Metric #11: Transmission and Distribution Automation

M.11.1.0 Introduction and Background

T&D automation is defined by the IEEE as "a system that enables an electric utility to remotely monitor, coordinate, and operate [transmission and] distribution components in a real-time mode from remote locations." This metric includes coordination between electric T&D components that are separate but co-located. This broad definition encompasses a large set of technologies, which includes SCADA technologies, remote sensors and monitors, switches and controllers with embedded intelligence, digital relays, and a large number of other technologies used in the T&D infrastructure. The general operating scheme of these devices is to gather real-time information about the grid through communication and coordination with other devices, process the information on site, take immediate corrective action if necessary, and communicate results back to human operators or other systems. These devices serve a variety of functions, including "fault location, fault isolation, feeder reconfiguration, service restoration, remote equipment monitoring, feeder load balancing, Volt-VAR controls, remote system measurements, and other options."[1] If operated properly, transmission and distribution automation systems can provide more reliable and cost-effective operation through increased responsiveness and system efficiency.

M.11.2.0 Description of the Metric and Measurable Elements

The metric for automation technology adoption are defined as:

(Metric 11) Percentage of substations having automation

M.11.3.0 Deployment Trends and Projections

Data from utilities across the nation show a clear trend of increasing T&D automation and increasing investment in these systems. Key drivers for the increase in investment include operational efficiency and reliability improvements to drive cost down and overall reliability up. The lower cost of automation with respect to T&D equipment (transformers, conductors, etc.) is also making the value proposition easier to justify. With higher levels of automation in all aspects of the T&D operation, operational changes can be introduced to operate the system closer to capacity and stability constraints.

Results of interviews undertaken for this report (see Annex B) indicate that:

- 28% of the total substations owned were automated
- 46% of the total substations owned had outage detection
- 46% of total customers had circuits with outage detection
- 81% of total relays were electromechanical relays
- 20% of total relays were microprocessor relays

Other nationwide data has shown that transmission automation has already penetrated the market highly, while distribution automation is primarily led by substation automation, with feeder equipment automation still lagging. Recent research shows that while 84% of utilities had substation automation and integration plans underway in 2005, and about 70% of utilities had deployed SCADA systems to

[1]Uluski, R. 2007. "Is Distribution Feeder Automation Right for You and Your Customers?" *EnergyPulse*. May 21, 2007. Accessed October 28, 2008 at: http://www.energypulse.net/centers/article/article_print.cfm?a_id=1481.

substations, the penetration of feeder automation is still limited to about 20%.[2,3] Because feeder automation lags other automation efforts so significantly, this should be an area addressed directly in future work.

It is worth noting that aside from the survey data which is presented here, there is a relative lack of data about the penetration of transmission and distribution automation. Differences in how these devices are operated make it difficult to directly draw conclusions about the impact of these devices on the actual performance of the grid.

A significant component of the measurement, analysis, and control of the T&D infrastructure relates to control centers at the transmission and distribution levels of the system (SCADA, energy management systems – EMS, and distribution management systems - DMS). According to a recent survey by Newton-Evans Research, almost all utilities with over 25,000 customers have SCADA/EMS systems in place, while only about 17% of utilities have DMS systems.[4] One smart grid trend is to integrate other functions with these centers. For example, about 30% of the SCADA/EMS systems are linked to Distribution Automation/DMS. Figure M.11.1 shows the projected integration of EMS/SCADA/DMS systems to a variety of other data systems.

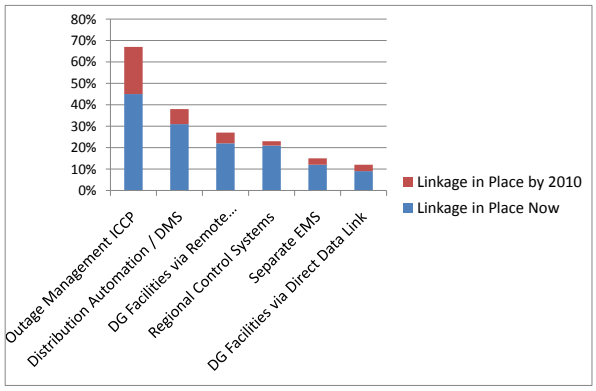

Figure M.11.1. Current/Future Plans for Connecting EMS/SCADA/DMS Systems to Other Data Systems[5]

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[2] *T&D Automation News*. Electric Light and Power. Accessed November 21, 2008 at: http://uaelp.pennnet.com/resource/transmission%20and%20distribution

[3] D McDonnell. 2006. "Beyond the Buzz: The Potential of Grid Efficiency." *Smart Grid News*. Accessed November 21, 2008 at: http://www.smartgridnews.com/artman/publish/industry/Beyond_the_Buzz_The_Potential_of_Grid_Efficiency_180_printer.html.

[4] Newton-Evans Research Company. 2008. *Market Trends Digest*, 3rd Quarter 2008 Edition. Newton-Evans Research Company, Endicott City, Maryland. Accessed November 11, 2008 at: http://www.newton-evans.com/mtdigest/mtd3q08.pdf

[5] Newton-Evans 2008.

The investment in T&D automation can be estimated either from total industrial output of specific automation products to U.S. markets or from the receiving demand side (utility company) as purchases. Market statistics for T&D investment already exist and could be readily utilized. Newton-Evans Research provides market-volume estimates on automation products aggregated to categories such as shown in Figure M.11.2 below. The figure shows that significant increases in T&D automation are expected between 2007 and 2010. For example, spending on distribution automation is expected to almost triple by 2010 to nearly $180 million. Protective relays are expected to increase 25% to $235 million, feed-switch investment by 225% to $65 million, control-center upgrades by 29% to $155 million; and substation investment by 35% to $540 million.[6]

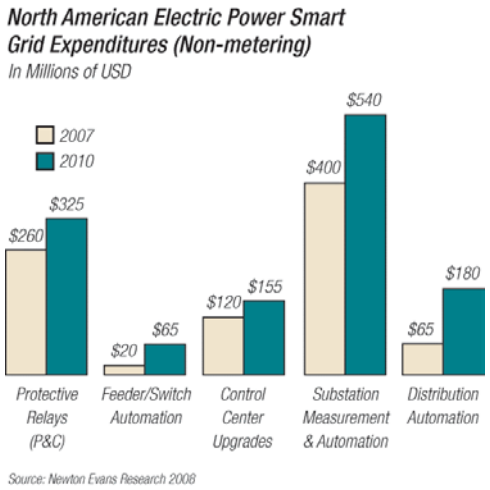

Figure M.11.2. North American Electric Power T&D Automation Expenditures (in Millions of USD)[7,8]

M.11.3.1 Stakeholder Influences

The major stakeholders in the T&D automation arena are those that are directly affected by the performance of this infrastructure including:

- Transmission providers as owners and operators of the assets to be maintained and upgraded.
- Distribution-service providers as owners and operators of the assets to be maintained and upgraded.
- Local, state and federal energy policy makers: local governments as regulatory entities for publicly owned companies; state regulators as regulatory entities for investor-owned T&D companies; federal regulators as enforcement entities for reliability. For investor-owned T&D companies, state regulators as regulatory entities approving rate structures.
- Financial community: the financial community will need to provide capital for the required upgrades.
- Reliability coordinators: ensuring that electricity quality and reliability are maintained.
- Balancing authorities, who will benefit from utilization and efficiency in the delivery system.

[6]Newton-Evans 2008
[7]Newton-Evans 2008.
[8]Ockwell G. 2008. "The Smart Grid Reaches Main Street USA". *Utility Automation & Engineering T&D*. 13(5). Accessed October 28, 2008 at: http://uaelp.pennnet.com/display_article/328726/22/ARTCL/none/none/1/Th

- End users: consumers, who stand to gain from more cost-effective reliability.

M.11.3.2 Regional Influences

While transmission is relatively homogeneous nationwide, distribution networks vary widely among utilities. Utilities differ in the design and sizing of distribution-system components, which manifests itself in the level of system loading. Some utilities maintain their feeders at a maximum of 50% loading, allowing a single other line to pick up the load of a failed feeder. Others allow their feeders to reach 66% loading or 100% loading, reflecting different operation and contingency schemes.[9] Some of these differences are due to historical or institutional reasons within the utility. Other differences are driven by regulators or by state policy. These characteristics will significantly change the business case for automation.[10]

For example,

- The highly dense urban core of New York City's mesh distribution network, with its demand for reliable power, lends itself to distribution-automation systems.[11,12]
- The long rural feeders of West Virginia, which require hours of driving for utility linemen, are good candidates for remote monitoring and control.[13]
- The well-connected network system and radially operated distribution grid of San Diego lends itself to automatic fault-detection and feeder-reconfiguration schemes.[14]

In addition, there are significant differences in the vintages of the distribution system, primarily determined by economic growth in different regions of the country. Southwestern and Southeastern regions have seen significant load growth in the last decades, which led to new T&D expansions with more modern technology. In contrast, established East Coast and Midwestern cities tend to have dated system components that are a half-century old or more.

M.11.4.0 Challenges

M.11.4.1 Technical Challenges

Challenges in T&D automation for transmission differ from those for distribution. Methods for transmission-side automation are fairly well known, but deployment is challenged by funding and

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[9]Personal communications with Kevin Schneider. Pacific Northwest National Laboratory. November 4, 2008.
[10]Moore D and D McDonnell. 2007. *Smart Grid Vision Meets Distribution Utility Reality*. The McDonnell Group. Accessed November 11, 2008 at http://www.themcdonnellgroup.com/media_center/inprint/SmartGridVision_Opinion.pdf
[11]Ross MP and B Kehrli. March 2008. *Secure Super Grids™: A New Solution for Secure Power in Critical Urban Centers*. Institute of Electrical and Electronics Engineers (IEEE). IEEE Xplore. Accessed November 11, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=04517197.
[12]Advanced Control Systems. *Case Studies*. Accessed November 24, 2008 at http://www.acsatlanta.com/pages/sd_list.html . Last updated September 30, 2008.
[13]Personal communications with Kevin Schneider. Pacific Northwest National Laboratory. November, 04, 2008.
[14]Advanced Control Systems. *Case Studies*.

institutional barriers.[15] Distribution-side automation has seen an influx of new technologies, some of which are not very well understood. There are few existing options for modeling the effects of these new technologies on utilities, and thus the business case for these devices is more difficult to sell. Many utilities, which traditionally have not had digital systems for managing their networks, are finding that the transition to automated T&D systems is expensive. This is because large-scale renovations are needed to install the prerequisite sensing and monitoring systems. Proving the value of these technologies through demonstration projects is an important first step toward gaining industry and regulatory acceptance. As with transmission automation, however, institutional barriers must be removed before high-level acceptance of this technology can foster widespread deployment.

M.11.4.2 Business and Financial Challenges

Deployment of new distribution-automation technology requires business-case analysis support for both the utility and the regulator. While advanced tools now exist for technology-savvy utilities, it is still difficult to model and justify these investments at a higher level. Standard business-case tools for utilities and regulators should be developed to expedite the analysis of these projects and verification of their value.

M.11.5.0 Metric Recommendations

In future reports, the indicative metric should be reviewed against two types of metrics: the first consists of directly measurable or numeric estimates; the second set consists of qualitative elements. Qualitative metrics describe how automation components are used. A few metrics can be chosen from the many described below.

The quantitative metrics consist of an estimation of the rate of deployment of technology and automation, and the amount of investment for automation products to capture the economic activity.

(11.a) Percentage of substations having automation (the metric used for this report)
(11.b) Percentage of substations with outage detection
(11.c) Percentage of circuits with fault-detection and -localization capabilities
(11.d) Number of automated Substations
(11.e) Number of electromechanical relays
(11.f) Number of microprocessor relays
(11.g) Number of intelligent electronic devices (IEDs) deployed
(11.h) Percentage of distribution circuits with sectionalization and reconfiguration capabilities
(11.i) Percentage of distribution circuits with feeder load-balancing strategies

The investment metrics are defined as annual expenditures in dollars for:

(11.j) Protective relays
(11.k) Feeder/switch automation
(11.l) Control-center upgrades
(11.m) Substation measurement and automation
(11.n) Distribution automation

[15] *EnergyBiz* Magazine. 2006. "Guide & Sourcebook. Transmission & Distribution Automation." January/February 2006, pp 51-66. Accessed October 28, 2008 at: http://energycentral.fileburst.com/Sourcebooks/gsbk0106.pdf

Based on Sheridan's scale for degree of automation, the following qualitative metrics are suggested:[16]

(11.o) Operational T&D control action performed manually by linemen or operators in central control centers

(11.p) Distributed electronic and computing devices detect normal and fault conditions and offer a set of action options

(11.q) Intelligent electronic devices (IEDs) narrow the options down to a few, or suggest one. For instance, system fault localization and suggestions for fault isolation and feeder reconfiguration

(11.r) IED recognizes a fault and executes a suggestion after operator/human approval. For instance, IEDs support an overarching control strategy that performs immediate remedial actions such as feeder reconfiguration and autonomous system restorations

(11.s) IED recognizes fault, then executes remedial actions automatically and informs operator after execution.

Because of its qualitative nature, assigning an appropriate scale to the degree of automation for any particular segment of the grid requires a judgment call. To assess the level of automation deployment it is recommended to use a set of quantitative metrics that capture a) the level of adoption of automation technology and b) the level of investment as indicator of a rate of change in the penetration of automation in the U.S. grid. Furthermore, a qualitative metric that describes the level of control autonomy of the automation products and the degree to which automation strategies can be executed without human interventions or interactions should be considered.

The metrics are only useful if data exist or can be collected at a cost low enough to allow tracking of the metrics over time. For this particular T&D automation assessment, we interviewed 21 service providers to collect a representative sampling of the data. In the future, the Edison Electric Institute (EEI) could function as an intermediary to the investor-owned companies; for the publicly owned entities, the Public Power Association could be consulted as a potential intermediary for collecting data from the over 3000 public T&D organizations. Note that progress in this area is difficult to accurately assess with respect to improvements over time. The total number of substations or total industry output figures for T&D automation products is only a crude indicator of the technological progress that will certainly continue into the coming decades.

[16]Sheridan TB. 1992. *Telerobotics, Automation and Human Supervisory Control*. MIT Press, Cambridge, Massachusetts.