Metric #10: Transmission and Distribution Reliability

M.10.1.0 Introduction and Background

This section examines the transmission and distribution (T&D) reliability value metric. As a value metric it will be difficult to establish which smart-grid attributes enhance or degrade the measurement, but features such as T&D automation are intended to enhance T&D reliability. There are over 700,000 miles of transmission lines and one million miles of distribution lines in the United States. The U.S. T&D system has been under scrutiny due to recent widespread outages, such as the 2003 New York City blackout and the California energy crisis. Approximately 80 to 90 percent of end-user outages can be traced to problems in the distribution system, most of which are caused by equipment malfunctions, such as a transformer failure, or by physical damage to distribution plants, such as a tree branches on power lines. Transmission-line problems account for only 10 to 20 percent of outages, but these include the largest and most costly events.[1] The Electric Power Research Institute (EPRI) in 2001 estimated power-interruption and power-quality cost at $119 billion per year,[2] and a 2004 study from Lawrence Berkeley National Laboratory (LBNL) estimated the cost at $80 billion per year.[3]

Smart-grid technologies will address transmission congestion issues through demand response and controllable load. Smart-grid-enabled distributed controls and diagnostic tools within the transmission system will help dynamically balance electricity supply and demand, thereby helping the system respond to imbalances and limit their propagation when they occur. These controls and tools could reduce the occurrence of outages and power disturbances attributed to grid overload. They could also reduce planned rolling brownouts and blackouts like those implemented during the energy crisis in California in 2000. Smart-grid technologies could also quickly diagnose outages due to physical damage of the transmission and distribution facilities due to weather and could direct crews to repair them quickly.[4]

M.10.2.0 Description of Metric and Measurable Elements

Several widely accepted metrics for measuring T&D reliability already exist in the industry. The System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI) describe the duration and frequency of sustained interruptions experienced by customers of a utility in one year.[5] These metrics are the focus of this paper.

---

[1]Hamachi LaCommare, K and J Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. Lawrence Berkeley National Laboratory (LBNL). LBNL-55718, LBNL, Berkeley, California. Accessed October 14, 2008 at http://certs.lbl.gov/pdf/55718.pdf

[2]Electric Power Research Institute (EPRI), 2001. *The Cost of Power Disturbance to Industrial and Digital Economy Companies.* Consortium for Electric Infrastructure to Support a Digital Society. Prepared by Primen for EPRI. Accessed October 15, 2008 at http://www.epri-intelligrid.com/intelligrid/docs/Cost_of_Power_Disturbances_to_Industrial_and_Digital_Technology_Companies.pdf

[3]Hamachi LaCommare and Eto 2004.

[4]Baer WS, B Fulton, and S Mahnovski. 2004. *Estimating the Benefits of the GridWise Initiative: Phase I Report.* TRI-160-PNNL, Prepared by Rand Science and Technology for the Pacific Northwest National Laboratory. Accessed October 15, 2008 at http://www.rand.org/pubs/technical_reports/2005/RAND_TR160.pdf.

[5]Institute of Electrical and Electronics Engineers (IEEE). *IEEE Recommended Practice for Monitoring Electric Power Quality*. IEEE Standard 1159-1995, IEEE, Inc., Piscataway, New Jersey.

(Metric 10.a) SAIDI represents the average number of minutes customers are interrupted each year, and is calculated as

$$SAIDI = \frac{\text{Sum of customer (sustained) interruption durations for all customers}}{\text{Total number of customers served}}.$$

(Metric 10.b) SAIFI represents the total number of customer interruptions per customer for a particular electric supply system, and is calculated as

$$SAIFI = \frac{\text{Total number of customer (sustained) interruptions for all customers}}{\text{Total number of customers served}}.$$

(Metric 10.c) CAIDI represents the average outage duration that a customer experiences; alternatively stated, it is the average restoration time.

$$CAIDI = \frac{\text{Sum of durations of all customer interruptions}}{\text{Total number of customer interruptions}} = \frac{SAIDI}{SAIFI}$$

(Metric 10.d) MAIFI represents the total number of customer interruptions per customer lasting less than five minutes for a particular electric supply system, and is calculated as

$$MAIFI = \frac{\text{Total number of momentary (< 5 min) interruptions for all customers}}{\text{Total number of customers served}}.$$

M.10.3.0 Deployment Trends

A recent study by LBNL on the cost of T&D reliability incidents compared several different studies that examined national statistics on SAIDI, SAIFI and MAIFI. The findings are presented in Table M.10.1. LBNL also compiled data and calculated trimmed means at the regional level. These regional indices are shown in Table M.10.2.

Table M.10.1. Summary of U.S. Reliability Event Estimates[6]

	SAIFI	SAIDI	MAIFI
EPRI Report	1.1	107	
IEEE 1995 Survey	1.3	120	5.5
EEI Annual Report			
1998	1.2	118	5.4
1999	1.4	101	11.6

[6]Hamachi LaCommare and Eto 2004.

Table M.10.2. Regional Variation in Collected Reliability Event Data[7]

Region #	Region Name	SAIDI	SAIFI	MAIFI
1	New England	131	1.1	N/A
2	Middle Atlantic	115	1.0	9.5
3	East North Central	N/A	N/A	N/A
4	West North Central	63	0.8	11.2
5	South Atlantic	N/A	N/A	N/A
6	East South Central	N/A	N/A	N/A
7	West South Central	95	1.3	N/A
8	Mountain	92	1.1	3.5
9	Pacific	105	1.2	3.2
10	California	138	1.3	2.3
U.S.	U.S.	106	1.2	4.3

The IEEE's 2005 benchmarking study[8] analyzed data from 55 companies between 2000 and 2005. Results showed an 8% increase in CAIDI, a 21% increase in SAIDI and a 13% increase in SAIFI. The national trend is shown in Figure M.10.1.

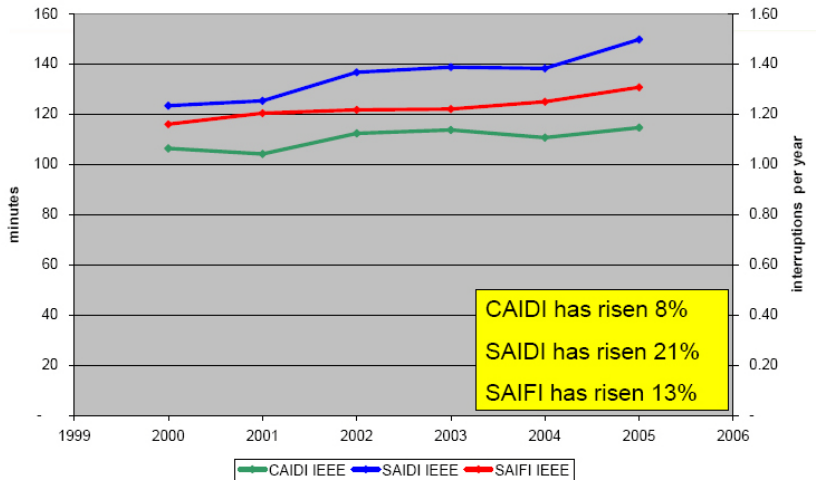

Figure M.10.1. Trends for 55 Utilities Providing Data Between 2000-2005[9]

The smart-grid interviews conducted for this report asked utilities to present SAIDI, SAIFI, and MAIFI data for the most recent year for which data were available and compare actual data against the levels predicted prior to the year in question. Findings from the interviews are summarized in Table M.10.3. Responses from each utility were weighted based on their share of the total customer base of those utilities providing data.

[7]Hamachi LaCommare and Eto 2004.
[8]Institute of Electrical and Electronics Engineers (IEEE). 2006. *IEEE Working Group on Distribution Reliability, Benchmarking 2005 Results*. July 2006. Accessed October 15, 2008 at http://grouper.ieee.org/groups/td/dist/sd/doc/2006-07-BenchmarkingUpdate.pdf.
[9]IEEE 2006.

Table M.10.3. Predicted and Actual SAIFI, SAIDI, and MAIFI

Metric Name	Predicted	Actual
SAIFI	1.2	1.3
SAIDI	132.5	158.9
MAIFI	8.4	4.6

The North American Electric Reliability Council's 2007 Long Term Reliability Assessment found that summer peak demand in the U.S. is forecast to increase over 135,000 MW or 17.7 percent in the next ten years, with committed resources projected to increase 77,000 MW or 8.4 percent (including uncommitted resources, 123,000 MW or 12.7 percent).[10] Their U.S. Capacity Margin Comparison, shown in Figure M.10.2, shows the U.S. capacity margins declining throughout the ten-year period.

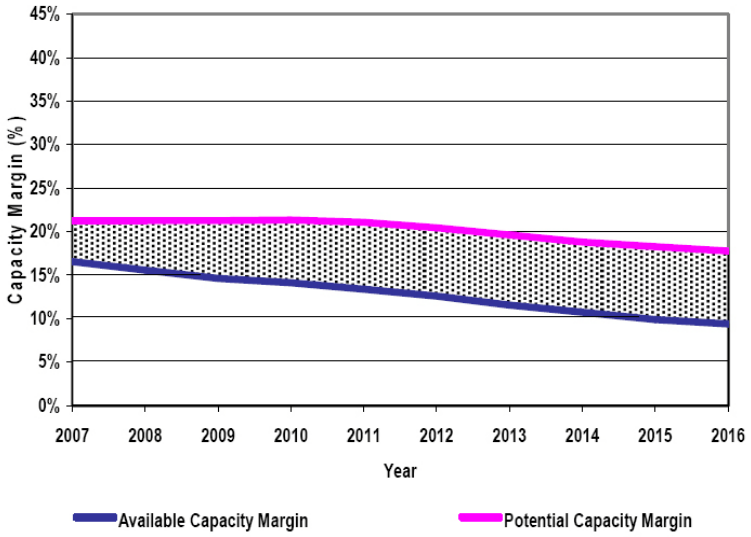

Figure M.10.2. U.S. Capacity Margin Comparison – Summer[11]

M.10.3.1 Associated Stakeholders

There are a number of stakeholders with interests in transmission and distribution reliability:

- Electric-service retailers wanting to cost-effectively provide a more reliable product
- End users (consumers) needing consistent reliable power
- Local, state, and federal energy policymakers concerned with the negative economic effects of poor power quality on commercial and industrial customers
- Regulators who decide the basic level of power quality and reliability that the system will provide to customers.

[10]North American Electric Reliability Council. 2006. *2006 Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America.* Accessed November 24, 2008 at http://www.nerc.com/files/LTRA2006.pdf

[11]NERC 2006.

M.10.3.2 **Regional** Influences

Reporting regulations and practices vary from state to state, making it difficult to compare data such as the above-mentioned metrics across regions. Regional differences arise for several reasons such as climate, geography, and design and maintenance of the distribution system. Some utilities will naturally have better reliability indices than others due to differences in frequency and types of severe weather, geography and natural vegetation in the region. For example, the number of lightning strikes, the length of exposed feeders, and urban network-system designs have a significant impact on reliability figures, regardless of the utilities' ability to operate and maintain their systems.[12] Each region of the country has a different combination of number and type of customers (residential, commercial, and industrial) and each utility has its own unique distribution system, all of which affect T&D reliability.

The 2006 National Electric Transmission Congestion Study conducted by the U.S. DOE investigated the eastern and western interconnections to identify constrained transmission paths of national interest. Transmission congestion can indicate areas of system stress that can impact reliability as well as the cost of electricity. Using scenarios projecting fuel prices for 2008 and 2011, the study identified 118 paths in the eastern interconnection that would be congested under almost every scenario. The western analysis modeled significantly larger nodes than the east and identified 10 paths that were likely to be the most heavily congested in their 2008 projections as ordered by the number of hours when usage is 90% or greater of a line's limit. Overall, the study identified two critical congestion areas: 1) the Atlantic coastal area from New York to northern Virginia, and 2) Southern California. Four congestion areas of concern were also identified (one in the east and three in the west). Five conditional congestion areas were also listed as situations to watch. It should be noted that the U.S. DOE did not include the Electric Reliability Council of Texas (ERCOT) in their study because it was explicitly excluded in their directive from Energy Policy Act of 2005.[13]

Electricity trading patterns and transmission congestion are different in the West than in the East for several reasons. First, the transmission system in the West was built primarily to carry power over long distances. Several large power plants in the West were intentionally built in remote locations where owners constructed high-voltage transmission lines to ship power to densely populated load centers. Also, the Pacific Northwest uses a great deal of hydroelectric power, which is greatest in the spring and summer, while demand in the region is greatest in the winter. Therefore, the Pacific Northwest sells its excess capacity in the spring and summer to California and other western states, and purchases excess supply from the same regions in the winter.

The Northeast blackout of 2003 affected 8 U.S. states in the Northeast and one Canadian province, leaving 50 million people without power for up to two days in some places. Twelve airports had to be shut down, leading to 700 canceled flights, and all trains in the New York City area came to a halt, stranding people in the city for the night. A joint commission of U.S. and Canadian representatives later

---

[12]Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices*. Oak Ridge National Laboratory (ORNL), ORNL/TM-2004/91, ORNL, Oak Ridge, Tennessee. Accessed October 14, 2008 at http://www.ornl.gov/sci/engineering_science_technology/eere_research_reports/power_systems/reliability_and_power_quality/ornl_tm_2004_91/ornl_tm_2004_91.pdf

[13]U.S. Department of Energy (DOE). 2006. *National Electric Transmission Congestion Study*. Accessed May 27, 2009 at http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf

traced the cause of the blackout to Ohio, where trees had not been cut back away from the power lines. It is estimated that the economic activity lost due to the blackout was between $4.5-12 billion.[14]

In 2000, California enacted legislation that introduced the "rolling blackout," which intentionally and systematically shuts down areas of peak demand for up to several hours (60 minutes to 2.5 hours) while the rest of the local or regional grid is equalized. If the grid is unstable after the first grid is blacked out, they will bring the first grid back online and black out the second grid, and so on, until the grid is stabilized. California customers' electric bills include the number of the power grid (1 through 14) to which they belong, giving the customers an idea of when their electricity will be turned off during rolling blackouts.[15,16]

M.10.4.0 Challenges to Deployment

M.10.4.1 **Technical** Challenges

Technical challenges include combining new technologies with the existing grid and updating the existing grid. Unique characteristics of wind, solar, and nuclear power generation must be taken into account when planning for the future. A recent NERC survey of industry professionals ranked aging infrastructure and limited new construction as the number one challenge to reliability—both in likelihood of occurrence and potential severity. Lastly, more standardized codes, requirements and reporting of T&D reliability are needed.[17]

M.10.4.2 **Business** and Financial Challenges

Upgrading and adding to the grid incurs costs that some may be cautious to take on. FERC, in a policy statement on matters related to bulk power system reliability, stated that public utilities may be reluctant to spend significant amounts of money without reassurance that they will be able to recover it. The report goes on to note:

> *"Regulators should clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. The Commission also assures public utilities that they will approve applications to recover prudently incurred costs necessary to ensure bulk electric system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices."*[18]

---

[14]U.S. Department of Energy (DOE). 2004. *National Electric Delivery Technologies Roadmap: Transforming the Grid to Revolutionize Electric Power in North America*. Office of Electric Transmission and Distribution, Washington, D.C. Accessed October 15, 2008 at http://www.oe.energy.gov/DocumentsandMedia/ER_2-9-4.pdf

[15] Galvinpower.org. October 2006. *Blackout the microgrid solution*. Access February 6, 2009 at http://www.galvinpower.org/files/Blackouts_the_microgrid_solution.doc

[16] Coleman**,** Jennifer**.** April 16, 2004**.** *California faces repeat of deregulation debate***.** Associated Press**.** Accessed February 6, 2009 at http://www.ontariotenants.ca/electricity/articles/2004/ap-04d16.phtml

[17]Federal Energy Regulatory Commission (FERC). 2007. *Results of the 2007 Survey of Reliability Issues*. 107 FERC 61,052, October 24, 2007, FERC, Washington, D.C., April. Accessed February 6, 2009 at http://www.nerc.com/files/Reliability_Issue_Survey_Final_Report_Rev.1.pdf

[18]Federal Energy Regulatory Commission (FERC). 2004. *Policy Statement on Matters Related to Bulk Power System Reliability*. 107 FERC 61,052, Docket No. PL04-5-00 2004. Issued April 19, 2004, FERC, Washington, D.C., April. Accessed October 14, 2008 at http://www.ferc.gov/whats-new/comm-meet/041404/E-6.pdf

A large portion of the utility workforce is approaching retirement without a skilled workforce to take their place. Utilities need to actively recruit and train skilled labor to ensure a knowledgeable workforce for the future. Lastly, educating and demonstrating to the end users the use of smart-grid enabled programs, such as dynamic pricing, should be a priority.

Currently, there are irregularities in the ways utilities and regions report T&D reliability incidents. Definitions are sometimes vague, and inconsistencies in reporting requirements are making it difficult to complete analyses. For example, SAIDI, SAIFI, and MAIFI are useful for assessing T&D reliability, but often are not collected or are collected inconsistently.[19] In a 2003 nationwide study by IEEE, several inconsistencies between utility practices were found. They found disparity in how start and end times of an interruption are reported, wide discrepancies in what defines a major event that would be excluded from reliability indices, and some utilities include MAIFI within SAIFI, which inflates SAIFI. Utilities vary on what level they measure reliability (i.e., substation, circuit breaker, meter, transmission, etc.), and interruption data is entered differently, either automatically by a computer or manually.[20]

M.10.5.0 Metric Recommendations

More interviews should be conducted in support of future smart-grid benchmark studies and a single data source should be identified for national statistics covering SAIDI, SAIFI, CAIDI and MAIFI. Support for a single source would allow analysts to compare trends over time in a consistent manner.

[19]Kueck et al 2004.

[20]Warren CA, DJ Pearson, and MT Sheehan. 2003. "A Nationwide Survey of Recorded Information used for Calculating Distribution Reliability Indices." *IEEE Transactions on Power Delivery* 18(2):449-453. DOI: 10.1109/TPWRD.2002.803693 Accessed November 26, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=1193863&isnumber=26850