UTILITIES COMMISSION
OF THE NORTHERN TERRITORY

Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels) Review

Draft Decision Paper

13 May 2025

Disclaimer

This Draft Decision Paper has been prepared by the Utilities Commission in accordance with the *Utilities Commission Act 2000*. To the maximum extent permitted by law, the Utilities Commission disclaims and excludes all liability for any loss, claim, demand, damages, costs and expenses of any nature (whether or not foreseeable and whether direct, indirect or consequential and whether arising from negligence or otherwise):

- suffered or incurred by any person relying or acting on any information provided in, referred to or omitted from, this document; or
- arising as a result of, or in connection with, information in this document being inaccurate or incomplete in any way or by reason of any reliance on it by any person, including by reason of any negligence, default or lack of care.

Enquiries

Any questions regarding this document should be directed to the Utilities Commission at any of the following:

Email: utilities.commission@nt.gov.au

Telephone: +61 8 8999 5480

GPO Box 915
DARWIN NT 0801

Contents

Abbreviations and acronyms

AER	Australian Energy Regulator
AER Guidelines	AER's (Retail Law) Performance Reporting Procedures and Guidelines
AF	availability factor
Code	Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels)
Commission	Utilities Commission of the Northern Territory
DIA	Darwin International Airport Pty Ltd
EAF	equivalent availability factor
EDL	EDL NGD (NT) Pty Ltd
EFOF	equivalent forced outage factor
Eni	Eni Australia Limited
ER Act	*Electricity Reform Act 2000*
ERS Code	Electricity Retail Supply Code
FNCES	First Nations Clean Energy Strategy
FOF	forced outage factor
IEEE	Institute of Electrical and Electronic Engineers
IES	Indigenous Essential Services Pty Ltd
Jacana	Jacana Energy
NEM	National Electricity Market
PPM	pre-payment meter
PV	photovoltaic
PWC	Power and Water Corporation
Researchers	a group of researchers
Rimfire	Rimfire Energy
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCI	Statement of Corporate Intent
STPIS	Service Target Performance Incentive Scheme
TGen	Territory Generation
UAF	unplanned availability factor
UC Act	*Utilities Commission Act 2000*

Draft Decision

In accordance with section 24(1) and (3) of the *Utilities Commission Act 2000* and regulation 2B of the Utilities Commission Regulations 2001, the Commission proposes to amend the Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels) (Code) as detailed in this Draft Decision Paper. The Draft Decision outlines the Commission's reasoning for the amendments that it proposes to make to the Code.

Below is a summary of the draft decisions, set out by chapter.

Exemption clause (Chapter 2)

The Commission proposes to amend the Code to:

- introduce a broad exemption clause consistent with the Electricity Retail Supply (ERS) Code
- remove the reporting-specific exemption under clause 5.1.3.

The Commission proposes not to amend the Code to include criteria or guiding principles in a new broader exemption clause.

Reporting requirements (Chapter 3)

The Commission proposes to amend the Code to clarify that historical data must also be segmented in the same manner as the reporting period data.

IEEE beta 2.5 events for network entities (Chapter 4)

The Commission proposes to amend the Code to:

- require that a report submitted to the Commission under clause 5.4.2 must also include the network entity's calculations and workings used to identify a statistical outlier using the Institute of Electrical and Electronics Engineers (IEEE) 2.5 beta method
- require network entities to report on both unadjusted System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics inclusive and exclusive of natural events (or major event days).

Schedule 2: Generation services performance indicators (Chapter 5)

The Commission proposes to amend the Code to:

- remove the requirement for generator entities to comply with the Code in relation to their intermittent generation (including solar photovoltaic [PV] systems and batteries)
- remove the requirement for generator SAIDI and SAIFI reporting.

The Commission proposes to revoke the Electricity Industry Performance Code – Direction June 2024 (intermittent generation and battery reporting), which it issued on 26 June 2024, effective the date the amended Code comes into effect.

Schedule 3: Network services performance indicators (Chapter 6)

The Commission proposes to amend the Code to require network entities to report on poorly performing feeders consistent with the methodology detailed in the Consultation Paper and this Draft Decision.

Schedule 4: Retail services performance indicators (Chapter 7)

The Commission proposes to amend the Code to:

- explicitly reference version 3 of the AER (Retail Law) Performance Reporting Procedures and Guidelines (AER Guidelines)

- add the explicit AER (Australian Energy Regulator) reference alongside where an indicator is identified as an AER indicator
- reorder the 'Total number of PPM customers self-disconnected' and 'Total number of PPM self-disconnection events' performance indicators
- remove the 'Reasons for customers exiting the hardship program' performance indicator
- include a definition for 'energy bill debt'.

The Commission proposes not to amend the Code:

- in relation to customer service and complaints performance indicators
- to include additional pre-payment meter (PPM), hardship program, life support customer and customers affected by family violence performance indicators.

The Commission proposes to revoke the Electricity Industry Performance Code - Direction January 2025 (retail reporting), which it issued on 6 January 2025, effective the date the amended Code comes into effect.

Other matters identified through consultation (Chapter 8)

The Commission proposes to amend the Code to:

- revise the definition of 'interruption' to more closely align with the AER's definition and to explicitly exclude interruptions due to faults in a customer's electrical installation
- revise the definition of 'premises' to remove the specific reference to 'small customer'
- remove the requirement for network entities to report on phone answering performance indicators.

The Commission proposes not to amend the Code to:

- expand the application to cover electricity entities' operations outside of the Darwin-Katherine, Alice Springs and Tennant Creek power systems
- include the development of or mandate the use of reporting templates or tools
- include examples under clause 7.2.3(d).

Administrative and minor improvements (Chapter 9)

The Commission proposes to amend the Code to incorporate administrative and minor improvements it has identified during the review process.

Transitional arrangements (Chapter 10)

The Commission proposes not to amend the Code to include transitional arrangements.

The Commission proposes to revoke the Electricity Industry Performance Code – Direction June 2023 (transitional matters), which it issued on 8 June 2023, effective the date the amended Code comes into effect.

1 | Introduction

The Commission is an independent statutory body established by the *Utilities Commission Act 2000* (UC Act) with defined roles and functions for declared (regulated) industries in the Northern Territory, including electricity supply, water supply, sewerage services, and ports. The Commission's purpose is to protect the long-term interests of consumers of services provided by regulated industries with respect to price, reliability, and quality.

The Code sets out the performance standards and reporting requirements for electricity entities in the Territory. The Code helps to ensure that these entities meet specified standards of service, contributing to the reliability and quality of electricity supply for consumers.

This review of version 2 of the Code was initiated by the publication of a Consultation Paper in September 2024. The Commission is reviewing the Code to ensure its content and operation are of continued relevance and effectiveness for the electricity supply industry in the Territory.[1] The review aims to address identified issues, incorporate feedback from stakeholders as considered appropriate and ensure that the Code is effective and relevant.

Context to the Draft Decision

The Code is made by the Commission under section 24 of the UC Act. The Commission is authorised to make a code relating to standards of service in the electricity supply industry under section 24 of the UC Act and regulation 2B of the Utilities Commission Regulations.

The Commission regularly reviews its codes and guidelines to ensure they remain relevant and effective in achieving their objectives. The current review of the Code is driven by the need to address certain challenges faced by some licensees in reporting against aspects of the Code and to provide for changes in the regulatory environment and technological advancements.

The Commission published a Consultation Paper in September 2024 which outlined the key issues identified through the operation of the Code and feedback from stakeholders. The Commission sought to gather further input from stakeholders to inform this Draft Decision.

Submissions were received from the following stakeholders:

- a group of researchers (Researchers)
- Assure Energy Asset Pty Ltd
- Darwin International Airport Pty Ltd (DIA)
- EDL NGD (NT) Pty Ltd (EDL)
- Eni Australia Limited (Eni)
- Jacana Energy (Jacana)
- Power and Water Corporation (PWC)
- Rimfire Energy (Rimfire)
- Territory Generation (TGen).

The Commission considered stakeholders' submissions in making its draft decisions, this associated Draft Decision and preparing the draft amended Code.

For further information on the Electricity Industry Performance Code Review please visit the Commission's website at http://www.utilicom.nt.gov.au.

[1] Section 24(9) of the UC Act.

Purpose of this paper

This paper sets out the Commission's proposed amendments to the Code, following consideration of submissions to its September 2024 Consultation Paper, and invites submissions on the proposed Code amendments.

Submissions

All interested parties (stakeholders) are invited to make submissions on the proposed Code amendments by **5pm (ACST) Tuesday 24 June 2025**. Responses to the Draft Decision will inform the Commission's Final Decision, which is expected to be released by the end of September 2025 for commencement on 1 January 2026, subject to feedback received.

To facilitate publication, submissions should be provided electronically by email to utilities.commission@nt.gov.au in Adobe Acrobat or Microsoft Word format.

Stakeholders need only respond to matters relevant to their areas of expertise or interest. The Commission encourages stakeholders to include sufficient explanatory detail in their responses to any matters discussed in the Draft Decision, or the draft amended Code.

Any questions regarding the Draft Decision and draft amended Code should be directed to the Commission at any of the following:

Email: utilities.commission@nt.gov.au

Telephone: +61 8 8999 5480

GPO Box 915
DARWIN NT 0801

Confidentiality

In the interests of transparency, the Commission will make all submissions publicly available on its website, with the exclusion of confidential information.

Confidential information is defined in section 26 of the UC Act as information that could affect the competitive position of a licensed entity or other person or is commercially sensitive for some other reason.

Submissions must clearly specify any information that a respondent considers confidential and advise why they would like the information treated as confidential. A version of the submission suitable for publication (that is, with any confidential information removed) should also be submitted to the Commission.

Timetable for review

The expected timeframe for publishing the amended Code is outlined below:

Action	Timing
Release of proposed amended Code and Draft Decision	13 May 2025
Consultation period ends/submissions due	24 June 2025
Final Decision to amend Code, including Notice of Variation in Gazette	September 2025
Amended Code commences	1 January 2026

2 | Exemption clause

Background

Clause 5.1.3 of the Code is an exemption clause which allows licensed entities to apply to the Commission for an exemption (or an extension) to their reporting obligations. This provision seeks to provide necessary flexibility, ensuring that the Code remains practical and adaptable to accord for various operational challenges and unforeseen events to the greatest extent possible. The exemption clause aims to balance regulatory compliance with operational realities, acknowledging that there may be legitimate reasons for an entity to be temporarily unable to meet certain reporting obligations.

During independent audits of compliance with the Code, as required under clause 6.2, there have been suggestions that the Code may benefit from a more comprehensive exemption clause. This overall exemption clause could allow entities to apply for exemptions from complying with any requirements of the Code, not just reporting obligations.

The Consultation Paper discussed that while such a clause would enhance the flexibility of the Code, it may be beneficial to specify criteria or principles the Commission must consider when granting an exemption, to make it clear an exemption request will not be simply approved. It will require well justified reasons that meet the Commission's expectations. The Consultation Paper suggested criteria or principles could include:

- public interest - the exemption must not adversely affect the public interest, particularly regarding service reliability, safety, and consumer protection
- compliance integrity - the entity's history of compliance and commitment to returning to full compliance within a reasonable timeframe should support the exemption request (where relevant)
- proportionality and temporariness - exemptions should be temporary, proportionate to the issue, and accompanied by a clear plan for achieving or resuming compliance.

The Commission considered that including exemption approval criteria or principles in the Code may assist in transparency by demonstrating on what basis the Commission makes its decisions, to ensure that exemptions are granted appropriately, maintaining the integrity of the Code while allowing for necessary flexibility.

Submissions

The feedback from stakeholders indicated general support for the current reporting exemption provision in clause 5.1.3 of the Code, recognising it allows for flexibility in reporting obligations. However, feedback from stakeholders also showed strong support for the introduction of a broader exemption clause, with only one stakeholder against.

In relation to the inclusion of criteria or principles for the Commission to consider when granting exemptions, feedback was varied. While some stakeholders supported the idea, they also proposed changes or additions to the criteria outlined in the Consultation Paper.

Further, the Researchers recommended that significant exemptions and extensions be publicly notified along with the Commission's reasons.

Commission's position and reasons

While there was general support for the current reporting exemption provision in stakeholder feedback, the rationale for a broader clause is to provide flexibility for licensees facing unique operational challenges or circumstances beyond the current scope of the reporting-specific exemption clause. Accordingly, the Commission proposes to amend the Code to introduce a broad exemption clause in the Code. The Commission consider this addition will enhance the flexibility of the Code and enable the Commission to address exemption requests more comprehensively.

Relevantly, the introduction of a broad exemption clause aligns with the Commission's recent decision to include a broad exemption clause in the ERS Code. The Commission consider that aligning the Code with the approach taken in the ERS Code provides consistency across Commission codes.

Noting this, and upon further reflection and review of stakeholder input, the Commission consider that while adding criteria or guiding principles may initially seem beneficial for enhancing transparency and consistency, it could inadvertently restrict the Commission's discretion in assessing unique cases. Accordingly, the Commission proposes not to amend the Code to include criteria or guiding principles in a new broader exemption clause.

With the introduction of a broad exemption clause, the Commission consider the current reporting exemption under clause 5.1.3 would become redundant. The broader clause would inherently cover the situations currently addressed by the reporting exemption. Therefore, the Commission proposes to amend the Code to remove the specific reporting exemption to streamline the Code and reduce potential duplication.

Regarding the Researchers' recommendation that significant exemptions or extensions be publicly notified, the Commission has opted not to adopt this. There may be sensitive information or reasons associated with licensees' requests that could be inappropriate for public disclosure. Further, the Commission consider that public notification of such exemptions would likely provide limited public benefit as they are largely operational-related, and the Commission's decision-making processes are already sufficiently transparent to ensure accountability (publication of major decisions in the Commission's annual report).

Proposal to implement

The Commission proposes to amend the Code to:

- introduce a broad exemption clause consistent with the ERS Code
- remove the reporting-specific exemption under clause 5.1.3.

The Commission proposes not to amend the Code to include criteria or guiding principles in a new broader exemption clause.

Proposed amendments:

1.9 Exemptions

1.9.1 The Commission may issue an exemption to an electricity entity or other person to whom this Code applies, that exempts the holder from the obligation to comply with one or more provisions of this Code.

1.9.2 An exemption:

(a) must be in writing;

(b) must identify the holder of the exemption and the provisions that the exemption applies to; and

(c) may be subject to conditions determined by the Commission.

1.9.3 The holder of an exemption must comply with any conditions of the exemption.

1.9.4 The Commission may, in writing, cancel or modify an exemption (including the conditions of an exemption).

1.9.5 Before it cancels or modifies an exemption, the Commission must notify the holder and must give the holder a reasonable opportunity to make representations to the Commission about the matter.

1.9.6 The Commission may publish information on its website about exemptions issued, modified or cancelled under this clause 1.9.

1.9.7 In deciding whether to issue, modify or cancel an exemption, the Commission:

(a) will have regard to the objects of the Act and the ERA and the matters listed in section 6(2) of the Act and section 44C of the ERA; and

(b) may have regard to such other matters that the Commission considers relevant.

5.1.3 ~~Where an **electricity entity** believes it cannot report all or part of its requirements under clauses 5.1.1 or 5.1.2 it may seek an exemption or an extension from the **Commission**. The request for an exemption or extension under clause 5.1.1 or 5.1.2 must be received prior to the end of the **reporting period**~~Not used.

3 | Reporting requirements

Background

Clause 5.2.2(c) of the Code requires licensed entities to include four years of historical data plus the reporting period data in their reporting to the Commission. Clause 5.2.2A requires the methodology used for the reporting of historical data under clause 5.2.2(c) to be consistent with the methodology used for the reporting period data under the same clause. Clause 5.2.2A was added to the Code following the last review.

While the required reporting methodology is now clear in the Code, the Commission has observed inconsistencies in how entities segment their historical data. Specifically, while the reporting period data is correctly segmented by quarter, the four years of historical data is often reported on an annual basis instead of quarterly, as required by the Code.

Ensuring that both historical data and the reporting period data are segmented consistently will provide a more detailed and accurate picture of performance trends over time. This will facilitate easier comparison and analysis, enabling the licensed entities and the Commission to identify patterns, anomalies, and areas requiring attention more effectively.

To address this issue, the Commission suggested in the Consultation Paper that it was considering making the Code more explicit that historical data must be segmented in the same manner as the reporting period data. While the proposed change would be consistent with current expectations, the Commission sought feedback on whether making this explicit in the Code would cause any concerns for stakeholders.

Submissions

Stakeholder feedback received on making the wording in the Code more explicit regarding the segmentation of historical data was mixed, but generally supportive. Importantly, no stakeholders raised objections to this change.

The Commission acknowledge the concerns raised by Jacana regarding the challenges of retrospectively applying changes to data segmentation. Jacana highlighted that, as long as data is initially collected and segmented in the required manner, segmenting historical data in future reports should not pose a problem. The primary concern arises when the Commission (or the AER through changes to its guidelines) requires data to be re-segmented in a way that differs from the original reporting requirements.

Commission's position and reasons

The Commission considers that making the Code more explicit regarding the segmentation of historical data will enhance consistency in reporting and support more accurate analysis of trends over time. While the requirement for consistent methodology between reporting period and historical data is already set out in clause 5.2.2A, the Commission proposes to amend the Code to clarify that historical data must also be segmented in the same manner as the reporting period data. This change will provide clearer expectations for licensees and improve the comparability of performance data.

The Commission acknowledges that retrospective application of updated segmentation (or methodologies) to historical data (or historical data for new performance indicators) may not always be feasible. In such cases, licensees may face genuine limitations in retrospectively reformatting or re-segmenting previously submitted data, particularly where the data was not originally collected or stored in a way that allows for the revised segmentation.

Accordingly, the Commission considers that where there has been a Commission-initiated change to a performance indicator, retrospective application of the new methodology or segmentation to historical data will be considered on a case-by-case basis, and if deemed necessary, may be supported by suitable transitional or exemption provisions to facilitate compliance. Licensees should nonetheless aim, where practicable, to implement processes that enable the capture and storage of data in a form that allows consistent segmentation, even if such segmentation is not currently required, to support future changes.

The Commission also proposes that, consistent with draft decisions elsewhere in this paper, AER-initiated changes (in the case of retail-related reporting) will no longer automatically flow through to licensees under the Code, and therefore the Commission is able to first assess and consult on any changes and how these may impact licensees in the Territory, including in relation to the reporting of historical data.

Importantly, the Commission distinguishes between retrospective application of new segmentation (or methodologies), and the correction of errors. In cases where a licensee identifies an error in historical reporting, including in segmentation, it is expected that the error will be corrected and applied retrospectively. This aligns with the principle that all reported data should be accurate, regardless of the reporting period.

Proposal to implement

The Commission proposes to amend the Code to clarify that historical data must also be segmented in the same manner as the reporting period data.

Proposed amendments:

5.2.2A The methodology and segmentation used for the reporting of historical *data* under clause 5.2.2(c) must be consistent with the methodology and segmentation used for the reporting of reporting period data under clause 5.2.2(c).

4 | IEEE beta 2.5 events for network entities

The IEEE 2.5 beta method is used to identify natural events (or major event days) that significantly impact the reliability metrics of network services. This method helps to separate the impact of extreme events from regular performance metrics, providing a clearer picture of underlying network reliability.

Natural event day calculations and data

Background

Clause 5.4.1 of the Code requires the Commission to be notified in writing within 14 business days of a natural event that occurs that is identified as a statistical outlier using the IEEE 2.5 beta method. Clause 5.4.2 of the Code requires that if a network entity excludes a network outage from the adjusted category or guaranteed service level payments under clause 7.2.3(f), it must issue a report to the Commission within 30 business days.

Clause 5.4.3 of the Code requires the report to include:

- the relevant event identified under clause 7.2.3(f)
- information and documentation on the circumstances surrounding the event
- the impact of the event on the network entity's ability to meet the guaranteed service levels
- the extent of the exclusion from the adjusted category
- the proposed extent of the exclusion
- reasons why the Commission should consider the event as an exclusion.

Currently, when assessing a natural event report, the Commission often requests the entity's workings and associated data to confirm the occurrence and correctness of the calculations. To improve efficiency and provide clarity on what is required to enable the Commission to verify the event was outside the network entity's control, the Commission suggested in the Consultation Paper that there may be benefit in including a specific requirement under clause 5.4.3 of the Code for entities to provide their workings and data as part of their report.

While the proposed change would aim to make the process more efficient by reducing the need for subsequent requests, and associated assessment delays, the Commission sought feedback on whether this proposed requirement would cause any concerns for stakeholders.

Submissions

PWC indicated in its submission that they currently provide the necessary workings and associated data for calculating natural events using the IEEE 2.5 beta method. Further, it foresees no issues in continuing to provide this information in the future.

Commission's position and reasons

The Commission note that no stakeholders raised concerns regarding this proposed change. Given the neutrality expressed, the Commission has proceeded with the proposed change to require network entities to provide their workings and associated data for calculating natural events under the IEEE 2.5 beta method as part of its Draft Decision. The Commission considers this change will enhance transparency and efficiency in its assessments.

Proposal to implement

The Commission proposes to amend the Code to require that a report submitted to the Commission under clause 5.4.2 must also include the network entity's calculations and workings used to identify a statistical outlier using the IEEE 2.5 beta method.

Proposed amendments:

5.4.3 A report submitted to the Commission under clause 5.4.2 must include:

(a) the relevant event identified under clause 7.2.3(f);

(b) information and documentation on the circumstances surrounding the event;

(c) the impact of the event on the network entity's ability to meet the guaranteed service levels;

(d) the extent of the exclusion from the adjusted category;

(e) the proposed extent of the exclusion; ~~and~~

(f) reasons why the Commission should consider the event as an exclusion; and

(g) the network entity's calculations and workings used to identify a statistical outlier using the IEEE 2.5 beta method.

Unadjusted SAIDI and SAIFI inclusive and exclusive of natural events days

Background

The current Code is not clear on whether natural events should be included in the unadjusted SAIDI and SAIFI performance metrics. A strict reading would imply inclusion, which could distort the reporting and not accurately reflect the underlying performance, providing a misleading picture. However, excluding natural events could obscure the full impact on customers during the reporting period.

In line with the AER's reporting requirements, the Commission suggested in the Consultation Paper that it considers there is merit in potentially requiring network entities to report both unadjusted SAIDI and SAIFI metrics inclusive and exclusive of natural events. This dual reporting approach would offer a more comprehensive view of network performance and its impact on customers.

While requiring both inclusive and exclusive reporting of SAIDI and SAIFI would help distinguish between underlying network performance and the impact of extraordinary events on service delivery, and align with the practice of the AER, the Commission sought feedback from stakeholders on whether there would be any barriers or difficulties in implementing this requirement.

Submissions

PWC stated in its submission that it has previously reported both adjusted and unadjusted SAIDI and SAIFI metrics and foresee no issues in continuing this practice. PWC recommended that for performance monitoring purposes, the Commission should only consider adjusted SAIDI and SAIFI metrics, after excluding major event days.

Commission's position and reasons

The Commission considers that PWC may have misinterpreted the intent of the question in its Consultation Paper. However, since no stakeholders raised concerns about requiring network entities to report both unadjusted SAIDI and SAIFI metrics inclusive and exclusive of natural events (or major event days), the Commission proposes to progress with the change. The Commission considers this requirement will provide greater clarity in performance reporting, ensuring a comprehensive understanding of network performance.

Additionally, the Commission notes PWC is already including unadjusted SAIDI and SAIFI reporting that is both inclusive and exclusive of major event days in its current Code reporting. This demonstrates that PWC has the capability to comply with this requirement, further justifying its formal inclusion in the Code as a reporting requirement.

Proposal to implement

The Commission proposes to amend the Code to require network entities to report on both unadjusted SAIDI and SAIFI metrics inclusive and exclusive of natural events (or major event days).

Proposed amendments:

5.4 IEEE 2.5 beta ~~2.5~~ events for network entities

5.4.1 If a natural event occurs that is, or that may be, identified as a statistical outlier using the IEEE 2.5 beta method (IEEE 2.5 beta event) the network entity must notify the Commission in writing within 14 business days of the event occurring.

7.2.3 A network entity may only exclude an unplanned network interruption from the adjusted category if the event that caused the unplanned network interruption is listed below and was beyond the reasonable control of the network entity:

(a) load shedding due to a generation shortfall;

(b) automatic load shedding due to the operation of under-frequency relays following the occurrence of a power system under-frequency condition;

(c) load shedding at the direction of the system controller;

(d) load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a network entity;

(e) for load interruptions caused or extended by a direction from state or federal emergency services, provided a fault in or the operation of the network did not cause, in whole or part, the event giving rise to the direction; and

(f) ~~a natural event identified as a statistical outlier using the *IEEE 2.5 beta method*~~IEEE 2.5 beta event.

Schedule 3: Network services performance indicators

Table 3: Distribution network reliability performance indicators

Performance Indicator	Report	Segmentation	*Target Standard*	Segmentation
System average interruption duration index (SAIDI) unadjusted inclusive of IEEE 2.5 beta events	Yes	Regional and Feeder Category	Not required	N/A
System average interruption duration index (SAIDI) unadjusted exclusive of IEEE 2.5 beta events	Yes	Regional and Feeder Category	Not required	N/A

System Average Interruption Duration Index (SAIDI) adjusted	Yes	Regional and Feeder Category	Yes	Feeder category
System Average Interruption Frequency Index (SAIFI) unadjusted inclusive of IEEE 2.5 beta events	Yes	Regional and Feeder Category	Not required	N/A
System Average Interruption Frequency Index (SAIFI) unadjusted exclusive of IEEE 2.5 beta events	Yes	Regional and Feeder Category	Not required	N/A
System Average Interruption Frequency Index (SAIFI) adjusted	Yes	Regional and Feeder Category	Yes	Feeder category
Poorly performing feeders	Yes	Individual feeder	Not required	N/A

S.3.3.6 SAIDI unadjusted (inclusive and exclusive of IEEE 2.5 beta events) and adjusted are to use the following formula using relevant data. That is, unadjusted SAIDI (inclusive and exclusive of IEEE 2.5 beta events) uses unadjusted data and adjusted SAIDI is to use adjusted data.

$$\text{SAIDI} = \left(\frac{\sum \text{IDi} * \text{Ci}}{\text{CS}}\right)$$

Where:

(a) ID (or 'interruption duration') is the sum of the duration of each unplanned network interruption expressed in minutes.

(b) C (or 'customers') is the sum of the number of impacted customers of each unplanned network interruption.

(c) CS (or 'customers supplied') is the average of the number of all customers supplied at the beginning of the reporting period and the number of all customers supplied at the end of the reporting period.

(d) Additional notes

i. Unmetered street lighting supplies are excluded. Other unmetered supplies can either be included or excluded from the calculation of reliability measures; and~~.~~

ii. Inactive accounts are excluded.

S.3.3.8 SAIFI unadjusted (inclusive and exclusive of IEEE 2.5 beta events) and adjusted are to use the following formula using relevant data. That is, unadjusted SAIFI (inclusive and exclusive of IEEE 2.5 beta events) uses unadjusted data and adjusted SAIFI is to use adjusted data.

$$\text{SAIFI} = \left(\frac{\text{TI}}{\text{CS}}\right)$$

Where:

(a) TI (or 'total interruptions') is the total number of unplanned network interruptions.

(b) CS (or 'customers supplied') is the average of the number of all customers supplied at the beginning of the reporting period and the number of all customers supplied at the end of the reporting period.

(c) Additional notes

i. Unmetered street lighting supplies are excluded. Other unmetered supplies can either be included or excluded from the calculation of reliability measures; and~~.~~

ii. Inactive accounts are excluded.~~;~~

Schedule 7: Definitions and interpretation

IEEE 2.5 beta event	A natural event identified as a statistical outlier using the IEEE 2.5 beta method

5 | Schedule 2: Generation services performance indicators

Background

The primary purpose of reporting on generation services performance indicators is to monitor and ensure the reliability, availability, and overall performance of electricity generators within the Territory's power systems, which has been important for protecting electricity consumer interests where there has been no or very limited competition.

The benefits of requiring generators to report on performance indicators include transparency, accountability and the ability to identify performance issues. However, there are costs associated with data collection, reporting, and compliance, which must be weighed against the benefits.

When the Commission originally implemented these requirements, it considered that the benefits of reporting generation services performance indicators outweighed the costs. However, given the evolving nature of the industry, the Commission suggested in the Consultation Paper that it considers it is timely to reassess whether this balance remains appropriate.

Historically, the electricity industry in the Territory was dominated by the government-owned monopoly, PWC (previously the Power and Water Authority) providing electricity network, retail and generation services. In 2014, PWC was split into three separate government owned corporations, including TGen. Since 2014, TGen has remained the dominant generator in all power systems. However, the Territory electricity market has changed, with the entry of new privately-owned generator entities, particularly in the Darwin-Katherine power system.

The Commission suggested in its Consultation Paper that the increase in generation competition could potentially reduce the need for its oversight of performance if market forces are sufficient to drive performance improvements. However, the extent to which competition has developed in the Darwin-Katherine power system, particularly in comparison to the Alice Springs and Tennant Creek power systems, raises the question of whether different approaches across the three power systems (or licensees) might now be justified.

From the Commission's research, it appeared that it is not common practice for generators in other Australian jurisdictions to report performance-related indicators to state or territory-based economic regulators, primarily because most generation in Australia is connected to the National Electricity Market (NEM). The Commission considered this may limit the direct comparability of practices between the Territory and other Australian jurisdictions.

Submissions

Stakeholders provided a range of views on generator performance reporting under the Code, covering the need for continued reporting, practices in other jurisdictions, the impact of competition in the Darwin-Katherine power system, the consistency of reporting across the Territory’s three power systems, and whether TGen should be subject to different reporting requirements due to its government ownership and dominant market position.

Continued requirement for generator performance reporting

Stakeholders expressed mixed views on whether generators should continue to report performance data under the Code. Some stakeholders supported continued reporting, citing transparency, accountability, and regulatory oversight benefits. Others argued that the evolving market dynamics, existing compliance obligations, and increased competition have reduced the need for detailed performance reporting.

Stakeholders in favour of maintaining generator performance reporting highlighted that reporting supports informed decision-making, helps identify necessary maintenance or system upgrades, and ensures regulatory oversight in a changing market. One stakeholder noted that reporting obligations should be cost-effective and not overly burdensome, especially in small markets.

Conversely, stakeholders opposed to continued generator performance reporting raised concerns about cost-benefit inefficiencies, noting that existing obligations, such as PWC System Control requirements, already ensure compliance and performance accountability. They pointed out that additional reporting requirements create duplication and unnecessary regulatory burden. Some stakeholders suggested that performance monitoring could be streamlined by a single entity, such as PWC System Control, rather than requiring individual generator reporting.

Generator performance reporting in other jurisdictions

Stakeholders provided insights into generator performance reporting practices in other jurisdictions. One stakeholder noted that in NEM jurisdictions, generators are typically not required to report performance indicators directly to state or territory regulators. Instead, market-based mechanisms drive generator performance through economic incentives, competitive pressures, and contractual obligations.

Similarly, international trends suggest that competitive electricity markets prioritise performance-based contracts, market penalties, or industry-led reporting rather than mandatory regulatory performance reporting. One stakeholder recommended that the Commission consider alternative market-driven accountability measures rather than extensive reporting obligations.

Another stakeholder suggested the Commission explore a flexible reporting approach, where reporting obligations are tailored to different types of generators or technologies to maintain relevance while avoiding unnecessary regulatory burden.

Impact of privately-owned competitors' entry in the Darwin-Katherine power system

In relation to the impact of increased competition in the Darwin-Katherine power system on the need for generator performance reporting, some stakeholders argued that the entry of new privately-owned competitors reduces the need for stringent regulatory oversight, as market forces naturally drive performance improvements and operational efficiencies.

However, others cautioned that despite competition, strong regulatory oversight remains necessary to ensure fair market practices and maintain system reliability. One stakeholder noted that while private competitors have entered the market, commercial operations have been constrained by PWC System Control, and therefore, oversight remains necessary until competition is fully realised.

Another stakeholder suggested that reporting requirements should be revisited to assess their continued relevance, given the evolving market landscape. However, they opposed reducing reporting obligations, emphasising the role of performance reporting in system security and planning.

Differentiated reporting for the three power systems

Stakeholders were divided on whether the Darwin-Katherine, Alice Springs, and Tennant Creek power systems should have different reporting requirements.

Some stakeholders supported a differentiated approach, suggesting that the Alice Springs and Tennant Creek power systems are significantly smaller, with different operational challenges, justifying a more tailored regulatory framework.

However, others advocated for consistency across all three power systems, arguing that uniform reporting ensures clear oversight, simplifies compliance, and provides a complete picture of system performance. They emphasised that while competition may vary across these power systems, consistent performance reporting is critical for system security and long-term planning.

Reporting obligations for TGen

There were differing views on whether TGen should have distinct reporting requirements due to its government ownership and dominant position in the Alice Springs and Tennant Creek power systems.

Some stakeholders argued that reporting obligations should be driven by system-specific characteristics rather than ownership status. They noted that while TGen has a dominant market position, compliance costs should remain reasonable, particularly for smaller systems.

Other stakeholders supported additional reporting requirements for TGen, given its majority market share and government ownership, to ensure greater transparency and public accountability.

One stakeholder opposed different treatment for TGen, advocating for uniform reporting obligations for all generators to ensure a level playing field and enhance market competition. Another stakeholder emphasised that government ownership should not result in reduced reporting requirements, highlighting the importance of full transparency and consistent regulatory oversight, particularly given TGen's position as the sole licensed generator in some regions.

Overall, stakeholders presented conflicting views on generator performance reporting. While some supported continued reporting for transparency and regulatory oversight, others argued that existing compliance obligations and competitive pressures reduce the need for Code reporting.

Stakeholders were similarly divided on whether reporting requirements should vary between power systems or whether TGen should be subject to different reporting obligations due to its government ownership and market dominance. Some stakeholders supported a differentiated approach, while others advocated for consistency across all generators and power systems to ensure fairness and system stability.

Commission's position and reasons

The Commission considers that some form of generator performance reporting remains necessary under the Code. While stakeholders presented mixed views on the need for continued reporting, the Commission considers that the benefits of transparency, accountability, and informed decision-making continue to outweigh the compliance costs. Performance reporting helps identify reliability trends, maintenance needs, and system vulnerabilities, particularly in a market where competition is still developing.

In an ideal scenario, market-based incentives and penalties would drive generator performance, reducing the need for regulatory reporting. However, under the current Territory electricity market framework, such mechanisms do not exist. As a result, the Commission does not consider the Territory can rely solely on market forces to ensure generator performance at this stage. While competition has increased with the entry of privately-owned generation licensees, market penetration remains limited, particularly outside the Darwin-Katherine power system. The current market structure does not provide sufficient competitive pressure to ensure consistent, high-quality performance across all generators without regulatory oversight.

Further, while compliance costs exist, generation licensees have already demonstrated an ability to meet the reporting requirements. The Commission acknowledges that regulatory obligations should be proportionate to their benefits, but given that reporting mechanisms are already established, the burden of continuing these requirements is considered manageable and justified.

The Commission has considered whether different reporting requirements should apply to the three power systems or to different licensees, particularly given the variation in market competition and the dominant position of TGen in Alice Springs and Tennant Creek. However, the Commission considers that a consistent approach across all power systems and licensees in the Code provides regulatory certainty, simplifies compliance obligations, and ensures uniform oversight. A uniform approach reduces administrative complexity and ensures comparability of data, which is particularly important for trend analysis.

While some stakeholders suggested alternative approaches, such as performance-based contracts or streamlined reporting through a single entity like PWC System Control, the Commission does not consider this to be a feasible solution at this time. PWC System Control's primary role is operational rather than regulatory and requiring it to take on generator performance monitoring, and associated public reporting, responsibilities would represent another function that has not been assessed in detail.

While market forces and or a change to the market framework could eventually replace the need for regulatory reporting for generation performance, current market conditions do not yet support such a transition. The Commission considers that generator performance reporting under the Code remains an important regulatory tool for ensuring transparency and accountability. Further, a consistent approach across power systems and licensees ensures clarity, comparability, and effective oversight.

Based on that discussed above, the Commission proposes to maintain generator performance reporting requirements under the Code at this time and is open to considering changes if there are material changes to the regulatory framework or market circumstances in the future.

While in general the Commission proposes to maintain generator performance reporting requirements under the Code, the next two sections consider the Code's current two generator performance indicator categories.

Generating unit availability performance indicators

Background

The following performance indicators are currently included in Schedule 2 of the Code:

- availability factor (AF)
- unplanned availability factor (UAF)
- equivalent availability factor (EAF)
- forced outage factor (FOF)
- equivalent forced outage factor (EFOF).

These indicators are related to unit availability and forced outages.

In its Final Decision Statement of Reasons, following the review of the Electricity Standards of Service and Guaranteed Service Level Codes and making of the Code, the Commission stated there was merit in undertaking further review of the generation performance indicators to ensure they are appropriate for not only current generators, but also future generators, including batteries and renewable energy (or intermittent generation).

Subsequently, a number of stakeholders have raised concerns (including in relation to the reporting of SAIDI and SAIFI for generators) and provided feedback as part of a previous Code review, suggesting that additional categories or guidance on reporting situations where plants are available but not dispatched due to system constraints should be considered. Again, the Commission committed to reviewing the obligations.

The Commission acknowledged in the Consultation Paper that traditional generation availability metrics may not be suitable for solar PV and battery energy storage systems (intermittent generation). These technologies have different operational characteristics compared to conventional thermal generation. For instance, solar PV availability is highly dependent on weather conditions, while battery storage performance is influenced by charging and discharging cycles.

Relevantly, to address immediate issues faced by generation entities with intermittent generation commencing operations, the Commission issued a direction on 26 June 2024 under clause 1.6 of the Code. This direction states that these entities are not required to report against the Code in relation to their intermittent generation assets until the Code is updated or advised otherwise by the Commission. This temporary measure aims to prevent potential non-compliance and reduce the reporting burden on relevant licensees.

The Commission sought stakeholders' views on the reporting of generating unit availability, particularly in relation to intermittent generation.

Submissions

Stakeholders provided a range of views regarding the suitability of current generating unit availability-related performance indicators for different generation technologies, including solar PV and batteries.

There was broad agreement among stakeholders that the current indicators are not well-suited for intermittent or inverter-based technologies such as solar PV and battery energy storage systems. Several stakeholders noted that these indicators were originally designed to assess the performance of traditional thermal generation, where units operate continuously or on demand, and do not appropriately account for the operational characteristics of renewable and storage technologies.

Stakeholders noted that for solar PV, availability is inherently tied to resource variability, namely irradiance, and therefore these units may technically be 'available' during periods of low or no output. Similarly, batteries may be available while charging or discharging, but this does not align with how availability is measured under the current indicators. Some stakeholders pointed out that applying these indicators to solar and battery technologies can lead to misleading results or offer little meaningful insight into their actual reliability or contribution to system performance.

While most stakeholders supported the view that the current indicators are unsuitable for solar PV and batteries, there was some divergence in views on how best to respond to this issue. Some stakeholders, including Assure Energy and EDL, suggested that licensees operating these technologies should be excluded from generating unit availability reporting under the Code. TGen supported the continuation of current exclusions already in place, at least until more suitable indicators are developed.

Other stakeholders favoured adapting the reporting framework rather than excluding these technologies altogether. Eni proposed that PV generators could report on inverter availability, measured as inverter service time relative to available irradiance time, and suggested tracking maintenance-related inverter downtime. PWC agreed that alternative indicators tailored to inverter-based technologies would be more appropriate. In particular, PWC suggested that metrics such as 'solar spill', the unused or curtailed portion of available solar generation, could be useful for understanding the operational availability and performance of solar assets. PWC opposed full exclusion of these technologies, arguing that their performance is still relevant and should be captured, albeit through more appropriate metrics.

Stakeholders generally agreed that the current indicators remain appropriate and relevant for thermal generation technologies and should continue to be applied to licensees operating these technologies without change.

Commission's position and reasons

The Commission agrees with stakeholder feedback that the current generating unit availability performance indicators are not appropriate for intermittent generation technologies, including solar PV and battery energy storage systems. These indicators were developed with thermal generation in mind and are based on assumptions of dispatchability and continuous operation, which do not reflect the operational characteristics of inverter-based or variable renewable energy technologies.

This position aligns with the Commission's earlier action to issue a direction on 26 June 2024, stating that generation licensees operating solar PV and or battery assets are not required to report against the Code in relation to these assets until the Code is updated or otherwise advised by the Commission. The Commission considers this direction to remain appropriate and proposes to formally incorporate this exemption into the Code.

The Commission has explored whether suitable alternative performance indicators exist for intermittent generation technologies. However, no widely accepted or standardised alternative indicators currently exist that are appropriate, readily implementable, and capable of being applied consistently across all licensees. Suggestions such as inverter availability or solar spill reporting were suggested by some stakeholders, but these remain bespoke and would likely require development, validation, and system changes by generators, actions that would introduce cost and complexity.

Given the absence of established and cost-effective alternatives, and the unquantified benefit of bespoke indicators at this stage, the Commission considers that excluding intermittent generation systems from unit availability reporting under the Code is a reasonable and proportionate response. The Commission does not consider that the benefit of requiring bespoke performance indicators would justify the likely implementation costs.

The Commission notes that while intermittent generation is a growing segment of the generation mix, thermal generation still makes up the majority of installed capacity in the Territory and continues to play a crucial role in meeting demand, particularly during periods of maximum demand, which coincide with periods of low renewable resource availability (such as late afternoon or during extended monsoon cloud cover). Importantly, the majority of this thermal generation is owned and operated by TGen, which continues to hold a dominant position in the Territory's electricity supply industry. Given this, the Commission considers that the current availability performance indicators remain relevant and should continue to apply to thermal generation assets operated by licensees.

To address potential visibility concerns related to prolonged outages or availability issues for intermittent generators, the Commission has considered other sources of information already available. This includes publicly available Northern Territory Electricity System and Market Operator market dispatch data, which provides daily generator output that can indicate non-use or limited use of a generator. Further, PWC System Control maintains an internal spreadsheet aggregating daily generation availability data sourced from licensee outage and testing requests. While not publicly available, this data could be accessed by the Commission if needed. Additionally, PWC System Control provides half-yearly reporting to the Commission and licensed participants, which may highlight long-term generation outages. Lastly, licensees are required to submit annual licence returns to the Commission, including disclosure of any material changes to their technical capacity, providing a further avenue for the Commission to be made aware of major outages or capacity issues.

On this basis, the Commission proposes to amend the Code to exclude generation entities from reporting generating unit availability indicators in relation to intermittent generation. This change aligns the Code with the 26 June 2024 direction and ensures that performance reporting remains proportionate, practical, and meaningful across all generator types as relevant.

As the proposed amendment to the Code effectively incorporates the substance of the direction issued by the Commission on 26 June 2024, the Commission considers the direction would no longer be necessary once the updated Code comes into effect. Accordingly, the Commission proposes to revoke the 26 June 2024 direction at the same time the amended Code commences, avoiding duplication.

Proposal to implement

The Commission proposes to amend the Code to remove the requirement for generator entities to comply with the Code in relation to their intermittent generation (including solar PV systems and batteries).

The Commission proposes to revoke the Electricity Industry Performance Code – Direction June 2024 (intermittent generation and battery reporting), which it issued on 26 June 2024, effective the date the amended Code comes into effect.

Proposed amendments:

Schedule 2: Generation services performance indicators

S.2.2.6 Intermittent generation, including solar photovoltaic systems and battery energy storage systems are excluded from the application of schedule 2 for the purpose of reporting generating unit availability performance indicators.

Generating services reliability performance indicators

Background

Generation services reliability performance indicators, such as SAIDI and SAIFI, are designed to measure the reliability of electricity supply by tracking the frequency and duration of interruptions. However, in power systems with multiple generators, accurately attributing interruptions to specific generators can be challenging and may lead to inaccurate or unfair reporting of SAIDI and SAIFI metrics, potentially distorting the performance assessment of individual generators.

As part of a previous review of the Code, TGen noted that the interconnected nature of power systems with multiple generators complicates the reporting of SAIDI and SAIFI metrics, suggesting that the network operator may be better equipped to report on these indicators. EDL also argued that SAIDI and SAIFI are not relevant performance indicators for generators and should be excluded. Eni suggested that only those generators [that are] paid for the provision of essential system services should report on these benchmarks, as they [Eni] are not considered firm sources of generation.

Network entities are already required to report both unadjusted and adjusted SAIDI and SAIFI metrics. Unadjusted SAIDI and SAIFI include all outages or interruptions to customers, while adjusted SAIDI and SAIFI allow for the exclusion of certain types of interruptions under clause 7.2.3 of the Code. These exclusions include, among others, outages due to generation shortfalls, load shedding, and natural events identified using the IEEE 2.5 beta method. The rationale for allowing these exclusions is to enable a clearer view of the true underlying performance of the network by focusing on factors within the network entity's control.

The Commission suggested in the Consultation Paper that given one of the exclusion criteria for network entities under clause 7.2.3 is related to generation shortfalls, the difference between unadjusted and adjusted SAIDI and SAIFI metrics reported by network entities may provide insights into generation performance. Therefore, there may be an argument that if network reporting of these metrics is deemed sufficient, additional reporting of SAIDI and SAIFI by generators might be unnecessary. This could simplify the reporting requirements for generators and reduce the potential for duplication of effort.

Relevantly, Schedule 3 of the Code, specifically clauses S.3.8.1 and S.3.8.2, requires network entities to provide details regarding exclusions applied under clause 7.2.3, including at a minimum, the type and number of exclusions by performance indicator and region. The Commission suggested this reporting by network entities may already, or could be modified to, capture sufficient information about the impact of generation-related outages on overall system performance.

The Commission sought stakeholders' views on the reporting of SAIDI and SAIFI by generators.

Submissions

Stakeholders provided a range of views on the relevance and appropriateness of requiring generators to report SAIDI and SAIFI metrics under the Code. Their feedback also addressed the practical challenges associated with reporting these metrics in interconnected systems with multiple generators and whether network reporting sufficiently captures generation-related reliability performance.

In relation to the relevance and appropriateness of SAIDI and SAIFI reporting by generators, most stakeholders expressed the view that SAIDI and SAIFI reporting is not appropriate or relevant for generators. These stakeholders argued that SAIDI and SAIFI are traditionally network-focused metrics, designed to measure the frequency and duration of customer interruptions at the network level, rather than to assess generation performance.

TGen submitted that the responsibility for reporting SAIDI and SAIFI should rest with the network operator, not individual generators. They highlighted practical difficulties in accurately attributing interruptions to generation, particularly when the generator has no control over network faults. They also noted that this requirement creates potential duplication of effort, given the network operator already reports on these metrics and has a system-wide view.

Eni and EDL supported this view, stating that the metrics are designed for network-level analysis and are not suitable for generator-level reporting. They agreed that SAIDI and SAIFI do not appropriately reflect generator performance and that the network operator is better positioned to report on these measures.

In contrast, PWC argued that SAIDI and SAIFI reporting by generators could provide valuable insights into how generation outages affect system reliability. However, PWC noted that such reporting should be linked to generation capacity and the impact on system performance, suggesting that generation-related contributions to customer interruptions are still a relevant aspect of overall system reliability.

In relation to challenges in reporting SAIDI and SAIFI in interconnected systems with multiple generators, stakeholders generally agreed that the interconnected nature of power systems in the Territory, particularly the Darwin-Katherine power system, creates challenges in accurately reporting SAIDI and SAIFI at the generator level.

TGen indicated that they rely heavily on data from the network operator [or PWC System Control] and therefore face difficulties in determining the cause and attribution of customer interruptions. They reiterated their position that the network operator is better placed to report on these metrics accurately.

DIA highlighted the complexity of identifying the source of disturbances, particularly during events such as rate of change of frequency incidents, where determining which generator triggered a system response can be difficult. They suggested that a collaborative approach and standardised methodology across entities may improve reporting accuracy, but acknowledged this would be resource intensive.

EDL reiterated its view that the network operator should be responsible for reporting, given the challenges of disaggregating SAIDI and SAIFI impacts between multiple generators operating simultaneously.

PWC acknowledged that attributing SAIDI and SAIFI to individual generators is challenging, particularly in systems with multiple generation sources, but did not offer specific solutions to overcome these operational issues.

In terms of the sufficiency of network reporting and possible enhancements, on the question of whether existing network reporting of SAIDI and SAIFI is sufficient to capture generation-related reliability impacts, only PWC provided detailed feedback. They advised that while network reporting does capture some generation-related outages, it may not provide sufficient visibility of the capacity impact of a generator outage or sufficiently distinguish causes of customer interruptions.

PWC suggested that enhancements to network reporting could be considered, such as including more detailed data on available and unavailable generation capacity, differentiating between types of outages, and accounting for different generation technologies. These modifications, they argued, could improve the accuracy and usefulness of reliability reporting without requiring duplicative reporting from generators.

Commission's position and reasons

The Commission acknowledges the concerns raised by stakeholders regarding the appropriateness and practicality of requiring generators to report SAIDI and SAIFI metrics under the Code. These metrics are traditionally used to assess network performance and the customer experience of supply interruptions, and most stakeholders considered them ill-suited for application at the generator level.

The Commission accepts that accurately attributing SAIDI and SAIFI to individual generators in interconnected systems presents significant challenges. This is particularly true in power systems like Darwin-Katherine, where multiple generators are connected and operate concurrently. Generators are often dependent on PWC System Control to identify the cause and extent of outages, and in many cases do not have the information necessary to determine whether or how they contributed to an interruption. The Commission also recognises the risk of duplication, as these indicators are already reported by network entities, and that the added regulatory burden on generators may not deliver sufficient additional value to justify the cost.

The Code already includes a mechanism for network entities to identify and categorise exclusions from adjusted SAIDI and SAIFI under clause 7.2.3, with associated reporting requirements under clauses S.3.8.1 and S.3.8.2. This includes identifying generation-related exclusions, which provides some visibility over the impact of generation-related events on reliability outcomes. However, the Commission is not proposing to amend network reporting requirements to serve as an alternative or supplement to generator SAIDI and SAIFI reporting. Rather, the Commission considers the existing network, and PWC System Control reporting framework is already sufficient for its current oversight and monitoring purposes.

In addition, PWC System Control now includes in its incident reports a breakdown of the root cause of each reportable incident by licensee, expressed as a percentage. While not a substitute for SAIDI and SAIFI figures, this provides a useful indication of each licensee's contribution to an incident. This information, while not publicly available, could be used by the Commission in its public reports and supports the conclusion that PWC System Control is better placed than individual generators to allocate responsibility for interruptions.

The Commission also notes that SAIDI and SAIFI are indicators that relate primarily to system security, which is already monitored through PWC System Control's incident reporting obligations under the System Control Technical Code.

Taking all of this into account, the Commission proposes to amend the Code to remove the requirement for generator SAIDI and SAIFI reporting. This will remove unnecessary duplication and reporting burden while maintaining appropriate regulatory oversight through continuing network and system control reporting.

Proposal to implement

The Commission proposes to amend the Code to remove the requirement for generator SAIDI and SAIFI reporting.

Proposed amendments:

Schedule 2: Generation services performance indicators

S.2.2.3 This schedule is separated into sections: *generation service performance indicators*; and *generating unit* availability *performance indicators*~~; and *generation services* reliability *performance indicators*~~.

Table 2: Generation Services Performance Indicators

Performance Indicator	Report	Confidential	Segmentation
Availability Factor (AF)	Yes	Yes	*Power station*
Unplanned Availability Factor (UAF)	Yes	Yes	*Power station*
Equivalent Availability Factor (EAF)	Yes	Yes	*Power station*
Forced Outage Factor (FOF)	Yes	Yes	*Power station*
Equivalent *Forced Outage* Factor (EFOF)	Yes	Yes	*Power station*
~~*System average interruption duration index (SAIDI)* relating to *generation interruption*~~	~~Yes~~	~~No~~	~~*Power system* and *region*~~
~~*System average interruption frequency index (SAIFI)* relating to *generation interruption**~~	~~Yes~~	~~No~~	~~*Power system* and *region*~~

~~**Note: To avoid doubt, clause 7.2.3 of this Code does not apply to generation services reliability performance indicators. However, any generation event that affects supply to customers and is caused by assets or equipment that are outside plant management control in accordance with the IEEE Standard 762-2006 must be excluded for the purpose of calculating generation services reliability performance indicators.*~~

S.2.5 Not used.~~**Generation services reliability performance indicators**~~

~~S.2.5.1~~ ~~When calculating *generation services* reliability *performance indicators*:~~

~~(a) for each *power system*:~~

~~i. only include those *generation interruptions* that are caused by *generation events* that are related to *generating units/facilities* that form part of the same *power system* and affect *supply* to *customers* located within the same *power system*; and~~

~~ii. only include those *customers* who are supplied by the same *power system*; and~~

~~(b) for each *region*:~~

~~i. only include those *generation interruptions* caused by *generation events* related to *generating units/facilities* that form part of the same *power system* and affect *supply* to *customers* located within the boundaries of the same *region*; and~~

~~ii. only include those *customers* who receive *supply* from within the boundaries of the same *region*.~~

6 | Schedule 3: Network services performance indicators

Poorly performing feeders

Background

The Commission advised in its Consultation Paper that it was not intending to conduct a comprehensive review of Schedule 3 as part of this Code review, as the focus is primarily on Schedules 2 and 4, along with some minor improvements. However, one specific area under Schedule 3 that the Commission proposed to clarify was the reporting methodology for poorly performing feeders.

The Commission previously identified that PWC may not have been applying the correct methodology for calculating the SAIDI when identifying poorly performing feeders. PWC was calculating SAIDI based on the feeder's contribution to the overall feeder category result (total of all outages in a feeder category). However, PWC should have been calculating SAIDI based on the individual performance of each feeder, specifically considering the duration and impact of outages on customers served by that feeder.

The correct formula for calculating SAIDI for a specific feeder (Feeder Y) is as follows:

$$feeder\ Y\ SAIDI = \frac{\sum duration\ of\ feeder\ Y\ outage \times feeder\ Y\ customers\ impacted}{customers\ served\ by\ feeder\ Y}$$

This formula means that SAIDI for a particular feeder is calculated by taking the total duration of all outages that occurred on that feeder, multiplying each outage duration by the number of customers affected, and then dividing this by the total number of customers served by that feeder. This approach focuses on the individual feeder's performance rather than its contribution to a broader category, providing a more accurate measure of reliability for that specific feeder.

The intended or expected calculation methodology has been clarified informally with PWC, but the Commission stated in its Consultation Paper that this should be formalised in the Code to remove any ambiguity and ensure consistent application.

Submissions

PWC did not raise any concerns with the proposed explicit calculation methodology for SAIDI. PWC advised that it has addressed the issue previously identified by the Commission and will continue to use this methodology unless directed otherwise by the Commission.

Commission's position and reasons

No concerns were raised by stakeholders regarding the proposed change. Therefore, the Commission intends to proceed with implementing the change as outlined in the Consultation Paper and this Draft Decision.

Proposal to implement

The Commission proposes to amend the Code to require network entities to report on poorly performing feeders consistent with the methodology detailed in the Consultation Paper and this Draft Decision.

Proposed amendments:

Schedule 3: Network services performance indicators

S.3.5.1 Network entities must report to the Commission on the 5 worst performing feeders for each feeder category for the reporting period including the following information:

(a) the SAIDI performance of the individual feeder that was used to identify each individual feeder that has performed poorly; and

(b) a statement that explains the poor SAIDI performance of each of these individual feeders and the action the network entity intends to take to improve the poor SAIDI performance of these individual feeders.

S.3.5.1A Individual feeder SAIDI is to be calculated using the following formula.

$$\text{Individual feeder SAIDI} = \left(\frac{\sum \text{IDi} * \text{Ci}}{\text{CS}}\right)$$

Where:

(a) ID (or 'interruption duration') is the sum of the duration of each unplanned network interruption for the individual feeder expressed in minutes.

(b) C (or 'customers') is the sum of the number of impacted customers of each unplanned network interruption for the individual feeder.

(c) CS (or 'customers supplied') is the average of the number of all customers supplied at the beginning of the reporting period and the number of all customers supplied at the end of the reporting period for the individual feeder.

(d) Additional notes

i. Unmetered street lighting supplies are excluded. Other unmetered supplies can either be included or excluded from the calculation of reliability measures; and

ii. Inactive accounts are excluded.

7 | Schedule 4: Retail services performance indicators

Retail services performance indicators in Schedule 4 of the Code fall under one of five categories:

- customer service and complaints
- handling customers experiencing payment difficulties
- PPMs
- de-energisation (disconnection) and re-energisation (reconnection)
- hardship program.

The primary purpose of retail services performance indicators is to monitor and report on the performance of the Territory electricity retail industry. It provides for accountability and transparency, which is important for protecting consumer interests.

AER Retail performance reporting procedures and guidelines review

Background

The AER completed a review of its Guidelines, with an updated version commencing on 1 July 2025. The AER's review aimed to ensure that data submitted is high-quality, relevant, and comprehensive. This included introducing new indicators, refining current indicators, and increasing the granularity of data collection.

The AER's review is particularly relevant to the Commission's review of the Code because many of the retail-related performance indicators in Schedule 4 of the Code point to the AER's Guidelines. Therefore, when the AER updates its Guidelines, some of the performance indicators in the Code are also (automatically) updated.

The changes to the AER's Guidelines, which impact retailers in the Territory reporting against the Code are shown in table 2.

Table 1 Material changes to the AER's Guidelines

EIP Code performance indicator	AER Guidelines indicator number	Change
Customer service and complaints		
Total number of calls to an operator	3.1	Relevant reporting period increased from annually to quarterly.
Number and percentage of calls forwarded to an operator that are answered within 30 seconds.	3.2	Relevant reporting period increased from annually to quarterly.
Number and percentage of calls abandoned before being answered by an operator	3.4	Relevant reporting period increased from annually to quarterly.
Complaints—billing	3.5	Increased segmentation (seven subcategories), including a sub-category of 'payment difficulties (including hardship calls).'
Handling customers experiencing payment difficulties		
Number of small customers repaying an energy bill debt	3.15	Increased segmentation.

Average amount of energy bill debt for small customers	3.17	Increased segmentation.
Number of residential customers on a payment plan	3.22	Scope increased to include small business customers in addition to residential customer. (The change states that customers in embedded networks should also be included)
De-energisation (disconnection) and re-energisation (reconnection)		
Total number of residential customers reconnected in the same name at the same address	(Previously 3.38)	Removed.

While there are some benefits to the 'automatic' updating of some Code retail-related performance indicators, the Commission considers that changes might not always be relevant for the Territory or require Territory retailers to make difficult or expensive changes to their retail systems. Therefore, the Commission needs to understand the AER's changes, their potential impacts on Territory retailers and the associated costs and benefits to adopting these in the Territory. If the Commission considers the costs would exceed the benefits, the Commission can amend the Code accordingly, to ensure the Code remains practical and relevant.

The Commission suggested its Code review also presents an opportunity to consider increasing or expanding the customer service and complaint-related performance indicators in the Code, noting the AER has expanded those in the AER Guidelines. For example, the AER has implemented a new indicator in relation to modern communication methods and modified the 'complaints billing' indicator to increase granularity.

The Commission sought stakeholders' views on the potential impacts of changes to retail performance indicators as a result of the changes to the AER Guidelines.

Delayed timing and direction issued

Relevantly, during the course of its review of the Code, the Commission identified that the review would not be completed in time for the updated AER Guidelines to take effect on 1 July 2025. Given this timing issue, and to ensure retail licensees had sufficient time to adjust to any potential changes, the Commission determined that a temporary measure was necessary to avoid automatic application of version 4 of the AER Guidelines before the Commission had the opportunity to fully assess its impact and consider stakeholder feedback.

To address this, on 6 January 2025, the Commission issued a Direction on Retail Reporting Requirements under clause 1.6 of the Code. The direction requires retail entities to continue reporting against version 3 of the AER Guidelines for the 2024-25 reporting period and subsequent periods until a variation to the Code is made or the Commission advises otherwise. This approach provides regulatory certainty for retailers, ensures consistency in reporting obligations, and allows the Commission to complete its review in a structured and considered manner.

The temporary direction ensures an orderly transition and avoids potential confusion or misalignment between the Code and AER Guidelines requirements.

Submissions

Jacana did not oppose application of the changes but highlighted concerns regarding sufficient implementation timeframes, retrospective application, and increased reporting frequency.

Rimfire was supportive of maintaining alignment of the Code with the updated AER Guidelines, noting that consistency allows the use of off-the-shelf retail operating and reporting systems, avoiding the costlier option of bespoke systems.

However, following further discussions with Rimfire, the Commission understand that while Rimfire has an off-the-shelf retail operating and reporting system that is used in the NEM, any necessary changes to the system to account for new requirements in the AER Guidelines are not automatic and would result in additional material costs to Rimfire (if not already provided for in the contract with the vendor). Further, any change that diverges from the AER Guidelines leads to a bespoke system, again incurring costs to Rimfire.

Commission's position and reasons

The Commission's draft decision is that the current (as of 1 July 2025) and future updates to the AER Guidelines should not automatically apply to the Code. Instead, the Commission proposes to amend the Code to explicitly reference version 3 of the AER Guidelines, rather than the current wording (clause S.4.2.2), which requires consistency with the AER Guidelines as updated from time to time. This change ensures that Territory retailers are not automatically subject to reporting obligations that may not be relevant to, or appropriate for, the Territory's circumstances.

While alignment with AER Guidelines in 2017 was initially considered beneficial by the Commission for reducing barriers for retailers operating in the NEM to enter the Territory retail market, the number of licensed retailers has not materially increased, and there are only two currently active retailers. The Commission considers this is unlikely to change and as such, the argument for maintaining automatic alignment with the AER Guidelines to facilitate market entry carries less weight.

Further, feedback from one active retailer indicates changes to performance reporting requirements, despite using off-the-shelf software, require a full system upgrade or bespoke modifications, both of which impose material costs on the retailer operating in a small market with limited economies of scale (in comparison to retailers that operate in the NEM).

To provide certainty and stability for retailers, the Commission has published version 3 of the AER Guidelines on its website and will continue to ensure the applicable version remains accessible. Moving forward, the Commission will assess future updates to the AER Guidelines on a case-by-case basis to determine whether they should be adopted in the Territory. This ensures a structured and considered approach to changes in retail performance reporting requirements in the Territory.

In relation to the current AER-based EIP Code performance indicators, the updated AER Guidelines (version 4) primarily introduce increased granularity and segmentation of data, rather than substantive changes to performance reporting. While these refinements may provide additional insights, they are not deemed essential for meeting the objectives of the Code. Further, misalignment between the Code and the updated AER Guidelines will not prevent benchmarking, as the relevant data will still be available for comparative analysis and context.

As a result of the Commission's draft decision to amend the Code to explicitly reference version 3 of the AER Guidelines, thereby ensuring future versions do not automatically apply, the direction issued by the Commission on 6 January 2025 is no longer required. That direction, which temporarily suspended the automatic application of version 4 of the AER Guidelines pending the outcome of this review, will become redundant once the amended Code takes effect. Accordingly, the Commission proposes to revoke the 6 January 2025 direction at the same time the updated Code commences.

Notwithstanding the Commission's draft decision to effectively 'lock in' version 3 of the AER Guidelines for the purpose of retailer services performance indicators in Schedule 4 of the Code, the Commission considers some minor changes to Table 5 in Schedule 4 are necessary or relevant. These are discussed below.

Table 5 in Schedule 4 of the Code sets out performance indicators that Territory retailers are required to report against. The majority of these indicators are AER-based performance indicators, meaning retailers must refer to the AER Guidelines when interpreting and applying these indicators.

Currently, the AER-based indicators are clearly marked in Table 5, however they do not include an explicit reference to the relevant performance indicator number in the AER Guidelines. This omission may create uncertainty or lead to inconsistencies in interpretation. As such, to improve clarity and ensure retailers can easily find the relevant AER indicator, the Commission proposes to amend the Code to add the explicit AER reference number where applicable.

Table 5 in Schedule 4 of the Code includes the AER performance indicator 'Total number of residential customers reconnected in the same name at the same address'. However, as noted in Table 1, as part of its updated AER Guidelines, the AER has removed this indicator. As the Commission intends to link the Code to version 3 of the AER Guidelines, which includes this indicator, and Territory retailers already report on this indicator, the Commission does not propose to remove it.

Table 5 in Schedule 4 of the Code includes the indicators 'Total number of PPM customers self-disconnected' and 'Total number of PPM self-disconnection events', but in the reverse order when compared with the AER Guidelines. To ensure consistency and avoid confusion, the Commission proposes a minor administrative amendment to reorder these indicators in the Code to align with the AER Guidelines.

Table 5 in Schedule 4 of the Code includes the performance indicator 'Reasons for customers exiting the hardship program', which is currently marked as an AER-related indicator. However, this indicator does not appear in the AER Guidelines. Additionally, this indicator is redundant on the basis that the 'Number of customers exiting the hardship program' indicator already includes segmentation by exit reasons. To correct this apparent error and avoid duplication, the Commission proposes to amend Table 5 in Schedule 4 to remove the 'Reasons for customers exiting the hardship program' performance indicator.

Proposal to implement

The Commission proposes to amend the Code to:

- explicitly reference version 3 of the AER Guidelines
- add the explicit AER reference alongside where an indicator is identified as an AER indicator
- reorder the 'Total number of PPM customers self-disconnected' and 'Total number of PPM self-disconnection events' performance indicators
- remove the 'Reasons for customers exiting the hardship program' performance indicator.

The Commission proposes to revoke the Electricity Industry Performance Code - Direction January 2025 (retail reporting), which it issued on 6 January 2025, effective the date the amended Code comes into effect.

<u>Proposed amendments:</u>

Schedule 4: Retail services performance indicators

S.4.2.2 Where indicated in Table 5, for the purpose of calculating *AER retail services performance indicators*, *retail entities* must be consistent with the *AER*'s, *AER* (Retail Law) Performance Reporting Procedures and Guidelines (~~or equivalent~~version 3)~~, as updated from time to time~~.

Performance Indicator	AER (reference) / NT	Relevant Reporting Period	Segmentation
Customer Service and *Complaints*			
Total number of calls to an operator	AER (S3.1)	AER	NT
Number and percentage of calls forwarded to an operator that are answered within 30 seconds.	AER (S3.2)	AER	NT
Number and percentage of calls abandoned before being answered by an operator.	AER (S3.4)	AER	NT
Complaints—billing	AER (S3.5)	AER	NT
Complaints—energy marketing	AER (S3.6)	AER	NT
Complaints—customer transfers	AER (S3.7)	AER	NT
Complaints - Hardship	NT	quarterly	NT
Complaints—Other	AER (S3.14)	AER	NT
Handling customers experiencing payment difficulties			
Number of small customers repaying an energy bill debt	AER (S3.15)	AER	NT
Average amount of energy bill debt for small customers	AER (S3.17)	AER	NT
Amount of residential customer energy bill debt	AER (S3.18)	AER	NT
Number of residential customers on a payment plan	AER (S3.22)	AER	NT
Number of residential customers who successfully completed their payment plan	AER (S3.25)	AER	NT
Pre-payment meters			
Number of PPM customers using a PPM system capable of detecting and reporting self-disconnections	AER (S3.32)	AER	Region
~~Total number of PPM customers self-disconnected~~Total number of PPM self-disconnection events	AER (S3.33)	AER	Region
~~Total number of PPM self-disconnection events~~Total number of PPM customers self-disconnected	AER (S3.34)	AER	Region
Average duration of self-disconnection events	AER (S3.35)	AER	Region
De-energisation (disconnection) and Re-energisation (reconnection)			
Number of customers disconnected for non-payment	AER (S3.36)	AER	NT
Number of customers reconnected within 7 days of disconnection	AER (S3.37)	AER	NT
Total number of residential customers reconnected in the same name at the same address	AER (S3.38)	AER	NT
Hardship Program			
Number of customers on a retailer's hardship program	AER (S4.1)	AER	NT
Average debt upon entry into the hardship program	AER (S4.3)	AER	NT
Levels of debt of customers entering the hardship program	AER (S4.4)	AER	NT
Average debt of hardship program customers	AER (S4.5)	AER	NT
Number of customers exiting the hardship program	AER (S4.11)	AER	NT
~~Reasons for customers exiting the hardship program~~	~~AER~~	~~AER~~	~~NT~~
Assistance provided to hardship program customers	AER (S4.14)	AER	NT

Customer service and complaints

Background

The customer service and complaints performance indicators in the Code are:

- total number of calls to an operator
- number and percentage of calls forwarded to an operator that are answered within 30 seconds
- number and percentage of calls abandoned before being answered by an operator
- complaints - billing
- complaints – energy marketing
- complaints – customer transfers
- complaints – hardship (Territory specific performance indicator)
- complaints – other.

Customer service

The Commission has previously discussed in the annual Northern Territory Electricity Retail Review its concern that the current Code customer service-related performance indicators are too basic and may need to be expanded. For example, performance indicators refer to phone calls only and more modern forms of communication with electricity retailers, such as through social media or messaging platforms, are not captured.

Relevantly, the review of the AER Guidelines expanded indicators to cover ‘total number of contacts made through the retailer’s customer service website portal’, which includes any digital channels of engagement utilised by the customer to contact their retailer, such as retailer apps, online chat, and websites. The Commission considered this may provide an opportunity to leverage off the AER and enhance Territory indicators, ensuring they reflect current communication trends and provide a more comprehensive view of customer service performance. However, this was subject to the benefit outweighing the cost.

Complaints

The Commission noted in its Consultation Paper that the AER Guidelines also include several metering-related complaint categories, with many related to smart meters. It considered this level of detail may not be necessary for the Territory, where metering-related complaints currently fall under the "other" category. However, the Commission sought stakeholders’ views on whether there would be benefits (that outweigh the costs) in introducing an overarching meter-related complaint category specific to the Territory.

Submissions

Customer service

PWC was supportive of expanding customer service-related indicators to capture modern communication methods, however the Commission notes PWC is not required to report on retail-related performance indicators under the Code.

Jacana raised concerns, including that current data capture and system availability can be limited and expanding these capabilities will necessitate investment. The Commission notes Jacana’s feedback on challenges associated with implementing these changes align with feedback provided by stakeholders to the AER during its review of the AER Guidelines.

Complaints

Feedback on the inclusion of a meter-related complaint category or categories was mixed. PWC supported the inclusion of a Territory-specific meter-related complaint category but suggested that it should include sub-categories. These sub-categories somewhat align with the AER's meter-related complaint categories. On the other hand, Jacana opposed a specific meter-related complaint category, arguing that a recent increase in complaints is temporary and associated with the rollout of smart meters.

Commission's position and reasons

Customer service

In terms of expanding customer service-related indicators to capture modern communication methods, such as adopting the AER's new 'total number of contacts made through the retailer's customer service website portal' indicator, the Commission is not proposing to include any new mandatory indicators in this area at this time. This is based on the potential challenges highlighted, the smaller scale of the Territory's electricity retail market (including challenges associated with changes to retailers' operating and reporting systems discussed earlier), and the fact that the AER's new indicator has only just been introduced, with potential issues yet to be discovered. This approach allows the Commission to monitor how the AER's implementation unfolds and assess whether adopting similar mandatory indicators would be appropriate in the future.

However, moving forward, the Commission encourages retailers to start thinking about how they may be able to capture data related to modern communication methods and facilitate a smoother potential transition in the future, given that modern communication methods between retailers and customers are becoming more prevalent.

Complaints

In relation to a meter-related complaints category or categories, and more specifically PWC's feedback, the Commission consider that if a meter compliant category was introduced, and it included sub-categories, it would be better to directly incorporate the AER's meter-related complaint categories rather than create bespoke Territory-specific requirements. Aligning with the AER's categories may avoid costs and complexities of more bespoke reporting systems. This approach would also achieve consistency across jurisdictions, allowing for increased benchmarking.

However, as advised by the Commission in its Consultation Paper, the AER's meter-related complaint categories are extensive and may not be entirely relevant to, or appropriate for, the Territory, and include:

- complaints – meter contestability – meter installation
- complaints – meter contestability – meter installation delay
- complaints – meter contestability – de-energisation
- complaints – meter contestability – meter data
- complaints – meter contestability – privacy
- complaints – meter contestability – cost
- complaints – non-smart meters.

The Commission considered the alternative approach of introducing an overarching meter-related complaint category specific to the Territory. However, consistent with other related discussion in this Draft Decision, this would result in bespoke reporting in the Territory, which comes with challenges and costs associated with changes to retailers' operating and reporting systems.

Relevantly, the Commission acknowledge Jacana's argument that complaints related to metering may decrease after the completion of the smart meter rollout.

Accordingly, the Commission is not proposing to amend the Code to include a meter-related complaint category or categories.

Proposal to implement

The Commission proposes not to amend the Code to in relation to customer service and complaints performance indicators.

Energy bill debt definition

Background

The 'handling customers experiencing payment difficulties' and 'hardship program' performance indicators in the Code are:

- number of small customers repaying an energy bill debt
- average amount of energy bill debt for small customers
- amount of residential customer energy bill debt
- number of residential customers on a payment plan
- number of residential customers who successfully completed their payment plan
- number of customers on a retailer's hardship program
- average debt upon entry into the hardship program
- levels of debt of customers entering the hardship program
- average debt of hardship program customers
- number of customers exiting the hardship program
- assistance provided to hardship program customers.

Previous feedback from retailers to the Commission has been that the Code may benefit from including a definition of 'energy bill debt', noting the AER's Guidelines include a definition, but the Code does not, other than more generally to refer to the AER Guidelines in Schedule 4.

Energy bill debt is defined in the current AER Guidelines (version 3) as 'the dollar amount owed to the retailer for the sale and supply of gas or electricity, excluding other services, which has been outstanding to the energy retailer for a period of 90 calendar days or more. An amount owing after the final bill has been issued by a retailer to a customer on termination of a customer contract (that is, where a customer changes retailer) should not be counted as energy bill debt.'

However, the updated AER Guidelines[2] (version 4) has removed the "period of 90 calendar days or more" timeframe in the definition and replaces it with a provision in the definition to specify the period under each relevant performance indicator in the Guidelines. The relevant indicators in the updated AER Guidelines provide more detail on energy bill debt. For example, the 'number of small customers with an energy bill debt' performance indicator requires reporting of the number of small customers with energy bill debt that has been outstanding for at least 30 calendar days but less than 60 calendar days, that has been outstanding for at least 60 calendar days but less than 90 calendar days and that has been outstanding for at least 90 calendar days or greater.

The Commission sought stakeholders' views on whether there is a need to include a definition of 'energy bill debt' in the Code and if so, whether it should be consistent with the (expected at the time) updated

[2] https://www.aer.gov.au/industry/registers/resources/guidelines/retail-performance-reporting-procedures-and-guidelines-2024-update.

AER Guidelines (taking into consideration the costs and benefits of reporting more detailed/segmented data).

Submissions

Stakeholders expressed support for including a definition of 'energy bill debt' in the Code, highlighting the benefits of clarity and consistency in reporting.

PWC supported aligning the definition of 'energy bill debt' with the updated AER guidelines, including the requirement for more detailed and segmented data. Whereas Jacana advised it prefers the definition to remain consistent with what Territory retailers are currently reporting. Further, Jacana noted that the current mix of monthly and quarterly billing cycles would necessitate additional testing to ensure the measure's robustness, and that quarterly billing may cause significant fluctuations at the 30-day debt level, requiring more detailed data.

As with earlier discussion in the Draft Decision, the Commission notes that PWC is not currently required to report against the Code, and therefore any change, such as introducing a definition for 'energy bill debt' would not impact it.

Commission's position and reasons

The Commission agrees with stakeholders that the Code may benefit from the inclusion of a definition for 'energy bill debt', as this would enhance clarity and consistency in reporting.

Given the Commission's draft decision to explicitly reference version 3 of the AER Guidelines in the Code, rather than allowing for automatic updates to apply, the Commission considers it appropriate to use the definition from version 3 of the AER Guidelines as the basis for inclusion in the Code. This approach provides continuity for Territory retailers, avoiding the additional segmentation requirements introduced in version 4 of the AER Guidelines, which would impose system modifications and additional reporting costs.

Further, the Code currently includes clause S.4.2.3, which establishes specific reporting conditions for energy bill debt in the Territory. Notably:

- S.4.2.3(c) requires energy bill debt to be counted from the date a bill is due to be paid, rather than the date the bill was issued
- S.4.2.3(d) excludes customers with energy bill debt of less than $10 from reporting requirements.

These provisions ensure that reporting aligns with the billing practices in the Territory, which may otherwise cause inconsistencies in reporting trends.

To maintain clarity and avoid conflicts with these existing Code provisions, the Commission proposes to amend the Code to include a definition for 'energy bill debt', as follows:

> *Energy Bill Debt – means the dollar amount owed to the retailer by a customer for the sale and supply of electricity (excluding any charges for other services), which has been outstanding for a period of 90 calendar days or more from the date the bill was due to be paid. For the purposes of the EIP Code:*
>
> - *the 90 calendar days is to be calculated from the due date for payment, not the bill issue date;*
> - *any amount less than $10 is excluded and must not be reported as energy bill debt; and*
> - *any amount owing after a final bill has been issued following termination of a customer contract (including where a customer has changed retailers) must not be counted as energy bill debt.*

This approach ensures that existing reporting requirements remain unchanged, avoids unnecessary compliance costs, and provides a clear and consistent framework for retailers in the Territory while maintaining alignment with the AER Guidelines where appropriate.

Proposal to implement

The Commission proposes to amend the Code to include a definition for 'energy bill debt'.

Proposed amendments:

S.4.2.3 Notwithstanding any requirements of the *AER*, *retail entities* must, for the purpose of calculating:

(a) retail services performance indicators for this Code, only include small customers that are taking (or likely to take less than) 160 megawatt hours of electricity from the distribution network during the reporting period.

(b) AER retail services performance indicators that require segmentation by residential customers and small business customers, apply the definition of residential customer and small business customer in this Code.

(c) AER retail services performance indicators in relation to debt ~~and energy bill debt~~, count debt from the date a bill is due to be paid.

(d) AER retail services performance indicators in relation to debt ~~and energy bill debt~~, exclude customers with debt or energy bill debt of less than $10.

Schedule 7: Definitions and interpretation

Energy bill debt	*means the dollar amount owed to the retailer by a customer for the sale and supply of electricity (excluding any charges for other services), which has been outstanding for a period of 90 calendar days or more from the date the bill was due to be paid. For the purposes of this Code:* • *the 90 calendar days is to be calculated from the due date for payment, not the bill issue date;* • *any amount less than $10 is excluded and must not be reported as energy bill debt; and* • *any amount owing after a final bill has been issued following termination of a customer contract (including where a customer has changed retailers) must not be counted as energy bill debt.*

Pre-payment meter, hardship program, life support customer and customers affected by family violence performance indicators

Background

The Code currently incorporates various AER-based performance indicators. However, many indicators included in the AER Guidelines have not been adopted in the Code to date.

For instance, the current AER Guidelines includes the following performance indicators, which are not currently captured under the Code:

- PPMs:
  - total number of PPM customers (S3.29)
  - number of PPM customers receiving an energy concession (S3.30)
  - number of PPMs removed due to payment difficulties (S3.31).

- hardship program indicators:
  - payment methods of hardship program customers (S4.9).

In addition, the AER's updated Guidelines (version 4, effective 1 July 2025) introduce new performance indicators relating to:

- life support customers:
  - number of life support customers with/without medical confirmation (S6.9)
  - number of life support customers registered (S6.10)
  - number of life support customers deregistered (S6.11).
- customers affected by family violence:
  - number of affected customers (S6.12)
  - number of affected customers added to a retailer's system (S6.13)
  - number of affected customers on a payment plan (S6.14)
  - number of affected customers on a hardship program (S6.15).

The Commission did not propose the inclusion of these additional performance indicators in its Consultation Paper. Instead, they are being considered as part of this Draft Decision following a submission from the Researchers, who recommended their adoption.

Relevantly, recent legislative amendments by the previous Territory Government to the *Electricity Reform Act 2000* (ER Act) established a legislative basis for electricity customer protections, including life support, hardship, and family violence protections under the ERS Code. Following these changes, the Commission updated the ERS Code to incorporate stronger protections in these areas. Given these developments, the Commission has considered the benefits and costs of incorporating corresponding consumer protection performance indicators into the Code.

Submissions

In their submission, the Researchers advocate for aligning the Code with the updated AER Guidelines, including the addition of several new performance indicators. The Researchers specifically recommend the indicators detailed above, which relate to family violence protections, hardship programs, life support customers, and PPM customers.

The Researchers' rationale for inclusion of the new indicators is to enhance transparency, ensure consistent monitoring, and provide detailed insights into consumer protection measures. The Researchers highlight the importance of reporting these indicators by payment type to address the significant use of PPMs in the Territory.

The Researchers further suggest that new indicators should be adopted to address existing disparities and improve the public reporting of retail service performance, including granular data that can help inform policy and support community organisations.

Following the submission from the Researchers, the Commission determined that additional targeted consultation was necessary as part of considering the potential inclusion of additional AER-based retail-related performance indicators in the Code. As these indicators were not contemplated in the Commission's Consultation Paper, stakeholders had not been given an opportunity to provide feedback. Instead of conducting a second public consultation, the Commission opted to engage directly with licensed retail entities on the matter.

Retail entities were asked to provide feedback on:

- the costs and benefits of including these indicators in the Code
- any challenges or barriers the retailer may face in collecting, reporting, or implementing these indicators
- any additional considerations or insights the retailer considers relevant to the potential adoption of these indicators.

Retailers provided a range of perspectives on the potential inclusion of additional AER-based retail-related performance indicators in the Code, with common themes emerging around regulatory burden, data availability, and applicability.

A retailer acknowledged that the indicators aimed to enhance transparency and regulatory oversight. However, they raised concerns that the benefits must be weighed against the significant costs and operational challenges associated with implementation. Two retailers highlighted that system upgrades, process changes, and additional staffing would be required to accurately collect and report the data. Estimated costs for compliance varied, with one retailer estimating significant software development expenses and ongoing administrative costs.

Data availability was identified as a key challenge, particularly in relation to PPM customers and affected customers under family violence protections. Retailers noted that in some cases, they lack visibility over specific residents using PPMs due to arrangements with government agencies. Where PPM credits are issued by a third party, retailers may not have access to up-to-date information on customers receiving energy concessions. Similar concerns were raised regarding hardship and family violence indicators, with retailers seeking clearer definitions and classification criteria for reporting affected customers.

Stakeholders also emphasised that implementation timeframes would be critical. Some retailers indicated that, if required, they could work towards compliance but recommended a phased approach to allow time for system upgrades and staff training.

Concerns were raised regarding the applicability of the indicators to all retailers. A retailer noted that it only services commercial customers and does not have residential customers. They argued that retailers without residential customers should not be subject to reporting obligations designed for residential electricity services. To avoid unnecessary reporting requirements, they recommended that any amendment to the Code clarify that the indicators only apply to retailers with relevant customers.

In considering the potential inclusion of these indicators, retailers stressed the importance of balancing regulatory objectives with practical implementation considerations. Some suggested that increased reporting obligations should only be introduced if there is clear evidence of a material benefit to customers.

Commission's position and reasons

The Commission has carefully considered the proposal to introduce additional AER-based retail-related performance indicators into the Code, as recommended by the Researchers, and proposes not to include additional PPM, hardship program, life support customer and customers affected by family violence performance indicators.

While the Commission acknowledges that greater transparency and more detailed reporting can enhance regulatory oversight and inform policy development, these benefits must be weighed against the costs.

The relatively recent amendments to the ER Act strengthened customer protections in the Territory through effectively mandating specific customer protections in the ERS Code. Under the current ERS Code, every retailer and network provider must comply with life support equipment customer protection obligations, including for customers outside the major centres of Darwin-Katherine, Alice Springs and Tennant Creek, and they must develop, make and publish standard complaints and dispute resolution procedures and handle complaints in accordance with these. The current ERS Code also requires retailers to have and comply with approved hardship and family violence policies in relation to their residential customers.

The Commission considers that the current customer protections in the ERS Code will have a material positive impact on customer outcomes, whereas introducing additional performance indicator reporting may not provide equivalent or proportionate benefits, particularly given the material costs and operational challenges raised by retailers to collect and report the data.

Also relevant to the Researchers' submission, in relation to the recent legislative changes to the ER Act, which introduce, and extend consumer protections Territory-wide, the Commission understands the Government did not contemplate imposing reciprocal performance reporting obligations.

On balance, the Commission does not consider the costs and complexities of implementing additional indicators in relation to PPM, hardship program, life support customers and customers affected by family violence outweigh the anticipated benefits at this time. Accordingly, the Commission proposes not to amend the Code to provide for this. However, the Commission remains open to revisiting this issue in the future if further evidence emerges that supports the need for additional performance reporting in these areas.

The Commission has also considered stakeholder concerns regarding the applicability of these indicators to all retailers, particularly those that service only commercial customers and do not have any residential customer base. The Commission notes that the Code is already sufficiently defined in this regard, retail performance reporting obligations in Schedule 4 are limited to small customers, and in several cases, are further restricted to residential customers only. The Commission confirms that should it consider introducing any additional retail-related performance indicators in the future, it will ensure the Code continues to clearly limit reporting obligations to only those retailers for whom the indicators are relevant and applicable. Accordingly, the Commission does not consider any amendment to the Code is required to address this matter.

Proposal to implement

The Commission proposes not to amend the Code to include additional PPM, hardship program, life support customer and customers affected by family violence performance indicators.

8 | Other matters identified through consultation

Application of the Code Territory-wide

Background

Since its introduction, the Code has applied to licensees providing generation, network, and retail services within the Darwin-Katherine, Alice Springs, and Tennant Creek power systems. This application has remained unchanged, and to remove any ambiguity, it was further clarified as part of the last review of the Code.

The Commission's current review of the Code did not contemplate a change to its application, nor was this issue raised in its Consultation Paper. However, the Researchers comprehensively raised the matter in their submissions, highlighting concerns about the absence of performance reporting requirements for electricity services in communities supplied by Indigenous Essential Services Pty Ltd (IES) and other remote indigenous communities (collectively 'communities') of the Territory.

Given the detailed arguments presented by the Researchers, the Commission considers it necessary to address this issue in its Draft Decision, despite it not being part of the original scope of the review. The Commission acknowledges the complexity of this matter, particularly in the context of government oversight and existing contractual arrangements for electricity services in communities and seeks to provide clarity on its current position.

Submissions

In their initial submission, the Researchers raised concerns about the lack of performance reporting for electricity services in communities in the Territory. They emphasised that while the Code applies to licensees operating in the Darwin-Katherine, Alice Springs, and Tennant Creek power systems, it does not extend to communities, including those serviced by IES under contract with the Territory Government.

The key points from their submission include:

- lack of transparency in communities - unlike customers in major networks, residents in communities do not have visibility over service quality, reliability, or access to key customer protections
- PPM customers - a significant proportion of customers in communities use PPMs, yet there is no public reporting on key indicators such as disconnections, hardship support, or customer experiences
- regulatory and policy gaps - the Researchers argued that the lack of reporting creates an accountability gap, and that government oversight alone does not guarantee transparency
- proposal for Territory-wide application - the Researchers recommended that the Commission extend the Code's retail performance reporting obligations to include all retail licensees, including those servicing communities, to ensure a consistent and equitable regulatory framework across the Territory.

The Researchers also noted that advancements in smart metering now allow for more detailed data collection in communities, making such reporting feasible.

In their supplementary submission, the Researchers referenced the First Nations Clean Energy Strategy (FNCES), which was released by the Australian Government on 6 December 2024. The strategy emphasises First Nations people's rights to affordable and reliable energy access and recommends policy actions to enhance regulatory protections in communities.

Key points from the Researchers supplementary submission include:

- alignment with national policy - the FNCES highlights the need for improved regulatory protections and transparency in remote energy supply, reinforcing the Researchers' argument for extending the Code's reporting obligations
- specific policy actions - the FNCES recommends mandatory reporting of disconnections, improved hardship protections, and the prohibition of disconnections during extreme weather. The researchers suggested that the Commission consider integrating these principles into the Code.

The Researchers suggest immediate actions for the Commission include:

- apply Code retail performance reporting requirements Territory-wide
- mandate historical reporting of disconnections in communities since the introduction of smart meters
- align retail performance reporting for PPM and hardship customers with the updated AER Guidelines.

The Researchers urged the Commission to take a leadership role in ensuring communities receive the same level of regulatory oversight and consumer protections as customers in major Territory power systems. The Researchers suggested that incorporating Territory-wide reporting requirements in the Code would improve data transparency and support better policymaking in line with national clean energy objectives.

Commission's position and reasons

The Commission acknowledges the detailed submissions from the Researchers, which raise important issues regarding the absence of performance reporting obligations for electricity services in communities. The Commission agrees that access to essential services, including reliable and affordable electricity, is fundamental for all Territorians, and supports broader efforts to ensure transparency and accountability in remote service delivery.

However, the Commission also recognises that the provision of electricity services in communities is fundamentally different from the services delivered in the larger and more regulated power systems of Darwin-Katherine, Alice Springs, and Tennant Creek. These differences are not only structural and operational, but also reflect the distinct policy and service delivery frameworks underpinning electricity supply in communities.

The Commission highlights that the Territory Government has taken direct responsibility for electricity supply in communities, mainly through its contractual arrangements with IES, operating under a funder-purchaser-provider model. While the Commission previously focused on the distinction between access-regulated and non-access-regulated networks in its last Code review, it acknowledges that the differences extend beyond network classification. The frameworks are fundamentally different, both in terms of governance and regulatory oversight, and it is therefore reasonable for performance reporting obligations and approaches to differ accordingly.

The Commission also acknowledges that the current framework of delivering electricity in communities lacks publicly available performance reporting and service standards and understands why the Researchers see this as a critical gap. Transparency in public service delivery is important, particularly in communities where customers may already face additional challenges in accessing services and support. However, given that the responsibility for electricity service delivery in communities rests with the Territory Government, the Commission considers that any changes to improve performance reporting and transparency should be led by the responsible departments in the first instance, which are directly accountable for funding and delivering these services.

To this end, the Commission has raised these matters with the relevant government entities, including the Department of Mining and Energy, the Department of Housing, Local Government and Community Development (which manages the IES contract), and IES itself. From this communication, the Commission understands that constructive work is already underway within Government:

- a recent review of the IES program has been completed, with recommendations including to revise the service level agreement and governance arrangements
- the introduction of an inaugural IES Statement of Corporate Intent (SCI) commencing 1 July 2025. The SCI sets out the nature and scope of IES business activities, key objectives, risk management, capital investment plans and performance targets over six years
- a working group has been established to improve the transparency and accountability of essential services in remote Aboriginal communities, with representation from Aboriginal-led organisations
- formal collection by government of SAIDI and SAIFI data has commenced for the 72 IES communities, with aggregated average electricity outage duration data now being reported through the Territory Government's Budget Paper No. 3 (Agency Budget Statements).

The Commission also understands that the relevant government departments have previously engaged with the Researchers on relevant and related matters.

Given the fundamentally different governance framework, the complexity and cost of delivering services in communities, and the fact that targeted reform is already underway within Government, the Commission does not propose to amend the application of the Code at this time. Extending the Code to cover communities could duplicate or interfere with ongoing government-led reforms and may not be the most effective way to improve transparency or outcomes for consumers in communities.

The Commission considers that the Government has clearly assumed responsibility for the provision of essential electricity services in communities, and accordingly, considers that performance reporting and the public availability of such information should, in the first instance, be led by Government. The Commission is encouraged by the early progress being made, particularly the recent steps taken to strengthen governance, data collection and transparency through internal reviews and a cross-agency working group, with representation from Aboriginal-led organisations. These initiatives appear to be heading in a positive direction.

Nonetheless, the Commission emphasises that public reporting and transparency in relation to the performance of electricity services in communities, including retail service performance, is important. These communities, like all others across the Territory, deserve visibility over service quality and system reliability, and clear information is essential to informed policymaking, accountability, and continuous improvement.

To this end, the Commission will write to the Territory Government as part of its Final Decision to encourage the continuation of recent efforts to improve transparency and accountability. However, if these efforts do not progress or stall over time, the Commission may consider a dedicated review of the Code to examine whether expanding its scope to include performance reporting obligations in communities is warranted and reasonably achievable. While this is not a preferred or immediate step, the Commission considers it is important to signal that this remains an option for future consideration should gaps in transparency persist.

Proposal to implement

The Commission proposes not to amend the Code to expand the application to cover electricity entities operations outside of the Darwin-Katherine, Alice Springs and Tennant Creek power systems.

Reporting templates and tools

Background

The Code requires licensees to report on their performance against specific indicators annually. Clause 5.1.1 of the Code requires retail and generator entities to submit a report to the Commission on their actual performance against the relevant indicators by 31 August each year. Clause 5.1.2 requires network entities to submit their final performance report by 31 October.

Under clause 5.2.1, these reports must include the applicable performance indicators set out in the relevant schedules of the Code:

- Schedule 2 for generation services
- Schedules 1 and 3 for network services
- Schedule 4 for retail services (limited to small customers).

Reports must also be segmented in accordance with clause 7 and the relevant schedules.

Unlike other jurisdictions, such as the AER, which in some cases provides standardised performance reporting templates to assist regulated entities with reporting requirements, the Code does not currently include or refer to any standard tools or templates to support reporting. This can potentially create inefficiencies and inconsistencies in the way information is provided to the Commission and may increase the administrative burden on both licensees and the Commission in reviewing and analysing data.

Submissions

In its submission to the Commission's Consultation Paper, Jacana suggested developing tools and templates to support reporting, similar to the AER's performance reporting template. It stated these could outline metrics, disaggregation requirements, and calculation methodologies, and include data analysis prompts to guide commentary, and this would help standardise formatting and improve consistency.

No other submissions included discussion regarding this issue, noting reporting tools and templates were not discussed or proposed in the Commission's Consultation Paper.

Commission's position and reasons

The Commission acknowledges the potential benefits of developing standardised reporting templates and tools to support licensees in complying with the Code. Such resources could help streamline reporting processes, reduce errors, improve consistency in the data provided, and reduce the administrative burden for both licensees and the Commission. The Commission also notes that in addition to Jacana, Rimfire has previously expressed support for the development of reporting templates during past discussions.

However, the Commission considers that, on balance, the cost and resource commitment required for the Commission to develop and maintain such tools, and for retailers to change to the new templates, likely outweighs the expected benefits in the current context. The Commission is a small regulator with limited resources and must prioritise its efforts to ensure maximum impact across the regulatory framework. In this case, the relatively small number of reporting entities and the maturity of existing reporting practices reduce the urgency or necessity for template development.

Specifically, only two retailers are active in the Territory and currently subject to the Code's retail performance reporting requirements, despite retail contestability since 2010, and it is unlikely this number will increase significantly in the foreseeable future. Over the years, the Commission has worked closely with both retailers to ensure performance reporting compliance, and each has developed its own internal templates and processes to meet the Code's requirements. While these arrangements are not without limitations, they have matured over time and currently function effectively. From a practical standpoint, they are manageable given the size of the market, and mandating the use of new tools or templates may impose unnecessary costs on retailers (and the Commission) without delivering a commensurate benefit.

This rationale applies equally to generation and network entities. While standardised templates could improve consistency across all reporting entities, the same practical considerations, limited market participants, mature existing practices, and manageable administrative demands, apply. Further, any introduction of standardised templates would itself require licensees to adjust current processes and potentially reconfigure internal systems, introducing additional costs and administrative burdens in the short term.

The Commission therefore does not propose to develop or mandate the use of reporting templates or tools under this review of the Code. The Commission remains open to exploring this option in the future, particularly if the number of licensees increases or if reporting obligations change materially. In the meantime, licensees are welcome to develop and propose reporting templates or tools for consideration by the Commission.

Proposal to implement

The Commission proposes not to amend the Code to include the development of or mandate the use of reporting templates or tools.

Definition of interruption

Background

The Code includes a definition of 'interruption' as "a temporary unavailability or temporary curtailment of the supply of electricity to a premises." The term 'supply' is defined under the ER Act as "physically conveying electricity to a customer by transmission or distribution," and 'premises' is defined in the Code as "the address for which a small customer has a contract for the supply of electricity."

Under clause 7.2.3, the Code sets out exclusions that may be applied by a network entity when calculating adjusted SAIDI and SAIFI metrics. These exclusions are intended to isolate performance issues within the network's control and include, among other things:

> *"load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a network entity (7.2.3(d))."*

The Code does not include an explicit exclusion for interruptions resulting from faults in a customer's electrical installation.

Separately, PWC, as a regulated network service provider, is also required to report annually to the AER under its Regulatory Information Notice (RIN) obligations. The AER's Distribution Reliability Measures Guideline provides a detailed definition of 'interruption', which includes an explicit exclusion for "disconnections caused by a fault in electrical equipment owned by a customer." The AER's guidance also specifies the method for determining the start and end of an interruption, including the use of SCADA systems or customer-reported outage times where SCADA is not available.

Submissions

In its submission to the Commission's Consultation Paper, PWC flagged a minor inconsistency between the AER and the Commission regarding the definition of 'interruption'.

PWC advised that the AER excludes interruptions caused by issues with the customer's electrical equipment, whereas the Code does not include an explicit exclusion. PWC suggested that in order to maintain alignment and clarity, the Commission may consider updating the definition of 'interruption' in the Code to reflect this explicitly.

Additionally, PWC highlighted that in clause 7.2.3(d), it considers it may be helpful to include examples related to safety obligations, such as those outlined under the *Electrical Safety Act 2022*, as this would provide further clarity and practical guidance to stakeholders.

No other submissions included discussion regarding this issue, noting the definition of 'interruption' and examples under clause 7.2.3(d) were not discussed or proposed in the Commission's Consultation Paper.

Commission's position and reasons

The Commission considers that PWC has raised a valid issue regarding the definition of 'interruption' in the Code. The current definition, "a temporary unavailability or temporary curtailment of the supply of electricity to a premises", is broad and does not explicitly exclude interruptions caused by faults within a customer's electrical installation. This omission contrasts with the AER's Distribution Reliability Measures Guideline, which specifically excludes "disconnections caused by…… a fault in electrical equipment owned by a customer."

The Commission recognises that the AER's approach ensures that network performance metrics, such as SAIDI and SAIFI, reflect only those outages within the control of the network service provider. By not explicitly excluding customer-side faults, the Code may result in:

- network entities being held accountable for interruptions beyond their control
- potential misalignment with AER reporting requirements, despite overlap in performance indicators
- the appearance of reduced reliability, which does not accurately reflect network performance.

While the ER Act includes definitions of "electrical installation" and "supply" that implicitly distinguish between network assets and customer-owned equipment, the Code does not currently reflect this delineation within its definition of 'interruption'. To address this, the Commission proposes to amend the definition of 'interruption' to more closely align with the AER's definition and to explicitly exclude interruptions due to faults in a customer's electrical installation. This change will promote clarity and consistency in reliability reporting across regulatory regimes.

In relation to clause 7.2.3(d) of the Code, which allows exclusions for load interruptions caused by the exercise of obligations under jurisdictional or national electricity legislation, the Commission acknowledges PWC's suggestion to include examples related to safety obligations, such as those under the *Electrical Safety Act 2022*, within clause 7.2.3(d) of the Code, but is not proposing to amend the Code. The Commission considers this clause already provides sufficient coverage of such obligations by referring to "jurisdictional electricity legislation," which includes the *Electrical Safety Act 2022*.

To avoid doubt, the Commission confirms its interpretation that clause 7.2.3(d) permits exclusions for load interruptions resulting from compliance with safety obligations imposed under applicable Territory legislation, including the *Electrical Safety Act 2022* and its subordinate instruments. This interpretation aligns with the intent of the Code and provides appropriate flexibility for network entities to maintain safety and regulatory compliance without penalising performance metrics.

In the course of considering the definition of 'interruption', the Commission also identified a separate but related issue concerning the definition of 'premises' in the Code. Currently, 'premises' is defined as "the address for which a small customer has a contract for the supply of electricity." This definition ties the term exclusively to small customers, implicitly excluding large customers or premises that fall outside that threshold.

This narrow definition may lead to:

- confusion or misinterpretation, as other provisions in the Code, including those dealing with interruptions, use the term 'premises' more generally
- inadvertent limitations on the scope of provisions intended to apply more broadly than just small customer arrangements.

To address these risks and ensure alignment with the Code's broader intent, the Commission proposes to amend the Code to revise the definition of 'premises' to remove the specific reference to 'small customer'. This amendment will ensure that provisions referencing 'premises' apply uniformly across customer types, avoiding unnecessary constraints or ambiguity.

Proposal to implement

The Commission proposes to amend the Code to:

- revise the definition of 'interruption' to more closely align with the AER's definition and to explicitly exclude interruptions due to faults in a customer's electrical installation
- revise the definition of 'premises' to remove the specific reference to 'small customer.'

The Commission proposes not to amend the Code to include examples under clause 7.2.3(d).

<u>Proposed amendments:</u>

Schedule 7: Definitions and interpretation

Interruption	A temporary unavailability or temporary curtailment of the supply of electricity to a premises, excluding interruptions resulting from a fault in the customer's electrical installation. Interruptions commence when the network entity first becomes aware of a loss of supply (either automatically or through customer notification), and end when supply is restored
Premises	The address for which a ~~small~~ customer has a contract for the supply of electricity

Network services – Phone answering performance indicators

Background

Under clause 5.1.2 of the Code, network entities must submit to the Commission, no later than 31 October each year, a final report on their actual performance against the performance indicators for the previous financial year. Clause 5.2.1 further specifies that in relation to network services, this report must include the performance indicators set out in Schedules 1 and 3 of the Code and be segmented in accordance with clause 7 and the relevant schedules.

Schedule 3 of the Code includes customer service performance indicators for network entities. Clause S.3.6.3 specifically requires reporting on telephone responsiveness through the following indicators:

- the average time taken to answer the phone
- the percentage and total number of calls not answered within 30 seconds of the caller requesting to speak to a person
- the percentage and total number of calls abandoned.

Additional guidance on interpreting and calculating these indicators is provided in clause S.3.6.4, which refers network entities to the AER's Service Target Performance Incentive Scheme (STPIS) requirements, as updated from time to time. An example is included in the Code to illustrate how to measure response times, including exclusions for calls routed through interactive services and estimates for calls abandoned within 30 seconds. The guidance also clarifies that placement in a queuing system does not constitute a response.

Currently, PWC is the only network entity required to report against the Code. PWC is also subject to economic regulation by the AER for its Darwin-Katherine, Alice Springs, and Tennant Creek networks. As part of the AER's annual RIN process, network entities are required to report on the following telephone performance indicators:

- number of calls to a call centre fault line
- number of calls answered within 30 seconds
- average waiting time before a call is answered
- percentage of calls abandoned.

In its most recent RIN submission (in relation to 2023-24), PWC reported against three of these AER indicators: the number of calls to a call centre fault line, the number of calls answered within 30 seconds, and the percentage of calls abandoned.

The Commission acknowledges that there is some overlap between the Code and AER reporting requirements for telephone responsiveness performance indicators.

In addition, a number of challenges and relevant issues have arisen over recent years:

- there have been difficulties in PWC reporting a single overall figure for phone answering-related performance indicators, due to differences in how calls during business and non-business hours are handled and recorded. As a result, two separate figures have been reported
- historically, data for non-business hours has lacked completeness, particularly in relation to average wait times and calls answered within 30 seconds. However, this improved in 2023-24 with more comprehensive reporting for both indicators
- PWC noted in its 2023-24 report to the Commission that it had implemented a new system for Customer Experience and Operations from 1 September 2022 and for PWC System Control (who manages non-business hours calls) from 31 July 2023. According to PWC, "this system has enhanced reporting and analytics capabilities, which should make [its] reporting processes more efficient and transparent compared to previous years"
- despite these improvements, some data reported to the Commission in previous years has appeared intuitively incorrect, with notable swings in values, particularly for average call wait times and calls answered within 30 seconds, leading to Commission concerns about the reliability of PWC's reporting.

Submissions

In its submission to the Commission's Consultation Paper, PWC pointed out challenges related to phone answering performance indicators, noting that as a multi-utility provider, categorising calls and meeting performance metrics can be complex. PWC suggested clarifying the indicators so that the measurement triggers when a customer is placed in the appropriate queue for their query.

Commission's position and reasons

The Commission acknowledges the valid concern raised by PWC in its submission regarding the interpretation and application of the telephone responsiveness performance indicators under the Code. Now that the issue has been formally raised and considered, the Commission considers it must take action to address it, as the current ambiguity undermines the value and integrity of the performance data reported and the Commission's associated public power system performance reporting.

The Commission has considered two primary options to resolve the issue.

Option one is to clarify the definition of call measurement. This approach would involve amending the Code to reflect PWC's suggestion that only calls placed in the appropriate queue for a specific query should be counted. While this clarification may improve accuracy and better reflect the customer experience, it would likely introduce bespoke reporting obligations for PWC that are not aligned with national benchmarks. As the Commission has not verified how other multi-utility providers report similar indicators under the AER framework, there is a risk of reducing comparability. Additionally, while PWC has suggested this change and the Commission assumes it is achievable without unreasonable cost, it has not been confirmed.

Option two is to remove the phone answering indicators from the Code, noting PWC is already required to report similar, if not identical, performance data to the AER under its annual RIN obligations. These indicators are publicly reported and subject to oversight by another independent regulator, ensuring that transparency and accountability are not diminished.

On balance, the Commission considers option 2 most appropriate given the current duplication of effort, lack of clear value-add from the Code reporting, and the overlap with the AER's reporting framework. As such, the Commission proposes to amend the Code to remove the requirement for network entities to report on phone answering performance indicators. This will reduce regulatory burden without compromising transparency and accountability of PWC's phone answering performance as it relates to its networks business.

Proposal to implement

The Commission proposes to amend the Code to remove the requirement for network entities to report on phone answering performance indicators.

Proposed amendments:

Schedule 3: Network services performance indicators

Table 4: Network customer service performance indicators

Performance Indicator	Report	Segmentation
Connections	Yes	*Region*
~~Phone Answering~~	~~Yes~~	~~NT~~
Network *Complaints*	Yes	*Region*

S.3.6.3 Not used.~~S.3.6.3 Phone answering: The performance indicators are:~~

~~(a) the average time taken to answer the phone:~~

~~(b) the percentage and total number of calls not answered within 30 seconds of caller asking to talk to a person; and~~

(c) ~~the percentage and total number of calls abandoned.~~

S.3.6.4 Not used.~~For further detailed information refer to the AER's Distribution STPIS requirements, as updated from time to time.~~

~~[Example: Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to calls to payment lines and automated interactive services and calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.~~

~~Note: Being placed in a queuing system (automated or otherwise) does not constitute a response.]~~

9 | Administrative and minor improvements

Background

In its Consultation Paper, the Commission advised stakeholders that it had identified several administrative and minor changes to enhance the clarity and operation of the Code. These changes include correcting typographical errors, clarifying ambiguous language, and updating outdated references.

While these amendments are considered non-substantive in nature, the Commission considers that they will improve the usability of the Code and facilitate better compliance and understanding among stakeholders.

The Commission invited stakeholders to provide feedback on any additional administrative or minor improvements they had identified. Specifically, the Consultation Paper included the following question:

> "Are there any administrative or minor improvements to the EIP Code that stakeholders have identified and would like to bring to the Commission's attention?"

Submissions

No stakeholders raised additional administrative or minor improvements in response to the Consultation Paper, beyond those matters already raised and addressed separately in other chapters of this Draft Decision.

Commission's position and reasons

In the absence of any additional matters raised through submissions, the Commission proposes to amend the Code to incorporate administrative and minor improvements it has identified during the review process.

While minor in nature, the Commission considers they will enhance the clarity and accuracy of the Code without altering its substantive obligations.

These changes are included in the draft amended Code to provide transparency and assist stakeholders in identifying the amendments.

Proposal to implement

The Commission proposes to amend the Code to incorporate administrative and minor improvements it has identified during the review process.

10 | Transitional arrangements

Background

Transitional arrangements are often included when regulatory instruments are amended, or new obligations are introduced. They are intended to provide regulated entities with sufficient time to understand and implement changes and help ensure an orderly and fair transition from one regulatory framework to another.

While the Commission did not specifically raise transitional arrangements in its Consultation Paper, it recognises that they are an important consideration in any regulatory reform or change process. Transitional provisions can assist stakeholders in aligning their systems, processes and reporting practices with new or revised requirements, and may help reduce the risk of non-compliance or unintended consequences during the initial implementation phase.

Relevantly, to support the implementation of version 2 of the Code following its previous review, the Commission issued a direction on 8 June 2023 under clause 1.6 of the Code (Electricity Industry Performance Code – Direction June 2023 (transitional matters)). This direction provided transitional arrangements to clarify the reporting and audit requirements applicable for the 2022–23 financial year, including which version of the Code applied for different reporting entities and how compliance audits were to be undertaken during the transition period.

Submissions

No submissions directly addressed transitional arrangements, noting that the matter was not raised in the Commission's Consultation Paper. However, some stakeholder submissions, particularly Jacana, did refer to the importance of having sufficient time to implement changes, and suggested the possibility of a phased approach to minimise implementation risks.

Commission's position and reasons

The Commission acknowledges the importance of transitional arrangements when regulatory obligations are substantively amended or introduced for the first time. In this case, however, the Commission considers that the draft amendments proposed in this Draft Decision do not warrant formal transitional arrangements.

The majority of the proposed changes either remove existing obligations, maintain current reporting requirements, or formalise and clarify current practices or interpretations. In these instances, the Commission notes that relevant licensees have already demonstrated their ability to comply, and no material implementation risk is anticipated.

Accordingly, the Commission proposes not to amend the Code to include transitional arrangements at this time. Should any material implementation concerns arise following publication of the Draft or Final Decisions, the Commission remains open to engaging with licensees to ensure a practical and reasonable approach to compliance.

Further, given that the transitional direction issued by the Commission on 8 June 2023 related specifically to the implementation of version 2 of the Code for the 2022–23 reporting period, and its purpose has now been served, the Commission considers the direction is no longer required. The Commission therefore proposes to revoke the 8 June 2023 direction at the same time the updated Code comes into effect. This will ensure redundant instruments are removed.

Proposal to implement

The Commission proposes not to amend the Code to include transitional arrangements.

The Commission proposes to revoke the Electricity Industry Performance Code – Direction June 2023 (transitional matters), which it issued on 8 June 2023, effective the date the amended Code comes into effect.