MEYRICK AND ASSOCIATES

and

PACIFIC ECONOMICS GROUP

DEVELOPMENT OF AN ELECTRICITY DISTRIBUTION SERVICE QUALITY REGIME TO TAKE EFFECT IN FUTURE REGULATORY PERIODS

Draft Report

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Denis Lawrence
Meyrick and Associates

Lawrence Kaufmann
Pacific Economics Group

Meyrick and Associates Pty Ltd
6 Kurundi Place
Hawker ACT 2614
AUSTRALIA
TEL +61 2 6278 3628
FAX +61 2 6278 5358
EMAIL denis@meyrick.com.au
WEB www.meyrick.com.au

Pacific Economics Group
22 East Mifflin, Suite 302
Madison, Wisconsin
USA 53703
TEL +1 608 257 1522
FAX +1 608 257 1540
EMAIL lkaufmann@earthlink.net
WEB www.pacificeconomicsgroup.com

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EXECUTIVE SUMMARY

Meyrick and Associates (Meyrick) and Pacific Economics Group (PEG) have been commissioned by the Queensland Competition Authority (QCA) to develop service quality incentive plans for Energex and Ergon, the state's two electricity distributors. This report develops a service quality incentive plan that is designed to deliver appropriate service quality to Queensland customers and is feasible given the limited amount of data available. Our work has involved a consultative process that gathered input from distributors, large individual customers, industry associations and other customer groups. This input was valuable for understanding the concerns and objectives of major stakeholders in Queensland regarding the quality of power distribution services.

The key steps involved in designing a service quality incentive scheme are:

- determining the coverage of the scheme and developing a series of indicators of the company's quality of service performance;
- determining a list of related and feasible service quality benchmarks against which measured performance will be judged;
- assigning values to different aspects of service quality; and
- developing a method for translating a utility's quality performance into a change in utility rates as a means of rewarding good performance and/or penalising poor performance.

We are recommending that a service quality incentive scheme of the CPI–X+S form be introduced for the two Queensland distributors to take effect from 1 July 2005. Given the lack of accurate data, we are recommending that the scheme be operated on a 'paper trial' basis for the first three years until the robustness and reliability of the data is established. The first rewards or penalties involving actual revenue would take effect for performance in the 2008–09 financial year, provided the data are judged to be sufficiently robust at the conclusion of the three year paper trial.

The coverage of the scheme will be all distribution services except for those where customers have entered into direct contracts with the distributors and for higher than basic price/service offerings, should they be offered. Reliability solutions provided by distributors beyond the current regulatory boundary will not be included as allowable expenditure for revenue requirements purposes but will be eligible for SQI reward payments provided reliability as seen by the customer can be accurately measured.

The SQI scheme will involve 10 performance indicators for Energex and 11 for Ergon. For Energex the indicators are: overall SAIDI and SAIFI for CBD, urban and short rural feeders; SAIDI for the worst 10 per cent of feeders (customer weighted) for both urban and short rural feeders; number of overall quality of supply complaints; and, the percentage of phone calls not answered in 30 seconds. For Ergon the indicators are: overall SAIDI and SAIFI for urban, short rural and long rural feeders; SAIDI for the worst 10 per cent of feeders (customer weighted) for urban, short rural and long rural feeders; number of overall quality of supply complaints; and the percentage of phone calls not answered in 30 seconds. For the reliability indicators, events solely related to generation and transmission interruptions and natural disasters where more than 5 per cent of the customers in the distributor's geographic region are affected will be excluded.

After the conclusion of the three year 'paper trial' period, the benchmark against which performance on an indicator is compared will be a rolling average of the distributor's own performance on that indicator for the three financial years preceding the financial year being assessed. The rolling average will be built up progressively starting with data for the 2004–05 financial year. The composition of the worst 10 per cent of feeders will be determined annually. The scheme will have no performance deadbands initially.

The scheme will have symmetric reward and penalty rates. For Energex the rewards/penalties are at the rate of $18 million for a change in SAIFI of one unit, $270,000 for each minute change in SAIDI and the same for each minute change in SAIDI for the worst 10 per cent of feeders, $25,000 for a one per cent change in the number of complaints, and $31,000 for a one per cent change in the number of phone calls answered in less than 30 seconds. For Ergon the rewards/penalties are at the rate of $12.5 million for a change in SAIFI of one unit, $190,000 for each minute change in SAIDI and the same for each minute change in SAIDI for the worst 10 per cent of feeders, $24,000 for a one per cent change in the number of complaints, and $42,500 for a one per cent change in the number of phone calls answered in less than 30 seconds. The aggregate net reward or penalty will be capped at 2 per cent of each distributor's 2002 revenue. For simplicity, the caps will not be updated over the term of the plan.

Because of time and budget constraints, this report has relied on estimates of the value of the various distribution services that were developed in other parts of Australia. These estimates were the best available, but they may not be precise reflections of Energex and Ergon customers' preferences. Further work estimating the value of service to customers in Queensland may be important for refining future award rates.

1. INTRODUCTION

Service quality is increasingly important in utility regulation. In addressing this topic for all regulated industries, a report by North American regulators stated that 'attention to service quality will be of greater importance as competitive markets proliferate and financial regulation diminishes' (NRRI 1995, p.4). These issues may be especially pronounced in the electricity industry. Advanced industrial economies are becoming more dependent on reliable power supplies. Increasing digitalisation and the 'e–economy' are leading to both greater demands for power and more reliable power supplies. The location of new demands is also more difficult to predict than in the past (eg suburban areas and hobby farms, in addition to central business districts and industrial parks). At the same time, restructuring and increased competition is putting pressures on power delivery systems. These policies have led to a greater volume of power transactions and flows, more desire to operate systems closer to their capacity limits, and increased emphasis on cost–cutting.

Some observers have questioned whether traditional regulation is best suited to this new environment. One statement of this view comes from a Power Outage Study Team (POST) commissioned by the US Department of Energy (DOE) to investigate several prominent power outages in the US in 1999. In addressing the relationship between regulation and appropriate reliability, DOE POST (2000, p.2–5) wrote:

> '(I)s the existing regulatory policy package adequate in light of the new demands on electricity delivery companies? Additional regulatory measures and increased incentives, including performance-based standards, may be required to assure that the necessary actions are taken to provide the proper level of reliability.'

Incentives and performance–based regulatory approaches are, therefore, viewed as important tools for delivering appropriate reliability levels to customers. Some regulators have implemented service quality incentive (SQI) mechanisms designed to ensure that electric utility customers receive adequate levels of reliability and other aspects of service quality. This is particularly important given the increasing use of price and revenue caps designed to extract greater efficiencies from distributors and the incentives these caps can unintentionally create for service quality to deteriorate.

The Queensland Competition Authority (QCA) wishes to introduce formal service quality incentives in conjunction with the update of distribution revenue controls in 2005. Designing appropriate SQIs for Queensland's distributors is challenging. The state's economy is diverse, and the reliability and quality of electricity distribution services is critical to many of the major industries (eg tourism, mining, refining and processing). At the same time, the state's territory is widely dispersed and sometimes features difficult operating conditions. Some customers for whom electricity distribution service quality is especially important are also located in remote areas. A SQI in Queensland should be cognizant of the diversity of service quality demands and the costs of meeting these demands that exist throughout the state.

Meyrick and Associates (Meyrick) and Pacific Economics Group (PEG) were commissioned by the QCA to develop SQI plans for Energex and Ergon, the state's two power distributors. Our work has involved a highly consultative process that gathered input from distributors, large individual customers, industry associations and other customer groups. This input was valuable for understanding the concerns and objectives of major stakeholders in Queensland regarding the quality of power distribution services.

Our report is organised as follows. Chapter 2 is an introductory analysis of the economics of service quality and service quality regulation. This chapter includes a discussion of approved SQI plans in Australia and North America.

Chapter 3 discusses the scope of the SQI plan, or which services will be covered and which will be excluded under the scheme. This chapter includes a brief introductory analysis of the price/service offerings (PSO) approach recommended by Energex. Our analysis of the PSO is not intended to be exhaustive, but rather designed to highlight some issues regarding PSOs and how they may relate to SQIs that deserve further attention.

Chapter 4 discusses and makes recommendations for the quality indicators to be used in the SQI. Chapter 5 discusses and makes recommendations on the quality benchmarks and deadbands. Chapter 6 analyses and makes recommendations on the details of the award mechanism. Chapter 7 discusses concrete steps to be followed to implement the recommended SQI. Chapter 8 presents concluding remarks and some areas that merit further research before the SQI plan is updated. Three appendices follow this chapter. The first presents summary information on a survey of approved North American SQI plans. The second summarises the value of reliability results from a number of studies, primarily from

North America. The third presents certain details of our calculations of the recommended penalty/reward rates.

2. SERVICE QUALITY ECONOMICS AND INCENTIVE PLANS

This chapter begins with a general analysis of service quality economics. We then consider the regulation of the quality of power distribution services more specifically. We conclude with a brief examination of service quality incentive plans that have been approved in Australia and North America.

2.1 Service quality economics

As one author has stated, 'when one investigates quality in economics, one is asking, in effect, what is it about a good or service that makes it more desirable?' (Payson 1994, p.2). Economists make this open-ended question more manageable by conceiving of products as a (finite) bundle of attributes or characteristics.[1] Each characteristic is desirable in the sense that it satisfies consumer tastes and preferences. Since all characteristics are valuable to consumers, consumers generally prefer 'more' rather than less of each.

However, higher quality comes at a price. It is typically costly to add quality characteristics to a product or to provide 'more' of any given attribute. The amount and number of quality attributes that firms choose to bundle with their products is ultimately limited by consumers' willingness to pay. Economists therefore believe that each quality attribute carries an implicit price that, in turn, is reflected in the overall price of the product or service in the marketplace.[2]

It is also important to recognise that preferences differ among customers. Consumers naturally have different tastes regarding the quality characteristics that they find desirable in a given product or service. Just as importantly, customers differ in their willingness to pay for

[1] One of the earliest analyses adopting this perspective can be found in Lancaster (1966).

[2] The implicit prices for various quality attributes can be quantified through statistical methods and aggregated in so-called hedonic price indexes that summarise overall quality differences between products. One of the earliest economic analyses of this issue is contained in Rosen (1974). Clearly, quality attributes are rarely priced explicitly in the marketplace, but it does not follow that the estimation and use of hedonic prices is simply an academic exercise. One example where these economic concepts are applied is by the Bureau of Labor Statistics of the US Department of Labor, which computes hedonic prices indices and adjusts for changes in the quality of some products when it computes the U.S. Consumer Price Index (CPI). For example, CPI calculations control for quality changes in personal computers. The quality of PCs has been increasing at the same time that their prices have fallen. The real decline in PC prices is, therefore, even greater than reflected in their list prices, since consumers are getting more for their money. Alternatively, if a firm were to offer a new PC that had quality levels equal to those of a PC ten years ago, it would certainly fetch a lower price than the higher-quality new models that are available. Hedonic price indexes adjust PC prices so that they reflect the price declines associated with a PC of constant quality.

quality (for absolute quality levels and in the relative valuation of different quality attributes). These differences stem from differences in income as well as heterogeneous tastes and preferences.

Firms in competitive markets have strong incentives to meet customers' demands for quality. Because consumer preferences are heterogeneous, firms are financially motivated to offer an array of products that cater to customers' different tastes and willingness to pay for quality. This can result in firms choosing to compete in different segments or 'niches' in the marketplace. A simple example is the distinction between 'high end" (eg David Jones) and 'low end' (eg Crazy Clarks) general retailers. The abundance of quality–differentiated products observed in most markets, therefore, reflects differences in product attributes that are bundled together to appeal to the multiplicity of consumer tastes, preferences and price–quality tradeoffs.

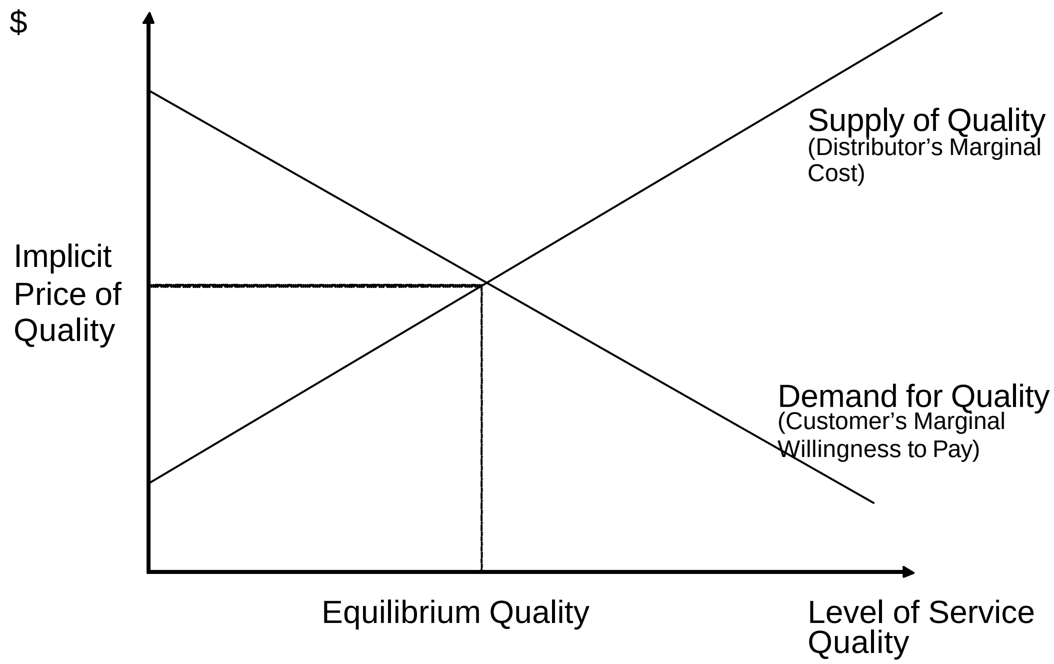
Firms' choices on quality levels, and the implicit prices they charge for quality, can have important financial consequences. Consumers choose among goods and services available in the market based on their price and quality. If customers believe that a product does not offer good quality for the money, they will purchase other products that offer more appropriate price–quality terms. Firms providing poor quality products (at a given price), therefore, suffer financially as sales are lost to competitors. By the same token, firms providing superior quality for the money are rewarded with additional sales and profits. Firms in competitive markets, therefore, have powerful incentives to provide appropriate quality levels on the products that customers demand.

This discussion naturally raises the question of what constitutes 'appropriate' quality for a given price. From the customer's perspective, the quality of any given attribute will be appropriate as long as the (implicit) price at which it is offered is no greater than his willingness to pay. Consumers' marginal willingness to pay for a quality attribute typically declines as the amount of quality increases. That is, as they attain higher quality levels, consumers place less value on additional improvements in quality. This implies, for example, that customers are prepared to pay less to go from a very good service to an excellent service than they would be to go from a poor to a mediocre service.

Firms are willing to supply a quality attribute as long as the (implicit) price received is at least equal to the marginal cost of providing that attribute. Firms typically face increasing marginal costs of improving quality. That is, as quality levels increase, firms often must incur greater incremental costs to increase quality still further.

Consumption and production decisions for each quality attribute lead to a type of equilibrium, pictured in figure 1 below. Customers' demand for quality will be given by plotting the willingness to pay for additional increments of quality. Therefore, going from one quality level to the next along the demand curve reflects consumers' marginal willingness to pay for quality. The firm's supply curve is given by the marginal cost of providing quality. Moving along the supply curve from one quality level to the next reflects the marginal cost of providing additional quality.

Figure 1**: The marginal benefits and costs of service quality**



Consumers continue to demand quality, and firms continue to supply it, until the point where the demand and supply curves intersect. At this point, the marginal willingness to pay for quality is just equal to the marginal cost to firms of supplying it. This yields the (implicit) equilibrium quality indicated.[3] These equilibrium quality levels and implicit prices are

[3] Rosen (1974, p.34) describes this equilibrium more formally as follows:

'A class of differentiated products is completely described by a vector of objectively measured characteristics. Observed product prices and the specific amounts of characteristics associated with each good define a set of implicit or "hedonic" prices. A theory of hedonic prices is formulated as a problem in the appropriate in that they reflect customers' preferences and willingness to pay for quality and firms' willingness to supply it. The market equilibrium depicted in this diagram is also optimal, since it maximises the difference between customers' total willingness to pay for the quality attribute and firms' total cost of producing quality.

This treatment is, of course, highly stylised. Actual quality choices and implicit prices are more complicated since quality attributes are not supplied in isolation but rather are bundled with the basic product or service in question. Firms' decisions regarding quality attribute bundling depend on customer preferences, among other things. Consumer tastes, company costs, and marketplace conditions (eg general competitive pressures) can also change over time, and these factors naturally affect firms' behaviour and the financial consequences of quality decisions.[4] Nevertheless, this analysis demonstrates that firms in competitive markets are driven to provide quality levels that reflect customer demands and their willingness to pay. Firms that meet these demands most successfully are rewarded, while companies that fail to provide appropriate quality levels suffer financial penalties. This analysis of service quality economics in competitive markets provides an important guide for evaluating how best to regulate the quality of regulated services.

2.2 Service quality incentive plan basics

In competitive markets, market forces create strong incentives for firms to provide appropriate quality levels to customers. These same forces are weaker for regulated services like electricity distribution. Regulation, therefore, does and should play an important role in ensuring that utility customers receive appropriate service quality.

Increasingly, regulators are using service quality incentive (SQI) plans to regulate quality. The main idea behind SQI plans, like all incentive regulation plans, is to establish rules that create inherent incentives for utilities to meet desired regulatory objectives. A well–designed SQI plan will create incentives for the utility to operate in an efficient and effective manner for the benefit of customers, so there is less need for continuous and detailed regulatory scrutiny of utility operations. An essential feature of incentive regulation is therefore the existence of well-defined rules that (1) provide clear guidance to the utility in

economics of spatial equilibrium in which the entire set of implicit prices guides both consumer and producer locational decision in characteristics space.'

[4] This discussion also abstracts from information available to consumers and producers and how this affects decisions, as well as the cost considerations of supplying multiple quality attributes jointly rather than in isolation.

structuring its operations to achieve the desired objectives, and (2) create a framework that allows for an objective evaluation of the distributor's performance, which is essential in minimising administrative burdens for regulators and the distributor.

SQI plans create appropriate incentives by replicating the market–type forces in which a firm's financial performance is linked to its service quality performance. A firm operating under a SQI plan can be penalised if its service quality declines or rewarded for service quality improvements. Since SQI plans are designed to simulate the market forces that deliver appropriate quality levels to customers in competitive markets (by linking financial considerations to performance), there is less need for detailed regulatory scrutiny of utility operations to ensure that customers receive adequate service quality.

There are three basic elements in a SQI plan: a series of indicators of the utility's quality of service; related performance benchmarks, often with deadbands around those benchmarks; and a method for translating a utility's quality performance into a change in utility rates via rewards or penalties. This section will simply define these terms. We analyse the three basic elements in more detail in chapters 4, 5, and 6, respectively.

Quality indicators are the aspects of a utility's service quality that are measured and monitored under the SQI plan. Quality benchmarks are the standards against which measured quality is judged. Deadbands refer to a zone around the benchmarks within which utility performance is neither penalised nor rewarded. The penalty/reward mechanism is used to reward or penalise the utility for its service quality performance. It accomplishes this by linking a quality assessment to a change in utility rates or allowed returns. In general, measured performance that 'exceeds' the benchmarks (or upper bands) signals superior quality and a possible reward. Performance below the benchmarks (or lower bands) indicates sub–standard quality and a possible penalty.

2.3 Service quality incentive precedents

This section examines precedents for approved SQI plans. Our focus is approved SQIs in Australia, but we also consider SQI plans from North America and the United Kingdom. Because the North American experience with service quality incentives is much more extensive, we will not describe any particular North American SQI plan in detail but rather will draw more general conclusions about how these SQI plans have been designed and evaluated.

2.3.1 *Australia*

Setting minimum service quality standards has been widespread in the regulation of most Australian infrastructure industries. While the general 'X' factors set for some water providers in NSW have been conditional on meeting minimum service standards, regulation of infrastructure outside of the electricity industry has not extended to explicitly linking the level of service quality achieved to financial rewards.

There have been only three regulatory SQI schemes implemented in Australia to date, and these have all been in the electricity industry. They cover state regulation of electricity distribution in Victoria and South Australia and the ACCC's regulation of electricity transmission. In this section we briefly review these SQI schemes.

Victorian electricity distribution

Commencing in 1996, Victoria set minimum reliability standards for its distributors differentiating between short and long feeders. The Office of the Regulator General (ORG) also published detailed reports on service quality for each distributor covering average performance and identifying problem feeders. While the minimum standards were generally considered to be too low, publication of service quality performance served to put pressure on poor performing distributors to improve their performance and increased public awareness.

In its electricity determination for 2001–2005, the ORG (reconstituted as the Essential Services Commission (ESC) in 2002) significantly expanded its regulation of service quality introducing a new incentive scheme within the price cap in addition to compensation payments to customers affected by poor reliability. Distributors are required to make guaranteed service level payments of $80 to urban customers who experience more than 9 supply interruptions in a year and to rural customers who experience more than 15 interruptions. Urban and rural customers both also receive payments of $80 if their power is off for more than 12 hours at any one time. These payments are not based on the estimated inconvenience cost to customers but are intended to be significant from the customer's perspective while providing the distributors with an incentive to improve service levels to problem areas. In particular, they are intended to help distributors justify investments to fix problems for those customers with the worst service where the necessary investments would not otherwise meet the distributor's investment return hurdle criterion.

The modification of the price cap formula to include an 'S' factor for service quality performance has been a more innovative move. In simplified terms, the price cap now becomes (1+CPI)(1–X)(1+S) where S is the product of an incentive rate and the gap between target and actual performance levels for a series of reliability indicators. The exact price control formula is as follows:

$$\frac{(1+CPI_t)(1-X_t)(1+S_t)}{(1+S_{t-6})}$$

The service adjustment, S_t, that will apply in year t for a particular distributor is calculated as a percentage according to the following formula:

$$S_t = \sum_{r,n} s_{r,n} (GAP^{r,n}_{t-2} - GAP^{r,n}_{t-3})$$

where:

r	Refers to the following indicators: Unplanned interruption frequency (SAIFI) Unplanned interruption duration (CAIDI) Planned minutes off supply (SAIDI)
n	Refers to the following customer categories: CBD Urban Rural
$s_{r,n}$	is the incentive rate for indicator *r* and customer category *n.*
$GAP^{r,n}_{t-2}$	is the performance gap for indicator *r* and customer category *n* in calendar year *t-2*; that is the difference in performance between target and actual performance ($GAP^{r,n}_{t-2} = TAR^{r,n}_{t-2} - ACT^{r,n}_{t-2}$).
$TAR^{r,n}_{t-2}$	is the distributor's performance target for indicator *r* and customer category *n* in calendar year *t-2.*
$ACT^{r,n}_{t-2}$	is the distributor's actual performance for indicator *r* and customer category *n* in calendar year *t-2*, not including the impact of excluded events.
$GAP^{r,n}_{t-3}$	is the performance gap for indicator *r* and customer category *n* in calendar year *t-3*; that is the difference in performance between target and actual performance ($GAP^{r,n}_{t-3} = TAR^{r,n}_{t-3} - ACT^{r,n}_{t-3}$).
$TAR^{r,n}_{t-3}$	is the distributor's performance target for indicator *r* and

customer category *n* in calendar year *t-3*.

$ACT_{t-3}^{r,n}$ is the distributor's actual performance for indicator *r* and customer category *n* in calendar year *t-3,* not including the impact of excluded events.

The Victorian scheme contains a number of unusual features relative to other CPI–X+S schemes. Firstly, the ORG did not have the power to set targets at the time of the price review so the distributors were asked to put forward proposals for service quality targets and estimates of the costs of achieving those targets. Once the targets and costs were agreed with the ORG, the relevant costs were built into the distributors' X factors.

A reward is only paid if the distributor reduces the gap between actual and target performance in period *t–2* relative to what it was in period *t–3*. This was done to reduce the scope for distributors to game the scheme as the ORG thought there could be scope for distributors to reduce maintenance and strategically claim reward payments in a simpler year–by–year scheme. The ORG was looking instead for distributors to produce long run sustainable improvements in performance, which the reducing gap scheme was thought to encourage more. The ORG also wanted some of the gains to be given back to customers, so distributors are allowed to keep the gains (or losses) for 5 years, consistent with the length of the efficiency carryover mechanism. This is facilitated by the term in the denominator of the price control formula.

The scheme includes measures for the number of unplanned interruptions, average unplanned interruption duration and total planned minutes off supply for CBD, urban and rural customers. Unplanned interruptions were given a weight of 100 per cent, average unplanned interruption duration a weight of 75 per cent and total planned minutes off supply a weight of 25 per cent. This was consistent with customer feedback that unplanned outages were the most inconvenient with most customers concerned by the number of interruptions more so than their duration. However, total planned minutes off supply was included rather than planned interruptions as the ORG wanted distributors to reduce the impact of planned outages on customers but without compromising safety incentives.

The scheme only includes reliability measures as customer service issues were thought to be mainly retail–related in Victoria. There were also no reliable data available on technical quality of supply. The ORG opted not to use complaints data as a proxy for technical quality as it wanted the distributors to be more proactive rather than reactive on technical quality issues. Being proactive requires the distributors to monitor their networks' technical characteristics, and expenditure for this has been approved.

Victoria was fortunate in having access to relatively robust and consistent data due to the former State Electricity Commission having had reliable connectivity data at the high voltage level for use in average measures. The ORG did not cap total incentives as it believed this might have led to distributors deciding to take the penalty cap each period and hence the scheme would have had no effect. The judgment was made that the Victorian data were sufficiently robust that caps were not necessary.

The Victorian scheme only uses system average results rather than also including a worst feeder dimension. This is because the ORG wanted to keep it simple and the worst feeder data were thought to be less robust. The scheme also only uses one rural category rather than differentiating short and long rural feeders. This was done to reduce volatility in the data and so that all distributors then only had two categories of indicators (ie CBD and urban or urban and rural).

The incentive is symmetric with performance above the target being rewarded at the same rate as penalties are imposed for performance below the target. The incentive rates are based on estimates of the distributors' marginal costs of improving reliability rather than estimates of customer valuation as is somewhat more common practice in CPI–X+S schemes. These marginal cost estimates, in terms of $ per kWh of unserved energy, were $3.96 for AGL, $7.05 for CitiPower, $6.47 for Eastern Energy (TXU), $4.55 for Powercor, and $4.67 for United Energy. These rates were considerably lower than available evidence on the valuation consumers place on improved reliability. If distributors can consistently outperform the targets, then they are compensated for the costs up to the point where they are eventually returned to customers. This provides them with some incentive to exceed the target.

Distributors have to apply to the ORG (now the ESC) to have exceptional events excluded from the incentive scheme. The ORG (2000, p.24) indicated it would consider exclusion of the following events:

- supply interruptions made at the request of the customer affected;
- load shedding due to a shortfall in generation;
- supply interruptions caused by a failure of the shared transmission network; and

- supply interruptions caused by a failure of transmission connection assets, to the extent that the interruptions were not due to inadequate planning of transmission connections.

Natural disaster events that are widespread in their effect, that the distributor could not have been reasonably been expected to have mitigated and that are rare events, were also excluded. This category has, however, generated considerable debate. The ORG and ESC have used definitions of affecting 10,000 or more customers for events being 'widespread' in urban areas and somewhat less than this number in rural and CBD areas (because each CBD 'customer' typically supplies several premises). The main area of dispute has been over what constitutes a 'rare' event with local area data on the particular attributes of a storm event such as wind speeds being hard to collect and there being a relative dearth of historical data for comparison purposes.

The scheme has operated for the first time in 2003, using 2001 and 2000 data. The impact on distributors' revenue has been larger than the one per cent originally anticipated. It is instead around four per cent, which will lead to roughly a two per cent increase in final electricity prices. The ESC believes the revenue impact is higher than anticipated due to a run of favourable weather conditions and good distributor management, with many of the distributors having explicitly tied their managers' contracts to improved reliability performance. Although the 2002 data have not been finalised, preliminary indications are that good performance has continued with the resulting S factors likely to be positive in 2004 as well.

Discussions with the ESC have indicated that the main areas of the scheme likely to be reviewed and extended in the next Victorian price determination are:

- the criteria for exclusions;
- reassessing the price volatility impacts;
- including momentary interruptions; and
- including a single technical quality measure.

South Australian electricity distribution

The South Australian Distribution Code established the first operational service quality incentive scheme in Australia for the South Australian electricity distributor, ETSA Utilities. The scheme is symmetric but not continuous. The maximum average distribution revenue allowed to ETSA Utilities is increased or decreased depending on actual performance relative to targets and bands across five indicators: SAIDI, SAIFI, CAIDI, time to restore supply to not less than 80 per cent of affected customers and operating cost per customer. For the first four measures, the points score is averaged across the Adelaide Central, Metropolitan, Rural and Remote areas and a category which was specified by the South Australian Independent Industry Regulator (now the Essential Services Commission of South Australia – ESCoSA) as the forty worst feeders in South Australia based on the number of interruptions per consumer.

ETSA Utilities receives points for its performance relative to the specified targets and revenue adjustments are made at the rate of $300,000 per point. The first revenue adjustment was made for the 2001–02 year based on performance for the year ending 31 March 2001. In this case, ETSA Utilities' allowed revenue was reduced by $900,000 mainly due to average operating costs per customer exceeding their target and reliability measures falling short of targets in rural and remote areas. While the calculation of reward points is symmetric, the timing of rewards and penalties is not, with revenue reductions being passed on to customers immediately but any increases in prices being delayed until the following year and then capped at a maximum of 1.5 per cent per annum.

In March 2003 ESCoSA (2003b) released an amendment to the scheme for the current regulatory year commencing April 2003. This involved an approximate doubling of both the target SAIDI and SAIFI values and associated deadbands for the rural region following the discovery of fundamental flaws in the customer allocation method used to calculate the initial targets.

ESCoSA is currently reviewing the coverage and operation of the scheme as part of the lead up to its price determination for the period 2005 to 2010. The current structure of the incentive scheme will be retained as ESCoSA (2003a, p.5) considers it has 'worked well over the past few years and stakeholders are familiar with it'. Changes will be centred on the measures used and/or their levels.

As part of this review ESCoSA commissioned a large scale consumer survey (KPMG 2003) in an effort to better target the scheme to what customers are willing to pay for. Although the details are yet to be finalised, ESCoSA (2003a) has indicated that it will change the emphasis of the scheme away from average reliability performance targets to reliability targets for those customers with the worst service levels. Targets will be set in terms of the percentage of customers who experience:

- more than a given number of interruptions in a year;

- more than a given number of minutes off supply in a year; and
- an interruption longer than a given number of minutes in a year.

The rationale for this proposed change comes from the consumer survey which indicated that 85 per cent of customers were happy with their current level of service quality and were not prepared to pay for further improvements. The remaining 15 per cent were those who generally experienced the worst service quality levels and who were prepared to pay for service quality improvements.

ESCoSA does not intend to include momentary interruptions in the revised scheme as the survey indicated this was not sufficiently important to customers, but it does intend to include call centre performance as the survey indicated customers value this highly. The indicators currently proposed for inclusion are the proportion of calls that are not answered within 30 seconds and the proportion of calls abandoned during emergencies.

Complementary changes are also being proposed to South Australia's guaranteed service levels. The current GSL scheme only applies to timeliness in making new connections, keeping appointments and repairing streetlights. ESCoSA is proposing to extend coverage to the number of interruptions experienced in the last year and the longest interruption experienced in the last year while removing the GSL on timeliness of appointments. The extension of the GSL scheme to cover reliability is intended to provide ETSA Utilities with an additional incentive to improve service quality to, say, the worst one per cent of customers which will involve relatively high cost and who may otherwise be ignored within the operation of the incentive scheme applying to the worst 15 per cent of customers as a whole.

ESCoSA also intends to supplement the service quality scheme by a 'best endeavours' requirement on ETSA Utilities to meet overall average reliability targets embedded in the general price cap. This is thought to be necessary to avoid ETSA Utilities achieving its targets for the worst 15 per cent of customers but allowing the service quality enjoyed by the best 85 per cent of customers to worsen.

To further refine its proposals, ESCoSA is currently seeking additional baseline data from ETSA Utilities and plans to release a 'working conclusions' paper in July 2003 which will allow ETSA Utilities to forecast its required capital and operating expenditure for the 2005–2010 period by mid–2004. The draft price determination including the fully specified service quality incentive scheme will be released in November 2004.

Electricity transmission in Australia

Under the National Electricity Market established in Australia's eastern and southern states in 1998, the Australian Competition and Consumer Commission (ACCC) has the responsibility of regulating the non–contestable parts of the transmission networks. The ACCC has progressively assumed this role and has issued revenue cap decisions for the NSW and ACT transmission systems in January 2000, for the Queensland system in November 2001 and for the Victorian and South Australian systems in December 2002.

In its first two decisions, those for the NSW and ACT system and the Queensland system, the ACCC (2000, 2001) specified a number of service standards it expected the transmission companies to meet. It thought there were insufficient data available at the time and insufficient work had been done to develop agreed measures to support the introduction of explicit service quality incentives. After having initiated the necessary work to develop agreed measures, the ACCC (2002a,b) has moved to incorporate explicit service quality incentives in its latest decisions, those for Victoria and South Australia. It has also flagged that the incentive schemes will be progressively refined and extended to the other states. The Tasmanian transmission company, Transend (2003), has also proposed a similar incentive scheme in its recent application to the ACCC for revenue caps to apply from January 2004.

The ACCC transmission incentive schemes involve the inclusion of an 'S' factor in the revenue cap. Targets are set for five performance areas generally based on average performance over the past three years. The performance areas covered are:

- circuit availability;
- loss of supply event frequency index;
- minutes constrained (inter–regional); and
- minutes constrained (intra–regional)

Data on the minutes constrained indicators are not currently available but will be collected during the scheme's first period of operation. The scheme's exact initial coverage varies between states depending on data availability. For instance, the Victorian scheme includes 7 indicators across the circuit availability and restoration time categories while the South Australian scheme includes 4 indicators across the circuit availability, frequency of loss of supply and restoration time categories.

The impact of the incentive scheme on revenue is generally limited to one per cent for the initial period. For Victoria, the impact on SPI PowerNet's revenue is limited to half of one per cent because SPI PowerNet has a separate incentive scheme in place with VENCorp which puts two per cent of its revenue at risk.

The incentives applied are asymmetric for all indicators with performance better than the target being rewarded at a higher rate than what performance worse than the target is penalised at. The rationale for this is that separate benchmarking studies have indicated that the Australian transmission companies are already operating at high levels of service quality and, hence, further improvements are likely to be relatively costly to achieve.

Indicators relating to circuit availability do not have deadbands around the targets while all outage duration and most frequency indicators do have deadbands.

There is generally a six month gap between the year for which performance is measured and the regulatory year in which the subsequent 'S' factor is applied. For South Australia, the first adjustment will be made for the 2003–04 regulatory year (coinciding with the financial year) based on performance relative to targets in the 2002 calendar year. For Victoria the scheme will first apply in the regulatory year ending March 2005 based on performance relative to targets in the 2003 calendar year.

The ACCC performance incentive scheme is applied as a separate 'add on' to the revenue cap each year and there is no compounding of the effect over time. That is, each year's service quality reward or penalty will only affect revenue in one regulatory year.

2.3.2 *North America*

Service quality incentives are well established in US regulation. These incentive plans are sometimes included as part of a larger package of performance–based regulation (PBR) programs. SQIs are also sometimes a component of merger agreements. In both cases, SQIs are often viewed as a kind of 'countervailing incentive' designed to ensure that utilities maintain existing quality levels even as they operate under arrangements (PBR or mergers) that create stronger incentives to contain cost.

A large sample of North American service quality incentive plans is contained in Appendix One. While the specific indicators vary widely among approved service quality incentive plans, there are broad similarities between the types of indicators used for energy utilities. We have found it useful to group service quality indicators into seven broad categories.

Reliability indicators measure the continuity of the basic service. Electric utilities are expected to provide a continuous power supply at all times, so interruptions in power supply constitute a diminution in service quality. Reliability is often measured by the frequency and duration of power interruptions.

Non–emergency on–site services pertain to non–safety related services that require visits to customer premises, such as a visit to repair a broken meter. On–site visits to restore power supplies may fall into this category if the supply problems are customer–specific rather than network–related. An example of a non–emergency on–site indicator is the percentage of non–emergency calls that the company responds to within 24 hours.

Safety indicators reflect possible health and safety problems if utility products are not delivered properly. Safety indicators are much more common for gas than electric utilities. An example is the time it takes to respond to calls about gas odours.

Telephone services pertain to the quality of service provided by the company's phone centre. Since most customers communicate complaints or concerns by telephone, the quality of phone contacts is an important component of overall service and is often linked to other indicators (eg the response time for emergency visits depends in part on how rapidly calls are answered and relayed to field personnel). One example of a telephone service indicator is the average time it takes to answer customer calls.

Metering and billing indicators reflect the quality of these services that the company provides. Quality in this area will be enhanced by timely and accurate meter–reading and bill preparation. Examples of quality indicators include the percentage of prepared bills that must be adjusted because of errors.

Customer satisfaction is a category that reflects how content customers are with their utilities. Indicators include surveys of overall customer satisfaction.

Finally, the *Other* category includes a panoply of miscellaneous indicators that have been featured in approved service quality incentive plans. Examples include employee safety and customer outreach and education programs.

Although the survey in Appendix One is not all–inclusive, it is a more than representative sample of approved North American SQI plans. This survey reveals some interesting points about approved SQIs.

First, SQI plans for electric utilities almost always feature reliability indicators. Nearly all of these plans have separate indicators for the frequency and duration of interruptions. Telephone indicators and customer satisfaction indicators are also popular, although a range of other indicators have been included in approved plans.

Second, most plans have established indicators for system–wide SAIFI and SAIDI but have not created geographically disaggregated reliability targets. There are some exceptions to this, most prominently in the state of New York. Several New York SQI plans create reliability benchmarks that vary by operating district or other network segment.

Third, the total number of indicators in most approved plans is between five and seven. Many plan updates have simplified and reduced the number of indicators used in the second plan. In a few cases, however, (eg San Diego Gas and Electric) the updated plan increased the number of indicators.

Fourth, there are both penalty–only and penalty/reward SQI plans for US energy utilities. Penalty–only plans are somewhat more common, but prominent examples of plans where the utility can be rewarded include Southern California Edison, San Diego Gas and Electric, Northern States Power, Otter Tail Power, and National Grid–Massachusetts. One reason that penalty-only plans are more common is that a number of SQIs were implemented as part of merger agreements. In these cases, the motivation for the SQI was simply to maintain existing quality levels while the consolidated utilities attempted to find cost efficiencies. In other words, SQIs in merger agreements are almost always seen as countervailing incentives against cost–cutting that can imperil quality rather than mechanisms to induce optimal service quality *per* se, and penalty–only mechanisms are usually seen as sufficient to achieve this goal.

In addition, New York has had a number of penalty/reward SQIs in the past but all SQIs in the state are now penalty–only. This change usually occurred as part of negotiated settlements between the companies and intervenor groups that took place at the outset of industry restructuring in the state. Among other things, these agreements included stranded cost recovery for utility generation assets, which was a key objective for the companies. One of the things the companies traded away in the negotiating process was rewards in SQIs. Some plans (eg the earlier New York plans, Northern States and Otter Tail Power) implement rewards and penalties via adjustments in an earnings–sharing mechanism (ESM). Better service quality raises the allowed return on equity in the ESM and reduces the probability of sharing earnings, while the opposite is true when service quality declines.

Fifth, in penalty–only plans, it is common for utilities to be able to 'offset' good performance on some quality indicators against poor performance on other indicators. Examples include the plans that apply to investor–owned gas and electric distributors in Massachusetts and National Grid–Rhode Island.

Sixth, all of the approved SQIs are multi–year plans. As a general rule, SQIs do not invite annual reviews or modifications of indicators, benchmarks or penalty/reward rates. In some cases, benchmarks are updated according to formulas (eg rolling averages) that are specified at the outset of the plan. However, in these cases, formulae rather than fixed benchmarks were applied primarily because of the lack of data at the outset of the plan. This use of rules (including fixed benchmarks for the duration of the plan) rather than regulatory discretion is consistent with the principles of sound design of incentive mechanisms.

Seventh, there are many examples of benchmarks based explicitly on a company's historical performance. One good example is in Massachusetts, where a statewide examination of service quality issues established benchmarks for each utility based entirely on the company's past performance on a service quality indicator. For all electricity indicators except SAIFI and SAIDI, benchmarks were to be based on 10 years' worth of data; benchmarks for SAIFI and SAIDI were based on five years' worth of data.[5] In contrast to the many examples where benchmarks are based on a company's own historical experience, there are almost no examples of benchmarks based explicitly on peer performance.

Eighth, although some regulators have recognised the importance of customer value for designing appropriate SQI regimes, most penalty/reward rates for performance have not been based on estimates of customer value. Instead, these penalty/reward rates have been set either through negotiation between parties or through judgment. This reflects two primary factors. One is the cost of undertaking original research on the valuation of quality to a company's own customers. A second is the fact that many SQI plans are implemented as part of a larger negotiated package (eg merger agreements, industry restructuring settlements), so service quality penalty/reward rates become another detail in a larger negotiation. One possible exception to this phenomenon is the SQI plan for Southern California Edison (SCE). As part of the mid–term review of its PBR plan, SCE was required to present a value of service study for its customers. The California Public Utilities Commission ordered this work in connection with setting appropriate reward/penalty rates for the reliability indicators in SCE's service quality incentive plan. At this time, however, this SQI plan has not yet been updated.

Ninth, on average for the sampled companies, total penalties or rewards as a percentage of revenues are just under 2 per cent. In some cases (eg Massachusetts) this limit

[5] If a company did not have ten years of data on an indicator, new data would be used to update benchmarks until 10 years of data were available.

was set by state statute rather than by the regulator. On average, about 45 per cent of total potential penalties/rewards is tied to reliability performance, about 12 per cent to telephone centre performance, and about 43 per cent to miscellaneous other indicators (metering, billing, employee safety, customer satisfaction, etc).

2.3.3 *United Kingdom*

Public Electric Suppliers (PESs) in the United Kingdom have long been subject to standards of performance on various aspects of service quality. The Director General of Electricity Supply has issued annual reports on PES service quality since 1992. Under sections 39 and 40 of the Electricity Act of 1989, all PESs must report to the Director General on their performance against the standards.

There are two types of standards. *Guaranteed standards* apply to services that must be met in every instance. If a PES ever fails to satisfy a guaranteed standard, it makes a penalty payment directly to the affected customer. *Overall standards* create minimum acceptable service levels on broader (eg system–wide) quality measures. Companies are not subject to automatic penalties for failing to meet these standards. However, the regulator can direct companies to take actions to improve their quality in order to comply with overall standards.

Specific standards were first introduced in 1991. They have since been revised in July 1993, April 1995, April 1998 and July 1998. These revisions have generally expanded the number of standards and made the performance benchmarks more demanding.

Standards also vary among companies. The initial standards varied because of differences in PES operating circumstances and historical differences in the quality levels that companies achieved. However, subsequent revisions in the performance standards have led the standards that apply to individual PESs to become more similar.

The current Guaranteed Standards of Performance primarily apply to responding to specific customer service problems, restoring supplies promptly, and notifying customers in advance of planned supply interruptions. The most common penalty payment is 20 pounds, although there are higher automatic penalties for estimating charges and failing to restore supplies within 24 hours. The latter penalty will vary with the amount of time that customers are without power.

The current Overall Standards of Performance are listed below.

1a. Minimum percentage of supplies to be reconnected following faults within three hours (percentage target varies among PESs).

1b. 99.5 per cent of supplies to be reconnected following faults within 18 hours.

2. All voltage faults to be corrected within six months.

3a. All new domestic customers to be connected within 30 working days.

3b. All non–domestic customers to be connected within 40 working days.

4. All customer letters responded to within 10 working days.

5. Minimum percentage of customers experiencing no more than five interruptions each lasting 3 minutes or more (percentage target varies among PESs).

The PESs have generally performed well against these standards. Ofgem writes that "since 1991, companies have demonstrated a steady improvement in their performance against the Overall Standards." The number of payments for failure to comply with Guaranteed Standards fell from over 13,000 in 1991–92 to 504 in 2001–02. This progress is especially notable given that the performance standards were generally tightened over this period.

Beginning in 2002, service quality regulation in the UK was augmented to include what is known as the Information and Incentives Project (IIP). This is an effort that evolved out of Ofgem's last review of power distribution prices. In that review, Ofgem stated that it has grown increasingly concerned about the information and methods used for rate regulation. One issue was the nature of information provided by PESs. Inconsistent variable definitions, accounting practices and other factors often led to data that were not comparable across companies. This made regulation more difficult and burdensome as regulatory staff grappled with the task of standardising data.

Ofgem also believed that its methods for price control (essentially what is known in Australia as the building block approach) were distorting incentives. It claimed that the regime created incentives for companies to "beat the regulator" by gaming the information provided. The IIP counters this by attempting to create incentives that are more similar to the marketplace. In competitive markets, rewards and penalties depend on a firm's performance relative to peers. The IIP will incorporate this feature into regulation by placing greater weight on PES's relative performance on both cost and quality measures.

The IIP is designed to standardise information on a utility's quality "outputs" and tie financial outcomes more precisely to performance. It is made up of four main components:

- a mechanism that penalises companies annually, up to 1.75 per cent of revenue, for failing to meet targets for the number and duration of supply interruptions;
- a mechanism for rewarding companies that exceed their quality of supply targets for 2004–05 based on their rate of improvement in performance up to that date;
- a commitment to rewarding "frontier" service quality performance in the next price control review; and,
- a mechanism for rewarding or penalising companies annually, up to 0.125 per cent of revenue, for the quality of their telephone response; beginning in 2003, rewards or penalties up to an additional 0.125 per cent of revenue will be implemented for the speed of telephone response.

The four output measures under the IIP are average number of supply interruptions per 100 customers (analogous to SAIFI); average duration of supply interruptions in minutes per connected customers (analogous to SAIDI); quality of telephone response, as measured by customers' expressed satisfaction on a survey; and speed of telephone response, using a metric to be devised. These outputs were chosen to satisfy three criteria: they should reflect what customers actually value; be attributable to PES distribution businesses; and, be capable of objective measurement over time and across companies.

The benchmarks that apply for the number and duration of interruption indicators are based on the 2004–05 benchmarks that were established during the process of creating the IIP. These targets are company–specific and designed to be at least as demanding as each PES's actual performance on the indicators in 2001–02. For some companies, adjustments to these benchmarks were made because of changes in data definitions and measurement systems implemented as part of the IIP to standardise interruption reporting. The quality of telephone services benchmark is based on the average performance of other PESs. This is an example of a peer benchmark. Ofgem believes that the benchmark for the speed of telephone services will be based on an absolute number for each company rather than a peer–based benchmark. There are no deadbands around any of the benchmarks.

Penalties or rewards depend on how companies perform relative to the established benchmarks. The maximum penalty/reward is specified as a percentage of revenues, and this percentage varies over the three year term of the IIP. In the first year, maximum penalties are capped at 0.85 per cent of distribution revenue. This is the sum of three separate caps: 0.5

per cent related to duration of interruptions, 0.25 per cent for number of interruptions, and 0.1 per cent related to the quality of telephone response. In the last two years of the IIP, the overall cap is 2 per cent of revenue. This is the sum of a 1.25 per cent cap duration of interruptions, a 0.5 per cent cap for number of interruptions, a 0.125 per cent cap for the quality of telephone response, and a 0.125 per cent cap related to the speed of telephone response. Caps are lower in the first year of the plan because of uncertainties associated with the new data definitions and measurement systems. A PES would earn the maximum reward on the number of interruptions indicator by "exceeding" the benchmark by 15 per cent. A PES would earn the maximum reward on the duration of interruptions indicator by "exceeding" the benchmark by 20 per cent. Greater performance gains are required to gain maximum rewards on the duration indicator because Ofgem believed distributors have more ability to improve performance on duration vis–à–vis number of interruptions.

Ofgem also intends to reward PESs that exhibit "frontier" service quality performance when the distribution price controls are updated. This will involve comparing PESs performance on the interruption number and duration indicators. Ofgem acknowledges that factors beyond management control can affect reliability performance and should be controlled for when making inter–utility comparisons. It is accordingly developing a "normalisation" model designed to quantify the impact of these factors, with the goal of promoting more robust comparisons among PESs. Among the factors being examined in this model are customer density, the incidence of severe weather, and tree growth.

3. SCOPE OF SQI FOR QUEENSLAND

3.1 Included and excluded services

The service quality incentive regime will normally cover all electricity distribution services provided by the distributor with two possible exceptions. These are where customers enter into direct contracts with the distributor for the supply of a special, higher quality service and where least cost solutions to improving reliability lie beyond the current regulatory boundary.

3.1.1 *Direct contracts*

The underlying rationale for service quality regulation relates to the distributor being in a monopoly position and customers not having the choice of purchasing from alternative suppliers who may be able to offer different price/quality packages. Service quality incentives are generally applied at the system–wide level and relate to the distributor's overall service quality performance. While some schemes include a measure of the performance of, say, the worst 10 per cent of feeders to avoid the spread in service quality levels becoming too wide, it is impractical to include the service quality levels individual customers receive as part of a general incentive scheme. The need to keep the scheme relatively simple with relatively few (but comprehensive) indicators precludes this.

Some customers, particularly large industrial customers who have special needs for a highly reliable power supply meeting strict technical criteria, are in a position to enter into direct contracts with distributors for the supply of a higher than standard quality power supply. Large customers are more likely to have countervailing power in negotiations with distributors and to be able to devote the necessary negotiating and legal resources to developing and enforcing a satisfactory agreement with the distributor. These contracts are likely to include sanctions against the distributor, usually in the form of compensation payments, if the agreed reliability and technical criteria are not met. They typically include some contribution towards the capital costs of delivering a better quality supply from the customer either in the form of higher prices or direct capital contribution.

Customers who have entered into direct contracts with the distributor should not be included when assessing the distributor's performance for the general service quality incentive as the higher service quality levels they receive will provide an upward bias in observed service levels received by the average customer who does not have a direct contract with the distributor. There may still, however, be a role for the regulator in monitoring compliance with these contracts or in acting as an impartial arbitrator in the event of disputes.

Some distributors have advocated the much more widespread use of contracts with customers in the form of 'price/service offerings' where customers are given the choice between a number of different price and quality combinations. These proposals are examined in more detail in section 3.2.

3.1.2 *Beyond the regulatory boundary issues*

In some instances it may be cheaper for the distributor to address the poor reliability faced by a customer, particularly a remote customer, by providing equipment on the customer's premises rather than by undertaking remedial work on the network serving that customer. While this appears relatively straightforward, it raises a number of issues that need to be addressed by the regulatory regime. Firstly, the current regulatory boundary is at the edge of the customer's premises and expenditure the distributor incurs in providing equipment on the customer's premises would not be allowable in calculating the distributor's revenue requirements for regulatory purposes. Secondly, reliability and technical characteristics are currently measured from the network side of the boundary rather than necessarily reflecting what the customer actually experiences on their premises. In addition, there are likely to be a number of ownership and financing issues associated with solutions the distributor might provide beyond the regulatory boundary.

Beyond the regulatory boundary issues are most likely to be relevant to the situation Ergon faces, particularly regarding the supply of remote customers. As an illustration, Ergon is developing a unit that smooths out dips, surges and momentary interruptions at a customer connection. The unit would benefit rural customers running small offices with computers, computer–controlled irrigation and watering equipment and business faxes by continuing their electricity supply during momentary outages. The unit can seamlessly handle drops in voltage down to 200 volts and over–voltages of up to 275 volts without requiring the complex controls found in more conventional universal power supply (UPS) systems. Although more expensive than conventional UPS systems, the unit could provide benefits to both the customer and the distributor and be a far cheaper solution to the problems of isolated customers than strengthening the network serving the customer.

As things stand, Ergon would not be able to include supply of the unit to the customer in its cost base for calculating revenue requirements and the benefits the customer receives would not be reflected in Ergon's service quality data. Ergon has proposed that it adopt supply of the unit as one of the options it has for improving service quality for the worst performing feeders on the network. Along with the benefits of the unit, the customer would accept a new tariff and load limiting/management conditions (the latter because Ergon is concerned that improvements in the quality of supply would lead to increases in demand that could not be accommodated with existing network infrastructure). A customer could avoid these conditions under the Ergon proposal if they purchased the unit themselves. Customers that did not take up either of these options would remain on the quality of supply provided by the network only. Ergon has proposed that customers with a distributor–provided unit would not be counted in the customer minutes records for outages on that feeder.

Under a service quality incentive scheme operating in conjunction with a revenue or price cap where there are incentives to reduce costs, distributors will have an incentive to provide solutions on customers' premises provided they receive credit for the improved service quality as experienced by the customer (rather than that which is seen from the network side). That is, the distributor will have an incentive to make service quality improvements in the most cost effective way, including substituting 'customer side of the meter' investments for network investments. This is true even though investments beyond the regulatory boundary are not included in the revenue requirements base. Rather, they directly earn rewards through the service quality incentive and the firm will pursue them as long as the marginal rewards are greater than the marginal (net present value) costs of providing this solution. Since the investments are long–lived, this requires confidence that there will be regulatory commitment and the current rewards will be retained over the life of the investment.

Rather than excluding the customer minutes records for outages on the feeder of those customers with distributor–provided units, it would be preferable under a service quality incentive scheme to include measures of the outages as observed by the customer (ie after the unit has played its part in reducing the outages observed by the customer). This is because the rewards and penalties the distributor receives under the scheme are linked to customer valuations of service quality changes. The rewards/penalties the distributor receives then need to be consistent with the changes the customer experiences. Facilitating the measurement of outages as seen by the customer rather than the network may require additional expenditure and verification processes.

3.2 Price–service offerings and service quality incentives

Another issue that relates to the coverage of the SQI is price service offerings (PSOs). PSOs refer to quality–differentiated variants of the basic electricity distribution service. Under a PSO approach, distributors would offer a number of distribution options with different quality levels, and higher quality services would command higher prices. Customers could then choose the price–quality option that they desired. A recent report describes PSOs as 'mechanisms for recreating the customer choices and other conditions that prevail in workably competitive markets.'[6] In other words, PSOs are designed to extend customer choice and competition from power supply and retailing activities, where they have mostly been applied to date, to the power distribution service.

PSOs have a direct bearing on the coverage of the SQI. By definition, PSOs offer differentiated quality levels to customers and allow customers to select a quality option that reflects their preferences and willingness to pay. This bears some resemblance to a competitive market where, as discussed in the previous chapter, competitive forces naturally create incentives for companies to provide the quality levels that customers desire. If a PSO can replicate these same market forces, then the quality of power distribution services provided to customers is also likely to be appropriate. This would reduce the need for SQIs and for service quality regulation more generally. This would be analogous to power supply and other services, where customer choice and competitive forces have largely substituted for regulation in many jurisdictions.

Energex has been the leading advocate of PSOs in Queensland. PSOs have been central to Energex's proposals for the form of regulation, the principles that should guide the update of revenue controls, and the company's overall strategic vision. In consultation on this project, Energex has said it believes a SQI regime is compatible with any PSO program the company may introduce in the next regulatory period. Over time, though, Energex would like to see PSOs expand and take on some of the role of the SQI.[7]

Energex's PSO proposal is certainly intriguing and, if successful, could even be revolutionary. However, at the present time we do not believe that PSOs either can or should

[6] *Assessment of Price-Service Offerings*, Report by Stephen Littlechild, December 4, 2002.
[7] 6 May 2003 e-mail correspondence, Energex to Larry Kaufmann.

substitute for an SQI. We also believe PSOs should be implemented through contract with selected customers rather than network–wide. Our analysis of the PSO issue in this report is far from exhaustive, but we will highlight three issues regarding Energex's PSO proposal that merit attention in the context of an SQI and further research during the next regulatory period. The first concerns the service quality indicators treated under Energex's current PSO proposal. The second is related to investments the company may make to achieve service quality targets under a PSO. The third stems from the nature of customer choice under the PSO and whether regulation is required even in a fully developed PSO approach. We deal with each of these issues in turn.

3.2.1 *Details of current PSO*

The broad outlines of Energex's PSO proposal are spelled out in the company's submission on the form of regulation. Three price–service packages are specified in this document: the 'essential' option, the 'value' option, and the 'premium' option. The quality features that differentiate these options are itemised in the submission. But it is clear from this list of features that none deal with reliability or voltage issues. We believe reliability measures, in particular, are central to nearly all customers' perception of the quality of their electricity distribution services. Indeed, the reliability of service is the main service quality concern for most customers. It would not be reasonable to expect PSOs, in and of themselves, to deliver appropriate quality levels to customers if they do not address these fundamental aspects of 'service.' Since the Energex PSO proposal does not in fact address reliability or voltage issues, we agree with the company that PSOs cannot substitute for a SQI in the next regulatory period. Beyond this perhaps transitional concern, however, there are at least two fundamental issues regarding PSOs and their relationship to service quality regulation that we analyse below.

3.2.2 *Asset specificity*

One of these issues concerns what economists refer to as 'asset specificity' and the risks of recontracting. Network services rely heavily on what are known as relationship–specific assets. These are assets dedicated to serve specific customers and whose costs are almost entirely sunk. A 'sunk' cost refers to one where the next best return on the asset is well below its value to the owner. For electricity distribution and other network industries, these assets are long–lived and cost recovery occurs (via regulated prices) over a multi–year period.

The nature of the assets creates 'recontracting' risk for companies. That is, once the assets are in place, companies are at risk for changes in the terms of contracts with customers since the assets have much lower values in their next best uses. If the services provided by the assets are regulated, this 'recontracting' risk pertains to regulatory recontracting, or regulators changing the terms of the (usually implicit) regulatory contract at price reviews in ways that do not allow companies to fully recover their costs. Such recontracting has the short–term benefit of lower prices but longer–term costs as investment is driven from the industry. The Productivity Commission (2001) and many others have noted this phenomenon, and the need to attract capital is an important motivating factor for the 'workably competitive market' paradigm.

It is not as common for relationship–specific assets to be found in competitive markets, but there are some instances. One example is a mine mouth generating plant built at the site of a coal mine. Once this investment is made, companies are at risk of recontracting by the coal producers, since the nature of the investment limits the ability to switch to other fuel suppliers. Such risks are usually contained via long–term contracts between the firm making the investment and the fuel supplier. These contracts are analogous to regulatory or legal protections that grant investors the opportunity to recover their costs and make a reasonable return on long–lived assets.

This issue could also be relevant for PSOs that are applied to network services. Suppose that, at some point, a company must invest capital to achieve the quality levels contained in a value or premium service offering. These investments are made to serve the customer or group of customers selecting the higher–quality services. But once the distributor has made these investments, and higher quality levels are expected to follow, customers have strong incentives to recontract and switch back to a base case, lower quality option. The company cannot pull its invested capital out in response, at least not without incurring additional costs. As a result, customers can now obtain higher quality service at a lower price simply by exercising their rights to select among network service offerings.

In principle, this problem could arise any time customers are bound to the network service for a period of time that is less than the lives of the assets needed to provide the higher quality service. While it may be reasonable to place limits on customer switching between PSOs, it would not be reasonable to bind customers to network service contracts for the lives of network assets (often 40 years or more) after they have made an initial price–service offerings selection. Such restrictions on switching would make a mockery of customer 'choice'. Although customers do make purchasing choices on other long–lived products, customers can almost always resell these assets in secondary markets, which limits the extent to which they are 'locked in' after making an initial choice. This clearly is not possible with network delivery services.

Inspecting Energex's initial PSOs, it appears that many of the factors that differentiate quality between the alternatives would not necessarily involve new investments or associated recontracting risks. However, that cannot be ruled out in all cases, particularly for options that addressed reliability or voltage, and these concerns remain especially relevant since price–service offerings are designed to encourage innovation and further tailoring of services to meet diverse customer demands. In a capital–intensive business like electricity distribution, this may entail capital investments at some point.

Given the above, it follows that PSOs can pose financial risks to distributors because of the very nature of the electricity distribution business and the assets needed to provide, and differentiate, distribution service. Certain regulatory protections, like stranded cost recovery, could perhaps contain these risks but may place an undue burden on consumers. Furthermore, such measures raise a whole host of other complications and seem incompatible with the concept of enhancing flexibility and extending the concept of choice to the network level. While the amount of relationship–specific assets involved in PSOs is ultimately an empirical question, we believe the issue of recontracting risk deserves attention in any PSO proposal to ensure that there are no 'hidden' costs for customers or risks to distributor shareholders or regulators, who have the ultimate responsibility for ensuring that customers receive appropriate service quality.

3.2.3 *PSO monitoring and appropriate penalties*

Another concern is that even a fully developed PSO would seem to require a substantial role for regulators. Fundamentally, this is because the ability of PSOs to replicate the choices available to customers in the marketplace is constrained by the nature of the electricity distribution service. The practical operation of a PSO could thereby give distributors new opportunities to exercise monopoly power rather than enhance customer choice.

This point can be illustrated by considering how PSOs compare with the operation of competitive markets. As discussed in chapter 2, firms in the marketplace provide a range of products with different price–quality terms. Customers choose among the available alternatives, and select those that most appeal to their price–quality preferences. Firms that can best match their product offerings with customers' price–quality preferences are rewarded with extra sales and profits, while firms that are less successful in doing so are penalised. A company's rewards and penalties therefore reflect its ability to retain existing customers and attract new customers relative to competitors.

In contrast, customers choosing among PSOs don't switch between different providers but rather between the price–service offerings of a single provider. A firm's rewards and penalties depend in part on its ability to get customers to switch from relatively low profit to high profit offerings. While this is also true to some extent in competitive markets, the nature of the choices still differ considerably.

In the market for nearly all products, consumers essentially face four choices: to choose from among the various product options that are available; to consume a related good or service that satisfies the same preferences; to postpone consumption until a later date; or to forgo consumption altogether. The latter two options become more viable for products viewed as 'luxuries' rather than 'necessities'. However, even the most necessary products that address basic human needs (eg food and clothing) can generally be satisfied with a vast array of possible products.

This is not the case for electricity distribution. This service is clearly essential and cannot be forgone without leading to a significant decline in welfare for the consumer and society as a whole. Electricity as a commodity is non–storable and therefore must be consumed in real-time. For nearly all customers, there are also effectively no other substitute products.[8] Under a PSO provided by a monopoly distributor, customers would therefore have to choose from among the price–service offerings that the distributor makes available to them. Customers have no ability either to 'opt out', temporarily or permanently, or to take service from another firm. There is, therefore, a lower bound to customers' demand for distribution service equal to the lowest quality PSO made available. Customers exercise choice relative to this minimum and effectively decide whether they should pay more for

[8] Although electricity competes with other fuels for a variety of end-uses, almost all consumers use electric power in end uses for which there are no good substitutes. Therefore, nearly all customers will have a need for some electric power and therefore for power distribution.

higher quality services. There is no guarantee that the minimum package is provided at an efficient price that provides consumers with 'value for money'.

In this context, the terms that are set for the minimum price–service offerings will clearly influence customer behaviour. These terms will include penalty payments that are made to the customer for failure to deliver the quality levels written into the contract. A customer comparing available PSOs rationally takes these penalty payments into account, and the decision on whether to switch to a different PSO depends in part on whether these payments adequately compensate for failures to perform under the current plan. If customers have been adequately compensated, they are less likely to switch. But if they have not, it could be rational for consumers to choose a higher valued PSO in order to avoid the poor service they have been receiving.

This point is directly related to the distributor's behaviour and whether there is a need to regulate the terms of PSOs. The distributor ultimately controls the terms of the PSO contract, including the amount of penalty payments. The company may be able to set these terms and penalty payments in a way that induces customers to choose higher quality options than they would otherwise select. If this occurs, consumer choices would not reflect underlying price–quality preferences but rather the lack of appropriate compensation for quality problems under a given PSO. This type of switching would result from the distributor's monopoly power rather than market–driven choices that reflect customer preferences.

This point can be illustrated through an example. Consider a customer who is trying to decide between the Essential and Value PSOs. The customer experiences service quality problems under the Essential package that have a value to him of $30 per year. Assume that the penalty payments associated with these service quality problems are also equal to $30 per year. If the customer switched to the Value PSO, these service quality problems would disappear, plus the customer would receive the higher service levels associated with this PSO. Assume that switching from the Essential to the Value PSO has a value to the customer of $40 per year. Of this extra value, $30 is due to elimination of the service quality problems in the Essential package, and $10 of this extra value is due to the higher level of service provided in the package. Assume that the company does in fact perform to these levels and therefore does not provide penalty payments to customers choosing the Value package. Also assume that the initial annual charge to the customer is $100 for the Essential package and $120 for the Value package, and the company's cost of providing service is equal to $50 for the Essential package and $70 for the Value package. This situation is summarised in the data below:

	Essential	Value
Charge to customer	100	120
Penalty payments to customer	–30	0
Net charge to customer	70	120
Change in value to customer	–	40
Cost to company	50	70
Profit for Company	20	50

Here, the net charge to the customer is equal to the total charge for the service minus the payments to the customer for failure to perform up to the PSO standards. The company's profit is equal to its net charges (which include the cost of penalty payments) minus the cost of providing the service.

In this example, the company earns a higher profit if the customer chooses the Value rather than the Essential service package ($50 versus $20). It would therefore like the customer to switch to the Value PSO. However, the customer is not willing to switch since the increase in the net charge for the service of $50 is greater than the increase in the value of the service to the customer of $40. Equivalently, the $20 increase in the charge for the service (excluding differences in penalty payments) is greater than the $10 increase in value to the customer associated with the package. The additional cost of the Value service is not worth it to the customer, so he stays with the Essential package.

Now consider an identical situation, except for a difference in penalty payments. Let the annual penalties for failure to deliver the service levels in the Essential PSO be equal to $8 rather than $30. The situation is now as follows:

	Essential	Value
Charge to customer	100	120
Penalty payments to customer	–8	0
Net charge to customer	92	120
Change in value to customer	–	40
Cost to company	50	70
Profit for Company	42	50

As before, the company earns higher profits under the Value package ($50 versus $42), so it would like for customers to select the Value option. With this penalty structure, the customer does in fact choose to switch to the Value option. Here, the change in net cost to the customer ($28) is less than the change in value ($40), so the customer decides to switch. But this switch does not reflect underlying price–quality preferences. As noted, the customer only places a $10 value on the change in quality associated with the Value package relative to the Essential package and, therefore, should not be willing to pay more than an additional $10 for this service. The customer chooses to switch only because the Essential PSO failed to compensate him appropriately for the degradation in service that he experienced under the plan. In essence, the customer is being induced to 'flee' poor quality and not to select higher quality because it reflects his underlying preferences.

Although this example is somewhat simplistic, it does demonstrate that customer choices can depend not just on the price–quality terms for the offered services but also on payments for failure to deliver quality. The extent to which these payments actually compensate customers for the losses they experience with possible quality degradation can influence their purchasing decisions. The power distributor may be in a position to set these terms in a way that induces customers to select higher price and higher value PSOs even if those choices don't really reflect their underlying preferences. Clearly, this is different from competitive markets, where customers face a richer array of choices and can postpone or forgo consumption or purchase related products. Here, the customer cannot 'trade down' to an alternative or lower quality service but may be induced to 'trade up' in order to obtain more appropriate quality levels.

This discussion implies that regulators will retain a role in regulating PSOs. This role will include more than simply adjudicating disputes or monitoring compliance with the terms of contracts. Regulatory responsibility should include evaluating the terms of the contracts, particularly whether penalty payments for poor quality are sufficient. Ultimately, this role results from the fact that electricity distribution will remain a monopoly service, and PSOs are not capable of replicating the type of consumer behaviour that occurs in competitive markets and creates incentives for companies to provide appropriate quality levels.

3.2.4 *Conclusion*

Energex has made a serious proposal with its PSO. Indeed, if it can be successfully implemented, the PSO approach could be revolutionary, since it would extend the principle of choice and quality differentiation to the provision of power distribution services. In principle, this would represent a potential gain in consumer welfare and would help to make distribution services more competitive.

At this point, however, we do not believe the PSO can substitute completely for a SQI. Important service quality indicators are not covered by the price–service offerings, there are unresolved issues regarding asset specificity and recontracting, and there would seem to be a continuing need to regulate the terms of PSO contracts in any case. We, therefore, believe that any PSOs should be voluntary and outside the provisions of the SQI.

4. QUALITY INDICATORS

4.1 Choosing quality indicators

A critical issue in the development of an effective SQI plan is the choice of indicators on which performance will be judged. To implement a service quality incentive scheme, objective, quantifiable and verifiable performance indicators are required. Kaufmann and Lowry (1999) note that the included service quality indicators should satisfy four criteria:

- they should be related to the aspects of service that customers value;
- they should focus on monopoly services;
- utilities should be able to affect the measured quality; and
- the indicators should not ignore pockets of service quality problems.

First, since measured service quality can ultimately affect customer rates, indicators should be linked to aspects of utility service that customers actually value. This may seem obvious, but a strict application of this criterion excludes indicators that have been included in some plans. For instance, the knowledge and courtesy of phone centre employees may be a legitimate quality indicator, but the goal of establishing worker training programs to build these skills is not.

Second, indicators should focus on the quality of the activities for which there are few if any alternative suppliers. This is consistent with the principle that regulation, including regulation of service quality, is less necessary in competitive markets. Market forces are likely to create acceptable quality levels when products are available from multiple providers.

Third, utilities should be able to influence measured quality through their own behaviour. It is nonsensical to link shareholder rewards or penalties to outcomes that are unrelated to management actions. As we discuss further in the next sub–section, the measured quality of energy distribution service is also potentially influenced by a number of external factors that are beyond managerial control. These factors vary substantially between distributors and some are quite volatile. If random or unforeseen incidents can affect important quality dimensions, the impact of these events should be eliminated from the indicators.

Overall, quality indicators should not focus on some areas while ignoring others because performance may deteriorate in the non–targeted areas. Comprehensiveness can be achieved simply by adding indicators to a plan. However, regulatory costs often rise accordingly since more utility and regulator resources must be devoted to quality monitoring and measurement of quality indicators. Some regulators have been sensitised to the regulatory costs of complex service quality plans. In these jurisdictions, service–quality incentives have been simplified by relying on fewer, but more broadly–based, indicators.

Considerable work has been done recently to standardise the definitions and reporting of service quality indicators across Australia (Utility Regulators' Forum 2002). The QCA commenced reporting distributor service quality performance using largely similar definitions in the September quarter, 2002. Service quality indicators are reported for reliability, technical quality and customer service. There are obvious advantages in using the indicators developed as part of this process, wherever possible, to maximise the scope for consistent performance comparisons.

4.2 Reliability indicators

The principal reliability indicators relate to the duration and frequency of interruptions. The system average interruption duration index (SAIDI) measures the total number of minutes, on average, that a customer on the distribution network is without electricity in a year. It excludes momentary interruptions of one minute or less. The system average interruption frequency index (SAIFI) measures the average number of times a customer's supply is interrupted in a year (excluding momentary interruptions). A third index, the customer average interruption duration index (CAIDI), can be obtained by dividing the SAIDI by the SAIFI to show the average duration in minutes of each interruption a customer on the network faces. Where measurement systems permit, momentary interruptions are measured by the momentary average interruption frequency index (MAIFI).

Most service quality incentive schemes exclude interruptions that are beyond the distributors' control (such as generation directed load shedding and transmission failures) and some degree of allowance for 'exceptional' natural events that the distributor could not have reasonably been expected to allow for. While there is general agreement that the former category is beyond the distributors' control, the second category can be a source of much debate and argument over exactly what constitutes a rare and extreme natural event that might lie outside prudent planning parameters.

Some schemes distinguish between interruptions that are planned and unplanned with greater weight usually being placed on unplanned outages that cause customers more inconvenience. However, too much focus on unplanned outages may simply create an incentive for distributors to have a higher number and duration of precautionary planned outages that also inconvenience customers.

Consistent with the Utility Regulators' Forum (2002) recommendations, current Queensland reporting covers four separate feeder categories: central business district, urban, short rural (less than 200 kilometres) and long rural (greater than 200 kilometres) feeders. While the current Victorian service quality incentive scheme combines the two rural categories to reduce variability and ensure all distributors have only two categories to report, the greater prevalence of long rural feeders in Queensland given the larger size of the state supports retention of the separate rural components.

To address the issue of the spread of reliability performance as well as the average, some service quality incentive schemes (such as that operating in South Australia) also include the performance of a given number of the worst performing feeders. The QCA currently collects data on worst performing feeders in Queensland.

4.3 Technical quality indicators

Technical quality indicators principally relate to the voltage characteristics of the electricity supplied. Voltage characteristics will be particularly important to large industrial customers. Most Australian distribution systems are not currently well placed to collect detailed data on the technical quality characteristics of supply across their systems although improvements in computer technology mean that some are making good progress in this area. As a result, the most common source of information on technical quality issues is the number of complaints received. Current Queensland reporting follows the Utility Regulators' Forum (2002) recommendations with complaints data relating to:

- low supply voltage;
- voltage dips;
- voltage swell;
- voltage spikes;
- waveform distortion;
- TV or radio interference;
- noise from appliances; and
- other.

While the number of complaints is only a rough proxy for the number of technical quality breaches, they can provide a starting point for an incentive scheme until such times as system reporting methods capture actual technical quality breaches more accurately.

4.4 Customer service indicators

The main dimensions of distributor customer service identified by the Utility Regulators' Forum (2002) and currently reported for the Queensland distributors relate to call centre performance, the timely provision of services, the timely repair of faulty streetlights and complaint handling. The indicators reported include:

- percentage of calls not answered within 30 seconds;
- percentage of calls abandoned;
- number of call centre overload events;
- percentage of connections not provided on or before the agreed date;
- average percentage of streetlights 'out' during each month;
- average number of days to repair a faulty streetlight;
- percentage of planned interruptions for which the required notice was not given; and
- percentage of complaints not resolved within 20 days.

Some North American service quality incentive schemes also include indicators developed around safety performance, metering and billing, non–emergency on–site repairs and customer satisfaction.

4.5 Coverage of the incentive scheme

It is important for the service quality incentive scheme to concentrate on those aspects of service quality that are of most concern to customers. However, it is also important to have at least some representation from each of the three main aspects of service quality – reliability, technical quality and customer service – as failure to include some aspects may provide an incentive for distributors to reduce service quality in those areas. Including representative indicators from the gamut of service quality attributes provides an important signal to distributors.

Reliability has traditionally been the major concern of consumers in Australia and overseas and this is reflected in the focus of most SQI schemes on reliability. Improving system reliability is the usually the highest priority compared to improving customer service and, for most customers, technical quality. Consequently, the primary focus of the current SQI proposal will also be on improving reliability. Reliability indicators are also among the most developed and work is well advanced on making the data reported across distributors consistent.

Some customer representatives expressed the view that Queenslanders were not receiving ‘value for money’ from their electricity distributors in that charges were similar to those in other states but the reliability performance was allegedly inferior. Hence, they questioned whether they should be expected to pay more to bring their service quality up to a level comparable to that found in other states. However, it is important to bear in mind that ‘value for money’ is an inherently relative concept and has to take account of a range of complex factors such as the different operating conditions faced by distributors. At this stage there is insufficient information available to fully assess the Queensland distributors’ performance relative to other Australian distributors or, as indicated in the following chapter, to use the performance of interstate peers as a benchmark. The development and implementation of the SQI will itself help to address this data deficiency. Furthermore, the operation of a ‘paper trial’ until such times as the Queensland data becomes sufficiently robust to form good historical benchmarks will also provide a direct benefit to consumers as distributor performance improves before the scheme formally commences.

While technical quality is also of particular importance to some major customers with voltage dips having caused major plant shutdowns in the past, solutions to these problems are best tailored to this small group of large customers. While these incidents have been of major concern and expense to these customers and have the potential to affect Queensland’s competitiveness, they will be most effectively handled in the short term by direct negotiations and contractual arrangements between the relatively small number of major customers and the distributors rather than through a general service quality incentive scheme. Data on technical quality in other parts of the network is not yet readily available and this aspect is generally less critical to smaller industrial, commercial and residential customers.

For the service quality incentive scheme to be comprehensible, the indicators included must be relatively few in number, be generally understood, not be subject to inconsistent definitions across utilities and the data required to support the measures must be readily available. To ensure that the measures capture as much of the relevant reliability/service quality dimension as possible, they also need to be comprehensive in nature. The trend in US service quality incentive schemes is to include a few broad measures in preference to many detailed measures.

The indicators recommended for the Queensland service quality incentive scheme span a total of five indicator types and four feeder types as shown in table 1 below.

ENERGEX has a total of 10 indicators while Ergon has a total of 11. ENERGEX has no long rural feeders category while Ergon has no CBD feeder category. While the urban, short rural and long rural feeder categories have total SAIDI and SAIFI for the category as a whole and total SAIDI for the worst 10 per cent of feeders in the category, only total SAIDI and SAIFI for the CBD category as a whole are used. Since the Brisbane CBD network is highly intermeshed, customers are supplied by a number of feeders, and interruptions would generally only occur due to a system–wide fault or at times when the system is configured atypically (eg during maintenance). Therefore, it is not likely to be accurate to assign a failure to the performance of a particular feeder and not appropriate to look at the performance of the worst 10 per cent of CBD feeders separately.

Table 1: **Recommended service quality incentive scheme indicators**

Feeder type	*Indicator*	*ENERGEX*	*Ergon*
CBD	SAIDI	v	
	SAIFI	v	
Urban	SAIDI	v	v
	SAIFI	v	v
	SAIDI worst 10%	v	v
Short rural	SAIDI	v	v
	SAIFI	v	v
	SAIDI worst 10%	v	v
Long rural	SAIDI		v
	SAIFI		v
	SAIDI worst 10%		v
System	Total quality of supply complaints (no.)	v	v
	% calls not answered in 30 secs	v	v

While the definitions of the main SAIDI and SAIFI indicators are clear cut, although some measurement issues do still exist, the definition of what constitutes the 'worst 10 per cent' of feeders is open to alternative interpretations. Some jurisdictions define the worst feeders category in terms of an absolute number of feeders, eg 40 in the case of South

Australia. However, defining a proportion of feeders could be done in terms of either the proportion of customers served by those feeders or the proportion of the distributors' total load normally provided by those feeders. The proportion of total load could in turn be defined by either the amount of installed kVA capacity of particular feeders or by the estimated total interrupted load (eg based on historical consumption patterns of particular classes of user).

While using the proportion of electricity supplied to define the worst feeders category has many attractions, the distributors indicated they would prefer to report worst performing feeders by customer–weightings. Customer–weightings are the industry standard and reflect the actual impact of outages on customers. They would also be reporting overall SAIDI and SAIFI figures on the basis of customer–weightings, so it could be argued to be anomalous to report worst feeders by connected kVA. Since defining the worst 10 per cent of feeders as those feeders that serve at least 10 per cent of customers is more consistent with established practice and data sources, we recommend that this definition be adopted.

Another issue to be resolved with the worst 10 per cent of feeders category is how often the composition of this category is to be updated. Annual resetting of the targets would require an annual redetermination of the worst 10 per cent of feeders. The distributors indicated they would be concerned if the list of worst performing feeders was redetermined as frequently as annually since it may encourage the application of strictly short–term solutions to reliability problems for these feeders. At present, both distributors have a number of reliability improvement projects running for identified sensitive areas. Analysis of the time–frames for implementing reliability improvements in these areas would suggest that it takes time for solutions to be implemented and for resulting improvements to flow through. Accordingly, ENERGEX suggested that the list of worst performing feeders be updated only every three years. However, not updating the list of worst performing feeders annually is likely to lead to customers receiving bad service feeling that the scheme is not addressing their needs. Consequently, we believe the benefits from updating the list of worst performing feeders annually outweigh any potential transactions costs for the distributors. The composition of the worst feeders list is unlikely to change dramatically from year to year with a core group of feeders with inherent weaknesses that will take some time to overcome (if it is cost–effective to do so) and a small group that reflects more unusual short term events and whose make up may change more frequently

It is recognised that the quality of supply complaints indicator is a very imperfect reflection of the technical quality of supply. However, in the absence of robust, objective data it is the only available starting point. In particular, it may be difficult for individual customers to distinguish between voltage dips and momentary interruptions. Voltage dips may be caused by events at the user's premises such as sudden load changes due to switching on or off of appliances such as air conditioners or washing machines or faulty neutral clamps. Network–related events such as the distributor switching on and off interruptible load such as hot water load or faults on part of the network that affect other parts of the network can also cause voltage dips. Momentary interruptions, on the other hand, are complete losses of supply that only last a short duration. Future work in this area should concentrate on developing the capacity of distributors to accurately monitor and report the technical quality of supply across the network and the occurrence of momentary interruptions.

Measuring call centre performance also presents a number of problems as both the Queensland distributors share call centres with their sister retail organisations. ENERGEX indicated that its incoming calls are assigned to eight queues (electricity; gas; loss of supply; emergency; E–commerce; business service centre; sales and support; and Energy Institute). Calls to the business service centre, sales and support, and Energy Institute queues are considered to be retail–related while calls to the loss of supply and emergency queues are considered to be distribution–related. However, given the diverse range of enquiries assigned to the electricity, gas, and E–commerce queues, it is frequently difficult to determine whether calls to these queues relate to a distribution or retail function. For example, calls to the E–commerce queue may relate to applications for supply (a distribution function) or registering new customers (a retail function). In view of the large number of calls received, ENERGEX makes an operational assumption to assign calls to the electricity, gas, and E–commerce queues equally between retail and distribution–related functions. Distribution–related call centre performance can then be measured on the basis of the performance of the distribution–related queues, and a fifty per cent weighting of the performance of the electricity and E–commerce queues.

Ergon indicated that its call centre response times are not separated out into retail and network due to the difficulty in defining what applies to network and what applies to retail. In many cases, calls could be put into either or both camps. For example, calls about customer connection or customer transfer (together constituting a great many calls) are both a retail and network function. That is, if network and retail were completely split apart, both calls centres would need to provide this function. Other calls are not defined into either camp – for example, general enquires or complaints are not tagged network or retail. In light of this, Ergon indicated that the response times for the whole call centre would be a good approximation of network call response times as distribution and retail calls are homogenous and treated the same.

Given the limited information currently available, the distributors' proposals for the best way to measure their call centre performance appear reasonable.

4.6 Exclusions

The QCA's current exclusions policy allows three types of events to be excluded from the electricity distributors' reliability measures:

- exceptions – interruptions within the distributor's network where at least 5 per cent of the customers in the distributor's geographical region are affected by widespread storms and flooding or other natural disaster;
- transmission – interruptions within the Powerlink transmission network; and
- generation – interruptions due to generation deficiency normally resulting in load shedding.

The QCA's gas reporting scheme currently allows no exclusions but electricity distribution is inherently more exposed to the elements and the influence of exogenous factors than is gas supply. Also, what is appropriate for a performance monitoring scheme may not be appropriate for an incentive scheme.

For an electricity distribution SQI, it appears reasonable to exclude outages caused by generation and transmission failures or deficiencies from the distributors' service quality incentive scheme as distributors can only influence the performance of these parts of the industry in a relatively indirect way. It is also reasonable to exclude certain large and rare natural disaster events that it would not be economic for the community to provide complete protection against. While it seems attractive to assess these events on a case–by–case basis, experience in Victoria has shown that this can be problematic as there is generally insufficient data available to base an assessment of what is truly a 'rare' event on. Basing exclusions on threshold size criterion appears to be preferable.

The Utility Regulators' Forum (2002) recommended the exclusion of outages that exceeded an overall SAIDI impact of 3 minutes, where the outage was caused by an exceptional natural or third party event, and the distributor could not reasonably be expected to have mitigated its impact through prudent asset management. This threshold does, however, appear too low. The current Queensland requirement that at least 5 per cent of the distributor's customers be affected by the natural disaster appears preferable. Consequently, we recommend that the QCA's current exclusions policy be retained for the service quality incentive scheme. This would involve the distributor making the case for exclusion using the same rules that currently apply to electricity service quality monitoring reports and providing detailed information on events beyond their control. This approach to exclusions would also allow the QCA to audit the data in an appropriate fashion.

4.7 Data availability

Reliability data for the Queensland distributors is not as consistent nor available for as long a time period as is the case in Victoria where the former SECV had set up good information systems prior to the privatisation of the distribution sector.

Having been formed from six regional electricity boards, all of which had different data collection methods, Ergon has moved to collect consistent, system–wide reliability information. Ergon now has more robust data for 2001–02 and 2002–03. Prior to this it has data going back to 1999 from legacy systems but this data is incomplete. Ergon introduced an integrated Outage Management System in July 2001 to ensure that all outages are now captured. Historical data for Ergon show a significant increase in the recorded outage statistics since the introduction of the new system, probably implying nearer 100 per cent of outages are now being recorded. Ergon is making continuing improvements to the quality, meaningfulness, and reportability of its data as enhancements are progressed. Projects are presently under way to install monitoring devices throughout the network that will report on sustained and momentary outages, quality of supply, and statistical metering data.

ENERGEX has collected system–wide reliability statistics in their current format since January 1997. Reliability statistics collected prior to this date are unlikely to be comparable. However, current reporting of reliability statistics is not fully accurate as it is based on estimated customer numbers. Actual customer numbers cannot exactly be determined because ENERGEX's databases only have connectivity down to the low voltage (LV) mains and not to the LV service connections. Thus, ENERGEX cannot identify the total number of customers connected to particular LV feeders.

At present, ENERGEX estimates customer numbers based on loadings on the 11 kV network and growth in billing records. This means that ENERGEX examines historical kVA loadings on particular feeders and updates these loadings for growth in billing records to arrive at a determination of the kVA loading per feeder. ENERGEX then estimates customer numbers interrupted on individual transformers on the assumption that each LV customer consumes 2 kVA on average.

ENERGEX is implementing a three–stage project to determine actual customer numbers and to identify customers' point of connection to each feeder. These projects are scheduled for completion by the end of June 2004, enabling ENERGEX to report reliability on the basis of actual customer numbers from July 2004. At this stage, it is not known what effect the transition to reporting on actual customer numbers will have on ENERGEX's reliability statistics. It is not clear once actual customer numbers are available whether ENERGEX will be able to correct historical data reported on estimated customer numbers.

We believe it is appropriate to base a financial year's incentive on reliability estimates up to and including the last financial year. Given the administrative lags inherent in the Queensland regulatory system before a reward or penalty can be implemented as changes have to be made on the basis of regulatory accounts, this allows sufficient time for the data to be verified and for decisions to be made about any applications for exclusions. It allows all components of the regulatory package to be processed and implemented at the one time each year rather than occurring in a piecemeal fashion through the year. Some performance indicators such as the reliability of the worst performing circuits are also only currently reported at the end of the financial year. Given these constraints it would not be possible to implement rewards and penalties for the 2005–06 financial year, for instance, until the beginning of the 2007–08 financial year. While a shorter delay between performance and reward such as basing a financial year's payments on performance in the preceding calendar year as is currently done in the ACCC's electricity transmission SQI scheme would be desirable, practical constraints make this infeasible for Queensland distribution.

The data difficulties outlined above will limit the accuracy of the information available for the commencement of the service quality incentive scheme in July 2005. ENERGEX's performance reporting for the 2004–05 financial year will be the first using its new reporting scheme using actual customer numbers which is scheduled to only come on stream in July 2004. It will most likely take some time for the new reporting basis to be bedded down and produce stable and consistent results. This has certainly been Ergon's experience following the introduction of its new Outage Management System. Given these data problems it may be desirable to operate the SQI on the basis of a 'paper trial' for the first few years until more confidence can be placed in the available data and initial teething problems are ironed out. It may also be appropriate to formally commence the operation of the scheme at different times for the two distributors if the data of one of them is sufficiently robust before that of the other.

4.8 Future refinements

Over time as experience with the service quality incentive scheme increases, the number of indicator types could be expanded somewhat and/or the focus of the indicators changed. However, the five indicator types currently recommended should probably not exceed nine even in the long run in the interests of keeping the scheme focussed and readily comprehensible. Once the reliability of the system is improved and data availability improves, the focus may change to place more weight on different dimensions of customer service. The priority for the second regulatory period should be including separate measures of momentary interruptions and robust and objective measures of the technical quality of supply.

5. QUALITY BENCHMARKS

5.1 The quality benchmarks and deadbands

5.1.1 *Benchmarks*

Quality benchmarks are the standards against which measured quality is judged. It is also common to have 'deadbands' around the benchmarks, or a zone within which utility performance is neither penalised nor rewarded. As with the quality indicators, some basic criteria can be used to evaluate the design of performance benchmarks and deadbands.

One important criterion is that benchmarks should be calculated on the same basis as the quality indicators. If the data used to measure quality are not comparable to those used to set the benchmark, the SQI plan will be unworkable in that it will not be possible to determine how the utility's performance compares to the benchmark and, therefore, whether there is a basis for rewarding or penalising the utility. This is almost literally a case of 'comparing apples to oranges'.

Benchmarks and deadbands should also reflect external business conditions in a utility's service territory. In the present context, external business conditions can be defined as factors that affect measured quality performance but are beyond the control of utility management. The list of relevant factors includes weather, the degree of ruralisation in the territory (typically increasing response times to customer calls for on-site service), the mix of residential, commercial, and industrial customers, the incidence of poverty, the rate of growth in customer numbers, the tendency of customers to relocate, and regulatory changes such as a restructuring of the industry to promote competition. Such factors differ across companies and may change over time for each individual company. Some are volatile in the sense that they are prone to fluctuations that are hard to predict.

External business conditions ultimately reflect exogenous factors that affect the demand for and supply of quality. The demand for service quality depends on customer preferences which, for power distribution, depend on the customer base. If the distributor has a high proportion of large industrial customers who are dependent on continuous power supply of a consistent technical quality then there will be a higher demand for service quality than in the territory of a distributor who supplies mainly residential customers. However, the increasing reliance on computerised equipment, the increasing trend for small business people to operate from home and the emergence of hobby farm areas in previously rural territory are all leading to increasing demands for higher levels of service quality over time.

Similarly, the supply of service quality depends on the distributor's marginal cost of supplying quality which depends, among other things, on the distributor's operating conditions. A distributor supplying a dense urban network in moderate climatic conditions will have lower marginal costs of improving service quality than a distributor supplying a sparse rural territory spread over long distances subject to climatic extremes. The equilibrium price and level of service quality depends on both the quality demand and supply characteristics the distributor faces. This influences both the quality benchmarks which are most appropriate for the distributor and the award and penalty rates that should be incorporated in the scheme. The latter are addressed in detail in the following chapter.

A failure to control for these business conditions can expose utilities to arbitrary penalties and rewards. For example, consider a SQI plan where a utility is rewarded or penalised depending on how its measured quality compares to that of another utility. Assume that both companies measure every quality indicator in the same way. This plan would still lead to unreasonable penalties or rewards if one utility had a more demanding territory (eg more severe weather). Not controlling for the effect of business conditions in that service territory would tend to handicap the utility serving that territory and, over time, lead to penalties that did not reflect its real quality performance.[9]

Third, benchmarks should be as stable as possible over the term of a SQI plan. Stable benchmarks give utility managers more certainty over the resources they must devote to providing adequate service quality, as reflected in those benchmarks. It is harder for managers to hit a 'moving target', particularly if operational changes can only be implemented over longer periods. Stable benchmarks therefore promote more effective, longer–term service quality programs.

In some cases, however, a lack of data available at the outset of a SQI plan may make it more difficult to set benchmarks that are viewed as reliable over the term of a multi–year plan. This would be true if the information systems used to record quality data had changed

[9] For example, suppose the company in the more demanding territory really had worse service quality performance than the other firm in a given year; this SQI plan would lead to penalties both for worse performance and because one firm had more demanding conditions that made it more difficult to provide the same level of service as the other firm. In principle, a firm in a more demanding territory could also have better service quality performance and yet still register worse measured quality performance because of the impact of its more demanding business conditions. Here, the company is penalized even though it is a superior performer. In both cases the company's penalties do not reflect its real quality performance unless adjustments are made to the SQI plan to reflect differences in the companies' service territories.

recently or if there was little confidence that a short data series reflected typical external business conditions for the utility. If this is the case, benchmarks can be updated using data that becomes available during the term of the previous SQI plan, but this should be done according to well–defined rules that are established at the outset of the plan. An example would be a benchmark equal to a ten year moving average of a company's historical performance on an indicator, until 10 years of historical data are available. Setting benchmarks according to such objective rules creates as much stability as is feasible given data constraints.

Two main sources of information can be used to set benchmarks and deadbands. The first option is peer performance. In principle, peer–based benchmarks may be attractive since they reflect the operation and outcomes of competitive markets, where firms are penalised or rewarded for their price and quality performance relative to their competitors. In practice, however, industry–based benchmarks are problematic. One reason is that uniform data are not generally available for utility quality measures, although the recent initiative of the Utility Regulators' Forum should improve this situation. Differences in measure definitions would make peer data difficult to compare and inappropriate as benchmarks. In any case, even if measures are defined comparably across utilities, peer benchmarks should control for differences in utility business conditions that affect quality performance. Controlling for the impact of business conditions on expected service quality performance is complex and virtually unprecedented in utility regulation. For all of these reasons, the use of industry–based quality benchmarks in SQIs is rare.

The alternative data source is the utility's own performance on an indicator. For example, benchmarks could be based on average performance on a given indicator over a recent period. Quality assessments would then depend on measured quality levels that differ either positively or negatively from recent historical experience.

The use of past utility performance to set benchmarks is appealing in many respects. Historical benchmarks reflect a company's own operating circumstances. Historical data will reflect the typical external factors faced by the company if the period used to set benchmarks is long enough to reflect the expected temporal variations in these factors. Longer periods are more likely to achieve this goal than shorter periods and are therefore preferred. As noted above, if only short time series are available at the outset of a SQI plan, benchmarks can be updated at the outset of future plans as more data become available. The rules for updating benchmarks should be spelled out clearly in advance to create the appropriate performance incentives and minimise administrative burdens.

In the case of Queensland, past distributor performance is currently the only feasible quality benchmark available and even this is subject to a number of major data limitations. Basing the quality benchmarks on peer data is problematic at this time given both the lack of consistent data available and the relatively unusual operating environments and characteristics of the Queensland distributors, particularly Ergon.

5.1.2 *Deadbands*

Although historical averages of company performance will reflect typical external factors faced by a company, they will not control for shorter–term fluctuations in external factors around their norms. As noted, some business conditions that can affect measured quality are quite volatile from year to year. Weather is the salient example, and it can affect a host of service–quality measures (eg number and duration of outages, response times to service calls, the number of calls to the phone centre and therefore response time, etc.).

Year–to–year fluctuations in external factors can be accommodated through deadbands. Suppose, by way of example, that the value of a quality indicator is known to fluctuate in a certain range due to external factors. The mean value of this indicator over a suitable historical period would reflect the typical long run external business conditions faced by the utility. Variation in the company's performance around this historical mean will accordingly reflect short run fluctuations in those business conditions. Deadbands should therefore reflect the observed variability in measured service quality performance. One straightforward measure of this year–to–year variability is the standard deviation of the quality indicator around its mean.

5.2 Moving averages versus the Victorian approach

The most common way of setting service quality benchmarks is to use averages of distributors' past performance. If few data are available to compute average past performance, moving or rolling average benchmarks can also be used. Using a rolling average smooths out the impact of short term operating environment variations such as the influence of favourable or unfavourable weather conditions. It also satisfies the criterion that the benchmarks chosen should be relatively stable in that they are not unduly influenced by random events and they should be realistic given the operating conditions faced by the distributor. This has some appeal as the prices charged by the distributor and the costs it currently faces should reflect the level of service quality currently delivered so marginal changes above or below this level can be safely rewarded or penalised in the early stages of the incentive scheme.

An alternative to the rolling average approach was used in Victoria by the ORG (2000). The ORG did not have the power to set targets at the time of the last price review so it asked the distributors to put forward proposals for appropriate targets and the costs of reaching those targets. After a process of negotiation, the targets and costs were agreed upon with the relevant costs then being built into the distributors' X factors. The regulator noted that this process had the advantage of forcing the distributors to look seriously at customer needs and avoided the regulator having to second guess what customers want. It is also then difficult for the distributors to argue that the targets set are unreasonable or unrealistic.

The self–revelation approach used in Victoria is appealing in some respects as it does place more explicit emphasis on customer demands and distributor costs. However, it is problematic in terms of the information burden on both the distributors and the regulator and could also be exposed to gaming by the distributors. To avoid this the regulator has to undertake a lengthy validation process to ensure the cost estimates are reasonable. There is no clear way to discipline the process other than through the negotiation process between the distributors and the regulator over what are appropriate targets and this again brings the regulator's prior beliefs to the fore.

Implementing the Victorian scheme was facilitated by a much longer history of relatively robust reliability data than is currently available in Queensland. The lack of consistent reliability data available for the Queensland distributors means that a simpler scheme will be necessary that can be built up as more data progressively becomes available over time. The rolling average approach best addresses this problem. The Victorian approach also involves a lengthy process of negotiation and verification before an implementable scheme is arrived at which is beyond the scope of the current project, a requirement of which is to deliver a 'turn key' incentive scheme rather than a road map for a relatively long and costly process.

The moving average benchmarks will be updated for each indicator based on experience under the plan. In the second round of service quality incentive regulation (expected to commence in 2010) there may be sufficiently robust data available both from the

Queensland distributors and nationally to permit a move towards external peer–based benchmarks.

Given that ENERGEX is not expected to have reliability data based on actual customer numbers available until the middle of July 2004, the benchmark for the first year of the incentive scheme in 2005–06 will be formed using data for the 2004–05 financial year. In the two subsequent years data for additional financial years will be brought in and averaged until a three year rolling average is formed. As noted in the preceding chapter, it would be prudent to operate the scheme initially on the basis of a 'paper trial' until the available data is sufficiently robust.

A three year rolling average provides a good trade–off between smoothing out the impact of random occurrences and ensuring that the benchmark reflects relatively recent performance. Longer time periods such as five and even ten years are used to form rolling averages in some US schemes but are probably more appropriate for relatively mature systems where the rate of service quality improvement is less rapid. Distributors starting off from a lower base would reap higher rewards from a rolling average based on a longer period of time. Also, the two year administrative lag necessary to implement the Queensland rewards/penalties points to the need for a shorter rather than longer rolling average lest the benchmark become too removed from the time of payment. The QCA may wish to review the period the rolling average is based on at the conclusion of the paper trial based on experience at that point.

Distributors will have an incentive to do better than the rolling average benchmark if the marginal costs of improving are less than the marginal benefits received as reflected in the scheme's award rates. Under a rolling average benchmark approach, benchmarks can go up or down over time and there should be some provision for this to occur until the quality of the data used is sufficiently refined. Our expectation, however, is that the rolling average would progressively improve as distributors have incentives to improve and each year the benchmarks would become more demanding as a result.

5.3 No deadbands initially

The main rationale for having deadbands in symmetric incentive schemes is that they can protect against small and probably insignificant random fluctuations in business conditions that are beyond company control. However, deadbands effectively remove the operation of the incentive scheme from some performance levels and may dull the distributor's focus on achieving service quality improvements. If instability is thought to be a problem, it is better addressed by means of a rolling average benchmark as we are proposing for the Queensland scheme.

It should also be noted that, if SQI plans allow only for penalties, deadbands are especially important for protecting against inappropriate penalties. In these plans, companies can be penalised if 'bad' business conditions like severe weather push measured service quality performance below the benchmark. In other years, mild weather or similar favourable factors may improve measured service quality. In a symmetric plan with no deadband, a company tends to be penalised when external business conditions are bad and rewarded when business conditions are good. These types of penalties and rewards would balance out over time. The SQI plan would therefore be fair, on average, and would not lead to arbitrary rewards or penalties. However, in a penalty–only plan with no deadband, the company is penalised for bad business conditions but never receives offsetting rewards. The penalty/reward mechanism would therefore, on average, impose arbitrary and unfair penalties and not reflect the company's real service quality performance.[10]

If the impact of a particular business or operating environment event is thought to be excessive then distributors can seek to have the event excluded from the statistics used to judge performance. Applying to have the statistics adjusted directly in this way will be more transparent.

Where deadbands are used, they are often set based on experience with how much variation normally occurs around the mean using measures such as the standard deviation. Given the very limited data available for the Queensland distributors, there is little or no information to gauge how much variation there typically is around the means of the performance indicators. Without this data, selecting deadbands would be little more than arbitrary.

[10] For example, suppose the company in the more demanding territory really had worse service quality performance than the other firm in a given year; this SQI plan would lead to penalties both for worse performance and because one firm had more demanding conditions that made it more difficult to provide the same level of service as the other firm. In principle, a firm in a more demanding territory could also have better service quality performance and yet still register worse measured quality performance because of the impact of its more demanding business conditions. Here, the company is penalized even though it is a superior performer. In both cases the company's penalties do not reflect its real quality performance unless adjustments are made to the SQI plan to reflect differences in the companies' service territories. This example also shows how various components of SQI plans can be interrelated. For example, it shows that the design of the deadbands depends on the penalty/reward mechanism (deadbands become less necessary if rewards are possible) and a longer-term plan reduces the possibility of arbitrary penalties or rewards, therefore, providing another reason in support of multi-year plans.

Given the relative dearth of available data, the detrimental impact deadbands can have on incentives and the fact that our proposed SQI is symmetric, we are proposing that there be no deadbands in the Queensland scheme initially. The desirability of introducing a deadband could be reconsidered at the end of the paper trial based on experience up to that point.

5.4 Worst feeders benchmark

As discussed in section 4.5, the worst performing feeder performance will be measured using the worst 10 per cent of feeders using customer weightings. The composition of the worst 10 per cent of feeders will be determined at the outset of the incentive program using data from the preceding financial year. This will ensure that the measurement of the worst 10 per cent of feeders is consistent with how reliability will be measured going forward under the plan. While Ergon is likely to have better quality data available for years prior to this, ENERGEX will not have accurate data available until July 2004. Hence, in the interests of equity of treatment, the worst 10 per cent of feeders for both distributors should be determined initially using data for 2004–05. The composition of the worst 10 per cent of feeders will then be updated each financial year using data for the previous financial year.

Once the composition of the worst 10 per cent of feeders list is known, the benchmark will be formed by calculating SAIDI for those feeders as a whole for 2004–05. In the two subsequent years data for additional calendar years for those same respective feeders will be brought in and averaged until the three year rolling average is formed.

6. PENALTY/REWARD MECHANISM

6.1 Mechanisms for penalties and rewards

The final element in a service quality incentive plan is the mechanism used to reward or penalise the utility for its service quality performance. A penalty/reward mechanism accomplishes this by linking a quality assessment to a change in utility rates or allowed returns. A quality assessment relates quality as measured by the indicators to the quality benchmarks. In general, measured performance that 'exceeds' the benchmarks signals superior quality and a possible reward. Performance below the benchmarks indicates sub–standard quality and a possible penalty.

Important design issues for a penalty/reward mechanism are whether the mechanism is symmetric and allows for both rewards and penalties, or asymmetric and penalty–only; whether award rates for individual quality indicators are based on estimates of the costs incurred to change quality or the value of quality changes to customers; how individual award rates are set; and the caps placed on maximum penalties and rewards. We deal with these issues in turn.

6.2 Symmetry/asymmetry

A basic issue that a regulator must decide is whether the award mechanism will be symmetric (both rewards and penalties are possible) or asymmetric (penalty–only). It is sometimes argued that only asymmetric service quality plans are appropriate. Proponents of this view contend that, in price or revenue cap regulation, service quality incentives are designed to prevent quality declines that may result from the incentives to reduce costs. Penalties are sufficient to deter such behaviour and rewards are, therefore, unnecessary. Moreover, it is argued, utilities benefit through cost reductions and marketing freedoms allowed under price caps, and additional rewards through quality incentives are too generous to shareholders.

However, a strong case can be made that symmetric incentive plans are more appropriate. Incentive regulation is intended to encourage superior performance up to the point where consumers' marginal valuations equal marginal costs, not simply to prevent performance from slipping. Since just and reasonable prices and the quality of service are both important to customers, symmetric service quality plans are needed to create incentives that improve performance in all areas valued by customers. Symmetric plans are also more consistent with the behaviour of unregulated markets than are asymmetric plans. Customers in competitive markets routinely pay higher prices for higher quality products, and a symmetric service quality incentive reflects this phenomena. However, competitive markets usually offer an array of goods with varying quality levels, and not all customers choose to consume high quality goods. When incentive plans lead to price increases on monopoly services at least some customers may be paying for quality improvements that they do not want.[11][12]

Symmetric service quality plans have been approved for a number of energy utilities. For example, both the Victorian and South Australian schemes are symmetric. In the US, regulators in several states have adopted symmetric SQI plans, although asymmetric plans are somewhat more common for reasons discussed in chapter 2.

We believe symmetric SQIs are supported by the fundamentals of service quality economics, as discussed in chapter 2. There is also considerable precedent for symmetric plans, including the two approved SQIs for Australian power distributors. We, therefore, recommend that the SQI plan be symmetric. For simplicity, and in the absence of compelling evidence to the contrary, we will also allow award rates for individual indicators to be symmetric in the sense that the same award rate applies to performance above and below the benchmark.

6.3 Cost versus value based rewards and penalties

Chapter 2 showed that the optimal level of quality depends on both the marginal cost of providing quality and the marginal benefit of quality to the customer. The latter is equivalent to consumers' willingness to pay for incremental quality improvements. Marginal costs also vary by company and depend on a company's operating conditions. For example, the marginal cost of increasing quality is likely to be greater in either central business districts or sparsely populated rural areas relative to suburban districts.

[11] Note that, depending on the other features of the PBR plan, symmetric service quality incentive plans may not lead to price increases even if the utility is rewarded under the plan. For example, if the PBR plan also features as ESM, the service quality reward can be an increase in the allowed return at which earnings are shared, rather than a price increase.

[12] This distributional implication is tempered somewhat by some research showing that the *optimal* level of quality in a monopoly market can be provided only if pries are sensitive to the quality of services (see White 1972.)

In theory, a regulator attempting to determine optimal quality would need information on the schedule of marginal costs and the marginal benefits of quality improvements relative to current performance. Attempting to estimate these marginal cost and marginal benefit schedules would be a daunting task. This information is difficult to obtain under the best of circumstances, and estimates are bound to be uncertain. One reason is that many operating and capital spending scenarios can be developed for reaching a given quality target. Estimating the value of quality is also inherently imprecise, perhaps especially for monopoly services like power distribution where consumers do not choose among different products, so observed price–quality differences in the marketplace do not necessarily reflect customer preferences.

While the information needed to provide optimal quality may be impossible to obtain in practice, SQIs can still create incentives for companies to move in the direction of the optimum. Choices for award rates are critical for creating such incentives. The award rate effectively sets a marginal reward, or benefit, to the company for service quality improvements. In principle, a distributor operating under this regulatory incentive will provide quality up to the point where its marginal cost of enhancing quality is just equal to the marginal reward.

Regardless of where quality initially begins relative to the optimum, setting award rates on the basis of customer value will move quality in the direction of the optimum. This can be seen in figure 2 below. This figure shows two possible initial quality levels. Point A is to the right of the optimum. Here, regulation has actually induced the firm to provide quality levels that exceed customers' willingness to pay.[13]

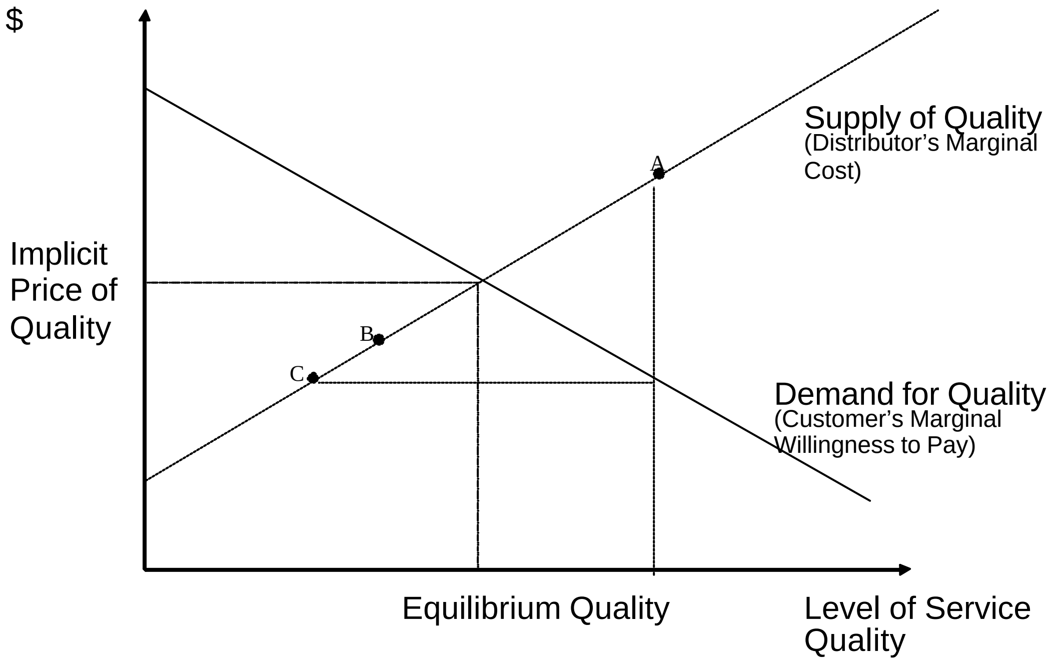
If the award rate was set at customers' actual willingness to pay at point A, distributors would respond rationally by letting quality decline since their incremental cost savings would exceed the penalties paid. This would move quality in the direction of the optimum. Similarly, at point B, quality is to the left of the optimum and consumers would be willing to pay more for quality improvements. Setting the award rate at a level reflecting customer value would thereby provide an incentive for companies to increase quality, since the incremental rewards exceed the incremental costs they incur.

These same incentives are not necessarily created if the award rate is set at the firm's marginal costs. In particular, if quality was initially at point A and the award rate was set at

[13] This is not an impossible situation to imagine, since it has long been alleged that traditional regulation create incentives for utilities to choose overly capital-intensive technologies and 'gold plate' the system in an effort to earn higher returns on invested capital.

the firm's marginal costs of enhancing quality, then the firm would have incentives to further expand quality, since the incremental rewards are at least as great as incremental costs. This would move quality further to the right and away from the optimum. However, if quality was initially less than optimal, such as at point B, setting award rates at marginal costs would create the right incentives.

Figure 2: **Optimising the level of service quality**



This discussion does not imply that any customer value estimate will necessarily deliver optimum quality. For example, in figure 2, if the award rate was set at that associated with Point A, the company would ultimately have an incentive to provide quality level C. This quality is less than the optimum, and consumers would now be willing to pay more to increase quality. Thus, while a value–based estimate did in fact move quality in the direction of what customers wanted, in this instance the particular value estimate led firms to 'overshoot' the optimum quality target by letting quality decline too far.

Ultimately, optimal quality involves a balancing of marginal cost and marginal benefits. While value–based estimates will move the market towards optimum quality levels, the process will unfold over time. Updates of SQI plan parameters (eg benchmarks and award rates) may be required to continue to move quality towards consumers' desired levels.

It should also be noted that, if regulators are confident that existing quality levels are less than optimal, it can be argued that marginal cost–based award rates will be a less costly means of delivering the quality levels that customers want. Whenever quality is to the left of the optimum, the marginal value of quality to customers is greater than the marginal cost to the company of improving quality. Marginal cost–based award rates will move quality in the direction of the optimum at these initial quality levels. Cost–based award rates, therefore, promote more appropriate quality levels at less cost to customers.

While acknowledging this potential advantage, we believe award rates for a SQI regime in Queensland should be linked to customer value rather than marginal costs. Value–based awards are preferred for three reasons. First, as noted above, there is a stronger a priori theoretical case that marginal values rather marginal cost based awards create the appropriate incentives. Second, there is far more publicly available information on customers' valuation of quality than of distributors' marginal costs of improving quality. This greater information base creates more confidence in the use of value rather than cost estimates. Finally, while some may argue that marginal cost based rewards represent a less costly approach, the financial 'risks' to customers can be contained by capping maximum rewards. The recommendations that follow will therefore be developed using customer value estimates, particularly those from Australia. However, since marginal costs and values are both important, we present evidence on each of these measures.

6.4 Marginal cost estimates – from Victoria

The 2000 Victorian electricity distribution price review presented estimates of the marginal cost of improving reliability for each of the five Victorian distributors (ORG 2000). The estimates were presented as the annualised cost per unit of unserved energy saved. Cost estimates assumed particular significance in the service quality incentive regime implemented in Victoria as the incentive rate is based on an estimate of distributors' costs rather than customers' valuations of improvements in reliability.

The marginal cost estimates ranged from $3.90 per kWh of unserved energy saved for AGL to $7.05 for CitiPower. The estimated marginal costs for Powercor, United Energy and Eastern Energy were $4.55, $4.67 and $6.47 per kWh of unserved energy saved, respectively. The marginal cost estimates represent the annual revenue required by each distributor to support the capital and operational expenditure required to provide enhanced reliability performance. The annual revenue requirements were calculated using capital and operational expenditure figures provided by the distributors and assuming a weighted average cost of capital of 7.6 per cent. The resulting marginal cost estimates are well below most of the equivalent Australian customer valuation estimates reported in the following section.

The Victorian price review did not calculate separate marginal cost estimates for reducing the frequency as opposed to the duration of interruptions. Instead, proportions of the marginal cost were allocated based on perceptions of the weight placed on the different attributes by customers. Reductions in the frequency of interruptions were allocated the full annualised cost while reductions in the unplanned interruption duration were allocated 65 per cent of the annualised cost and reductions in planned minutes off supply were allocated 25 per cent of the annualised cost. The incentive rates were then further adjusted to compensate for the fact that the weightings and the lag between reliability improvement costs being incurred and the consequential increase in revenue from improved performance would under–reward the distributor with the net present value of benefits being less than costs.

While the incentive scheme implemented in Victoria contains judgements about consumer valuations in deriving the final incentive rates, the marginal cost estimates derived as part of the process are probably the most robust available in Australia. They are, however, specific to the business and operating environment conditions found in Victoria and may not provide an accurate guide to the marginal costs of improving reliability in Queensland.

6.5 Value of service estimates

Most early service quality plans did not feature explicit evidence on customer quality valuations, but such evidence is becoming more common. For example, the service quality incentive proposed by Southern California Gas (SoCalGas) relied on both survey evidence and statistical methods to estimate SoCalGas customers' valuations of various aspects of service. The price cap plan for Southern California Edison's (SCE's) non–generation services featured a symmetric reliability incentive, where the penalties and rewards for power interruptions (compared to benchmark levels) amounted to approximately $15 per hour for each affected customer. As part of the update of that plan, the California regulator directed SCE to present evidence on the value of service reliability to their customers. This research has been presented but to date the SCE plan has not been updated.

There have been several studies of electricity customer valuation and customer preferences in Australia since 1997. Two of these (Khan and Conlon 1997; Charles Rivers and Associates 2002) have concentrated on obtaining estimates of the value of lost load (VoLL). Several distributor–initiated studies have sought information from customers on their broad preferences for a wide range of service quality attributes. These have mainly been undertaken in Victoria, NSW and, more recently, in Queensland by ENERGEX. More structured studies of consumer valuations have recently been carried out in Tasmania, South Australia and NSW although the latter has not yet been released.

6.5.1 *Monash VoLL study*

Khan and Conlon (1997) from Monash University's Centre for Electrical Power Engineering undertook a survey based study across Australia to estimate VoLL for the Victorian Power Exchange. At the time of the study the VoLL being used in the Victorian wholesale electricity market was $5 per kWh. Khan and Conlon used data from a survey sent to 12,500 residential, agricultural, commercial, industrial and major users asking for the perceived costs of interruptions of differing lengths. These cost estimates were then normalised by consumption and averaged for each sector. Finally, an overall expected VoLL figure was obtained by multiplying the costs of interruptions of differing lengths by the probability of an interruption of that length occurring and summing over all interruption lengths.

The Monash study obtained an overall expected VoLL estimate of $28.89 per kWh for Victoria. This was made up of sectoral VoLL estimates of $0.74 per kWh for residential, $75.96 for commercial, $96.19 for agricultural and $11.19 for industrial and major users. The estimate of VoLL for the Victorian commercial sector was around 40 per cent higher than the corresponding national figure leading to concerns about the representativeness of the Victorian survey sample. Since the commercial sector accounted for 30 per cent of the sectoral weight this led to the national estimate of VoLL being $22.19 per kWh. Khan and Conlon concluded that the likely range for the overall VoLL was between $20 and $30 per kWh with a figure towards the lower end of that range being most likely. The VoLL figure used in the National Electricity Market was eventually increased from $5 to $10 per kWh in April 2002.

6.5.2 *VENCorp study*

In late 2001, VENCorp initiated further work on estimating the VoLL that should be used in assessing transmission system augmentations. Charles Rivers Associates (CRA 2002) updated the Monash study using a broadly similar methodology. A higher response rate and a higher proportion of useable responses enabled the CRA study to use more data than was available to the Monash study despite the CRA survey having sent out considerably fewer questionnaires. One of the criticisms of the Monash study was that it had only been able to use data from 7 per cent of the questionnaires sent out.

CRA obtained an overall value of customer reliability (VCR) for Victoria of $29.60 per kWh of unserved energy, only marginally different from the Monash study's overall VoLL of $28.89 per kWh. However, the CRA study found a very different distribution of VCR across the four sectors. Its residential VCR was $11.88 per kWh compared to Monash's $0.74 and its commercial VCR was $56.67 per kWh compared to Monash's $75.96. There were also substantial differences in the agricultural estimates with CRA obtaining $55.49 compared to Monash's $96.19 per kWh and the industrial estimates with CRA obtaining $18.54 compared to Monash's $11.19 per kWh. CRA attributed the difference in residential VCR to differences in the lists of preparatory actions and associated costs presented to participants while they speculated that the difference in agricultural VCR may have been due to a biased sample in the Monash study coming from electricity intensive dairy farms whereas the CRA sample used was more representative. Differences in the commercial sector VCR estimates were attributed to differences in the treatment of billing data for tenants of multi–storey commercial buildings.

VENCorp (2003) announced that it intended to use the new statewide VCR figure of $29.60 per kWh for future transmission investment decision analysis.

6.5.3 *Distributor–initiated studies*

In 1998 Energy Australia carried out a survey of 1,000 of its customers and found that over half the respondents were prepared to pay higher variable charges to improve or maintain their reliability.[14] Up to a third of the respondents were prepared to pay substantially higher fixed charges in exchange for undergrounding of electricity infrastructure.

[14] This section draws on a summary of the findings of the NSW and Victorian surveys in The Allen Consulting Group (2001).

In the leadup to the last Price Determination in Victoria, four of the five Victorian distributors carried out customer surveys or consultations. CitiPower found that its customers placed a high weight on reliability with almost half of its residential and business customers preferring fewer interruptions of longer duration. Over half of Eastern Energy's and Powercor's customers were prepared to pay a higher price to improve or maintain their reliability. While most Eastern Energy customers valued improvements in interruption duration more than reductions in the frequency of flickers, Powercor found that its customers, particularly dairy farmers, were concerned about momentary interruptions. United Energy found that most of its customers valued reductions in the frequency and duration of outages more than price reductions.

In mid–2002, ENERGEX (2002) commissioned a survey of electricity consumer preferences. The survey covered 604 residential customers and 400 small business customers selected at random from the ENERGEX franchise area. It was administered by telephone to the person responsible for paying the electricity bill and focused on the following seven service concepts:

- improving reliability;
- starting to underground the distribution network;
- doing more to protect the environment;
- improving safety;
- helping regional development;
- providing better customer service; and
- helping those in hardship.

The survey responses indicated that all of the service concepts were supported or strongly supported by at least 80 per cent of residential customers and by 62 to 81 per cent of business customers even though this would involve paying more for electricity. Improving safety was ranked the most important among the service concepts by 25 per cent of residential customers, starting to underground and doing more to protect the environment by 17 per cent each and improving reliability by 16 per cent. Small business customers exhibited a different set of preferences with 37 per cent ranking improving reliability as the most important service concept, 16 per cent ranking not increasing price as the most important, 12 per cent ranking improving safety highest while 9 per cent ranked starting to underground as the highest priority.

In terms of reported customer willingness to pay more for improvements across all of the seven service concepts, the survey found a total of 50 per cent of residential customers indicated they were 'very likely' or 'quite likely' to pay over $8 per month more for improvements across the service concepts. Around 60 per cent indicated they would be 'very likely' or 'quite likely' to pay $5–$8 per month more for service improvements.

6.5.4 *Tasmanian customer value study*

Aurora Energy (2002) has recently reported the findings of customer focussed research on service quality issues undertaken by EMRS involving focus groups and an extensive telephone survey of 1,200 business customers and 1,000 residential customers. Amongst the 1,200 business customers 'providing a continuous power supply' was identified as being critically important by 68 per cent of respondents, followed by 'restoring power quickly after blackouts' (61 per cent) and 'keeping the price of electricity as low as possible' (58 per cent). Amongst the 1,000 residential customers the same three issues were identified as most important, but in a different order. 'Keeping the price of electricity as low as possible' was identified as being critically important by 59 per cent, followed by 'providing a continuous power supply' (53 per cent) and 'restoring power quickly after blackouts' (43 per cent). The large sampling done in the EMRS research confirmed the findings of earlier annual Aurora customer satisfaction research that there is a strong inverse relationship between customer satisfaction and the number of power interruptions.

Participants in the focus groups also participated in a conjoint analysis experiment where they were asked to indicate their preferences when choosing between a number of power outcomes, each of which was linked with a direct cost outcome for the consumer. Thirteen outcome bundles were presented to the focus group participants using combinations of three variables:

- percentage reduction in the number of outages;
- percentage reduction in the duration of outages; and
- percentage increase in the Aurora bill.

The conjoint analysis found that the contribution to consumer wellbeing provided by price is in excess of 50 per cent, of reducing the number of outages is 35 per cent and of reducing the duration of outages is 12 per cent. The consumer wellbeing gain from a 40 per cent reduction in power failures was found to be almost 30 times greater than a reduction in duration by 40 per cent. Against this is the consumer wellbeing loss from increasing the

Aurora bill by 7.5 per cent which was more than twice as great as the consumer wellbeing gain from reducing power failures by 40 per cent.

There were significant differences between the responses of business and residential customers and between those of people in known poor quality areas and elsewhere. Businesses in general and customers in areas of poor reliability were generally more prepared to pay for improvements than residential customers in areas of good reliability. The conjoint analysis result that customers attach much higher value to reducing power failures than they do to reducing the duration of failures is consistent with the telephone survey information.

The telephone survey also confirmed that the lower the satisfaction score business customers gave to Aurora, the more likely they were prepared to pay extra to reduce the number of power failures. The survey found relatively strong willingness by both businesses and residential customers to pay an additional 2.5 per cent to secure an improvement of around 20 per cent in the number of power failures.

6.5.5 *South Australian consumer preferences study*

As part of the leadup to its next price review, ESCoSA has commissioned research on consumer preferences and the willingness to pay for distribution services (ESCoSA 2003a, KPMG 2003). The study used the discrete choice experiments (DCE) method, where consumers are asked to state their willingness to pay for improved service based on a hypothetical departure from existing levels. The DCE method is claimed to have the advantage of being able to estimate willingness to pay for changes to multiple variables at the same time, thus closely simulating a package of different service levels.

The survey identified 18 different attributes of distribution service performance that were relevant to stakeholders, including measures of supply reliability, aspects of customer service, undergrounding and future needs in different parts of the state. Each survey respondent received 16 different service level packages for which they were asked to choose whether they were willing to pay for the described change or whether they preferred to retain their current service.

The sample used was made up of 1,488 respondents across the whole distribution network, including 904 residential consumers, 404 small business consumers (those that consume less than 160 MWh per year), 94 large business consumers and 86 farmers. The sample was weighted to resemble the underlying population statistics of South Australia.

The mean willingness to pay results from the consumer survey were expressed as a percentage change in the existing total electricity retail bill, which includes transmission, distribution and retail charges. Since the distribution component of the total bill accounts for around half of the total electricity retail bill, the results in the consumer survey report have to be doubled to obtain an estimate of the percentage change in the distribution bill (ESCoSA 2003a, p.9). This implicitly assumes that the distributor is responsible for all changes that will affect the service quality perceived by the consumer. In reality the transmission company and retailers may also be able to influence service quality attributes the consumer is prepared to pay for.

The survey results showed that:

- consumers are not willing, on average, to pay a large amount to improve their current levels of reliability or quality;
- where reliability needs to be improved, consumers are willing to pay for such improvements in urban, rural and remote areas;
- consumers are most willing to pay for improvements in customer service, such as for ETSA Utilities to respond to telephone calls within 30 seconds once an interruption has occurred; and
- consumers support the undergrounding of overhead poles and wires in areas were this has not yet occurred.

The key willingness to pay for reliability results from the survey–based analysis are presented in Table 1 below, expressed as a percentage of the retail bill. Residential and small business customers appear to value a reduction in the number of sustained interruptions by one more than a reduction in the duration of interruptions by one hour but the opposite is true for large business customers. Small business customers would be prepared to pay a retail bill which was 0.32 per cent higher in exchange for a reduction of one in the fequency of sustained interruptions. This is equivalent to an increase in their distribution charges of around 0.64 per cent. CBD and rural customers also appear to value a reduction in the frequency of sustained interruptions by one more highly than a reduction in the duration of interruptions by one hour while remote customers value the reduction in duration more highly.

All customer groups place considerably less value on reducing the frequency of momentary interruptions than they do on sustained interruptions. Most customer groups are prepared to pay more to reduce the duration of their longest sustained interruption than they are to reduce the total annual interruption duration with small business indicating they would pay a 0.41 per cent increase in their retail bill (0.82 per cent increase in distribution charge) in exchange for a one hour reduction in the length of their longest interruption.

Table 1: **South Australian consumer survey willingness to pay results**

Customer segment	*Value of a reduction as percentage of retail bill*			
	No. of sustained interruptions (planned & unplanned) by one	*No. of momentary interruptions by one*	*Duration annual interruptions (planned & unplanned) by one hour*	*Longest interruption (planned & unplanned) by one hour*
Customer type				
Residential	0.27	0.02	0.20	0.34
Small business	0.32	0.04	0.25	0.41
Large business	0.25	0.02	0.33	0.28
Network type				
CBD	0.40	0.04	0.15	0.33
Metropolitan	0.25	0.02	0.28	0.36
Rural	0.34	0.03	0.15	0.39
Remote	0.16	0.02	0.23	0.21

Source: ESCoSA (2003a, p.51)

6.5.6 *Overseas value of service estimates*

The value of power reliability has been the subject of considerable investigation overseas, particularly in North America. Researchers have estimated the costs that outages impose on different types of customers under different circumstances. Appendix 2 summarises the value of service estimates in a number of these studies. Most of these studies were conducted in the US, but others come from Canada, the UK, Taiwan and Israel. We will not review these outage cost studies in detail, since many are less recent and all are less relevant in terms of the service level experience and characteristics of Australian customers. The primary purpose of these studies is as a 'check' on the Australian estimates. Broadly speaking, the VENCORP and Monash studies fall on the high end of the overseas estimates. They are more similar to research that has been done recently, which is perhaps not surprising given the increasing importance of reliable power supplies to advanced economies. On the other hand, the value of service estimates in the KPMG South Australian study appear to be quite low relative to the outage cost literature.

6.6 Actual penalty/reward rates

6.6.1 *Reliability indicators*

Our recommended award rates for the reliability indicators (SAIFI, SAIDI and SAIDI for the worst feeders) are derived using information on the value of reliability from the VENCorp and KPMG studies. Our approach essentially averaged the reliability values in these studies. We believed this approach is appropriate for several reasons. First, the ideal approach would be to use valuation data that was specific to the circumstances in Queensland and the characteristics and preferences of Energex and Ergon customers. Since these valuation data did not exist, it is less risky to rely on a broader range of evidence from closely related valuation studies than the estimates contained in any single study. Using both the VENCorp and KPMG studies "spreads risks" in that these studies are derived from different states (Victoria and SA, respectively) and utilise different approaches for estimating customer value. Relying on both, therefore, places less weight on the customer characteristics or valuation approach associated with either study and reduces the "risks" that either is not appropriate for Queensland. In addition, these estimates also tend to be at the high and low ends, respectively, of value of service estimates reported overseas. This further supports the notion that averaging these study results is an appropriate means of spreading "risks" and is likely to yield more reliable estimates of the value of reliability appropriate for an SQI in Queensland than the results of any single study.

KPMG expressed customer values for particular service attributes in terms of the percentage change in a final bill they would be willing to pay for a one unit change in SAIFI and a one hour reduction in SAIDI. These values were estimated for different customer groups and network segments. Because values were expressed in terms of the final retail bill, KPMG said the estimated values should essentially be doubled to be expressed in terms of the value of distribution services, since distribution accounts for about half of the final retail bill in South Australia.

Using these disaggregated data and estimates of each distributor's share of kWh deliveries to different customer groups, we developed kWh–weighted average estimates of the value of the frequency and duration of interruptions (as reflected in the SAIFI and SAIDI indicators, respectively) to Energex's and Ergon's average customer. For SAIFI, these values were a 0.58 per cent change in revenues for Energex and a 0.55 per cent change in revenues for Ergon for a one unit change in SAIFI relative to current experience. For SAIDI, the values were a 0.49 per cent change in revenues for Energex and a 0.53 per cent change in revenues for Ergon for a one hour reduction in SAIDI relative to customers' experience. The differences in these estimates are due to differences in customer mix between the companies. These estimates were then translated into the total value resulting from a change in measured reliability by multiplying each company's 2002 revenue by the associated system–wide willingness to pay.

The VENCorp study was also used to derive values for SAIFI and SAIDI, in a somewhat more complicated way. More detail on this approach is presented in Appendix 3. We began by computing a kWh–average of system–wide outage costs for each company, using disaggregated estimates on the value of reliability to different customer groups and the shares of kWh deliveries to each. These values were equal to $32.29 per unserved kWh for Energex and $30.35 per unserved kWh for Ergon. Quite similar, but somewhat higher, system–wide outage costs would have been obtained for the distributors if we had used the Monash rather than the VENCorp research ($34.89 per unserved kWh and $32.56 per unserved kWh, respectively).

Given these estimates, the total value of an average one hour, system–wide outage for each distributor was computed by multiplying the system–wide outage cost estimate by the kWh that would have been unserved during a typical hour. The average amount of unserved kWh was computed as total kWh deliveries divided by 8,760 hours per year. Applying this formula to each distributor's deliveries data yields a total value for a one–hour, system–wide outage for each distributor.

The outage cost literature suggests that outages impose both fixed and variable costs on customers (see Caves, Herriges, and Windle 1989). Fixed costs are those that occur immediately when, for example, service interruptions disrupt an industrial customer's production plans. Variable costs are related to the duration of an outage. The relative proportions of these costs vary among customer groups. Industrial customers typically have a higher proportion of fixed costs, while residential customers usually have a lower proportion of fixed costs.

It is possible to infer the relative values of fixed and variable outage costs for different customer groups from the KPMG study.[15] This can be done using the values listed above for

[15] Caves, Heriges, and Windle (1989) present evidence on the relative proportions of fixed and variable outage costs by regressing the estimated outage costs from a number of studies against the hours of interruption. The intercept in such a regression would represent the fixed outage costs. They find that, for a one hour outage for residential customers, 3 per cent of outage costs are fixed and 97 per cent are related to outage duration. For

customers' willingness to pay for SAIFI and SAIDI changes. For Energex, customers are willing to have a 0.58 per cent higher bill in exchange for a one unit reduction in SAIFI and a 0.49 per cent higher bill in exchange for a one hour reduction in SAIDI. This implies that SAIFI is somewhat more important than SAIDI. An estimate for the relative importance of SAIFI relative to SAIDI is 0.58/(0.58+0.49) = 54 per cent. Using similar data above for Ergon, the relative importance of SAIFI relative to SAIDI can be computed as 0.55/(0.55+0.53) = 51 per cent. The average between these distributors is therefore 52.5 per cent.

These results are broadly consistent with each other and also with other findings in Australia (eg Tasmania) that customers on average place somewhat more weight on reducing the frequency rather than duration of outages. We therefore used the average computed above to estimate the fraction of outage costs that are 'fixed' in Queensland and associated with the occurrence of an outage. This percentage of 52.5 per cent was multiplied by the total value of unserved kWh in a one–hour outage computed earlier.

This process yielded estimates for the value of a one unit change in SAIFI and one hour change in SAIDI based on both the VENCorp and KPMG studies. Our recommended award rates are obtained by averaging these two values. These averages are listed below (per one unit of SAIFI and per minute of SAIDI).

	SAIFI *$/one unit*	SAIDI *$/minute*
Energex	$18,004,449	$270,123
Ergon	$12,538,128	$190,379

These values are obviously estimates rather than being precise, and since it is easier to work with whole numbers we round them off to produce the recommended award rates listed below.

	SAIFI *$/one unit*	SAIDI *$/minute*
Energex	$18,000,000	$270,000
Ergon	$12,500,000	$190,000

industrial customers, the fixed and variable cost proportions are 27 per cent and 73 per cent, respectively. Similar estimates were not presented for commercial customers. While the proportion of costs associated with fixed costs is much lower than in the Australian research, it should be noted that the Caves *et al* estimates were derived from outage cost studies in the 1970s and 1980s. The increased presence of computers and digital equipment has almost certainly increased the proportion of costs immediately imposed by an outage since that time.

It should be noted that the award rate for SAIDI for the worst 10 per cent of feeders is the same as that for SAIDI above. While customers' willingness to pay may very well be greater for these feeders, we have no precise estimates of how this value may differ from the values obtained above. For simplicity, we have therefore kept the same award rate for SAIDI performance system–wide as for the worst performing feeders.

6.6.2 *Quality of supply complaints*

We also used information from the KPMG study to determine award rates for the quality of supply indicator. KPMG estimated customers' willingness to pay for a perceived drop in one quality of supply incident for different customer groups and network segments. As with the reliability indicators, we used this information to obtain estimates of this value for an average customer of Energex and Ergon. In this case, however, the averages are based on customer–weighted averages of the disaggregated data rather than kWh–weighted averages. The values obtained for reducing quality of supply incidents by one is equal to 0.05 per cent of distribution bills for Energex and 0.04 per cent of distribution bills for Ergon.

KPMG also reports that customers perceived the total number of such incidents each year to be 12. A drop of 1 incident therefore corresponds to a 8.5 per cent reduction in perceived quality problems (and by extension quality complaints). We, therefore, obtained reward rates for each 1 per cent change in the number of quality of supply complaints using the formulas below:

Energex = (Energex 2002 Revenue * 0.0005)/8.5

Ergon = (Ergon 2002 Revenue * 0.0004)/8.5

These calculations lead to an award rate of about $25,078 for Energex and $24,213 for Ergon for each 1 per cent change in complaints relative to the benchmark. Our recommended award rate for this indicator are therefore $25,000 for Energex and $24,000 for Ergon for each 1 per cent change in total quality of supply complaints relative to the benchmark in each year.

6.6.3 *Telephone response*

KPMG also presents information on customers' willingness to pay for call response times within 30 seconds. Since not all customers call the phone centre each year, estimates of customer value should try to control for the fraction of customers who actually experiencing telephone service quality. We estimated this fraction using Energex's September 2002 service quality report. This report shows about 330,000 distribution–related calls to the call centre, or just less than 1 in 3 of the company's customer base. This confirms anecdotal evidence from North America about approximately what fraction of customers contact the utility phone centre each year.

We computed average values for the telephone indicator in a manner similar to those calculated for the reliability and quality complaints indicators. We began with the disaggregated figures for different customer groups, and computed customer–weighted averages for each company. We then divided by three, on the assumption that only about one in three customers calls in and actually experiences this service. This yielded valuation figures of about 0.56 per cent of distribution bills for Energex and 0.55 per cent of distribution bills for Ergon.

These estimates represent the respective amounts by which the average Energex and Ergon customer calling the phone centre is willing to pay to reduce call response to less than 30 seconds. It follows that if 100 per cent of calls were in fact responded to in this time frame, customers' total value would increase by 0.56 per cent of revenue for Energex and 0.55 per cent of revenue for Ergon. To translate this change in value into an award rate for each 1 per cent increase in the company's actual response rate within 30 seconds, we calculated the differences between each company's current call response rate and a 100 per cent response rate and divided the total value of improved service proportionally. In the December 2002 report, Ergon reports a response rate within 30 seconds of just under 40 per cent. Data from Energex's report can be used to estimate a response rate of a little less than 25 per cent. Therefore, the recommended award rates for each 1 per cent change in the number of telephone calls answered within 30 seconds were estimated as follows:

Energex = (Energex 2002 Revenue * 0.0056)/75

Ergon = (Ergon 2002 Revenue * 0.0055)/60

These calculations turn out to be approximately $31,000 and $42,500 for Energex and Ergon, respectively. These are the recommended award rates for this indicator.

6.7 Total caps on rewards/penalties

Because of the uncertainties involved in designing a SQI plan, it is appropriate to cap both the potential rewards and penalties available under the plan. These caps protect shareholders from especially large penalties and customers from unreasonably large rewards. Setting these caps is largely a matter of judgment rather than economic reasoning.

We recommend that maximum penalties and rewards be capped at 2 per cent of each distributors' 2002 revenues. These caps are around $9.8 million for Energex and around $9.2 million for Ergon. For simplicity, total reward or penalty caps will not be updated over the term of the plan.

The 2 per cent of revenue recommendation is based largely on precedent. Our review of US SQI plans indicated that the average amount of the capped penalties and/or rewards was just under 2 per cent of revenues. In the UK, rewards and penalties under the comparable Information and Incentives Project were capped at 1.875 per cent of distribution revenues. We, therefore, believe that a 2 per cent cap is reasonable and in line with international experience.

6.8 Interaction with Efficiency Carryover Mechanism

Efficiency carryover mechanisms provide distributors with an incentive to outperform efficiency targets by allowing them to keep cost reductions in excess of those targeted for a particular year for a given period, usually five years. In the absence of a service quality incentive scheme, the operation of an efficiency carryover mechanism may provide the distributor with an incentive to seek cost reductions at the expense of service quality. However, a service quality incentive scheme can also interact with an efficiency carryover mechanism in a number of complex ways.

Firstly, new and improved distribution equipment and work methods may simultaneously improve both efficiency and reliability. In this case the distributor would get an efficiency carryover benefit and also the S factor reward, allowing them to effectively 'double dip'.

Secondly, some regulators have expressed a concern that unless the benefits from the service quality incentive are available for the same length of time as those from the efficiency carryover mechanism then distributors may still have an incentive to run the system down and reduce service quality. This is because the benefits from cutting costs available under the multi–period efficiency carryover mechanism may outweigh the single period S factor reward and, hence, it is still more profitable for them to run the system down. ESCoSA (2003a) has recently proposed making the benefits from its service quality incentive scheme available for a five year period to match the timeframe of its efficiency carryover mechanism.

Given that there are potentially counteracting interactions between the efficiency carryover mechanism and the service quality incentive, we propose that the two schemes operate independently in the first regulatory period, after which interactions between the two be reviewed on the basis of subsequent experience.

7. IMPLEMENTATION DETAILS

To summarise the discussion of the preceding chapters, we are recommending that a CPI–X+S service quality incentive scheme be introduced for the two Queensland distributors to take effect from 1 July 2005. Given the lack of accurate data, particularly for Energex, we are recommending that the scheme be operated on a 'paper trial' basis for the first three years until the robustness of the reliability data is established. The first rewards or penalties involving actual revenue would take effect for the 2008–09 financial year, provided the data are judged to be sufficiently robust at the conclusion of the three year paper trial.

The coverage of the scheme will be all distribution services except for those where customers have entered into direct contracts with the distributors and for higher than basic price/service offerings, should they be offered. Reliability solutions provided by distributors beyond the current regulatory boundary will not be included as allowable expenditure for revenue requirements purposes but will be eligible for SQI reward payments provided reliability as seen by the customer can be accurately measured.

The SQI scheme will involve 10 performance indicators for Energex and 11 for Ergon. For Energex the indicators are: overall SAIDI and SAIFI for CBD, urban and short rural feeders; SAIDI for the worst 10 per cent of feeders (customer weighted) for both urban and short rural feeders; number of overall quality of supply complaints; and, the percentage of phone calls not answered in 30 seconds. For Ergon the indicators are: overall SAIDI and SAIFI for urban, short rural and long rural feeders; SAIDI for the worst 10 per cent of feeders (customer weighted) for urban, short rural and long rural feeders; number of overall quality of supply complaints; and the percentage of phone calls not answered in 30 seconds. For the reliability indicators, events related to generation and transmission interruptions and natural disasters where more than 5 per cent of the customers in the distributor's geographic region are affected will be excluded. After the conclusion of the three year 'paper trial' period, the benchmark against which performance on an indicator is compared will be a rolling average of the distributor's own performance on that indicator for the three financial years preceding the financial year being assessed. The rolling average will be built up progressively starting with data for the 2004–05 financial year, noting that Energex's customer number based reporting system is not expected to commence until July 2004 and may take some time to be bedded in. The QCA will make a judgment at the end of the three year paper trial on whether the available data at that time is sufficiently robust to justify moving to the payment of actual rewards and penalties for the fourth year of the scheme. If the data is sufficiently robust for one distributor but not the other then the commencement date for paying actual rewards and penalties may differ between the two distributors. The composition of the worst 10 per cent of feeders will be determined annually. The scheme will have no performance deadbands initially.

The scheme will have symmetric reward and penalty rates. For Energex the reward/penalty rates are $18 million for a change in SAIFI of one unit, $270,000 for each minute change in SAIDI and the same for each minute change in SAIDI for the worst 10 per cent of feeders, $25,000 for a one per cent change in the number of voltage complaints, and $31,000 for a one per cent change in the number of phone calls answered in less than 30 seconds. For Ergon the reward/penalty rates are $12.5 million for a change in SAIFI of one unit, $190,000 for each minute change in SAIDI and the same for each minute change in SAIDI for the worst 10 per cent of feeders, $24,000 for a one per cent change in the number of voltage complaints, and $42,500 for a one per cent change in the number of phone calls answered in less than 30 seconds. The aggregate net reward or penalty will be capped at 2 per cent of each distributor's 2002 revenue.

To operationalise the scheme we envisage the following process, assuming a five year regulatory period:

Year 1 (2005–06):

- determine the composition of the worst 10 per cent of feeders using customer–weighted SAIDI data for the 2004–05 financial year
- form benchmarks based on the 2004–05 financial year
- compare actual performance measured for 2005–06 to benchmarks
- apply reward/penalty rates, calculation done by 31 December 2006
- add up total penalties and rewards, apply caps if necessary
- 'paper trial' price/revenue adjustment would take place on 1 July 2007

Year 2 (2006–07):

- determine the composition of the worst 10 per cent of feeders using customer–weighted SAIDI data for the 2005–06 financial year
- form benchmarks based on average of the two financial years 2004–05 and 2005–06
- compare actual performance measured for 2006–07 to benchmarks

- apply reward/penalty rates, calculation done by 31 December 2007
- add up total penalties and rewards, apply caps if necessary
- 'paper trial' price/revenue adjustment would take place on 1 July 2008

Year 3 (2007–08):

- determine the composition of the worst 10 per cent of feeders using customer–weighted SAIDI data for the 2006–07 financial year
- form benchmarks based on average of the three financial years 2004–05, 2005–06 and 2006–07
- compare actual performance measured for 2007–08 to benchmarks
- apply reward/penalty rates, calculation done by 31 December 2008
- add up total penalties and rewards, apply caps if necessary
- 'paper trial' price/revenue adjustment would take place on 1 July 2009
- review experience with paper trial, review appropriateness of parameters based on experience and decide whether to proceed with implementation of scheme if data are sufficiently robust by 31 March 2009

Year 4 (2008–09):

- determine the composition of the worst 10 per cent of feeders using customer–weighted SAIDI data for the 2007–08 financial year
- form benchmarks based on average of the three financial years 2005–06, 2006–07 and 2007–08
- compare actual performance measured for 2008–09 to benchmarks
- apply reward/penalty rates, calculation done by 31 December 2009
- add up total penalties and rewards, apply caps if necessary
- price/revenue adjustment takes place on 1 July 2010 (actual)

Year 5 (2009–10):

- determine the composition of the worst 10 per cent of feeders using customer–weighted SAIDI data for the 2008–09 financial year
- form benchmarks based on average of the three financial years 2006–07, 2007–08 and 2008–09
- compare actual performance measured for 2009–10 to benchmarks
- apply reward/penalty rates, calculation done by 31 December 2010
- add up total penalties and rewards, apply caps if necessary

- price/revenue adjustment takes place on 1 July 2011 (actual)

Since the form of regulation will be a revenue cap, the net reward or penalty will be added to the company's 'unders and overs' account for true–up.

8. CONCLUSIONS AND AREAS FOR FURTHER RESEARCH

This report presents a concrete SQI incentive for Queensland's electricity distributors. We have attempted to use sound economic reasoning and the best available data to fashion a service quality incentive plan that is likely to deliver appropriate quality outcomes for Queensland's consumers of distribution services. However, the amount of data available to construct this SQI has been quite limited. Here we will briefly discuss some areas where additional information and analysis may be valuable in refining service quality regulation in Queensland.

1. The Nature and Role of Price–Service Offerings: Price service offerings (PSOs) are central to Energex's proposals for delivering appropriate quality to its customers. Our preliminary analysis of Energex's proposal concludes that, during the term of the next revenue or price controls, PSOs should only be offered on a voluntary, contractual basis with willing customers. Looking forward, we have identified several aspects related to implementing PSOs that deserve more attention, including the role that regulators should play in overseeing the terms of PSOs and provisions for dealing with asset specificity.

2. Number and Choices of Indicators: We have chosen indicators that we believe cover the most important aspects of electricity distribution service quality, but there may be scope to expand or amend these indicators when the plan is updated.

3. Benchmarks: Benchmarks will be based on moving averages of the company's performance on an indicator. It could be valuable to compare the company's rolling–average performance to service quality performance by other distributors in Australia and overseas once more robust data becomes available. Such comparisons could be the basis for peer–based benchmarks in the future. However, any such comparisons should ensure that performance is measured comparably across companies and control to the greatest extent possible for differences in external business conditions that may affect measured quality.

4. Estimate Value of Service to Queensland Customers: Because of time and budget constraints, this report relied on estimates of the value of the various electricity distribution

services that were developed in other parts of Australia. These estimates were the best available, but they may not be precise reflections of Energex and Ergon customers' preferences. Further work estimating the value of service to customers in Queensland may be important for refining award rates which, as discussed, play a critical role in creating incentives under a SQI plan.

5. Estimate marginal costs: Optimal quality depends on both the marginal benefit and marginal costs of quality to customers. Some work has been done to estimate the marginal cost of reliability improvements in Victoria, but this work may not be a good guide to the costs faced by Energex and Ergon. Further work on estimating the marginal costs of quality changes could be valuable when refining parameters of the SQI plan.

6. Relationship between SQI and an earnings sharing mechanism: There was some interest in integrating a SQI into an earnings sharing mechanism (ESM). This can be an attractive means of implementing SQIs, particularly if there is considerable uncertainty about the value of quality changes to customers. However, there are no precedents with ESMs in Australian regulation, and they are unfamiliar to some interested parties. Establishing an ESM would also represent a significant change in the form of regulation and go beyond the scope of this project. Nevertheless, because this can be an attractive method of implementing SQIs, the concept could merit further investigation, to take effect either at the end of the 'paper trial' period or at the end of the next regulatory period.

APPENDIX 1: SURVEYED SERVICE QUALITY INCENTIVE PLANS FROM NORTH AMERICA

A. Reliability

Jurisdiction	Company	Indicators	Benchmarks	Weights
Maine	Central Maine Power	- CAIDI	180 outage minutes per customer.	20%
		- SAIFI	Minimum index value of 2.0.	20%
	Central Maine Power	- CAIDI[8]	2.58 hours per year	12.5%
		- SAIFI[8]	1.8 interruptions per year	12.5%
	Bangor Hydro	- CAIDI[8]	2.13 hours per year	14.3%
		- SAIFI[8]	1.43 interruptions per year	14.3%
Massachusetts	Electric Companies[6]	- SAIFI	Average of 5 years most recent years	22.5%
		- SAIDI	Average of 5 years most recent years	22.5%
	National Grid - MA[7]	- SAIFI	Maximum of 1.34	16.7%
		- SAIDI	Maximum of 101.60	16.7%
		- Dx line losses	N/A	8.3%
New York	National Grid-NY[2]	- SAIFI	Under 0.93	18.3%
		- CAIDI	Under 2.07	18.3%
		- No of Momentary Interruptions Per Year	- For 115KV Maximum of 200	3.1%
			- For 23-69KV Maximum of 725	3.1%
			- For Dx Maximum of 2000	3.1%
Oregon				
	PacifiCorp	- SAIDI	3-year weighted average of the three most recent years	NA
		- SAIFI	3-year weighted average of the three most recent years	NA
		- MAIFI	3-year weighted average of the three most recent years	NA
Rhode Island	The National Grid Group - RI	- frequency of interruptions per customer served	Minimum of 1.43 (coastal area)	20.8%
			Minimum of 1.27 (capital area)	20.8%

Jurisdiction	**Company**	**Indicators**	**Benchmarks**	**Weights**
		- duration of interruptions per customer served	Minimum of 82.7 minutes per customer (coastal area)	20.8%
			Minimum of 70.3 minutes per customer (capital area)	20.8%
Washington	Puget Sound Power and Light	- SAIFI[4]		
		- SAIDI[4]		
California	San Diego Gas & Electric	- System Average Interruption Duration Index	70 minutes	NA[2]
	San Diego Gas & Electric	- System Average Interruption Duration Index	52 Minutes	NA[2]
		- System Average Interruption Frequency Index	0.90 outages per year	NA[2]
		- Momentary Average Interruption Frequency Index	1.28 outages per year	NA[2]
	Southern California Edison	- Average Customer Minutes of Interruption	59 minutes, declining by two minutes each year during the life of the plan.	NA[2]
		- Total interruptions per year	10,900	NA[2]
New York	Rochester Gas & Electric	- System Average Interruption Frequency Index (SAIFI)	Minimum index value of 1.27.	NA[2]
		- Customer Average Interruption Duration Index (CAIDI)	Minimum index value of 1.73.	NA[2]
	New York State Electric & Gas	- SAIFI	Varies by district served.	NA[2]
		- CAIDI	Varies by district served.	NA[2]
	Niagara-Mohawk Power	- SAIFI	0.93 outages per year	NA[2]
		- SAIDI	Maximum index value of 2.07	NA[2]
	Consolidated Edison	- SAIFI:	Varies by network and radial circuits	NA[2]
		- CAIDI:	Varies by network and radial circuits	NA[2]
	Long Island Lighting	- SAIFI: by Divisions	Varies by district served.	NA[2]
		- CAIDI: by Divisions	Varies by district served.	NA[2]

[1] Service quality indexes were not computed; instead, payments are made directly to affected customers if certain indicators fall below the benchmark.

[2] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.

[3] Latest data available indicates Puget Sound Power and Light has not set benchmarks for reliability

[4] 100% of penalties for these measures of reliability will be assessed on electric revenues. For the customer service measures, detailed unde telephone services, metering/billing, customer satisfaction and other, 80% of penalties will be assessed on electric revenues and 20% will be gas revenues.

[5] The plan applies to all electric utilities except National Grid

[6] Benchmarks update annually based on five year rolling averages of historical performance. All figures are initial values.

[7] Data for the indicator excluded during outages that affect more than 10% of the customers in any of CMP's 11 service areas.

B. Public Safety

Jurisdiction	Company	Indicators	Benchmarks	Weights
Massachusetts	Gas companies	- Response to odour calls	95% of odour calls responded to in 1 hour.	NA
New York	Brooklyn Union Gas - Benchmark Plan	- Emergency telephone responsiveness	80% of calls handled within 20 seconds, 9-5 M-F.	20% of threshold services
		- Emergency field responsiveness	98% of customer requests for emergency service responded to in 1 hour.	20% of threshold services
	Brooklyn Union Gas - Price Cap Plan	- Emergency telephone responsiveness	85.6% of calls handled within 20 seconds, 9-5 M-F.	10%
		- Emergency field responsiveness	94.4% of customer requests for emergency service responded to in 1 hour.	5%
Oregon	PacifiCorp	- Major safety violations	0.0 violations	NA[3]

C. Non-Emergency On-Site Services

Jurisdiction	Company	Indicators	Benchmarks	Weights
California	Southern California Gas	- On-time arrival for a service call	94.2% on-time arrival for service appointments	NA[1]
		- Satisfaction with appliance service representative	93.3% very satisfied	
Maine	Central Maine Power	- Customer installations	72% of installations on time.	20%
	Central Maine Power Company	- Percent of new service installed by date promised to customer	93%	12.5%
		- Market responsiveness	100% of enrollments from competitive electricity providers processed within the timeframe provided by the Commission	12.5%
	Bangor Hydro	- Service order timeliness	89% of all orders fulfilled by goal dates	14.3%
		- Market responsiveness	100% of enrollments from competitive electricity providers processed within the timeframe provided by the Commission	14.3%
Massachusetts	Boston Gas	- Service calls met	95% of service calls met on same day as requested.	NA
	Gas and electric companies[3]	- Percent of service appointments met as scheduled	Average of most 10 recent years	12.5%

Jurisdiction	Company	Indicators	Benchmarks	Weights
New York	Brooklyn Union Gas - Benchmark Plan	- Same day appointments	89.1% of same day appointments kept within a 6 hour standard.	7.5% of non-threshold services
		- Future day appointments	77.1% of future day appointments kept.	7.5% of non-threshold services
	Brooklyn Union Gas - Price Cap Plan	- Same day responsiveness	83.6% of same day appointments kept within a 6 hour standard.	15%
		- Service appointments kept	88.4% of appointments kept.	15%
	Consolidated Edison	- Work orders, initial phase	Average 6 days between receipt of customer request and issuance of service layout for initial phase completion.	NA[1]
		- Work orders, final phase	Average 7.9 days between receipt of customer request and completion of final inspection.	NA[1]
	Consolidated Edison	- Work orders, initial phase	Average 7.5 days between receipt of customer request and issuance of service layout for initial phase completion.	NA[1]
		- Work orders, final phase	Average 10 days between receipt of customer request and completion of final inspection.	NA[1]
	National Fuel Gas	- Non-emergency appointments kept	92% of appointments kept on an a.m./p.m. or daily basis depending on appointment type.	NA[1]
		- New service installations	92% of new service installations completed within 10 calendar days.	NA[1]
	National Fuel Gas	- Non-emergency appointments kept	91% of appointments kept on an a.m./p.m. or daily basis depending on appointment type.	NA[1]
		- New service installations	91% of new service installations completed within 10 calendar days.	NA[1]
	Rochester Gas & Electric	- Appointments kept	99% of appointments kept.	NA[1]
Washington	Puget Sound Power and Light	- Appointments Kept	92% of appointments kept	

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[3] The plan applies to all electric utilities except National Grid

D. Telephone Services

Jurisdiction	Company	Indicators	Benchmarks	Weights
California	Southern California Gas	- % Emergency calls answered within 20 seconds	90% emergency calls	NA[2]
		-% non-emergency calls answered within 60 seconds	80% non-emergency calls	
		- Satisfaction with telephone customer service representative	89.7% very satisfied	
		- Satisfaction with scheduling of an appointment for a field service call	78.1% very satisfied	
	San Diego Gas and Electric	- % personal and electronic calls answered within 60 seconds	- 80% of calls answered within 60 seconds on a 24 hour annual basis	
New York	Brooklyn Union Gas - Benchmark Plan	- Correspondence responsiveness	84.1% of responses to written inquiries within 12 calendar days.	3.8% of non-threshold services
		- Non-emergency telephone responsiveness	55.1% of calls answered within 45 seconds, M -F 9-5.	7.5% of non-threshold services
		- Abandoned calls	Maximum 3.5% of calls abandoned before contact with a representative.	5% of threshold services
	Brooklyn Union Gas - Price Cap Plan	- Non-emergency telephone responsiveness	73.2% of calls answer within 45 seconds, M -F, 9-5.	7%
	National Fuel Gas	- Telephone responsiveness	74% of calls answered within 30 seconds.	NA[2]
	National Fuel Gas	- Telephone responsiveness	72% of calls answered within 30 seconds.	NA[2]
	Rochester Gas & Electric	- Telephone responsiveness	73% of calls answered within 30 seconds.	NA[2]
	Consolidated Edison	- Abandoned calls	Maximum 2.6% calls abandoned.	NA[2]
	Consolidated Edison	- Abandoned calls	Maximum 5.1% calls abandoned.	NA[2]

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[2] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.

D. Telephone Services

Jurisdiction	Company	Indicators	Benchmarks	Weights
Maine	Central Maine Power	- Phone employees knowledgeable	82% of customers surveyed report phone center employees were knowledgeable when contacted.	20%
	Central Maine Power Company	- Percent of business calls answered within 30 seconds[5]	80%	12.5%
		- Percent of outage calls answered within 30 seconds	80% (for calls received on the company's outage line)	12.5%
	Bangor Hydro	- Percent of business calls answered within 30 seconds	80%	14.3%

Jurisdiction	Company	Indicators	Benchmarks	Weights
Massachusetts	Boston Gas	- Percent of calls answered within 30 seconds	95% - Emergency 80% - Service and billing	NA
	Gas and electric companies[3]	- Percent of calls answered within 20 seconds	Average of most 10 recent years	12.5%
	National Grid - MA[4]	- Percent of calls answered within 20 seconds	Minimum of 68.5 calls answered within 20 seconds	8.3%
New York	National Grid- NY	- Percent of calls answered within 30 seconds	Minimum of 77 calls answered within 30 seconds	7.7%
Rhode Island	The National Grid Group - RI	- Percent of calls answered within 20 seconds	Minimum of 72.4 calls answered within 20 seconds	8.3%

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[2] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.
[3] The plan applies to all electric utilities except National Grid
[4] Benchmark updates annually based on five year rolling averages of historical performance. Figure is initial value.
[5] Data for this indicator excluded on days when more than 10% of the customers in any of CMP's 11 service areas experience outages.

E. Metering/Billing

Jurisdiction	Company	Indicators	Benchmarks	Weights
Maine	Bangor Hydro	- Bill error rate	0.40%	14.3%
Massachusetts	Boston Gas	- On-cycle meter reads	95% of meters read on cycle.	NA
		- Bill adjustments	Less than 65% of total DPU consumer division customer bill adjustments	NA
	Gas and electric companies[3]	- Bill Adjustments	Average of most 10 recent years	5.0%
		- On-cycle meter reads	Average of most 10 recent years	10.0%
	National Grid - MA[4]	- Percent meters read	Minimum of 88.5	8.3%
New York	Brooklyn Union Gas - Benchmark Plan	- Estimated meter reads	Maximum 15.4% of meters not read during actual cycle.	5.6% of non-threshold services
		- Billing field investigations	Average 19 days to conduct field investigation.	5.6% of non-threshold services
		- Meters read on schedule	98.8% of meter routes reached on date promised.	10% of threshold services
		- Billing accuracy	96.5% of bills adjusted for less 5% of total.	15% of threshold services
		- Payments not posted	0.45% payments not posted within one business day.	15% of threshold services
	Brooklyn Union Gas - Price Cap Plan	- Estimated meter reads	20.8% of meters not read during actual cycle.	15%

Jurisdiction	Company	Indicators	Benchmarks	Weights
	Brooklyn Union Gas - Price Cap Plan	- Estimated meter reads	20.0% of meters not read during actual cycle.	15%
	National Fuel Gas	- Bill adjustments	1.9% of bills adjusted.	NA[1]
		- Estimated readings	19.9% of meter readings estimated.	NA[1]
	Consolidated Edison	- On-cycle meter reads	90.2% of meters read on schedule.	NA[1]
		- Billing accuracy	99.7% of bills not adjusted due to company error.	NA[1]
	Consolidated Edison	- On-cycle meter reads	86.9% of meters read on schedule.	NA[1]
		- Billing accuracy	97.2% of bills not adjusted due to company error.	NA[1]
	Rochester Gas & Electric	- Bills adjusted	2.7% of bills adjusted.	NA[1]
		- Estimated bills	13.7% of bills estimated.	NA[1]
	Brooklyn Union Gas - Benchmark Plan	- Estimated meter reads	Maximum 15.4% of meters not read during actual cycle.	5.6% of non-threshold services

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[3] The plan applies to all electric utilities except National Grid

[4] Benchmark updates annually based on five year rolling averages of historical performance. Figure is initial value.

F. Customer Satisfaction

Jurisdiction	Company	Indicators	Benchmarks	Weights
New York	Brooklyn Union Gas - Benchmark Plan	- Annual customer satisfaction	90.7% satisfactory responses to random customer survey.	8% of non-threshold services
		- Customer contact satisfaction	89% satisfactory responses of customers contacted by the utility over the last 12 months.	22% of non-threshold services
		- PSC contacts	230 contacts per month.	17.5% of non-threshold services
	Brooklyn Union Gas - Price Cap Plan	- PSC contacts	1953 contacts per year	23%
		- Contact survey	84.8% satisfactory responses from random customers who have contacted the utility in the last month.	10%
	National Fuel Gas	- Annual customer satisfaction	85.1% satisfactory responses to annual random survey.	NA[2]
		- Customer complaints	10 complaints to the PSC per 100,000 customers.	NA[2]

Jurisdiction	Company	Indicators	Benchmarks	Weights
	National Fuel Gas	- Annual customer satisfaction	81.6% satisfactory responses to annual random survey.	NA[2]
		- Customer complaints	10 complaints to the PSC per 100,000 customers.	NA[2]
	Consolidated Edison	- PSC complaints threshold	9.6 divided by total customers multiplied by 100,000	NA[2]
		- PSC complaints performance	9.6 divided by total customers multiplied by 100,000, with rewards earned under stricter standards each year.	NA[2]
		- Visitor satisfaction	84.2% satisfaction on annual survey	NA[2]
		- Caller satisfaction	83.5% satisfaction on annual survey	NA[2]
		- Emergency center satisfaction	80.5% satisfaction on annual survey	NA[2]
	Consolidated Edison	- PSC complaints threshold	8.0 divided by total customers multiplied by 100,000	NA[2]
		- PSC complaints performance	8.0 divided by total customers multiplied by 100,000, with rewards earned under stricter standards each year.	NA[2]
		- Visitor satisfaction	84.2% satisfaction on annual survey	NA[2]
		- Caller satisfaction	83.5% satisfaction on annual survey	NA[2]
		- Emergency center satisfaction	80.5% satisfaction on annual survey	NA[2]
	Rochester Gas & Electric	- Customer satisfaction survey	Initial customer satisfaction survey in first plan year. Benchmark set at a later date.	NA[2]
		- PSC complaints	9 per 100,000 customers	NA[2]
	New York State Electric & Gas	- PSC complaints	5 per 100,000 customers	NA[2]
		- Customer expectation survey	Complete study and report.	NA[2]
		- Customer satisfaction index	83% satisfaction on annual survey	NA[2]
		- Contact satisfaction index	88% satisfaction on follow-up survey of customers who contact the utility.	NA[2]
	New York State Electric & Gas	- PSC complaints	4 per 100,000 customers	NA[2]
		- Customer expectation survey	Complete study and report.	NA[2]
		- Customer satisfaction index	71% satisfaction on annual survey	NA[2]
		- Contact satisfaction index	83% satisfaction on follow-up survey of customers who contact the utility.	NA[2]

Jurisdiction	Company	Indicators	Benchmarks	Weights
	Niagara-Mohawk	- PSC Complaint Rate - Customer satisfaction index	10 per 100,000 customers Minimum index value of 80	NA[2] NA[2]

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[2] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.

F. Customer Satisfaction

Jurisdiction	Company	Indicators	Benchmarks	Weights
California	Southern California Edison San Diego Gas & Electric San Diego Gas & Electric	- Customer satisfaction survey - Customer satisfaction survey - Customer satisfaction survey	64% of responses to annual survey in top two categories on a six point scale. 92% "very satisfied" responses on annual survey. 92.5% "very satisfied" responses on annual survey.	NA[2] NA[2] NA[2]
Maine	Central Maine Power Central Maine Power Company	- PSC complaints - MPUC Complaint Ratio	1.17 per 1,000 customers 1.17 complaints per 1,000 customers per year	20% 12.5%
		- MpUC Complaint Ratio	1.52 complaints per 1,000 customers per year	14.3%
		- Call center service quality survey	84% favorable answers to questions in two categories	12.5%
Massachusetts	Boston Gas Gas and electric companies[6]	- Complaints made to DPU - DTE complaint rate	Less than 50% of total DPU complaints Average of most 10 recent years	NA 5.0%
	National Grid - MA[6]	- Customer Satisfaction Survey	Minimum of 90% satisfied	8.3%
		- Customer Contact Satisfaction	Minimum of 74.9% satisfied	8.3%
		- DTE complaint rate	Maximum of 0.87 cases per 1000 customer	8.3%
New York	National Grid- NY	- PSC Complaint Rate	Maximum of 4 complaints per 100,000 customers	15.5%
		- Residential Transaction Satisfaction Index[5]	- Year 1 Maximum of 79 - Year 2 Maximum of 80 - Year 3 and beyond Maximum of 81	7.7%

Jurisdiction	Company	Indicators	Benchmarks	Weights
		- Small/Medium Commercial and Industrial Transaction Satisfaction Index	- Year 1 Maximum of 74 - Year 2 Maximum of 76 - Year 3 and beyond Maximum of 78	7.7%
Oregon				
	PacifiCorp	At Fault Customer Complaints	Not available	
Rhode Island	The National Grid Group - RI	- Customer Contact	Minimum of 76.2% surveyed customers satisfied w/ customer contact	8.3%
Washington	Puget Sound Power and Light	- Customer Satisfaction Survey	90% of surveyed customers rated company a 5 on a 7 point scale	NA

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[2] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.
[3] The plan applies to all electric utilities except National Grid
[4] This index has three components: customer satisfaction with the telephone representative, field service representative and problem resolution.
[5] Benchmarks update annually based on five year rolling averages of historical performance. All figures are initial values.

G. Employee Safety

Jurisdiction	Company	Indicators	Benchmarks	Weights
California	Southern California Edison	OSHA Total Reportable Rate	13.0 accidents and illnesses per 200,000 hours worked.	NA[1]
	San Diego Gas & Electric	OSHA Total Reportable Rate	8.80 OSHA- reportable frequency rate	NA[1]
	Southern California Gas	OSHA Total Reportable Rate	10.3 accidents and illnesses per 200,000 hours worked.	NA[1]
Massachusetts	Gas and electric companies[3]	- Lost work time accident rate	Average of most 10 recent years rate per 200,000 employee hours	10%
	National Grid - MA[4]	- Lost work time accident rate	Maximum of 1.74 per 200,000 employee hours	8.3%
		- Restricted work case rate	Maximum of 6.27 per 200,000 employee hours	8.3%
Washington	Puget Sound Power and Light	- Employee safety[2]		

[1] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.
[2] Latest data available indicates Puget Sound Power and Light has not set benchmarks for employee safety
[3] The plan applies to all electric utilities except National Grid
[4] Benchmarks update annually based on five year rolling averages of historical performance. All figures are initial values.

H. Other

Jurisdiction	Company	Indicators	Benchmarks	Weights
California	San Diego Gas & Electric	- National rate comparison	138% of national system average rate index.	NA[2]
	Southern California Gas	- Notification of payment due	Write to customer within 10 working days of failure to pay.	NA[1]
New York	Brooklyn Union Gas - Benchmark Plan	-PSC complaint responsiveness	80.1% of complaints addressed within 15 calendar days.	5% of non-threshold services
		- Communication effectiveness : residential heating	40.1% of customers "very familiar" with 60% of the company's core messages.	4% of non-threshold services
		- Communication effectiveness : residential non-heating	30.1% of customers "very familiar" with 60% of company's core messages.	2% of non-threshold services
		- STAR outreach effectiveness	45,001 customers identified for special protection, such as disabled or elderly.	4% of non-threshold services
		- District office waiting time	7 minutes average waiting time.	10% of threshold services
		- Social work	450 residential low income customers obtaining financial assistance.	5% of threshold services
	Consolidated Edison	- Deferred payment default rate	21.1% of deferred payment agreements broken or voided.	NA[2]
		- Routine investigations	91.5% of investigations completed within 30 days.	NA[2]
	New York State Electric & Gas	- Standards of Excellence Program	100 on index of 16 customer related indicators.	NA[2]
		- Outreach and education	0 on index of involvement of customers in decision making process (scale -7 to 7).	NA[2]
		- Uncollectible index	No movement in percentage of uncollectible from 3 year average.	NA[2]
		- Implementing improvements	No new milestones of implementation achieved, but action taken.	NA[2]
	National Grid- NY	- Low income customer assistance	Minimum of 95% of three performance goals[3]	7.7%

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[2] Service quality indexes were not computed; instead, there is a direct link between service quality performance and rewards or penalties.
[3] The three goals include # of enrolment of customers, # of energy services and # of management workshops.

APPENDIX 2: OVERSEAS VALUE OF RELIABILITY ESTIMATES

RESIDENTIAL OUTAGE COSTS FOR A ONE HOUR INTERRUPTION ($/KwH)

Study	Country	Method	Outage Costs ($/kWh unserved)	Special Conditions
Wood, Niemann, Brandreth (2000)	USA (SCE)	Survey	4.56	residential WTP, summer wkday
Beenstock and Goldin (1997)	Israel	Survey	10.58	
Kariuki and Allan (1996)	UK	Survey	0.43	residential
Sullivan et.al. (1996)	USA	Survey	2.95	per peak kWh
BC Hydo (1994)	Canada	Survey	0.68	
Goett, McFadden and Woo (1988)	USA	Survey	3.46##	winter 10 A.M.
Doane, Hartman and Woo (1988a)	USA	Survey	26.43##	winter P.M
		Survey	8.75##	summer P.M.
Doane, Hartman and Woo (1988b)	USA	Survey	22.12##	winter P.M.
		Survey	7.25##	summer P.M.
		Survey	14.91##	- -
Meta Systems, et.al. (1986)	USA	Proxy	27.13	upper bound
		Survey	7.10##	winter P.M.
Sanghvi (1983a)	USA	Estimated loss in Consumer Surplus	.04 to .51	summer weekday
		Proxy	3.27	upper bound
Gilmer and Mack (1983)	USA	Estimated loss in Consumer Surplus	0.30	- -
		Proxy	1.20 to 4.07	upper bound
Billinton, Wacker and Wojczynski (1982)	Canada	Survey	.85# to 2.78**	- -
Ontario Hydro (1980)	Canada	Survey	.16 to .32	daily interruptions
Mosbaek (1980)	USA (Key West)	Survey	0.16	daily interruptions, advance notice

#assumes demand at time of outage is equal to 75%of annual peak.

OUTAGE COSTS FOR A ONE HOUR INTERRUPTION ($/kWh)
COMMERCIAL AND MISCELLANEOUS SECTORS

Study	Country	Method	Outage Costs ($/kWh unserved)	Special Conditions
Moeltner and Layton (2002)	USA	Survey	36.03 25.78	small commercial large commercial
Wood, Niemann, Brandreth (2000)	USA	Survey	25.15	small/med. comm&ind. WTP, summer wkday
Kariuki and Allan (1996)	UK	Survey	10.05	commercial
Sullivan et.al. (1996)	USA	Survey	65.21	per peak kWh
BC Hydo (1994)	Canada	Survey	29.92	Summer/afternoon
Woo and Train (1989)	USA	Survey	13.38**	commercial
Fisher (1986)	USA	Survey	37.02	machinery
		Survey	14.85	electronic & electronic machinery
		Survey	31.11	Measuring Analysis & Control Instruments
		Survey	25.69	other manufacturing
Billinton, Wacker and Wojcaynski (1982)	Canada	Survey	16.13# to 36.87##	retail
		Survey	20.71# to 35.23##	retail food
		Survey	25.16# to 62.70##	retail trade
		Survey	9.08# to 21.84##	retail service
Mosbaek (1980)	USA (Key West)	Survey	7.37	All non-residential, daily interruptions, and advance notice
Ontario Hydro (1980)	Canada	Survey	20.08# to 32.86##	retail
		Survey	39.30# to 96.96##	office buildings
		Survey	2.78# to 4.92##	government and institutions
		Survey	756.08# to 1730.30##	large farms

* PR denotes a proxy emthod, CS denotes consumer surplus mehod , DC denotes the use direct cost survey techniques,

** assumes demand at time of outage is equal to annual average hourly kWh.

Doane, Hartman and Woo's (1989a) figure of .75 kWh/interruption was used to convert $/interruption costs to $/kWh unserved.

INDUSTRIAL OUTAGE COSTS FOR A ONE HOUR INTERRUPTION ($/kWh)

Study	Country	Method	Outage Costs ($/kWh unserved)	Special Conditions
Moeltner and Layton (2002)	USA	Survey	17.49	Small and large ind.
Wood, Niemann, Brandreth (2000)	USA (SCE)	Survey	105.07	Large comm. &ind WTP
Beenstock, Goldin and Haitovsky (1997)	Israel	Proxy	10.88	- -
Beenstock and Goldin (1997)	Israel	Proxy	10.57	
Kariuki and Allen (1996)	UK	Survey	24.46	Industrial
Sullivan et.al. (1996)	USA	Survey	10.83	per peak kWh
BC Hydro (1994)	Canada	Survey	9.75	small industrial
Chang and Chen (1994)	Taiwan	Proxy	2.07	Industry average
		Survey	3.91	Industry average
Grosfeld-Nir and Tishler (1993)	Israel	Market Demand	13.10	chemical and oil
			35.87	electronics and electrical equipment
			26.16	metal
			7.39	non-metallic minerals
			27.03	clothing
			26.44	transport equipment
			11.16	food and beverages
			7.24	mining and quarrying
			7.14	textiles
			32.13	rubber and plastic
			23.98	all others
Tishler (1993)	Israel	Market Demand	6.96	chemical and oil
			20.75	electronics and electrical equipment
			11.69	metal
			7.04	non-metallic minerals
			39.04	clothing
			16.55	transport equipment
			9.20	food and beverages
			2.43	mining and quarrying
			5.88	textiles
			11.48	rubber and plastic
			15.51	all others
				January 10 a.m.

APPENDIX 3: Outage Costs And Reliability Indicators

The outage cost literature suggests that outages impose both fixed and variable costs on customers. Fixed costs are those that occur immediately when, for example, service interruptions disrupt an industrial customer's production plans. Variable costs are related to the duration of an outage. The relative proportions of these costs vary among customer groups. Industrial customers typically have a higher proportion of fixed costs, while residential customers usually have a lower proportion of fixed costs.

Let the system–wide cost for each outage, *i*, be given by

$$C_i = a + bh_i \qquad [1]$$

Here, C_i is the cost of the outage and h_i is the total duration of the outage experienced by customers on the system. This simple, linear expression says that outage costs can be decomposed into two components. The fixed costs, *a*, are incurred immediately as power interruptions disrupt production plans. The variable costs, bh_i, are related to the length of the outage. The function is general enough to include the possibility that some customers will have no fixed cost. If that was true system–wide, then $a = 0$ and the line passes through the origin of the graph.

Total annual outage costs are obtained by summing the costs per outage in [1] over the number of outages in each year. Total outage costs in each year, *t*, are therefore equal to

$$TC_t = \sum_i \left(a + bhi\right) = N_t a + b \sum h_{i,t} \qquad [2]$$

Here, N_t stands for the number of interruptions experienced in year, *t*. The average outage costs experienced by customers on the system can be obtained by dividing [2] by the average number of customers served in year *t*, or C_t. Therefore

$$\frac{TC_t}{C_t} = a\frac{N_t}{C_t} + b\frac{\sum h_{i,t}}{C_t} \qquad [3]$$

In equation [3], $\frac{N_t}{C_t}$ corresponds to the average number of interruptions experienced by a customer on the system in year *t*. This is equivalent to the value of SAIFI in that year, or $SAIFI_t$. Similarly, $\frac{\sum h_{i,t}}{C_t}$ stands for the total duration of outages experienced by an average customer on the system in year *t*. This is equivalent to the value of SAIDI in that year, or

$SAIDI_t$. [3] therefore implies that the annual outage costs experienced by an average customer is a linear function of values for SAIFI and SAIDI. SAIFI is multiplied by the average fixed costs associated with an outage. SAIDI is multiplied by the average variable costs associated with a typical outage. If there are no fixed costs, then outage costs in year *t* are equivalent to the value
for $SAIDI_t$ multiplied by the average outage cost.

Equation [3] applies for all periods, so between two years t and *t+1*, the change in outage costs experienced by customers on the system, on average, is equal to

$$\frac{TC_{t+1}}{C_{t+1}} - \frac{TC_t}{C_t} = \left(a\frac{N_{t+1}}{C_{t+1}} + b\frac{\sum h_{i,t+1}}{C_{t+1}} \right) - \left(a\frac{N_t}{C_t} + b\frac{\sum h_{i,t}}{C_t} \right)$$

$$= a\left(\frac{N_{t+1}}{C_{t+1}} - \frac{N_t}{C_t} \right) + b\left(\frac{\sum h_{i,t+1}}{C_{t+1}} - \frac{\sum h_{i,t}}{C_{i+t}} \right) \quad [4]$$

$$= a\left(SAIFI_{t+1} - SAIFI_t\right) + b\left(SAIDI_{t+1} - SAIDI_t\right)$$

[4] implies that the change in outage costs for an average customer is a linear function of changes in values for SAIFI and SAIDI. The change in SAIFI is multiplied by the average fixed costs associated with an outage. The change in SAIDI is multiplied by the average variable costs associated with an outage.

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