Recommendations for Strengthening the Massachusetts Department of Public Utilities' Service Quality Standards

Prepared for the Massachusetts Office of the Attorney General

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Table of Contents

Table of Contents

Executive Summary

The Office of the Attorney General, in its statutory role as ratepayer advocate, has deemed it appropriate to review the Service Quality ("SQ") regulations in light of recent events and has commissioned this independent study, *Recommendations for Strengthening the Massachusetts Department of Public Utilities' Service Quality Standards*, conducted by O'Neill Management Consulting, LLC. This study provides recommendations to improve the Massachusetts Department of Public Utilities' ("DPU") current system of SQ metrics, reporting, and penalties for jurisdictional Massachusetts investor-owned electric and gas utilities.

There are new reasons to revisit the SQ regulations:

- Recent investments in utility infrastructure, funded by capital trackers and/or rate increases, should result in improved performance on some metrics.
- Recent storms, outage events, and equipment malfunctions point to weaknesses in the ability of many Massachusetts utilities to maintain adequate service under challenging weather conditions and at other times.
- Our analysis of the utilities' recent performance on the metrics shows that Massachusetts utilities are positioned to provide better quality of power and service.

Our key recommendations fall into four categories.

Metrics: The DPU should add new penalty and reporting metrics to the SQ Guidelines that will improve the ability of the DPU to measure the experience of the customer.

Benchmarks: The DPU should adopt benchmarks that are designed both to update the benchmarks for those metrics where MA utilities routinely exceed their targets and to provide additional motivation for the MA utilities to improve their performance on those metrics where their year-to-year performance has stagnated.

Offsets: In order to ensure MA utilities are not able to mask poor performance with a penalty offset earned in an unrelated area of SQ, the metrics should offset each other only if they are included in the same category of SQ metrics (i.e., (1) Safety and Reliability, (2) Customer Service and Billing, and (3) Customer Satisfaction).

Penalty levels: The Legislature recently increased the maximum SQ penalty cap to 2.5% of annual transmission and distribution revenues, and presumably intended for that 2.5% to be used as a penalty. The DPU's current SQ structure makes it nearly impossible for a MA utility to meet the 2.5% penalty threshold. The penalty structure should be amended to allow for the maximum penalty of 2.5% to be incurred within each category: (1) Safety and Reliability, (2) Customer Service and Billing, and (3) Customer Satisfaction.

In this study, O'Neill Management Consulting, LLC:

- Surveys the history and current state of the art of SQ regulation in Massachusetts, nationwide, and even internationally, citing the literature on the subject and conducting our own primary research with other jurisdictions.
- Examines in detail the list of metrics and how they are measured, making suggestions for improvement in various measures, including new measures that ensure a "no customer left behind" approach to reliability performance and that adopt new reporting-only measures in asset management and outage communication.
- Examines the structure of the penalty/offset mechanism, with recommendations for how to make the penalties and offsets more effective by allowing for maximum penalties within categories and reducing cross-category offsets that undermine the purpose.

Summary of our recommendations

Below is a summary of our detailed recommendations. See the appropriate section below for details on the rationale, current regulations, and recent performance of each metric or penalty/offset mechanism:

1) Include Customers Experiencing Multiple Interruptions ("CEMI") and Customers Experiencing Long Interruption Durations ("CELID") as additional penalty-eligible measures of reliability (a second tier within the reliability measures) in the manner in which Poor Circuit Remediation ("PCR") is handled at present. These would be storm-adjusted values for CEMI and CELID. Also, revise the benchmarks for SAIDI and SAIFI to reflect a goal of continuous improvement.

2) Move the Customer Satisfaction Surveys from reporting-only to penalty-eligible.

3) Include for reporting purposes only at first, measures of Estimated Time of Response ("ETR") reach and accuracy.

4) Include reliability reporting by municipality for electric local distribution companies.

5) Include leaks and breaks on targeted infrastructure as a reporting requirement for gas companies that have a Targeted Infrastructure Recovery Factor ("TIRF").

6) Develop information requests and elicit suggestions and options for the purpose of requiring submission of an annual plan for inspection and maintenance by Transmission and Distribution ("T&D") asset category, and then including reporting of the actual percentage completion of planned inspection and maintenance by category.

7) Provide on a reporting-only basis an annual summary, with monthly detail, of the number of service terminations for non-payment.

8) No longer require as an annual reporting metric the designation of service territory, the vegetation management policy and the spare component and inventory policy.

9) Adopt new common standards across all Massachusetts utilities for each of the Customer Service and Billing metrics that are subject to penalty, accounting for Massachusetts utilities' recent historical performance on these metrics.

10) Revise the benchmarks for the Massachusetts utilities that have demonstrated poor historical performance on the DPU's safety metric, "Lost Time Accident Rate," to ensure a minimum standard of safety across every investor-owned utility in Massachusetts.

11) Revise the benchmarks for Odor Response Rate to be more consistent with the recent performance of gas companies in Massachusetts.

12) Change the structure of the penalty/offset mechanism to no longer allow offsets from one SQ category (i.e., Safety and Reliability, Customer Service and Billing, or Customer Satisfaction) to be used in another category, but instead only allow offsets within each category.

13) Change the structure of the penalty/offset mechanism to allow each category to reach the maximum statutory penalty, provided that the overall maximum has not yet been reached.

14) Change the weighting of the metrics in the penalty/offset mechanism to reflect the inclusion of the new metrics and the revised penalty/offset structure as noted above.

Our recommendations are based on analysis of the strengths and weaknesses in the current program and can serve as a roadmap for the next step in SQ regulation that will put

Massachusetts at the forefront of this innovative, penalty/offset-based approach to regulating the performance of those investor-owned utility companies which enjoy a monopoly in providing electric and gas distribution service to the ratepayers of Massachusetts.

Introduction

The time is right for a change

This review comes at an appropriate time. The SQ program has been reviewed at regular intervals since its inception in approximately 1997. This was done by design, with an explicit call in each order for a review after a certain period, usually three years. The following timeline sets forth the history of SQ reviews by the DPU:

- Pre-1997 the DPU and the Attorney General (AG) prepare for de-regulation and the DPU approves settlement agreements that include SQ reporting and incentives.
- 1997 The Legislature passes G.L. c. 164, § 1E to establish a framework for the adoption of a SQ penalty system by the DPU.
- 1999 Docket D.T.E. 99-84 was opened in order to establish the SQ Guidelines.
- 2001 D.T.E. 99-84 final order is issued and SQ reporting under the SQ Guidelines begins, with review due in “three years.”
- 2004 D.T.E. 04-116 was opened, with intent to revise SQ metrics.
- 2006-7 D.T.E./D.P.U. 04-116A, B, C, D Orders issued updating the SQ Guidelines, with review due in three years.

The current SQ Guidelines, established in 2001 and revised in 2006-7 established performance measures for customer service and billing, safety and reliability, and customer satisfaction. The Guidelines also set benchmarks for each category based upon the historical performance of each Company between 1996-2005, where that information was available. Additionally, the SQ Guidelines set up a penalty and offset formula for each category, normalized by using a standard deviation.

From our review of the recent history of performance and penalties under the Massachusetts SQ Guidelines, we can conclude that, in addition to changing the details of the mechanism, particularly the offsets, we recommend adjustment of some of the benchmarks for the following reasons.

- Increased investment – The companies participating in increased investment programs approved by the Department have been granted recovery of costs due to increased investment, whether through rate cases or through accelerated recovery mechanisms such as TIRFs and trackers. Such investments may be expected to produce enhancements in service levels. Even for those trackers whose purpose is narrowly defined, such as replacement of cast iron and bare steel mains and services, the accelerated recovery of those investments has freed up cash that would otherwise have been devoted to normal replacement without accelerated recovery, making more cash available for other service-enhancing programs.

- Repetitive offsets can be abused – While the incentive mechanism in the SQ Guidelines provides deadbands and offsets in order to allow for random variations in metrics to not unduly penalize the companies, situations in which the metrics continue to generate offsets year-after-year only serve to undermine the impact of the rest of the program, allowing non-random performance shortfalls in other metrics to be "funded" by those in which superior performance can be virtually "banked." This undermines the original intent of the program.
- Continuous improvement – We live in a world in which technology allows and society expects continuous improvement in the delivery of services. Standard rate cap programs tend to have built into them some productivity improvement. Since the current rate caps have no such factors, an increase in the expected levels of SQ metrics can serve the same purpose.

In addition, recent events have called attention to the potential disparity between utility performance and the penalties/rewards earned under the SQ program. Significant rate increases received by MA electric and gas companies in recent years and accelerated (annual) rate recovery to finance infrastructure upgrades should result in real improvement to the quality of services provided to ratepayers, including a reduction of the duration and frequency of outages on "blue sky" days and also during major storm events, which have been frequent recently. However, we have not always seen such improvements. In addition, there have been newsworthy underground system fires resulting in widespread outages in Boston in 2012.

The current standards are deficient because despite the incidence of major outages, some utilities are eligible for incentive payments under the current rules. Recent major outages include outages derived from a December, 2008 ice storm; December, 2010 snowstorm; Tropical Storm Irene in August 2011; and the October, 2011 Snowstorm. The DPU opened docketed proceedings in each of those cases. The rate cases and accelerated recovery mechanisms include full rate cases for ten companies (See Table 1), and capital trackers for National Grid's electric companies and many of the gas companies.

Table 1 - Rate cases since January 1, 2009

Docket #	Company	Revenue Increase
D.P.U. 09-30	Bay State Gas Company	$19,054,659
D.P.U. 09-39	Massachusetts Electric Company, Nantucket Electric Company, each d/b/a National Grid	$42,201,877
D.P.U. 10-70	Western Massachusetts Electric Company	$16,669,925
D.P.U. 10-114	New England Gas Company	$5,072,686
D.P.U. 10-55	Boston Gas Company, Essex Gas Company and Colonial Gas Company, each d/b/a National Grid	$60,721,542
D.P.U. 11-01/02	Fitchburg Gas and Electric Light Company, d/b/a Unitil (separate rate cases for electric and gas divisions)	$6,999,406
D.P.U. 12-25	Bay State Gas Company	$7,853,163

The impetus behind the DPU's original establishment of the SQ Guidelines was to prevent MA utilities from allowing service quality to deteriorate under a new regulatory regime. The goal now must be different because we have entered an era of enhanced financial security for utilities, which includes decoupling, recovery mechanisms to avoid regulatory lag for utilities that invest in capital replacement of aging infrastructure like cast iron and bare steel mains and services, as well as aging electric wire, poles, and equipment. Some utilities have taken advantage of this regulatory change and have invested heavily in these programs. As such, targets for service quality metrics that were based on performance for utility systems in the 1996-2005 era may no longer be appropriate yardsticks for today's investment-enhanced systems. Instead, one would expect to see improved performance because of the higher investment for which ratepayers are now paying. Table 2 below shows the increased investment for which companies have filed for recovery:

Table 2 – Increased Investment Requested for Recovery

Year	Company	Investment
2012	Bay State Gas Company	$14,187,932
2009	Massachusetts Electric Company, Nantucket Electric Company, each d/b/a National Grid	$170,000,000
2011	New England Gas Company	$7,698,017
2010	Boston Gas Company, Essex Gas Company and Colonial Gas Company, each d/b/a National Grid	$10,402,692

Another issue is the structure of the existing program, which allows utilities to avoid penalties for poor reliability by offsetting them with extraordinary performance on customer service measures.[1]

In order to fix this problem **we recommend adjusting the structure of the penalties and offsets, namely, restricting "offsets" (credits) to the area in which they are generated, e.g., (a) reliability and safety, (b) customer service, or (c) customer satisfaction**. Thus, for example, good performance on answering phone calls might earn credits to offset subpar performance on meter reading, but not subpar performance on reliability.

It is to explore such refinements in the targets, measures, and penalty mechanisms that this study has been commissioned.

Scope of this review

The scope of this review is wide-ranging, including gas and electric companies, and the SQ Guidelines and their component measures, targets, and penalty/offset mechanisms. However, it does not encompass the many other ways in which the DPU is empowered to regulate utility companies, including, but not limited to, general rate cases, merger agreements entered into to obtain DPU approval for a merger, emergency preparedness plans and execution of the same, as dealt with in recently passed Massachusetts statutes, financial and other operational reporting requirements, safety regulations, employment regulations, tax regulations, and so on.

[1] The AG previously made recommendations for limiting the use of offsets on customer service metrics from offsetting poor performance on reliability metrics in D.P.U. 04-116

The utilities covered by this review are the regulated electric and gas local distribution companies in Massachusetts. These include:

- Bay State Gas Company d/b/a Columbia Gas of Massachusetts
- Berkshire Gas Company
- Blackstone Gas Company
- Boston Gas Company, Essex Gas Company and Colonial Gas Company, each d/b/a National Grid
- Fitchburg Gas and Electric Light Company d/b/a/ Unitil (with separate reports for the Electric and Gas divisions)
- Massachusetts Electric Company and Nantucket Electric Company d/b/a/ National Grid
- New England Gas Company (with separate reports for Fall River and North Attleboro regions)
- NSTAR Gas Company
- NSTAR Electric Company
- Western Massachusetts Electric Company.

Each separate company listed above files an annual SQ report (and, as noted, two companies file separate reports by division or region), with the result that each year there are 15 reports: 5 electric reports, and 10 gas reports. Each company files its report on March 1st for the DPU's approval. Each report includes performance for the calendar year on penalty-eligible requirements and reporting purposes. In addition, the reports typically include historical information, back-up data, the establishment of targets for the next calendar year as well as capital spending and inventory reports. The DPU issues an order approving the reports and determining if the Company's calculations for its penalties and offsets are correct, among other things.

Structure of the report

This report is structured around the three major categories of SQ Guidelines that are subject to penalties and offsets:

- Safety and Reliability
- Customer Service and Billing
- Customer Satisfaction

This mirrors the structure of the existing SQ metrics and reinforces our recommendation that each category be judged in itself, without allowing cross-category offsets or limiting the penalties in any category to a fractional percentage of the total, on which we elaborate in the final section below.

In addition, we address metrics in each category that we recommend be included not as part of the penalty/offset mechanism but as reporting-only metrics. We expect that our recommended additional reporting-only metrics will provide visibility of certain metrics and additional transparency to MA Electric and Gas Utilities' SQ performance and will create the potential for possible further specific investigation by the DPU where warranted.

Finally, we conclude with our analysis and recommendations regarding the structure of the penalties and offsets.

We have also included a number of informative appendices, including:

- A survey of SQ practices in other jurisdictions.
- A history of SQ regulation in Massachusetts.
- A discussion of issues in the definition and measurement of SQ metrics, including an example of potential inaccuracies in outage reporting in order to illustrate how the actual measurement of each metric may deserve independent scrutiny over and above the weight given to such metrics in an SQ penalty/offset mechanism.
- The current SQ guidelines based on the 2007 order from D.P.U. 04-116-C.
- A bibliography of relevant sources.

Safety and Reliability

Summary of performance and penalties to date

The category of safety and reliability is the first of the three categories of SQ metrics. It includes measures of reliability for electric companies, gas system integrity--and therefore public safety--for gas companies, and worker safety for both. Some of the measures are included in the penalty/offset mechanism and some are for reporting purposes only.[2]

[2] Relegation of a metric to a reporting-only status does not necessarily mean that it is less important. In some cases it is done because there is not yet a good way to set reliable benchmarks to use in a penalty/offset mechanism, or because interpretation of a shortfall is more problematic. In all cases, however, the DPU has made

The current metrics in this category, separated by those subject to penalty/offset and those for reporting purposes only are:

Metrics subject to penalty/offset (Definitions of each metric are included in Appendix D, which is taken excerpted from the final order in D.P.U. 04-116-C):

- SAIDI (System Average Interruption Duration Index) (Electric Companies Only)
- SAIFI (System Average Interruption Frequency Index)(Electric Companies Only)
- Worst CKAIDI (Circuits with worst circuit-level average interruption duration index) (Electric Companies Only)
- Worst CKAIFI (Circuits with worst circuit-level average interruption frequency index) (Electric Companies Only)
- Response to Odor Calls (Gas Companies Only)
- Lost Work Time Due to Accidents (Electric and Gas Companies)

Metrics provided on a reporting-only basis:

- SAIDI and SAIFI using the IEEE P1366 definition (Electric Companies Only)
- CAIDI (Customer Average Interruption Duration Index) (Electric Companies Only)
- Poor Performing Circuits List (Electric Companies Only)
- Excludable Major Events (Electric Companies Only)
- Tree Pruning Policy (Electric Companies Only)
- Restricted Work Days (Electric and Gas Companies)
- Average Emergency Response Time (Electric Companies Only)
- Property Damage (>$50k Electric, >$5k Gas)
- Reportable Incidents (Gas Companies Only)

In addition, we note that the electric utilities provide to the DPU (not as part of the SQ filings) an Annual Reliability Report which contains a great deal of detailed data[3] and also quarterly reports on outages involving 500 or more customers, by town, with detailed action plans for remediating each outage.

Table 3 below shows the number of MA electric companies earning penalties and offsets on each metric in the safety and reliability category for the period 2006 through 2011:

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it clear that a disturbing trend in any metric may be the subject of further inquiry by the DPU, and including metrics for reporting purposes facilitates such action.

[3] For example, in 2012, these reports are filed in dockets D.P.U. 12-ARR-01, 02, 03, 04.

Table 3 – Number of MA Electric Companies Earning SQ Penalties and Offsets Since 2006

Metric	Penalties	Offsets
SAIDI	8	8
SAIFI	5[4]	10
Lost Time Accident Rate	1	7
Total	**14**	**25**

From this we can see that the category of Safety and Reliability has been a source of both penalties and offsets for the MA electric companies, with a tendency toward more offsets.[5]

In general, the gas companies have not paid a penalty for a failure to meet SQ guidelines since one (New England Gas) paid in 2006. Moreover, except for New England Gas, most gas companies do not even need to use offsets in most years, meeting or exceeding benchmarks in all categories.

Gas Odor Response Rate

We will begin our detailed analysis of the performance to date with the key metric for gas companies, the Odor Response Rate. The odor response rate is measured as the percent of Class I and Class II odor calls that are responded to within one hour. Class I calls are defined as "a strong odor of gas throughout a household or outdoor area, or a severe odor from a particular area," and Class II calls are defined as "involving an occasional or slight odor at an appliance." These definitions are straightforward.

Chart 1 below shows the trend in the Odor Response Rate for the seven gas Local Distribution Companies (LDCs) under the jurisdiction of the MA DPU[6]:

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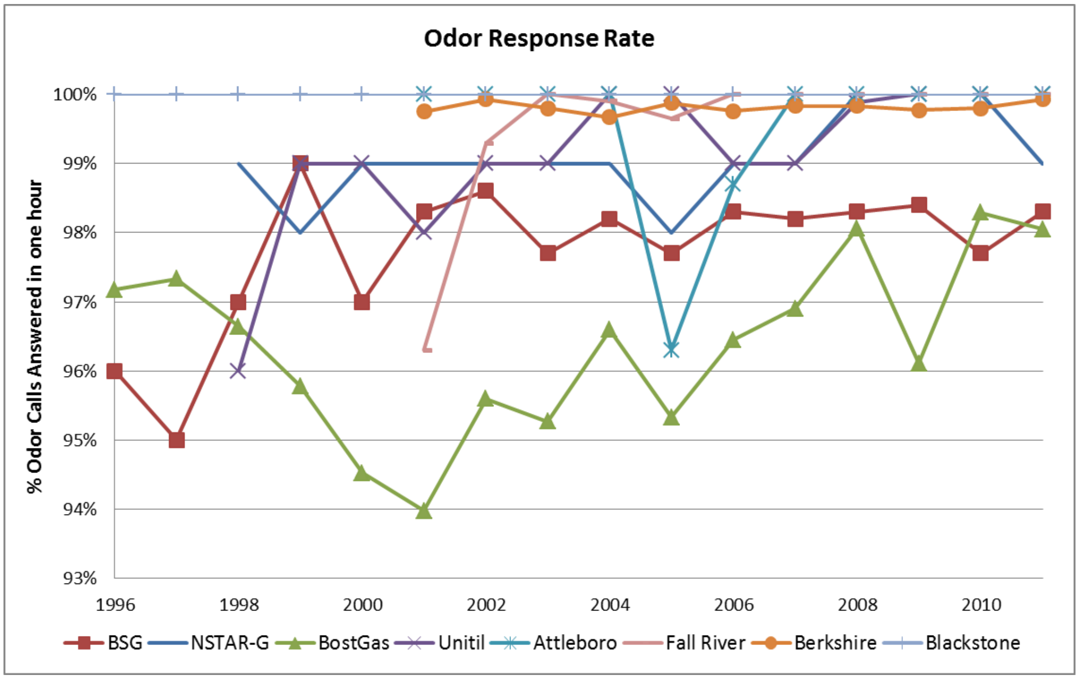
[4] For Calendar Year (CY) 2006, Nantucket Electric Company originally reported a SAIFI of .671, along with a benchmark of 0.377 and a deadband of 0.347, and was therefore not eligible for a penalty because it was under the penalty threshold of 0.742 (0.377 + 0.347). However, by CY 2011, Nantucket Electric Company had substantially revised its historical data, reporting a 0.693 SAIDI for 2006, along with a benchmark of 0.426 and a deadband of 0.252, which would have made Nantucket Electric Company eligible for a penalty if the historical data as revised had been applied. The five penalties reported for SAIFI in the table above reflects that Nantucket Electric Company would have earned a penalty if the Company had had the benefit of its updated data for CY 2006 at the time it filed its Service Quality Report.

[5] The DPU has not yet adjudicated the Massachusetts electric companies' SQ reports for CY 2010 and CY 2011. Accordingly, Table 3 reflects the penalties and offsets reported by each company in their SQ reports for those two years. Also, Unitil filed SQ reports for reporting purposes only in 2006 and 2007 and was not subject to penalties until 2008. The table above reflects the penalties and offsets that Unitil would have earned in 2006 and 2007 had it been subject to penalties in those years.

Chart 1 – Trend in Odor Response Rate



While most benchmarks are computed from a 10-year average of 1996-2005, the benchmark for the Gas Odor Response Rate was fixed at 95 percent for all gas companies by the Department. The performance of the companies has exceeded the benchmark substantially since 2005, and in the last five years the performance of many of the companies has exceeded the 98 percent threshold set by the DPU for earning offset. We note particularly that Boston Gas, which had underperformed relative to the others on this metric in earlier years, has now achieved an Odor Response Rate of over 98 percent for the last two years. In its review that began in 2004, the DPU recommended increasing the benchmark to 97 percent, but in the end did not include that change in its final order in 2007. **We recommend that the 97 percent threshold be established beginning in 2013, with a penalty for response rates below 95 percent, and an offset for rates above 99 percent.**

We note that for the Gas Odor Response Rate metric, the DPU used a different methodology for establishing the benchmark. For other metrics, it uses the ten-year average of 1996-2005, or a similar window where data was not available in the early years of that period. For the Gas Odor Response Rate, the DPU exercised its judgment in two significant ways: setting the target

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[6] Colonial Gas, a subsidiary of National Grid, is not shown in this chart. Its performance is regularly grouped with Boston Gas, its sister company, though for the SQ purposes its report is judged independently. Essex Gas has been integrated with Boston Gas for SQ reporting.

without explicit reference to the ten-year period, and setting a single target for all jurisdictional MA gas local distribution companies, as opposed to allowing the differing performance in the ten-year period to set different benchmarks for each company. We agree with this approach on those measures for which there seems to be some convergence to a common standard or no strong reason to suspect territorial differences to weigh on the proper target, e.g., the telephone answering factor (see the next major section of this report, Customer Service and Billing), for which all the companies employ similar technology.

Emergency Response Rate - Electric

For the electric companies, the metric corresponding to the Gas Odor Response Rate is the emergency response rate, which is not subject to a penalty mechanism, but is for reporting purposes only. The emergency response rate is compiled by aggregating individual cases in which emergencies (wire down, gas meter vandalized, etc.) were reported by "official emergency personnel," e.g. police, fire. Each case is recorded in terms of date, time, address, city or town, nature of the call, and the time of the response, with the data reported monthly during the year and annually for the annual SQ report. Recent investigations into storm response have revealed that in a major storm with thousands of such requests, the records may be incomplete in some ways, and that the systems used to record this information may replace an earlier response by a first responder with a later response by a repair crew, thus making it impossible to be sure when the first responder actually arrived, and hence what the true response time was. Such reporting deficiencies should be remediated. **We considered recommending that this metric be included as a penalty measure, but we feel that the better approach is to handle the significant deficiencies that have occurred in major storms as a part of the investigation of each storm, where a separate set of penalties, related to emergency preparedness, obtains.**

Similarly, other safety-related metrics which we might have included were reports of 'stray' voltage (public contact with low-voltage energized structures, as can occur on manhole covers, grates or streetlight standards) and manhole events (explosions, fires, smoking manholes, and 'popped' covers). These metrics are currently covered by other programs, and we recommend that they remain under that focus, as opposed to inclusion in SQ metrics.

Lost Time Accident Rate – Electric and Gas

The Lost Time Accident Rate is a standard statistic reported to the Federal Occupational Safety and Hazard Administration (OSHA). It is meant to be a rate per 100 full-time employees ("FTEs"). As such, it is calculated as the ratio of two numbers:

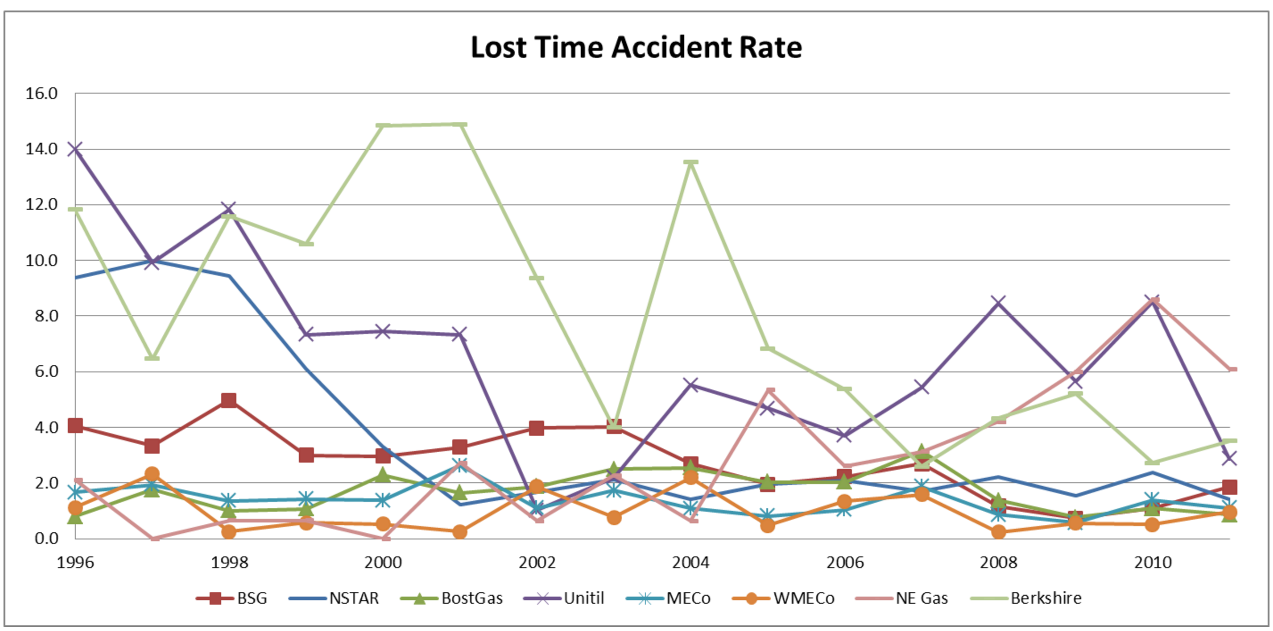
- The number of lost-time cases multiplied by 200,000 (100 workers x 2,000 hours per year); and
- The number of employee labor hours worked.

This allows for the inclusion of part-time employees' experience. It assumes the average worker only works 2,000 hours per year (forty hours per week times 50 weeks per year), which, while not exactly accurate, is the industry standard and should continue to be used.

When it comes to employee safety, as measured by the Lost Time Accident Rate, most Massachusetts utilities have had favorable experiences on this metric, with improved performance in the last decade that has been sustained recently at levels below 3.0, and with many hovering around 1.0. Chart 6 below demonstrates this pattern, but also shows that three of the smaller companies, namely, Unitil (combined gas and electric), New England Gas, and Berkshire Gas, now stick out as the only ones that still have a rate higher than 3.0 in many years, even though New England Gas had a rate lower than 3.0 in earlier years.

For the other MA companies, the Lost Time Accident Rate has outperformed the benchmark in the years since the benchmark was established. In this case, it is clear that the companies' performance in the early part of the benchmark window of 1996-2005, especially the first four or five years, is not reflective of their recent performance. But the high rate of variability during the benchmark years caused a large standard deviation, with the result that this metric is not earning many companies an offset at this time, and is unlikely to do so at recent rates.

Chart 6 – Trend in Lost Time Accident Rate



While we acknowledge that differences in territory between companies and between types of work for electric and gas companies could conceivably cause differences in the ability of companies to achieve comparable safety levels, we also feel that, as demonstrated in Chart 6 above, it is within the reach of all of the Massachusetts utilities covered by the SQ program to achieve LTA rates less than 3.0, and a Massachusetts utility worker should not have to face a higher risk when working at a different utility. **Therefore, we believe that every company should have a benchmark no greater than 3.0. For those companies whose current benchmarks are even more stringent, we recommend keeping the benchmarks and offset/penalty thresholds as is, so as not to send the wrong signal with respect to worker safety.**

Specifically, we note in Table 4A below the existing benchmarks and thresholds for the LTA rate:

Table 4A - LTA Rates for selected MA companies (Current)

Company	Offset Threshold	Benchmark	Penalty Threshold
WMECo	0.23	1.04	1.84
NE Gas	0.00	1.50	3.16
MECo	1.00	1.51	2.03
Boston Gas	1.13	1.75	2.38
Bay State Gas	2.57	3.43	4.28
NSTAR	0.97	4.66	8.35
Unitil (E&G)	3.08	7.13	11.17
Berkshire Gas	6.69	10.39	14.10

We recommend setting the benchmark for Bay State Gas, NSTAR, Unitil, and Berkshire Gas at 3.0, as shown in Table 4B below

Table 4B - LTA Rates for Selected MA companies (As Proposed)

Company	Offset Threshold	Benchmark	Penalty Threshold
WMECo	0.23	1.04	1.84
NE Gas	0.00	1.50	3.16
MECo	1.00	1.51	2.03
Boston Gas	1.13	1.75	2.38
Bay State Gas	2.00	3.00	4.00
NSTAR	2.00	3.00	4.00
Unitil (E&G)	2.00	3.00	4.00
Berkshire Gas	2.00	3.00	4.00

Electric Reliability (SAIDI, SAIFI, etc.)

As we turn to electric reliability, we begin with the industry-standard measures of overall system reliability, the System Average Interruption Duration Index (SAIDI), and System Average Interruption Frequency Index (SAIFI). SAIDI and SAIFI are system average interruption duration and frequency measures, respectively. They measure the experience of the average customer. They are customer-weighted. This means that a very large building that has a single meter counts as one customer, the same as an individually metered apartment in another building. An industrial customer that uses as much load as 1000 customers may have an individual meter and count as just one.

One of the aspects of the current SQ program that requires special DPU diligence is how the DPU rules on Company requests for exclusion of certain types of outages and also of major events, for example MECo's 2006 request.[7] With respect to which types of outages are excluded, the SQ Guidelines are specific. When calculating SAIDI and SAIFI, the companies are

[7] For its 2006 performance, MECo's original filing excluded four storms that it felt should be excluded, but which did not meet the criteria for excludable events. The Department ordered that they not be excluded. In 2010, MECo requested exclusion of a February, 2010 storm which, if excluded, could result in an offset $2,166,041. Without the exclusion, the result would be a penalty (if not offset elsewhere) of $5,500,264, a swing of $7,666,305 dependent on the exclusion of just one storm event. The Department has not yet ruled on the 2010 Electric SQ filings.

to exclude, in addition to excludable major event outages, the following: customer equipment outages, planned outages, and momentary outages (those lasting less than one minute).[8]

We have seen in detail how outage management systems are used to capture data on outages, and how that can affect the reported performance. We know from firsthand experience that judgment is sometimes required to “clean up” data because of the kinds of problems we mentioned above – multiple devices going out at the same time, with a resultant erroneous estimate of the true number of customers affected, errors in the connectivity model assigning customers to devices, assumptions about how many or which phases are out, assumptions about customers restored by partial restoration, etc. In fact, we conducted an audit in 2006 of NSTAR’s Outage Management System. Appendix A in that report shows an example of how NSTAR’s system incorrectly calculated the number of customers affected by an outage. The degree of the error was, in our judgment at the time, immaterial, but the details revealed how errors can be made in such a process.

We turn next to an analysis of the performance of a single company to illustrate how the reliability performance metrics operate within the context of the penalty/offset mechanism.

We analyze WMECo’s SAIDI trend in Chart 3 below. The benchmark window of 1996-2005 accurately represents an average of the historical performance, i.e., it is not the midpoint of an upward or downward trend, but rather a point around which the index oscillates. WMECo’s recent post-benchmark performance has seen three years well above and three years just below the benchmark. Since the standard deviation of the 1996-2005 period is 28 minutes, the three years above the benchmark have been outside of the deadband of plus or minus one standard deviation[9], and therefore generated a penalty in each of those years.

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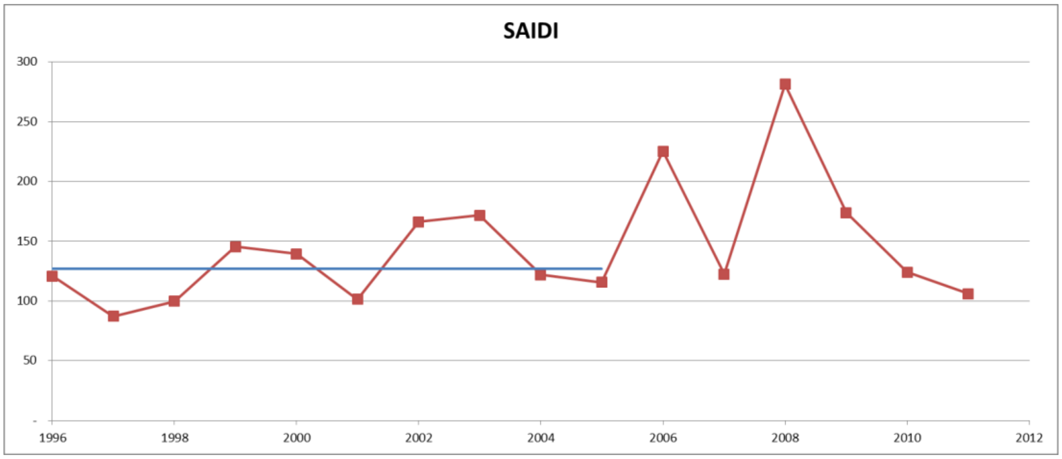
[8] At one time, secondary-only (“non-primary”) outages were excluded, but now they are included. Outages caused by switching to restore power are not counted in the frequency measures, but their minutes are counted in the duration measures. Where the number of customers affected by a device outage or a partial outage or partial restoration is not known, the number of customers interrupted is to be estimated.

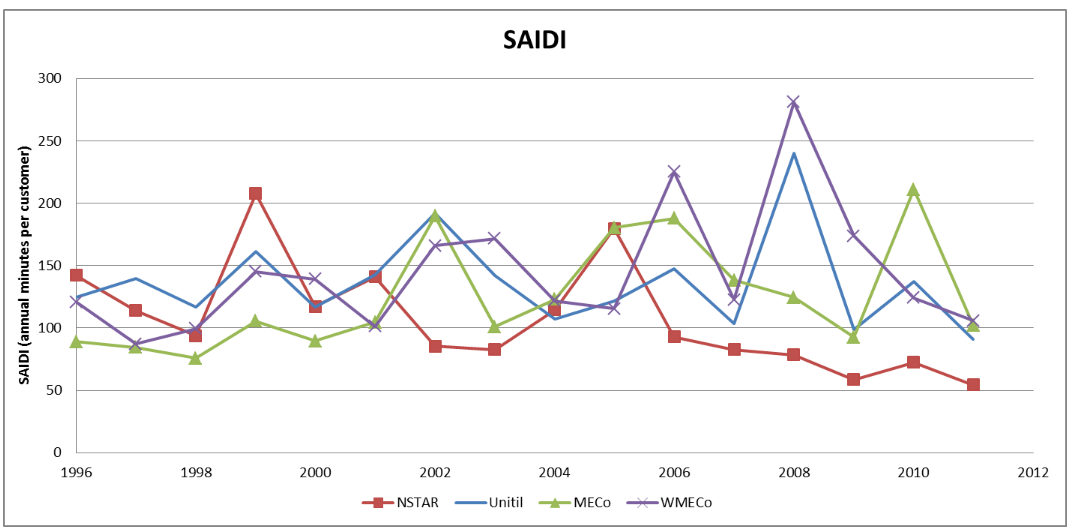
[9] For details of the mechanism, see the section on the structure of the penalty/offset mechanism.

Chart 3 – Trend in SAIDI for WMECo



We now turn to a trend analysis of the performance of the Massachusetts electric distribution companies compared to one another. When we look at SAIDI this way, the results, shown below in Chart 4, show that not all the MA utilities had the same performance in the post-benchmark period.[10]

Chart 4 – Trend in SAIDI for all MA Electrics



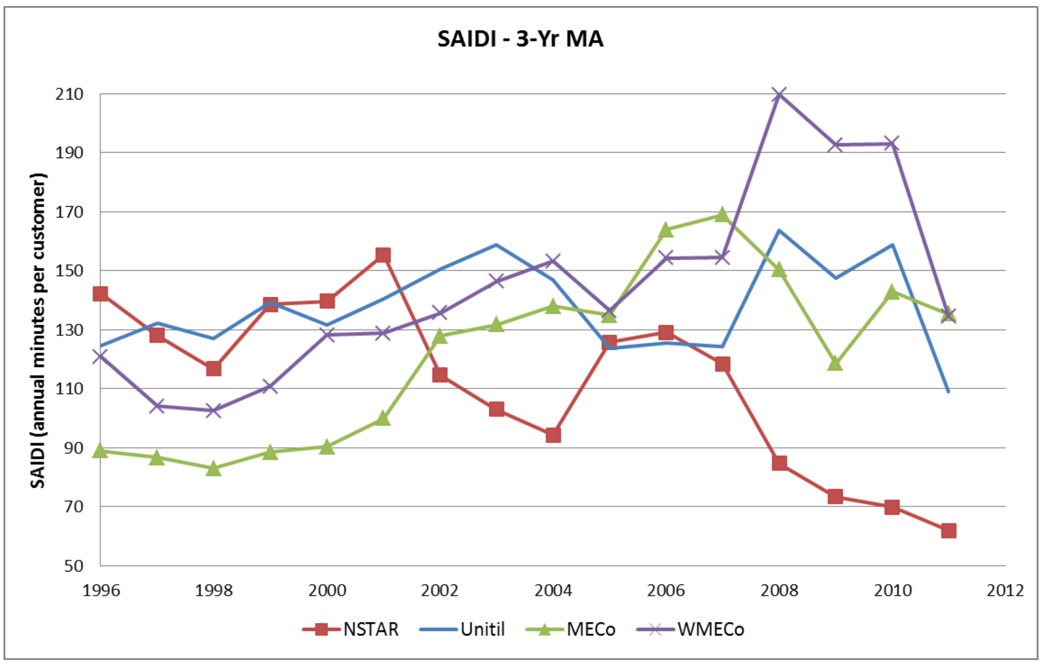
During the benchmark window from 1996-2005, all of the companies seem to be operating for the most part in a band of approximately 100 minutes (plus or minus 50 minutes) around an average of 130 minutes, i.e. 80 minutes to 180 minutes. But after 2005, the pattern changes

[10] In these and the other charts, the separate performance of Nantucket Electric is not shown. The much larger sister company, Massachusetts Electric Company, is shown.

for one of the four electric companies. Data as filed shows that NSTAR sets off on a definite improvement trend. In contrast, MECo and WMECo deteriorate in average level and volatility. Unitil's average remains the same for 1996-2005 as for 2006-2011, namely 136.5 minutes.

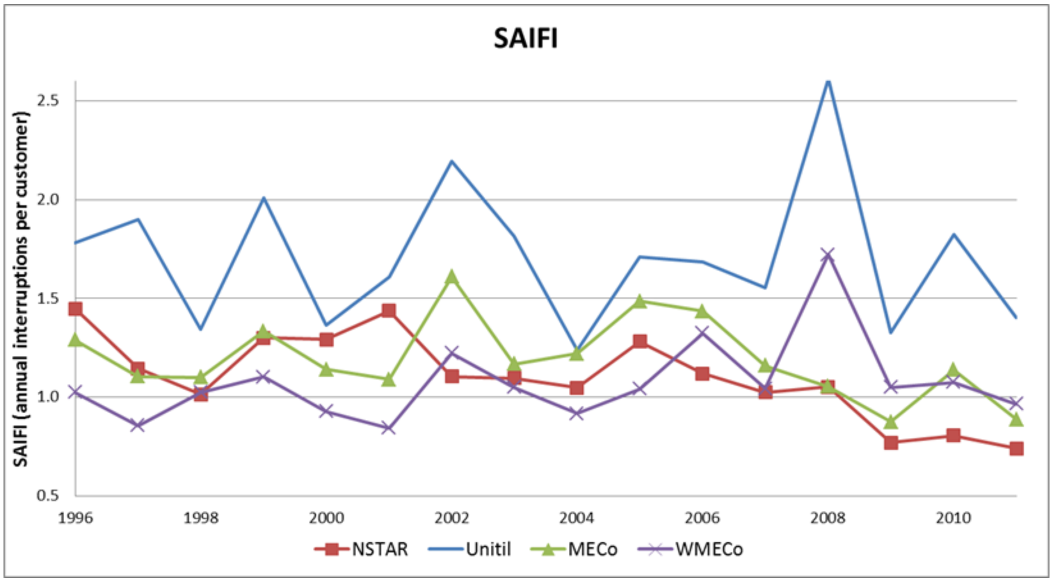
We recognized the value of smoothing trend data. Therefore, we have provided Chart 4A which shows the SAIDI trend for the same four companies using a trailing three-year moving average. From this chart it is even clearer that NSTAR has trended downward after 2005 while MECO and WMECO exceeded their typical 1996-2005 levels, and that Unitil oscillated around its benchmark level.

Chart 4A Trend in SAIDI Using Three-Year Trailing Moving Average



Turning to the interruption frequency metric, SAIFI, Chart 5 shows the trend in that key statistic for the four electric companies.

Chart 5 – Trend in SAIFI for all MA Electrics



Here, as with SAIDI, we see a clear improvement trend in NSTAR's SAIFI since 2005. MECO's SAIFI, after having ended the benchmark period with an alarming trend toward deterioration (rising), followed an improvement trend (decrease) from 2006-2009, interrupted by an uptick in 2010, and then flattened in 2011 at the 2009 level. Since an improvement in SAIFI would, other things equal, normally drive an improvement in SAIDI (less frequent outages mean less total minutes of outage, if the duration of each outage stays constant), we might have expected to see an improvement trend in MECo's SAIFI, but, as we saw above, that was not the case. We recommend that the DPU ask MECo to address the causes of the significant deterioration in CAIDI that robbed the SAIFI improvement of its potential impact on MECo's SAIDI.

We noted in our comments on Chart 4 above that NSTAR has a definite improvement trend after 2005 in SAIDI, and that, except for 2010, MECo showed a similar though less pronounced trend in its SAIFI.

We believe that the DPU's best option when it comes to adjusting the SAIDI-SAIFI benchmarks would be to call for a steady, annual improvement. As for the amount of such adjustments, we note in Table 5 below the following changes in SAIDI and SAIFI between the benchmark period of 1996-2005 and the post-benchmark period of 2006-2011:

Table 5 – Average Annual Percent Change in System Interruption Duration and Frequency (negative means improvement in reliability)

Company	SAIDI	SAIFI
MECo	3.8%	(2.3%)
NSTAR	(8.9%)	(4.6%)
Unitil	0.0%	0.4%
WMECo	5.2%	3.0%

From this table it is clear (and it is our experience elsewhere) that average annual (compound rate) improvement of 4.5 percent in both SAIFI and CAIDI (and therefore 9 percent improvement in SAIDI) is achievable, as NSTAR has demonstrated. **We recommend the DPU invite a dialogue with the companies as to what target would be appropriate for an average annual percentage increase.** What that would mean is that for a company that had a SAIDI of, say 130, and a SAIFI of 1.20, each year the benchmark would be decreased by, say 5 percent for SAIDI and 2.5 percent for SAIFI, or in this example 6.5 minutes of SAIDI and .03 interruptions for SAIFI. In three years, that would accumulate to an improvement of 15 percent, or almost 20 minutes, of SAIDI and 7.5 percent, or.09 interruptions, for SAIFI. At that time the DPU might want to review the companies' progress, perhaps comparing them to benchmark performance of other comparable utilities, and make a determination of whether the progress should continue and if so at what rate. Presumably, the adjustment of the benchmark would start in 2014. The standard deviation could remain unchanged.

We recognize that one might argue that ratcheting up (or in this case, down) the benchmarks creates a perverse incentive for companies. This argument is countered by the consideration that companies which have outperformed their previous benchmarks have had the benefit of offsets over those years. Moreover, the companies themselves often claim to have goals of continuous improvement. We see no reason why the SQ benchmarks should not reflect that aspiration. What is required for fairness is only that the benchmarks be set not in an arbitrary way, nor retroactively, but rather provide the companies a fair prospect of return. We recognize that the purpose of the SQ program is not to generate penalties, but rather to both penalize deterioration, which was the original purpose behind the creation of the SQ Guidelines and reflect the benefits of investment, the return on which has been accelerated through innovative regulatory mechanisms (the new, broader intent discussed above).

Momentary Interruptions (MAIFI) - Electric

We note that the existing metrics include only the classic system average interruption frequency and duration indices (SAIFI and SAIDI), with a second-tier examination of Poor Circuit Remediation (PCR) that is enabled only if the SAIFI and SAIDI targets are met.

What these measures leave out are a number of other possible measures that relate to system reliability. One has already been discussed at length in the original proceedings, namely, a measure of momentary interruptions, Momentary Average Interruption Frequency Index (MAIFI). Since the standard SAIDI and SAIFI definitions exclude interruptions of less than one minute, often labeled momentary interruptions, or momentaries, this aspect of power quality is completely ignored by the standard measures. Yet, residential consumers and commercial/industrial customers often report their frustration and cost associated with momentary interruptions that cause resets of many older and less expensive digital devices (those without sufficient capacitors or batteries to ride through a momentary), leading to blinking clock lights or worse, computer data loss and industrial processes or lighting that may require considerable time and expense to restart. For manufacturers, costs can also include the costs of overtime to pay workers for previously unscheduled time when power is restored.

The problem often cited by the utilities in not being able to adequately count momentaries is the incompleteness of the system of communications with the electric/electronic devices that control the system (SCADA – supervisory control and data acquisition – relays on circuit breakers, reclosers, and automatic sectionalizers). Since not all the devices which could cause momentaries are able to be polled via communications, some momentaries would go uncounted. While this might make comparison between utilities not appropriate, it still would allow comparison over time for each utility, particularly if the utility keeps track of and adjusts for any increase in the number of devices with communications.[11] **Our recommendation for MAIFI is that the DPU should further investigate how this measure can be made more accurate**. In the meantime, we focus our attention on the reliability issue of those customers receiving the worst customer experience with sustained interruptions (and who, we suspect, may also have the worst experience with momentary interruptions as well). This is the subject of the next few paragraphs.

[11] This would be comparable to the way retail stores measure themselves on "same store" sales, even while they are adding new store locations each year.

No Customer Left Behind (CEMI, CELID) - Electric

Perhaps even more important than any system interruption averages would be measures of excessive frequency or duration for individual customers or groups of customers. These measures, defined by the Institute of Electrical and Electronics Engineers (IEEE) as CEMI (Customers Experiencing Multiple Interruptions) and CELID (Customers Experiencing Long Interruption Durations), capture a different aspect of reliability than do the system averages (SAIDI and SAIFI). They capture a more important and more appropriately regulated aspect, in that they measure the experiences of customers who are experiencing the worst reliability, and whose experience may be masked by an acceptable overall system average. It is not uncommon to find that while the system average frequency might be from 1.0 to 1.5 sustained (non-momentary) interruptions per year, there is a large contingent of customers, maybe as much as five or ten percent, who experience 5.0 or more sustained interruptions per year. $CEMI_5$ measures the percent of customers with 5 or more sustained interruptions per year. Similarly, $CELID_8$ measures the percent of customers who have experienced an interruption duration of more than 8 hours for any one interruption.

Together, these measures institute a regime of "no customer left behind" as opposed to regulating the experience of a statistical "average customer." In Michigan, the Public Service Commission has even taken the step of dropping SAIDI and SAIFI while instituting measurement of CEMI and CELID. We prefer an "all of the above" approach that includes SAIDI and SAIFI, CKAIDI and CKAIDI, and CEMI and CELID.

One way to include CEMI and CELID within the current structure is to do so in the same way in which poor circuit remediation (PCR) is incorporated, namely as a second tier within the reliability category. At present, if an electric utility meets its targets (within one standard deviation) for SAIDI, it then is assessed for performance on the basis of its PCR with respect to duration (CKAIDI). Similarly, if it misses its target for SAIFI, it is subject to penalty based on its PCR with respect to frequency (CKAIFI). Up to half of the respective penalties for SAIDI and SAIFI can be assessed from poor performance on PCR duration and frequency. **We recommend that the other half of the SAIDI and SAIFI penalty be based on CELID and CEMI**. In this way, just as the DPU already extended its reliability performance regulation from system averages to the circuit level (this was done with the revisions in D.P.U. 04-116 in 2007), it should now extend that further to the level of worst-performing groups of customer locations, i.e., via CEMI and CELID.

In order to set targets for $CEMI_5$ and $CELID_8$ we recommend requesting historical data on these measures be developed. We note that it should be possible for companies to develop data on CEMI and CELID by recasting existing historical data, i.e., it would not be necessary to start benchmarking from 2013 and wait for three years or so to begin making the penalty/offset mechanism effective. In the interest of not making the mechanism retroactive, the DPU may want to pick 2014 as the initial year in which they become effective. If the utilities are close enough to each other in their recent historical performance, the DPU might want to set a common standard for all the electric utilities in the state on these measures. Based on the experience of other states, we would expect the values for $CEMI_5$ and $CELID_8$, excluding major events, to be on the order of 5 percent.[12]

We want to emphasize that including CEMI and CELID reporting is not as difficult as it may seem or be portrayed. The utilities already have a complete outage database that provides for each outage the interrupting device ID, the number of customers interrupted, and the start time/end time (and therefore duration) of each outage (as well as cause codes and other details). Where multiple restoration steps were involved, the outage record is broken into parts with the same information: device ID, start time, end time, and the number of customers impacted. What is required for CEMI and CELID reporting is a mapping of customers to the interrupting device, known as a connectivity map.[13] In the normal case in which a utility has a full connectivity model, if the utility has one million customers, then the database involves creating one million 'buckets', and each time an outage occurs, the connectivity model is traced to show which customers have been affected, and an outage counter and duration is incremented in the appropriate buckets. In today's world, a one million-item database is not a problem to maintain. Moreover, this computation need not be done in real time and would not delay restoration. It can be done in a batch process at a later time.

Reliability Reporting by Municipality - Electric

In addition, we recommend that the SQ program incorporate a system of reliability reporting by area, preferably even by municipality. Currently, the electric utilities provide the DPU a quarterly report on all outages affecting 500 or more customers. We also note that the current regulations require utilities to report their emergency response rates by town, monthly, and then aggregate them for the system for the year. We recommend that in addition the annual SQ filing should contain reporting of SAIDI, SAIFI, CAIDI, CEMI, and CELID by municipality as a

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[12] The Office of the Attorney General, through the use of its authority to ask Oversight Questions each month, has inquired about the electric companies' current ability to measure CEMI and CELID. The companies generally recognize the importance of this measure and have already begun, or will soon begin, to measure them in some form.

[13] In some utility outage management systems, the utility may not have a full connectivity mapping of each customer to the nearest transformer. It may only have a count of the customers behind that transformer. In such instances a suitable proxy for CEMI and CELID could be devised based on transformer-level detail.

reporting-only metric. We know that utilities sometimes struggle with the way in which their circuits and taps do not map perfectly to towns or counties, but we think that as the utilities move more toward CEMI-like measures that require customer-level views of reliability, this will become not an issue. We offer as an example, though it is not down to the town level, the reporting required in Florida, an example of which, for Progress Energy of Florida, is reproduced in Table 6 below.

Table 6 Reliability Reporting by Area for Progress Energy - Florida

SYSTEM RELIABILITY INDICES – ACTUAL (ABSENT ADJUSTMENTS)

Utility Name: Progress Energy Florida Year: **2011**

District or Service Area (a)	SAIDI (b)	CAIDI (c)	SAIFI (d)	MAIFIe (e)	CEMI5 (f)
North Coastal	291.1	108.8	2.68	9.7	10.80%
Inverness	250.8	104.5	2.40	10.2	6.75%
Monticello	412.9	135.0	3.06	10.0	15.23%
Ocala	253.7	94.2	2.69	9.0	11.81%
South Coastal	129.0	85.4	1.51	13.4	1.53%
Clearwater	87.0	62.3	1.40	13.8	0.80%
Seven Springs	84.0	65.7	1.28	12.2	1.31%
St. Petersburg	151.6	96.8	1.57	12.9	2.20%
Walsingham	206.1	110.6	1.86	15.6	1.82%
Zephyrhills	84.0	63.0	1.33	9.3	1.47%
North Central	268.9	149.2	1.80	12.0	3.52%
Apopka	269.2	149.5	1.80	15.1	3.60%
Deland	240.2	110.7	2.17	10.0	6.83%
Jamestown	153.5	109.4	1.40	9.9	1.05%
Longwood	470.5	226.8	2.07	13.3	4.17%
South Central	99.0	77.3	1.28	9.0	1.40%
Buena Vista	54.1	58.4	0.93	6.5	0.44%
Clermont	127.0	69.8	1.82	8.5	1.35%
SE Orlando	149.8	90.3	1.66	8.5	3.69%
Highlands	85.4	66.0	1.29	11.1	1.96%
Lake Wales	86.0	78.3	1.10	12.5	0.44%
Winter Garden	118.8	88.8	1.34	6.9	0.92%
SYSTEM	**172.4**	**104.1**	**1.66**	**11.5**	**3.05%**

Communicating Outage Information to Customers - Electric

An area which has received considerable attention of late, but is not directly included in any other SQ program, is outage communication. In storm after storm, studies have shown that a critical factor in customer satisfaction is accurate, complete, and timely information about the outage. In some sense, this measure is included in many SQ programs that include customer satisfaction surveys, because outage communication is a component of many customer satisfaction surveys. More direct measures that some utilities use to ensure that their performance will be satisfaction-inducing include the reach and accuracy of Estimated Times of Restoration (ETR's, also sometimes referred to as ERT's – Estimated Restoration Times). The reach statistic measures what percent of those calling in were given an ETR, and the accuracy measures how close the ETR was to the actual time of restoration. Companies that measure their own ETR reach and accuracy are among the leaders in customer satisfaction. **We therefore recommend a requirement that companies report ETR reach and accuracy, with the ultimate goal of considering them for inclusion in the penalty/offset mechanism**.[14]

Asset Management – Electric and Gas

Massachusetts ratepayers are paying a significant amount to utilities so that they may increase electric system reliability and gas system integrity. As such, the SQ program should reflect this investment. In part, this can be accomplished by revising the targets on existing electric reliability metrics to ensure better performance. On the gas side, we would expect to see an improvement in leaks and breaks on the targeted infrastructure. As mentioned above, at present, the SQ metrics for gas companies do not include leaks and breaks on targeted infrastructure (cast iron and bare steel mains and services). **We recommend that such measures be added to the reporting metrics, and that the trends in such variables be examined at each annual review of the prudency and use and usefulness of the capital dedicated to that purpose.**[15]

While the current set of metrics includes capital spending, it does not provide the information that might speak to the effectiveness of that spending, such as the units of replacement accomplished with that spending, which, if obtained, would also allow examination of trending in unit costs, a key indicator of process efficiency and possible imprudence if foreseeable at the time the decision to commit spending was made. Different categories of spending call for different types of units, but in general one would look for the change in the retirement units to which all capital spending for replacement is mapped.

An area of expanding interest for many regulators is the linkage between investment in infrastructure and the improved performance that investment can be expected to achieve. This was evidenced in the Illinois action to add SQ metrics as part of the Energy Infrastructure Modernization Act. We have also seen many regulators require the reporting, without being subject to penalties, of key aspects of asset management such as:

[14] Again, as with CEMI and CELID, the Office of the Attorney General has used its Oversight Questions authority to request information from companies about their ERT measurement, and has found the companies in various states of maturity in such reporting. We anticipate that the DPU will want to explore this further through technical sessions or workshops in which the utilities can further discuss what they already measure or intend to measure and can then report to the DPU as part of the SQ metrics.

[15] Bay State Gas has recently been so ordered. *See* D.P.U. 12-25 (2012).

- Percent of wood poles inspected and replaced or reinforced each year,
- Percent of circuit miles trimmed each year,
- Percent of manholes inspected and priority repairs completed,
- Percent of meters inspected and replaced each year,
- Percent of substation equipment inspected by type of inspection (visual, infrared, dissolved gas analysis, if appropriate, internal inspection, etc.) and by type of equipment (transformers, circuit breakers, batteries, etc.),
- Or, more generally, a detailed annual inspection and maintenance plan, and then an annual reporting of the percent of planned inspection and maintenance completed in the year, by category of asset.

We believe this is the next level for regulators seeking advancement in SQ reporting, and **we recommend that the Department begin developing information requests and eliciting suggestions and options with the utilities to see what they are currently doing that might easily fit into this category of reporting**.

We note that the DPU has begun to investigate Grid Modernization initiatives by the electric companies. Such initiatives typically include two mains thrusts: 1) automated meter infrastructure that would allow more frequent meter reading and even two-way communication of signals for peak-day and time-of-day pricing, and 2) distribution automation that allows for automatic fault detection, isolation and partial restoration, as well as automated power quality optimization. Clearly, these innovations may have a profound impact on reliability, especially as regards the second thrust. A two-way communication system over distribution facilities can communicate outages automatically and quickly, which allows for faster restoration. Distribution automation can allow for quicker restoration by providing valuable insight into feeder outages and automatic switching to isolate faults and partially restore segments of the system. We believe that the DPU's examination of Grid Modernization should recognize that any such program may have implications for the appropriate benchmarks in the SQ program, and may even be cause to change the structure of that program in some way as yet undefined.

SQ Requirements to Be Changed - Metrics to Be Dropped

In any review of SQ metrics to be included we should also address whether any should be dropped. **We recommend three of the current requirements for the SQ filing be dropped from the requirement of the annual filing**:

1) Designation of the service territory,
2) Vegetation management policy, and the

3) Spare component and acquisition inventory policy and practice.

These are policies, not annual performance measures, and hence they are not consistent with the overall focus of the program on annual performance of key indicators. There are other ways for the DPU to audit the processes and procedures of utility companies, e.g., management audits: and such other ways would not be limited to vegetation and inventory but may include any of a utility's processes and procedures.

Customer Service and Billing

Summary of performance and penalties to date

The category of Customer Service and Billing is the second of the three categories of SQ metrics. The current metrics in this category, separated by those subject to penalty/offset and those for reporting purposes only, are:

Metrics subject to penalty/offset[16]:

- Telephone Service Factor (% of Calls Answered within 20 seconds)
- Service Appointments Met As Scheduled (%)
- On-Cycle Meter Readings (%)

Metrics provided on a reporting-only basis:

- Customer Service Guarantees (Missed Appointments, Failed Notification of Planned Outage)

Table 7 below shows the number of MA electric companies earning penalties and offsets on each metric in the Customer Service category for the period 2006 through 2011[17]:

[16] Definitions of each metric are included in Appendix D, which is excerpted from Order D.P.U. 04-116-C. There are minor measurement issues in each of these, all of which have been discussed in the orders that established and refined the SQ metrics program. See also Appendix C below for a discussion of some of the measurement issues.

[17] The DPU has not yet adjudicated the Massachusetts electric companies' SQ reports for CY 2010 and CY 2011. Accordingly, the following table reflects the penalties and offsets reported by each company in their SQ reports for those two years.

Table 7 – Number of MA Electric Companies Earning SQ Penalties and Offsets Since 2006[18]

Metric	Penalties	Offsets
Telephone Service Factor	0	4
Service Appointments Met (%)	3	12
Meter Reads (%)	0	17
Total	**3**	**33**

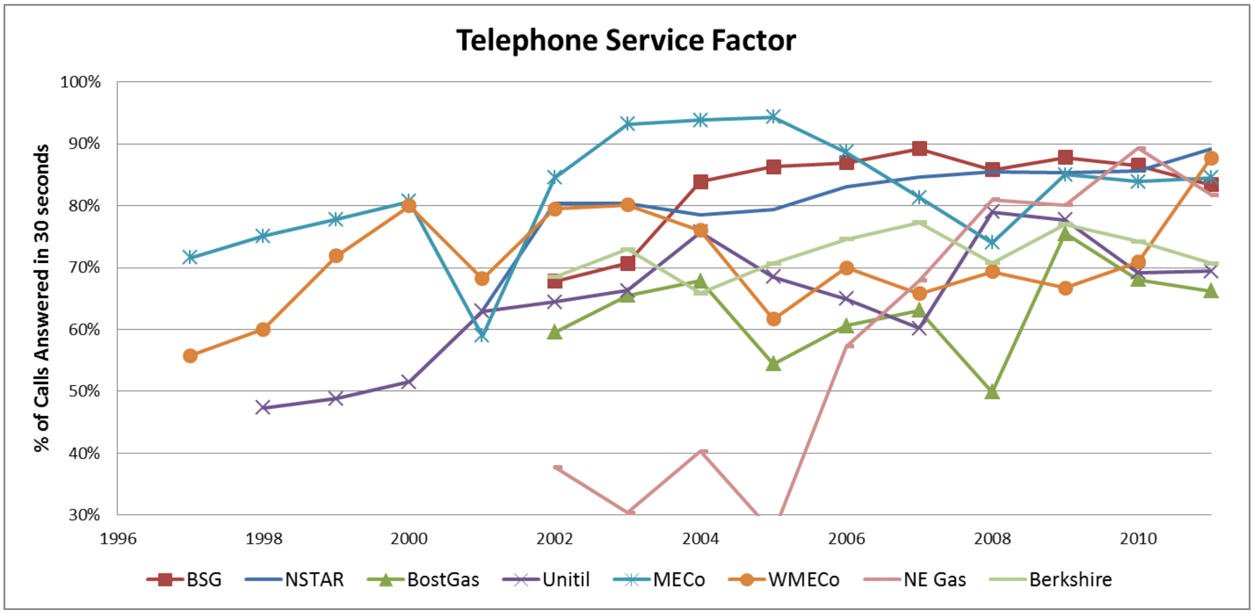
Clearly, the category of Customer Service and Billing has been a significant source of offsets for the MA electric companies.

Telephone Service Factor

A good statistic for comparing different companies without concerns relative to the differences between service territories is the telephone service factor (percent of customer calls answered within 20 seconds). With comparable technology being employed by most service providers (utility and non-utility), one might expect some convergence of SQ. Chart 6 displays the comparison below:

[18] Unitil filed SQ reports for reporting purposes only in 2006 and 2007 and was not subject to penalties until 2008. Similarly, WMECO filed its 2006 SQ report for information purposes only and was not subject to penalties until 2007. The table above reflects the penalties and offsets that Unitil and WMECO would have earned in 2006 (and for Unitil, 2007) had they been subject to penalties in those years. Unitil filed SQ reports for reporting purposes only in 2006 and 2007 and was not subject to penalties until 2008. The table above reflects the penalties and offsets that Unitil would have earned in 2006 and 2007 had it been subject to penalties in those years. Strictly speaking, the customer service guarantees are not subject to the SQ penalty/offset mechanism, but they do involve payments of $50 (in the form of a billing credit) for each violation.

Chart 6 – Trend in Telephone Service Factor



From Chart 6 we can see that four companies, Bay State Gas, MECo, New England Gas, and NSTAR (combined factor for electric and gas), score consistently above 80 percent, while three others, Berkshire Gas, Boston Gas and Unitil (combined electric and gas) score below 80 percent. WMECo started at about 80 percent, fell down to the 65-70 percent level for six years, and only recently recovered to over 80 percent. As shown in Table 8 below, the benchmarks for the top three companies are 80 percent or more, whereas the benchmarks for the other two gas companies are under 65 percent, and WMECo's is 70 percent. WMECO's significant jump up in 2011 earned it an offset. NSTAR's low standard deviation and recent blip up also earned an offset[19]. No companies earned penalties on this metric in 2011.

Table 8 – Benchmarks and Penalty/Offset Thresholds for the Telephone Service Factor

Company	Penalty	Benchmark	Offset
Bay State Gas	74.9%	82.8%	90.6%
MECo	70.5%	81.9%	93.3%
NSTAR	73.2%	80.0%	86.9%
WMECo	61.5%	70.3%	79.2%
Boston Gas	55.0%	62.7%	70.4%
Unitil	51.9%	61.1%	70.2%

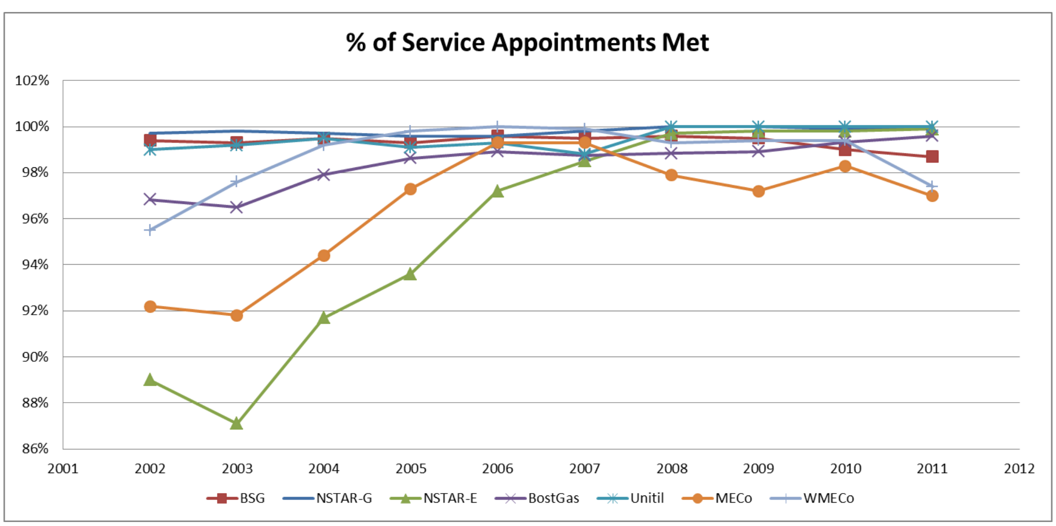
[19] NSTAR measures calls answered within 30 seconds, not 20, which tends to increase the level of current and historical performance.

The technology for achieving high service levels in telephone calls answered within 20 to 30 seconds is available to all companies, nor are territorial differences any reason to expect different performance or different customer expectations. Given that the technology for managing call centers and interactive voice response units ("press 1 for English") is by now quite mature, we are somewhat surprised at the disparity between the companies on this metric. Apparently, WMECO has learned how to get from the lower tier of companies to the higher tier. **We recommend asking the other companies in the lower tier, Boston Gas and Unitil, to submit a report on why their performance is not better**. Upon review of those reports, **we recommend that the DPU consider a common standard across all companies for this metric, such as it has done for the Gas Odor Response Rate metric**.

Service Appointments Met

Another performance metric for which the trend is particularly interesting is the percent of service appointments met. At the time the SQ metrics were put in place, utilities were required to make a $25 payment to any customer whose appointment was missed under normal circumstances. Later, on November 26, 2011, this fee was raised to $50 by D.T.E. 04-116-A. We note in Chart 7 below the general improvement in the performance of this metric for all companies since the institution of this payment, with two of those who were close to 100 percent now maxed out at that level, and those who were in the lower 90s now achieving higher levels than before. **We recommend that the DPU adopt a common standard across all companies for this metric**, such as it has done for the Gas Odor Response and such as we also recommend for the Telephone Service Factor.

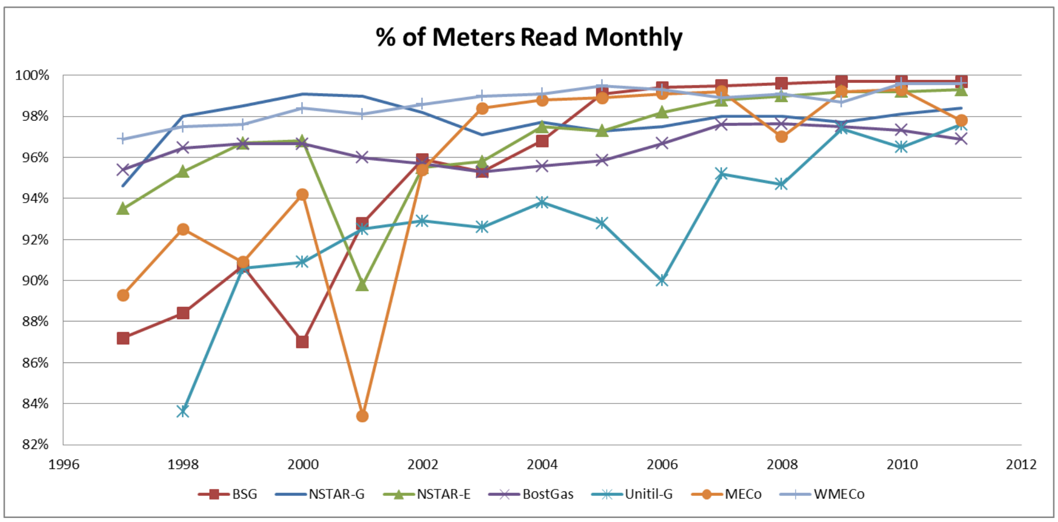
Chart 7 – Trend in Service Appointments Met



On-Cycle Meter Reads

Still within the category of Customer Service and Billing, we turn to the Percent of Meters Read, the data for which are displayed in Chart 8 below. As with the Service Appointments metric, it is clear that those companies which in the benchmark period had low and erratic performance on this metric have moved higher and most are now consistently above 96 percent, with many above 98 percent in most years. Once again, **we recommend that the DPU adopt a common standard for all the companies on this metric**, one that reflects recent performance of the group.

Chart 8 – Trend in Percent of Meters Read Monthly



Service Terminations for Non-Payment

Finally, we note that there has been increasing interest in Massachusetts and elsewhere over the impacts on low-income customers of service terminations for non-payment. Clearly, utilities must balance the need for effective revenue collection with concerns that customers not be put in positions of comprised health or safety due to billing disputes that might be satisfactorily resolved with appropriate intervention other than termination of service. In this regard, **we recommend that electric and gas utilities be asked to provide annually a monthly count of the number of terminations of service for non-payment**. The DPU can then monitor this data series for any alarming trends in the indicator. This would be a reporting-only metric, i.e., not subject to the pre-set penalty mechanism.

Customer Satisfaction

Summary of performance and penalties to date

The category of Customer Satisfaction is the third of the three categories of SQ metrics. The current metrics in this category, separated by those subject to penalty/offset and those for reporting purposes only are:

Metrics subject to penalty/offset[20]:

- Consumer Division Cases (Complaints to the DPU)
- Billing Adjustments (Per 1,000 Residential Customers)

Metrics provided on a reporting-only basis[21]:

- Customer Satisfaction (Surveys – Random and Post-Transaction)
- Efficiency (Unaccounted for Gas, Annual Line Loss - Electric)
- Capital Expenditures (with detail on projects > 10%)
- Spare Component & Inventory Policy

Table 9 below shows the number of MA electric companies earning penalties and offsets on each metric in the Customer Satisfaction category for the period 2006 through 2011[22]:

Table 9 – Number of MA Electric Companies Earning SQ Penalties and Offsets Since 2011[23]

Metric	Penalties	Offsets
Consumer Division Cases	2	14
Billing Adjustments	2	10
Total	**4**	**24**

[20] Again, definitions of each metric are included in Appendix D, which is excerpted from Order D.P.U. 04-116-C, and issues in measurement are discussed in Appendix C.

[21] The last three are not specifically related to Customer Satisfaction, but are shown here because this is the most generalized, and last, category.

[22] The DPU has not yet adjudicated the Massachusetts electric companies' SQ reports for CY 2010 and CY 2011. Accordingly, the following table reflects the penalties and offsets reported by each company in their SQ reports for those two years.

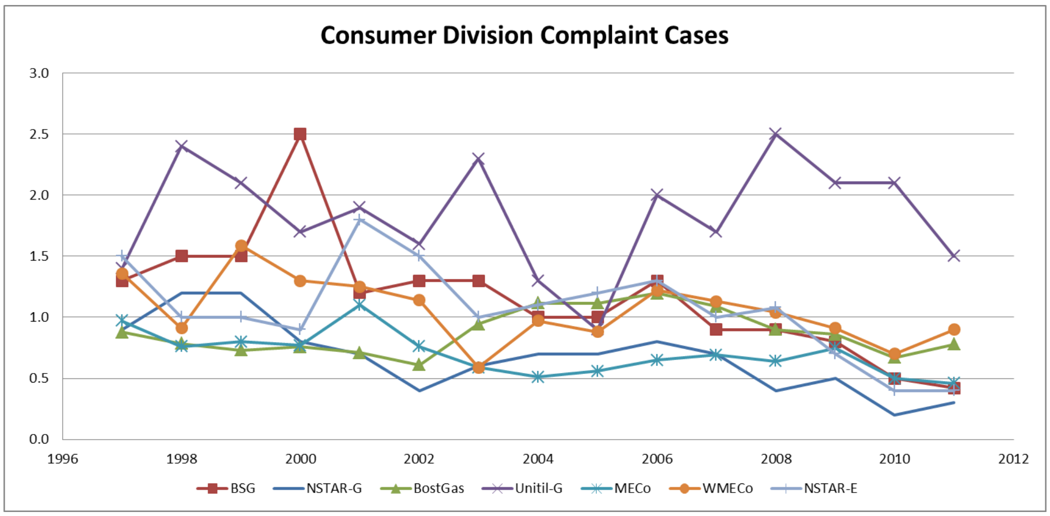
[23] Unitil filed SQ reports for reporting purposes only in 2006 and 2007 and was not subject to penalties until 2008. Similarly, WMECO filed its 2006 SQ report for information purposes only and was not subject to penalties until 2007. The table above reflects the penalties and offsets that Unitil and WMECO would have earned in 2006 (and for Unitil, 2007) had they been subject to penalties in those years.

Clearly, the Customer Satisfaction category has been a significant source of offsets for the MA electric companies.

Consumer Division Cases (Complaints)

On the metric Consumer Division Complaint Cases, the data in Chart 9 below show a clear downward trend from the period 1996-2005 to the last 6 years, except for Unitil, which peaked in 2008 (the year of the ice storm) and has trended downward since then, though still at levels comparable to the benchmark period of 1996-2005.

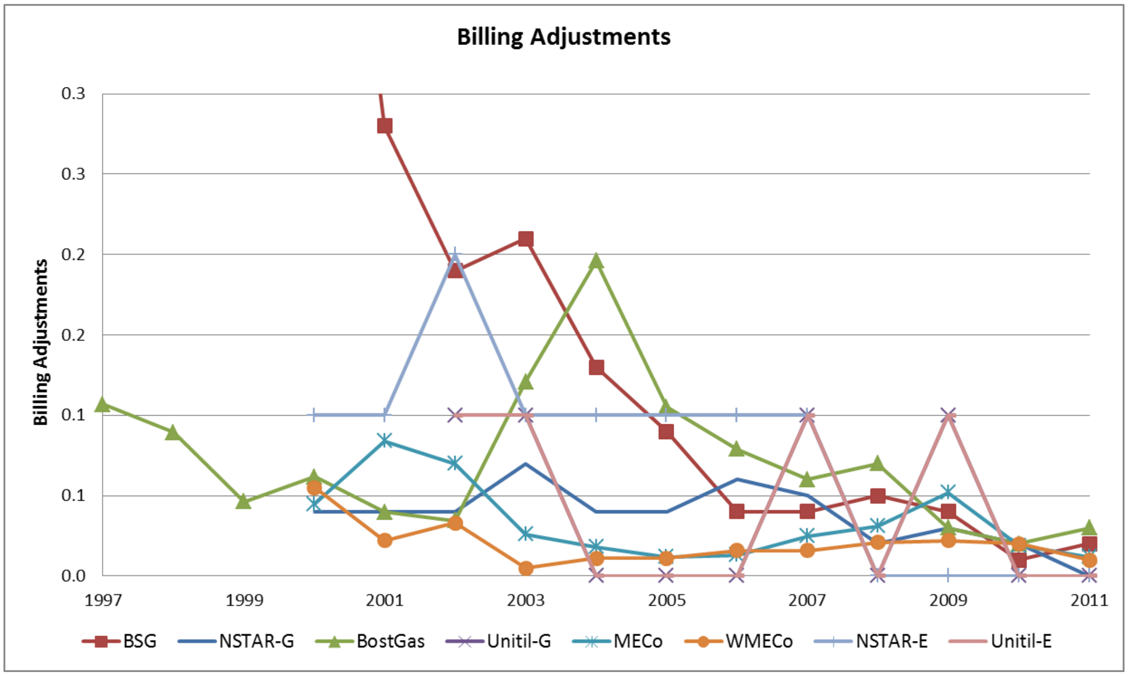
Chart 9 – Trend in Consumer Division Complaint Cases



Billing Adjustments

On the metric Billing Adjustments, the data in Chart 10 below again show a clear downward trend from the period 1996-2005 to the last six years, with all the companies in the last two years remaining below 0.1. For many companies, this meant they were earning offsets for this metric. The exceptions were Bay State Gas, NSTAR-Gas and Unitil (both gas and electric), because the standard deviation of their performance during the benchmark period means that no offset is possible.

Chart 10 – Trend in Billing Adjustments

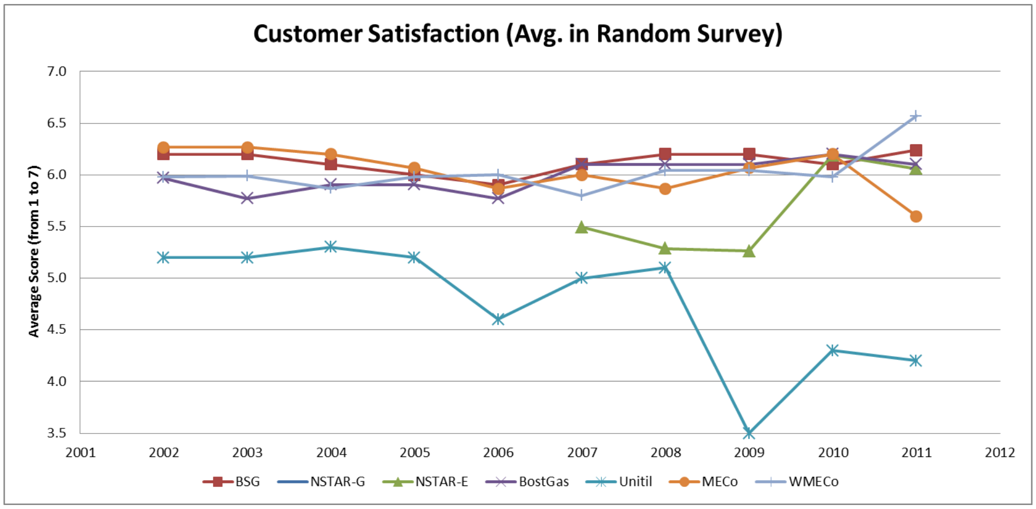


Customer Satisfaction

In measuring customer satisfaction, the Department has asked the companies to report on two surveys of customer satisfaction, one a random sample of customers and the other a post-transaction survey for customers who have had some reason to call the company. All of the companies were asked to use the same question on the survey, rating the company from 1 to 7 with 7 being best. From 2007 on, the companies were asked to add the words "excluding price." Chart 11 shows the results for selected companies.[24]

[24] Some of the companies report their customer satisfaction results as an average score, while others report it as the percent of customers scoring 5, 6, or 7. We believe the results should be shown in detail, and the average should be used as the penalty/offset metric.

Chart 11 – Trend in Customer Satisfaction



A number of points are worth noting on this chart. First, it is clear that Unitil's rating is, and has long been, much lower than the rest, and dived even lower in 2009 after the company's protracted response to the December, 2008 ice storm. Second, it is also evident that the change in wording in 2007 gave almost all the companies a bump upwards, as customers no longer factored in price in their satisfaction rating (WMECO was the only exception, and it bumped up in 2008 and stayed there, with a considerable rise in 2011 as well). Third, NSTAR Electric had a relatively low score through 2009, during which time its survey was conducted by JD Power and Associates. Since 2010, its survey has been conducted by NCO Financial Systems, a call center and collections outsourcing vendor, and has been much higher.

In the current system, these customer satisfaction surveys (random and transaction) have been included on a reporting-only basis. **We recommend that they become part of a revised customer satisfaction category in the penalty/offset mechanism, as described in more detail in the following section.** The rationale for including customer satisfaction is that it is a good overall measure that can capture aspects of performance that might not be captured elsewhere. In fact, it can also be an antidote to 'gaming the system' in such a way as to produce a sufficient score on the required metrics without actually achieving the goal for which the metric was established. SAIDI, for example, weights all customer interruptions the same, whether they hit on the hottest day of summer or when air conditioning is not being used heavily. Likewise, a large athletic stadium might count as only one meter, but customers might feel that an interruption to that facility when it is filled with tens of thousands of people is a significant reliability failure. Including customer satisfaction as a penalty/offset measure helps better align the SQ performance metrics with customers' sense of utility performance.

The Structure of the Penalties and Offsets

Structure of setting the targets

We begin our analysis of the structure of the penalty/offset mechanism with a discussion of the mechanism for setting the targets. In Massachusetts these targets are called the benchmarks.[25]

Two issues in this regard are the number of years of history to include, e.g., five or ten, and whether to base the targets on a fixed period in the past or to have it be a rolling window, e.g., the previous ten years each year as opposed to say, the 1996-2005 period. Under the current mechanism in Massachusetts, the targets are based on a fixed ten-year period, normally 1996-2005, with the exception that some measures were judged to not have useable data in some of the early years of that period, and are therefore based on a ten-year period that starts later.

The pros and cons of those two specifications were weighed in the original proceedings, in terms of how a longer period provides a more robust baseline from which to judge current performance, and how a rolling window will tend to ratchet up the targets for companies that are performing well (not necessarily a bad thing, but may be viewed as unfair in some sense) and ratchet down for companies that are not performing well (not a good thing).

The real issue with the targets is whether they are fair and effective in achieving the goal of allowing at least no deterioration in SQ, and perhaps an improvement such as might be expected to result from the investment which Massachusetts utilities have made. We have made recommendations above for adjusting the targets in each category as we felt were warranted.

The penalty/offset mechanism in detail

The next issue to address is whether to use a deadband. This mechanism allows for the possibility that random variations in SQ metrics that do not really represent significant deviations from the targets should not trigger unwarranted penalties (or rewards). By specifying that there is a band of performance around the target which would represent a neutral zone, where performance is assumed to be not sufficiently different from the target, the deadband addresses the issue of random or non-meaningful variation.

[25] The choice of words is interesting, because at one time during the development of the current mechanism in Massachusetts the Department made it clear that it would be preferable that the targets were based on a benchmarking of performance among comparable utilities in Massachusetts and elsewhere. As this was seen as not practicable because of incomparabilities in measurement across different jurisdictions and even different companies in Massachusetts to some extent on some measures, the Department opted instead, as did virtually all other jurisdictions, to base the targets on a fixed number of years of history for each measure.

It is in this area that the regulators have relied most heavily on statistical theory to guide their regulatory mechanism design. One could argue that the deadband could and should be set by simply querying the public or its representatives what performance would constitute a significant variation, i.e., would you (the average customer) care if the average telephone wait time when you called the company rose by one minute? Five minutes? Ten minutes?

Instead, regulators, including the DPU, have used the statistical concept of the standard deviation to define the deadband. In the theory of statistics, it is well known that the mean of a sample drawn from a typical distribution of random occurrences will itself have a distribution, as a statistic, that approaches the Normal (Gaussian) distribution as the sample size increases (see the Law of Large Numbers, and the Central Limit Theorem). That being the case, it is possible to predict the distribution of such a statistic, i.e., the mean of a random sample of a given size, and to have a certain confidence that the statistic so derived will be within a certain range around the true mean of the underlying variable (the performance being measured). The standard deviation, which is one of the two parameters of the Normal distribution, is a measure of the dispersion of the distribution of the underlying performance, and it can be estimated from the standard deviation of the sample. Statistical theory predicts that, if the underlying distribution is approximately Normal itself, then a sample size of 30 or more will produce a distribution of the sample mean that has around two-thirds of its mass within one standard deviation plus or minus the true mean, and at least 95 percent of its mass within two standard deviations of the mean (And the Central Limit Theorem proves that even if the distribution of the underlying phenomenon is not distributed as the Normal, under typical conditions the distribution of the sample mean, as a random variable in itself, will approach that of the Normal distribution as the sample size increases, so that two-thirds of the mass of the distribution of the sample mean will lie within plus or minus one standard deviation of the true mean, etc.).

As was pointed out in the SQ hearings (See Table B1 in Appendix B), this means that for a deadband of one standard deviation, which is what the current Massachusetts system uses, there is about a 16 percent chance that any metric will score out of the deadband by pure chance (33 percent divided by two, since there are two tails of the distribution). Because of that, the utilities proposed a method that would require something closer to two standard deviations, but that was rejected by the DPU. In that regard, we suspect that the DPU found that the deadband obtained using one standard deviation accorded better with the common sense values we suggested two paragraphs above.

What was not pointed out in the SQ hearings was that when multiple SQ metrics are subject to penalty, the fact that any one metric has a 16 percent chance of falling outside of the deadband means that there is an even higher chance that at least one will do so. Having multiple metrics has the advantage, however, that while one may score outside of the deadband on the low side, another may do so on the high side, Thus, in a system that allows rewards and penalties, the effects of random variations will tend to nullify each other, leaving only truly significant changes in performance. Since the statute which required SQ in Massachusetts has been interpreted by the DPU as not allowing for rewards, but only penalties, the Department instead developed a system of offsets, whereby favorable variances above the deadband could be used to offset unfavorable variances below the deadband. This has the same effect as allowing both rewards and penalties in terms of allowing random variations to cancel each other, with the exception that there can be no net reward, only a net penalty. As a design for an SQ system, this combination of a deadband, multiple metrics, and offsets has much to recommend it.

Another key element of the design is the proportionality of the penalty or offset. Once the performance falls outside of the deadband, one might expect that the penalty or offset would increase to the degree that the performance is unfavorable or favorable to the target. A simple proportionality might be the most straightforward approach, but the DPU chose to use a quadratic function, which makes the penalty or offset increase as the square of the deviation from the target (normalized by dividing by the standard deviation). The DPU calls this a parabolic formula, since a quadratic equation traces out a parabola when graphed. The actual form is as follows:

Penalty =

maximum penalty for that metric x .25 x $\{ (\text{benchmark} - \text{performance}) / \sigma \}^2$

Where σ is the symbol for standard deviation.

This formula is applied in the range when the performance is from 1 to 2 standard deviations above or below the benchmark, so the value that is squared ranges from 1 to 2, and therefore the square ranges from 1 to 4, and the factor .25 normalizes the highest value back to unity, making the penalty or offset equal the maximum when the performance is two standard deviations above the benchmark. Note that if the metric is inherently undesirable, the terms in the difference are reversed, e.g., for SAIDI, for which a higher value is not desirable, the formula assigns a penalty when the performance is above the benchmark, whereas for the percent of meters read, where higher is better, the penalty is assigned when the performance is below the benchmark. This can be done in formulas by multiplying the difference by a variable which is either plus 1.0 or minus 1.0 depending on whether the metric was desirable or not.

The last part of the incentive mechanism is the amount of the penalty, in total and for each metric. In Massachusetts, the statute originally limited the total penalty to two percent of transmission and distribution (T&D) revenue. The Green Communities Act changed that percentage to 2.5 percent of the T&D revenue.[26] The Department has also allowed utilities to deduct any payments made through service guarantee programs, for example, a program that might pay a customer $25 or $50 for each missed appointment.

The formula for the penalty for the Gas Odor Response Rate is slightly different. The benchmark for all companies is set at 95 percent. The percent of maximum penalty is not computed by the quadratic formula that is used for other metrics, but is linear and limited to whole percentages, i.e., 25 percent for 94 percent, 50 percent for 93 percent, 75 percent for 92 percent, and 100 percent for 91 percent. Likewise, on the favorable side, except that no offset is granted for a response less than 98 percent, it would be 75 percent for 98 percent and 100 percent for 99 percent. In addition, no other offsets are allowed to reduce the penalty earned from an unfavorable Gas Odor Response Rate. We commend this approach, as mentioned above in the Gas Odor Response Rate sub-section.

The final part of the system, and one that was not added until the revisions made through D.T.E. 04-116 in 2007, is the aspect of poor circuit remediation (PCR). As mentioned above, many jurisdictions include at least a reporting mechanism for PCR, and some incorporate penalties as well. In Massachusetts, the PCR metric is incorporated in a unique way: not as simply an additional metric, but as a second tier of metrics within the reliability category. The PCR mechanism is only activated if the utility does *not* incur a penalty based on the first tier, in this case SAIDI or SAIFI. If SAIDI is within the deadband, then the duration aspect of PCR is activated, and if SAIFI is within the deadband, then the frequency aspect of PCR is activated. Moreover, each is allowed to carry a weight equal to half of their respective first-tier metric, so that even if SAIDI and SAIFI fall within the deadbands, the utility may be penalized up to half of the SAIDI-SAIFI components' weight if the PCR criteria are met. In addition, the PCR penalty for duration and the one for frequency are all-or-nothing based on the following calculations: if the mean CKAIDI for the worst 5 percent of circuits (ranked by CKAIDI) is greater than one standard deviation (of CKAIDI) from the mean CKAIDI of all circuits, and one or more of the worst circuits are also on the list of worst circuits in two previous years (three years in a row), then the CKAIDI penalty of 11.25 percent of the maximum total penalty is assessed, and likewise for CKAIFI. The reasonableness of this mechanism was argued at length by the companies in a motion to

[26] We note that some companies did not update their computations of maximum penalty when this change took place, with the result that their subsequent filings presumably need to be amended.

reconsider, and that motion was denied with extensive explanation of the rationale in the final order of D.T.E. 04-116-D.

What we recommend for the inclusion of CELID and CEMI is that they be handled analogously to CKAIDI and CKAIFI, making up the other half of the unused SAIDI and SAIFI penalties.

Apportionment of the penalties across the metrics

The apportionment of the total penalty among the metrics is what might be called the weighting of each metric in the total penalty, like the weights in a weighted average. The simplest approach would be equal weighting for each metric, but the DPU chose to exercise its judgment in this case and assign values to the weights as follows:

Table 10 – Current Weighting of SQ Metrics

Category	Metric	Electric	Gas
Reliability and Safety	SAIDI	22.5%	
	SAIFI	22.5%	
	CKAIDI, if no SAIDI penalty	11.25%	
	CKAIFI, if no SAIFI penalty	11.25%	
	Odor Response		45%
	Lost Time Accidents Rate	10%	10%
Customer Service	% Calls Answered in 20”	12.5%	12.5%
	% Meters Read	10%	10%
	% Appointments Met	12.5%	12.5%
Customer Satisfaction	Consumer Division Cases	5%	5%
	Billing Adjustments	5%	5%
	Total	100%	100%

It is worth noting that in this system, adding additional metrics must necessarily diminish the weight of at least one or all of the other metrics, unless the metric is included for reporting only and not as part of the penalty mechanism. On the other hand, it also means that adding more metrics reduces the offset that any one metric can generate to offset penalties earned by other metrics.

In the end, the penalty or offset earned by each metric is added to obtain a total. If the total is a net penalty, that amount is assessed to be paid by the utility, or preferably returned to customers through a bill credit. If the total is a net offset, no action is taken. Note that offsets do not carry over as a credit toward future years.

We recommend a change to this weighting system. We believe there is no reason why the statutory maximum penalty of 2.5 percent of T&D revenue need be apportioned proportionately across the penalty-eligible metrics. To do so is to diminish the impact of any one metric. Instead, we favor a system that would allow the maximum penalty to be incurred in any of the three categories. If a company were to incur it in more than one category, the other would be redundant. Yet, in order to avoid the penalty entirely, the company would have to improve in each category. Hence, each category would still have relevance and influence, yet each would also have more impact than under the current system.

Let us explain with an example. Suppose a utility's performance in the category of Reliability and Safety warranted payment of the maximum penalty in that category. Under our proposal, the utility would then be subject to a fine of the full 2.5 percent of T&D revenue. If that utility's performance in the category of Customer Satisfaction also warranted the maximum penalty, it would incur no additional penalty. (The DPU should, however, require an explanation and a remediation plan). However, in order to avoid paying any penalty at all, the utility would have to show acceptable performance in both categories (in fact, all three categories). So, under our proposal, the maximum penalty could be incurred more easily, but it would be just as hard to avoid any penalty. In practice, we note that it is rare for a utility to perform so badly in so many categories that it would earn a "free ride" in one category because it had "maxed out" in another. For example, to earn the maximum penalty in the Reliability and Safety category under our proposal (see below), the utility would have to score more than two standard deviations above the benchmark in SAIDI, SAIFI, and lost time accidents. If it scores less than two standard deviations on any of these, there is room left under the maximum penalty for it to earn more penalties in other categories, though only up to the overall maximum. In our judgment, this change makes each category and each metric in each category more significant and still requires excellent performance to avoid all penalties.

In further support for this recommendation, we note that the under the current apportionment structure, the likelihood of a utility earning the statutory maximum penalty of 2.5 percent of revenue is virtually nil. This is because in order to reach the maximum in any one metric the performance would have to be two standard deviations above the benchmark, which itself is the mean of the benchmark period, and is therefore only likely to happen once every 40 years if the company makes no significant change in its behavior.[27] Moreover, to the extent each

[27] Assuming a Normal distribution, only 5 percent remains outside of plus or minus two standard deviations, or only 2.5 percent in each tail, or 1/40th.

metric is independent, the chances that all seven metrics[28] would reach their individual maximums becomes over 100 billion to one, like hitting the same number on a roulette wheel seven times in a row. Or, another example would be winning the lottery with the purchase of a single ticket.[29] Now, this is the correct calculation if the utility's performance is comparable to its performance in the benchmark period. However, even if the company were to embark on a concerted path toward poorer performance across the board, then we could expect that the likelihood on any one metric would be higher, say for example, 10 percent instead of 2.5 percent. That would still make the odds 10 million to one for seven independent metrics. With non-independence, the odds would be lower, but still highly unlikely. What this demonstrates is that the current structure of the penalty/offset mechanism effectively does not carry the weight that was allowed in the statute. We fully understand that the SQ penalty/offset mechanism is not designed to make it especially likely that a good-performing utility would suffer a penalty, but we believe that it should be designed such that a poor-performing utility would face the full brunt of the force of the penalty.

In summary, with the addition of our recommendation that the customer satisfaction metric become a penalty-eligible metric, we propose the following system of allocation of the maximum penalty (2.5 percent of T&D revenue) across the metrics as follows:

[28] Seven for gas companies, and also for electric if we say for illustrative purposes that SAIDI and SAIFI would behave as one metric.

[29] In Massachusetts, the odds of winning the Mega Millions involves matching the six numbers (five plus the Mega Ball), each of which has a chance of one in 56 (one in 46 for the Mega Ball). This makes the odds of winning with a single ticket 176 million to one.

Table 11 – Proposed Weighting of SQ Metrics

Category	Metric	Electric	Tier 2	Gas
Reliability and Safety	SAIDI	40%		
	CKAIDI, if no SAIDI penalty		20%	
	CELID, if no SAIDI penalty		20%	
	SAIFI	40%		
	CKAIFI, if no SAIFI penalty		20%	
	CEMI, if no SAIFI penalty		20%	
	Gas Odor Response Rate			80%
	Lost Time Accidents Rate	20%		20%
	Category Total	100%		100%
Customer Satisfaction	Customer Satisfaction	50%		50%
	Consumer Division Cases	25%		25%
	Billing Adjustments	25%		25%
	Category Total	100%		100%
Customer Service	% Calls Answered in 20”	33%		33%
	% Meters Read	33%		33%
	% Appointments Met	33%		33%
	Category Total	100%		100%

Limitations on the use of offsets

As mentioned above, we recommend eliminating the use of offsets in one category to reduce the penalty earned in another category (we will call this ‘eliminating the cross-category offsets’). The Department has already exercised its discretion to structure the penalties in this way, prohibiting the use of other offsets to avoid a penalty earned by poor performance on the Gas Odor Response Rate metric. What we propose is that offsets only be used within each one of the three categories, namely, 1) Reliability and Safety, 2) Customer Service and Billing, and 3) Customer Satisfaction. With this change, a company could not use superior performance on meter reading to offset poor performance on safety or reliability; it could only use it to offset poor performance on another customer service and billing metric, such as telephone service factor or service appointments met. Similarly, customer service and billing offsets could not be applied against penalties in customer satisfaction measures like Consumer Division Cases or Billing Adjustments.

We feel this change in the structure of the penalty/offset mechanism is very important. As we have seen above, offsets in the Customer Service category have become easier to generate through the application of modern technology and processes. We might have been tempted to recommend dropping this category entirely as a result, but we note that it is a regular feature of SQ programs elsewhere, that it was a key part of the original SQ Guidelines, and one that has demonstrated significant progress in the post-benchmark period. We would not want to see that progress reversed, and so we recommend keeping it as part of the mechanism, while adjusting the benchmarks to reflect the utilities' common use of new technology and processes.

At the same time, we think it completely unacceptable that progress on these customer service metrics would be used to subsidize, as it were, poor performance on or Customer Satisfaction (including Consumer Division Cases and Billing Adjustments). That is why it is essential that the DPU eliminate cross-category offsets, just as it has eliminated the use of other offsets to avoid penalties associated with the Gas Odor Response Rate.

Penalty and offset structure recommendations

We recommend that the overall structure of the current incentive system be retained for the most part. The basic structure, including the deadband, quadratic proportionality, offsets, and multi-tier design (two tiers for reliability measures, and a tier for reporting-only measures) is a good design that balances the various advantages and disadvantages of each feature. Our recommendations relate to four areas:

1) The specific targets – We recommend changes as noted above.

2) The specific metrics to be included and their measurement, as discussed in earlier sections, including adding CEMI and CELID as second-tier reliability measures, and the customer satisfaction index as a customer satisfaction measure in the penalty mechanism, and additional measures, including gas leaks, for reporting only.

3) The allocation of the maximum penalty across the metrics, currently adding to 100 percent. Instead, we favor the method described above that allows the maximum penalty to be achieved within each category.

4) The offsets should only be allowed to offset penalties within a category, not across categories.

We believe each of these recommendations has merit in and of itself. Together, though, we feel they would bring the SQ program in Massachusetts to a higher level of effectiveness.

Appendix A - Survey of Practices in SQ Standards

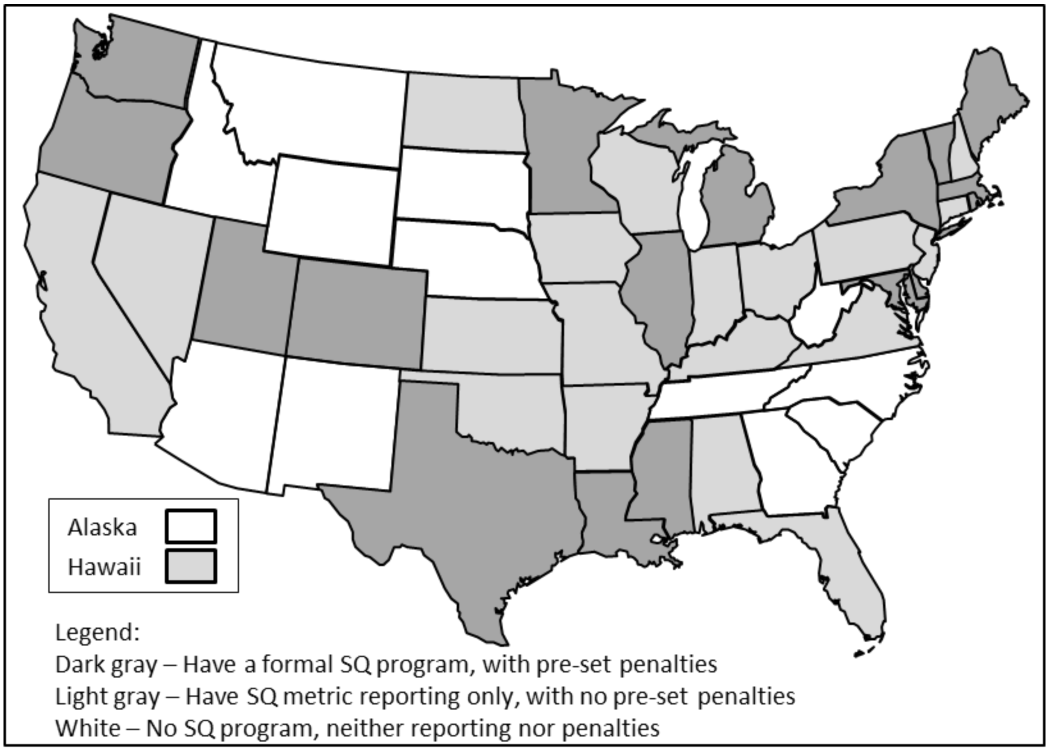
States generally fall into three categories with respect to SQ regulation:

1) Have a formal, annual SQ penalty program, with penalties computed according to pre-set rules,
2) Have SQ reporting, and possibly standards, with or without a general authority to fine, but no automatic computation of penalties according to pre-set rules,
3) Have no SQ program, not even reporting.

The states that fall into the latter category are fewer, and usually exceptional in some way.[30]

[30] For example, neither Nebraska nor Tennessee have SQ reporting, presumably because they are both served mainly or exclusively by public power (there are, by law, no investor-owned utilities in Nebraska, and Tennessee is served mainly by TVA as the generation and transmission entity, with municipal distribution companies like Memphis Gas, Light & Water). Some of the states in the inner west (Alaska, Idaho, Montana, Wyoming, Arizona, New Mexico, South Dakota) and the southeast (North Carolina, South Carolina, Georgia) have less detailed regulatory environments, and what PBR programs they have often originated with merger agreements. In the west, many states have over 50 percent of land area owned by the government. The top 10 states by percent of land owned by the government (Federal or state) are: Alaska (96%), Nevada (88%), Utah (75%), Idaho (70%), Oregon (60%), Arizona (57%), Wyoming (56%), California (52%), New Mexico (47%), and Colorado (43%).

Chart A1 - SQ Regulation by State



Based upon the literature and selected direct contacts with commissions in various jurisdictions we have compiled the following list of SQ programs by state (See Table A1 below, and Chart A1 above for a map).

The codes for the columns in Table A1 are as follows:
R – Reliability and Safety (SAIDI, SAIFI, CAIDI; wire down response, odor response, accidents)
W – Worst Circuits (Frequency and/or duration for a fixed number or percent)
T – Telephone answering (average speed of answer, or % answered in x sec.)
C – Complaints to the commission
M – Percent of meters read monthly
A – Appointments kept (for installation and/or service)
S – Satisfaction (S* means only for some companies, or some aspects of satisfaction)

Table A1 – SQ Programs by State

State	Type of SQ	R	W	T	C	M	A	S
Alabama	Reporting	X	X					
Arkansas	Reporting							
California	Reporting	X	X	X				X
Colorado	**Penalties**	X	X	X	X			
Connecticut	Reporting	X	X					
Delaware	**Penalties**	X	X		X		X	
Dist. Of Columbia	Reporting	X	X	X			X	
Florida	Reporting	X	X					
Hawaii	Reporting							
Illinois	**Penalties**	X	X					
Indiana	Reporting	X		X	X			
Iowa	Reporting	X						
Kansas	Reporting	X	X	X		X	X	
Kentucky	Reporting	X		X				
Louisiana	**Penalties**	X		X				
Maine	**Penalties**	X		X	X		X	X
Maryland	**Penalties**	X	X					
Massachusetts	**Penalties**	X	X	X	X	X	X	X
Michigan	**Penalties**	X	X	X	X	X	X	
Minnesota	**Penalties**	X	X	X	X			
Mississippi	**Penalties**	X						X
Missouri	Reporting	X		X				
Nevada	Reporting	X	X					
New Jersey	Reporting	X	X	X	X		X	
New York	**Penalties**	X	X	X	X	X	X	X
North Dakota	Reporting	X						X
Ohio	Reporting	X	X	X			X	
Oklahoma	Reporting	X	X	X			X	
Oregon	**Penalties**	X	X		X			
Pennsylvania	Reporting	X	X	X	X	X		
Rhode Island	**Penalties**	X	X	X		X		X
Texas	**Penalties**	X	X	X			X	
Utah	**Penalties**	X	X					
Vermont	**Penalties**	X	X	X	X	X	X	X
Virginia	Reporting	X						
Washington	**Penalties**	X	X	X	X		X	X
Wisconsin	Reporting	X	X	X	X			

In addition to the states listed above, the following states have no SQ program: Alaska, Arizona, Georgia, Idaho, Montana, Nebraska, New Hampshire, New Mexico, North Carolina, South Carolina, South Dakota, Tennessee, West Virginia, Wyoming.
Note: The penalties in Louisiana and Mississippi are part of a Formula Rate Plan. The penalties for Texas are for worst circuits only.

Examining the details of Table A1 we find that approximately half of the states with any SQ program at all have penalties, and the other half have SQ reporting only. Even in those states with only reporting, there is often authority for the commission to impose penalties of thousands of dollars per day for performance that is judged to be not consistent with the public interest (defined in various ways), but we have adopted the approach that only those with a pre-set formula for the calculation of penalties are labeled as a "penalties" program in Table A1.

With each state enacting its own rules, and in some cases the rules applying to only certain utilities in the state, it is difficult to draw a coherent overall picture as we have in Table A1 and Chart A1. Even within the category of states that have SQ programs with pre-set penalties, not all are alike. The program in Texas has penalties only on worst circuit reliability. The programs in Mississippi and Louisiana are mainly formula rate plans that adjust rates for returns of equity outside of a deadband, but they also contain a minimal set of service quality standards. Most of the other programs resemble that of Massachusetts, with a relatively full set of eight to ten SQ metrics and individual penalties for each. Some of the states with reporting only also have a full set of metrics, but have no pre-set penalties.

More recent trends have included revenue decoupling in order to encourage conservation, capital trackers to encourage replacing aging infrastructure, and renewable energy standards. As far as SQ programs with penalties, some states had them and then dropped them, like California, Idaho, and North Dakota, while some states are just moving toward penalties, like Maryland and Illinois.[31] We will have more to say in subsequent sections about the details of

[31] One of the reasons why California dropped its penalty program was because of an incident of SQ cheating that occurred because of some rogue managers at Southern California Edison (SCE). In order to maximize their reported performance on customer satisfaction and health survey and safety metrics, they interfered with the data collection process and falsified some reports. As a result, the California Public Utility Commission in 2004 required SCE to pay $146 million in fines and refunds of incentives earned over the period 1997 to 2003. Another case of purported metric tampering occurred in 2002 when a Minnesota subsidiary of Xcel Energy, Northern States Power, was accused by an internal whistleblower of falsifying reliability data in order to maximize performance on SAIDI. The Minnesota PUC required an investigation by an external firm, headed by a former FBI agent, and the matter

which indices are included, how they are measured, and how the targets are set and penalties calculated, but for now a general review of the columns of Table A1 shows that a "full" set of metrics, in some sense, can be said to include measures on:

1) Reliability and Safety (including, for electric, SAIFI, SAIDI, and/or CAIDI, as well as worst circuit performance, and wire down response, and for gas, odor response, for both, employee safety like lost-time accident rate),
2) Customer Service (including, average speed of answer or telephone service factor for customer calls, percent of appointments kept and percent of meters read monthly),
3) Customer Satisfaction (complaints to the commission, customer satisfaction index, and maybe billing adjustments).

Many states have programs that include the full set, with individual variations as to which indices are included. Metrics on reliability and worst circuits are ubiquitous. Both customer telephone call service and commission complaints are also quite common. Some states do not require reporting or set targets for monthly meter reading, allowing companies to achieve cost efficiencies in that area. Metrics on appointments kept and customer satisfaction are less common, but help complete the "full set." The metric on employee safety that is included in Massachusetts, lost time accident rate, is not that common, in that few states have metrics for employee safety as part of their SQ program. Metrics for gas companies tend to mirror those for electric, with the exception that the electric reliability metrics are obviously not included. Odor response is included, though that can be said to be comparable to wire down response for electrics. One might have expected that gas system integrity statistics (leaks, breaks, incidents) might have substituted for electric reliability, but that is not the case. The system integrity statistics tend to figure more in the justification for gas capital trackers rather than SQ programs. In addition, many states may feel that the federal compliance reporting to the US Department of Transportation's Pipeline and Hazardous Material Safety Administration (PHMSA) is more than sufficient, though they do not include penalties for meeting goals, but only for violating certain limited safety standards like maximum allowable operating pressure (MAOP), such as those contained in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, and even those are not pre-set, but must be determined by a deliberative process.

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was settled in an agreement with the company. One of the reasons why Illinois is adding a SQ penalty program to its longstanding reporting of SQ is the passage in 2012 of the Illinois Energy Infrastructure Modernization Act, which is designed to encourage utilities to spend billions of dollars investing in replacement and modernization of aging infrastructure. The Illinois Commerce Commission (the public utilities commission of IL) and the legislature want to be sure the investment has a return in terms of improvement in service quality, mainly reliability. In Maryland, the main impetus for adding SQ regulation has been perceived SQ problems, especially in recent storms.

A key issue in SQ measurement is the list of which indices to include and whether to include them with penalties, or only as performance reporting. This section of the report explores this issue in detail.

Balanced Scorecard

SQ measurement can also be seen as related to the desire by all companies to measure performance on various measures in order to achieve operational excellence. In the general corporate milieu, the term ‘balanced scorecard’ became widely used to describe a full menu of performance measures, including financial, customer service, operational/logistical, human resources, safety, environmental, and so on. Many companies use such scorecards in conjunction with internal incentive compensation programs for managers, with a structure of metrics, weightings, and payouts that in many ways mirror similar features in regulatory SQ systems.

A related movement was the effort to focus on continuous quality improvement, inspired in part by the work of J. Edward Deming and the Japanese kaizen movement. Training and practice of these methods often emphasized measurement of key variables seen as either root causes or measures related to product/service quality. In more recent years, many companies, including General Electric, have taken this to a new level with six-sigma techniques, seeking the ultimate in product/service quality.

One of the innovations in this field was called the “Voice of the Customer,” which involved insights from market research and customer surveys and focus groups, often finding that what industrial engineers, marketers, and company management thought were key drivers of product quality were not as important to customers as other factors that may have been ignored, like the way automobile doors and parts “fit” and the apparent depth of an automobile’s paint “finish.”

Appendix B - History of SQ Metrics in Massachusetts

SQ standards have been in place for many years throughout the United States and Massachusetts (as well as in many other countries). Table B1 below lists the relevant DPU dockets in the evolution of SQ in Massachusetts.

Table B1 – History of PBR and SQ Metrics in Massachusetts

Docket/Act (Year)	Title
D.P.U. 94-158 (1995)	Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction
D.P.U. 96-50 (1996)	Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 944 through 970, filed with the Department on May 17, 1996, to become effective June 1, 1996, by Boston Gas Company; and investigation of the proposal of Boston Gas Company to implement performance-based ratemaking, and a plan to exit the merchant function
D.P.U. 96-100 (1996)	Investigation by the Department of Public Utilities upon its own motion commencing a Notice of Inquiry/Rulemaking, pursuant to 220 C.M.R. §§ 2.00 et seq., establishing the procedures to be followed in electric industry restructuring by electric companies subject to G.L. c. 164
Chapter 164 of the Acts of 1997	An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protection Therein
D.T.E. 99-84 (2001)	Investigation by the Department of Telecommunications and Energy on its own Motion to Establish Guidelines for Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies Pursuant to G.L. c. 164, § 1E.
D.T.E. 01-65 (2002)	Investigation by the Department of Telecommunications and Energy on its Own Motion into the Service Quality of Boston Edison Company Commonwealth Electric Company and Cambridge Electric Light Company, d/b/a NSTAR Electric [due to outages in the summer of 2001]
D.T.E. 01-68 (2002)	Investigation by the Department of Telecommunications and Energy on its Own Motion into the Service Quality of Massachusetts Electric Company and Nantucket Electric Company [due to outages in the summer

	of 2001]
D.T.E. 01-71 (2002) A (NSTAR) B (NGrid)	Investigation by the Department of Telecommunications and Energy on its own motion, pursuant to G.L. c. 164, §§ 1E, 76 and 93, into the electric distribution companies' quality of electric service, including but not limited to their service filings, to be submitted in response to Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84.
D.T.E. 04-116 A,B,C,D (2006-7)	Investigation by the Department of Telecommunications and Energy on its own motion regarding the service quality guidelines established in Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84 (2001)
D.T.E. 05-85	Petition of Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and NSTAR Gas Company, pursuant to General Laws Chapter 164, § 94, and 220 C.M.R §§ 5.0 et seq. for approval of a rate settlement effective January 1, 2006
Various annual dockets since 2004	20xx Service Quality Reports for Electric Distribution and Local Gas Distribution Companies
c. 169 of the Acts of 2008	An Act Relative to Green Communities (Changed the maximum penalty from 2.0 percent to 2.5 percent of T&D revenues)

Each year, multiple dockets are opened that receive the companies' filings, sometimes including some information requests by the Department or interveners, and ultimately rule on the penalties. The individual dockets can be identified by reference to Table B2 below:

Table B2 – Annual SQ Dockets before the MA DPU (or DTE)

Company	2004-2006	2007-2008	2009-2011
Bay State Gas	XX-12	XX-12	XX-SQ-01
Berkshire Gas	XX-13	XX-13	XX-SQ-02
Blackstone	XX-14	XX-14	XX-SQ-03
Unitil (Gas)	XX-21	XX-18	XX-SQ-04
Boston Gas	XX-16	XX-15	XX-SQ-05
Essex Gas	XX-20	XX-16	XX-SQ-06
Colonial Gas	XX-18	XX-17	XX-SQ-07
New England Gas	XX-24	XX-22	XX-SQ-08
NSTAR Gas	XX-23	XX-21	XX-SQ-09
Unitil (Electric)	XX-21	XX-18	XX-SQ-10
MECo	XX-22	XX-19	XX-SQ-11
Nantucket	XX-22	XX-19	XX-SQ-12
NSTAR Electric	XX-15,17,19	XX-20	XX-SQ-13
WMECO	XX-25	XX-23	XX-SQ-14

Appendix C - Issues in SQ Measurement – How to Measure Each Index

In this Appendix we discuss the details of how each metric is measured, and the issues that are involved in those definitions.

Overview of Definitional Issues

Before examining the definition of each metric, we explore some issues that are likely to affect all or most of the measures.

System limitations

Each of the metrics is produced by an information system developed by or at least customized for the utility that uses it. Reliability measures tend to be produced by an Outage Management System. Call answering statistics are produced by a combination of customer care systems including the system that queues call and assigns them to the first available agent, an interactive voice response unit ("press 1 if you want to report an outage"), or a call overflow services vendor, and may also involve the customer information system and even the outage management system. The data on meter reads may be stored in the customer information system, but the details of the capture may involve data capture with handheld devices or radio-enabled meters, and so on.

The details of these systems have effects on the measurement of the phenomenon in question. Outage data, for example, often requires some manual adjustment, as for example when two customers call in at the same time, and their outages are caused by a coincidental outage of two devices (e.g., fuses) at the same time in the same general area. The outage management system (or the dispatcher, if done manually) will likely at first assume that the interrupting device is a single device common to both customers (upstream of both). Only after a field technician discovers that it was two almost simultaneous fuses that caused the outage will the dispatcher or an analyst be able to properly count the number of customers interrupted (on just two fused taps, and not the device upstream of both and perhaps many others). The way each utility handles such cases will slightly affect the way the metric performs. Since the typical SQ system only measures a utility's performance relative to its own past performance, one can take some assurance that as long as the system or process does not change, the data will be comparable. When either does change, an adjustment in the target may be in order. There is regulatory precedent for that.

Averages and Percentiles

The most typical measure of interest is often a simple average, like the average speed of answer for telephone calls to a utility – which would be obtained by adding up the time it took for each call and dividing by the number of calls. The next most common measure might be a weighted average, like SAIDI, for which the duration of each outage associated with each interrupting device is multiplied by the number of customers affected by (downstream of) that device (whether they called in or not). That in turn is divided by the total number of customers to get a weighted average customer interruption duration for the system.

Another common measure is a percentile, as in the percent of customers whose duration was over a certain number of hours (the definition of CELID), or the percent of calls answered within 20 seconds, or the percent of meters read monthly. Note that there is a choice to be made in most cases – average speed of answer or percent of calls answered in less than 20 seconds. Or similarly, average frequency of interruptions per year or the percent of customers interrupted more than 5 times per year. The average is straightforward and emphasizes the experience of all customers. The percentile focuses on the experience of those few whose experience is not typical, and likely to be unsatisfactory. In a manufacturing process, one would say the percentile approach examines defects, rather than what is typical. Of course, the 50th percentile (the median) is a form of average, but obviously we are talking about percentiles that measure the tail of distributions – the 95th percentile or the 5th percentile, for example. As we examine our choices of metrics, this distinction of which metrics emphasize which aspects of the performance will be worth keeping in mind.

Customer focus or Company focus

In the literature on performance management for industry in general, there is a discussion about whether a metric is customer-focused or company-focused. A perfect example in the utility industry is the definition of reliability in terms of sustained outages. The industry felt it was best to focus on sustained outages because that is what it could most easily measure and control. The customer, on the other hand, assumes that all customer interruptions are counted in some way, with short-duration interruptions not adding much to average duration, but each such interruption adding to the frequency of interruptions. Similarly, call centers know they can manage the “service level” (defined as the percent of calls answered in ‘n’ seconds), but not (without a little more effort) the percent of calls blocked at the switch. But to the customer, it’s the same – no answer (although perhaps with a fast busy signal). So, companies that view things from the customer point of view, measure call blocking as well as the speed with which calls that do get through the switch get answered (this was discussed in the original proceedings).

Some issues in the definition of the Customer Service Metrics

For the Telephone Service Factor (calls answered) there is the issue that some companies reported calls answered in 20 seconds and some in 30 seconds. Obviously, the percent for the latter would normally be somewhat higher. A bigger issue is whether the figure includes calls that are blocked at the switch, for example, those that received a busy signal and hung up. The Department has made it clear that it prefers to include the latter in the count of calls not answered in 20 seconds, but that is not the case at this time. Also, the current rules say that the response time begins not when the utility's automated response starts a dialogue with the customer, but when the customer has selected the option that then requires an operator to respond. For Service Appointments Kept, the Department has ruled that appointments for which the customer does not have to be present do not count, nor do appointments where the customer did not show. That seems reasonable, since it would appear that no one is inconvenienced, but occasionally it may mean that work which the customer expected to get done on a given day is not done. It would be hard to tell when that is the case, so the Department's decision is a reasonable compromise in an imperfectly measured situation. Also, it is noteworthy that the current measure requires only accuracy by day, not by morning or afternoon. The utility only needs to show up on the same day as the day for which the appointment was made.

For meter reading, there is a genuine debate about whether the utilities should be incented to read a high percentage each month. Many customers are on budget plans that fix the monthly payments based on an annual average reading. For those customers, semi-annual readings would probably be sufficient. The problem comes when disputes arise, because then the monthly detail can be useful in resolving the dispute. Likewise, the utility's planning accuracy depends in part on knowing the load on different parts of the feeder with some accuracy, but it can be argued that anything over say, 85 percent is not really necessary for that purpose. Again, the problem is likely to be that if certain customers have very hard to access meters, they may be skipped more often. If their bill becomes subject to dispute, the low frequency could make resolution more difficult. But all of these considerations are more relevant to a discussion of whether meter reads should be included as a metric rather than how it is measured. In some jurisdictions, the metric that is measured is labeled Percent of Meters Estimated, which is just the additive inverse (one minus) of the percent read, but it highlights the real issue, which is that meters that are not read must be estimated in order to be billed, and it is the satisfaction with the accuracy of that bill that is the real issue. If the estimating works well, the frequency of estimation would not matter. Residential customer meters must have an actual read every other month but commercial/industrial customers have no such requirement and can wait for long periods of time before receiving an actual read.

Some issues in the definition of Customer Satisfaction Metrics

The first two metrics are not measured by the utilities, but by the Department, and then provided to the utilities for inclusion in their reports. The utilities have sixty days to dispute the appropriateness of the case. For a complaint to be appropriate it must pass certain criteria, including that the matter was something “over which the Company has control” [Citation from the SQ rules from D.T.E. 04-116-C]. The Customer Satisfaction Survey metrics include two surveys: a random sample of all customers and a random sample of customers having recently contacted the utility’s customer service department. While the Department refers to the latter as a “customer-specific survey,” in the industry, the latter is most closely associated with the term “transactions” survey because it relates to customers who have had a recent “transaction” or customer-initiated interaction with the utility. The Department has specified that the question refer to a seven-point scale. The Department allows the survey to be performed internally, but it appears that most utilities use an outside firm.

Recommendations

We have no recommendations for changing the way the current or proposed penalty-eligible metrics are measured, except that we would encourage the Department to scrutinize, perhaps even formally audit, the metrics for these highlighted issues:

1) Continue to review reliability statistics for the way in which major events are excluded,
2) Occasionally audit the process by which manual adjustments are made to the outage statistics to ‘clean up’ the data,
3) When a metric changes significantly in a single year, ask for an explanation of what caused the change, and particularly if there are any changes in the process by which the data is gathered, as for example, when NSTAR switched vendors in 2010 for its Customer Satisfaction survey and saw a significant increase,
4) On the emergency response data, insist on a change in the recording system so that accurate records can be kept of when the first responder arrived at the scene, regardless of when subsequent crews may work on the location.

Appendix D - Definitions of SQ Metrics

APPENDIX 2007

SERVICE QUALITY GUIDELINES

I. GENERAL

A. Provisions

The following guidelines shall apply to every gas and electric distribution company ("Company") authorized to do business in the Commonwealth of Massachusetts, unless otherwise indicated. In the event of a conflict between these guidelines and any orders or regulations of the Department of Telecommunications and Energy ("Department"), said orders and regulations shall govern. If a gas or electric distribution company requests approval of a Service Quality ("SQ") plan that deviates, in whole or in part, from these guidelines, the request must be accompanied by reasons for each and every departure. These standards supersede those previously issued, including those issued in 99-84 and D.T.E. 04-116-B.

B. Definitions

"Billing Adjustment" shall mean a revenue adjustment amount resulting from Departmental intervention in a billing dispute between a Company and a residential customer except for those adjustments which the Department and Company acknowledge have been made although the Company is not at fault in the billing dispute.

"Circuit" shall mean a conductor or system of conductors through which an electric current is intended to flow. A transformer serves to divide any circuit in which it is placed into two smaller circuits, one side having energy of one voltage and the other at a voltage set by the transformer. The primary circuit is the circuit that flows into the transformer and back to the end of the circuit that feeds the energy. The primary circuit supplies the power which is eventually used by the secondary circuit. Non-primary or secondary circuits begin and end at the transformer, and it is this circuit that actually delivers the energy to the consumer.

"Circuit Average Interruption Duration Index" or "CKAIDI" shall mean the total minutes of customer interruptions for a circuit divided by the total number of customers connected to the circuit, expressed in minutes per year. CKAIDI characterizes the average length of time customers connected to a circuit are without electric service during the period.

"Circuit Average Interruption Frequency Index" or "CKAIFI" shall mean the total number of customer interruptions divided by the total number of customers connected to the circuit, expressed in average interruption frequency per year. CKAIFI characterizes the frequency of interruptions for customers connected to a circuit.

“Class I Odor Call” shall mean those calls that relate to a strong odor of gas throughout a household or outdoor area, or a severe odor from a particular area.

“Class II Odor Call” shall mean calls involving an occasional or slight odor at an appliance.

“Company” or “Companies” shall refer to investor-owned gas and electric distribution companies unless otherwise indicated.

“Complaint” shall mean a formal complaint to the Consumer Division of the Department wherein the Consumer Division creates a systems record with a customer’s name and address.

“Consumer Division Case” shall mean a written record opened by the Consumer Division of the Department in response to a Complaint that meets the criteria set forth in Section III.A.

“Customer Average Interruption Duration Index” or “CAIDI” shall mean the total duration of customer interruption in minutes (as calculated by application of Section V, below) divided by the total number of customer interruptions, expressed in minutes per year. CAIDI characterizes the average time required to restore service to the average customer per sustained interruption during the reporting period.

“Customer Equipment Outage” shall mean an outage caused by customer operation or the failure of customer-owned equipment.

“Electric Distribution Company Service Territory” shall mean the service territory or territories approved by the Department for Electric Distribution Companies providing electric service in the Commonwealth.

“Electric Distribution Facility” shall mean plant or equipment used for the distribution of electricity that is not a transmission facility, a cogeneration facility, or a small power production facility.

“Electric Distribution Feeder” shall mean a distribution facility circuit conductor between the service equipment, the source of a separately derived system, or other power-supply source and the final branch-circuit overcurrent device.

“Electric Line Loss” shall mean a total energy loss on a distribution and transmission system calculated as the difference between energy purchased and sold, expressed as a percentage. The total loss includes: (1) technical losses (actual load and no load loss in the electric system, consisting of transmission and distribution losses between sources of supply and points of delivery); and (2) nontechnical losses (losses such as meter reading error or theft).

“Electric Distribution Service” shall mean the delivery of electricity over lines that operate at a voltage level typically equal to or greater than 110 volts and less than 69,000 volts to an end-use customer within the Commonwealth.

“Emergency Call” shall mean a telephone call where the caller believes that he or she is confronting special circumstances that might lead to bodily and/or system-related damage if the circumstances remain unaddressed. Examples include, but are not limited to, downed wires, gas leaks, and gas odor reports.

“Excludable Major Event” shall mean a major interruption event that meets one of the three following criteria: (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency being proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act); (2) any other event that causes an unplanned interruption of service to fifteen percent or more of the electric company’s total customers in the Company’s entire service territory or area as otherwise approved by the Department; or (3) the event was a result of the failure of another Company’s transmission or power supply system. Notwithstanding the foregoing criteria, an extreme temperature condition is not an Excludable Major Event.

“High-Profile Customer” shall mean any customer an interruption to whose service could pose a threat to public safety (e.g., a hospital or airport) or a large commercial or institutional customer with a demand of one megawatt or greater.

“IEEE 1366" shall mean the information set forth in the Institute of Electrical and Electronics Engineers’ Standard 1366-2003, the *Guide for Electric Power Distribution Reliability Indices*.

“Interruption” shall mean the loss of service to one or more customers connected to the distribution portion of the system. It is the result of one or more component outages, depending on system configuration.

“Lost Work Time Accident Rate” shall mean the Incidence Rate of Lost Work Time Injuries and Illness per 200,000 Employee Hours as defined by the U.S. Department of Labor Bureau of Labor Statistics.

“Meter Reading” shall mean the act of manually or automatically acquiring customer-specific usage levels of an energy resource, for a defined period through the customer’s meter.

“Momentary Outage” or “Momentary Interruption” shall mean an outage or interruption of electric service of less than one minute.

“Non-Emergency Call” shall mean any telephone call other than an emergency call.

“Outage” shall mean the state of a component when it is not available to perform its intended function due to some event directly associated with that component.

“PBR” shall mean a performance-based ratemaking plan.

“Planned Outage” or “Planned Interruption” shall mean an interruption that is scheduled by the Company and of which customers are notified in advance, including, for example, during the connection of new customers or to ensure the safe performance of maintenance activities.

“Poor Performing Circuit” shall mean any distribution feeder that possesses a CKAIDI or CKAIFI value(s) for a reporting year that is among the highest (worst) five percent of that Company’s feeders for any two consecutive reporting years.

“Restricted Work Day Rate” shall mean the Incidence Rate of Restricted Work cases per 200,000 Employee Hours as defined by the U.S. Department of Labor Bureau of Labor Statistics.

“Service Appointment” shall mean a mutual agreement that shall be recorded in the Company’s business records in the ordinary course of business, as to date, time, and location, where Company personnel are to perform a service activity that requires the presence of a customer at the time of service.

“Service Interruption To A High-Profile Customer” shall mean an interruption that has a reasonable probability of involving a high-profile customer, including a hospital, airport, or large manufacturing, commercial, or institutional customer (who has a demand of one megawatt or greater).

“System Average Interruption Duration Index” or “SAIDI” shall mean the total duration of customer interruption in minutes (as calculated by application of Section V, below) divided by the total number of customers served by the distribution system, expressed in minutes per year. SAIDI characterizes the average length of time that customers are without electric service during the reporting period.

“System Average Interruption Frequency Index” or “SAIFI” shall mean the total number of customer interruptions divided by the total number of customers served by the distribution system, expressed in interruptions per customer per year. SAIFI characterizes the average number of sustained electric service interruptions for each customer during the reporting period.

"Sustained Outage" or "Sustained Interruption" shall mean an outage or interruption of electric service that lasts at least one minute and is not classified as a Momentary Outage or Momentary Interruption.

"Transmission and Distribution Revenues" shall mean revenues collected through the base rates of a transmission and distribution company.

"Unaccounted-for Gas" shall mean the differential between the amount of gas that enters the Company's city-gates, and the amount of gas billed to customers, expressed as a percentage of the amount of gas that entered the Company's city-gates.

"Year" shall mean calendar year unless otherwise noted.

C. Benchmarking

The historical fixed average and standard deviation for benchmarking will be based on ten years' worth of data for all SQ performance measures, including SAIDI and SAIFI, for each Company. Data for the most recent ten years will become a fixed benchmark for the Company. If ten years' worth of information is not available to a specific Company, the Company is directed to use the maximum number of years of data available, so long as three years are available. As the Company collects additional data, that data will be included in benchmarking until ten years' worth of data is collected, after which the benchmark will consist of the fixed ten-year average of the data. This benchmarking methodology will be employed for all SQ performance measures.

The Department will review each Company's annual SQ report and, if it deems necessary, may hold evidentiary hearings to investigate the appropriateness of any benchmark for any Company, on a case-by-case basis.

II. CUSTOMER SERVICE AND BILLING PERFORMANCE MEASURES

A. Telephone Service Factor

Each Company shall gather data and report statistics on its handling of telephone calls. Call data shall be compiled and aggregated monthly. Reporting shall occur annually. The reports shall be submitted in accordance with Section IX, below. Each Company shall report the percentage of telephone calls that are handled within a time interval that is consistent with a Company's existing telephone response-time measurement system, or as otherwise approved by the

Department. Companies who have had no telephone response-time measurement system until the date of this Order shall adopt a 20-second performance standard. Each Company shall also provide, separately, call-handling times for Emergency Calls and Non-Emergency Calls.

Telephone Service Factor shall be measured beginning at the point that the caller makes a service selection and ending at the point that the call is responded to by the service area selected by the caller. If the caller does not make a selection, the response time shall be measured from a point following the completion of the Company's recorded menu options and ending at the point that a customer-service representative responds to the call.

Telephone Service Factor shall be a performance measure subject to a revenue penalty.

B. Service Appointments Met As Scheduled

Each Company shall gather data and report statistics regarding the number of service calls met on the same day requested, excluding when a customer misses a mutually-agreed upon time. Each Company shall report the percentage of scheduled service appointments met by Company personnel on the same day requested. Service appointment data shall be compiled and aggregated monthly. Reporting shall occur annually. The reports shall be submitted in accordance with Section IX below. Service Appointments Met As Scheduled shall be a performance measure subject to a revenue penalty.

C. On-Cycle Meter Readings

Each Company shall gather data for the percentage of meters that are actually read by the Company, monthly. Eligible meters include both residential and commercial accounts. Meter reading data shall be compiled and aggregated. Reporting shall occur annually. The reports shall be submitted in accordance with Section IX, below. On-cycle Meter Reading shall be a performance measure subject to a monetary penalty.

III. CUSTOMER SATISFACTION MEASURES

A. Consumer Division Cases

Customer complaints ("Complaints") shall be categorized as a Consumer Division Case where a written record is opened by the Consumer Division using the following criteria:

(1) the individual making the Complaint provides his or her identity to the Consumer Division and is either a (a) current, prospective, or former customer of the Company against which the Complaint has been lodged, or (b) designee of the current, prospective, or former customer of the Company;

(2) the individual or his/her designee has contacted the Company from which the customer receives distribution service prior to lodging a Complaint with the Department;

(3) the Department's investigator cannot resolve the Complaint without contacting the Company to obtain more information;

(4) the matter involves an issue or issues over which the Department typically exercises jurisdiction; and

(5) the matter involves an issue or issues over which the Company has control.

Consumer Division Case data shall be employed as a SQ performance measure. The Department will compile and aggregate monthly the frequency of Consumer Division Cases per 1,000 residential customers. Once the data is provided to a Company, it has sixty (60) days to dispute the classification of a complaint as a Consumer Division Case. The Department will also provide an annual measure, and upon request, offer company-specific meetings to discuss each Company's performance. Monetary penalties shall apply to this measure.

B. Billing Adjustments

Billing Adjustments data shall be employed as a service quality performance measure. The Department will compile and aggregate monthly the number of residential Billing Adjustments per 1,000 residential customers. If a Company wishes to dispute the inclusion of any residential Billing Adjustments listed by the Consumer Division, it must do so no later than sixty (60) days after the monthly data has been provided by the Department. The Department will also provide an annual measure, and upon request, offer company-specific meetings to discuss each Company's performance. Monetary penalties shall apply to this measure.

C. Consumer Surveys

Each Company shall provide the results of two surveys to the Department on an annual basis: (1) a customer satisfaction survey of a statistically representative sample of residential customers; and (2) a survey of customers randomly selected from those customers who have contacted the Company's customer service department within the year in which service is being measured. The representative sample shall be newly drawn from customers contacting the Company's customer service area in the year previous and shall be conducted with a sample of respondents who are redialed after having concluded a contact with the Company's customer service area. The surveys, if conducted internally, shall be pre-approved by the Department regarding the method and customer questions.

For the residential customer satisfaction survey, the following question shall be used: "Using a scale where 1 = very dissatisfied and 7 = very satisfied; how satisfied are you with the service, excluding price, that you are receiving from Company Name?"

For the customer-specific survey, the following question shall be employed: "Using a scale where 1 = not and 7 = very; how courteous was the customer service department of Company Name?"

For the customer-specific survey, the following question shall be employed: "Using a scale where 1 = not and 7 = very; how well did the customer service department of Company Name respond to your call?"

The arithmetic mean of the responses to these two survey questions shall be provided to the Department in each Company's annual service quality report.

Each Company shall report the results of these surveys to the Department on an annual basis as specified in Section IX and shall include the results from all available previous years of the survey up to a maximum of ten years. No benchmarks shall be calculated for these survey measures, because no revenue penalty mechanism has been assigned to these measures.

IV. STAFFING LEVEL BENCHMARK

Staffing levels will be established on a company-specific basis. The effective date regarding the establishment of a staffing benchmark for union personnel, regarding Companies operating under performance-based ratemaking, will be November 1, 1997, unless otherwise provided by collective bargaining agreements, Department directive, or law.

V. ASSUMPTIONS FOR CALCULATING ELECTRIC RELIABILITY MEASURES

For the purpose of calculating SAIDI, SAIFI, CAIDI, CKAIDI, and CKAIFI, the following assumptions and criteria are to be used in accumulating interruption data for standardizing reliability measurements:

A. Customer Equipment Outages shall be excluded from the calculation of SAIDI, SAIFI, CAIDI, CKAIDI, and CKAIFI;

B. Planned Outages shall be excluded from the calculation of SAIDI, SAIFI, CAIDI, CKAIDI, and CKAIFI;

C. Excludable Major Events shall be excluded from the calculation of SAIDI, SAIFI, CAIDI, CKAIDI, and CKAIFI;

D. Momentary Outages shall be excluded from the calculation of SAIDI, SAIFI, CAIDI, CKAIDI, and CKAIFI;

E. The beginning of an interruption shall be recorded at the earlier of an automatic alarm or the first report of no power;

F. The end of an interruption shall be recorded at that point when power to customers is restored;

G. Interruptions involving primary and secondary distribution circuits shall be included in the calculation of SAIDI, SAIFI, CAIDI, CKAIDI, and CKAIFI;

H. Where only part of a circuit experiences an interruption, the number of customers affected shall be estimated, unless an actual count is available. When power is partially restored, the number of customers restored also shall be estimated unless an actual count is available; and

I. When customers lose power as a result of the process of restoring power (such as from switching operations and fault isolation), the duration of these additional interruptions shall be included, but the additional number of interruptions shall not be included in the calculation.

VI. <u>RELIABILITY AND SAFETY PERFORMANCE MEASURES</u>

A. <u>Electric Reliability</u>

Each electric Company shall measure SAIDI and SAIFI on an annual basis in accordance with Section V and compare its performance to a benchmark established by Section I.C. SAIDI and SAIFI shall be service quality performance measures subject to a monetary penalty in Section VII. IEEE 1366-2003 reporting will be reported annually and not subject to penalty. IEEE 1366-2003 calculations will be based on a sustained interruption of more than one (1) minute.

B. <u>Service Territories</u>

Each electric company may file with the Department a proposed designation of its service territories.

C. <u>Poor Circuit Remediation/ Poor Performing Circuits</u>

To address Poor Circuit Remediation (“PCR”), each electric company shall identify the five percent of circuits in its service territory with the most outages (<u>i.e.</u>, with regard to duration and frequency) as measured by CKAIDI and CKAIFI. Electric distribution companies that do not incur SAIDI or SAIFI penalties in a given year must evaluate whether CKAIDI and CKAIFI penalties apply.

If a circuit appears among the worst five percent for two consecutive years, that circuit shall be labeled as a problem circuit ("Problem Circuit"). The Company shall compare the mean CKAIDI and CKAIFI of the Problem Circuits to the mean CKAIDI and CKAIFI of all circuits. In performing these two comparisons, the Company shall employ the standard deviation of 100 percent of the circuits. If the mean CKAIDI and CKAIFI of the Problem Circuits is greater than one standard deviation above the mean CKAIDI and CKAIFI of 100 percent of the circuits, the Company may be subject to a monetary penalty. If all Problem Circuits are not repaired by the end of the third year, the PCR penalty shall be imposed.

For the purposes of this measure, each Company shall begin by using data from SQ reporting year 2007 as the first year. All penalties will be apportioned as provided in Section VII, below. All penalty calculations will be arrived at using the following penalty formula:

If (Mean of 5% Problem Circuits - Mean of 100% of circuits) is > Std Deviation of 100% of circuits, then the maximum penalty for CKAIDI and CKAIFI will apply.

Penalty for CKAIDI = 11.25% * (2% of Company's total Annual Transmission and Distribution Revenue for the applicable year) &

Penalty for CKAIFI = 11.25% * (2% of Company's total Annual Transmission and Distribution Revenue for the applicable year)

D. <u>Response to Odor Calls</u>

Each gas company shall respond to 95 percent of all Class I and Class II Odor Calls in one hour or less with appropriately qualified emergency response personnel. If a Company's performance exceeds 98 percent on the Odor Calls measure, it shall be allowed to offset substandard performance in other SQ performance measures where penalties apply. However, a Company's high performance in other SQ performance measure categories cannot be used to offset poor performance with regard to Odor Calls. For the purpose of calculating SQ performance on this benchmark, only the first call reporting an individual odor-related incident shall be considered. Response to Odor Calls shall be a performance measure subject to a revenue penalty in Section VII.C, below.

E. <u>Lost Work Time Accident Rate</u>

Each Company shall measure annually its Lost Work Time Accident Rate. The Lost Work Time Accident Rate shall be a performance measure subject to a revenue penalty in Section VII.B, below.

VII. REVENUE PENALTIES

A. Applicability

The monetary or revenue penalty for the performance measures set forth above in Sections II, III, and VI shall be determined in accordance with the penalty formulas and apportionment in Section VII. Penalty offsets are calculated in the same way as revenue penalties, and are represented as revenue penalties with negative values.

If a Company's annual performance for a performance measure falls within or is equal to one standard deviation from the benchmark, a revenue penalty or offset shall not apply. If a Company's annual performance for a performance measure is greater than one standard deviation (to the closest tenth of a decimal point) below the benchmark, a revenue penalty shall apply. If a Company's annual performance for a performance measure exceeds two standard deviations below the benchmark in any year, then the Department may open a formal investigation into the reasons for the Company's performance.

If a Company's annual performance exceeds one standard deviation up to two standard deviations (to the closest tenth of a decimal point) above the benchmark, a revenue offset shall apply and may only be used to offset revenue penalties. Revenue offsets have no value other than to offset revenue penalties. Revenue offsets will expire at the conclusion of the year of the Company's service quality plan. Revenue offsets acquired on any performance measure, above, may be used to offset monetary penalties on any other performance measure, except Odor Calls, described in Section VI.D, above.

The revenue penalty for Section VI.D, Odor Calls, shall be determined and apportioned in accordance with the penalty formula in Sections VII.C, VII.D, below. If a Company's annual performance for this measure equals or falls below 93 percent, the Department may open a formal investigation into the reasons for the Company's performance.

B. Penalty Formulas

The revenue penalty formula for all performance measures (except for the measure in Section VI.D) shall be:

Penalty_M = [0.25*(Observed Result - Historical Average Result)^2]* Maximum Penalty Standard Deviation

If: (Observed Result - Historical Average Result) is a positive value.

Observed Result = the average actual performance measure achieved in year_y, rounded to the applicable decimal place as specified for each measure in Section VIII.A;

Historical Average Result = the average historical actual result, based on an arithmetic average of the previous $\text{years}_{a..x}$ of historic data, rounded to the applicable decimal place as specified for each benchmark in Section VIII.C;

Standard Deviation = standard deviation of the historical average result; and

Maximum Penalty = (PCL_M)*(AR*0.02)

Where:

PCL_M = Performance category liability for the measure expressed as a percentage (derived from Section VII.D); and

AR = Annual Transmission and Distribution Revenues of a Company for the applicable year.

C. Penalty Formula for Class I and Class II Odor Calls

The revenue penalty formula for the performance measure set forth in Section VI.D shall be:

Class I and II Odor Call Penalty = Penalty Factor*Maximum Penalty

Where:

Penalty Factor is derived from Table PF, below:

Table PF

Penalty Factor	Calculation
.25	when PP-OR = 1 percent
.50	when PP-OR = 2 percent
.75	when PP-OR = 3 percent

1.00 when PP-OR = 4 percent or more

Where:

PP = 95 percent Fixed Target Benchmark

OR = Observed percentage of Class I and Class II Odor Calls actually responded to within 60 minutes achieved in $year_y$, rounded to the nearest percentage point; and

Maximum Penalty = (PCL)*(AR*0.02)

Where:

PCL = Performance category liability for the Class I & II Odor Calls measure expressed as a percentage (derived from Section VII.D); and

AR = Annual Transmission and Distribution Revenues of a Company for the applicable year. Appendix Page 14

If a Company exceeds 98 percent in any given year, the percentage (in nearest 1/10ths of a percentage) exceeding 98 percent may be allocated to offset a Company's other service quality performance measures where penalties apply. However, high performance in other service quality performance measures cannot be used to offset any penalty that applies to the Odor Calls service quality performance measure.

D. Apportionment of Penalty Among Performance Measures

The following table reflects the percentage of the overall two percent of Transmission/Distribution Revenue specified in G. L. c. 164, § 1(E) allocable to specific penalty measures.

Electric Companies

Measure	Penalty Percentage
SAIDI	22.5
SAIFI	22.5
CKAIDI	11.25*
CKAIFI	11.25*

Telephone Answering (20 Sec)	12.5
Service Appointments	12.5
Lost Work Time Rate	10
On-cycle Meter Reads	10
DTE Consumer Cases	5
DTE Billing Adjustments	5

VIII. <u>REPORTING REQUIREMENTS</u>

A. <u>Reliability, Electric Line Loss, and Safety Indices and Rates</u>

Each Company shall report on an annual basis SAIDI, SAIFI, CAIDI, Lost Work Time Accident Rate, Electric Line Loss, Unaccounted-for Gas, Restricted Work Day Rate, and damage to Company property, and percentage of all Class I and Class II odor calls responded in one hour or less. These reports shall be submitted in accordance with Section IX, below.

SAIDI and CAIDI shall be reported in terms of minutes and shall be measured and reported to the nearest 100th of a minute. SAIFI shall be reported to the nearest 1000th of a reported interruption. The Lost Work Time Accident Rate shall be reported to the nearest 100th of an accident. Restricted Work Day Rate shall be reported to the nearest 100th of a case. Electric Line Loss shall be reported to the nearest 10th of a percentage point. Unaccounted-for Gas shall be reported to the nearest 100th of a percentage point. The Consumer and Billing Measures shall be reported to the nearest 10th of a percentage point. The Class I and Class II odor calls shall be reported to the nearest percentage point.

For the annual reports on electric line loss, each electric Company shall provide sufficient substantiation of:

(1) its electric distribution and transmission line loss value,
(2) electric transmission and distribution line loss value in megawatts by voltage class at system peak,
(3) the accompanying adjustments that were made to standardize the value to specific reference conditions, and
(4) the specific reference conditions.

For the annual reports on damage to Company property, each electric Company shall file annually property damage reports on incidents involving property damage of the Company in excess of $50,000 per incident that is attributed to Company-owned facilities. A report shall be submitted within 48 hours of the incident and shall include the same information as that submitted for accidents as described in this Section VIII.I.

B. Penalty Measure Benchmarks

Each Company shall provide the supporting calculations that were used in determining the standard and benchmark values. SAIDI shall be reported in terms of minutes and shall be measured and reported to the nearest 100th of a minute. SAIFI shall be reported to the nearest 1000th of a reported interruption. The Lost Work Time Accident

Rate shall be reported to the nearest 100th of an accident. The Consumer and Billing standards shall be reported to the nearest 10th of a percentage point. The reports shall be submitted in accordance with Section IX, below.

Each Company shall report on an annual basis the Lost Work Time Accident Rate and the Consumer and Billing performance standards and benchmarks that were determined in accordance with Sections II and VI, above. Each electric Company shall report on an annual basis the SAIDI and SAIFI performance standards and benchmarks that were determined in accordance with Section VI, above.

C. Annual Major Outage Events

Each electric Company shall identify and report on an annual basis the interruptions that are considered Excludable Major Events. For each major event excludable under the standard above (or excluded using a Company's historic method), each electric Company shall report the total number of customers affected, the service area affected, the number of customers without service at periodic intervals, the time frame of longest customer interruption, and the number of crews used to restore service on a per shift basis. In addition, the report shall include the particular electric Company's policy on tree trimming, including its tree trimming cycle, inspection procedures, and typical minimum vegetation clearance requirement from electric lines. These reports shall be submitted in accordance with Section IX, below.

D. Capital Expenditure Information

Each Company shall report on an annual basis the capital investment approved and capital investment completed in the Company's transmission and distribution infrastructure to ensure delivery of reliable electricity and gas. This report shall include a list of capital investment projects, any one of which accounts for more than ten percent of the Company's capital expenditures. The report shall include a summary description of each project including a list and location of each transmission and distribution facility that was modified, upgraded, replaced, and/or constructed as well as the costs and scope of work involved in the facility modification, upgrade, replacement, and/or construction.

Each Company shall report the same capital expenditure data from the ten most recent years in the same fashion as in the previous paragraph. The data shall be provided in each Company's first annual report. The reports shall be submitted in accordance with Section IX, below.

E. Spare Component and Acquisition Inventory Policy and Practice

Each Company shall report on an annual basis its policy for identifying, acquiring, and stocking critical spare components for its distribution and transmission system. The reports shall be submitted in accordance with Section IX, below.

F. Poor Performing Circuits

Each Company shall identify and report on an annual basis its poor performing circuits. The report on these Poor Performing Circuits shall include the following information:

(1) the feeder or circuit identification number;
(2) the feeder or circuit location;
(3) the reason(s) why the circuits performed poorly during the reporting year;
(4) the number of years that the circuit(s) performed poorly;
(5) the steps that are being considered and/or have been implemented to improve the reliability of these circuits; and
(6) the CKAIDI or CKAIFI value for the specific circuit(s).

The reports shall be submitted in accordance with Section IX, below.

G. IEEE Reporting Requirement

Each electric Company will compile its SAIDI and SAIFI measures in accordance with these guidelines. However, in addition, each electric Company will compile and calculate its SAIDI and SAIFI performances using IEEE 1366-2003 standards and will report these measures to the Department annually in accordance with Section IX, below.

H. Reporting Electric Service Interruptions

Each electric Company shall continue to report the distribution and transmission interruptions consistent with the Department's Outage and Accident Reporting Procedures.

Each electric Company shall report every sustained distribution and transmission interruption that occurs within or impacts its service territory. Each electric Company shall report to the Department within a one-hour period, from the beginning of the interruption, every interruption that results in 500 or more customer-interruption hours or that results in a service interruption to a High-Profile

Customer. All other interruptions shall be reported to the Department within a 24-hour period from the beginning of the interruption. Reports shall be revised to reflect updated/analyzed interruption information submitted within seven (7) days of the initial interruption reporting.

All interruption reports shall include the following information:

1. Date filed
2. Company name
3. District/Division name
4. Location of interruption (City/town where fault occurred)
5. Street name
6. Substation name and ID
7. Circuit number ID
8. Circuit branch ID
9. Voltage level to the nearest (transmission, 35kV, 25kV,12kV, 5kV, Secondary)
10. Circuit type (OH/UG/Customer owned)
11. Original number of customers affected
12. Current number of customers affected (show zero if restoration is completed)
13. Actual duration (in hours)
14. Total customer interruption hours
15. Date and time out
16. Date and time in
17. Reason for interruption (nature/cause of interruption)
18. Failed or damaged device/equipment
19. Indicate if the interruption was planned/unplanned/intentional
20. Weather condition
21. Primarily affected load type (Residential/Industrial/Commercial/mix)

22. Whether the interruption affected a critical facility/customer (yes/no)

23. Whether the interruption is major excludable event (yes/no)

24. Whether an injury occurred as a result of the event (yes/no)

26. Name of the person responsible for filling the report

27. Time restoration commenced

28. Expected duration

29. Town/City Official notification (yes/no)

30. Name of notified/contacted person

31. Telephone number of notified/contacted person(s)

These reports shall be submitted in accordance with Section X, below.

I. Other Safety Performance Measures

In compliance with the requirements of G.L. c. 164, § 95, each Company shall report within a 24-hour period of an accident the following information:

(1) time and date of incident;

(2) time and date of the notice to the Department;

(3) location of the incident;

(4) a detailed description of the accident including information about fatalities, injuries, facilities and third-party property damage; and

(5) the name and telephone number of a Company employee who may be contacted about the accident.

These standards supercede previous Interruption and Accident Reporting Procedures. These reports shall be submitted in accordance with Section X.

J. Emergency Response Times

Each Company shall compile and report an annual average of its response times to formal emergency incidents reported by official emergency personnel. That is, the companies will calculate the total duration of time between notification of a system incident (e.g., gas meter vandalized; wire down, fire) and an arrival response by the utility Company. Companies shall also report the location (street address) and nature of each incident. Such data shall be compiled by city and town, and reported monthly, with an annual average duration calculated and reported to the Department. These reports shall be submitted in accordance with Section IX, below.

IX. SUBMITTING ANNUAL REPORTS TO THE DEPARTMENT

The annual reports described previously shall be submitted to the Department by March 1 of each year reflecting the data from the previous year(s) and shall be submitted in the following manner:

A. the original to Secretary;

B. one (1) copy to the Electric Power Division Director;

C. one (1) copy to the Rates and Revenues Division Director;

D. one (1) copy to the Gas Division Director;

E. one (1) copy of the report to the Consumer Division Director; and

F. an electronic copy of the report to the Department, by one of two means:

(1) by e-mail attachment to dte.efiling@state.ma.us; or (2) on a 3.5" floppy diskette, IBM-compatible format to the Secretary, Department of Telecommunications and Energy, One South Station, Boston, Massachusetts 02110. The text of the e-mail or the diskette label must specify: (1) an easily identifiable case caption; (2) docket number (if known); (3) name of the person or Company submitting the filing, and (4) a brief descriptive title of document (e.g., annual service quality report). The electronic filing should also include the name, title and phone number of a person to contact in the event of questions about the filing. Text responses should be written in Word Perfect (naming the document with a .wpd suffix) or in Microsoft Word, (naming the document with a .doc suffix). Data or spreadsheet responses should be compatible with Microsoft Excel.

X. SUBMITTING INTERRUPTION AND OTHER SAFETY PERFORMANCE MEASURES REPORTS TO THE DEPARTMENT

The interruption, outage, and safety reports required by these standards shall be submitted to the Department in the following manner:

A. Consistent with the Department's Outage Reporting Protocol ("ORP"), on-line through the Department-secured website. If website access is not available, an electronic copy of the report shall be submitted to the Department, by using one of the following methods: by e-mail attachment to dte.efiling@state.ma.us; or compact disc, IBM-compatible format, to the Director of Electric Power Division, Department of Telecommunications and Energy, One South Station, Boston Massachusetts 02110. The text of the e-mail or disc label must specify:

(1) an easily identifiable case caption; (2) docket number; (3) name of person or Company submitting the filing; and (4) a brief descriptive title of document (e.g., Company Name outage or interruption report). The electronic filing should also include the name, title and phone number of a person to contact in the event of questions about the filling. Text responses should be written in Word Perfect or Microsoft Word. Data or spreadsheet response should be compatible with Microsoft Excel; and

B. One (1) copy of the report submitted to the Consumer Division Director, Department of Telecommunications and Energy, One South Station, Boston Massachusetts 02110.

For electric service interruptions that are required to be reported within a one-hour period as described in Section VIII.H, each Company shall, in addition to submitting a written report, contact by telephone the Electric Power Division Director, Consumer Division Director, Executive Director, or one of the commissioners of the Department to convey the information surrounding the interruption.

XI. BILLING INFORMATION

Each Company is directed to include language placed on the back side of customer bills, which notifies customers of (a) their ability to contact the Department regarding service quality complaints or questions, and (b) the Department's website address: (www.mass.gov/dte).

XII. CUSTOMER SERVICE GUARANTEES

If gas and electric distribution companies fail to keep a service appointment or notify customers of planned service interruptions, those customers affected will receive a direct payment of $50.00. The company shall automatically credit the payment to the affected customer's account. The company shall provide to the Department relevant information regarding the number of payments made to customers and the reason.

An appointment is considered "missed" if a company's representative fails to arrive within a "four-hour window" of the scheduled time except for appointments made the same day. The company must contact the customer at least one calendar day in advance of the scheduled appointment to reschedule unless: (1) it is a same day appointment; or (2) an emergency or severe weather situation exists.[1] The Department will not require customer guarantee payments in situations where a service appointment has been made that does not require the physical presence on the premises served of either the customer or a designee of the customer.

XIII. GENERAL RESERVATION

The Department retains the discretion to waive or depart from any provision guidelines as the interests of fairness may require.

[1] Any company that seeks an exclusion from payment due to emergency and severe weather conditions must provide justification in support of its claims made in good faith as part of their annual SQ filings, which the Department will evaluate.

Appendix E - Bibliography and References

(A weblink is shown beneath the title of each paper)

Massachusetts DTE/DPU Orders – See Appendix B

NRRI Papers

"Results of 2004 Survey on Electric Reliability and Service Quality, A Report to the NARUC Staff Subcommittee on Electric Reliability," Vivian Witkind Davis, Nov. 15, 2004. Survey is mainly about reliability, but also records that in 2004 nine states had PBR based on SQ: CO, ME, MA, MS, NY, ND, OR, IA, MN, with latter two having added it since 2001.
http://www.narucmeetings.org/Presentations/elecrel_davis1104.pdf

"Where Does Your Utility Stand? A Regulator's Guide to Defining and Measuring Performance," by Evgenia Shumilkina, NRRI Report No. 10-12, August 2010.
http://www.nrri.org/pubs/multiutility/NRRI_performance_measures_aug10-12.pdf

"Utility Performance: How Can State Commissions Evaluate It Using Indexing, Econometrics, and Data Envelopment Analysis?" by Evgenia Shumilkina, NRRI Report No. 10-05, March 2010, (Revised April 26, 2010).
http://www.nrri.org/web/guest/home?p_auth=c8C87fwe&p_p_auth=Wb8KCq8b&p_p_id=20&p_p_lifecycle=1&p_p_state=exclusive&p_p_mode=view&_20_struts_action=%2Fdocument_library%2Fget_file&_20_groupId=317330&_20_folderId=0&_20_name=5623

"How Performance Measures Can Improve Regulation," by Ken Costello, NRRI Report No. 10-09, June 2010.
http://www.nrri.org/pubs/multiutility/NRRI_utility_performance_measures_jun10-09.pdf

"Should Public Utilities Compensate Customers for Service Interruptions?" by Ken Costello, NRRI Report No. 12-08, July 2012.
http://www.nrri.org/documents/317330/e798e667-af5f-44ff-82ff-b8c7518033a4

Selected Other Papers - Annotated

"Service Quality Regulation for Detroit Edison: A Critical Assessment," by Larry Kaufmann, Pacific Economics Group, March, 2007. Submitted to the Michigan Public Service Commission in Case U-15244, The Detroit Edison Company, Witness: D. Broome, Exhibit A-21. See tables of PBR by state for each category of SQ metric.
http://efile.mpsc.state.mi.us/efile/docs/15244/0024.pdf

"Resetting the 2009 Quality Thresholds: Investigation Report," by Parson Brinkerhoff Associates, December 19, 2007. Prepared for the Commerce Commission of New Zealand. See the extensive references on pages 159-161, and the discussion of the literature on SQ/PBR in the UK, Europe, and Australia (Victoria) on pages 128-130.
http://www.comcom.govt.nz/assets/Imported-from-old-site/industryregulation/Electricity/ElectricityLinesBusinesses/TargetedControl/ContentFiles/Documents/Resetting-the-2009-Quality-Thresholds---PBA.pdf

Innovative Corporate Performance Management, Five Key principles to Accelerate Results, Bob Paladino, Wiley, 2010. Excerpted in Strategic Finance, February, 2011. This book is the sequel to his 2007 Wiley book, Five Key Principles of Corporate Performance Management. Step 1 is to establish and deploy a Corporate Performance Management Office and Officer. NSTAR is cited as an example of good practice.
http://www.wiley.com/WileyCDA/WileyTitle/productCd-0470627735.html

"J.D. Power and Associates 2012 Electric Residential Customer Satisfaction Study", by J.D. Power and Associates, a McGraw-Hill Company. Shows Overall Customer Satisfaction Index by Company grouped by Region (East, Midwest, South, West) and Segment (Large and MidSize Companies). There is also a separate commercial customer survey. Survey results for previous years are available as well. The utility survey practice leaders at J.D. Power and Associates, Al Destribats, Jeff Conklin, and Chris Oberle, were colleagues of Dan O'Neill and Charlie Fijnvandraat when they were all consultants at Navigant Consulting, Inc., which was the original co-sponsor of the J.D. Power survey in the utilities industry, and O'Neill and Fijnvandraat played a role in developing the reliability part of the initial survey.
http://www.jdpower.com/content/press-release/d7cFGW5/2012-electric-utility-residential-customer-satisfaction-study.htm

"Staff Proposed New and Revised Regulations", Maryland Public Service Commission, October 27, 2011 memo from Leslie Moore Romine, Staff Counsel, to David J. Collins, Executive Secretary, MD PSC. The new and revised regulations were in response to the passage of SB 692

(2011 Session). The regulations themselves became codified in the Code of Maryland Regulation (COMAR) with minor changes in definitions in earlier chapters of COMAR 20.50.x.x and added a new chapter, 20.50.10, on Service Quality and Reliability Standards. http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=2&ved=0CDkQFjAB&url=http%3A%2F%2Fwebapp.psc.state.md.us%2FIntranet%2FCaseNum%2FNewIndex3_VOpenFile.cfm%3Ffilepath%3D%255C%255CColdfusion%255CEWorkingGroups%255CRM43%255C%255CRM43%2520Proposed%2520Staff%2520Regs.pdf&ei=NgK1UJSZI7Pp0QHS9IHYCA&usg=AFQjCNE6ZPEeOtbciZ8uluCnMaJSjaIyTQ&sig2=mkyZfVf5ZbJ9awh-VQyYxg

"State of Michigan Court of Appeals, Nos. 252949, 253899, LC No. 00-012270, Appellants: Michigan Electric Cooperative Association, Michigan Electric & Gas Association, Consumers Energy, and Detroit Edison; Appellee: Michigan Public Service Commission", August 4, 2005. This ruling affirms the MPSC's January 4, 2004 ruling in MPSC docket U-11270 regarding the MPSC's establishment of service quality guarantees and resulting payments to customers. The discussion of the legal basis for the required payments to customers is informative, e.g., standard of review, statutory authority, appellants' claim of arbitrary and capricious nature of automatic penalties, and due process in being deprived of property. http://statecasefiles.justia.com/documents/michigan/court-of-appeals-published/20050804_C252949_30_144O.252949.OPN.COA.PDF

"Utah Service Quality Review, January 1 – December 31, 2011 Report", Rocky Mountain Power, a Division of PacifiCorp. This report shows the extent of the company's service quality reporting and also shows the payments made under its customer guarantee program. With a success rate of over 99.9 percent, the payments amounted to less than $10,000 for the year. http://www.psc.utah.gov/utilities/electric/servicequalityreports/svcqualitymonitoring.html

"Electric Service Regulation No. 25, General Rules and Regulations, Customer Guarantees", Idaho Public Utilities Commission, Advice Letter 06-06, August 13, 2006. This letter details the conditions under which customer guarantee payments are made by PacifiCorp's Rocky Mountain Power division operating in Idaho. It is also referenced in the company's SQ report to Utah.
http://www.puc.idaho.gov/internet/cases/elec/PAC/PACE1212/20120813APPLICATION.PDF

"Electricity Service Quality Incentives Scoping Paper" prepared for the Queensland Competition Authority, dated July 4, 2002 by Meyrick & Associates. This paper outlines recommendations to the Queensland Competition Authority to move toward introducing formal incentives for utilities to improve both reliability and service quality. The second link is the February 2004

Queensland Competition Authority draft decision, using to a significant degree the Meyrick & Associates 2002 report
http://www.regulationbodyofknowledge.org/documents/175.pdf
http://www.qca.org.au/files/ACF17D2.pdf

Testimony on House Bill 391: Maryland Electricity Service Quality and Reliability Act, Galvin Electricity Initiative, dated February 24, 2011. The Galvin Electricity Initiative was founded by former Motorola CEO Bob Galvin and has been vocal in proposing an improvement in how electricity is generated, delivered and consumed in the US. This particular testimony is insightful because of discussion on how utilities can improve service quality with limited no rate increase along with a discussion of new SQ indices that better drive system investment and improvement.
http://www.galvinpower.org/sites/default/files/Maryland%20Performance%20Metrics%20Testimony.pdf

Illinois Commerce Commission annual Electricity Reliability Reports. The Illinois commission has in recent years taken an active role in overseeing the various utilities in Illinois. The reliability reports go into details on what the utilities are required to file, including annual budgets, CAIDI improvement initiatives, and inspection programs and results.
http://www.icc.illinois.gov/electricity/electricreliability.aspx

The State of Pennsylvania, Electric Reliability Standards. Pennsylvania is another state which takes an active role in measuring the operations of its electric utilities. These electric reliability standards detail the metrics, including worst performing (5%) circuit programs, O&M budgets of both Transmission and Distribution expenses and inspection and maintenance standards (as defined by the utility)
http://www.pacode.com/secure/data/052/chapter57/subchapNtoc.html

Order Instituting Rulemaking for Electric Distribution Facility Standard Setting. Decision 00-05-022, dated May 4, 2000. This decision paper by the California commission summarizes the various historical documents along with a summary of the various pros and cons offered by the various utilities on how reliability and service quality should be measured.
http://docs.cpuc.ca.gov/published//FINAL_DECISION/3474-05.htm

Overview of Service Quality Regulation in NY, Raj Addepalli – NYS PSC June 2007. While this white paper is sponsored by USAIDI and NARUC, this is a good primer on the reliability and service quality requirements in the neighboring state of New York (which NGRID also serves).
http://www.narucpartnerships.org/Documents/Raj_Addepalli_Service_Quality_Regulation_in_NY.pdf

NARUC 2011: Pipeline Safety, Transmission and Distribution Integrity. Jesus Soto – VP Operations services, El Paso Pipeline Group, July 18, 2011. This presentation goes into detail on the recently enacted Federal requirements for pipeline inspection and integrity and how one utility is complying. It also has a good discussion on root cause analysis and failure modes along with recommendations for mitigation. http://www.narucmeetings.org/Presentations/Pipeline%20Safety,%20Transmission%20and%20Distribution%20Integrity.pdf

Minnesota Public Utilities Commission, Staff Briefing Papers, for the meeting held on February 2, 2012 where they discuss if the commission should accept the 2010 Natural Gas service quality reports. This discussion covers the details of current requirements and subsequent performance of the gas utilities in Minnesota. http://www.mmua.org/news/Gas%20Service%20Quality%20Report%202012.pdf