DRAFT STANDARDS OF SERVICE CODE

CONSULTATION PAPER

May 2012

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GLOSSARY OF TERMS

Term	Definition
2.5 Beta Method	Statistical method developed by the IEEE to identify events that are outside the reasonable control of the network service provider. The 2.5 beta method is used to adjust network reliability performance data for both reporting and target setting purposes.
Act	*Utilities Commission Act*
AER	Australian Energy Regulator.
Average outage duration (minutes)	The cumulative summation of the outage duration time for the period, divided by the number of connection point outage events during the period.
CAIDI	Customer Average Interruption Duration Index. The average duration of each supply interruption per customer who experienced a supply interruption.
DNSP	Distribution network service provider.
ESS	Electricity Standards of Service.
IEEE	US Institute of Electrical and Electronics Engineers.
GSL Code	Guaranteed Service Levels Code effective from 1 January 2012, sets out a scheme by which the network service provider makes payments to customers when service performance is outside a defined threshold.
MAIFI	Momentary Average Interruption Frequency. The average number of customer interruptions of one minute or less per customer per year.
MW	Megawatt
NEM	National Energy Market.
Power systems	Refers to Darwin-Katherine power system, Tennant Creek power system, and Alice Springs power system.
PWC	Power and Water Corporation.
Region	Regional categories include Darwin, Katherine, Tennant Creek and Alice Springs.
Regulatory bargain	A regulator’s assessment of the optimum balance between price and service levels.
SAIDI	System Average Interruption Duration Index. The average number of minutes that a customer is without supply in a given year.
SAIFI	System Average Interruption Frequency Index. The average number of times a customer’s supply is interrupted in a given year.
TNSP	Transmission network service provider.

CHAPTER 1

Executive Summary

1.1 The Utilities Commission of the Northern Territory (the Commission) proposes to revoke the existing Electricity Standards of Service Code (ESS Code) and make a new Standards of Service Code (proposed Code).

1.2 The objectives of the proposed Code include:

- establishing standards of service and performance measures for retail services, network services, and generation services; and
- promoting appropriate improvement of standards of service in the electricity supply industry in the Northern Territory.

1.3 The proposed Code will apply to the regulated network, generation, and all retail service providers licensed in the Territory.

1.4 Under the *Utilities Commission Act* (the Act), the Commission has the power to make codes and rules if authorised to do so under a relevant industry regulation Act or by regulations under the Act.

1.5 The Utilities Commission Regulations allow the Commission to make a code relating to standards of service by licensed entities in the electricity supply industry. Without limitation, the code may deal with:

- standards of service by licensed entities in the electricity supply industry; and
- performance measures for standards of service by licensed entities in the electricity supply industry.[1]

1.6 As part of the code-making process, the Act requires the Commission to (among other things):

- consult with the Minister (the Treasurer)[2] and representative bodies and participants in the regulated industry;
- give notice of the making, variation or revocation of a code to the Minister, and to each licensed entity to which the code applies; and
- ensure copies of the code are made available for inspection for the public.[3]

1.7 In accordance with the Act, this Consultation Paper advises the Minister, representative bodies and participants in the electricity supply industry, and seeks comments on the

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[1] Section 24, Utilities Commission Act, Reg 2B Utilities Commission Regulations.

[2] Administrative Arrangements Order as at 31 January 2012.

[3] Section 24 Utilities Commission Act.

Commission's intention to revoke the existing ESS Code and establish the proposed Code.

1.8 The Commission seeks submissions on the proposed Code by 8 June 2012. The Commission welcomes submissions on any matter relevant to the improvement of standards of service in the electricity supply industry in the Territory.

1.9 Late submissions will be considered at the discretion of the Commission.

1.10 The timetable for the consultation of the proposed Code is set out in table 1.1.

Table 1.1: Proposed timetable

Action	Timeframe
Release of the proposed Code for consultation	15 May 2012
Submissions due	8 June 2012
Release of final Code and Statement of Reasons, and publication of Notice in the NT Government Gazette	27 June 2012
Implementation of the Code	1 July 2012

1.11 This consultation should be read in conjunction with the proposed Code.

1.12 In November 2010, the Commission released its final report on the Review of Electricity Standards of Service for the Northern Territory. The review discussed the adequacy of the current standards of service framework, and explored potential improvements to ensure standards of service are appropriate within the context of the Territory.

1.13 The review was conducted in accordance with the terms of reference provided by the Treasurer in November 2009 and is part of the Government's Priority Work Program.[4]

1.14 The Commission's review provides additional background information on the proposed Code. [5] A copy of the final report is available on the Commission's website (www.utilicom.nt.gov.au).

Background

1.15 The Commission is an independent statutory authority responsible for the economic regulation of the electricity supply industry, which is governed by the Act, the *Electricity Reform Act*, the *Electricity Networks (Third Party Access) Act*, and associated legislation.

1.16 Under the Act, the Commission has the power to make codes and rules if authorised to do so under a relevant industry regulation Act or by regulations under the Act. These relevant industry regulation Acts include the *Electricity Reform Act*, and the *Electricity Networks (Third Party Access) Act* among others.

[4] Utilities Commission, November 2010, Review of Electricity Standards of Service for the Northern Territory – Final Report.

[5] Ibid.

1.17 On 21 December 2005, the Commission released the ESS Code. The ESS Code was made pursuant to the Act, and in accordance with the Commission's powers to do anything necessary or convenient to be done for or in connection with or incidental to the performance of the Commission's functions under:

- section 92 (1) of the *Electricity Reform Act*, which requires the Commission to make provisions imposing minimum standards of service and safety for non-contestable customers**;**
- section 10 of the *Electricity Networks (Third Party Access) Act*; and
- section 6 of the Act.

1.18 In accordance with the introduction of full-retail contestability, the last tranche of non-contestable customers became contestable on 1 April 2010. This means that the Commission's functions in relation to electricity standards of service under section 92 (1) of the *Electricity Reform Act* have become redundant, and the existing ESS Code is partially ineffective.

1.19 The Act prescribes a code-making process for the creation, variation, and revocation of industry codes. Underlying this process is a requirement for the Commission to keep the contents and operation of codes under review to ensure their continued relevance and effectiveness.[6] As a result, the Commission has decided to revoke the existing ESS Code and develop a new Standards of Service Code in response to recent regulatory changes and the Government's Priority Work Program.

1.20 In making a code, the Commission must have regard to the need:

- to promote competitive and fair market conduct;
- to prevent the misuse of monopoly or market power;
- to facilitate entry into relevant markets;
- to promote economic efficiency;
- to ensure consumers benefit from competition and efficiency;
- to protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries;
- to facilitate maintenance of the financial viability of regulated industries; and
- to ensure an appropriate rate of return on regulated infrastructure assets.[7]

Key Aspects of the Proposed Code

1.21 The proposed Code will apply to all regulated electricity entities providing generation, network and retail services, excluding Independent Power Producers.

1.22 The objectives of the proposed Code are to establish performance target standards in the electricity supply industry, monitor and enforce compliance with standards of

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[6] Section 24 (9), *Utilities Commission Act.*

[7] Ibid, Section 6 (2).

service, and require electricity entities to have systems in place which allow regular reporting of actual performance.

1.23 Table 1.2 presents a summary of the proposed performance indicators for reporting and setting target standards, and the segmentation of each performance indicator.

Table 1.2: Performance indicators for generation, network and retail service providers

Electricity entity	**Performance indicator**	**Report**	**Segmentation**	**Target**	**Segmentation**
Generation	Availability factor	Yes	Power station	No	
	Unplanned availability factor	Yes	Power station	No	
	Equivalent availability factor	Yes	Power station	No	
	Forced outage factor	Yes	Power station	No	
	SAIDI	Yes	Power system; Region	No	
	SAIFI	Yes	Power system; Region	No	
Transmission network	Average circuit outage duration (unadjusted)	Yes	Power system	No	
	Average circuit outage duration (adjusted)	Yes	Power system	Yes	Transmission network
	Frequency of circuit outages (unadjusted)	Yes	Power system	No	
	Frequency of circuit outages (adjusted)	Yes	Power system	Yes	Transmission network
	Frequency of transformer outage duration (unadjusted)	Yes	Power system	No	
	Frequency of transformer outage duration (adjusted)	Yes	Power system	No	Transmission network
	Frequency of transformer outages (unadjusted)	Yes	Power system	No	
	Frequency of transformer outages (adjusted)	Yes	Power system	Yes	Transmission network
	SAIDI	Yes	Power system	No	
	SAIFI	Yes	Power system	No	
Distribution network	SAIDI (unadjusted)	Yes	Power system; Region; Feeder category	No	
	SAIDI (adjusted)	Yes	Power system; Region; Feeder category	Yes	Feeder category
	SAIFI (unadjusted)	Yes	Power system; Region; Feeder category	No	
	SAIFI (adjusted)	Yes	Power system; Region; Feeder category	Yes	Feeder category

Electricity entity	Performance indicator	Report	Segmentation	Target	Segmentation
	Feeder performance	Yes	Individual feeder	No	
Network	Connections	Yes	CBD/Urban; Rural	No	
	Phone answering	Yes	NT	No	
	Network complaints	Yes	Power system; Region	No	
	Written enquiries	Yes	Power system; Region	No	
Retail	Phone answering	Yes	NT	No	
	Complaints	Yes	Region	No	
	Hardship	Yes	Region	No	
	Written enquiries	Yes	Region	No	

CHAPTER 2

Standards of Service in the Northern Territory

Background

2.1 The electricity supply industry in the Northern Territory is regulated through the *Electricity Reform Act*, the *Electricity Networks (Third Party Access) Act*, the *Utilities Commission Act,* and associated legislation. This regulatory framework was introduced on 1 April 2000.

2.2 The regulatory framework is primarily focused on regulating the activities of electricity industry participants and customers in the Darwin-Katherine, Alice Springs, and Tennant Creek power systems – referred to as the market systems. Key elements of the framework include:

- third party access to the Darwin-Katherine, Alice Springs, and Tennant Creek electricity networks (owned and operated by the Power and Water Corporation (PWC));
- all customers became contestable from 1 April 2010; and
- the Commission as an independent economic regulator, responsible for regulating monopoly electricity services, licensing market participants, and monitoring and enforcing compliance with regulatory standards for market conduct and service performance.

2.3 PWC is the main electricity business in the market systems, generating the majority of electricity used, operating the electricity networks and supplying retail services.

2.4 PWC is a vertically integrated Territory Government owned corporation with generation, network and retail business units operating as separate businesses. The commercial relationship and transactions between each unit is subject to oversight and regulation by the Commission. PWC is also subject to oversight by a shareholding Minister and portfolio Minister under the *Government Owned Corporations Act.*

2.5 In the three market systems, PWC has been the only electricity retailer in recent years, supplying electricity to about 76,600 customers as at 30 June 2011[8].

2.6 In February 2011, the Commission issued a retail electricity licence to QEnergy Limited in February 2011.

2.7 PWC is the Territory's main electricity generator, with about 91 per cent of generation capacity in the market systems. There are three other generators producing electricity in the Darwin-Katherine and Alice Springs systems. However, these businesses

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[8] Power and Water Corporation Annual Report 2010-11.

generate electricity under contract for PWC rather than selling directly to an electricity retailer or to customers, and PWC provides the fuel used for electricity generation.

2.8 PWC owns and operates the Darwin-Katherine, Alice Springs, and Tennant Creek electricity networks, which comprise 709 km of high voltage transmission lines and 7,650 km of distribution lines.[9] The networks are not interconnected, and are separated by long distances.

2.9 PWC is responsible for system control.[10] The System Controller is a statutory position responsible for monitoring and controlling the operation of the power system with a view to ensuring that the system operates reliably, safely and securely in accordance with a technical code prepared by the System Controller and approved by the Commission.

2.10 PWC is the major electricity supplier in regional and remote parts of the Territory, and is the water and sewerage service provider throughout the Territory.

2.11 Electricity, water and sewerage services supply in regional and remote centres of the Territory is generally managed through a contract for service model, with supply arrangements agreed between the service purchaser (most often the Territory Government) and a service provider (in most cases, PWC or a PWC subsidiary). These systems include the 72 communities and 82 outstations where essential services are provided through the Territory Government Indigenous Essential Services program; three mining townships, where electricity is supplied by the associated mining company; and eight remote townships.[11]

Standards of Service Schemes in other jurisdictions

2.12 Electricity standards of service in Australia are regulated by governments or industry regulators to ensure that customers receive reasonable standards of reliability and quality of supply, and customer service levels. Average and minimum service performance targets are defined for electricity transmission and distribution network service providers (TNSP and DNSP), and the electricity generation and retail sectors in most jurisdictions.

2.13 The most common approaches for regulating standards of service in Australia are:

- monitoring or information disclosure requirements, with organisations required to publish information about service performance against a number of reliability, quality, and customer service performance measures or benchmarks;
- definition of minimum service standards, with minimum standards of performance mandated in legislation;

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9 Power and Water Annual Report 2010-11.

10 The System Controller is located in the PWC networks business unit, and is responsible for monitoring and controlling the operation of the power system to ensure the system operates reliably, safely and securely in accordance with the System Control Technical Code.

11 The three mining townships are Nhulunbuy, Alyangula and Jabiru. The eight remote townships are Timber Creek, Borroloola, Daly Waters, Elliot, Newcastle Waters, Kings Canyon, Yulara and Ti-Tree.

- guaranteed service level (GSL) schemes, with payments made to customers when service performance is outside a defined threshold;
- financial incentive schemes, with financial incentives established through a price regulation framework to encourage defined performance outcomes; and
- contractual service standards, whereby organisations agree with a customer through the contract negotiation process to achieve a particular service level.[12]

2.14 The key factor in establishing standards of service arrangements is identifying acceptable levels for service performance, which involves understanding customer preferences, and customers' willingness to pay more or less for improved or reduced levels of service.[13]

2.15 In determining acceptable levels of service performance, local circumstances, such as prevailing weather, number and location of customers, size of the network and other local conditions are considered. The variation in the costs of providing reliable supply in the range of local circumstances means that standards of service may differ between jurisdictions, and between regions within jurisdictions.

2.16 Standards of service frameworks most commonly apply to DNSPs and TNSPs. As natural monopolies, DNSPs and TNSPs have less incentive to strive to provide improved, or different, levels of service as customers generally cannot move to an alternative provider. The standards of service achieved by DNSPs and TNSPs are a key consideration of regulators in undertaking network price regulation, and identifying the optimum balance between price and service levels.

2.17 Additionally, the performance of the equipment an organisation uses to provide a service can influence standards of service. For example, the safe, secure and reliable operation of a power system requires that electricity generators design and operate their equipment so as to meet specified technical and performance parameters. As such, the technical and service performance of generators is regulated and managed to avoid the adverse reliability (for example outages) or quality (for example power surges) outcomes for customers that could result from operating outside these parameters.[14]

2.18 Finally, electricity retailers have been required to report on aspects of service performance in most Australian jurisdictions, with the main objective of providing information to household customers on access to electricity services, and customer satisfaction with the quality of service. A focus of examining retailers' standards of service, and the monitoring of retail service performance, is to bring transparency and

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[12] Energy Networks Association, March 2007, Service Standard Regulatory Policy & National Reliability Reporting Framework, page 8.

[13] Ibid, pages 7-8.

[14] The operating parameters for the Territory power systems are managed by PWC Networks (as network operator) and System Control, and documented in the Network Connection Technical Code and System Control Technical Code.

accountability to how retailers are treating their customers, and particularly vulnerable customers.[15]

Measures of service performance

2.19 Measures of service performance used in Australia typically include:[16]

- reliability of supply, which identifies the ability of a service provider to maintain the availability of the service in question, typically being measured by how often and for how long customers go without the service during a given period;
- quality of supply, which identifies the specification of supply, and involves measures such as voltage levels, frequency and harmonic content; and
- customer service, which identifies how the service provider interacts with individual customers and involves measures of customer complaints, and service provision (for example attending appointments, billing).

Reliability of supply

2.20 Transmission network reliability measures are derived from the availability of transmission network related equipment. Measures of transmission network reliability used in Australia include[17]:

- transmission circuit availability – the percentage of total hours that transmission circuits are available (i.e critical circuits, non-critical circuits, transmission lines, transmission transformers and transmission reactive), and takes into account periods of demand (i.e. peak periods and intermediate periods);
- average outage duration – the average number of minutes that transmission lines and transmission transformers/plant are unavailable each year due to all faults on the transmission system (whether or not loss of supply occurs);
- frequency of 'off-supply' events – the number of significant events on the transmission system each year;
- inter-regional constraints – the number of hours that binding constraints exist on any part of the interconnected transmission system within a region each year (excluding interconnectors); and
- intra-regional constraints – the number of hours that binding constraints exist on an inter-regional interconnector each year.

2.21 Distribution network reliability measures are derived from the duration and number of power outages experienced by network customers. Measures of network reliability used in the Territory and Australia include:[18]

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[15] For example, refer Essential Services Commission of Victoria, December 2009, Energy Retailers Comparative Performance Report – Customer Service 2008-09.

[16] See discussion in Utilities Commission, August 2004, Developing a Standards-of-Service Framework, page 1.

[17] Australian Competition and Consumer Commission, 12 November 2003, Statement of principles for the regulation of transmission revenues, Service standards guidelines, page 5.

- System Average Interruption Duration Index (SAIDI) – the average number of minutes that a customer is without supply each year. SAIDI is calculated as the sum of the duration of each sustained customer interruption (in minutes), divided by the total number of customers. SAIDI excludes momentary interruptions (one minute or less);
- System Average Interruption Frequency Index (SAIFI) –the average number of times a customer's supply is interrupted each year. SAIFI is calculated as the sum of each sustained customer interruption, divided by the total number of customers. SAIFI excludes momentary interruptions;
- Customer Average Interruption Duration Index (CAIDI) – the average duration of each supply interruption per customer. CAIDI is calculated as the sum of the duration of each sustained customer interruption (in minutes) divided by the total number of sustained customer interruptions (SAIDI divided by SAIFI). CAIDI excludes momentary interruptions; and
- Momentary Average Interruption Frequency Index (MAIFI) – the average number of momentary interruptions per customer per year. MAIFI is calculated as the total number of customer interruptions of one minute or less, divided by the total number of customers.

2.22 Supply interruptions can be planned or unplanned. For example, a planned power outage would occur when a DNSP de-energises a substation or feeder to undertake routine maintenance, and an unplanned outage would occur when there is an equipment failure, resulting in loss of supply to customers.

2.23 Jurisdictions can adopt different approaches to treating planned and unplanned outages when measuring and reporting on reliability performance, for example by excluding planned interruptions or excluding extreme unplanned interruptions caused by infrequent and catastrophic natural events like cyclones.

Quality of supply

2.24 Quality of supply refers to the electrical specification of supply, and is measured by such indicators as voltage levels, frequency and harmonic content. Poor quality of supply shows up as dimming, flickering or overly bright lights, and results in damage to electrical appliances. Quality of supply is a particular concern where customers use voltage sensitive electrical appliances and equipment (for example computers and electronically controlled systems).

2.25 Quality of supply is difficult to measure at customer premises. Although the quality of supply is the subject of fairly detailed regulation specified in various Australian Standards, there are no commonly used measures for monitoring and reporting the response to, and prevention of, quality problems. A common, albeit imprecise approach to monitoring quality, is to rely on customer feedback, or complaints, about voltage problems.

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[18] Refer Utilities Regulators Forum, March 2002, National Regulatory Reporting for Electricity Distribution and Retailing Businesses Discussion Paper, page 6, table 1.

2.26 In the longer term, policies being implemented or considered by governments across Australia to mandate the installation of ‘smart’ meters for households may facilitate improved measurement of quality of supply outcomes.

Customer service

2.27 Retailers and DNSPs provide services directly to customers, whether through billing for energy consumed or through responsibility for connections or distribution reliability. Most jurisdictions monitor standards of customer service to bring transparency and accountability to the level of service performance. A particular focus on monitoring of customer service is the treatment of vulnerable customers.

2.28 Measures of customer service by retailers and DNSPs commonly monitored in Australia include:

- the number of connections, disconnections and reconnections, focusing on customers disconnected due to non-payment of bills, and reconnections in the same name;
- call centre responsiveness, with reporting of the time taken for customer telephone calls to be answered, the length of time the callers have to wait, and use of automated interactive services;
- whether a DNSP keeps appointments made with customers;
- the time taken by a DNSP to repair a faulty street light once notified;
- advice of planned interruptions – adequate planning, assessment of impact of planned interruptions on customers, and communication to customers; and
- the number and type of customer complaints.

Northern Territory Standards of Service Framework

2.29 Service performance in the Territory has been monitored by the Commission since January 2006, with the introduction of the existing ESS Code. The existing ESS Code establishes a performance reporting framework, and minimum standards (or target standards) for specified outcomes or services provided by PWC Generation, PWC Networks and PWC Retail (non-contestable only) in Darwin-Katherine, Alice Springs and Tennant Creek systems. These minimum standards set targets that must be met by service providers.

2.30 The existing ESS Code establishes 46 performance indicators, and defines a process for establishing target standards for 45 of these indicators. The indicators focus on:

- network and generation reliability, with data on the frequency and duration of outages experienced on average by customers in a year;
- feeder performance, with data on poorly performing urban and rural feeders;
- quality of supply complaints;
- time taken to connect properties to the network;
- the response to telephone calls; and
- customer service complaints, with categories including billing service level.

2.31 The Commission requires service providers to submit a report on actual performance for the financial year. The Commission uses this report to prepare an assessment on overall performance against the target standards. Performance data is available for 1999-00 to 2010-11 on the Commission's website.

2.32 The levels of target standards for each performance indicator set through the existing ESS Code are based on service performance achieved in 1999-00. This approach to setting the standards is prescribed in legislation.[19]

2.33 The service performance of PWC has come under greater scrutiny in recent years due to a series of major outages affecting a large number of customers. The outages in September and October 2008 in the Casuarina zone substation service area caused extensive community disruption, with the most significant event causing more than 11,000 customers to lose power for up to 14 hours. The Darwin-Katherine system black incident on 30 January 2010 caused all customers served by the Darwin-Katherine system to lose power for up to 10 hours (affecting more than 58,000 customers, or 78 per cent of all customers in the market system). In response to this incident, PWC implemented an extensive capital and maintenance investment program which was intended to avoid future deterioration in current levels of generation and network service performance, and meet future demand.

2.34 The Commission published its final reports on the Review of Options for Implementation of a Customer Service Incentive Scheme for the Northern Territory in August 2010, and the Review of Electricity Standards of Service for the Northern Territory in December 2010.

2.35 In December 2011, the Commission released the Guaranteed Service Level (GSL) Code. The GSL Code prescribes requirements for payments to be made to customers affected by a specific instance of poor service performance.

2.36 To minimise the effects on customers, and to complement PWC's capital maintenance investment program and the Commission's GSL Code, the Commission considers it appropriate to develop a new Standards of Service Code, which should incorporate a more robust and comprehensive Standards of Service Scheme in order to prevent similar wide-spread and systemic outages in the future.

Objectives of Standards of Service Scheme

2.37 The purpose of a standards of service scheme is to provide a process for defining target standards of service, establish reliability of supply and customer service measures, establish a process for monitoring of performance outcomes (including a reporting framework), and to promote improvement in service performance.

2.38 The standard of service scheme should also complement the network price determination under the *Electricity Network (Third Party Access) Act* as the Commission sets prices to recover the cost of providing network services at standards expected by customers.

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[19] Section 92, *Electricity Reform Act.*

2.39 The proposed Code aims to focus on reliability of supply and customer service measures. The Commission considers that quality of supply measures may not be feasible at least at this stage given the apparent need for new equipment (i.e. smart meters) and reporting systems. However, the Commission believes that quality of supply complaints should be reported as part of the customer service measures.

Purpose of Target Standards

2.40 The standards of service established under the proposed Code are referred to as target standards. The target standards are distinct from the standards established under the Commission's GSL Scheme. The standards under the GSL Scheme are intended to set a threshold to recognise poor service performance to affected customers in the form of a GSL payment.

2.41 Target standards under the proposed Code are intended to reflect customer preferences and willingness to pay for services, must be achieved on a best endeavours basis, and focus on the on-going assessment of reliability of supply in the power system.

2.42 Target standards should be set for transmission and distribution network services consistent with the approaches taken in other Australian jurisdictions. The reliability measures for network services are discussed further in Chapter 3 of this Consultation Paper.

2.43 Despite not having a target standard, reliability measures for generation services, and customer service measures associated with network and retail services are still required to be reported as part of the on-going assessment of reliability of supply in the power system.

CHAPTER 3

Proposed Code

Objectives and purpose of the proposed Code

3.1 The proposed Code broadly follows the Commission's recommendations in the Review of Electricity Standards of Service for the Northern Territory

3.2 The objectives of the proposed Code are to:

- establish standards of service and performance measures in the electricity supply industry;
- develop, monitor, and enforce compliance with and promote improvement in standards of service by electricity entities in the electricity supply industry; and
- require electricity entities to have adequate systems, processes and procedures in place which allow for regular reporting of actual performance to assess compliance with and further the objectives of the Code.

3.3 The proposed Code prescribes the following matters:

- process for adding to or amending the Code, and the creation of guidelines and directions;
- process for establishing target standards for distribution and transmission network reliability measures;
- performance indicators for generation services, network services, and retail services with and without a target standard;
- reporting of performance indicators with and without a target standard;
- mandatory and discretionary obligations on the Commission; and
- mandatory obligations on electricity entities to which the Code will apply.

Provisions of the proposed Code

3.4 The proposed Code is divided into six sections, and six Schedules:

- Section 1 – Introduction
- Section 2 – Adding to or amending this Code
- Section 3 – Target standards
- Section 4 – Reporting
- Section 5 – Data quality
- Section 6 – Data Segmentation
- Schedule 1 – Generation performance indicators

- Schedule 2 – Network service performances indicators
- Schedule 3 – Customer service performance indicators
- Schedule 4 – Definitions and interpretation
- Schedule 5 – Transitional provisions
- Schedule 6 – Responsibility statement

Section 1 - Introduction

3.5 Section 1 of the proposed Code specifies the authority under which this Code will be made, the Commission's considerations in making the Code, the Code's commencement date, rules of interpretation, application, and objectives.

3.6 Section 1 of the proposed Code also includes a process for the creation of guidelines for the administration of the Code.

3.7 The Commission may publish guidelines for the administration of the Code. The Commission has legislative authority to publish guidelines under section 7 of the Act. Matters of administration are wide ranging and may include matters of interpretation or process, manner and form[20], or anything necessary or convenient to be done for or in connection with or incidental to the Commission's functions under this Code.[21]

3.8 The proposed Code also empowers the Commission to issue a direction concerning any matter in relation to the Code. Without limitation, the direction may require electricity entities to segment and report the performance indicators in additional ways that the Commission considers appropriate.

3.9 This provision is flexible and allows for possible short-term changes in the regulatory environment (e.g. the Commission may require the performance indicators to be reported in different ways to assess any quality of supply issues in the power system). The provision does not give the Commission power to add or replace performance indicators in the relevant schedules. Substantive amendments to the Code (e.g. adding performance indicators) would require the Commission to amend the Code in accordance with section 24 of the Act.

Section 2 – Adding to or amending the Code

3.10 Section 2 of the proposed Code outlines the process for adding to or amending the Code. This section should be read in conjunction with section 24 of the Act, which prescribes the Commission's obligations with respect to making, varying, or revoking a Code.

3.11 The proposed Code requires a variation or revocation to take effect at least 20 business days after a notice is given to the relevant electricity entity and published

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[20] The Commission released a Statement of Approach on Compliance on 31 January 2012, outlining the considerations in prescribing manner and form requirements for compliance monitoring and reporting purposes.

[21] Section 6 (3), *Utilities Commission Act*.

in the Gazette, or such later date as the Commission specifies by notice in the Gazette.[22]

Section 3 – Target Standards

3.12 Section 3 of the proposed Code sets out the process and obligations for establishing, amending, and meeting the approved target standards, and applies only to network service providers.

Alignment between the target standard setting process and the network price determination

3.13 The proposed Code requires the Commission to set target standards prior to the start of each regulatory control period. The regulatory control period is the five year period defined under the *Electricity Networks (Third Party Access) Act,* which prescribes the requirements with respect to the network price (or revenue) determination. By aligning the network reliability target setting process with the network price determination cycle, the Commission recognises that the network service provider will need to be provided with sufficient revenue to meet its reliability target standards in an efficient manner.

3.14 Clause 68 (b) of the Electricity Networks Access Code[23] stipulates that the Commission will have regard, inter alia, to service standards applicable to the network provider in determining the required network price / revenue cap.

3.15 Clause 3.1.1 of the proposed Code provides that the network provider must no later than the date specified by the Commission (being a date prior to the commencement of the regulatory control period) submit proposed target standards to the Commission for approval.

Setting target standards

3.16 Schedule 2 of the proposed Code specifies the service performance indicators requiring a target. These are discussed in the performance indicator section of this Consultation Paper.

3.17 The proposed target standards must include the network service performance indicators requiring a target as specified in Schedule 2, be segmented in accordance with clause 6, and contain proposed calculations for the target standards that are:

- an average of the data from all the preceding five financial years;
- if the data is not available, an average of comparable and available data from the preceding five financial years; or
- consistent with such other methodology that the Commission considers appropriate.

3.18 The proposed Code requires set target standards to be based on adjusted performance data only, using the IEEE 2.5 beta method[24]. This is intended to remove

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22 See also Section 24 (8) *Utilities Commission Act*.

23 The Electricity Networks (Third Party Access) Code is a schedule of the *Electricity (Third Party Access) Act.*

24 Statistical method developed by the US Institute of Electrical and Electronics Engineers to identify events that are outside the reasonable control of the network service provider. The 2.5 beta method is used to adjust network reliability performance data for both reporting and target setting purposes.

any short term fluctuations beyond the reasonable control of the network provider that do not reflect the true performance of the network. The events excluded from the adjusted performance indicators are contained in clause 6 of the proposed Code, and discussed at paragraph 3.57-63 of this Consultation Paper.

3.19 The Commission considers that an average of the performance data from the preceding five years should provide a reasonable guide to the performance levels expected from a network provider.

3.20 The proposed Code acknowledges that five years of data may not be available in all circumstances and proposes that the target standards be derived from comparable or available data within the preceding five financial years.

3.21 The Commission may also impose a different methodology to calculate the target standards at any time. This may occur in instances where:

- the Commission is not satisfied with the quality of data submitted in the proposed target standards;
- the Commission considers that the proposed target standards do not further the objectives of the Act or the Code;
- the network provider has not submitted the proposed target standards by the due date; or
- the proposed target standard are less than the target standard for the current regulatory control period.

3.22 In developing an alternative methodology for setting target standards, the Commission will be guided by regulatory developments in the National Electricity Market (NEM), and other Australian jurisdictions.

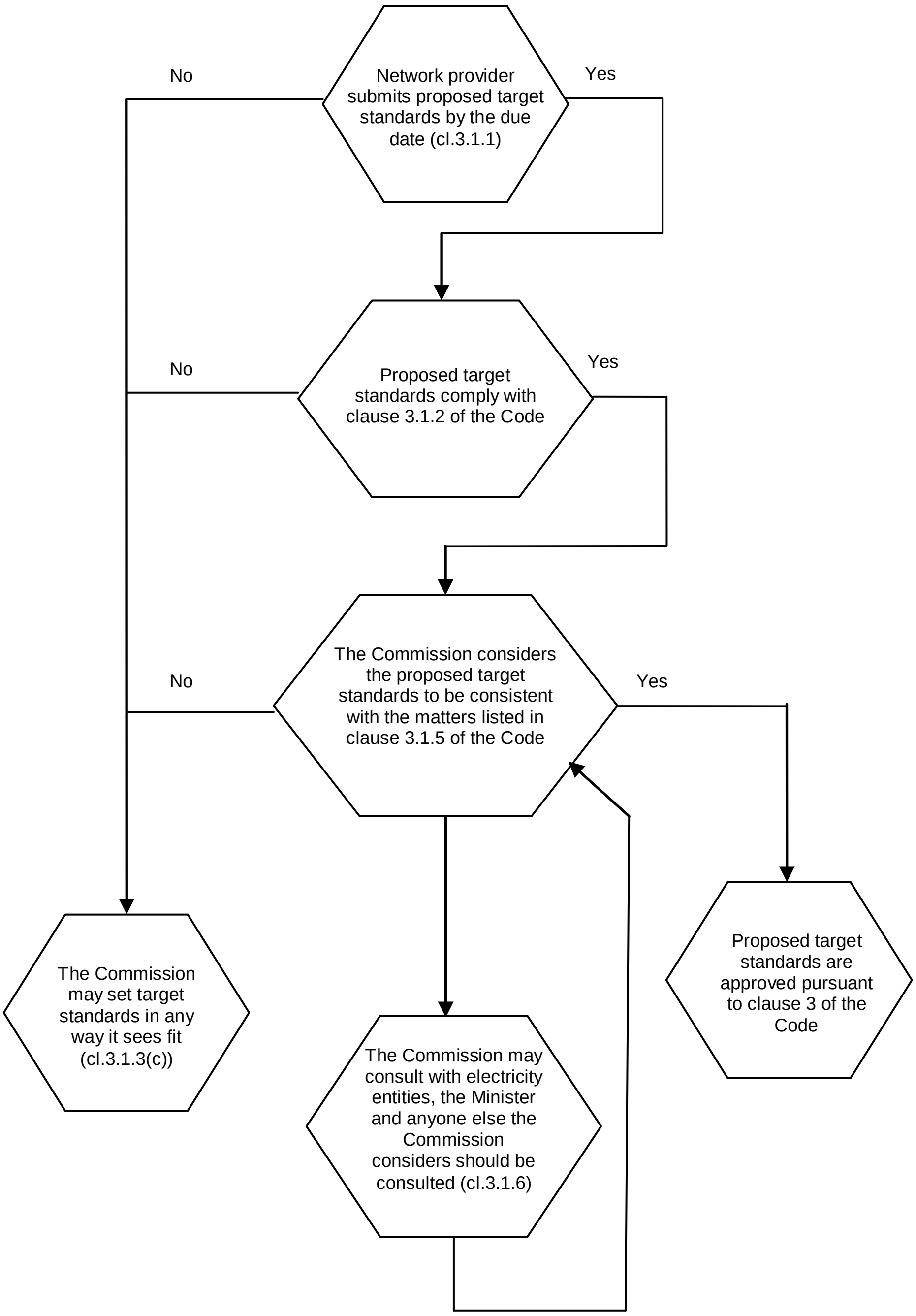
3.23 Should the network provider be aware that it will not be able to submit its proposed target standards to the Commission, the network provider should inform the Commission as soon as possible so that an alternative approach can be considered prior to the start of the network price determination.

3.24 The Commission may issue an information request in connection with the proposed target standards. The information request will assist the Commission in approving target standards prior to the commencement of each regulatory control period. The network provider must comply with an information request as issued by the Commission. The Commission may also consult with other regulated entities, the Minister, or representative bodies or participants as required.

3.25 The Commission will approve standards after having regard to the matters listed in section 6 (2) of the Act, the objectives of the Code, and whether or not the proposed target standards are consistent with good electricity industry practice.

3.26 The Commission will also consider good electricity industry practice as reflected in the standards expected of industry peers in other Australian jurisdictions (including data quality standards, and sound auditable processes for the collection and collation of data).

Figure 1: Schematic of the process for setting target standards



Variation of the target standards

3.27 A network provider may make a request to the Commission to vary the approved target standards at any time. The Commission must consider section 6 (2) of the Act, the objectives of the Code, and whether the proposed variation is consistent with good electricity industry practice.

3.28 In making a request to vary the target standards, the network provider must also state the reasons for the proposed variation, provide sufficient information and supporting documentation for the variation, and ensure that the proposed variation specifically addresses the objectives of the Code and the matters listed in section 6 (2) of the Act. The requirement to address these key considerations reflects the Commission's desire to improve supply standards for the long-term interests of consumers.

3.29 The proposed Code allows the Commission to vary the target standards if they are thought to be contrary to the objectives of the Code. The Commission intends to use this power only in exceptional circumstances.

Best endeavours

3.30 Once the target standards are approved (or varied as the case may be), the network provider must use its best endeavours to meet the target standards in place from time to time. This requirement reflects the approaches in other Australian jurisdictions, and is considered to strike the right balance between promoting service standards in the electricity supply industry, and reducing any perceived regulatory burden on industry participants.

3.31 The proposed Code defines 'best endeavours' as:

> *To act in good faith and use all reasonable efforts, skill and resources.*

3.32 The Commission considers that the best endeavours principle should account for the possibility that a network provider may not be able to meet the target standards at all times. The Commission considers absolute targets to be unworkable as they may result in a disproportionate financial impact on customers and increased regulatory burden on industry participants. The Commission expects that a network provider should be able to achieve a consistent level of service over a financial year based on a historical average.[25]

Interim arrangements

3.33 Schedule 5 of the proposed Code sets out interim arrangements for the interim period, which is the period commencing on the commencement date of the Code up until the end of the current regulatory control period on 30 June 2014. The interim arrangements deal with setting interim target standards during the interim period.

3.34 A network provider will be required to submit proposed interim target standards to the Commission within three months of the commencement date of the Code.

3.35 Under the interim arrangements, the Commission may:

- approve the proposed interim target standards;
- set the target standards in any manner it sees fit; or
- waive any of the requirements under Schedule 5 of the Code.

3.36 The proposed Code recognises that a network provider may not have the comprehensive datasets required to submit robust target standards to the Commission for the interim period. The Commission notes that the network provider has collated at least two years of relevant performance data as part of the Commission's annual publication of the Power System Review.

3.37 The Commission considers that having interim target standards for the interim period will provide incentives on the network provider to develop systems, processes, and procedures to collect data to support its proposed target standards for the 2014-19

[25] Utilities Commission, Review of Electricity Standards of Service for the Northern Territory – Draft Report, August 2010, page 36.

network price determination. It will also ensure that the network provider does not operate without any target standards during the July 2012 – June 2014 period.

Section 4 - Reporting

3.38 Section 4 of the proposed Code sets out the reporting requirements for generators, the network provider, and retailers in the electricity supply industry.

3.39 Section 4 of the proposed Code requires generators, the network provider, and retailers to submit a report on actual performance for the preceding financial year by 1 November each year. The report on actual performance must:

- for generators – include the generation performance indicators for reporting in Schedule 1;
- for the network provider –
  - include the network performance indicators for reporting in Schedule 2; and
  - include details on actual performance against the target standards (which are compiled based on the network performance indicators requiring a target in Schedule 2) as approved from time to time;
- for retailers – include the customer service performance indicators for reporting in Schedule 3;
- be segmented in accordance with clause 6; and
- include an original copy of a responsibility statement.

3.40 The relevant schedules contain the performance indicators, the segmentation of the performance indicators, and the way in which they must be calculated and compiled, including examples (in Schedule 1) to assist the reader.

3.41 If a report on actual performance does not comply with all of the requirements of the relevant schedules (or the approved target standards as the case may be), the Commission may require a new report on actual performance to be submitted containing all the relevant information in accordance with the requirements of the relevant schedules and/or target standards as approved from time to time.

3.42 Schedule 6 of the proposed Code contains a template of the responsibility statement. A completed original copy of the responsibility statement must accompany any report on actual performance submitted to the Commission. The responsibility statement must be signed and dated by the Chief Executive Officer or a responsible senior officer capable of warranting the accuracy of the report provided to the Commission.

3.43 The requirement to provide a responsibility statement is generally consistent with the requirements of the NEM and other Australian jurisdictions.[26]

3.44 The requirement to provide a responsibility statement will assist electricity entities in providing consistent and accurate information to the Commission. It may also encourage the development of internal quality control mechanisms.

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[26] For example, the AER’s Statement of Approach to Retail Law, and the accompanying guidelines.

3.45 The network provider is required to provide a more detailed report on actual performance. Information on actual performance is to be provided for performance indicators for reporting purposes and performance indicators against the target standards as approved from time to time. Segmentation requirements for performance indicators against the target standards may differ.

3.46 In the event that the network provider is unable to meet the target standards for the financial year, the report on actual performance must include a statement:

- of the reasons for any failure to meet the target standards;
- that explains and demonstrates how the electricity entity has used its best endeavours to meet the target standards; and
- on the measures the network provider proposes to take to ensure the target standards will be met in future.

3.47 The above requirements will assist the Commission in monitoring compliance with the Code.

3.48 Section 4 of the proposed Code specifies the obligations on the Commission. On receipt of a report on actual performance, the Commission:

- will publish an assessment of the report;
- may make the report on actual performance publicly available; and
- must ensure that the information made publicly available complies with section 26 of the Act.[27]

3.49 The Commission will publish the report on actual performance as soon as possible. This is consistent with past practice. The Commission may publish an assessment of the report on actual performance in a manner and form specified by the Commission, which may include a separate document, in conjunction with the report on actual performance, or inclusion in another document published by the Commission (e.g. the annual Power System Review).

3.50 The Commission must identify all commercial in-confidence information provided to the Commission during the course of its administration of the Code. The Commission will liaise with the relevant electricity entity prior to the possible publication of sensitive commercial in-confidence information to ensure compliance with the Act.

Section 5 – Data quality

3.51 Section 5 of the proposed Code contains obligations and procedures associated with the collection, collation, and maintenance of data, and the audit of data quality.

3.52 The proposed Code requires generators, the network provider, and retailers to periodically collect and maintain data in connection with the reporting requirements under this Code (including the target standards as the case may be).

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[27] Section 26 of the Act relates to the disclosure of commercial in-confidence information. The Commission cannot publish commercial in-confidence information without the relevant regulated entity's approval.

3.53 The proposed Code sets out the procedure for the appointment of the auditor for data quality purposes. The process requires:

- the Commission to give notice to the relevant electricity entity requiring the appointment of an independent auditor to assess the collection and maintenance of data in accordance with good electricity industry practice;
- the Commission to determine whether the independent auditor has the necessary technical expertise;
- the Commission to determine the audit requirements in consultation with the electricity entity; and
- the relevant electricity entity to meet the costs of the audit.

3.54 If the relevant electricity entity fails to comply with a notice to appoint an independent auditor, the Commission may:

- appoint an independent auditor to assess the collection and maintenance of data in accordance with good electricity industry practice; and
- require the relevant electricity entity to meet the costs of the audit.

3.55 The audit requirements under the proposed Code are to be separate from the yearly compliance audit under the licence. The audit requirements are proposed to be codified due to the expertise required to conduct the audit at a reasonable standard, and the importance of having quality assurance processes for compliance with the Code.

3.56 The Commission may refer to the Statement of Approach on Compliance (or equivalent document) in considering whether or not to appoint an auditor or in determining the audit requirements.[28]

Section 6 – Data Segmentation

3.57 Section 6 of the proposed Code sets out the requirements for the segmentation of performance indicators for network services into the adjusted and unadjusted categories. This section should be read in conjunction with schedule 2 of the proposed Code, which also contains segmentation requirements.

3.58 Section 6 of the proposed Code defines the adjusted and unadjusted categories. In particular, it defines the events that are permitted to be excluded when reporting adjusted performance indicators. These events are characterised as being beyond the reasonable control of the network provider. In contrast, unadjusted performance indicators include all of these events.

3.59 The proposed Code defines an event as being beyond the reasonable control of the network provider if it consists of:

- load shedding due to generation shortfall;
- an interruption where more than two business days' notice was given to the customer;

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[28] The Statement of Approach on Compliance released on 31 January 2012.

- a network outage due to the System Controller exercising any functions or powers under any applicable law or code;
- a network outage resulting from a direction by a police officer or other authorised person exercising powers in relation to public safety, but only to the extent that the exercise of that function or power, or the giving of that direction, is not caused by a failure by the regulated electricity entity to comply with any applicable law or code;
- a traffic accident;
- an act of vandalism;
- a natural event that is identified as a statistical outlier using the US Institute of Electrical and Electronics Engineers (IEEE) 2.5 beta method; or
- an interruption caused by a customer's electrical installation or failure of that electrical installation.

3.60 The proposed Code defines the events that are beyond the reasonable control of the network provider. This definition is consistent with the GSL Code.

3.61 The Commission considers it appropriate to align the definition of excluded events with the GSL Code to streamline reporting requirements on the network provider.

3.62 If the network provider's performance has been affected by a natural event identified as a statistical outlier using the IEEE 2.5 beta method, the network provider must write to the Commission within 30 business days specifying:

- the relevant event;
- the proposed extent of the exclusions; and
- the reasons why the event should be considered as an exclusion.

3.63 The Commission will approve the exclusion if it considers the event (or parts of the event) to be beyond the reasonable control of the network provider. This ensures that the adjusted figures provide a meaningful assessment of the true performance of the network.

Performance indicators

3.64 Schedules 1 to 3 of the proposed Code contain the performance indicators associated with generation, network, and retail services in the electricity supply industry. Each schedule contains a table(s) listing the various performance indicators, whether the indicator is for reporting purposes or to be reported against a target standard, and the segmentation requirements. The tables should be read in conjunction with the clauses in the relevant schedules. Examples are provided in the schedules to assist readers where appropriate.

Schedule 1 – Generation performance indicators

3.65 Schedule 1 of the proposed Code specifies the generation performance indicators for generation services.

3.66 The Commission considers that the Standards of Service Code would not be the best mechanism to set target standards for Unserved Energy (USE).

3.67 In the Commission's Final Report on the Review of Electricity Standards of Service for the Northern Territory, the Commission recommended that generation target standards be set for USE for each power system.[29] Following expert advice, the Commission considers that USE target standards should be set and managed by System Control rather than individual generation service providers. Therefore, the Commission proposes that USE measures should be codified in the System Control Technical Code administered by System Control.

3.68 The Commission proposes that generators report on generation availability performance indicators which assess the effects of generation outages to give a direct indication of reliability, the level of maintenance, and forward planning measures for breakdown maintenance.

3.69 The generation performance indicators only take into account events caused by generator or generation unit/facilities and exclude events that are outside plant management control. Plant management control is defined as the methodology in the IEEE Standard 762-2006 that is used to determine causes that are internal or external to plant operation and equipment.[30]

3.70 The generating unit availability performance indicators in Table 1 of Schedule 1 are based on the group performance indexes in the IEEE Standard 762-2006.[31] The Commission considers these measures to be the best guide to assessing generation performance (including relevant operational and maintenance functions) and is consistent with good electricity industry practice.

Table 3.1 – Generation performance indicators

Performance Indicator	**Report**	**Segmentation**
Availability Factor (AF)	Yes	Power station
Unplanned Availability Factor (UAF)	Yes	Power station
Equivalent Availability Factor (EAF)	Yes	Power station
Forced Outage Factor (FOF)	Yes	Power station
Equivalent Forced Outage Factor (EFOF)	Yes	Power station
System Average Incident Duration Index (SAIDI)	Yes	Power System and Region
System Average Incident Frequency Index (SAIFI)	Yes	Power System and Region

29 Utilities Commission, Review of Electricity Standards of Service for the Northern Territory -Final Report, page 28.

30 US Institute of Electrical and Electronics Engineers, March 2007, Standard 762-2006 – IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity.

31 Ibid.

3.71 Generation performance indicators will be reported by power station (with the exception of SAIDI and SAIFI which will be reported by power system and region). Power station is defined in the proposed Code as the 'electricity generating plant identified as a power station in a generation licence issued by the Commission in accordance with the *Electricity Reform Act*'. Each term in the equation of each generation performance indicator is weighted by the net maximum capacity (NMC) of the relevant generating unit.[32] NMC is defined in the proposed Code as 'the value for a generating unit expressed in MWs and calculated in accordance with IEEE Standard 762-2006'.

3.72 Availability factor (AF) measures the percentage of time that the generating units within the power station are available for operation within a given period. Availability factor takes into account the hours in which the generating units are offline due to planned outages and unplanned outages. Planned outage is defined as a generation outage that is planned in advance and notified to System Control in accordance with the System Control Technical Code, whereas unplanned outage is defined as a generating outage that is not a planned outage.

3.73 AF gives a direct indication of reliability, the level of maintenance, and the speed of maintenance. This indicator is considered in conjunction with forced outage factor. The calculation is:

$$\mathrm{AF} = 1 - \left(\frac{\mathrm{Sum(Unavailable\ Hours_{unit\ i} X\ NMC_{unit\ i})}}{\mathrm{Sum(Hours_{unit\ i} X\ NMC_{unit\ i})}} \right)$$

3.74 Unplanned availability factor (UAF) measures the percentage of time that the generating units within the power station are available for operation within a given period after removing unplanned outages. The calculation is:

$$\mathrm{UAF} = 1 - \left(\frac{\mathrm{Sum(Unplanned\ Outage\ Hours_{unit\ i} X\ NMC_{unit\ i})}}{\mathrm{Sum(Hours_{unit\ i} X\ NMC_{unit\ i})}} \right)$$

3.75 Equivalent availability factor (EAF) measures the percentage of time that the generating units within the power station are available for operation within a given period. It is similar to availability factor, but also provides an allowance for instances where the generating units are only capable of partial output (i.e. partial planned outages and partial unplanned outages). Partial planned outage is defined in the proposed Code as a planned outage that results in a unit derating, where as partial unplanned outage is defined as a unplanned outage that results in a unit derating. Unit derating is calculated in accordance with IEEE Standard 762-2006. The calculation of EAF is as follows:

$$\mathrm{EAF} = 1 - \left(\frac{\mathrm{Sum(Unavailable\ Hours_{unit_i} X\ NMC_{unit\ i}) + Sum\left(Partial\ Availability\ Hours_{unit\ i} x\ NMC_{unit\ i}\right)}}{\mathrm{Sum(Hours_{unit\ i} X\ NMC_{unit\ i})}} \right)$$

[32] Ibid, pages 41-6

3.76 A partial outage of a generating unit occurs when the generating unit is on load (or available to be on load) at the unit derating value. Partial outages may be caused by internal issues, such as cooling or oil systems, or external issues, such as ambient temperature or fuel availability

3.77 Partial outage hours of a generating unit are the hours of operation calculated as if the generating unit was available at NMC. The calculation is:

$$\text{Partial Outage Hours} = \text{Unavailable Hours x}\left(\frac{\text{Unit Derating Value}}{\text{NMC}}\right)$$

3.78 Forced outage factor (FOF) measures the percentage of time that the generating units within the power station are unavailable due to forced outages within a given period. Forced outage means a generating unit outage to perform breakdown maintenance or repair which could not be delayed until the next period of reduced system demand as determined by system control. The calculation is:

$$\text{FOF} = \left(\frac{\text{Sum(Forced Outage Hours}_{\text{unit i}}\text{X NMC}_{\text{unit i}})}{\text{Sum(Hours}_{\text{unit i}}\text{X NMC}_{\text{unit i}})}\right)$$

3.79 Forced outage factors are unplanned and can have a major impact on the cost of supply of electricity in the event that a base load unit becomes unavailable. This may require more expensive generation capacity in the interim. This measure intends to anticipate the risk of breakdown, and assist the generator in planning for unexpected outages in an attempt to align these outages with periods of low demand. A generator with a low forced outage factor will be effectively managing costs and risks associated with generation services.

3.80 Equivalent forced outage factor (EFOF) measures the percentage of time that the generating units within the power station are unavailable due to forced outages and also includes an allowance for partial forced outages within a given period. Forced partial outages means a generating outage to performance breakdown maintenance in relation to a generating unit which could not be delayed until the next period of reduced system demand as determined by system control.

$$\text{EFOF} = \left(\frac{\text{Sum(Forced Outage Hours}_{\text{unit}_i}\text{X NMC}_{\text{unit i}}) + \text{Sum}\left(\text{Partial Forced Outage Hours}_{\text{unit i}}\text{x NMC}_{\text{unit i}}\right)}{\text{Sum(Hours}_{\text{unit i}}\text{X NMC}_{\text{unit i}})}\right)$$

3.81 Partial forced outage hours are calculated using the formula in paragraph 3.77 of this Consultation Paper.

3.82 The Commission considers that SAIDI and SAIFI indicators can be used as a means of assessing the direct impact of generation events on customers. The calculations are as follows:

$$\text{SAIDI} = \left(\frac{\text{Sum(Customer Minutes}_i)}{\text{Sum(Customer}_i)}\right)$$

$$\text{SAIFI} = \left(\frac{\text{Sum(Outage}_i)}{\text{Sum(Customer}_i)}\right)$$

Schedule 2 – Network service performance indicators

3.83 Schedule 2 of the proposed Code specifies the transmission and distribution indicators for network services.

3.84 Network service performance indicators are categorised into transmission and distribution network performance indicators and customer service indicators associated with network related events. The Commission considers this approach to be consistent with the reporting requirements in the NEM and other Australian jurisdictions. It also allows the network provider and the Commission to assess the individual needs of the transmission and distribution networks.

Transmission performance indicators

3.85 The proposed Code stipulates that specific reliability measures should be established for the transmission elements of the Territory's electricity networks. Transmission network is defined as 'that part of the regulated network that operates at a high voltage level suitable for the transmission network to convey electricity from the relevant entry point to the bulk supply point and to supply transmission customers, and includes the bulk supply points, transmission assets and transmission network connection assets owned or operated by the relevant network provider'.

3.86 The Commission acknowledges that there might not be any transmission customers at present in the Territory transmission networks.

3.87 The Commission has selected the transmission performance indicators in Table 3.2 below in order to improve the performance of transmission equipment in the network. The Commission is of the view that the transmission network is crucial in maintaining reliable electricity supply and therefore requires specific planning and operational requirements. To this end, the proposed indicators measure the extent to which transmission equipment (lines and transformers) is out of service, and the impact of outages on customers (SAIDI and SAIFI).

Table 3.2 – Transmission performance indicators

Performance Indicator	Report	Segmentation	Target	Segmentation
Average Circuit Outage Duration (ACOD) Unadjusted	Yes	Power System	Not Required	
Average Circuit Outage Duration (ACOD) Adjusted	Yes	Power System	Yes	Transmission network
Frequency of Circuit Outages (FCO) Unadjusted	Yes	Power System	Not Required	
Frequency of Circuit Outages (FCO) Adjusted	Yes	Power System	Yes	Transmission network
Average Transformer	Yes	Power System	Not Required	

Performance Indicator	Report	Segmentation	Target	Segmentation
Outage Duration (ATOD) Unadjusted				
Average Transformer Outage Duration (ATOD) Adjusted	Yes	Power System	Yes	Transmission network
Frequency of Transformer Outages (FTO) Unadjusted	Yes	Power System	Not Required	
Frequency of Transformer Outages (FTO) Adjusted	Yes	Power System	Yes	Transmission network
System Average Incident Duration Index (SAIDI) Unadjusted	Yes	Power System	Not Required	
System Average Incident Duration Index (SAIDI) Adjusted	Yes	Power System	Not Required	
System Average Incident Frequency Index (SAIFI) Unadjusted	Yes	Power System	Not Required	
System Average Incident Frequency Index (SAIFI) Adjusted	Yes	Power System	Not Required	

3.88 Some transmission performance indicators are separated into adjusted and unadjusted categories. The way in which adjusted and unadjusted performance indicators are to be reported is contained in clause 6 of the proposed Code, and discussed at paragraphs 3.57-63 of this Consultation Paper.

3.89 In the Final Report on the Review of Electricity Standards of Service for the Northern Territory, the Commission recommended that transmission line and transformer availability indicators be used for reporting and target setting purposes.[33] Following expert advice, the Commission considers that this information can be derived using the proposed transmission indicators. The Commission is therefore of the view that the transmission line and transformer availability indicators do not need to be included in the proposed Code.

[33] Utilities Commission, Review of Electricity Standards of Service for the Northern Territory -Final Report, page 31.

3.90 The transmission performance indicators for reporting purposes are to be segmented by power system. The transmission performance indicators for target setting are for the entire transmission network. Transmission network is defined as that part of the regulated network that operates at a high voltage level suitability for the transmission network to convey electricity from the entry point to the bulk supply point and to supply transmission customers, and includes the bulk supply points, transmission assets and transmission network connection assets owned or operated by the relevant network provider.

3.91 Average circuit outage duration (ACOD) measures the average time (in minutes) of all network outages on the transmission network within a given period. Network outage is defined as any full or partial unavailability of apparatus, equipment, plan and buildings used to convey, and control the conveyance of electricity and excludes MAIFI events. The calculation is:

$$\mathrm{ACOD} = \left(\frac{\mathrm{Sum(Transmission\ Circuit\ Unplanned\ Outage\ Minutes_i)}}{\mathrm{Sum(Transmission\ Outage_i)}} \right)$$

3.92 Frequency of transmission circuit outages (FCO) measures the total number of network outages within a given period.

$$\mathrm{FCO} = \mathrm{sum}\left(\mathrm{Transmission\ Circuit\ Outage_i}\right)$$

3.93 Average outage duration of transformers (ATOD) measures the average time of network outages due to transformers within a given period. Transformer is defined as a facility or device that reduces or increases the voltage of alternating current. The calculation is:

$$\mathrm{ATOD} = \left(\frac{\mathrm{Sum(Transmission\ Transformer\ Unplanned\ Outage\ Minutes_i)}}{\mathrm{Sum(Transmission\ Transformer\ Outage_i)}} \right)$$

3.94 Frequency of transformer outages measures the total number of network outages due to transformers within a given period.

$$\mathrm{FTO} = \mathrm{sum}\left(\mathrm{Transmission\ Tranformer\ Outage_i}\right)$$

3.95 SAIDI measures the impact interruptions on customers by identifying the length of time that the average customer was without supply due to transmission related events. Interruption is defined as a network outage that results in a temporary unavailability or temporary curtailment of supply to customers services by the relevant network and excludes MAIFI events. The calculation is:

$$\mathrm{SAIDI} = \left(\frac{\mathrm{Sum(Customer\ Minutes_i)}}{\mathrm{Sum(Customer_i)}} \right)$$

3.96 SAIFI measures the impact of interruptions on customers by identifying the number of occasions that the average customer was without supply due to transmission related events. The calculation is:

$$\text{SAIFI} = \left(\frac{\text{Sum}(\text{Outage}_i)}{\text{Sum}(\text{Customer}_i)} \right)$$

Distribution performance indicators

Table 3.3 – Distribution performance indicators

Performance Indicator	**Report**	**Segmentation**	**Target**	**Segmentation**
System Average Incident Duration Index (SAIDI) Unadjusted	Yes	Power System and Region and Feeder Category	Not Required	
System Average Incident Duration Index (SAIDI) Adjusted	Yes	Power System and Region and Feeder Category	Yes	Feeder Category
System Average Incident Frequency Index (SAIFI) Unadjusted	Yes	Power System and Region and Feeder Category	Not Required	
System Average Incident Frequency Index (SAIFI) Adjusted	Yes	Power System and Region and Feeder Category	Yes	Feeder Category
Feeder Performance	Yes	Individual Feeder	Not Required	

3.97 Some distribution performance indicators are separated into adjusted and unadjusted indicators. The way in which adjusted and unadjusted performance indicators are to be reported is contained in clause 6 of the proposed Code, and discussed at paragraphs 3.57-63 of this Consultation Paper.

3.98 Distribution network is defined in the proposed Code as ‘that part of the regulated network that is not part of the transmission network and includes distribution assets and distribution network connection assets owned or operated by the network provider’.

3.99 The distribution performance indicators for reporting are to be segmented by power system, region, and feeder category (with the expectation of feeder performance, which is to be segmented by individual feeder only). The distribution performance indicators for target setting are to be segmented by feeder category only.

3.100 The Commission proposes the following feeder categories:

- CBD feeders;
- urban feeders;
- rural long feeders; and
- rural short feeders.

3.101 The proposed feeder categories follow the feeder categories prescribed under the GSL Code administered by the Commission. Like the GSL Code, the Commission expects the feeder categories to be identified in a map published by the network provider.

3.102 SAIDI measures the impact of interruptions on customers by identifying the length of time that the average customer was without supply due to distribution related events. The calculation is:

$$\text{SAIDI} = \left(\frac{\text{Sum(Customer Minutes}_i)}{\text{Sum(Customer}_i)} \right)$$

3.103 SAIFI measures the impact of interruptions on customers by identifying the number of occasions that the average customer was without supply due to distribution related events. The calculation is:

$$\text{SAIFI} = \left(\frac{\text{Sum(Outage}_i)}{\text{Sum(Customer}_i)} \right)$$

3.104 Feeder performance identifies poorly performing feeders in the distribution network. This is done by measuring the SAIDI performance ratio for an individual feeder against a pre-defined SAIDI threshold. The feeder will be poorly performing if the SAIDI performance ratio exceeds the SAIDI threshold in two or more consecutive years (this would reduce the impact of one-off events in the year such as extreme weather related events). This is similar to the approach adopted by the Essential Services Commission of South Australia.[34] The Commission considers that this approach would provide a dynamic link between poorly performing feeders and the SAIDI target standards. The calculation is:[35]

$$\text{SAIDI Performance Ratio} = \frac{\text{SAIDI for an individual feeder}}{\text{SAIDI target standard for the individual feeder's feeder category}}$$

3.105 The SAIDI target standard for the individual feeder’s feeder category is the target standard as approved by the Commission and in force in the relevant financial year.

3.106 This measure intends to identify the bottom 5 per cent of worst performing feeders across the distribution network. However, this will depend on the SAIDI threshold. The Commission proposes to set the SAIDI threshold at 3 initially with a view to capturing the bottom 5 per cent of worst performing feeders across the distribution network.

3.107 Once the poorly performing feeders are identified, the Commission will require the following information:

- performance ratio used to identify poorly performing feeders against the SAIDI threshold;
- number of feeders identified as poorly performing;
- explanations for the poor results of each poorly performing feeder; and

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[34] Essential Services Commission of South Australia, June 2010, South Australian Electricity Distribution Service Standards 2010-2015 Review of Regulatory Instruments – Final Decision, page 15.

[35] Essential Services Commission of South Australia, June 2010, South Australian Electricity Distribution Service Standards 2010-2015 Review of Regulatory Instruments – Final Decision, page 15.

- intended action to rectify the poor results.

Distribution and transmission customer service performance indicators

Table 3.4 – Distribution performance indicators

Performance Indicator	Report	Segmentation
Connections	Yes	CBD/urban; rural
Phone Answering	Yes	NT
Network Complaints	Yes	Power System and Region
Written Enquiries	Yes	Power System and Region

3.108 Distribution and transmission customer service performance indicators measure connections, phone answering, and complaints and written enquiries associated with distribution and transmission related services. Given the circumstances of the Territory, PWC will be required to combine these results (where applicable) with the PWC retail division.

3.109 Information for connections includes:

- percentage and total number of reconnections not undertaken within 24 hours;
- percentage and total number of new connections not undertaken in the CBD or urban areas within 5 business days, or as otherwise agreed with the customer (excluding connections to new subdivisions where minor extensions or augmentation is required);
- percentage and total number of new connections in rural areas not undertaken within 10 business days, or as otherwise agreed with the customer (excluding connections to new subdivisions where minor extensions or augmentation is required); and
- number and average length of time taken to provide new connections to new subdivisions where minor extensions or augmentation is required in urban areas.

3.110 Information for phone answering includes:

- average time taken to answer the phone;
- percentage and total number of calls not answered within 20 seconds of caller asking to talk to an operator; and
- percentage and total number of calls abandoned.

3.111 Information for network complaints include:

- percentage and total number of complaints associated with network activities segmented into complaint categories; and
- percentage and total number of complaints associated with distribution network quality of supply issues.

3.112 The indicator for written enquiries measures the average time taken to respond to a written customer enquiry.

Schedule 3 – Retail customer service performance indicators

3.113 Schedule 3 of the proposed Code specifies the customer service performance indicators for retail services.

3.114 Where applicable, the proposed retail customer service performance indicators will apply to all licensed retailers, irrespective of the customers' consumption levels.

Table 3.5 – Retail customer service performance indicators

Performance Indicator	Report	Segmentation
Phone Answering	Yes	NT
Complaints	Yes	Region
Hardship	Yes	Region
Written Enquiries	Yes	Region

3.115 Retail customer service performance indicators measure phone answering, complaints, hardship, and written enquiries associated with retail services.

3.116 Information for phone answering comprises:

- average time taken to answer the phone;
- percentage and total number of calls not answered within 20 seconds of caller asking to talk to a human; and
- percentage and total number of calls abandoned.

3.117 Information for complaints comprises:

- percentage, total number, and type of complaint associated with retail services.

3.118 Information for customer hardship enquiries and complaints includes:

- total number of disconnections for failure to pay and reconnections in same name;
- total number of customer service and customer complaints;
- total number of calls associated with the use of prepayment meters;
- total number of calls relating to the collection of security deposits; and
- total number of calls associated with social welfare concessions, including membership of pensioner concession schemes and other relevant schemes.

3.119 Written enquiries comprise:

- Average time taken to respond to a written customer enquiry.