The Brattle Group

Approaches to setting electric distribution reliability standards and outcomes

January 2012

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1 Executive Summary

1. Distribution planning involves making trade-offs between cost and reliability. Simply put, distributors should be able to achieve high levels of reliability (i.e., low levels of service interruptions) if they spend enough, in terms of capital and operating and maintenance expenses, on their systems. Although empirically based algorithms which capture such trade-offs are elusive at best, planners have developed a reasonable sense of where spending will produce the best results and develop their annual capital and operating budgets accordingly.

2. Regulators around the world are also keenly aware of the trade-off, and seek to ensure that customers in their jurisdictions receive high quality services at reasonable prices. To influence the outcome, they typically set reliability standards (e.g., durations and frequencies of service interruptions) and provide financial incentives or other consequences.

3. In Australia, jurisdictional regulators and the Australian Energy Regulator (AER) have observed that regulatory standards are likely influenced the levels of spending by distributors on distribution systems which, in turn, had a notable impact on customer bills. In response, the Ministerial Council on Energy (MCE) directed the Australian Energy Market Commission (AEMC) to investigate regulatory approaches to reliability as well as the impact that such practices may have upon costs and allowed revenues.

4. The AEMC engaged The Brattle Group to review regulatory practices and outcomes in a number of jurisdictions around the world, to analyse the effectiveness of the approaches applied, and to provide advice, in terms of " best practices" that may be relevant in Australia. The AEMC also requested that regulatory practices and outcomes across Australia be included in our study. Thus, we have analysed the reliability regulations in Australia, New Zealand, Great Britain, the Netherlands and Italy and New York and California in the U.S.

5. Regulators around the world have taken a range of approaches to regulating reliability and have developed their own priorities and, in many case, terminologies. Correlating outcomes with regulatory approaches is challenging and requires considerable caution when interpreting results. This is because reliability outcomes are determined by a myriad of inter-related factors, notably the design and age of the distribution infrastructure and the density of the customer base, as well as regulatory incentives.

1.1 Findings

6. *Approach to Regulating Reliability:* The regulators in all of the jurisdictions studied consider reliability to be a critical dimension of their mandate, and have taken an active approach to reliability regulation. All require that distributors file reports concerning reliability performance; most set standards and require reporting on performance against those standards. Standards are typically set for relating to the average frequency and duration of interruptions.[1] Regulators also frequently track reliability at a more detailed level (and may also set standards at this level), such as by geographic operating area or type of area (e.g., rural / urban) or feeder, and may require identification of circuits that supply the "worst-served" customers. In addition, some regulators require distributors to provide them with analysis of reliability trends, explanation for changes and updated spending plans.

7. Many regulatory jurisdictions have added a reliability component to already-established performance-based allowed revenue regulations. Typically, reliability performance regulations have a financial incentive structure. This may be one-sided i.e. distributors face a penalty for not meeting their standards, or two-sided i.e. the distributors can also receive a bonus for exceeding them. None of the jurisdictions studied apply a bonus-only incentive mechanism. The inclusion of an incentive scheme, above and beyond tracking of performance against standards, is perhaps the single most significant differentiator among regulatory approaches to reliability.

[1] For a more precise discussion of the standards that regulators typically impose, see section 3.2 .

8. Reliability incentive structures also provide regulators with a direct lever to improve reliability standards. In the absence of an incentive mechanism, compliance with reliability standards is generally accomplished through one-off regulatory investigations into major outages or chronic underperformance or is encouraged via “naming and shaming”.

9. Several jurisdictions have also introduced guaranteed service programmes under which distributors make payments directly to affected customers for certain types of service interruptions and/or inconveniences. Generally, the guarantees relate to outage restoration times and the provision of information about outages (including expected time of service restoration).

10. *Measuring Reliability:* Reliability standards and targets are typically set for “normal” conditions; that is, conditions for which distributors can plan, or, alternately stated, conditions over which a distributor may have some control. Determining what is “normal” is, understandably, an area of debate. Industry organizations, such as the Institute of Electrical and Electronics Engineers (IEEE) have proposed statistical methods for calculating reliability under normal conditions. However, some regulators have developed their own methods for calculating reliability under normal conditions, and these vary considerably across jurisdictions. While such a local approach is effective in addressing jurisdictional views on reliability, it also makes comparisons of reliability performance across jurisdictions somewhat problematic.

11. *Input Standards:* In the majority of cases, regulators rely on “output” standards (i.e., measures that reflect results) as opposed to “input” standards that direct the way reliability planning should be conducted. Input standards may require a distributor to follow a prescribed planning methodology, such as probabilistic or predictive methods, or plan to a particular contingency level, such as N-1 or N-2.[2] While regulators may review and even comment on utility distribution plans and analyses, few, with the notable exception of the regulator in New South Wales in Australia, impose input standards that appear to be driving investment.

[2] See glossary (Annex VI) for an explanation of these terms.

12. *Statutory Authority and Governance:* In nearly all cases, the same agency is responsible for virtually all aspects of regulating distributors. This makes for a consistent approach to regulating reliability and setting allowed revenues, even if the two areas of regulation are carried out separately. The notable except to this practice is Australia, where the AER is responsible for regulating prices in most jurisdictions, but other regulators (or Governments) are at least partly responsible for regulating reliability.

13. *Customer Willingness to Pay:* Most of the distributors reviewed used internal data concerning costs and system characteristics when deciding on enhancements and maintenance levels for their distribution systems. "Value-based" planning (i.e., planning based on the value of reliability to customers or customers' willingness to pay for heightened reliability) is more market oriented. Such value-related metrics are used in Australia and some European jurisdictions (GB, Italy).

14. *Impact of Regulation on Reliability Performance:* Standards and performance vary considerably between distributors, but the degree of under- or over-performance varies less. In most jurisdictions, the match between performance and standards is quite close. This suggests that the standard setting process has resulted in standards reflective of the unique circumstances facing each distributor so that distributors believe that they are able to meet standards with proper planning and attention. We also found that that distributors with the most to lose (i.e., facing the highest potential penalties) tend to comply more closely with reliability standards than those facing less punitive sanctions, at least as regards the average duration of interruptions.

15. *Cost Effectiveness:* An overarching question concerning the effectiveness of regulating reliability involves its relationship with cost. This is a particularly complex issue because measures of costs and reliability vary considerably across jurisdictions. Also, there is inevitably a lag between costs being incurred and reliability improving, which accentuates measurement inconsistencies.

16. Our analysis resulted in three key findings in this area. First, we were able to follow reliability performance over time within jurisdictions and found that jurisdiction-wide reliability performance appears to have been reasonably stable over the past ten years, see Figure 1 and Figure 2 below, although there may be marked variations in levels of reliability within jurisdictions. (Italy, which has seen a steady improvement in reliability over the study period, provides an exception.)

Figure 1: SAIDI Performance over Time

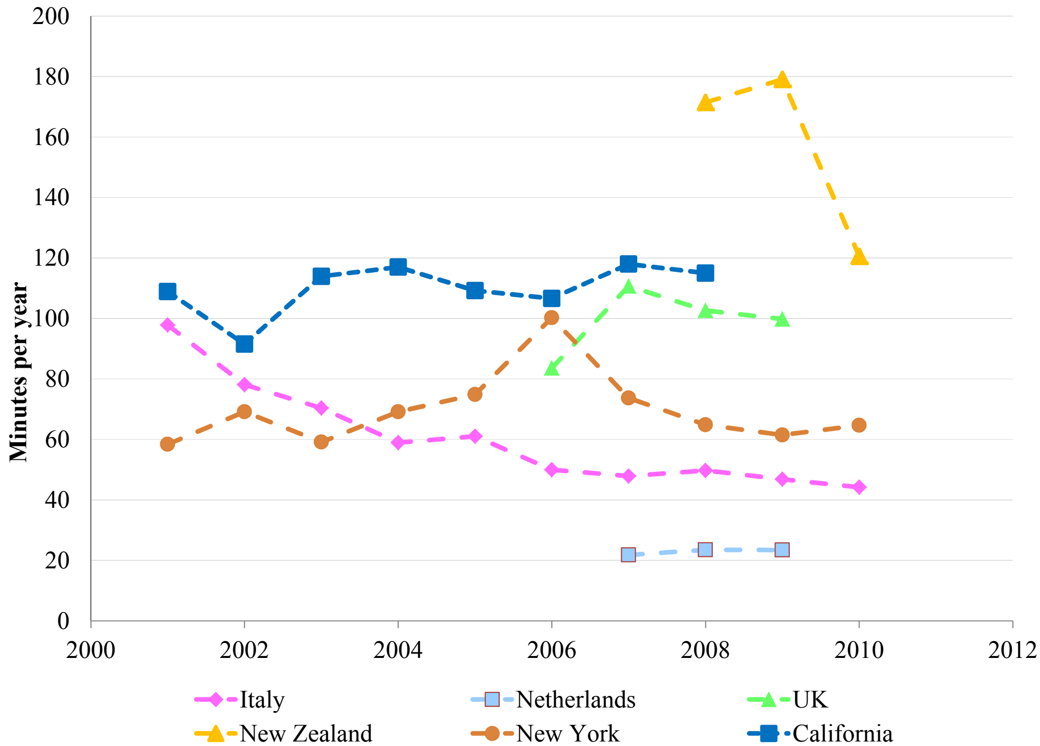
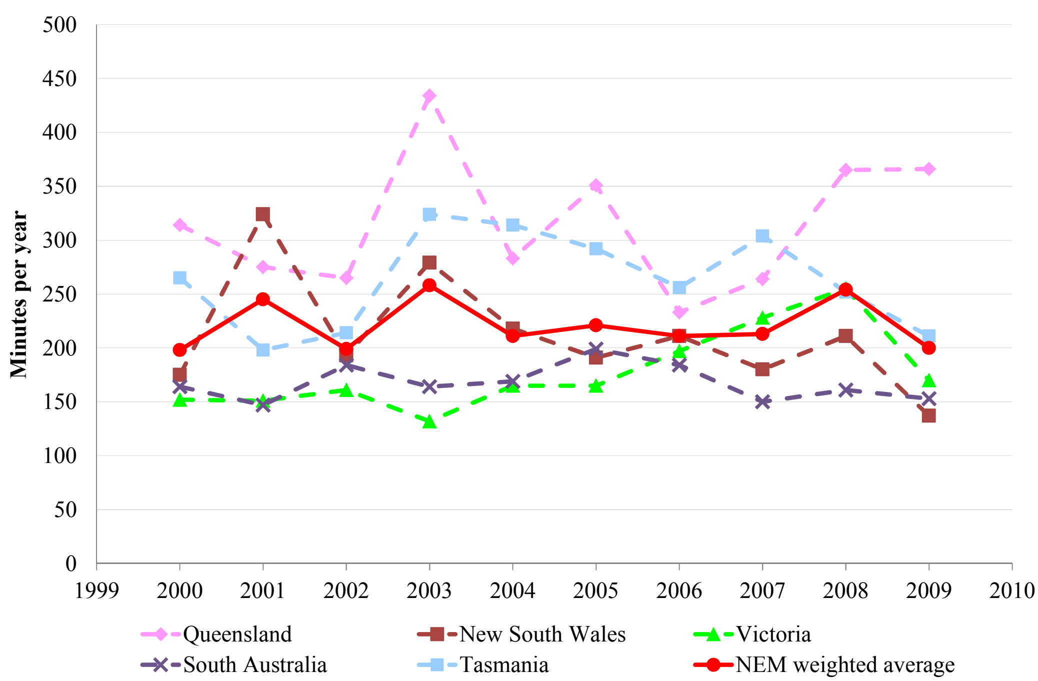


Figure 2: SAIDI Performance over Time in Australia



17. Second, distribution related costs per customer for Europe and the U.S. on a jurisdiction-wide basis largely fall within the same cluster of observations, while per

customer costs in Australia and New Zealand appear to be considerably higher. Third, numerous factors impact both reliability and cost outcomes, notably customer density, system design and topology as well as the age of the distribution infrastructure.

1.2 Australia in Comparison to the other Jurisdictions

18. Whilst the Australian approach to regulating distribution reliability is generally very much in line with other jurisdictions, it differs in three notable respects. First, it appears unique in splitting the regulation of reliability between jurisdictional regulators and the AER. Second, NSW appears unique in applying input standards that are driving investment decisions. Third, at the national level Australia has the lowest level of reliability of any of the jurisdictions studied.

19. Australia's comparatively low level of reliability performance is explained in part by the low customer density, and the challenging terrain and system topology for significant portions of the country. High costs and low levels of reliability in rural areas contrast with the performance in the country's urban areas, where costs are lower and levels of reliability are generally as good as or even better than that realized by the most reliable European distributors.

20. Australia's unique situation is the primary determinant of what can be accomplished through regulation. Our analysis suggests that whilst regulation may be able to influence the trade-offs distributors make between costs and reliability, the costs of low customer density distribution systems will remain high compared to more urban systems and the levels of reliability lower.

1.3 Best Practice Recommendations

21. Our review and analysis of regulatory approaches to reliability has led us to formulate a set of high-level "best practices". These represent recommendations that we consider to be applicable to the situation in Australia; they are not intended to be universally applicable. To provide a complete picture, we provide an overview of best practice in most aspects of distribution regulation, which means that some of our recommendations have already been implemented in Australia e.g. with respect to incentive arrangements.

22. *Reliability Reporting*. Regulation of reliability in Australia should include a requirement that distributors provide detailed reporting regarding reliability performance.

Reporting on performance should be at a dis-aggregated level so that trends and variations across the distribution system can be assessed.

23. *Incentive Plan*. Reliability performance reporting should be complemented by an incentive scheme with material financial implications, similar to the structure used in other jurisdictions. Performance targets should be set at a reasonably aggregate level, considerably less detailed than that required under the performance reporting requirements. While very detailed reporting (e.g., at the circuit level, especially for "worse performing" circuits) is valuable in a reporting context, incentive targets should not be set at this level. Nonetheless, it is important that the incentive targets distinguish between very urban, semi-urban and rural regions.

24. *Target Setting*. Reliability performance targets should be set at realistic and achievable levels. This does not mean that targets should not provide distributors with a challenge, but placing targets out of touch with historical performance takes the incentive away.

25. It almost goes without saying that reliability standards and targets need to be set in a transparent and predictable fashion. The regulatory concerns which led to this study involve the appropriate trade-off between cost and reliability. Understanding reliability targets in the short and long term allows distributors more fully to incorporate reliability thresholds into their planning. We therefore recommend developing a methodology for setting standards (probably some form of glide path) that provides distributors with long term certainty regarding the reliability targets they will have to achieve.

26. *Willingness to pay studies*. In setting standards and targets, customer willingness to pay studies should be taken into account to the extent that such analysis is available. Understanding the value of reliability to customers provides important information which can be used to set reliability target levels. It can also provide the information needed to determine whether or not a distributor's allowed revenues reflect acceptable levels of reliability or if customers would be willing to pay more if reliability was enhanced.

27. *Two-sided Incentives*. Even if there is full information on the values that customers place on reliability in Australia, we recommend that the incentive structure should include both bonuses and penalties. Such a structure ensures that there is not a "cliff edge" effect, whereby distributors will be reluctant to invest to improve reliability when they are close to

their target if this could lead to higher than target reliability for which they will not be rewarded.

28. *Coordination with Price Controls*. Reliability incentive mechanisms set short-term targets. Sustainably improving reliability also requires a commitment to longer term investment. Therefore, reliability incentive plans need to be carefully coordinated with the regulation of investments, returns and prices. This is particularly important in Australia, given the dual governance structure of distribution regulation.

29. In at least one of the jurisdictions studied (California), the regulator found that the shorter term reliability incentive mechanism had achieved its reliability goals and opted to replace the plan with a longer term investment oriented plan. This does not currently seem appropriate for Australia where it seems likely that reliability can be further enhanced through short-term incentives.

30. *Supplemental Measures*. Reliability incentive mechanisms do not address all the issues concerning reliability since they focus on average performance. Accordingly, we recommend including supplemental measures relating to worst-served customers and preparations for extreme weather conditions. These do not necessarily have to focus on financial measures – for example, distributors could be required to publish information on the plans that they have to address these issues.

31. *Input Standards*. Finally, we recommend that reliability regulation should focus on output standards. By imposing input standards, regulators risk becoming overly involved in a distributor's planning process. We conclude that prescription of input standards should be considered as a last resort, when distributors appear unable to improve reliability levels despite their best efforts.

2 Introduction

32. This study of approaches to distribution reliability regulation is empirically based and involved comparisons among regulatory jurisdictions from around the world. The study also reviewed reliability performances for the various jurisdictions over time and analysed performance in terms of distribution system characteristics and standards and/or financial incentives set by regulators.

2.1 Study Objective and Methodology

33. The objective of the study is to provide sufficient analysis for the AEMC to develop positions and provide advice concerning the framework for, and implementation of, distribution reliability standards in Australia. Consequently, we have looked at how regulators influence distributors' behaviour in relation to the reliability of their systems, including the following key areas:

- The process by which distribution reliability standards are set and how they have evolved over time;
- Governance arrangements - who sets, directs and oversees distribution standards;
- Whether or not willingness to pay ("WTP") studies have been conducted and how their findings have been taken into account;
- Whether standards are uniform across a system, or vary by location, density or some other type of distribution system characteristic;
- Whether standards relate only to "outputs," such as the frequency and duration of interruptions, or also to "inputs", such as planning standards or the technical design of system elements;
- Whether the standards relate to performance under "normal" conditions (i.e., excluding the impact of extreme events, such as ice storms) or whether the standards relate to performance even during times of system stress;
- How the standards are applied - for example, do the distributors have financial incentives to provide a particular level of reliability and is the incentive one-sided (only penalties for failing to meet the target reliability) or two-sided (in addition to penalties, bonuses are paid for exceeding the target reliability);

- Whether customers are entitled to payments when a distributor performs poorly in terms of, for example, responding to queries or providing information about outages;

- The extent to which reliability standards are perceived to be driving investment in the electric distribution system (or, conversely, the extent to which lack of investment in the past is perceived to have resulted in poor performance);

- How transparent the approach to distribution system management is since this affects the extent to which the regulator and other stakeholders can easily review a distributor's performance, which can be important in assessing a distributor's performance during a major outage.

2.2 Panel of Jurisdictions

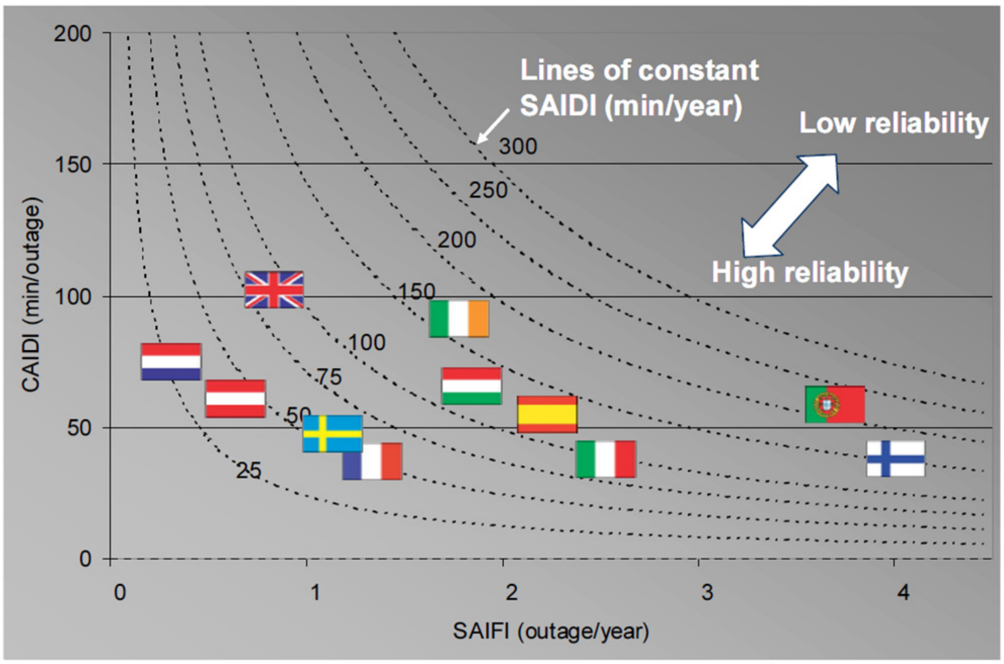
34. The AEMC specified that our analysis should include a review of distribution reliability standards and outcomes in Australia, New Zealand and Great Britain, and should also include other jurisdictions in Europe and in the United States.

35. We considered two factors in determining which jurisdictions to include in this study, beyond those initially specified by the AEMC. First, we took into account which jurisdictions have consistently reliable distribution systems or have experienced improvements in reliability over time. Second, we sought out jurisdictions which have well-developed regulatory mechanisms in place, including but not limited to financial incentive mechanisms, or which have adopted a unique or, in our view, interesting approach to regulating electric distribution reliability.

36. *European Jurisdictions*. We considered historical levels of system reliability combined with regulatory approach in selecting the European jurisdictions to include in our study. From Figure 3 below, it can be seen that in 2004 the four most reliable distribution systems in Europe were Austria, France, the Netherlands and Sweden. Studies sponsored by the Council of European Energy Regulators (CEER) confirmed that Austria, France and the Netherlands continued to have reliable systems through to 2007. However, the stuides

that reliability in Sweden deteriorated during that time[3] and, for this reason, we did not include it in this study. Of the three consistently reliable systems, we chose only to include the Netherlands, because Austria and France do not have explicit reliability components within their regulatory frameworks. We then added Italy, which achieved a 46% decrease in customer minutes lost in the four years after it introduced a reliability incentive component in its regulatory framework.

Figure 3: Comparison of Reliability of European systems in 2004[4]



37. *U.S. Jurisdictions*. In the United States, the reliability of the bulk power system (i.e., power generation and transmission) is regulated at the federal level (through the U.S. Federal Energy Regulatory Commission, or FERC), while electric distribution is regulated at the individual state level. At least 35 jurisdictions in the U.S. out of a total of 51

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[3] According to Figure 2.5 of the CEER 4th benchmarking report on quality of electricity supply. However, this figure relate to unplanned interruptions at all voltage levels.

[4] "Quality of supply and market regulation; survey within Europe", Kema, December 2006.

currently actively regulate electric distribution reliability.[5] Several U.S. states have undergone restructuring of their electric utility industries causing state regulation to be more focused on retail and distribution services. We included the states of New York and California in this study because they are both large and topographically diverse jurisdictions served by numerous distributors. The regulators for these states have developed approaches to regulating distribution reliability since the mid-1990s spanning several regulatory proceedings. Both states have developed distributor specific standards for reliability and have also incorporated reliability components into their structure of performance based rates[6] (either in their current or previous regulatory approaches).

38. The jurisdictions which comprise the scope of our comparative analysis are shown in Table 1 below.

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[5] These 51 jurisdictions include the 50 states plus the District of Columbia. Regulatory frameworks for all jurisdictions include statutory provisions concerning reliable electric service. “Active” regulation refers to the establishment of targets and/or standards and possibly inclusion of incentives and/or penalties within a form of performance based rates.

[6] “Rates” is the term used in the US for what is typically referred to as “allowed revenues” elsewhere.

Table 1: Scope of Jurisdictions and Distributors

Jurisdiction	Distribution Utilities Covered	Jurisdiction	Distribution Utilities Covered
New Zealand		***Australia***	
	29 Distribution companies	ACT	ActewAGL
Europe		New South Wales	Ausgrid (Energy Australia) Endeavour (Integral) Energy Essential (Country) Energy
Great Britain	14 Distribution companies		
Italy	160 Distribution companies; largest is Enel		
Netherlands	8 Distribution companies	Queensland	Energex Ergon Energy
United States		South Australia	ETSA Utilities
New York	6 major Distribution utilities	Tasmania	Aurora
California	3 major Distribution utilities		
		Victoria	Citipower Powercor Jemena SP AusNet United Energy
		Northern Territory	Power and Water Corporation
		Western Australia	Western Power

2.3 Structure of the report

39. An executive summary of our findings, conclusions and determination of best practices precedes this chapter. The remainder of the report is structured as follows. Chapter 3 provides some background on distribution reliability and its regulation. Chapters 4 and 5 describe the regulatory regimes in Australia and New Zealand respectively. These are followed by three chapters on the European jurisdictions: Great Britain (Chapter 6), Italy (Chapter 7) and the Netherlands (Chapter 8). Chapter 9 discusses approaches to distribution reliability generally in the United States, followed by two chapters which describe the specific situations in New York State (Chapter 10) and California (Chapter 11) in more detail.

40. Our findings are summarised in Chapter 12. Finally, our conclusions, concerning how regulation of reliability in Australia compares to that applied in other jurisdictions, are included in Chapter 13. We also provide our determination of "best practices" for Australia – a distillation of effective practices that may be particularly relevant in Australia – in Chapter13.

41. Note that a glossary of the acronyms used in this report is provided in Annex VI.

3 Background

3.1 Distribution Reliability

42. The focus of our analysis involves the economic and regulatory issues relating to interruptions to electricity supplies that are caused by problems on distribution systems.[7] In designing and maintaining reliability, distribution planners focus on ensuring that the right mix of capital investment (that is, the "adequacy" of distribution system resources) and operations and maintenance (O&M) practices produce the desired levels of security and quality – or, more to the point, reliability.

43. Distribution systems are large, complex structures composed of substations, lines, and transformers, which span a wide area. They are generally designed using a contingency coverage perspective; that is, the system is designed to minimize interruptions through efficient restoration of power under varying scenarios of equipment failure and breaks in power lines. The system may be analysed, and contingencies set, in terms of reliability metrics such as the level of interruption (in terms of duration and frequency) that should be realized at different load points. Maintaining the system involves assessing the outage exposure of the various nodes and load points on an on-going basis, and determining the appropriate levels of capital investment and O&M costs that minimize such exposures.

44. The planning and design of distribution systems is largely within the province of electrical engineers since it is a complex undertaking that requires considerable resources and expertise. In particular, there may not be a straightforward relationship between the design of a system and the level of reliability that is achieved.

45. Distribution planners have developed sophisticated modelling software and techniques; however "there is no generally available implementation or methodology that

[7] From a technical perspective, there are significant differences between distribution systems that are radial in nature i.e. where lines radiate out from a few points; and those that form a network mesh. However, the term "network" is used in some jurisdictions to refer to both types of system, but we have done so in this report.

will permit distribution system planners to predict distribution system reliability."[8] Nonetheless, two primary techniques are used in analysing distribution reliability:

- *Historic analysis*, as the name suggests, involves the collection and analysis of actually observed reliability performance (such as customer interruption frequency and durations ideally at a disaggregated and/or feeder level). These historic data become an indicator of future performance and serve as a guide to problem areas which may require enhancement.

- *Predictive analysis* builds upon historical analysis. It uses historic data in order to model (frequently through simulation techniques) each node of the distribution system and thereby attempts to predict specific points of exposure. Not surprisingly, predictive models of electric distribution systems require software and simulation capabilities. While such capabilities are becoming more commonplace for transmission planning purposes, they have not been fully developed at the distribution level.

46. Both these methods provide information on likely weaknesses in a distribution system and planners must then make decisions concerning the costs of addressing such weaknesses. In some regards, the overall modelling and planning of distribution systems is similar to that carried out for transmission systems. However, distribution systems are frequently radial in design, whereas transmission systems are normally meshed. A failure in a radial line may result in relatively contained interruptions, whereas an interruption in a transmission line generally has more widespread consequences.

3.2 Regulation of Distribution Reliability

47. Regulators need to set standards because the majority of electricity customers are not in a position to negotiate with their distributor regarding their preferred level of reliability. Furthermore, reliability is largely determined on a system-wide, or at least regional, basis. This means that all the customers located in the same region of the system necessarily receive the same level of reliability, irrespective of their individual preferences. For these

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[8] Electric Power Research Institute. Reliability of Electric Utility Distribution Systems: EPRI White Paper. October 2000.

reasons, regulators have to be involved in determining reliability standards, and in reaching an appropriate balance between increased reliability and higher prices.

48. Furthermore, a focus on reliability by regulators is necessary in order to balance other regulatory objectives, notably low prices. Regulators encourage distributors to be efficient and to ensure that prices are no higher than necessary, which may – through regulatory mechanisms that promote efficiency – encourage distributors to reduce reliability. "Reliability" per se cannot easily be priced, so under a price or revenue cap a regulated firm can increase its profits by reducing costs, even if the cost reductions imply reduced reliability.

49. The regulation of distribution reliability is generally implemented through a set of codes and rules that are frequently, but not always, overseen by a single regulator. These regulations may be broken down into distinct, albeit related, areas: output standard setting; input standard setting; and enforcement.

50. In this study, we focus primarily on input and output standards and incentives. Another possible form of reliability regulation is the direct regulation of spending programs. While we have reviewed regulatory practices to ascertain where and to what extent these types of regulation are applied, we found that it is not as prevalent as the types of standards and incentives that we discuss throughout the remainder of this report. Most regulators try to avoid becoming involved in the details of which projects are funded and which are postponed, and, in any case, this simply substitutes regulatory decision-making for management decision making, but does not help determine what the reliability outcome should be.

51. Output standards refer to specific measures of reliability performance that distributors have to meet and output targets refer to measures of reliability performance that distributors have an incentive to meet. Output standards or targets are universally applied in the jurisdictions studied. The primary output standards measured are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI measures the average number of minutes that interruptions last each year, and SAIFI measures the average number of times customers are interrupted in a year. In both cases, the averages are calculated by weighting the values for each interruption by the number of affected customers.

52. Regulators must specify the data that is to be included in the calculations of SAIDI and SAIFI. For example, very short interruptions – those lasting less than 3 minutes (1 minute in some jurisdictions) – are normally excluded. Most importantly, regulators must decide whether or not extreme events, such as storms or other "acts of God", should be included and also the circumstances under which service interruptions should be excluded.

53. Other standards may also be applied and monitored:

- Customer Average Interruption Duration Index (CAIDI = SAIDI/SAIFI);
- Customer Minutes Lost (CML = SAIFI);
- Customer Interruptions (CI): number of interruptions per 100 customers per year i.e. SAIFI x 100;
- Momentary Average Interruption Duration Index (MAIFI): the same as SAIDI but for very short interruptions.

54. Input standards refer to regulators specifying how distributors should plan and implement improvements to their distribution systems – with the intention of ultimately influencing performance (i.e., output standards). Input standards are in general less rigidly applied compared to output standards. Regulators typically do not attempt to involve themselves in distribution planning and operations by prescribing adherence to specific distribution planning methodologies, such as contingency planning methods (i.e., N-1 or N-2 standards). As a matter of practice, however, distributors often use N-1 type approaches as internal guidelines, even if this is not mandated by the regulator.

55. Enforcement relates to the processes by which regulators ensure that distributors are taking steps to meet the standards that have been set. Nearly every regulatory jurisdiction requires some level of reporting of reliability performance (i.e., outputs). Some jurisdictions address poor reliability performance on an ad hoc basis, while others have adopted automatic adjustments to revenues in the form of penalties for not meeting standards, and/or bonuses for exceeding them. Some jurisdictions also require that distributors make payments directly to customers for failing to meet prescribed reliability targets.

4 Australia

4.1 Introduction

56. There are a total of fifteen distribution systems in Australia, with only three states (New South Wales, Queensland and Victoria) having more than one distributor. The characteristics of the distribution systems vary widely in terms of customer density and circuit length, as can be seen from Table 2.

Table 2: Distribution System Characteristics in Australia

State/Territory		Company	Network Length (km)	% Underground	Number of Customers	Density (Customers/ km)	Revenue Requirement ($ millions, nominal)
		[A]	[B]	[C]	[D]	[E]	[F]
ACT	[1]	ActewAGL	5,396	54%	164,900	31	$133.7 (2009-10)
New South Wales	[2]						
		Ausgrid (Energy Australia)	48,590	28%	1,600,000	33	$1231.4 (2009-10)
		Endeavour (Integral) Energy	29,394	31%	866,767	29	$809.9 (2009-10)
		Essential (Country) Energy	200,000	3%	800,000	4	$937.9 (2009-10)
Queensland	[3]						
		Energex	53,256	31%	1,298,790	24	$1133.1 (2010-11)
		Ergon Energy	151,200	4%	680,095	4	$1105 (2010-11)
South Australia	[4]	ETSA Utilities	86,000	17%	812,529	9	$609.6 (2010-11)
Tasmania	[5]	Aurora	OH: 20,000 UG: 2,170	10%	271,750	12	$246.4 (2012-13 Draft)
Victoria	[6]						
		Citipower	6,445	37%	305,000	47	$210.6 (2011)
		Powercor	82,000	5%	700,000	9	$437.4 (2011)
		Jemena	12,600	-	315,000	25	$188.2 (2011)
		SP AusNet	2,300 (66 kV), 33,000 (≤22 kV)	0.50%	608,311	17	$518 (2011)
		United Energy	12,600	-	630,000	50	$282.9 (2011)
Northern Territory	[7]	Power and Water Corporation	HV Underground: 637 LV Overhead 1,758 LV Underground 1,781	52%	72,327	10	$99.9 (2009-10)
Western Australia	[8]	Western Power	OH conductors: 69,710	23%	1,018,275	11	$680.9 (2011)

Notes and sources:
[B], [C], [E], [F]:
[1] to [6]: Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion, Final Report 4.0, 13 May 2009. Sinclair Knight Merz. Appendix B: Summary of Reliability and Quality of Supply Obligations /Objectives.
[7]: Power and Water Corporation's Annual Report 2010-11. p. 22.
[8]: Western Power Network Management Plan, 1 July 2011 - 30 June 2017. p. 16-17, 80, 88.
[D]: From individual utility's 2009/2010 Annual Reports or webpages.

57. Some elements of the regulatory framework pertaining to distribution reliability in Australia are national, and contained within the National Electricity Rules (NER), and other elements are "jurisdictional". Jurisdictional elements are either outside, and additional to, the NER or are legacy arrangements which will transition to the NER over

time. In this chapter we describe the components of the NER which relate to distribution reliability, and review the jurisdictional requirements in each jurisdiction within the NEM. We also review arrangements in the Northern Territory and Western Australia.

58. The NER contain a reliability incentive mechanism (the Service Target Performance Incentive Scheme or STPIS). It provides for incentive arrangements under which reliability performance is measured using standard metrics (for example, SAIDI), and distributors receive a financial bonus for exceeding reliability targets, or are penalised if they miss the targets.

59. Broadly speaking, the NER does not address "inputs" or system planning arrangements pertaining to reliability. [9]

60. Jurisdictional requirements are mostly SAIDI and SAIFI standards, but in some jurisdictions also address system planning.

4.2 Governance

61. We have summarised the institutional and governance arrangements for reliability in Table 3. For the most part, we find that a normal regulatory process of public consultation on a draft decision is used, similar to the process that is used to address other regulatory issues, rather than a special process specific to reliability issues.

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[9] However, see Schedule 5.1.2.1 of the NER which provides for reliability standards to be contained in connection agreements.

Table 3: Institutional and Governance Arrangements in Australia

Jurisdiction	Body Responsible for Setting Reliability Standards	Body Responsible for Setting Reliability Incentives	Reliability Standards Settting Process	Reliability Incentive Setting Process
Australian Capital Territory	The standards are in the Electricity Distribution (Supply Standards) Code, administered by the ACT Government (Environment and Sustainable Development Directorate)	Will be the AER from 2014	Standards have not been changed since 2000. However, the utility itself is required to publish new standards each year (no looser than the Code standards)	Will be the standard STPIS process (part of the price review determination)
New South Wales	Licence conditions set by the Minister for Utilities, advised by the Independent Pricing and Regulatory Tribunal	Will be the AER from 2014	Consultation prior to imposing new licence conditions	Will be the standard STPIS process (part of the price review determination)
Queensland	Standards are in the Elecrticity Industry Code, which is issued by the Utilities Minister	AER	Consultation process specified in Queensland electricity legislation	Standard STPIS process (part of the price review determination)
South Australia	Standards are in the Distribution Code, which is issued by the Essential Services Commission	AER	Normal regulatory process, including consultation	Standard STPIS process (part of the price review determination)
Tasmania	The Tasmanian Electricity Code is administered by the Tasmanian Economic Regulator	Will be the AER from 2012	Normal Code change procedure, including consultation	Will be the standard STPIS process (part of the price review determination)
Victoria	The Victorian Electricity Distribution Code is administered by the Essential Services Commission. It requires distributors to set their own targets	AER	Normal regulatory process, including consultation	Standard STPIS process (part of the price review determination)
Western Australia	The standards are in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005, issued by the Minister for Energy	n/a	The Code has not been amended since first implemented	n/a
Northern Territory	There are currently no standards	Will be the Utilities Commission	n/a	n/a

4.2.1 STPIS Governance

62. The governance arrangements for the STPIS mirror those for the NER and distribution determinations generally. In particular, the AER consults publicly on draft decisions, and the AER's decisions can be appealed. The AER is responsible for monitoring compliance with the STPIS alongside other elements of the distribution determination.

4.2.2 Governance of Jurisdictional Reliability Standards

63. Table 3 indicates that jurisdictional reliability standards are set out in "industry codes", with two exceptions: in New South Wales (NSW) the standards are in licence conditions (this distinction does not appear to us to be a material one); and in Victoria, the code does not itself contain standards, but requires the distributors to set standards. The code in Victoria also refers to standards set as part of the price control process.

64. In some jurisdictions (South Australia, Tasmania, Victoria and the Northern Territories) the reliability standards are governed by a "regulator", whereas in others (Australian Capital Territory, NSW, Queensland and Western Australia) the standards are more directly the responsibility of a minister in the jurisdictional government.

65. We note that, at least in some Australian jurisdictions, there are mechanisms for the government to influence reliability outside of the formal standard-setting process. The distributors in Queensland, NSW, Tasmania, the Northern Territory and Western Australia (WA) are owned by the jurisdictional governments, so that, at least in principle, the governments should be able to influence spending on reliability directly. In Queensland, for example, there have been two significant government-sponsored investigations into reliability. Following concerns about poor reliability performance, the Queensland government commissioned an independent review that, in 2004, recommended significant changes to the way in which the distributors planned and managed their systems. The distributors subsequently agreed to implement new planning standards recommended by the review, which amounted to an "N-1" approach to major system elements. In 2011 the independent panel looked at reliability again, and recommended further changes aimed at reducing the cost of achieving the recommended reliability standard.[10] So far as we are aware, the new planning standards were implemented informally (for example, no obligations were placed on the distributors through the Queensland Electricity Code).

4.3 Methodology

4.3.1 STPIS Methodology

66. The STPIS provides distributors with a financial incentive to improve reliability: depending on their performance (in terms of reliability and customer service), each distributor may receive a bonus or pay a penalty, in each case of up to 7% of its total regulated revenue in a year. The STPIS has four elements: reliability of supply; quality of supply (not yet implemented); customer service; and guaranteed service levels (GSL).

67. Although the various parameters of the national STPIS have been set out by the AER, individual distributors are able to propose that different parameters should apply to

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[10] *Electricity Network Capital Program Review 2011, Detailed report of the independent panel*

them, and the AER has modified many of the parameters of the national scheme in applying it to individual distributors. The STPIS is implemented as part of the distribution determination that sets allowed revenues for each distributor every five years.

68. The STPIS currently applies in Victoria, Queensland and South Australia (SA), and is to be implemented in 2012 in Tasmania and in 2014 in NSW and the Australian Capital Territory (ACT).

69. The reliability element of the STIPS requires SAIDI, SAIFI and MAIFI to be measured. The distributor receives a bonus or pays a penalty if performance in a given year is respectively above or below target, where the target is its average performance in the prior five years. In using the historical performance to set the target, a number of adjustments are made: "major event days" are excluded; and the target may be tightened to reflect the impacts of system investment completed or planned in the current or prior regulatory period.

70. In measuring SAIDI and SAIFI, interruptions of less than one minute are excluded. Extreme events are identified by a standard "2.5 beta" method, and the impact of extreme events is capped at 2.5 beta.[11]

71. The "power" of the STPIS incentive scheme – the rate at which the reliability incentive bonus or penalty accrues is based on the "value of customer reliability", expressed as a value per unsupplied MWh. This value is set at $97,500/MWh for central business district (CBD) customers and half this value for other customers. The value of unsupplied energy is used to derive individual incentive parameters for SAIDI, SAIFI and MAIFI. The value of unserved energy and the derivation of individual parameters are based on WTP studies.[12,13]

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[11] The 2.5 beta method involves analyzing five years' worth of daily SAIDI data. The logarithm of each observation is taken and the average (alpha) and standard deviation (beta) of the set is calculated. Any day whose logarithmic SAIDI value exceeds alpha plus 2.5 times beta is classified as an extreme event day.

[12] See *Proposed Electricity distribution network service providers service target performance incentive scheme*, AER 2008.

72. The STPIS GSL arrangements require distributors to make payments to individual customers affected by interruptions. In addition to providing customers with payments when they experience poor reliability, the guaranteed service arrangements also provide the distributors with an incentive to improve performance: to the extent that performance improves and payments go down over time, the distributor is able to retain the difference between expected and actual payments for the duration of the price control. However, if a distributor is already subject to a jurisdictional GSL scheme, the GSL element of the STPIS does not apply.

73. The customer service element of the STPIS relates to telephone answering, streetlight repairs, new connections, and responding to written enquiries. The customer service portion of the STIPS may result in incentive payments/penalties of up to +/- 1% of revenue. Since these customer service metrics do not relate directly to reliability, we do not consider this part of the STIPS further here.

4.3.2 Reliability Standards Methodology

74. The methodology for measuring reliability is not uniform across the Australian jurisdictions. In Table 4 we summarise the main differences (Table 4 refers to the jurisdictional standards, not to the AER's STPIS which may additionally apply). In the following sub-sections we describe what kind of reliability standards are set in each jurisdiction.

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[13] Note, however, that the willingness to pay study on which the STPIS parameters are based is the value of customer reliability determined by AEMO/VENCorp for Victorian customers.

Table 4: Reliability Measurement in Australia

Jurisdiction	Specific Reliability Measures Applied	Outage Thresholds and Exceptions	Level of Disaggregation
Australian Capital Territory	SAIDI, SAIFI	Interruptions less than one minute are excluded. Extended storm outages are excluded (where 10% of customers in an area are affected). Both planned and unplanned outages included	None
New South Wales	SAIFI, SAIDI, both average figures and for individual feeders	Interruptions less than one minute are excluded. Planned interruptions are excluded. Load-shedding is excluded. Severe weather/storm events are excluded, and the "IEEE Guide for Electric Power Distribution Reliability Indices" - the "2.5 beta" method applies.	By utility and feeder type
Queensland	SAIFI, SAIDI	Interruptions are measured with the exclusion of "major event days", per ANSI.Std. 1366-2003 "IEEE Guide for Electric Power Distribution Reliability Indices" - the "2.5 beta" method.	By utility and feeder type
South Australia	SAIDI, SAIFI, maximum time to restore supplies	Excluding outages of less than one minute. Both planned and unplanned outages are included.	By region
Tasmania	SAIFI, SAIDI	Outages of less than one minute are excluded. SAIFI and SAIDI are measured for each transformer on the system, then aggregated to give a weighted average where the weights are the transformer capacities. Both planned and unplanned outages are included.	By location and by location type (urban / rural etc)
Victoria	SAIDI (planned), SAIDI (unplanned), SAIFI (unplanned), MAIFI	Interruptions shorter than one minute are excluded. There are separate targets for planned and unplanned outages.	By feeder type
Western Australia	SAIDI , SAIFI, maximum restoration time	SAIDI is measured as the average of the annual figures in the prior four years.	By area
Northern Territory	n/a	Not stated	By area

4.3.3 Methodology - South Australia

75. In South Australia, the South Australian Electricity Distribution Code, with which ETSA Utilities is required to comply by virtue of its licence, contains reliability standards. There are standards are for the maximum time to restore supplies following an outage as well as SAIDI/SAIFI standards, all of which vary by location.[14] Distributors are required to meet these standards on a "best endeavours" basis. From these, ETSA Utilities has derived deterministic system planning criteria (N-1 type).[15]

76. ETSA Utilities publishes a system management plan, as required by the *Electricity Industry Guideline No. 12- Demand Management for Electricity Distribution Networks*. The plan describes ETSA Utilities' approach to identifying and resolving system constraints. The Distribution Code also sets out guaranteed service levels and customer payments (within the standard connection and supply contract).[16]

4.3.4 Methodology - Victoria

77. The Victorian distributors are required to comply with the Victorian Electricity Distribution Code, which contains all the distribution reliability requirements. The

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[14] *Electricity Distribution Code*, Essential Services Commission of South Australia, p. A6.

[15] See *Electricity System Development Plan 2011*, p. 8.

[16] *Electricity Distribution Code*, Essential Services Commission of South Australia, part B.

Victorian Electricity Distribution Code requires that each distributor set its own reliability targets (in terms of SADI, SAIFI, MAIFI and CAIDI), for various parts of the system.[17] The distributor is then required to use "best endeavours" to meet these targets, which are updated annually. The Distribution Code also requires the distributor to meet any targets set as part of a price control.

78. The Distribution Code also contains provisions for guaranteed service levels, and customer payments.

79. The Code obliges distributors to produce a "Distribution System Planning Report".[18] The required planning approach is probabilistic: the distributor identifies major "capacity constraints" in terms of a forecast impact on reliability (unserved MWh and length of interruption), and investment options for resolving the forecast constraints.

4.3.5 Methodology - Tasmania

80. The Tasmanian Electricity Code sets reliability standards,[19] and also requires Aurora to publish an annual system planning report.[20] The standards are SAIFI and SAIDI, which vary by system location.[21]

81. Aurora is not currently subject to an incentive mechanism in respect of reliability, although such a mechanism was in place for the 2003-7 control period, and the STPIS is expected to be implemented for the 2012-17 period.[22] Rather, the code requires that Aurora uses "reasonable endeavours" to meet the standards.

82. The code also requires Aurora to make payments to customers that experience the worst reliability performance, with the detail of the scheme determined by the

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[17] *Electricity Distribution Code*, Essential Services Commission, Chapter 5.

[18] See *Distribution System Planning Report 2010*, Jemena, p. 8.

[19] *Tasmanian Electricity Code*, section 8.6.11.

[20] *Tasmanian Electricity Code*, section 8.3.2.

[21] See also *Distribution System Planning Report 2011*, Aurora Energy, section 4.2.1.

[22] *Framework and approach paper Aurora Energy Pty Ltd Regulatory control period commencing 1 July 2012*, AER November 2010, section 4.5.

jurisdictional regulator. Under this scheme, the thresholds (in terms of number and duration of interruptions) which trigger a payment to individual customers, depend on system location. Urban customers are expected to receive better reliability than rural customers.[23]

4.3.6 Methodology - New South Wales

83. The approach to distribution reliability in NSW is described in the AEMC's recent issues paper for the NSW workstream.[24]

84. The reliability standards are set out in the distributors' licences. The distributors are required by a licence condition to plan their systems to deterministic criteria, which vary according to system location. For example, sub-transmission [25]lines in the Sydney central business district (CBD) are planned to N-2, whereas other sub-transmission lines are planned to N-1 (over 10MVA) or N (under 10MVA).[26]

85. The licence also sets reliability standards (SAIDI and SAIFI), both as an average across all customers and for individual feeders. Both sets of standards vary by location. The distributors must report against the reliability standards, and investigate instances of non-compliance.[27]

86. The licence provides for guaranteed service levels, and payments to customers who experience poor service.

87. The distributors produce a "Network Management Plan" as required by the Electricity Supply (Safety and Network Management) Regulation 2008, and also produce an "Electricity System Development Review", required by licence condition (and the Demand Management Code of Practice).

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[23] *Framework and approach paper Aurora Energy Pty Ltd Regulatory control period commencing 1 July 2012*, AER November 2010, p. 95.

[24] *Issues paper – NSW workstream: Review of Distribution Reliability Outcomes and Standards*, AEMC November 2011, chapter 3.

[25] Sub-transmission lines are lines whose voltage is above that at which consumers are supplied.

[26] See *Ausgrid Network Management Plan 2011*, section 4.1.

[27] *Issues paper – NSW workstream: Review of Distribution Reliability Outcomes and Standards*, AEMC November 2011, p. 18.

4.3.7 Methodology - ACT

88. The distribution reliability regulations are set out in the Electricity Distribution (Supply Standards) Code,[28] which sets minimum reliability standards (SAIFI, SAIDI and CAIDI). The Code also requires distributors to set their own standards each year, which can be no lower than the minimum standards.

4.3.8 Methodology - Queensland

89. The distribution reliability regulations are set out in the Queensland Electricity Code, which sets minimum reliability standards (SAIDI and SAIFI) for various feeder types. Distributors must use best endeavours to ensure that the minimum standards are met.[29]

90. The Code also sets guaranteed service levels and provides for payments to customers experiencing poor reliability.

91. Energex also has a program to prioritise work on those feeders with the worst performance, although it is not clear that it is required to do this.

92. The Code requires distributors to publish a system management plan. The Energex system management plan details system planning standards of the "N-1" type, which range from N-2 for sub-transmission lines in its CBD, to N for less critical assets.[30] It is not clear how the planning standards relate to the legal or regulatory requirements placed on the distributors.

4.3.9 Methodology - Western Australia

93. The distribution reliability regulations are set out in the Electricity Industry (Network Quality and Reliability of Supply) Code. Distributors are obliged by the code to improve reliability for any customer where the standards are not met.

94. The standards are that, for 9 years in every 10, supply must be interrupted no more often than 9 times per year (urban areas, 16 times in rural areas), and never for longer than

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[28] *Electricity Distribution (Supply Standards) Code*, Australian Capital Territory (2000).

[29] *Queensland Electricity Industry Code*, 2011, section 2.4.

[30] *Energex Network Management Plan* 2011, p. 35.

12 hours at a time.[31] Furthermore, there are SAIDI standards (varying by location), which the distributor must meet so far as is reasonably practicable.[32] Customers whose supplies are interrupted for more than 12 hours are eligible to receive a payment.[33]

95. Although the reliability standards in Western Australia are not expressed in a standard way (SAIDI/SAIFI with exclusion for major events), the distributors are in addition required to report reliability using these more usual reliability statistics.[34]

96. The distributors publish a detailed system management plan, which describes policies and drivers for system investment,

97. The Code also provides for payments to customers where reliability is poor.

4.3.10 Methodology - Northern Territory

98. There are currently no standards or other mechanisms explicitly designed to regulate reliability in the Northern Territory. However, the Utilities Commission has developed an incentive mechanism, which will be introduced following a trial period. The Commission has also developed proposals for a GSL scheme, but there need to be legislative changes before this can be implemented. The Commission publishes reliability metrics (SAIDI and SAIFI) for various regions of the Power and Water Corporation system.

99. Unlike most other jurisdictions, reliability performance in the Northern Territory is influenced to a degree by generator as well as system reliability. For example, in the Darwin region in 2010, the overall SAIDI was 495 minutes, of which 61 minutes were due to generation, 238 minutes to a lightning strike on the transmission system, and the remaining196 minutes to general system reliability.[35]

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[31] Section 12 of the code.

[32] Section 13 of the code.

[33] Section 19 of the code.

[34] Under the *Code of Conduct for the Supply of Electricity to Small Use Customers*.

[35] *2009-10 Electricity Standards of Service: Summary of Power and Water Corporation Service Performance*, Utilities Commission, paragraph 3.

4.4 Targets and Standards

100. As explained above, all Australian jurisdictions, apart from the Northern Territory, set reliability standards. In addition, the AER has implemented the STPIS incentive scheme in some of the NEM jurisdictions.

4.4.1 Reliability Standards

101. In this section we describe the reliability standards in the various jurisdictions. We have attempted to summarise the targets in a way that aids comparison (for ETSA Utilities we have expressed the standards as a range because there are different standards in different parts of the same system). SAIDI standards are listed in Table 5 and SAIFI standards in Table 6.

Table 5: Jurisdictional SAIDI Standards[36]

Region	Utility Company	CBD	Urban	Rural Short	Rural Long
ACT	ActewAGL	-	40	40	40
New South Wales	Ausgrid (Energy Australia)	45	80	300	700
	Endeavour (Integral) Energy	-	80	300	none
	Essential (Country) Energy	-	125	300	700
Queensland	Ergon Energy	-	149	424	964
	Energex	15	106	218	-
SA	ETSA Utilities	25	115	240 - 450	240 - 450
Tasmania	Aurora Energy	60	120	480	600
Victoria	CitiPower	11	22	-	-
	JEN	-	68	153	153
	Powercor	-	82	115	234
	SP AusNet	-	102	209	257
	United Energy	-	55	99	99
NT	Power and Water Corporation	-	-	-	-
WA	Western Power	30	160	290	290

Notes:
Aurora Energy's targets are not broken down into feeder categories (i.e. urban, rural etc.)
The Tasmanian Electricity Code reports SAIDI and SAIFI for "Higher density rural" and "Lower density rural." These are linked to "Rural Short" and "Rural Long" respectively.
Jemena Electricity Networks (JEN) does not distinguish between Rural Short and Rural Long, so Rural targets are placed in both categories.
For the Northern Territory, there are no standards.

[36] In most Australian jurisdictions, different standards are set according to "feeder type" (CBD, urban, rural short feeders and rural long feeders). Where different descriptions are used, we have attempted to map the standards onto this same classification for ease of comparison across jurisdictions.

Table 6: Jurisdictional SAIFI standards

Region	Utility Company	CBD	Urban	Rural Short	Rural Long
ACT	ActewAGL	-	1.0	1.0	1.0
New South Wales	Ausgrid (Energy Australia)	0.3	1.2	3.2	6.0
	Endeavour (Integral) Energy	-	1.2	2.8	none
	Essential (Country) Energy	-	1.8	3.1	4.5
Queensland	Ergon Energy	-	2.0	4.0	7.4
	Energex	0.2	1.3	2.5	-
SA	ETSA Utilities	0.3	1.4	2.1 - 3.3	2.1 - 3.3
Tasmania	Aurora Energy	1.0	2.0	4.0	6.0
Victoria	CitiPower	0.2	0.5	-	-
	JEN	-	1.1	2.6	2.6
	Powercor	-	1.3	1.6	2.5
	SP AusNet	-	1.4	2.6	3.3
	United Energy	-	0.8	1.7	1.7
NT	Power and Water Corporation	-	-	-	-
WA	Western Power	-	-	-	-

Notes:
Aurora Energy's targets are not broken down into feeder categories (i.e. urban, rural etc.)
The Tasmanian Electricity Code reports SAIDI and SAIFI for "Higher density rural" and "Lower density rural." These are linked to "Rural Short" and "Rural Long" respectively.
Jemena Electricity Networks (JEN) does not distinguish between Rural Short and Rural Long, so Rural targets are placed in both categories.
For the Northern Territory, there are no standards.

102. These standards relate to the average performance across the specified parts of the systems, and the distributors are expected to use reasonable or best endeavours to meet the standards.

4.4.2 Incentive Schemes

103. By 2014, the STPIS will be in place throughout the NEM. In addition, an incentive scheme similar to the STPIS is to be developed in the Northern Territory. In the following subsections, we describe the main features of the incentive arrangements in each jurisdiction.

4.4.3 *Incentive Scheme – South Australia*

104. The STPIS currently applies in South Australia. The revenue at risk for ETSA Utilities is +/-3% against targets for SAIDI, SAIFI and telephone answering (within the 3%, the component for telephone answering is 0.3%).[37] The jurisdictional guaranteed service level arrangements continue to apply.

4.4.4 *Incentive Scheme – Victoria*

105. The STPIS applies in Victoria. The Victorian distributors have +/-5% of revenue at risk, with the exception of SP AusNet, which has +/-7%.[38] The SP AusNet cap was increased because the SP AusNet system historically had worse reliability than the other distribution systems. Consequently, the 5% incentive cap would have been reached before its performance matched the historical performance of its peers. The AER therefore increased the cap.[39] Various adjustments to the STPIS were made to reflect the need to transition from prior jurisdictional arrangements. In addition, the threshold for identifying "Major Event Days" was slightly adjusted for some of the distributors (by increasing the number of standard deviations). The jurisdictional arrangements for guaranteed service levels continue to apply.

4.4.5 *Incentive Scheme – Tasmania*

106. There is currently no incentive scheme in Tasmania.

107. For the next price control period (2012-17), the AER has signalled that Aurora will be subject to the incentive arrangements in the national STPIS. This means that its revenue at risk will be +/-5%.[40] Separate targets will be calculated for different parts of the system.

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[37] See, *South Australia distribution determination*, AER (May 2010), p. 200-2.

[38] See *Victorian electricity distribution network service providers distribution determination*, AER (October 2010), p. 739-43.

[39] See *Draft Victorian electricity distribution network service providers distribution determination*, AER (June 2010), p. 640.

[40] With a maximum revenue at risk for telephone response speed f +/-0.5%.

Customer payments (guaranteed service levels) will, however, be based on the existing jurisdictional scheme.[41]

4.4.6 Incentive Scheme – NSW

108. The national STPIS does not currently apply in NSW, and there are no incentive arrangements in place.

109. The AER is monitoring performance during the current control period, and intends to apply the national STPIS from the start of the next control period in 2014.

4.4.7 Incentive Scheme – ACT

110. The national STPIS does not currently apply in the ACT.

111. The AER is monitoring performance during the current control period, and intends to apply the STPIS at the beginning of the next control period in 2014.

4.4.8 Incentive Scheme – Queensland

112. The national STPIS is in place in Queensland. Revenue at risk is +/-2% for SAIDI and SAIFI (and telephone answering for Ergon Energy, but not Energex).

113. The jurisdictional guaranteed service levels continue to apply.

4.4.9 Incentive Scheme – Western Australia

114. There is no incentive scheme in Western Australia.

4.4.10 Incentive Scheme – Northern Territory

115. The Utilities Commission has investigated whether it would be appropriate to implement an incentive scheme for the Power and Water Corporation. The Commission concluded that the quality of data on historical reliability performance was not good enough to form the basis of an incentive scheme similar to the STPIS. It therefore intends

[41] *Framework and approach paper Aurora Energy Pty Ltd Regulatory control period commencing 1 July 2012*, AER November 2010, section 4.10.

to make a trial run of such a scheme for the remainder of the current price control period (to 2013/14).[42]

4.4.11 Worst-served Customers

116. Both incentive schemes and standards which apply to the average performance across a system or part of a system may not address pockets of particularly poor performance. While customers experiencing particularly poor performance may receive payments from their distributor in many jurisdictions, some jurisdictions additionally have specific mechanisms to target the worst-performing parts of each system.

117. The only formal standards are those in NSW: in addition to standards relating to the average performance of feeders (which we described above), distributors in NSW must also meet laxer standards on all feeders. The interruption duration standards for individual feeders are around 2-3 times higher than the SAIDI standard. Where feeders fail the individual standard, the distributor is required to develop and implement a plan to improve performance.

118. In Queensland distributors are required to identify and describe the performance of worst-performing feeders in their system management plans.

4.5 Customer Service

119. Guaranteed service levels, and provision for payments to be made to those customers receiving service below the guaranteed levels, are contained in the jurisdictional reliability arrangements for all of the Australian jurisdictions apart from the ACT and the Northern Territories (and a GSL scheme is expected to be implemented in the Northern Territory in 2012).

120. The STPIS provides an overall incentive to encourage distributors to provide sufficient call centre capacity to ensure that calls from customers are answered promptly.

121. In most jurisdictions, there is no detailed requirement for distributors to provide information about unplanned interruptions. In Victoria, however, distributors are required

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[42] *Review of options for implementation of a customer service incentive scheme for electricity customers – final report*, Utilities Commission (June 2010), paragraphs 1.15–1.22.

to provide information on likely restoration times on the internet and to customers who call in.[43]

4.6 Performance

122. As we have described above, reliability is measured in different ways in different jurisdictions, meaning that it is difficult to compare performance between jurisdictions. The AER publishes some reliability performance data for the NEM jurisdictions, shown in Table 7 below. Note, in particular, that the data in Table 7 is aggregated across regions and feeder types (urban, rural etc.), and cannot be compared with the standards described above.

43 Distribution code, section 5.4.1.

Table 7: Reliability Performance in the NEM[44]

	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
SAIDI (minutes)										
Queensland	314	275	265	434	283	351	233	264	365	366
New South Wales	175	324	193	279	218	191	211	180	211	137
Victoria	152	151	161	132	165	165	197	228	255	170
South Australia	164	147	184	164	169	199	184	150	161	153
Tasmania	265	198	214	324	314	292	256	304	252	211
NEM Weighted Average	198	245	199	258	211	221	211	213	254	200
SAIFI (number of interruptions)										
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4	2.9	2.7
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7	1.8	1.5
Victoria	2.0	2.0	2.2	1.9	1.8	1.9	2.1	1.7	2.5	1.7
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5	1.5	1.9
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6	1.9	1.8
NEM Weighted Average	2.4	2.4	2.0	2.2	1.9	2.1	2.0	1.9	2.2	1.8

Notes and sources:
Data from AER's *State of Energy Market 2011,* p. 68, Table 2.4.
The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control. Some data have been adjusted to remove the impact of natural disasters (for example, Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.
The NEM averages are weighted by customer numbers.
Victorian data are for the calendar year beginning in that period. Queensland data for 2009 – 10 are for the year ended 31
Sources cited by AER: Performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), AusGrid, Endeavour Energy and Essential Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates when developing historical data.

123. In Annex I, we present performance data for the individual jurisdictions. We have summarised this more detailed performance data in Table 8 and Table 9.

[44] Reproduced from the AER's *State of the Energy Market 2011*, p.

Table 8: Jurisdictional SAIDI Performance

Region	Utility Company	CBD	Urban	Rural Short	Rural Long
ACT	ActewAGL	-	26	11	11
New South Wales	Ausgrid (Energy Australia)	40	70	180	440
	Endeavour (Integral) Energy	-	65	150	1330
	Essential (Country) Energy	-	69	204	384
Queensland	Ergon Energy	-	149	426	828
	Energex	6	80	202	-
SA	ETSA Utilities	16	192	167 - 733	167 - 733
Tasmania	Aurora Energy	45	155	154	384
Victoria	CitiPower	-	-	-	-
	JEN	-	-	-	-
	Powercor	-	-	-	-
	SP AusNet	-	-	-	-
	United Energy	-	-	-	-
NT	Power and Water Corporation	-	-	-	-
WA	Western Power	37	333	87 - 679	87 - 679

Notes:
The Tasmanian Electricity Code reports SAIDI and SAIFI for "Higher density rural" and "Lower density rural." These are linked to "Rural Short" and "Rural Long" respectively.
We were unable to find performance for Victoria broken down by feeder type. Please refer to a later table for average performance.
For the Northern Territory please refer to a later table for performance by region.

Table 9: Jurisdictional SAIFI performance

Region	Utility Company	CBD	Urban	Rural Short	Rural Long
ACT	ActewAGL	-	0.5	1.8	1.8
New South Wales	Ausgrid (Energy Australia)	0.1	0.9	2.1	2.5
	Endeavour (Integral) Energy	-	0.8	1.7	8.3
	Essential (Country) Energy	-	1.0	2.2	2.9
Queensland	Ergon Energy	-	1.6	3.5	5.3
	Energex	0.0	0.7	1.7	
SA	ETSA Utilities	0.1	1.6	1.35 - 2.86	1.35 - 2.86
Tasmania	Aurora Energy	0.5	0.9	1.1	1.9
Victoria	CitiPower	-	-	-	-
	JEN	-	-	-	-
	Powercor	-	-	-	-
	SP AusNet	-	-	-	-
	United Energy	-	-	-	-
NT	Power and Water Corporation	-	-	-	-
WA	Western Power	0.2	2.8	5.1 - 13.1	5.1 - 13.1

Notes:
The Tasmanian Electricity Code reports SAIDI and SAIFI for "Higher density rural" and "Lower density rural." These are linked to "Rural Short" and "Rural Long" respectively.
We were unable to find performance for Victoria broken down by feeder type. Please refer to a later table for average performance.
For the Northern Territory please refer to a later table for performance by region.

4.7 Interaction with Investment

124. The AER's STPIS recognises a link between investment and reliability: when the AER sets targets for a distributor, the starting point is the average reliability it achieved in the prior five-year period, but this can be adjusted if the AER is simultaneously funding reliability improvements through the price control. Thus, if a distributor plans to invest to improve reliability, and this investment is approved and funded through the price control, the AER may set targets which reflect an assumed improvement in reliability performance. Were it not to do so, the risk is that the distributor would effectively be paid twice for the same investment: it would be funded through the normal price control revenue, and in addition the distributor would receive a performance payment under the STPIS.

125. In practice it may be difficult to make such an adjustment, because the link between investment and expected reliability improvement can be difficult to demonstrate.

126. As part of the distribution determination process, the AER reviews the distributors' capex plans in detail, and the finally-approved capex allowance is usually less than that initially requested by the distributors. Sometimes the approved allowance is significantly less: for example, in the last review of ETSA Utilities, the initial request was for $2,723 million over five years, and the AER finally approved $1,588 million.[45] A significant amount of the reduction was in capex programs which would appear to have an impact on reliability (for example, the low-voltage system upgrade program, asset replacement, and system control expenditure). However, as we have noted, it is difficult to predict a relationship between investment and reliability outcomes.

127. In the ETSA Utilities review, stakeholders queried why the reliability targets under the STPIS were not tighter than the historical average, given the increased capex (and opex) allowances that the AER was going to approve:

> *ECCSA submitted the AER proposes to increase ETSA Utilities' capex and opex allowances, resulting in tariff increases, without any improvement in service standards.*
>
> *The AER previously noted ETSA Utilities did not propose any expenditure for the purpose of improving service performance as measured by the STPIS.760 If the AER's decision did provide any expenditure which would result in improvements in service performance as measured by the STPIS, the AER would be required to adjust the performance targets to make the targets more onerous.761 This reflects that under the STPIS, DNSPs should only be rewarded under the STPIS for improvements in efficiency. DNSPs do not receive financial rewards under the STPIS for improved service performance where this improvement is a result of increased expenditure allowances.*
>
> *The AER notes that the increased expenditure allowances provided to ETSA Utilities result from various factors, including the need to augment South Australia's electricity distribution network due to continuing economic growth, growth in population and energy use per customer, and real*

[45] See *Final Decision South Australia Distribution Determination 2010-11 to 2014-15*, AER (May 2010).

increases in the cost of labour and materials (see chapters 7 and 8 of this decision).

Accordingly, the AER considers that the approved expenditures will not correspond to improvements in service performance as measured by the STPIS. However, the STPIS does provide incentives for the DNSP to maintain and improve service performance through improved efficiency.

128. In the case of the Queensland distributors, an additional complication was the fact that under the jurisdictional standard which had applied historically, reliability was measured in a different way to that incorporated in the STPIS. The AER took the approach of setting a STPIS target which approximated the performance that the distributors would have achieved in the past if they had been meeting the jurisdictional reliability standards. It did so on the grounds that the distributors prepared (or should have prepared) their opex and capex forecasts on the basis of meeting the jurisdictional standards. Therefore, it was appropriate to set the STPIS targets on this basis.[46]

4.8 Cost and Reliability

129. The data presented above shows that the distributors in the different jurisdictions across Australia achieve a wide range of reliability outcomes. When comparing two distributors, we would expect that many other factors besides the achieved level of reliability will influence their costs. Nevertheless, having observed a wide range of reliability outcomes, we thought it potentially worthwhile to investigate whether there is any association between reliability and cost.

130. In Figure 4 below we plot a measure of cost (total annual distribution-related revenues divided by total customer numbers) against reliability (SAIDI). The data plotted in Figure 4 is shown in table format in Annex I.

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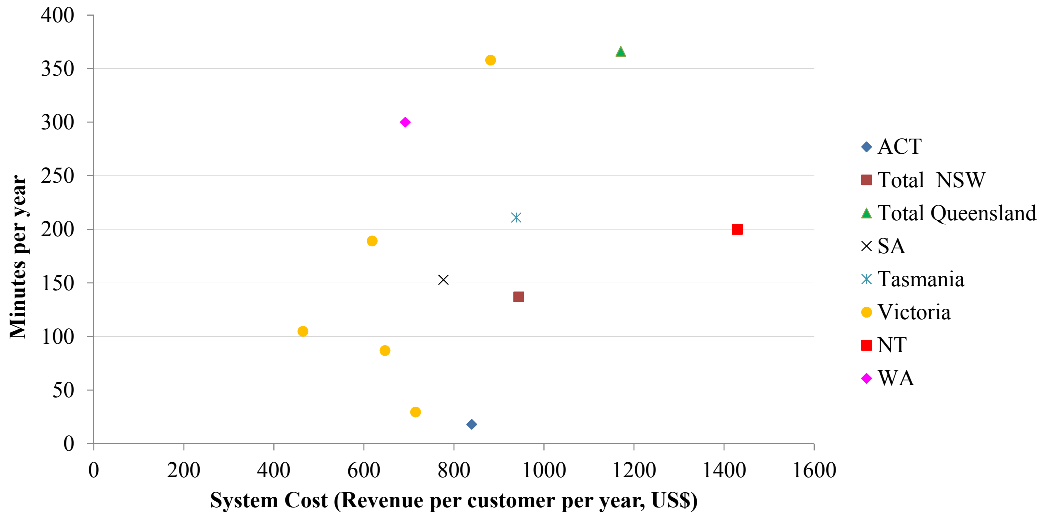
[46] See *Final Decision Queensland Distribution Determination 2010-11 to 2014-15*, chapter 12, AER (May 2010).

Figure 4: Cost and Reliability for Australian Distributors



131. No clear relationship between costs and reliability is apparent in Figure 4. Any analysis of this kind is bound to be problematic: we expect that many factors besides reliability should influence cost, and for many distributors, reliability (and presumably cost per customer) is very heterogeneous across the system. However, with the data available to us we do not see any association between high cost and high reliability or low cost and low reliability.

4.9 Reliability Incidents

132. There have been a number of interventions by Australian regulators in response to concerns over reliability performance (and in response to concerns over the costs of reliability improvements).

133. The system planning approach to reliability in NSW was originally introduced in 2005, following reliability problems in the Sydney CBD. Prior to this, there were no jurisdictional reliability standards in NSW.[47]

134. Queensland distributors have been investing to improve reliability as a result of an investigation into extended outages triggered by hot weather and storms. An independent review recommended in 2004 that the distributors should increase reliability by upgrading

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47 See AEMC NSW issues paper, p. 13.

their systems, using an N-1 planning standard for major assets. In 2011 the review panel re-examined the distributors' performance, and recommended a number of changes aimed at reducing the cost of a reliable system.[48] We note that the emphasis on increased reliability from 2004, and the adoption by the systems of input-type planning standards, was achieved without a formal requirement on the distributors (the only formal requirements in Queensland are the output reliability standards described above).

4.10 Conclusions

135. One outstanding feature of the regulatory approach to reliability in Australian jurisdictions is that reliability is regulated both by jurisdictional regulators and by the AER (for NEM jurisdictions). Furthermore, for at least some distributors and jurisdictions, the way in which the distributors approach reliability is independent of formal rules. For example, the Queensland distributors have apparently adopted stricter system planning standards in recent years, and have invested significant amounts in order to meet these standards, but the standards are not formal regulatory requirements.

136. Most of the jurisdictions, with the exception of the ACT and the Northern Territory, require distributors to produce a detailed network management plan.

137. Reliability outcomes actually achieved by Australian distributors vary widely, as is only to be expected given the widely varying characteristics of the systems (e.g., customer density).

138. We develop further conclusions in Chapters 12 and 13 below.

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[48] *Electricity Network Capital Program Review 2011, Detailed report of the independent panel*

5 New Zealand

5.1 Introduction

139. There are 29 distributors (known as Electricity Distribution Businesses or "EDBs") in New Zealand, of which 17 are privately-owned and 12 are "consumer-owned". There is a considerable variation in the characteristics of the various systems, which range in size from 4,000 to over 500,000 customers and in customer density from 3 to 29 connections/km.[49]

140. All the distributors are regulated by the Commerce Commission. Reliability is principally regulated through two mechanisms:

- As part of the overall economic regulation of all privately-owned[50] distributors, the Commerce Commission sets binding service quality standards[51]
- All distributors, privately-owned or not, are required to publish "asset management plans" (AMPs) explaining how the system will be managed (including both operations and system development), for Commerce Commission review.[52]

141. In addition to the mechanisms described above, there are other legislative requirements which the distributors must meet and which influence system reliability. For example, technical requirements for connecting load and embedded generators are in Use of System Agreements (industry governance); supply quality (in terms of voltage stability) is controlled by legislation and technical standards; and vegetation management standards are also controlled by legislation.[53]

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[49] Details of the individual system characteristics can be found in Annex II.

[50] Consumer-owned distributors are exempt from this mechanism.

[51] See http://www.comcom.govt.nz/electricity-default-price-quality-path/

[52] See http://www.comcom.govt.nz/review-of-asset-management-plans/

[53] See *Wellington Electricity 10 Year Asset Management Plan*, section on "legislative and regulatory environment" (pp. 11-12).

142. All distributors, whether investor-owned or not, are required to disclose financial and performance data in a uniform format.[54]

5.2 Governance

143. Rule-making with respect to reliability seems to follow the governance arrangements for regulation generally. The same regulator (the Commerce Commission) is responsible for regulating both quality and price. In fact, the "price control" in New Zealand is referred to as the "Price-Quality Path" – price and quality are, in principle, treated together.

144. The Commerce Commission is an independent statutory body. Its decision-making follows a consultation process that is similar to that used by regulators in other jurisdictions, and its decisions can be appealed.

145. Although the overall framework for regulating distributors has been in place for some time, the details of the framework have been subject to change. The current 2010-15 price controls are the first to have been set since the framework was reformed in 2009 (the Commerce Amendment Act 2008), and certain aspects the framework are not yet fully implemented (because the price-quality path was determined before some of the implementing details, such as those relating to the cost of capital, had been determined).

5.3 Methodology

5.3.1 SAIDI and SAIFI Standards

146. Under the 2010-15 "default price-quality path", privately-owned distributors are required to meet SAIDI and SAIFI performance standards in two out of every three years. Customer-owned distributors are exempt from price-quality regulation (but all distributors are subject to the same information disclosure rules, including the requirement to publish asset management plans.

147. The annual reliability standard is equal to the historically-achieved annual average of daily reliability (in the prior five-year period) plus one standard deviation.[55] SAIFI and

[54] See http://www.comcom.govt.nz/electricity-information-disclosure/

SAIDI are measured in a fairly standard way, in logarithms, with "zero days" excluded and extreme event days capped at 2.5 beta above the mean.

148. SAIFI and SAIDI include both planned and unplanned interruptions (originating on the distribution system), but exclude interruptions shorter than one minute, and also exclude interruptions originating on lines at voltages below 3.3 kV.

149. We are not aware of formal WTP studies having been used by the Commerce Commission in determining standards. However, individual distributors apparently use customer surveys to gauge whether they should attempt to increase reliability (and raise prices), decrease reliability and drop prices, or continue as they are.[56]

5.3.2 Asset Management Plans

150. All distributors are required to publish an annual AMP. These mandatory AMPs provide a detailed description of system management and planning, including how investment projects are prioritised. They must cover a 10-year period. Detailed requirements for the content of the asset management plans are set out in an *Electricity Information Disclosure Handbook*, published and updated by the Commerce Commission. While the distributors are required to disclose a prescribed set of information, and the Commerce Commission reviews the asset management plans for compliance with the requirements, the review seems to be fairly high-level. For example, the Commerce Commissions states: "*Feedback that an EDB receives from the compliance reviews enables it to continuously improve its plans and, by doing so, improve its asset management processes.*"[57] The Commerce Commission's 2011 review document (covering all 29 distributors) is a 5-page document, accompanied by a more substantial report from technical consultants.

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[55] In other words, for a data set extending over five years, the annual average is the sum of all daily observations divided by five, and the annual standard deviation is the standard deviation of the daily values, multiplied by $\sqrt{365}$. See *Default Quality Price Path Determination 2010*, Schedule 3. Note that when the historically-achieved reliability is measured, days with zero SAIDI/SAIFI are excluded, and days with SAIDI/SAIFI greater than 2.5 standard deviations from the mean are capped at 2.5 standard deviations. All measures are in logarithms.

[56] See the discussion below of Wellington Electric's Asset Management Plan.

[57] See http://www.comcom.govt.nz/review-of-asset-management-plans/

151. Since an important component of reliability regulation is contained within individual asset management plans, we have reviewed the AMP of one of the distributors. Wellington Electricity, a major (privately-owned) distributor, introduces its asset management plan by saying that the "*primary purpose of the AMP is to communicate with consumers and other stakeholders Wellington Electricity's asset management strategies, polices and processes for effective and responsible management of the network assets.*" The AMP describes the distributor's approach to system reliability, part of which is the regulatory SAIDI/SAIFI limits described above. In the case of Wellington Electric, the distributor also sets itself other targets (on a voluntary basis): maximum fault restoration time; maximum faults per circuit km per year; and various customer satisfaction measures, for example relating to call centre performance. Wellington Electric says: "*Within these legal constraints* [the SAIDI/SAIFI standards and legislative requirements] *Wellington Electricity has discretion in managing its assets to meet the requirements of its stakeholders. It must ensure that the reliability of supply meets or exceeds the reasonable expectations of the retailers and consumers that use the system. Further, it must ensure that the assets that provide distribution service are used efficiently if the conflicting expectations of stakeholders regarding price and profitably are both to be met in a reasonable way*." Wellington Electric conducts customer surveys, and concludes that the majority of its customers want neither to pay more for increased reliability, nor to pay less and see reliability decrease.[58]

152. We note that the Commerce Commission is currently reviewing the information disclosure requirements, including the requirements relating to AMPs. A draft determination is expected in January 2012. The Commerce Commission's preliminary view appears to be that the current arrangements work well (to the extent that the arrangements applying to electricity distributors may be adopted for gas distributors, which currently are not required to publish AMPs).[59]

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[58] See *Wellington Electricity 10 Year Asset Management Plan*, p. 76.

[59] *Information Disclosure Regulation, Electricity Lines Services and Gas Pipeline Services, Process and Issues Paper*, February 2011, p. 10.

5.3.3 Planning Standards

153. There are no legislative requirements for system planning/system security (for example, an "N-1-type" standard, but Wellington Electric describes its own system security standard as follows: "*As there are no regulated national standards currently in force, this security criteria was adopted from the previous system owners and was the basis on which the system was designed and operated. These security standards are consistent with industry best practice, and are designed to: match the security of supply with customers' requirements and what they are prepared to pay for; optimise capital expenditure (Capex) without a significant increase in supply risks; increase asset utilisation.*"[60] The standard is essentially a "relaxed" N-1 approach, with higher standards where customer density is highest. The standard is "relaxed" in the sense that, following a fault, a short interruption for automatic system reconfiguration is permitted, and the standard itself only has to be met 95% to 99.5% of the time (for different parts of the system). Wellington Electric says: "*A true deterministic standard, such as N-1, implies that supply will not be lost after a single fault at any time. The Wellington Electricity security standard accepts that for a small percentage of time, a single fault may lead to outages. By somewhat relaxing the deterministic standard, significant reductions in required asset capacity and redundancy levels become possible.*"[61] The N-1 standard does not apply to overhead spurs serving less than 1 MVA or underground spurs serving less than 400 kVA.

5.4 Targets and Standards

154. As discussed above, only investor-owned distributors are subject to price-quality regulation. However, all distributors are required to publish information on reliability performance. The required regulatory reporting includes several measures in addition to the standard SAIDI and SAIFI metrics discussed above, including faults/km by voltage level, as well as planned interruptions and interruptions due to transmission or generator faults) must be reported under the regulatory reporting requirements.

155. We report SAIDI and SAIFI standards, as well as performance, in section 5.6 below.

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[60] See *Wellington Electricity 10 Year Asset Management Plan*, p. 78.

[61] See *Wellington Electricity 10 Year Asset Management Plan*, p. 78.

156. There is no reliability incentive scheme in New Zealand.

5.5 Customer Service

157. We are not aware of any formal regulatory standards in respect of the customer service aspects of reliability (for example, telephone response times). However, we note that distributors may set and report performance against such metrics in their AMPs.

5.6 Performance

158. Distributors publish reliability targets and performance in their AMPs. Performance and historical targets are also published in the standardized regulatory information disclosure documents, which the Commerce Commission publishes in spreadsheet format. This dataset includes performance and targets for customer-owned distributors, even though there is no formal requirement for these companies to meet reliability standards.

159. In Figure 5 and Figure 6 we display standards and performance for all the distributors. The data relates to the three years from 2008 to 2010; data points above the grey line ("match") indicate that a company's performance was worse than its target. The distributors have been ranked in terms of average performance over the three year period (the data plotted in these charts is also given in tabular format in Annex II)

Figure 5: SAIDI (Unplanned Interruptions) Performance and Standards (min)

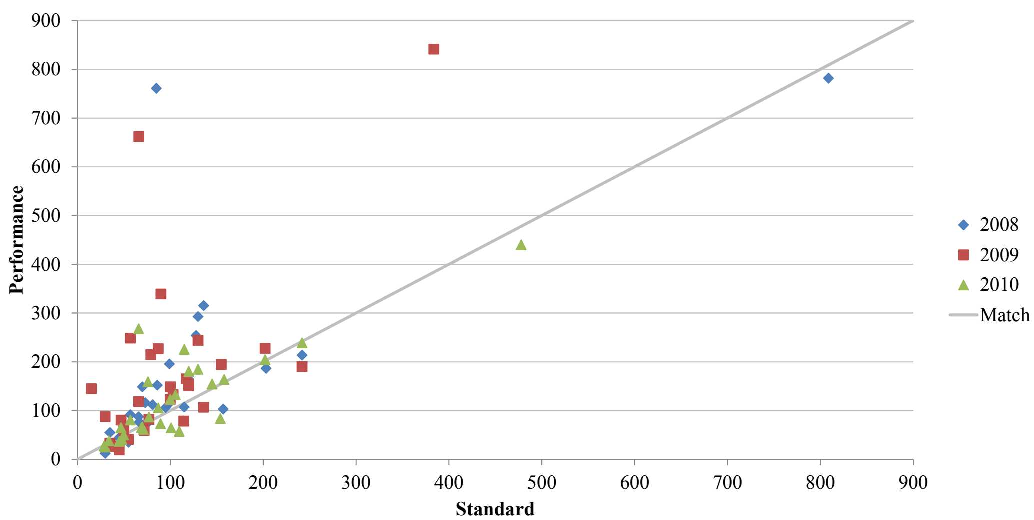
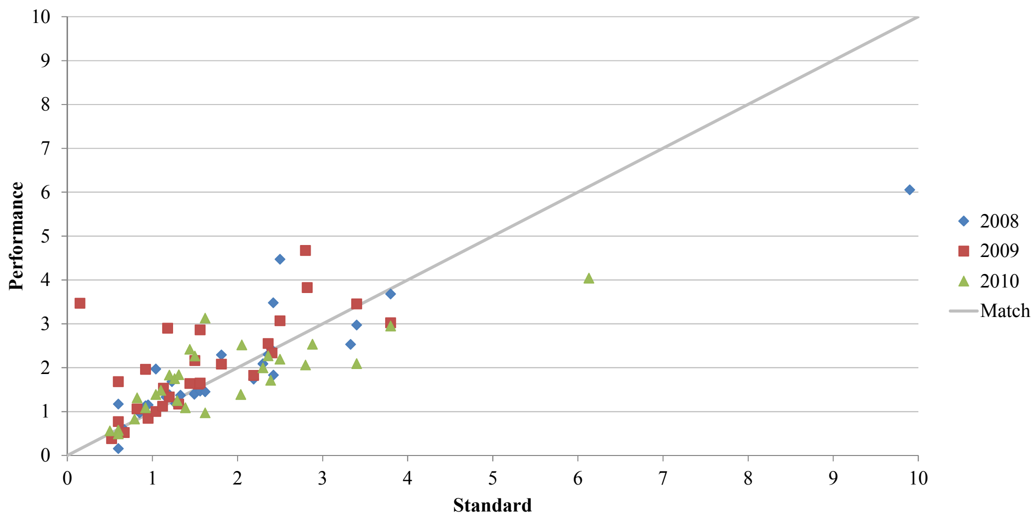


Figure 6: SAIFI (Unplanned Interruptions) Performance and Standards



5.7 Interactions with Investments

160. We are not aware of specific programs aimed at improving reliability that have been separately identified and funded by the regulator.

161. The Commerce Commission's approach to reviewing investment plans at the time of price control reviews appears to have been relatively "light touch", although we note that the regulatory arrangements in New Zealand are evolving (the current rules have been in place for less than one full price control cycle, and certain key decisions are currently subject to appeal). We also note that in determining the "default price-quality path", the Commerce Commission appears to have adopted the distributors' own capex forecasts (from AMPs), without review, when setting allowed revenues.[62]

5.8 Cost and Reliability

162. We have been unable to find any analysis of cost effectiveness or benchmarking of distributor reliability expenditure as part of the price control process. In section 12.13

[62] "Although we have some concerns about the quality of the AMP data, suppliers did not know that the data would be used for setting starting prices when providing the data and so there was no explicit incentive to inflate forecasts when preparing their AMPs." (*2010-2015 Default Price-Quality Path for Electricity Distribution: Draft Decisions Paper*, Commerce Commission)

below, we present some analysis of the costs and reliability performance of New Zealand distributors.

5.9 Reliability Incidents

163. There have been a number of high-profile power outages in New Zealand in recent years. However, these have been associated with problems on the high-voltage transmission system.

164. We were not able to find any instances of specific regulatory changes triggered by investigation of power outages on the distribution systems.

165. The Commerce Commission investigated several distributors that failed to meet reliability standards during the 2009/10 period (i.e., prior to the current control period). It decided to conduct a detailed investigation of one of those distributors, but the outcome of the investigation is not yet published.[63]

5.10 Conclusions

166. The reliability of distributors in New Zealand spans quite a wide range of performance. This is unsurprising given the range of system characteristics (for example, customer density). The regulatory approach is uniform across the companies: reliability performance should not deteriorate over time.[64]

167. New Zealand is unusual in that there is no explicit financial incentive mechanism associated with regulating reliability. Instead, breaches of the reliability standards can trigger regulatory investigation and possible enforcement action.

168. The regulatory arrangements in New Zealand are still evolving. The current arrangements have only been in place for a short time, so there is not much evidence as to whether the arrangements are effective in ensuring that quality does not decline over time.

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[63] See *Commerce Commission, Reasons for not declaring control*, 1 April 2011.

[64] The required standard is that reliability should be no worse than one standard deviation above historical performance for two years in three, which is broadly equivalent to a requirement that reliability should not deteriorate over time.

6 Great Britain

6.1 Introduction

169. In Great Britain, there are fourteen separately licenced distribution systems which are owned by seven companies. The distribution systems range from the highly urban London system (68 consumers per circuit km[65]) to the extremely rural SSE Hydro system (15 customers per circuit km). For the purpose of this chapter, when we refer to "distributors" we mean one of the fourteen distribution systems.

170. Three main schemes are currently used to incentivise distributors to provide an appropriate level of reliability: the Interruption Incentive Scheme, Guaranteed Standards and the Worst Served Customer Fund. These schemes use incentive targets and rates for interruptions, automatic and non-automatic payments for failure to meet pre-specified standards, and investment allowances for improving reliability for customers in rural/low density areas.

6.2 Governance

171. Whilst the incentive arrangements for distribution reliability are set by the Office of the Gas and Electricity Markets (Ofgem) via the distributors' licences, the reliability standards as they relate to customer payments are set out in secondary legislation via a "statutory instrument". In other words, the payments to customers are a legal obligation on the distributors.

172. Ofgem reviews and announces changes to the incentive arrangements for distribution reliability through a distribution price control review (£DPCR"), which it carries out every five years. Distribution price controls are used to set the revenues that each distributor can collect from its customers along with incentives to invest in capacity and to provide a service with an appropriate level of security, reliability and quality service. The current price control, which is Ofgem's 5th distribution price control (DPCR5), began on 1st April 2010 and will end on 31st March 2015.

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[65] According to 1999/00 Electricity Association data.

173. During a DPCR, Ofgem consults with industry players on its proposed changes to the incentive arrangements for the next price control and seeks feedback on its proposals before publishing its final decisions. Ofgem's final decisions include the incentive targets and rates for each distributor for each year of the next price control along with the investment allowances and customer payment levels under the guaranteed standards for the next price control period. Distributors can appeal any aspect of Ofgem's price control decisions.

6.3 Methodology

6.3.1 Interruption Incentive Scheme (IIS)

174. The IIS provides distributors with a financial incentive to improve reliability.[66] Each distributor can receive an annual bonus or pay an annual penalty depending on how they perform relative to the targets set for them by Ofgem. The rate at which bonuses and penalties accrue has essentially been set for each distributor on the basis of the results of a WTP survey.

175. The parameters that are monitored under the interruption incentive scheme are the number of customers interrupted per 100 customers (CI = 100xSAIFI) and the average minutes without power per customer (CML = SAIDI). CI and CML are considered separately for each distributor. So a distribution could receive a bonus for CI while also paying a penalty for CML.

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[66] See the following Ofgem documents for further details:

"Electricity Distribution Price Control Review Policy Paper – Supplementary appendices", Ref: 159a/08, 5 December 2008.

"Electricity Distribution Price Control Review; Initial Proposals – Incentives and Obligations", Ref: 93/09, 3 August 2009.

"Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009.

176. Ofgem's methodology for setting the CI and CML targets distinguishes between unplanned and planned outages. Ofgem calculates separate targets for unplanned and planned outages and then combines these targets to produce a single CI target and a single CML target for each distributor for each year of the price control period. In calculating CI and CML targets, unplanned outages on the distribution system and outages caused by distributed generators are given a weighting of 100% whilst pre-arranged outages on the distribution system only have a weighting of 50%. For CI, outages originating on the transmission system or other connected systems are excluded from the targets. For CML, 10% of CML from interruptions on transmission and other connected systems are also included in the CML targets unless the interruptions result from the distributors complying with statutory and/or licence requirements.

177. For the current price control the CI and CML targets were set using the following methodology.[67] For the first year of the price control period, the CI/CML target was set to be the lower of i) the average of the company's actual CI/CML over the last three years and ii) the CI/CML target for the company for the last year of the previous price control. The CI/CML target for the final year of the price control was set to the lower of i) the benchmark figure calculated by Ofgem for 2014/15 and ii) the CI/CML target assigned to the company for the last year of the previous price control. Where there is a change in the target between the beginning and the end of the price control period, the CI/CML targets change by equal increments each year.

178. Ofgem's methodology for calculating the CI/CML benchmarks comprises the following stages[68]: disaggregation of the distribution system into subsystems, calculation of the benchmark for each of these sub-systems; and aggregating the benchmarks to produce a single benchmark for each company.

[67] Ofgem publication, "Electricity Distribution Price Control Review Policy Paper – Supplementary appendices", Ref: 159a/08, 5 December 2008, p. 81.

[68] Ofgem publication "Electricity Distribution Price Control Review, Update", October 2003, p.23 onwards.

179. Ofgem disaggregates distribution systems prior to calculating the benchmarks because it recognises that each distribution system has different characteristics and is not necessarily comparable to the other distribution systems

180. Ofgem's disaggregation first separates the distribution systems into four voltage levels: LV, HV, EHV and 132 kV.[69] The HV level is then further divided into sub-groups defined by factors such as percentage of overhead cables, circuit length, and number of connected customers. Ofgem ensures that no sub-group is dominated by a single distributor.

181. Ofgem bases the benchmarks on the actual performance of the distribution systems. Ofgem's treatment is slightly different for each sub-group. In some cases, Ofgem bases the benchmark on the performance of individual systems and in other cases on the average performance of all the systems within a subgroup. For the 4th price control period, Ofgem based the HV benchmarks on three years of performance but for the 5th price control extended this to four years of data in order to dampen year-on-year volatility. Although more years of data were available Ofgem did not extend to a greater number of years because it recognised that using too many years of data could mask service improvements in recent years.

182. At the LV level distributors are expected to have limited scope to control interruptions and so Ofgem set benchmarks equal to the actual performance of each distributor. However, for distributors with poor performance, Ofgem set the CML benchmark at 75% of the national average.

183. For the HV systems, Ofgem bases its benchmarks on i) the average number of faults per km of the system, ii) the average number of customers interrupted per fault relative to customer density, and iii) average and first quartile CML per CI. The benchmarks are based on the average performance of all the distributors with each sub-group.

184. The EHV circuits and the 132 kV assets experience relatively few interruptions per year and therefore performance is volatile. Relying on only four years of data could result

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[69] In the GB system, *LV* refers to all voltage levels up to and including 1kV. *HV* refers to all voltage levels above 1kV up to and including 20 kV. *EHV* includes all voltage levels above 20kV up to but excluding 132 kV and *132kV* refers to 132kV assets.

in benchmarks that are affected by the volatility of performance. For this reason, the EHV and 132 kV benchmarks are set equal to the average of each distributor's performance over the last ten years.

185. Once Ofgem has determined the benchmarks for each sub-group the benchmarks are then combined for each distributor to give a total benchmark for that distributor. For the 5th distribution price control period, Ofgem made a number of changes to its target setting methodology, including taking into account customer density on feeders.[70]

186. Ofgem has also derived allowances for each distributor for the number and duration of interruptions due to planned interruptions. Ofgem derived these allowances from the forecast of the work that needs to be undertaken by distributors and the impact that different types of work has on the number and duration of interruptions. Ofgem relied on the opinion of industry to inform this work. Ofgem also made use of weights to link interruptions more closely to particular types of activities. Ofgem categorised the work undertaken by distributors into the following different types of activities: load, non-load, inspections and maintenance, and tree-cutting. For the current price control period, Ofgem has spread the allowance for planned outages equally across each year of the price control period.

187. For the past two price controls. Ofgem has commissioned WTP studies that have informed the reliability incentive rates i.e. the rates at which bonuses or penalties accrue. In the case of the current price control, the incentive rates for the IIS were set in accordance with the findings of the WTP study, although these findings were adjusted downwards by 10% as a result of some qualitative customer research that was carried out a year after the WTP study.

188. The main finding of the study was that, on average, consumers outside London were willing to pay around £4 per year for a reduction in the frequency of outages whereas London consumers were willing to pay £13 per year for the same reduction.

[70] See Ofgem publication "Electricity Distribution Price Control Review; Initial Proposals – Incentives and Obligations", Ref: 93/09, 3 August 2009, p. 85.

189. Responses from the WTIP surveys have indicated that customers are keener to receive compensation for receiving a poorer service than they are for paying more for receiving a better quality service. While one option would therefore be to have asymmetric incentive rates with higher rates when companies perform below the targets, Ofgem has kept the system of symmetric incentive payments as used in the last price control.

6.3.2 Guaranteed Standards

190. Distributors are required to make payments to customers under the terms of their guaranteed standards of service obligations.[71] The standards cover such things as how quickly distributors restore supplies after interruptions, how long distributors take to respond to system failures, the notice that distributors give to customers when they know supply will be interrupted, how long distributors take to investigate complaints, and the time taken to make payments to customers. Some of the payments are automatic whilst others are non-automatic which means the customer needs to make a claim for the payment. In addition some distributors are pro-active and make voluntary payments to customers under the non-automatic standards even when customers haven't made a claim. The details of the standards are shown in Table 10.

191. The guaranteed standards were originally developed with domestic customers in mind. However, Ofgem distinguishes between domestic and non-domestic in terms of the level of payments paid to these different types of customers.

[71] See, Details of the current mechanism are given in Ofgem publication, "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009.

Table 10: Guaranteed Standards[72]

Reporting code	Service	Performance Level	Guaranteed standards Payments
GS1	Respond to failure of distributors fuse (Regulation 10)	All DNOs to respond within 3 hours on a working day (at least) 7 am to 7 pm, and within 4 hours on other days between (at least) 9 am to 5 pm , otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS2*	Supply restoration: normal conditions (Regulation 5)	Supply must be restored within 18 hours, otherwise a payment must be made. Where a large scale event occurs then supply must be restored within 24 hours, otherwise a payment must be made.	£54 (£50) for domestic customers and £109 (£100) for non-domestic customers, plus £27 (£25) for each further 12 hours up to a cap of £218 (£200) per customer where the interruption is part of a large scale event
GS2A*	Supply restoration: multiple interruptions (Regulation 9)	If four or more interruptions each lasting 3 or more hours occur in any single year (1 April – 31 March), a payment must be made	£54 (£50) for domestic and non- domestic customers
GS4*	Notice of planned interruption to supply (Regulation 12)	Customers must be given at least 2 days notice, otherwise a payment must be made	£22 (£20) for domestic and £44 (£40) for non- domestic customers
GS5	Investigation of voltage complaints (Regulation 13)	Visit customer's premises within 7 working days or dispatch an explanation of the probable reason for the complaint within 5 working days, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS8	Making and keeping appointments (Regulation 17)	Companies must offer and keep a timed appointment, or offer and keep a timed appointment where requested by the customer, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS9	Payments owed under the standards (Regulation 19)	Payment to be made within 10 working days, otherwise a payment must be made	£22 (£20) for domestic and non- domestic customers
GS11*	Supply restoration: severe weather conditions (Regulation 6)	Depending on category of event supply must be restored within 24, 48 or a multiple of 48 hours (see Table 17.2 below), otherwise a payment must be made	£27 (£25) for domestic and non domestic customers, plus £27 (£25) for each further 12 hours up to a cap of £218 (£200) per customer
GS12*	Supply restoration: Highlands and Islands (Regulation 7)	Supply must be restored within 18 hours, otherwise a payment must be made	£54 (£50) for domestic customers and £109 (£100) for non-domestic customers, plus £27 (£25) for each

Notes and sources:
Ofgem, *Electicity Distribution Price Control Rview Final Proposals - Incentives and Obligations* p. 92.

192. Ofgem was satisfied with the performance of its guaranteed standards scheme during the last price control and so did not propose any major amendments to the scheme for the current price control. Furthermore, the general feedback from customers was that they were satisfied with the scheme. [73]

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[72] Note we have not shown GS3 which is related to estimating charges for connections.

[73] See Ofgem publication "Electricity Distribution Price Control Review; Initial Proposals – Incentives and Obligations", Ref: 93/09, 3 August 2009, p. 93 onwards.

193. Customers had indicated that they thought the 18 hours allowed for distributors to restore supplies was too lenient.[74] However, Ofgem found that consumers were not willing to pay more to tighten this obligation on distributors. Furthermore, Ofgem did not think that tightening this requirement would improve performance for many customers without significant cost implications in part due to requirements to work at night. Ofgem has therefore kept the time limit for restoring supplies to 18 hours for the current price control.

194. One amendment that Ofgem made to the guaranteed standards for this price control was to place a cap on the payments that distributors would need to make for exceeding the supply restoration time following large scale events under normal weather conditions.[75] This was in response to a request from distributors. Similar caps already exist for large scale events under severe weather conditions.

6.3.3 The Worst-served Customer Fund

195. The worst served customer fund is a recent addition to Ofgem's approach to incentivising service reliability.[76] The purpose of the fund is to improve the reliability for customers who have experienced a large number of interruptions over several years. The fund is particularly focused on customers for whom the distributors may not be incentivised to improve their service under the IIS because, for example, they reside in an area where supply interruptions only affect a small number of customers. These customers typically reside in low density/rural areas and, under the Electricity Act, Ofgem has a statutory obligation with respect to these customers.

196. Ofgem has defined a worst-served customer as a customer that has suffered an average of at least five HV interruptions per year over the last three years. Under the scheme, Ofgem defines the total fund and then divides this between the distributors in proportion to the number of worst served customers each company serves. Distributors

[74] Ofgem publication, "Electricity Distribution Price Control Review Policy Paper – Supplementary appendices", Ref: 159a/08, 5 December 2008, p. 61.

[75] Ofgem publication, "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009, p.91.

[76] Details of the current mechanism are given in Ofgem publication, "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009.

keep a record of the investments they have made to improve service reliability for these customers. The distributors can qualify for a contribution from their worst served customer fund if they provide evidence that an investment has improved supply interruptions by at least 25% over three years.[77] A cap is placed on the amount awarded to distributors of £1,000 per customer whose reliability is improved.

197. In deciding how to divide the fund between distributors, Ofgem also considered different ways to define worst served customers, such as the number of interruptions experienced by a given percentage of the total customer base or by a fixed number of customers.[78] Ofgem rejected these approaches because performance within a given sub-set of the customer base can vary widely. For instance the number of interruptions could be the same for two customer bases of 1,000 customers even if in one case each customer only suffered one interruption per year whereas in the other case 100 customers suffered 10 interruptions per year while the other 900 customers did not suffer any interruptions.

198. Ofgem also considered different ways of incentivising improvements in reliability for the worst served customers, such as using incentives or guaranteed standards in place of the allowance.[79] It was thought that an incentive scheme would not work because interruption information is not currently reported in a way that distinguishes between customer types. A guaranteed standards approach was rejected because a reasonable penalty might well be smaller than the system investment necessary to improve service quality due to the likely relatively small number of worst-served customers. In other words, there could be significant payments to customers without any improvement in service quality. Ofgem has stated that it will consider moving towards an incentive based scheme in future price controls.

199. Ofgem also considered other ways of setting the allowance including the cost of laying cables underground and the cost of proposals submitted by distribution for

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[77] Distributors can also provide evidence that improvements will occur but over a longer term.

[78] Ofgem publication, "Electricity Distribution Price Control Review Policy Paper – Supplementary appendices", Ref: 159a/08, 5 December 2008, p.69.

[79] Ofgem publication, "Electricity Distribution Price Control Review Policy Paper – Supplementary appendices", Ref: 159a/08, 5 December 2008, p.68.

improvement projects for worst served customers. Both of these approaches were rejected as being too expensive.[80]

6.4 Targets and Standards

6.4.1 Interruption Incentive Scheme

200. Table 11 shows the range of the CI and CML targets for each year of the current price control period and the averages in each case. The CI and CML targets for each distributor are shown in Table 54 and Table 55 in Annex III.

Table 11: Current Interruption Incentive Scheme Parameters[81]

		2010/11	2011/12	2012/13	2013/14	2014/15
CI						
	Min	33.4	33.4	33.4	33.4	33.4
	Max	109.9	109.9	109.9	109.9	109.9
	Average	70.4	70.3	70.2	70.0	69.9
CML						
	Min	41.0	41.0	41.0	41.0	41.0
	Max	97.0	96.3	95.6	94.9	94.2
	Average	66.8	66.0	65.3	64.8	63.7

201. Distributors can request an adjustment to CI and CML for exceptional interruptions that have a significant impact, such as interruptions resulting from severe weather events or other one-off events such as transmission faults or third-party damage. Severe weather events are measured against a threshold that is equal to eight times the distributor's daily average HV interruption rate for the last ten years.[82,83] To be eligible for consideration as an

[80] Ofgem publication, "Electricity Distribution Price Control Review Policy Paper – Supplementary appendices", Ref: 159a/08, 5 December 2008, p.70.

[81] The CI targets decline over time for 5 of the 14 companies although not those that have the .maximum (North-West) and minimum (London) targets.

[82] Ofgem publication, "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009, p.88.

one-off event, the event must have resulted in more than 25,000 customers being interrupted and/or more than 2,000,000 customer minutes lost.[84] During the previous price control review (DPCR4), distributors requested that Ofgem broaden the circumstances that can be treated as one-off exceptional events. In response, Ofgem added asset failures to the outage causes that could be considered as one-off exceptional events.

202. Although they are not included in the incentive scheme, distributors need to report details of outages that last less than 3 minutes. They also need to provide details on interruptions broken down by source, voltage, HV circuit and frequency. During the current price control Ofgem intends to look into improving the system for reporting and recording short interruptions and to better understand customer opinions on short interruptions.

203. Non-domestic customers have expressed concerns that distribution systems may be incentivised to minimise interruptions to domestic customers at the expense of non-domestic customers because there are many more domestic customers and the incentives do not distinguish between different types of customer then. Ofgem intends to develop interruption reporting by type of customer.

204. Ofgem sets CI and CML incentive rates for each distributor. Table 12 shows the range of the CI and CML rates as well as the average of the incentive rates in each case.

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[83] The regulations recognize three types of severe weather conditions. “Category 1” conditions are those in which (i) eight or more times the daily mean faults on the designated electricity distributor's distribution system at distribution higher voltage caused by weather predominantly related to lightning in a 24 hour period affect less than the category 3 threshold number of customers; or (ii) conditions in which eight or more but less than thirteen times the daily mean faults on the designated electricity distributor's distribution system at distribution higher voltage caused by weather not predominantly related to lightning in a 24 hour period affect less than the category 3 threshold number of customers. “Category 2” conditions means conditions in which thirteen or more times the daily mean faults on the designated electricity distributor's distribution system at distribution higher voltage in a 24 hour period caused by weather not predominantly related to lightning affect less than the category 3 threshold number of customers. “Category 3” conditions means conditions in which faults on the designated electricity distributor's distribution system caused by weather interrupt a number of customers that is equal to or greater than the category 3 threshold number of customers. The time within which supply restoration has to occur in order for the distributor to avoid making a payment increases from 18 hours in normal weather conditions, to 24 hours under category 1 conditions, and 48 hours under category 2 and beyond for category 3.

[84] Ofgem publication, “Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations”, Ref: 145/09, 7 December 2009, p.89.

The same real level of rates applies for each year of the price control period. The incentive rates for each distributor are shown in Table 56 in Annex III.

Table 12: Incentive Rates for CI and CML (£ mn)

	CI	***CML***
Min	0.03	0.15
Max	0.30	0.57
Average	0.11	0.35

205. Previously there was a limit on the percentage of a distributor's allowed revenue that was exposed to interruption incentive penalties. Their exposure is still limited but is now set in terms of a limit on the reduction of the allowed return on regulatory equity (RORE). For CI the limit is 7.4 basis points per year and for CML the limit is set 20.4 basis points per year, i.e. a maximum of 139 RORE basis points over the course of the 5 year price control. There is no limit on the amount that can be earned by distributors for outperforming the targets.

206. In Table 13 we show the revenue exposure to incentive payments under the IIS for each of the distributors. The figures shown relate to the revenue exposure across the five-year price control period (e.g. the total revenue exposure is equivalent to the 139 RORE basis points stated above).

Table 13: Revenue Exposure under the IIS

	CI exposure	CML exposure	Total exposure
	Annual revenue (£mn)	Annual revenue (£mn)	Annual revenue (£mn)
CN West	2.0	5.4	7.4
CN East	1.9	5.3	7.2
ENW	1.7	4.7	6.4
CE NEDL	1.2	3.2	4.4
CE YEDL	1.5	4.2	5.7
WPD S Wales	0.9	2.5	3.4
WPD S West	1.3	3.5	4.8
EDFE LPN	1.7	4.6	6.3
EDFE SPN	1.5	4.2	5.7
EDFE EPN	2.4	6.6	9.0
SP Distribution	1.7	4.7	6.4
SP Manweb	1.6	4.4	6.0
SSE Hydro	1.1	3.0	4.1
SSE Southern	2.3	6.3	8.6
Min	0.9	2.5	3.4
Max	2.4	6.6	9.0
Average	1.6	4.5	6.1

6.4.2 Worst-served Customer Fund

207. For the current five-year price control period, Ofgem has allocated £42 million to the fund, which is provided on a use-it-or-lose it basis. The figure of £42 million was set by reference to the average cost already paid by customers for service quality and as such includes the net amount of bonuses/penalties from the IIS and the interruption capex and opex allowances given to distributors in the last price control. The allowances for each company range up to £8 mn as shown in Table 14.

Table 14: Worst-served Customer Fund Allowances

Distribution company	Allowance (£ mn)
CN West	8.0
CN East	4.6
ENW	2.3
CE NEDL	1.3
CE YEDL	2.0
WPD S Wales	3.4
WPD S West	2.7
EDFE LPN	0.0
EDFE SPN	4.7
EDFE EPN	2.3
SP Distribution	2.6
SP Manweb	1.5
SSE Hydro	3.3
SSE Southern	3.2
Total	42

Notes and sources:
Data from Ofgem publication "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009.

6.5 Customer Service

208. Ofgem currently has several customer service schemes that have elements that relate to reliability. For example, the telephony incentive scheme (which ends in March 2012) relates to the quality of communication between distribution customers and their companies in relation to outages.

209. This scheme will be replaced by the "broad measure of customer satisfaction" scheme which covers a wider range of customer services but will have an element relating to communications during outages.[85] Companies will be penalised for failing to provide an

[85] Ofgem publication, "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009, p.72.

adequate level of service – defined as the upper quartile score over all the distribution systems.

210. In addition, one of the criteria in the customer reward scheme relates to the treatment of worse served customers. The customer reward scheme requires companies to demonstrate what they have done to improve their service and how successful their initiatives have been. Companies' submissions are judged by a panel, which determines whether or not to make a payment from a pre-defined fund.

6.6 Performance

211. Since the implementation of the IIS in 2002 there has been a decline in the interruptions experienced by customers. Between 2001 and 2010, the overall CI value fell by 20% and the overall CML value by 14%. We show, in Figure 7 and Figure 8, the trends in CI and CML between 2001 and 2010.

212. Whilst the number and duration of interruptions have decreased there has been an increase in the number of short (<3 min) interruptions, which do not fall within the incentive scheme. Ofgem intends to review the collection of information on short interruptions and has considered the possibility of including incentives for short-interruptions in the next price control period. Customers in GB have indicated a high WTP for reducing the number of short-term interruptions.

Figure 7: Average Customer Interruptions per 100 Customers[86]

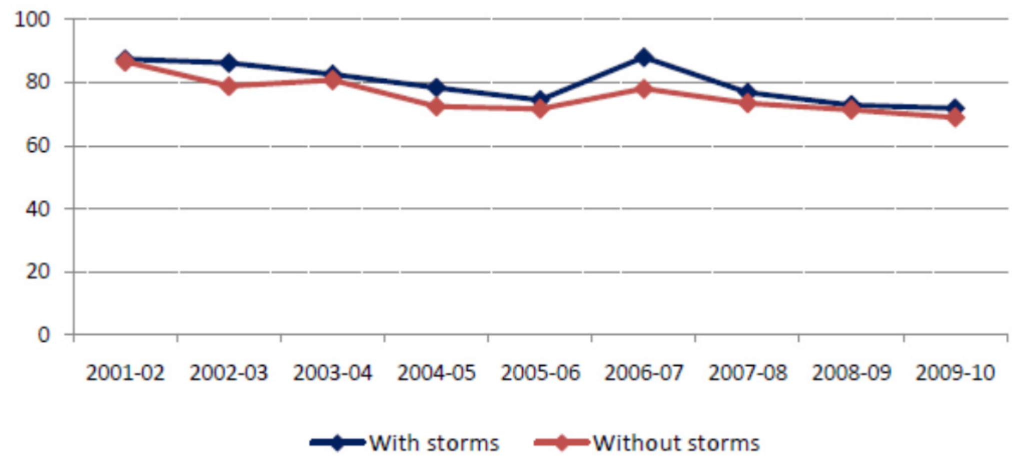
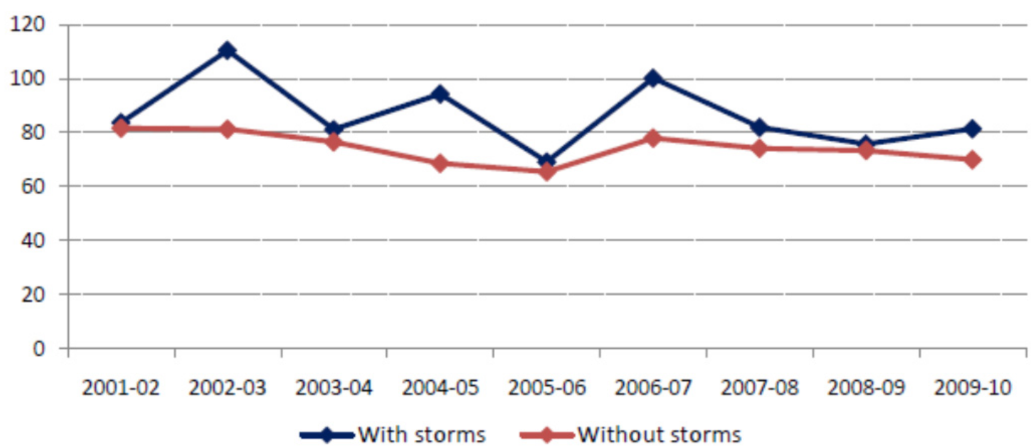


Figure 8: Customer Minutes Lost per Customer Interrupted[87]



213. Figure 9 shows how each distributor compared to its CI target in 2009/10. All but three of the distributors performed better than their target and so received a bonus. The other three companies performed slightly worse than their target.

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[86] From Ofgem publication, "Electricity Distribution Annual Report for 2008-09 and 2009-10", 31 March 2011, p.18.

[87] From Ofgem publication, "Electricity Distribution Annual Report for 2008-09 and 2009-10", 31 March 2011, p.19.

214. Figure 10 shows how each distributor compared with respect to its CML target in 2009/10. Around half of the companies out-performed their target in 2009/10.

Figure 9: CI Performance in 2009/10 Compared to Targets[88]

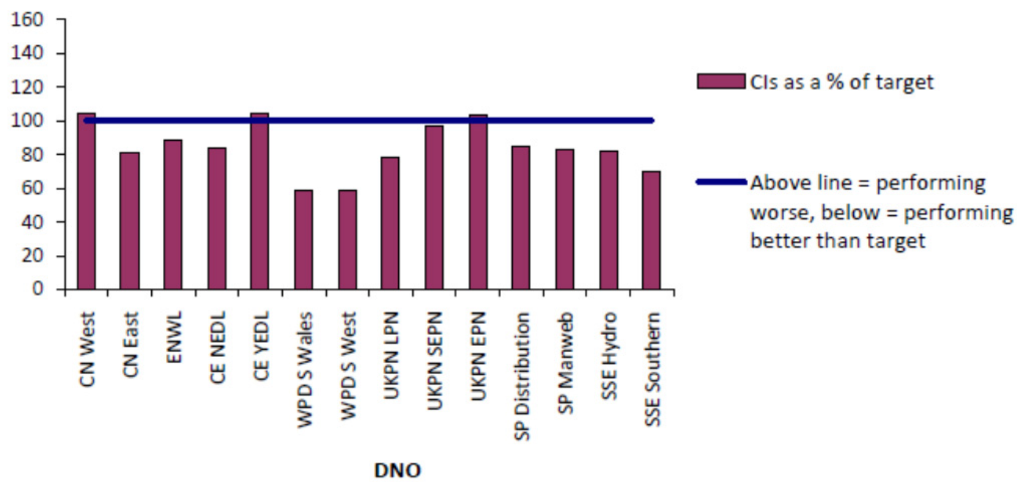
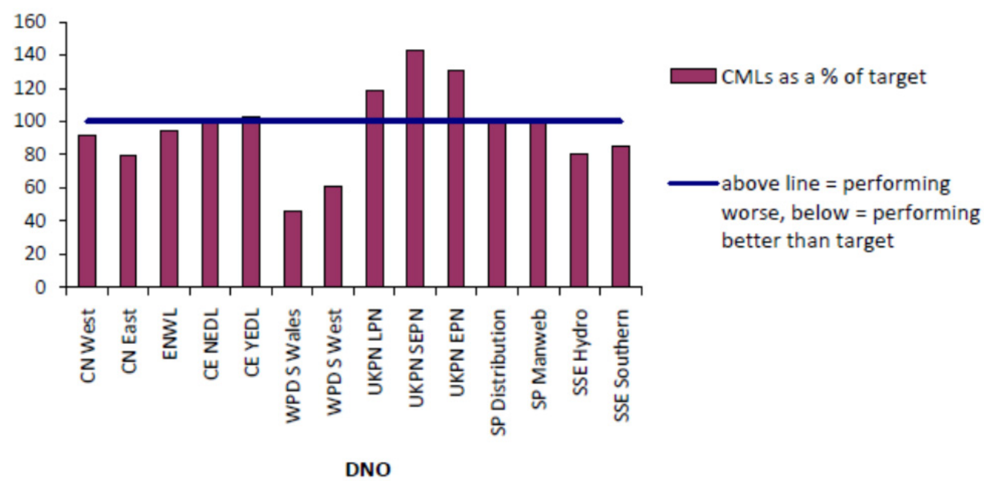


Figure 10: CML Performance in 2009/10 Compared to Targets[89]



[88] From Ofgem publication, "Electricity Distribution Annual Report for 2008-09 and 2009-10", 31 March 2011, p.16.

[89] From Ofgem publication, "Electricity Distribution Annual Report for 2008-09 and 2009-10", 31 March 2011, p.17.

215. Table 15 shows details of payments that distributors have made to customers under the Guaranteed Standards Scheme.[90] The payments shown in Table 15 include automatic payments under the Guaranteed Standards, payments where customer have made a claim under non-automatic Guaranteed Standards, and some "voluntary" i.e. automatic; payments made by distributors under the non-automatic Guaranteed Standards. Not all the voluntary payments made to customers have been recorded as a Guaranteed Standards payment and reported to Ofgem.[91] By contacting distributors directly, Consumer Focus, an organisation in the GB that acts on behalf on consumers, has been able to find out about the payments made on a voluntary basis. Table 16 shows the voluntary payments disclosed in 2008/09 and 2009/10. We understand that, from 2010/11, distributors will be recording all payments made under Guaranteed Standards as a Guaranteed Standard payment whether they are voluntary or not.

[90] Table 15 does not show payments made under severe weather conditions because these can vary from year to year and for different distributors.

[91] Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10", p.14.

Table 15: Customer Payments Under Guaranteed Standards Scheme[92]

Guaranteed standard		Automatic/ non-automatic payment	2008/09 No. of payments	2008/09 Value of payments (£)	2009/10 No. of payments	2009/10 Value of payments (£)
GS1 –	Time limit for responding to failure of distribution fuse	Automatic	275	5,500	239	4,780
GS2 –	Time limit for restoring supplies under normal conditions	Non-automatic	17,069	819,475	13,810	660,925
GS2a –	Time limit for restoring supplies when multiple interruptions	Non-automatic	801	40,050	1,105	55,250
GS3 –	Time limit for providing estimates of connection charges	Automatic	161	6,440	127	5,080
GS4 –	Notice of planned interruption to supply	Non-automatic	1,005	22,980	1,337	29,960
GS5 –	Time limit for investigating voltage complaints	Automatic	6	120	9	180
GS8 –	Requirement to keep appointments	Automatic	157	3,140	280	5,600
GS9 –	Time limit for making payments owed under the standards	Automatic	218	4,360	180	3,600
Total			19,692	902,065	17,087	761,425

Notes and sources:
From Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10", p. 20, Table 7.

[92] The Consumer Focus publication does not provide information about payments made under GS11 or GS12.

Table 16: Voluntary Payments made by Distributors

Distributors	Voluntary payments (£) 2008/09	2009/10
Central Networks –East	170,000	225,000
Central Networks –West	275,000	272,000
ENWL	17,195	23,969
CE Electric –NEDL	130,825	149,970
CE Electric –YEDL	228,145	71,275
EDF Energy Networks (EPN)	Recorded as GS	Recorded as GS
EDF Energy Networks (LPN)	Recorded as GS	Recorded as GS
EDF Energy Networks (SPN)	Recorded as GS	Recorded as GS
Scottish and Southern Energy Power Distribution Scottish Hydro Electric Power Distribution	47,550	52,529
SP Distribution	87,400	159,225
SP Manweb	86,040	105,000
WPD South Wales	350	150
WPD South West	2,150	450
Total	1,044,655	1,059,568

Notes and sources:

From Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10", p. 6, Table 14.

216. Table 15 suggests that, in both 2008/09 and 2009/10, the majority of Guaranteed Standard payments made by distributors were because they failed to restore supplies within the required time limit following normal weather events (Guaranteed Standard GS2). Table 17 shows the breakdown of reported GS2 payments by distributor. The three EDF distributors clearly paid the majority of the reported GS2 payments – together, they were responsible for over 95% of the reported GS2 payments in both years. The GS2 is a non-automatic payment which means that the customers must make a claim in order to ensure payment. One reason for the much higher EDF payments is that EDF was pro-active in informing customers that they could claim for these payments.[93] Other distributors may also have made voluntary payments to customers under GS2 but not reported these payments to Ofgem as a Guaranteed Standard payment.

[93] Consumer Focus publication “Guaranteed Standards of Electricity Distribution 2009/10”, p. 48.

Table 17: Customer Payments Made Under GS2

Distribution company	2008/09 Number of payments	2008/09 Value of payments (£)	2009/10 Number of payments	2009/10 Value of payments (£)
Central Networks – East	0	0	0	0
Central Networks – West	0	0	0	0
ENWL	308	15,675	258	12,425
CE Electric – NEDL	295	14,850	160	7,875
CE Electric – YEDL	36	1,975	35	1,925
EDF Energy Networks (EPN) plc	9,592	470,925	7,636	356,825
EDF Energy Networks (LPN) plc	1,712	80,725	1,821	95,250
EDF Energy Networks (SPN) plc	5,120	235,075	3,898	182,575
Scottish and Southern Energy Power Distribution Ltd	0	0	2	100
Scottish Hydro Electric Power Distribution Ltd	0	0	0	0
SP Distribution	4	175	0	0
SP Manweb	2	75	0	0
WPD South Wales	0	0	0	0
WPD South West	0	0	0	0
Total	17,069	819,475	13,810	656,975

Notes and sources:
From Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10", p. 24, Table 9.

217. As Table 17 suggests the Guaranteed Standard payments made by each distributor vary widely. Table 18 shows, for each Guaranteed Standard both the minimum and maximum amounts paid by an individual distributor. These amounts only include payments reported to Ofgem as Guaranteed Standard payments. Annex III contains the payments against each guaranteed standard for each distributor in the period 2008-2010.

Table 18: GS Payments Made by Individual Distributors (£)

Guaranteed Standards	2008/09 Minimum amount paid by a distributor	2008/09 Maximum amount paid by a distributor	2009/10 Minimum amount paid by a distributor	2009/10 Maximum amount paid by a distributor
GS1	0	2,760	0	1,820
GS2	0	470,925	0	356,825
GS2A	0	14,250	0	37,250
GS4	0	7,200	0	12,300
GS5	0	80	0	100
GS8	0	1,340	0	2,740
GS9	0	1,680	0	1,600

Notes and sources:
From Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10".

6.7 Interactions with Investments

218. Ofgem has considered whether to provide funding allowances for system improvements in relation to the IIS. However, Ofgem concluded that incentive rates should determine decision-making on investments to improve the reliability of supply. For the current price control period, Ofgem excluded any ex ante revenue allowance for such investments, which is a change from the previous price control period. Nonetheless, Ofgem did include allowances for "fault level" investment i.e. for investments designed to reduce fault levels. Overall, this amounted to around 2% of the overall allowed investment (compared to under 1% of actual spending in the previous price control).[94]

219. In addition, the worst served customer fund scheme works to incentivise distributors to invest in the distribution system to improve reliability for the worst served customers. Distributors that have made these investments can claim reimbursement from the fund if they can show that the supply interruptions have improved by a pre-specified amount for the worse served customers.

[94] Further details can be found in Annex I.

220. Distributors are also subject to input planning standards in that it is a condition of their distribution licences that they comply with Engineering Recommendation (ER) P2/6. However, according to a study carried out for Ofgem in 2007,[95] the planning standards contained in ER P2/6 have effectively been superseded by the IIS for the HV and LV networks, although it may still be playing a role in respect of EHV networks.

221. Moreover, since March 2007, Ofgem has put in place a blanket derogation that relieves distributors of their obligation to meet P2/6 in respect of those parts of the network where the demand is less than 60 MW and certain other criteria are met. This derogation will last until at least March 2015. Ofgem introduced this derogation in acknowledgment of the fact that "*compliance with P2/6 can be difficult to maintain on all parts of a licensee's distribution system as the licensee does not have certainty about or control over customer actions. It* [Ofgem] *considered that it is generally in the wider interests of customers that electricity distribution licensees use their best commercial and engineering judgment when considering forecast demand and making decisions in relation to expenditure on measures to reinforce a distribution system to ensure P2/6 compliance*".[96]

222. In other words, although GB distributors are subject to some input planning standards, it is not clear that they have a significant influence on the maintenance of network reliability.

6.8 Cost and Reliability

223. We observe quite a wide range of reliability performance across the 14 GB distributors. For any given distributor, improving reliability will cost money. However, when comparing two distributors, it is likely that many other factors besides the achieved level of reliability will influence their costs. Nevertheless, having observed a wide range of reliability outcomes, we thought it potentially worthwhile to investigate whether there is any association between reliability and cost. We therefore plot a measure of cost per

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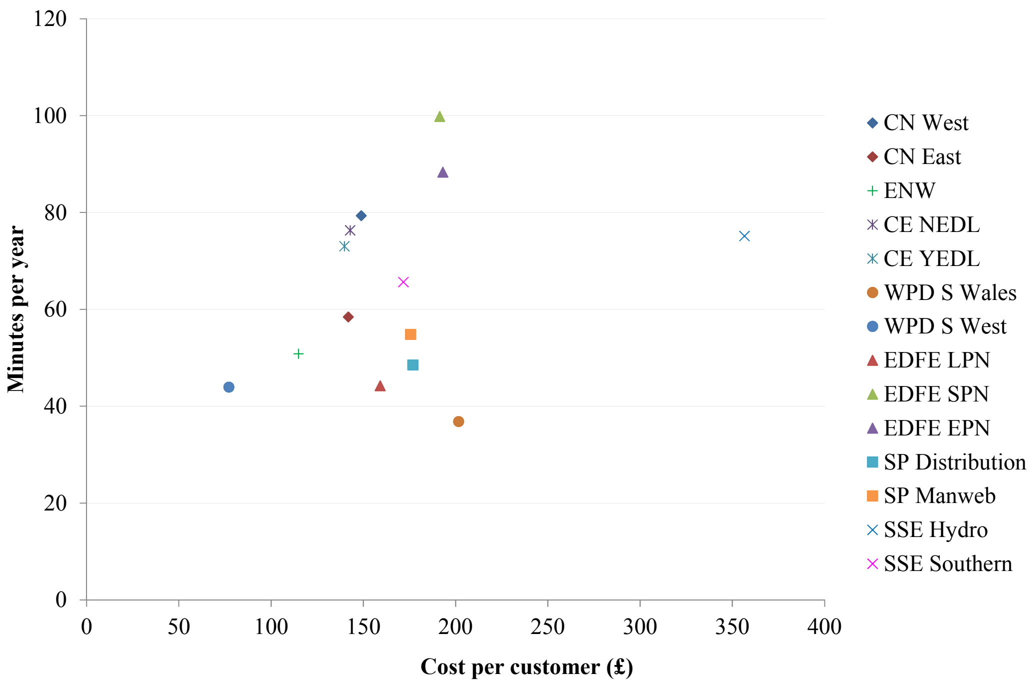
[95] "Final Report: Review of Distribution Network Design and Performance Criteria", Kema with Imperial College, July 2007. See also "Review of international network design standards, practices and plant and equipment specifications", Kema report for the UK Department of Energy and Climate Change, 2009.

[96] "Derogation from Standard Condition 24 (Distribution System planning standard and quality of performance reporting) of the Electricity Distribution Licence", July 2010.

customer against SAIDI (Figure 11). Figure 11 does not suggest any clear link between cost and reliability. There are a number of companies clustered around £100-150 cost per customer range. However, reliability for these customers varies widely.

Figure 11: SAIDI Performance Versus Cost Per Customer (GB)



224. As part of the DCPR4 process, the DNOs identified ways in which they tried to manage their costs in dealing with faults and the level of faults. These included[97]:

- Shortening the tree-cutting period from 5 to 3 years.
- Implementing a detailed tree clearance program
- The targeted replacement of overhead lines and Consac cables
- Implementing a new fault reporting system to monitor and record faults
- Installing automated remote post-fault restoration systems
- Improving communication between staff to ensure speedy response to faults
- Obtaining third-party insurance for lightning and storms damage
- Performing a review of the cable laying contract to identify and derive efficiencies

[97] See Ofgem document "Electricity Distribution Price Control Review. Second Consultation – Data and Cost Commentary Appendix", December 2003.

- HV system shrouding
- Increase in the use of mobile generators to reduce customer interruptions and minutes lost
- Focusing on investments in rural areas which are dependent on overhead lines and therefore more vulnerable to weather damage
- Expanding remote control to the wider rural systems
- Making wider of devices for LV transient fault automatic reclosures (REZAPs) and intermittent fault location equipment to provide faster location of intermittent faults
- Investment in overhead line protection
- Sectionalising the system
- Reduction of pre-arranged interruptions by using live-line working techniques

225. We cannot, of course, be certain that these actions took place as a result of the incentive scheme but it does at least suggest that the distributors were prepared to incur costs to improve reliability.

6.9 Reliability Incidents

226. A number of DNOs saw their costs related to outages increase during the period 2000-03. Part of the reason was severe weather-related events including flooding (in October and November of 2000 and in 2002 which affected underground cables), storms (including in October 2002), and snow storms (February 2001). Aging assets were also cited as a reason for the increased number of faults.

227. Major events that have not qualified as exceptional events under the IIS have influenced the development of the incentive arrangements. One example is the interruption to almost 80,000 customers resulting from the loss of three of SSE Southern's grid transformers in October 2005. Another example is the interruption to the supply to almost 125,000 customers after the malfunction of an SP Manweb circuit breaker in November 2008. Outages on this scale, prompted the distributors to voice concerns about their exposure to such events. In response, Ofgem broadened its definition of one-off exceptional events to include asset failure. Ofgem also included a limit on distributors' exposure to customer payments for slow supply restoration following major outages.

228. Following a fire in one EDF's distribution systems in 2009 which interrupted supplies to 94,000 customers over several days, EDF applied to Ofgem for the outage to be treated as an exceptional event. Ofgem initially rejected EDF's claim on the basis that, while EDF acted appropriately to minimise interruptions and restore supplies as quickly as possible, EDF had not taken appropriate action to prevent the interruption happening.

229. Ofgem concluded that, because the fire occurred at an important point in the system which was used to supply many customers, EDF should have carried out a more adequate risk assessment. In particular, EDF should have considered the cost and benefits of investment to make this part of the system more reliable. Ofgem thought that EDF should have performed maintenance inspection more often and should have had a higher level of security at the site of the fire. Ofgem also noted that the company had experienced a similar interruption incident five years earlier.

230. During the consultation process that Ofgem held into whether the EDF fire should be treated as an exceptional event, EDF, along with another distributor, challenged Ofgem's interpretation of the legal test for classing interruption events as one-off exclusions. The parties argued that a causal link between the lack of actions on behalf of EDF and the interruption event must be presented for EDF's claim to be refused.

231. Ofgem subsequently further reviewed the legal test for exclusions and concluded that it could not demonstrate that a more detailed risk assessment would have indicated that EDF should perform more frequent maintenance inspections or install a higher level of security at the site. Ofgem also concluded that it could not be certain that these actions would have prevented the fire from happening. Accordingly, Ofgem decided that the fire could be classed as an exceptional event under the IIS.

6.10 Conclusions

232. The regulation of distribution reliability via an incentive scheme is well-developed in GB since this is the third incentive scheme that has been put in place and there have been developments in thinking and best practice over time. Of particular interest is the direct use of the results of a customer willingness to pay study in setting incentive rates and the creation of the worst served customer fund. It is also clear that the interactions between the reliability incentive scheme and the distributors' price controls have been carefully considered.

7 Italy

7.1 Introduction

233. There are almost 170 distributors in Italy.[98] The size of the distributors, in terms of the number of customers they serve, varies widely. The largest distributor, Enel, distributed over 80% of electricity in 2007 and there are three other distributors serving more than 500,000 customers. At the other end of the scale, there are over 50 "small" operators, each of which serves less than 1,000 customers.

7.2 Governance

234. The Italian Regulatory Authority for Electricity and Gas ("AEEG") is responsible for establishing minimum service quality levels in the electricity market and also for monitoring compliance in relation to service quality standards.[99] The AEEG is also legally required to ensure that customers are compensated if their service quality falls below the standards set and that distributors are rewarded if they provide a better quality of service.

235. The AEEG applies quality standards to distributors in the following three areas: service continuity, commercial quality and helpline service quality. Service continuity involves setting incentives for improving supply reliability whilst commercial quality covers distributor response times for responding to customer requests. Since the helpline service quality standards do not apply directly to outages, we do not consider them in this report.

236. The targets and incentives relating to service continuity and commercial quality are set out in the Electricity Quality Code[100], whilst the helpline service quality standards are covered in a separate regulation.

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[98] See IEA publication, "Energy Policies of IEA Countries, Italy 2009 review", p. 82 for discussion of Italian distributors.

[99] AEEG publication "Annual Report to the European Commission on the State of the Services and on the Regulation of the Electricity and Gas Sectors", 31 July 2005, p. 5 and p. 17.

[100] Testo Integrato Della Regolazione Della Qualita' Dei Servizi Di Distribuzione, Misura E Vendita Dell'Energia Elettrica. Periodo di regolazione 2008-2011, 1 July 2011, Article XXX.

7.3 Methodology

237. Under the service continuity scheme, the AEEG sets SAIDI and SAIFI targets for the distributors as well as bonuses and penalties. Whilst the SAIDI target applies only to outages that last between 3 minutes and 8 hours, the SAIFI target applies to all outages shorter than 8 hours that occur on a LV system.[101] In both cases, outages that are not attributable to the distribution system or are caused by exceptional weather conditions are excluded from the calculations.

238. The AEEG defines a set of three "baseline" targets for both SAIDI and SAIFI for supply to LV customers. The three sets of targets apply to individual districts, of which there are 300, that are classified by population as follows[102]:

- Low – Less than 5,000 consumers (rural)
- Medium – Between 5,000 – 50,000 consumers (semi-urban)
- High – More than 50,000 consumers (urban)

239. The baseline targets are viewed as the long-term goals for all distributors. Distributors serving areas where there are more consumers expected to provide a higher quality of service per customer. The SAIFI baseline targets for the 3rd regulatory period (2008-11) were set to be consistent with the 20th to 33rd percentile range of actual SAIFI performance in 2006.[103]

240. The SAIDI baseline targets for rural and semi-urban areas have been set to be broadly consistent with the first decile of the actual SAIDI performance by the distributors prior to the start of the second regulatory period (2004-07). In this context, SAIDI performance is defined as the average of performance across two years. For urban areas,

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[101] The AEEG uses "SAIFI" to describe long interruptions of more than 3 minutes while "MAIFI" is used for interruptions of 3 minutes or less but longer than 1 second but when we use SAIFI we also to MAIFI.

[102] Testo Integrato Della Regolazione Della Qualita' Dei Servizi Di Distribuzione, Misura E Vendita Dell'Energia Elettrica. Periodo di regolazione 2008-2011, 1 July 2011, Article XXX.

[103] AEEG presentation "Proposte per la Regolazione della Qualita' dei Servizi Elettrici nel III Periodo di Regolazione (2008-2011), Seminario informative di presentatzione del document di consultazione n. 36/07, 14 September 2007", p. 31.

the SAIDI baseline was set to correspond broadly to the 3rd decile of actual SAIDI performance by the distributors prior to the start of the second regulatory period. The AEEG decided to use the third decile for urban areas instead of the first decile because the volatility of SAIDI at the 25-minute duration level is such that is does not make it useful to tighten the target further.[104]

241. Although the AEEG sets baseline targets it does not expect each distributor to reach these targets within a regulatory period. For each of the areas they serve, the distributors can apply to the AEEG to have their baseline targets replaced by a new target that is more generous but that also includes unexpected interruptions due to factors not within the control of the distributor.

242. At the beginning of the regulatory period, the distributors are each given their own targets for each year of the regulatory period which are based on their performance in the previous two years. In other words, the AEEG incentivises *improvements* in performance rather than a particular performance level. Each distributor's target is then either the baseline target or its actual performance in the previous year reduced by the expected improvement factor, whichever is higher.[105] For SAIDI, the expected improvements factor is equal to the annual percentage improvement that would be required to reach the baseline target in 8 years, but it is never less than 2%.[106] For SAIFI, the expected improvement

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[104] From AEEG document "Relazione Tenica, Testo integrato delle disposizioni dell'Autorità per l'energia elettrica e il gas in materia di qualità dei servizi di distribuzione, misura e vendita dell'energia elettrica per il periodo di regolazione 2004-2007 (deliberazione n. 4/04)", 30th January 2004, Article 7.12.

[105] For the first year of the regulatory period, the target is set slightly differently. For SAIDI, the target is the average performance in the previous two years reduced by the improvement factor. For SAIFI, the target is equal to the average of the performance in the previous two years. AEEG may not have applied the improvement factor for SAIFI the first year of the regulatory period 2008-2011 because the SAIFI targets were first applied in this year.

[106] See "Testo Integrato Della Regolazione Della Qualita' Dei Servizi Di Distribuzione, Misura E Vendita Dell'Energia Elettrica, periodo di regolazione 2008-2011", 1 July 2011, Article 21.

factor is the annual improvement that would be required to reach the baseline target within 12 but it is never more 6%.[107]

243. If a distributor misses its SAIFI or SAIDI target by more than 5% then it pays a penalty. Conversely, if it beats its SAIDI or SAIFI target by more than 5% it receives a bonus. The size of the penalty/bonus is set by a formula in accordance with the findings of a WTP survey carried out in 2004. The survey covered both domestic and non-domestic customers and involved 2,600 interviews which were representative of customers nationally. The survey presented different hypothetical scenarios to the customers and asked them to quantify the direct cost resulting from the interruption or the amount they would willing to accept as compensation for the interruption or the amount they would be willing to pay to avoid the interruption.

244. To prevent distributors focusing on improving performance in areas where they are likely to beat their targets and hence earn bonuses whilst making less effort in areas where they are unlikely to meet their targets, the AEEG has changed the incentives for the next regulatory period i.e. 2012-15.[108] Any region whose actual level of reliability is currently more than 1.5 times worse than its baseline target will be classified as a badly performing area. If a distributor succeeds in improving the reliability of a badly performing area so that it matches what would otherwise have been required by the end of the regulatory period, it will be entitled to additional payments.

245. Medium voltage (MV) customers are only entitled to the compensation following outages if they have demonstrated to distributors that their equipment meets the regulator's technical requirements. If a MV customer has not done this, the customer has to pay a "specific tariff charge" to the distributor, part of this charge remains with the distributor and part of the charge goes to the Electricity Sector Compensation Fund. When distributors have to compensate MV customers following an interruption, part of the distributor's payment goes to the customer and part goes to the Electricity Sector Compensation Fund.

[107] These are the improvement factors used in the 3rd regulatory period from 2008-2011.

[108] AEEG document "Regolazione della qualità dei servizi di trasmissione, distribuzione e misura dell'energia elettrica nel periodo di regolazione 2012-2015 - Orientamenti finali e schema di Testo integrato (Quinto documento per la consultazione)" DCO 39/11.

Details of the specific tariff charge payments made over the period 2007 to 2010 are included in Table 60 in Annex IV.

246. The Electricity Sector Compensation Fund is used to pay compensation to customers when their supplies are interrupted for external reasons such as weather-related incidents, security of supply reasons and force majeure reasons. There is a limit on a distributor's exposure to interruption compensation. If compensation payments for a particular distributor exceed this limit, then the Electricity Sector Compensation Fund is used for compensation payments above the limit.

247. For MV systems, the AEEG has also established initiatives for monitoring voltage quality. Through collaboration with Ricerca di Sistema (RSE), information on distributor power quality has been collected since 2006 and the resulting database is publicly available.[109] Participation in the database by distributors in not mandatory but is encouraged by the AEEG. The database covers information about voltage dips or sags which are characterized by two parameters: residual voltage expressed as a percentage of operating voltage and duration expressed in milliseconds. The database now also covers voltage swells. Monitoring of voltage quality in HV and EHV systems also exists in Italy.

248. Distributors can sign power quality contracts with customers which commit them to providing a specified level of quality. Until 2012, the quality level had to be higher than or equal to the standard quality level but from 2012 onwards it can be lower. In the quality contracts, the parties define the level of quality that the distributor will provide, the amount that the customer will pay for additional quality, and the penalties applicable if the distributor fails to provide the quality specified in the contract. The AEEG does not require that the power quality contracts be submitted for approval however the regulator has set a number of rules for them, including:

- the quality level should be stated as a limit that applies to continuity of supply measures (e.g. number or duration of outages) or voltage quality;
- the contract duration must be between one and four years;

[109] See RSE's website http://queen.rse-web.it.

249. Revenues that distributors receive from power quality contracts are excluded from the distributor's revenue control and distributors are required to report to the regulator the number and the contents of power quality contracts.

7.4 Targets and Standards

250. The baseline targets for consumers connected to the low voltage grid for the period 2008-11 are shown in Table 19 below.

Table 19: Italian Baseline Targets

	Duration of interruption (min)		Number of interruptions	
District type	Excluding external causes [A]	Including external causes [B]	Excluding external causes [C]	Including external causes [D]
Rural	60	68	4	4.30
Semi-urban	40	45	2	2.25
Urban	25	28	1	1.20

Notes and sources:
[A], [C]: From Article 20, Annex A, Resolution 333/07.
[B], [D]: From Article 23, Annex A, Resolution 333/07.

251. The actual targets applied to individual distributors for supply to LV connected customers vary widely and can be much larger than the baseline targets (see Table 20). As shown in Table 21, only a small proportion of the distributors are already at the baseline target.

Table 20: Actual Targets Applied to Distributors

	SAIFI (min)			SAIDI (number)		
	Min	Average	Max	Min	Average	Max
Rural	4.0	6.9	24.1	60	74.4	154
Semi-urban	2.0	4.4	13.1	40	52.6	90
Urban	1.0	2.9	27.9	25	35.0	101

Notes and sources:
For the averages we have weighted by number of customers.

Table 21: Number of Distributors at Baseline Already

	SAIFI	SAIDI
Rural	5%	6%
Semi-urban	6%	9%
Urban	2%	9%

252. The size of the penalty/incentive payment for supplies to LV customers is based on the product of the amount by which the actual number/duration of interruptions differs from the target plus a 5% tolerance, the energy supplied to consumers and the incentive rates set by the AEEG.

253. There is a limit on the total size of the penalties/bonuses that distributors can receive in relation to the SAIFI/SAIDI targets for LV customers. The bonuses are not allowed to be greater than the product of the number of LV customers and the parameter Tinc. Penalties cannot be greater than the product of the number of LV customers and the parameter Tpen. These parameters are shown in Table 22 below.

Table 22: Maximum Penalty Parameters

	Tinc €/LV client [A]	Tpen €/LV client [B]
Urban	4.0	3.0
Semi-urban	6.0	4.5
Rural	10.0	6.0

Notes and sources:
From Article 24 and Table 6, Annex A, Resolution 333/07.

254. For MV customers (1-35 kV), there are separate targets for the number of outages (Table 23).

Table 23: Targets for MV Customers

	Number of Interruptions	
	2008-2009 (int/cl) [A]	2010-2011 (int/cl) [B]
Number of residents		
Less than 5,000	5	4
Between 5,000 and 50,000	4	3
More than 50,000	3	2

Notes and sources:
From Article 33, Delibera 333/07.
[A], [B]: Number of interruptions refers to long unannounced interruptions.

255. If a distributor misses its MV target, then it has to pay a penalty which is in proportion to the amount of power supplied to interrupted customers. We have estimated the amount of this cap for Enel Distribution to be around 2.3% of its revenue.

256. The AEEG also sets a limit on the minimum amount of notice that should be given for pre-arranged interruptions. If an interruption is required in order to restore supplies following an outage or emergency, then the distributors must give their customers 24 hours' notice. In all other cases of announced interruptions, distributors must give their customers 2 days' notice. The AEEG has also set upper limits on the amount of time that distributors should take to restore supplies following an interruption. In the event that these targets are not met, customers are entitled to automatic payments. Details of the standards and the payments are provided in Annex IV.

7.5 Customer Service

257. The commercial quality regulations cover metering and supply issues and were designed to protect consumers, particularly small consumers following market liberalisation. The commercial quality standards provide the distributors with targets for the time it takes to respond to customer requests for services such as connections, activation, quotations, and technical checks. The AEEG has also set automatic refunds for customers when the distributor fails to meet a time target.

258. Annually, the regulator publishes the average time taken to provide a service and the maximum time limit. The regulator also reports the percentage of cases that do not meet the standard. Cases that are not due to the distribution system are excluded.

7.6 Performance

259. The service continuity scheme for distributors serving customers connected to the low voltage system has resulted in improvements in the duration of outages across the period 2000-08 as shown in Table 24.

Table 24: Actual duration and number of interruptions by district type (all voltages, min)

	1999	2000	2001	2002	2003	2004	2005	2006	2007
Urban	86.71	84.33	71.23	54.66	53.01	41.31	43.7	42.4	48.28
Suburban	149.09	170.19	152.58	112.32	90.67	72.21	63.71	58.13	65.65
Rural	282.47	229.18	193.7	170.97	165.11	129.82	98.57	73.03	77.79

Notes and sources:
From Table COS 2.9, CEER, 4th Benchmarking Report on Quality of Electricity Supply, Annex 1, 10th of December 2004.

260. There was a sharp drop in the reliability of the LV systems in 2008, which continued through to 2010, as can be seen from Table 25. However although the average duration of all outages increased from 2008, outages resulting from actions by the distributors remained at around the 2006-07 levels. The increase in the duration of outages outside the distributor's control increased by a factor of four between 2007 and 2008 due to weather related events, as described below.

Table 25: Low Voltage Reliability Data

			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Duration of interruptions, min													
Due to other reasons	[1]	AEEG	56	52	37	35	32	19	11	10	40	32	45
Due to the distributor	[2]	AEEG	131	97	78	70	59	61	50	48	50	46	44
Total	[3]	[1]+[2]	187	149	115	105	91	80	61	58	90	78	89
Number of interruptions													
Long interruptions	[4]	AEEG	-	-	-	-	-	-	2.29	2.16	2.37	2.35	2.26
Short Interruptions	[5]	AEEG	-	-	-	-	-	-	-	-	3.61	3.54	2.79

Notes and sources:
From AEEG AR 2011 'Relazione Annuale sullo Stato dei Servizi e sull'Attività svolta', 31st March 2011.
[1], [2]: From Fig. 2.23.
[4], [5]: From Table 2.57.

7.7 Interactions with Investment

261. As far as we can ascertain, there are no specific rules for distribution system planning in Italy. This was the case in 1996[110] and we are not aware of any new rules. It is also unclear precisely whether and, if so, how the distributors' allowed revenues include an explicit allowance relating to investments connected to the reliability incentives.

7.8 Cost and Reliability

262. We have only been able to gather cost data for three of the Italian distributors, as shown in Table 26 below. This is because the published allowed or actual revenues for most of the distributors include the revenues associated with gas distribution as well as electricity distribution.

Table 26: Italian Cost and Reliability Data

		Enel Distribution	Acegas-Aps	Aem Torino Distribuzione
Actual revenue in 2010 (€ mn)	[1]	7,427	21.3	353
Number of customers	[2]	31,382,770	141,389	687,299
Cost per customer	[3]	237	151	514
Average SAIDI performance (min)	[4]	45.1	20.3	18.1

Notes and sources:
[1]: From individual companies' Annual Reports. Values for Enel includes Deval.
[2], [4]: AEEG, Quality Database.
[3]: [1]x10^6/[2]

7.9 Reliability Incidents

263. The most significant recent reliability incident was transmission outage in 2003, caused by a breakdown in the interconnector between Switzerland and Italy, which lead to widespread and prolonged outages throughout Italy, However, this does not appear in the performance indicators shown in section 7.6 above.

[110] J. de Jong (Essent) "Review of current utility planning approaches for DG and detailed policy guidelines for network planners to encourage the consideration of DG as an alternative to network infrastructure upgrade", 25th April 2006, p. 30.

264. In addition, there were extreme weather-related events in November and December 2008. Both snowfall in northern Italy and flooding in central Italy led to outages and difficulties in restoring supplies due to safety reasons resulted in longer than normal outage times.[111]

7.10 Conclusions

265. The Italian market is a clear example of where an incentive scheme has led to improved reliability. It is likely that this, in part, is due to the targets taking into account historic actual performance since this means that it is relatively straightforward for distributors to beat their targets and earn additional revenues. This is an important condition for an incentive scheme to be effective.

266. On the other hand, the incentive system is not particularly transparent: it is unclear how the various targets and incentive rates have been derived. It is equally unclear how the interactions between distributors allowed revenues and the reliability incentives are handled.

[111] AEEG publication, "Annual Report on the State of Services and the Regulatory Activities", 31 March 2009, p. 99.

8 The Netherlands

8.1 Introduction

267. In the Netherlands, there are eight distributors. The three largest distributors (Enexis, Liander and Stedin) each have more than 2 million customers[112] and are responsible for distributing most of the power (over 90% of a total 95 TWh distributed in 2010[113]). The five smaller distributors (Cogas Infra en Beheer, Delta Netwerkbedrijf, Endinet, RENDO Netbeheer and Westland Infra Netbeheer) each have between 30,000 and 210,000 customers. The majority of the distribution systems are underground. At the LV and MV levels almost all of the distribution system is underground. However at the HV level, only around 40% of the system is underground.[114]

268. The Netherlands has generally seen very high levels of distribution system reliability. One reason for this may be that the systems are relatively small in extent without any very rural regions. However, a study commissioned by the Dutch regulator in 2010 indicated that most of the distributors did not have sufficient insight into the physical state of their systems to be able accurately to assess the need for replacement investment.[115] Therefore, as a priority, the regulator plans to require distributors to be more aware of the state of their systems and replacement needs.

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[112] See "Energy in the Netherlands, 2011", a publication by Energiezaak in collaboration with Energie-Nederland (an association of Dutch energy companies) and Netbeheer Nederland (an association of Dutch distributors).

[113] From NMa "Factsheet 2010" presentations for each distributor available from the website of the NMa.

[114] See "Energy in the Netherlands, 2011", a publication by Energiezaak in collaboration with Energie-Nederland (an association of Dutch energy companies) and Netbeheer Nederland (an association of Dutch distributors), p. 38.

[115] 2011 National Report of Energiekamer to the European Commission. http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202011/NR_En/C11_NR_Netherlands-EN.pdf

8.2 Governance

269. The Netherlands Competition Authority (NMa) in an independent government body that has responsibility for supervising compliance with the general competition law and with laws relating to energy and transportation. One department within the NMa, The Office of Energy and Transport Regulation (DREV), is in charge of regulating energy and transport markets, which includes overseeing the activities of regional energy distributors.

270. The Board of the NMa is an Autonomous Administrative Authority which means that it carries out tasks on behalf of the government, but it does so independently from the government. The board has the obligation to carry out the NMa's statutory tasks. The board comprises one chairman and two board members and each board member is assigned certain responsibilities. The Minister of Economic Affairs, Agriculture and Innovation is responsible for appointing board members.

8.3 Methodology

271. The NMa includes service quality in its yardstick regulation through the q-factor. Yardstick regulation provides a mechanism through which distributors can compete with each other. It gives distributors an incentive to outperform the other companies as the most efficient distributors are allocated additional revenue allowances while those that perform the worst have their revenue allowances reduced.

272. The yardstick regulation works in a similar way for service quality. Distributors that perform better than average on service quality have increased revenue allowances whilst those that perform worse than average have reduced revenue allowances. Service quality has been included in the yardstick regulation so that companies are not rewarded for efficiency improvements that compromise service quality.

273. In the first (2007) and second (2008-10) application of the q-factor, the NMa used only SAIDI to measure service quality. However, for the regulatory period from 2011 to 2013 inclusive, the NMa has measured both SAIFI and CAIDI[116] and applied both measures to determine the q-factor. Research conducted on behalf of the NMa found that the frequency of interruptions affected customers more than the duration of interruptions.

[116] CAIDI = SAIDI/SAIFI.

While two scenarios could yield the same SAIDI, the research found that the penalty should be higher for the scenario with the higher SAIFI. The NMa deliberately chose to use only two dimensions of quality in their incentive regulation scheme (SAIFI and CAIDI), to provide a clearer incentive to system managers.

274. Based on customer research[117], the NMa has developed formulae which yield the estimated cost of the inconvenience of interruptions for customers as a function of both SAIFI and CAIDI. These "value of quality" functions are indicative of the level of compensation that customers would be happy to receive for interruptions or the amount that they would be willing to pay for a certain level of quality. The NMa uses the functions to derive q-factors for the distributors. The formulae were revised in 2009 and separate formulae have been developed for domestic and non-domestic customers.

275. Data on SAIFI and CAIDI are collected for each distributor. The q-factors are based on SAIFI and CAIDI data from the first two years of the previous regulatory period and the last year of the last but one regulatory period. The NMa uses three years of performance data rather than a single year because of the stochastic nature of interruptions. For each of these years, NMa uses the value of quality functions to estimate the value that consumers assign to interruptions at the SAIFI and CAIDI levels that actually occurred. Separate cost functions are used for domestic customers and non-domestic customers and then a weighted average of the values for domestic and non-domestic customers is calculated using the number of customers nationally as weights. The NMa refers to this weighted average value as the "quality performance" of the company. Annex V shows the NMa's methodology for two of the Dutch distributors.

276. The q–factor for each distributor is calculated relative to the average level of quality performance based on all distributors. The average quality performance is calculated as the average of the quality performance for each company weighted by their number of customers. The "Q-amount" is the revenue adjustment for a distributor and is calculated from the difference between the quality performance of the company and the average quality performance, multiplied by the number of customers served by the company.

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[117] SEO Economic Research. See SEO Economic Research, "Op prijs gesteld, maar ook op kwaliteit", 2004 and "Waardering van stroomstoringen" 2009.

277. Two changes were made to the q-factor methodology for the fifth regulatory period. First, the q-factors are now calculated from data for years closer to the start of the regulatory period. Previously, quality performance was measured as the performance in the last regulatory period relative to the average performance in the last but one regulatory period.[118] This approach was used so that companies knew the average ("target") performance prior to start of the regulatory period in which performance was to be measured. As discussed above, the q-factor is now largely based on performance in the previous regulatory period.

278. Second, only two-thirds of the allowed revenues for quality performance (Q-amount) will be paid (or recovered) in the three years of the fifth regulatory period. The remaining third will be paid (or recovered) in the sixth regulatory period. The reason for this is that the allowed revenue in the sixth regulatory period will depend in part on the allowed revenues in the last year of this regulatory period. Consequently, this approach is required to avoid double counting of q-factor effects.

8.4 Targets and Standards

279. The maximum impact that the q-factor can have is to increase or decrease a distributor's revenue allowance by 5%. The NMa chose symmetric limits on the impact of the q-factor to demonstrate its impartiality between the financial implications for customers and distributors. In reality, we understand that the normal range of revenue adjustment due to the q-factor is between -0.1% and +1.4%. Table 27 shows the q-factors allocated to the distributors for the current (fifth)regulatory period.

[118] Strictly, actual performance was based on performance in the last two years of the last regulatory period and the last year of the regulatory period prior to the last regulatory period. The target performance was based on the three years prior to the three years that actual performance was based on.

Table 27: Q-factors for Distributors for Fifth Regulatory Period

Distribution Company	q-factor
Cogas Infra & Beheer B.V.	1.28
DELTA Netwrkbedrijf B.V.	0.05
Endinet Regio Eindhoven B.V.	0.83
Enexis B.V.	0.02
Liander N.V.	-0.13
N.V. RENDO	0.91
Stedin B.V.	0.08
Westland Infra Netbeheer B.V.	-0.03

280. The calculation of the q-factor includes nearly all outages, including incidents that are outside of the direct control of the distributor such as the severing of a cable due to road works by a third party. The NMa informed us that, while so-called force majeure incidents would not contribute toward the measures of SAIFI and CAIDI, in reality force majeure has in fact never been successfully invoked, and would only cover very exceptional incidents such as an act of terrorism. Only unplanned interruptions are included the SAIFI and CAIDI measurements used to calculate the q-factor. However, distributors are required to report planned interruptions.

281. As well as the q-factor, which adjusts system revenues based on quality, the distributors must pay compensation to all customers for interruptions which last longer than four hours. The current level of compensation to households in €35 for each qualifying interruption, whilst customers with larger capacity connections receive greater compensation. The compensation is not necessarily sufficient to fully compensate customers for the damage of the outage – although it is based on the research of inconvenience of customers – but it does provide a strong incentive for the distributors to restore service within four hours.

282. Dutch distributors are obliged to give notice to customers about planned interruptions. This needs to be done three working days in advance of the interruption. They do not need to provide customers with updates on existing interruptions. However, in practice, several of the distributors (at least the largest 3) provide updates either on their website or via Twitter.

8.5 Customer Service

283. The NMa recognises that there are several other dimensions of quality in electricity distribution, such as voltage quality and commercial quality. Voltage quality refers to distortions in the alternating current of the supply, which could relate to the voltage level or to the frequency or symmetry of the phases. Commercial quality relates to the contact between consumers and their distributor such as telephone calls, written contact and face-to-face contact.

284. Regulation of both voltage quality and commercial quality are covered by the Dutch Network Code. The NMa has the power to fine distributors that do not meet the standards in the Network Code, and have applied these powers in the recent past. From mid-December 2011, the NMa will start publishing Key Performance Indicators (KPIs) for the different distributors on such metrics as speed of telephone answering, quality of service etc. While these KPIs do not have a financial impact, the hope is that making them public and 'naming and shaming' poorly performing distributors will provide an incentive for the firms to improve or maintain service quality.

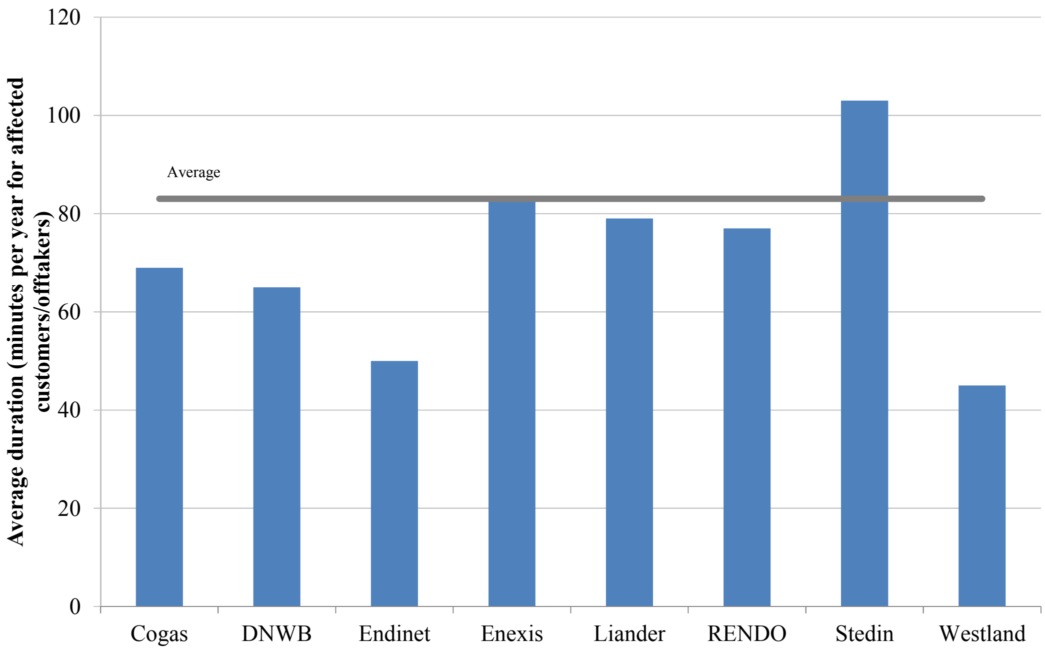
8.6 Performance

285. Distributors report information about their outages into the Nestor database. The NMa then uses an independent company to audit the information provided by companies.

286. Figure 12 shows the 2010 SAIDI for each Dutch distributor along with the average for all of the Netherlands. In Figure 13 we show the same data for SAIFI

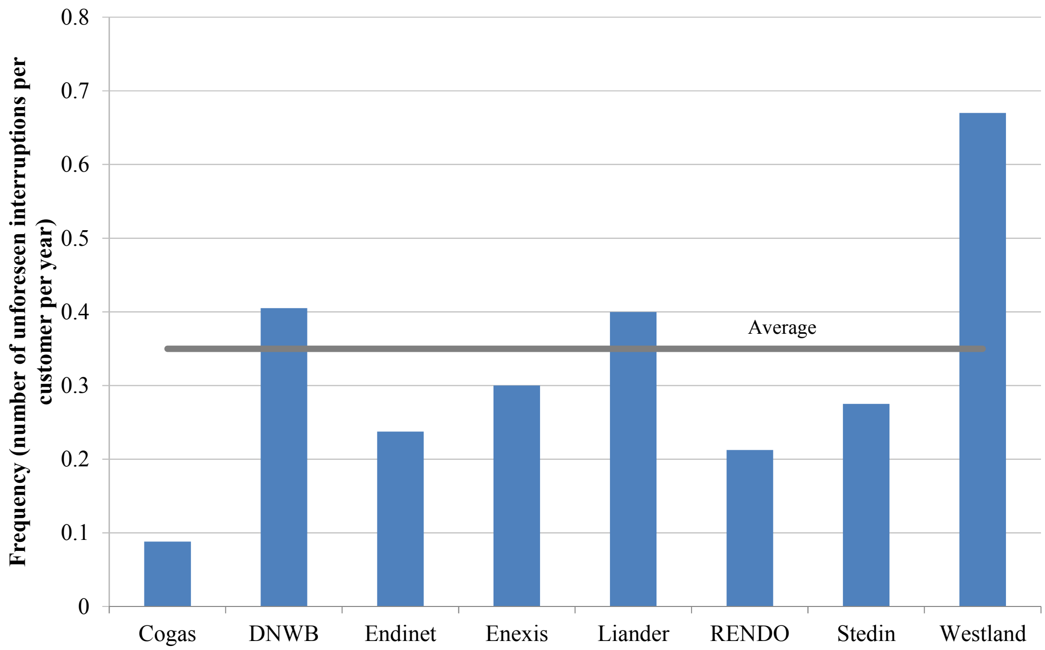
287. In Annex V we show how SAIDI and SAFI for each distributor varied across the period 2006 – 2010 and for the Netherlands as whole. The average interruption duration during 2010 was very similar (just over 80 minutes per year per customer) to the average interruption duration in 2006 although there has been some variation in the intervening years (ranging from around 75 up to 100 minutes per year per customer). The average number of interruptions was slightly lower in 2010 (around 0.34 per customer per year) than in 2006 (around 0.36 per custome3) but it dipped to less than 0.3 per customer in 2008.

Figure 12: Average Interruption Duration (minutes per year) Per Customer Affected[119]



[119] From presentation entitled "Factsheet 2010, Kwaliteit Regionaal Netbeheer Elektriciteitsnetten & Gasnetten". Available from the NMa website at http://www.nma.nl/regulering/energie/elektriciteit/regulering_regionale_netbeheerders/NMa_publiceert_Factsheets_Kwaliteit_Regionale_Netbeheerders.aspx.

Figure 13: Frequency of Unplanned Interruptions[120]



8.7 Interactions with Investments

288. Under the Dutch Electricity Act, distributors have had to produce a Quality and Capacity Plan every two years since 2005. The plan must cover the next seven years. The companies must set out the future quality standards for their system in terms of SAIFI, SAIDI and CAIDI and explain how they plan to meet these standards. The Quality and Capacity Plans must also meet the Ministerial Regulations in Relation to Quality Aspects of Electricity Grid and Gas Network Management. The NMa is responsible for assessing the plans and it has recently initiated an investigation into the companies' compliance with the Ministerial Regulations.[121]

[120] *Ibid*

[121] ERGEG publication "2011 National Report of Energiekamer to the European Commission",

289. There is no requirement for Dutch distributors to follow specific rules when designing their systems although there is a generally accepted handbook.[122] A high proportion of distribution cables are underground which contributes to the high reliability of Dutch distribution grids. Dutch distributors have both meshed and radial systems, with meshed networks often being operating radially. A survey carried out in 1998 suggests that in rural areas, both radial and meshed systems exist while in urban areas systems are more typically meshed.[123]

8.8 Cost and Reliability

290. Our cost effectiveness analysis for the Netherlands supports a similar finding as for other jurisdictions. The amount spent in providing distribution services is not an indicator of how reliable the service will be. In the Netherlands, most of the distributors have very similar costs per customer. However, the reliability (as measured by SAIDI) of the least reliable service is one sixth the reliability of the most reliable distributor (Figure 14).

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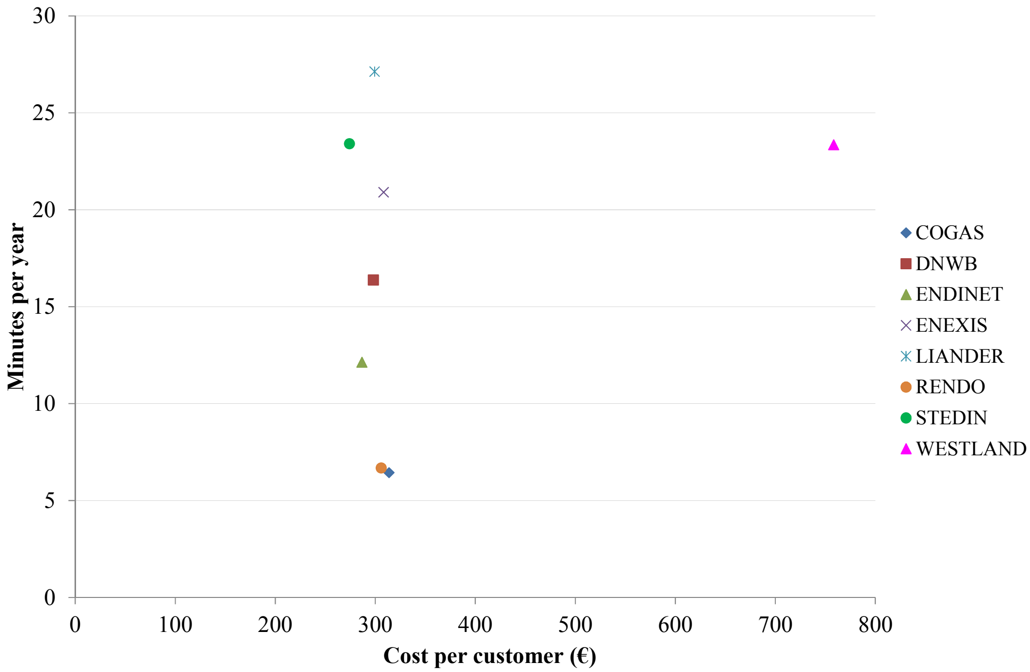
[122] Electricity distribution grids" published EnergieNed. See J. de Jong (Essent) "Review of current utility planning approaches for DG and detailed policy guidelines for network planners to encourage the consideration of DG as an alternative to network infrastructure upgrade", 25th April 2006, p. 29.

[123] J. de Jong (Essent) "Review of current utility planning approaches for DG and detailed policy guidelines for network planners to encourage the consideration of DG as an alternative to network infrastructure upgrade", 25th April 2006, p. 24.

Figure 14: SAIDI Performance Versus Cost Per Customer (Netherlands)



8.9 Reliability Incidents

291. A large number of outages in the city of Groningen in 2005 led Essent Netwerk, who operated the system, to investigate the causes of the outages and to consider whether the quality of the supply could be improved.[124] Essent investigated how the reliability of its system compared to the reliability of systems in similar cities, which parts of its system largely determined reliability, and the likely effect of possible remedies on its system reliability. Essent used SAIFI, SAIDI and CAIDI to measure reliability in its analysis. Since there were not anticipated to be substantial differences in improvement between the remedies it considers, the choice of remedy was based on cost and preference.

292. Following a significant increase in the interruptions in the Netherlands in July 2006, distributors commissioned a study to investigate a possible connection between outages in

[124] M. Berende et al, "Advanced Reliability Assessment of a Distribution Network; Objectifying of Proposals to Improve the Quality of Supply", Cired 19th International Conference on Electricity Distribution, May 2007.

underground distribution systems and climate.[125] The supposition was that the outages were caused by hot weather followed by a very wet spell. The study was able to show a statistical link between weather conditions and frequency of interruptions.

8.10 Conclusions

293. Whilst in many respects the Dutch approach to reliability regulation is similar to that in other jurisdictions, it differs significantly when it comes to the incentive mechanism. The use of the average outage levels across the distributors as a benchmark only makes sense in a jurisdiction where all the systems have broadly similar characteristics, are likely to face the same weather patterns, and already have high levels of reliability. Consequently, the Dutch approach, whilst interesting, is unlikely to provide a suitable template for Australia where there is a wide variation in the characteristics of the different systems and some systems have relatively low reliability levels.

[125] Press release of the Association of Energy Network Operators in the Netherlands "Dutch households without power for 33 minutes in 2007, 4 March 2008.

9 Regulation of Distribution Reliability in the US

294. The regulation of distribution systems is the responsibility of the individual states in the U.S. The scope of the regulations are codified in state laws and expanded upon in rules and regulations applicable to the state regulators ("regulatory commissions"). In all cases, distributors have a statutory requirement to provide high quality service to their customers. In a number of states, the public utility codes specify that reliable service should be a goal of utility resource planning. However such planning exercises are generally concerned with generation resource adequacy.

295. Distribution reliability and customer service received some focused attention from regulators in the mid to late 1990s and in the early 2000s. During this time frame, the US electricity utility industry went through the deregulation of generation and the consolidation of transmission assets, as well as the California energy crisis. In addition, many customers across the country experienced unusual and sometimes prolonged outages, which caused some state regulators to initiate special investigations concerning capital investment and maintenance practices, preparation for and responses to storms, and customer communications practices.[126] This led state regulators to re-focus on the "basics" of retail regulation; that is, rates (price controls) and service, with the latter including both distribution reliability and the quality of service to customers.

296. For most of their history, regulators did not assess reliability performance. More recently, however (i.e., since the late 1990s and in the early 2000s), most - but not all - state regulatory commissions have required distributors to track and report various indicators of distribution reliability. Some have set targets for desired ranges of reliability performance; others have gone further, developing systems of penalties and incentives regarding compliance with performance standards, sometimes within the context of already established performance based rate (PBR) plans.[127] Furthermore, most regulators conduct some level of review of distributors' capital plans and O&M spending. Importantly, state

[126] Major outages in this time period included a substation caused outage in Chicago, a transmission grid failure in the northeastern US and a series of ice storm related outages.

[127] These typically involve a structure of financial rewards and/or penalties for utility performance above or below a targeted neutral range.

regulators in the U.S. do not prescribe how distributors should carry out these responsibilities. That is, they do not dictate how distributors should plan and do not prescribe analytic methodologies (such as historic, predictive, probabilistic or deterministic approaches).

9.1 Reliability Metrics

297. The scope of the regulatory examination of distribution reliability has expanded over time. Initially, state regulators began looking at measures of service interruption frequency and duration on an aggregate distribution system basis. For many states, this has expanded to include measures of distribution reliability on a disaggregated basis, sometimes down to the performance of individual circuits. The reliability measures that are currently tracked by state regulars in the U.S. include SAIDI, SAIFI, MAIFI, CAIFI and Individual Circuit Reliability Performance Levels (ICRPL: the SAIFI, SAIDI or CAIDI indices for each circuit in an operating area, typically ranked from the lowest level of performance to the highest level of performance). Other less frequently applied indices include measures of load interruption frequency and duration (measured in term of kWs) and energy loss indices (measured in terms of kWhs).

298. Measuring reliability using the metrics described above involves a considerable degree of specification. Notably, it involves determining which types of interruptions should be included in the calculation of reliability. Many distributors have tracked distribution system reliability, and benchmarked themselves against others, as a way to assess their on-going capital investment and O&M practices on a comparable and "level playing field"; that is, excluding "major events" (such as weather-related events) over which they have no control.

299. After years of individual distributors selectively determining what constituted a major event, many distributors have adopted the standards of measurement developed by the Institute of Electrical and Electronics Engineers (IEEE), specifically Standard 1366-2003 (IEEE Guide for Electric Power Distribution Reliability Indices), which introduces a consistent means for defining major events using the 2.5 beta method. This has allowed for more consistent benchmarking across distributors. As far as reporting to regulators is concerned, however, the level of disaggregation and frequency of reporting, as well as the specific algorithms underlying reliability calculations are the result of negotiations (and regulatory proceedings) involving the distributors, regulators and other interested parties.

300. Many state regulators also track aspects of customer service and communications, areas considered by many to be closely related to the physical system measures of reliability. Such measures include call centre performance (e.g., average speed of answer, percentage of calls answered and busy-out or blockage rates), measures of billing and/or customer complaints, and meter reading accuracy. Some states include such measures in a customer service quality (CSQ) component of utility PBRs, similar to the reliability components that are included in some PBR plans.

9.2 Framework of Reliability Regulation

301. In nearly all cases, state regulators in the US review distribution reliability in either a formal or informal fashion. A recent survey of distributors and regulators indicates that at least 35 state regulatory commissions in the US require distributors to routinely report their reliability performance.[128] The level of reporting ranges from providing distributor-wide measures on an annual basis to reporting reliability measures for specific geographic regions within a distributor's service territory on a more frequent (e.g., monthly or quarterly) bases.

302. Beyond tracking and monitoring reliability performance, regulators may set targets for acceptable reliability performance, or may set standards to which distributors are required to adhere. Enforcement of reliability standards has been accomplished in one of three ways:

- Some regulators (including those in New York and California, discussed in greater detail below) have instituted specifically designed financial bonus and/or penalty structures for distribution reliability.

- Regulators have the option to conduct a special investigation of distribution practices if they find that reliability has deteriorated below industry standards. More frequently, regulators institute such an investigation when distributors have had poor responses to major events (such as ice storms). These investigations typically review the immediate planning for, and response to, the major event as well as on-going capital investment and O&M practices. The end result may include a penalty levied against the distributor and/or an order to modify its practices concerning maintaining its distribution system.

- Some regulators may simply publish reports which highlight the reliability performance for the distributors within their jurisdiction. Thus, even absent a censure and/or penalty, distributors risk poor public, investor and industry perceptions and relations.

303. Reporting and enforcement of reliability standards may vary across distributors within a state.[129] Distribution system areas frequently do not coincide with the geographic boundaries of a state jurisdiction. Many states have more than one major distributor operating within their jurisdiction, and it is not uncommon for distributors within a state to be regulated under slightly different frameworks. (For example, some distributors in a given state may be regulated under a PBR framework while others are regulated under a more traditional cost of service framework.) Fully assessing the extent of regulatory authority over distribution reliability performance thus requires more in-depth review of specific regulatory decisions and implementations. We provide a summary and analysis of the approaches used by two state regulators with respect to distribution reliability: and the California Public Utilities Commission (CPUC).[130]

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[128] Ernest Orlando Lawrence Berkeley National Laboratory. Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions. October 2008.

[129] State regulatory commissions in the U.S. generally have jurisdiction over investor-owned utilities (IOUs). Municipal electric utilities and/or electric cooperative utilities may also operate within a state and are generally, but not always, exempt from state commission regulatory authority.

[130] In addition to the geographies and utilities included under the jurisdiction of the NYPSC and CPUC, the staffs employed by these Commissions are of sufficient size and have expertise to examine reliability and customer service issues, as well as other regulatory issues.

10 New York State

10.1 Introduction

304. Electric service in New York State is provided by six investor owned utilities (IOUs), a power authority (i.e., a municipal instrumentality of the state of New York) and several smaller municipal and electric cooperative distribution utilities. The New York Public Service Commission (NYPSC) regulates the six IOUs. Also, it collects reliability data from the Long Island Power Authority (LIPA), even though it is not responsible for regulating the LIPA.[131]

305. The distributors provide service to over 18 million people and cover a wide ranging geographic area including very dense urban areas e.g., Consolidated Edison (Con Edison) provides electric service to most of New York City; as well as rural geographies (e.g., New York State Electric & Gas and Niagara Mohawk cover very rural stretches of Upstate New York). Con Edison's system serves roughly 2.4 million customers over a network system (much of which is underground) with another 900,000 customers served over a radial system. The other distributors in New York State serve customers primarily over aerial radial distribution systems. A summary of the characteristics of the six IOU distributors covering New York State is shown in Table 28.

[131] The Long Island Power Authority is the successor to the Long Island Lighting Company (LILCO) which was an IOU under the NYPSC's jurisdiction. It is a large utility, with over one million meters served.

Table 28: New York IOUs Sales and Customers

	Total sales (MWh)	Total Customers (number)	%
Central Hudson Gas & Electric Corp	5,214,735	299,971	4%
Long Island Power Authority	20,375,741	1,118,230	15%
Consolidated Edison Co of New York Inc	58,073,715	3,308,064	42%
New York State Electric & Gas Corp	15,048,131	877,738	11%
Niagara Mohawk Power Corp	29,513,518	1,621,191	21%
Orange & Rockland Utilities Inc	4,074,132	224,293	3%
Rochester Gas & Electric Corp	7,283,731	365,521	5%
Total	139,583,703	7,815,008	100%

Notes and sources:
Data from Ventyx - Electric Company Retail Sales
Total sales are bundled & delivery only total sales. Total customers are bundled & delivery only total customers.

10.2 Governance

306. The NYPSC regulates the quality of service and distribution reliability of the IOUs. The State's codes, rules and regulations, which provide general authority for the NYPSC to regulate electric distribution reliability, were enhanced in 1991 when the NYPSC approved an Order "Adopting Standards On Reliability and Quality of Electric Service". This Order set out more explicit oversight of reliability, including setting specific standards for SAIDI and SAIFI.

307. In addition, the NYPSC also has authority to set rates for the six IOUs and has put a specifically designed PBR in place for each distributor. Each of these PBRs includes a penalty component (called the reliability performance mechanism, or RPM) should the distributor fail to comply with a set of reliability targets.

10.3 Methodology

308. The NYPSC regulates electric distribution reliability through two related methods.

10.3.1 Performance against standards

309. First, the IOUs and the LIPA are required to submit detailed monthly interruption data. Specifically, the distributors provide interruption data that enables NYPSC staff to calculate SAIFI and CAIDI at an "operating area" level; i.e., geographic subsets of the distributor's service territory.

310. The NYPSC adopted electric service standards which set quantitative measures of acceptable electric distribution reliability for each distribution system.[132] The standards contain minimum acceptable performance levels for both the frequency and duration of service interruptions for each major distributor's operating areas. The number and scope of reporting (in terms of operating areas) and range of SAIDI and SAIFI standards applied as shown in Table 29 below. Note: the standards actually set by the NYPSC are for SAIFI and hourly CAIDI. To be consistent with the reporting used in many of the other jurisdictions included in this study, we converted the hourly CAIDI targets to SAIDI using the convention SAIDI = SAIFI x CAIDI, and also converting hours to minutes.)

Table 29: Level of Detail for NY Reliability Reporting

Electric Distribution Utility		Operating Areas for Reliability Reporting	SAIDI Standards (minutes)	SAIFI Standards (incidence)
Central Hudson Gas & Electric	5	Geographic area around major population areas.	69.30 - 192.00	0.77 - 1.60
Con Edison (Radial)	6	NYC's 4 boroghs excluding Manhattan, Westchester county and a small segment stradding Queens and Nassau counties.	19.53 - 82.66	0.29 - 1.23
Con Edison (Network)	5	4 NYC boroughs excluding Staten Island but included Manhattan, and Westchester.	0.41 - 3.38	0.003 - 0.02
Long Island Power Authority	3	Geographic areas (Central and East and West Suffolk county).	72.59 - 149.94	1.09 - 2.10
Niagara Mohawk Power / National Grid	8	Geographic areas broken down across large service area with urban pockets interpersed across rural tracks.	31.98 - 253.80	0.41 - 1.41
New York State Gas & Electric	13	Geographic areas covering largely rural base with some urban areas.	32.23 - 262.50	0.41 - 2.75
Orange & Rockland	3	Geographic areas (Central, Eastern and Western).	112.35 - 255.00	1.75 - 2.50
Rochester Gas & Electric	4	Geographic areas relating to population areas.	69.12 - 194.04	0.72 - 2.20
Total	47			

311. The table above includes a range of reliability standards for each of the New York distributors. This range reflects differences in expectations concerning service interruptions across the various operating areas. There are typically significant differences among the operating areas included within a single distribution system, reflecting differences in system condition and population density.

312. A review of the reliability standards indicates that the standards set for Con Edison's distribution system reflect very low expected incidents and durations of service interruptions. This is because Con Edison's distribution system is largely underground and

[132] Order Adopting Standards On Reliability and Quality of Electric Service was issued on July 2, 1991 (case 90-E-1119). Standards may be modified (if approved by the NYPSC) from time to time either through a Commission staff or utility initiated request. The service standards were last revised in 2004.

has a networked (or meshed) design,[133] this combination of factors has resulted in historically low outage rates compared to the other New York distributors.

313. Con Edison recently introduced a new outage management system (System Trouble Analysis Response, or STAR), which should produce more precise data on service interruptions than that provided by its old system. However, the STAR results will suggest a change in reliability when compared to the old system's results even if there is no change in the actual level of reliability. To overcome this problem, the NYPSC modified the reliability metrics from SAIFI and CAIDI to the number of interruptions per 1,000 customers and the average interruption duration.

314. Distribution reliability performance is assessed with respect to these standards. That is, the monthly data provided by the distributors are reviewed by the NYPSC staff and included in an annual electric reliability performance report, which compares distributors' performance against the standards.

315. Distributors are also required to include an analysis of outage trends for each of their operating areas, a summary of their reliability improvement projects, and an analysis of their worst-performing feeders.

316. The NYPSC's Order concerning reliability standards requires that distributors submit a corrective plan to the NYPSC if they have failed to comply with the established minimum reliability standard, but does not directly include any monetary penalty for failing to meet the standards (nor does it provide a bonus for exceeding them). Financial penalties concerning distribution reliability are included under a related but separate regulatory method, discussed in more detail below.

10.3.2 Performance Based Rates

317. Second, as part of the rate regulation of IOUs in the State, the NYPSC has put in place a reliability performance mechanism (RPM) as part of the rate plans for each of the IOUs. The RPMs are considered and decided upon at the time of each rate case i.e. every

[133] Network systems are designed with redundant supply paths, although lines to individual customer premises are typically stand-alone.

time a distributor's allowed revenues/prices are reviewed, and are specific for each individual distributor.[134]

318. Overall, the IOUs are opposed to the NYPSC applying RPMs. In its 2009 rate case, Con Edison argued that it had adequate incentives under the Commission's regulation to provide adequate levels of distribution reliability without the imposition of an RPM.[135] It also argued that revenues at risk under the RPM could also be considered in any regulatory case in which the prudence of its past actions is under review i.e. when ascertaining the appropriate ratemaking consequences of any imprudent actions. The NYPSC did not find any of the company's arguments a valid basis upon which to eliminate an RPM. It also found that Con Edison places emphasis on "headline" rate of return, and reasoned that earnings and financial incentives matter greatly to the company.

319. The RPMs impose penalties (negative revenue adjustments) on distributors for failing to meet their reliability targets. Variances on the targets are factored in with commensurate graduated penalties. Overall, the penalties are subject to a maximum revenue exposure cap. The RPMs do not include a corresponding positive incentive component which would reward distributors for exceeding a targeted level of reliability.

320. The reliability duration and frequency targets included in the RPMs are similar to the standards included in New York's reliability performance reporting. However, the targets included in the RPM tend to reflect system-wide averages rather than detailed operating area dis-aggregation. In addition, the RPMs include additional areas of reliability that are not directly included as standards in distributor monthly reliability performance reporting.

[134] The NYPSC also considers, during the course of each electric rate case, whether or not there should be an RPM at all. In its most recent rate case decided in 2009 (Cases 08-E-0539 and 08-M-0618), Con Edison opposed the NYPSC tying an RPM to its rates.

[135] CASE 08-E-0539 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service. CASE 08-M-0618 - Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers. Order Setting Electric Rates (Issued and Effective April 24, 2009)

10.4 Targets and Standards

321. As discussed above, the primary areas covered in the NYPSC's reliability reporting and standards involve the duration (CAIDI) and frequency (SAIFI) of service interruptions dis-aggregated by operating areas. In the case of Con Edison, these measures have been replaced (at least temporarily) with number of interruptions per 1,000 customers and the average interruption duration. In addition to these metrics, the distributors are required to provide detailed assessments of performance, including outage trends in a distributor's various geographic regions, reliability improvement projects and analyses of worst-performing feeders. [136]

322. The distributors also are required to delineate the nature of the cause of interruptions into one or more of 10 categories (referred to as a "cause code').[137]

323. As discussed above, the RPMs typically include average system-wide measures of duration and frequency of service interruption. The areas of reliability performance included in an RPM also go beyond the more conventional measures of reliability included under the NYPSC's reliability reporting standards by including "program standards." While the definition and scope of service interruption frequency and duration are for the most part uniform across distributors (even though the specific standards may differ), the definition and scope of program standards are unique to a particular distributor and reflect areas of reliability that are of particular concern to the NYPSC.

324. Con Edison provides a good example of the design, scope and enforcement of reliability standards in New York State because the standards and the structure of its RPM reflect the State's most complex electric distribution system. The reliability measures that

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[136] The top two and one-half percent of circuits on each of the SAIFI and CAIDI lists are identified as the worst-performing circuits per operating area. Combined, the worst-performing circuits report includes five percent of the circuits in each operating area, or three circuits, whichever is more. Circuits which meet SAIFI and CAIDI Minimum Levels for their respective operating areas, those serving less than 100 customers, and those having fewer than two interruptions per year are excluded for the worst performing circuit analysis.

[137] These cause codes are specified in the New York State's Codes, Rules and Regulations (16 NYCRR Part 97, Notification of Interruption of Service). The cause codes reflect the nature of the interruptions: major storms, tree contacts, overloads, operating errors, equipment failures, accidents, prearranged interruptions, customers' equipment, lightning, and unknown. There are an additional seven cause codes used exclusively for Con Edison's underground network system.

Con Edison is required to report to the NYPSC each year are considerably more extensive than the reliability indices that are included in the RPM. (For example, the reliability indices included in the RPM do not set standards by operating areas, nor do they include worst circuit performance.) In practice, the NYPSC staff reviews the annual reliability reports filed by the State's distributors each year at a detailed level, and may discuss specific remedies with distributors if their reliability targets are not met.[138]

325. Con Edison's RPM includes eight elements:

- Threshold Standards consisting of measures of service outage frequency (SAIFI) and duration (CAIDI) on Con Edison's non-network ("radial") distribution system, and measures of service outage frequency (number of outages per 1,000 customers and feeder open-automatics during summertime) and average outage duration on Con Edison's network distribution system;
- A Major Outage metric;
- A Program Standard for repairs to damaged poles;
- A Program Standard for the removal of temporary shunts;
- A Program Standard for the repair of no current street lights and traffic signals;
- A Program Standard for the replacement of over-duty circuit breakers;
- A Remote Monitoring System metric; and
- A Restoration Performance metric.

326. The NYPSC established maximum penalties for each area of RPM reliability performance. A break-down of the target areas included in Con Edison's RPM together with the maximum revenue exposure are shown in Table 30 below.

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[138] These may include enhancement of maintenance practices (such as tree trimming) or capital programs.

Table 30: Summary of Con Edison RPM's Penalty Structure

	Max Exposure ($ mn)	% of Allowed Revenue (%)
Frequency and duration of outages		
Network outage duration	5	0.06%
Radial outage duration	5	0.06%
Network outages per 1,000 consumers	4	0.05%
Network automatics	1	0.01%
Radial SAIFI	5	0.06%
Total	20	0.25%
Major outages - network and radial	30	0.37%
Remote monitoring system - network	50	0.62%
Programme standards		
Pole repair	3	0.04%
Shunt removal	3	0.04%
Street light repair	3	0.04%
Over-duty circuits	3	0.04%
Total	12	0.15%
Total Revenue exposure	112	1.38%

327. As indicated in the above table, Con Edison's RPM is composed of four primary areas. The first area includes the traditional scope of distribution reliability (i.e., interruption frequency and duration), and has a maximum revenue exposure of $20 million.[139] The remaining three areas largely reflect particular issues associated with Con Edison's distribution system, and the associated levels of revenue at risk are higher . Con Edison's system is largely networked and underground; so monitoring and communications are critical to locating and correcting problems. The standards associated with the assurance that Con Edison's remote monitoring system (RMS) functions as needed and the distributor's ability to respond to interruptions, especially on its networked systems, are

[139] The NYPSC measures Con Edison's network performance using two measures: the number of interruptions per 1000 customers and the average interruption duration. This is because traditional SAIDI, SAIFI and CAIDI indices may overstate customers affected in a network system. By using measures that are not based on the number of customers affected, it contends that it is able to monitor and trend network reliability performances without questioning the validity of the measures.

particular areas of concern for the NYPSC.[140] Accordingly, the penalties with not meeting standards in these areas can be as high as $80 million, more than 70% of the distributor's total possible revenue exposure. Finally, the NYPSC has identified several specific areas of complaint, that have been labelled as "program standards." These address customer complaints about repair and maintenance practice; e.g., repairs of damaged poles or malfunctioning street lights.

328. In total, Con Edison has a maximum revenue exposure under its RPM of $112 million out of a total revenue requirement of over $8 billion. This translates into a maximum revenue exposure of roughly 1.4% of the distributor's annual revenue requirement, or approximately 90 basis points on its return on equity.

329. In practice, Con Edison has met most of the RPM standards and has paid modest penalties. In 2010, Con Edison failed to achieve the average interruption duration target for its network system and also failed its RMS target, which translate into negative rate adjustment of $15 million. However, the distributor has asked for an exclusion based on its contention of extraordinary circumstances associated with a specific event. If this exclusion is granted by the NYPSC, Con Edison will comply with its RPM standards and will not incur any negative revenue adjustment.

330. The duration and frequency targets included in the RPMs are based on normal modes of operation; that is, excluding unusual circumstances. A major event (i.e., an unusual circumstance that should be excluded from normal reliability calculations) is defined by the Commission's regulations as any storm which causes service interruptions to at least 10% of customers in an operating area, and/or interruptions with duration of 24 hours or more. The NYPSC does not use the IEEE 2.5 beta method for defining major events.

331. Defining normal circumstances for the program standards included in the RPMs is less straight forward. Not only to the performance standards applied to distributors vary but also the specification of normal operations under the same standard can vary significantly.

[140] The Con Edison distribution system has roughly 24,000 RMS devices on its network transformers. Approximately one-third of these are at least 20 years old (i.e., first generation of RMS technology) and another 20% or so are 10 years old (i.e., second generation RMS). Transmission of data from network transformers to operating is important in an underground network system.

In other words, performance standards do not lend themselves to benchmarking between distributors, as is typically the case for SAIDI and SAIFI.

332. For example, as noted above, Con Edison is contesting its failing of the target set for its Remote Monitoring System (RMS) in its RPM for 2010. Con Edison's RMS targets involve the functionality of communications devices. The company has stated that transfers in load across substations in a certain part of its operations will require extensive re-wiring in order to make the RMS devices functional.

9.5 Customer Service

333. The NYPSC also has instituted a Customer Service Performance Mechanism (CSPM), which also penalizes a distributor for failing to meet the performance standards. These standards were set by the NYPSC for: customer complaints, customer satisfaction (per a survey), outage notification, and call answer rates. For Con Edison, the total revenue exposure under the CSPM is $40 million, or approximately 30 basis points on its return on equity. In 2010, Con Edison met each of the standards included under its CSPM and, therefore, did not incur a negative revenue adjustment.

10.6 Performance

334. Reliability performance for the New York electric distributors has been relatively stable on average. The state-wide SAIFI, excluding major storms, has been nearly identical for the past three years, and better than the five year average. The 201o performance of Central Hudson and Niagara Mohawk/ National Grid improved when compared with 2009. The 2010 performance for the remaining IOUs was not quite as good as their 2009 levels, but they still performed satisfactorily and met the criteria in the performance mechanisms to which they were subject. For the most part, SAIDI values were acceptable in 2010.

335. The reliability performances of New York's six IOUs compared to the standards set by the NYPSC are presented in Figure 15 and Figure 16 below. Also included in tthese figures is the reliability performance for the LIPA (as indicated above, this an unregulated municipal distributor) compared to standards previously set for its regulated predecessor company (LILCO).

Figure 15: New York Distributors - SAIDI Performance and Standard Comparison

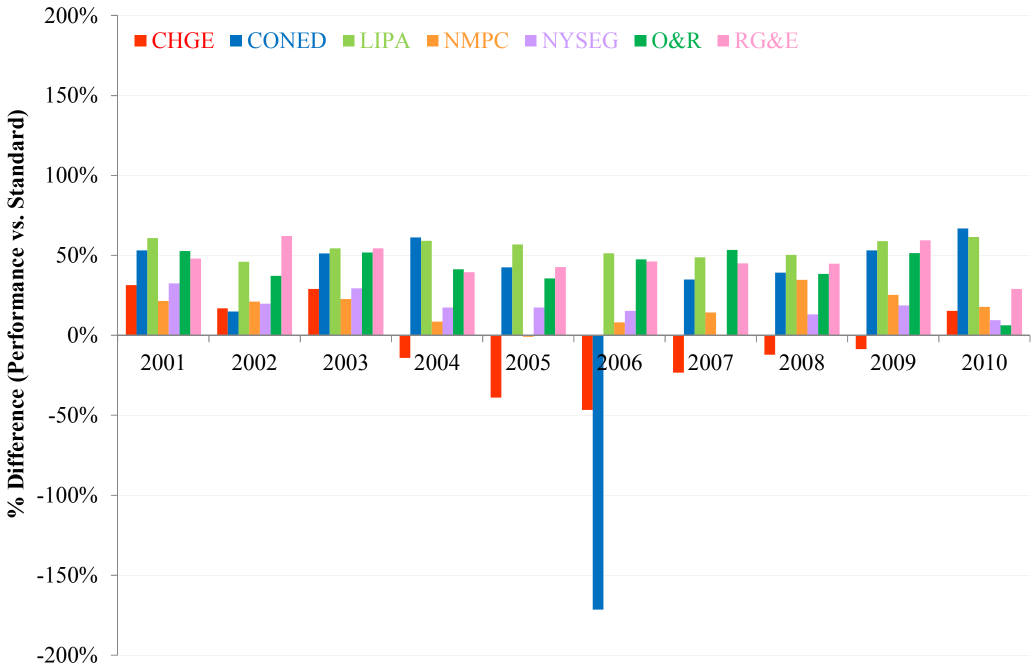
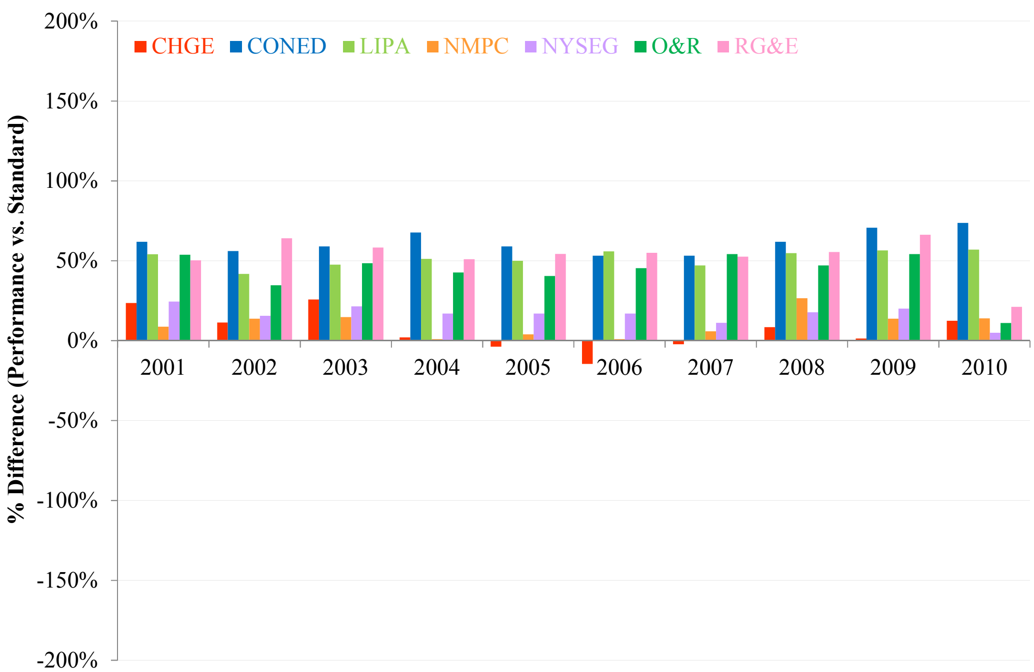


Figure 16: NY Distributors - SAIFI Performance and Standard Comparison



336. A timeline trend of SAIDI and SAIFI performance for the seven major New York distributors is shown in Figure 17 and Figure 18. With the notable exceptions of Central Hudson from 2003 onwards and Con Edison in 2006, reliability performance over time has been broadly stable.

Figure 17: NY Distributors' Historical SAIDI (Excluding Major Events)

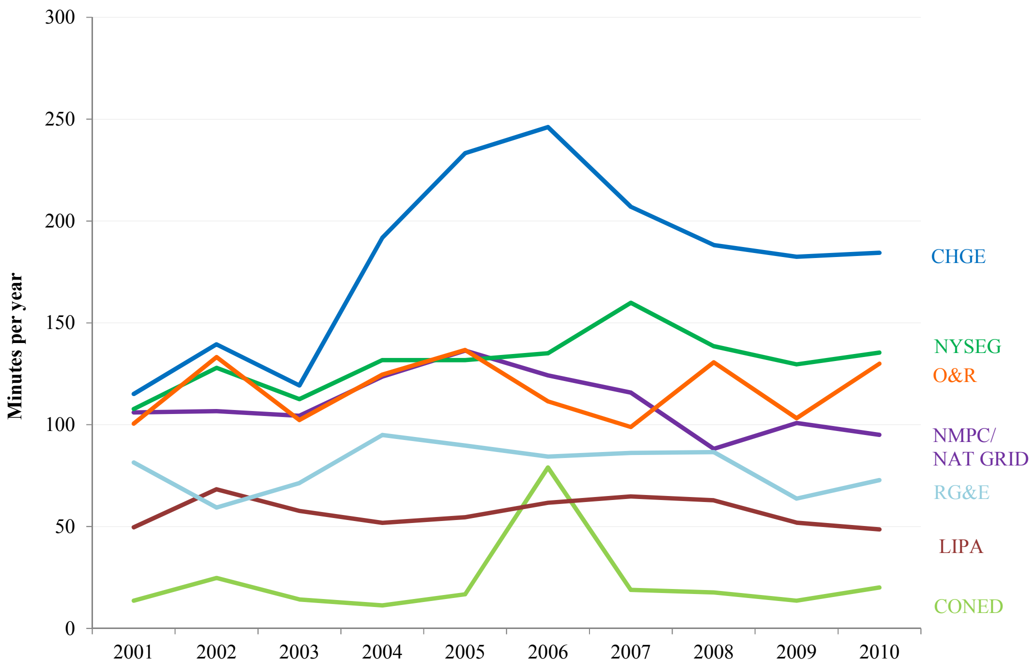
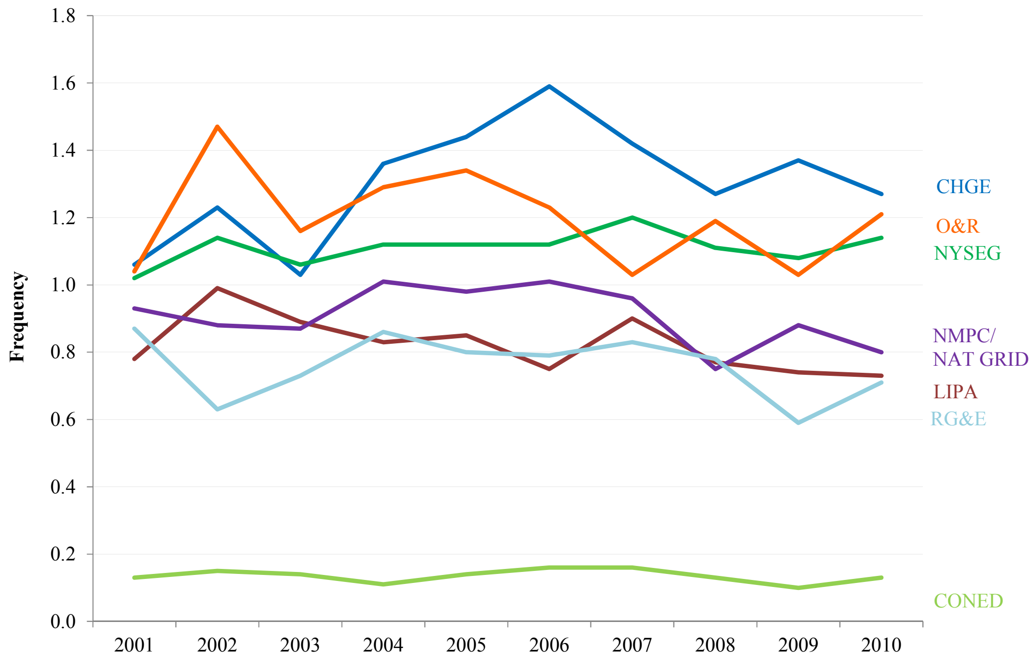


Figure 18: NY Distributors' Historical SAIFI (Excluding Major Events)



337. The above reliability performance trends reflect distribution operations under normal conditions (i.e., excluding major events). The reliability performance of the distributors changes somewhat when storms and other major events are included. Table 32 below provides a comparison of SAIDI and SAIFI performance when major events are excluded and included.

Table 31: NY Distributors SAIFI & SAIDI - Including Major Events Vs. Excluding Major Events

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SAIFI										
CHGE	13%	33%	83%	4%	27%	38%	6%	69%	19%	106%
CONED	8%	20%	7%	0%	7%	44%	13%	8%	10%	77%
LIPA	21%	24%	22%	10%	26%	57%	16%	42%	9%	42%
NMPC/NAT GRID	10%	48%	48%	11%	30%	47%	36%	83%	15%	23%
NYSEG	19%	53%	88%	25%	57%	60%	43%	93%	36%	61%
O&R	3%	42%	34%	12%	35%	47%	14%	38%	12%	48%
RG&E	15%	70%	259%	13%	16%	24%	40%	74%	25%	11%
NY STATEWIDE	*14%*	*39%*	*63%*	*11%*	*33%*	*48%*	*28%*	*66%*	*20%*	*47%*
SAIDI										
CHGE	18%	83%	204%	9%	54%	121%	10%	295%	33%	833%
CONED	23%	56%	29%	2%	25%	115%	78%	29%	48%	936%
LIPA	51%	63%	63%	18%	67%	129%	32%	72%	17%	136%
NMPC/NAT GRID	19%	187%	185%	17%	54%	413%	83%	303%	21%	52%
NYSEG	31%	167%	472%	44%	162%	721%	132%	555%	82%	233%
O&R	6%	171%	62%	24%	92%	110%	36%	121%	26%	293%
RG&E	31%	203%	4266%	25%	18%	49%	45%	255%	41%	42%
NY STATEWIDE	*26%*	*136%*	*452%*	*20%*	*76%*	*282%*	*76%*	*287%*	*41%*	*317%*

Notes and sources:
Difference is calculated as (performance including major events - performance excluding major events) / performance excluding major events.

338. The differences between including major events and excluding them are very noticeable in 2010. This year was historically one of the worst with respect to major storms. Three significant storms in the Hudson Valley and Downstate contributed to the entire State having the fifth highest hours of actual customer interruptions in the past twenty years.

10.7 Interactions with Investment

339. In addition to the areas of recourse discussed above – penalties associated with failing to meet the standards set in the RPM and the NYPSC's ability to discuss and negotiate areas for improvement following its analysis of the annual distributor reliability performance reports, examine the reasons – the regulator also has other avenues to address reliability issues.

340. First, the NYPSC can allow recovery of costs earmarked for specific reliability improvement initiatives, and then follow-up to ensure that funds were used as approved.

341. Second, the NYPSC can, and does, initiate special investigations regarding reliability-related issues, see section 10.9 below.

10.8 Cost and Reliability

342. New York's regulation of distribution reliability is primary focused on establishing levels of acceptable performance for distributors through the use of standards in annual reporting requirements and targets through reliability performance mechanisms. Cost levels (i.e., the trade-off between spending levels and reliability) were considered by the NYPSC when setting standards and targets. Direct consideration of distributor spending levels is addressed as part of the utility rate case process. Reliability related programs (capital and expense) designed to address specific problems and/or improve reliability in general are typically highlighted and the NYPSC approves (or disapproves) them in its rate case related decisions and orders.

10.9 Reliability Incidents

343. The NYPSC performs a detailed analysis of distributor reliability performance each year, in which it examines reliability under normal conditions as well as reliability when storms and other major events are included. Standards may be adjusted by the NYPSC as a result of proposals made by its staff or by the distributors.

344. In 2011 there were prolonged power outages throughout much of the State due to several major weather events (notably Hurricane Irene). The NYPSC required the affected distributors to perform an internal performance review and submit their finds to it within 60 days following the completion of service restoration.[141] The NYPSC staff's assessment of the distributors' performance in responding to these storms will be based on a combination of factors, including: a thorough review of the self-assessment reports filed by the distributors, as required by the Commission's regulations, discussions and interviews with public officials, evaluation of complaint data filed with the NYPSC's Office of Consumer Services, and public comments.

345. In addition, the NYPSC has retained an independent consultant to review the New York distributors' responses to the recent storms. This study will also examine on-going levels of investment and O&M practices associated with the distribution systems.

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[141] Following Commission regulation 16 NYCRR Part 105, Electric Utility Emergency Plan.

Depending on the outcome of this special investigation, the NYPSC may take action on a one-off basis or adjust reporting requirements or utility RPMs.

10.10 Conclusions

346. The NYPSC has developed a multi-pronged approach to regulating distribution reliability, spanning three broad areas:

- A detailed reporting process, includes regular reporting concerning reliability by distributors at a detailed level, an annual review by NYPSC staff of the distributors' performance against the standards set for them, reliability performance trend analysis by distributors accompanied by explanations for failure to comply with standards, and plans for correcting deficiencies.
- Including reliability considerations in the rate making process, including reviewing capital plans and levels of O&M spending, as well as setting of a reliability incentive (penalty) mechanism, in which rates are adjusted downward when reliability targets are not reached.
- Focused investigations which address specific areas of concern regarding reliability. Most recently, the NYPSC has initiated such an investigation of the State's distributors preparation and response to a series of major storms in 2011.

347. It is unclear whether or not any particular aspect of regulation has provided a more significant influence upon reliability in New York than the others, but the combination of all three elements has contributed to a reasonable overall level of reliability within the jurisdiction.

11 California

11.1 Introduction

348. The State of California is served by three major investor owned distributors (Pacific Gas & Electric, San Diego Gas & Electric and Southern California Edison), a smaller IOU (Sierra Pacific Power) and multiple municipal and co-operative distributors, including the Los Angeles Department of Water and Power which has nearly 1.5 million customers. The California Public Utilities Commission (CPUC) is responsible for regulating the State's investor owned distributors.[142]

349. A summary of the customers and MWh sales for California's three largest IOUs is shown in Table 32 below.

Table 32: California 3 Major IOUs Sales and Customers

	Total sales	Total Customers	
	(MWh)	(number)	%
Pacific Gas & Electric Co	90,469,503	5,225,733	45%
San Diego Gas & Electric Co	19,485,051	1,382,922	12%
Southern California Edison Co	83,547,420	4,900,257	43%
Total	193,501,974	11,508,912	100%

Notes and sources:
Data from Ventyx - Electric Company Retail Sales
Total sales are bundled & delivery only total sales. Total customers are bundled & delivery only total customers.

350. The CPUC began examining electric distribution reliability issues in depth following a series of storms that affected the northern part of the State in the spring of 1995. It began with a review focusing on Pacific Gas & Electric's (PG&E), whose distribution system was worst effected by the storms. The CPUC found that the combined effect of certain PG&E

[142] This followed from the CPUC's restructuring of the State's electricity market. Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation. Decision 95-12-063 (December 20, 1995) as modified by D.96-01-009 (January 10, 1996).

actions – specifically, reduced employee headcount, over-extended maintenance cycles and an inadequately staffed customer service telephone system – contributed to problems on the distributor's distribution system and with its storm response efforts.[143] The CPUC also took that opportunity to re-assess its approach to ensuring reliability in the State's distributors. It determined that the its regulatory program had not necessarily promoted high quality service and safety, and it recognized that evolving competition in the electric industry (following the restructuring of the industry in the State) might lead the distributors to compromise service levels. The CPUC then concluded that it needed to set specific and measurable standards of reliability for maintenance operations as well as measuring overall system reliability, and required that the State's distributors to report major or persistent service and safety problems and submit periodic reports on service reliability using standard measures.

351. The CPUC also reviewed the framework for regulating distribution reliability. It drew a distinction between the distributors' statutory obligations to provide high quality electric service – which it defined as historically accepted levels of interruption duration and frequency – and economic incentives that encourage distributors to strive to exceed minimum acceptable levels. Taking into account the impact of restructuring and the consequent pressures to maintain earnings, the CPUC found that general rate case incentive structures were unlikely to perform well in encouraging reliability above statutorily acceptable levels. That is, it concluded that as competition from resellers and aggregators grew, the distributors might find it advantageous (from an earnings standpoint) to cut costs at the expense of reliability.

11.2 Governance

352. As discussed above, the CPUC has reviewed its authority to regulate reliability in depth in the mid-1990s and settled upon a general approach of detailed reporting of reliability performance combined with the inclusion of a reliability component in the PBRs for the three major distributors under its jurisdiction. As will be discussed in greater detail below, the CPUC modified its use of PBRs to address electric distribution reliability in 2006.

[143] CPUC Decision 95 09 073

11.3 Methodology

11.3.1 Reliability performance reporting

353. The CPUC set reliability reporting and recording requirements for distributors as part of its 1996 Order (CPUC Decision 96-09-045). In this Order, the CPUC stated its intention to "adopt a uniform method for collecting and assessing data on the frequency and duration of system disturbances" which it had previously established in Decision 95-09-073. Prior to this, there was no common basis for assessing or reporting system reliability; each distributor used several measures of system reliability and different types of information.

354. The CPUC's 1996 order required each distributor to submit a report to the Commission by 1 March each year, containing SAIDI, SAIFI and MAIFI statistics on a system-wide basis for the previous calendar year. The CPUC did not include specific standards or targets within its reliability reporting system. Instead, it opted to consider such approaches in the context of rate making.

11.3.2 Performance based rates

355. The CPUC analysed the inter-relationships between rates set under traditional rate of return regulation and the incentive and penalty structure associated with performance based rates (PBR), and found that PBRs are an appropriate mechanism by which to regulate reliability. The CPUC reasoned that so-called statutory obligation levels of reliability are enforceable through annual rate of return proceedings via negative revenue adjustments (penalties), as well as by initiating one-off investigations and orders to show cause. The CPUC found that a PBR framework was needed in order to incentivize higher levels of reliability at a localized level.

356. Importantly, the CPUC also concluded that, over time, performance improvements brought about by PBRs are likely to render Commission actions for failure to meet minimum levels or reliability unnecessary.[144]

357. As part of Decision 96-09-045, the CPUC directed the distributors under its jurisdiction to adopt an incentive and penalty structure for system-wide reliability and customer service through their PBRs. The PBR component that addresses distribution

[144] CPUC Decision 96-09-045

reliability was generally referred to as a Reliability Incentive Mechanism (RIM). The structure of targets and incentives for RIMs in California is summarized in Table 33 below.

Table 33: Structure of California Reliability Incentive Mechanisms (SAIDI and SAIFI)

Distribution Utility	Target	Deadband	Incentive Structure
SAIDI (minutes)			
San Diego Gas and Electric	52	No deadband	Rewards or penalties vary with each minute of change from the benchmark, with a maximum reward of $3.75 milion at 37 minutes or less, and a maximum penalty of $3.75 million at 67 minutes or more.
Pacific Gas & Electric	157	10 minutes per year	Liveband of 15.8 minutes per year; maximum reward and penalty of $12 million per year.
SAIFI (frequency)			
San Diego Gas and Electric	0.90	No deadband	Rewards or penalties vary with each 0.01 units of change from the benchmark, with a maximum reward of $3.75 milion at 0.7 outages per year or less, and a maximum penalty of $3.75 million at 1.05 outages per year or more.
Pacific Gas & Electric	1.24	0.10 outages per year	Liveband of 0.15 outages per year; maximum reward and penalty of $12 million per year.

Note:

The CPUC's RIMs for SDG&E and PG&E allow for rewards and penalties based on utility performance. Some of the CPUC's PBRs include a range of performance in which the utility is deemed to have reached a target range and the utility does not receive a reward nor pay a penalty. This range is referred to as a "neutral" range or "deadband." The RIM for PG&E includes a deadband while the RIM for SDG&E does not.

358. As indicated in the table, PG&E was subject to a maximum revenue exposure through its RIM of $24 million. The RIM for San Diego Gas and Electric (SDG&E) also included a MAIFI component. Including this component as well as the SAIDI SAIFI components, SDG&E was subject to a maximum revenue exposure of $8.5 million.

359. The reliability component of the PBR for Southern California Edison (SCE) was based on Average Customer Minutes of Interruption (ACMI) and had a maximum bonus or penalty of $18 million per year. The initial target, set in 1997, was 59 minutes and the plan called for the target to decline by two minutes in each subsequent year down to an ACMI of 55 minutes. The target was surrounded by deadband of +/-6 minutes, within which no bonuses or penalties arose. Bonuses and penalties accrued at a rate of $1 million per minute outside the deadband.

360. California's PBR approach to incentivizing distributor reliability performance using PBRs was discontinued in 2006 (this discussed in greater detail in section 11.7 below).

11.4 Targets and Standards

361. As discussed in the proceeding sections, the CPUC developed reliability performance targets as part of the RIMs for the major distributors in the state. Such targets were discontinued after the Commission discontinued the RIM. Nonetheless, distributors remain responsible for filing annual reliability performance reports.

362. The scope of reliability reporting largely follows the areas set out by the CPUC in its 1996 order, with some adjustment over the years. The CPUC now requires the distributors to report on:

- SAIDI, SAIFI and MAIFI at a system-wide level (excluding major events) and to record reliability indices at a more dis-aggregate level as available.[145]
- Poorly performing circuits. In this regard, the CPUC is interested in determining, and the distributor analysing and addressing, groups of customers being served via a common cluster of distribution facilities that experience repeated interruptions. (Note that the CPUC made it clear that it does not expect all the circuits in a distributor's system to perform at an equal level.)
- Accidents or incidents which affect reliability.
- Distribution system inspection, maintenance and replacement cycles. The CPUC has developed guidelines for tree trimming and foliage clearances, albeit in other regulatory proceedings.

363. The CPUC summarized its general view of distribution system reliability in its 1996 Order as follows: "*Reliability should not merely be a measure that reflects the fictional*

[145] The CPUC requires the utilities to record information at the circuit, division, region, or district level on a frequent basis (no more frequent than monthly), commensurate with their existing information collecting capacities. Some utilities have proposed adopting the IEEE 2.5 beta method in place of this.

happenstance of a world without any disturbance: it should reflect the actual responsiveness of the distributor in addressing disturbances."146

364. For purposes of reporting SAIDI, SAIFI, MAIFI and poorly performing circuits, the CPUC requires that distributors exclude major events. Specifically, interruptions may be excluded from the reported indices if they were caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government. Other natural disasters may be excluded but only if they affect more than 15% of a system's facilities or 10% of a distributor's customers.

365. Most, if not all, distributors in the state favour a change from the method for calculating electric system reliability approved by the CPUC in Decision 96-09-045. Distributors have proposed adopting IEEE Standard 1366-2003, and have begun providing reliability performance calculated using IEEE 1366-2003 in their annual reliability reports, in addition to showing the calculations required under D. 6-09-045.

11.5 Customer Service

366. The CPUC supplemented its regulation of reliability with additional regulations on customer service through incentives and guarantee plans.

11.5.1 Customer Satisfaction Incentives

367. The CPUC has implemented customer satisfaction incentive plans, under which a distributor is expected to achieve a targeted level of customer satisfaction, as measured through a survey of customers. The distributor may then be rewarded for exceeding this or penalized for falling short of this level.

368. SCE, in conjunction with an outside consulting firm, conducts a survey to measure customer satisfaction in four service areas: field services and meter reading; local offices; telephone centres; and service planning. In each of the areas surveyed, the distributor asks a variety of questions, including a question as to the respondent's overall satisfaction with the specific service provided. Customers choose among six satisfaction categories with the top two being "completely satisfied" and "delighted."

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[146] CPUC Decision 96-09-045, page 17.

369. SCE's plan calls for it to be rewarded or penalized $2 million for each percentage point above or below a +/-3% deadband around its historic customer performance standard of 64%. SCE can be rewarded up to $10 million through this mechanism, but will not receive a bonus if 10% of customers fall in the bottom two of the six response categories surveyed. In addition, SCE can be penalized up to $10 million if performance if any one of four survey areas falls below 56%.

370. The CPUC recently reviewed the customer satisfaction results presented by SCE and included in its customer satisfaction incentive plan. The Commission found that SCE manipulated and submitted false customer satisfaction data which was used to determine the company's PBR customer satisfaction rewards for a period of seven years. The CPUC ordered SCE to refund to its ratepayers all the PBR rewards it had received ($28 million) and forgo an additional $20 million in rewards that it has requested.

371. For SDG&E, the CPUC has applied an indicator which measures SDG&E's responsiveness to customer telephone inquiries. The benchmark is 80% of calls being answered in 60 seconds, as measured on an annual basis. There is no deadband. For each 0.1% change in performance results, the bonus or penalty increases by $10,000 up to a maximum of $1.5 million.

11.5.2 Customer Service Guarantees

372. The CPUC has also instituted service guarantee plans through which customers are compensated by their distributor for service interruptions and/or inconveniences.

373. SDG&E provides a credit to customers if it does not meet its scheduled appointment time for service visits at the customer's premises. Basically, the customer may receive a credit for between $15 and $50 if SDG&E does not arrive within its scheduled time frame and does not notify the customer in advance. The amount of the credit depends on the type of service visit.

374. In D.04-07-022, the Commission adopted the service guarantee program for SCE, which addresses certain areas of customer satisfaction performance by providing compensation to certain customers who have been inconvenienced by SCE. Under the service guarantee program, four situations require SCE to pay rebates to customers: a) failure to meet agreed-upon appointment times; b) failure to provide service restoration within 24 hours; c) failure to provide planned interruption notification; and d) failure to timely and accurately report the first bill. SCE is required to report program results

(number of claims made, claims paid, and amounts of money paid) to the CPUC on a semi-annual basis.

11.6 Performance

375. Reliability performance for the five major IOUs in California is shown in Figure 19 and Figure 20 below. California's distributors have displayed erratic reliability performance, especially the two smaller IOUs, PacifiCorp and Sierra Pacific Power Corp. (SPPC). In recent years, SDG&E and PG&E have displayed more consistent reliability performance, but there has been a notable increase in the duration of service interruptions in the SCE service area.

Figure 19: California Distributors Historical SAIDI (Excluding Major Events)

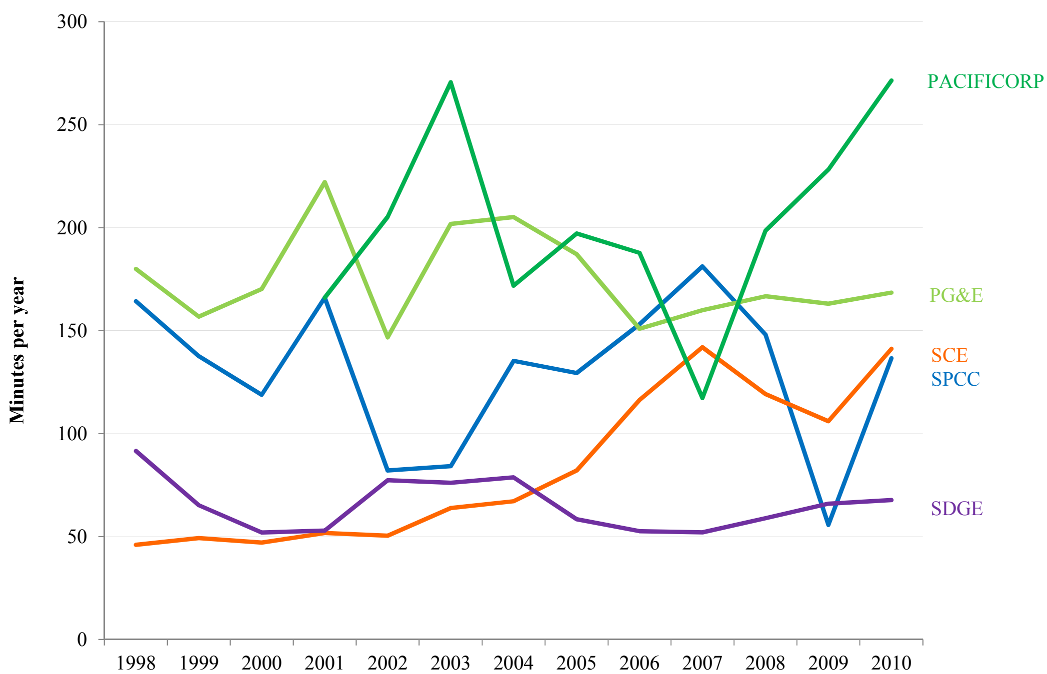
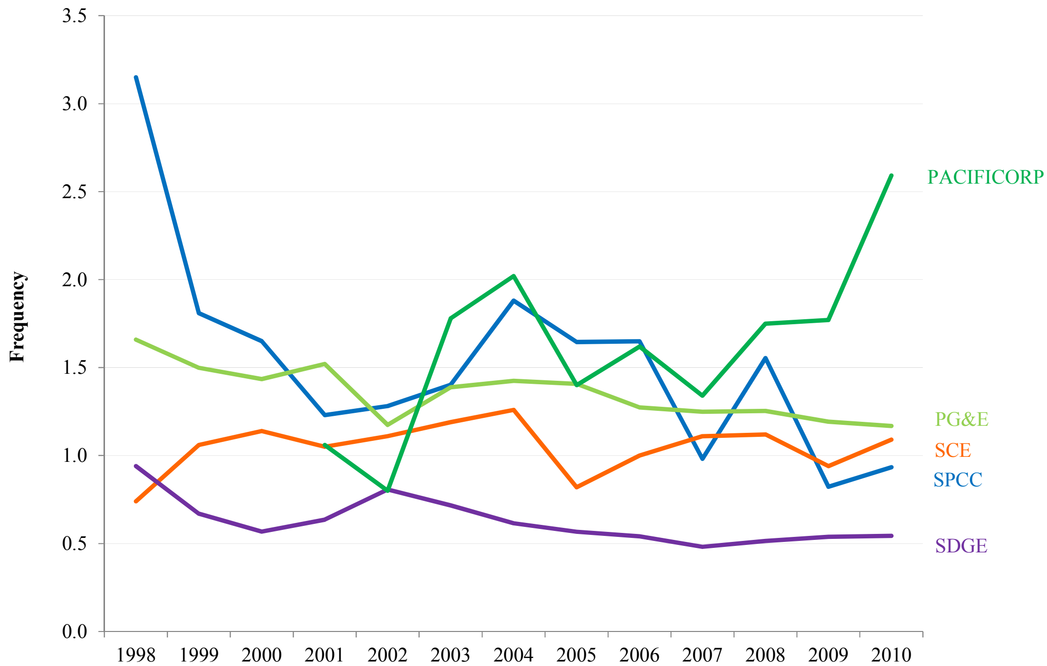


Figure 20: California Distributors Historical SAIFI (Excluding Major Events)



376. These reliability trends reflect distribution performance excluding major events. Table 32 below provides a comparison of SAIDI and SAIFI performance when major events are excluded and included.

Table 34: CA Distributors' SAIFI & SAIDI - Including Major Events Vs. Excluding Major Events

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SAIFI										
PACIFICORP	106%	86%	54%	133%	141%	179%	174%	135%	42%	76%
SPPC	0%	1069%	0%	14%	29%	49%	0%	0%	12%	0%
PG&E	8%	50%	2%	0%	10%	36%	0%	25%	10%	18%
SCE	0%	11%	17%	6%	24%	8%	4%	0%	0%	0%
SDGE	37%	1%	20%	9%	12%	1%	22%	0%	1%	59%
SAIDI										
PACIFICORP	163%	110%	119%	293%	201%	231%	340%	369%	45%	338%
SPPC	***-8%***	1059%	0%	37%	471%	162%	0%	0%	24%	0%
PG&E	18%	173%	3%	0%	33%	86%	0%	150%	28%	46%
SCE	0%	5%	37%	12%	30%	22%	7%	0%	0%	0%
SDGE	30%	7%	292%	18%	6%	0%	249%	0%	2%	33%

Notes and sources:
Difference is calculated as (performance including major events - performance excluding major events) / performance excluding major events.

377. The difference between including major events and excluding them is most noticeable for PacifiCorp, which is located in northern California (as well as in southeastern Washington and Oregon) whose system has been more subject to major weather events than systems elsewhere in the State.

11.7 Interactions with Investment

378. The CPUC reviewed the effectiveness of its RIMs in 2006 General Rate Case (GRC) for SCE. (In California, components of PBRs including reliability related incentives, are reviewed and decided as part of the GRC process.) The CPUC replaced the RIM with a Reliability Investment Incentive Mechanism (RIIM). The RIM was aimed at maintaining specific short-term measures of reliability (i.e., SAIDI and SAIFI). By contrast, the goal of the RIIM is to provide a mechanism for distributors to spend money on projects or other activities that will likely maintain or improve distribution reliability for the longer term.

379. Specifically, under the SCE RIIM, the CPUC has established an authorized level of capital investment on distribution reliability, notably in the areas of distribution infrastructure replacement, preventative maintenance, load growth, and substation infrastructure replacement. If SCE cannot not demonstrate that it has undertaken the authorized investment, it is required to reduce its revenue requirements, by refunding a portion of its rates to its customers.

380. The RIIM also requires SCE to develop programs to recruit and retain linemen and groundsmen as part of their efforts to preserve long-term electric system reliability. In this regard, SCE is required to demonstrate that it has added the agreed additional headcount in these areas; if not, it again has to refund a portion of its rates to its customers.

381. The CPUC largely adopted the views of SCE that the RIM had not resulted in improved levels of reliability and had taken a great deal of management time and attention that could be better used to address more significant issues, such as the efficient replacement of SCE's aging infrastructure. Importantly, however, the CPUC will continue to receive detailed annual reports concerning SCE's reliability performance and will be able to reconsider its decisions in future GRCs, should it be dissatisfied with SCE's performance.

382. Following on from the introduction of a RIIM for SCE, RIIMs have been put in place for the other major distributors in California.

11.8 Cost and Reliability

383. Cost and rate consideration are almost entirely within the province of GRCs in California. These rate cases are typically processed every three years. The rate case process requires that the distributor file an updated infrastructure plan, which reflects the necessary level of investment and spending to ensure an appropriate level of distribution system reliability. Cost levels (i.e., the trade-off between spending levels and reliability) are considered by the CPUC when setting rates.

384. In addition, the CPUC may institute focused reviews or audits of distributor spending programs to ensure that the distributor has made the investment and incurred expenses in the areas identified in the GRC. This general practice was enhanced when the CPUC instituted the RIIM plans.

11.9 Reliability Incidents

385. The CPUC monitors the reliability performance of distributors each year when they file their annual reliability reports. The CPUC also has initiated regulatory proceedings and/or investigations in response to specific areas of concern, notably responses to wild fires in southern California and service interruptions in gas and electric service in northern California. The CPUC's primary tool to improve reliability is its RIIM program, which allows it to select specific prioritized areas where distributors need to invest in order to address reliability concerns.

11.10 Conclusion

386. Although the CPUC requires distributors to file reports on reliability performance annually, the distributors face no penalties for failing to comply with standards or targets. Instead the CPUC has adopted a longer-term view which it hopes will fortify the State's distribution systems through an investment incentive mechanism. Comparatively, reliability among California's distributors is higher than the average for New York State. Recent SAIDI levels for PG&E have been higher than was the case for all of the New York distributors except for CHG&E. The CPUC will be tracking improvements in reliability performance as the distributors within its jurisdiction implement their RIIMs.

12 Findings

12.1 Introduction

387. Our comparative analysis has spanned 14 regulatory jurisdictions: 3 in Europe (Great Britain, Italy and the Netherlands), 2 in North America (the States of New York and California.), New Zealand and the 8 regulatory jurisdictions in Australia. In most cases, the jurisdictions cover several distributors. Moreover, the distributors cover a diversity of geographies and densities and face a range of different climate-related problems, as shown in Table 35 and Table 36 below.

Table 35: Australian Distribution System Characteristics in 2009

State/Territory		Company	Network Length (km)	% Underground	Number of Customers	Density (Customers/ km)	Revenue Requirement ($ millions, nominal)
		[A]	[B]	[C]	[D]	[E]	[F]
ACT	[1]	ActewAGL	5,396	54%	164,900	31	$133.7 (2009-10)
New South Wales	[2]						
		Ausgrid (Energy Australia)	48,590	28%	1,600,000	33	$1231.4 (2009-10)
		Endeavour (Integral) Energy	29,394	31%	866,767	29	$809.9 (2009-10)
		Essential (Country) Energy	200,000	3%	800,000	4	$937.9 (2009-10)
Queensland	[3]						
		Energex	53,256	31%	1,298,790	24	$1133.1 (2010-11)
		Ergon Energy	151,200	4%	680,095	4	$1105 (2010-11)
South Australia	[4]	ETSA Utilities	86,000	17%	812,529	9	$609.6 (2010-11)
Tasmania	[5]	Aurora	OH: 20,000 UG: 2,170	10%	271,750	12	$246.4 (2012-13 Draft)
Victoria	[6]						
		Citipower	6,445	37%	305,000	47	$210.6 (2011)
		Powercor	82,000	5%	700,000	9	$437.4 (2011)
		Jemena	12,600	-	315,000	25	$188.2 (2011)
		SP AusNet	2,300 (66 kV), 33,000 (≤22 kV)	0.50%	608,311	17	$518 (2011)
		United Energy	12,600	-	630,000	50	$282.9 (2011)
Northern Territory	[7]	Power and Water Corporation	HV Underground: 637 LV Overhead 1,758 LV Underground 1,781	52%	72,327	10	$99.9 (2009-10)
Western Australia	[8]	Western Power	OH conductors: 69,710	23%	1,018,275	11	$680.9 (2011)

Notes and sources:
[B], [C], [E], [F]:
[1] to [6]: Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion, Final Report 4.0, 13 May 2009. Sinclair Knight Merz. Appendix B: Summary of Reliability and Quality of Supply Obligations /Objectives.
[7]: Power and Water Corporation's Annual Report 2010-11. p. 22.
[8]: Western Power Network Management Plan, 1 July 2011 - 30 June 2017. p. 16-17, 80, 88.
[D]: From individual utility's 2009/2010 Annual Reports or webpages.

Table 36: Characteristics of Other Systems Studied

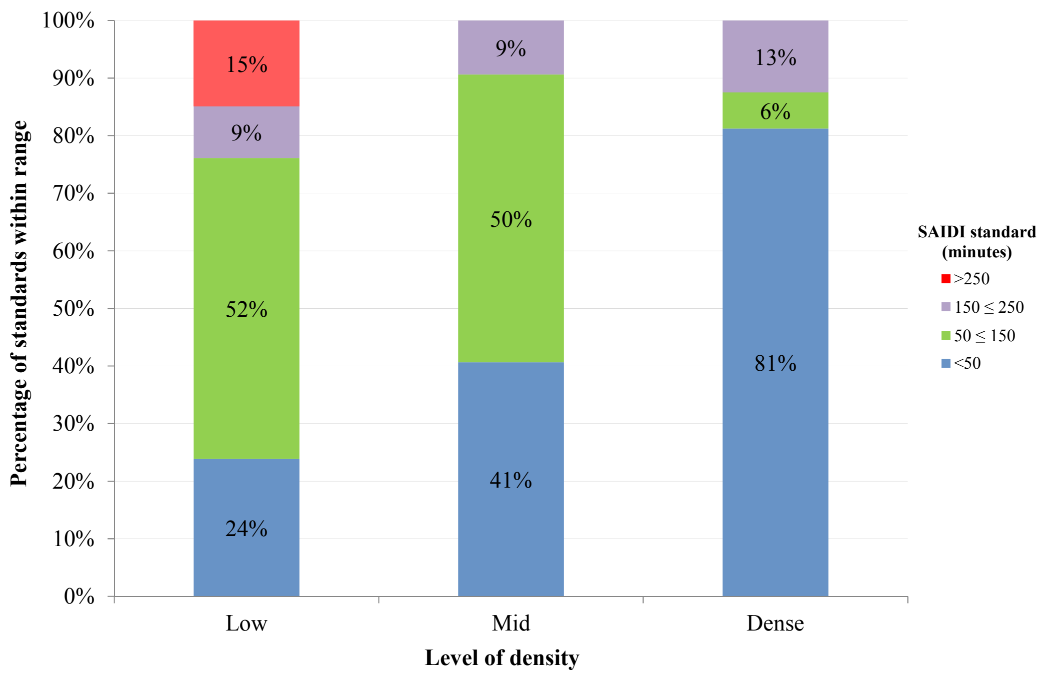
Jurisdiction	Scope of Distribution System (Serving Utilities, Size, Load Composition)	Distribution System Characteristics (Radial/Network Overhead/Underground)	Climate, Weather and/or Special Issues
New Zealand	There are 29 distributors ranging from 4,000 to over 500,000 customers, with a total of 2 million connection points. Total circuit length is 150,000 km. Average network density is 13 connections/km, ranging from 3-29 connections/km across the 29 distributors. Peak demand ranges from 9 to 1,775 MW across the 29 distributors.	A total of 27% of the network is underground (the range is 1% to 91%).	Various weather-related problems impact distribution reliability, including high wind, snow/ice storms, and salt deposition in coastal areas. In addition, earthquake activity has caused significant disruption.
Europe			
Great Britain	In GB, there are fourteen separately licenced distribution systems that are owned by seven companies. In total the distribution systems are 800,000 km in length and range from the highly urban (around 68 consumers per circuit km) to the extremely rural (around 15 customers per circuit km).	On average, approximately 60% of systems are underground.	Storms affect the reliability of GB networks. Ofgem publishes CI and CML performance data both with and w/out outages caused by storms.
Italy	There are 160 distributors in Italy. The size of distributors in terms of the number of customers they serve varies widely. The largest distributor, Enel, distributed over 85% of electricity in 2010. There are three other "large" distributors which each serve more than 500,000 customers. At the other end of the scale, there are over 50 "small" distributors which each serve less than 1,000 customers. The volume distributed in 2010 was 286 TWh (based on 141 of the 144 distributors at that time). 22% of this electricity was delivered to residential customers.	For the MV (15-20 kV) and LV (220-400V) systems, around 60% of cables are underground. For HV (132-150kV), all cables are overhead. Both MV and LV networks are built in a meshed configuration but operated radially, although rural and urban networks typically have different layouts.	Snowfall and flooding have in the past increased the duration of interruptions (e.g. winter of 2008).
Netherlands	There are eight distributors in the Netherlands. Together they have over 8 mn connections and transported 95 TWh in 2010. The three largest distributors (Enexis, Liander and Stedin) are responsible for over 90% of the connections (over 2 mn each) and distributed over 90% of the electricity in 2010. The remaining 5 distributors are much smaller with been 30,000 and 210,00 connections each. Residential consumption on the Netherlands is 25.7 TWh which is 27% of the amount distributed by distributors.	The majority of the distribution systems are underground: HV(150/110/50kV) - 9,836 km; 40% underground MV (3-25 kV) - 101,275 km 100% underground LV (230/400 v) - 195,706km 99% underground The Netherlands is similar to other European systems in that radial systems typically dominate in rural areas whereas meshed or ring-shaped systems prevail in urban areas. A survey carried out in 1998 showed that both radial and meshed networks were used in rural areas and that meshed networks used in urban areas although these are often operated radially.	Weather more of a problem for HV networks probably due to higher % of cables overhead. One concern has been that underground outages have exacerbated by hot weather followed by very wet spells (e.g. in July 2006) and KEMA study has shown statistical link between frequency of outages and weather.
North America			
New York	New York State is served by 7 major electric utilities plus a range of smaller municipal and cooperative utilities. Only 6 IOUs fall under regulation of NY PSC. In total, State has a population of roughly 20 million; NYC population is roughly 8 million. State is about 55,000 square miles; 7th in density in the U.S. Total sales served by 7 major electric utilities was nearly 50,000 GWhs in 2010, with residential customers accounting for nearly 40%.	Geographic majority of State is served via overhead distribution system with radial design. New York City, however, is served by Con Edison using an underground system with network design.	Systems face stress from short periods of high temperatures in summer which causes feeder overloads in areas of NYC. Rest of State experiences outages caused by winter storms (primarily ice storms).
California	California is served by 3 major IOUs plus a smaller IOU and multiple municipal and cooperative electric utilities, including the relatively large LADWP. The IOUs are regulated by the CPUC. California is the most populous State in the U.S. (roughly 38 million) and covers about 164,000 square miles. Roughly 14 million people are in the LA metro area. Total sales served by 4 major electric utilities was roughly 67,000 GWhs in 2010, with residential customers accounting for roughly 35%. PG&E alone has sales of roughly 31,000 GWhs.	Majority of State is served by overhead distribution lines in radial design. Downtown urban areas served via underground system, also primarily of radial design.	Systems have faced stresses from wild fires and occasional feeder overload in heat waves. Largely unaffected by major winter storms that impact the mid-west and east coast of the U.S.

388. Distribution planners and regulators recognize that distribution reliability will vary across each system. This is largely because customer density (i.e., the number of customers

per kilometre of distribution line) has a significant impact on the cost per customer of deploying and maintaining distribution facilities. For example, it is more costly on a per customer basis to restore supplies to a single customer at the end of a long rural line than to restore a cluster of customers in a more populated area. In addition, underground distribution lines are more storm resistant than overhead lines, but are much more expensive, and so their use is largely restricted to more densely populated regions.

389. Figure 21 provides a comparison of the reliability standards (SAIDI) applied by regulators in terms of the customer density of the service areas covered.

Figure 21: Spread of SAIDI Standards Across Regions of Varying Density Levels

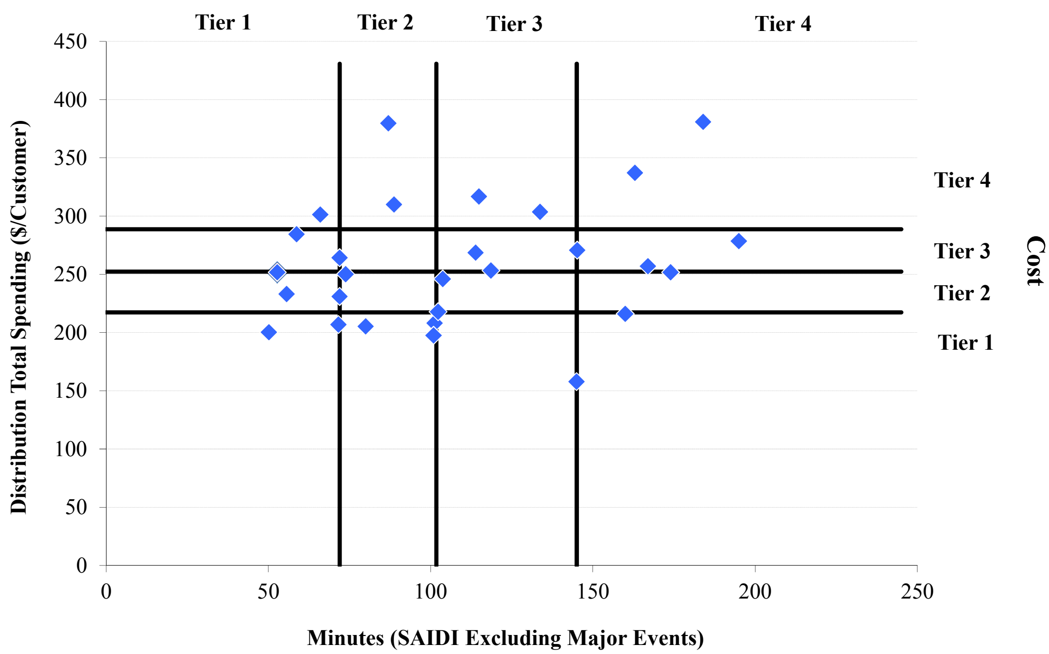


390. Following the theory discussed above and practical experience, regulators tend to accept that customers in less densely populated areas will experience a longer duration of service interruptions than customers in denser areas.

391. Distribution planners and regulators are also aware that there is a trade-off between costs (including capital expenditure as well as O&M spending) and reliability performance. However, most distributors in developed economies appear to have settled on a common range of cost-reliability trade-offs. For example, as is shown in Figure 22 below, in analysing levels of spending on distribution operations and levels of reliability for a panel of comparable US distributors, we found that there was no correlation between reliability and levels of spending per customers. This is because all of the distributors included in the

panel had maintained reasonable levels of spending over many years. In other words, we were not able to observe any instances where distributors dramatically altered spending either up or down.

Figure 22: Cost Vs. Reliability in 2010 – Panel of U.S. Distributors



392. The challenge in setting regulatory standards for reliability, then, becomes providing incentives for distributors to improve distribution reliability without raising costs to customers to unreasonable levels. In the remaining sections of this chapter, we examine the practices applied by regulators in the jurisdictions studied with respect to distribution reliability. We also review distribution reliability performance by jurisdiction in order to determine whether or not there appears to be any indication that regulatory approaches have strongly influenced reliability levels.

12.2 Approach to Regulating Reliability

393. The regulators in almost all of the jurisdictions included in our study set reliability standards and required that distributors file reports which compare their actual performance against these standards. Many regulators have implemented incentive mechanisms which provide a financial bonus if targets are exceeded, and/or penalise distributors for poor performance. Standards are typically set for SAIFI and SAIDI. The regulators usually set standards at a dis-aggregate level, typically in terms of geographic operating areas and/or by characteristic of service area (e.g., rural or urban), or different standards for different

individual distributors or systems. They sometimes additionally require reporting of other reliability measures without corresponding standards, such as hours of customer interruption (by area) and performance of individual feeders. In many cases, distributors are required to make payments to customers that experience particularly poor reliability. Table 37, 37 and 38 summarize these features across the jurisdictions we have studied.

Table 37: Comparison of regulatory approaches

Jurisdiction	Reliability standards	Incentive scheme (% of revenue at risk)	Guaranteed standards scheme	Planning standard	Detailed asset management plan	Separate treatment for "worst circuits"	Different standards for urban/rural
ACT	SAIDI, SAIFI	no, expected in 2014	no	no	no	no	no
NSW	SAIDI, SAIFI	no, expected in 2014	yes	deterministic	yes	yes - standards for individual feeders	yes
Queensland	SAIDI, SAIFI	yes (+/-2%)	yes	deterministic, internal only	yes	no - reporting only	yes
SA	SAIDI, SAIFI, maximum outage duration	yes (+/- 3%)	yes	deterministic, internal only	yes	no	yes
Tasmania	SAIDI, SAIFI	no, expected in 2012 (+/-5%)	yes	no	yes	no	yes
Victoria	SAIDI, SAIFI., MAIFI	yes (+/- 5% to 7%)	yes	probabilistic	yes	no - reporting only	yes
NT	no standards of any kind	no, expected in 2014	from 2012	no	no	no	--
WA	SAIDI, SAIFI, maximum outage duration	no	yes	no	yes	no	yes
New Zealand	SAIDI, SAIFI for investor-owned distributors	no	no	deterministic, internal only	yes	worst performing regions are highlighted	no
UK	SAIDI, SAIFI	yes (4%)	yes	yes, but in practice is exceeded	no	program to encourage investment	no
Netherlands	CAIDI,SAIFI	yes (5%)	yes	no	yes	no	no
Italy	SAIDI, SAIFI	yes (6.2%)	yes	no	no	yes; recently introduced	yes
California	SAIDI, SAIFI	yes	no	no	yes	yes	yes
New York	SAIDI, SAIFI	yes (+0/-1.4%)	no	no	yes	yes	yes

Notes
In Australia all jurisdictions apart from the Northern Territory have reliability targets (at least SAIDI / SAIFI) that the distributors are required to meet.
For those jurisdictions with separate incentive schemes, those schemes operate in addition.
In New Zealand, distributors must report faults per km, but there is no target.
In New Zealand, Italy, Netherlands and the UK, individual distributors do not have different targets for rural / urban areas, but the targets for different distributors are different. In Italy the baseline targets vary according to the number of customers served, and thus mirror an urban/rural distinction.
In the UK, Netherlands and Italy there are no standards (there is only an incentive mechanism).
The New York incentive arrangement includes targets on network automation and monitoring, as well as specific asset renewal programs.
In Australia, the incentive scheme has different targets in different parts of each network, and there are different standards in different parts of the network; in New York there are different standards for different parts of the network, but the incentive scheme targets are network-wide averages.

Table 38: Comparison of SAIFI standards

Region	Utility Company	CBD	Urban	Rural Short	Rural Long
ACT	ActewAGL	-	1.0	1.0	1.0
New South Wales	Ausgrid (Energy Australia)	0.3	1.2	3.2	6.0
	Endeavour (Integral) Energy	-	1.2	2.8	none
	Essential (Country) Energy	-	1.8	3.1	4.5
Queensland	Ergon Energy	-	2.0	4.0	7.4
	Energex	0.2	1.3	2.5	-
SA	ETSA Utilities	0.3	1.4	2.1 - 3.3	2.1 - 3.3
Tasmania	Aurora Energy	1.0	2.0	4.0	6.0
Victoria	CitiPower	0.2	0.5	-	-
	JEN	-	1.1	2.6	2.6
	Powercor	-	1.3	1.6	2.5
	SP AusNet	-	1.4	2.6	3.3
	United Energy	-	0.8	1.7	1.7
NT	Power and Water Corporation	-	-	-	-
WA	Western Power	-	-	-	-
New Zealand	29 utilities	0.5-7.1, mean 1.8, median 1.5			
UK	14 utilities	0.3-1.1, mean 0.7			
Netherlands	3 major utilities	benchmarking to performance of all utilities			
Italy	4 large, many small utilities	1.00		2.00	4.00
California	3 major utilites	0.54-1.24			
New York	7 utilities	0.44-1.92, mean 1.14			

Table 39: Comparison of SAIDI standards/targets

Region	Utility Company	CBD	Urban	Rural Short	Rural Long
ACT	ActewAGL	-	40	40	40
New South Wales	Ausgrid (Energy Australia)	45	80	300	700
	Endeavour (Integral) Energy	-	80	300	none
	Essential (Country) Energy	-	125	300	700
Queensland	Ergon Energy	-	149	424	964
	Energex	15	106	218	-
SA	ETSA Utilities	25	115	240 - 450	240 - 450
Tasmania	Aurora Energy	60	120	480	600
Victoria	CitiPower	11	22	-	-
	JEN	-	68	153	153
	Powercor	-	82	115	234
	SP AusNet	-	102	209	257
	United Energy	-	55	99	99
NT	Power and Water Corporation	-	-	-	-
WA	Western Power	30	160	290	290
New Zealand	29 utilities	30-557, mean 109, median 86			
UK	14 utilities	41-97, mean 67			
Netherlands	3 major utilities	benchmarking to performance of all utilities			
Italy	4 large, many small utilities	25.0		40.0	60.0
California	3 major utilites	66-157			
New York	7 utilities	22-142, mean 89			

12.3 Worst-served Customers

394. Reliability standards are usually specified as an average of performance across a region of a system, sometimes disaggregated by feeder type. In addition to rules relating to the average across systems (or parts of systems) several regulators have specific rules relating to the circuits supplying the worst-served customers. These are designed to address pocket of poor performance, for example by setting minimum standards which all feeders must meet. Some regulators require distributors to publish distribution planning

documentation on a regular basis, which highlight how system black spots will be improved. Other regulators provide sharper incentives for improvements in worse performing regions.

12.4 Measuring Reliability

395. How reliability is to be measured has to be specified in detail so that compliance can be assessed. The exact details vary across the different jurisdictions, but overall the methods are similar. The standard reliability measures adopted are SAIDI and SAIFI.. Generally, the SAIDI and SAIFI metrics exclude the impacts of major events (storms) and momentary interruptions (although this is currently under review in some locations because, with the widespread use of consumer electronics, such short outages can cause significant disruption). Various regulators have adopted or are considering adopting standards of measurement developed by the Institute of Electrical and Electronics Engineers (IEEE), specifically Standard 1366-2003 (IEEE Guide for Electric Power Distribution Reliability Indices), which introduces a consistent means for defining major events using the concept of "major event days."[147] However, several of the regulators in our study sample rely more on their own judgement in defining what interruptions to exclude from the reliability metrics. For example, in California, the regulator does not use the IEEE method because it believes that "*reliability should not merely be a measure that reflects the fictional happenstance of a world without any disturbance: it should reflect the actual responsiveness of the distributor in addressing disturbances.*"[148] The way in which reliability is measured in the jurisdictions we studied is summarized in Table 40.

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[147] This involves the "2.5 beta method", see footnote 11 above.

[148] CPUC Decision 96-09-045, page 17.

Table 40: Reliability Measurement

Jurisdiction	Specific Reliability Measures Applied	Outage Thresholds and Exceptions	Level of Disaggregation
Australia			
Australian Capital Territory	SAIDI, SAIFI	Interruptions less than one minute are excluded. Extended storm outages are excluded (where 10% of customers in an area are affected). Both planned and unplanned outages included	None
New South Wales	SAIFI, SAIDI, both average figures and for individual feeders	Interruptions less than one minute are excluded. Planned interruptions are excluded. Load-shedding is excluded. Severe weather/storm events are excluded, and the "IEEE Guide for Electric Power Distribution Reliability Indices" - the "2.5 beta" method applies.	By utility and feeder type
Queensland	SAIFI, SAIDI	Interruptions are measured with the exclusion of "major event days", per ANSI.Std. 1366-2003 "IEEE Guide for Electric Power Distribution Reliability Indices" - the "2.5 beta" method.	By utility and feeder type
South Australia	SAIDI, SAIFI, maximum time to restore supplies	Excluding outages of less than one minute. Both planned and unplanned outages are included.	By region
Tasmania	SAIFI, SAIDI	Outages of less than one minute are excluded. SAIFI and SAIDI are measured for each transformer on the system, then aggregated to give a weighted average where the weights are the transformer capacities. Both planned and unplanned outages are included.	By location and by location type (urban / rural etc)
Victoria	SAIDI (planned), SAIDI (unplanned), SAIFI (unplanned), MAIFI	Interruptions shorter than one minute are excluded. There are separate targets for planned and unplanned outages.	By feeder type
Western Australia	SAIDI , SAIFI, maximum restoration time	SAIDI is measured as the average of the annual figures in the prior four years.	By area
Northern Territory	n/a	Not stated	By area
New Zealand	SAIDI and SAIFI are regulated for investor-owned distributors. All distributors must report reliability metrics (SAIDI, SAFI, faults/km, planned and unplanned)	Interruptions of less than 1 minute are excluded. Daily SAIDI and SAIFI values are capped at 2.5 standard deviations above the average value. Both planned and unplanned outages are included.	By network.
Europe			
Great Britain	CI/CML (equivalent to SAIDI/SAIFI)	Outages longer than 3 minutes are included. Severe weather events that exceed 8 times the daily average HV fault rate for the last ten years are excluded. One-off exceptional events are also excluded. Eligible to be classed as one-off exceptional events if >25,000 interrupted customers and/or >2,000,000 interrupted minutes.	By network
Italy	SAIDI and SAIFI	Outages less than 3 minutes ar excluded from SAIDI target but included in SAIFI target.Targets typically exclude interruptions due to external causes such as weather-related events but DNOs can apply to have their baseline targets replaced by a new target that is more generous but that also includes unexpected interruptions due to factors not within the control of the distribution company	Baseline targtes are distinguished by rural/semi-urban/urban. Actual targets are set for individual distribution companies.
Netherlands	SAIFI & CAIDI	Outages longer than 1 min are included and force majeure interruptions are excluded.	By distribution companies
North America			
New York	SAIFI, CAIDI, Customers Affected, Worst Performing Circuits	All reliability metrics are measured "with" and "without" the effect of major events, defined as any storm which causes service interruptions of at least 10% of customers in an operating area, and/or interruptions with duration of 24 hours or more.	Operating areas or geographic subdivisions of each utility's service territory. Also, utilities are required to break down CAIDI and SAIFI into % "cause code." For Con Edison, reliability standards are set separately for radial and network areas of the distribution system.
California	SAID, SAIFI, CAIDI, MAIFI, Customers Experiencing >12 Sustained Outages	Major events are not included in reliability measurement. Utilities report a detailed list of excusable events	Operating areas or geographic subdivisions of each utility's service territory.

12.5 Input Standards

396. We found few instances where regulators require distributors to follow specific methodologies, such as probabilistic or predictive methods, in planning for and/or designing distribution systems (see Table 37). NSW is a notable exception, because in NSW the planning standard appears to be an important mechanism for influencing reliability outcomes. Victoria also has a planning standard, but this standard relates to the publication of system development plans, whereas the NSW standard relates to how the system is built. Queensland also appears to follow a planning standard, although this standard is not defined in legislation or the industry codes. In GB, input standards are in place, but they are currently only apply to higher voltage levels and, in any case, it is generally the case that the distributors plan their networks to higher standards than those imposed upon them.

397. Regulators elsewhere have clearly preferred output standards over input standards, which may be due to the potential for inefficiency if regulators become overly involved in distribution system development. Alternatively, it may be that operational practices, as well as system design, are important for achieving reliability but are harder to standardise. Output standards relate directly to the reliability actually experienced by customers. Also, such standards empower a distributor to meet the standard in the way that, in its view and based on years of experience, provides the "best" or most efficient solution. This is in contrast to an input standard which specifies a defined solution.

398. However, this is not to suggest that regulators rely only on output standards. On the contrary, they frequently require some level of system planning documentation, typically in the form of a distribution system management plan, especially when there are indications of areas of poor performance (see above).

12.6 Enforcement and Incentives

399. Many, but not all, of the jurisdictions under study have put an incentive system in place as a mechanism to promote and/or enforce reliability standards (see Table 37). This may be one-sided i.e. distributors face a penalty for not meeting their standards, or two-sided i.e. the distributors can also receive a bonus for exceeding them. None of the jurisdictions studied apply a bonus-only incentive mechanism. In the absence of an incentive mechanism, enforcement is generally encouraged via "naming and shaming" or

via one-off regulatory investigations into major outages (presumably with the backstop of standard regulatory enforcement mechanisms, such as fines).

400. In some jurisdictions, incentive arrangements have been criticized by stakeholders who feel that distributors should (and are paid to) deliver reliable service, so that an incentive payment on top amounts to paying twice for the same thing. This may explain why incentive arrangements are sometimes "penalty only".

401. Irrespective of the structure (or absence) of bonuses and/or penalties, reliability standards or targets are generally not "absolute": That is, distributors are typically required to make "reasonable endeavours" or "best endeavours" to meet the standards, but they are not expected to expend limitless resources in an effort to meet the standards. As indicated above, few regulators get involved in prescribing how distributors plan for meeting standards or targets. However, where there are input (planning) standards, as is the case in New South Wales, the cost of meeting the standard may be more transparent to regulators, because an input standard relates directly to the design of the network, and hence cost.

12.7 Statutory Authority and Governance

402. In most of the jurisdictions we reviewed, the same body is responsible for regulating both reliability and the price charged for distribution services (see Table 41). Australia is unusual in this regard, in that the AER is responsible for regulating prices in most jurisdictions, but other regulators (or Governments) are at least partly responsible for regulating reliability in all Australian jurisdictions.

403. For most of the jurisdictions reviewed, development and implementation of reliability regulation is accomplished through normal regulatory processes. This means that the governance of distribution reliability regulation is no different to that for other aspects of regulation. This is the case in Australia so far as the NEM and AER incentive schemes are concerned. For the jurisdictional reliability standards that are also in effect, the governance arrangements (for the NEM jurisdictions) are clearly distinct from the processes used for decision-making in respect of price controls. Generally, normal regulatory practice involves the regulator consulting on proposed standards and incentives, considering responses to the consultation and issuing final proposals. There is sometimes also an appeal mechanism if a distributor believes that the reliability regulations are unfair or the process for setting them has not been correctly followed. However, such an appeal can often only be launched as part of a wider appeal of a price control.

Table 41: Governance, Process and Institutional Arrangements

Jurisdiction	Body Responsible for Setting Reliability Standards	Body Responsible for Setting Reliability Incentives	Reliability Standards Setting Process	Reliability Incentive Setting Process
Australia				
Australian Capital Territory	The standards are in the Electricity Distribution (Supply Standards) Code, administered by the ACT Government (Environment and Sustainable Development Directorate)	Will be the AER from 2014	Standards have not been changed since 2000. However, the utility itself is required to publish new standards each year (no looser than the Code standards)	Will be the standard STPIS process (part of the price review determination)
New South Wales	Licence conditions set by the Minister for Utilities, advised by the Independent Pricing and Regulatory Tribunal	Will be the AER from 2014	Consultation prior to imposing new licence conditions	Will be the standard STPIS process (part of the price review determination)
Queensland	Standards are in the Elecrticity Industry Code, which is issued by the Utilities Minister	AER	Consultation process specified in Queensland electricity legislation	Standard STPIS process (part of the price review determination)
South Australia	Standards are in the Distribution Code, which is issued by the Essential Services Commission	AER	Normal regulatory process, including consultation	Standard STPIS process (part of the price review determination)
Tasmania	The Tasmanian Electricity Code is administered by the Tasmanian Economic Regulator	Will be the AER from 2012	Normal Code change procedure, including consultation	Will be the standard STPIS process (part of the price review determination)
Victoria	The Victorian Electricity Distribution Code is administered by the Essential Services Commission. It requires distributors to set their own targets	AER	Normal regulatory process, including consultation	Standard STPIS process (part of the price review determination)
Western Australia	The standards are in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005, issued by the Minister for Energy	n/a	The Code has not been amended since first implemented	n/a
Northern Territory	There are currently no standards	Will be the Utilities Commission	n/a	n/a
New Zealand	Regulator (Commerce Commission)	No incentive arrangements	Set by the regulator (Commerce Commission) responsible for regulating price. Only set for investor-owned utilities. Quality	n/a
Europe				
Great Britain	Regulator (Ofgem) as part of price control review.	Ofgem	Based on company's past performance, company's reliability in last price control and benchmarks set by Ofgem.	Incentive rates derived from WTP studies
Italy	Regulator (Regulatory Authority for Electricity and Gas (AEEG))	AEEG	Worst of baseline and average of actual outages over last two years. If not at baseline, annual	Derived from WTP studies
Netherlands	Regulator (DREV)	DREV	All companies measured relative to average performance of distribution companies.	Allowed revenue for next regulatory period adjusted based on performance in previous regulatory period. Revenue adjustment based on
North America				
New York	New York Public Service Commission for IOU only.	NYPSC	Regulatory proceeding; negotiated process; separate from incentive setting proceeding.	Part of regular scheduled rate proceeding; included as performance based rate plan.
California	California Public Utilities Commission for IOUs only.	CPUC	Regulatory proceeding; negotiated process; separate from incentive setting proceeding.	Part of regular scheduled rate proceeding; included as performance based rate plan.

12.8 Output Standards versus Incentive Targets

404. Mechanisms for regulating reliability include both "standards" and "targets" – the difference being that an explicit incentive mechanism is associated with a reliability target, but not with a standard. There is a second difference in several jurisdictions that have put in place both annual reporting of reliability and also incentive plans. Targets tend to be more high-level and applied to average performance, whereas standards tend to be more detailed and applied to performance at a more disaggregated level (for example, different operating areas within a system, or even to individual feeders). Thus, there may be more than one level of expected outcome in jurisdictions for those which have both annual reporting of reliability at a detailed level and reliability related incentive plans. In most cases, the detailed standards and financial incentive targets are set by the same regulatory body, and have an internal consistency. (For example, a SAIDI target may be the system-wide average of the detailed SAIDI standards adopted for specific operating areas, with consistent measurement methodology.)

12.9 Ad-hoc Issues

405. Output standards and associated enforcement mechanisms address routine matters of distribution reliability. As indicated above, most service interruption metrics as included in enforcement plans are measured excluding the impact of major events. However, it is major events, such as service interruptions as a result of storms, that are most visible to customers. Regulators, therefore, also review reliability outside the scope of routine operations. Notably, regulators may conduct special investigations into distributor storm response practices and costs. As part of these reviews, regulators may examine capital investment and maintenance programs and may prescribe how distributors should address shortcomings.

12.10 Customer Willingness to Pay

406. None of the jurisdictions we examined used WTP explicitly to set the required level of reliability. However, WTP studies are frequently used in designing the power of incentive mechanisms (i.e., if a particular reliability target is missed by a certain amount, the relationship between the amount by which the target is missed and the penalty imposed on the distributor may be determined with reference to a willingness to pay study).

407. It is also notable that regulators do not aim to provide explicit compensation to customers for poor reliability. While it is common (see Section 12.11 below) for regulators

to require distributors to make payments to those customers that experience particularly poor reliability, the amount paid is generally not related to the value that customers put on reliability (the payment is lower).

12.11 Payments to Customers

408. Another significant aspect of reliability regulation relates to distributors interactions with consumers when they are experiencing problems with reliability. Many jurisdictions have guaranteed standards of performance relating to outage restoration, as well as to the provision of information during outages and response times. Under those arrangements, customers are entitled to a payment if the distributor fails to meet these targets (see Table 37). Whilst such standards may have little impact on the frequency or duration of outages, they can significantly affect the impact that an outage has on consumers. For example, accurate and timely information regarding the duration of an outage is often very important to consumers, although reliability standards usually do not address this issue directly.

12.12 Impact of Regulation on Reliability Performance

409. We have sought to assess the extent to which the various regulatory approaches implemented in the different jurisdictions appear to be affecting reliability performance in three ways. However, we find it important to note that the empirical analysis of distribution reliability is complex, particularly when comparing across jurisdictions. A comprehensive empirical analysis would take many additional factors into account in an attempt to improve comparability. Thus, our analysis here should be treated with caution.

410. First, we examined the relationship between the standards set and distributor performance across the jurisdictions studied in order to assess whether or not different jurisdictions (and their specific regulatory approach) had realized higher levels of performance than the rest of the panel. Figure 23 shows the scatter plot of performance versus the standards set by regulators for SAIDI whilst Figure 24 shows the same comparison for SAIFI.

Figure 23: Comparison of Performance vs. Standards for SAIDI

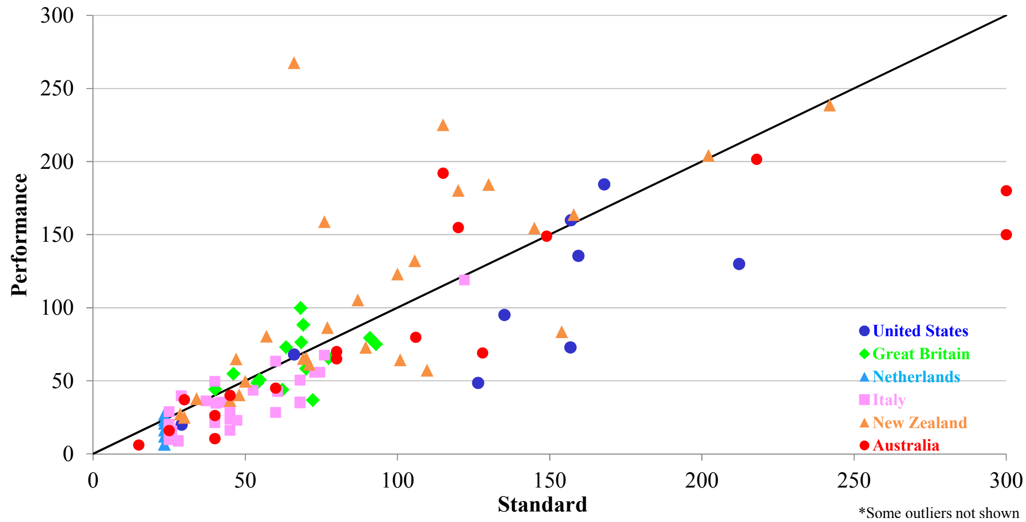
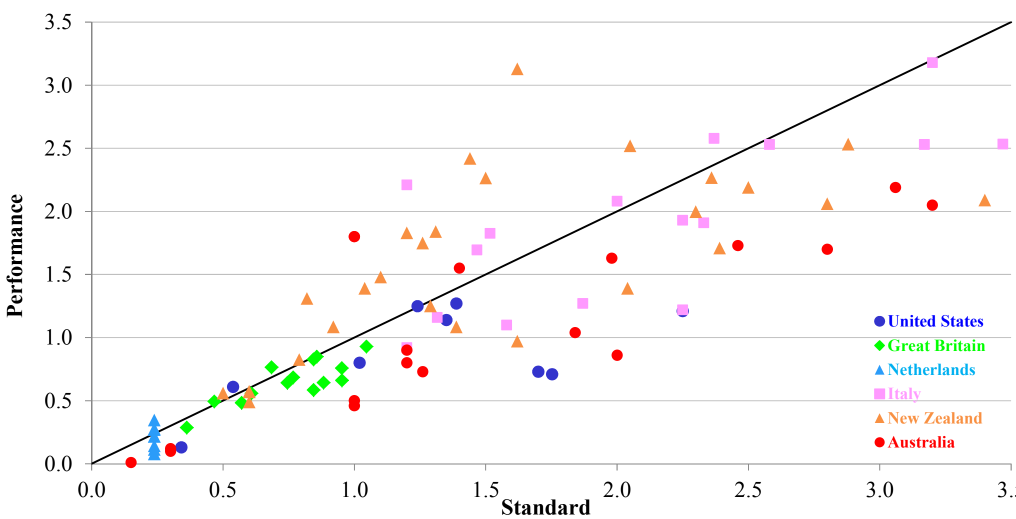


Figure 24: Comparison of Performance vs. Standards for SAIFI



411. The analyses depicted in the figures above demonstrate a relatively consistent distribution of reliability standards that generally follows a pattern of higher expected durations of service interruptions in rural areas and lower levels of expected durations in urban areas.

412. Most distributors are clustered around the 45 degree line in the figures, which indicates where performance matches standards. Standards and performance vary considerably between distributors, but the level of under- or over-performance varies less. This suggests that standards cannot be "universal", but must reflect the particular circumstances of different distributors.

413. The variation in standards combined with the relatively high levels of compliance with those suggests that the regulatory process has resulted in realistic standards (i.e., those that reflect specific distributor circumstances). The standard setting process, involving input and from numerous interested parties, likely was a key part of this.

414. Second, we examined the relationship between distributors' performance relative to their standards and the extent of their potential penalty exposure. Figure 25 presents a scatter plot of performance minus standard vs. the maximum possible financial penalty (expressed as a percentage of distributor revenue requirements) for SAIDI whilst Figure 26 shows the same comparison for SAIFI.

Figure 25: Comparison of Performance – Standards Vs. Maximum Penalty for SAIDI

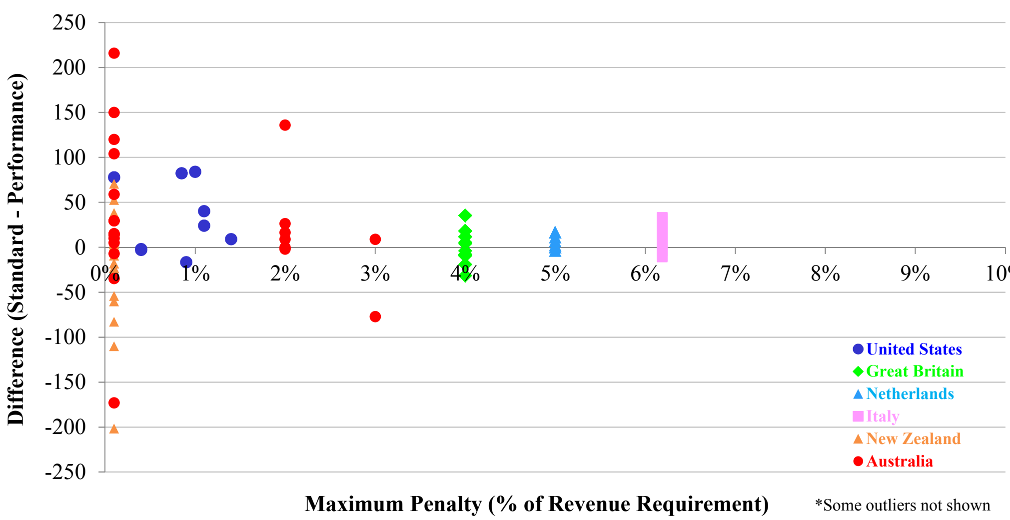


Figure 26: Comparison of Performance - Standards Vs. Maximum Penalty for SAIFI

415. Figure 25 suggests that distributors with the most to lose (i.e., the highest possible maximum penalties) tend to comply more closely with their SAIDI standards. The figure, which compares the difference between standards and performance vs. maximum possible penalties, shows a greater spread in performance when maximum penalties are comparatively low than when they are high. The distribution of observations in Figure 25 is closely aligned with jurisdictions, however, with the Netherlands having high levels of maximum penalties and commensurate reliability performance.

416. This pattern is less obvious in Figure 26 which provides a similar depiction for SAIFI, suggesting that distributors may have more control over the duration of interruptions than over their frequency. Removing the observations associated with Italy from Figure 26 brings the distribution somewhat closer to that shown in Figure 25.

417. Finally, as summarized in Figure 27 and Figure 28, we examined how SAIDI performance has changed over time to ensure that the snapshots for a single year presented above do not give a misleading picture.

Figure 27: SAIDI performance over time

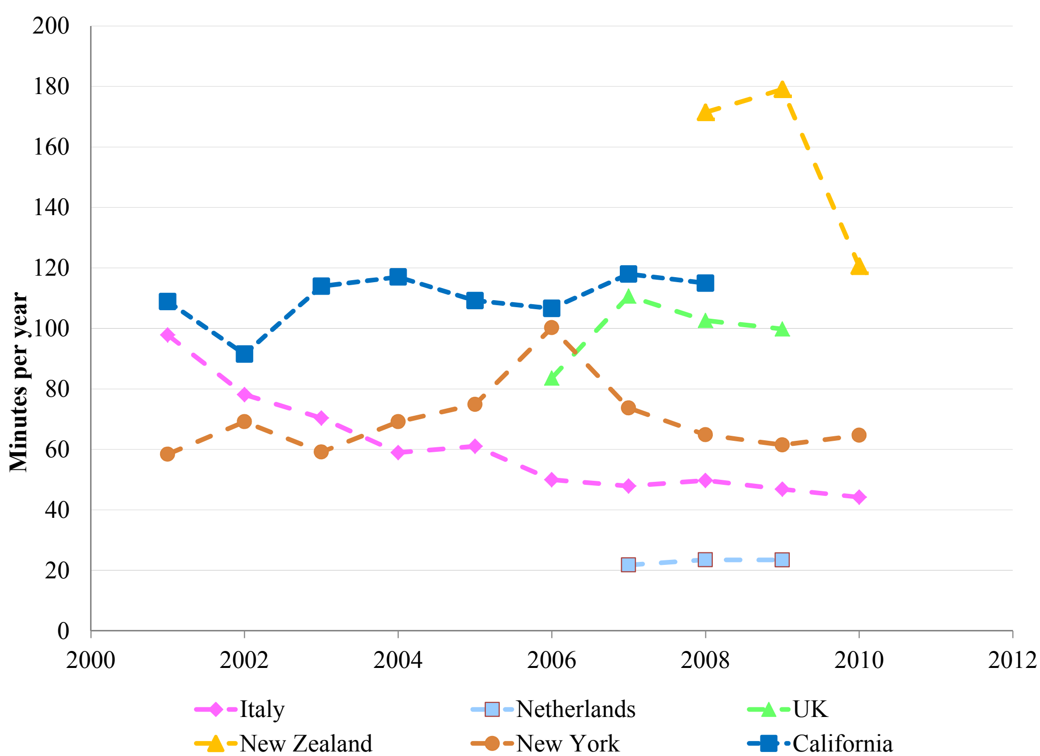
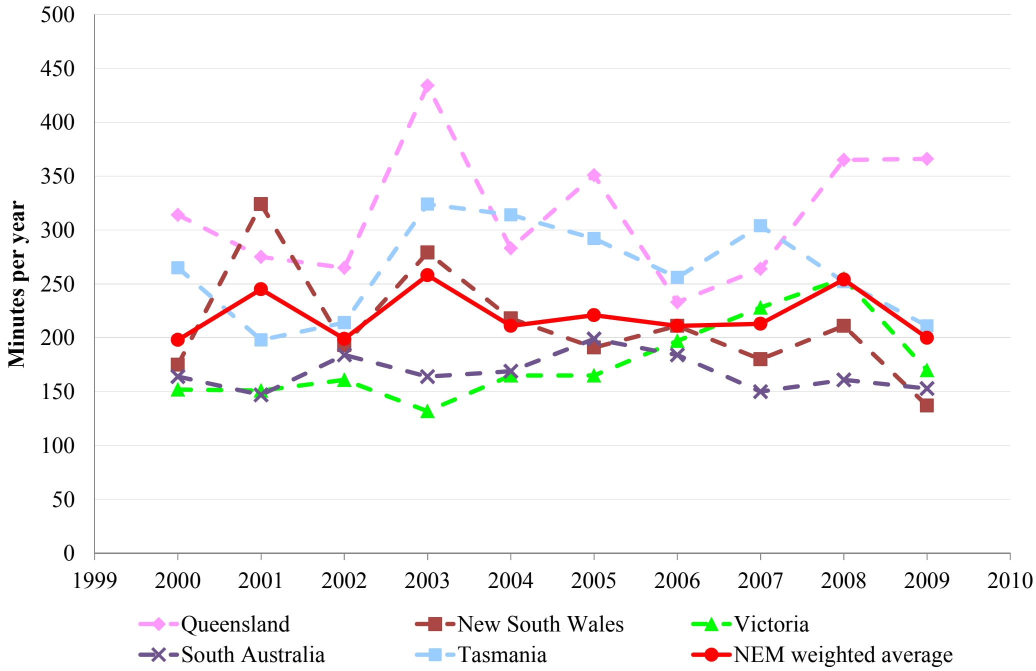


Figure 28: SAIDI performance over time in Australia



418. Country level reliability performance appears to have been reasonably stable over the past ten years, with the exception of Italy where there has been a steady improvement in reliability. Of course, there are fluctuations in performance from year to year, reflecting changing weather patterns but, in general, there appears to be limited evidence that different regulatory approaches significantly impact on reliability.

419. It is also clearly apparent that Australia[149] and New Zealand have worse levels of reliability than those seen in Europe and the US (at least for the jurisdictions we have studied). By far the best performing jurisdiction is the Netherlands, but this probably reflects the fact that its distribution systems are relatively small, cover relatively densely populated areas and are not in a region that is prone to extreme weather conditions. It is precisely these features that make it practical to implement an explicit annual

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[149] The data for Australia is an average across NEM jurisdictions. However, it includes all interruptions experienced by customers, apart from those caused by “natural disasters”.

[149] In the “Second consultation – Data and cost commentary appendix”, December 2003 published by Ofgem there are statements by the distributors regarding the investments that they have undertaken to improve faults and interruptions.

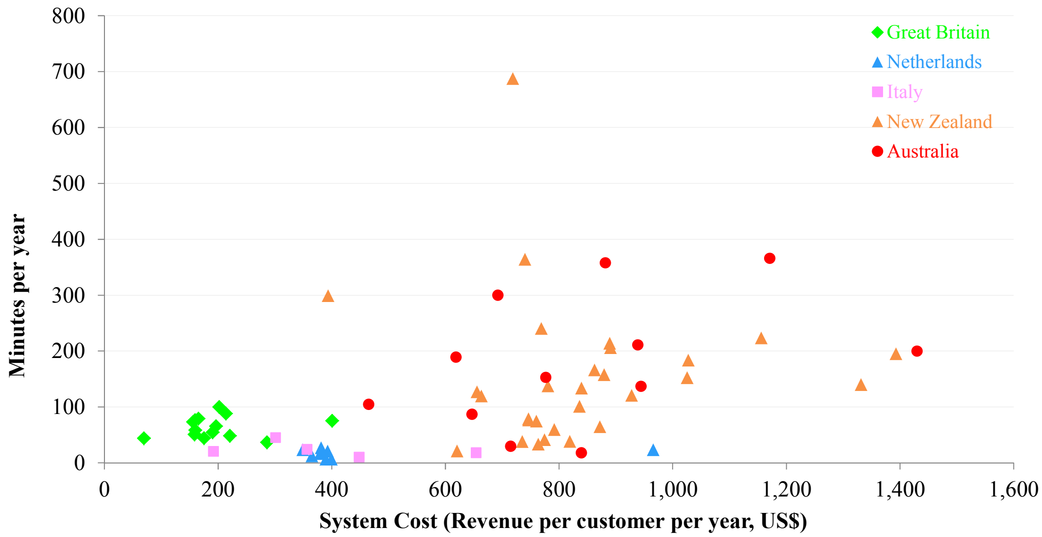
benchmarking approach to incentivising reliability. In jurisdictions with widely varying distribution system characteristics such an approach would not make sense.

12.13 Cost and Reliability

420. It is apparent that reliability performance and standards vary considerably between jurisdictions and between urban and rural areas within a single jurisdiction. For any given distributor, improving reliability will cost money. However, when comparing two distributors, it is of course likely that many other factors besides the achieved level of reliability will influence distribution costs. Nevertheless, having observed a wide range of reliability outcomes, we thought it potentially worthwhile to investigate whether there is any association between reliability and cost.

421. In Figure 29 below we plot a measure of cost (total annual distribution-related revenues divided by total customer numbers) against reliability (SAIDI). We plot data from New Zealand and Australia as well as for Great Britain, Italy and the Netherlands. Each point in Figure 29 represents either an individual distributor or an average of the distributors in a jurisdiction. The US jurisdictions (New York and California) are not included in the figure because distributors in the US do not break down revenues for distribution only. However, we presented total annual distribution spending (i.e., annual capital spending plus operation and maintenance expenses) for a panel of U.S. distributors in Figure 22. The distribution costs shown in that figure exclude depreciation of distribution assets, taxes and other expenses that are included in Figure 29. Nonetheless, it appears that the U.S. distributors would fall closer to the European distributors reviewed in terms of distribution related costs as well as durations of service interruptions than to the observations for Australian and New Zealand distributors.

Figure 29: SAIDI performance vs. cost/customer



422. No clear relationship between costs and reliability is apparent in Figure 29. If anything, it would appear that distributors with higher costs tend to have lower reliability (in our view, this is reasonable: the high cost distributors tend to be those with very low customer density systems which make it more difficult to achieve high levels of reliability).[150] However, the clearest observation is that (consistent with the US results shown in Figure 22), for the many distributors bunched around average costs, there are a very wide range of reliability outcomes. Any analysis of this kind is bound to be problematic: we expect that many factors besides reliability should influence cost, and for many distributors, reliability (and presumably cost per customer) is very heterogeneous across the system. However, with the data available to us we do not see any association between high cost and high reliability or low cost and low reliability.

[150] We would not claim anything about the relative efficiencies of the different utilities from this very simple analysis.

13 Conclusions

13.1 Australia in Comparison to the other Jurisdictions

423. Whilst Australia is generally very much in line with other jurisdictions, it differs in a number of notable respects.

424. *Governance*. Australia appears unique (compared to the other jurisdictions under review) in this regard. A single regulator usually oversees both price regulation and regulation of reliability. By contrast, in Australia, certain aspects of reliability *standards* are set by a jurisdictional regulator (or Government), whereas price controls in the NEM jurisdictions are set by the AER. Additionally, reliability *incentives* are set (or will be) by the AER. This difference seems particularly important because of the link between reliability and investment. A split in responsibilities would seem to risk inefficient outcomes: the entity setting reliability standards may need to take into account the levels of investment approved in the price control (which influence the ability of the utility to meet the standards), and the entity setting the price control may need to take into account reliability standards in order to determine the level of investment that should be allowed.

425. *Input Standards*. The regulator/Government in New South Wales (and the utilities in Queensland) appears unusual in ascribing significant importance to enforcing an input standard that requires a specified degree of redundancy in different parts of the distribution systems. Regulators in other jurisdictions rely entirely or mostly on output performance standards. Even if input standards are imposed, as in GB, they do not seem to be driving investment in the same way as in NSW.

426. *Level of Reliability*. As shown in Figure 27 and Figure 28 above, Australia at a national level has the lowest level of reliability of any of the jurisdictions studied. We recognise that the reliability data from different jurisdictions in Figure 27 and Figure 28 are not measured in a completely consistent way: different jurisdictions focus on (and publish) different reliability metrics. For example, the Australian data includes both planned and unplanned interruptions, and excludes only the most severe storm-related events, whereas the European data relates only to unplanned interruptions. Nevertheless, we would not expect these measurement differences to change the picture significantly. Our expectation is that the apparently low level of reliability in Australia is explained in part by the challenging geography and system topology. We note, for example, that standards and performance in the CBD areas in Australia are generally as good as or better than the most

reliable European distributors. Standards and performance in urban and (especially) rural areas in Australia are much lower.

13.2 Our Best Practice Recommendations

427. On the basis of the analysis that we have carried out, we have reached the following "best practice" recommendations regarding regulating reliability in Australia. It is important to note that these recommendations are not intended to be universally applicable, rather they have been specifically chosen to reflect the circumstances prevailing in Australia. To provide a complete picture, we provide an overview of best practice in most aspects of distribution regulation, which means that some of our recommendations are already implemented in Australia e.g. with respect to incentive arrangements.

428. *Reliability Reporting*. Regulation of reliability in Australia should include a requirement that distributors provide detailed reporting regarding reliability performance. Reporting on performance should be at a reasonably dis-aggregate level so that regulators can assess trends and variations across the distribution system. Detailed reporting provides regulators with a valuable look into distributor operation and performance and can highlight problems that would be hidden in more aggregated data (see discussion of worst-served customers below).

429. *Incentive Plan*. Performance reporting should be complemented by an incentive scheme with material financial implications, similar to the structure used in other jurisdictions. Performance targets should be set at a reasonably aggregate level, considerably less detailed than that required under the performance reporting requirements. While very detailed reporting (e.g., at the circuit level, especially for "worse performing" circuits) is valuable in a reporting context, especially as regulators try to understand where additional investments should be made, it is not advised that targets be set at this level within an incentive plan. Nonetheless, it is important that the incentive targets distinguish between very urban, semi-urban and rural regions.

430. *Target Setting*. Reliability performance targets should be set at realistic and achievable levels. This does not mean that targets should not provide distributors with a challenge, but setting targets that are out of touch with historic performance takes the incentive away. In other words, incentives are only effective when a distributor has a realistic chance of at least avoiding the maximum penalty.

431. It almost goes without saying that reliability standards and targets need to be set in a transparent and predictable fashion. The regulatory concerns which led to this study involve the appropriate trade-off between cost and reliability. Understanding reliability targets in the short and long term allows distributors more to fully incorporate reliability thresholds into their planning.

432. We therefore recommend developing a methodology for setting standards (probably some form of glide path) that provides distributors with long term certainty regarding the reliability targets they will have to achieve. This maximises the chance that distributors will make efficient cost versus reliability trade-offs. Incentive schemes should promote desired long-term behaviour; that is, encourage distributors to take whatever actions, including investment, are required to deliver the required reliability standards. Most systems have evolved to the point where distributors provide an overall high level of service and are trying to fine-tune their reliability-cost trade-offs. Thus far, however, there appears to be relatively little direct evidence of companies making these trade-offs,[151] although this may simply reflect the way that expenditure data are reported. On the other hand, it may indicate that the evolution of reliability standards has not been sufficiently predictable to make reliability-cost trade-offs practical.

433. *Willingness to pay studies*. In setting standards and targets, regulators should take customer WTP into account to the extent that such analysis is available. Understanding the value of reliability to customers provides important information which can be used to set the "power" of reliability incentive schemes. They can also provide the information needed to determine whether or not the allowed revenues currently in place reflect acceptable levels of reliability or if customers would be willing to pay more if reliability was enhanced. (For example, the last WTP study conducted in Great Britain found that customers' willingness to pay varied depending upon where they live.).

434. *Two-sided Incentives*. We recommend that the incentive structure should include both bonuses and penalties. Such a structure ensures that there is not a "cliff edge" effect, whereby distributors will be reluctant to invest to improve reliability when they are close to

[151] In the "Second consultation – Data and cost commentary appendix", December 2003 published by Ofgem there are statements by the distributors regarding the investments that they have undertaken to improve faults and interruptions.

their target if this could lead to higher than target reliability for which they will not be rewarded.

435. *Coordination with price controls*. Investments funded through the price control will have an impact on performance under the incentive scheme. Therefore, reliability incentive plans need to be carefully coordinated with the regulation of investments, returns and prices. This is particularly important in Australia, given the dual governance structure of distribution regulation.

436. Incentive schemes by themselves seem to work well to guard against the risk of short-term cost-cutting that can lead to reduced reliability. However, in at least one of the jurisdictions studied (California), the regulator opted to replace its annual reliability targets with an investment oriented plan. It seems likely that this decision was driven by the reluctance of distributors to undertake significant investments whose funding was entirely dependent on reliability incentive payments. Since the review of and commitment to allowing returns on investment in distribution infrastructure is an important component of the overall regulatory approach in Australia, we do not recommend that an entirely investment based approach is adopted. It seems likely that reliability can be further enhanced through the application of annual targets.

437. *Supplemental Measures*. Reliability incentive mechanisms do not address all the issues concerning reliability since they focus on average performance. This is true even if there are separate targets and incentive rates for different regions or kinds of feeders. Accordingly, we recommend including supplemental measures relating to worst-served customers and preparations for extreme weather conditions. Such measures do not have to be direct financial incentives: a requirement to publish annual distribution planning statements appears to be a useful measure for dealing with worst-served customers. We note that, at present, there are no provisions for worst-served customers in Australia in the STPIS (in NSW there are minimum standards for all feeders, and in Queensland there are reporting requirements).

438. *Input Standards*. Finally, we recommend that reliability regulation should focus on output standards. By imposing input standards, regulators risk becoming overly involved in the utility's distributor planning process. Theoretically, rigid planning standards could be counter-productive because they can prevent distributors implementing innovative approaches to improving reliability. We conclude that prescription of input standards

should be considered as a last resort, when distributors appear unable to improve reliability levels.

Annex I. Australia

Table 42: Cost and reliability data for Figure 4

State/ Territory	Company	Number of Customers [A]	Revenue Requirement (AUD $ millions, nominal) [B]		Revenue per Customer (AUD $) [C]	Revenue per Customer (US $) [D]	2009-10 SAIDI Performance [E]
ACT		164,900	$133.7	(2009-10)	$811	$839	18
New South Wales							
	Ausgrid (Energy Australia)	1,600,000	$1231.4	(2009-10)	$770	$797	-
	Endeavour (Integral) Energy	866,767	$809.9	(2009-10)	$934	$967	-
	Essential (Country) Energy	800,000	$937.9	(2009-10)	$1,172	$1,214	-
	Total NSW	*3,266,767*	*$2979.2*	*(2009-10)*	*$912*	*$944*	*137*
Queensland							
	Energex	1,298,790	$1133.1	(2010-11)	$872	$903	-
	Ergon Energy	680,095	$1105	(2010-11)	$1,625	$1,682	-
	Total QLD	*1,978,885*	*$2238.1*	*(2010-11)*	*$1,131*	*$1,171*	*366*
South Australia		812,529	$609.6	(2010-11)	$750	$777	153
Tasmania		271,750	$246.4	(2012-13)	$907	$939	211
Victoria							
	Citipower	305,000	$210.6	(2011)	$690	$715	30
	Powercor	700,000	$437.4	(2011)	$625	$647	87
	Jemena	315,000	$188.2	(2011)	$597	$618	189
	SP AusNet	608,311	$518.0	(2011)	$852	$882	358
	United Energy	630,000	$282.9	(2011)	$449	$465	105
Northern Territory		72,327	$99.9	(2009-10)	$1,381	$1,430	200
Western Australia		1,018,275	$680.9	(2011)	$669	$692	300

Sources:
[A]: Individual company 2009-2010 annual reports, except the values for Powercor, Jemena, United Energy, and Western Australia (Western Power) are sourced from the company's website (2012).
[B]: Individual state's Final Distribution Determination by AER, except for NT and WA.
[B] NT: based on: *Final Determination Networks Pricing: 2009 Regulatory Reset. Utilities Commission. March 09*
[B] WA based on page 1, column 16, row 27 from: http://www.erawa.com.au/cproot/8283/2/20100119%20AA2%20Info%20-%20Attachment%202%20-%20Revenue%20Model.pdf
[C]: [B]/[A].
[D]: [C] converted to US$ using a conversion factor of $1 US = $0.966002 AUD.
[E]: State of the Energy Market 2011. p. 68. AER. Dec. 9, 2011, except for Victoria, NT, and WA.
[E] Victoria:
Victorian Electricity Distribution Businesses Comparative Performance Report for Calendar Year 2009. Australian Energy Regulator. December 2010. p. 61, 64.
NSW and Queensland figures are averages because we only have state-wide SAIDI data.
Since there was no regional average for Northern Territory, we estimate the statewide SAIDI to be 200 after reviewing: *2009-10 Electricity Standards of Service: Summary of Power and Water Corporation Service Performance.* Utilities Commission.
Since there was no regional average for Western Australia's SAIDI, we estimate the statewide SAIDI to be 300 after reviewing table 12 of: *2009/10 Annual Performance Report Electricity Distributors.* March 2011. Economic Regulation Authority Western Australia. p. 8.

Table 43: Reliability performance statistics published by ETSA Utilities

Development Area	SAIDI	SAIFI	CAIDI
Performance from - 1/7/2010 to 31/3/2011			
Adelaide Business Area	16	0.12	114
Barossa, Mid North, Yorke Peninsula, Riverland & Murrayland	513	2.48	187
Major Metropolitan Area	192	1.55	123
Eastern Hills & Fleurieu Peninsula	374	2.86	131
Kangaroo Island	167	2.06	80
South East	208	1.35	152
Upper North & Eyre Peninsula	733	2.4	293
Performance from - 1/7/2009 to 30/6/2010			
Adelaide Business Area	1	0.02	51
Barossa, Mid North, Yorke Peninsula, Riverland & Murrayland	337	2.28	147
Major Metropolitan Area	147	1.56	96
Eastern Hills & Fleurieu Peninsula	438	3.49	125
Kangaroo Island	371	4.89	76
South East	278	2.54	109
Upper North & Eyre Peninsula	632	2.52	250
Performance from - 1/7/2008 to 30/6/2009			
Adelaide Business Area	23	0.19	117
Barossa, Mid North, Yorke Peninsula, Riverland & Murrayland	218	1.8	122
Major Metropolitan Area	113	1.21	93
Eastern Hills & Fleurieu Peninsula	316	3.03	105
Kangaroo Island	225	2.87	78
South East	219	1.83	120
Upper North & Eyre Peninsula	364	2.42	150
Performance from - 1/7/2007 to 30/6/2008			
Adelaide Business Area	16	0.13	122
Barossa, Mid North, Yorke Peninsula, Riverland & Murrayland	196	1.47	134
Major Metropolitan Area	104	1.17	89
Eastern Hills & Fleurieu Peninsula	245	2.32	106
Kangaroo Island	548	7.62	72
South East	318	2.57	124
Upper North & Eyre Peninsula	350	1.95	180

Notes and sources:
Electricity System Development Plan 2011, Issue 1.1. ETSA Utilities. Appendix A.

Table 44: Victoria reliability performance[152]

	SAIDI		SAIFI	
Utility	Target	Performance	Target	Performance
CitiPower	31.3	29.6	0.7	0.56
Jemena	75.4	86.9	1.33	1.28
Powercor	162.1	189.2	2.17	1.89
SP AusNet	179.7	357.9	2.7	2.8
United Energy	62.3	104.8	1.15	1.34

Notes and sources:
DNSPs 2009 Reliability Targets and SAIDI/SAIFI Performance (Unplanned)
Victorian Electricity Distribution Businesses Comparative Performance Report for Calendar Year 2009. Australian Energy Regulator. December 2010. p. 61, 64.
These values represent averages across the different feeder categories.

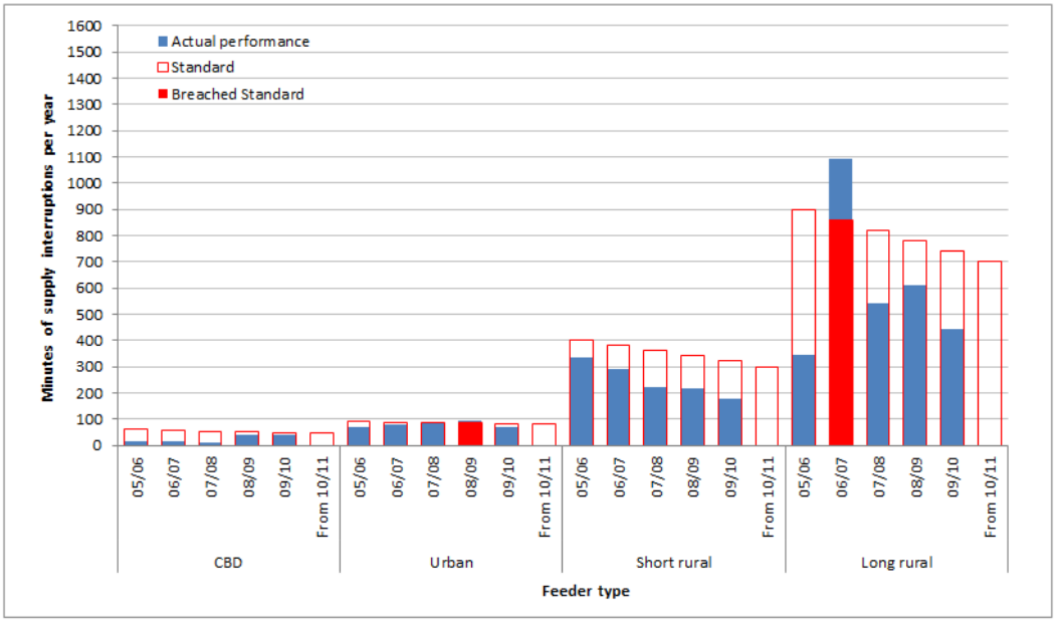
Table 45: Reliability performance in Tasmania

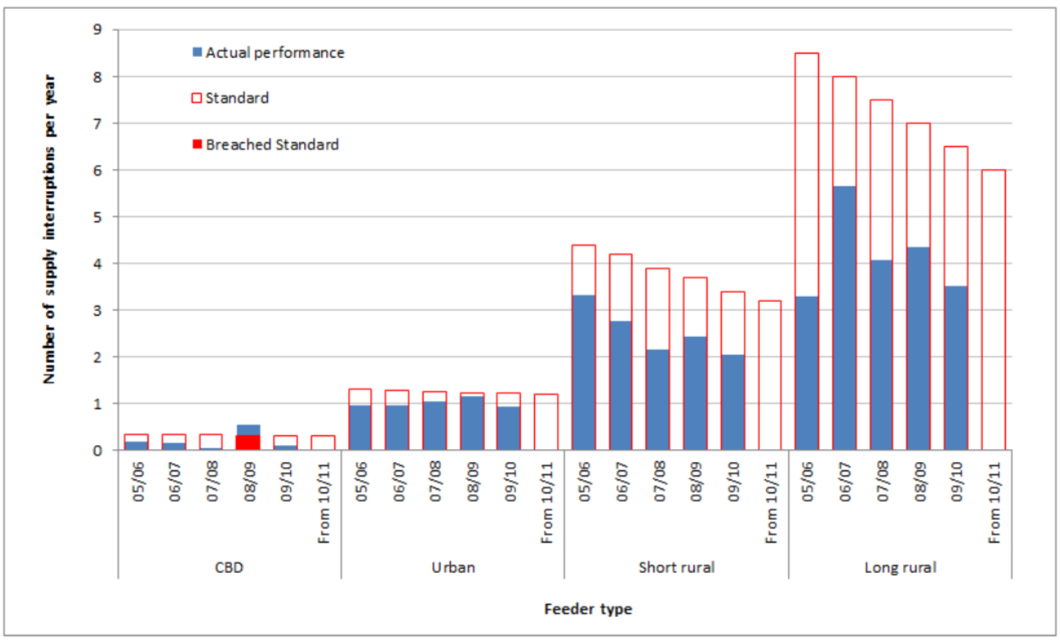
			Critical infrastructure	High density commercial	Urban and regional centres	Higher density rural	Lower density rural
SAIDI Target (minutes)	[1]		30	60	120	480	600
Actual Average percentage of SAIDI limit	[2]			75%	129%	32%	64%
Actual Average SAIDI performance	[3]	[1]x[2]		45	154.8	153.6	384
SAIFI Target (interruptions)	[4]		0.2	1	2	4	6
Actual Average % of SAIFI limit	[5]			46%	43%	28%	31%
Actual Average SAIFI performance	[6]	[4]x[5]		0.46	0.86	1.12	1.86

Notes and sources:
Aurora Energy distribution network 09/10 performance and issues. Otter 2010 Reliability Review Workshop. 19 October 2010. p. 3.

152 We were unable to find performance data for Victoria measured against the STPIS targets described above. The data in Table 9 is an average figure for each system (Table 9 also shows an equivalent average of the standards for each system which were in force under the ESC incentive scheme in force in 2009).

Figure 30: Reliability performance for Ausgrid[153]





153 Reproduced from the AEMC's NSW issues paper *Review of Distribution Reliability Outcomes and Standards*.

Figure 31: Reliability performance for Endeavour Energy[154]

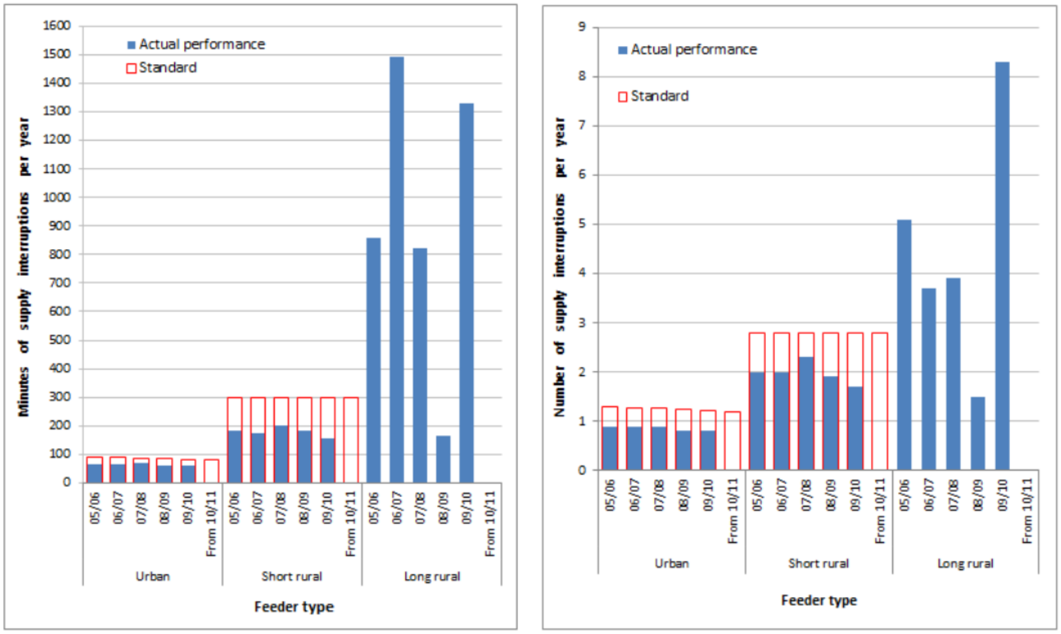
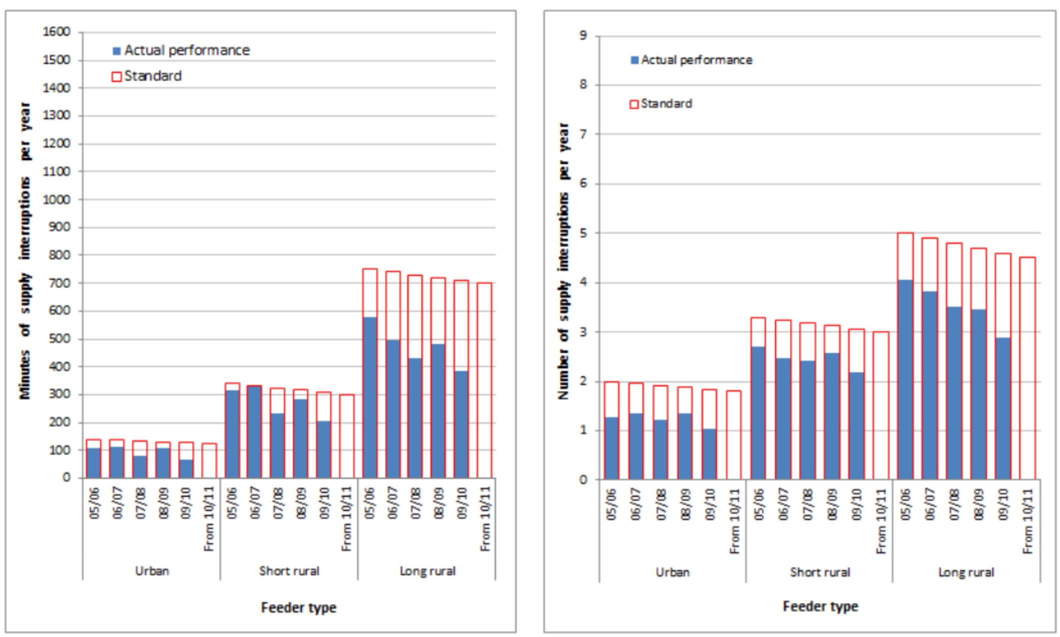


Figure 32: Reliability performance for Essential Energy[155]



[154] Reproduced from the AEMC's NSW issues paper *Review of Distribution Reliability Outcomes and Standards*.

[155] Reproduced from the AEMC's NSW issues paper *Review of Distribution Reliability Outcomes and Standards*.

Table 46: Reliability performance in the ACT[156]

	2004-05	2005-06	2006-07	2007-08
SAIDI (average minutes per customer per year without power)				
Urban	28.6	45.5	30.7	26.2
Rural	93.5	42.9	70.7	10.5
Network total	31.0	44.1	32.2	25.6
SAIFI (average number interruptions per customer per year)				
Urban	0.5	0.8	0.6	0.5
Rural	2.2	2.9	0.6	1.8
Network total	0.6	0.8	0.6	0.6
CAIFI (average duration in minutes per interruption)				
Urban	52.7	59.8	52.3	51.0
Rural	43.3	15.0	113.5	5.9
Network total	51.5	55.1	54.7	45.7

Notes and sources:
Data from Independent Competition and Regulatory Commission, 'Licensed Electricity Gas and Water and Sewerage Utilities, Compliance and Performance Report for 2007-08', June 2009, Table 5.9.

156 Unplanned interruptions, performance indices, electricity distribution, Actew AGL Distribution, 2004-05 to 2007-08.

Table 47: Energex reliability performance

	2006-07 [A] Actual	2007-08 [B] Actual	2008-09 [C] Actual	2009-10 [D] Actual	2010-11 [E] Actual	2010/11 [F] MMS
SAIDI (minutes)						
CBD	0.0	4.0	3.1	1.2	6.0	15.0
Urban	80.0	85.0	91.2	88.5	79.7	106.0
Short Rural	203.0	242.0	228.0	216.0	201.6	218.0
SAIFI (outages)						
CBD	0.00	0.04	0.60	0.08	0.01	0.15
Urban	1.00	1.05	1.05	1.20	0.73	1.26
Short Rural	2.33	2.71	2.56	2.41	1.73	2.46

Notes and sources:
Normalised reliability performance.
Data from ENERGEX Network Management Plan 2011/12 to 2015/16 Final Part.
MSS stands for "Minimum Service Standards", the standards set out in the code.

Table 48: Ergon Energy reliability performance

	2006-07	2007-08	2008-09	2009-10	2010-11
Urban					
Planned	52	51	66	76	25
Unplanned	120	146	145	146	124
2009/10 Est. LLW Cont				35	
MSS	205	195	180	197	149
Short Rural					
Planned	162	125	199	139	77
Unplanned	296	377	421	346	349
2009/10 Est. LLW Cont				58	
MSS	570	550	500	430	424
Long Rural					
Planned	292	245	338	319	147
Unplanned	669	741	752	680	680
2009/10 Est. LLW Cont				72	
MSS	1,130	1,090	1,040	980	964

Notes and sources:
Data from Ergon Energy, 'Network Management Plan Part A: Electricity Supply for Regional Queensland 2011/12 to 2015/16', Table 16
Data represents the comparison of SAIDI (5 years historical planned and unplanned performance) with MSS.
MSS stands for "Minimum Service Standards", the standards set out in the code.

Table 49: Reliability performance in Western Australia (2007-10)

	Perth CBD	Urban	Rural
SAIDI (minutes)	37	333	679
SAIFI (outages)	0.3	2.8	4.9

Sources:

Based on figures in *2009/10 Annual Performance Report Electricity Distributors*. March 2011. Economic Regulation Authority Western Australia.

Table 50: Reliability performance in the Northern Territory

	Darwin	Katherine	Alice Springs	Tennant Creek
SAIDI (minutes)				
Due to Generation	61.2	10.4	23.4	31.2
Due to Networks	196.2	201.5	208.4	157.5
Due to Major Event	237.6	-	-	-
Total	494.9	211.9	231.9	188.7
SAIFI (outages)				
Due to Generation	2.3	1.0	1.8	1.0
Due to Networks	4.0	5.5	3.7	6.5
Due to System Black	0.8	-	-	-
Total	7.1	6.6	5.5	7.6

Notes and sources:

2009-10 Electricity Standards of Service: Summary of Power and Water Corporation Service Performance. Utilities Commission. p. 1-5.

Annex II. New Zealand

Table 51: Characteristics of the New Zealand Distributors

	Total Circuit Length Underground (km)	Total Circuit Length (km)	Proportion of Circuit Underground	Maximum System Demand	Electricity Supplied (GWh)	Number of Connection Points	Company type
Alpine Energy Limited	651	4,106	16%	123	727	30,615	Privately-owned
Aurora Energy	1,709	5,600	31%	285	1,280	81,573	Privately-owned
Buller Electricity	32	617	5%	9	48	4,422	Consumer-owned
Centralines Limited	96	1,837	5%	20	108	7,976	Privately-owned
Counties Power	584	3,022	19%	96	476	36,447	Consumer-owned
Eastland Network	382	3,662	10%	57	280	25,432	Privately-owned
Electra Limited	958	2,577	37%	94	416	42,204	Consumer-owned
Electricity Ashburton	396	2,933	14%	138	529	17,452	Privately-owned
Electricity Invercargill	594	653	91%	63	275	17,198	Privately-owned
Horizon Energy Distribution	438	2,359	19%	88	541	24,504	Privately-owned
Mainpower New Zealand	707	4,518	16%	89	516	33,793	Consumer-owned
Marlborough Lines Limited	454	3,334	14%	72	368	24,073	Consumer-owned
Nelson Electricity Limited	216	248	87%	34	147	9,008	Privately-owned
Network Tasman Limited	785	3,348	23%	146	579	36,219	Privately-owned
Network Waitaki Limited	83	1,714	5%	51	241	12,257	Consumer-owned
Northpower Limited	825	5,829	14%	150	950	53,706	Consumer-owned
Orion New Zealand	4,885	10,708	46%	616	3,278	192,179	Privately-owned
OtagoNet Joint Venture	39	4,387	1%	61	385	14,768	Privately-owned
Powerco Limited	7,420	30,035	25%	813	4,295	317,489	Privately-owned
Scanpower Limited	61	905	7%	17	83	6,786	Consumer-owned
The Lines Company	285	4,491	6%	64	311	24,435	Privately-owned
The Power Company	314	8,603	4%	130	669	34,050	Consumer-owned
Top Energy Limited	787	3,846	20%	63	328	30,824	Privately-owned
Unison Networks	3,700	9,571	39%	319	1,599	108,212	Privately-owned
Vector Lines Limited	9,126	17,631	52%	1,775	8,311	527,096	Privately-owned
Waipa Networks Limited	340	2,072	16%	67	338	23,176	Consumer-owned
WEL Networks	1,802	5,043	36%	263	1,165	84,276	Consumer-owned
Wellington Electricity Demand	2,838	4,610	62%	565	2,504	164,058	Privately-owned
Westpower Limited	154	2,130	7%	53	294	12,782	Consumer-owned

Notes and sources:
Information Disclosure Requirements Database (for the periods ending 31 March 2008, 2009 and 2010).
Commerce Commission website

Table 52: SAIDI performance and targets

Company	2008 Target	2008 Reliability	2009 Target	2009 Reliability	2010 Target	2010 Reliability
Nelson Electricity Limited	30	12	30	87	30	25
Electricity Invercargill	35	55	35	33	29	27
Wellington Electricity Demand	-	-	40	26	34	38
Scanpower Limited	45	44	45	19	45	36
Mainpower New Zealand	48	49	47	80	47	65
Network Waitaki Limited	50	71	50	59	50	50
Counties Power	70	149	15	145	70	66
Orion New Zealand	55	35	55	40	48	40
Electricity Ashburton	57	92	57	248	57	80
Alpine Energy Limited	66	87	66	118	66	268
Electra Limited	67	76	66	662	76	159
Aurora Energy	73	116	72	59	71	61
WEL Networks	77	77	77	82	69	65
Network Tasman Limited	81	112	79	215	77	86
Northpower Limited	85	761	87	227	87	105
Horizon Energy Distribution	100	117	100	122	100	123
Westpower Limited	95	106	90	339	115	225
Vector Lines Limited	99	196	100	149	110	57
Centralines Limited	115	107	103	133	101	64
Unison Networks	115	79	115	78	90	73
Buller Electricity	86	152	120	151	145	155
The Power Company	128	254	117	165	106	132
Marlborough Lines Limited	120	165	120	154	120	180
Powerco Limited	130	293	130	244	130	184
OtagoNet Joint Venture	136	315	136	107	158	164
Waipa Networks Limited	157	103	155	195	154	84
The Lines Company	203	186	202	227	202	204
Eastland Network	242	213	242	190	242	239
Top Energy Limited	809	782	384	841	478	440

Notes and sources:
Class C Reliability and Targets.

Table 53: SAIFI performance and targets

Company	2008		2009		2010	
	Target	Reliability	Target	Reliability	Target	Reliability
Nelson Electricity Limited	0.60	0.16	0.60	1.68	0.60	0.58
Electricity Invercargill	0.95	1.15	0.95	0.84	0.79	0.83
Wellington Electricity Demand	-	-	0.52	0.38	0.50	0.56
Scanpower Limited	0.60	1.17	0.60	0.77	0.60	0.57
Mainpower New Zealand	0.85	0.97	0.82	1.06	0.82	1.31
Network Waitaki Limited	1.04	1.97	1.04	1.00	1.04	1.39
Counties Power	2.30	2.09	0.15	3.47	2.30	2.00
Orion New Zealand	0.67	0.59	0.67	0.52	0.60	0.49
Electricity Ashburton	0.92	1.13	0.92	1.96	0.92	1.08
Alpine Energy Limited	1.20	1.38	1.20	1.33	1.20	1.83
Electra Limited	1.62	1.45	1.56	2.86	1.62	3.13
Aurora Energy	1.33	1.37	1.31	1.17	1.29	1.25
WEL Networks	1.49	1.39	1.54	1.62	1.39	1.08
Network Tasman Limited	1.16	1.33	1.13	1.53	1.10	1.48
Northpower Limited	2.50	4.47	2.50	3.07	2.50	2.19
Horizon Energy Distribution	1.50	1.42	1.50	2.16	1.50	2.26
Westpower Limited	1.27	1.18	1.18	2.90	1.31	1.84
Vector Lines Limited	1.56	1.47	1.56	1.65	1.62	0.97
Centralines Limited	3.33	2.53	2.80	4.67	2.80	2.06
Unison Networks	2.19	1.74	2.19	1.82	2.04	1.39
Buller Electricity	1.23	1.68	1.12	1.12	1.26	1.75
The Power Company	2.42	3.48	2.82	3.83	2.88	2.53
Marlborough Lines Limited	2.40	2.42	1.44	1.64	1.44	2.42
Powerco Limited	2.36	2.30	2.36	2.55	2.36	2.27
OtagoNet Joint Venture	1.81	2.29	1.81	2.08	2.05	2.52
Waipa Networks Limited	2.42	1.83	2.41	2.33	2.39	1.71
The Lines Company	3.40	2.97	3.40	3.45	3.40	2.09
Eastland Network	3.80	3.68	3.80	3.02	3.80	2.95
Top Energy Limited	9.90	6.05	5.28	10.28	6.13	4.04

Notes and sources:
Class C Reliability and Targets.

Annex III. Great Britain

Table 54: Targets for customer interruptions

Network	2010/11	2011/12	2012/13	2013/14	2014/15
CN West	109.9	109.9	109.9	109.9	109.9
CN East	75.7	75.7	75.7	75.7	75.7
ENW	52.9	52.7	52.5	52.4	52.2
CE NEDL	68.3	68.2	68.2	68.1	68.1
CE YEDL	75.3	75.3	75.3	75.3	75.3
WPD S Wales	79.5	79.5	79.5	79.5	79.5
WPD S West	73.6	73.6	73.6	73.6	73.6
EDFE LPN	33.4	33.4	33.4	33.4	33.4
EDFE SPN	85	84.2	83.3	82.5	81.7
EDFE EPN	76.1	75.9	75.7	75.5	75.4
SP Distribution	60.1	60.1	60.1	60.1	60.1
SP Manweb	45.6	45.5	45.3	45.1	44.9
SSE Hydro	77	77	77	77	77
SSE Southern	73.8	73.2	72.6	72	71.4
Min	33.4	33.4	33.4	33.4	33.4
Max	109.9	109.9	109.9	109.9	109.9
Average	70.4	70.3	70.2	70.0	69.9

Notes and sources:

Ofgem "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009, p.86.

Table 55: Targets for customer minutes lost (min)

Network	2010/11	2011/12	2012/13	2013/14	2014/15
CN West	97.0	96.3	95.6	94.9	94.2
CN East	69.0	68.6	68.2	67.8	67.4
ENW	55.6	55.6	55.6	55.6	55.6
CE NEDL	71.3	71.1	70.9	70.7	70.6
CE YEDL	76.0	76.0	76.0	76.0	76.0
WPD S Wales	44.6	44.6	44.6	44.6	44.6
WPD S West	51.0	51.0	51.0	51.0	51.0
EDFE LPN	41.0	41.0	41.0	41.0	41.0
EDFE SPN	87.6	82.9	78.1	78.3	68.5
EDFE EPN	71.1	69.7	68.3	66.8	65.4
SP Distribution	65.5	63.5	61.5	59.5	57.5
SP Manweb	61.1	60.6	60.1	59.6	59.1
SSE Hydro	75.1	75.1	75.1	75.1	75.1
SSE Southern	69.1	68.3	67.5	66.6	65.8
Min	41.0	41.0	41.0	41.0	41.0
Max	97.0	96.3	95.6	94.9	94.2
Average	66.8	66.0	65.3	64.8	63.7

Notes and sources:

Ofgem "Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations", Ref: 145/09, 7 December 2009, p.87.

Table 56: Incentive rates (£ mn)

Network	CI	CML
CN West	0.11	0.4
CN East	0.12	0.42
ENW	0.11	0.56
CE NEDL	0.07	0.26
CE YEDL	0.1	0.37
WPD S Wales	0.09	0.18
WPD S West	0.07	0.25
EDFE LPN	0.3	0.34
EDFE SPN	0.1	0.36
EDFE EPN	0.16	0.57
SP Distribution	0.09	0.33
SP Manweb	0.07	0.21
SSE Hydro	0.03	0.15
SSE Southern	0.13	0.47
Min	0.03	0.15
Max	0.3	0.57
Average	0.1	0.3

Notes and sources:

Ofgem “Electricity Distribution Price Control Review; Final Proposals – Incentives and Obligations”, Ref: 145/09, 7 December 2009, p.88.

Table 57: Distributor Payments Under Each Guaranteed Standard (GS1, GS2 and GS2A)

Distributor	No. payments 2008/09	Payments (£) 2008/09	No. payments 2009/10	Payments (£) 2009/10
GS1				
Central Networks – East	3	60	11	220
Central Networks – West	2	40	6	120
CE Electric – NEDL	3	60	3	60
CE Electric – YEDL	3	60	5	100
EDF Energy Networks (EPN) plc	76	1,520	82	1,640
EDF Energy Networks (LPN) plc	34	680	28	560
EDF Energy Networks (SPN) plc	138	2,760	91	1,820
Scottish and Southern Energy Power Distribution	7	140	10	200
Scottish Hydro Electric Power Distribution	1	20	0	0
SP Distribution	1	20	2	40
SP Manweb	5	100	0	0
WPD South Wales	1	20	0	0
WPD South West	1	20	1	20
GS2				
ENWL	308	15,675	258	12,425
CE Electric – NEDL	295	14,850	160	7,875
CE Electric – YEDL	36	1,975	35	1,925
EDF Energy Networks (EPN) plc	9,592	470,925	7,636	356,825
EDF Energy Networks (LPN) plc	1,712	80,725	1,821	95,250
EDF Energy Networks (SPN) plc	5,120	235,075	3,898	182,575
Scottish and Southern Energy Power Distribution	0	0	2	100
SP Distribution	4	175	0	0
SP Manweb	2	75	0	0
GS2A				
Central Networks – West	1	50	0	0
ENWL	2	100	11	550
CE Electric – NEDL	21	1,050	24	1,200
CE Electric – YEDL	41	2,050	5	250
EDF Energy Networks (EPN) plc	141	7,050	213	10,650
EDF Energy Networks (LPN) plc	267	13,350	105	5,250
EDF Energy Networks (SPN) plc	285	14,250	745	37,250
Scottish Hydro Electric Power Distribution	1	50	0	0
SP Distribution	41	2,050	2	100
SP Manweb	1	50	0	0

Notes and sources:
From Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10".
We have not shown dsitributors who did not payments.

Table 58: Distributor Payments Under Each Guaranteed Standard (GS4, GS5, GS8 and GS9)

Distributor	No. payments 2008/09	Payments (£) 2008/09	No. payments 2009/10	Payments (£) 2009/10
GS4				
ENWL	105	2,300	109	2,640
CE Electric –NEDL	173	3,880	147	3,480
CE Electric –YEDL	112	2,820	113	2,720
EDF Energy Networks (EPN) plc	275	6,380	591	12,300
EDF Energy Networks (LPN) plc	12	280	19	580
EDF Energy Networks (SPN) plc	322	7,200	354	8,160
Scottish and Southern Energy Power Distribution	0	0	3	60
SP Distribution	2	40	0	0
SP Manweb	4	80	1	20
GS5				
CE Electric – NEDL	1	20	0	0
CE Electric – YEDL	4	80	5	100
EDF Energy Networks (EPN) plc	0	0	0	0
EDF Energy Networks (LPN) plc	0	0	4	80
SP Distribution	1	20	0	0
GS8				
Central Networks –East	0	0	3	60
Central Networks –West	2	40	12	240
ENWL	2	40	2	40
CE Electric –NEDL	20	400	5	100
CE Electric –YEDL	17	340	13	260
EDF Energy Networks (EPN) plc	67	1,340	58	1,160
EDF Energy Networks (LPN) plc	12	240	50	1,000
EDF Energy Networks (SPN) plc	32	640	137	2,740
SP Manweb	5	100	0	0
GS9				
ENWL	6	120	19	380
CE Electric – NEDL	7	140	3	60
CE Electric – YEDL	12	240	7	140
EDF Energy Networks (EPN) plc	84	1,680	35	700
EDF Energy Networks (LPN) plc	51	1,020	80	1,600
EDF Energy Networks (SPN) plc	54	1,080	30	600
Scottish and Southern Energy Power Distribution	3	60	2	40
SP Distribution	1	20	1	20
WPD South West	0	0	3	60

Notes and sources:
From Consumer Focus publication "Guaranteed Standards of Electricity Distribution 2009/10".
We have not shown dsitributors who did not payments.

Table 59: Fault level investments

System	Fault level investment		Total investment		Fault investment %	
	DCPR4 Actual	DCPR5 Baseline	DCPR4 Actual	DCPR5 Baseline	DCPR4 Actual	DCPR5 Baseline
CN West	0.0	19.6	512.0	597	0.0%	3.3%
CN East	13.9	9.4	492	606	2.8%	1.6%
ENW	4.8	2.5	431	554	1.1%	0.5%
CE NEDL	1.0	8.9	271	378	0.4%	2.4%
CE YEDL	2.7	14.1	352	508	0.8%	2.8%
WPD S Wales	0.0	0.7	155	224	0.0%	0.3%
WPD S West	0.0	2.9	249	339	0.0%	0.9%
EDFE LPN	4.1	1.3	400	493	1.0%	0.3%
EDFE SPN	0.6	3.0	387	520	0.2%	0.6%
EDFE EPN	2.8	25.1	634	657	0.4%	3.8%
SP Distribution	1.1	17.3	348	384	0.3%	4.5%
SP Manweb	5.9	14.7	381	547	1.5%	2.7%
SSE Hydro	0.1	2.0	174	207	0.1%	1.0%
SSE Southern	1.2	4.3	515	644	0.2%	0.7%
Overall	38.2	125.8	5,301	6,658	0.6%	1.8%

Notes and sources:
From Ofgem “Electricity Distribution Price Control Review, Initial Proposals – Allowed revenue – Cost assessment” Ref: 94a/09, 3 August 2009, from p. 38 onwards.
Values in £ mn, 2007/08 prices.
CN West forecast £6.1 m higher costs than allowed in baseline.
EDF EPN forecast £3.2 m higher costs than allowed in baseline.

Annex IV. Italy

Table 60: Specific tariff charge payments by medium voltage customers (€ mn)

	2007	2008	2009	2010
Collected by distribution companies	12.8	45.2	62.5	54.6
Remains with distribution companies	5.2	5.4	5.5	5.3
To the electricity sector compensation fund	7.6	39.8	57.0	49.3

Notes and sources:
From Table 2.59, AEEG AR 2011 'Relazione Annuale sullo Stato dei Servizi e sull'Attività svolta', 31st March 2011.

Table 61: Supply restoration targets (hours)

District type	Low voltage		Medium voltage	
	Pre-arranged	Unexepected	Pre-arranged	Unexepected
Rural	16	8	8	8
Semi-urban	12	8	6	8
Urban	8	8	4	8

Notes and sources:
From Article 44, Annex A, Resolution 333/07.

Annex V. The Netherlands

Table 62: Examples of Methodology Used by NMa to Calculate q-factors

			COGAS	DNWB	Total/ Average
Number of conenctions in Netherlands					
% Domestic	[1]	Input	88%		
% Non-domestic	[2]	Input	12%		
Inflation between years below and 2010					
2007	[3]	Input	4.6%		
2008	[4]	Input	3.5%		
2009	[5]	Input	0.3%		
Inputs					
Allowed Revenue in 2010	[6]	Input	16,416,592	60,784,311	
x-factor 2011-2013	[7]	Input	-3.4	-6.6	
2007					
CAIDI	[8]	See note	84.08	71.02	
SAIFI (corrected)	[9]	See note	0.355	0.228	
Value (domestic)	[10]	See note	-3.96	-2.08	
Value (non-domestic)	[11]	See note	-44.71	-27.93	
Quality performance	[12]	[10]x[1]+[11]x[2]	-8.85	-5.19	-6.10
# Customers	[13]	Input	51,373	198,003	7,580,286
Q-amount	[14]	([12]-[12]ave)x[13]	-141,409	180,469	0
2008					
CAIDI	[15]	See note	103.42	56.09	
SAIFI (corrected)	[16]	See note	0.055	0.332	
Value (domestic)	[17]	See note	11.32	-2.80	
Value (non-domestic)	[18]	See note	77.43	-32.86	
Quality performance	[19]	[17]x[1]+[18]x[2]	19.25	-6.40	-5.95
# Customers	[20]	Input	51,839	202,081	7,744,419
Q-amount	[21]	([19]-[19]ave)x[20]	1,306,796	-91,082	0
2009					
CAIDI	[22]	See note	56.95	60.49	
SAIFI (corrected)	[23]	See note	0.113	0.271	
Value (domestic)	[24]	See note	10.46	-2.42	
Value (non-domestic)	[25]	See note	-7.59	-29.52	
Quality performance	[26]	[24]x[1]+[25]x[2]	8.29	-5.67	-6.59
# Customers	[27]	Input	52,323	203,848	7,767,225
Q-amount	[28]	([26]-[26]ave)x[27]	778,744	187,320	0
Q-factor calculation					
Total Q-amount (in 2010 value)	[29]	[14]x(1+[3])+[21]x(1+[4])+[28]x(1+[5])	1,985,757	282,460	
2/3 Q-amount	[30]	[29]x2/3	1,323,838	188,307	
(Rev - x + 2/3 Q-amount)	[31]	[6]x(1-[7]/100)+[6]x (1-[7]/100)^2+[6]x(1-[7]/100)^3+[30]	53,999,154	207,688,407	
(Rev - x + q)	[32]	[6]x(1-[7]/100+[34]/100)+[6]x (1-[7]/100+[34]/100)^2+[6]x (1-[7]/100+[34]/100)^3	53,999,154	207,688,407	
Difference	[33]	[31]-[32]	0	0	
q-factor (not rounded)	[34]	Set so that [33]=0	1.27	0.05	
q-factor (rounded to 2dp)	[35]		**1.28**	**0.05**	

Notes and sources:

Based on calculations provided by NMa on its website.

[8],[9],[15],[16],[22],[23]: Actual performance of companies in each year.

[10],[11],[17],[18],[24],[25]: Value of quality calculated from cost functions based on the interruption measurements in [8],[9],[15],[16],[22],[23].

[12],[19],[26]: Quality of performance is average of the domestic and non-domestic values weighted by [1] and [2]. The average is weighted by the number of customers.

[14],[21],[28]: Q-amount is the difference between the quality performance of the company and the average quality performance, multiplied by the number of customers.

[31]: Amount that companies can recover in next regulatory period.

[31]: Amount that companies can recover in next regulatory period. Used to calculate q-factor that is equivalent to [30].

Figure 33: Cogas average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[157]

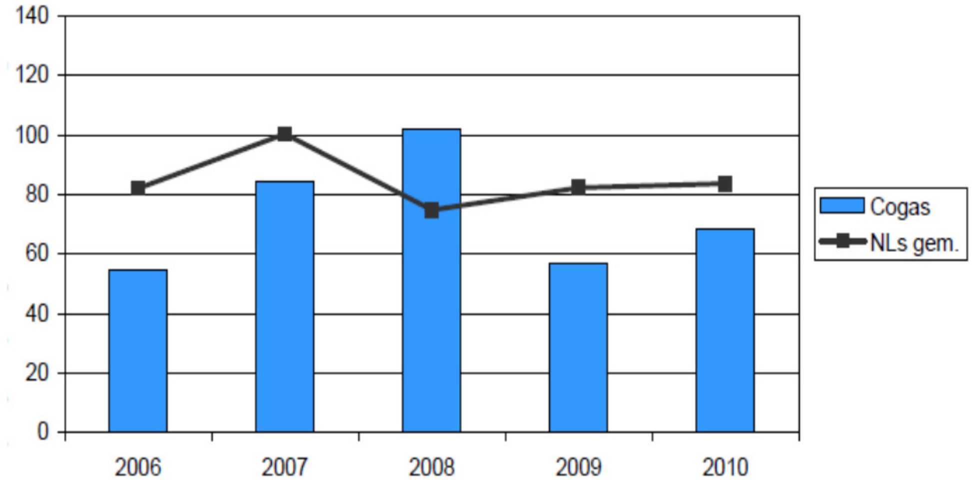
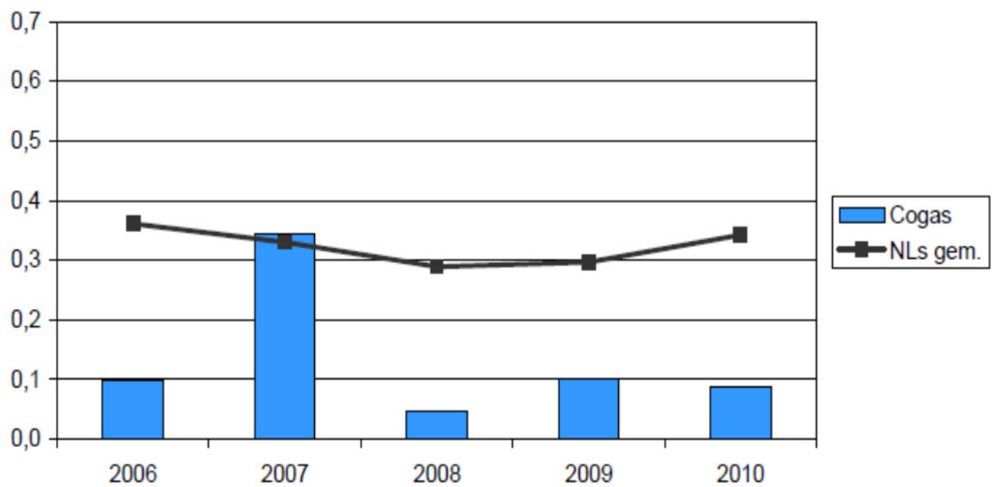


Figure 34: Cogas frequency of unplanned interruptions (NLS gem.=average for Netherlands)[158]



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[157] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Cogas Infra & Beheer B.V.".

[158] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Cogas Infra & Beheer B.V.".

Figure 35: Delta Netwerkbedrijf average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[159]

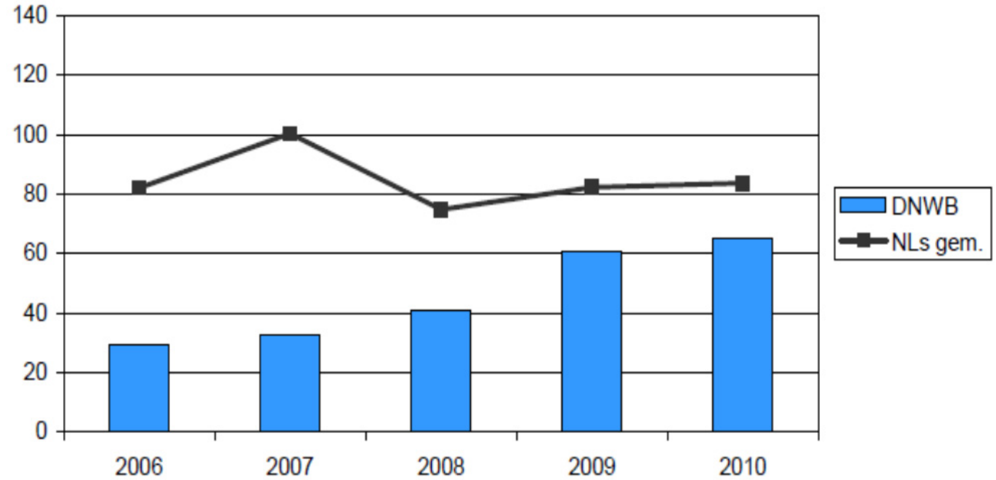
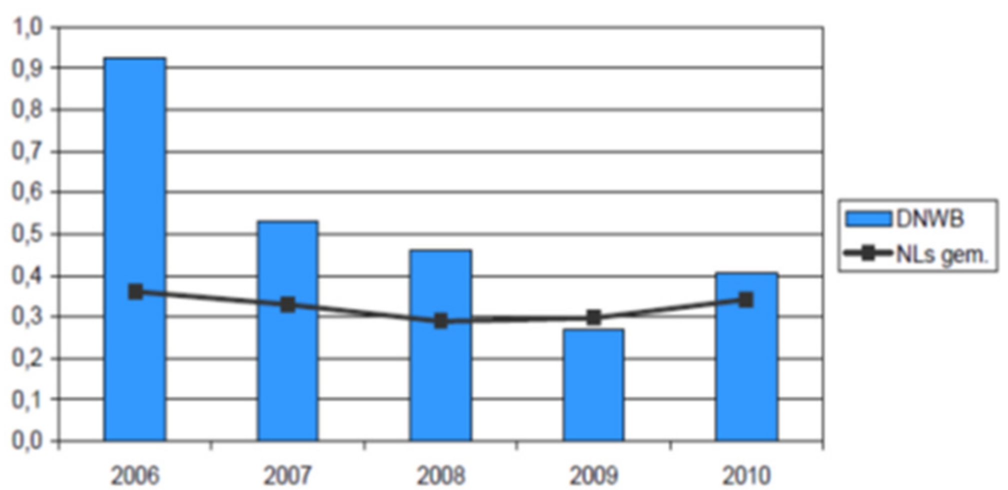


Figure 36: Delta Netwerkbedrijf frequency of unplanned interruptions (NLS gem.=average for Netherlands)[160]



159 From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Delta Netwerkbedrijf B.V."

160 From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Delta Netwerkbedrijf B.V."

Figure 37: Endinet average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[161]

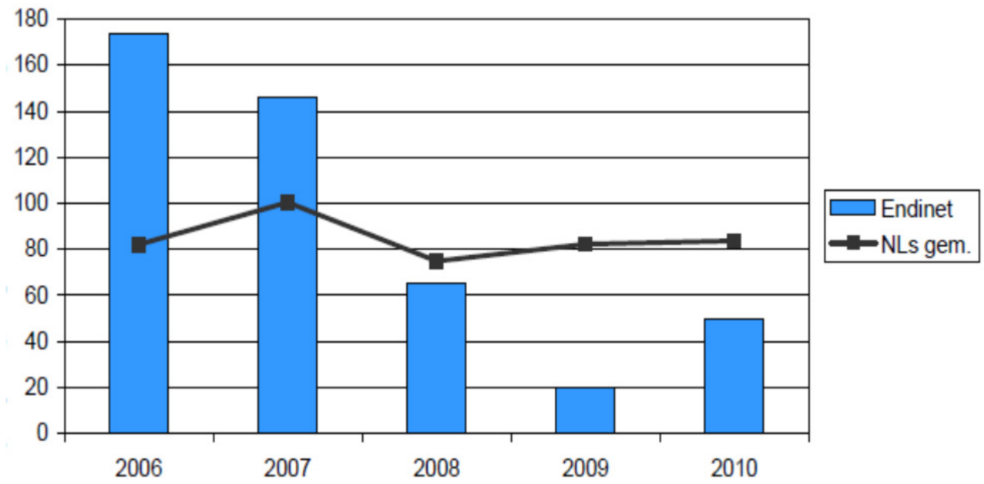
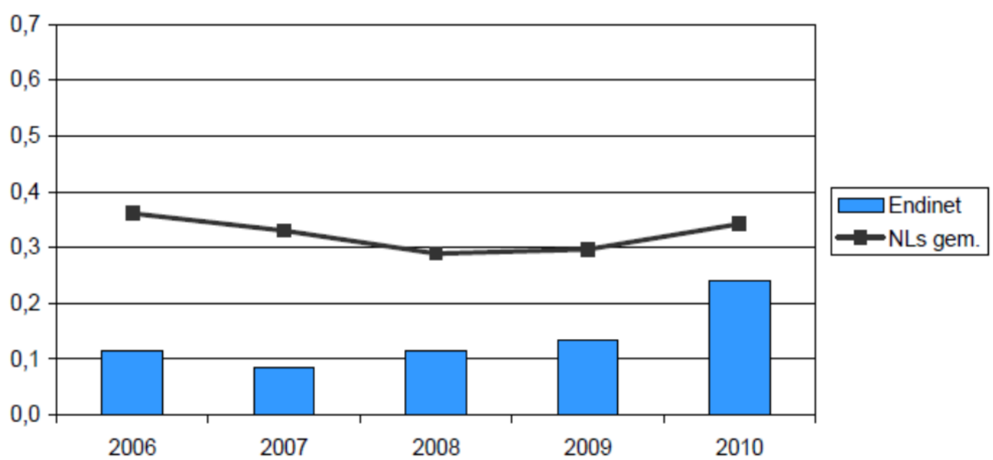


Figure 38: Endinet frequency of unplanned interruptions (NLS gem.=average for Netherlands)[162]



[161] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Endinet B.V.".

[162] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Endinet B.V.".

Figure 39: Enexis average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[163]

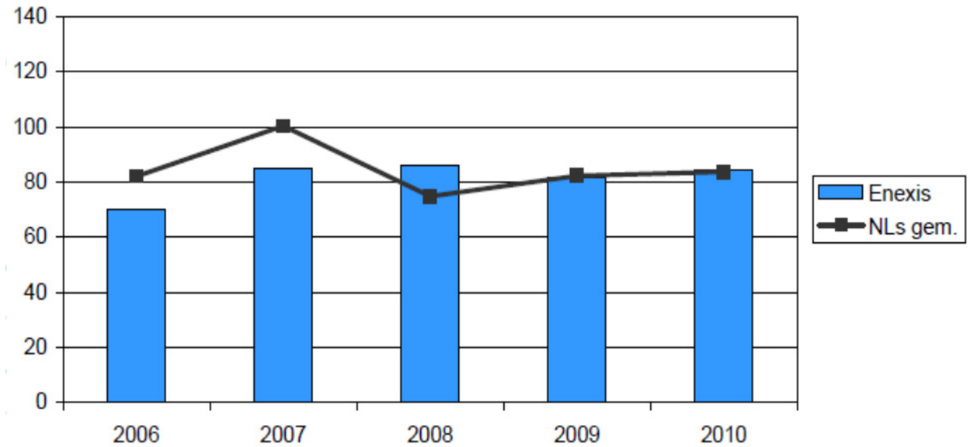
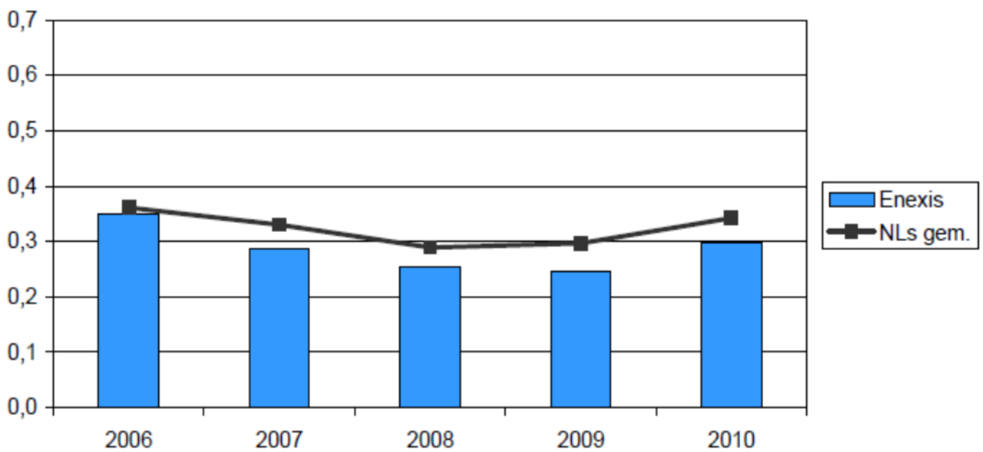


Figure 40: Enexis frequency of unplanned interruptions (NLS gem.=average for Netherlands)[164]



[163] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Enexis B.V.".

[164] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Enexis B.V.".

Figure 41: Liander average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[165]

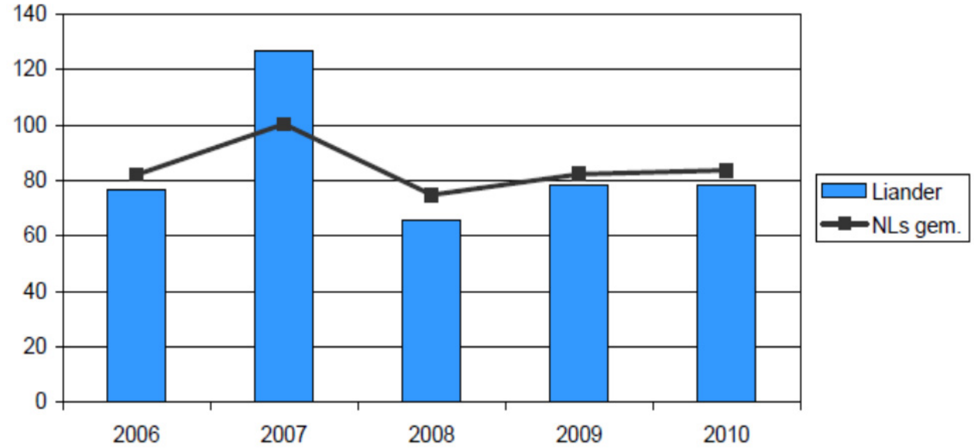
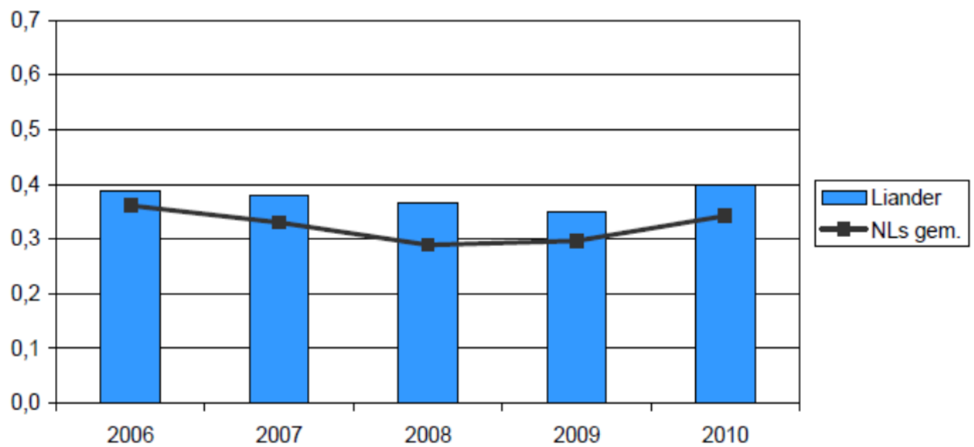


Figure 42: Liander frequency of unplanned interruptions (NLS gem.=average for Netherlands)[166]



[165] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Liander B.V.".

[166] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Liander B.V.".

Figure 43: Rendo average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[167]

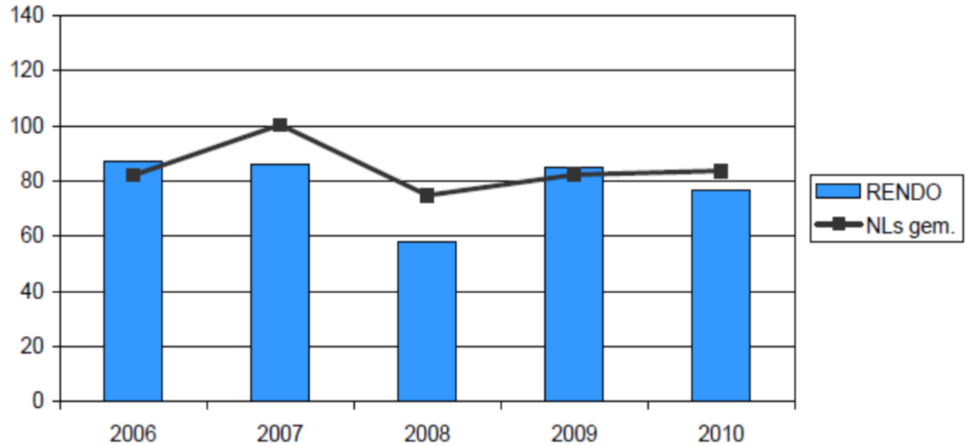
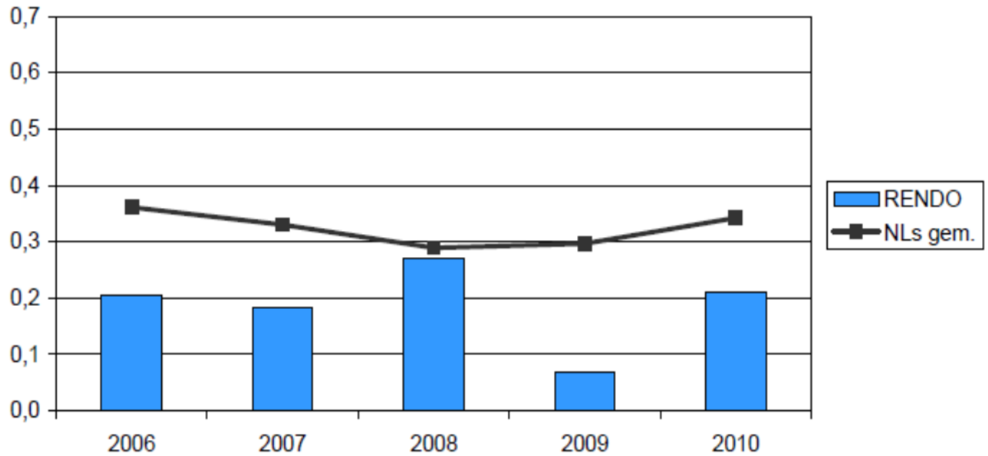


Figure 44: Rendo frequency of unplanned interruptions (NLS gem.=average for Netherlands)[168]



[167] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; N.V. Rendo".

[168] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; N.V.Rendo".

Figure 45: Stedin average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[169]

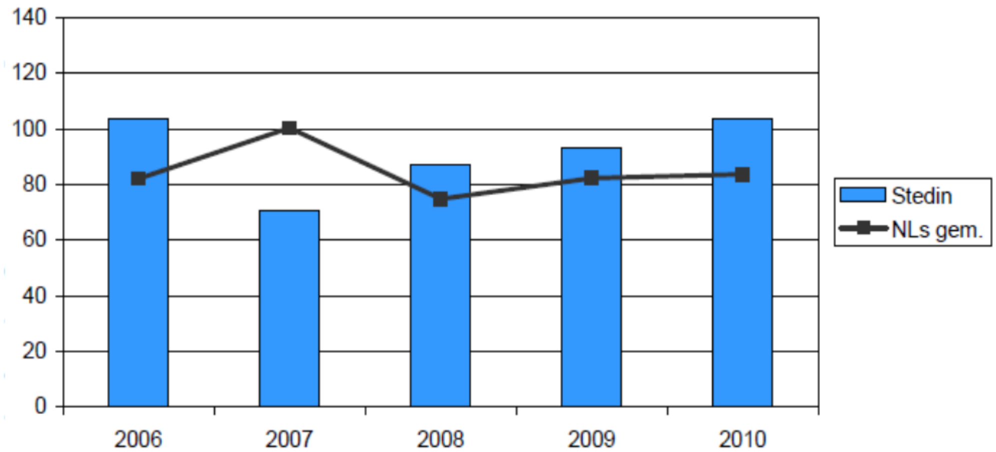
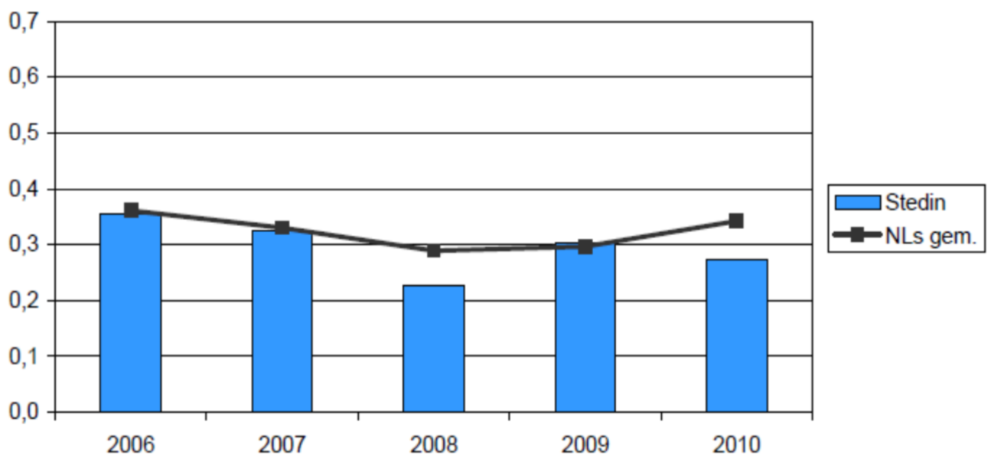


Figure 46: Stedin frequency of unplanned interruptions (NLS gem.=average for Netherlands)[170]



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[169] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Stedin Netbeheer B.V.".

[170] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Stedin Netbeheer B.V.".

Figure 47: Westland average duration (minutes) of unplanned interruptions per customer affected (NLS gem. = average for Netherlands)[171]

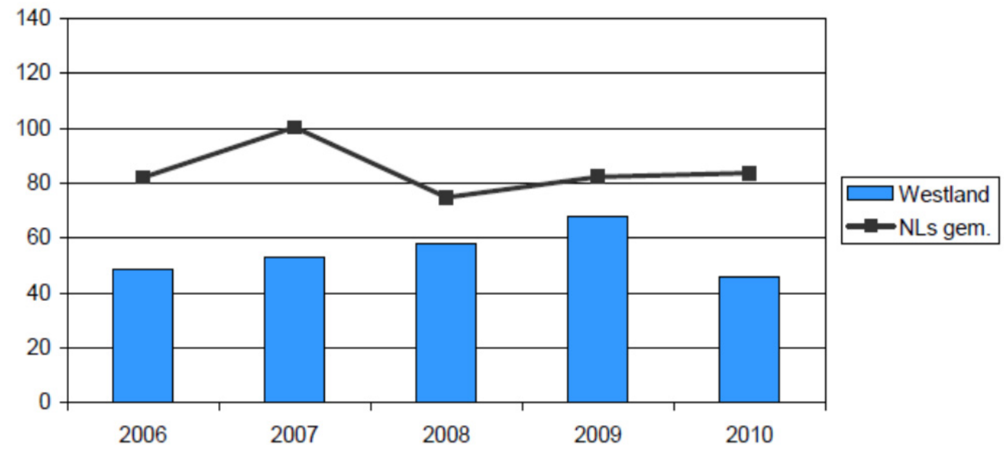
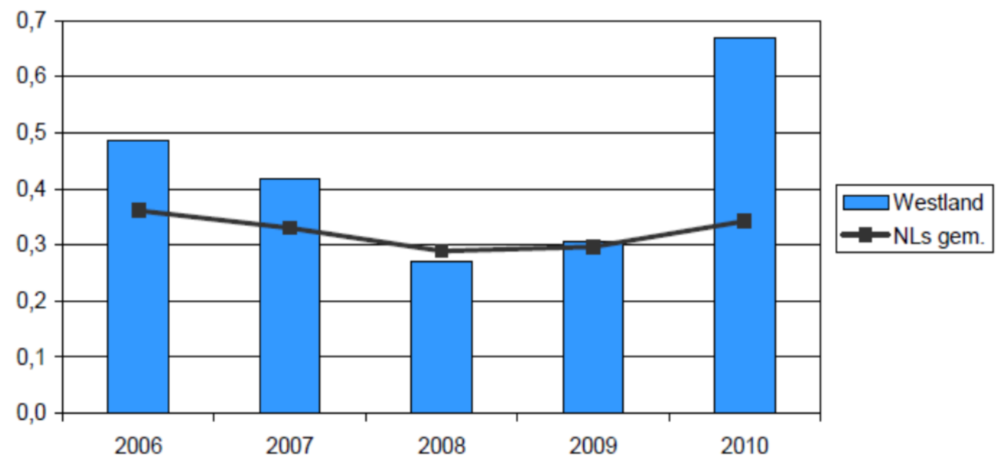


Figure 48: Westland frequency of unplanned interruptions (NLS gem.=average for Netherlands)[172]



[171] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Westland Infra Netbeheer B.V.".

[172] From NMa presentation "Factsheet 2010; Kwaliteit Regionaal Netbeheer; Elektriciteitsnetten & Gasnetten; Westland Infra Netbeheer B.V.".

Table 63: Customer payments for exceeding supply restoration targets

	Domestic	Non-domestic		
Power, kW		< 100	> 100	> 100
Voltage	Low	Low/Medium	Low	Low/Medium
Exceeding limit	30 €	15 €	2 €/kV	1.5 €/kV
Unit of extra hours	4 hours	4 hours	4 hours	2 hours
Charge per unit of extra hours	15 €	75 €	1.00 €/kV	0.75 €/kV
Maximum	300 €	1,000 €	3,000 €	6,000 €

Notes and sources:
From Article 45 and Table 9, Annex A, Resolution 333/07.

Annex VI. Glossary

Accronym	Applies	Description
2.5 beta method	Various	Method developed by IEEE and codified in IEEE Standard 1366-2003 which provides for a statistically based definition for classiifcation of major event days used in determining reliability standards. It involves analyzing five years' worth of daily SAIDI data. The logarithm of each observation is taken and the average (alpha) and standard deviation (beta) of the set is calculated. Any day whose logarithmic SAIDI value exceeds alpha plus 2.5 times beta is classified as an extreme event day
ACMI	US	Average Customer Minutes of Interruption = SAIDI
AEEG	Italy	Authority for Electricity and Gas (Italian regulator)
AEMC	Australia	Austrlian Energy Market Commission
AER	Australia	Australian Energy Regulator
AMP	NZ	Asset Management Plan
CAIDI	All	Customer Average Interruption Duration Index = SAIDI/SAIFI
Capex	All	Capital expenditure
CBD	Australia	Central Business District
CEER	Europe	Council of European Energy Regulators
CI	GB	Customer Interruptions = SAIFI x 100
CML	GB	Customer minutes lost = SAIDI
CPUC	US	California Public Utility Commission (California state regulator)
CSPM	US	Customer Service Performance Mechanism (NY)
CSQ	US	Customer Service Quality
DPCR	UK	Distribution Price Control Review
DREV	Netherlands	Office of Energy and Transport Regulation, department of NMA
EDB	NZ	Electricity Distribution Business
ESC	Australia	Essential Services Commission, a regulator in Victoria
EHV	All	Extra high voltage, definitions vary between jurisdictions
FERC	US	Federal Energy Regulatory Commission (the US national regulator)
GRC	US	General Rate Case, equivalent of a price control review/determination
GSL	Australia	Guaranteed Service Level
HV	All	High voltage, definitions vary between jurisdictions
ICRPL	US	Individual Circuit Reliability Performance Levels
IEEE	N.A.	Institute of Electrical and Electronic Engineers
IIS	GB	Interruptions Incentive Scheme
IOU	US	Investor owned utility
KPI		Key Performance Indicators
LV	All	Low voltage, definitions vary between jurisdictions
MAIFI	All	Momentary Average Interruption Frequency Index (SAIFI for short interruptions)
MCE	Australia	Ministerial Council on Energy
Meshed system	All	Distribution system where there is network of lines
MV	All	Medium voltage, definitions vary between jurisdictions
N-1	All	A network planning standard, requiring the network to continue to function without interrupting any customers following the loss of one network component, or one "credible contingency"
N-2	All	A network planning standard, requiring the network to continue to function without interrupting any customers following the (independent) loss of two network components
NEM	Australia	National Electricity Market
NER	Australia	National Electricity Rules
NMA	Netherlands	Netherlands Competition Authority (Dutch regulator)

Accronym	Applies	Description
NYPSC	US	New York Public Service Commission (NY state regulator)
O&M	All	Operations and maintenance
Ofgem	GB	Office of Gas and Electricity Markets (GB regulator)
Opex	All	Operating expenditure
PBR	US	Performance-based ratemaking, which typically involves a structure of financial rewards and/or penalties for utility performance above or below a targeted neutral range
Q-amount	Netherlands	The bonus or penalty applicable to a distributor, which is derived from its q-factor
q-factor	Netherlands	The value of quality yardstick function used to determine bonsues and penalties for reliability
Radial system	All	Distribution system where lines radiate out from a limited number of points, in contrast to a meshed or networked system
RIM	US	Reliability Incentive Mechanism (California)
RIIM	US	Reliability Investment Incentive Mechanism (California)
RMS	US	Remote Monitoring System
RPM	US	Reliability Performance Mechanism (NY)
SAIDI	All	System Average Interruption Duration Index
SAIFI	All	System Average Interruption Frequency Index
STAR	US	System Trouble Analayis Report
STPIS	Australia	Service Target Performance Incentive Scheme
Sub-transmission	Various	Voltages below transmission levels but above those at which end users are actually supplied
Tinc	Italy	Maximum bonus per LV customer supplied
Tpen	Italy	Maximum penalty per LV customer supplied
Unserved energy	All	Energy that a customer wanted to use but could not (due to an interruption)
WTP	All	Willigness to pay