

REVIEW

Australian Energy Market Commission

ISSUES PAPER - NATIONAL WORKSTREAM

Review of distribution reliability outcomes and standards

Commissioners

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011 COAG announced it would establish the new Standing Council on Energy and Resources (SCER) to replace the Ministerial Council on Energy. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the SCER.

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Executive summary

This issues paper commences consultation on the review that the Standing Council on Energy and Resources (SCER) has directed the Australian Energy Market Commission (AEMC) to undertake regarding distribution reliability frameworks.¹

The AEMC previously noted in its *Review of National Framework for Electricity Distribution Network Planning and Expansion* that there is a lack of consistency and transparency in how distribution reliability outcomes are determined. Distribution reliability outcomes are currently set separately for each of the National Electricity Market (NEM) jurisdictions by jurisdictional regulators, relevant government bodies or Distribution Network Service Providers (DNSP) themselves, under different frameworks that are in place for each jurisdiction.

The AEMC's review of distribution reliability outcomes and standards includes both a review of distribution reliability outcomes in New South Wales and a review of the frameworks across the NEM for the delivery of distribution reliability outcomes. This issues paper commences the first stage of the national workstream and sets out for comment the proposed scope and approach to the review.

As part of this review, the AEMC will provide an analysis of the different approaches to achieving distribution reliability across the NEM.

The current approach adopted in each NEM jurisdiction is explored and discussed in this issues paper. Based on this analysis, the AEMC will prepare a draft report that assesses whether there is merit in developing a nationally consistent framework for expressing, delivering, and reporting on distribution reliability outcomes. This issues paper sets out our proposed assessment framework for deciding whether there would be merit in a nationally consistent framework.

While there are considerable similarities in which aspects of reliability are regulated across NEM jurisdictions, there are considerable differences in how each jurisdiction currently regulates these matters.

In assessing whether there would be merit in moving to a nationally consistent framework, we are mindful that consistency for the sake of consistency is likely to produce relatively limited benefits. However, a nationally consistent framework could potentially offer significant benefits if that framework represents best practice and is a substantial improvement on at least some aspects of the approaches currently adopted by most or all jurisdictions. For example, a nationally consistent framework is likely to be efficient where decisions to invest in maintaining or improving reliability outcomes are determined on the basis of how much the customer values reliability.

Upon receipt of the AEMC's advice as to whether there is merit in a nationally consistent framework, the SCER may request that we develop a best practice

¹ The Ministerial Council on Energy (MCE) has changed its title to the Standing Council on Energy and Resources (SCER).

framework that delivers nationally consistent reliability outcomes that could be adopted by NEM jurisdictions or used as a reference to amend aspects of existing jurisdictional frameworks.

We welcome the views of interested parties in relation to any of the matters discussed in this document. To help focus responses, we have set out a number of specific questions in each chapter. In particular, we are requesting stakeholder views about:

- the scope of the issues that should be considered as part of this review; and
- the approach we intend to take.

Responses to those questions, and any other issues raised by this paper, are due by 9 August 2012.

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1 Introduction

On 30 August 2011 the Standing Council on Energy and Resources (SCER) directed the Australian Energy Market Commission (AEMC) to undertake a review of distribution reliability outcomes and standards.²

The review has two separate workstreams, working to separate (but overlapping) timetables:

- a review of the distribution reliability outcomes in New South Wales ("New South Wales workstream"); and
- a review of the frameworks across the National Electricity Market (NEM) for the delivery of distribution reliability outcomes ("national workstream").

The national workstream commences with the publication of this issues paper.

This issues paper sets out the proposed scope and approach for the national workstream for comment. It also provides a detailed description of the current approaches to distribution reliability regulation in each NEM jurisdiction and discusses the key differences between those approaches.

1.1 Purpose of the national workstream

The SCER has directed the AEMC to undertake a national review of frameworks for achieving distribution reliability outcomes.

The national workstream requires the AEMC to provide an analysis of the different approaches to achieving distribution reliability across the NEM. Based on this analysis, the AEMC is to consider if there is merit in developing a nationally consistent framework for expressing, delivering, and reporting on distribution reliability outcomes.

Following the completion of that analysis, we will publish a report on whether there is merit in developing such a nationally consistent framework. The SCER will consider that report and may then, request that we develop a best practice framework that delivers nationally consistent reliability outcomes that could be voluntarily adopted or used as a reference by the jurisdictions to amend aspects of the existing approaches.

This review is partly a response to the AEMC's suggestion that the SCER initiate a review of the methodology underpinning security and reliability in our 2009 *Review of National Frameworks for Electricity Distribution Network Planning and Expansion*.³

² The Ministerial Council on Energy has changed its title to the Standing Council on Energy and Resources (SCER).

³ The final report for this review is available on the AEMC website.

Distribution reliability outcomes are currently set separately for each NEM jurisdiction by jurisdictional regulators, relevant government bodies or individual Distribution Network Service Providers (DNSP), and different approaches are used between jurisdictions. It is appropriate for certain reliability outcomes to differ across jurisdictions due to differing regional issues and variations in operating environments, consistent with the Australian Energy Market Agreement (AEMA).⁴ However, the SCER has noted that the lack of consistency in expressing, delivering and reporting on reliability outcomes may be adversely impacting the efficiency and timeliness of network investments and making it difficult for non-network providers to operate on a NEM-wide basis.⁵

The SCER's terms of reference also note that the Energy Ministers seek to ensure that there is an effective balance between ensuring sufficient investment in distribution networks to maintain reliability, and pricing outcomes for customers. In requesting the AEMC to undertake this workstream, the Energy Ministers noted that outcomes from recent distribution regulatory determinations have been a significant contributor to retail electricity price rises.⁶

Chapter 2 discusses the SCER's terms of reference for the national workstream in detail.

1.2 Interaction with the New South Wales workstream

In conjunction with the national workstream, the SCER has requested that the AEMC undertake a review of the approach to distribution reliability in New South Wales.

The objective of the New South Wales workstream is fundamentally different to that of the national workstream. The focus of the national workstream is on the frameworks for expressing, delivering and reporting on distribution reliability outcomes in the NEM, as opposed to the actual level of the relevant reliability standards or outcomes. In contrast, the New South Wales workstream will provide advice on the costs and benefits of alternative outcomes or levels of distribution reliability in New South Wales.

The New South Wales workstream commenced with the publication of an issues paper on 3 November 2011 that sought feedback from interested parties on various issues relating to the New South Wales network design planning criteria and reliability standards. This was followed by the publication in February 2012 of a report from the

⁴ The AEMA was entered into by the Commonwealth and each state and territory of Australia on 30 June 2004, and most recently amended on 2 July 2009. It promotes an open and competitive national energy market in the long term interests of consumers with regard to the price, quality and reliability of electricity and gas services, and establishes a framework for reforming the energy markets.

⁵ AEMC, *Final Report for the Review of National Framework for Electricity Distribution Network Planning and Expansion*, September 2009, p xii.

⁶ MCE, Terms of Reference, *Review of Distribution Reliability Outcomes and Standards*.

Brattle Group that provided an assessment of best practice national and international approaches to distribution reliability.

On 8 June 2012, the Commission published a draft report on distribution reliability outcomes in New South Wales. That report provides draft advice to the New South Wales Government on the costs and benefits of alternative levels of distribution reliability in New South Wales.

The New South Wales workstream commenced prior to the national workstream in order to allow time for the New South Wales Government to make any changes to the New South Wales distribution reliability outcomes in time for the next distribution regulatory control period commencing on 1 July 2014.

1.3 Stakeholder engagement process

In conducting the review, the SCER's terms of reference require us to consult with a range of stakeholders including:

- jurisdictional Ministers responsible for setting distribution reliability standards;
- jurisdictional representatives and the Standing Committee of Officials for Energy Ministers;
- jurisdictional regulatory bodies;
- the Australian Energy Regulator (AER);
- the Australian Energy Market Operator (AEMO);
- network companies;
- market participants; and
- customers and their representatives.

1.3.1 How to make a submission

The closing date for submissions to this issues paper is 9 August 2012.

Submissions must be on letterhead (if submitted on behalf of an organisation), signed and dated. Submissions should quote project number "EPR0031" and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

1.4 Structure of this paper

The remainder of the issues paper is structured as follows:

- Chapter 2 discusses the terms of reference and the scope of the national workstream;
- Chapter 3 provides an overview of the important aspects of distribution reliability frameworks, the characteristics of current distribution reliability frameworks in NEM jurisdictions and key differences between those frameworks, and aspects of existing jurisdictional approaches that could be adopted in a nationally consistent framework;
- Chapter 4 explains our initial views of the potential costs and benefits of a nationally consistent framework for achieving distribution reliability outcomes and discusses implementation considerations; and
- Appendix A provides a detailed description of the current distribution reliability frameworks in NEM jurisdictions.

2 Terms of reference for the national workstream

This Chapter outlines the SCER's terms of reference and required considerations for the national workstream.

2.1 Terms of reference for the national workstream

The terms of reference require the AEMC to undertake three key tasks:

1. identify and analyse current NEM approaches to distribution reliability;
2. advise on whether there is merit in developing a nationally consistent framework for expressing, delivering and reporting on reliability outcomes; and
3. if requested by the SCER, develop a best practice framework that delivers nationally consistent reliability outcomes that could be voluntarily adopted by jurisdictions or used as a reference to amend aspects of existing jurisdictional approaches.

This issues paper primarily focusses on tasks 1 and 2. We will consult on task 3 at a later date if the SCER requests that we undertake that task.

2.1.1 Analysis of the NEM jurisdictional approaches to distribution reliability

The SCER has requested that the AEMC identify and analyse the different approaches to achieving distribution reliability outcomes across the NEM. This work should acknowledge differences between methodologies and approaches within each NEM jurisdiction, and should focus on the outcomes of different approaches.

Issues relating to this task

Chapter 3 and Appendix A to this issues paper provide an overview of existing NEM jurisdictional distribution reliability frameworks and the main differences between them. Chapter 3 also briefly outlines the current reliability outcomes in different jurisdictions.

Further information regarding the existing NEM jurisdictional approaches to distribution reliability, including how they compare to other international approaches, is contained in the Brattle Group report on best practice national and international approaches to distribution reliability approaches, which was published earlier in this review.

The Commission proposes to analyse the following aspects of existing NEM jurisdictional approaches to distribution reliability. These issues are discussed in greater detail in Chapter 3.

- *Design planning criteria* - refers to the approach taken by the DNSP to build and maintain the distribution network in relation to security and reliability of supply.

This includes both deterministic standards, which require specific network operational conditions to be met, and probabilistic standards, where network investments are justified on the basis of whether the value to customers outweighs the costs.

- *Reliability performance standards* - refers to the level of average service standards that a DNSP is required to meet. The most common indices used for measuring service standards are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI is used to measure the duration of outages, usually as minutes per customer per year. SAIFI measures the frequency of outages, and is usually measured as number of outages per customer per year.
- *Requirements relating to worst served customers* - refers to obligations on the DNSP, such as improvement programs or annual reporting, directed at service standards for customers in poor performing parts of the network. These standards can be used to complement the reliability performance standards referred to above and protect customers that experience significantly worse reliability outcomes than the average required by the reliability performance standards.
- *Governance arrangements* - refers to the administration framework in place for the DNSP security and reliability standards. This includes the approach to determining the standards, the body responsible for enforcing the standards, and the penalties for not meeting the standards.
- *Monitoring and reporting* - refers to the requirements on the DNSP in relation to reporting of network reliability performance and planning for network development.
- *Incentive schemes* - refers to the schemes that are in place that provide incentives to a DNSP to maintain or improve reliability performance. Currently, the AER is in the process of applying the Service Target Performance Incentive Scheme (STPIS) to each of the NEM jurisdictions. The STPIS operates to provide financial incentives to maintain and improve service performance by assigning rewards or penalties to a DNSP, as a per cent of revenue, where performance is better or worse than the target performance level.
- *Guaranteed service level (GSL) payments* - refers to payments that a DNSP is required to make directly to customers when certain reliability standards are not achieved. The threshold for GSL payments being made is usually defined relative to SAIDI and SAIFI targets a DNSP is required to meet.

There are also a number of aspects that the AEMC proposes should not be included in the analysis of NEM jurisdictional approaches. These include any aspects of jurisdictional approaches that relate to safety standards, customer service standards such as telephone answering times and responding to written queries, and quality of supply parameters, such as operating voltage and frequency, as defined by the frequency operating standards.

Question 1 Analysis of NEM jurisdictional approaches to reliability

Should the AEMC consider any other aspects of existing NEM jurisdictional approaches to distribution reliability?

2.1.2 Merit in developing a nationally consistent framework for distribution reliability

The SCER has requested the AEMC to consider and advise whether there is merit in developing a nationally consistent framework for expressing, delivering and reporting on reliability outcomes.

The Commission proposes to use the following definitions for expressing, delivering and reporting on reliability outcomes:

- 'expressing' refers to the types of reliability standards or outcomes that are used (including issues related to probabilistic or deterministic approaches, and input or output standards) and how the relevant standards and outcomes are defined and measured;
- 'delivering' refers to the governance arrangements in place to regulate the setting and enforcement of the required standards or outcomes, including the methodology employed to determine the level at which to set the required standards or outcomes and incentive schemes to incentivise delivery of the required outcomes;
- 'reporting' refers to the publication of reliability outcomes and other reliability related reporting by DNSPs, governments or regulators.

Issues relating to this task

Nationally consistent framework

The terms of reference note that “there will be no harmonisation of existing jurisdictional obligations”. In determining the merits of moving to a nationally consistent framework, the SCER notes that it is appropriate for standards to differ across jurisdictions due to the differing characteristics of distribution networks.

The focus of this review is the “framework” for distribution reliability. The intention is to assess the merits of having a common overarching framework for expressing, delivering, and reporting on distribution reliability outcomes, which would allow for local differences, for example to reflect local network or geographic conditions.

We do not intend to assess as part of this workstream what “level” of reliability outcomes or standards should be adopted in each jurisdiction. This review will not result in a single harmonised level of reliability outcomes that will apply across the NEM.

Chapter 4 discusses in more detail our views on the meaning of a “nationally consistent framework”.

Approach to determining the merits of developing a nationally consistent framework

The AEMC’s analysis will draw on an analysis of the existing approaches to jurisdictional distribution reliability in the NEM, including an assessment of the methodologies and outcomes, the differences in approaches between jurisdictions, and what the implications of these differences are in consideration of a nationally consistent framework.

The analysis of existing jurisdictional approaches will be supported through the conclusions in the assessment of best practice national and international approaches to distribution reliability commissioned by the Commission and undertaken by the Brattle Group, which was published in February 2012.

The Commission’s recommendations in relation to the merits of moving to a nationally consistent framework will be provided to the SCER and published in a draft report in November 2012.

We will seek stakeholder submissions on our draft report and provide a summary of those submissions to the SCER to assist its consideration of whether there is merit in such an approach and whether it wishes to request us to undertake the third task discussed below.

2.1.3 Best practice approach for delivering nationally consistent reliability outcomes

The SCER will consider the AEMC’s draft report and if it considers that there is merit in moving to a nationally consistent framework, the SCER may request the AEMC to develop a best practice framework that delivers nationally consistent reliability outcomes that could be voluntarily adopted by jurisdictions or used as a reference to amend aspects of existing jurisdictional approaches.

Issues relating to this task

As noted above, this issues paper primarily focuses on tasks 1 and 2. The scope and timelines for this third task will be determined upon the SCER’s decision to proceed.

The terms of reference require that the merits of moving to a nationally consistent framework are assessed before we begin work on developing a best practice approach that could be adopted by NEM jurisdictions.

The Commission considers that a significant level of resources and stakeholder consultation may be required to develop a best practice approach. We therefore support the SCER’s approach to consider the merits behind a nationally consistent framework before undertaking this more substantial task.

However, we consider that in order to assess the merits of a nationally consistent framework, the high-level content of a nationally consistent framework will need to be identified and explored so that the expected costs and benefits of moving to such a framework can be assessed. Consistency for the sake of consistency is likely to produce relatively limited benefits, but a nationally consistent framework could potentially offer significant benefits if that framework represents best practice and is a substantial improvement on aspects of the approaches currently adopted in some or all jurisdictions.

The Commission does not intend at this stage to undertake a detailed analysis of best practice approaches to distribution reliability, but rather intends to focus on the likely advantages and efficiencies that could be obtained from a nationally consistent framework that incorporates certain key features. Those key features are discussed in Chapters 3 and 4.

The terms of reference requires the AEMC to publish a final report setting out our recommended best practice framework four months after the SCER has provided a response to the draft report, and provide that final report to the SCER two weeks prior to publication. The terms of reference does not appear to contemplate a period of consultation on our recommended best practice framework prior to publication of that final report, and this short timeframe would not allow for such a consultation period.

We consider that development of a best practice framework will require careful consideration and engagement with stakeholders. Accordingly, if the SCER requests that we develop a best practice framework we will consider and discuss with the SCER at the time whether it would be appropriate to add an additional consultation step prior to publication of our final report.

2.2 Required considerations for the national workstream

In undertaking the assessment, the SCER has requested that the AEMC acknowledge:

- differences between existing methodologies and approaches within each NEM jurisdiction, and focus on the outcomes of the different approaches; and
- that jurisdictional regulators and relevant government agencies are predominantly involved in setting targets for end customer reliability and customer service standards which aim at balancing reliability and costs to consumers.

In making any recommendations to change the current arrangements, the SCER has requested that the AEMC have regard to the need for changes to be proportionate to the materiality of the issue, as well as the value of stability and predictability in the energy market regime.

The SCER has also requested that the AEMC provide advice on the implementation of any such recommendations.

Question 2 Approach to the national workstream

Should the AEMC consider any other aspects in its approach to the national workstream?

3 Current jurisdictional frameworks for distribution reliability in the NEM

Reliability refers to the extent to which customers have a continuous electricity supply. While supply interruptions to consumers may arise from issues at any of a number of points in the electricity supply system, such as generator outages or transmission line faults, this review focuses on the reliability of supply to customers based on the performance of the distribution network.

Interruptions to continuous supply can be of varying duration from fractions of a second to several hours, depending on the cause and what has to be done to restore supply. Reliability performance currently varies across different networks, in part due to different operating conditions.

This Chapter provides an overview of the key characteristics and differences between current distribution reliability frameworks in NEM jurisdictions, and outlines some aspects of existing jurisdictional approaches that could be adopted in a nationally consistent framework.

3.1 An overview of existing jurisdictional approaches to distribution reliability

This section provides an overview of the existing jurisdictional approaches to distribution reliability in the NEM and discusses some of the important differences between jurisdictions.

3.1.1 Approaches to regulating reliability

Overview of the regulation of reliability

Deterministic and probabilistic approaches

Deterministic and probabilistic approaches are the two main forms of distribution reliability regulation in the NEM.

- The deterministic approach aims to provide adequate and secure supplies of electricity by incorporating sufficient levels of redundancy in the network. Investments in the distribution network are undertaken to comply with specific reliability standards, either as input standards that define minimum levels of network redundancy or as output standards that define minimum levels of reliability performance, in terms of frequency and duration of supply interruptions to customers.
- The probabilistic approach takes into account the probabilities of supply interruptions to consumers under a range of possible operating conditions and assigns an economic value to customer loads that are not served. The value of customer load is measured through a value of customer reliability (VCR) or other

measure that places a value on expected supply interruptions, to assess whether an augmentation should proceed, rather than applying pre-determined criteria. VCRs estimate the costs of different types of interruptions for different customer types. A VCR is used to value the benefits of a proposed network upgrade so they can be compared to the costs of the upgrade. Investments only proceed if the benefits outweigh the costs.

Victoria is the only NEM jurisdiction that currently adopts a probabilistic approach. In summary, this approach to distribution network planning in Victoria involves DNSPs:

- completing detailed assessments of forecast maximum demand;
- calculating "energy at risk" in cases where the forecast maximum demand is greater than the station/plant ratings under outage conditions;
- estimating the probability of an outage coincident with the forecast maximum demand (to give the "probability weighted energy at risk");
- estimating the cost to the community of the "probability weighted energy at risk" utilising a VCR estimate;
- establishing a sector-weighted cost for VCR based on customer composition and sectoral VCR estimates; and
- estimating the expected cost of unserved energy by multiplying the sector-weighted cost by the probability weighted energy at risk.

Generally speaking, if the expected cost of unserved energy is greater than the annualised cost of network augmentation, then the project is justified.

A purely probabilistic approach does not include a requirement to meet pre-determined reliability standards or outcomes. However, target reliability outcomes may be adopted in combination with a probabilistic approach in order to provide a level of transparency to customers and for use in performance incentive schemes. Such an approach is adopted in Victoria, where probabilistic planning is adopted together with a service incentive scheme and requirements that DNSPs must publish target reliability outcomes.

Input and output methodologies

There are two general approaches to regulating reliability under a deterministic framework:

- Input methods dictate requirements for the design of the network in order to achieve specified reliability outcomes. In some jurisdictions, input requirements are referred to as design planning criteria, redundancy requirements or security standards.
- Output methods specify the desired reliability outcomes. DNSPs then determine how the network is planned and operated in order to meet the desired outcomes.

These approaches can be used on their own or together. Most deterministic frameworks in the NEM use a combination of these approaches.

Input methods usually contain requirements that prescribe the level of redundancy that the DNSP is required to build and maintain in its network to minimise the consequences of an outage. These requirements are usually expressed as N-x, where 'N' refers to the network and the 'x' is the number of bulk power system elements out of service whilst maintaining customer loads. A higher value of x should apply to areas of the network where the economic costs of a loss of supply would be greatest, such as in densely populated regions. For example, a standard of N-2 may be applied to the CBD, N-1 may be applied to urban areas, and N may be applied to rural or remote regions.

In some NEM jurisdictions, input requirements are set out in distribution licences or other regulatory instruments. In other jurisdictions, the regulatory instrument requires the DNSP to develop and publish its own planning criteria.

Output methods are usually based on reliability performance standards that specify the level of service that a DNSP is required to meet. The most common measures that are used in the NEM are:

- System Average Interruption Frequency Index (SAIFI) which is a measure of the average number of supply interruptions that a typical customer will experience in a year;
- System Average Interruption Duration Index (SAIDI) which is a measure of the average aggregate number of minutes that supply is lost to the average customer in a year;
- Customer Average Interruption Duration Index (CAIDI) which is a measure of how long the average supply interruption lasts, usually measured in minutes; and
- Momentary Average Interruption Frequency Index (MAIFI) which is a measure of how many supply interruptions occurred of a specific very short duration.

Performance standards are generally set based on an average of performance over a defined preceding period. In the calculation of standards, and the measurement of performance against those standards, some types of interruptions are excluded. The purpose of exclusions should be to avoid distorting the measurements through outlier events or events that are beyond the control of the DNSP.

In addition, performance standards can be set at a network-wide level or disaggregated to reflect expectations for certain parts of the network or customer groups.

Output methods may also contain additional provisions that are designed to protect worst served customers. These measures may be adopted because the reliability standards focus on average performance levels and specific parts of the network may have much lower performance, particularly in rural areas. Without specific

mechanisms for these areas, DNSPs could focus their investments on improving reliability of service to specific areas of the network where they can achieve the largest improvements at lowest cost, such as high customer density urban areas, which may result in very poor outcomes for other higher cost areas.

Both probabilistic and deterministic frameworks also often incorporate incentive schemes, which are discussed in section 3.1.3 below.

Value of customer reliability and willingness to pay

VCR or willingness to pay (WTP) studies can be used to estimate the cost or value to customers of reliability when determining the appropriate level of reliability outcomes or standards.

VCR and WTP are not interchangeable concepts. VCR estimates are typically derived from surveys that pose a series of questions to customers on the costs they would incur from interruptions to supply under a range of conditions. WTP studies typically examine the willingness of customers to pay for an improvement to the level of reliability. The survey undertaken for the AEMC's New South Wales draft report asked VCR and WTP questions as well as 'willingness to accept' questions that sought to estimate whether customers would prefer lower levels of reliability if this resulted in lower electricity costs.

Victoria is the only NEM jurisdiction to use estimates of the value of customer reliability in its approach to distribution reliability planning. South Australia and the Australian Capital Territory, while not adopting a probabilistic approach to network planning, have used WTP studies in the past as one input into the determination of reliability performance standards. It is not apparent that the bodies responsible for setting reliability standards or outcomes in New South Wales, Queensland or Tasmania undertook any form of VCR or WTP study when determining the level at which to set the current standards or outcomes in those jurisdictions.

Reporting requirements

Reporting requirements are intended to promote transparency of compliance with regulations and provide further information regarding the approaches DNSPs take to meeting any requirements. Reporting requirements currently apply in all NEM jurisdictions, regardless of whether they adopt deterministic or probabilistic approaches or rely primarily on input or output criteria.

A comparison of jurisdictional approaches to regulating reliability

Table 3.1 provides an overview of how each of the NEM jurisdictions approach reliability regulation.

Table 3.1 Jurisdictional approaches to regulating reliability

Jurisdiction	Deterministic planning criteria?	Performance measure	Performance measure category	Performance measure exclusions	Worst served customer provisions	Reporting requirements
Australian Capital Territory	no (see section A.1.2)	SAIDI; SAIFI; CAIDI; minimum targets set out in Code; DNSP can set higher targets	n/a	Outages of less than 1 minute, extended outages due to storms are excluded	Set separate reliability targets where groups of customers are expected to receive substantially different levels of service	Annual compliance report
Queensland	N-2, N-1, and N network security standards set by DNSPs in their network management plans	SAIDI; SAIFI; standards set out in Code	Feeder type	Interruptions of less than one minute; interruptions resulting from shortfall in generation, transmission failure, AEMO directions, automatic load shedding due to under-frequency or directions of policy; major event days; caused by a customer connection	Network management plans are required to report on how worst performing feeders are defined, an analysis of the performance in the previous financial year and an analysis of worst performing feeder identified in the proceeding network management plan	Annual Network Management Plan; Summer Preparedness Plan
South Australia	N-1 and N security standards set by the DNSPs	SAIDI; SAIFI; standards set out in Code	Region	Planned supply interruptions and supply interruptions of less than one minute are excluded	Required to report annually on the nature of any discrete areas of poor performance; the reasons for that performance; and the remedial actions taken or proposed to improve performance	Annual performance report
Tasmania	no (see section A.4.2)	SAIDI; SAIFI; standards set out	Customer category	Planned maintenance or repair; unplanned maintenance or repair necessary to address immediate	Required to report on areas which are underperforming and how the DNSP proposes	Annual Distribution Planning

Jurisdiction	Deterministic planning criteria?	Performance measure	Performance measure category	Performance measure exclusions	Worst served customer provisions	Reporting requirements
		in Code		threat of injury or material damage to any person or to the distribution system; the need to shed load; and the need to eliminate the risk of fire	to improve performance. Poor performing communities are identified on the basis of exceeding the Tasmanian Electricity Code limits for frequency or duration of outages	Report; Performance Report
Victoria	no (probabilistic approach - see section A.5.2)	Planned SAIDI; unplanned SAIDI; SAIFI excluding momentary interruptions; MAIFI; and CAIDI targets set and published by DNSPs (based on AER STPIS targets)	Feeder type	Exclusions determined by the AER as part of the STPIS process	DNSPs are required to report where feeder performance falls below targets set by the ESCV based on the worst served five per cent of customers	Distribution System Planning Report
New South Wales	N-2; N-1; N; design planning criteria set out in licence conditions	SAIDI; SAIFI; standards set out in licence conditions	Feeder type	Interruptions of less than one minute; interruptions resulting from load shedding, a failure of the transmission system, automatic load shedding due to a power system under-frequency condition, or a direction issued to interrupt supply; planned interruptions; major event days; interruptions caused by a customer's electrical installation	Standards set out minimum performance requirements for individual feeders. DNSPs required to report and take steps to improve performance of those feeders if standards are not met	Quarterly and annual performance reports to minister and annual independent audit

Differences in jurisdictional approaches to regulating reliability

Table 3.1 outlines a number of similarities and differences between the approaches adopted by NEM jurisdictions to the regulation of distribution reliability. There appear to be considerable similarities in which aspects of distribution reliability most jurisdictions currently regulate. However, there are considerable differences in how they regulate these matters, and in particular how they express the relevant standards or outputs.

Deterministic and probabilistic approaches

Deterministic planning criteria are either voluntarily adopted by DNSPs or mandated for the regulation of distribution reliability in New South Wales, Queensland, and South Australia. In New South Wales the input standards are set out in licence conditions rather than being determined by the DNSP.

In all NEM jurisdictions that employ deterministic planning criteria, the security ratings are set according to types of network elements. In this regard, different types of substations, sub-transmission lines, and feeders may have different security ratings applied. In addition, higher security ratings are generally placed on areas of the network of critical importance or with higher customer densities, such as urban and central business districts, where the impacts of a disruption to supply are likely to have the largest economic impact.

Exceptions to the use of N-x based deterministic planning requirements are the Australian Capital Territory, Tasmania and Victoria.

Victoria is the only NEM jurisdiction that adopts a probabilistic approach to distribution system planning. The Victorian DNSPs currently use the 2008 VENCORP/AEMO estimates of Victorian value of customer reliability.⁷ The only other jurisdictions to use a willingness to pay (WTP) study are the Australian Capital Territory and South Australia who, while not adopting a probabilistic approach to network planning, have used these studies in determining their supply standards.⁸

Input and output methodologies

Table 3.1 shows that four jurisdictions adopt some form of input planning standards based on N-x redundancy requirements. The levels of the input standards are generally placed at the discretion of the DNSP, with the exception of New South Wales where the input standards are set out under licence conditions.

Table 3.1 also shows that, irrespective of planning approach, all jurisdictions in the NEM use SAIDI and SAIFI performance measures as output objectives. The Australian

⁷ CRA International, Assessment of the value of customer reliability, 2008

⁸ ActewAGL Distribution, ActewAGL Distribution Determination 2009-14 – Regulatory proposal to the AER, 2008, p33; ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p39

Capital Territory extends the performance measures to include CAIDI, and Victoria includes both CAIDI and MAIFI.⁹

However, the expression of these performance measures varies between jurisdictions. In particular, there are significant differences in relation to excluded events.

All NEM jurisdictions have some form of supplemental measures in place that focus on worst-served customers. These measures are either separate reliability performance measures where groups of customers are expected to receive substantially different levels of service, as in the Australian Capital Territory, or through identification of worst performing feeders and intended remedial action, as in Queensland, South Australia, New South Wales and Tasmania.¹⁰

Reporting requirements

All jurisdictions require DNSPs to undertake some form of reliability reporting. Jurisdictional reliability reporting is undertaken on an annual basis in most jurisdictions and may, according to the individual jurisdiction, involve the preparation by the DNSP of a network development and planning report or a report on achieved performance against reliability service standards or both.

3.1.2 Governance arrangements

Overview of governance arrangements

Governance refers to the arrangements for setting, changing, and enforcing reliability measures, including the legal standing of measures.

The approach taken to governance varies depending on a number of factors, including whether a performance measure is a compliance requirement (as it is in most deterministic frameworks), or a target to guide performance expectations (as it is in most probabilistic frameworks).

A comparison of jurisdictional governance arrangements

Table 3.2 summarises the governance arrangements currently in place across the NEM jurisdictions.

⁹ Electricity Distribution (Supply Standards) Code, 2000, schedule 2; Victorian Electricity Distribution Code, 2011, clause 5.1

¹⁰ Electricity Distribution (Supply Standards) Code (ACT), clause 7.1(2); Queensland Electricity Industry Code, 2011, clause 2.3.2(k); ESCOSA, Final Decision – South Australian Electricity Distribution Service Standards 2010-2015, 2008, p57; Tasmanian Electricity Code, clause 8.3.2(b); NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, schedule 3

Table 3.2 Jurisdictional governance arrangements

Jurisdiction	Requirement(s)	Compliance effort ¹¹	Legal instrument ¹²	Administrator ¹³	Conditions for variations	Penalties
Australian Capital Territory	DNSP must publish and meet performance targets that are no worse than those specified in the Code	Must comply fully, but penalties only apply if contravene 'without reasonable excuse'	Electricity Distribution (Supply Standards) Code	Independent Competition and Regulatory Commission (ICRC)	ICRC can review the Code and approve variations to the Code	Cannot contravene a condition of its licence without reasonable excuse - max penalty \$1.65 million
Queensland	Performance standards set out in Code	Best endeavours	Queensland Electricity Industry Code	Queensland Competition Authority (QCA)	Review can be directed by the Minister and QCA can propose amendments subject to stakeholder consultation	Contravention of the Queensland Electricity Industry Code can result in civil penalties of up to \$500,000
South Australia	Performance standards set out in Code	Best endeavours	South Australia Electricity Distribution Code	Essential Services Commission of South Australia (ESCOSA)	ESCOSA is responsible for reviewing and setting the performance standards. ESCOSA can vary the Code, but must consult with the Minister and industry stakeholders	Contravention of licence conditions carries a maximum penalty of \$1 million
Tasmania	Performance standards set	Reasonable endeavours	Tasmanian Electricity	Office of the Tasmanian Economic	OTTER has the discretion to review the Tasmanian Electricity Code but can also be directed by	Contravention of licence conditions carries a maximum

¹¹ This refers to the level of compliance required by the DNSP under the relevant legal instrument

¹² This refers to the document that sets out the DNSPs' obligations

¹³ This refers to the body responsible for administering the relevant legal instrument, for example in relation to enforcement and variations

Jurisdiction	Requirement(s)	Compliance effort ¹¹	Legal instrument ¹²	Administrator ¹³	Conditions for variations	Penalties
	out in Code		Code	Regulator (OTTER)	the Minister to review the Code. The Minister has the power to amend, rescind or substitute the Code	penalty of \$140,000
Victoria	DNISP must publish and meet performance targets	Best endeavours	Victorian Electricity Distribution Code	Essential Services Commission of Victoria (ESCV)	ESCV may amend the Code persons if it considers this would better achieve the ESCV's objectives	Compliance with the Code is an obligation under the DNSPs' distribution licences. Non-compliance could trigger enforcement action by ESCV under a DNISP's licence, which could result in revocation of the licence in certain circumstances
New South Wales	Security standards and performance standards set out in licence conditions	Must be "as compliant as reasonably practicable" with the security standards by 1 July 2014 and fully compliant by 1 July 2019; absolute obligation to comply with the performance standards	NSW Electricity Distribution Licences	NSW Minister for Energy (The Independent Pricing and Regulatory Tribunal (IPART) also has enforcement functions)	NSW Minister for Energy may amend licence conditions subject to consultation obligations	Penalties apply if the DNISP has "knowingly contravened" its licence conditions. The Minister can impose penalties of up to \$100,000 or revocation of the DNISP's licence. IPART can impose penalties of up to \$40,000

Differences in jurisdictional governance arrangements

Table 3.2 shows that for all NEM jurisdictions, the reliability governance arrangements place some form of obligation on DNSPs to perform to the level of prescribed security and reliability standards. However, how that obligation is expressed varies considerably between jurisdictions, as do the consequences for non-compliance.

Regulation of standards

Reliability performance standards are usually established under jurisdictional codes with the exception of New South Wales, where the standards are specified under DNSP licence conditions. In contrast, the code in Victoria does not contain standards but requires that the DNSPs develop targets. In practice, the targets set by Victorian DNSPs are largely based on the AER's STPIS targets.

With the exception of New South Wales and Victoria, the jurisdictional regulator determines the form and level of the reliability standards and largely leaves the approach to meeting these standards at the discretion of the jurisdictional DNSPs. In New South Wales the form and level of the standards are determined by the Minister. Victoria's probabilistic approach largely leaves DNSPs to determine these matters themselves.

Administration of standards

In South Australia, Tasmania, and Victoria, the standards are governed by the jurisdictional regulator. In the Australian Capital Territory, New South Wales, and Queensland, the standards are within the control of the Minister, although they are typically determined in consultation with the jurisdictional regulator (except in New South Wales).

Variations or amendments to jurisdictional codes can generally be made by the jurisdictional regulator, although with the exception of the Australian Capital Territory and Victoria, this must be done in consultation with the state energy minister.¹⁴ In New South Wales, the state energy minister is responsible for variations to the licence conditions.¹⁵

Compliance

Compliance with jurisdictional codes or licence conditions is enforced through the relevant jurisdictional legal framework. The compliance requirements vary across the jurisdictions, with most jurisdictions requiring 'reasonable' or 'best endeavours'.

¹⁴ Essential Services Commission Act 2002 (SA), section 28; Electricity Supply Industry Act 1995 (TAS), section 49B; Electricity Distribution Code Victoria, clause 1.7; Utilities Act 2000 (ACT), Part 4; Electricity Act 1994 (QLD), sections 120P, 120PA

¹⁵ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, p4

With the exception of New South Wales, compliance with the code is a requirement of the distribution licence conditions, the contravention of which may entail penalties ranging from as low as \$140,000 in the case of Tasmania to as high as \$1.65 million in the case of the Australian Capital Territory.¹⁶ In New South Wales, the security and reliability standards are legally enforced as part of the licence conditions. The New South Wales Energy Minister may impose a penalty of up to \$100,000 or a suspension of the licence if the conditions of the licence are breached.¹⁷ A breach of the Code in Victoria could also potentially lead to revocation of the DNSP's licence. However, the revocation of a distribution licence has no precedent in the NEM.

3.1.3 Incentive schemes

Overview of incentive schemes

Incentive schemes provide a financial compensation to DNSPs to justify improvements in reliability performance. Incentive schemes may either reward or penalise DNSPs based on whether reliability performance is above or below the target levels.

Service Target Performance Incentive Scheme

Currently, the Australian Energy Regulation (AER) is in the process of applying the service target performance incentive scheme (STPIS) to each of the jurisdictions. The STPIS operates to provide financial incentives to maintain and improve service performance by assigning rewards or penalties to a DNSP where performance is better or worse than the target performance level.

These rewards or penalties are implemented through the DNSP's distribution determination, under which the AER determines the DNSP's allowed revenues for each regulatory control period. If a DNSP exceeds its STPIS targets in a regulatory control period, it receives a reward by way of an increase in its revenue allowance for the next regulatory control period. If it fails to meet its STPIS targets, it is penalised by having a reduced revenue allowance.

Targets set under the STPIS are based on average performance over the preceding five-year period and may be altered to reflect the impact of investment that has recently been undertaken or is planned to be undertaken over the coming regulatory period.¹⁸

Reliability targets set under the STPIS are in addition to the service performance standards or targets set out under electricity distribution codes or licence conditions in NEM jurisdictions.

¹⁶ Electricity Supply Industry Act 1995 (TAS), section 114B(1); Utilities Act 2000 (ACT), section 47, Legislation Act 2001 (ACT), section 133

¹⁷ Electricity Supply Act 1995 (NSW), schedule 2, clause 8

Guaranteed service level payments

An additional form of incentive on DNSPs relates to guaranteed service level (GSL) payments that are made directly to customers following disruptions to supply. Payments to customers are made according to the duration and frequency of supply interruptions or under a range of other circumstances related to the DNSP's level of service. The level of payments varies according to the specific issue and is usually capped at a maximum total payment to any particular customer in a year.

The STPIS also has elements in relation to guaranteed service levels. GSL are either set at the jurisdictional level or under the STPIS and, if a DNSP is already subject to a jurisdictional GSL scheme, the GSL element of the STPIS does not apply.¹⁹

GSL schemes have the potential to act as an incentive on DNSPs to avoid supply disruptions to customers. However, the level of payments made are typically immaterial or small with respect to the DNSP's total revenue base and the cost of improving reliability performance to avoid making GSL payments. The current jurisdictional GSL schemes are therefore unlikely to significantly influence decisions regarding expenditure on reliability performance.

A comparison of jurisdictional incentive schemes

Table 3.3 summarises the incentive arrangements that apply across the NEM jurisdictions.

18 The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p29

19 The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p30

Table 3.3 Jurisdictional incentive schemes

Jurisdiction	Commencement of AER STPIS	AER STPIS revenue at risk	Qualifying services for guaranteed service level (GSL) payments	Value of GSL payments to customers
Australian Capital Territory	2014 (in line with the start of the next regulatory period)	Not yet determined	Customer connection times; keeping agreed appointments; responding to written queries and complaints; acceptable response time to customer notification of a problem or concern; required notice periods for planned interruptions of supply; provision of a reporting service and reasonableness of time for rectification of unplanned interruptions to supply	\$20 or \$50 per breach; \$60 per day over standard up to a maximum of \$300
Queensland	Currently in operation	+/- 2%; Ergon also has +/- 0.2% for telephone answering customer service parameter	Wrongful disconnection; connection not being provided on the agreed date; re-connection not being provided within the required time; failure to attend a customer's premises within the required time concerning loss of hot water; failure to attend appointments on time; failing to provide notice of a planned interruption; duration of interruptions; frequency of interruptions	\$26 - \$130 per breach; annual maximum payments per customer of \$416
South Australia	Currently in operation	+/- 3%; ETSA also has +/- 0.3% for a telephone answering performance parameter	Frequency of interruptions; duration of interruptions	\$90 - \$185 per customer depending on annual outage frequency; \$90 - \$370 per customer depending on annual duration of outages
Tasmania	Will apply for Aurora Energy's 2012-2017 regulatory period	+/- 5%; Aurora also has a +/- 0.25% on the telephone answering parameter for performance in the first 3	Frequency of outages; duration of outages	\$80 for outages over a certain threshold depending on feeder/region; \$80 - \$160 for outage durations over a certain threshold depending on

Jurisdiction	Commencement of AER STPIS	AER STPIS revenue at risk	Qualifying services for guaranteed service level (GSL) payments	Value of GSL payments to customers
		years then a cap of +/- 0.5% for the last two years		feeder/region
Victoria	Currently in operation	+/- 5% for all but SP AusNet which has a +/- 7% cap	SAIDI and SAIFI targets	\$100 - \$300 per customer per year depending on duration of outages; \$25 - \$300 per customer per year depending on outage frequency
New South Wales	Expected to commence for the 2014-2019 regulatory period	Not yet determined	Interruptions greater than 12 hours (metro) or 18 hours (non-metro); four interruptions greater than 4 hours in a financial year (metro) or 4 interruptions greater than 5 hours (non-metro)	\$80 per customer per breach up to an annual maximum of \$320

Differences in jurisdictional incentive schemes

Table 3.3 shows that incentive schemes are in place, or soon to be in place, for all NEM jurisdictions.

Service Target Performance Incentive Scheme

Table 3.3 shows that the STPIS currently applies in Victoria, Queensland and South Australia and is to be implemented in 2012 in Tasmania and in 2014 in New South Wales and the Australian Capital Territory.²⁰ In the interim, DNSPs in those three jurisdictions are required to submit performance data to the AER during the current regulatory period, but no revenue has been placed at risk.

Guaranteed service level payments

All NEM regions have some form of GSL scheme in place although how those schemes are expressed varies considerably. In particular, the levels of payments and the specific reasons for payments vary by jurisdiction.

In most cases, payments to customers are made according to the duration or frequency of supply interruptions and each jurisdiction has separate thresholds that are deemed to be acceptable before a GSL payment occurs. In Victoria, the GSL scheme specifies minimum levels to allow for DNSPs to provide enhanced services if they wish to.²¹ In addition to duration and frequency levels, some jurisdictions have a list of other circumstances where payments to customers may be required or justified. These broadly include keeping agreed appointments with customers, responding to customer complaints and problems, and failing to provide sufficient notice of a planned interruption.

DNSPs in some jurisdictions, notably Queensland, are required to use best endeavours to automatically make payments to customers while other jurisdictions, such as New South Wales, are required to use best endeavours to make customers aware that they can apply for payments.²²

The jurisdictional guaranteed service level arrangements continue to apply in the Australian Capital Territory, Queensland, New South Wales, and Tasmania.²³ In South Australia and Victoria the jurisdictional GSL arrangements continue to apply for the current regulatory period.²⁴

²⁰ Ibid, p30

²¹ Victorian Electricity Distribution Code, 2011

²² Queensland Electricity Industry Code, 2011, clause 2.5.11; NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, clause 17.4

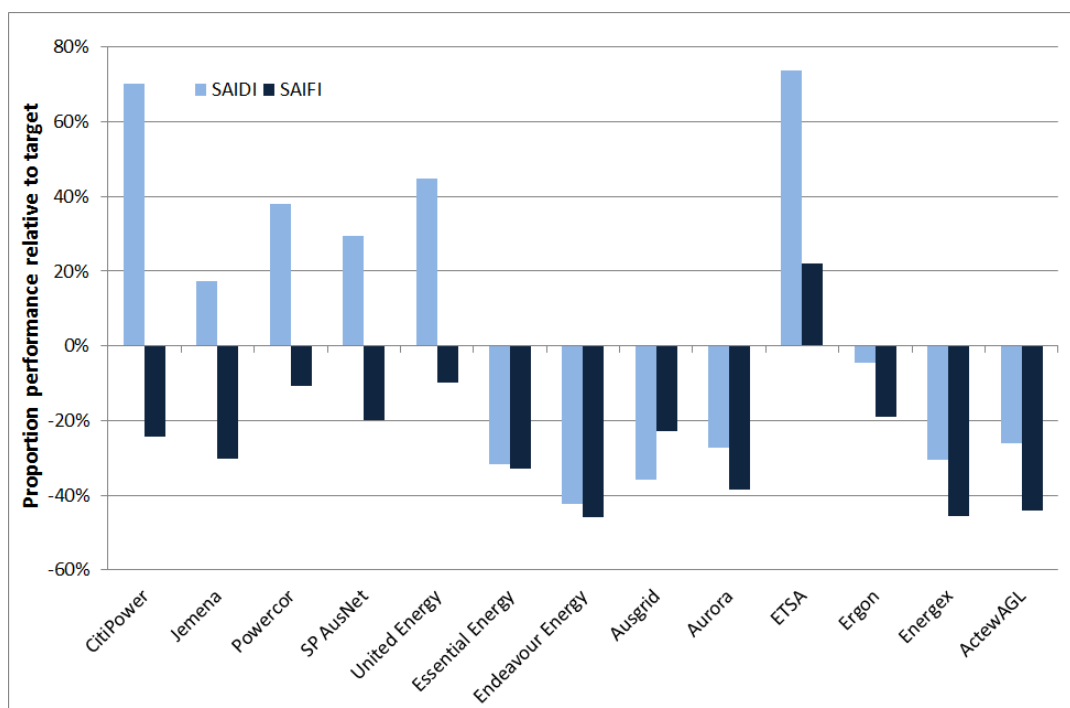
²³ The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p40

²⁴ AER, Final decision – South Australia distribution determination 2010 – 2011 to 2014 – 2015, 2010, p202; AER, Final decision – Victorian electricity distribution network service providers – distribution determination 2011 – 2015, 2010. p740

3.1.4 Recent reliability performance

Figure 3.1 shows the most recent available reliability performance for the DNSPs in each NEM jurisdiction compared with the relevant jurisdictional standard or target. For each DNSP there may be a number of targets that it is intended to meet and so an average result is presented.²⁵ The results are calculated as a margin relative to the target such that DNSPs that are outperforming on reliability will be below the target (ie a negative margin) and those that are underperforming will be above the target (ie a positive margin).

Figure 3.1 DNSP reliability performance for the most recent available year



Source: Data reproduced from DNSP reliability performance tables in Appendix A of performance for the years 2009-10, 2010 or 2010-11 as applicable. Network total is used where available, otherwise performance taken as average across feeder/customer types.

As Figure 3.1 shows, there are significant variations across the jurisdictions regarding the reliability performance relative to the targets. Generally, DNSPs in:

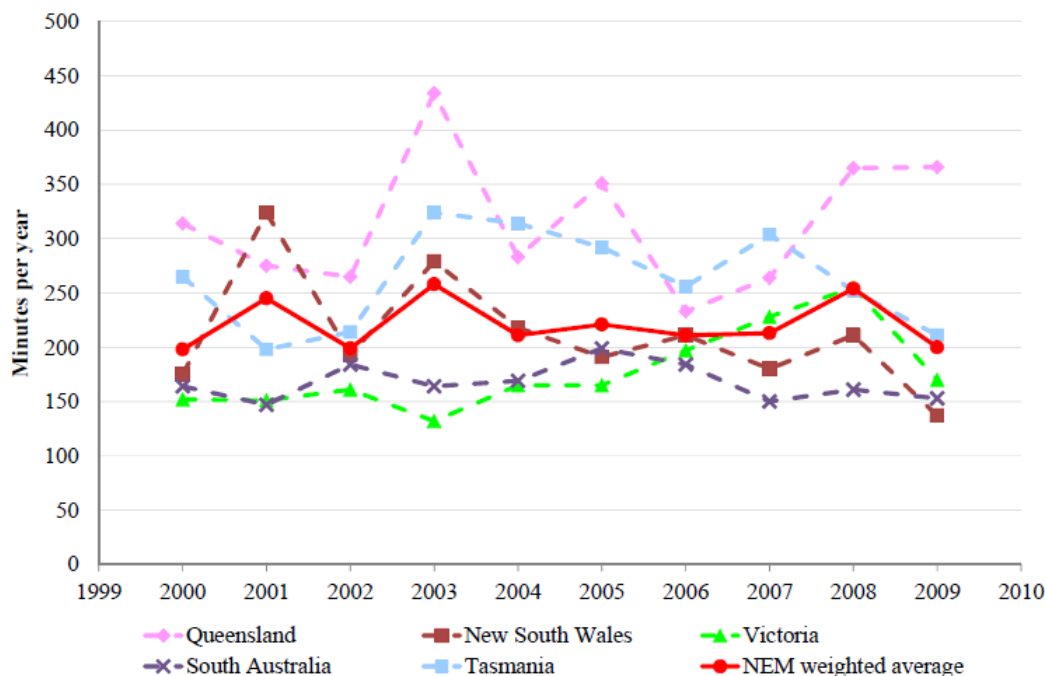
- Queensland, the Australian Capital Territory, Tasmania, and New South Wales are outperforming the targets by a material margin;
- South Australia are underperforming relative to the target; and
- Victoria are outperforming on SAIFI but underperforming on SAIDI.

However, Figure 3.1 only shows a one-year snapshot of performance and conclusions about relative performance between DNSPs and jurisdictions should not be drawn

²⁵ Individual SAIDI targets may be set for a number of different elements of the network including feeder types, substations, sub-transmission lines, etc.

from it. As Figure 3.2 shows, reliability performance within NEM jurisdictions varies materially from year to year.

Figure 3.2 SAIDI performance over time in the NEM



Source: The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p12

Consistent large variations between actual performance and targets would however raise questions about whether more rigorous compliance monitoring and clearer incentives for non-performance are necessary. Equally, consistent over-performance against the standards could be detrimental as it may indicate that customers are paying more than is necessary to achieve the level of reliability that the jurisdiction deemed appropriate when setting the targets.

3.2 Aspects of existing jurisdictional approaches for a nationally consistent framework

This section provides a discussion of aspects of existing jurisdictional approaches to distribution reliability in the NEM in consideration of the development of a nationally consistent framework.

3.2.1 Conclusions on the degree of similarities and differences between jurisdictions

From the analysis provided in section 3.1, it is evident that there are considerable similarities in the framework for reliability regulation across the NEM jurisdictions. Most NEM jurisdictions currently seek to regulate the same aspects of reliability, subject to a few exceptions. In particular:

- four jurisdictions require DNSPs to adopt some type of planning standard;
- all jurisdictions require DNSPs to meet SAIDI and SAIFI performance targets or standards;
- all jurisdictions have some form of protection for worst served customers;
- all jurisdictions require DNSPs to undertake some form of reliability-related reporting;
- DNSPs in all jurisdictions are currently, or will from the start of the next regulatory control period, be subject to the AER's STPIS; and
- all jurisdictions operate a guaranteed service level payments scheme.

However, there are differences in how the general frameworks are expressed, delivered and reported upon. For example, reliability standards and targets are expressed differently in different jurisdictions, making a comparison of performance problematic. This includes the level of disaggregation and the events that are excluded from the measures. While the AER publishes reliability performance data for the NEM jurisdictions, the data is aggregated across areas and feeder types and cannot be compared against the more detailed jurisdictional reporting.²⁶

While there is some broad overlap between jurisdictions, the existing NEM jurisdictional arrangements, when considered together, do not represent a nationally consistent framework.

It is unclear to what extent any differences in application reflect differences in characteristics of DNSPs or geographic or other differences between jurisdictions. Such differences may justify setting the required reliability outcomes at different levels, for example different SAIDI and SAIFI standards in different jurisdictions.

However, in some cases, such as the variability in penalties for contravention of the jurisdictional codes or licence conditions, the different amounts of compensation payable under GSL schemes, and the different reporting requirements, it appears unlikely that the differences are due to any underlying different characteristics between jurisdictions. For example, at present a customer who experiences a supply interruption can expect to receive a very different GSL payment depending on their residing jurisdiction.

One area where there are clear differences in approach is the regard administrators and DNSPs have to estimates of customers' willingness to pay to set reliability standards or targets and plan network augmentations. Whilst there has been some regard to willingness to pay in the Australian Capital Territory and South Australia, Victoria remains the only jurisdiction that explicitly utilises this approach in its framework,

²⁶ AER, State of the Energy Market 2011, p68

with a VCR used as part of the probabilistic approach to network planning.²⁷ However, even in Victoria, it is not apparent that the VCR or any similar assessment of the cost to customers of an outage is used when setting the level of GSL payments.

The remainder of this section outlines our initial analysis of some of the potential weaknesses of aspects of existing jurisdictional approaches and discusses specific aspects, which if adopted more widely, may provide benefit either within jurisdictions individually or as part of a nationally consistent framework.

3.2.2 Reliability planning

Responsibility for reliability planning

Most jurisdictions in the NEM employ deterministic planning criteria. This approach to reliability planning is either voluntarily adopted by the DNSP or enforced by the jurisdictional regulator for the purposes of achieving the reliability standards. Deterministic planning can use either or both input and output criteria, although there is typically no clear link between the levels of output standards and the setting of input standards.

Strict input standards may be enforced upon the DNSP by the administrator. The enforcement of input standards requires the involvement of the regulator in determining the bounds within which the DNSP is able to plan to meet the reliability standards. A chief criticism of strict input planning standards is that they blur the bounds between the respective functions of the regulator and the DNSP. The regulator takes on the responsibility for determining the level of security or redundancy that is required to best meet the reliability standards, which is a function that may be better achieved by the DNSP. Strict regulatory control through the use of input planning standards reduces flexibility and inhibits the DNSP from meeting their reliability standards through innovative means.

In the majority of NEM jurisdictions the use of deterministic planning criteria is voluntarily adopted by the DNSPs and the regulator is removed from involvement in design planning criteria. In Queensland, the regulator requires the DNSP to set its own planning standards, which both avoids the issues associated with involvement by the regulator and adds transparency to the planning process.

The Brattle Group report discusses the issues associated with regulator involvement in planning criteria and suggests that the prescription of strict input standards is most likely to be better used as a last resort when DNSPs appear unable to improve reliability.²⁸

²⁷ The New South Wales workstream has provided values of customer reliability that could be incorporated into the setting of reliability standards or targets and the planning of network augmentations

Value-based planning decisions

Design planning criteria have a significant impact on distribution reliability outcomes and the capital expenditure which is required to achieve these outcomes. In a deterministic planning process, changes to planning criteria are likely to have the largest impact on the levels of capital expenditure required to meet the prescribed reliability outputs, which in turn will impact the end cost to consumers.

An alternative approach is the adoption of probabilistic planning criteria where a DNSP's decision to invest in improvements to the distribution network is based on the value of that improvement to the customer. It follows that the most efficient delivery of improvements to reliability in the network are those that employ a proper cost/benefit analysis that incorporates some level of customers' willingness to pay.

Of course, distribution network planning does not necessarily have to strictly follow either of these approaches. For example, the jurisdictional regulator or DNSP could set input standards based on the results of a VCR study. This would combine some of the benefits of a probabilistic approach in terms of ensuring standards reflect customers' value of reliability, and some of the benefits of a deterministic approach in terms of having a standard that is transparent and enforceable. An example of how such a hybrid approach could be developed is provided in the draft report for the New South Wales workstream that was published on 8 June 2012.²⁹ In that report, a VCR study was used to undertake a cost-benefit assessment to inform decisions about the levels at which New South Wales' deterministic standards should be set.

Question 3 Reliability planning

- a) **What are the most appropriate administration arrangements for distribution reliability planning?**
- b) **What are the different approaches that could be adopted for distribution reliability planning and how could these approaches employ a proper analysis that incorporates an estimate of the value of customer reliability or willingness to pay?**

3.2.3 Reliability standards

Reliability standards refer to the minimum level of performance that a DNSP is required to meet in the supply of electricity to customers. Reliability standards are the primary output criteria to guide reliability performance. While NEM jurisdictions adopt some consistency in the standards used to measure reliability performance, there are a number of aspects of the expression of the standards in individual jurisdictions that would make proper comparison or benchmarking of performance problematic.

²⁸ The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p160

²⁹ The draft report for the New South Wales workstream is available on the AEMC website

Consistency in expressing reliability standards

In the calculation of reliability standards, and the measurement of performance against those standards, not all periods of service are included. The purpose of these exclusions should be to avoid distorting the measurement through outlier events or events that are beyond the reasonable control of the DNSP. The types of exclusions vary by jurisdiction and different forms of exclusions have been developed as a result of local factors specific to each area of network and the jurisdictions within which they operate. While this is effective in assessing the DNSP's reliability performance at a local level, it makes comparisons of reliability performance across jurisdictions problematic. Different forms and specifications of jurisdictional reliability standards also make it difficult for market participants to understand and forecast network performance.

Some jurisdictions have previously noted the importance of consistency and the ability to make comparisons with other jurisdictions. For example, in its Review of South Australian Electricity Distribution Service Standards 2010 – 2015, ESCOSA decided to retain the use of SAIDI and SAIFI as the appropriate measures of reliability performance, citing their continued use as providing national consistency and robust benchmarking of ETSA Utilities against other DNSPs in other jurisdictions.³⁰

While the types of exclusions vary by jurisdiction, DNSPs in some jurisdictions are also subject to the STPIS and therefore may have two sets of applicable reliability standards, each with different exclusions. Under these circumstances, DNSPs may be required to keep two sets of outage records, which may promote inconsistent or unclear incentives. For example, New South Wales currently has different major event day definitions for SAIDI under the New South Wales licence conditions and under the requirements for STPIS. This may result in unnecessary costs associated with collecting and reporting two sets of data, and may lead to inconsistencies once the STPIS targets apply.

While the occurrence of certain events are beyond the control of the DNSPs, there are usually measures that can be taken by the DNSP to minimise the consequences of these events. Standards that exclude certain events may incentivise DNSPs to disregard these measures. For example, excluding disruptions to supply that are caused by traffic accidents in densely populated areas may provide the wrong performance signal to DNSPs. While the DNSP is not directly responsible for the traffic accident, there are measures that could be taken by the DNSP to improve supply performance under these circumstances, such as positioning power poles away from street corners or placing distribution lines underground.

While it is important that reliability standards are set consistently, transparently, and predictably, it is also necessary to consider that the benefits of consistency in expressing reliability standards across NEM jurisdictions may be limited in order that specific locational characteristics of distribution networks are accommodated.

Exclusions are an important consideration in the measurement of reliability standards. Just as exclusions may be used to isolate aspects of customer supply that are within the

³⁰ ESCOSA, Final Decision – South Australian Electricity Distribution Service Standards 2010 – 2015, 2008, p37

reasonable control of the DNSP, they can also form an important signal for DNSPs as to which aspects of reliability to focus on. For example, excluding planned outages may incentivise DNSPs to have more planned outages to avoid the likelihood of more unplanned outages, or excluding short outages from the calculation of SAIDI, and not having MAIFI targets, can incentivise DNSPs to implement systems that avoid longer outages but result in a greater occurrence of very short outages.

Responsibility for reliability standards and price control

In NEM jurisdictions, reliability standards are either contained in electricity distribution codes or licence conditions and are governed by the jurisdictional regulator or government. The exception is Victoria, where the code does not contain standards but requires that standards are set and published by the DNSPs.

A DNSP's ability to meet reliability standards rests on the capital investments that it makes in maintaining and improving the distribution network. Except Victoria, the setting of reliability standards is influenced to some extent by the jurisdictional regulator or government and yet the price control that determines revenue and levels of capital expenditure is set by the AER. This has led to a situation where the entity setting reliability standards is not also responsible for determining the allowed levels of investment to achieve those standards.

A single entity to coordinate both the setting of reliability standards and the capital expenditure necessary to meet those standards could potentially provide a more efficient outcome. The Brattle Group report notes that it is important that reliability incentive plans are carefully coordinated with the regulation of investments, returns and prices, particularly in the NEM given the current dual governance structure of distribution regulation.³¹

In some jurisdictions the government does not have a hand in the formal setting of reliability standards, and the standards are instead independently determined by the jurisdictional regulator. However, in many of these cases, the government still has ownership of the distribution networks and is therefore able to influence levels of capital expenditure to achieve certain reliability outcomes. In these cases, there may be some merit in having the reliability standards set by an entity that is independent of the network owner.

Reporting on reliability performance

For the purposes of comparing distribution network performance between jurisdictions, it is important that reliability standards, and performance against standards, is monitored and reported with consistency and transparency. The AER publishes some aggregated data but more detailed dis-aggregated performance is reported at the jurisdictional level. It is more likely that regulators will be able to assess variations across the distribution networks with more dis-aggregated reporting of data.

³¹ The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p15

Increasing the availability of information on network standards may encourage open discussion about their appropriateness and the requirements to meet the standards.

The Brattle Group report notes that the regulation of reliability should include a requirement that DNSPs provide detailed reporting regarding reliability performance so that trends and variations across the distribution system can be assessed.³²

Question 4 Reliability standards

- a) **What are the expected costs and benefits associated with consistency in expressing reliability standards and how can locational differences between jurisdictions be accommodated?**
- b) **Is there merit in having one entity regulating both reliability standards and investments and what are the possible alternatives to this approach?**
- c) **What are the important elements of distribution reliability reporting and is there value in a nationally consistent approach?**

3.2.4 Incentives

Incentive schemes provide financial motivation to DNSPs to deliver on reliability targets and align their incentives with the value placed by customers on higher or lower reliability. Incentives may be in the form of adjustments to DNSP revenue based on performance against targets or required payments to customers for interruptions to supply.

Consideration should be given to whether the incentives carry sufficient financial implications to motivate the DNSP to improve the network and whether the incentives are correctly targeted such that certain areas of the network are not improved at the expense of others.

Compliance obligations in relation to jurisdictional standards

In most NEM jurisdictions DNSPs are required to use either “best endeavours” or “reasonable endeavours” to maintain reliability at levels consistent with or better than the reliability standards. However, the exact meaning of “best endeavours” or “reasonable endeavours” is unclear, particularly considering that reliability performance can be significantly affected by external factors such as storms, bushfires, and traffic accidents.

In most NEM jurisdictions the reliability standards are either set out in codes or in licence conditions. Compliance with jurisdictional codes or licence conditions is enforced through the relevant jurisdictional legal framework. A failure to perform to

³² Ibid, p13

the level of the reliability standard may be considered a contravention of the code or licence conditions.

While the penalties imposed on DNSPs for contravention of the code or licence conditions are subject to jurisdictional variability, it is unclear to what extent the difference in characteristics of DNSPs between jurisdictions justifies this level of variability and whether the existing penalties impose sufficient incentives on DNSPs to comply. In most cases, the penalties for contravention of the code or licence conditions are either extreme and potentially counter-productive, such as the revocation of a DNSP's distribution licence, or are financially-based but are small in comparison to total DNSP revenue.

Penalties are imposed to encourage the DNSP to perform to the level required by the standard. In cases where the penalties are not financially material to the DNSP, it may be argued whether the incentive is sufficient to encourage required improvements. In addition, in cases where the incentives have only a punitive element there may be a one sided effect where DNSPs are reluctant to invest to improve the reliability of their network beyond the minimum standard required if they believe they will not be rewarded.

As shown in Figure 3.1, it is not uncommon for DNSPs to fail to meet the reliability standards, and yet, in these cases, no enforcement action appears to have been taken, even in jurisdictions like New South Wales where there is an absolute obligation to comply with the standards.

Accordingly, the current compliance obligations under jurisdictional licences and codes may not provide a sufficiently clear incentive to DNSPs to provide an appropriate level of reliability.

Performance target incentives

Currently, the AER is in the process of applying the STPIS to each of the NEM jurisdictions. The STPIS operates to provide financial incentives to maintain and improve service performance by assigning rewards or penalties to a DNSP, as a per cent of revenue, where performance is better or worse than the target performance level.

The STPIS establishes material financial incentives on DNSPs to perform to their set targets and, in this sense, differs from previous or existing jurisdictional arrangements.³³ The purpose of having an incentive scheme with material financial implications is to strengthen the accountability of DNSPs for cost-effective achievement of the reliability and security standards, and to base those incentives on the value that customers place on reliability.

Reliability targets set under the STPIS are in addition to the standards or targets set out under electricity distribution codes or licence conditions in NEM jurisdictions. The

³³ Victoria had a jurisdictional 'S factor' incentive scheme for a number of years prior to adopting the STPIS for the current 2011-2015 regulatory control period

STPIS applies a framework for the setting of reliability targets across NEM jurisdictions, which are based on the previous five years of reliability performance. The common framework enhances consistency and ease of comparison, although individual DNSPs are able to propose that different parameters apply to them, and the AER has made a number of modifications to date in applying the STPIS to individual DNSPs.³⁴

In the NEM, the jurisdictional regulators are responsible for regulating the reliability standards of DNSPs while the AER is responsible for approving the DNSPs' expenditure to maintain reliability and meet the jurisdictional reliability standards through the distribution determination process. The AER recognises the link between investment and reliability in the STPIS and sets reliability targets which reflect assumed improvements in performance from any approved investments in reliability. This should avoid the possibility of the DNSP being compensated twice – once for the funding of the reliability improvement and a second time for the STPIS incentive payments from better performance. Of course, predicting the likely impacts of investments on levels of reliability is difficult and there is usually a lag between when costs have been incurred and when reliability improves.

Worst-served customers

While reliability incentive schemes can act to improve reliability performance, there is a limit to the level of detail of network performance and customer value of reliability on which they can be based. For practical reasons, incentive schemes tend to focus on average or aggregated performance across networks. As a result, they are not likely to provide incentives to the DNSP to provide a level of reliability for every customer in the network that reflects that customer's value of reliability or willingness to pay for reliability.

Disaggregation of standards or incentives so that different standards apply for different regions, types of customer, or types of feeders in the network, can partially address this issue. However, incentive schemes almost always still only apply to the average level of reliability provided to each customer type, feeder or region.

Aggregated incentive structures can result in incentives for DNSPs to focus their investments on improving reliability of service to specific areas of the network where they can achieve the largest improvements at lowest cost. One specific risk is that it is often most cost effective to improve average reliability by providing even better reliability to those customers that already receive better than average levels of reliability, rather than targeting customers with poor performance. Such an approach may arguably be the most economically efficient strategy, but can raise concerns regarding equity and fairness.

Most NEM jurisdictions therefore have supplemental measures in place that focus on worst served customers. There are currently no provisions for worst served customers in the STPIS.

³⁴ The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes,

The Brattle Group report notes that there may be benefits to including supplemental measures relating to worst served customers.³⁵ These measures may be direct financial incentives, but could also be a requirement to publish annual distribution planning statements that outline actions to be taken with regard to worst served customers.

Guaranteed Service Level (GSL) payments

A further form of incentive scheme adopted by NEM jurisdictions are guaranteed service level payments made directly to customers when certain levels of reliability are not met. All NEM regions have some form of GSL scheme in place although the levels of payments and the specific reasons for payments vary by jurisdiction.

GSL payments only act as incentives to DNSPs if the payments to customers are higher than the cost of improving reliability to avoid making those payments. The current levels of payments by DNSPs under GSL schemes in the NEM are low, and as noted in the draft report for the New South Wales workstream, GSL payments do not appear to have been taken into account by DNSPs in making decisions on reliability-related expenditure.³⁶

The STPIS can also cover GSL payments. Under the STPIS GSL arrangements the DNSP is able to retain the difference between expected and actual payments for the duration of the regulatory price control period.³⁷

If a DNSP is already subject to a jurisdictional GSL scheme, the GSL element of the STPIS does not apply. As a result, the STPIS GSL provisions do not currently apply in any NEM jurisdiction.

Currently, a customer who experiences an interruption to supply can expect to receive a very different GSL payment depending on their residing jurisdiction. Ideally, the GSL payments made to a customer should reflect the value to that customer of the interruption that was experienced. The GSL arrangement under the STPIS attempts to achieve this by basing GSL payments on the value of customer reliability from willingness to pay studies. GSL payments under STPIS relate to VCR studies unlike under jurisdictional GSL arrangements.

In most jurisdictions, customers must apply for GSL payments. However, DNSPs in some jurisdictions are required to automatically make payments to customers while other jurisdictions are required to make customers aware that they can apply for payments. As an incentive scheme, GSL arrangements may be more effective where the DNSPs have an obligation to automatically make payments to customers.

January 2012, p28

35 Ibid, p160

36 See section 2.1.4 of the New South Wales draft report, which is available on the AEMC website

37 The Brattle Group, Approaches to setting electric distribution reliability standards and outcomes, January 2012, p30

Customer communication requirements

While some customers may value greater reliability in the distribution network and less interruptions to supply, others may prefer to be forewarned of planned outages or factors that may disrupt supply, or be provided with better information regarding the existence and likely duration of unplanned outages.

Customer preferences for improved communications over greater levels of reliability were explored in the residential customer survey as part of the New South Wales workstream.³⁸ The results showed that 60 per cent of all respondents prioritised investment to reduce the number of outages, while close to a quarter of respondents prioritised investment in communications systems.

A number of different channels are available to DNSPs to notify customers of possible disruptions to supply, including text messaging, telephone, social media and the internet. Notifications allow customers to plan for outages and reduce the potential for any costly impacts. In cases where the customer places less value on reliability, customer notification may be a significantly less expensive alternative to network augmentation.

Provisions exist regarding customer communications under the National Energy Customer Framework (NECF). These include:

- DNSPs will be required to maintain a 24-hour fault information and reporting telephone number;³⁹
- DNSPs will be required to provide customers notice at least four days in advance for planned interruptions, and the notice must specify the expected date, time and duration of the interruption;⁴⁰ and
- for unplanned interruptions, DNSPs will be required to provide customers information within 30 minutes of the DNSP being advised of the interruption and for the DNSP to use best endeavours to restore supply to affected customers as soon as possible.⁴¹

None of the NEM jurisdictions currently mandate more proactive communications such as text message notifications. However, some DNSPs such as CitiPower and Powercor in Victoria have voluntarily adopted such systems.⁴²

Given the additional expenses that are likely to be required in implementing a customer service system, it would seem inappropriate to mandate them unless there is clear evidence of a net benefit. However, jurisdictional reliability requirements should provide DNSPs with flexibility to adopt such systems if the benefits of doing so exceed

³⁸ See section 4.3 of the New South Wales draft report, which is available on the AEMC website

³⁹ National Energy Retail Rules, section 85

⁴⁰ Ibid, section 90

⁴¹ Ibid, section 91

⁴² www.powercor.com.au/Latest_News/_97/

the costs, for example if the DNSP can demonstrate that it is more cost effective to implement such a system as an alternative to making a network investment to improve reliability and that the DNSP's customers would prefer that alternative.

Question 5 Incentives

- a) **What are the expected costs and benefits associated with existing jurisdictional incentive schemes for distribution reliability performance and the movement towards a more consistent approach across the NEM?**
- b) **How could a nationally consistent incentive scheme for distribution reliability performance accommodate worst served customers?**
- c) **What are the important considerations for GSL schemes and is there value in a nationally consistent approach?**
- d) **What are the expected costs and benefits associated with customer communications?**

4 Consideration of a nationally consistent framework

As noted in Chapter 2, the terms of reference for this review require the AEMC to advise on whether there is merit in developing a “nationally consistent framework for expressing, delivering and reporting on distribution reliability outcomes”.

A “nationally consistent framework” may have a range of interpretations.

This Chapter provides an initial view of our proposed approach to the meaning of that term, the potential costs and benefits of moving to such a framework, and the required considerations for the implementation of a nationally consistent framework.

4.1 The meaning of a nationally consistent framework

Before assessing the merits of moving to a nationally consistent framework, consideration must be given to the meaning of a “nationally consistent framework”.

A key consideration in the design of an efficient framework for delivering reliability in distribution networks is that the level of reliability is consistent with the economic and/or social value placed on reliability by the consumer and the costs of providing different levels of reliability to consumers.

Distribution network standards in the NEM currently appear to give some recognition to the variance in economic and social impacts of supply reliability according to population density, customer type, and/or location, and the variance in costs depending on those and other criteria. For example, this appears to be reflected in most NEM jurisdictions where the distribution network reliability standards for urban areas are at a higher level than in other rural and remote areas. These different standards have presumably been adopted because the body setting those standards has concluded that the value of reliability is higher in urban areas than rural areas or that the costs are higher in rural areas than urban areas. However, we note that most jurisdictions have not undertaken detailed VCR or WTP studies to confirm the extent of any such differences.

In addition, specific locational differences may mean that the economic and social impacts of supply interruptions vary by jurisdiction. Therefore, areas of the distribution network in separate jurisdictions that have loads of a similar size or critical importance may not be suited to the same level of reliability standard. As noted in the terms of reference, “it is entirely appropriate for standards to differ across jurisdictions due to the different characteristics of distribution networks”.

For the purposes of this review, a “nationally consistent framework” does not mean that the same level of reliability standard should be applied to all areas of a DNSP’s network. It also does not necessarily mean that the same level of reliability standards or outcomes should be applied to areas of DNSPs’ networks in different jurisdictions with similar load sizes or critical importance.

Rather, the focus of a nationally consistent framework should be on implementing a consistent framework for reliability standards and outcomes. Using the words of the terms of reference, the focus of this framework is the approach to “expressing, delivering and reporting on distribution reliability outcomes”.

The terms of reference note that “there will be no harmonisation of existing jurisdictional obligations”. We interpret this comment to mean that the level of jurisdictional reliability standards and outcomes would not be harmonised, but that the approach to expressing, delivering and reporting on those standards or outcomes would be made more consistent under a national framework.

There are several potential ways of achieving a nationally consistent framework.

- One option would be to move to a consistent framework that is adopted by each jurisdictional government or regulator in the relevant jurisdictional code or licence conditions.
- Another approach would be to transfer some or all of the responsibility for applying and enforcing distribution reliability standards and outcomes to the AER.
- Given that the AER’s STPIS already provides for a consistent framework for incentive schemes and GSL payments, a third approach would be for jurisdictions to remove at least some of their current jurisdictional reliability requirements and rely instead on the AER’s STPIS. As discussed in Chapter 4, there are costs and risks of inconsistent incentives if there is duplication between jurisdictional requirements and the requirements of the STPIS. A significant degree of consistency could be achieved relatively easily by simply removing some of the existing jurisdictional requirements that may no longer be needed once the STPIS is in place.

Question 6 The meaning of a nationally consistent framework

- a) What should a nationally consistent framework mean, and what should it not mean?**
- b) How should a "nationally consistent framework" be interpreted and what degree of consistency/harmonisation is appropriate?**
- c) In the context of setting and enforcing regulatory requirements, is it appropriate for the same body (eg the AER, a jurisdictional regulator, or a jurisdictional minister) to be responsible for both setting and enforcing reliability standards and outcomes?**

4.2 The costs and benefits of moving to a nationally consistent framework

Consistency for the sake of consistency is likely to produce relatively limited benefits. However, a nationally consistent framework could potentially offer significant benefits if that framework represents best practice and is a substantial improvement on at least some aspects of the approaches currently adopted by jurisdictions.

Based on our initial analysis, the Commission's preliminary view is that a nationally consistent framework for expressing, delivering and reporting on reliability outcomes is likely to provide benefits if it is:

1. *Expressed* effectively and determined transparently so that proper comparison of reliability levels across jurisdictions can be made and a basis for changes to reliability levels can be justified;
2. *Delivered* economically through proper cost/benefit analysis of expenditure according to the value to customers of maintaining or improving reliability; and
3. *Reported* and monitored consistently against reliability targets with proper incentives/penalties in place with material financial implications.

4.2.1 Expressed effectively

A move towards ensuring that reliability standards in separate jurisdictions are expressed transparently, predictably, and consistently is likely to allow for proper comparisons of performance to be made, leading to more efficient investment decisions and more robust justifications for expenditure on reliability.

Currently, different forms of reliability standards, and the variation of exclusions in calculating the standards, make it difficult for market participants to understand and forecast network performance between NEM jurisdictions.

However, the degree of consistency in expressing reliability standards across NEM jurisdictions is likely to be limited by the specific locational characteristics of distribution networks. Exclusions in the calculation of reliability standards are usually based on events that are beyond the direct control of the DNSP. Harmonisation of the expression of reliability standards may compromise on tailoring reliability standards to the characteristics of individual distribution networks.

Accordingly, complete harmonisation in the expression of standards or outcomes may not be appropriate, although greater consistency in how these factors should be assessed and reflected when setting standards or outcomes is still likely to be beneficial.

4.2.2 Delivered economically

Design planning criteria and reliability standards have a significant impact on distribution reliability outcomes and the capital expenditure which is required to achieve these outcomes.

A nationally consistent framework for delivering reliability outcomes is likely to be efficient where decisions to invest to maintain or improve reliability are determined on the basis of how much the customer values such reliability. Net benefit is likely to be obtained where the framework recognises the trade-off between the costs of investment to improve reliability and the costs to customers of outages, and incorporates some level of the value of customer reliability or customer willingness to pay in investment decisions.

However, changes in the form of standards can significantly impact the resources that are required for distribution planning. For example, probabilistic planning is likely to require considerably greater modelling and analysis by DNSPs than deterministic planning.

Distribution standards that identify a requirement for greater capital expenditure may contribute to an increase over time in the level of distribution charges faced by customers. These higher charges may deliver higher levels of reliability, but will only be efficient if customers value such improved reliability more than the costs of the required investment.

Conversely, moving to a lower level of distribution standard may see a gradual reduction in capital expenditure and distribution charges, which may be viewed as a benefit. However, while the reduced expenditure may be realised immediately, the impacts from the reduction in distribution reliability may take some time to be made clear. In addition, the reduction in reliability may be imperceptible most of the time, and only become apparent when there is an outage on the network.

At this stage, the Commission does not have a view on the most appropriate method for determining customers' value of reliability and willingness to pay for reliability improvements. In the New South Wales workstream of this review, the Commission based its cost-benefit analysis on a VCR survey, with some willingness to pay questions added. That approach was required due to time constraints, and also had the benefit of consistency with the VCR studies that AEMO has previously undertaken in Victoria. However, the Commission is aware that there are a number of alternative approaches to estimating willingness to pay.

If the Commission considers that there is merit in moving to a nationally consistent framework, and the SCER asks the Commission to develop such a framework, we will give more detailed consideration to the most appropriate method for estimating customers' value of reliability and willingness to pay for reliability improvements.

4.2.3 Reported consistently

Consistency in the monitoring and reporting of performance against reliability target levels is likely to provide for more transparent and reliable comparisons to be made across NEM jurisdictions.

In order to achieve consistency in reporting between jurisdictions, there would need to be some level of consistency in the approach to expressing reliability targets and outcomes. Currently, the AER is in the process of applying the STPIS to each of the NEM jurisdictions. The STPIS operates to provide financial incentives to maintain and improve service performance by assigning rewards or penalties to a DNSP where performance is better or worse than the target performance level. The STPIS establishes material financial incentives on DNSPs to perform to their set targets and, in this sense, differs from previous or existing jurisdictional arrangements.

The purpose of having an incentive scheme with material financial implications is to strengthen the accountability of DNSPs for cost-effective achievement of the reliability standards. A transparent and effective incentive structure is likely to reduce the long-term costs of maintaining reliability, thereby reducing costs to consumers.

However, while the imposition of a uniform incentive structure for the development of reliability targets across NEM jurisdictions would assist with consistency and ease of comparison, it is unclear to what extent this would be feasible or appropriate given the specific locational characteristics of different networks within NEM jurisdictions. As noted above, any national framework is likely to seek to achieve greater consistency rather than complete harmonisation.

Question 7 Costs and benefits of a nationally consistent framework

What are the expected costs and benefits of moving to a nationally consistent framework?

4.3 The National Electricity Objective

For the purposes of the review, the AEMC intends to assess the merits of a nationally consistent framework within the context of contributing to the achievement of the National Electricity Objective (NEO).

The NEO is set out in section 7 of the National Electricity Law (NEL) as follows:

“The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- a) price, quality, safety, reliability and security of supply of electricity;
and
- b) the reliability, safety and security of the national electricity system.”

In the context of a nationally consistent framework, the Commission considers that the relevant elements of the NEO are the promotion of efficient investment in electricity services with respect to price and the reliability of supply.

The Commission considers that a nationally consistent framework for expressing, delivering, and reporting on distribution reliability outcomes has the potential to contribute to the achievement of the NEO through:

- Provision of transparent, predictable, and consistent forms of reliability standards to facilitate market participants' operations across the NEM and to encourage a more efficient allocation of investment. In particular, transparent expression and reporting of reliability outcomes would allow customers to make more informed decisions about which jurisdiction to locate in. It would also allow the AER and other bodies to undertake more effective benchmarking of DNSPs in different jurisdictions.
- Promotion of a more efficient allocation of resources through the use of value-based planning and reliability decisions which incorporate an assessment of the value to customers of improved reliability in consideration of the costs of network investment. This would improve efficiency by ensuring that reliability outcomes reflect a price-reliability trade-off that reflects customers' preferences.
- Strengthening of the accountability of DNSPs for cost-effective achievement of the reliability standards through a transparent and materially financial incentive structure. If accountability arrangements provide strong incentives then DNSPs are more likely to undertake an efficient level of investment to meet (but not unduly exceed) the required reliability outcomes.
- Consistency between jurisdictional and national reliability requirements. To the extent that there continue to be separate reliability and outcomes set by jurisdictions and by the AER under the STPIS, there is a significant risk of inefficiency and inconsistent incentives if those requirements are not aligned or closely coordinated.

In recommending a nationally consistent approach, it will be necessary to consider the proportionality of the changes that are required with respect to the materiality of the issues and the value of stability and predictability in the energy market regime.

Question 8 The National Electricity Objective

- a) How would a nationally consistent framework be likely to contribute to the achievement of the NEO?**
- b) How material are the current jurisdictional differences in reliability standards and outcomes to consumers? What impact do those differences have on consumers' locational decisions?**

4.4 Implementation of a nationally consistent framework

Given the differences between existing distribution reliability approaches in NEM jurisdictions, the implementation of a nationally consistent framework will be likely to require significant changes to jurisdictional and national laws, regulations, licences and codes. These changes will need to be transitioned, in a coordinated manner, across the NEM.

In most NEM jurisdictions, compliance with distribution standards in codes or licence conditions is a critical component in the licensing and regulatory regimes faced by DNSPs. Any implementation plan will need to recognise how the establishment of a nationally consistent framework will affect the committed investment plans and future capital and operational expenditure of DNSPs.

In addition, if the form of standards is changed, or if there are significant changes to the planning methodologies used, then network planning may become more costly and require additional resources. DNSPs will need to be given time to transition to these changes. In these cases, the AER may need to make adjustments to the regulatory allowances for DNSPs.

Distribution reliability standards require DNSPs to plan, build, and operate their networks to meet the level of reliability standards in an efficient manner. DNSPs are held accountable for network reliability by the following bodies:

- the AER, which enforces the National Electricity Rules (NER), including those relating to power system performance and security, makes distribution determinations, as part of which it approves capital and operating expenditures to meet jurisdictional reliability obligations and maintain network reliability, sets regulated distribution charges, establishes target performance levels and incentives as part of the STPIS, and monitors compliance with those determinations and performance targets; and
- jurisdictional ministers and regulators, who issue distribution licences, set jurisdictional security and reliability standards, and enforce distribution licence conditions and codes.

The implementation of a nationally consistent framework for distribution reliability outcomes would need to recognise the above interdependencies if all of these bodies continue to have responsibilities under a nationally consistent framework.

Consideration would also need to be taken of how to give effect to the new standards. It is likely that this could be undertaken through either a change to existing jurisdictional codes, referral in existing jurisdictional codes to the new standards, or abolition of the jurisdictional codes and replacement with a common instrument in which the new distribution standards are specified.

Question 9 Implementation of a nationally consistent framework

- a) What are the important considerations in moving away from existing jurisdictional frameworks to an approach that is nationally consistent?
- b) What issues are likely to arise in the process of moving from existing jurisdictional frameworks to an approach that is nationally consistent and how could these best be managed or overcome?
- c) What implementation costs would likely to be incurred in moving to a nationally consistent framework?

Glossary and abbreviations

Administrator	The body responsible for varying and enforcing the jurisdictional code or licence conditions
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAIDI	Customer Average Interruption Duration Index - the average time taken to restore supply to a customer after an interruption occurs
Design planning criteria	See input reliability standard
Deterministic planning	Network planning that seeks to provide the adequate and secure supply of electricity to consumers by incorporating sufficient levels of redundancy in the network
Distribution	The supply of electricity to consumers through the low voltage network
DNSP	Distribution Network Service Providers
GSL	Guaranteed Service Level - payments made by the DNSP to customers according to the duration and frequency of supply interruptions or under a range of other circumstances related to the level of service
ICRC	Independent Competition and Regulatory Commission
Incentive scheme	A mechanism that holds DNSPs accountable through a system of rewards and penalties based on performance against standards
Input reliability standard	Specification of the level of redundancy in the network to which the DNSP must plan in order to control the consequences of an outage

MAIFI	Momentary Average Interruption Frequency Index - a measure of how many supply interruptions occurred in a year of a specific very short duration
Major event	A day that is excluded from the measurement of performance against reliability targets due to the occurrence of a major interruption to supply, defined as occurring when the daily total system SAIDI exceeds a pre-determined threshold which is based on historical SAIDI values
MCE	Ministerial Council on Energy
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
Outcomes	The level of reliability actually provided by the DNSP
Output reliability standard	Specification of the level of reliability that the DNSP is required to meet
Probabilistic planning	Network planning that takes into account the probabilities of supply interruptions to consumers under a range of possible operating conditions and assigns an economic value to customer loads that are not served. The value of customer load is measured through a VCR or other measure that places a value on expected supply interruptions, to assess whether an augmentation should proceed, rather than applying pre-determined criteria. VCRs estimate the costs of different types of interruptions for different customer types. A VCR is used to value the benefits of a proposed network upgrade so they can be compared to the costs of the upgrade. Investments only proceed if the benefits outweigh the costs.
Reliability	The ability of the network to transport sufficient electricity to meet consumer demand

RAB	Regulatory Asset Base
SAIDI	System Average Interruption Duration Index - the sum of the duration of each sustained customer interruption, multiplied by the number of customers impacted by each interruption, divided by the total number of customers serviced
SAIFI	System Average Interruption Frequency Index - the total number of sustained interruptions, multiplied by the number of customers impacted by each interruption, divided by the total number of customers serviced
SCER	Standing Council on Energy and Resources
Security standard	See input reliability standard
STPIS	Service Target Performance Incentive Scheme - a scheme operated by the AER to provide financial incentives to maintain and improve service performance by assigning rewards or penalties to a DNSP where performance is better or worse than the target performance level
VCR	value of customer reliability - the costs that supply interruptions impose on end-use customers, as defined in the New South Wales draft report
WTP	willingness to pay - the willingness of customers to pay for an improvement to the level of reliability

A Summary of jurisdictional distribution reliability requirements in NEM

This appendix provides an overview of the approaches used to determine distribution reliability standards and outcomes in each of the National Electricity Market (NEM) jurisdictions.

In undertaking the jurisdictional analysis, we have incorporated discussion on the following issues, for each of the jurisdictions:

- Security or redundancy requirements - refers to the way in which the distribution network service provider (DNSP) is required to build and maintain the network in relation to security of supply. This includes both deterministic standards (requiring network investment to ensure specified network operational conditions will be met) and probabilistic standards (where the network investment is justified on the basis of the benefits outweighing the costs).
- Reliability performance standards - refers to the level of service standards a DNSP is required to meet. The most common indices used for measuring service standards are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI is used to measure the length of outages, usually on a minutes per customer per year basis. SAIFI measures the frequency of outages, and is usually measured using a number of outages per year approach.
- Worst-served customer reliability standards - does the DNSP face any requirements or obligations to improve the service standards for customers in low-reliability areas? For example, the DNSP may be required to implement improvement programs or meet annual reporting obligations for poor performing parts of their network.
- Guaranteed service level (GSL) payments - this refers to payments a DNSP is required to make to customers where certain reliability standards are not met. The threshold for GSL payments being made is usually defined relative to the SAIDI and SAIFI targets a DNSP is required to meet.
- Incentive schemes - do DNSPs face incentives to maintain or improve service performance? Currently, the Australian Energy Regulator (AER) is in the process of applying a national Service Target Performance Incentive Scheme (STPIS) to each of the jurisdictions. The STPIS operates to provide a financial incentive to maintain and improve service performance by assigning rewards or penalties (usually expressed as a percentage of overall DNSP revenue) to a DNSP where performance is better or worse than the target performance level. The target performance levels are usually derived from historical performance records.
- Governance arrangements - what is the governance framework in place for the DNSP security and reliability standards - how are the standards determined,

who is responsible for enforcing the standards, what are the penalties for not meeting the standards?

- Reporting requirements - what requirements are placed on the DNSP in relation to reporting of network reliability performance - for example, are they required to report annually and publish their own reports, or are the reports submitted to and published by the jurisdictional regulator?
- Recent distributor reliability performance - this section provides an overview of the most recent DNSP reliability performance against relevant SAIDI and SAIFI targets.
- Any relevant customer willingness to pay (WTP) studies that have been completed for the jurisdictions and how these have been incorporated into network security and reliability standards.
- Any other relevant issues (for example, jurisdictional reliability reviews).

A.1 Australian Capital Territory

A.1.1 Overview

The Australian Capital Territory has only one DNSP, ActewAGL Distribution, with the following characteristics:

- 157,635 customers;
- 4,858 kilometres of distribution network lines;
- customer density of 32 customers per kilometre of network
- maximum demand of 604 Mega Watts (MW); and
- a regulatory asset base (RAB) of \$617 million.⁴³

A.1.2 Jurisdictional requirements

Security standards

There are currently no deterministic security standards in the Australian Capital Territory. However, the Electricity Distribution (Supply Standards) Code does require DNSPs to include provisions in its standard customer contract to the effect that the DNSP will take all reasonable steps to ensure that its electricity network will have sufficient capacity to make an agreed level of supply available.⁴⁴

⁴³ Australian Energy Regulator, 2011, State of the Energy Market 2011, p. 56

⁴⁴ Electricity Distribution (Supply Standards) Code, 2000, clause 8

Reliability performance standards

The Electricity Distribution (Supply Standards) Code requires DNSPs to publish their targets for reliability of supply for the following year before 31 December each year.⁴⁵ ActewAGL Distribution is given discretion over the reliability targets it chooses. However, as a minimum, the reliability targets chosen by ActewAGL Distribution can be no worse than those specified in Schedule 2 of the Electricity Distribution (Supply Standards) Code.⁴⁶ Schedule 2 of the Electricity Distribution (Supply Standards) Code specifies the following minimum targets:

- SAIDI - 91.0 minutes;
- SAIFI - 1.2; and
- Customer Average Interruption Duration Index (CAIDI) - 74.6 minutes.⁴⁷

These minimum targets are based on the outcomes achieved by ACTEW Corporation in 1996-97.⁴⁸

ActewAGL Distribution has adopted these supply reliability targets for each year of the 2009-14 regulatory period.⁴⁹

Outages of less than one minute, and extended outages due to storms, are excluded from these performance standards.⁵⁰

Worst-served customer reliability standards

Clause 7.1(2) of the Electricity Distribution (Supply Standards) Code requires DNSPs to set separate reliability targets where groups of customers are expected to receive substantially different levels of service.

Guaranteed service levels payments

The Consumer Protection Code provides for customers to apply for rebates of between \$20 and \$60 per incident, depending on the subject of the customer application, where service levels are below certain levels. For certain subjects (eg customer connection times) customers can only apply for rebates totalling no more than \$300 in one year.⁵¹

Relevant rebateable performance standards cover the following actions:

⁴⁵ Electricity Distribution (Supply Standards) Code, 2000, clause 7.1(1)

⁴⁶ Electricity Distribution (Supply Standards) Code, 2000, clause 7.2(3)

⁴⁷ Electricity Distribution (Supply Standards) Code, 2000, schedule 2. CAIDI is a measure of the average length of supply interruption that any customer will experience.

⁴⁸ Electricity Distribution (Supply Standards) Code, 2000, schedule 2, note 4

⁴⁹ ActewAGL Distribution, 2008, ActewAGL Distribution Determination 2009-14 - Regulatory Proposal to the Australian Energy Regulator, p. 33

⁵⁰ Electricity Distribution (Supply Standards) Code, 2000, schedule 2, note 5

⁵¹ Consumer Protection Code, 2007, Schedule 1

- customer connection times;
- keeping agreed appointments;
- responding to written queries and complaints;
- acceptable response time to customer notification of a problem or concern;
- required notice periods for planned interruptions of supply; and
- provision of a reporting service and reasonableness of time for rectification of unplanned interruptions to supply.⁵²

Incentive schemes

The AER STPIS will apply in the Australian Capital Territory from 2014 (in line with commencement of the next regulatory period).⁵³ However, during the current regulatory period, ActewAGL Distribution has been required to implement measures so that it can fully comply with the national STPIS from 2014. In addition, ActewAGL Distribution has been required to submit performance data to the AER during the current regulatory period, but no revenue has been placed at risk.⁵⁴

A.1.3 Governance arrangements

The Independent Competition and Regulatory Commission (ICRC) is responsible for administering the Electricity Distribution (Supply Standards) Code, including approving variations to the code.⁵⁵

As a company holding a utility licence, ActewAGL Distribution is required to comply with the Electricity Distribution (Supply Standards) Code under the *Utilities Act 2000* (ACT).⁵⁶ Licence conditions can be reviewed by the ICRC, subject to stakeholder consultation taking place.⁵⁷

Under the *Utilities Act 2000* (ACT), a utility cannot contravene a condition of its licence without reasonable excuse.⁵⁸ The maximum penalty is \$1.65 million.⁵⁹

52 Consumer Protection Code, 2007, Schedule 1

53 AER, 2009, Final Decision - Australian Capital Territory distribution determination 2009-10 to 2013-14, p. 112

54 AER, 2009, Final Decision - Australian Capital Territory distribution determination 2009-10 to 2013-14, p. 112

55 *Utilities Act 2000* (ACT), Part 4

56 *Utilities Act 2000* (ACT), section 25

57 *Utilities Act 2000* (ACT), section 46

58 *Utilities Act 2000* (ACT), section 47

59 *Utilities Act 2000* (ACT), section 47, *Legislation Act 2001* (ACT), section 133

A.1.4 Reporting requirements

The Electricity Distribution (Supply Standards) Code requires ActewAGL Distribution to monitor the quality of supply, and report annually to the 'Chief Executive' on ActewAGL Distribution's performance against each of the standards specified in the Electricity Distribution (Supply Standards) Code.⁶⁰ However, it is unclear whom the 'Chief Executive' is. The definition in the Electricity Distribution (Supply Standards) Code refers to the meaning provided in the *Utilities Act 2000* (ACT). However neither the current version of the *Utilities Act 2000* (ACT) or the *Legislation Act 2001* (ACT) provide any further definition of 'Chief Executive'.

The ICRC publish an annual compliance and performance report for licensed electricity, gas, water and sewerage utilities in the Australian Capital Territory. These reports contain information provided by ActewAGL Distribution to the ICRC on reliability performance achieved by ActewAGL Distribution, and are available on the ICRC's website.

A.1.5 Recent reliability performance

The table below shows ActewAGL Distribution's reliability performance for 2009-10. The use of a 'network total' reflects the fact that ActewAGL Distribution is only required to set reliability targets for the network as a whole, and not at the individual feeder level.

Table A.1 ActewAGL Distribution reliability performance 2009-10

Feeder type	SAIDI (average minutes per customer)		SAIFI (average number of interruptions per customer per year)		CAIDI (average duration in minutes per interruption)	
	Target	Actual	Target	Actual	Target	Actual
Urban	n/a	29.7	n/a	0.66	n/a	45.00
Rural	n/a	26.1	n/a	0.78	n/a	33.40
Network total	40.0	29.6	1.2	0.67	74.6	44.50

A.1.6 Customer willingness to pay

In 2003 ActewAGL Distribution commissioned NERA Economic Consulting to undertake a WTP study to establish customers' marginal WTP for a range of service quality elements.⁶¹ To complete the study, NERA Economic Consulting used a stated

⁶⁰ Electricity Distribution (Supply Standards) Code, clause 10.1

⁶¹ ActewAGL Distribution, 2008, ActewAGL Distribution Determination 2009-14 - Regulatory Proposal to the Australian Energy Regulator, p. 34

preference choice modelling survey to reveal customer preferences, and simulate a market environment whereby customers are provided with choices between various service quality and price options.⁶²

In their 2008 regulatory proposal on network charges to the AER, ActewAGL Distribution noted that "a clear outcome from the WTP study was customers' aversion to the frequency and duration of both planned and unplanned outages. The study found that customers were less concerned with planned outages (of a given duration), as long as they were given sufficient notice of that outage (two to seven days prior notice)."⁶³

ActewAGL Distribution has incorporated the findings of their WTP study in determining their supply standards during the current regulatory period.⁶⁴

A.2 Queensland

A.2.1 Overview

Queensland has two DNSPs - Ergon Energy, which provides distribution network services to regional Queensland, and Energex, which provides distribution network services to south-east Queensland.

Currently, Energex has:

- 1,298,790 customers;
- 53,256 kilometres of distribution network;
- customer density of just over 24 customers per kilometre of network;
- maximum demand of 4,817 MW; and
- a RAB of \$7,867 million.⁶⁵

Ergon Energy has:

- 680,095 customers;
- 146,000 kilometres of distribution network;
- customer density of just under 5 customers per kilometre of network;

⁶² ActewAGL Distribution, 2008, ActewAGL Distribution Determination 2009-14 - Regulatory Proposal to the Australian Energy Regulator, p. 34

⁶³ ActewAGL Distribution, 2008, ActewAGL Distribution Determination 2009-14 - Regulatory Proposal to the Australian Energy Regulator, p. 34

⁶⁴ ActewAGL Distribution, 2008, ActewAGL Distribution Determination 2009-14 - Regulatory Proposal to the Australian Energy Regulator, p. 33

⁶⁵ Australian Energy Regulator, 2011, State of the Energy Market 2011, p. 56

- maximum demand of 2,608 MW; and
- a RAB of \$7,149 million.⁶⁶

A.2.2 Jurisdictional requirements

Security standards

Distribution security standards for the Queensland DNSPs are set using a deterministic approach. Both Queensland DNSPs are required to meet N-x standards on their distribution networks, as detailed in their respective network management plans. The security standards are determined by each of the DNSPs and set out in their network management plans. This approach stems from the 2004 Electricity Distribution and Supply Delivery Review which recommended that Queensland electricity DNSPs should be planned to an N-1 level.⁶⁷

The recent Electricity Network Capital Program Review has made recommendations that would change some of these standards however they have not yet been implemented. One such recommendation was a proposal from Ergon Energy that, for remote locations requiring extensive capital investment to meet the N-1 standard, a cost benefit approach be used to determine whether the augmentation should occur.⁶⁸

For the period 2011-12 to 2015-16, Energex has adopted the security standards as detailed in the following table.

Table A.2 Energex network security standards

Load Category	Threshold Load Magnitude	Transmission or sub-transmission lines	Bulk supply stations	Zone substations	Distribution feeders
CBD or Critical Installations	≥ 1.5MVA	N-2	N-1(a)	N-1(a)	N-1(a)
	<1.5MVA				N
Mixed with significant commercial or industrial (urban or non-urban)	≥ 5MVA	N-1(a)	N-1(a)	N-1(a)	N
Mixed with predominately residential (urban or	≥ 15MVA	N-1(b)	N-1(b)	N-1(c)	N

⁶⁶ Australian Energy Regulator, 2011, State of the Energy Market 2011, p. 56

⁶⁷ Electricity Network Capital Program Review 2011, Detailed report of the independent panel, p. 28

⁶⁸ Electricity Network Capital Program Review 2011, 2011, Detailed report of the independent panel, p.10

Load Category	Threshold Load Magnitude	Transmission or sub-transmission lines	Bulk supply stations	Zone substations	Distribution feeders
non-urban)					
Mixed with significant commercial or industrial (urban or non-urban)	<5MVA	N	N-1(a)	N	N
Mixed with predominately residential (urban or non-urban)	<15MVA	N	N	N	N

Source: Energex, 2011, Energex Network Management Plan 2011-12 to 2015-16, p. 35

Energex has adopted the following security standards definitions:

- N-2 is defined as a system which can withstand a credible single contingency with no interruption to supply and can be restored to a secure state (ie able to withstand a second credible contingency with no loss of load) within 1 hour.
- N-1(a) is defined as a system which has the capability to withstand a credible single contingency involving an outage of the largest and most critical system element (eg transformer or feeder) without an interruption to supply of greater than one minute.
- N-1(b) limits interruptions to no more than 30 minutes and utilises remote switching to restore supply.
- N-1(c) limits interruptions to the majority of customers to no more than one minute, but up to 6MVA of load may be interrupted for up to 3 hours (urban) or 4 hours (non-urban) and utilises manual transfers.
- For urban distribution feeders, a security standard of N will allow for interruptions to supply restored within 3 hours utilising remote or manual switching of the 11 kV network.
- For non-urban distribution feeders, a security standard of N will allow for interruptions to be restored within 4 hours utilising remote or manual switching of the 11 kV network.
- For transmission level assets, N is defined as allowing for supply interruptions of up to 8 hours for urban and 12 hours for non-urban assets.⁶⁹

⁶⁹ Energex, 2011, Energex Network Management Plan 2011-12 to 2015-16, p. 34-35

The security standards Ergon Energy has adopted for the purposes of its network planning for the period 2011-2016 are contained in the following table.

Table A.3 Ergon Energy security standards

Site	Indicative peak loading (MVA)	Substation base security level	Transmission lines base security level	Sub-transmission lines base security level
Bulk supply substations	> 15	N-1(A)	N-1	n/a
	< 15	N-1(C)	N	n/a
Zone substations	> 25	N-1(A)	n/a	N-1
	15-25	N-1(B)	n/a	N-1
	5-15	N-1(C)	n/a	N
	< 5	N	n/a	N

Source: Ergon Energy, 2011, Network Management Plan 2011-12 to 2015-16, p. 35

In its Network Management Plan 2011-12 to 2015-16, Ergon Energy notes that "in practice, there are three N-1 standards defined within Ergon Energy."⁷⁰ These standards are defined as follows:

- N-1(A) or "Full N-1" allows for outages of up to one minute while automatic switching takes place;
- N-1(B) or "Remote Switch N-1" allows for short outages of up to 30 minutes while load transfers are undertaken via remote control;
- N-1(C) or "Manual Switch N-1" allows for medium outages of up to 3 hours while manual switching is undertaken to effect load transfers;
- N allows for interruptions for substations of up to 12 hours, sub-transmission lines of up to 6 hours for loads greater than 5MVA and up to 12 hours for loads less than 5MVA.⁷¹

Reliability performance standards

Reliability standards for the Queensland DNSPs are set down in the Queensland Electricity Industry Code. Ergon Energy and Energex are required to use their best endeavours to ensure they do not exceed the SAIDI and SAIFI targets in any given (financial) year.⁷²

⁷⁰ Ergon Energy, 2011, Network Management Plan 2011-12 to 2015-16, p. 33

⁷¹ Ergon Energy, 2011, Network Management Plan 2011-12 to 2015-16, p. 33

⁷² Queensland Electricity Industry Code, clause 2.4.2

The Queensland Electricity Industry Code was recently amended to implement a recommendation from the Electricity Network Capital Program Review to flat-line Energex's Minimum Service Standards at the 2011-12 level.⁷³

The following table contains the Queensland SAIDI targets.

Table A.4 Queensland SAIDI targets

Energex		2007/ 08	2008/ 09	2009/ 10	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15
Feeder type	CBD	20	20	15	15	15	15	15	15
	Urban	134	122	110	106	102	102	102	102
	Short rural	244	232	220	218	216	216	216	216
Ergon Energy									
Feeder type	CBD	195	180	150	149	148	147	146	145
	Urban	550	500	430	424	418	412	406	400
	Short rural	1090	1040	980	964	948	932	916	900

Source: Queensland Electricity Industry Code, 2011, Schedule 1

The following table shows the Queensland SAIFI targets.

Table A.5 Queensland SAIFI targets

Energex		2007/ 08	2008/ 09	2009/ 10	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15
Feeder type	CBD	0.33	0.33	0.33	0.15	0.15	0.15	0.15	0.15
	Urban	1.54	1.43	1.32	1.26	1.22	1.22	1.22	1.22
	Short rural	2.63	2.56	2.50	2.46	2.42	2.42	2.42	2.42
Ergon Energy									
Feeder type	CBD	2.50	2.30	2.00	1.98	1.96	1.94	1.92	1.90
	Urban	5.00	4.50	4.00	3.95	3.90	3.85	3.80	3.75
	Short rural	8.50	7.80	7.50	7.40	7.30	7.20	7.10	7.00

Source: Queensland Electricity Industry Code, 2011, Schedule 1

⁷³ QCA website, <http://www.qca.org.au//electricity-retail/industry-code/codechanges.php>

When determining DNSP performance against these targets, the following exclusions apply:

- interruptions of duration less than one minute;
- interruptions resulting from shortfall in generation, transmission failures, AEMO directions, automatic load shedding due to under-frequency or directions of policy;
- any interruption that commences on a major event day (defined as occurring when the daily total system SAIDI exceeds a pre-determined threshold which is based on historical SAIDI values)⁷⁴; and
- interruptions caused by a customer's installation.⁷⁵

The Queensland Competition Authority (QCA) is required to review the minimum service standards to apply at the beginning of each regulatory control period, and must consult with Ergon Energy and Energex in conducting the review.⁷⁶

Worst served customer reliability standards

The network management plans are required to report on how worst performing feeders are defined, an analysis of the performance of worst performing feeders in the past financial year, and an analysis of worst performing feeders identified in the preceding network management plan.⁷⁷

Ergon Energy addresses reliability performance issues on the worst performing feeders through its "Worst Performing Feeder Program". According to Ergon Energy's network management plan "the Worst Performing Feeder Program aims to deliver improvement by providing targeted solutions to address the underlying causes of historical poor performance in the 50 worst performing feeders in the Ergon Energy Distribution network."⁷⁸ Problems with the worst performing feeders are addressed by a combination of proactive and reactive reliability improvement programs. The worst performing distribution feeders are identified based on three years of performance data and average performance indices.⁷⁹

Energex seeks to address its worst performing feeders through its "10 per cent Feeder Improvement Program", which identifies and reports on the ten per cent worst performing feeders based on individual feeder three year average SAIDI performance. Worst performing feeders are identified in a two stage process. First, identification of any feeders where performance is worse than 150 per cent of the minimum service

⁷⁴ Queensland Electricity Industry Code, 2012, Schedule 1, clause 3

⁷⁵ Queensland Electricity Industry Code, 2012, clause 2.4.3

⁷⁶ Queensland Electricity Industry Code, 2012, clause 2.4.4

⁷⁷ Queensland Electricity Industry Code, 2012, clause 2.3.2(k)

⁷⁸ Ergon Energy, 2011, Network Management Plan 2011-12 to 2015-16, p. 112

⁷⁹ Ergon Energy, 2011, Network Management Plan 2011-12 to 2015-16, p. 116

standards takes place. Then, more detailed analysis of the factors driving performance takes place to inform a program of capital works to improve performance.⁸⁰

Guaranteed service level payments

Queensland DNSPs are subject to GSL payments regime (subject to the exclusions listed above).⁸¹ Customers are eligible to receive GSL payments for:

- wrongful disconnection;
- connection not being provided on the agreed date;
- re-connection not being provided within the required time;
- failure to attend a customer's premises within the required time concerning loss of hot water;
- failure to attend appointments on time;
- failing to provide notice of a planned interruption;
- duration of interruptions; and
- frequency of interruptions.⁸²

For the period 1 July 2010 to 30 June 2015, the level of payments vary between \$26 (for notice of planned interruption not given) through to \$130 (for wrongful disconnection).⁸³ Customers are not entitled to receive more than \$416 worth of GSL payments per financial year.⁸⁴

Energex and Ergon Energy are required to use their best endeavours to automatically make GSL payments to customers. Where the DNSP fails to make a GSL payment within three months of the relevant interruption, then the customer can make a claim for the GSL payment.⁸⁵ The Queensland DNSPs are also required to use their best endeavours to make GSL payments by cheque, electronic funds transfer or any other means agreed with the customer.⁸⁶

Incentive schemes

The AER's STPIS is already in operation in Queensland. Overall revenue at risk is +/-2 per cent and DNSP performance will be determined by reference to SAIDI and SAIFI

⁸⁰ Energex, 2011, Energex Network Management Plan 2011-12 to 2015-16, p. 86-87

⁸¹ Queensland Electricity Industry Code, 2012, section 2.5

⁸² Queensland Electricity Industry Code, 2012, section 2.5.10

⁸³ Queensland Electricity Industry Code, 2012, clause 2.5.10

⁸⁴ Queensland Electricity Industry Code, 2012, clause 2.5.15

⁸⁵ Queensland Electricity Industry Code, 2012, clause 2.5.11

⁸⁶ Queensland Electricity Industry Code, 2012, clause 2.5.12

targets. Ergon Energy will have +/-0.2 per cent of revenue at risk in relation to a telephone answering customer service parameter.⁸⁷

A.2.3 Governance arrangements

The *Electricity Act 1994* (QLD) allows both the Minister and the QCA to make industry codes, such as the Queensland Electricity Industry Code.⁸⁸ Consultation is only required where QCA is making a code and QCA does not consider the code would be materially detrimental to anyone's interests, or the code is needed urgently.⁸⁹

Review of the Queensland Electricity Industry Code can be directed by the Minister.⁹⁰ The QCA can also propose amendments to the Queensland Electricity Industry Code, subject to stakeholder consultation.⁹¹

Contravention of the Queensland Electricity Industry Code can result in civil penalties of up to \$500,000, enforced by Supreme Court order.⁹² However, as noted in section A.2.2, Queensland DNSPs are only required to use their 'best endeavours' to comply with the minimum service standards set out in the Queensland Electricity Industry Code.

A.2.4 Reporting requirements

The Queensland Electricity Industry Code requires each Queensland DNSP to publish an annual network management plan, and a summer preparedness plan (owing to the summer storm period that Queensland experiences). The network management plan is required to contain how the DNSP will manage and develop its supply network, and includes:

- growth forecasts;
- planning policy;
- risk assessment of major constraints in the network, and how they will be relieved; and
- consideration of reliability performance.⁹³

In addition, Ergon Energy and Energex are both required to submit quarterly performance report to the QCA within two months of the end of each quarter, and for

⁸⁷ Australian Energy Regulator, 2010, Final decision - Queensland distribution determination 2010-11 to 2014-15, p. 282

⁸⁸ Electricity Act 1994 (QLD), sections 120B, 120F

⁸⁹ Electricity Act 1994 (QLD), sections 120B, 120H

⁹⁰ Electricity Act 1994 (QLD), section 120L

⁹¹ Electricity Act 1994 (QLD), sections 120P, 120PA

⁹² Electricity Act 1994 (QLD), section 120X

⁹³ Queensland Electricity Industry Code, 2012, section 2.3

the financial year to the end of each quarter.⁹⁴ The report is required to include information on:

- compliance with the minimum service standards, including performance against SAIDI and SAIFI limits, details of excluded interruptions, a description of any major event days, and an explanation of reasons for a distribution entity exceeding the minimum service standards;
- compliance with the guaranteed service levels, including the number of GSL payments given by category and the amount of payments, the number of GSL payment claims by category, and the number of rejected GSL payment claims; and
- any other matter reasonably notified by the QCA.⁹⁵

A.2.5 Recent reliability performance

The table below provides a summary of the Ergon Energy and Energex's reliability performance for 2010-11.

Table A.6 Queensland distribution network reliability performance 2010-11

DNSP	Feeder	SAIDI (minutes)		SAIFI	
		Target	Actual	Target	Actual
Energex	CBD	15	6.05	0.15	0.01
	urban	106	79.75	1.26	0.92
	short-rural	218	201.58	2.46	2.05
Ergon Energy	urban	149	148.88	1.98	1.63
	short-rural	424	425.74	3.95	3.53
	long-rural	964	827.35	7.40	5.27

Source: AEMC, 2012, Annual Market Performance Review, p. 62

A.2.6 Customer willingness to pay

Based on information in the network management plans for the respective Queensland DNSPs, it does not appear that any customer willingness to pay information is used to determine the network planning and performance standards utilised by Ergon Energy and Energex.

⁹⁴ Queensland Electricity Industry Code, 2012, clause 2.6.2

⁹⁵ Queensland Electricity Industry Code, 2012, clause 2.6.2

A.2.7 Other issues

Queensland regulated tariff freeze

The Queensland Government has announced it intends to introduce legislation which will prevent any increases in the standard electricity tariff in Queensland for 12 months, commencing 1 July 2012.⁹⁶ The legislation will entail issuing a new directive to the QCA. These intentions are reflected in the QCA's final retail price determination for 2012-13, which was released on 31 May 2012.

As part of the announcement, the Queensland Minister for Energy and Water Supply went on to state "the government is also committed to electricity tariff reform in Queensland and is establishing a review to consider future pricing options and strategies to address cost pressures."⁹⁷

A.3 South Australia

A.3.1 Overview

ETSA Utilities is the only DNSP in South Australia and currently has:

- 817,300 customers;
- 87,220 kilometres of distribution network;
- customer density of approximately 9 customers per kilometre of distribution network;
- maximum demand of 2,981 MW; and
- a RAB of \$2,772 million.⁹⁸

A.3.2 Jurisdictional requirements

Security standards

The security standards adopted by ETSA Utilities are deterministic, and have been developed by ETSA Utilities to meet and maintain the reliability requirements (SAIDI and SAIFI targets) within the South Australian Electricity Distribution Code.⁹⁹ The planning criteria adopted by ETSA Utilities are:

⁹⁶ Queensland Minister for Energy and Water Supply, Media Statement - *Newman Government keeps cost of living commitments*, 23 April 2012

⁹⁷ Queensland Minister for Energy and Water Supply, Media Statement - *Newman Government keeps cost of living commitments*, 23 April 2012

⁹⁸ Australian Energy Regulator, 2011, *State of the Energy Market 2011*, p. 56

⁹⁹ ETSA Utilities, 2011, *Electricity System Development Plan 2011 Report*, p. 6

- N-1 for all interconnected 66 and 33 kV CBD and meshed 66kV metropolitan sub-transmission lines, and the Pirie-Bungama 33kV line;
- N for radial 66kV metropolitan sub-transmission lines, rural 66 and 33 kV sub-transmission lines; and
- N-1 for all sub-stations, except rural substations with a peak load of less than 6.25MVA which are subject to planning criteria of N.¹⁰⁰

Reliability performance standards

The South Australian Electricity Distribution Code requires ETSA Utilities to use its best endeavours to achieve the following SAIDI and SAIFI reliability standards during each year ending on 30 June.¹⁰¹ 'Best endeavours' is defined as 'to act in good faith and use all reasonable efforts, skill and resources.'¹⁰²

Table A.7 SA SAIDI standards

Region	SAIDI (average minutes off supply per customer per annum)
Adelaide business area	25
Major metropolitan areas	130
Barossa/Mid-North and Yorke Peninsula/Riverland/Murrayland	260
Eastern Hills/Fleurieu Peninsula	295
Upper North and Eyre Peninsula	425
South East	295
Kangaroo Island	450

Source: SA Electricity Distribution Code, clause 1.2.3.1

Table A.8 SA SAIFI standards

Region	SAIFI (average number of supply interruptions per customer per annum)
Adelaide business area	0.25
Major metropolitan areas	1.45

¹⁰⁰ ETSA Utilities, 2011, Electricity System Development Plan 2011 Report, p. 9

¹⁰¹ South Australia Electricity Distribution Code, 2010, Clause 1.2.3.1

¹⁰² South Australia Electricity Distribution Code, 2010, Schedule 1

Region	SAIFI (average number of supply interruptions per customer per annum)
Barossa/Mid-North and Yorke Peninsula/Riverland/Murrayland	1.80
Eastern Hills/Fleurieu Peninsula	2.80
Upper North and Eyre Peninsula	2.30
South East	2.50
Kangaroo Island	n/a

Source: SA Electricity Distribution Code, clause 1.2.3.1

Planned supply interruptions and supply interruptions of durations less than one minute are excluded from these standards.¹⁰³

In its Review of South Australian Electricity Distribution Service Standards 2010-2015, the Essential Services Commission of South Australia (ESCOSA) decided to retain the use of SAIDI and SAIFI as the appropriate measures of reliability performance.¹⁰⁴ ESCOSA noted that it had not been provided with any evidence to support departing from the use of these measures, and that continued use would provide national consistency and robust bench marking of ETSA Utilities against other DNSPs in other jurisdictions.¹⁰⁵

As part of the review, ESCOSA also considered the targets that should be used for each measure of reliability performance. After consideration of a range of issues involved, ESCOSA determined that the numerical values for SAIDI and SAIFI would be based on four year's Outage Management System data (up until 30 June 2009) from ETSA Utilities, except for Kangaroo Island which ESCOSA determined would continue to have a SAIDI target of 450 minutes and no SAIFI targets.¹⁰⁶

In respect of the approach to determining the relevant regions, ESCOSA also considered the issue of regional classification. For the 2005-2010 regulatory period, ESCOSA determined that reliability standards should be set for seven geographical regions, to enable transparency in monitoring reliability performance across different

¹⁰³ South Australia Electricity Distribution Code, clause 1.2.3.1

¹⁰⁴ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 37

¹⁰⁵ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 37

¹⁰⁶ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 63. The exception for Kangaroo Island was due to ongoing operational issues with the network servicing Kangaroo Island, and the lack of reliable historical average values at the time ESCOSA made its final decision. ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 62

regions within South Australia.¹⁰⁷ As part of the review for determining 2010-15 standards, ESCOSA considered whether the approach should be changed and if an approach based on categorisation of feeders by network type (CBD, urban, short rural and long rural) should be adopted. ESCOSA's final decision was to retain a regionally based categorisation for reliability service standards, with an additional requirement on ETSA Utilities to regularly report on its performance in relation to poorly performing pockets of its network.¹⁰⁸

Worst-served customer reliability standards

ETSA Utilities is required to report annually on its reliability of supply performance in respect of poorly performing parts of the network.¹⁰⁹ The report must cover the following matters:

- the nature of any discrete areas of poor performance;
- the reasons for that performance; and
- the remedial actions ETSA Utilities has taken (or proposed) where the improved performance is within its control.¹¹⁰

Guaranteed service level payments

A GSL scheme is in place in South Australia. The current payment levels are set out in Tables A.9 and A.10, for frequency and duration of interruptions respectively.

Part B (Standard Customer Contract) of the South Australian Electricity Distribution Code is silent on whether customers need to apply for GSL payments. However, it does specify that payments in relation to the frequency of interruptions will be made in the quarter directly following the regulatory year. Payments in relation to the duration of interruptions will be made within 3 months of the event occurring. Payments are made in respect of the supply address and not the customer.¹¹¹

The South Australian GSL scheme excludes:

- interruptions caused by transmission and generation failures, disconnection required in emergency situations (eg bushfire), and single customer faults caused by that customer;
- interruptions of a duration less than one minute; and

¹⁰⁷ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 44

¹⁰⁸ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 58

¹⁰⁹ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 57

¹¹⁰ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 57

¹¹¹ South Australia Electricity Distribution Code, Part B, clause 5.3(d)

- planned interruptions.¹¹²

Table A.9 South Australia GSL payments - frequency of interruptions

	Threshold 1	Threshold 2	Threshold 3
Number of interruptions in a regulatory year, ending 30 June	9-12	12-15	>15
Payment	\$90	\$140	\$185

Source: SA Electricity Distribution Code, Schedule B, Clause 5.3(d)

Table A.10 South Australia GSL payments - duration of interruptions

	Threshold 1	Threshold 2	Threshold 3	Threshold 4
Duration (hours)	12-15	15-18	18-24	>24
Payment	\$90	\$140	\$185	\$370

Source: SA Electricity Distribution Code, Schedule B, Clause 5.3(d)

Incentive scheme

The AER STPIS already applies in South Australia.¹¹³ The revenue at risk for ETSA Utilities is +/-3 per cent against targets for SAIDI, SAIFI and also includes +/-0.3 per cent for a telephone answering performance parameter.¹¹⁴ Jurisdictional GSL arrangements continue to apply for this regulatory period.¹¹⁵

A.3.3 Governance arrangements

ESCOSA has responsibility for the South Australia Electricity Distribution Code, including amendment and revocation.¹¹⁶ ESCOSA is required to consult with the Minister and industry stakeholders (participants and representative bodies) prior to any variation of the South Australia Electricity Distribution Code.¹¹⁷ ESCOSA is also

¹¹² South Australia Electricity Distribution Code, Part B, clause 5.3(d)

¹¹³ Australian Energy Regulator, 2010, Final Decision - South Australia distribution determination 2010-11 to 2014-15, p. 202

¹¹⁴ Australian Energy Regulator, 2010, Final Decision - South Australia distribution determination 2010-11 to 2014-15, p. 202

¹¹⁵ Australian Energy Regulator, 2010, Final Decision - South Australia distribution determination 2010-11 to 2014-15, p. 202

¹¹⁶ Essential Services Commission Act 2002 (SA), section 28

¹¹⁷ Essential Services Commission Act 2002 (SA), sub-section 28(3)

required to review the contents and operation of the South Australia Electricity Distribution Code to ensure the code remains relevant and operates effectively.¹¹⁸

Compliance with the South Australia Electricity Distribution Code is a licence condition.¹¹⁹ Contravention of licence conditions carries a maximum penalty of \$1 million.¹²⁰ However, as noted in section A.3.2, ESTA Utilities is only required to use its 'best endeavours' to achieve the SAIDI and SAIFI reliability standards. ESCOSA has the power to vary licence conditions by written notice, and subject to consultation with ETSA Utilities.¹²¹

ESCOSA is also responsible for reviewing and determining the South Australian electricity distribution service standards. The current standards for 2010-2015 were determined by ESCOSA in 2008, and contain the average service standards, the GSL payment scheme, and certain regulatory reporting requirements (for example, on poor performing parts of the electricity network) that apply to ETSA Utilities.¹²²

A.3.4 Reporting requirements

ETSA Utilities is required to provide a performance report to ESCOSA by 31 August of each year. This performance report is required to include:

- ETSA Utilities' compliance with the service standards set out in the South Australian Electricity Distribution Code, or under its customer connection and supply contracts;
- the amount of rebates paid or credited to customers under the GSL scheme;
- an explanation of the reason for any non-compliance; and
- how ETSA Utilities will improve its performance so as to meet the applicable service standards.¹²³

This assessment is updated and published quarterly by ESCOSA on its website, and includes statistics on SAIDI and SAIFI, as well as information on GSL payments.¹²⁴

118 Essential Services Commission Act 2002 (SA), sub-section 28(8)

119 Electricity Act 1996 (SA), section 21(1)(a)

120 Electricity Act 1996 (SA), section 25

121 Electricity Act 1996 (SA), section 27

122 ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 10

123 South Australia Electricity Distribution Code, clause 1.2.5

124 For example, the September 2011 quarter assessment can be viewed at:<http://www.escosa.sa.gov.au/Content.aspx?p=300>

A.3.5 Recent reliability performance

ETSA Utilities' performance against the required SAIDI and SAIFI targets are contained in the table below for 2010-11.

Table A.11 Performance of ETSA Utilities for 2010-11

Region	SAIDI (minutes)		SAIFI (number of outages)	
	Target	Actual	Target	Actual
Adelaide Business Area	25	19	0.25	0.14
Major Metropolitan Areas	130	218	1.45	1.79
Central	260	582	1.80	2.74
Eastern Hills/Fleurieu Peninsular	295	465	2.80	3.29
Upper North and Eyre Peninsular	425	841	2.30	2.72
South East	295	277	2.50	1.67
Kangaroo Island	450	198	n/a	-
Total network	179	311	1.68	2.05

Source: ESCOSA, 2011, 10-11 Annual Performance Report - South Australian Energy Supply Industry, p. 24

A.3.6 Customer willingness to pay

As part of ESCOSA's determination of the services standard framework for 2010-2015 in 2007, ESCOSA engaged McGregor Tan Research to undertake a survey of consumer preferences for electricity distribution service standards in South Australia.¹²⁵

As a result of telephone surveys of both regional and metropolitan households and businesses, McGregor Tan Research concluded that "both residents and businesses have demonstrated in an overwhelming way that they do not wish to pay additional

¹²⁵ A copy of McGregor Tan Research's report to ESCOSA can be obtained via the following link: <http://www.escosa.sa.gov.au/library/071130-ConsumerPreferenceElectricityServiceStandards-McGregorTanResearch.pdf>

fees to improve their electricity supply reliability."¹²⁶ McGregor Tan Research cited two findings as evidence of this conclusion:

- first, few residents (13 per cent) and businesses (9 per cent) surveyed indicated they would be prepared to pay more for an improvement in their electricity supply reliability; and
- second, those residents who indicated they were willing to pay more for increased reliability indicated they would only be prepared to pay between \$25 and \$49 per year for the improved reliability.¹²⁷

The findings of the McGregor Tan report were used by ESCOSA in determining the appropriate level of reliability service standards to apply for the 2010-2015 period.¹²⁸

A.4 Tasmania

A.4.1 Overview

Tasmania has only one DNSP, Aurora Energy, with the following characteristics:

- 271,750 customers;
- 24,385 kilometres of distribution network;
- customer density of 11 per kilometre of distribution network;
- maximum demand of 1,042MW;
- a RAB of \$1,105.¹²⁹

A.4.2 Jurisdictional requirements

Security standards

Aurora Energy does not apply strict deterministic security standards across its distribution network. Instead, it adopts a combination of deterministic planning and 'group firm philosophy'.¹³⁰

¹²⁶ McGregor Tan Research, 2007, Essential Services Commission of South Australia - Consumer Preference for Electricity Service Standards, p. 5

¹²⁷ McGregor Tan Research, 2007, Essential Services Commission of South Australia - Consumer Preference for Electricity Service Standards, p. 5

¹²⁸ ESCOSA, 2008, Final Decision - South Australian Electricity Distribution Service Standards 2010-2015, p. 39

¹²⁹ Australian Energy Regulator, 2011, State of the Energy Market 2011, p. 56

¹³⁰ Aurora Energy, 2011, Distribution System Planning Report 2011, p. 100

The Tasmanian approach involves undertaking economic cost effective analysis of possible options whilst also meeting the technical requirements of the National Electricity Rules, chapter 8 of the Tasmanian Electricity Code and applicable Australian standards.¹³¹ In addition, Aurora Energy seeks to apply "good electricity industry practice."

Aurora Energy identifies the five primary drivers for planning (and investment) as being:

- capacity of the system;
- cost of capital and operational activities;
- customer service;
- inherent risk of the infrastructure; and
- performance of the system for reliability and power quality.¹³²

Average reliability performance standards

Since 2008, reliability targets have been determined by an overall number and duration of outage targets (ie SAIDI and SAIFI) for five customer categories. Within each customer category, defined geographical communities are also identified and reliability targets are also set on a community basis. These requirements are detailed in the table below. Aurora Energy is required to use reasonable endeavours to meet these targets by the end of the current regulatory period.¹³³

Table A.12 Tasmanian Reliability Targets

Customer Category	Communities per category	Overall		Each Community	
		SAIDI	SAIFI	SAIDI	SAIFI
Critical infrastructure	1	30	0.2	30	0.2
High density commercial	8	60	1	120	2
Urban and regional centres	32	120	2	240	4
High density rural	33	480	4	600	6
Low density rural	27	600	6	720	8

¹³¹ Aurora Energy, 2011, Distribution System Planning Report 2011, p. 18

¹³² Aurora Energy, 2011, Distribution System Planning Report 2011, p. 1

¹³³ Electricity Supply Industry Expert Panel, 2011, A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses, p. 59

Source: Electricity Supply Industry Expert Panel, 2011, A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses, p. 59

The current reliability and performance standards were determined by a joint working group, consisting of OTTER, Aurora Energy and the Office of Energy Planning and Conservation. The Joint Working Group undertook a review, including public consultation, in 2006-2007, and released its final report on distribution network performance standards in February 2007.

For SAIFI, the Joint Working Group established an annual outage count for the classification, and a minimum annual outage count (frequency) for each area within the classification.¹³⁴

The annual outage count standard for all customers within a given classification was established by finding the average of this measure over the period 2001-02 to 2005-06 (5 years).¹³⁵

The minimum annual outage count standard of any individual area within a classification (the 'community' standard) was nominally set at twice the category average. However, for the rural classification, this was revised downwards due to the fact that the initial number resulted in a standard worse than the Tasmanian Electricity Code standards in place at the time, and to provide Aurora Energy with a 'true' target, and not a target that Aurora Energy could meet with little effort.¹³⁶

For SAIDI, the Joint Working Group used the historical, feeder level data to set the cumulative outage duration standards. As with the SAIFI targets, the Joint Working Group established two outage duration standards for each area category.

An annual cumulative outage duration standard for all customers within a given classification was established by finding the average of this measure over the period 2001-02 to 2005-06.

A minimum annual cumulative outage duration standard for each area within the classification was nominally then set at twice the category average. As with the SAIDI measures, this initial setting of the standard was then adjusted downward for rural classifications on the same basis as the SAIDI adjustments.¹³⁷

These standards are in place for the 2008-2012 regulatory period for Aurora Energy.

The following supply interruptions are excluded from the reliability standard:

¹³⁴ Tasmanian Joint Working Group, 2006, Distribution Network Performance Standards - Draft Report, p. 47

¹³⁵ Tasmanian Joint Working Group, 2006, Distribution Network Performance Standards - Draft Report, p. 47

¹³⁶ Tasmanian Joint Working Group, 2006, Distribution Network Performance Standards - Draft Report, p. 47-48

¹³⁷ Tasmanian Joint Working Group, 2006, Distribution Network Performance Standards - Draft Report, p. 49

- planned maintenance or repair of the distribution system;
- unplanned maintenance or repair necessary to address immediate threat of injury or material damage to any person or to the distribution system;
- the need to shed load; and
- the need to eliminate the risk of fire.¹³⁸

The Joint Working Group have not released a new decision on network planning and performance standards for Tasmania for the 2012-17 regulatory period

Worst served customer reliability standards

Historically, the reliability performance targets in Tasmania have been derived on the principle of reducing the statewide averages of SAIFI and SAIDI by improving the reliability of the 20 worst-performing feeders in the network. However, there are no explicit requirements to address poor performing feeders.¹³⁹

The Tasmanian Electricity Code also requires DNSPs to report (as part of their annual planning report) on the areas which are underperforming and how the DNSP proposes to improve performance.¹⁴⁰

Poor performing communities are identified on the basis of exceeding the Tasmanian Electricity Code limits for frequency or duration of outages. In 2010-11, there were a total of 16 communities that were classified as poor performing, compared to 35 in 2009-10. These 16 communities represent 12 per cent of the connected load in the distribution network.¹⁴¹

Guaranteed service level requirements

Aurora Energy is required to comply with the GSL guidelines issues by OTTER.¹⁴²

The following table shows GSL payments by frequency of outages.

Table A.13 Tasmanian GSL payments - frequency of outage

Category	Threshold (number of outages)
Urban, high density commercial, critical infrastructure	10

¹³⁸ Tasmanian Electricity Code, clause 8.6.11(c)

¹³⁹ Joint Working Group, 2007, Tasmanian Distribution Network Reliability Standards - Final Report, p. 20

¹⁴⁰ Tasmanian Electricity Code, clause 8.3.2(b)

¹⁴¹ Office of the Tasmanian Economic Regulator, 2012, Tasmanian Reliability Review 2011, p. 32

¹⁴² Tasmanian Electricity Code, section 8.5

Category	Threshold (number of outages)
Higher density rural	13
Lower density rural	16
Applicable GSL payment	\$80

Source: Office of the Tasmanian Economic Regulator, 2007, Guideline - Guaranteed Service Level Scheme, p. 6

Aurora Energy is also required to make GSL payments based on the duration of outages, detailed in the following table.

Table A.14 Tasmanian GSL payments - duration of outage

Category	Threshold (duration of outage, minutes)	
Urban, high density commercial, critical infrastructure	8	16
Higher density rural	8	16
Lower density rural	12	24
Applicable GSL payment	\$80	\$160

Source: Office of the Tasmanian Economic Regulator, 2007, Guidelines - Guaranteed Service Level Scheme, p. 6

Incentive Scheme

The AER's STPIS will apply for Aurora Energy's 2012-17 regulatory period. The maximum revenue at risk is +/- 5 per cent of annual revenue.¹⁴³ Within this revenue at risk, there will be a cap of +/-0.25 per cent for a telephone answering parameter for performance in the first three years, and +/-0.5 per cent for the last two years.¹⁴⁴

In determining the SAIDI and SAIFI targets that were to be used as part of the application of the STPIS to Aurora Energy, the AER had to consider which customer classifications to use. The AER's final decision was that the community classifications contained in the Tasmanian Electricity Code would be adopted.¹⁴⁵

In its final determination, the AER determined that it would apply the SAIDI and SAIFI parameters, calculated using embedded transformer capacity in each area of

¹⁴³ AER, 2011, Distribution Determination Aurora Energy 2012-13 to 2016-17 Attachments - STPIS, p. 169

¹⁴⁴ AER, 2011, Distribution Determination Aurora Energy 2012-13 to 2016-17 Attachments - STPIS, p. 170

¹⁴⁵ AER, 2011, Distribution Determination Aurora Energy 2012-13 to 2016-17 Attachments - STPIS, p. 169

Aurora Energy's distribution network. Individual SAIDI and SAIFI targets will be set for segments of Aurora Energy's distribution network.¹⁴⁶

A.4.3 Governance arrangements

Under the *Electricity Supply Industry Act 1995* (Tas), OTTER is responsible for issuing, maintaining, administering and enforcing the Tasmanian Electricity Code.¹⁴⁷ OTTER has the discretion to review the Tasmanian Electricity Code, but can also be directed by the Minister to review the Code.¹⁴⁸ As noted in section A.4.2, the current standards were set following a joint working group comprised of OTTER, Aurora Energy and the Office of Energy Planning and Conservation.

In addition, the Minister also has the power to amend, rescind or substitute the Tasmanian Electricity Code for particular purposes (for example, to facilitate participation in the NEM or the application of the National Electricity Rules in Tasmania).¹⁴⁹

Compliance with the Tasmanian Electricity Code is a licence condition.¹⁵⁰ Contravention of the licence conditions carries a maximum penalty of \$140,000.¹⁵¹ However, as noted in section A.4.2, Aurora Energy is only required to use reasonable endeavours to meet the reliability targets.

A.4.4 Reporting requirements

Under the Tasmanian Electricity Code, Aurora Energy is required to submit an annual distribution system planning report to OTTER, detailing how it plans to meet predicted demand, improve customer reliability and meet the supply reliability standards over the following five years.¹⁵² The Tasmanian Electricity Code prescribes the information that is to be included in the report, including historical and forecast demand and capacity for each transmission connection site, the DNSP's planning standards, a description of feasible options for meeting forecast demand, the supply reliability areas that do not meet the supply reliability standards, and the strategies for improving reliability in underperforming supply areas.¹⁵³

In addition, Aurora Energy has an obligation to prepare a performance report to OTTER each year, covering performance related to reliability, quality, call centre performance and financial performance.

¹⁴⁶ AER, 2011, Distribution Determination Aurora Energy 2012-13 to 2016-17 Attachments - STPIS, p. 169

¹⁴⁷ *Electricity Supply Industry Act 1995* (Tas), section 6(1)(ca)

¹⁴⁸ *Electricity Supply Industry Act 1995* (Tas), section 49B

¹⁴⁹ *Electricity Supply Industry Act 1995* (Tas), section 49B(4)

¹⁵⁰ *Electricity Supply Industry Act 1995* (Tas), section 22(1)(d)

¹⁵¹ *Electricity Supply Industry Act 1995* (Tas), section 114B(1)

¹⁵² Tasmanian Electricity Code, clause 8.3.2(a)

¹⁵³ Tasmanian Electricity Code, clause 8.3.2(b)

A.4.5 Recent reliability performance

Over the period 2001-2010, there has been a small downward trend in underlying SAIDI (ie after excluding major event days) and a more significant declining trend in SAIFI.¹⁵⁴

Analysis of the trends in reliability targets shows a deteriorating performance in CBD and urban categories, but generally improving performance in the rural category.¹⁵⁵

The below table summarises Aurora Energy's distribution network performance for 2010-11 against the current performance standards.

Table A.15 Performance of Aurora Energy 2010-11

Community category	SAIDI (minutes)		SAIFI	
	Required standard	Actual performance	Required standard	Actual performance
Critical infrastructure	30	15	0.20	0.18
High density commercial	60	31	1.00	0.44
Urban and regional centres	120	114	2.00	1.01
Higher density rural	480	341	4.00	2.59
Lower density rural	600	575	6.00	3.51

Source: AEMC Reliability Panel, 2012, Annual Market Performance Review 2011, p. 76

A.4.6 Customer willingness to pay

Aurora Energy's network planning, or reliability performance targets, do not appear to be based on any formal customer willingness to pay studies.

¹⁵⁴ Electricity Supply Industry Expert Panel, 2011, A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses, p. 58

¹⁵⁵ Electricity Supply Industry Expert Panel, 2011, A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses, p. 61

A.4.7 Other issues

Transmission networks in Tasmania

Transend owns and operates the electricity transmission system in Tasmania. The Tasmanian transmission system consists of a 'backbone network' predominantly operating at 220 kV connecting main generators to main load centres. A 110 kV transmission network connects other generators and regional load centres.¹⁵⁶ However, unlike most other transmission network service providers, Transend's system also includes sub-transmission assets that operate at voltages between 6.6 and 44 kV.

As a result, parts of what would normally be considered to be the distribution network in other jurisdictions is treated as transmission in Tasmania, and is subject to transmission reliability standards.

On 15 May 2012, the Tasmanian Government announced its intention to merge Aurora Energy's electricity distribution business with Transend Networks.

OTTER Reliability Review

Clause 12.6.1(a) of the Tasmanian Electricity Code requires OTTER to review and report annually on the performance of the electricity supply industry, in terms of reliability of the power system. The 2011 review final report was released in March 2012, and provides an assessment of power system performance for 2010-11 and assesses the outlook for reliability in the medium term (the next three to five years).¹⁵⁷

With respect to distribution performance (noting that the review covers all aspects of the Tasmanian power system), the review concluded "the performance of the distribution system for all community categories with regards to both frequency and duration of outages improved in 2010-11 compared to 2009-10 with all community categories meeting the frequency and duration limits."¹⁵⁸ The review also noted that the performance improved for poor performing areas, with a reduction in poor performing communities from 35 in 2009-10 to 16 in 2010-11.¹⁵⁹

In terms of medium term performance, the review noted that Aurora Energy has in place development plans focussed on eliminating issues affecting the reliability of the distribution system in Tasmania, and Aurora Energy's targeted reliability improvement strategy "aims to improve the underlying reliability of the distribution system and compliance with the community-based performance standards."¹⁶⁰

¹⁵⁶ Transend, 2008, Revenue Proposal for the period 1 July 2009 to 30 June 2014, p. 18

¹⁵⁷ Office of the Tasmanian Economic Regulator, 2011, Tasmanian Reliability Review 2011, p. iii

¹⁵⁸ Office of the Tasmanian Economic Regulator, 2011, Tasmanian Reliability Review 2011, p. v

¹⁵⁹ Office of the Tasmanian Economic Regulator, 2011, Tasmanian Reliability Review 2011, p. v

¹⁶⁰ Office of the Tasmanian Economic Regulator, 2011, Tasmanian Reliability Review 2011, p. vi

A.5 Victoria

A.5.1 Overview

Victoria has the largest number of DNSPs out of all the NEM jurisdictions, with distribution networks being operated by SP AusNet, Jemena, CitiPower, Powercor and United Energy. Some of the characteristics for each of the Victorian DNSPs are listed in the table below.

Table A.16 Victorian DNSP characteristics

DNSP	Number of customers	Length of network (km)	Customer density (customer per km of network)	Maximum Demand (MW)	RAB (\$ million)	Proposed investment in current regulatory period (\$ million)
Powercor	706,577	84,027	8	2,362	2,189	1,550
SP AusNet	623,027	48,259	13	1,774	2,052	821
United Energy	634,508	12,628	50	2,016	1,365	877
CitiPower	308,203	6,506	47	1,354	1,273	821
Jemena	309,505	5,971	52	958	748	468

Source: Australian Energy Regulatory, 2011, State of the Market 2011, p. 56

A.5.2 Jurisdictional requirements

Security standards

The Victorian Electricity Distribution Code requires Victorian DNSPs to use best endeavours to develop and implement plans so the distribution system minimises the risks associated with the failure or reduced performance of assets.¹⁶¹ Victorian DNSPs are also required to develop, test, simulate and implement contingency plans (including plans to strengthen security of supply) to deal with low probability but realistic events which would have substantial impacts on customers.¹⁶²

Victoria is the only NEM jurisdiction that adopts a probabilistic approach to distribution network planning. This approach means that there are no mandatory security standards or reliability performance standards that the Victorian DNSPs must

¹⁶¹ Victorian Electricity Distribution Code, clause 3.1(b)

¹⁶² Victorian Electricity Distribution Code, clause 3.1(c)

meet. Instead, the need for reliability-related investments is determined by applying a cost-benefit assessment.

Broadly, this approach to network planning in Victoria involves DNSPs:

- completing detailed assessments of forecast maximum demand against N and N-1 ratings;
- calculating "energy at risk" and "hours at risk" in cases where the forecast maximum demand is greater than the station/plant ratings (under outage conditions);
- estimating the probability of an outage coincident with the forecast maximum demand (to give the "probability weighted energy at risk");
- estimating the cost to the community of the "probability weighted energy at risk" utilising Victorian value of customer reliability (VCR) estimates;
- establishing a sector-weighted cost for VCR based on customer composition and sectoral VCR estimates; and
- estimating the expected cost of unserved energy by multiplying the sector-weighted cost by the probability weighted energy at risk.¹⁶³

Generally speaking, if the expected cost of unserved energy is greater than the annualised cost of network augmentation, then the project is justified.¹⁶⁴

In addition, the Victorian Electricity Distribution Code requires the Melbourne CBD distributor (currently CitiPower) to take steps to strengthen the security of supply in the Melbourne CBD.¹⁶⁵ CitiPower is required to submit a plan to the ESCV that specifies the strengthened security of supply objectives for the Melbourne CBD (including the dates by which the objectives will be met), specifies the capital and other works proposed in order to achieve the relevant security of supply objectives, and meets the relevant AER regulatory test.¹⁶⁶

Average reliability performance standards

The Victorian Electricity Distribution Code requires Victorian DNSPs to annually publish the reliability targets for the following year. As a minimum, for customers supplied from CBD, urban, short rural and long rural feeders, the targets are required to include:

- SAIDI due to planned interruptions;

¹⁶³ Sinclair Knight Merz, 2009, Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion, p. 23-24

¹⁶⁴ Sinclair Knight Merz, 2009, Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion, p. 24

¹⁶⁵ Victorian Electricity Distribution Code, clause 3.1A.1

¹⁶⁶ Victorian Electricity Distribution Code, clause 3.1A.2

- SAIDI due to unplanned outages;
- SAIFI, excluding momentary interruptions;
- momentary interruptions per customer (MAIFI); and
- average duration of unplanned interruptions (CAIDI).¹⁶⁷

Unlike all other NEM jurisdictions, there are no minimum targets or standards in the Victorian Electricity Distribution Code, and the DNSPs have full discretion when setting their own targets.

In addition, Victorian DNSPs are also required to publish estimates of the number of customers the DNSP expects will be entitled to payments under the Victorian GSL scheme.¹⁶⁸

Victorian DNSPs are required to use best endeavours to meet the published targets.¹⁶⁹

The published reliability performance targets adopted by the Victorian DNSPs for 2012 are contained in the following tables. The unplanned targets are the same as those contained in the AER's final distribution determination for the 2011-2015 regulatory period for the purposes of the STPIS.¹⁷⁰

Table A.17 Powercor 2012 reliability performance targets

Reliability measure	Outage type	Urban lines	Rural short lines	Rural long lines
SAIDI	Unplanned	82.5	114.8	233.8
	Planned	16	35	70
SAIFI	Sustained (>1 minute)	1.26	1.57	2.54
MAIFI	Momentary (<1 minute)	1.4	2.8	6.5
CAIDI		65	73	92

Source: Powercor, Reliability of supply targets for 2012, available at: <http://www.powercor.com.au/docs/pdf/Electricity%20Networks/Powercor%20Network/2012%20Powercor%20reliability%20targets.pdf>

¹⁶⁷ Victorian Electricity Distribution Code, 2011, clause 5.1

¹⁶⁸ Victorian Electricity Distribution Code, 2011, clause 5.1

¹⁶⁹ Victorian Electricity Distribution Code, 2011, clause 5.2

¹⁷⁰ AER, Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final December, October 2010, page 695

Table A.18 CitiPower 2012 reliability performance targets

Reliability measures	Outage type	Greater CBD	Urban areas
SAIDI	Unplanned	11.3	22.4
	Planned	5.90	9.90
SAIFI	Unplanned	0.19	0.45
	Planned	n/a	0.03
	Momentary	0.03	0.18
CAIDI	Unplanned	61	50

Source: CitiPower, Reliability of supply targets for 2012, available at:
<http://www.powercor.com.au/docs/pdf/Electricity%20Networks/CitiPower%20Network/2012%20CitiPower%20reliability%20targets.pdf>

Table A.19 SP AusNet 2012 reliability performance targets

Reliability measures	Outage type	Urban feeder	Short rural feeder	Long rural feeder
SAIDI	Unplanned	102	209	257
SAIFI	Unplanned	1.45	2.63	3.32
CAIDI	Unplanned	70	79	77
MAIFI	n/a	2.51	5.41	8.92

Source: SP AusNet, 2012 Electricity reliability measures, available at:
<http://www.sp-ausnet.com.au/?id=23013230071D13F354E42CC88CA257576002E5073>

Table A.20 United Energy 2012 reliability performance targets

Reliability measures	Outage type	Urban feeder	Rural feeder
SAIDI	Planned	27	93
	Unplanned	55	99
SAIFI	Unplanned	0.9	1.7
MAIFI	Unplanned	1.1	2.1
CAIDI	Unplanned	61	58

Source: United Energy, Reliability service level targets for 2012, available at:
http://www.unitedenergy.com.au/industry/supply_reliability/default.asp

Table A.21 Jemena 2012 reliability performance targets

Reliability measures	Outage type	Urban feeder	Rural feeder
SAIDI	Planned	14	48
	Unplanned	68	153
SAIFI	Unplanned	1.13	2.59
MAIFI	Unplanned	0.78	1.94
CAIDI	Unplanned	61	59

Source: Jemena, Electricity reliability measures for 2012, available at: <http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Information/Reliability%20Service%20Level%20Targets%202012.pdf>

Worst served customer reliability standards

Victoria does not currently have any specific requirements in relation to reliability standards for worst-served customers. However, the ESCV set low-reliability thresholds based on the worst-served five per cent of customers and required DNSPs to report and provide comments on plans for each feeder that fell below the threshold.¹⁷¹ The AER assumed responsibility for this reporting from the ESCV when it became the relevant economic regulator. It has recently published its final report under the ESCV framework which applied to the 2006-10 regulatory period. The AER will be reporting under the national framework for the current regulatory period which will include reporting on worst served customers in order to "improve transparency and for possible future application of the AER's STPIS."¹⁷²

Guaranteed service level requirements

Victoria has a GSL scheme in place which specifies the minimum guaranteed service levels required to be provided by distributors. Distributors may undertake to provide enhanced guaranteed service levels above these minimum levels.

Victorian GSL payments are set out in the following tables. Payments for SAIFI targets depend on whether or not the interruption is an unplanned sustained interruption, or a momentary interruption.

¹⁷¹ AER, Victorian Electricity Distribution Network Service Providers, Annual Performance Report 2010, May 2012, page 54

¹⁷² AER, Victorian electricity distribution network service providers, Distribution determination 2011-2015, Final Decision, October 2010, page 962

Table A.22 Victorian GSL payments for SAIDI targets

Duration of interruption (hours per year)	Level of payment (\$ per customer)
>20	100
>30	150
>60	300

Source: Victorian Electricity Distribution Code, 2011, clause 6.3.1

Table A.23 Victorian GSL payments for SAIFI targets

Frequency of interruptions (number per year)	Level of payment (\$ per customer)
>10 unplanned sustained	100
>15 unplanned sustained	150
>30 unplanned sustained	300
>24 momentary	25
>36 momentary	35

Source: Victorian Electricity Distribution Code, 2011, clause 6.3.2

There are exclusions where the interruption is due to:

- load shedding due to a shortfall in generation;
- failure of the transmission network;
- failure of transmission connection assets; and
- a shortfall in demand response initiatives (where prior approval has been obtained from the ESCV).^{173,174}

Incentive Scheme

Victoria has had a reliability-related service incentive scheme for a number of years, with the AER's STPIS replacing the ESCV's 'S factor' incentive scheme.

¹⁷³ Victorian Electricity Distribution Code, 2011, clause 6.3.4

¹⁷⁴ Supply interruptions on a day where the unplanned interruption frequency exceeds certain thresholds are also excluded from requiring GSL payments. Victorian Electricity Distribution Code, 2011, clause 6.3.4(d)

The AER's STPIS applies for the 2011-15 regulatory control period for Victorian DNSPs. The maximum revenue at risk for all Victorian DNSPs is five per cent of annual revenue, except for SP AusNet which has a seven per cent cap.¹⁷⁵

The Victorian GSL scheme will continue to operate in conjunction with the AER's STPIS for the current regulatory period.¹⁷⁶

A.5.3 Governance arrangements

The *Electricity Industry Act 2000* (Vic) and the Victorian Electricity Distribution Code govern the obligations and performance of the Victorian DNSPs.

The ESCV may amend the Victorian Electricity Distribution Code on its own initiative, or in response to a proposal by a distributor, the ESCV's Customer Consultative Committee, or other interested persons, if it considers the amendments would better achieve the ESCV's objectives.¹⁷⁷

As explained in the above sections, Victoria's probabilistic approach means that reliability targets and outcomes are determined by the DNSPs themselves, subject to the incentives created by the AER's STPIS.

A.5.4 Reporting requirements

Victorian licence conditions require Victorian DNSPs to annually submit to the ESCV, and to publish on its website, a distribution system planning report detailing the plans over the next five years to meet forecast demand, and reliability standards.¹⁷⁸ As noted above, the AER requires service standards reporting as part of its role as the economic regulator. This includes reliability and quality of supply measures, customer services measures, worst served customers, and network performance during major event days, in addition to the reporting required under the STPIS.¹⁷⁹

A.5.5 Recent reliability performance

The following table shows Victorian DNSP reliability performance for 2009.

¹⁷⁵ Australian Energy Regulator, 2010, Final decision - Victorian electricity distribution network service providers - distribution determination 2011-2015, p. 741

¹⁷⁶ Australian Energy Regulator, 2010, Final decision - Victorian electricity distribution network service providers - distribution determination 2011-2015, p. 740

¹⁷⁷ Electricity Distribution Code Victoria, clause 1.7

¹⁷⁸ Electricity Distribution Code Victoria, clause 3.5

¹⁷⁹ AER, Victorian electricity distribution network service providers, distribution determination 2011-2015, Final decision, October 2010, page 962

Table A.24 Victorian DNSP performance for 2010

	Average number of unplanned interruptions per customer			Average duration of unplanned interruptions		
	2010 reported result	2010 targets	Better/(worse) than target (%)	2010 reported result	2010 targets	Better/(worse) than target (%)
CitiPower						
unplanned interruptions	0.53	0.70	24	75.7	44.5	(70)
Jemena						
unplanned interruptions	0.93	1.33	30	66.6	56.8	(17)
Powercor						
unplanned interruptions	1.92	2.15	11	102.8	74.5	(38)
SP AusNet						
unplanned interruptions	2.09	2.61	20	85.4	66.0	(29)
United Energy						
unplanned interruptions	1.02	1.13	10	78.9	54.5	(45)

Source: AER, 2012, Victorian Electricity Distribution Network Service Providers, Annual Performance Report 2010, p64

A.5.6 Customer willingness to pay

For the purposes of distribution system planning and network performance, the Victorian DNSPs currently use the VENCORP/AEMO 2008 estimates of Victorian VCR. VCR provides a measure of customer willingness to pay for changes in reliability standards. This VCR estimate is an update of VCR estimates prepared first in 1997 and then updated in 2002 and 2008. Utilising the same methodology as developed by Monash University for the initial estimates, CRA International arrived at the following estimates for VENCORP (now AEMO):

Table A.25 Victorian VCR

Sector	VCR (\$/MWh)
Residential	13,120

Sector	VCR (\$/MWh)
Commercial	131,000
Agricultural	90,650
Industrial	36,320
Composite (all sectors)	47,850

Source: CRA International, 2008, Assessment of the Value of Customer Reliability, p34

AEMO also published updated Victorian VCR as part of its National VCR project in 2012:

Table A.26 AEMO updated Victorian VCR

Year	VCR (\$/MWh)
2008	52,940
2009	56,180
2010	57,290

Source: AEMO, 2012, Final - National Value of Customer Reliability, p4

A.6 New South Wales

A.6.1 Overview

New South Wales has three DNSPs: Ausgrid, Endeavour Energy and Essential Energy. Details of the New South Wales DNSPs are contained in the table below.

Table A.27 Overview of New South Wales DNSPs

DNSP	Number of customers	Length of network (km)	Customer density (customer per km of network)	Maximum Demand (MW)	RAB (\$ million)	Proposed investment in current regulatory period (\$ million)
Ausgrid	1,605,635	49,442	32	5,609	8,688	8,579
Endeavour Energy	866,724	33,817	26	3,697	3,803	3,052
Essential Energy	801,913	190,844	4	2,239	4,451	4,277

Source: AER, 2011, State of the Energy Market 2011, p. 56

On 18 March 2012, the New South Wales Government announced its intention to merge Ausgrid, Endeavour Energy and Essential Energy. The merger is set to commence on 1 July 2012 and will be overseen by the Electricity Network Reform Taskforce.

A.6.2 Jurisdictional requirements

Further details on security and reliability standards in New South Wales can be found in the AEMC's New South Wales workstream draft report on reliability standards and outcomes. Further, the New South Wales workstream of the review of distribution reliability standards and outcomes may result in changes to these requirements from 1 July 2014.

Security standards

New South Wales DNSPs are subject to deterministic security standards as part of the New South Wales electricity distribution licence conditions. Currently in New South Wales, the following deterministic standards apply:

- N-2 for CBD sub-transmission lines, sub-transmission substations, and zone substations;
- N-1 for urban and non-urban sub-transmission lines with load greater than 10MVA, urban and non-urban sub-transmission substations, urban and non-urban zone substations with load greater than 10MVA, CBD distribution feeders, and CBD distribution substations;
- N for urban and non-urban sub-transmission lines with load less than 10MVA, urban and non-urban zone substations with load less than 10MVA, urban and non-urban distribution feeders, and urban and non-urban distribution substations.¹⁸⁰

The security standards are defined as follows:

- for N-2, nil customer interruption for the first credible contingency, and less than one hour for the second credible contingency;
- for N-1, nil customer interruption times for CBD distribution substations, less than one minute of customer interruptions for sub-transmission lines, sub-transmission substation and zone substations, and less than 4 hours for urban distribution feeders;

¹⁸⁰ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 1. The load 'break-point' used in the security standards is 15MVA for Essential Energy.

- for N, a customer interruption time equivalent to 'best practice repair time' is allowed.¹⁸¹

Under the current licence conditions, New South Wales DNSPs are required to be as compliant as "reasonably practicable" by 1 July 2014, and fully compliant by 1 July 2019.¹⁸²

Average reliability performance standards

The New South Wales DNSP licence conditions also specify reliability performance standards that each of the DNSPs are required to meet. From 2005-06 to 2010-11, all New South Wales DNSPs were required to meet decreasing SAIDI and SAIFI targets (ie improving reliability standards). From 2010-11 onwards, however, the SAIDI and SAIFI targets remain constant.¹⁸³

The average SAIDI standards for each DNSP by feeder type are detailed in the table below.

Table A.28 New South Wales SAIDI average standards

DNSP	Feeder type	Average SAIDI to apply from 2010-11 (minutes per customer)
Ausgrid	CBD	45
	Urban	80
	Short-rural	300
	Long-rural	700
Endeavour Energy	Urban	80
	Short-rural	300
	Long-rural	n/a
Essential Energy	Urban	125
	Short-rural	300
	Long-rural	700

Source: NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 2

¹⁸¹ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 1

¹⁸² NSW Design, reliability and performance licence conditions for distribution network service providers, clause 14.2

¹⁸³ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 2

Note: Endeavour Energy does not have a performance standard for long-rural feeders as it only has two long-rural feeders in its network.

The average New South Wales SAIFI targets are detailed in the following table.

Table A.29 New South Wales SAIFI average standards

DNSP	Feeder type	Average SAIFI to apply from 2010-11 (number per customer)
Ausgrid	CBD	0.3
	Urban	1.2
	Short-rural	3.2
	Long-rural	6
Endeavour Energy	Urban	1.2
	Short-rural	2.8
	Long-rural	n/a
Essential Energy	Urban	1.8
	Short-rural	3.0
	Long-rural	4.5

Source: NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 2

Note: Endeavour Energy does not have a performance standard for long-rural feeders as it only has two long-rural feeders in its network.

The following interruptions are excluded when determining New South Wales DNSP performance:

- an interruption duration of less than one minute;
- an interruption resulting from load shedding, a failure of the transmission system, automatic load shedding due to a power system under-frequency condition, or a direction issued to interrupt supply;
- a planned interruption;
- any interruption which commences on a major event day (defined as occurring when the daily total system SAIDI exceeds a pre-determined threshold which is based on historical SAIDI values); and

- an interruption caused by a customer's electrical installation or failure of that installation.¹⁸⁴

Worst served customer reliability standards

In addition to the reliability standards, the licence conditions also set out SAIDI and SAIFI standards for individual feeders. While the reliability standards require the NSW DNSPs to maintain an *average* level of reliability performance across their network, the individual feeder standards provide a *minimum* level of reliability performance for all customers.

The purpose of the individual feeder standards is to ensure that the level of reliability experienced by customers in the worst served areas, which are usually remote rural areas, does not fall below a specified minimum level.

SAIDI and SAIFI standards for individual feeders are contained in the following tables.

Table A.30 New South Wales SAIDI and SAIFI individual feeder standards

DNSP	Feeder type	SAIDI standards (minutes per customer)	SAIFI standards (number per customer)
Ausgrid	CBD	100	1.4
	Urban	350	4
	Short-rural	1000	8
	Long-rural	1400	10
Endeavour Energy	Urban	350	4
	Short-rural	1000	8
	Long-rural	1400	10
Essential Energy	Urban	400	6
	Short-rural	1000	8
	Long-rural	1400	10

Source: NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 3

¹⁸⁴ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Schedule 4

Guaranteed Service Level payments

The current New South Wales licence conditions also contain requirements in relation to GSL payments. Upon application by the customer, a DNSP must make a payment of \$80 to a customer, where the customer experiences:

- an interruptions greater than 12 hours (metropolitan) or 18 hours (non-metropolitan); or
- four interruptions greater than four hours in a financial year (metropolitan) or four interruptions greater than five hours (non-metropolitan).¹⁸⁵

Under the licence conditions, New South Wales DNSPs are required to take reasonable steps to make customers aware of the availability of payments. Reasonable steps include, as a minimum, publication of information on the DNSP's website and annual newspaper advertisements.¹⁸⁶ GSL payments are capped at a maximum of \$320 per customer per year.¹⁸⁷

Incentive schemes

In the current regulatory period (2009 to 2014), the New South Wales DNSPs are required to provide the AER with service performance data, but no revenue is at risk. Collection of this data is intended to allow for application of the STPIS to the New South Wales DNSPs from 1 July 2014 for the next regulatory period (2014-2019).¹⁸⁸

There is currently no reliability performance incentive scheme in place in New South Wales.

A.6.3 Governance arrangements

The current New South Wales security and reliability standards were determined by the New South Wales Minister for Energy as part of the 2007 DNSP licence conditions. These conditions are also supplementary to obligations imposed on New South Wales DNSPs by the *Electricity Supply Act 1995*, the *Electricity Supply (General) Regulation 2001*, the *Electricity Supply (Safety and Network Management) Regulation 2002* and other regulatory instruments.

As part of the licence conditions, the security and reliability standards are enforceable under the *Electricity Supply Act 1995 (NSW)* by both the New South Wales Minister for Energy and the Independent Pricing and Regulatory Tribunal (IPART). The Minister

¹⁸⁵ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Clause 17 and Schedule 5

¹⁸⁶ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Clause 17.4

¹⁸⁷ NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, Clause 17.6

¹⁸⁸ Australian Energy Regulator, 2009, Final Decision - New South Wales distribution determination 2009-10 to 2013-14, p. 244

can enforce the licence conditions through the imposition of a monetary penalty (up to \$100,000) or by revoking the licence.¹⁸⁹ IPART can enforce the licence conditions monetary penalties only (up to \$40,000).¹⁹⁰

The security and reliability standards are able to be varied as part of variations to the licence conditions.¹⁹¹ The Minister for Energy may vary the conditions of a licence, but must consult with the Minister administering the *Protection of the Environment Administration Act 1991* before varying the conditions of a licence under this clause.¹⁹²

Unlike most other jurisdictions in the NEM, the New South Wales DNSPs have an absolute obligation to meet the average reliability performance standards or are in breach of their licences, as opposed to a best or reasonable endeavours obligation.

A.6.4 Reporting requirements

The New South Wales DNSPs are required to submit quarterly reports to the Minister on their performance against the average reliability performance standards, and the GSL payments.¹⁹³

The DNSPs are required to report the actual individual feeder performance against the required standards on an annual basis.¹⁹⁴ Additional reporting is required where a DNSP does not meet the individual standard. In these instances, the DNSP must investigate and report to the Minister on the causes for exceeding the standard and identify any action to improve the performance. DNSPs must complete any operational actions which were identified within six months of finalising their investigation. The DNSP must also develop a project plan for any required non-operational actions, including non-network solutions.¹⁹⁵

New South Wales DNSPs are also required to obtain an independent audit of their performance against each of the licence conditions. The audit must be provided to the Minister and IPART.¹⁹⁶

A.6.5 Recent reliability performance

The following table shows the 2010/11 performance of the New South Wales DNSPs against the SAIDI targets.

189 Electricity Supply Act 1995, Schedule 2, clause 8
190 Electricity Supply Act 1995, Schedule 2, clause 8A
191 NSW Design, reliability and performance licence conditions for distribution network service providers, 2007, p. 4
192 Electricity Supply Act 1995, Schedule 2, clause 7
193 NSW Licence Conditions, clauses 18.8 and 18.5
194 NSW Licence Conditions, clauses 18.7-18.8
195 NSW Licence Conditions, Schedule 3, clause 16 and clause 18.4
196 NSW Licence Conditions, clauses 18.7-18.12

Table A.31 New South Wales DNSP performance against SAIDI targets

DNSP	Feeder type	SAIDI (minutes per customer)	
		Standard	2010-11 performance
Ausgrid	CBD	45	5.11
	Urban	80	82.62
	Short-rural	300	225.10
	Long-rural	700	467.57
Endeavour Energy	Urban	80	52.5
	Short-rural	300	149.3
	Long-rural	n/a	922.7
Essential Energy	Urban	125	66
	Short-rural	300	245
	Long-rural	700	493

Source: AEMC Reliability Panel, 2012, *Annual Market Performance Review*, final report, p. 64

Note: Endeavour Energy does not have a target for long-rural feeder performance due to only having two long-rural feeders in its network.

New South Wales DNSP performance against the SAIFI targets is detailed in the next table.

Table A.32 New South Wales DNSP performance against SAIFI targets

DNSP	Feeder type	SAIFI (number per customer)	
		Standard	2010-11 performance
Ausgrid	CBD	0.3	0.06
	Urban	1.2	0.97
	Short-rural	3.2	2.06
	Long-rural	3.0	4.31
Endeavour Energy	Urban	1.2	0.7
	Short-rural	2.80	1.4
	Long-rural	n/a	2.1
Essential Energy	Urban	1.8	0.85

DNSP	Feeder type	SAIFI (number per customer)	
		Standard	2010-11 performance
	Short-rural	3.0	2.38
	Long-rural	4.5	3.37

Source: AEMC Reliability Panel, 2012, *Annual Market Performance Review*, final report, p. 64

Note: Endeavour Energy does not have a target for long-rural feeder performance due to only having two long-rural feeders in its network.

A.6.6 Customer willingness to pay

To date, estimates of New South Wales customer willingness to pay have not been used to inform or design New South Wales security and reliability standards.

However, as part of the New South Wales workstream of the distribution reliability standards and outcomes review, the AEMC estimated New South Wales-specific VCRs for each of the DNSPs. The results are contained in the table below. Further detail can be found in the draft report for the New South Wales workstream.

Table A.33 Estimates of New South Wales VCR

DNSP	VCR (\$/MWh)
Ausgrid	86,790
Endeavour Energy	110,710
Essential Energy	90,710