tasks.

2.75.1 We note that Orion can provide terms of use alongside geospatial information on its website if they wish for such terms to apply to third parties. This would not affect the Commission's powers to monitor and analyse the information it receives under ID as set out in the Act.

2.75.2 We have also now deferred this requirement by a year, which should allow Orion (and other EDBs) the time required to prepare this data.

Our final decision considers the feedback from submissions

2.76 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.76.1 deferred the first disclosure of geographic information by one year to 31 August 2025 for disclosure year 2025; and

2.76.2 made further changes to the proposed definition of 'publicly disclose' under clause 1.4.3 of the ID determination. We have expanded part (c) of the definition so that geospatial information is only required to be provided via the EDB's website or by email.

[67] Orion submission, page 4.

D3.3 – Network constraints – New AMP requirements

Final decision

2.77 Unchanged from our draft decision, our final decision is to require EDBs to disclose additional information related to network constraints within their AMPs. We have added the following requirements to Attachment A of the ID determination, which require EDBs to describe:

2.77.1 in relation to both load and injection constraints on LV networks specifically:[68]

2.77.1.1 any challenges, and progress, towards collecting or procuring data used to inform the EDB of current and forecast constraints, including historical consumption data; and

2.77.1.2 any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with that constraint-related data.

2.77.2 any policies or practices for sharing information on current and forecast constraints across the EDB's network (both load and injection), including any LV network constraint information, to inform the decision-making of potential consumers connecting to the network and potential providers of non-network solutions.[69]

2.78 EDBs are first required to disclose:

2.78.1 narrative information required by clause 17.2.2 of Attachment A by 31 August 2024 in a document publicly available on the EDBs' websites.[70] EDBs may choose the form of subsequent disclosures in accordance with clause 2.6.1(4) of the ID determination; and

2.78.2 information required by Attachment A (excluding clause 17.2.2) within their next AMP. The next mandatory AMP is due by 31 March 2026.[71]

2.79 Consistent with existing assurance and certification requirements, narrative information and AMPs are subject to only director certification.

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68 We have expanded the voltage quality requirement that focuses on LV networks, under clause 17.2 of Attachment A, to cover LV network constraints.

69 We have added this requirement to Attachment A within existing requirements regarding policies on non-network solutions and practices for connecting new consumers.

70 This requirement is under clause 2.6.1B of the ID determination.

71 For the avoidance of doubt, EDBs must comply with the new Attachment A requirements if they decide to disclose an AMP, instead of an AMP update, for the disclosure due by 31 March 2025.

Purpose of the amendment

2.80 The purpose of this amendment is to help stakeholders understand how well EDBs grasp whether constraints are occurring on their LV networks.

2.81 Network constraint data requirements are currently primarily focused on MV networks (ie, at the zone substation level) as we acknowledge the challenges EDBs currently face with obtaining the LV network data required to report meaningful constraint information (particularly quantitative information and resulting constraint maps).[72]

2.82 To help bridge the gap until LV network data is more readily available, EDBs must report their journey towards LV network constraint monitoring and reporting, for both load and injection constraints. This includes describing any progress toward obtaining LV network constraint-related data (including historical consumption data) and when available, how that data is used, or intended to be used, to inform the EDB of current and forecast constraints.

2.83 EDBs must also describe any policies or practices for sharing constraint information to key stakeholders, including LV network constraint information. We consider it important for stakeholders generally to understand whether EDBs are providing sufficient constraint information to certain stakeholders such as providers of non-network solutions.

2.84 EDBs sharing such constraint information will assist them and providers of non-network solutions to identify opportunities and practices (including EDBs' request for proposals) to address those constraints, which could be met through demand response or DER. This will assist a stakeholders' assessment of whether EDBs are making efficient investment decisions (including in some cases not to invest and rely on DER) and delivering services at a quality that reflects consumer demands.

2.85 This amendment will also enable stakeholders to monitor whether EDBs are sharing LV network constraint information with providers of non-network solutions, which is a potential issue identified by the EA in its "Updating the regulatory settings for distribution networks" issues paper: [73]

[72] Considering the current data limitations, during the Tranche 1 amendments in 2022 we added a narrative requirement for EDBs to report on their LV network practices. However, that was in respect of voltage quality only. We have now expanded on those narrative requirements to now cover constraints.

[73] Electricity Authority, Issues Paper: Updating the regulatory settings for distribution networks, (December 2022), page 42.

> The main issue preventing flexibility traders from getting access to (1) a static picture of current congestion on LV networks, and (2) a projection of likely future congestion on LV networks, is that distributors do not have access to granular historical Consumption Data to calculate congestion on their LV networks.
>
> However, once distributors can calculate network congestion, there are currently no requirements in place for this information to be shared with flexibility traders. It is possible that distributors will be disincentivised to share congestion data if they feel it will be used by flexibility traders to offer services that compete with a distributor's related businesses. However, it should be beneficial to distributors to share this data as flexibility traders could offer solutions to network problems caused by congestion.

There was broad support for this amendment

2.86 All submissions relating to this amendment were supportive. However, a small number were concerned about the timing of first disclosure for new network constraint requirements.[74]

2.87 Due to the descriptive nature of this amendment, we have maintained the due dates outlined in our draft decision as we consider a relatively small amount of resource will be required to disclose this information.

[74] Alpine Energy submission, page 2; Wellington Electricity submission, page 7.

D3.4 – Network constraints – Schedule 9e(iii)

Final decision

2.88 Unchanged from our draft decision, our final decision is to require EDBs to report more granular zone substation transformer capacity by splitting total capacity reported in Schedule 9e(ii) into 'EDB owned' and 'non-EDB owned' capacity.[75] To support this change, we have added several defined terms to Schedule 16 of the ID determination.

2.89 EDBs are first required to disclose the amended Schedule 9e(iii) by 31 August 2024 for disclosure year 2024.

2.90 Consistent with existing assurance and certification requirements, the amended Schedule 9e(iii) is subject to only director certification.

Purpose of the amendment

2.91 This amendment will make capacity information disclosed by EDBs more useful for stakeholders to undertake an assessment of whether the purpose of Part 4 is being met, including if EDBs are making efficient investment decisions.

2.92 This amendment is intended to improve the usability of zone substation transformer capacity information in Schedule 9e(iii) by making it more comparable to that reported within Schedule 12b(i). Zone substation transformer capacity in Schedule 9e(iii) did not previously differentiate between EDB-owned and non-EDB owned capacity, yet zone substation capacity in Schedule 12b(i) may include non-EDB owned capacity.

2.93 We recognise that EDBs may not know the precise capacity of non-EDB owned zone substation transformer. In this situation, in line with non-EDB owned distribution transformer capacity in Schedule 9e(iii), an estimated value may be used. However, EDBs should make reasonable inquiries to obtain that estimate. No submissions opposed this amendment to Schedule 9e(iii).

2.94 Aurora Energy supported the proposed amendment and considered that our proposed amendments are achievable and meet the objectives.[76]

2.95 ENA recommended in general that no new quantitative disclosures come into effect for disclosure year 2024.[77]

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75 We have also removed the words "estimated" in the name of the defined term "Distribution transformer capacity (Non-EDB owned, estimated)", for consistency with these new definitions.

76 Aurora Energy submission, paragraph 38.

77 ENA submission, page 3.

2.95.1 We consider the burden on EDBs to comply with this requirement in disclosure year 2024 will be minimal. We acknowledge that some EDBs may not know the exact value of 'Non-EDB Owned Capacity', particularly the first time this information as disclosed. As outlined in the definition of 'Non-EDB owned capacity', EDBs may disclose an estimated value, but first must make reasonable enquiries into the actual value of this capacity.

2.95.2 The Commission is mindful of the overall compliance burden on EDBs for the decarbonisation requirements. The amendments to Schedule 9e(iii) are the only quantitative requirement that have not been pushed back from the proposed 2024 implementation date.

2.96 Network Waitaki and Vector noted that the TIDR (2024) draft decision reasons paper indicated that Schedule 9e(iii) is audited.[78]

2.97 We acknowledge that this was an error and note it is correct that audit assurance is not required for Schedule 9e(iii). According to the definition of 'Audited disclosure information' under clause 1.4.3 of the ID determination, information required by clause 2.5.1 must be audited only to the extent the SAIDI or SAIFI information is included. Schedule 9e(iii) does not require the disclosure of SAIDI or SAIFI information.

[78] Network Waitaki submission, page 3; Vector Limited submission, paragraph 16.

D5.1 – Work and investment on flexibility resources (non-network solutions) – AMP requirements

Final decision

2.98 Our final decision is to require EDBs to report more detailed information on non-network solutions within their AMPs by amending Attachment A of the ID Determination (containing the AMP requirements). We have:

2.98.1 added a new clause 4.2.7 into Attachment A, which requires EDBs to quantify the contribution non-network solutions make towards solving a network risk or constraint, and the extent to which the non-network solution is provided by a related party, or third party; and

2.98.2 amended the commentary in clause 11.10 of Attachment A, to require EDBs to disclose in their AMP a detailed description of the investigations undertaken towards the potential for non-network solutions to be more cost effective than network augmentations and vice versa.[79] This description should specify if any non-related parties were approached in relation to non-network solutions. For the purposes of disclosing this information, an EDB is not required to include commercially sensitive or confidential information.

2.99 These new requirements under Attachment A are first required to be complied with when EDBs disclose their next AMP. The next mandatory AMP is due by 31 March 2026.[80]

2.100 Consistent with existing certification and assurance requirements, AMPs (in accordance with Attachment A of the ID determination) are subject to only director certification.[81]

Purpose of the amendment

2.101 The information disclosed as a result of these amendments will allow stakeholders to better understand EDBs' consideration and uptake of non-network solutions to provide a cheaper or better-quality distribution service. We also expect these amendments to promote the uptake of non-network solutions market, allowing more flexibility services to be provided to other types of businesses, eg, electricity retailers.

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79 The commentary also states, that for the purposes of disclosing this information, an EDB is not required to include commercially sensitive or confidential information.

80 For the avoidance of doubt, EDBs must comply with the new Attachment A requirements if they decide to disclose an AMP, instead of an AMP update, for the disclosure due by 31 March 2025.

81 We note that EDBs often voluntarily disclose useful information within the AMP for stakeholders. This voluntary information is not required by the ID determination and as such, does not require director certification.

2.102 Furthermore, the new requirement in clause 4.2.7 of Attachment A is intended to lead to improved visibility of each EDB's network configuration in relation to the capacity of any non-network solutions. We also expect an improvement in the efficiency of EDBs by promoting the uptake of non-network solutions.

2.103 Along with the other D5 amendments, these changes will better promote the purpose of ID because they will allow any interested persons to assess what investments are being made by EDBs in relation to assets or services that are innovative in nature, eg, non-network solutions. This may also lead to opportunities for market participants to offer non-network solutions to EDBs which will increase the supply of electricity and ultimately lower prices for consumers. Improving efficiencies are a limb of s52A.

We received broad support in submissions and cross-submissions for the proposed new AMP requirements

2.104 Counties Energy, Vector, Meridian, Network Waitaki, Electra, Firstlight Network, Aurora Energy, Wellington Electricity, and the Major Electricity Users' Group (MEUG) supported the new AMP requirements either in full or in principle.[82]

2.105 Powerco and The Lines Company suggested alternative approaches to these amendments; Powerco suggested fostering discussions around long-term programmes and policies and The Lines Company suggested that a summary is preferable to a detailed description.[83]

2.106 In response, due to the broad support of this amendment, we do not believe these are sufficient reasons to modify the amendment. We instead encourage EDBs to plan and document their flexibility resources as per these suggested approaches above voluntarily, along with the new AMP requirements, if they believe it will add value.

2.107 MEUG questioned whether guidance notes for EDBs would be useful given this is still an emerging area.[84] Orion supported this suggestion in its cross-submission.[85]

2.108 We acknowledge this concern and may consider providing guidance in the future if we become aware of potential consistency issues across EDBs.

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82 Counties Energy, Counties Energy – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Counties Energy submission**), page 1; Vector Limited submission, page 3; Meridian Energy submission, page 2; Network Waitaki submission, paragraph D5.1; Electra submission, page 2; Firstlight Network submission, page 6; Aurora Energy submission, paragraph 13; Wellington Electricity submission, paragraph 3.4; Major Electricity Users' Group, Major Electricity Users' Group – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Major Electricity Users' Group submission**), paragraph 7.

83 Powerco submission, page 4; The Lines Company submission, page 8.

84 Major Electricity Users' Group submission, paragraph 7.

85 Orion cross-submission, page 4.

2.109 The Lines Company suggested defining the term 'capacity' in relation to non-network solutions because this capacity depends on many factors.[86]

2.110 We have updated the proposed wording under clause 4.2.7 of Attachment A, outlined below.

Our final decision considers the feedback from submissions

2.111 In response to stakeholder feedback, we have made the following key change from the draft decision:

2.111.1 removed the proposed wording for clause 4.2.7 of Attachment A, and instead adopted the following:

> 4.2 a description of the **network** configuration, including – […]
>
> 4.2.7 a quantification of the contribution each **non-network solution** makes towards solving a **network** risk or constraint, and a description of the extent to which those **non-network solution**s are provided by a **related party** or third party.

86 The Lines Company submission, page 8.

D5.2 – Work and investment on flexibility resources (non-network solutions) – Definition of ‘Non-network solution’

Final decision

2.112 Our final decision is to require EDBs to report against a defined term for ‘non-network solution’ to support consistent reporting across the sector. We have:

2.112.1 defined the term ‘non-network solution’ in clause 1.4.3 of the ID determination;[87] and

2.112.2 where we considered it appropriate, replaced several instances of ‘distributed generation’ within the ID determination with ‘non-network solutions’.

2.113 EDBs are first required to comply with this amendment for the disclosures due to be publicly disclosed by 31 March 2025.

Purpose of the amendment

2.114 Defining the term ‘non-network solution’ in the ID determination will help to provide guidance and certainty when EDBs are completing their AMPs. The term ‘non-network solution’ was not previously defined.

2.115 We believe the additional guidance and certainty that results from defining 'non-network solution' is necessary. The ID determination already required EDBs to disclose their network development plans in relation to non-network solutions. However, we are aware of EDBs having different interpretations of what qualifies as a non-network solution creating reporting inconsistencies between EDBs when disclosing this information. Furthermore, some EDBs (including Aurora Energy) have previously indicated that guidance on this topic that sets out the Commission’s expectations would be helpful.[88]

2.116 As noted above, we have also replaced ‘distributed generation’ in Attachment A with the newly defined term for ‘non-network solution.’ We have done this only in instances where we consider stakeholders would further benefit if these requirements captured non-network solutions more broadly (which includes distributed generation).

87 Under clause 1.4.3 of the ID determination, ‘non-network solution’ means any of ‘(a) distributed generation; (b) electricity storage; or (c) demand response measures.’ Demand response measures includes pricing strategy.

88 Aurora Energy, Submission on EDB targeted ID review process and issues paper, (20 April 2022), paragraph 92.

We received broad opposition on the proposed use of 'non-traditional solution'

2.117 In the draft paper we proposed using the term 'non-traditional solution', however we incorporated feedback from the submissions and have amended this to 'non-network solution'.

2.118 WEL Networks, Vector, Electra, Aurora Energy, and Orion requested a workshop between the Commission and EDBs to improve the definition for 'non-traditional solutions'.[89]

2.119 Network Waitaki, Powerco, Firstlight Network, and the Independent Electricity Generators Association (IEGA NZ) provided feedback on the proposed definition not being clear enough, and therefore, it may not capture the correct information.[90]

2.120 IEGA NZ, Vector, Electra, Aurora Energy, Wellington Electricity, Orion, and ENA provided more specific feedback in relation to opposing the use of the term 'non-traditional' along with the definition in general.[91]

2.121 Vector's view is that 'non-traditional' is time bound in nature and it instead suggested using 'non-wired' alternative or solution to delineate a clear boundary.[92] However, Northpower, Aurora Energy, and Electra highlighted the complexity of the issue via cross-submissions, stating that the term 'non-wired' was no clearer than 'non-traditional'.[93]

2.122 We appreciate the broad feedback from submissions and in response we have reverted to using the term that already existed in the ID determination ('non-network solution') and have also updated the clause 1.4.3 definition (set out below).

2.123 Furthermore, we consider a workshop is not necessary at this stage as the newly defined term 'non-network solution' is expected to address the primary concerns raised in submissions.

Our final decision considers the feedback from submissions

2.124 In response to stakeholder feedback, we have made the following key changes from the draft decision:

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89 WEL Networks cross-submission, paragraph 4; Vector Limited cross-submission, paragraph 25; Electra cross-submission, page 1; Aurora Energy cross-submission, paragraph 13; Orion cross-submission, page 3.

90 Network Waitaki submission, paragraph D5.2; Powerco submission, page 4; Firstlight Network submission, page 6; IEGA cross-submission, page 1.

91 IEGA cross-submission, page 1; Vector Limited submission, paragraph 17; Electra submission, page 1; Aurora Energy submission, paragraphs 40-45; Wellington Electricity submission, paragraphs 3.4; Orion submission, page 4; ENA submission, page 5.

92 Vector Limited submission, paragraph 17.

93 Northpower cross-submission, paragraph 6; Aurora Energy submission, paragraph 14; Electra cross-submission, page 3.

2.124.1 removed the proposed defined term ‘non-traditional solution’ from clause 1.4.3 of the ID determination; and

2.124.2 added ‘non-network solution’ as a defined term under clause 1.4.3 of the ID determination, which means any of:

(a) **distributed generation**; (b) electricity storage; or (c) demand response measures.

D5.3 – Work and investment on flexibility resources (non-network solutions) – Opex reporting requirements

Final Decision

2.125 Our final decision is to require EDBs to provide more granular reporting (historical and forecast) of opex spend on non-network solutions provided by a related party or third party.

2.126 EDBs must now report against a new non-network solution-related expenditure line item in Schedules 5b(i), 5b(iii), 5d(i), 5f, 6b(i), 7(iii) and 11b.

2.127 EDBs are first required to disclose the amended Schedules by:

2.127.1 31 March 2025 for Schedule 11b (eg, forecast reporting); and

2.127.2 31 August 2025 for disclosure year 2025 for Schedules 5b(i), 5b(iii), 5d(i), 5f, 6b(i), and 7(iii) (eg, historical reporting).

2.128 Consistent with existing certification and assurance requirements:

2.128.1 the amended Schedule 11b is subject to only director certification; and

2.128.2 the amended Schedules 5b(i), 5b(iii), 5d(i), 5f, 6b(i), and 7(iii) is subject to both audit and director certification.

Purpose of the amendment

2.129 We recognise that previous ID opex reporting requirements did not provide clear visibility to stakeholders of the expenditure related to non-network solutions, such as payments to related or third party providers of non-network solutions.

2.130 Separating out non-network solution-related expenditure from other opex will provide stakeholders with better visibility of EDBs' expenditure in this area. Previously other types of opex could be included in the same category where non-network solutions opex was disclosed.

2.131 We have included the non-network solutions provided by a related party or third party service supplier opex category for related party transactions in Schedule 5b to address earlier concerns of potential market distortion by EDBs.

2.132 The amendments will better promote the purpose of ID because they will allow interested persons to assess what investments are being made by EDBs in relation to assets or services that are innovative in nature (eg, non-network solutions). This may also lead to opportunities for market participants to offer non-network solutions to EDBs which will increase the supply of electricity and ultimately lower prices for consumers. EDBs being more efficient is one of the limbs of the purpose of Part 4 of the Act under s52A.

We received broad support in submissions for historical reporting of this expenditure

2.133 Submitters supported the amendment in principle but requested clarification around how related party transactions should be treated.

2.134 Horizon Networks, Vector, and Aurora Energy requested clarification on whether related party transactions are to be included in all proposed new opex lines or if these transactions should only be recorded in the report on related party transactions (eg, Schedule 5b).[94]

2.135 Having considered this feedback, to provide certainty for EDBs and other stakeholders on the expenditure reported, we have changed the proposed name of the opex line item to 'non-network solutions provided by a related party or third party' and updating Schedule 16 of the ID determination.

2.136 Vector suggested adding an additional reporting line:[95]

> We believe that to provide more clarity around costs incurred towards non-traditional solutions, there should be an additional line entitled 'Enabling non-traditional solutions' under 'Non-network opex' with the following definition: Means operating expenditure relating to non-traditional solutions incurred by the EDB.

2.137 We do not consider that there is currently enough stakeholder interest in this information to add it as a reporting requirement and the delineation between this and other categories may often not be clear.

2.138 In relation to the forecast reporting requirement in Schedule 11b, some submitters raised concerns over the accuracy of the forecasts and alignment with Default Price-Quality Path (DPP) allowances. Aurora Energy, Wellington Electricity and Vector commented in their submissions that it could be difficult to complete Schedule 11b accurately, with Wellington Electricity citing concerns such as the unknown cost and effectiveness of future services from flexibility providers along with unknown constraints which will be impacted by the uptake of electric vehicles.[96]

2.139 We appreciate that there may be some inherent uncertainties around forecasting opex on non-network solutions in Schedule 11b. However, we consider that these uncertainties already exist for forecasts of total opex, and there are uncertainties in other areas of the AMPs too.

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94 Horizon Networks submission, paragraph 25; Vector Limited submission, paragraph 20; Aurora Energy submission, paragraphs 51-52.

95 Vector Limited submission, paragraph 21.

96 Aurora Energy submission, paragraph 49; Wellington Electricity submission, page 7; Vector Limited submission, paragraphs 27-31.

2.140 Vector commented that it did not support the amendment to schedule 11b on the basis that there will likely be no allowance for the opex expenditure in the current DPP cycle.[97]

2.141 In response, we do not believe this comment is relevant to this amendment as the purpose of the DPP is different to that of ID. This amendment is about improving transparency, and enabling stakeholders to assess what investments are being made by EDBs in relation to assets or services that are innovative in nature (eg, non-network solutions). If there is no allowance for the opex expenditure in the current DPP cycle, this is still useful for stakeholders to be aware of.

2.142 Some EDBs raised concerns about the proposed implementation timing for this reporting requirement. Horizon Networks, Vector, Network Waitaki, Electra, Firstlight Network, and ENA all requested that the requirement be pushed back to disclosure year 2025.[98] As disclosure year 2024 is already underway, they consider it would be difficult to reconfigure their systems.

2.143 We understand submission points that it would be more difficult to get this information out of historical financial data systems than we anticipated. We accept that it would be better for EDBs to be able to start recording this data in the required way as it happens, rather than trying to reclassify historical data. Therefore, our final decision is to defer the first disclosure of the non-network solution-related expenditure in the backward-looking schedules (eg, historical reporting) to 31 August 2025 (with respect to disclosure year 2025).

Our final decision considers the feedback from submissions

2.144 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.144.1 updated the name of the proposed opex line item within the Schedules (and the relevant Schedule 16 definitions) from 'non-traditional solutions provided by a third party service supplier' to 'non-network solutions provided by a related party or third party'; and

2.144.2 deferred the first disclosure of the amended backward-looking opex schedules by one year to 31 August 2025 (with respect to disclosure year 2025).

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97 Vector Limited submission, paragraph 28.

98 Horizon Networks submission, paragraph 18; Vector Limited submission, paragraph 30; Network Waitaki submission, paragraph D5.5; Electra submission, page 1; Firstlight Network submission, page 6; ENA submission, page 5.

D6.1 – Standardised pricing components including transmission costs – Standardised connection types

Final decision

2.145 Our final decision is to require EDBs to report billed quantities and line charge revenues against standardised connection type options in Schedules 8(i) and (ii).

2.146 EDBs can use the ‘Free text’ option to report against their own connection types. There are also three other options for EDBs to choose from should they decide to; these are Residential, Commercial, and Industrial.[99]

2.147 EDBs are first required to disclose the amended Schedule 8 by 31 August 2025 for disclosure year 2025.

2.148 Consistent with existing assurance and certification requirements, the amended Schedule 8 is subject to only director certification.

Purpose of the amendment

2.149 This amendment will help stakeholders better understand EDBs pricing performance, such as how cost reflective the pricing is. For example, the EA is one of these stakeholders and this will assist their work around monitoring EDBs pricing performance.[100] We have worked closely with the EA in designing these final requirements to help ensure there is no regulatory overlap between the two regulators.

2.150 We consider these amendments will significantly improve the timeliness and robustness of stakeholder assessments, support distribution pricing related regulatory decisions, more effectively monitor progress of distributors’ progress towards cost reflective pricing and drive better outcomes for consumers.

2.151 We have retained the option for EDBs to use a ‘Free text’ field to report consumer connections. This will allow EDBs freedom to innovate and create their own categories as required. If they decide to, EDBs can use the three other options to report against their connection types; these are Residential, Commercial, or Industrial.

2.152 These amendments will allow stakeholders to more accurately analyse and better understand the performance of EDBs in the area of pricing, thereby meeting the purpose of Part 4 (particularly relating to efficiency) and the purpose of ID.[101]

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[99] Due to how different EDBs internally categories different connections, at this stage we have decided to not add defined terms for any connection types.
[100] Electricity Industry Act 2010, Part 2, s 32(2)(b).
[101] Section 52A(1)(b) and (c).

There was broad opposition to the amendment as proposed in the draft reasons paper.

2.153 There was broad opposition from submitters to the proposed amendment with many submitters raising issues with the definitions of connection types.

2.154 WEL Networks, Orion, Alpine Energy, Network Waitaki, Aurora Energy, Powerco, Vector, Horizon Networks, and ENA do not believe the standardised connection types are fit for purpose in terms of being able to select one of the standardised options based on their connection definitions, or in terms of providing meaningful data to interested persons.[102]

2.154.1 In response, we have decided to adopt only three optional, undefined categories for EDBs to choose from. Unlike the draft decision, these will not be linked to metering types as defined by the Electricity Industry Participation Code.

2.154.2 Analysis done over time across EDBs could potentially help drive a consensus on consistent connection types, which could be considered in a future ID review.

2.155 Horizon Networks also raised a concern around disclosing consumption details of individual businesses using the proposed standardised connection types. It believes this requirement would rely on information that EDBs do not control and therefore can't confirm the accuracy of, as the retailer does the metering. Horizon Networks also said it incentivises EDBs to price by customer type and meter category.[103]

2.156 The Lines Company's submission requested definitions/guidance about what is a 'standardised connection type'.[104]

> we would strongly recommend that the Commission provides definitions/guidance about what is a "standardised connection type". For example, is a holiday home residential or a very small non-residential (metering installation category 1)?

2.157 We have considered stakeholder feedback and have decided to relax this requirement compared to the proposed changes so now there are only three optional undefined standard categories (eg, they can be interpreted more broadly). Individual business consumption details should not need to be disclosed and EDBs are permitted to use a free text field in Schedule 8.

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102 WEL Networks cross-submission, page 1; Orion submission, page 5; Alpine Energy submission, paragraph 21; Network Waitaki submission, page 6; Aurora Energy submission, paragraph 54; Powerco submission, page 5; Vector Limited submission, paragraph 33; Horizon Networks submission, paragraphs 29-32; ENA submission, page 5.

103 Horizon Networks submission, paragraph 33.

104 The Lines Company submission, page 8.

2.158 Horizon Networks, Alpine Energy, and ENA raised concerns of regulatory overlap with the EA.[105]

2.159 Powerco mentioned a misalignment between EDB price categories, and the metering categories detailed in the Electricity Industry Participation Code and suggested EDBs could provide this data directly to the EA in a database format.[106]

2.160 Powerco further noted the proposed information bears a close resemblance to the PQ pricing schedules already disclosed by non-exempt EDBs in their DPP Price Setting and Annual Compliance Statements. It considered, therefore, that an alternative approach could involve mandating that exempt EDBs also disclose this data.

2.161 Powerco's comments appear to relate to both the standardised connection types and standardised price components.

2.162 Electra, in its cross-submission, opposed Powerco's suggestion to mandate exempt EDBs to provide this information.[107]

2.163 Given the lack of support for this proposal, we have not adopted this change.

2.164 As with other requirements proposed in D6, Horizon Networks, Vector, Network Waitaki, Firstlight Network, Alpine Energy, Unison and Centralines and ENA all requested that the requirement be pushed back to the disclosure year 2025 as disclosure year 2024 is already underway and it would be difficult to reconfigure their systems.[108]

2.165 Having considered this feedback, we have decided to defer the first disclosure of the amended Schedule 8 to 31 August 2025 (with respect to disclosure year 2025).

Our final decision considers the feedback from submissions

2.166 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.166.1 removed the proposed definitions within Schedule 16 of the ID determination for the standardised connection types (eg, Residential, Commercial, Industrial); and

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105 Horizon Networks submission, paragraph 49; Alpine Energy submission , paragraph 22; ENA submission, page 5.

106 Powerco submission, page 5.

107 Electra cross-submission, page 5.

108 Horizon Networks submission, paragraph 18; Vector Limited submission, paragraph 2; Network Waitaki submission, page 1; Firstlight Network submission, page 7; Alpine Energy submission, paragraph 5; Unison and Centralines submission, page 1; ENA submission, paragraph 3.

2.166.2 deferred the first disclosure of the amended Schedule 8 to 31 August 2025 for disclosure year 2025.

D6.2 – Standardised pricing components including transmission costs – Standardised pricing components

Final decision

2.167 Our final decision is to require EDBs to report billed quantities and line charge revenues against standardised price component options in Schedules 8(i) and (ii).[109] If the standard options are not appropriate, EDBs may use the 'other' option to disclose their own pricing component.

2.168 EDBs are first required to disclose the amended Schedule 8 by 31 August 2025 for disclosure year 2025.

2.169 Consistent with existing assurance and certification requirements, the amended Schedule 8 is subject to only director certification.

Purpose of the amendment

2.170 This amendment will help stakeholders better understand EDBs pricing performance, such as how cost reflective the pricing is. For example, the EA is one of these stakeholders and it will help their work to monitor EDBs' pricing performance.

2.171 We expect the amendments to significantly improve the timeliness and robustness of stakeholder assessments, support distribution pricing related regulatory decisions, more effectively monitor progress of distributors' progress towards cost reflective pricing and drive better outcomes for consumers.

2.172 It will be simpler for stakeholders to assess the pricing performance of EDBs by having standardised pricing components as comparative analysis across the sector will be improved. We expect stakeholder analysis to be more robust if EDBs are required to report against defined terms where reasonably possible (eg, if EDBs use the same, or very similar, pricing components).

2.173 We have retained the option within Schedule 8(i) to use 'other,' which will allow EDBs to report against their own unique price components. This will allow EDBs the freedom to innovate and create their own categories when required. We will monitor the 'other' options used and will consider if these can later be incorporated as a 'standardised option' in Schedule 8.[110]

[109] These pricing component options have been defined in Schedule 16 of the ID Determination.
[110] We may also consider defining options where appropriate.

2.174 These amendments will allow stakeholders to more accurately analyse and better understand the performance of EDBs in the area of pricing, thereby meeting the purpose of Part 4 (particularly relating to efficiency) and the purpose of ID.[111]

Overall, there was broad support for the proposed amendment from submitters

2.175 Horizon Networks proposed the inclusion of additional options for standardised price components:[112]

> […] suggest the proposed standardised price components are updated to allow for fixed monthly charges. Additional standardised price components could include:
>
> > $/fixture/month – to accommodate streetlights and other load that is charged based on the number of fixtures per month.
> >
> > $/month – to accommodate other load, such as telecommunication cabinets and major customers that are charged a fixed monthly fee.

2.176 We agree that both price components should be included as a standardised options within Schedule 8. We have added the following terms and definitions to Schedule 16 of the ID determination:

> Monthly fixed charge – means a fixed charge per month of connection.
>
> Monthly fixed charge per fixture – means a fixed charge per fixture per month of connection.

2.177 Orion recommended that the Commission and EA work together to align the definitions for 'device' and 'appliance'.[113]

2.178 After consultation with the EA, we have decided to amend the name of the term from 'Device Tariff' to 'Device and/or appliance charge.' We have also modified the definition under Schedule 16 of the ID determination so that it now reads 'means a charge for either (or both of) particular devices and appliances, such as electric vehicle chargers.'

2.179 ENA recommended that the term 'tariffs' be replaced with 'charges' for all schedule 16 defined terms.[114]

2.180 We have adopted this feedback. There is no apparent disadvantage if we make this change. We consider that 'charges' is likely to be the more familiar term for most stakeholders (eg, consumers). We also tested the proposed change with the EA, who raised no concerns.

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111 Section 52A(1)(b) and (c).
112 Horizon Networks submission, paragraph 52.
113 Orion submission, page 5.
114 ENA submission, page 5.

2.181 Aurora Energy submitted that an additional price component for 'all inclusive' be added so that it can categorise certain consumers without resorting to using the 'other' category. Aurora Energy noted that the connections of consumers in Dunedin often have an aspect that is 'controlled' by the EDBs, but the amount of 'control' is unable to be recorded as the smart meters used by these consumers cannot differentiate between controlled and uncontrolled load.[115]

2.182 We acknowledge the validity of Aurora Energy's concern and in response, after consulting the EA, we have decided to:

2.182.1 add 'all inclusive' price components to the standardised options; and

2.182.2 add several new terms to Schedule 16 of the ID determination relating to all-inclusive connections, which includes a definition for the term 'all-inclusive charge' that means:

> 'means an electricity distribution charge applying to energy that has both controlled and uncontrolled components that are not separately metered.'

2.183 As mentioned above, Powerco suggested that all pricing data ie, standardised connection types and standardised pricing components, could be provided directly to the EA in a database format.[116]

2.184 We have not adopted this suggestion because the EA is not the only interested person that will use the data.

2.185 Powerco also suggested that the proposed information bears a close resemblance to the PQ pricing schedules already disclosed by non-exempt EDBs in their DPP Price Setting and Annual Compliance Statements and an alternative approach could involve mandating that exempt EDBs also disclose this data.

2.185.1 Electra, in its cross-submission, opposed Powerco's suggestion. They believe it is inappropriate for the Commission to impose obligations set under price-quality regulation onto EDBs that are not subject to that regulation.[117]

2.185.2 We have not adopted Powerco's suggestion, we agree with the above point made by Electra and there was also broad support from other submitters for the amendment as proposed.

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115 Aurora Energy submission, paragraph 16.
116 Powerco submission, page 5.
117 Electra cross-submission, page 5.

2.186 Horizon Networks, Vector, Network Waitaki, Bruce Palmer, and ENA all raised concern that the 'total' field in the billed quantities in Schedule 8(i) would result in overstated amounts due to double counting.[118]

2.187 We agree that the new 'total' field is appropriate only for the line revenue calculations in Schedule 8(i) (eg, not when reporting billed energy usage). This total field for billed quantities has not been adopted for our final decision.

2.188 As with other requirements proposed in D6, ENA and many EDBs requested that the implementation of new requirements be pushed back to disclosure year 2025, as the disclosure year 2024 is already underway and it would be difficult for EDBs to reconfigure their systems.[119]

2.189 Having considered this feedback, we have decided to defer the first disclosure of the amended Schedule 8 to 31 August 2025 (with respect to disclosure year 2025).

Our final decision considers the feedback from submissions

2.190 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.190.1 added new options to standardised price components in Schedules 8(i) and (ii), and relevant support definitions to Schedule 16 of the ID determination. The new selections are:

2.190.1.1 'Monthly fixed charge - $/fixture/month';

2.190.1.2 'Monthly fixed charge - $/month';

2.190.1.3 'All-inclusive non-TOU variable charge - $/kWh';

2.190.1.4 'All-inclusive TOU peak charge - $/kWh';

2.190.1.5 'All-inclusive TOU off-peak charge - $/kWh';

2.190.1.6 'All-inclusive TOU shoulder charge - $/kWh'; and

2.190.1.7 'All-inclusive non-TOU charge - $/kWh'.

2.190.2 changed the name of the option 'Device tariff' within Schedule 8(i) to 'Device and/or appliance charge', and updated the corresponding term and definition within Schedule 16 of the ID determination;

118 Horizon Networks submission, paragraph 50; Vector Limited submission, paragraph 33; Network Waitaki submission, page 6; Bruce Palmer, Bruce Palmer – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Bruce Palmer submission**), Pages 1-3; ENA submission, page 5.

119 ENA submission, paragraph 3.

2.190.3 replaced all proposed instances of ‘tariff’ with ‘charge’ for all other Schedule 8-related terms in Schedule 16 of the ID determination; and

2.190.4 deferred the first disclosure of the amended Schedule 8 to 31 August 2025 (with respect to disclosure year 2025).

D6.3 – Standardised pricing components including transmission costs – Transmission costs

Final decision

2.191 Our final decision is to require EDBs to report more granular billed quantities and line charge revenue information in Schedules 8(i) and (ii). EDBs must now report the split between distribution and transmission rather than only reporting totals.

2.192 EDBs are first required to disclose the amended Schedule 8 by 31 August 2025 for disclosure year 2025.

2.193 Consistent with existing assurance and certification requirements, the amended Schedule 8 is subject to only director certification.

Purpose of the amendment

2.194 We consider this amendment meets the purpose of Part 4 and the purpose of ID as we expect stakeholders to be able to more accurately analyse, and better understand, the pricing performance of EDBs (with respect to the efficiency limb).[120] Stakeholders being able to differentiate between distribution and transmission components will allow them to better assess the cost reflectivity of EDBs.

There was broad support overall for the proposed amendment

2.195 Horizon Networks, Meridian Energy, Firstlight Network, Aurora Energy, The Lines Company, Wellington Electricity, and MEUG expressed support for the proposed amendment. Wellington Electricity said in its submission:[121]

> This provides clarity for customers on what the breakdown of charges is and the controllable portion of their bill that they can influence.

2.196 Counties Energy opposed the proposed amendment:[122]

> Counties Energy believes that the disaggregation of the "distribution" and "transmission" components of the billed quantities and line charge revenue fields will provide misleading results. This is because the new transmission pricing methodology (TPM) benefit-based charges cannot be allocated with any meaningful accuracy to customer groups. The calculation of the benefit-based charges by Transpower is complex because it involves market modelling using historic hydro inflows to simulate GXP prices with and without a long list of transmission assets. Add to this the list of transmission assets will grow over-time making the analysis increasingly complex. Consequently, it is not possible, or of value, for EDBs to then accurately split their line prices between the distribution and transmission components. Given this, what is the insight that the Commission is seeking from EDBs providing a split of its billed quantities and line revenue into distribution and transmission?

120 Efficiency limb (c) in Section 52A (1).
121 Wellington Electricity submission, page 9.
122 Counties Energy submission, page 2.

2.197 We have retained this proposed change as we consider that this is not a sufficient reason to discard it, particularly given no other EDBs raised compliance concerns with this requirement (or supported this point in cross-submissions). Without knowing the allocation of transmission costs for each pricing component, it is difficult for stakeholders to determine the extent to which EDBs are adopting cost reflective pricing.

2.198 Vector also raised concerns about the proposed amendment in their cross-submission, stating that there will be no transmission billed quantities to report at a price component level because they now charge the retailer directly for the previous year's quantities billed for each of their GXP:[123]

2.199 We believe even if EDBs cannot provide exact values for transmission billed quantities at a price component level they should be able to provide a reasonable estimate which will still be of use to stakeholders.

2.200 Consistent with other submissions on D6, Unison and Centralines raised a concern with the first required disclosure of this new information (this was supported by Orion via cross-submission):[124]

> Our pricing methods do not currently disaggregate components in the manner that reporting is proposed for, eg, transmission and distribution. While these requirements are achievable for FY25 onwards, reporting as proposed for FY24 would result in estimation and would be necessarily less accurate.

2.201 Having considered this feedback, we have decided to defer the first disclosure of the amended Schedule 8 to 31 August 2025 (with respect to disclosure year 2025).

Our final decision considers the feedback from submissions

2.202 In response to stakeholder feedback, we have made the following key change from the draft decision:

2.202.1 deferred the first disclosure of the amended Schedule 8 to 31 August 2025 for disclosure year 2025.

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123 Vector Limited cross-submission, paragraph 32.

124 Unison and Centralines submission, page 2; Orion cross-submission, page 4.

D6.4 – Standardised pricing components including transmission costs – Other items

Final decision

2.203 Our final decision is to remove the following fields from Schedule 8 of the ID Determination:

2.203.1 the 'Unit charging basis' field from Schedule 8(i); and

2.203.2 the 'Notional revenue foregone from posted discounts (if applicable)' and 'Rate' fields from Schedule 8(ii).

2.204 EDBs are first required to disclose the amended Schedule 8 by 31 August 2025 for disclosure year 2025.

Purpose of the amendment

2.205 The purpose of this amendment is to help ensure the requirements within Schedule 8 remain fit-for-purpose:

2.205.1 retaining the 'Unit charging basis' is likely to be redundant with the new standardised price components introduced under amendment D6.2;

2.205.2 removing the 'rate (eg, $ per day, $ per kWh, etc.)' field from Schedule 8(ii) and including this within the standardised pricing component options will reduce the risk of errors when EDBs input data; and

2.205.3 removing the 'Notional revenue foregone from posted discounts (if applicable)' field from Schedule 8(ii) will reduce the compliance obligations for EDBs. There are now options for consumer discounts in the standardised pricing components. The new definition for consumer discount has been included in Schedule 16 and aligns with the IM Determination.

All submissions in relation to this amendment supported the removal of these fields

2.206 Wellington Electricity supported the removal of the 'Unit charging basis' and 'Rate' fields, noting that it allows greater flexibility for EDBs to customise their pricing structures to suit their customers.[125]

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125 Wellington Electricity submission, page 9.

2.207 Consistent with submissions on other D6-related amendments, ENA and many EDBs requested that the implementation of this amendment be pushed back to disclosure year 2025 as disclosure year 2024 is already underway (starting 1 April 2024) and that it would be difficult to reconfigure their systems (partway through a disclosure year).[126]

2.208 Having considered this feedback, we have decided to defer the first disclosure of the amended Schedule 8 to 31 August 2025 (with respect to disclosure year 2025).

Our final decision considers the feedback from submissions

2.209 In response to stakeholder feedback, we have made the following key change from the draft decision:

2.209.1 deferred the first disclosure of the amended Schedule 8 to 31 August 2025 for disclosure year 2025.

[126] ENA submission, paragraph 3.

Asset management

2.210 An EDB's asset management practices underpin its investment and operational activities. Effective asset management enables EDBs to provide more reliable and efficient electricity lines services and helps ensure they provide services at a price and quality that reflects the demands of consumers.

2.211 It is important that we adapt our ID requirements on asset management to capture new information relevant to EDBs' changing operating environment. It is also becoming increasingly important to assess whether investment is sufficient and efficient as the impacts of climate change pose increasing risks to network resilience. Network resilience has been an increasing focus for EDBs and consumers following recent extreme weather events. Consumers have an ongoing expectation that EDBs are managing risks related to extreme events caused by severe weather, earthquakes, and other natural disasters.

2.212 In TIDR (2024) our focus within the asset management section is on vegetation management, which refers to an EDB's practices of controlling vegetation (primarily trees) in the proximity of distribution lines and other assets, to reduce the potential for service interruptions and damage caused by vegetation coming into contact with network assets (primarily overhead lines).

2.213 Effective vegetation management can have a significant impact on consumers, both in terms of prices (vegetation management being a significant cost for many EDBs), and interruptions. In the 2023 disclosure year, EDBs spent $58.6 million on vegetation management (17% of network opex), and at least 27% of interruptions (Class B and C interruptions) were caused by vegetation.[127]

2.214 To a large extent, the occurrence and severity of vegetation-related interruptions on the network can be influenced by an EDB's asset management practices. Deteriorating trends in vegetation-related interruptions can indicate that an EDB's vegetation management practices, including expenditure levels, may need to be reviewed and changed to be more effective.

2.215 Our final decision for TIDR (2024) includes a suite of changes to EDBs' ID requirements relating to vegetation management. These are mostly new disclosure requirements, focusing on vegetation management costs, performance, and risk.

2.216 We have discussed submitters' views on the specific ID amendments which were proposed, in the sections below. However, there were some submission points which related to the topic of vegetation management more generally.

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[127] Commerce Commission, Electricity distributors' information disclosure data 2019-2023, (14 December 2023).

2.217 Several submitters encouraged the Commission to wait for MBIE's review of the Electricity (Hazards from Trees) Regulations 2003 to be completed before making any amendments relating to vegetation management reporting.[128]

2.218 Vector stated:[129]

> Instead of guessing now, it makes more sense to wait for the outcome of MBIE's review in order to fully ascertain the policy needs, and then propose the ID changes. The Commission has already changed the goalposts once on this amendment, we urge the Commission to pause and reconvene once MBIE has finalised their needs in this space. EDBs will not want to make system changes twice, ultimately meaning consumers will pay twice.

2.219 Network Waitaki stated:[130]

> At the very least the Commission should try to align with tree regulation amendments and instead of pre-empting regulatory change liaise with MBIE to obtain clarity on expected timelines of completion of the tree regulations. This will be more efficient and prevent unnecessary ID amendments.

2.220 Electra stated:[131]

> The MBIE review will drive extensive changes to the Tree Regulations and, therefore, EDB vegetation management practices, negating all expenditure disaggregation reported before the MBIE review is completed. Moving on the Commission's proposed amendment now (i.e., for the 31 August 2025 disclosure year) will only introduce cost, as EDBs will need to make extensive system changes to capture the disaggregated expenditure, with little benefit to consumers, as the measures will not provide a time-series against which to base EDB performance.

2.221 We are aware that MBIE has not yet made any final decisions on the review of the Electricity (Hazards from Trees) Regulations 2003.

2.222 We are of the view that ID for vegetation management should be updated as soon as possible, and therefore, we consider it appropriate for us to rely on the systems (eg, the tree regulations) in place currently. The impacts of climate change are causing a greater frequency and magnitude of extreme weather events in some parts of New Zealand, with increased wind speeds and rainfall, which will likely cause greater tree damage. Despite this, some EDBs may currently not be aware of the risk their networks are exposed to from vegetation (particularly considering these evolving factors) and as a result, take a largely reactive approach to asset management (particularly towards out-of-zone trees).

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128 MBIE is currently conducting a review of the Electricity (Hazards from Trees) Regulations 2003: https://www.mbie.govt.nz/have-your-say/tree-regulations/.

129 Vector Limited submission, paragraph 46.

130 Network Waitaki submission, page 7.

131 Electra submission, page 5.

2.223 Though we consider that the amendments we have made to ID for vegetation management reporting are relatively future-proofed, we note that we can update the ID requirements again in the future, if needed, to align to any changes made by MBIE to the Electricity (Hazards from Trees) Regulations 2003.

AM6.1 – Vegetation management reporting – Schedule 6b(i)

Final decision

2.224 Our final decision is to require EDBs to disclose opex relating to vegetation at a further disaggregated level in Schedule 6b(i).

2.224.1 For 'Service interruptions and emergencies' opex, EDBs will be required to disclose opex which is vegetation-related, and other.

2.224.2 For 'Vegetation management' opex, EDBs will be required to disclose opex in the following subcategories: assessment and notification costs, felling or trimming vegetation – in-zone, felling or trimming vegetation – out-of-zone, and other.

2.225 We have added definitions for the new disclosure requirements to Schedule 16 of the ID determination.

2.226 We have also made one clarification change to the existing definition of 'Routine and corrective maintenance inspection' in clause 1.4.3 of the ID determination.

2.227 EDBs are first required to disclose this information by 31 August 2026 for disclosure year 2026.

2.228 The disaggregated disclosure information (the new vegetation opex subcategories) is not subject to the audit requirement. The opex totals (eg, total service interruptions and emergencies opex, and total vegetation management opex) remain subject to the audit requirement.

2.229 The disclosure is subject to the director certification requirement.

Purpose of the amendment

2.230 The purpose of this amendment is to disaggregate opex on vegetation-related activities, so that stakeholders can better understand (and compare between EDBs):

2.230.1 the cost of damage to the network caused by vegetation (including clearing vegetation, repairs, and re-livening);

2.230.2 whether an EDB is going beyond the standard maintenance trim process (trimming vegetation that encroaches the growth limit zone), and taking a proactive approach to managing out-of-zone vegetation (including fall zone trees); and

2.230.3 the cost of managing out-of-zone vegetation, over which EDBs have less control, and which we have heard from EDBs, cause a large portion of unplanned interruptions.

2.231 This information will be valuable to stakeholders (including consumers), particularly in relation to the quality of service provided by EDBs, since vegetation is the largest cause of unplanned interruptions on the network.

2.232 This amendment promotes the purpose of ID regulation, as the information disclosed will help to show whether EDBs are improving efficiency and quality in their vegetation management activities.

Submissions on the proposed amendment were mixed

2.233 While there were some submissions in support of the proposed amendment, there were others which proposed changes and encouraged further consideration of the issue by the Commission, as well as submissions which did not support the proposed amendment.

2.234 Many submitters noted that it would take some time for EDBs to establish the necessary systems and processes for data collection and reporting.[132]

2.235 In response, we have delayed the entry into force date for the amendment, so that it first applies to disclosures due on 31 August 2026 (for disclosure year 2026).

2.236 Many submitters requested that the breakdown of vegetation opex be simplified, as the subcategories proposed did not necessarily align to how these costs are recorded by EDBs or by third party contractors.[133] Submitters were also concerned that the disaggregated vegetation opex information would not be auditable, particularly in-zone and out-of-zone trimming/felling costs.[134] In its cross-submission, Vector suggested that the Commission speak to EDBs' field service providers about the workability of the proposed amendment.[135]

2.236.1 We acknowledge that large system and process changes may be required for EDBs to accurately record the proposed opex information to a standard satisfactory for audit. Therefore, our final decision is to not include the audit requirement for the disaggregated vegetation opex information.

2.236.2 We note that in future, we may consider adding an audit requirement for this information. In the meantime, not including the audit requirement:

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[132] Aurora Energy submission, paragraphs 68-70; Firstlight Network submission, page 8; Northpower submission, page 1; Orion submission, page 5; Powerco submission, page 6; The Lines Company submission, page 10.

[133] Aurora Energy submission, paragraphs 64-67; Horizon Networks submission, paragraphs 59-61; Network Waitaki submission, page 7; Vector Limited submission, paragraph 35.

[134] Alpine Energy submission, paragraph 15; Aurora Energy submission, paragraphs 68-69; ENA submission, page 6; Network Waitaki submission, page 7; Orion submission, page 5; Vector Limited submission, paragraph 36.

[135] Vector Limited submission, paragraph 40.

2.236.2.1 allows EDBs to take an apportionment/best estimate approach to disclosing opex in the new vegetation subcategories; and

2.236.2.2 allows EDBs more time to improve the accuracy of the information reported in these disclosures.

2.236.3 We also note that EDBs can disclose information about their approach to recording/estimating opex in the new vegetation subcategories in the voluntary explanatory notes in Schedule 15.

2.237 Subsequent to receiving submissions and cross-submissions on our draft decision, and in response to the request from Vector, we met with a selection of EDBs and their field service providers to discuss the workability of the proposed amendment.[136] From these meetings, we understand that as part of their maintenance trim programmes, EDBs will rarely trim just to the notice zone.[137] Vegetation encroaching the growth limit zone may be the trigger for cut work, but in many cases, EDBs will trim back past the notice zone to better manage the vegetation risk.[138] This could be for a variety of reasons, including to better address vegetation growing directly under lines, to address overhanging branches, where it is more appropriate for the health of the tree, or to remove a tree at ground level.

2.238 In the draft decision reasons paper, we stated that *"where vegetation has grown into the notice zone, and trimming/felling is carried out outside of the notice zone (effectively, trimming has taken place both in-zone and out-of-zone), it is intended that this cost is recorded as "felling or trimming vegetation – out-of-zone"*.[139] We acknowledge that if applying this guidance (and given the 'maintenance trim' process detailed in paragraph 2.237 above), the reported opex to 'felling or trimming vegetation – in-zone' and 'felling or trimming of vegetation - out-of-zone' would likely be inaccurate and may overstate the 'out-of-zone' opex.

2.239 Therefore, our final decision is to amend the definition in Schedule 16 for 'felling or trimming vegetation – in-zone' to clearly state that where the felling or trimming is of vegetation that is both inside and outside the notice zone, it should be recorded as 'felling or trimming of vegetation - in-zone'.

136 Notes from the meetings we held with EDBs and their field service providers are published here.

137 "Notice zone" is defined in the Electricity (Hazards from Trees) Regulations 2003.

138 "Growth limit zone" is defined in the Electricity (Hazards from Trees) Regulations 2003.

139 Commerce Commission, Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses – Draft Decision – Reasons Paper, (17 August 2023), paragraph 3.144.

2.240 Some submitters suggested that vegetation management opex reporting should be driven by the legal ability that EDBs have to remove vegetation risks (under the Electricity (Hazards from Trees) Regulations 2003), and that there are currently no regulatory incentives to cut out-of-zone vegetation.[140]

2.241 We agree that under the current tree regulations, there is limited ability, and little regulatory incentive (outside of the Commission's quality standards, quality incentive scheme, and performance analysis function) to proactively cut out-of-zone vegetation. However, we know from speaking to the industry that some EDBs are taking a proactive approach to managing out-of-zone vegetation anyway. This often involves the creation of additional notice types for out-of-zone trees (which could be those that are diseased, at risk during high windspeeds or heavy rainfall, or are fall-zone trees), and actively engaging and negotiating with owners of out-of-zone trees (to communicate the risk to the network) to get them cut/trimmed/felled.

2.242 Many submitters were concerned that the costs of the proposed additional reporting outweigh the benefits, as many EDBs would need to introduce material changes to contractor processes, reporting or contracts to comply.[141] Of particular concern was the in-zone and out-of-zone trimming/felling costs.

2.242.1 We do not agree that the costs outweigh the benefits. Currently, stakeholders are not aware of the cost of managing out-of-zone vegetation, nor are they aware of the cost of dealing with service interruptions caused by vegetation (mostly by out-of-zone vegetation).

2.242.2 We are of the view that understanding where vegetation management effort and expenditure is being placed is a key part of implementing an effective management strategy (by enabling EDBs to optimise vegetation expenditure) and assessing the success of that strategy.

2.242.3 We know from speaking to the industry that when EDB's do take a proactive approach to managing out-of-zone vegetation, they usually bear the costs of these additional processes. Therefore, if an EDB is taking this approach with success (eg, risky out-of-zone trees are trimmed/felled), then this will show in the amended disclosures. This information, paired with the amended disclosures in Schedule 10(ii) (breakdown of vegetation interruptions to 'in-zone' and 'out-of-zone'), will give some insight into the effectiveness of an EDB's vegetation management strategy.

140 Unison and Centralines submission, page 2; Vector Limited submission, paragraph 35.

141 Alpine Energy submission, paragraph 14; ENA submission, page 6; Firstlight Network submission, page 8; Network Tasman, Network Tasman – Submission on Targeted ID Review (2024) draft decision – reasons paper for EDBs, (14 September 2023) (**Network Tasman submission**), page 1; Network Waitaki submission, page 7; Northpower cross-submission, paragraph 3; Orion cross-submission, page 5; Vector Limited submission, paragraph 40.

2.242.4 We believe that the benefits of this information to stakeholders (being transparency of the most important areas of vegetation opex, and the potential efficiency improvements in vegetation management activities) outweigh the costs for EDBs to implement process changes for the new reporting requirements.

2.242.5 We note that as mentioned in paragraph 2.236.1, we have not included the audit requirement for the disaggregated vegetation opex information, which lowers the compliance cost for EDBs for this amendment.

2.242.6 Regarding the proposal in our draft decision to require EDBs to disclose disaggregated 'Routine and corrective maintenance and inspection' opex, we acknowledge that collecting the proposed information could be cumbersome for EDBs, and the information would be of less value to stakeholders than the information on costs for vegetation-related service interruptions and emergencies. Therefore, our final decision does not include the requirement for EDBs to disclose disaggregated 'Routine and corrective maintenance and inspection' opex.

2.243 Counties Energy noted in its submission that clarification is required as to what is intended to be included in the 'Vegetation-related' subcategory within 'Service interruptions and emergencies' opex.[142]

2.244 In response, we have amended the definition of 'Vegetation-related' in Schedule 16, so that it should be more easily applied in practice. We note that it is intended that the total 'Service interruption and emergencies' cost associated with the vegetation-related interruption is captured in this opex line.

Our final decision considers the feedback from submissions

2.245 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.245.1 delayed the entry into force date for the amendment, so that it first applies to disclosures due on 31 August 2026 (for disclosure year 2026);

2.245.2 removed the requirement to disclose disaggregated 'Routine and corrective maintenance and inspection' opex;

2.245.3 removed the audit requirement for disaggregated vegetation opex information;

[142] Counties Energy submission, page 2.

2.245.4 amended the definitions of ‘felling or trimming vegetation – in-zone’ and ‘felling or trimming vegetation – out-of-zone’ in Schedule 16 of the ID determination; and

2.245.5 amended the definition of ‘Vegetation-related’ in Schedule 16 of the ID determination.

AM6.2 – Vegetation management reporting – Schedule 9c

Final decision

2.246 Our final decision is to require EDBs to disclose the number of overhead circuit sites on their network that are at high risk from vegetation damage. This will replace the existing metric in Schedule 9c 'overhead circuit requiring vegetation management (km/%)'.

2.246.1 The new disclosure includes the total number of sites newly identified throughout the disclosure year, and the total number of sites remaining at the disclosure year-end.

2.246.2 EDBs are also required to disclose the number of sites within different site categories, and the number of sites involving critical assets within each category. This disclosure is in a separate breakdown table within Schedule 9c.

2.246.3 We have added definitions for the new disclosure requirements to Schedule 16 of the ID determination.

2.247 EDBs are first required to disclose this information by 31 August 2026 for disclosure year 2026.

2.248 The disclosure is subject to the director certification requirement.

Purpose of the amendment

2.249 The purpose of this amendment is to provide more meaningful information on the results of vegetation risk assessments, so that stakeholders can better understand the risk to the network from vegetation, and whether EDBs are successfully managing the risk.

2.250 The new information will highlight for stakeholders the level of risk and different sources of vegetation damage risk that EDBs face.

2.251 This amendment promotes the purpose of ID regulation, as the information disclosed will help to show whether EDBs are improving efficiency and quality in their vegetation management activities.

Submissions on the proposed amendment were mixed

2.252 While there were some submissions in support of the proposed amendment, there were others which proposed changes and encouraged further consideration of the issue by the Commission, as well as submissions which did not support the proposed amendment.

2.253 Many submitters noted that it would take some time for EDBs to establish the necessary systems and processes for data collection and reporting.[143]

2.254 In response, we have delayed the entry into force date for the amendment, so that it first applies to disclosures due on 31 August 2026 (for disclosure year 2026).

2.255 Many submitters were of the view that a clear definition for 'overhead circuit site' is needed, as without this the measure will lead to inconsistent reporting between EDBs.[144]

2.255.1 It was intentional that 'sites' and the different categories of sites are flexible for EDBs, as we consider that this lowers compliance costs for the reporting requirement. We understand that EDBs' approaches to 'sites' and how these are identified and categorised are different. Therefore, in reporting against the new measure, EDBs can maintain and align with their existing individual vegetation management risk assessment processes.

2.255.1.1 The intention is that EDBs will use the table to disclose any 'Category of overhead circuit site', and any number of categories. The site categories listed in the table are provided as examples (EDBs can overwrite with their own categories).

2.255.1.2 We also note that EDBs can disclose further information about their internal policies for categorising 'sites' in the voluntary explanatory notes in Schedule 15.

2.255.2 We acknowledge that this will make the reporting less comparable between EDBs, however we consider that since this is primarily a measure of network risk (not performance), accuracy on an individual EDB basis (with a lower compliance cost) is more beneficial than comparability.

2.255.3 We see little benefit to stakeholders in cross-EDB comparability for this measure, as the networks are different (with different vegetation, topography, and strategies). A consumer would be interested in how their local EDB is managing vegetation risk and may want to compare year-on-year for a single EDB.

143 Orion submission, page 5; Powerco submission, page 6; The Lines Company submission, page 10.

144 Aurora Energy submission, paragraph 71; Counties Energy submission, page 3; Northpower submission, page 2; Vector Limited submission, paragraph 43.

2.255.4 We do note though, that by separately analysing EDBs' data in this area, stakeholders could still make a comparison between EDBs based on their conclusions. For example, a stakeholder could separately analyse the data of different EDBs and conclude that one EDB's risk is smaller or larger than another, or that one EDB's performance is better or worse than another. We note that this would not be a direct comparison of quantitative data - the analysis may need to be different for each EDB, due to the differences in the data.

2.256 Submitters were concerned that the new requirement would require significant EDB resources to collate and report.[145]

2.256.1 The new measure is designed to fit in with (and be flexible for) EDBs' existing vegetation management risk assessment practices, and their current obligations under the Electricity (Hazards from Trees) Regulations 2003. The Industry Guide for Vegetation Management (published by ENA and the Electricity Engineers' Association (EEA))[146] provides EDBs with a risk-based approach to managing vegetation, and our proposed measure does not require any more from EDBs than what is outlined in the industry guide. We have seen presentations from industry on the topic, and from these, we know that many EDBs are taking a risk-based approach.

2.256.2 EDBs are already reporting on the existing measure, 'Overhead circuit requiring vegetation management' (km and % of total circuit), which requires an EDB to have assessed the entire network for areas which require vegetation management.

2.256.3 The key differences between the existing (replaced) measure and the new (replacement) measure are:

2.256.3.1 EDBs will disclose the number of sites (and the site categories that the EDB uses), rather than the total kilometres;

2.256.3.2 EDBs will disclose the sites involving critical assets; and

2.256.3.3 the definition for the measure is reframed to focus on risk, and to ensure the measure captures the risk from out-of-zone vegetation posing a risk (including fall zone trees).

145 ENA submission, page 6; Network Tasman submission, page 1; Orion cross-submission, page 5.
146 EEA and ENA, (July 2016), "Risk Based Vegetation Management Guide".

2.256.4 Our understanding is that when an area of the network 'requiring vegetation management' is identified (as part of the network inspection/assessment, informing the reporting against the existing measure), EDBs would record these areas so that the appropriate vegetation management can be undertaken. What we expect EDBs to report under the replacement/proposed measure is the number of these 'areas' (sites). Therefore, apart from the inclusion of out-of-zone trees in the measure (via the change in the measure/definition), and the addition of sites involving critical assets, we don't expect that the proposed measure would require major system changes for EDBs.

2.257 Some submitters were concerned that 'high risk' was not clearly defined and could be subjectively interpreted.[147]

2.257.1 We are of the view that 'high risk' was clearly defined in the draft decision (proposed definition for 'overhead circuit site at high risk from vegetation damage'). We agree the definition will be subjectively interpreted, as it relies on EDBs' individual assessments of a 'hazard tree', which is defined in Schedule 16 using an existing definition from the Industry Guide for Vegetation Management (published by ENA and the EEA).[148] Each EDB will be able to assess independently (exercising their own discretion, particularly when taking a risk-based approach) whether vegetation/a tree has the potential to damage the network. This assessment needs to be done on an individual basis as EDBs are each subject to different risks (eg, vegetation types, topography) and so we consider that it would not be efficient or helpful for the Commission to apply a more specific definition for this measure.

2.257.2 Following further analysis, our final decision is to amend the definition in Schedule 16 for 'overhead circuit site at high risk from vegetation damage', to remove the reference to cut or trim notices and hazard warning notices issued under the Electricity (Hazards from Trees) Regulations 2003. We have removed this element of the proposed definition as its inclusion could have resulted in overstatement of the number of sites at high risk, particularly where EDBs are proactive with their processes related to issuing notices. This leaves the definition as 'an overhead circuit site for which an EDB has identified a Hazard tree'.

147 Northpower cross-submission, paragraph 3; Orion submission, page 5.
148 EEA and ENA, Risk Based Vegetation Management Guide, (July 2016).

2.258 Many submitters suggested the Commission adopt the vegetation management reporting requirements used for Aurora Energy's Customised Price Path (CPP)/enhanced ID requirements, instead of the proposed measure, with justification being that Aurora Energy measures are more practical for EDBs to report, and easier for stakeholders to understand.[149]

2.258.1 The purpose of the new reporting requirement is to enable stakeholders to better understand the level of risk of vegetation damage to the network. Aurora Energy's CPP/enhanced ID measures are forecast vs. actuals for 'percentage of the network inspected' and 'percentage of the network felled, trimmed, removed or sprayed', and the purpose of these measures is to enable stakeholders to understand how Aurora Energy is tracking against its plan to manage vegetation. These measures do not show the risk to the network.

2.258.2 Regarding the 'percentage of the network inspected', it would not necessarily be correct to presume that the percentage of the network that has not yet been inspected is at risk, especially if EDBs take a risk-based approach and inspect the riskiest areas of the network first. We also cannot presume for the portion of the network that has been inspected, that the vegetation risk is being managed sufficiently.

2.258.3 Regarding the 'percentage of the network felled, trimmed, removed, or sprayed', a low percentage reported here will not necessarily represent poor vegetation management/higher risk to the network, as EDBs would all have different risk profiles. For example, there may be EDBs for which, across the network, there is generally very low risk from vegetation and only a small portion of the network where routine trimming is ever needed.

2.258.4 EDBs can be exposed to risk from out-of-zone trees which they may not be able to fell/trim/remove or spray. Aurora Energy's measures would not capture this risk.

2.259 Wellington Electricity submitted in support of the proposed amendment, but proposed an alternative reporting option:[150]

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149 Alpine Energy submission, paragraph 16; Aurora Energy submission, paragraphs 73-77; Counties Energy submission, page 3; Electra cross-submission, page 2; ENA submission, page 6; Network Tasman submission, page 1; Vector Limited cross-submission, paragraphs 52-53; WEL Networks cross-submission, paragraph 3.

150 Wellington Electricity submission, paragraph 4.3.

> It would be more useful to provide a total number of 'overhead circuits at high risk of vegetation damage' identified throughout the disclosure year and the percentage of those circuits that have been actioned or resolved. This would provide a consistent view and comparability of EDB's proactive mitigation of high-risk vegetation.

2.259.1 We consider that Wellington Electricity's proposal for the measure is a better alternative to the draft decision proposal, as it would also show EDBs' management of high-risk sites.

2.259.2 Therefore, our final decision is to adopt Wellington Electricity's proposal, however, we have inverted the second element, so that total sites 'remaining at high risk at the disclosure year-end' is reported, rather than the percentage of sites 'actioned or resolved during the disclosure year' as Wellington Electricity suggested.

Our final decision considers the feedback from submissions

2.260 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.260.1 delayed the entry into force date for the amendment, so that it first applies to disclosures due on 31 August 2026 (for disclosure year 2026);

2.260.2 amended the definition for 'Overhead circuit site at high risk from vegetation damage' in Schedule 16 of the ID determination;

2.260.3 amended the definitions for 'Hazard tree' and 'Fall zone tree' in Schedule 16 of the ID determination (replaced the word 'contact' with 'damage' to align the definitions more closely with the definitions in the Industry Guide for Vegetation Management (published by ENA and the EEA)); and

2.260.4 amended Schedule 9c so that the disclosure includes both the total number sites identified throughout the disclosure year, and the total number of sites remaining at high risk at the disclosure year-end.

AM6.3 – Vegetation management reporting – Schedule 10

Final decision

2.261 Our final decision is to require EDBs to break down reporting of unplanned interruptions caused by vegetation in Schedule 10(ii). The additional vegetation reporting categories are 'in-zone' and 'out-of-zone'.

2.262 We have added definitions for 'in-zone' and 'out-of-zone' to Schedule 16 of the ID determination.

2.263 EDBs are first required to disclose this information by 31 August 2026 for disclosure year 2026.

2.264 The disclosure is SAIDI and SAIFI information in Schedule 10 and is therefore subject to the audit and director certification requirements.

Purpose of the amendment

2.265 The purpose of this amendment is to enable stakeholders to better understand the causes of vegetation interruptions. Having information at the disaggregated level will enable stakeholders (and EDBs themselves) to better understand the cost to society of interruptions caused by out-of-zone trees. It should also help to inform EDBs' approaches to managing out-of-zone vegetation.

2.266 This information will be valuable to stakeholders, particularly since we know that typically a large portion of vegetation interruptions are caused by vegetation from out-of-zone.

2.267 This amendment promotes the purpose of ID regulation, as the information disclosed will provide further detail about the quality of service provided by EDBs (interruptions caused by vegetation) and should incentivise EDBs to manage vegetation more effectively.

Submissions on the proposed amendment were mixed

2.268 While there were some submissions in support of the proposed amendment, there were others which proposed changes and encouraged further consideration of the issue by the Commission, as well as submissions which did not support the proposed amendment.

2.269 Many submitters noted that it would take some time for EDBs to establish the necessary systems and processes for data collection and reporting.[151]

2.270 In response, we have delayed the entry into force date for the amendment, so that it first applies to disclosures due on 31 August 2026 (for disclosure year 2026).

151 Orion submission, page 5; Powerco submission, page 6; The Lines Company submission, page 10.

2.271 Many submitters noted that classification to the proposed subcategories in the draft decision would rely on a subjective assessment by field staff and the resulting information would be unlikely to be auditable.[152]

2.272 Subsequent to receiving submissions and cross-submissions on our draft decision, we have met with the Office of the Auditor-General and confirmed that this information would be auditable.

2.273 Many submitters noted that the proposed reporting would require material and costly changes to EDBs' internal processes and reporting, and some noted that the additional assessment required from field staff may remove their focus from ensuring consumers' power is promptly restored.[153] Vector suggested that the Commission speak to EDBs' field service providers about the workability of the proposed amendment.[154]

2.273.1 Subsequent to receiving submissions and cross-submissions on our draft decision, and in response to the request from Vector, we met with a selection of EDBs and their field service providers to discuss the workability of the proposed amendment.[155] From these meetings, we understand that, generally, the fault response person who is sent to the fault determines the cause of the interruption. We note that identification of any interruption cause (not just vegetation that is in-zone or out-of-zone) requires fault response teams to be trained and experienced in this area. Under the amended requirement, if vegetation was identified as the cause of the interruption, the fault response person would then also need to identify whether the vegetation that caused the fault was from out-of-zone.

2.273.2 The reporting requirement is not intended to be burdensome, and it is expected that the classification to in-zone or out-of-zone may be a best estimate based on reasonable assumptions (since the assessment is done retrospectively, upon arrival at the fault location).

2.273.3 For these reasons, we consider it likely that a fault response person would be able to identify whether an interruption was caused by an in-zone or out-of-zone tree, and we do not expect that this task would impact the primary task of safely restoring services.

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152 Alpine Energy submission, paragraph 15; ENA submission, page 7; Horizon Networks submission, paragraph 56; Orion submission, page 5; Unison and Centralines submission, page 2.

153 ENA submission, page 7; Firstlight Network submission, page 8; Horizon Networks submission, paragraph 55; Network Tasman submission, page 1; Vector Limited submission, paragraphs 37-40; Wellington Electricity submission, paragraph 4.4.

154 Vector Limited cross-submission, paragraph 40.

155 Notes from the meetings we held with EDBs and their field service providers are published here.

2.274 Some submitters had concerns about the proposed subcategories, particularly the subcategory 'Related to inclement weather' (concerns that the definition was unclear).[156] There were also concerns that the proposed subcategories would overlap.[157] Network Waitaki said in its submission:[158]

> The only clear disaggregation that makes sense is in-zone and out-of-zone. Wind-borne debris, inclement weather will probably be all "out-of-zone" in any event.

2.275 We agree that the proposed subcategories would overlap which could be confusing. Therefore, our final decision is to amend the disclosure in Schedule 10(ii) such that the breakdown of vegetation interruptions is limited to 'in-zone' and 'out-of-zone'.

Our final decision considers the feedback from submissions

2.276 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.276.1 delayed the entry into force date of the amendment, so that it first applies to disclosures due on 31 August 2026 (for disclosure year 2026); and

2.276.2 amended Schedule 10(ii) so that the breakdown of vegetation interruptions is limited to 'in-zone' and 'out-of-zone'. This includes the removal of the definitions for other proposed (since removed) subcategories from Schedule 16 of the draft determination.

156 Aurora Energy submission, paragraphs 78-80; Counties Energy submission, page 2; Electra submission, page 5; Horizon Networks submission, paragraph 55; Network Waitaki submission, page 8; Vector Limited cross-submission, paragraphs 41-43.

157 Northpower submission, page 2; Vector Limited cross-submission, paragraphs 41-44.

158 Network Waitaki submission, page 8.

Quality of service

2.277 Quality of service (quality) is a major focus of our regulation of EDBs.[159] As part of our Tranche 1 final decision, we refined reporting requirements on quality to improve the accuracy of disclosed information such as clarifying definitions to ensure successive interruptions are recorded consistently. We also expanded requirements to capture different dimensions of quality such as connection and customer service information.

2.278 Quality and reliability of electricity supply will become increasingly important as the electrification of the economy occurs. Many consumers currently rely on electricity for their heating, transport and other demands, and we expect this to only increase in future. In this environment it will be exceedingly important that electricity is reliably supplied.

2.279 In terms of improving our ID requirements in TIDR (2024), our priority is to extend reporting requirements to capture more granular information on quality and reliability of EDB services to ensure that information is more useful for assessing or understanding performance.

2.280 Disclosed information is more useful when it is comparable, consistent over time, and captures the details that matter to stakeholders. Current ID requirements on quality are relatively high-level and provide limited visibility of specific or localised issues.

2.281 We are mindful there may be implementation challenges in collecting meaningful and useful quality data from a network at a detailed level. It is important that we continue to enable stakeholders to assess EDB performance while accounting for these limitations.

[159] Section 52A(1)(a)-(b).

Q14.1 – Raw interruption data

Final decision

2.282 Our final decision is to require EDBs to annually disclose raw interruption data in a new Schedule 10a.

2.282.1 We have added a new report to the ID determination, in Schedule 10a, which requires EDBs to disclose the following information about each interruption on its network, consistent with data non-exempt EDBs typically provide before a PQ reset. We have added definitions to Schedule 16 of the ID determination for the four terms marked in brackets as "(new)".

2.282.1.1 interruption identifier (new);

2.282.1.2 circuit location (new);

2.282.1.3 sub-network, where applicable;

2.282.1.4 feeder(s) affected by the interruption (new);

2.282.1.5 start date and time;

2.282.1.6 end date and time;

2.282.1.7 SAIDI value;

2.282.1.8 SAIFI value;

2.282.1.9 number of installation control points (ICPs) interrupted;

2.282.1.10 ICP interruption minutes (new);

2.282.1.11 whether the interruption is planned or unplanned;

2.282.1.12 the cause of an interruption; and

2.282.1.13 any explanation the EDB wishes to disclose to clarify the context of an interruption.

2.282.2 EDBs are required to record successive interruptions as an additional SAIFI and SAIDI interruption value if restoration of supply occurs for longer than one minute, adopting what is referred to as the "multi-count approach".[160]

[160] Commerce Commission, Targeted Information Disclosure Review – Electricity Distribution Businesses - Final decision paper - Tranche 1, (25 November 2022), paragraph 3.145.

2.282.3 Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, eg, one interruption record per feeder.

2.282.4 With reference to the cause of an interruption disclosed as part of the raw interruption data (see paragraph 2.282.1 above):

2.282.4.1 'Cause' and the various primary causes of customer interruptions, being lightning, vegetation, adverse weather, adverse environment, third party interference, wildlife, human error, defective equipment, and unknown, are already defined in Schedule 16 of the ID determination.

2.282.4.2 We have added the term 'other cause' to Schedule 16, which means "an unplanned interruption for which the primary cause is not lightning, vegetation, adverse weather, adverse environment, third party interference, wildlife, human error, or defective equipment". The other cause category is not the same as the unknown cause category, because the unknown cause category is a residual category when the cause of the unplanned interruption is not known. We have also added an optional field to provide more details of what the 'other cause' interruption is.

2.282.4.3 Not all types of interruption causes can be anticipated, so the 'other cause' category has merit. The 'other cause' category allows for non-anticipated known interruption causes to be recorded. Without an 'other cause' category, non-anticipated known causes would likely be either miscategorised into one of the listed categories or erroneously recorded as unknown.

2.282.4.4 Adding the 'other cause' category also aligns the data collected with that which we collect from non-exempt EDBs under a section 53zd notice.

2.282.5 We require EDBs to first disclose this information above by 31 August 2025 for disclosure year 2025.

Purpose of the amendment

2.283 Our decision requiring raw interruption data will allow stakeholders to better assess whether EDBs are providing services at a quality that reflects consumer demands.

2.283.1 Stakeholders having access to raw interruption data will serve the purpose of ID regulation in the following ways:

2.283.1.1 primarily by enabling stakeholders to better assess the level of network reliability and quality being delivered, and therefore whether EDBs are providing services at a quality that reflects consumer demand;[161]

2.283.1.2 the data would create a level of public scrutiny on EDBs' quality performance that should incentivise them to maintain quality at appropriate levels across the entire network; and

2.283.1.3 disclosure of detailed interruption data should play a role in incentivising EDBs to innovate and invest to maintain network quality, and in helping to ensure EDBs have a limited ability to extract excessive profits by limiting the incentives that might have existed to profit by underspending on network quality.[162]

2.283.2 Access to raw interruption data will allow stakeholders, including the Commission, to undertake more fulsome and detailed reliability analysis and to better understand EDB performance:

2.283.2.1 stakeholders will be able to better assess interruptions, drivers and causes of those interruptions, and the corresponding link to expenditure (such as vegetation management) disclosed in other areas of ID; and

2.283.2.2 stakeholders will be able to assess reliability within particular parts of the network, which is not possible with the current network level reporting (existing network level metrics may mask poor performing areas within the network).

Submissions on the proposed amendment were generally mixed

2.284 Many submitters stated that they supported the disclosure of raw interruption data in principle.[163] However, there was mixed support for the proposed amendment. The main concerns were that disclosing raw interruption data would mean that there would be too much information in the schedule, making it unwieldly and that stakeholders including consumers would not use the detailed data.

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161 Section 52A(1)(b).

162 Section 52A(1)(a) and (d).

163 Counties Energy submission, page 3; Electra submission, page 6; Powerco submission, page 6; Aurora Energy submission, paragraph 82; The Lines Company submission, page 11; Wellington Electricity submission, paragraph 5.1.

2.284.1 We agree that having the schedule within the same workbook as Schedules 1-10 could be unwieldly and cumbersome. Consequently, we have moved the new Schedule 10a to a separate workbook to be completed. EDBs will not have to provide Schedule 10a as a PDF, only as an Excel file.

2.284.2 We do not agree that stakeholders will not use the detailed data. We believe that the data will be of interest to a variety of parties, and the format of the data enables stakeholders to run their own analysis if they wish.

2.285 Some submitters suggested excluding raw interruption data from disclosed ID schedules and requiring EDBs to publish the data in Excel format on their respective websites.[164]

2.286 We are requiring this public disclosure to be within a standardised template, because we believe requiring disclosure within an ID schedule is key to keeping the data consistent across EDBs, enabling the Commission to process and analyse the disclosure more quickly and effectively. This will also enable the data to be stored and accessible from a single location, rather than in parts in multiple locations.

2.287 Submitters who mentioned the addition of the 'Other' interruption category for SAIDI and SAIFI supported its inclusion.[165] Firstlight Network requested we provide an example of what we expect would be included in the 'Other' interruption category.[166]

2.288 We don't intend to provide an example of 'other' as this is deliberately provided to be a "catch-all" category, eg, if the cause of the interruption is known but it doesn't fit into one of the other designated interruption categories.

Our final decision considers the feedback from submissions

2.289 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.289.1 Schedule 10a has been split into its own workbook for ease of data entry and size considerations.

2.289.2 Director certification will not be required for Schedule 10a.

164 Aurora Energy submission, paragraph 86; Counties Energy submission, page 3; Electra submission, page 6; Powerco submission, page 6.

165 Firstlight Network submission, page 9; Wellington Electricity submission, paragraph 5.1.

166 Firstlight Network submission, page 9.

Q14.2 – Worst-performing feeders

Final decision

2.290 Our final decision is to require EDBs to disclose information on worst-performing feeders (unplanned) in Schedule 10.

2.290.1 We have defined 'worst-performing feeders (unplanned)' in clause 1.4.3 of the ID determination as:

> the **feeder** lines on an EDB's **network** that, in respect of a **disclosure year,** are in the 90th percentile or higher for one or more of any of the following: (a) **unplanned feeder SAIDI** , (b) **unplanned feeder SAIFI**, and (c) **customer impact ratio**.

2.290.2 We have defined 'feeder' in clause 1.4.3 of the ID determination as:

> a **low voltage** or **distribution voltage** circuit that originates at a substation circuit breaker and radiates outward for the purpose of supplying electricity.

2.290.3 We have used the following definition for customer impact ratio:

> means, in respect of a **feeder** line on a **network**, the value of *q* for a **disclosure year** calculated using the following formula:
>
> *q = a/b*, where:
>
> a = **unplanned customer interruption minutes** on the **feeder** for that **disclosure year**
>
> b = the **average number of ICPs in disclosure year** served by the **feeder**

2.290.4 These requirements have been added in Schedule 10(vi):

2.290.4.1 identification of the worst-performing feeders (unplanned), and for each of those feeders:

- unplanned SAIFI values;
- unplanned SAIDI values;
- customer impact ratio;
- Number of unplanned interruptions;
- Most common cause of unplanned interruption;
- Length of feeder;
- Number of ICPs served; and
- % of Feeder overhead (optional).

2.290.5 We will require EDBs to first disclose the information above by 31 August 2025 for DYE 31 March 2025.

Purpose of the amendment

2.291 Our decision requiring information on worst-performing feeders (unplanned) will make readily available information on areas of an EDB's network that are receiving a relatively poor quality of service.

2.291.1 Providing stakeholders with access to data on worst-performing feeders on the basis of unplanned interruptions will serve the purpose of ID regulation by enabling stakeholders to better assess the level of network reliability and quality being delivered, and therefore whether EDBs are providing services at a quality that reflects consumer demand.

2.291.2 One of the key findings in our technical elements workshop is that nearly all, if not every network, does feeder analysis and most EDBs break down reliability by feeder.[167] This information often feeds into prioritisation and investment decisions (eg, the worst-performing SAIDI and SAIFI feeders often led to a focus on improving performance through investment in repair and replacement or increased vegetation management along that feeder). As such, we don't expect that providing information on worst-performing feeders (unplanned) would place a significant compliance burden on EDBs.

Overall, submissions supported the inclusion of data on worst-performing feeders in principle

2.292 Many submitters recommended that worst-performing feeders should only be identified on the basis of unplanned interruptions, not planned interruptions as well, as this would provide a better indication of "worst-performing".[168]

2.293 ENA's submission was representative of the submissions received on this proposal.[169]

> ENA does not oppose the introduction of reporting on worst-performing feeders. However, the reporting should be limited to those feeders in the 90th percentile of unplanned SAIDI and or SAIFI. ENA recommends that contextual data for each of the identified feeders be included in the disclosure. This contextual information should include its length and the number of customers served.

2.293.1 We agree with submitters that the level of unplanned interruptions is the best indicator of worst-performing feeders, and have added a new definition of worst-performing feeders (unplanned) which applies to Schedule 10(vi) that includes unplanned interruptions only.

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[167] Commerce Commission, Targeted Information Disclosure Review – Tranche 2 – Technical Elements Workshop Presentation, (27 March 2023).

[168] Alpine Energy submission, paragraph 20; Aurora Energy submission, paragraph 92; ENA submission, page 7; Northpower submission, paragraph 11; Powerco submission, page 7; Orion submission, page 6; Vector Limited submission, paragraph 52a.

[169] ENA submission, page 7.

2.293.2 We also agree that contextual information should be provided alongside the list of worst-performing feeders because this approach gives a richer source of information about the characteristics of the worst-performing feeders. This allows stakeholders and interested parties to run their own analysis on the information provided if they wish to. We have expanded the information required for worst-performing feeders to include 'Number of Unplanned Interruptions', 'Most Common cause of Unplanned Interruption', 'Circuit Length of Feeder', and 'Number of ICPs'. We will also optionally enable EDBs to provide % of feeder overhead as context.

2.294 Some submitters asked for further clarity over the definition of 'feeder'.[170]

2.295 While we believe the definition of feeder is relatively well understood within the industry, we have included a definition of feeder to avoid ambiguity.

2.296 Counties Energy suggested that capturing reliability data at a feeder level is not granular enough to create an informed view of the quality of supply a customer could experience.[171] They suggest that a more granular view would give customers a better view of the quality of supply in their area.

2.297 While more granular data would be of benefit, most EDBs do not have data at this more granular level yet, and the changes required would be impractical and too high a cost at this time.

2.298 Firstlight Network expressed specific views about whether worst-performing feeders was the best description and proposed a method for identifying "worst-performing feeders".[172]

> The feeders that contribute to high SAIDI and SAIFI may not necessarily be the worst-performing feeders. For instance, a feeder with a very low number of ICPs would contribute to low SAIDI and SAIFI, even after experiencing many interruptions throughout the year. On the other hand, a feeder with a significant number of ICPs can contribute to high SAIDI and SAIFI, even if there are only a few interruptions on that feeder. The disclosure should not be referred to as the "worst performing feeder list" but rather as "feeders contributing to high SAIDI and SAIFI." To identify the worst-performing feeder, one should calculate the ratio of the ICP number on that feeder to the total customer minutes of all interruptions on that feeder.

170 Counties Energy submission, page 4; Firstlight Network submission, page 9; Network Waitaki submission, page 10; Orion submission, page 6; Wellington Electricity submission, paragraph 5.1.

171 Counties Energy submission, page 4.

172 Firstlight Network submission, page 9.

2.298.1 Worst-performing feeders has been defined for Aurora Energy as part of their CPP. As we stated in the final reasons paper for the Aurora CPP, we consider focusing on the worst-served consumers by feeder is an effective way of providing more granular information that is focused on the most important areas.[173]

2.298.2 We agree that feeders contributing to low customer service could be shown more easily, so we have amended the disclosure to require an additional list of worst-performing feeders by customer impact, using the ratio recommended by Firstlight Network (see paragraph 2.290.3).[174]

Our final decision considers the feedback from submissions

2.299 In response to stakeholder feedback, we have made the following key changes from the draft decision:

2.299.1 amended the criteria for reporting on worst-performing feeders within Schedule 10(vi) to be on the basis of unplanned interruptions only;

2.299.2 added an additional table to record worst-performing feeders by customer impact; and

2.299.3 expanded the data collected on worst-performing feeders to include:

2.299.3.1 number of unplanned interruptions;

2.299.3.2 most common cause of unplanned interruption;

2.299.3.3 length of feeder;

2.299.3.4 number of households served; and

2.299.3.5 an option to provide information on % of feeder overhead vs underground.

2.300 Aurora, which is regulated under a customised price-quality path (CPP) already discloses worst-performing feeder information in its Annual Delivery Report (ADR). Aurora's disclosure of worst-performing feeders is based on the 90% percentile or higher for the SAIDI and SAIFI of both unplanned and planned interruptions.

2.301 Aurora will continue to determine and disclose worst-performing feeder information in its ADR as it does now. However, Aurora will also have to determine and disclose separate worst-performing feeder information (on the basis of unplanned interruptions) in accordance with these new ID requirements.

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173 Commerce Commission, Aurora Energy Additional Information Disclosure Final Reasons Paper, (31 August 2021), paragraphs 6.57-6.58.

174 Firstlight Network submission, page 9.

2.302 We recognise this is additional analysis and reporting for Aurora. However, after considering the feedback we received, we agree with industry stakeholders that for an EDB-wide requirement the best measure for determining worst-performing feeders is unplanned interruptions. For consistency purposes we should require the same information from all EDBs. We do not want to adjust Aurora's ADR requirement in this change, so we will keep Aurora's requirement the same and require Aurora to disclose both their current ADR worst-performing feeders, and the worst-performing feeders (unplanned) in Schedule 10(vi).

Q14.3 – Removal of normalised SAIDI and SAIFI

Final decision

2.303 Our final decision is to remove the existing requirement for disclosure of normalised SAIFI and SAIDI from Schedule 10(i).

2.304 We will also require EBDs to further break down unplanned SAIDI and SAIFI in Schedule 10(ii) into an additional cause category termed 'other cause', as appropriate. This will help ensure that the categorisation of SAIDI and SAIFI by cause in Schedules 10 and 10a is aligned.

2.305 The entry into force date for this amendment is 1 January 2025.

Purpose of the amendment

2.306 The provision of raw interruption data (see paragraph 2.282) will allow stakeholders to calculate normalised SAIDI and SAIFI using the methodology used in the PQ framework or an alternative methodology that better suits their analytical needs. As such, we have removed the existing ID requirement for EDBs to calculate and report normalised SAIDI and SAIFI.

Submissions on the proposed amendment were supportive

2.307 All submitters who mentioned the removal supported it.[175]

2.308 Vector submitted that they believed the date of removal should be brought forward.[176]

2.309 We do not agree with Vector's proposal, because the removal of normalised SAIDI and SAIFI is dependent upon the provision of raw interruption data. We do not want to remove the requirement to disclose normalised SAIFI and SAIDI until the new requirements for worst-performing feeders (unplanned) (see paragraph 2.290) come into effect, to ensure that data is available for all years.

175 ENA submission, page 7; Firstlight Network submission, page 9; Northpower submission, paragraph 12; Powerco submission, page 6; The Lines Company submission, page 11; Wellington Electricity submission, page 11.

176 Vector Limited submission, paragraph 5.

Other amendments

2.310 We have made the following other amendments to the ID determination which were proposed in the draft decision:

2.310.1 clarifying the definition of gains/losses on asset disposals;

2.310.2 updating the assurance standards;

2.310.3 aligning existing audit and director certification obligations to the verification framework; and

2.310.4 other minor amendments.

2.311 We have made the following additional amendments which were suggested by submitters on our draft decision:

2.311.1 split out the cybersecurity disclosure from Schedules 1-10 so that the publication of these schedules is not duplicated; and

2.311.2 removed Schedule 3(iii) and update the IRIS line in Schedule 2(v) so that the term aligns with the IMs.

A3 – Definition of Gains/losses on asset disposals

Final decision

2.312 Our final decision is to amend the Schedule 16 definition for 'Gains / (losses) on asset disposals' to treat related party transactions involving asset disposals similarly to any other asset disposal transactions. Specifically, the following amendments have been made to the definition:

2.312.1 subpart 'a) asset disposals to a related party' of 'Gains / (losses) on asset disposals' changed to remove the nil provision and include reference to the related party transaction rules in clause 2.3.6 of the ID determination; and

2.312.2 subpart 'c) asset disposals (other than below)' changed to 'any other asset disposal'.

2.313 The definition of 'Asset disposals (other than below)' was also deleted because it is longer required.

2.314 The new definitions will be applied for the disclosures due 31 August 2024 for disclosure year 2024.

Purpose of the amendment

2.315 The purpose of this amendment is to reduce the risk of EDBs misinterpreting the regulatory accounting rules around asset sales to related parties.

Submitters supported the proposed amendment

2.316 All submissions received on this issue were in support of the proposed amendment.[177] Therefore, our final decision is to proceed with the amendment proposed in the draft decision.

[177] Aurora Energy submission, paragraph 24; Electra submission, page 4; Firstlight Network submission, page 10; Orion submission, page 6; The Lines Company submission, page 12.

Update of assurance standards

Final decision

2.317 Our final decision is to amend the definitions of assurance standards in clause 1.4.3 of the ID determination and remove items. Specifically, the following amendments have been made to the definitions:

2.317.1 updates to the definitions of 'ISAE (NZ) 3000' and 'SAE 3100' to refer to the current version of these assurance standards that are issued by the External Reporting Board;

2.317.2 removal of the guidance note under the definition of 'Arm's length transaction' that refers to ISA (NZ) 550, as this is not needed given that "Arm's length transaction has the meaning given in the IM determination"; and

2.317.3 removal of the definition for 'ISA (NZ) 550' as this term was not used anywhere else in the ID determination other the guidance note which is now removed.

2.318 The entry into force date for these amendments is 1 April 2024.

Purpose of the amendment

2.319 The purpose of the amendment is to update assurance standards to reduce the risk that auditors may not be able to undertake an engagement or issue an opinion on the basis of an incorporated standard where it has been changed or superseded.

Submitters supported the proposed amendment

2.320 All submissions received on this issue were in support of the proposed amendment.[178] Therefore, our final decision is to proceed with the amendment proposed in the draft decision.

[178] Firstlight Network submission, page 10; Orion submission, page 7; The Lines Company submission, page 13.

Aligning audit and director certification obligations with the verification framework

Final decision

2.321 Our final decision is to make amendments to align existing audit and director certification obligations in the ID determination to the verification framework established when the ID requirements were first set under Part 4.[179]

2.322 The definition of 'audited disclosure information' under clause 1.4.3 has been amended by adding the SAIDI and SAIFI information disclosed under clause 2.5.2 to paragraph (b) of the definition.

2.323 The amendments to director certification obligations are as follows:

2.323.1 under clause 2.9.2 of the ID determination, addition of related party information disclosed under clauses 2.3.8 to 2.3.12;

2.323.2 under clause 2.9.5, removal of Aurora Energy's customer charter and customer compensation disclosures under clause 2.5.3; and

2.323.3 amendments to Schedule 18 Certification of Disclosures: addition of clauses 2.3.8 to 2.3.12 and removal of clause 2.5.3 from the certification text.

2.324 The entry into force date for these amendments is 1 April 2024.

Purpose of the amendment

2.325 The purpose of the amendment is to align existing audit and director certification obligations in the ID determination to the verification framework.

Submitters supported the proposed amendment

2.326 All submissions received on this issue were in support of the proposed amendment.[180] Therefore, our final decision is to proceed with the amendment proposed in the draft decision.

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179 Commerce Commission, Chapter 9 Assurance report and Certification, Information Disclosure for Electricity Distribution Businesses and Gas Pipeline Businesses: Final Reasons Paper, (1 October 2012) page 9.

180 Firstlight Network submission, page 10; Orion submission, paragraph 7; The Lines Company submission, page 13.

Submitter suggested changes

Final decision

2.327 Our final decision is to split out the cybersecurity disclosure from Schedules 1-10 so that the publication of these schedules is not duplicated.

2.328 The existing cybersecurity disclosure requirements within Schedules 6a, 6b, and 7 have been relocated to a new Schedule 5h, and the existing cybersecurity disclosure requirements within 11a and 11b have been relocated to a new standalone Schedule 11c.

2.329 The relevant clauses in the ID determination have been amended to reflect this change (namely the deletion of clause 2.3.1A, amendments to clause 2.3.2, and amendments to clause 2.6.6).

2.330 Our final decision is to remove Schedule 3(iii) and update the IRIS line in Schedule 2(v) so that the term aligns with the IMs.

2.330.1 Schedule 3(iii) has been removed - EDB's will still disclose their IRIS in Schedule 2(v).

2.330.2 The definitions in the ID Determination that relate to Schedule 3(iii) have been removed.

2.330.3 The line item 'Net recoverable costs allowed under incremental rolling incentive scheme' in Schedule 2(v) has been renamed to 'IRIS incentive adjustment' to align with the IMs.

2.330.4 A definition for 'IRIS incentive adjustment' has been added to the ID Determination which refers to the definition in the IM Determination.

2.331 The entry into force date for these amendments is 1 April 2024.

Purpose of the amendment

2.332 Relocating the cybersecurity disclosure removes unnecessary duplication of Schedules without removing any disclosure.

2.333 Removing Schedule 3(iii) and updating the IRIS line removes an outdated schedule and ensures the existing schedule aligns with the IMs.

These changes were suggested by submitters

2.334 Aurora Energy and Electra submitted that the cybersecurity disclosure should be split out from Schedules 1-10, so that the publication of those schedules is not duplicated.[181]

2.334.1 Aurora Energy stated:[182]

> The Commission's current approach to report cybersecurity will require EDBs each August to 'publicly disclose' two sets of Schedule 1-10 and potentially two Schedule 15 voluntary notes. One set would be published on the EDB website with opex and capex itemised and Cybersecurity (Commission only) left blank. A second set of Schedules 1-10 would need to be provided to the Commission, including all opex and capex, including Cybersecurity (Commission only).

2.334.2 We agree that this is an unnecessary duplication and agree with Aurora Energy's proposed change to move the cybersecurity disclosures to a new schedule 5h, to be disclosed only to the Commission alongside schedules 5f and 5g.

2.335 Vector submitted:[183]

> Schedule 3(iii) - the Commission should remove this as it does not correctly relate to IRIS.

2.335.1 A background review of this issue found that Schedule 3(iii) has effectively been out of date since the IM amendment which has impacted disclosure years commencing 1 April 2020. Furthermore, the Input Methodologies Review (IM Review) final decision published in December 2023 changed the definition.

2.335.2 A review of the use of Schedule 3(iii) in the 2023 disclosures filed by all EDBs shows that only four have entered partial data and only one has completed the whole schedule. Therefore, it is clear the data has not and is not able to be used by interested persons.

2.335.3 EDBs can currently include their net recoverable costs allowed under the incremental rolling incentive scheme in Schedule 2(v) Financial Incentives and Wash-Ups eg, the bottom line from Schedule 3(iii) is meant to be transposed to Schedule 2(v). A review of the 2023 IDs filed confirms that five EDBs have included IRIS in Schedule 2(v) without completing Schedule 3(iii). Given this, we have changed Schedule 2(v) to have the correct title as per the latest IM review, and changed it to a direct data entry cell rather than a calculated cell.

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181 Aurora Energy submission, paragraph 100; Electra submission, page 6.

182 Aurora Energy submission, paragraph 100.

183 Vector Limited submission, paragraph 6a.

Other minor amendments

Final decision

2.336 Our final decision is to make the following minor changes which were outlined in the draft decision:

2.336.1 reinsertion of the term 'Feeder SAIFI' to clause 1.4.3 of the ID determination, which was deleted in error as part of the non-material amendment determination published in April 2023; and

2.336.2 correction of typographical errors in paragraph 2 of Schedule 16.

2.337 We have also made the following additional minor drafting amendments to the ID determination which were not outlined in the draft decision:

2.337.1 Typographical error corrections throughout the determination; and

2.337.2 Amendments to clause 2.5.1 and 2.5.2 (removing expired transitional clauses).

2.338 The entry into force date for these amendments is 1 April 2024.

Purpose of the amendment

2.339 The purpose of the amendments is to correct typographical and other minor errors in the ID determination.

We did not receive any submitter feedback on the proposed amendments

2.340 We did not receive any specific submission responses in relation to the amendments outlined in paragraphs 2.336.1-2.336.2 above. Therefore, our final decision is to proceed with the amendments proposed in the draft decision and the minor drafting amendments that we identified as being needed after the draft decision.