Sensors for Real-Time Distribution System Information: Key Elements of a 21st Century Grid

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Executive Summary

The U.S. electric utility industry has been in existence for well over one hundred years. Its employees have extensive experience and understanding of their distribution systems, but do not have access to complete, live grid information on which to base decisions.

Regulatory requirements, customer expectations, and the need to control costs all have greater influence over the management and operation of electric distribution infrastructure than at any time in the industry's history.

Real-time and archived historical information provided by grid sensors enables utilities to improve customer service and system performance while reducing costs, and serves as the foundation of a modern, comprehensive asset management and operations strategy.

Overview

Old Technology, Modern Demands

Electric utilities require continuous, real-time knowledge of system conditions in order to provide the best service to their customers, respond to interruptions and overloads, and manage their distribution infrastructure effectively and efficiently while controlling costs.

> *"Throughout the 20th century, the U.S. electric power delivery infrastructure served our nation well, providing adequate, affordable energy to homes, businesses and factories. This once state-of-the-art system brought a level of prosperity to the United States unmatched by any other nation in the world. But a 21st-century U.S. economy cannot be built on a 20th-century electric grid."*
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> *A Vision for the Modern Grid,*
> *National Energy Technology Laboratory, March 2007*

- Business and residential customers of electric utilities demand highly reliable service. They expect fewer interruptions and shorter outage durations, and they do not tolerate momentary interruptions.
- Regulators have established performance standards for system reliability to ensure that utilities are meeting customers' expectations.
- Public utility commissions require accurate monitoring and reporting of reliability statistics.
- Compliance with reliability standards is enforced via detailed reporting, mandated infrastructure spending, and, in some cases, direct financial penalties.

In March 2007, National Energy Technology Laboratory (NETL), part of the Department of Energy's National Laboratory System, issued a series of reports prepared by the Modern Grid Initiative (MGI) Team. These documents describe the need for a modernized electric delivery system, and define the structure, characteristics, key elements, and benefits of a modern grid. The MGI Team identified five key technologies as essential elements of the modern grid:

- Integrated Communications
- Sensing and Measurement
- Advanced Components
- Advanced Control Methods
- Improved Interfaces and Decision Support.

This paper will discuss sensing and measurement as a foundation supporting the other key technologies.

The Distribution Information Gap

What Is Happening on Your System Right Now?
How Do You Manage Real-Time and Predicted System Conditions?
How Can Sensors Help You Better Manage Your System?

Large equipment in distribution substations has some degree of monitoring, and automated meters are providing greater monitoring at the customer level. However, a data gap exists between the substation and the customer, in that there is little or no monitoring along the distribution grid itself.

Existing distribution systems do not provide real-time and archived grid condition information necessary to support daily operations decisions, plan long-term asset management strategies, and meet regulatory reporting requirements.

Five major functions of distribution grid management currently rely on inadequate or estimated field data:

1) outage identification
2) fault location
3) system planning
4) temporary overloads
5) reliability reporting.

The following pages detail the ways that utilities currently perform these functions, and how each function will be improved with deployment of sensors providing real-time grid information.

1. Outage Identification

Currently	With Sensors Deployed
• Utilities typically receive notification of interruptions when customers phone their call centers. They also rely on outbound customer calls to confirm that service has been restored. • While customers are less tolerant of momentary interruptions than in the past, most utilities do not have accurate records of momentaries.	• System Operators are notified immediately via monitoring software when sensors detect a sustained interruption. The utility is aware of interruptions *before* customers call to report them. • When customers complain of momentary interruptions, the utility has accurate, detailed historical records at hand to confirm the customer's perception, and to initiate appropriate action. • Utilities gain the ability to track and report MAIFI (Momentary Average Interruption Frequency Index). • Accurate interruption records facilitate resolution of customer complaints, and provide valuable circuit level data for reliability-centered maintenance programs.

2. Fault Location

Currently	With Sensors Deployed
• Possible fault locations are identified by making assumptions based on customer calls and equipment operations. Crews must then be dispatched to patrol miles of overhead conductors to locate faults before they can begin service restoration and repairs. Searching for damage in this way is inefficient and costly in terms of crew expenses, reliability performance, and lost revenue.	• When sensors detect a fault, an instantaneous alarm identifies the phases affected and the fault location, to within one sensor span (the distance between two sensors on the faulted circuit). Crews travel directly to the fault location to restore service and make repairs. • With remote switching and automated restoration, it is possible to restore service to customers served by unfaulted sections quickly enough to prevent a sustained interruption. • SAIDI (System Average Interruption Duration Index) improves because of shorter durations due to reduced patrol time. SAIFI (System Average Interruption Frequency Index) also improves with remote/automated restoration. SAIDI and SAIFI are expected to improve by 25 to 35% during the first year of deployment. • Reduced time patrolling circuits results in lower operating costs. • Shorter interruption duration reduces lost revenue. • Line crews operate more safely than in the past, because they have complete, live intelligence regarding energized circuit segments available at all times.

3. System Planning

Currently	With Sensors Deployed
• System Planners predict load growth and available capacity to determine the need for capital investments. These predictions are usually based on inaccurate or incomplete records (often paper charts collected manually from substations) and overly conservative risk assessments necessitated by the poor data quality. • When unexplained recurring interruptions seem to indicate unbalanced phases, field crews install load loggers on the conductors, and return weeks later to collect data records. Planning Engineers interpret the data, and if load-balancing is required, issue work orders to rebalance the load. Unbalanced loading is wasteful, and results in energy loss and accelerated loss of equipment life, but is difficult to detect. Losses due to imbalance on overhead distribution lines can equal 1.5% to 2.5% of all energy sold.	• Archived historical load data improves planning of overload relief or capacity upgrade projects. Planners can accurately predict circuit and station load growth, and assess associated risks. • Better risk assessment facilitates long-range planning and provides credible justification for prioritizing, accelerating or deferring individual capacity projects within a multi-year plan. • Cost savings are realized as fewer capital projects are engineered and built, since predictions are based on observed trends rather than conservative assumptions and poor data. • The cost of sending crews to install and remove temporary load loggers is eliminated. • Circuit imbalance is easily identified and corrected, minimizing energy losses and conserving power.

4. Temporary Overloads

Currently	With Sensors Deployed
• During heat storms (extended periods of hot weather), System Operators must temporarily reconfigure circuits in order to relieve overloads. These decisions are often (at best) based on calculations using connected load and assumed available capacity on adjacent circuits or substations. • System reconfiguration based on incomplete data increases the risk of equipment failure and widespread power outages.	• Operations personnel (or an automated distribution management system), quickly and accurately assess available capacity, and safely transfer load during heat events.

5. Reliability Reporting

Currently	With Sensors Deployed
• Interruption data is recorded manually, and is based on observed or remembered information. • During storms or other periods of widespread outages, System Operators are focused on dispatching crews and restoring service, and do not have resources available to manually record outage information. Weeks or months often elapse before outage data is backfilled. • Under-reporting of outage data can result in failure to identify Major Events, which are excluded from PUC reports. Incidents that should qualify for exclusion can result in reliability indices that appear worse than they should. • Inaccurate outage records hinder investigation of customer complaints, and can conceal problem areas, or falsely identify circuits as poor performers.	• Interruption data is automatically stored and time-stamped with accurate start and end times. Momentary and sustained interruptions are segregated, based on each utility's reporting criteria. • During storms, Operations personnel can remain focused on safety, crew dispatch and service restoration. • Automated data collection and reporting reduce labor costs. • Improving the accuracy of reliability measures assures regulatory compliance. • Verification of interruption records improves customer satisfaction. • Archived interruption data can be used to develop metrics for assessing circuit performance within a utility's distribution system, assuring regulatory compliance by identifying and addressing worst performing circuits.

Conclusions

Utility professionals need accurate data to manage their distribution assets, comply with regulatory requirements, reduce inefficiencies and increase customer satisfaction.

Low-cost sensors provide immediate and long-term benefits.

The Operations, Customer Service, Planning, Engineering, Maintenance, Vegetation Management and Asset Management Groups of electric distribution companies all have extensive understanding regarding practices, processes and programs that will enable them to provide the best possible service in the most efficient manner, but lack detailed, real-time knowledge of system conditions and accurate historical data on which to base their decisions.

Low-cost sensors with reliable communications provide immediate, actionable intelligence to managers of electric distribution systems, and continue to increase in value by providing data inputs to future deployments such as Outage/Distribution Management Systems (OMS/DMS), reliability databases, load forecasting programs, vegetation management maintenance plans, call center systems and demand side response applications.

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Wayne Honath joined Tollgrade Communications, Inc. in 2007 as Program Manager, and brings 25 years of electric utility experience to this position.

Previously, he was Manager of Reliability and Standards at Duquesne Light Company, an investor-owned utility serving Allegheny and Beaver Counties in Western Pennsylvania.

While at Duquesne, Wayne worked in collaboration with the Energy Association of Pennsylvania and the Pennsylvania Public Utility Commission to develop the state's reliability standards for electric utilities. Between 2000 and 2006, Duquesne Light's system reliability improved by 15% to 25%, becoming the most reliable distribution system in the state of Pennsylvania.