Distribution Reliability Opportunities

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Introduction

The term "Smart Grid" has been used to describe a wide range of opportunities for improving service to electric utility customers. In this paper, we focus on the least-smart portion of the electrical grid — the Distribution system — and in particular, the overhead Distribution system and an emerging opportunity to address the related reliability issues.

Background

Energy companies strive to provide a very high level of reliability — both from a quality (appropriate voltage, etc.) and quantity (always on) standpoint. At the Bulk Electric System (BES) level which includes generation and transmission lines, the system is commonly engineered and managed to a 1-in-15-year outage standard. The North American Electricity Reliability Corporation (NERC) sets standards for the BES and audits energy companies for compliance. Energy companies manage BES assets carefully using various measurements and frequent monitoring using Supervisory Control and Data Acquisition (SCADA) systems. The reason for all this attention at the BES level is that outages would affect potentially millions of people and thousands of businesses. Accomplishing the reliability mission at the BES level is expensive, but the resulting BES system is relatively "Smart" and few outages actually originate in the BES.

By contrast, the Distribution system (lower voltage, primarily overhead, local delivery of energy) can only be kindly characterized as significantly less smart. Distribution assets are traditionally not monitored and measurements that would help with reliability improvement are not available and therefore not used. The reasons are twofold. First, a Distribution outage affects far fewer people/businesses than a BES outage. Second, the cost to monitor and actively manage Distribution assets has been historically prohibitive. Distribution is therefore a "run-to-failure" asset, at many utilities. However, times are changing.

The Cost of Reliability

When an outage occurs, the energy company forgoes some revenue related to consumption that would have taken place, the energy company (and ultimately the end customers) has to bear the cost to fix the outage, and customers are damaged by not being able to conduct business. This last reality is the most difficult of the three to quantify, and is the largest by far, and has recently taken a more center stage role.

A September 2004 study[1] conducted by Lawrence Berkeley National Laboratory (Berkeley Labs) for the U.S. Department of Energy estimates that electric power outages and blackouts cost the nation about $80 billion ($91 billion in 2009 dollars) annually. A full 98% of this number relates to Commercial and Industrial businesses rather than inconveniences and losses suffered by residential customers.

[1] http://www.EnergyCollection.US/Energy-Reliability/The-Cost-Of-Power-Interruptions-2004-09-01-70.pdf

To put the $80B annual loss rate into perspective, consider that the total of all electricity bills in the United States is $300B per year (including residential). Also, because of the attention paid (and resultant reliability success) at the BES level, l more than 80%[2] of all outages are directly related to Distribution facility failures.

The Opportunity

Of course, energy companies are concerned about these Distribution outages and the real impact on their customers. State Regulators too are concerned and work with the energy companies to address the issue by providing cost recovery for prudent investments in reliability-focused projects. A bevy of reliability measurements are possible and several are in use, but one that is in fairly common use is the **S**ystem **A**verage **I**nterruption **D**uration **I**ndex **(SAIDI)**. SAIDI is the annual outage minutes per customer served, and is calculated as:

$$\textbf{SAIDI} = \frac{\textbf{sum of all customer interruption durations}}{\textbf{total number of customers served}}$$

SAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-1998, the median value for North American utilities is approximately 1.50 hours (90 minutes). The DOE study previously mentioned pegs the number at a somewhat higher 106 minutes per year per customer.

Typically, energy companies strive to improve this measure by directly reducing the total Customer Minutes of Interruption (CMI) — the numerator of SAIDI.

Outage causes are commonly grouped into three main areas: vegetation-related failures (32%), equipment failures (31%), and animal / other-related failures (37%). Of these, the vegetation-related failures are being directly addressed by ever-present vegetation management programs, and animal-related failures are addressed by a number of physical prevention/guard mechanisms. In total, energy companies spend $45B per year on such programs to address Distribution reliability concerns. Notably, the $80B annual reliability losses to customers are <u>after</u> this aggressive program of prevention.

However, equipment failures (32%) remain largely unaddressed because of the high cost of monitoring, and the widely disbursed nature of the Distribution system.

Enter the Smart Grid.

[2] Assessing the Reliability of Distribution Systems, Richard E. Brown, Andrew P. Hanson, H. Lee Willis, Frank A. Luedtke, Michael F. Born, IEEE Computer Application in Power, January 2001, pp 45-49

The Smart Grid

As previously noted, Distribution is significantly less smart than the BES for historical (lack of technology) cost/benefit reasons. However, several technology advances — most notably in monitoring and low-cost communications — are now enabling the opportunity for measurement, monitoring, and management of Distribution Assets. Many of the approaches traditionally used in the BES can be right-sized and productively deployed in the Distribution Grid — and these improvements will ultimately lead to reduced-equipment outages. Indeed, these innovations — properly selected in a cost/benefit analysis, and coordinated with emerging technology and capability on the customer side of the meter — make up the heart of the emerging "Smart Grid."

However, the Smart Grid gives rise to new challenges as well. Customer expectations for power reliability rise given the press coverage and possibility of new incremental charges. New communications systems deployed in the Distribution grid are subject to interference caused by aging components in a failing mode – and require a “clean” Distribution system to properly operate. And finally, customer applications are increasingly computer-based and sensitive to poor-quality power and loss of power. Run to failure, and poor quality power are not acceptable options going forward.

To address these and other issues, many new technologies are coming onto the scene. For example, one utility is deploying power quality support via specialized inverters and solar-generating assets embedded in the Distribution system on a pole-by-pole basis. Another emerging application taking advantage of technological advances is mobile monitoring and identification of failing components. This last technology enables a utility to directly address the issue of failing components — a very large and growing (due to an aging infrastructure) problem.

Failing Equipment

Outages caused by failing equipment are particularly problematic due to the difficult nature of locating and fixing equipment in a failing mode — but before catastrophic failure (causing an outage). Locating a failure even after an outage is a problem. The distribution of utility costs to restore power following an outage is shown below and is labeled as Figure 1.22 from its original use. This 1998 study shows that 40% of the restoration costs are discovering the cause of the outage, and 60% of the costs are the actual restoration effort.

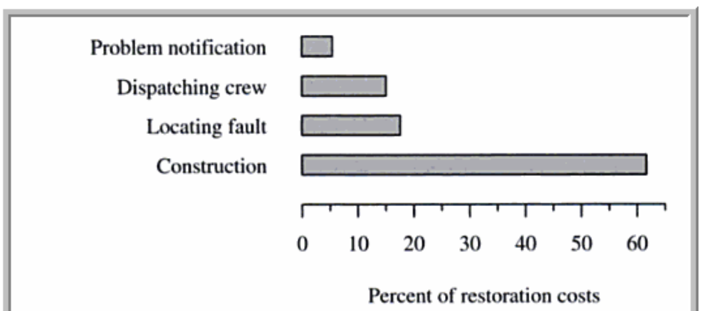
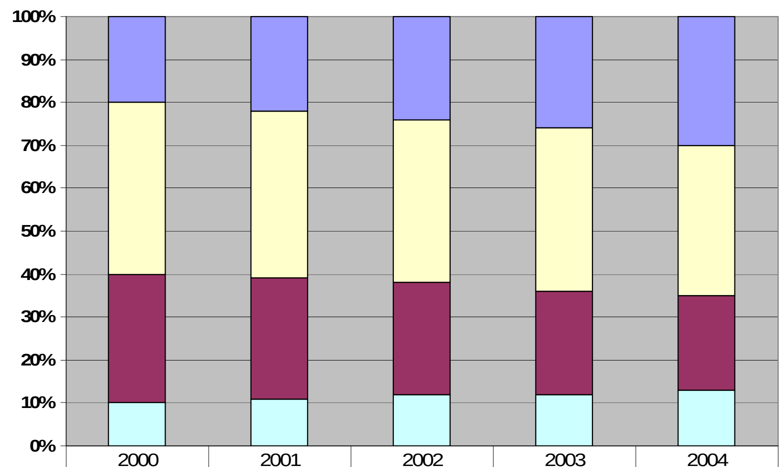


FIGURE 1.22
Breakdown of utility restoration costs. (Data from [EPRI TR-109178, 1998].)

Figure 1 [3]

[3] Distribution Reliability and Power Quality, Thomas Allen Short, http://www.chipsbooks.com/distrelb.htm

The mobile-monitoring application[4] mentioned above is of particular importance given this cost structure. Also, the graph below provides a review of trends in the contributors to outages over a five-year period. In this report, weather- and animal-related outages maintain a relatively consistent, year-to-year trend, while tree-related outages decline year-to-year due to sustained investment in vegetation management programs. It is also clear that equipment failure rates are rising each year. Ironically, the growing Equipment related failure category has historically enjoyed the least investment attention due to the difficult nature of a frontal attack on the issue.



	2000	2001	2002	2003	2004
Equipment	20	22	24	26	30
Weather	40	39	38	38	35
Trees	30	28	26	24	22
Animals	10	11	12	12	13

Figure 2 [5]

Utilities have become experts in emergency preparedness and outage management. This has resulted in a run-to-failure (RTF) operating mode that once led the overall reliability strategy: Wait until an outage occurs and then fix the problem as fast as possible. This operating mode has proven to be an expensive methodology, the most dangerous for operating personnel, and the most upsetting to the customer who wonders why power is interrupted without any visible cause such as bad weather. In one study by the DOE, RTF was compared to Predictive-based Maintenance (PbM). The study concluded PbM has the highest ROI of any maintenance strategy: typically, 10 times that of RTF[6]

[4] This technology is exposed to the Distribution system in multiple drive-by passes and examines/logs failure signatures in RF and ultrasonic waves being thrown off by equipment in a failing mode.

[5] Asset Management – Maintenance and Replacement Strategies Workshop 3A at PMAPS 2006 John Endrenyi and Gerard Cliteur, KEMA

[6] "Predictive Maintenance," U.S. Department of Energy–Energy Efficiency and Renewable Energy, Federal Energy Management Program–Operations and Maintenance, (10 Jan 2007), 2 pp

Equipment Failure Prevention — ROI

As previously noted, annual expenditures to address Distribution reliability concerns are about $45B. These expenditures must be ultimately approved by regulators for pass-through to be paid by the customers. Close scrutiny is given to these costs and projects are arranged from highest to lowest return on investment to guide prioritization and project selection. The ideal ROI measurement to guide the prioritization of projects is to calculate Benefits/Costs. In this case, Benefits are customer losses that can be prevented, and Costs are the utility expenditures related to eliminating an outage. Note that both Benefits and Costs in this ratio are ultimately and totally about the end user of electricity.

In the case of equipment failures, developing the Benefit/Cost metric has been problematic, but advances have been made based on the need to press ahead. Several utilities have developed a "rule of thumb" to address the Benefit (losses not experienced) issue. While this measure can differ from utility to utility based on system configuration and age, an approximate customer Benefit value of $1.5M[7] per SAIDI minute of reduced outage is commonly being used.

One large investor-owned utility in the southeastern U.S. has studied their system and systematically recorded data on outages caused by equipment failures. On a specific subset of Distribution, they found equipment-related minutes of outage (CMI) represented 20,646,314 minutes. They also recorded that the replacement of this failed equipment following the outage cost them $2,237,750. Finally, they calculated the benefit of eliminating the equipment-related CMI by replacing the equipment before it failed to be a 16.6-minute reduction in SAIDI or $24,900,000 using the $1.5-million-per-SAIDI-minute rule of thumb mentioned above.

Using the information above, and a few conservative assumptions, it is straightforward to create a business case (Benefit/Cost ratio) for addressing the removal of weakened equipment, the reduction of CMI, and the resulting improvement in SAIDI.

- For a system of 1,500 Distribution circuit miles:
    - CMI = 20,500,000 minutes (caused by equipment-related outages)
    - Number of Total Customers = 1.2 million
    - SAIDI reduction opportunity = CMI/Number of Customers = 17 minutes
- Implement an active mobile-monitoring/replacement program to locate weakened equipment — and conservatively assume the result is <u>only a 10% reduction</u> in equipment-related outages by identifying failing components.[8]
    - The affect of locating and removing weakened equipment = 10% outage reduction or 2,050,000 minutes = SAIDI reduction of 1.7 minutes
    - The investment to locate weakened equipment = $450,000
    - The average replacement cost is $200,000
    - SAIDI reduction is valued at $1,500,000 per minute

[7] Doug Staszesky, Director – Product Management, Automation Systems Division, S&C Electric Company - see page 22 of http://www.energycollection.us/Energy-Distribution-Automation/SANDC-Presentation-Distribution-Automation.pdf

[8] Such technology exists and can identify equipment components in a failing mode with 98% accuracy and at a cost of less than $350 per circuit mile.

- ROI
  = 1.7 minutes of SAIDI / ($450,000 + $200,000)
  = Benefit/Cost Ratio = $2,550,000/$650,000 = 392%

Such Benefit/Cost ratios are very high when compared with other more traditional projects for addressing reliability. This customer based analysis opens the door to increased investment in finding and replacing failing equipment due to the high value to customers. If increased budgets are not available, vegetation budgets and animal outage prevention budgets should be analyzed for customer impact and budgets should be appropriately reallocated to deliver maximum customer impact.

Summary

Technology is opening the door to improved ways to address the Distribution reliability issue and directly address the annual $80B ($91B in 2009 dollars) in lost value to the U.S. economy. A wide variety of Smart Grid technologies will eventually make a large improvement. One such technology is mobile-monitoring and accurate identification and replacement of failing components prior to an outage. The technology and the data to estimate Benefit/Cost ratios to prioritize projects are available. High-Benefit/Cost-Ratio projects give utilities a way to effectively defend the need for the expenditures and resulting cost recovery from customers — customers that are the ultimate beneficiaries of the value provided by reliable electric service.

About the Author

Paul Feldman is an independent participant in the energy industry. He is a Director and Chairman of the Midwest ISO, an Independent Director of the Western Electricity Reliability Council (WECC, part of NERC) where he serves on the Board's Compliance Committee, is a member of the National Association of Corporate Directors, and serves on energy company advisory boards.