Smart Grid for Distribution Systems: The Benefits and Challenges of Distribution Automation (DA)

(Draft Version 2) White Paper for NIST

1. Introduction

1.1 Scope

This White Paper, "Smart Grid for Distribution Systems" addresses the benefits and challenges of implementing the many different Distribution Automation functions.

Distribution systems have traditionally not involved much automation. Distribution equipment, once installed on feeders, was expected to function autonomously with only occasional manual setting changes. Capacitor bank switches might switch on or off based on local signals, such as time of day or current. After a local fault condition, reclosers would attempt reclosing a set number of times before locking out. Lateral fuses would blow if the current became too high.

Recently, in response to the growing demand to improve reliability and efficiency of the power system, more automation is being implemented on the distribution system. The Smart Grid policy requirements as outlined in Energy Independence and Security Act (EISA) of December 2007 will increase the need for Distribution Automation, and therefore a better understanding of the benefits and challenges of Distribution Automation for all of its stakeholders.

1.2 Definition of Distribution Automation

A broad definition of Distribution Automation includes any automation which is used in the planning, engineering, construction, operation, and maintenance of the distribution power system, including interactions with the transmission system, interconnected distributed energy resources (DER), and automated interfaces with end-users.

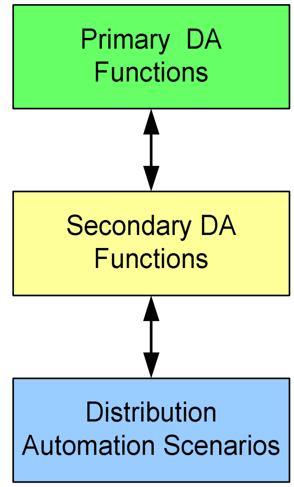
2. Distribution Automation Functions

2.1 Interconnectedness of Distribution Automation Functions

Individual distribution automation (DA) functions, such as monitoring VArs on a feeder or detecting faults on a circuit, cannot have their benefits or challenges assessed in isolation. Most of these DA functions can only be cost-effective if they are part of a larger set of functions. In this report, groups of DA functions have been combined into Distribution Automation scenarios, so that the combined capabilities can be assessed.

In addition, many of the DA functions must rely on "primary functions", such as SCADA monitoring and control, to even begin to provide some benefits. Therefore, this report has developed a hierarchy of Distribution Automation Scenarios which are constructed from

Secondary Distribution Automation (DA) functions, which in turn are supported by Primary DA infrastructure functions:



The Primary DA functions typically include the installation of equipment, communications, and/or basic data systems. Each primary DA function is described in terms of what its purpose is, the key technologies needed by the function, the technology challenges, and the potential benefits.

The Secondary DA functions typically utilize the data provided by the primary DA functions. Each secondary DA function identifies which primary DA functions it depends on, its description, and its primary purposes.

Many Distribution Automation Scenarios can be implemented by different utilities, based on the relative benefits and challenges for the different stakeholders. No one DA Scenario is appropriate for all utilities, so that the set of scenarios described in this report is an example.

2.2 List of Primary and Secondary DA Functions

A relatively comprehensive list of Primary and Secondary Distribution Automation functions is shown below, although this list will continue to grow as new concepts, technologies, and challenges inspire new functions.

Primary Distribution Automation Functions
a. Monitoring and control of distribution equipment within substations • Distribution SCADA System Monitors Distribution Equipment in Substations • Supervisory Control on Substation Distribution Equipment • Substation Protection Equipment Performs System Protection Actions • Reclosers in Substations b. Local automation of DA equipment on feeders • Local Automated Switch Management • Local Volt/Var Control • Local Field Crew Communications to Underground Network Equipment c. Monitoring and control of DA equipment on feeders • SCADA Communications to Automated Feeder Equipment • SCADA Communications to Underground Distribution Vaults d. Management of Distributed Energy Resources (DER) systems • Protection Equipment Performs System Protection Actions on DER Interconnections • Monitoring of DER Units • Controlling DER Units e. DA analysis software applications • Study-Mode and Real-Time Distribution System Power Flow (DSPF) Model • DSPF /DER Model of Distribution Operations with Significant DER Generation/Storage f. Advanced Metering Infrastructure (AMI) • Implementation of AMI to Industrial, Commercial, and Residential Customers • Direct Customer Load Control

Secondary Distribution Automation Functions	
Operational DA functions	1. Real-time normal distribution SCADA operations to substations • Alarm Processing • Distributed Energy Resources (DER) in Substations • SCADA System Provides Data to Mobile Computing Devices 2. Local automation of feeder equipment beyond substations • Reclosers Interact with Field Equipment • Local Field Crew Communications to Automated Feeder Equipment 3. Remote monitoring and control of automated feeder equipment, possibly using the AMI system for communications 4. Normal distribution operations using the Distribution System Power Flow (DSPF) model • Adequacy Analysis of the Distribution System to Meet the Load • Reliability Analysis of Distribution System to Minimize Outages • Contingency Analysis (CA) of Distribution System • Efficiency Analysis of Distribution System • Optimal Volt/Var Control of Distribution System • Relay Protection Re-coordination (RPR) of Distribution System 5. Emergency distribution operations using the DSPF model • SCADA System Performs Disturbance Monitoring • Automated Fault Location, Fault Isolation, and Service Restoration (FLISR) • Multi-level Feeder Reconfiguration (MFR) • Load Management Activities for Emergency Conditions • Mitigating the Effects of Major Storms, Earthquakes, and other Disasters • Enhancing Repair Activities After Major Disasters 6. Distribution system operations training and assessments using the DSPF model • Dispatcher Training Simulation (DTS) • Audit Logging and Reporting • Diagnostic Analyses of Events

Automated Distribution Systems - with Significant DER	1. Planning for interconnection of DER to the distribution system • Assessment of Proposed DER Interconnections • Engineering, Monitoring, and Analyzing DER Interconnections 2. Energy Service Provider (ESP) management of DER units • ESP Monitors Non-Operational Data from DER Site • ESP Manages Market Operations of DER Units 3. Local and basic SCADA operations with DER units • Utility SCADA Monitoring and Control of DER Units • Supervisory Control of Switching Operations with Significant DER • Local Automated Switching Operations (IntelliTeam) with Significant DER 4. Normal distribution operations with significant DER using DSPF / DER models • Adequacy Analysis of Distribution System with Significant DER Generation/Storage • Reliability Analysis with Significant DER Generation/Storage • Contingency Analysis with Significant DER Generation/Storage • Efficiency Analysis with Significant DER Generation/Storage • Optimal Volt/Var Control with Significant DER Generation/Storage • Relay Protection Re-coordination (RPR) with Significant DER Generation/Storage • Assessment of the Impact of/on DER Generation/Storage during Distribution Planned Outages 5. Emergency distribution operations with significant DER using DSPF / DER models • Fault Location, Fault Isolation, and Service Restoration (FLISR) with Significant DER Generation/Storage • Multi-Level Feeder Reconfiguration (MFR) with Significant DER Generation/Storage • Post-Emergency Assessment of DER Responses and Actions 6. Customer-driven actions with significant DER generation / storage • Planned Establishment of Temporary Microgrids • Emergency Establishment of Microgrids during Power Outage or Other Emergencies

Customer interactions related to automation	1. Use of Advanced Metering Infrastructure (AMI) information in distribution operations • Automatic Meter Reading (AMR) • Customer Outage Detection and Correlation to Fault Location • Assessment of Customer Power Quality 2. Customer demand response • Customer Response to Demand Response Signals • Analysis of Demand Response • Demand Response Interactions with Home Automation Networks 3. Customer use of DER generation / storage • Customer Use of DER for Self-Supply • Plug-in Hybrid Electric Vehicle (PHEV) as Combined DER Generation and Storage • DER Units Bid into Market Operations
Distribution Planning	1. Operational planning • Assessing Planned Outages • Storm Condition Planning 2. Short-term distribution planning • Short-Term Load Forecast • Short-Term DER Generation and Storage Impact Studies 3. Long-term distribution planning • Long-Tem Load Forecasts by Area • Optimal Placements of Switches, Capacitors, Regulators, and DER • Distribution System Upgrades and Extensions • Distribution Financial Planners
Maintenance, engineering, and construction	1. Distribution system equipment maintenance • Predictive Maintenance Application Assesses Distribution Equipment • Management of Maintenance Assets • Scheduling of Maintenance and Equipment Replacement • Maintenance Updates to Documentation and Maps • Maintenance of DSPF Model and Other DA Applications 2. Distribution system design and engineering • Design and Engineering of Substations and Feeders • Specification of Distribution Equipment 3. Construction management • Asset Tracking and Updating • Planning Construction Projects

3. Benefits and Challenges of Distribution Automation

Distribution Automation functions can provide both benefits and challenges. Often these benefits and the challenges are closely intertwined, with the real and complete benefits not achievable until some of the challenges (including the financial challenges) have been overcome. Yet waiting for these challenges to be overcome or ameliorated often means missing out on some of the benefits – not doing anything can often be worse than doing something. Therefore the key to distribution automation is assessing the balance of benefits versus challenges, including the "lost opportunity" risks of doing nothing.

No one approach is optimal for a utility or its customers. Certain distribution automation functions, such as optimal volt/var control, can be more beneficial to one utility or even a few feeders in one utility, while other distribution automation functions, such as fault detection, isolation, and service restoration, could be far more beneficial in other utilities.

3.1 Stakeholders in Distribution Automation

The benefits of distribution automation can be categorized for three stakeholders: **utility, customer, and societal**. Societal benefits are often harder to quantify, but can be equally critical in assessing the overall benefits of a particular function.

3.2 Key Benefits of Distribution Automation

The Use Case scenarios and the Primary DA functions are assessed for the types of benefits that they can provide. Five types of benefits are described for each of the benefit categories (utility, customer, and society):

- **Direct financial benefits**, including lower costs, avoided costs, stability of costs, and pricing choices for customers.
- **Power reliability and power quality benefits**, including reduced number and length of outages, reduced number of momentary outages, “cleaner” power, and reliable management of distributed generation in concert with load management and/or microgrids.
- **Safety and security benefits**, including increased visibility into unsafe or insecure situations, increased physical plant security, increased cyber security, privacy protection, and energy independence.
- **Energy efficiency benefits**, including reduced energy usage, reduced demand during peak times, reduced energy losses, and the potential to use “efficiency” as equivalent to “generation” in power system operations.
- **Energy environmental and conservation benefits**, including reducing greenhouse gases (GHG) and other pollutants, reducing generation from inefficient energy sources, and increasing the use of renewable sources of energy.

In some benefits, particularly those which directly reduce costs for utilities, customers also “benefit” from either lower tariffs or avoiding increased tariffs, although the connection may not be direct. Societal benefits are often harder to quantify, but can be equally critical in assessing the overall benefits of a particular function.

The qualitative benefits associated with each of the functions can be converted into quantitative values, which would be dollars for “hard” benefits and estimated value for “soft” benefits. However, this conversion can only take place when specific, detailed Use Cases are generated from the functions, since only then can the numbers be determined. These quantitative values can then be used in actual business cases. Nonetheless, basic formulas can be expressed to illustrate how such conversions could be made.

3.3 Key Technical Challenges of Distribution Automation

The key technical challenges for distribution automation functions include the following:

- **Electronic equipment**: Electronic equipment covers all field equipment which is computer-based or microprocessor-based, including controllers, remote terminal units (RTUs), intelligent electronic devices (IEDs), laptops used in the field, handheld devices, data concentrators, etc. It can include the actual power equipment, such as switches, capacitor banks, or breakers, since often the power equipment and its controller electronic equipment are packaged together, but the main emphasis is on the control and information aspects of the equipment.
- **Communication systems**: Communication systems cover not only the media (e.g. fiber optic, microwave, GPRS, multiple-address radio (MAS), satellite, WiFi, twisted pair wires, etc.), but also the different types of communication protocols (e.g. Ethernet, TCP/IP, DNP, IEC 61850, IEC 61850-lite for narrow band, Web Services, VPNs, etc.). It also addresses communications cyber security issues.
- **Data management**: Data management covers all aspects of collecting, analyzing, storing, and providing data to users and applications, including the issues of data identification, validation, accuracy, updating, time-tagging, consistency across databases, etc. Often data management methods which work well for small amounts of data can fail or become too burdensome for large amounts of data – a situation common in distribution automation and customer information.
- **Systems integration**: System integration covers the networking and exchanges of information among multiple disparate systems. The key issues include interoperability of interconnected systems, cyber security, access control, data identity across systems, messaging protocols, etc.
- **Software applications**: Software applications cover the programs, algorithms, calculations, data analysis, and other software that provides additional capabilities to distribution automation. These software applications can be in electronic equipment, in control center systems, in laptops, in handhelds, or in any other computer-based system.

It is clearly recognized that "financial challenges" as well "regulatory and legal challenges" play key roles in determining the cost-benefit of any particular distribution automation function. Assessing the importance of these financial challenges can be very difficult since they can be vastly different for different utilities, the technologies are changing so rapidly that any assessment is obsolete almost before it is stated, and often the costs are directly associated with particular regulatory and tariff environments.

4. Distribution Automation Scenarios

In this White Paper, the Distribution Automation Scenarios briefly describe their purpose, and then point to the primary and secondary DA functions that are needed to meet those purposes. The following is the list of selected DA scenarios described in the report:

1. **Basic Reliability Scenario** – Local Automated Switching for Fault Handling (e.g. IntelliTeam)

2. **Advanced Reliability Scenario –** FLISR with Distribution System Power Flow (DSPF) Analysis
3. **Efficiency Scenario –** Efficiency Assessment with DSPF Analysis
4. **DER Planning Scenario –** Planning, Protection, and Engineering of Distribution Circuits with Significant DER Generation
5. **Basic Real-Time DER Management Scenario –** SCADA Monitoring and Control of DER Generation
6. **Advanced Real-Time DER Management Scenario –** DSPF Analysis for FLISR, Microgrids, Safety, Market with Significant DER Generation
7. **Distribution Maintenance Management with DER Scenario –** Maintenance, Power Quality, and Outage Scheduling with Significant DER Generation/Storage
8. **Demand Response with DER Scenario –** Distribution Operations with Demand Response and Market-Driven DER Generation/Storage

Each of the Distribution Automation Scenarios focuses on specific purposes that distribution automation may be used for. The supporting Primary and Secondary DA functions provide the details of how those purposes may be met.

Figure 1 illustrates the relationships between these Use Case Scenarios, the secondary DA functions, and the primary DA functions. Although this report describes only a few Use Cases Scenarios, the DA functions may be used in many combinations to develop other Scenarios.

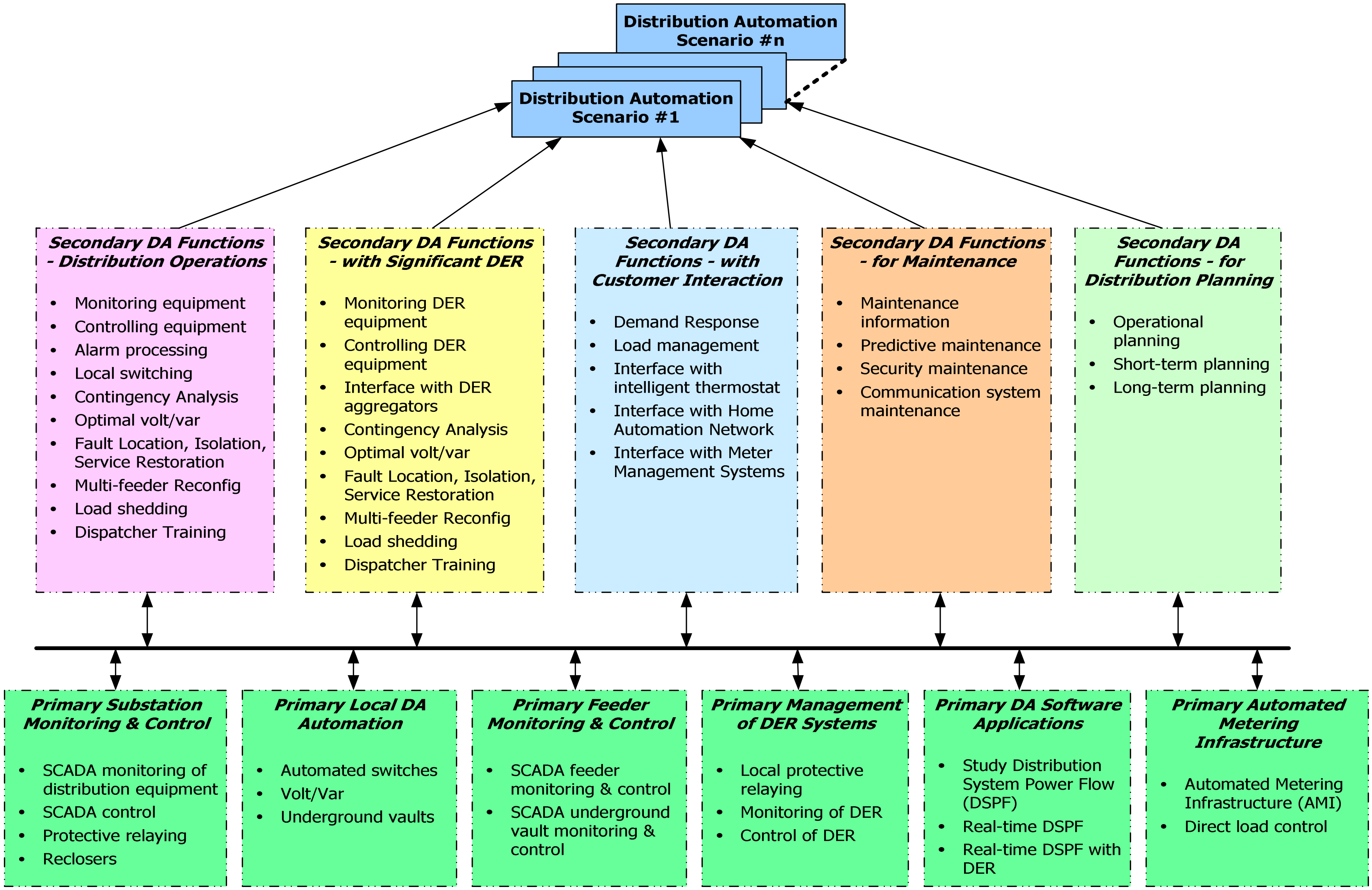


Figure 1: Hierarchy of Primary DA Functions, Secondary DA Functions, & DA Scenarios

5. Standards, Interoperability, and Technologies

5.1 Electronic Equipment

1. Substation equipment
   a. SCADA RTU
   b. SCADA IED

2. Feeder equipment
   a. Locally controlled cap bank
   b. Remotely controlled cap bank
   c. Locally controlled automated feeder switch
   d. Remotely controlled automated feeder switch
   e. Reclosers
   f. Locally controlled voltage regulator
   g. Remotely controlled voltage regulator
   h. Remotely monitored fault detector
   i. Other

3. DER units and controllers
   a. Passive PV inverter
   b. Controllable PV inverter
   c. Local storage (e.g. batteries)
   d. Fuel cell
   e. Wind turbine
   f. Combined Heat & Power (CHP)
   g. Diesel generator
   h. Combustion turbine
   i. UPS with DER unit
   j. Battery storage
   k. Plug-In Hybrid Electric Vehicle (PHEV)
   l. Other storage DER
   m. Other renewable DER
   n. Other DER

4. Customer site equipment
   a. Smart meter
   b. AMI gateway into building
   c. DER management system
   d. Building management system
   e. Home management system
   f. Load management system
   g. Demand response equipment - PCT, price indicator
   h. Other

5.2 Communication Media and Protocols

1. Communications Media
   a. Wide Area Network (any high bandwidth media)
   b. Local Area Network (any media)
   c. Multiple Address Radio System (MAS)

d. Zigbee mesh radio system
e. Spread spectrum radio system
f. WiFi
g. WiMax
h. Telephone dial-up or leased line
i. Cellphone
j. Broadband Powerline Carrier
k. Distribution Powerline Carrier
l. Internet (DSL or Cable)
m. HomePlug for in-premise powerline
n. Zigbee Smart Energy Profile (SEP)
o. AMI system communications (generic)
p. Other

2. Field protocols
   a. IEC 61850-7-420 for DER
   b. IEC 61400-24 for Wind
   c. DNP3 (IEC 60870-5)
   d. IEC 61850 for substation devices
   e. OpenHAN
   f. BACNet for building automation
   g. ANSI C12.22 for metering
   h. Modbus
   i. CAN
   j. Fieldbus
   k. Profibus
   l. COMTRADE for fault information
   m. IEEE 1159.3 PQDIF for power quality
   n. Internet-based protocols - IP, TCP, HTTP, HTML
   o. VPN
   p. Proprietary AMI and DA protocols
   q. Other

5.3 Data Management

1. Communication system management
   a. Simple Network Management Protocol (SNMP)
   b. Telecommunication Network Management (generic)

2. Database Access
   a. Structured Query Language (SQL)
   b. ebXML
   c. FTP
   d. Historian interfaces
   e. Enterprise access to relevant AMI data
   f. Microsoft database APIs
   g. Other de facto standard database APIs
   h. Other

5.4 System Integration

1. Enterprise messaging

a. IEC 60870-6 ICCP
b. IEC 61968 CIM for distribution
c. MultiSpeak
d. IEC 61970 CIM for transmission
e. IEC 62325 ebXML for power systems
f. OPC
g. OPC/UA
h. Web services - XSD, SOAP, WSDL
i. Internet and Web protocols
j. Multi-protocol label switching (MPLS)
k. DRBizNet
l. OpenADR
m. Proprietary protocols
n. Other

2. Security Policies and Frameworks
    a. NERC CIP 002-009
    b. ISO/IEC 27000 series - cross-industry guidance on security risks
    c. Corporate security policy
    d. Corporate security training
    e. Multiple layers of security
    f. Role-Based Access Control
    g. Password management
    h. Service level agreements
    i. Audit logging

3. Security Protocols
    a. Public Key Infrastructure (PKI) X.509
    b. Transport Layer Security (TLS)
    c. IPSec
    d. Virtual Private Network (VPN)
    e. AMI-SEC for AMI system security
    f. IEC 62351 for ICCP, 61850, & DNP security
    g. SNMP v3 with security
    h. IEEE 802.11i security for wireless
    i. Firewalls with access control
    j. Intrusion detection systems
    k. IEC 62351-7 Network & System Management
    l. Intelligent alarming and reporting
    m. Time synchronization and timestamping
    n. AGA-12
    o. OASIS security assertion markup language (SAML)
    p. Anti-virus detection
    q. Non-repudiation capabilities
    r. Other

5.5 Software Applications

1. Distribution Automation
    a. SCADA data acquisition and control
    b. Disturbance analysis
    c. Alarm management
    d. Field-based fault detection, isolation, and restoration
    e. Control center-based fault detection, isolation, and restoration
    f. Feeder voltage monitoring and control

g. Feeder var management
h. Distribution Power Flow Model
i. Distribution system contingency analysis
j. Multi-level feeder reconfiguration
k. Relay protection re-coordination
l. Remedial action schemes
m. Operational analysis based on Distribution Power Flow Model
n. Study and planning distribution power flow modeling and analysis
o. Other software applications

2. DER Management
   a. Utility planning models for DER impacts and interconnections
   b. Local DER management - CHP, load following, import/export, volt/var
   c. SCADA monitoring (and control) of DER units
   d. Management of aggregated or community DER units
   e. Market management of DER energy and ancillary services
   f. DER maintenance management applications
   g. DER credit rating assessment
   h. Management of DER for microgrid creation and operation
   i. Management of DER during emergency conditions
   j. Management of planned outages with DER
   k. Market settlements with DER - LMP for energy & ancillary services
   l. Metered DER generation and storage information
   m. Statistical analysis of DER operational & market impacts
   n. Meteorological predictions for renewable DER
   o. Storage DER management
   p. PHEV load, storage, and generation management
   q. Other software applications

6. Conclusions

Many technical issues affect the cost-benefit analysis of implementing different types of distribution automation functions. However, some of the technologies for meeting those requirements have universal themes that present the key challenges to implementing automation.

The development of Distribution Automation Scenarios, based on both secondary and primary DA functions, allows utilities to understand both the benefits and the challenges involved in implementing these functions. Primary functions typically require heavy capital expenditures to implement equipment, communication, and data infrastructures whose payback can only truly come when one or more secondary functions utilize these infrastructures. Therefore, using the Use Case Scenario approach permits utilities to fully appreciate the need for a comprehensive, multi-function approach to distribution automation.

The cost and other challenges of implementing the primary functions may be daunting. However, often a phased approach can be used in distribution automation, because, unlike tightly networked transmission systems, distribution systems can fairly easily deploy pilot projects or initial implementation of DA functions that affect only a few feeders. Lessons can be learned from these initial deployments which can improve eventual deployment of the functions to a larger set of feeders.