Arnold Schwarzenegger
Governor

BENEFITS AND CHALLENGES OF DISTRIBUTION AUTOMATION (DA): USE CASE SCENARIOS AND ASSESSMENTS OF DA FUNCTIONS

DRAFT

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Preface (*DRAFT)*

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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Benefits and Challenges of Distribution Automation

Distribution Automation 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.

Different types of customers can benefit from different distribution automation functions as well. Power quality such as minimizing harmonics may be crucial to certain industries, while of virtually no benefit to most residential customers. Society can also benefit, often indirectly but sometimes directly.

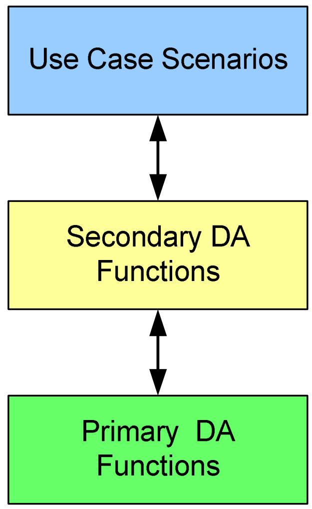
The benefits of distribution automation can be categorized as three types: utility benefits, customer benefits, and societal benefits. However, often the same function provides benefits in all three categories. For instance, in some benefits, particularly those which directly reduce costs for utilities, 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.

Many technical issues affect the benefit-cost analysis of implementing different types of distribution automation functions (including those functions which impact or are impacted by other distribution automation functions). Not all functions share the same technologies, since each function has its own specific and detailed technical requirements. However, some of the technologies for meeting those requirements have universal themes that present the key challenges to implementing automation.

Distribution Automation "Use Case" Scenarios and 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 "Use Case" 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 "Use Case" 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.

Each of the Use Case 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 Use Cases Scenarios.

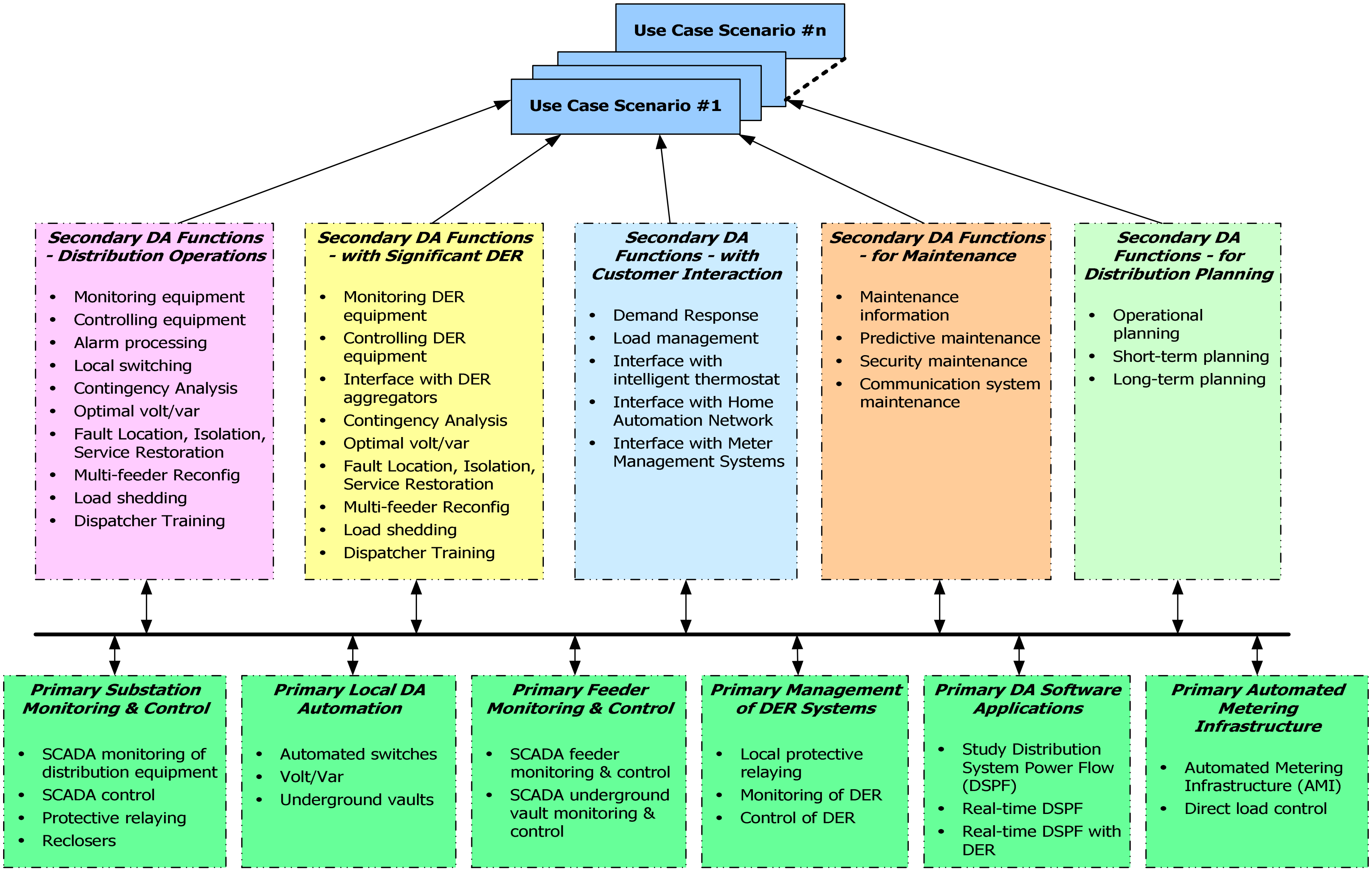


Figure 1: Hierarchy of Primary DA Functions, Secondary DA Functions, & Use Case Scenarios

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.

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, 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, but it is beyond the scope of this report to assess these challenges: 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.

Scope of Distribution Automation

Many definitions of distribution automation have been promulgated with no single one any better necessarily than any other. However, for this set of Use Case Scenarios and DA functions, a very broad definition is used: "*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.*"

Descriptions of Use Case Scenarios

In this report, the Use Case 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 Use Case scenarios described in the report:

- **#1: Basic Reliability Use Case –** Local Automated Switching for Fault Handling (e.g. IntelliTeam)
- **#2: Advanced Reliability Use Case –** FLISR with Distribution System Power Flow (DSPF) Analysis
- **#3: Efficiency Use Case –** Efficiency Assessment with DSPF Analysis

- **#4: DER Planning Use Case –** Planning, Protection, and Engineering of Distribution Circuits with Significant DER Generation
- **#5: Basic Real-Time DER Management Use Case –** SCADA Monitoring and Control of DER Generation
- **#6: Advanced Real-Time DER Management Use Case** – DSPF Analysis for FLISR, Microgrids, Safety, Market with Significant DER Generation
- **#7: Distribution Maintenance Management with DER Use Case –** Maintenance, Power Quality, and Outage Scheduling with Significant DER Generation/Storage
- **#8: Demand Response with DER Use Case** – Distribution Operations with Demand Response and Market-Driven DER Generation/Storage

Distribution Automation Functions

This report describes the following distribution automation functions:

1. **Primary Distribution Automation functions**
   a. Monitoring and control of distribution equipment
   b. Local automation of DA equipment on feeders
   c. Monitoring and control of DA equipment on feeders
   d. Management of Distributed Energy Resources (DER) systems
   e. DA analysis software applications
   f. Advanced Metering Infrastructure (AMI)
2. **Secondary Distribution Automation functions – Operational DA functions**
   a. Real-time normal distribution SCADA operations to substations
   b. Local automation of feeder equipment beyond substations
   c. Remote monitoring and control of automated feeder equipment
   d. Normal distribution operations using the Distribution System Power Flow (DSPF) model
   e. Emergency distribution operations using the DSPF model
   f. Distribution system operations training and assessments using the DSPF model
3. **Secondary Distribution Automation functions – Automated Distribution Systems with Significant DER**
   a. Planning for interconnection of DER to the distribution system
   b. Energy Service Provider (ESP) management of DER units
   c. Local and basic SCADA operations with DER units
   d. Normal distribution operations with significant DER using DSPF / DER models
   e. Emergency distribution operations with significant DER using DSPF / DER models
   f. Customer-driven actions with significant DER generation / storage
4. **Secondary Distribution Automation functions – Customer interactions related to automation**
   a. Use of Advanced Metering Infrastructure (AMI) in distribution operations
   b. Customer demand response
   c. Customer use of DER generation / storage

5. **Secondary Distribution Automation functions – Distribution planning**
    a. Operational planning
    b. Short-term distribution planning
    c. Long-term distribution planning
6. **Secondary Distribution Automation functions – Distribution maintenance, engineering, and construction**
    a. Distribution system equipment maintenance
    b. Distribution system design and engineering
    c. Construction management

Conclusions

The development of Use Case 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 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.

Acknowledgments

This report was developed as part of a project managed by Navigant Consulting, Inc. on the "***Value of Distribution Automation***". Its primary purpose was to provide the technical background for that report.

1. Introduction

1.1 Purpose of this Document

The purpose of this document is to describe key Use Cases Scenarios which are built up from secondary Distribution Automation (DA) functions, which in turn are supported by primary DA infrastructure functions.

The Use Case Scenarios each focus on specific purposes that distribution automation may be used for. The supporting DA functions provide the details of how those purposes may be met. Although this document describes only a few Use Cases Scenarios, the DA functions may be used in many combinations to develop other Use Cases Scenarios.

Two types of DA functions are identified: the primary DA functions which typically include the installation of equipment, communications, and/or basic data systems; and the secondary DA functions which utilize the data provided by the primary DA functions. 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. Each secondary DA function identifies which primary DA functions it depends on, its description, and its primary purposes.

Figure 2 illustrates the relationships between the primary DA functions, secondary DA functions, and the Use Case Scenarios.

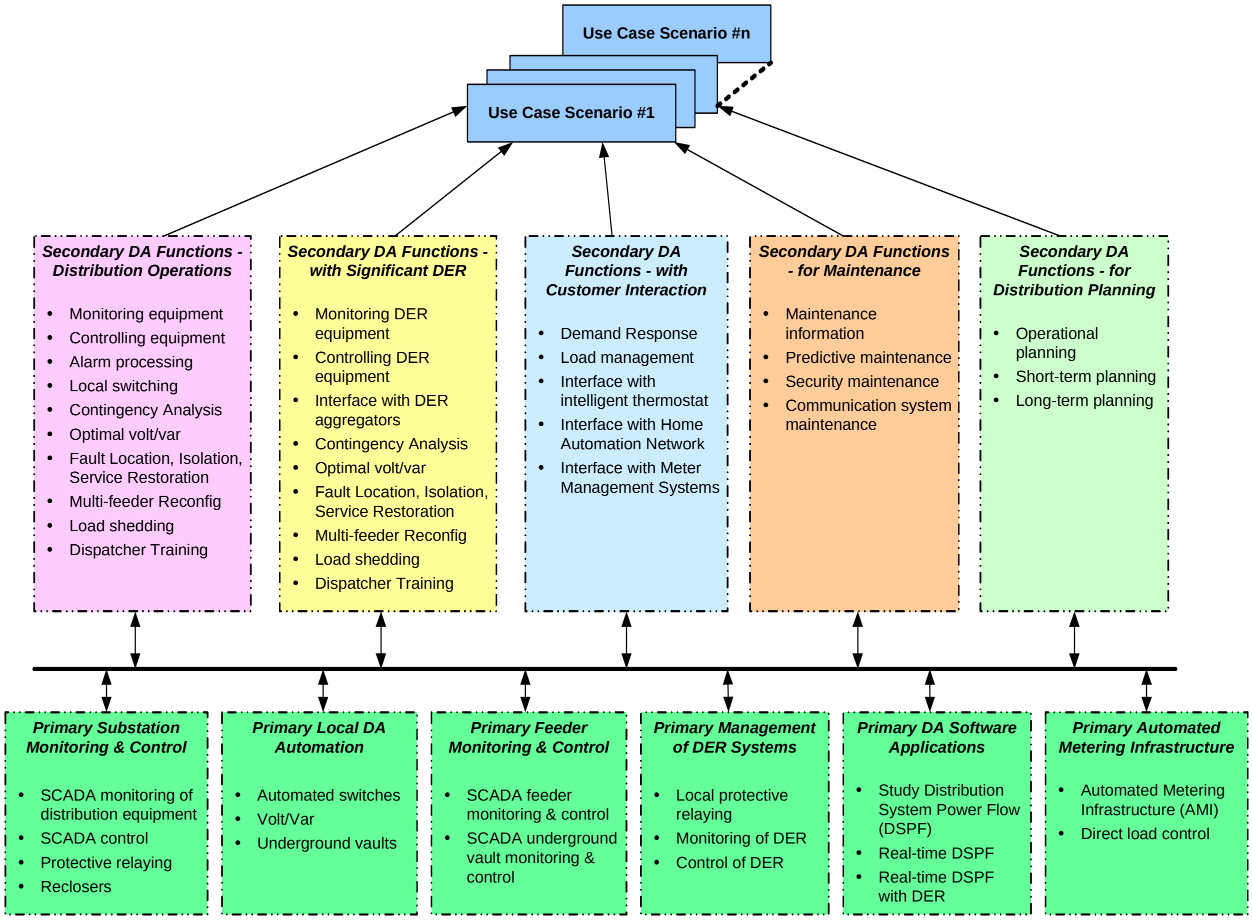


Figure 2: Hierarchy of Primary DA Functions, Secondary DA Functions, & Use Case Scenarios

1.2 Use Case Scenarios versus Functions

The term "Use Case Scenario" is used in this document to group different combinations of functions which build upon each other (piggyback) in order to provide additional overall benefits, while taking advantage of infrastructures and costs already allocated to base functions. At the top level, these two terms are used interchangeably, but Use Cases can also be analyzed in more detail using the well-established Use Case procedures and diagrams.

Selected Distribution Automation Use Case scenarios are described in Section 2.

The term "function" is used in this document to mean a combination of software, hardware, data, and interactions which have specific purposes. Although functions could be described at different "levels" from a high generic level (e.g. "*implement distribution automation*") to low detailed level (e.g. "*implement voltage regulators with MAS radio communications*"), an attempt is made to keep the descriptions of functions at the same "level": with clear goals, specific activities, and identified users, but no direct implication of what products or technologies would actually get used to implement the function.

The Distribution Automation functions are described in Sections 5 through 10.

1.3 Scope of Distribution Automation

Many definitions of distribution automation have been promulgated with no single one any better necessarily than any other. However, for this set of DA Use Cases, a very broad definition is being used: "*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.*"

This definition therefore includes any automation used for distribution and DER equipment in substations, along feeders, in distribution networks, and up to the end-user including the meter. Distribution automation thus includes all equipment, communications, as well as the data and software applications needed to utilize, operate, and manage the automation.

1.4 Analysis of Distribution Automation (DA) Functions

Each DA function is identified and analyzed through the following characteristics as described in the following subsections:

- Type/Dependency (Primary or Secondary)
- Description
- Purpose
- Technical Challenges (addressed for primary functions, and occasionally addressed for secondary functions when they add significant technical challenges)
- Benefits (addressed for primary functions, and occasionally addressed for secondary functions when they add significant benefits)

1.4.1 Type/Dependency of DA Functions: Primary and Secondary

Two types of Distribution Automation functions are described: **Primary** and **Secondary**. Primary DA functions generally entail the installation of significant equipment, communication systems, and/or software applications. These installations can then provide the foundation and infrastructure for the secondary DA functions.

In the Primary functions, computer-based equipment, communications, software applications, and other automation/integration would have to be implemented before any benefits could be achieved. Usually there are many variations on how much equipment, what type of communications, and what applications are needed. These variations imply different costs and different potential benefits. In addition, sometimes these functions may already be (commonly) implemented, but may not include all the capabilities needed for achieving the most benefits.

In Secondary functions, the "presumption" is that automated equipment has already (or will be) installed for a Primary functions. Thus Secondary functions are dependent on one or more Primary functions. Additional information from and/or control capabilities to distribution equipment would allow the Secondary functions to perform their activities more accurately and/or more quickly. These Secondary functions would thus be "piggybacking" on the Primary functions, and would accrue additional benefits. Typically the additional costs would include upgrading equipment, providing communications or integration between the Primary function and the Secondary function, and/or implementing new software applications or enhancements to existing software applications to take advantage of the additional capabilities.

Although there is often no precise distinction between Primary functions and Secondary functions, conceptually Secondary functions would not be implemented unless they could piggyback on some Primary equipment/applications. So in different situations, Secondary functions might become Primary functions, and vice versa. Nonetheless, the current document describes the most likely situations, with respect to defining Primary versus Secondary types.

1.4.2 Description of DA Functions

Each function is briefly described so that its scope can be identified. It is understood that many variations may exist for any one function; if selected as one of the Use Cases for more detailed analysis, these variations can be captured. But for the brief descriptions, these variations are not directly addressed.

1.4.3 Purpose of DA Functions

As further amplification of the function, its main purposes are identified.

1.4.4 Technical Challenges of Primary DA Functions

For primary DA functions, the technical challenges address the issues that are most in need of additional study and research, as opposed to the "normal" incremental enhancements usually provided by vendors. These are amplified in Section 4.

The following table is used to help categorize and codify the technical challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment		
Communication systems		
Data management		
System integration & security		
Software applications		

The types of challenges are categorized as:

- **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, Web Services, VPNs, etc.).
- **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. Data management is probably the most time-consuming and difficult in many of the functions, although some recent technology methodologies are helping to alleviate this problem.
- **System integration & security**: System integration & security 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. Interoperability can be supported by the use of standards. Cyber security issues, including risk assessment, are becoming increasingly important.
- **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. These applications are becoming increasingly sophisticated in order to solve increasingly complex problems, while demanding vastly larger amounts of accurate and timely data – a very real challenge.

The descriptions of the technical challenges discuss the key issues that lead to consideration of that aspect as being a technical challenge.

The level of challenge is rated as high (H), medium (M), or low (L). ***The focus of this rating is for technical challenges that may require concerted research & development efforts across regulators, vendors, standards-making bodies, utilities, customers, and other stakeholders.*** The ratings do not reflect available technologies that may not have yet been implemented by vendors, or vendor pricing/market issues, or non-technical issues unless they directly impact technical issues.

1.4.5 Benefits Related to DA Functions

The benefits from Distribution Automation functions are separated into three categories: customer benefits, utility benefits, and societal benefits. Often the same function provides benefits in all three categories, but in different ways and by different amounts. 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.

Each of the 3 categories (customer, utility, and societal) address 5 different types of benefits:

- **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.

Potential benefits are described briefly for each key function, with an indication of how the benefit is related to the function. Detailed discussions of benefits are contained in Section 3.

1.5 References

1. “*IntelliGrid Architecture*”, http://IntelliGrid.info, EPRI 2004
2. “*Studies to Determine the Impact on DER Object Models of Distribution Operation with Significant DER Penetration*”, EPRI 2003
3. S&C web site: http://www.sandc.com/

1.6 Glossary of Terms

The following is a brief glossary of some terms found in this document.

Term	Definition
ADA	1. Advanced Distribution Applications 2. Advanced Distribution Automation
Application Concept	In this document, a group various combinations of functions which build upon each other (piggyback) in order to provide additional overall benefits, while taking advantage of infrastructures and costs already allocated to base functions. [This document]

Term	Definition
CAIDI	Customer Average Interruption Duration Index CAIDI = SAIDI / SAIFI
CIS	Customer Information System
DER	Distributed Energy Resources
Distribution Automation	“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.” [This document’s definition]
DSPF	Distribution System Power Flow
GHG	Greenhouse Gas
OMS	Outage Management System
SAIDI	System Average Interruption Duration Index: Sum of all customer interruption durations
SAIFI	System Average Interruption Frequency Index: Total number of customer interruptions
SCADA	Supervisory Control and Data Acquisition
Use Case	1. In software engineering and system engineering, a use case is a technique for capturing functional requirements of systems and systems-of-systems. Each use case provides one or more scenarios that convey how the system should interact with the users called actors to achieve a specific business goal or function. Use case actors may be end users or other systems. Use cases typically avoid technical jargon, preferring instead the language of the end user or domain expert. Use cases are often co-authored by business analysts and end users. Use cases are separate and distinct from use case diagrams, which allow one to abstractly work with groups of use cases. [Wikipedia] 2. Within system engineering, use cases are used at a higher level than within software engineering, often representing missions or stakeholder goals. The detailed requirements may then be captured in requirement diagrams or similar mechanisms. [Wikipedia]
Use Case Scenario	In this document, a Use Case Scenario contains various combinations of secondary functions which build upon each other (piggyback) in order to provide additional overall benefits, while taking advantage of infrastructures and costs already provided by primary functions. Any Use Case Scenario can then be analyzed using Use Case procedures. [This document]

2. Selected Distribution Automation Use Case Scenarios

In this document, a Use Case Scenario contains various combinations of secondary functions which build upon each other (piggyback) in order to provide additional overall benefits, while taking advantage of infrastructures and costs already provided by primary functions. Any Use Case Scenario can then be analyzed using Use Case procedures.

The following DA Use Case Scenarios describe key sets of distribution automation functions that could provide significant benefits to utilities, customers, society, and (directly or indirectly) regulators.

2.1 #1: Basic Reliability Use Case – Local Automated Switching for Fault Handling (e.g. IntelliTeam)

Reliability of supplying electric energy to customers is a high priority to all stakeholders in the electric power industry: customers and society benefit directly from it, regulators therefore require high reliability, and utilities respond as cost-effectively as they can. Although manual methods have been used for years to provide certain levels of reliability, automation can provide increased levels of reliability.

The "Basic Reliability Use Case" covers the use of SCADA to the substation, automated switches on feeders that respond to faults locally, and SCADA monitoring of these automated switches. It includes the following functions:

- Distribution SCADA to the substation (see Section 5.1.1)
- Local Automated Switching (e.g. IntelliTeam) (see Section 5.2.1)
- SCADA communications to automated switches (fault indicators, switches, etc.) (see Section 5.3)

2.2 #2: Advanced Reliability Use Case – FLISR with Distribution System Power Flow (DSPF) Analysis

The "Advanced Reliability Use Case" provides Fault Location, Isolation, and Service Restoration (FLISR) using Advanced Distribution Applications (ADA) with Distribution System Power Flow (DSPF) analysis, as well as other reliability-enhancing software applications. This Use Case utilizes the power flow model of the distribution system as the primary means to assess real-time conditions by providing full power system "visibility" to operators, and by providing software applications with a computerized model of the power system for them to perform their analyses. Figure 3 illustrates the components of the DSPF set of applications.

The "Advanced Reliability Use Case" includes the following functions:

- Distribution SCADA to the substation (see Section 5.1.1)
- Local Automated Switching (e.g. IntelliTeam) (see Section 5.2.1)
- SCADA communications to automated switches (fault indicators, switches, etc.) (see Section 5.3)

- Real-time DSPF model to run power flows using real-time SCADA data (see Section 5.1.3)
- Study DSPF model to run power flows on sets of historical or study data (see Section 5.1.3)
- Fault Location, Isolation, and Service Restoration, using the automated switching capabilities and the real-time DSPF to manage fault situations (see Section 6.5.2)
- Contingency Analysis, using the real-time and/or study DSPF model to analyze contingencies of feeders (see Section 6.4.3)
- Reliability Analysis, using the real-time and/or study DSPF model to assess the reliability of feeders (see Section 6.4.2)
- Relay Protection Re-coordination, using the real-time and/or study DSPF model to assess protection settings (see Section 6.4.5)
- Multi-Feeder Reconfiguration, using the real-time and/or study DSPF model to assess feeder loading and recommend reconfiguration of feeders (see Section 6.5.3)
- Predictive Maintenance (see Section 10.1.1)
- Power Quality Management (see Section 8.1.3)
- Load Management (see Section 6.5.4)
- Storm Mitigation Actions (see Section 6.5.5)

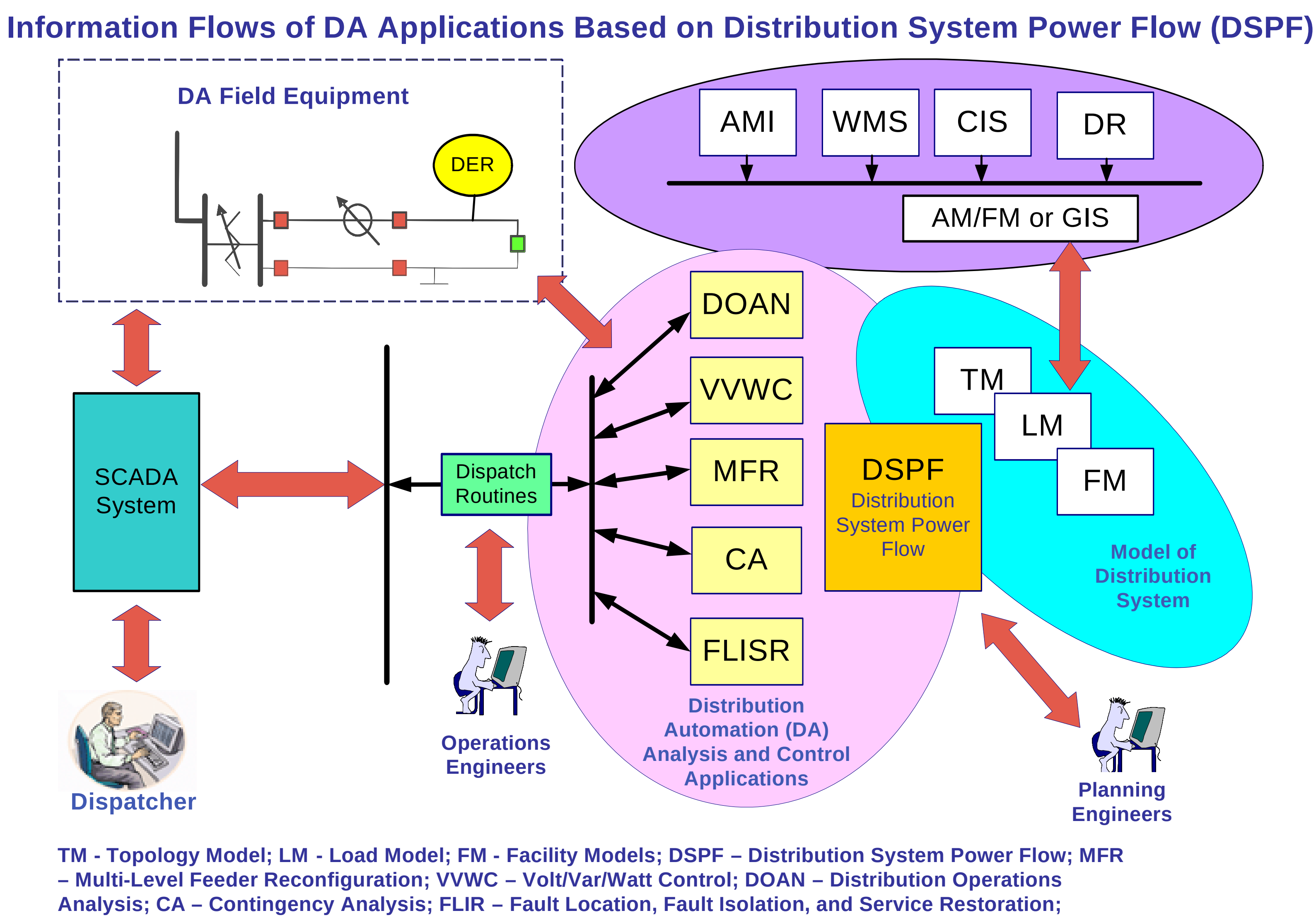


Figure 3: Information Flows of DA Applications Based on the Distribution System Power Flow (DSPF)
[from EPRI's IntelliGrid Architecture, developed by Utility Consulting International]

2.3 #3: Efficiency Use Case – Efficiency Assessment with DSPF Analysis

Efficiency of the distribution system is often considered of secondary importance to reliability, but can become of significant interest on specific feeders and substations that are handling high loads and/or variable power factor situations, so that it actually can improve reliability.

In addition, new laws and regulatory pressures that focus on “reducing dependence on foreign energy sources” and/or “reducing greenhouse gases and other polluting emissions” may make efficiency of more direct importance in the future.

The Efficiency Use Case utilizes the ADA’s DSPF model of the distribution system, along with real-time data from the SCADA system, to assess first the adequacy (will the equipment be able to handle the expected loads) and the efficiency (how efficiently is the power system operating and what can be done to improve that efficiency). It also includes automation to support customer-side incentives to improve overall energy usage, through demand response, time-of-use metering, and load management.

The “Efficiency Use Case” includes the following functions:

- Distribution SCADA to the substation (see Section 5.1.1)
- SCADA communications to automated feeder equipment (fault indicators, switches, capacitor banks, voltage regulators, etc.) (see Section 5.3)
- Adequacy Analysis of Distribution Operations using the DSPF model (see Section 6.4.1)
- Efficiency Analysis of Distribution System using the DSPF model (see Section 6.4.3)
- Optimal Volt/VAr Analysis and Control using the DSPF model (see Section 6.4.5)
- Demand Response, TOU, and Real-Time Pricing to encourage conservation and direct response to the cost of generation (see Section 8.1)
- Load Management to shift load during times of high generation costs (see Section 5.6.2)

2.4 #4: DER Planning Use Case – Planning, Protection, and Engineering of Distribution Circuits with Significant DER Generation

Utilities have been required for many years to permit the interconnection of non-utility generation, but the pressure to interconnect these generating (and storage) units to the distribution system has increased significantly over the past few years, and is expected to increase even more rapidly in the future.

Distributed Energy Resources (DER) (also often termed Distributed Generation (DG) or Distributed Resources (DR), and include both generation and storage of electrical energy) are slowly, but increasingly being interconnected with distribution systems. Although no-one can predict how much DER generation and/or storage will ultimately be interconnected, it is clear that these decisions will be made more by utility customers than by utilities. This decentralized decision-making on where and how much generation will be implemented adds a degree of uncertainty that utilities have never had to manage before.

Many DER units are small, and can rightly be viewed as “negative load” by utilities and thus be treated essentially as invisible to distribution operations (so long as they comply with the interconnection standards such as IEEE 1547, California’s Rule 21, or the utility’s requirements).

Some larger DER units have been and will continue to be implemented, owned, and/or operated by utilities. Some DER units have been and will continue to be implemented, owned, and/or operated by customers or third parties. Over time, aggregated amounts of generation from small DER units will become “visible” in distribution operations.

Distribution planning and/or engineering must assess each proposed DER interconnection to ensure it meets the required interconnection standards. They must also assess any impact on distribution feeders, feeder equipment, substations, distribution operations, maintenance procedures, etc. to accommodate the DER interconnection. If changes must be made, these changes must be engineered and implemented before the DER interconnection is finalized.

The “DER Planning Use Case” includes the following functions:

- Study DSPF model to run power flows on sets of historical or study data (see Section 5.1.3)
- Assessment of proposed DER interconnections (see Section 7.1.1)
- Monitoring/Assessment of Implemented DER Interconnections (see Section 7.1.2)

2.5 #5: Basic Real-Time DER Management Use Case – SCADA Monitoring and Control of DER Generation

Larger DER units and aggregates of smaller DER units are impacted by, and can impact, real-time distribution operations. SCADA monitoring and (direct or indirect) control of these DER units allows them to be “visible”, thus adding to reliability and safety of distribution operations.

The “Basic Real-Time DER Management Use Case” includes the following functions:

- Distribution SCADA to the substation (see Section 5.1.1)
- SCADA communications to automated feeder equipment (fault indicators, switches, capacitor banks, voltage regulators, etc.) (see Section 5.3)
- SCADA Monitoring and Control of DER Units (see Section 7.3.1)
- Supervisory Control of Switching Operations with DER Units (see Section 7.3.2)
- Utility Controls DER to Meet Distribution Operational Requirements (see Section 7.3.1)

2.6 #6: Advanced Real-Time DER Management Use Case – DSPF Analysis for FLISR, Microgrids, Safety, Market with Significant DER Generation

Advanced Real-Time DER Management involves analyzing the distribution system in real-time or “near” real-time to determine actions in response to planned or unforeseen situations that involve significant DER generation/storage. This analysis would be needed for fault location, isolation, and service restoration, protection coordination, establishment of microgrids, safety of field crews and the public during outages, power quality, market operations involving DER units, and many other activities.

This type of analysis would be impossible for distribution operators to handle without support from the DSPF model that forms the foundation of the ADA capabilities. The DSPF model would need to cover not only the distribution system but also the larger DER units as well as some model of aggregated small DER units.

The "Advanced Real-Time DER Management Use Case" includes the following functions (although it is not expected that all functions would be implemented initially):

- Distribution SCADA to the substation (see Section 5.1.1)
- Local Automated Switching (e.g. IntelliTeam) (see Section 5.2.1)
- SCADA communications to automated switches (fault indicators, switches, etc.) (see Section 5.3)
- Real-time DSPF model to run power flows using real-time SCADA data (see Section 5.1.3)
- Study DSPF model to run power flows on sets of historical or study data (see Section 5.1.3)
- DSPF Model of Distribution Operations with Significant DER Generation/Storage (see Section 5.5.2)
- Adequacy Analysis with Significant DER Generation/Storage (see Section 7.4.1)
- Reliability Analysis with Significant DER Generation/Storage (see Section 7.4.2)
- Contingency Analysis with Significant DER Generation/Storage (see Section 7.4.3)
- Fault Location, Fault Isolation, and Service Restoration (FLISR) with Significant DER (see Section 7.5.1)
- Multi-Level Feeder Reconfiguration (MFR) with Significant DER (see Section 7.5.2)
- Efficiency Analysis with Significant DER (see Section 7.4.4)
- Optimal Volt/Var Control with Significant DER (see Section 7.4.5)
- Relay Protection Re-coordination (RPR) with Significant DER (see Section 7.4.6)
- Assessment of the Impact of DER during Distribution Planned Outages (see Section 7.4.7)
- Planned Establishment of Microgrids for Peak Shaving or Other Financial or Operational Reasons (see Section 7.6)
- Emergency Establishment of Microgrids during Power Outage or Other Emergencies (see Section 7.6.2)
- Post-emergency Assessment of DER Responses and Actions (see Section 7.5.3)
- Management of Power Quality Using DER and DA Equipment (see Section 7.6.2)
- Management of Market Operations with DER (see Section 8.3.3)

2.7 #7: Distribution Maintenance Management with DER Use Case – Maintenance, Power Quality, and Outage Scheduling with Significant DER Generation/Storage

Maintenance of the distribution system that includes significant DER can be a new challenge. These new challenges include the following:

- Although DER units are now all expected to turn off or disconnect during a power system outage, those actions need to be verified for every DER unit to ensure that both utility field crews and the public are safe from presumably "dead" circuits that are actually still "live".
- Planned outages or even work on "live" circuits needs to be coordinated with DER operations to ensure they are able to manage the situation.
- Power quality of circuits can be affected by DER installations – both for the better or for the worse.
- Microgrids may need to be established before maintenance activities can commence, to avoid loss of power to customers.
- Maintenance or loss of DER units may affect distribution system operations if significant load was expected to be supported by the DER units – financial contracts not withstanding.
- If feeders are reconfigured to minimize the impact of maintenance activities, protection settings will need to be changed to reflect those reconfigurations, since the mix of generation and load will change.
- Managing the uncertainties of large numbers of smaller customer-owned DER units will require more sophisticated assessments before outages or power restorations can be scheduled.

As the number of DER units grows and as the amount of generation is derived from DER units, distribution operations will no longer be able to manage the maintenance of the system without significant support from automation.

The "Distribution Maintenance Management with DER Use Case" includes the following functions:

- Distribution SCADA to the substation (see Section 5.1.1)
- Real-time DSPF model to run power flows using real-time SCADA data (see Section 5.1.3)
- Study DSPF model to run power flows on sets of historical or study data (see Section 5.1.3)
- DSPF Model of Distribution Operations with Significant DER Generation/Storage (see Section 5.5.2)
- Contingency Analysis with Significant DER Generation/Storage (see Section 7.4.3)
- Multi-Level Feeder Reconfiguration (MFR) with Significant DER (see Section 7.5.2)
- Relay Protection Re-coordination (RPR) with Significant DER (see Section 7.4.6)

- Assessment of the Impact of DER during Distribution Planned Outages (see Section 7.4.7)
- Planned Establishment of Microgrids for Peak Shaving or Other Financial or Operational Reasons (see Section 7.6)
- Emergency Establishment of Microgrids during Power Outage or Other Emergencies (see Section 7.6.2)
- Post-emergency Assessment of DER Responses and Actions (see Section 7.5.3)
- Management of Power Quality Using DER and DA Equipment (see Section 7.6.2)
- Predictive Maintenance Application Assesses Distribution Equipment (see Section 10.1.1)
- Scheduling of Planned Outages (see Section 9.1.1)
- Management of Maintenance Assets and Schedules (see Section 10.1.2)
- Maintenance of Databases and Software Applications (see Section 10.1.3)
- Maintenance Updates to Documentation and Maps (see Section 10.1.3)

2.8 #8: Demand Response with DER Use Case – Distribution Operations with Demand Response and Market-Driven DER Generation/Storage

Demand response by customers can encompass many different incentive structures, but fundamentally entails two types of response:

- Decrease load in response to higher prices, and vice versa
- Increase DER generation in response to higher prices, and vice versa

With the inclusion of DER generating and storage capabilities, demand response becomes even more complex, and requires Advanced Distribution Applications (ADA) using the DSPF model. Without such automation, distribution operations with demand response would become extremely difficult if not impossible.

The "Demand Response with DER Use Case" includes the following functions:

- Distribution SCADA to the substation (see Section 5.1.1)
- Real-time DSPF model to run power flows using real-time SCADA data (see Section 5.1.3)
- Study DSPF model to run power flows on sets of historical or study data (see Section 5.1.3)
- DSPF Model of Distribution Operations with Significant DER Generation/Storage (see Section 5.5.2)
- Contingency Analysis with Significant DER Generation/Storage (see Section 7.4.3)
- Multi-Level Feeder Reconfiguration (MFR) with Significant DER (see Section 7.5.2)
- Efficiency Analysis with Significant DER (see Section 7.4.4)

- Planned Establishment of Microgrids for Peak Shaving or Other Financial or Operational Reasons (see Section 7.6)
- Management of Power Quality Using DER and DA Equipment (see Section 7.6.2)
- Automatic Meter Reading (AMR) (see Section 8.1.1)
- Customer Response to Demand Response Signals (see Section 8.2.1)
- Analysis of Demand Response (see Section 8.2.2)
- Management of Market Operations with DER (see Section 8.3.3)

3. Benefits and their Conversion to Quantitative Values

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. The benefits and their conversion to quantitative values are described below.

The benefits are separated into three categories: utility benefits, customer benefits, and societal benefits. Often the same function provides benefits in all three categories. Each category contains 5 different types of benefits:

- Direct financial benefits
- Power reliability and power quality benefits
- Safety and security benefits
- Energy efficiency benefits
- Energy environmental and conservation Benefits

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.

3.1 Utility Benefits

Utilities can receive significant benefits from distribution automation. Each function identifies the type of benefit, which are described in more detail below, along with proposed conversion formulas.

3.1.1 Utility Capital and O&M Financial Benefits

Utilities can have capital and O&M financial benefits from distribution automation. These include the following:

1. *Deferred construction/upgrades – capital savings:* Deferring construction, deferring upgrades, and deferring equipment replacements can provide significant capital savings, since carrying costs are delayed.

   Some ways of deferring construction or upgrades include:
   - Real-time knowledge of distribution equipment/line status, including length of time of any overload situations, so not reliant on "worst case" planning criteria.
   - Balancing loads on 3-phase lines to take maximum advantage of equipment

– Use of load control or demand-side management to reduce load during peaks for equipment close to upper limits

– Use of voltage and/or VAr reduction during peak loads for equipment close to upper limits.

– Feeder reconfiguration during high loads or periodically to alleviate potential overloads for equipment close to upper limits

– Use of predictive maintenance and knowledge-based maintenance to ensure equipment is in proper condition to meet loads which exceed limits.

– Implementation of DER generation to offset possible overloads, either temporarily during peak times.

Calculation of benefit:

- = decrease in carrying costs, based on avoided capital expenditures

2. *Decreased field crew personnel time:* This benefit identifies reductions in the costs associated with field crew personnel due to less time or fewer personnel needed to perform a particular function. It is understood that small decreases that do not result in actual fewer personnel or fewer overtime hours may not result in actual savings. However, larger decreases can result in significant savings from either fewer personnel, minimizing the need for additional personnel, fewer contract hours, and/or fewer overtime hours.

   Some of the ways to decrease field crew personnel time include:

   – More monitoring of field equipment permits greater visibility into where a problem might be. Field personnel can be sent directly there, instead of patrolling the entire line until they see the problem.

   – Automation of switches can avoid the need to send personnel to the field to perform the switching.

   – Monitoring of capacitor banks and other feeder equipment can avoid the need to send personnel to check or test their status or change their parameters.

   – Monitoring of field equipment can provide maintenance personnel with more accurate historical and current information, thus allowing more timely maintenance or avoidance of maintenance when not needed.

   – AMR can avoid or minimize the sending of metering personnel to read meters

   – Automated connect/disconnect of meters (soft and/or hard) can avoid additional trips for metering personnel

   Calculation of benefit:

- = field crew burdened hourly rates * decrease in number of field crew personnel
- = field crew burdened hourly rates * decrease in hours (normal and overtime) of field crew personnel

3. *Decreased engineering personnel time:* This benefit identifies reductions in the costs associated with engineering personnel due to less time or fewer personnel needed to perform a particular function. These time savings might come from:

– Improved tools to perform specific engineering functions
– Decrease in time spent validating data
– Reduction in time spent tracking down problems
– Reduction in time spent designing, specifying, and installing systems

Calculation of benefit:

- = field crew burdened hourly rates * decrease in number of field crew personnel
- = field crew burdened hourly rates * decrease in hours (normal and overtime) of field crew personnel

4. *Extend equipment life-time:* if the life-time of equipment can be extended then utilities can defer the cost of replacing it. This savings may be in O&M or capital expenditures, depending upon the type of equipment. Possible methods for extending equipment life-time include:
   – Avoiding overloads of equipment
   – Limiting the length of time that equipment is overloaded
   – Improved information on its true health
   – Predictive maintenance policies and procedures

   Calculation of benefit:

- = decrease in carrying costs, based on avoided O&M or capital expenditures

5. *Improve utilization of equipment:* If the same equipment can carry higher loads without concerns about overloads, then additional equipment is not needed. Possible methods for improving utilization of equipment include:
   – Improved real-time information on its true health, including length of time of any overload situations, so that equipment could be used up to its rated capacity based on actual facts, not estimated facts.
   – Predictive maintenance policies and procedures so that equipment can be used up to its rated capacity with less risk

   Calculation of benefit:

- = decrease in carrying costs, based on deferred O&M or capital expenditures
- = avoided purchase cost, if additional equipment is never needed

6. *Reduce non-distribution O&M expenses:* If non-distribution O&M expenses can be reduced, these are direct savings. Possible methods for reducing O&M expenses (in addition to those listed above) include:
   – Improved real-time information of distribution status could lower the O&M costs of transmission, substations, and customer equipment.
   – Predictive maintenance policies and procedures so that equipment can be used up to its rated capacity with less risk

   Calculation of benefit:

- = decrease in carrying costs, based on deferred O&M or capital expenditures

- = avoided purchase cost, if additional equipment is never needed

7. *Reduce the cost of energy generation:* Most utilities either generate their own energy or purchase it from generating companies to serve their customer loads. Since most customer tariffs do not directly reflect the cost of energy generation, any reductions in generation costs accrue directly to the utilities – until/unless tariffs are modified to reflect these changes. If customer demand-response is implemented, the utilities may still benefit, depending upon the tariff structures. Some methods by which actions at the distribution level may reduce the cost of generation include:
   – Increase efficiency of distribution system (see Section 3.1.4)
   – Reduce peak loads to avoid using more expensive generation sources
   – Utilize less costly DER sources, including both utility-owned DER and customer-owned DER, particularly to serve local loads with high locational marginal prices (LMP)

   Calculation of benefit:

- Less load = delta load * (cost of generation – lost revenue)
- Greater fuel efficiency benefit = fuel efficiency gain * cost of fuel * amount of fuel used
- Less expensive fuel benefit = (cost of normal fuel – cost of less expensive fuel) * amount of fuel used
- Market price decrease in response to lower loads = delta market price * amount of energy
- Cap-and-trade (if/when available) of generation with CO_2 levels lower than the cap = delta trade price * amount of energy.

8. *Reduce peak loads (peak shaving) by demand reduction or deferral:* Peak generation, or whenever there is a step function from one cost of generation to another, can be more expensive than the average revenues received from customers for that energy, particularly since the prices that most customers pay for energy does not reflect the actual real-time cost, just an average. Peak shaving through reducing or shifting loads can be complex to assess, given the wide variety of loads that can be reduced, the payback energy when shifted loads return, and the personal responses of customers to particular situations.

- Demand response to market prices = delta market price * amount of energy

9. *Reduce peak loads by managing DER generation/storage:* DER generation/storage can also be used to increase local generation, thus minimizing the need for expensive generation.

10. *Reduce loss of revenue:* Loss of revenue can occur due to outages or energy theft, as well as not meeting customer tariff agreements. Reducing these revenue losses results in a net increase in revenues.

- = delta increase in revenue

11. *Avoid legal and regulatory penalties:* Some failures to meet contractual, safety, security, and regulatory requirements can result in penalties

- = amount of the penalty

12. *Participate in market operations:* Market operations can enhance the payback from investment in distribution automation technologies.

3.1.2 Power Reliability and Power Quality Benefits

Utilities have a "mission" to provide high power reliability to their customers, and are also typically mandated by regulations to provide good power reliability and power quality. Although no "hard" financial benefits accrue to utilities (except the avoidance of regulatory penalties and small amounts of revenue), utilities can gain "soft" benefits from improved power reliability (in addition to any direct financial gains). These soft benefits may be harder to assess, but they do exist.

1. *Shorten or avoid permanent outages (e.g. outages longer than 1 to 5 minutes) to customers:* For utilities, shortening or avoiding outages do not intrinsically provide a monetary benefit aside from the reduced costs associated with field crews (which is handled separately). Utility benefits stem primarily from reducing their outage metrics which is seen by customers and regulators as a "good thing". Potential methods for shortening or avoiding permanent outages include:
   - Implement remotely monitored fault detectors so that outages can be detected before customers start calling in.
   - Use automated switching to permit remote switching of feeder sections after an outage
   - Use the function "fault location, isolation, and service restoration" in combination with automated switching to detect and resolve many outages within the "permanent outage" timeframe.
   - Monitor distribution equipment so that alarms from unusual situations (e.g. overheating transformer, severe power quality fluctuations, swinging lines, etc.) are detected in real-time before an outage actually occurs.
   - Set automated switching to occur before fuses blow, thus avoiding the travel time required to replace fuses. (There is a trade-off here of more customers potentially affected by the switching, versus the smaller number affected by the fuses.)

   Calculation of benefit:

- = decrease in SAIDI, SAIFI, CAIDI, or other metric used to measure the impact of outages * the "soft" value of goodwill, fees for not meeting the Service Level Agreements (SLA) in some customer tariffs, regulatory impacts, legal costs, etc.

2. *Decrease the number of customers experiencing permanent outages:* Similarly to shortening permanent outages, utility benefits stem primarily from reducing their outage metrics which is seen by customers and regulators as a "good thing". Potential methods for decreasing the number of customers experiencing permanent outages include:
   - Implement remotely monitored fault detectors so that loss of power can be detected and possibly restored before it is categorized as permanent.
   - Use automated switching to permit remote switching of feeder sections after an outage, thus possibly restoring customers before the loss of power is categorized as permanent

- Use the function "fault location, isolation, and service restoration" in combination with automated switching to detect and resolve many outages within the "permanent outage" timeframe.
- Monitor distribution equipment so that alarms from unusual situations (e.g. overheating transformer, severe power quality fluctuations, etc.) are detected in real-time before an outage actually occurs.

Calculation of benefit:

- = decrease SAIDI, SAIFI, CAIDI, or other metric used to measure the impact of outages * the "soft" value of goodwill, fees for not meeting the Service Level Agreements (SLA) in some customer tariffs, regulatory impacts, legal costs, etc.

3. *Decrease the number of temporary or momentary outages:* Since momentaries are not usually counted in SAIDI, SAIFI, or CAIDI metrics, they must usually be accounted for separately. If a metric is used which includes momentaries, such as MAIFI, then that can be used. Potential methods for decreasing the number of momentary outages include:
   - Monitor distribution equipment so that alarms from unusual situations (e.g. overheating transformer, severe power quality fluctuations, etc.) are detected in real-time before an outage actually occurs.

Calculation of benefit:

- = decrease in the number of momentaries * the "soft" value of goodwill, fees for not meeting the Service Level Agreements (SLA) in some customer tariffs, regulatory impacts, legal costs, etc.

4. *Decrease the number of customers experiencing temporary or momentary outages:* Since momentaries are not usually counted in SAIDI, SAIFI, or CAIDI metrics, they must usually be accounted for separately. If a metric is used which includes momentaries, then that can be used. Potential methods for decreasing the number of customers experiencing momentary outages include:
   - Monitor distribution equipment so that alarms from unusual situations (e.g. overheating transformer, severe power quality fluctuations, etc.) are detected in real-time before an outage actually occurs.

Calculation of benefit:

- = decrease in the number of momentaries * the "soft" value of goodwill, fees for not meeting the Service Level Agreements (SLA) in some customer tariffs, regulatory impacts, legal costs, etc.

5. *Permit and support additional DER interconnections:* Distribution automation can help support additional DER interconnections while maintaining or improving power system reliability. DER could also be used to operate the power system more efficiently. These benefits are very "soft" with respect to the utilities, but DER interconnections are increasingly required by customers and encouraged by regulators.

6. *Manage DER generation/storage to improve reliability:* Although currently seen as basically as "negative load" (and a nuisance), DER generation and storage can be used to improve reliability and power quality, for instance, to support overloaded feeders, create

microgrids, provide volt/var support, provide local backup energy, etc. This DER management could either improve SAIDI/SAIFI or at a minimum, keep them from deteriorating as more DER generation/storage is added by customers.

7. *Support operators in decision-making during emergencies:* Often operators are overwhelmed during emergencies due to the vast amount of data pouring in. Analysis software programs and local automation can quickly sift through this data to isolate and determine the key decisions that need to be made. These decisions can be made "closed-loop" by the system, or in "advisory-mode" to present the operator with clear choices. Although more difficult to quantify, the results can include more timely operator actions, fewer operator mistakes, and more auditable handling of the emergency (fewer potential legal or financial penalties)

8. *Reduce loads during emergency conditions:* During peak power conditions, severe storms, or some power system emergencies, utilities can request or instigate load control, load interruptions, and/or load shedding to avoid more prolonged or serious outages.

- = estimated delta SAIDI/SAIFI due to load reductions to avoid outages

9. *Improve power quality (voltage deviation, voltage imbalance):* Improved power quality usually benefits customers more than the utilities, but if power quality requirements are written into tariffs, then utilities also gain by avoiding penalties.

10. *Improve knowledge of source of power quality problem:* Often utilities are blamed for power quality problems that are really being caused by certain customers. If utilities can determine the real source of these types of power quality problems, they can request those customers to fix the problem, and therefore will not be liable for the problem.

11. *Provide on-demand pricing, billing, and energy usage information to customers:* Although providing information to customers is not directly related to reliability, it is related to customer service, similar to the other metrics. The benefit to utilities is "good" customer relationships, which might translate into retaining customers for those customers with a choice of utilities, generation, or self-provision with DER.

3.1.3 Safety and Security Benefits

Safety is clearly important in and of itself, but can also be assessed from a financial perspective, based on the various costs for medical, legal, regulatory, safety assessment, loss of worker's time, and retraining efforts.

Security risk assessment is a complex undertaking which covers both deliberate and inadvertent security threats to power system security. However, rough estimates can be made on the costs of security breaches which may be adequate enough for estimating benefits, given the broad uncertainties of security threats.

1. *Increased safety of field crews and the public:* Safety of field crews and the public often entail carelessness, mistakes, or lack of awareness of a dangerous situation, such as a live wire on the ground.

- = the cost of handling injuries or safety incidents – medical, legal, regulatory, loss of worker's time, retraining, etc. * decrease in percent of injuries or safety incidents.

2. *Support operators in decision-making during safety or security breaches:* Often operators are not aware of safety or security breaches in a timely manner since the relevant information is often not available to the operator. Some automation can enhance detection of safety and/or security breaches, including "closed-loop" reactions or "advisory-mode" information to the operator for timely and simplified decision-making.

- = cost of managing a safety or security breach during its occurrence, including power system events, equipment damage, personnel safety, legal costs, regulatory issues, security breach assessment, and retraining * the decreased risk of the security breach occurring and the decreased impact of those security breaches that may occur.

3. *Support engineers in designing systems with improved safety and/or reliability:* Engineers are being confronted by increasingly complex power systems, including the need to operate the systems closer to their limits and the interconnection of a growing number of DER units and increased generation capacity on systems not initially designed for them. Automation can help engineers assess power system safety and reliability during design, specification, and installation.

- = cost of managing a safety or security breach during its occurrence, including power system events, equipment damage, personnel safety, legal costs, regulatory issues, security breach assessment, and retraining * the decreased risk of the security breach occurring and the decreased impact of those security breaches that may occur.

4. *Increase physical and cyber security of power system operations:* Determining the criticality and privacy needs of particular systems and data, their vulnerability to physical and cyber attacks, and the types of security countermeasures to protect against the more probable attacks would be part of security risk assessment.

- = cost of managing a security breach during and after its occurrence, including power system events, equipment damage, personnel safety, legal costs, regulatory issues, security breach assessment, and retraining * the decreased risk of the security breach occurring and the decreased impact of those security breaches that may occur.

3.1.4 Energy Efficiency Benefits

Since there are currently no direct financial benefits or regulatory mandates for improving energy efficiency for distribution utilities, these efficiency benefits would need to be tied to other incentives, such as energy losses tied to tariff structures for customers or cap-and-trade incentives to reduce loads for environmental reasons. Typically, the "cost" of these losses is small in comparison to the cost any technology used to minimize these losses: only by piggybacking efficiency on other functions could minimizing these losses become financially attractive to utilities.

1. *Reduce losses in the distribution system:* Utilities are paid (directly or indirectly) for the power they provide at the customer's meter. They pay for the generation measured at the generators' meters. Therefore losses in the distribution system are energy that the utility pays for, but is not paid back for.

- = Reduction in losses percentage * cost of energy

2. *Reduce transmission losses through coordinated distribution operations:* Transmission losses can be ameliorated by coordinated actions in distribution operations. For instance, distribution can provide VAr support to transmission, or can reduce voltage if transmission needs to reduce voltage (rather than fighting against it).

3.1.5 Energy Environmental and Conservation Benefits

For utilities, environmental and conservation benefits are primarily in meeting the relevant legal and regulatory mandates, since there are no direct benefits to stockholders. Therefore these benefits are considered "soft", but can be somewhat quantified by either determining the penalties for not meeting the mandates, or, in the case of market incentives for carbon trading, etc., the benefits from making gains in those markets. In all of the following "benefits", the same discussion applies:

Although reducing losses, loads, or emissions can also have an impact on reduced generation, deferring equipment replacement, or other financial benefits to utilities, those benefits are handled elsewhere. This benefit addresses only the environmental aspects of reduced losses/loads/emissions. These reductions provide significant benefits to society, but can be a financial burden to utilities. Therefore, well-tailored financial incentives – either market or penalty incentives – could make these reductions a benefit to utilities.

Without the cap-and-trade regulations or other incentives, detailed assessment of benefits cannot be made.

1. *Reduce energy losses in the distribution system*
2. *Reduce loads for energy conservation*
3. *Reduce particulate pollution (SO_X and NO_X)*
4. *Reduce greenhouse gases (GHG) pollution (in line with laws SB 1368 and AB 32):*
5. *Reduce peak loads*
6. *Reduce transmission losses through coordinated distribution operations*
7. *Reduce footprint of distribution substations, lines, and equipment*

3.2 Customer Benefits

Customers can share some benefits with utilities, but can also have some of their own direct benefits. In shared benefits, customers may benefit over time by reductions in utility costs through the reflection of those reductions in customer tariffs. There is, however, no formula for calculating these benefits quantitatively, since customer tariffs are based on rate cases. These cost reduction benefits are therefore identified in each of the relevant areas, but are not quantified.

3.2.1 Customer Financial Benefits

Customer direct financial benefits varies significantly, depending upon the type of customer (residential, commercial, or industrial), the ways they use electric energy, and their flexibility to shift their use of energy.

1. *Demand Response:* Demand response can cover many approaches, including Time-of-Use (TOU), Load Control (LC), Real-Time Pricing (RTP), and other financial incentives for customer to respond to power system situations. If customers take advantage of these demand response programs, then they can benefit financially. However, there are a number of issues:

- Load control typically is used for reliability concerns, so cannot be used as part of measuring demand response, but still takes away some of the available load reduction capacity from demand response, which has the focus of reducing the cost of energy.
- For residential customers, the regulated current flat pricing and AB 1X either prevent or seriously impact the ability of price signals to make demand response attractive to customers.
- AB 1X (legislated in response to the California crisis of 2001) basically uses higher tiered customers to subsidize the lower tiered customers.
- Many customers would only be interested in demand response if it were very easy to use, since the delta in cost is too small for them to spend much time or effort in it.
- Customers are nervous that any type of dynamic pricing would actually pose a greater risk for higher prices rather than lower prices.
- Some customers would have more incentive from reducing CO_2 rather than reducing costs.
- Hedging premiums or other types of special rates could help customers to feel less risk.
- Customers respond both to "proper" price signals as well as "improper" price signals. Any panic "fixes" or continuous changing rate structures are worse in the long run because customers get tired of the changes.
- Many customers want stable rates, because they are less interested in low rates and more concerned with predictability.
- Customers want to have the choice of what type of rates they implement, so a balance of options must be provided to them.
- Automation/technology must be available to provide methods for customers to manage their energy consumption, such as smart thermostats, smart appliances, and easy-to-use interfaces to them.

2. *Customer DER generation and/or storage:* Increasingly, customers are installing their own DER generation and/or storage systems, either for backup power, or for cost savings on their energy bills, or for combined-heat and power (CHP) to make use of their waste heat from industrial processes. The financial benefits for customers must be assessed on a case-by-case basis.

- Customers have financial incentives for implementing renewable DER generation in California, particularly PV, wind, and CHP that may or may not reflect utility need or usage of this generation.
- Storage can significantly improve load factors and load shifting, while improving electric reliability and reducing energy costs
- Customers may implement renewable DER in order to participate in reducing CO_2 and other GHGs, just because they believe it is important.

3. *Provide information to customers:* Information can be a valuable commodity for customers, which could be in near-time or, as customers more typically want, every month with the monthly bill. The types of information include the following:

- Up-to-date status of outages
- Potential for unplanned outages due to scheduled work or storm conditions
- Current energy price
- Current customer's energy usage
- Customer billing information

4. *Decreased time to resolve financial, billing, or commercial problems associated with individual customers:* Most customers are sensitive to problems associated with billing, and some could directly benefit financially from rapid resolution of these problems.
5. *Deferred construction*: Deferred construction of utility infrastructure could benefit customers eventually through minimizing rate increases.
6. *Decreased field crew personnel time:* For customers, the benefits could be reduced utility O&M costs, if these eventually translate into a positive impact on prices in tariffs.
7. *Extend equipment life-time:* Extended equipment life-time could benefit customers eventually through minimizing rate increases.
8. *Participate in market operations:* Market operations can enhance the payback from investment in automation technologies. For customers this is typically load management, TOU, demand response, and DER generation based on market prices.
9. *Reduce the cost of energy generation:* If utilities reduced the cost of energy generation – or minimized the increase in generation costs, then customer could share in this cost savings through their tariffs, particularly if these tariffs include the actual cost of energy as one factor in the determination of the price the customer must pay.
10. *Reduce peak loads (peak shaving) by demand reduction or deferral:* Peak generation, or whenever there is a step function from one cost of generation to another, can be more expensive than the average revenues received from customers for that energy, particularly since the prices that most customers pay for energy does not reflect the actual real-time cost, just an average. Peak shaving through reducing or shifting loads can be complex to assess, given the wide variety of loads that can be reduced, the payback energy when shifted loads return, and the personal responses of customers to particular situations.

11. *Reduce peak loads by managing DER generation/storage:* DER generation/storage can also be used to increase local generation, thus minimizing the need for expensive generation.

12. *Reduce peak loads (peak shaving) by demand reduction or deferral:* Peak generation, or whenever there is a step function from one cost of generation to another, can be more expensive than the average revenues received from customers for that energy, particularly since the prices that most customers pay for energy does not reflect the actual real-time cost, just an average. Peak shaving through reducing or shifting loads can be complex to assess, given the wide variety of loads that can be reduced, the payback energy when shifted loads return, and the personal responses of customers to particular situations.

3.2.2 Power Reliability and Power Quality Benefits

For customers, power reliability and power quality are the most important benefits (except for the price of energy). More and more customers, from small residences to huge industrial facilities, are relying on electric energy for business, safety, security, and quality of life.

1. *Shorten or avoid permanent outages (e.g. outages longer than 5 minutes) to customers:* This benefit is typically the second most important (after lowering/stabilizing rates) that customers want. The degree of benefit varies by the type of customer and the importance of reliable power to the customer. In general:

- = the decrease in length and number of outages * the impact of outages to the customers. Commercial and industrial customers can often quantify the impact of outages due to loss of production, loss of inventory, and/or loss of sales. Residential customers generally cannot directly quantify the impact of outages other than their decreased quality-of-life. Exceptions for residential customers include any medical reliance on power, use of the residence for business, and, if the outage is long, possible health impacts due to loss of heating or air conditioning.

- = the decrease in length and number of outages * the increased "willingness" to start, maintain, or move power-dependent businesses to the area. Although this can only be quantified by making many assumptions, some relationships between outages and the "business friendly environment" have been developed.

2. *Decrease number of temporary or momentary outages:* This benefit is mostly, but not entirely, a benefit against the "nuisance" of momentary interruptions of power. Again, different customers will have different levels of impact, with those that cannot "ride through" a momentary outage experiencing the greatest impact. The same formulas can be used, but the ultimate values are likely to be smaller:

- = the decrease in length and number of momentary outages * the impact of outages to the customers. Commercial and industrial customers can often quantify the impact of outages due to the cost of buying "ride through" capabilities, any loss of production, loss of inventory, and/or loss of sales. Residential customers generally cannot directly quantify the impact of outages other than their decreased quality-of-life. Exceptions for residential customers include any medical reliance on power, use of the residence for business, and, if the outage is long, possible health impacts due to loss of heating or air conditioning.

- = the decrease in length and number of outages * the increased "willingness" to start, maintain, or move power-dependent businesses to the area. Although this can only be quantified by making many assumptions, some relationships between outages and the "business friendly environment" have been developed.

3. *Decreased time to resolve electrical problems associated with individual customers*

- Individual outages
- Connect time for new customers
- Reconnect time after disconnects, for whatever reasons

4. *Permit/support additional DER interconnections*
5. *Improve power quality (voltage deviation, voltage imbalance)*

3.2.3 Safety and Security Benefits

1. *Increased safety of field crew:* Safety is clearly important in and of itself, but can also reduce utility costs. For customers, the benefits could be:

- Reduced utility safety-related costs

2. *Increase physical and cyber security of power system operations:* Rough quantitative estimates can be made on the costs of security breaches which may be adequate enough for estimating benefits, given the broad uncertainties of security threats. Customers will benefit through:

- = avoidance of possible outage or power quality disturbances * the decreased risk of the security breach
- Reduced utility O&M costs by lowering the probability and the impact of security breaches

3.2.4 Energy Efficiency Benefits

For customers, energy efficiency benefits may be reflected in lower rates or lower rate increases as utilities reduce their own costs as they reduce losses.

1. *Reduce losses in the distribution system:* Utilities are paid (directly or indirectly) for the power they provide at the customer's meter. They pay for the generation measured at the generators' meters. Therefore losses in the distribution system are energy that the utility pays for, but is not paid back for.

- = Reduction in losses percentage * cost of energy

2. *Reduce peak loads for demand reduction:* Peak generation, or whenever there is a step function from one cost of generation to another, can be more expensive than the average revenues received from customers for that energy, particularly since the prices that most customers pay for energy does not reflect the actual real-time cost, just an average.

3. *Reduce transmission losses through coordinated distribution operations:* Transmission losses can be ameliorated by coordinated actions in distribution operations. For instance, distribution can provide var support to transmission, or can reduce voltage if transmission needs to reduce voltage (rather than fighting against it).

3.2.5 Energy Environmental and Conservation Benefits

For customers, environmental and conservation benefits are becoming extremely important and can be used as incentives for demand response, renewable generation development, and other "green" efforts. 17% of customers are highly interested in environmental issues. They are far more motivated by these concerns than by small reductions in cost.

{from SCE on DR} Need policy toward demand response, need technology implemented more widely, and consumer education in exactly how electricity usage can affect these issues. Cost with relationship to DR is less an issue, and, for larger customers, has already been implemented for energy efficiency through load control and interruptible power. There is customer confusion between DR for price & energy reductions, and load control for power system reliability.

There is a "response" issue in that even if customers are signed up for DR, they do not always respond to an event or rise in price because of their own needs and situation. Home Area Networks (HAN) and Programmable Communicating Thermostats (PCTs) must be involved to provide the automation that residential customers need or they will not take the time or effort to participate. They also need to educate customers on the time dimension of the use of energy – right now only flat rates are used for residential customers. Even TOU rates are rather large blocks of time.

There is a very real distinction between external control of appliances versus customer-initiated control of appliances. Need to have both as options because different customers have different philosophies.

1. *Reduce greenhouse gases (GHG) pollution*
2. *Reduce particulate pollution (SO_X and NO_X)*
3. *Reduce energy losses in the distribution system*
4. *Reduce loads for energy conservation*
5. *Reduce peak loads*
6. *Reduce transmission losses through coordinated distribution operations*

3.3 Societal Benefits

Societal benefits can have both a quantitative (financial) component and a qualitative (quality of life) component. Quantitative benefits can be more "compelling" but are often hard to derive because of the scope and complexity of societal interactions with electrical energy. For instance, some societal benefits may stem from the reduced risk of crime if outages are handled more rapidly, but quantifying the reduced costs for police, fire, medical, insurance, political, etc. activities that can be directly attributed to shorter outages could be a challenging undertaking.

3.3.1 Societal Financial Benefits

Direct financial benefits to society derive primarily from having high power reliability. These benefits stem from:

1. Minimizing the costs of police due to criminal activities that are abetted by power outages.
2. Minimizing emergency actions needed to assist people during prolonged outages, providing heat, cooling, food, and/or shelter.
3. Minimizing business disruptions due to outages, which affect the business attractiveness of the community.
4. Minimizing lost business time, where some workers are adversely affected when they are not paid during the time a business is closed.

Alternatively, taxes could be used to provide funding for some of automation that could minimize these costs. In this scenario, there could be a net zero social benefit overall, but clearly would affect different areas in society differently.

3.3.2 Power Reliability and Power Quality Benefits

Quality of life of the community is affected by power reliability:

1. People have come to rely on electric power and are often not prepared to cope with the loss of power for any length of time. For instance, if elevators do not work, they can be stuck or have to use stairs that they may not be physically comfortable with.
2. People with medical problems can be relying on electric power for some of their care, including protection against life-threatening situations.
3. Although some critical facilities such as hospitals generally have backup power, this backup power may not serve all areas.

3.3.3 Safety and Security Benefits

Safety of the community can be threatened by power outages and lines down. Safety from other threats also relies heavily on power availability.

3.3.4 Energy Efficiency Benefits

For society, energy efficiency benefits are connected both to energy independence and environmental benefits.

1. The more efficiently energy is generated, transmitted, and used, the less society will be dependent on external sources of energy.
2. The more efficiently energy is generated, transmitted, and used, the fewer harmful effects on the air, water, and land environments

3.3.5 *Energy Environmental and Conservation Benefits*

For society, environmental and conservation benefits are primarily in minimizing the harmful effects of electricity consumption on the air, water, and land. These benefits are primarily derived from reducing transmission and distribution losses, managing DER generation/storage effectively, managing loads more efficiently, and minimizing emissions.

1. *Reduce energy losses in the distribution system*
2. *Reduce loads for energy conservation*
3. *Reduce particulate pollution (SO_X and NO_X)*
4. *Reduce greenhouse gases (GHG) pollution (in line with laws SB 1368 and AB 32):*
5. *Reduce peak loads*
6. *Reduce transmission losses through coordinated distribution operations*

3.4 Regulator Benefits

Benefits of distribution automation to regulators are different in nature from the benefits to other groups. These benefits can be better characterized as follows:

1. *Transparency*
2. *Auditability*

4. Key Technical Challenges Affecting Distribution Automation Functions

Many technical issues affect the benefit-cost analysis of implementing different types of distribution automation functions (including those functions which impact or are impacted by other distribution automation functions). Not all functions share the same technologies, since each function has its own specific and detailed technical requirements. However, some of the technologies for meeting those requirements have universal themes that present the key challenges to implementing automation.

These 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, 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.

4.1 Challenges Related to Electronic Equipment Capabilities

4.1.1 Types of Electronic Equipment

There are a very large number of different types of electronic equipment used in the distribution power system to monitor and control the power system equipment. Some types of electronic equipment are used primarily in substations, some on distribution feeders, and some in both. Some equipment is sold as a complete solution, while other equipment is integrated together, often from different vendors.

Most "controllers" are microprocessor-based and are often capable of providing basic power system data (e.g. voltage, current, watts, vars) in addition to the functions they are specifically designed for.

- Sensors, including PTs, CTs, temperature, pressure, vibration, leaks, acoustics, humidity, wind speed
- Circuit breaker controllers
- Load tap changer controllers
- Capacitor bank switch controllers
- Voltage regulator controllers
- Automated switch controllers
- Protective relay controllers
- Controllers for Distributed Energy Resources (DER), including diesel, photovoltaics, fuel cells, wind, biomass, microturbines, hydro, combined heat and power (CHP), energy storage technologies, etc.
- Meters with interval metering, time-of-use, and other capabilities beyond simple metering
- Remote Terminal Units (RTUs)
- Intelligent Electronic Devices (IEDs) (generic term used for many controllers)
- Data concentrators (generic)

4.1.2 Electronic Equipment Challenges

Electronic equipment presents many technical challenges, with the desired capabilities ranging from the simple to the complex to the totally infeasible (at this time). Nowadays, electronic equipment generally includes microprocessors or larger computers, and typically handles digital data, although some may include conversions between analog and digital data. They may be embedded in power system equipment or may be separate. They are often ruggedized for installation in harsh, outdoor and substation environments, although protection may be provided by separate housing (control houses or NEMA enclosures).

Some of the technical challenges posed by electronic equipment include:

- Determining the appropriate and necessary specifications needed for the electronic equipment to the meet the function's requirements (including determining if alternate ways exist or might be better for meeting those requirements)
- Determining what types of flexibility for expansion, upgrades, and future replacements should be included in the specification
- Determining if the electronic equipment should provide (or should be upgradeable to provide) additional capabilities for other functions
- Assessing whether vendor products actually provide the required capabilities

- Addressing security and reliability issues
- Assessing interfacing issues (see communications, data, and integration challenges)
- Planning for maintenance through training, test equipment, diagnostics, and scheduling
- Upgrading equipment while maintaining reliability

4.2 Challenges Related to Communication System Technologies

Communication system technologies can be categorized either as a media or as a service provided by a public or private telecommunications provider. The reason they are often separated in this manner is because utilities may own and operate a particular communications system based on a particular medium (or set of media), but if communication services are leased or purchased from a telecommunications provider, the actual media, interfaces, and management are often hidden from the users, with a Service Level Agreement (SLA) as the main method for determining the requirements. Often communication technologies from telecommunication providers also come with pre-established transport layer protocols.

4.2.1 Types of Communication System Media

Communications system media can be purchased, installed, operated, and maintained by utilities for meeting specific needs. Interfaces to these communication systems can be embedded in products or added externally. These can include the following media:

- Fiber optic cables – from large bundles of fiber pairs to simple Ethernet cabling
- Microwave systems (digital and analog)
- Twisted pair sets of wires
- Category 5 cables for LANs
- Multiple address radios systems (MAS)
- Mobile radio (predominantly voice)
- Trunked mobile radio (can add some data channels)
- Spread spectrum point-to-point radio systems
- Pager systems
- Coaxial cable
- Hybrid fiber coax (HFC)
- Bluetooth
- WiFi
- WiMax
- Zigbee
- Power line carrier (PLC)
- Broadband power line (BPL)

4.2.2 Types of Communication System Services

Telecommunication providers can provide communication services either for general communications or for very specific types of requirements.

- Leased voice-grade telephone line
- Leased T1 and fractional T1
- Leased frame relay capacity
- Leased SONET capacity
- Leased Wide Area Network (WAN)
- Digital Subscriber Loop (DSL)
- CATV
- Analog cellphone (almost obsolete)
- CDMA data cellphone
- GPRS and other newer G3/G4 cellphone data technologies
- Text messaging and short messaging systems (SMS)
- Very small aperture terminal (VSAT) satellite
- Lease of satellite transponder bandwidth
- TWACS power line carrier (AMR and some types of DA)
- Turtle power line carrier (AMR)
- CellNet (AMR and some DA)
- UtiliNet (AMR and some DA)
- Global Positioning Satellite (GPA)
- Radio frequency identification (RFID)

4.2.3 Communication System Challenges

Cost-effective, adequately secure, and functionally capable communications systems are needed to reach the wide-spread locations often needed to interact with distribution equipment and/or customer sites. Many decisions must be made, including:

- Assessing the available types of communications systems
- Determining the time-sensitivity requirements for each type of data exchange
- Determining throughput requirements
- Selecting communications media, balancing cost, capabilities, and disadvantages
- Determining the communications configuration
- Sharing communication networks with other departments or other companies
- Leasing capacity from telecommunication providers

- Selecting vendor equipment
- Determining the Service Level Agreements
- Establishing network management capabilities
- Determining and monitoring communications availability and performance

4.3 Challenges Related to the Management of Data

4.3.1 Types of Data Systems

Many types of systems provide, store, and/or utilize distribution-related data. The data in these systems are often incompatible or inconsistent with each other. Different utilities have different types of these systems, as well as often quite different functionality. Generically, some of these data systems include:

- Electronic sensors and controllers (see above) which generally can provide power system measurements (voltage, var, current, frequency) in addition to the specific functions they provide.
- Fault recordings
- Harmonic and power quality readings
- DER systems
- Data concentrators
- Substation master stations
- SCADA systems with real-time database (RTDB)
- Disturbance analysis data
- Historical and archival data
- Energy Management Systems (EMS)
- Distribution Management Systems (DMS)
- Outage scheduling systems
- Geographic Information Systems (GIS) and/or Automated Mapping and Facilities Management (AM/FM) systems
- Customer Information Systems (CIS)
- Outage Management Systems (OMS)
- Work Management Systems (WMS)
- Trouble Call systems
- Meter reading systems
- Distribution planning systems
- Distribution engineering systems
- Distribution construction systems

- Distribution purchasing systems
- Distribution asset management systems
- Staking systems
- Protective relay management
- Maintenance systems
- Laptops and mobile computing systems for field crews

4.3.2 Data Management Challenges

Managing the ever-increasing volume of data has become one of the largest challenges in all forms of automation. Distribution automation is no exception – particularly since distribution systems are so extensive. The main challenges are to ensure the consistency and accuracy of data, all the way from the data sources, through intermediate databases, to end-use applications. For distribution automation, data management involves:

- Determining what data is available for different users
- Determining how to provide the data to the users in a timely manner
- Handling large volumes of data, including collecting, storage, and retrieval
- Ensuring correctness of data or flagging inaccuracies, not only from real-time sources, but from "static" databases such as Geographic Information Systems
- Developing methods to identify data across different systems with different meanings and varying accuracy or completeness
- Managing consistency of data across databases
- Updating data to reflect constant changes in field equipment and customer characteristics
- Ensuring the adequate privacy and security of data, based on security risk assessment and privacy requirements
- Updating data messaging and database technologies (versioning) while maintaining the required data flows and data consistency/accuracy
- Updating software applications and their access to the appropriate data

4.4 Challenges Related to the Integration and Security of Disparate and Legacy Systems

4.4.1 Types of System Integration and Security Technologies

Many of the systems identified as providing, storing, and utilizing data will also need to be integrated with each other – able to exchange information securely, reliably, in a timely manner, to the right user, for the right purposes, and with mutually understandable formats and meanings. Some of the key system integration and security technologies include:

1. Communication protocols for end-to-end transportation of data (OSI layers 1-4) (although often there is overlap)
    a. Physical layer protocols appropriate to the different media, e.g. Sonet for fiber optics, frequency modulation for radio, spread spectrum for WiFi, etc.
    b. Link layer protocols, such as Ethernet, Token ring/bus, IEEE 802.1x wireless, ATM, DSL, HDLC, FTP, proprietary, etc.
    c. Network layer protocols, such as IP, IPSec, UDP, routing management, proprietary
    d. Transport layer protocols, such as TCP, proprietary
2. Communication protocols for application layers (OSI layers 5-7)
    a. HTTP, HTML, email's SMTP, MMS, DNP3, ICCP, etc.
    b. Client-server concept (many different implementations)
    c. Publish-subscribe Corba, GID, etc.
    d. Web services
    e. Many proprietary RTU protocols
3. Data modeling protocols
    a. SNMP's Management Information Bases (MIBs)
    b. XML, RDF, XLST, etc.
    c. IEC 61968 Common information model (CIM)
    d. IEC 61850 for substations, DER, and hydro plants. Distribution being developed.
    e. ebXML market and business models
    f. OAG modeling structures
    g. OWL
4. Cyber security technologies
    a. Transport Layer Security (TLS)
    b. Virtual Private Network (VPN)
    c. Internet Protocol Security (IPSec)
    d. Router security such as Access Control Lists (ACL)
    e. Role-based access control (RBAC) with individual authentication
    f. IEC 62351 security for utility protocols such as DNP, ICCP, and IEC 61850
    g. IEEE 802.11i wireless security
    h. Communication network management, such as Simple Network Management Protocol (SNMP)
    i. Intrusion Detection Systems (IDS)

4.4.2 System Integration and Security Challenges

Systems, particularly the special systems designed exclusively for utility operations, are typically specified and purchased to meet only the specific requirements of the software applications which will run on them. Often these applications rely on proprietary interfaces: interfaces to input data, interfaces to exchange data with other applications within the one system, and interfaces for providing the results to the user. These utility operations systems are rarely designed to use standard interface technologies, although some of the newer implementations attempt to take advantage of some standards. In addition, many "legacy" systems are very difficult if not impossible to upgrade to use standard interfaces.

Cyber security is a growing challenge for system integration. The interchange of accurate and timely data is one of the most critical parts of power system operations, responsible for retrieving information from field equipment and, vice versa, for sending control commands. Despite their key function, communication protocols have rarely incorporated any security measures, including security against inadvertent conditions or deliberate sabotage, such as:

- Power system equipment malfunctions
- Communications equipment failures
- Careless mistakes
- Inadvertent design or maintenance problems
- Natural disasters, which may increase in their impacts as the distribution infrastructure ages, as more DER is relied upon in the distribution system, and as changes in weather conditions affect distribution system design
- Deliberate bypassing of security measures just for convenience
- Disgruntled employees who want to cause harm
- Industrial espionage as market forces become a major player
- Customer privacy violations for multitudes of reasons from product marketing to life-style monitoring
- Kiddie hackers over the Internet
- Terrorist attacks (less likely than any other security problem on the distribution system)

In the past, "Security by Obscurity" has been the primary approach. However, it is no longer a reasonable approach to managing communications among systems and equipment. Although distribution systems are not often considered as "critical" as transmission systems, in the future their criticality for reliable power and customer privacy may increase significantly.

As the automation of power system operations requires more interactions between systems, as well as more flexible and responsive exchanges of data between applications, the greater is the need for utilizing standardized interfaces to manage these interactions and data exchanges. The challenges for integrating systems and software applications include:

- Selecting the data and communication protocols which will be used to transmit from one system/application to another
- Developing the data messaging models to permit applications to understand what data they are sending/receiving

- Assessing security requirements and implementing appropriate security measures, usually with multiple layers of security
- Deploying network and system management to meet security, reliability, and other network performance requirements
- Managing software application implementation and testing
- Managing system, application, and data model versioning
- Managing on-going software application maintenance and upgrading
- Managing on-going system maintenance and upgrading

4.5 Challenges Related to the Development and Enhancement of Software Applications

4.5.1 Types of Software Applications

There are literally thousands of software applications used in distribution power system operations. Some areas where software applications could be affected by distribution automation include:

- Intelligent electronic devices, controllers
- SCADA
- Distribution System Power Flow
- Distribution Management Systems
- DER management
- Mobile computing
- Outage management
- Work order management
- Engineering analysis
- Asset management
- Maintenance
- Planning
- Metering
- Construction
- Purchasing
- Auditing
- Etc.

4.5.2 Software Application Challenges

In addition to the system and communication technical challenges, the distribution automation functions need sophisticated software applications and often complex algorithms to take advantage of the automation, and return feasible and even optimal solutions. Many such applications and algorithms exist, but not all are sophisticated enough, user-friendly enough, or maintainable enough to produce the desired benefits that were used to justify the implementation of the automation in the first place. Some of the software applications which may need development and/or enhancements include:

- Real-time distribution system power flow (DSPF) models, based on three-phase models, using accurate, up-to-date power system data (both static and dynamic data), and data maintenance mechanisms which allow the model to remain accurate as on-going power system changes are undertaken.
- Real-time modeling of DER power and operational impacts included in real-time DSPF models.
- Real-time analysis of contingencies, power system switching, DER generation, and load changes, using the DSPF/DER models.
- Data consistency-checking applications, validating the consistency of data across disparate databases and sources of data.
- Standards for data models of distribution types of data (e.g. IEC's Common Information Model (CIM), IEC 61850)

4.6 Costs Associated with Functions

Costs must be assessed for implementing functions in order to undertake a true "benefit-cost" analysis. Although it is out of scope of this document to discuss costs in detail, it is important to recognize that costs can be related to many aspects of functions; these are listed in the following sections.

4.6.1 Planning Costs

- Project management
- Requirements development
- Technical specifications
- Contractual specifications
- Vendor assessments, meetings, qualification, etc.
- Bidding management or purchase management
- Contract negotiation
- Planning for data management
- Planning for integration

4.6.2 Purchase Costs

- Equipment
- Systems
- Communications
- Software applications

4.6.3 Implementation Costs

- In-house development
- Installation of equipment, systems, communications, and applications
- Training of personnel
- Data preparation
- Integration of systems, equipment, and data
- Testing of equipment, systems, communications, applications, data, and integration

4.6.4 Operation Costs

- On-the-job training to really use the function
- Keeping data up-to-date and consistent
- Handling problems, failures, mistakes, and other issues during operation

4.6.5 Maintenance and Life-Cycle Costs

- On-going maintenance of equipment, systems, communications, and applications
- Upgrading of equipment, systems, communications, and applications
- Expanding system to encompass new areas, functions, users, etc.
- Planning for replacing equipment, systems, communications, and applications

4.6.6 Financial Costs

- Inflation Rate
- Discount rate (% cost of borrowing money)
- Annual carrying charge (% cost to pay existing debts, insurance, depreciation, etc.)
- Typical Operations and Maintenance (O&M) costs (% of equipment cost)
- Typical installation costs (% of equipment cost)
- Financial lifetimes of equipment (years)
- Load Growth Rate (Average or by year)
- Growth in number of customers

- Base Year for Net Present Value Calculations

5. Primary Distribution Automation Functions

Primary Distribution Automation functions generally entail the installation of significant equipment, communication systems, and/or software applications. These installations can then provide the foundation and infrastructure for the secondary distribution automation functions.

Many variations exist on how much equipment, what type of communications, and what applications are needed in any specific primary DA functions. These variations imply different costs and different potential benefits.

There is not an absolute distinction between primary and secondary DA functions. Although primary DA functions imply significant additions of equipment and communications, some secondary DA functions may also require a certain amount of equipment to be installed in addition to primary equipment.

Also sometimes only parts of primary DA functions are implemented, and then many secondary DA functions are added without needing the full implementation of the primary functions. Sometimes just a primary DA function is installed and proves adequate for the key DA needs. Often, both primary and secondary DA functions are implemented together but in a phased approach.

5.1 Monitoring and Control of Distribution Equipment within Substations

5.1.1 Distribution SCADA System Monitors Distribution Equipment in Substations

Type/Dependency: Primary

Purpose:

Distribution SCADA monitoring would provide:

- Substation distribution breakers and reclosers state (open/close)
- Distribution feeder head measurements (current, voltage, vars, frequency, load, revenue metering)
- Feeder power quality information (fault detectors, harmonics, power quality measurements, etc.)
- Distributed energy resources (DER) within the substation (status, energy, vars, ramp rate, metering, etc.)
- Equipment condition (overheat, overload, battery level, capacity)
- Environmental (fire, smoke, temperature, sump level)
- Security for both physical and cyber security (door alarm, intrusion, cyber attack, audio/video recording)

Description:

SCADA systems at the control center monitor status and measurements of distribution equipment in substations. This status and measurement data is displayable to operators and available for other functions (the use of this data by other functions are covered in other scenarios, not this one). See Figure 4.

SCADA systems consist basically of:

- **Electronic equipment** (e.g. controllers, RTUs, IEDs) that monitors and controls the power equipment in the substation yard (and at other field locations). These controllers can be located in a control house in the substation or sometimes physically closer to the power equipment.
- **Short distance communications** between the electronic equipment and the power equipment can be copper wires, fiber optic cables (preferred for long runs because of its immunity to electromagnetic interference), and wireless (new technologies, which are still being evaluated for reliability, availability, and capabilities).
- **Remote Terminal Unit (RTU)** or substation master station which collects the appropriate data for transmission to the control center, and which passes control commands on from the control center to the electronic equipment.
- **Long distance communications** between the substation RTU/master station and the control center where the SCADA computer system is located. These communications can be any media or telecommunications service which is capable of providing at least 1200 bits per second (most can provide significantly more bandwidth nowadays).
- **Front-end processor** located in the control center (or some other distribution operations site) which handles the sending and receiving of data between the substation RTU/master station and the SCADA computer. It also translates between the different communication protocol formats and the SCADA database. Although currently the front-end processor is considered as just part of the SCADA system, some newer designs separate it from the SCADA so that it can provide data to other systems without impacting the SCADA computer.
- **SCADA computer** is typically located in close proximity to the front-end processor since the performance requirements usually entail less than one- or two-second retrieval and display of data. Although these systems can have many different software applications, typically they focus more on providing the data to the User Interface through one-line diagrams and other displays. Many SCADA systems also provide basic alarm processing, data archiving, and a method by which other systems can be provided with selected sets of data.
- **User Interface** is typically a set of one, two, or three large computer monitors per console (dispatcher desk) which can be used by distribution dispatchers to view the data on one-line and tabular displays, and issue control commands.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Sensors, controllers, IEDs, RTUs, and/or other computer-based equipment convert signals from power equipment (or other hardware) into digital data. This data can then be immediately transmitted or can be temporarily stored in the substation for later access. Most of the power equipment controllers/IEDs are mature, although new capabilities are always being added. However, DER units are still quite immature, with the types and availability of DER data still in flux.	L
Communication systems	SCADA systems require communications between the substations and the control center (minimum of 1200 bps) to provide the data in near-real-time (e.g. within 1 to 10 seconds for critical data) to the SCADA system. Communications channels to existing transmission substations usually exist; providing new communications channels to distribution-only substations can be a major cost issue.	H
Data management	Data from different types of equipment and from different vendors must be converted to the data protocol in the substation, then converted back in the SCADA system. This often results in mismatched data and significant manual effort to correct data, particularly on startup and on changes/upgrades. Compared to transmission systems, distribution systems have at least one or two more orders of magnitude of data that could be monitored, and experience significantly more frequent modifications. This data management issue is therefore a major problem requiring significant efforts to be minimized. Use of the IEC 61850 data model could assist in this data management, but it has not yet been applied to distribution SCADA (work-in-progress).	H
System integration & security	SCADA systems are used to collect, store, and perform basic calculations on the data from the field. They are designed for real-time operations, so that often the data needed by other groups are not collected. If that data is collected, it can overwhelm the SCADA system. Therefore, collection of data from the field, particularly the significantly larger amounts of data from distribution automation, should be separated from the actual real-time SCADA functions, and then made available to non-SCADA systems. Many SCADA implementations provide this connection, but usually in a customized, non-standard way. Use of the IEC Common Information Model (CIM) would allow a more standardized approach.	H
Software applications	SCADA applications are mature, but may not be capable of handling large amounts of distribution data. Although SCADA systems are very common for monitoring the transmission system, only some utilities use their existing SCADA systems for monitoring distribution equipment in those substations containing both transmission and distribution equipment. Often this distribution monitoring is very minimal, such as current at the feeder bus or feeder head and feeder breaker status. Some utilities provide SCADA for their larger distribution-only substations.	M

Potential benefits:

Direct benefits from monitored SCADA data include:

- *Decrease field crew time on routine tasks* through real-time visibility of distribution system status by operators, so fewer truck rolls to substations to check measurements
- *Increase safety* by providing safety-related information to operators

- *Increase physical and cyber security of power system operations* by monitoring access to substations

Indirect benefits (see Secondary functions) from monitored SCADA data include:

- Availability of data for many other functions
- Real-time data for historical records

5.1.2 Supervisory Control on Substation Distribution Equipment

Type/Dependency: Primary

Purpose:

Control of distribution substation equipment would include:

- Control substation distribution breakers and reclosers (open/close) for both reconfiguration purposes as well as emergency actions
- Raise and lower tap changers for voltage control
- Control capacitor bank switches for var control
- Control ancillary equipment (run diagnostics, switch to backup devices, change operating modes)
- Control environmental equipment (start/stop pumps, start/stop cooling/heating)
- Control security (lock/unlock doors, pan/zoom security cameras, turn on/off lights, update security "keys")

Description:

SCADA systems require remotely controllable equipment in the substations, communications from the substations to the control center, and SCADA supervisory control software applications.

No additional technology is needed beyond the SCADA system, except that the field equipment is enabled for control, and permission for supervisory control is granted to the distribution dispatchers.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Although SCADA systems are very common for controlling substation equipment for the transmission system, only some utilities use their existing SCADA systems for controlling the distribution equipment in substations. Therefore, many devices would have to be upgraded to permit control.	M
Communication systems	NA if monitoring already available	L
Data management	NA if monitoring already available	L

Challenge	Technical Challenges Discussion	Level
System integration & security	NA	L
Software applications	If transmission control capabilities exist then no enhancements are needed.	L

Potential benefits:

Direct benefits from controlling substation distribution equipment include:

- *Decrease field crew time on routine tasks* through initiating controls from the control center rather than having field crews perform tasks
- *Increase safety* by providing safety-related control capabilities to operators
- *Increase efficiency of power system* by improving power factors through capacitor control
- *Improve power quality for customers* by being able to control voltage and var levels
- *Increase physical and cyber security of power system* by locking gates, controlling cameras, etc.

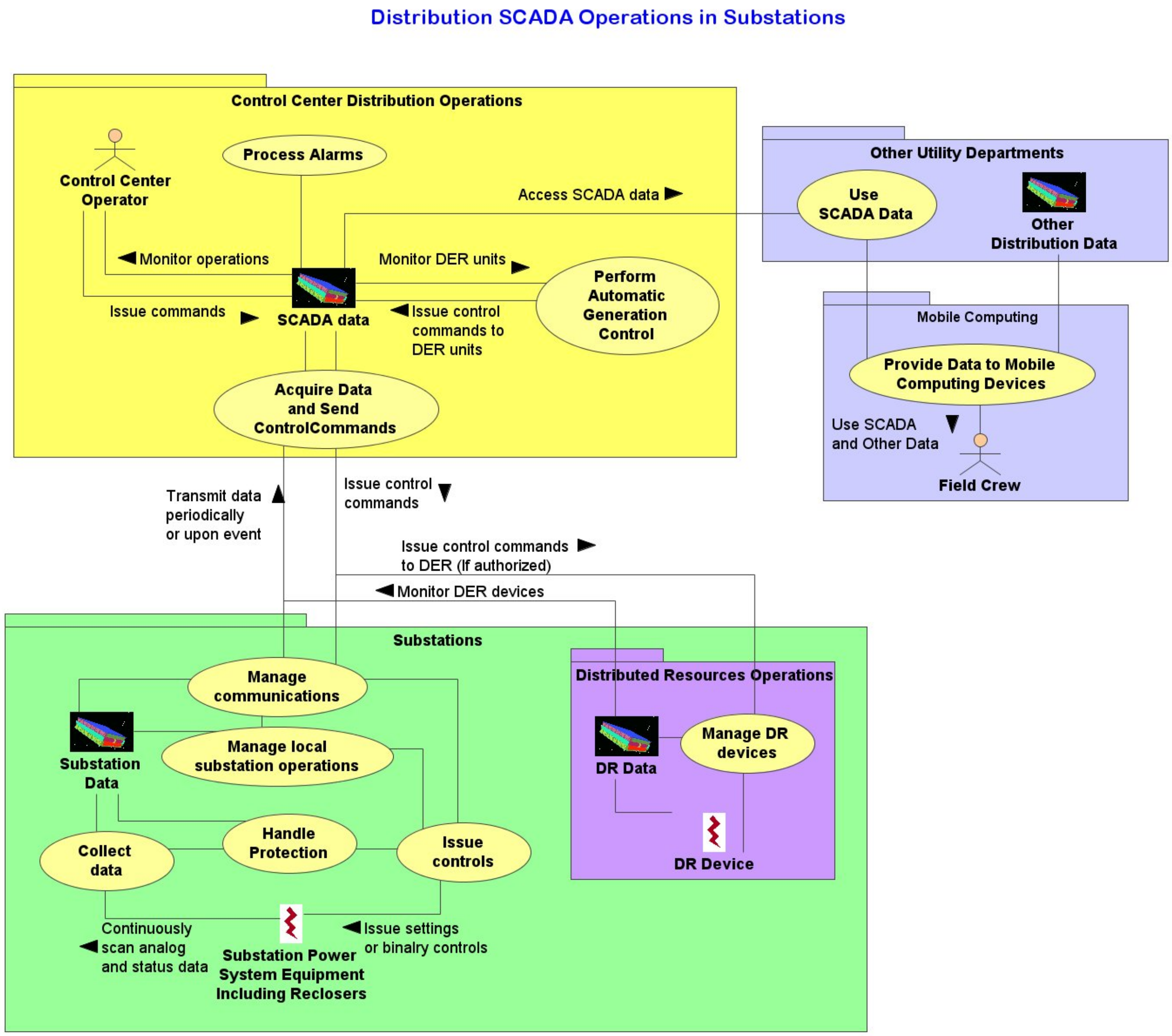


Figure 4: Real-Time Distribution SCADA Operations in Substations

5.1.3 *Substation Protection Equipment Performs System Protection Actions*

Type/Dependency: Primary

Purpose:

The purpose of protective relay and breaker actions are:

- Fault detection, clearing, and reclosing
- Under-frequency load-shedding

- Under-voltage load-shedding

Description:

Distribution protective relays respond to feeder fault and other emergency conditions and trip distribution feeder breakers in the substation.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Protective relaying equipment is quite mature	L
Communication systems	Communication systems are moving toward LAN-based configurations, although these are primarily implemented in transmission substations. Nonetheless, no technical challenges are related to using LANs in distribution substations.	L
Data management	Only protective relaying data is needed.	L
System integration & security	Protective relays interact only with each other, and indirectly with the SCADA system, so long as the action is within the substation. Security is a larger concern between substations.	M
Software applications	Protective relaying software is quite mature, although new applications may be needed as distribution systems add more DER units.	M

Potential benefits:

Direct benefits from protective relaying in distribution substations include:

- *Avoid damage* to power system equipment
- *Increase safety* for customers and field crews by de-energizing faulted lines.

5.1.4 Reclosers in Substations

Type/Dependency: Primary

Purpose:

Reclosers can be used to:

- Sense and interrupt fault currents by opening their breaker
- Attempt reclosing their breaker after a fault is detected on a feeder, usually three to four times before locking open
- Restore service via a remote control command after automated or manual switching has isolated the faulted feeder section

Description:

Installation of reclosers in substations so that power can be restored after temporary faults or if automated switching has isolated permanent faults. Reclosers are available from a number of vendors. They act on locally available data (fault currents), so they do not need communications (unless connected to a SCADA system).

Reclosers are usually provided as a single unit from a vendor, but they could be integrated from different vendor equipment. They consist of:

- Circuit breaker which trips open upon certain fault conditions
- Recloser equipment which can close the circuit breaker
- Recloser controller which handles when and how often to attempt to close the breaker after it has tripped open.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Reclosers are available from a few vendors. The basic capabilities are mature, although enhancements are always being made	L
Communication systems	NA, assuming SCADA communications from the substation to the control center	L
Data management	No significant amounts or new types of data	L
System integration & security	No integration issues	L
Software applications	Power system analysis software may need enhancements to account for recloser actions	L

Potential benefits:

- *Reduced number of outages* to customers not on the actual faulted section of the feeder
- *Decreased field crew time* to handle momentary outages that are restored by recloser actions

5.2 Local Automation of DA Equipment on Feeders

Local automation of feeder equipment consists of power equipment that is managed locally by computer-based controllers which are preset with various parameters to issue control actions. These controllers may just monitor power system measurements locally, or may include some short range communications to other controllers and/or local field crews. However, in these scenarios, no communications exist between the feeder equipment and the control center. The interactions among these activities are shown diagrammatically in Figure 5.

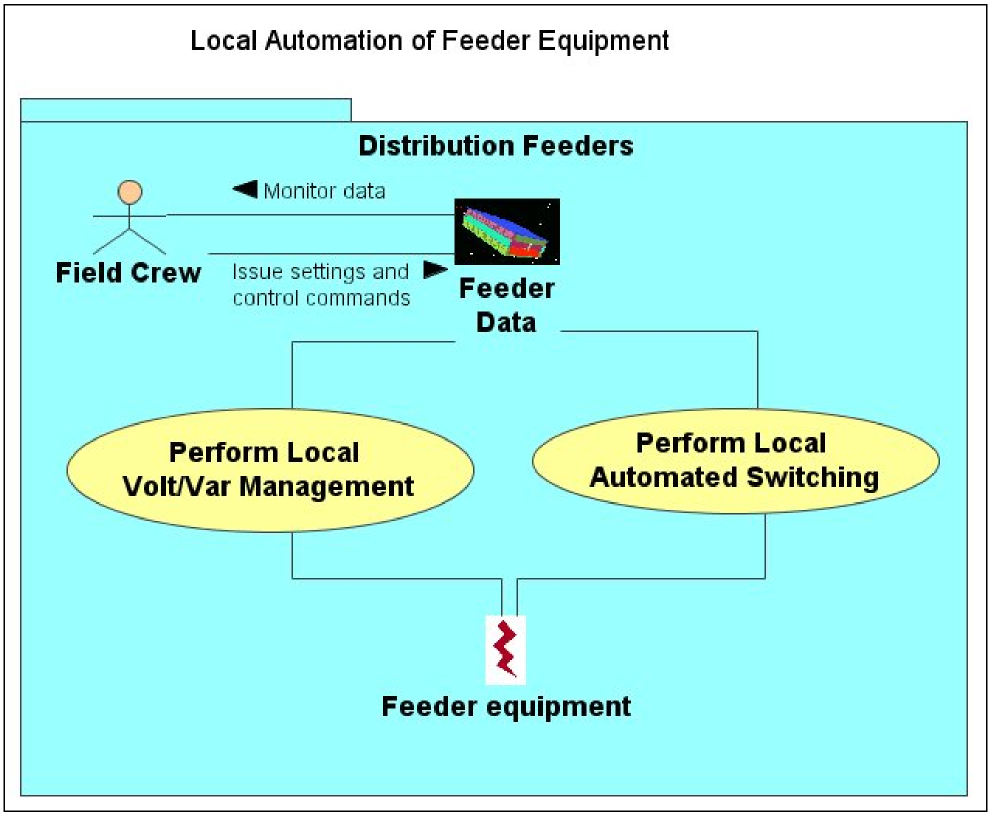


Figure 5: Local Automation of Feeder Equipment

5.2.1 Local Automated Switch Management

Type/Dependency: Primary

Purpose:

Providing "intelligent" automated switching of feeder sections, based on locally identified faults, with the purpose to:

- Reduce the number of customers experiencing a permanent outage
- Identify the location of fault to one feeder segment for rapid repair
- Allow heavier loading on feeders, since, in case of a fault, the excess capacity of adjacent feeders can be used to restore service to unfaulted segments

Description:

Automated switches are installed along feeders and at feeder tie-points. These automated switches can communicate with each other locally (typically within a few miles), and are programmed to respond appropriately to feeder fault conditions.

The steps for automated switching include:

- The vendors, engineers, and/or field crews pre-set the configuration parameters for each automated switch in a group of switches, which establishes the sequence of interactions for different fault and switching scenarios.
- When a fault occurs, it is automatically isolated by opening the source-side protective devices (typically a circuit breaker or recloser in the substation) along with the switches on the affected feeder(s).
- Using the voltage and fault current measurements in conjunction with the configuration settings, the automated switches identify the location of a fault to a specific feeder "segment".
- Once the location of the fault has been identified, the switches determine which possible power sources are available to handle the expected load of the unfaulted segments.
- The switches then proceed to restore service to as many feeder segments as possible.
- After field crews repair the faulted segment, the switches restore the feeders to their normal configuration.

In this scenario, they do not have an interface with the SCADA system (see below for that function).

The local automated switching system includes:

- Switches which can close one feeder segment into another feeder segment, typically to re-energize the segment. They can open between de-energized segments, but do not provide circuit breaking capabilities.
- Intelligent electronic controllers which can determine what action to take (open, close), based on pre-set algorithms and the current status of neighboring feeder segments.
- Communications between the intelligent electronic controllers to provide the necessary data for the controllers to determine the appropriate activity.
- Local communications between controllers and field crews who update parameter settings and download historical information.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Given that there is no connection with a SCADA system, these automated switches can respond only to local events. It is unclear whether they could, on their own, handle feeders with significant DER or respond correctly after major feeder reconfigurations. They may result in less-than-optimal global feeder configurations, since their "knowledge" is only local.	M
Communication systems	Local communications between the automated switches can be handled by many different media, including radio-based systems, telephone, cellphone (GPRS), and fiber optic systems. These are usually provided by the automated switch vendor.	L
Data management	Determining the proper parameters for switching under different conditions and events, and updating them after an event, can pose a challenge.	M

Challenge	Technical Challenges Discussion	Level
System integration & security	None at this time, since these systems are typically provided by one vendor as a whole. This may change in the future as other vendors expect to interface with these systems.	L
Software applications	Distribution planning power system analysis applications must be aware of these local actions and take them into account.	M

Potential benefits:

- *Reduce the number of customers experiencing permanent outages* by rapidly switching unfaulted feeder segments to adjacent sources of power.
- *Reduce the length of outages* by identifying the feeder segment with the fault so that field crews can go to the correct site.
- *Defer construction* of new feeders by allowing existing feeders to be more heavily loaded, since the loads can be shifted automatically to other power sources.
- *Defer upgrading* of feeder transformers since feeder loads can be reconfigured to other feeders if they are close to the transformer limits.

5.2.2 Local Volt/Var Control

Type/Dependency: Primary

Purpose:

Implementation of volt/var and power factor control, based on local conditions:

- End users have voltage levels within the specified limits
- Maintaining a power factor close to 1 minimizes losses due to excess vars

Description:

Installation of capacitor banks and voltage regulators on feeders which are controlled locally in response to time-of-day, current, voltage, or other locally measured values. (DER units that might assist in volt/var control are not considered in this scenario – see below).

These capacitor banks and voltage regulators are generally supplied as a complete unit from a specific vendor. They connect directly to the power system and respond directly to it locally. No communications are involved.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Many distribution systems already have locally controlled capacitor banks and/or voltage regulators. The feeders are assumed to be radial, with a "normal" configuration of closed and open switches and a "normal" load profile. The equipment is therefore set to be most effective for this normal condition. It is assumed that there is not a significant amount of DER generation connected to the feeder that might affect the "normal" condition.	L
Communication systems	None, since only monitoring of local power measurements is involved	L
Data management	None	L
System integration & security	None	L
Software applications	None, except power system analysis applications must be aware of these local actions and take them into account.	L

Potential benefits: Direct benefits include:

- *Improve power quality for customers* by being able to control voltage and var levels
- *Minimize losses* by maintaining a good power factor
- *Reduce greenhouse gases (GHG) pollution* (in line with regulations SB 1368 and AB 32) by reducing losses

5.2.3 Local Field Crew Communications to Underground Network Equipment

Type/Dependency: Primary

Purpose:

Field crews can use laptops to monitor vault conditions and receive alarms for abnormal conditions from outside the vault. For instance, they can:

- Monitor switch and network protector status
- Monitor environmental parameters such as temperature, pressure, and moisture in the vault, network protectors, and cables
- Monitor physical states, such as position of network protector handle
- Monitor vault equipment for safety, and avoid entering unsafe vaults
- Change setpoints from outside vault
- Issue control commands from outside vault
- Block/unblock relay actions from outside vault

Description:

Equipment in vaults are capable of local communications to field crews (e.g. wireless communications to field crews with laptops in vans in the street above the vault). This permits the field crews to monitor and possibly control vault conditions, including power, safety, and environmental equipment. In addition, some vaults are difficult to gain access to, if they are in buildings not belonging to the utility. This scenario does not include remote access to this data – see below for that scenario.

The equipment includes:

- Sensors in the vault for various conditions, including temperature, pressure, water level, moisture, gas leaks, vibration, acoustics (for possible arcing noise), etc.
- Controllers for vault equipment, such as network protectors, switches, etc. These usually include transducers which provide voltage, var, current, and frequency measurements.
- Communication equipment in the vaults, usually short distance wireless technologies, which are connected to the sensors and controllers in the vault.
- Field crew laptops with the same wireless communications technology, as well as software for accessing the vault data when within range of the vault.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Electronic controllers for monitoring and controlling networks are already in vaults. Most newer controllers have the ability to support communications, but some may need additional capabilities added. The field crew laptops are generic, but would have to support the selected communications interface.	L
Communications systems	Communications between a vault and field crews near by could be provided by a number of wireless media, including WiFi and GPRS. Although these are commonly available technologies, combining them with utility-specific data protocols and interfaces requires customization by vendors. It is unclear whether the vendor solutions provide the cyber security and reliability needed for safe operations, particularly across multi-vendor environments.	M
Data management	Data management would probably not be a major consideration for just local access to vault information. It could be a problem in a larger context, namely, if the data on the field crew laptops is used for other functions, such as engineering, planning, maintenance, and thus would have to use consistent naming, formatting, engineering units, time stamping, etc.	M
System integration & security	Some integration would be needed between the power and monitoring equipment in the vaults, the communications equipment, and the software on laptops, particularly if they come from different vendors. Communication protocols and data messaging protocols would have to be determined.	M
Software applications	Software applications would provide the monitoring and control capabilities to the field crews on their laptops. These applications would be similar to simple SCADA applications, which are quite mature.	L

Potential benefits:

- *Decreased field crew time* by allowing many activities to be performed without entering the vaults
- *Increased field crew safety* by allowing them to remain outside the vault, and to block network protective relay actions if they need to enter the vault.
- *Shorten or avoid permanent outages* on networked systems by monitoring the status of network protective relays, and getting alarms of anomalous situations before they cause an outage.

5.3 Monitoring and Control of DA Equipment on Feeders

5.3.1 SCADA Communications to Automated Feeder Equipment

Type/Dependency: Primary

Purpose:

Operators can monitor the equipment on the feeders and determine whether any overriding actions should be taken: For instance, they can:

- Remotely open or close automated switches
- Remotely switch capacitor banks in and out
- Remotely raise or lower voltage regulators
- Block local automated actions
- Send updated parameters to feeder equipment

Description:

SCADA monitoring and control is extended to automated feeder equipment. This permits operators to see the feeder data and to issue supervisory control commands to the feeder equipment. No additional software applications are used (see below for those scenarios).

Remote SCADA monitoring and control of feeder equipment requires the following additional equipment:

- Controllers for feeder equipment which are capable of remote communications, including an interface to the communications system and conversion of data into the appropriate communications protocol, such as DNP3.
- Communications system, which could be one of many configurations and technologies, including:
  - MAS radio between the feeder equipment and the closest substation, where the data would then be sent via the normal SCADA channels from the substation to the control center
  - One-way paging system to issue control commands to feeder equipment. The paging system would be connected to the SCADA system.

- Fiber optic cables strung along feeder between the feeder equipment and the substation. The data would then be sent via the normal SCADA channels from the substation to the control center.
- Coaxial cable strung along feeder between the feeder equipment and the substation or some other central site. Then higher speed communications would be used between the telecommunications provider and the control center, including private channels and/or the Internet.
- Cellphones (probably using GPRS technology) between feeder equipment and a central site, which may be the control center but could also be a telecommunication provider site. Then higher speed communications would be used between the telecommunications provider and the control center, including private channels and/or the Internet.
- Leased telephone lines between feeder equipment and a central site, which may be the control center but could also be a telecommunication provider site.
- Power line carrier (PLC) using vendor-proprietary protocols, such as TWACS and Turtle.
- Utility-owned trunked mobile radio, using one or more channels for data
- Vendor-proprietary communication networks, such as CellNet and UtiliNet
- Broadband power line (BPL) which is still in its infancy
- WiMax which is being awaited with great interest, but no deployments as yet.

• SCADA system configured to handle the additional feeder data and feeder equipment control commands.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Most newer electronic equipment that can respond locally can also be connected via communications to a SCADA system, however some might be more capable than other equipment. The technical challenge may be more a question of specifying and purchasing the most effective choice of equipment able to perform both locally and remotely.	L
Communication systems	Communications between feeder equipment and control centers are a key technical challenge. Although many alternatives for media exist (MAS radio, spread spectrum radio, paging systems, power line carrier, GPRS cellphones, etc.), the cost of implementing them has deterred most system-wide implementations. However, some solutions are becoming more cost-effective, such as GPRS and possibly WiMax, so additional analysis of these could be warranted	H
Data management	The amount of feeder data can be extremely large in comparison to the typical amounts of transmission data monitored by SCADA systems. Given the relative number of distribution-only substations and the number of feeders versus the number of transmission substations, often a 15-to-1 or more ratio, if all feeders were automated, the management of this data could be a significant issue. In particular, SCADA data would need to be correlated with GIS data, outage information, engineering databases, maintenance databases, etc.	H

Challenge	Technical Challenges Discussion	Level
System integration & security	Just like the management of the large amount of data from the distribution system, system integration for using that data would be a difficult effort. In particular, keeping track of data names, formats, engineering units, time stamps, and other consistency aspects of data management would be a large undertaking.	H
Software applications	SCADA applications are mature. Although the additional data could be large, the actual applications for monitoring and control could be the same.	L

Potential benefits:

- *Decreased field crew time* since the remote monitoring provides the information that often field crews were required to collect, including fault location, switch state, feeder voltage and var measurements, power factor, power quality
- *Increased safety of field crews* since the status of feeder equipment is better known. In addition, breakers, reclosers, and switches can be "locked out" remotely, with the locked out status monitored, to better ensure that de-energized feeders are truly de-energized.
- *Increased safety for the public* since feeder status, fault location, and outage information is known and can be used to warn the public if downed lines are a possibility, while getting field crews there more rapidly. In addition, breakers, reclosers, and switches can be opened and locked out to ensure problematic feeders are de-energized.
- *Shorten permanent outages* by either performing the appropriate switching operations remotely, or monitoring the automated switching operations and taking any additional necessary actions.
- *Defer construction* by being able to switch feeder segments remotely to off-load overloaded transformers. Also monitoring of actual feeder loads, as opposed to using peak feeder loads, can avoid replacing/upgrading transformers by using multi-feeder reconnections under the rare circumstances when those peaks actually occur.
- *Improve power quality* by monitoring the actual power quality and taking remedial actions when quality deviates beyond limits.
- *Reduce power losses through improved power factor* by monitoring the power factor in real-time and taking remedial actions whenever limits are exceeded.
- *Reduce greenhouse gasses pollution* through reducing power losses.

5.3.2 SCADA Communications to Underground Distribution Vaults

Type/Dependency: Primary

Purpose:

Operators can monitor the equipment in the vaults and determine whether any overriding actions should be taken: For instance, they can:

- Remotely open or close automated switches
- Remotely switch capacitor banks in and out

- Remotely raise or lower voltage regulators
- Block local automated actions
- Send updated parameters to feeder equipment

Description:

SCADA monitoring and control is extended to underground vaults. This permits operators to see the vault data and to issue supervisory control commands to the vault equipment. No additional software applications are used beyond standard SCADA applications (see below for those scenarios).

Many of the same types of equipment are needed for monitoring and controlling vault equipment as for monitoring and controlling automated feeder equipment, although there are some differences. For instance, some power system equipment is different, while other aspects of vaults are important to monitor because of their enclosed nature and difficulty for access by field crews. In addition, some communications media are more or less appropriate for underground systems:

- Sensors for environmental conditions
- Controllers for vault equipment which are capable of remote communications, including an interface to the communications system and conversion of data into the appropriate communications protocol, such as DNP3.
- Communications system, which could be one of many configurations and technologies, including:
  - Fiber optic cables in the conduits between the vault equipment and the substation serving the underground network. The data would then be sent via the normal SCADA channels from the substation to the control center.
  - Coaxial cable in the conduits between the vault equipment and the substation or some other central site. Then higher speed communications would be used between the telecommunications provider and the control center, including private channels and/or the Internet.
  - Cellphones (probably using GPRS technology) between vault equipment and a central site, which may be the control center but could also be a telecommunication provider site. Then higher speed communications would be used between the telecommunications provider and the control center, including private channels and/or the Internet.
  - Leased telephone lines between vault equipment and a central site, which may be the control center but could also be a telecommunication provider site.
  - Utility-owned trunked mobile radio, using one or more channels for data
  - Vendor-proprietary communication networks, such as CellNet and UtiliNet
  - WiMax which is being awaited with great interest, but no deployments as yet.
- SCADA system configured to handle the additional vault data and vault equipment control commands.

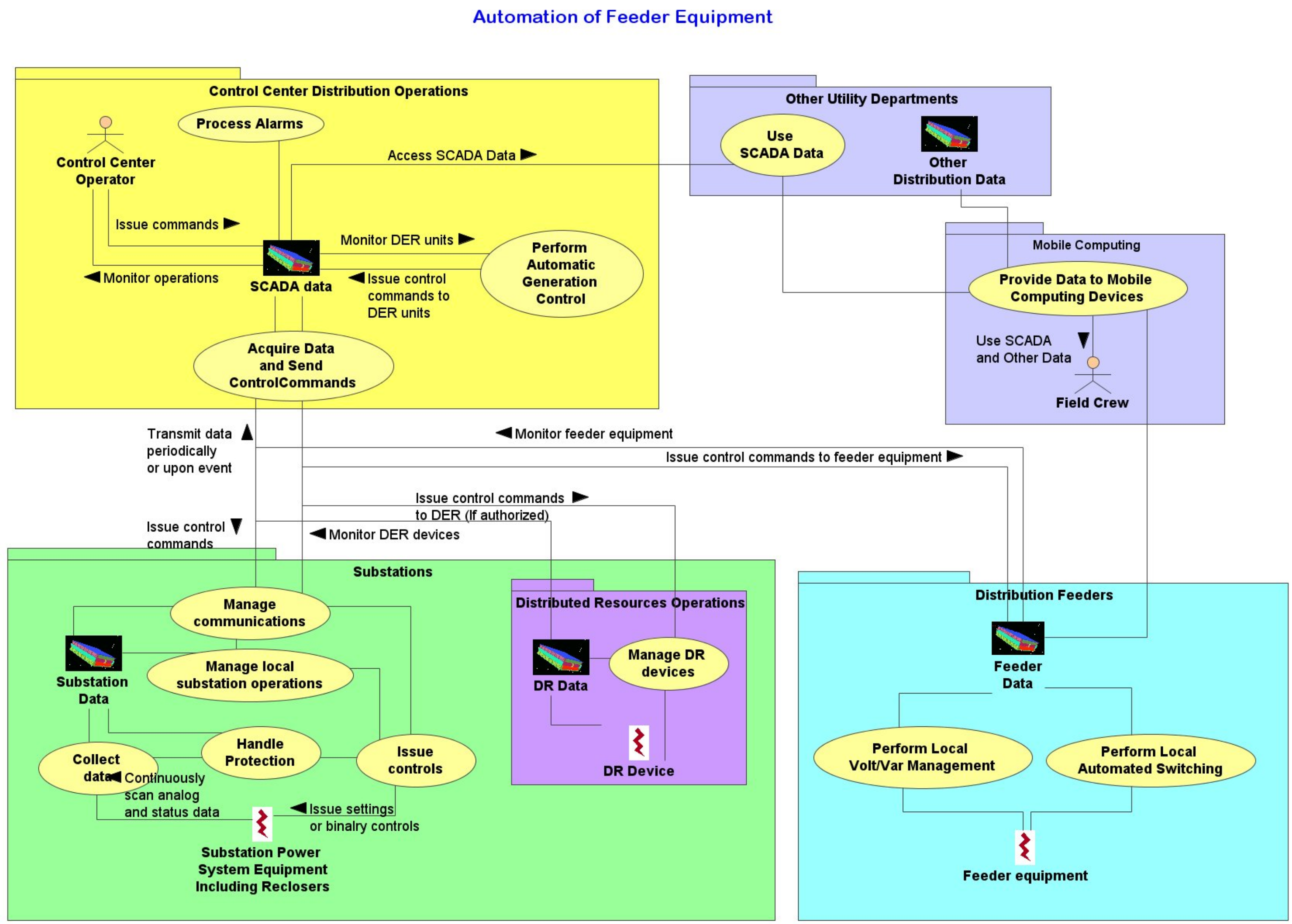


Figure 6: Information Flows in the Automation of Feeder Equipment
[from EPRI's IntelliGrid Architecture, developed by Utility Consulting International]

5.4 Management of DER Systems

As used in this document (since different terms can have different meanings in different contexts), the term "Energy Service Provider (ESP)" is either an entity affiliated with a utility (department or subsidiary) or a non-utility entity (the customer or a third party) that is charged with managing and/or directly operating DER units. The DER units can be located at a customer site or at a utility site, such as in a substation, but are being monitored and, in some instances, controlled from a remote location. Again, as used in this document, an ESP can also be an aggregator of DER units.

These functions establish the real-time monitoring and control of the DER units, but do not address how these DER units might be used or how they might impact distribution operations – those are secondary functions which are handled in subsequent sections. It is assumed that the DER units are "large enough" singly or in aggregate to warrant remote monitoring and control.

5.4.1 Protection Equipment Performs System Protection Actions on DER Interconnections

Type/Dependency: Primary

Purpose:

If the power system experiences an outage or serious power quality problem, protective equipment will disconnect any interconnected DER systems. In addition, these protective devices will also respond to faults within the DER systems.

Description:

Protection equipment monitors the interconnection between the power system and the DER units, taking appropriate actions to disconnect and/or shut down the DER units if problems occur on the power system.

It is assumed for this primary function that microgrid creation is not possible or not available – secondary functions will provide that capability.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Protective relaying equipment is quite mature	L
Communication systems	Communication systems are moving toward LAN-based configurations, although these are primarily implemented in transmission substations. Nonetheless, no technical challenges are related to using LANs in DER installations.	L
Data management	Only protective relaying data is needed.	L

Challenge	Technical Challenges Discussion	Level
System integration & security	Protective relays interact only with each other.	L
Software applications	Protective relaying software is quite mature, although new capabilities may be needed as distribution systems add more DER units, and as dynamically formed microgrids are developed.	H

Potential benefits:

Direct benefits from protective relaying in distribution substations include:

- *Avoid damage* to power system equipment
- *Increase safety* for customers and field crews by de-energizing faulted lines.

5.4.2 Monitoring of DER Units

Type/Dependency: Primary

Purpose:

ESPs monitor DER units for one or more of the following reasons:

- Monitoring of status, alarms, kW output, voltage, amps, statistics, etc.
- Aggregating the data from multiple DER units to provide to a distribution utility SCADA system
- Providing DER owners, distribution utilities, and/or market operators with the results and other information on DER operations
- Providing net metering information from DER revenue meters
- Handling market settlements and billing for DER owners
- Providing regulators and auditors with compliance information on DER operations related to contractual and environmental commitments

Description:

ESPs use SCADA or SCADA-like systems to access to real-time DER data in order to monitor the operation of DER units.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Larger DER units can have monitoring and control capabilities built-in, but smaller DER units may not. The technical challenge is to ensure that all DER units that will be remotely monitored have the capability to provide the key data in a timely manner. For instance, net meters can provide data, but not in a timely manner.	M

Challenge	Technical Challenges Discussion	Level
Communication systems	Communications between DER units and ESPs are a key technical challenge. Although many alternatives for media exist (GPRS cellphones, leased telephone lines, Internet, MAS radio, spread spectrum radio, power line carrier, etc.), the costs of these media could add up if not combined with other functions.	M
Data management	The amount of DER unit data could eventually be extremely large although only a small fraction might be used for power system operations. Nonetheless, other parts of this data would be needed for market operations, maintenance, compliance monitoring, emissions monitoring, and many other needs.	M
System integration & security	Just like the management of the large amount of data from the distribution system, system integration for the DER data could become difficult. In particular, keeping track of data names, formats, engineering units, time stamps, and other consistency aspects of data management would be a large undertaking.	H
Software applications	Although most DER units have some self-management software in their controllers, almost no software applications exist to manage significant numbers of differing DER units within a large distribution system. For instance, local switching of feeders becomes more complex if not impossible if significant DER is interconnected to the feeders. More global analysis of the impact of such generation and storage is needed to make operational and safety decisions.	H

Potential benefits:

- *Decreased field crew time* since the remote monitoring of DER units will provide the information that often field crews were required to collect on significant amounts of DER generation and storage
- *Increased safety of field crews* since the status of DER units is better known to ensure that de-energized feeders are truly de-energized.
- *Increased safety for the public* since DER unit status is known and can be used to warn the public if downed lines are a possibility, while getting field crews there more rapidly. In addition, breakers, reclosers, and switches can be opened and locked out to ensure problematic feeders are de-energized.
- *Shorten permanent outages* by using DER units in a microgrid arrangement to provide local generation.
- *Defer construction* by being able to use local DER generation to off-load overloaded transformers during peak periods, or to decrease the effective load of many feeders to off-load transmission.
- *Improve power quality* by monitoring the actual power quality and taking remedial actions with DER units when quality deviates beyond limits.
- *Reduce power losses through improved power factor* by monitoring the power factor in real-time and taking remedial actions with DER units whenever limits are exceeded.
- *Reduce greenhouse gasses pollution* through reducing power losses by using local generation. In addition, many types of DER units, such as PV, wind, CHP, and biomass, have lower overall carbon footprints than large generating plants.

5.4.3 Controlling DER Units

Type/Dependency: Primary, but requires the capability to monitor the DER units as well (see 5.4.1)

Purpose:

Control of DER units could involve one or more of the following purposes:

- ESP dispatches a local operator to manually control the DER device (on, off, or at specified settings).
- ESP responds to distribution utility request (e.g. demand, permission, or pricing signal) to turn DER unit on (to run at full power) or off
- ESP sets DER at a specific setpoint to provide a fixed amount of generation (e.g. to offset load, to provide local generation for reliability and/or demand-response, to shave peaks).
- ESP controls DER operations through automatic control to meet specified operational needs and contracts (e.g. power quality, emissions, economic dispatch, energy schedules, ancillary service contracts, real-time pricing, local backup, interconnection with distribution system)

Description:

ESPs use SCADA or SCADA-like systems to control DER units. This function would entail significantly closer monitoring and analysis of the DER units than just monitoring them, since control actions could have far reaching ramifications to the distribution power system and customers connected to the feeders with the DER units.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Larger DER units can have monitoring and control capabilities built-in, but smaller DER units may not. The technical challenge is to ensure that all DER units that will be remotely monitored have the capability to provide the key data in a timely manner. For instance, net meters can provide data, but not in a timely manner.	M
Communication systems	Communications between DER units and ESPs are a key technical challenge. Although many alternatives for media exist (GPRS cellphones, leased telephone lines, Internet, MAS radio, spread spectrum radio, power line carrier, etc.), the costs of these media could add up if not combined with other functions.	M
Data management	The amount of DER unit data could eventually be extremely large although only a small fraction might be used for power system operations. In particular, control over DER units will necessitate close monitoring of DER unit characteristics and responses to ensure the control actions are effective, safe, and do not have unintended consequences.	M
System integration & security	Just like the management of the large amount of data from the distribution system, system integration for the DER data could become difficult. In particular, keeping track of data names, formats, engineering units, time stamps, and other consistency aspects of data management would be a large undertaking.	H

Challenge	Technical Challenges Discussion	Level
Software applications	Although most DER units have some self-management software in their controllers, almost no software applications exist to manage significant numbers of differing DER units within a large distribution system. For instance, local switching of feeders becomes more complex if not impossible if significant DER is interconnected to the feeders. More global analysis of the impact of such generation and storage is needed to make operational and safety decisions. In particular, remote control over DER units will provide challenges related to operational issues, safety issues, market issues, privacy issues, reliability issues, tariff issues, legal issues, and other external considerations.	H

Potential benefits:

- *Decreased field crew time* since the remote monitoring and control of DER units will provide the information that often field crews were required to collect on significant amounts of DER generation and storage
- *Increased safety of field crews* since the status of DER units is better known and can be remotely turned off to ensure that de-energized feeders are truly de-energized.
- *Increased safety for the public* since DER unit status is known, this information can be used to warn the public if downed lines are a possibility, and additional control actions can be taken to ensure the appropriate feeders are truly de-energized.
- *Shorten permanent outages* by controlling DER units in a microgrid arrangement to provide local generation.
- *Defer construction* by being able to use local DER generation to off-load overloaded transformers during peak periods, or to decrease the effective load of many feeders to off-load transmission.
- *Improve power quality* by monitoring the actual power quality and taking remedial actions with DER units when quality deviates beyond limits.
- *Reduce power losses through improved power factor* by monitoring the power factor in real-time and taking remedial actions with DER units whenever limits are exceeded.
- *Reduce greenhouse gasses pollution* through reducing power losses by using local generation. In addition, many types of DER units, such as PV, wind, CHP, and biomass, have lower overall carbon footprints than large generating plants.

5.5 DA Analysis Applications

5.5.1 Study-Mode and Real-Time Distribution System Power Flow (DSPF) Model

Type/Dependency: Primary

Purpose:

The purpose of the DSPF model is to use as much asset data and real-time data as is available to develop a computer model of the distribution power system. Not all data can or even should be expected to be available, since that would necessitate extensive communication networks. But reasonably accurate and up-to-date models of the distribution power system can be used by power flow algorithms to calculate the flows of energy and reactive power, and allow secondary functions to make use of the results.

- Validate the consistency and accuracy of the modeling data and the real-time SCADA data. Very often this data is far from consistent; the DSPF model can detect inconsistencies and sometimes even correct it.
- Update and analyze real-time operating conditions using state estimation and distribution power flow algorithms.
- Assess system capacity to handle current and near-term conditions, based on equipment ratings and how close the power system is to those ratings as measured by real-time data.
- Provide operators with visibility of the actual distribution system status through the DSPF model.
- Issue alarming/warning messages to the operator on inconsistent data, limits that are exceeded, and other results from the basic power flow execution.
- Generate distribution operation reports and logs as an audit trail of distribution operations and conditions.
- Provide a model of the distribution system that can be used by other applications for additional analysis.

Description:

The real-time distribution system power flow (DSPF) model is a computer model of the distribution system that reflects current operating conditions. This power system model is constructed from the following models and types of data:

- **Topology model**: 3-phase physical connectivity of the distribution system, often found in Geographic Information Systems, Automated Mapping systems, and paper drawings. This configuration model includes connectivity to the transmission system, interconnections between feeders, locations of aggregated loads, and connections to distributed energy resources.
- **Facilities model**: power system equipment such as circuit cable characteristics, substation transformers, circuit breakers, capacitor banks, voltage regulators, and feeder

switches, as well as the capabilities of the equipment controllers. This facilities data is derived from the Facilities Management system and other engineering databases.

- **Load model**: aggregated loads with load profiles, associated with locations along feeders. These load models are derived from the Customer Information System (CIS).
- **Transmission interface model**: the characteristics of the interfaces between the transmission system and the distribution system. This transmission model is extracted from the Energy Management System power system model.
- **Real-time data**: distribution system status and measurement data from the SCADA system applied to the combined models, so that the result is an up-to-date model of the current distribution system, showing actual electrical connectivity and power system measurements.

These models must be updated continuously, given the frequency of construction, upgrades, maintenance, reconfigurations, and other work on the distribution system. Data access from the SCADA system is continuous, while data updates from the other databases would be change-driven.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Although the DSPF does not explicitly require automated equipment in the field, the secondary functions which utilize its power flows would need automated field equipment.	L
Communication systems	LAN or WAN connections to SCADA system and other operational systems.	L
Data management	Accurate information on the distribution system must be available and up-to-date, so that power flow results of the DSPF can be accurate. This data comes from the Geographical Information System (GIS), primary and secondary asset information from asset databases, load profiles from the Customer Information System (CIS), electrical connectivity from SCADA data, study data from historical SCADA databases, etc. In many utilities, this data is not always accurate and is often out-of-date. Keeping the data up-to-date once the DSPF has been implemented can be an enormous task.	H
System integration & security	Access to accurate information comes from multiple systems, including accurate physical connectivity of the distribution system from the Geographical Information System (GIS), primary and secondary asset information from asset databases, load profiles from the Customer Information System (CIS), electrical connectivity from SCADA data, study data from historical SCADA databases, etc. Interfacing to these many different systems typically supplied by different vendors should make use of communication and data standards for such interfaces, but most vendor products do not support many of these standards yet.	H

Challenge	Technical Challenges Discussion	Level
Software applications	DSPF applications using 3-phase models of distribution power systems do exist from a number of vendors, but some products have greater or lesser capabilities than others. For instance, many are designed for planning or off-line study/static conditions, and are not designed for real-time operations. These are limited in handling daily operational decisions as well as emergency responses to abnormal conditions. Therefore, ensuring that the DSPF software is adequate for not only current requirements but future requirements can be an enormous challenge.	H

Potential benefits:

An accurate, real-time, 3-phase DSPF model of the distribution system provides the key to the following benefits which may be realized by adding (secondary function) software applications to make use of the model.

Direct financial benefits:

1. *Improved visibility into distribution operations for utilities and regulators*
2. *Deferred construction – capital savings:*
3. *Decreased field crew personnel time:*
4. *Decreased engineering personnel time:*
5. *Extend equipment life-time:*
6. *Improve utilization of equipment:*
7. *Reduce O&M expenses:*
8. *Reduce the cost of energy generation:*
9. *Reduce peak loads (peak shaving) by demand reduction or deferral:*
10. *Reduce peak loads by managing DER generation/storage:*
11. *Avoid legal and regulatory penalties:*

Power reliability and power quality benefits:

12. *Participate in market operations: Market operations can enhance the payback from*
13. *Shorten or avoid permanent outages (e.g. outages longer than 5 minutes) to customers:*
14. *Decrease the number of customers experiencing permanent outages:*
15. *Permit and support additional DER interconnections:*
16. *Manage DER generation/storage to improve reliability:*
17. *Support operators in decision-making during emergencies:*
18. *Reduce loads during emergency conditions:*
19. *Improve power quality (voltage deviation, voltage imbalance):*
20. *Improved transparency of operations*
21. *Improved auditability*

5.5.2 DSPF /DER Model of Distribution Operations with Significant DER Generation/Storage

Type/Dependency: Primary, although based on the real-time DSPF model of the distribution system (see Section 5.5.1).

Purpose:

The purpose of DSPF/ DER model of the distribution system is to provide additional visibility into the distribution system when significant amounts of DER generation and storage have been interconnected with distribution circuits. This model would then permit additional real-time, short time, and planning assessments to be made on the distribution system.

In addition to the purposes described for the basic DSPF model, the following capabilities would be available:

- Validate the consistency and accuracy of the DER models and the real-time SCADA data. Very often this data is far from consistent; the DSPF model can detect inconsistencies and sometimes even correct it.
- Update and analyze real-time operating conditions using state estimation and distribution power flow algorithms, now with DER units adding generation and storage capabilities.
- Assess system capacity, given the availability of DER generation and storage, to handle current and near-term conditions, based on equipment ratings and how close the power system is to those ratings as measured by real-time data.
- Provide operators with visibility of the actual distribution system status and the DER generation and storage capabilities through the DSPF model, thus providing concise and accurate "information" about the distribution operations, not just reams of "data".
- Issue alarming/warning messages to the operator on inconsistent data, limits that are exceeded, and other results from the basic power flow execution, covering both the distribution system equipment as well as DER equipment.
- Generate distribution operation reports and logs as an audit trail of distribution operations and conditions, including the DER generation and storage capabilities.
- Provide a model of the distribution system including DER generation and storage that can be used by other applications for additional analysis (see functions below).

Description:

The DSPF model of the distribution power system would have to be updated to include power system models of the different types of DER units. These DER models would need to include the following aspects:

- Ratings of larger DER units
- Equivalent "ratings" of aggregated smaller DER units
- Possible modes of operation at the Point of Common Coupling (PCC)

- Real-time mode of operation at the PCC
- Current status

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Although the DSPF does not explicitly require automated equipment in the field, the secondary functions which utilize its power flows would need automated field equipment.	L
Communication systems	LAN or WAN connections to SCADA system and other operational systems.	L
Data management	Accurate information on the distribution system must be available and up-to-date, so that power flow results of the DSPF can be accurate. This data comes from the Geographical Information System (GIS), primary and secondary asset information from asset databases, load profiles from the Customer Information System (CIS), electrical connectivity from SCADA data, study data from historical SCADA databases, etc. In many utilities, this data is not always accurate and is often out-of-date. Keeping the data up-to-date once the DSPF has been implemented can be an enormous task.	H
System integration & security	Access to accurate information comes from multiple systems, including accurate physical connectivity of the distribution system from the Geographical Information System (GIS), primary and secondary asset information from asset databases, load profiles from the Customer Information System (CIS), electrical connectivity from SCADA data, study data from historical SCADA databases, etc. Interfacing to these many different systems typically supplied by different vendors should make use of communication and data standards for such interfaces, but most vendor products do not support many of these standards yet.	H
Software applications	DSPF applications using 3-phase models of distribution power systems do exist from a number of vendors, but some products have greater or lesser capabilities than others. For instance, many are designed for planning or off-line study/static conditions, and are not designed for real-time operations. These are limited in handling daily operational decisions as well as emergency responses to abnormal conditions. Therefore, ensuring that the DSPF software is adequate for not only current requirements but future requirements can be an enormous challenge. In addition, most DSPF applications do not have good models of DER units. Simple models of small DER units are adequate for general planning, but as/if DER units become larger or as more, small DER units reside on the same feeders, then these simple models will not be adequate for most DSPF applications.	H

Potential benefits:

An accurate, real-time, 3-phase DSPF model of the distribution system provides the key to the following benefits which may be realized by adding (secondary function) software applications to make use of the model.

Direct financial benefits:

1. *Improved visibility into distribution operations for utilities and regulators*
2. *Deferred construction – capital savings:*
3. *Decreased field crew personnel time:*

4. *Decreased engineering personnel time:*
5. *Extend equipment life-time:*
6. *Improve utilization of equipment:*
7. *Reduce O&M expenses:*
8. *Reduce the cost of energy generation:*
9. *Reduce peak loads (peak shaving) by demand reduction or deferral:*
10. *Reduce peak loads by managing DER generation/storage:*
11. *Avoid legal and regulatory penalties:*

Power reliability and power quality benefits:

12. *Participate in market operations: Market operations can enhance the payback from*
13. *Shorten or avoid permanent outages (e.g. outages longer than 5 minutes) to customers:*
14. *Decrease the number of customers experiencing permanent outages:*
15. *Permit and support additional DER interconnections:*
16. *Manage DER generation/storage to improve reliability:*
17. *Support operators in decision-making during emergencies:*
18. *Reduce loads during emergency conditions:*
19. *Improve power quality (voltage deviation, voltage imbalance):*
20. *Improved transparency of operations*
21. *Improved auditability*

5.6 Advanced Metering Infrastructure (AMI)

Advanced Metering Infrastructure (AMI) has many more justifications than just for supporting distribution automation, but those functions are outside the scope of this document. So the DA functions associated with AMI that are described in this document are limited to those that directly support distribution automation.

5.6.1 Implementation of AMI to Industrial, Commercial, and Residential Customers

Type/Dependency: Primary

Purpose:

The purpose of the AMI system is to provide the communications infrastructure between the utility and customer premises. This infrastructure can then provide the foundation that many secondary functions can use. *(Many definitions of AMI exist; in this document, AMI is defined as just the infrastructure, while the secondary functions provide the capabilities. This slightly simplistic approach permits utilities to select which secondary functions are required to meet* *their needs. Again in this document, only those secondary functions that are relevant to DA are included.)*

Description:

Implementation of the Advanced Metering Infrastructure (AMI) communications and gateway into the customer premises would be required before direct and timely interactions can be undertaken with customers. The AMI would provide a communications infrastructure to each customer's intelligent meter and possibly to customer energy management systems, smart thermostats, and/or home automation networks.

This AMI would permit not only reading of customer meters, but also exchanges of many different types of data. Those data exchanges are the secondary functions: but only the secondary DA functions are described in Section 8.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Smart meters, smart thermostats, customer energy management systems, home automation systems, and customer gateways are all being developed, but still need significant efforts to manage the technical and financial challenges to make AMI beneficial	H
Communication systems	Communications from customer premises are a key technical challenge. Although many alternatives for media exist (GPRS cellphones, leased telephone lines, Internet, MAS radio, spread spectrum radio, BPL, power line carrier, etc.), the costs of these media could make AMI very expensive.	H
Data management	Vast amounts of data from millions of customers will make data management a very great technical challenge. Although techniques and standards are being developed to address these challenges, they are neither fully developed nor implemented by many vendors in their products.	H
System integration & security	Customer information will be utilized by many different functions in many different forms. For instance, aggregated residential customer loads is required by the DSPF to model load shapes over time. The same will be true for DER generation and storage information, which will be needed for establishing microgrids as well as normal distribution operations. Security will be a major challenge, since customer systems and utility systems will need to be integrated at some level, so that access and privacy will be key challenges.	H
Software applications	Many disparate software applications exist which can utilize some data that would come through an AMI system. But since no AMI system yet exists, almost all software applications would need to be enhanced or developed completely.	H

Potential benefits:

AMI by itself does not have benefits: it is the secondary functions that use the AMI infrastructure that provide the benefits. Even meter reading is considered a secondary function in this context.

5.6.2 Direct Customer Load Control

Type/Dependency: Primary

Purpose:

Direct load control allows the utility to issue control commands directly to customer appliances in order to reduce, cycle, shut off, or otherwise directly control some pre-specified set of customer loads. *(In comparison, indirect load control would leave it up to the customer to control their own loads upon a signal from the utility.)*

Direct control of customer loads plays a very important role in power system reliability. These direct load control actions include:

- Residential load control usually includes cycling control over of water heaters, air conditioners, pool pumps, and other appliances
- Commercial and industrial load control can refine the control actions:
  - Curtails customer loads
  - Interrupts customer loads
  - Sheds customer loads (under frequency / under voltage)
  - Requests load-reducing volt/var control
- Permissive power provision -- devices can request a limit of power. This would allow an emergency device to use power while other loads might not. Scheduled and load limited. Actual compliance is based on metering information.
- Aggregation of customers who are requested to reduce load amongst them when asked to curtailed. Actual compliance is based on metering information.

Description:

Direct load control requires the implementation of automation connected to customer appliances and equipment, so that these loads can be managed through remote utility actions. Many different communications configurations can be used to provide load control, including:

- One-way paging systems directly to customer loads
- One-way radio-based systems directly to customer loads
- Two-way power line carrier through home automation network
- Customer energy management system manages in response to signals or schedules
- Any of the communications infrastructures provided by AMI

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Direct control equipment has been available for many years. Improvements and new capabilities require some development	L

Challenge	Technical Challenges Discussion	Level
Communication systems	Except for the AMI infrastructure, the other communication systems have been available for years.	L
Data management	Determining what loads need to be reduced, and whether they actually were reduced can require some data management. At the present time, direct load control assumes that a certain percentage of load will probably be reduced, so only after-the-fact compliance needs to be managed. This may change as direct load control is more finely tuned in the future, for instance if a customer's DER energy is available to replace direct reduction of their load.	M
System integration & security	System integration and particularly security (including customer privacy) will become greater challenges as more finely tuned direct load control is implemented, and as DER energy may be substituted for load reduction.	H
Software applications	Existing direct load control uses well-established load control software applications. However, in the future, customer energy management systems will need to become significantly more sophisticated to respond appropriately to load control commands from utilities.	H

Potential benefits:

Direct load control .

6. Secondary DA Functions – Operational DA Functions

6.1 Real-Time Normal Distribution SCADA Operations – Substations

Real-time normal distribution SCADA operations in substations are typically (but not always) the first step toward distribution automation. These distribution SCADA activities often piggyback on transmission SCADA if the utility also manages transmission power systems. The interactions among these activities are shown diagrammatically in Figure 4.

6.1.1 Alarm Processing

Type/Dependency: Secondary: dependent on Distribution SCADA system

Purpose:

Alarm processing of distribution information from the substations

- Real-time alarms are announced to operators via the SCADA system
- Intelligent alarm processing by SCADA system to identify the true source or nature of the problem, particularly analyzing raw alarm data and annunciating the overall problem to the operator rather than each individual alarm
- Distribution of alarms to non-operators:
  – overloads and replacement issues to maintenance engineer
  – automated work management system
  – fault records and SOEs to protection engineers
  – information to outage management systems

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	NA, assuming SCADA monitoring of raw alarms is already available	L
Communication systems	NA, assuming SCADA communications systems are already available	L
Data management	Large number of alarms can overwhelm operators, so they cannot determine the exact nature of the problem. This problem can be ameliorated by software analysis of raw alarm information.	M
System integration & security	Alarms need to be available to other users, not just operators, including maintenance, engineers, etc. The alarm data must be made available to non-SCADA systems.	M
Software applications	Analyzing alarms through software can require sophisticated algorithms. Knowledge-based and neural network approaches have been tried.	H

Potential benefits:

- *Avoid or shorten outages or other problems* through the greater speed and accuracy in recognizing potential problems
- *Decreased field crew time to determine and drive to* the true source of the distribution system problems
- *Improved safety for field crews* when alarm conditions are relayed to them (by voice or automation)

Indirect benefits (see other Secondary functions) include:

- Provide alarm information to other groups for their decisions on immediate or scheduled actions:
  - overloads and replacement issues to maintenance engineer
  - automated work management system
  - fault records and SOEs to protection engineers
  - information to outage management systems

Description:

Some alarms can be directly detected from power equipment in the substation, while additional alarm processing software applications are added to the basic SCADA system in the control center.

Alarm processing is usually software applications that are embedded or closely integrated with SCADA systems.

6.1.2 Distributed Energy Resources (DER) in Substations

Type/Dependency: Secondary, with dependency on distribution SCADA to monitor and control DER units

Purpose:

DER units within substations can be used for the following purposes:

- Provide energy
- Provide volt/var support
- Provide ancillary services, such as generation reserves, load following, peak shaving, etc.
- Provide emissions balancing (if renewable DER technologies are used)
- Potentially allow microgrids to be formed

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Different types of DER generating and storage devices are being developed, with some technologies more mature than others, and some very much in their infancy as robust, highly reliable products, for extended use in substations (as opposed to occasional use as backup or other temporary purposes). These technologies are being rapidly modified, improved, scaled up in size, and enhanced in capabilities, so interconnecting them to the substation grid and utilizing them effectively while maintaining system reliability can still be a challenge.	H
Communication systems	Assume that SCADA communications between the substation and the control center are adequate for additional data from DER units	L
Data management	DER units may provide significant amounts of data to many different groups. Standards are being developed (IEC 61850-420) for data models of DER communications requirements. These standards are, as yet, incomplete, but will help in managing the data.	H
System integration & security	Since DER data may be of significant interest to many other groups, the data from the SCADA system will need to be available in a timely, secure, and reliable manner.	H
Software applications	The addition of DER generating equipment into substations is relatively new. Therefore, very little assessment of how best to utilize and/or manage this DER equipment has been undertaken. It is expected that significant effort to develop and enhance software applications will be needed to ensure reliable operations under contingency/emergency conditions.	H

Potential benefits:

- *Increase efficiency of power system* by improving power factors through DER control
- *Deferred upgrades of feeder transformers* through using DER to offset peak loads and switching feeders to backup/redundant transformers
- *Reduce outages due to failed transformers* through using DER and/or switching feeders between transformers
- *Improve power quality for customers* by being able to control voltage and var levels with DER
- *Decrease payment for generation (increase revenues from generation)* through use of DER for both energy and ancillary services in the electricity market or utility contracts
- *Reduced costs for operational or other energy reserves* through the availability of DER generation
- *Reduce GHG emissions (dependent on type of DER unit)* for meeting SB1368 and AB32 regulations, for emission's market benefit, and for general societal benefit

Description:

Interconnection of DER units to the distribution system within substations. These DER units are managed by the utility. This function is separate from the more complex management required of

DER units which are interconnected along distribution circuits. The latter are discussed in more detail in Section 7.

DER units consist of:

- Prime movers (e.g. the diesel engine, the wind turbine, the hydro turbine, photovoltaic cells)
- Generators which convert the prime mover's energy into electrical energy
- Controllers which manage the prime movers and generators
- Auxiliary systems which monitor fuel, environment, protection, etc.

6.1.3 SCADA System Provides Data to Mobile Computing Devices

Type/Dependency: Secondary: dependent on Distribution SCADA system and assuming the availability of mobile computing devices

Purpose:

Real-time distribution system information from the substations is provided to field crews and activities are logged

- Field crews receive substation measurements
- Field crews receive switching orders
- Field crews acquire GIS drawings, equipment records, customer profiles
- Field crews log activities and results of tests
- Field crews identifies assets installed and/or removed

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Mobile computing equipment is available from a number of vendors, and is continuously being upgraded in response to requirements and technology enhancements.	L
Communication systems	Additional communications systems must be able to transmit this relevant data to the mobile computing devices. These might be LANs in field offices or could be wireless communications to the field (e.g. mobile radio system, GPRS, etc.). However, these systems use typical IT technologies, so those technical challenges are not considered in this document	L
Data management	The data needed by the field crews must be identified and/or calculated; possibly combining SCADA real-time data with switching orders from the operators and with other more static data (e.g. GIS maps, customer information). This data management, particularly the management of data consistency and data validity, can be an immense challenge.	H
System integration & security	SCADA data and data from other sources need to be accessed by the system sending the information to the mobile computing devices. This integration often uses a customized approach which could be improved through standardization efforts.	M

Challenge	Technical Challenges Discussion	Level
Software applications	Vendors have software to display data on mobile computing devices, and are updating their offerings continually.	L

Potential benefits:

- *Improved safety* – field crews have accurate information on substation distribution system status
- *Decreasing time of field crews* to determine status of distribution system
- *Decreased time of field crews* to report activities and log the status of equipment
- *Avoid or shorten outages or other problems affecting customers* through the greater speed and accuracy in providing information to field crews

Description:

Mobile computing devices receive data from SCADA system. This requires the provision of mobile computing devices to field crews and the means of uploading data to them in real-time or near real-time, either through direct connections (e.g. LAN in field crew offices) or wireless communications (e.g. cellphone or mobile radio network).

Mobile computing systems consist of the following:

- Laptops or equivalent PDA systems used by field crews
- Communications media to the laptops/PDAs which could be the utility's mobile radio system, GPRS cellphone systems, WiFi LAN from a computer system, Ethernet cable LAN
- Communications interface between the SCADA data and the communications media, which converts data to the appropriate communications protocol and format
- SCADA system with the ability to send data to the communications interface.

6.2 Local Automation of Feeder Equipment – Beyond Substations

6.2.1 Reclosers Interact with Field Equipment

Type/Dependency: Secondary, dependent upon reclosers being installed in substations

Purpose:

Reclosers can be used to:

- Sense and interrupt fault currents by opening their breaker
- Attempt reclosing their breaker to determine if power can be restored, usually three to four times before locking open
- Restore service via a remote control command after automated or manual switching has isolated the faulted feeder section

Description:

Reclosers in substations initially trip on feeder faults, but can attempt reclosing 3 or 4 times to determine if power can be restored after temporary faults or if automated switching has isolated permanent faults. They act on locally available data (fault currents), so they do not need communications (unless connected to a SCADA system).

6.2.2 Local Field Crew Communications to Automated Feeder Equipment

Type/Dependency: Secondary, dependent on the implementation of automated feeder equipment.

Purpose:

Field crews (typically as authorized by operators and/or engineers) use their laptops to:

- Upload parameter settings to field equipment, such as voltage regulator settings, capacitor bank switching settings, and switch fault settings.
- Download real-time and historical data from field equipment, such as historical list of actions, current measurements, and current settings.
- Issue commands to field equipment, such as raise/lower, open/close, and change mode of operation.
- Exchange information with engineering systems, including the parameter settings, the real-time and historical data, the commands issued, and other field crew activities.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	Automated feeder equipment would need software applications and communications capabilities to interact with laptops used by field crews. Laptops themselves are a mature technology. The software applications in the equipment is typically supplied by the vendors of that field equipment. Although that software might be a challenge for the vendor, it would not be a general challenge.	L
Communication systems	Short distance communications media are usually used, including infrared, spread spectrum point-to-point, WiFi, Bluetooth, cable, etc. These communications media are relatively mature, but the use of them in this application are rather new.	M
Data management	Data management for this function could be part of a larger data management effort for distribution automation information. If so, it would need to be handled in that larger context.	M
System integration & security	The data and software applications on the laptops would need to be coordinated and consistent with those on engineering systems.	M
Software applications	The software applications on the laptops would most likely be supplied by the equipment vendors, in order to be compatible with the equipment software and communications. Although that software might be a challenge for the vendor, it would not be a general challenge.	L

Potential benefits:

- *Decreased field crew personnel time* by providing access to the field equipment information without the need to climb the pole.
- *Improved safety of field crew* by minimizing the need to climb poles or get near high voltage circuits.
- *Shorten permanent outages* by allowing field crews to open and close switches more quickly once any repairs have been performed.
- *Defer construction* by allowing field crews to modify settings and configurations easily, and thus be able to take advantage of these changes to delay power equipment upgrades or replacements.

- *Improve power quality* by making power quality settings more consistent with current distribution system configurations
- *Reduce power losses through improved power factor* by allowing field crews to easily change settings to reflect current operating conditions.
- *Reduce greenhouse gasses through reduce power losses.*

Description:

Field crews use laptops or other computer-based equipment to communicate with automated field equipment, typically from a short distance away (e.g. at the base of the pole).

The equipment in this function includes:

- Controllers for voltage regulators, capacitor switches, automated switches, fault detectors, and other field equipment. These can be at the top of poles, part way down poles, or in locked containers at the base of poles. In addition to their primary functions, they often include transducers for voltage, var, current, and frequency measurements.
- Laptops or other PDAs which contain communications software and typically the vendor's software for interacting with the automated feeder equipment.
- Short distance communications, such as Ethernet cable that can be plugged into the controller at the base of the pole, point-to-point wireless communications, or network wireless systems, both of which allow the controller to be more protected, higher on the pole.

6.3 Remote Monitoring and Control of Automated Feeder Equipment

Remote monitoring and control of automated feeder equipment provides communications between the feeder equipment and other systems, including the SCADA systems, engineering systems, maintenance systems, field crew laptops, etc. This scenario assumes only typical SCADA software applications are used for operations, i.e. only monitoring and operator supervisory control, but does assume that the data is available to other groups. Functions including DER monitoring and control, as well as functions with ADA software applications are described below.

The interactions among these activities are shown diagrammatically in Figure 6.

6.4 Normal Distribution Operations Using DSPF Model

Advanced Distribution Applications (ADA) for normal operations are a set of software programs and databases whose purpose is to model and analyze the entire distribution system in order to improve the power system reliability, power quality, and power system efficiency. Many of the same software applications are also used for emergency operations, but for clarity, these are described as separate functions (see below).

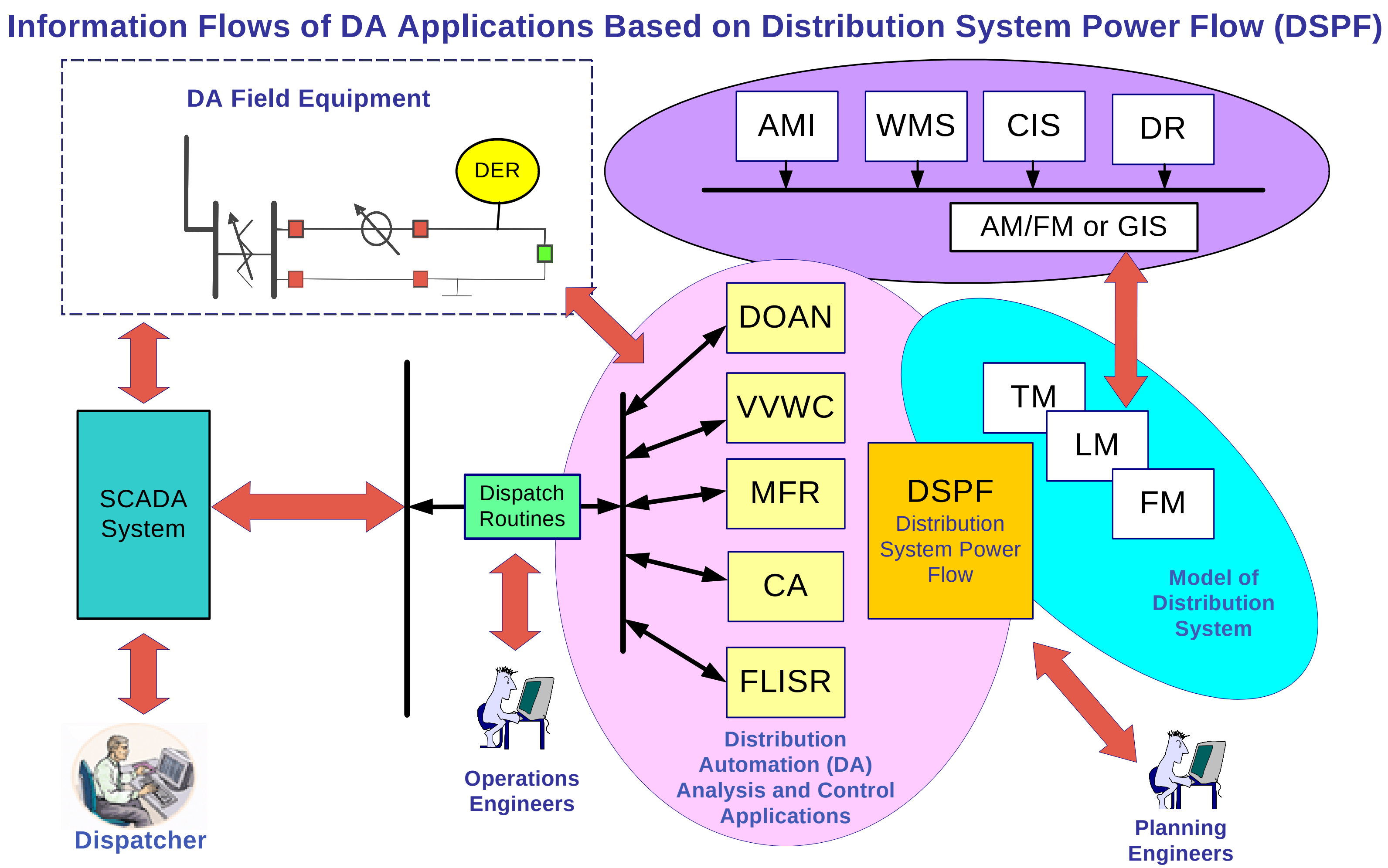
ADA automates the following three processes of distribution operation control:

- **Data** collection, validation, correction, and analysis in near-real-time. Accurate, up-to-date, and consistent data are critical to the other ADA processes.
- **Optimization** of different factors through global assessment of distribution power system situations. Optimization can be focused on different objectives, depending upon the circumstances and the needs of the power system.
- **Automated control** of distribution operations to implement the optimized decisions in coordination with transmission and generation systems operations. Automated control can be set as "recommended actions" in which an operator reviews the recommendations and then initiates the action, or as "closed loop actions" in which the actions are issued by the system without direct operator intervention.

The ADA function for normal operations performs:

- Data gathering, along with data consistency checking and correcting
- Integrity checking of the distribution power system model
- Periodic and event-driven system modeling and analysis
- Current and predictive alarming
- On-going contingency analysis

These processes are performed through direct interfaces with different databases and systems, (SCADA, EMS, OMS, CIS, MOS, AM/FM/GIS, AMR, and WMS), comprehensive near real-time simulations of operating conditions, near real-time predictive optimization, and actual real-time control of distribution operations. See Figure 7.



TM - Topology Model; LM - Load Model; FM - Facility Models; DSPF – Distribution System Power Flow; MFR – Multi-Level Feeder Reconfiguration; VVWC – Volt/Var/Watt Control; DOAN – Distribution Operations Analysis; CA – Contingency Analysis; FLIR – Fault Location, Fault Isolation, and Service Restoration;

Figure 7: Information Flows of DA Applications Based on the Distribution System Power Flow (DSPF)
[from EPRI's IntelliGrid Architecture, developed by Utility Consulting International]

6.4.1 Adequacy Analysis of the Distribution System to Meet the Load

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

The purpose of the adequacy analysis is to:

- Notify operators of actual or potential overload situations where specific power system equipment is not rated to meet the load
- Determine loss-of-life for overloaded equipment
- Assess the equipment most likely to fail
- Issue reports to maintenance and engineering

Description:

Since no distribution system is completely monitored in real-time, distribution planners rely on installing power system equipment that is rated for the highest expected loads or other constraints. This approach allows the distribution system to meet the customer needs for power for many years. However, as the distribution system ages, as fewer upgrades to power system equipment are made, and as loads grow in ways not foreseen during the planning stages, some power system equipment can be pushed beyond their ratings. Sometimes these excesses cause outages directly; sometimes they just shorten the life of the power equipment so that they may fail unexpectedly.

The DSPF model of the distribution power system can use real-time data or, alternatively, "study scenarios" to determine if and where the power system equipment may not be adequate to meet the loads.

6.4.2 Reliability Analysis of Distribution System to Minimize Outages

Type/Dependency: Secondary, dependent on the DSPF and on the Adequacy Analysis

Purpose:

The purpose of reliability analysis is to:

- Minimize the number of customers or the amount of power that might be affected by outages due to overloaded or failure-prone feeder segments.

Description:

In addition to determining the adequacy of the power system equipment, a reliability analysis application can recommend power system configuration changes which could alleviate overloads or could deliberately under-load feeder segments which are more prone to outages, thus improving the overall reliability of the power system.

6.4.3 Contingency Analysis (CA) of Distribution System

Type/Dependency: Secondary, dependent on the DSPF

Purpose:

Contingency analysis identifies potential distribution power system faults and assesses the following:

- Severity of the impact of the potential fault
- Resulting customer outages in the distribution system

Description:

Contingency analysis (CA) of the distribution system uses the DSPF model to undertake "what-if" studies, specifically "what-if faults occur" on key distribution feeders. The CA application would perform a contingency analysis of the relevant portions of distribution system, running:

- Periodically in real-time
- By event in real-time (topology change, load change, availability of control change)
- Study mode, in which the starting status and measurements are defined (often by taking a snapshot of some real-time situation which warrants additional study) and the application analyzes the distribution system for potential contingencies.

The application then provides the operator with the reliability status of the real-time distribution system.

6.4.4 Efficiency Analysis of Distribution System

Type/Dependency: Secondary, dependent on the DSPF and on the Adequacy Analysis

Purpose:

The purpose of efficiency analysis is to:

- Determine the most efficient configuration and settings of the distribution system, while still meeting all limits and other constraints, such as adequate reliability.
- Develop commands and/or switching orders which would carry out the actions needed to move to the most efficient configuration and settings
- Issue the commands either as:
  - Closed-loop mode, where commands are issued by the software application to the equipment in the field
  - Advisory mode, where commands are presented to the operators for their decisions on which and whether to issue the commands
  - Combination, where some types of actions are closed loop (such as voltage control) and others are advisory (such as switching feeder segments).

Description:

In addition to determining the adequacy of the power system equipment, an efficiency analysis of the distribution system uses the DSPF with the objective of minimizing losses. The efficiency analysis application optimizes volt/var settings, transformer loadings, phase load balancing, transmission settings, etc. to minimize losses globally across all distribution feeder, and then either issues the commands directly (closed loop control) or recommends commands to the operator (operator assistance control).

6.4.5 Optimal Volt/Var Control of Distribution System

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

The following purposes, which could be preset for different times of the day, overwritten by operator if needed, and/or mixed in various combinations, would be supported by the application by changing the states of voltage controllers, shunts, and distributed resources in a coordinated manner for different purposes under normal and emergency conditions:

- Power quality improvement by:
  - Maximizing the amount of customer load that remains within the established voltage quality limits (i.e., ensure standard voltages at customer sites as much as possible)
  - Improving the efficiency of customer appliances by ensuring appropriate voltage and var levels
- Power reliability improvement by:
  - Transformer overload elimination/reduction
  - Emergency load reduction
  - Minimize feeder segment(s) overload
  - Reduce or eliminate overload in transmission lines
  - Provide spinning reserve support
- Power efficiency improvement by:
  - Reducing peak load
  - Load management
  - Transmission operation support in accordance with T&D contracts
  - Loss minimization in distribution and transmission
  - Conserve energy via voltage reduction
  - Reduce load while respecting given voltage tolerance (normal and emergency)
  - Reduce or eliminate voltage violations on transmission lines
  - Provide reactive power support for transmission/distribution bus

Description:

The volt/var optimization application calculates the optimal settings of the load tap changers (LTCs) for voltage control of transformers, voltage regulators, power electronic devices, and capacitor statuses optimizing the operations by either following different purposes at different times, or considering conflicting purposes together in a weighted manner.

Three modes of operation could be used:

- **Closed-loop mode**, in which the application runs either periodically (e.g., every 15 min) or is triggered by an event (i.e., topology or change in purpose), based on real-time information. The application's recommendations are executed automatically via SCADA control commands.
- **Study mode**, in which the application performs "what-if" studies, and provides recommended actions to the operator.
- **Look-ahead mode**, in which conditions expected in the near future (from 1 hour to 1 week) can be studied by the operator.

6.4.6 Relay Protection Re-coordination (RPR) of Distribution System

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

The purpose of relay protection re-coordination is to ensure that the distribution system protection system is configured correctly to handle situations after changes have been made, including:

- Changes to the electrical connectivity of feeders after feeder reconfiguration actions
- Specific goals have changed due to changed conditions, such as the need to save fuses connected on laterals, and thus minimize outages on laterals

Description:

The relay protection re-coordination application assesses changes to the real-time distribution, and adjusts the relay protection settings to better match these real-time conditions based on preset rules. This is accomplished through analysis of relay protection settings and operational mode of switching devices (i.e., whether the switching device is in a switch or in a recloser mode), while considering the real-time connectivity, protective tagging, and weather conditions.

Relay re-coordination can be used after feeder reconfiguration, when weather conditions change significantly and in situations when "fuse management" goals change. Fuse management on feeder laterals is a major issue for utilities. Over 90% of temporary faults on overhead distribution circuits occur on laterals. Over the years, utilities have dealt with lateral protection in a couple of ways.

- **Fuse Blowing**: Some utilities employ a "fuse blowing" philosophy: The substation feeder breaker is properly coordinated with the lateral fuse, so that the fuse will clear any downstream fault within its rating by blowing the fuse rather than tripping the breaker. However, service to customers on the lateral is permanently interrupted even for a temporary fault, the utility must deal with the high cost of service calls to replace lateral fuses, and the number of permanent faults increases for a small number of customers, thus increasing SAIFI/CAIFI.
- **Fuse Saving:** Other utilities employ a "fuse saving" philosophy, in which the first trip of the substation feeder breaker is intentionally set so that the breaker operates faster than the lateral fuse to clear a fault downstream of the lateral fuse. When the recloser tries the circuit again, the second trip of the breaker is set slower than the fuse blow-point, so that if the fault is still present, the lateral fuse will operate to clear it. The problem is that all customers on the feeder experience a momentary interruption for all faults, thus increasing MAIFI, the number of customers experiencing momentary outages.

6.5 Emergency Distribution Operations Using DSPF Model

Advanced Distribution Applications (ADA) for emergency operations are a set of software programs and databases whose purpose is to model and analyze the entire distribution system in order to help prevent, ameliorate, or respond to power system emergencies. These ADA functions are also based on the DSPF model, combined with accurate, consistent, and timely data.

6.5.1 SCADA System Performs Disturbance Monitoring

Type/Dependency: Secondary, dependent on SCADA system

Purpose:

The purposes of disturbance monitoring is to:

- Maintain a record of events leading up to disturbances
- Capture time-tagged snapshots during disturbances
- Determine fault currents
- Assist in fault location
- Record results of disturbances for further analysis

Description:

The SCADA system maintains a "circular file" of snapshot records of system status and measurements, updated every 10 seconds or so. If a system disturbance occurs, the last records of pre-disturbance snapshots are saved, more snapshots are taken, often more rapidly (every 2 seconds) until the disturbance settles into a steady state. A few more snapshots are then taken.

This collection of disturbance records are then made available to engineers and software applications for analysis of the disturbance.

6.5.2 Automated Fault Location, Fault Isolation, and Service Restoration (FLISR)

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data from the SCADA system

Purpose:

The purpose of the automated FLISR is to improve distribution system reliability by identifying faults rapidly, responding to isolate the faults, and taking a broad view (as opposed to local view) on the best method for restoring service to unfaulted sections.

Description:

The automated fault location, isolation, and service restoration (FLISR) function uses the combination of the DSPF model with the SCADA data from the field on real-time conditions to determine where a fault is probably located, by undertaking the following steps:

- Determines the faults cleared by controllable protective devices:
  - Distinguishes faults cleared by fuses
  - Distinguishes momentary outages
  - Distinguishes inrush/cold load current
- Determines the faulted sections based on SCADA fault indications and protection lockout signals
- Estimates the probable fault locations, based on SCADA fault current measurements and real-time fault analysis
- Determines the fault-clearing non-monitored protective device, based on trouble call inputs and the DSPF model

It then uses closed-loop or advisory methods to isolate the faulted segment. Once the fault is isolated, it determines how best to restore service to unfaulted segments through feeder reconfiguration.

The FLISR function can perform its actions in one or more of the following modes:

- **Closed-loop mode**, where the FLISR application issues control commands directly to field equipment through the SCADA system, to first isolate the fault, then restore service to the unfaulted segments.
- **Advisory mode**, where the FLISR application notifies the operator of the conditions, provides a set of switching orders, then executes the switching orders upon the authorization of the operator through the SCADA system.
- **Open-loop mode**, where the FLISR application notifies the operator of the conditions, provides a set of switching orders. The operator then uses the switching orders to tell field crews what actions to take.

- **Coordinated mode**, where local automated switch management (see Section 5.2.1) takes the initial fault isolation steps autonomously. Once the fault is isolated, the FLISR application assesses the distribution system from a global perspective and issues control commands to restore service to the unfaulted segments.

After the fault is corrected, the application determines how to return the distribution system to "normal" while taking into account the availability of remotely controlled switching devices, feeder paralleling, and cold-load pickup. Again this process can be performed in on of the four modes described above.

6.5.3 Multi-level Feeder Reconfiguration (MFR)

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

Multi-level feeder reconfiguration software application analyzes many different distribution system configurations, assessing each configuration from a global perspective on how it best meets one or more of the following purposes, as set up by the operator or situation:

- **Service restoration**: Optimally restore service to customers utilizing multiple alternative sources. The application meets this objective by operating as part of Fault Location, Isolation, and Service Restoration application.
- **Overload elimination:** Optimally unload an overloaded segment. This purpose is pursued if the application is triggered by the overload alarm from SCADA, or from the adequacy and/or contingency analyses using the DSPF model.
- **Transmission facilities overload**: Reconfiguring feeders to have some or all of their power source from other substations could alleviate transmission overloads.
- **Load balancing**: Balanced loads on the 3 phases of a feeder help to minimize losses, since most voltage and var actions affect all 3 phases simultaneously. If they are unbalanced, either some phases could be outside the efficiency or even reliability limits, or the most optimal settings could not be implemented.
- **Voltage balancing**: Voltage balancing is similar to load balancing in its purpose, but could include selective setting of voltage levels on different phases.
- **Loss minimization**: Loss minimization could include load balancing, voltage balancing, as well as shortening distances between the power source and the loads.
- **Reliability improvement**: Reliability improvement could include minimizing exposure to faults (e.g. based on feeder reliability statistics), as well as ensuring faster restoration after faults if some feeders have better automation capabilities, such as reclosers, automated switches, fuses not set as primary protection, etc.

Description:

The multi-level feeder reconfiguration software application recommends an optimal configuration of feeder(s) to meet one or more different purposes. It uses the DSPF model and real-time SCADA data to assess different feeder configurations to meet the purposes in the most optimal manner. The feeder reconfiguration process is a multi-objective function with a very large number of variables. Theoretically, the number of possible combinations to consider during the search of the best solution is equal $2^{n,}$ where n is the number of switching devices in the interconnected circuits. Heuristics, constraints, and other methods need to be used to minimize the total number of possible configurations.

It supports three modes of operation:

- **Closed-loop mode**, in which the application is initiated by the Fault Location, Isolation, and Service Restoration application if it is unable to restore service by simple (one-level) load transfer, to determine a switching order for the remotely-controlled switching devices to restore service to the non-faulted sections by using multi-level load transfers.
- **Advisory mode**, in which the application is initiated by SCADA alarms triggered by overloads of substation transformer, by overloaded segments of distribution circuits, or by the operator establishing the purpose and the reconfiguration area. In this mode, the application recommends a switching order to the operator.
- **Study mode**, in which the application is initiated and the conditions are defined by the user.

The feeder reconfiguration solution could be used for different timeframes, such as:

- For several hours after clearing a fault for service restoration to healthy sections. The solution is needed within a few seconds.
- For several hours or days for voltage equalization, when there is an urgent need for load reduction via volt and/or var control. The solution is needed within a few minutes.
- For several days or weeks for load balancing during maintenance of distribution facilities. The solution should be found in the matter of seconds. The solution is needed within a few tens of minutes.
- For a season or a year for minimization of customer exposure to interruptions, normal load balancing, and loss minimization. The solution is needed within several hours.

6.5.4 Load Management Activities for Emergency Conditions

Type/Dependency: Secondary, dependent on SCADA, the DSPF model, load interruption devices, and manual interactions with customers.

Purpose:

The purpose of load management during emergency conditions is to decrease loads selectively to best match the emergency needs, while maintaining critical loads as best as possible.

Description:

Load management can be performed by shedding load at the substation (trip an entire feeder or lower the voltage level on an entire feeder), for a feeder segment (open an automated switch if it has circuit breaking capability), for portions of the customer site (if load control has been implemented), or manually by requesting a customer to reduce/interrupt parts of his load. Depending upon the type of emergency, all or some of these methods can be used. Operators or planners can identify critical loads (hospitals, etc.) ahead of time so that whichever action is taken, these critical loads are not affected if at all possible.

The DSPF model can be used either ahead of time or in real-time to determine the most appropriate actions and locations for the specific emergency conditions. These actions include:

- Operator activates direct load control
- Operator activates load curtailment
- Operator applies load interruption
- Operators enables emergency load reduction via volt/var control
- Operator applies manual rolling blackouts

6.5.5 Mitigating the Effects of Major Storms, Earthquakes, and other Disasters

Type/Dependency: Secondary, dependent on the SCADA system, the DSPF model, and accurate, consistent, and timely data.

Purpose:

The purpose of mitigating the effects of disasters is to minimize the disruption of power to customers.

Description:

No single action can prevent storms, earthquakes, and other types of catastrophic disasters from impacting the distribution system, but a number of actions taken ahead of time as well as during the disaster can mitigate the effects.

Ahead of time:

- Good design for the expected severity of storms (changing with global warming)
- Good design for different types of disasters (e.g. ice storms, flooding, earthquakes, wildfires, etc.)
- Good maintenance to ensure equipment is functioning correctly and robustly
- Redundancy of equipment and sources of power for feeder segments
- Personnel preparedness training

During the event:

- Model the real-time state of the distribution system through SCADA where possible, and via the DSPF model where monitoring does not exist or has been disrupted.
- Perform contingency analysis to determine what areas of the distribution system are potentially weaker, particularly if the course of the storm can be monitored
- Perform "what-if" scenarios based on the real-time situation, so that rapid actions can be taken if any of the scenarios occur
- Perform automated switching and multi-feeder reconfiguration as appropriate, preferably globally assessed
- Shed loads and perform load management as needed
- Assess the impact of possibly losing DER generation on sensitive feeders.

6.5.6 Enhancing Repair Activities After Major Disasters

Type/Dependency: Secondary, dependent on the SCADA system, the DSPF model, and accurate, consistent, and timely data.

Purpose:

The purpose of enhancing the repair activities after a major disaster is to prioritize repair activities based on the assessment of the distribution system, using the DSPF model and any SCADA data.

Description:

Repair activities after major disasters can be very labor-intensive, but can benefit significantly from monitoring, modeling, and automation actions. These include:

- Use DSPF model to assess the post-storm status of the distribution system
- Locate faults along feeders using FLISR
- Use DSPF model in coordination with transmission supply to assess general area priorities for repair
- Assess specific high priority repairs to critical customers
- Determine status of distribution feeders even without transmission power via the DSPF model and the status of breakers and automated switches
- Assess DER availability and impact of DER start-up

6.6 Distribution System Operations Training and Assessments Using DSPF Model

6.6.1 Dispatcher Training Simulation (DTS)

Type/Dependency: Secondary, dependent on the SCADA system, the DSPF model, and real-time data.

Purpose:

The purpose of dispatcher training simulators is to provide new and experienced dispatchers with training on the actual power system they are operating, by providing scenarios of events and circumstances that they must respond to.

Description:

Dispatcher Training Simulation (DTS) provides a computer model of the distribution system (the DSPF) with sets of data taken from real-world situations as well as from study scenarios. Trainers can set up these scenarios, with trainees taking actions in response. These two types

- DTS Study Case Analysis
- DTS Real-Time Analysis

6.6.2 Audit Logging and Reporting

Type/Dependency: Secondary, dependent on the SCADA system, the DSPF model, and real-time data.

Purpose:

The purpose of the audit logging and reporting is to provide an auditable trail of significant information that can be used by planners, engineers, operators, maintenance, construction, regulators, executives, and other authorized personnel.

In addition to the audit trail, this data can also be used to analyze situations, including as study input to the ADA software applications and especially the Dispatchers Training Simulator.

Description:

Audit logging and reporting captures timestamped information including:

- Alarms
- Significant events
- States of the power system
- Snapshots of values

- Historical information
- Other information required by regulators

6.6.3 Diagnostic Analyses of Events

Type/Dependency: Secondary, dependent on the SCADA system, the DSPF model, and real-time data.

Purpose:

Diagnostic analyses can be used both by power engineers to assess power system problems and by maintenance personnel to assess the health or status of primary and secondary equipment. Much of this analysis can be done on the real-time equipment historical data, e.g. how many times a breaker has tripped under load. In addition, more global analysis using the DSPF model of the power system can assist predictive software applications to determine what parts of the power system are under the greatest stress and when the equipment really needs maintenance (not just when it is scheduled for maintenance).

Description:

Diagnostic analyses of power system events and secondary system events provide information on equipment and situations that can help avoid or minimize future problems.

7. Secondary DA Functions – Automated Distribution Systems with Significant Distributed Energy Resources (DER)

Distributed Energy Resources (DER) (also often termed Distributed Generation (DG) or Distributed Resources (DR), and include both generation and storage of electrical energy) are slowly, but increasingly being interconnected with distribution systems. Although no-one can predict how much DER generation and/or storage will ultimately be interconnected, it is clear that these decisions will be made more by utility customers than by utilities. This decentralized decision-making on where and how much generation will be implemented adds a degree of uncertainty that utilities have never had to manage before.

Many DER units are small, and can rightly be viewed as "negative load" by utilities and thus be treated essentially as invisible to distribution operations (so long as they comply with the interconnection standards such as IEEE 1547, California's Rule 21, or the utility's requirements).

Some larger DER units have been and will continue to be implemented, owned, and/or operated by utilities. Some DER units have been and will continue to be implemented, owned, and/or operated by customers or third parties. Over time, aggregated amounts of generation from small DER units will become "visible" in distribution operations. All of these situations are impacting:

- Distribution planning
- Distribution engineering and construction
- Distribution normal operations
- Distribution emergency operations
- Distribution maintenance
- Real-time interactions with customers
- Customer tariffs and rate structures
- Regulators

7.1 Interconnection of DER to the Distribution System

Utilities are required by law to allow DER units to be interconnected to the distribution system, provided they follow the interconnection requirements. In California, Rule 21 specifies standard interconnection, operating, and metering requirements for DER generators.

7.1.1 Assessment of Proposed DER Interconnections

Type/Dependency: Primary

Purpose:

Distribution planning and/or engineering must assess each proposed DER interconnection to ensure it meets the required interconnection standards. They must also assess any impact on distribution feeders, feeder equipment, substations, distribution operations, maintenance procedures, etc. to accommodate the DER interconnection. If changes must be made, these changes must be engineered and implemented before the DER interconnection is finalized.

Technical Challenges:

Challenge	Technical Challenges Discussion	Level
Electronic equipment	N/A	
Communication systems	N/A	
Data management	Accurate information on the distribution system must be available and up-to-date, so that the assessment of proposed DER interconnections can be accurate.	H
System integration & security	Access to accurate information comes from multiple systems, including the GIS, CIS, historical SCADA data, asset databases, as-built maps, etc.	M
Software applications	Planning models which include interconnected DER systems do not have good models of DER units. Simple models of small DER units are adequate for general planning, but as/if DER units become larger or as more small DER units reside on the same feeders, then these simple models may not be adequate	H

Potential Benefits:

Description:

The assessment of proposed DER interconnections involves two aspects:

- Assessment of engineering compliance of the proposed DER interconnection to the appropriate standards
- Assessment of the distribution system to handle the DER interconnection

For larger DER systems (or large amalgamations of smaller DER units), these assessments usually require studies of different types of events on the distribution system with the interconnected DER. These studies may use planning models of the distribution system. However, not many planning models have adequate representation of different types of DER systems.

The types of planning information include:

- DER sizing, including the expected power flows at the Point of Common Coupling (PCC)
- DER technology and specific characteristics
- Interconnection configuration and equipment, including protection, modes of operation, emergency operations, etc.

- Planned ancillary services such as backup, emergency loads, use in market operations, emission trading, etc.

Distribution planners study the impact of planned DER installations on the distribution system, and integrate these results with other distribution upgrades and additions.

7.1.2 Engineering, Monitoring, and Analyzing DER Interconnections

Type/Dependency: Secondary, dependent upon DER planning information, access to DER data either in real-time or as historical information

Purpose:

The purpose of continuous monitoring and assessment of the DER interconnections is to ensure that the DER installation is continuing to meet requirements, and that the distribution system can manage any impact from the DER interconnections over time.

Description:

Once the planning for DER interconnections has been completed, the actual engineering of the DER interconnection equipment and capabilities are finalized. In addition, the DER interconnections are monitored and analyzed to determine whether the actual status and operational characteristics of these DER interconnections actually meet the planning criteria and contractual agreements, after the

- Installer installs and tests DER devices in the local EPS
- Distribution utility tests DER installation with interconnection to area EPS
- Distribution utility interacts with DER owner on DER installation physical and electrical configuration, contractual arrangements, planned operations, and/or other information
- DER operator tests DER communications system performance and management
- Vendors of different equipment (including DER systems, switches, protection, and communications system) gather real-time data and statistics, and perform troubleshooting of their own equipment.
- DER maintainer maintains DER system
- DER environmental monitoring
- Energy Service Provider meets contractual obligations for managing the DER system.

7.2 Energy Service Provider (ESP) Management of DER Units

As used in this document (since different terms can have different meanings in different contexts), an Energy Service Provider (ESP) is a non-utility entity (the customer or a third party) or an entity affiliated with a utility (department or subsidiary) that is charged with managing and/or directly operating DER units. The DER units can be located at a customer site or at a utility site, such as in a substation, but are being managed from a remote location (for instance, small residential PV systems would only be managed locally, while large interconnected CHP units would necessarily be managed remotely).

These functions provide the real-time monitoring and control of the DER units, but do not address how these DER units might impact distribution operations – those functions are handled in subsequent sections. It is assumed that the DER units are "large enough" to warrant remote monitoring and control.

7.2.1 ESP Monitors Non-Operational Data from DER Site

Type/Dependency: Secondary, based on monitoring provided by ESP SCADA or SCADA-like systems

Purpose:

Non-operational data from DER sites can be used for many purposes, including:

- Condition monitoring of DER prime mover
- Status and/or characteristics of DER fuel
- Condition monitoring of "peripheral" electrical equipment, such as protective relays, switches, automatic transfer switches, UPS systems, etc.
- Meteorological information, not only for assessing weather-impacted DER performance, but also for use for general meteorological information
- Emissions, including air, heat, water, etc.

Description:

ESPs use SCADA or SCADA-like systems to access to real-time DER data in order to monitor non-operational information, such as prime mover characteristics, weather, emissions, protective relays, switches, etc.

7.2.2 ESP Manages Market Operations of DER Units

Type/Dependency: Secondary, based on monitoring provided by ESP SCADA or SCADA-like systems

Purpose:

DER units, singly or in aggregate, can be bid or contracted into the electricity market for supplying energy and/or ancillary services. The terms of these contracts must then be met by the DER units. Therefore the ESPs need to monitor and control the DER units.

Description:

ESPs bid or contract into the electricity market to use DER units for energy or ancillary services. They also use SCADA or SCADA-like systems to ensure the DER units perform as contracted in the market operations. (This function does not include ESPs who only manage bidding into the market and not the operations of the DER unit to meet these contracts – that function does not involve any technologies of interest.)

7.3 Local and Basic SCADA Operations with DER Units

DER units are impacted by, and can impact, distribution operations. The functions described in this section cover the key types of impacts, assuming only SCADA-type capabilities. More complex interactions are described in subsequent sections.

7.3.1 Utility SCADA Monitoring and Control of DER Units

Type/Dependency: Secondary, based on monitoring provided by utility distribution SCADA systems

Purpose:

- Direct SCADA monitoring of larger DER units
- Indirect SCADA monitoring of aggregated smaller DER units, through an ESP or other DER management entity
- SCADA control, direct or indirect, of DER units
- Verification of the tripping of interconnected DER units on outages
- As per tariff, control DER for different distribution operational requirements

Description:

Distribution utilities use SCADA systems to monitor and possibly control DER units. These DER units could be owned by the utility or owned by a customer. The distribution SCADA could have direct communications with the DER units or could have indirect access through an ESP or other DER management entity.

The monitoring can be used not only for managing the distribution system, but also for safety, to ensure that the DER units are indeed disconnected from a de-energized distribution circuit which is presumed to have no power sources on it.

7.3.2 Supervisory Control of Switching Operations with Significant DER

Type/Dependency: Secondary, based on monitoring and control of distribution circuit switches by utility distribution SCADA systems, and the monitoring (directly or indirectly) of the DER generation and storage capabilities.

Purpose:

The purpose of this function is to be able to continue to perform necessary switching operations even when significant amounts of DER generation/storage are interconnected to the distribution circuit. These switching operation include:

- Remote operator dispatches field crew to perform manual switching operations on feeders with DER present
- Remote operator performs supervisory control of switching operations on feeders with DER present

- Remote operator performs supervisory control of load tap changers and/or voltage controllers with DER present

Description:

During normal supervisory control for switching of distribution circuits, any circuits with significant amounts of interconnected DER energy needs to be managed. A number of issues or scenarios arise in this case:

- Customers with DER units may need to be notified so they can take appropriate action (e.g. determine whether to ride through any switching, or shut down DER units, or start up additional DER units in order to establish microgrids, or turn on backup power, etc.)
- DER units may need to be remotely controlled to be disconnected from the distribution circuit before any switching operations take place
- The impact of DER units being switched from one distribution circuit to another needs to be assessed. For instance, which ones can ride through such a switching operation and which might shut down.
- If the DER units do shut down, will the circuit being switched to still be able to handle the load.
- Impact on DER units of changes in voltage levels on the distribution circuit.

7.3.3 Local Automated Switching Operations (e.g. IntelliTeam) with Significant DER

Type/Dependency: Secondary, based on monitoring and control of distribution circuit switches by utility distribution SCADA systems, and the monitoring (directly or indirectly) of the DER generation and storage capabilities.

Purpose:

The purpose of this function is to allow local switching to take place without interfering with normal DER operations any more than necessary.

Description:

If switching operations are performed by local automation, the potential impact on the DER units (and vice versa) of this switching needs to be taken into account before any such switching takes place. In particular, the local automation systems must be able to:

- Assess the current DER status – not just current load
- Determine whether or how to let DER ride-through switching, shut down and restart, or shut down

7.4 Normal Distribution Operations with Significant DER Using DSPF / DER Model

These functions assume that the distribution utility has both a SCADA system and advanced distribution applications based on the DSPF / DER models. These advanced distribution applications can assess power system status and DER capabilities in both "study-mode" and "real-time". These capabilities are similar to those discussed in Section 6.4 and have parallel purposes, but would include additional functionality to handle significant amounts of DER generation and/or storage.

The DER units would be monitored (and possibly controlled) by the distribution utility during normal operations. These normal operations could include monitoring and managing:

- Power system reliability
- Power system efficiency
- Power quality assessment
- Market operations
- Power system and DER maintenance

The DER units could be located at customer sites or at utility sites, such as in a substation, and could include multiple points of common coupling (PCCs) of multiple DER units along a distribution circuit.

7.4.1 Adequacy Analysis of Distribution System with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data from the distribution system and all significant amounts of interconnected DER generation and storage

Purpose:

The purpose of the adequacy analysis is to:

- Allow distribution planners to study different scenarios and assess the impact of significant amounts of DER generation and/or storage on distribution system designs and configurations
- Notify operators of overload situations where specific power system equipment is not rated to meet the load
- Determine loss-of-life for overloaded equipment
- Assess the equipment most likely to fail
- Issue reports to maintenance and engineering

Description:

With significant amounts of DER generation and/or storage being interconnected to distribution circuits, distribution planners will have increasing difficulty in determining whether the distribution system is truly designed to meet the necessary reliability and efficiency requirements. The DSPF /DER model can use real-time data or, alternatively, connectivity and values from “study scenarios” to determine if and where the power system equipment may not be adequate to meet the loads.

7.4.2 Reliability Analysis with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and on the Adequacy Analysis

Purpose:

The purpose of reliability analysis is to:

- Minimize the number of customers or the amount of power that might be affected by outages due to overloaded or failure-prone feeder segments.
- Minimize the impact of unplanned DER generation and/or storage actions on customers on the affected distribution circuits
- Develop plans for alleviating reliability problems through performing “what-if” studies on distribution circuits with significant DER generation and/or storage.

Description:

In addition to determining the adequacy of the power system equipment and distribution system design, a reliability analysis application can recommend power system configuration changes and/or DER management criteria which could alleviate overloads or could deliberately under-load feeder segments which are more prone to outages, thus improving the overall reliability of the power system.

7.4.3 Contingency Analysis with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model

Purpose:

Contingency analysis identifies potential distribution power system faults and assesses the following:

- Severity of the impact of the potential fault and the resulting customer outages in the distribution system
- Can the DER devices impacted by the fault withstand the fault, or will some or all DERs disconnect?
- Will adequate generation still be available, or should the load be disconnected together with the DER?
- Can the disconnected segments of the feeder normally supported with DER be restored without the DER, or should the segment be restored with possibly overloaded backup circuits and with fast DER re-synchronization to shortly afterwards pick up the load again?

- Should the segment be divided for balanced islanding?
- How can normal operating conditions be restored, given the need to re-synchronize DER devices if they drop during the restoration process? Can this be done without interruption when the loading permits?

Description:

Contingency analysis (CA) of the distribution system uses the DSPF / DER model to undertake "what-if" studies, specifically "what-if faults occur" on distribution feeders with significant amounts of DER generation and/or storage. The CA application would perform a contingency analysis in the relevant portions of distribution system, running:

- Periodically in real-time to determine if any potential problem appears to be happening
- By event in real-time (topology change, load change, change in DER generation capabilities, change in DER storage levels, availability of control change)
- Study mode, in which the starting status and measurements are defined (often by taking a snapshot of some real-time situation which warrants additional study) and the application analyzes the distribution system for potential contingencies.

The application then provides the operator with the reliability status of the real-time distribution system (or the results of the study mode analysis).

Contingency analysis of distribution feeders with significant amounts of DER generation has an increased dimension due to the many different alternatives that could be taken in response to the initial fault. Using the DSPF / DER model, the CA function would assess the impact of an outage of each key feeder segment or DER unit, simulate the impact on the load, and assess the reaction of the DER units to the fault.

7.4.4 Efficiency Analysis with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and on the analysis of the adequacy of the distribution system

Purpose:

The purpose of efficiency analysis is to:

- Determine the most efficient configuration and settings of the distribution system, while still meeting all limits and other constraints, such as adequate reliability.
- Determine switching orders which would carry out the actions needed to move to the most efficient configuration and settings

Description:

An efficiency analysis of the distribution system with significant DER generation and/or storage would use the DSPF / DER model with the purpose of minimizing losses on the distribution system. Alternatively, the purpose could be to minimize greenhouse gas (GHG) emissions or balance losses against DER GHG emissions, or other combinations.

The efficiency analysis function would optimize volt/var settings, transformer loadings, phase load balancing, DER generation, DER storage settings, and local transmission settings to minimize losses globally across all distribution feeders. The optimal settings could either be issued automatically to the field equipment or could be recommended to the operator for their decision-making.

7.4.5 Optimal Volt/Var Control with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data

Purpose:

The following purposes, which could be preset for different times of the day, overwritten by operator if needed, and/or mixed in various combinations, would be supported by the application by changing the states of voltage controllers, shunts, and DER generation and/or storage in a coordinated manner for different purposes under normal and emergency conditions:

- Power quality improvement by:
  - Maximizing the amount of customer load that remains within the established voltage quality limits (i.e., ensure standard voltages at customer sites as much as possible)
  - Improving the efficiency of customer appliances by ensuring appropriate voltage and var levels
  - Using DER generation and/or storage to improve power quality
- Power reliability improvement by:
  - Transformer overload elimination/reduction
  - Emergency load reduction
  - Minimize feeder segment(s) overload
  - Reduce or eliminate overload in transmission lines
  - Provide spinning reserve support through DER generation, storage, or load control
- Power efficiency improvement by:
  - Reducing peak load
  - Load management
  - Transmission operation support in accordance with T&D contracts
  - Loss minimization in distribution and transmission
  - Conserve energy via voltage reduction
  - Reduce load while respecting given voltage tolerance (normal and emergency)
  - Reduce or eliminate voltage violations on transmission lines
  - Provide reactive power support for transmission/distribution bus

Description:

In addition to determining the optimal settings of distribution system equipment, the function also takes into account the DER generation and storage on the distribution circuits to optimize operations by either following different purposes at different times, or considering conflicting purposes together in a weighted manner.

7.4.6 Relay Protection Re-coordination (RPR) with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data

Purpose:

The purpose of relay protection re-coordination is to ensure that the distribution system protection system is configured correctly to handle situations after changes have been made, including:

- Changes to the electrical connectivity of feeders after feeder reconfiguration actions
- Specific goals have changed due to changed conditions, such as the need to save fuses connected on laterals, and thus minimize outages on laterals
- Distributed generation and/or storage has changed the protection requirements

Description:

With significant amounts of DER generation and/or storage capacity in the distribution system, the relay protection re-coordination is much more complex, especially when supporting the fuse-saving protection policy. Since the room for adjustment of the settings of the protective devices is limited, it is possible that the coordination for the fuse saving protection cannot be provided. In addition, the disconnection of DER units may be necessary to avoid asynchronous connections before reclosing on a circuit, thus complicating the assessment of the best approach.

7.4.7 Assessment of the Impact of/on DER Generation/Storage during Distribution Planned Outages

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data

Purpose:

The purpose is to take into account the presence of DER generation and/or storage during planned outages.

Description:

Planned outages of distribution circuits and segments is a common, daily occurrence in distribution operations. However, with the interconnection of significant amounts of DER generation and/or storage to these circuits, new factors must be taken into account, including:

- Assessment of the impact of interconnected DER generation and/or storage on the planned outage process, including switching orders and validation procedures to ensure that the circuit is de-energized
- Assessment of the impact of the planned outage on DER generation and/or storage, particularly related to any tariff or penalty issues
- Coordination with DER owners to determine how they want to handle the outage. They may, for instance, establish microgrids during the outage
- "Graceful" disconnection of DER generation/storage to ensure no equipment is harmed
- Assurance that no DER energy is present on de-energized circuits
- Methodology for re-synchronizing either microgrid or DER units when the distribution circuit is re-energized

Therefore, the impact of DER generation and/or storage on planned outages of distribution circuits and segments needs to be studied using the DSPF / DER model, covering distribution operations analysis, DER availability analysis, multi-level feeder reconfiguration, coordinated volt-var control, reliability assessment, cold load pickup, work order creation.

7.5 Emergency Distribution Operations with Significant DER Using DSPF / DER Model

The DER units can be located at a customer site or at a utility site, such as in a substation. The DER is monitored by the utility and available to be operated to meet emergency needs, particularly if there is significant penetration of DER on some of its feeders or in its substations. These emergency responses can also include protection schemes and actions, load shedding, alarm management, disturbance monitoring, emergency switching, and establishment of microgrids.

7.5.1 Fault Location, Fault Isolation, and Service Restoration (FLISR) with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data from the SCADA system, including data directly or indirectly from significant DER generation and/or storage units.

Purpose:

The purpose of the automated FLISR is to improve distribution system reliability by identifying faults rapidly, responding to isolate the faults, and taking a broad view (as opposed to local view) on the best method for restoring service to unfaulted sections.

Description:

This function is similar to that described in Section 6.5.2, but includes the additional complexity that stems from significant amounts of DER generation and/or storage on the distribution circuits.

The automated fault location, isolation, and service restoration (FLISR) function uses the combination of the DSPF / DER model with the SCADA data from the field on real-time conditions to determine where a fault is probably located, by undertaking the following steps:

- Determines the faults cleared by controllable protective devices:
  - Distinguishes faults cleared by fuses
  - Distinguishes momentary outages
  - Distinguishes inrush/cold load current
- Determines the faulted sections based on SCADA fault indications and protection lockout signals
- Estimates the probable fault locations, based on SCADA fault current measurements and real-time fault analysis
- Determines the fault-clearing non-monitored protective device, based on trouble call inputs and the DSPF / DER model

It then uses closed-loop or advisory methods to isolate the faulted segment. Once the fault is isolated, it determines how best to restore service to unfaulted segments through feeder reconfiguration.

The FLISR function can perform its actions in one or more of the following modes:

- **Closed-loop mode**, where the FLISR application issues control commands directly to field equipment through the SCADA system, to first isolate the fault, then restore service to the unfaulted segments. This could include the creation of islands supported by DER.
- **Advisory mode**, where the FLISR application notifies the operator of the conditions, provides a set of switching orders, then executes the switching orders upon the authorization of the operator through the SCADA system.
- **Open-loop mode**, where the FLISR application notifies the operator of the conditions, provides a set of switching orders. The operator then uses the switching orders to tell field crews what actions to take.
- **Coordinated mode**, where local automated switch management (see Section 5.2.1) takes the initial fault isolation steps autonomously. Once the fault is isolated, the FLISR application assesses the distribution system from a global perspective and issues control commands to restore service to the unfaulted segments. This could include the creation of islands supported by DER.

After the fault is corrected, the application determines how to return the distribution system to "normal" while taking into account the availability of remotely controlled switching devices, feeder paralleling, and cold-load pickup. Again this process can be performed in on of the four modes described above.

7.5.2 Multi-Level Feeder Reconfiguration (MFR) with Significant DER Generation/Storage

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data from the SCADA system, including data directly or indirectly from significant DER generation and/or storage units.

Purpose:

Multi-level feeder reconfiguration software application analyzes many different distribution system configurations, assessing each configuration from a global perspective on how it best meets one or more of the following purposes, as set up by the operator or situation:

- **Service restoration**: Optimally restore service to customers utilizing multiple alternative sources, including available DER generation and/or storage. The application meets this objective by operating as part of FLISR function.
- **Overload elimination:** Optimally unload an overloaded segment. This purpose is pursued if the application is triggered by the overload alarm from SCADA, or from the adequacy and/or contingency analyses using the DSPF / DER model.
- **Transmission facilities overload**: Reconfiguring feeders to have some or all of their power source from other substations could alleviate transmission overloads.
- **Load balancing**: Balanced loads on the 3 phases of a feeder help to minimize losses, since most voltage and var actions affect all 3 phases simultaneously. If they are unbalanced, either some phases could be outside the efficiency or even reliability limits, or the most optimal settings could not be implemented. Some of this imbalance may stem from more DER units on one phase than another, which could affect the load shape and load values on that phase.
- **Voltage balancing**: Voltage balancing is similar to load balancing in its purpose, but could include selective setting of voltage levels on different phases.
- **Loss minimization**: Loss minimization could include load balancing, voltage balancing, as well as shortening distances between the power source and the loads.
- **Reliability improvement**: Reliability improvement could include minimizing exposure to faults (e.g. based on feeder reliability statistics), as well as ensuring faster restoration after faults if some feeders have better automation capabilities, such as reclosers, automated switches, fuses not set as primary protection, etc. DER could be used in combination with the MFR function to improve this reliability.

Description:

This function is similar to that described in Section 6.5.3, but includes the additional complexity that stems from significant amounts of DER generation and/or storage on the distribution circuits.

The multi-level feeder reconfiguration software application recommends an optimal configuration of feeder(s) to meet one or more different purposes. It uses the DSPF / DER model and real-time SCADA data to assess different feeder configurations to meet the purposes in the most optimal manner. The feeder reconfiguration process is a multi-objective function with a very large number of variables. Theoretically, the number of possible combinations to consider during the search of the best solution is equal $2^{n,}$ where n is the number of switching devices in the interconnected circuits. Heuristics, constraints, and other methods need to be used to minimize the total number of possible configurations.

It supports three modes of operation:

- **Closed-loop mode**, in which the application is initiated by the Fault Location, Isolation, and Service Restoration application if it is unable to restore service by simple (one-level) load transfer, to determine a switching order for the remotely-controlled switching devices to restore service to the non-faulted sections by using multi-level load transfers.
- **Advisory mode**, in which the application is initiated by SCADA alarms triggered by overloads of substation transformer, by overloaded segments of distribution circuits, or by the operator establishing the purpose and the reconfiguration area. In this mode, the application recommends a switching order to the operator.
- **Study mode**, in which the application is initiated and the conditions are defined by the user.

The feeder reconfiguration solution could be used for different timeframes, such as:

- For several hours after clearing a fault for service restoration to healthy sections. The solution is needed within a few seconds.
- For several hours or days for voltage equalization, when there is an urgent need for load reduction via volt, var, and/or watt control. The solution is needed within a few minutes.
- For several days or weeks for load balancing during maintenance of distribution facilities. The solution should be found in the matter of seconds. The solution is needed within a few tens of minutes.
- For a season or a year for minimization of customer exposure to interruptions, normal load balancing, and loss minimization. The solution is needed within several hours.

7.5.3 Post-Emergency Assessment of DER Responses and Actions

Type/Dependency: Secondary, dependent on the DSPF / DER model and accurate, consistent, and timely data from the SCADA system, including data directly or indirectly from significant DER generation and/or storage units.

Purpose:

This data can be used to calculate performance and historical statistics of distribution operations, DER actions, and distribution equipment functionality, as well as risk assessments based on these statistics. The communications networks used to collect this information can also be assessed to determine if they are providing the amount, frequency, timeliness, and accuracy of the information needed to manage these types of emergencies.

Description:

Much can be learned from assessing the causes, progression, and results of emergency situations. With data received prior and during the emergency, an analysis of the event can be undertaken, studied, used for training, and possibly used to ameliorate the conditions that led to the event in the first place.

This is less a "function" than a recognition that the vast amounts of data should also be used for analyzing and assessing the operational capabilities and status of the distribution system as it continues to change and expand with varying types of loads and varying impacts of DER units.

7.6 Customer-Driven Actions with Significant DER Generation/Storage

In addition to distribution operations which are currently (more or less) done during normal and emergency situations, customers may undertake actions which affect distribution operations and the planning of distribution systems. These customer-driven actions rely heavily on DER generation and/or storage as well as the information and automation capabilities needed to manage them.

7.6.1 Planned Establishment of Temporary Microgrids

Type/Dependency: Primary, requiring additional DER management systems to monitor, assess, and control the microgrid.

Purpose:

The purposes of planned establishment of microgrids would normally be based on decisions by the customers within the microgrid. For instance, they might have better power quality, or, conversely, they might not inflict poor power quality on neighboring customers. Financial and security concerns might also be purposes.

To the utility, a microgrid can be viewed as an electrical load that can be controlled in magnitude. The load could be constant, or the load could increase at night when electricity is cheaper, or the load could be held at zero during times of system stress.

Description:

A microgrid is a system of multiple DER generation and/or storage units of potentially different sizes and technologies that have been designed to serve selected loads. Three types exist:

- Microgrids that are permanently disconnected from any external power system, such as those used in isolated communities which can be characterized just as small power systems.
- Microgrids that consist of a balanced group of generation and load even though they are still connected to an external power system. These might be a campus, shopping mall, industrial complex, or other closely connected loads.
- Microgrids that are temporarily disconnected from a normally-connected external power system. These might be disconnected to maintain a particular level of power quality, to isolate neighboring customers from power quality problems within the microgrid, to

retain control over power system reliability, for security concerns, or during loss of the external power system

Permanently isolated microgrids and those used as a balanced group of generation and load have their own issues. However, the real challenge is the dynamic establishment of temporary microgrids, consisting of well-defined combinations of generation and load normally supplied by the distribution system. Once established, these temporary microgrids must be managed over a period of time, similar to any small power system. An additional challenge comes when they are eventually re-connected to the distribution system.

The planned establishment of temporary microgrids can be handled locally by a DER management system. This DER management system would first determine whether there is adequate DER generation and/or storage within area covered by the microgrid to meet the load over the expected time period that the temporary microgrid will operate. The DER management system would then control the combined generation and load until the net energy flow at the Point of Common Coupling (PCC) is essentially zero. It then would open the PCC switch to isolate the microgrid from the distribution system. This process would be reversed to re-connect the microgrid, with the addition of synchronizing the frequencies of the microgrid with the distribution system before closing in the switch.

Although ostensibly invisible to distribution utilities since the energy flow across the PCC would be zero upon disconnection and reconnection, the establishment of microgrids could have significant impacts on distribution operations and planning. Therefore they should be included in the DSPF / DER model, and accurate, consistent, and timely data from key equipment in the microgrid should be available to the utility SCADA system.

Additionally, the distribution utility could be charged with managing the microgrid, in which case the functions described for the DER management system would need to be available to the utility.

7.6.2 Emergency Establishment of Microgrids during Power Outage or Other Emergencies

Type/Dependency: Secondary, dependent on the availability of a DER management system to manage the establishment and operation of microgrid.

Purpose:

The purpose of establishing microgrids during emergency conditions is to continue to supply power to the microgrid loads while possibly helping to stabilize the external power system as it responds to the emergency.

Description:

Unlike the planned establishment of microgrids, emergency establishment of a microgrid requires rapid response to the loss of the external source of energy, similar to that provided by battery-based Uninterruptible Power Supply (UPS) system, but presumably covering larger, more diverse loads and more diverse DER generation and/or storage units.

The key issue is how to detect and locate a fault in a timely manner. If the fault is within the microgrid, then the appropriate loads and/or DER generation need to be disconnected. If the fault is on the external power system, then the DER generation within the microgrid needs to ride through the fault conditions while the microgrid is being disconnected at the PCC. In addition, the DER generation and storage must rapidly balance the microgrid load through a combination of rapid modification of DER power levels and possibly load shedding. The coordination of all these potential situations implies sophisticated power system equipment, good design, rapid analysis capabilities, and automation to carry out the actions.

8. Secondary DA Functions – Customer Interactions Related to Automated Distribution Operations

8.1 Use of Advanced Metering Infrastructure (AMI) in Distribution Operations

The Advanced Metering Infrastructure (AMI) provides an automated connection between utilities and their customers. The AMI system will have many different capabilities, with many not directly related to distribution operations – these are out-of-scope for this document. However, some AMI capabilities will directly or indirectly provide significant information that can be used by distribution for both planning and real-time operations. Therefore, this section does not address AMI in general, but focuses primarily on those AMI-based functions which can provide information to distribution functions.

To distinguish AMR from AMI, AMI provides the infrastructure that can be used for many different interactions between the utility and the customer, which includes advanced meter reading (AMR), but also permits many other functions.

8.1.1 Automatic Meter Reading (AMR)

Type/Dependency: Secondary, dependent on an AMI infrastructure or on manual or semi-automated methods for retrieving meter data from customer meters.

Purpose:

Customer meter reading data can provide specific information on selected customers as well as aggregate information on groups of customers. For distribution operations, typically the former information is critical for outage management, while the latter information is more important for analyzing load shapes for use by DSPF functions.

AMR, using an AMI infrastructure or manual/automated methods, retrieves meter readings from customer sites, including:

- Monthly meter readings for monthly energy used
- Monthly meter readings of hourly (or other periodic) energy usage
- Monthly meter readings of periodic energy usage and demand levels
- On-demand meter readings
- Other functions, such as sub-metering, pre-payment management, and non-electric meter reading

Description:

AMR provides meter data to a Meter Data Management Agent (MDMA), which could be a utility or a third party. The following are some aspects of meter reading.

- MDMA reads meters with handheld/mobile technologies
- MDMA reads industrial and/or commercial meters with fixed AMR technology

- MDMA reads residential meters with fixed AMR technology
- MDMA provides individual and aggregated meter readings to market settlements, DisCos, and/or TransCos
- MDMA or DisCo provides individual energy usage and billing to customers
- MDMA provides prepay metering
- Metering data includes non-electric metering such as water and gas
- Sub-metering including customer bill disaggregation and rental space allocations
- Non-intrusive load monitoring, such as deducing load contributions by monitoring aggregate consumption and applying load shapes for different appliances

8.1.2 Customer Outage Detection and Correlation to Fault Location

Type/Dependency: Secondary, dependent on AMI with near-real-time customer information

Purpose:

Individual customer outage information is both used to identify individual outages, and aggregated to determine the possible location of a faulted section of the distribution system.

Description:

AMI system detects customer outages and reports it in near-real-time to the distribution utility. The utility uses the customer information from the Customer Information System, the Trouble Call System, Geographical Information System, and the Outage Management System to identify the probable location of the fault. The process includes the following steps:

- Outage management systems collect trouble calls, generate outage information, arrange work for trouble shooting
- Interactive utility-customer systems inform the customers about the progress of events
- Customer reports trouble and trouble ticket is generated
- Trouble ticket is used by outage management function
- Trouble ticket is used for statistical analysis

8.1.3 Assessment of Customer Power Quality

Type/Dependency: Secondary, dependent on AMI

Purpose:

Power quality is becoming increasingly important to customers whose businesses and home equipment is more sensitive to serious variations in the quality of power. Power quality information directly from customer sites can assist in distribution planning and operations, including:

- Prioritize system improvements based on reliability and PQ levels being supplied to customers

- Coordinate with power conditioning equipment to improve performance
- Notify customer of current PQ information, including current harmonic content and any PQ events
- Implement power quality contracts, such as power factor correction, harmonic filters, UPS and power conditioning equipment
- Improve power quality through supervisory control

Description:

Power quality information can be used not only for alerting utilities to specific power quality problems, but also for helping distribution operations to minimize these problems in the short term and for providing distribution planning with the data to minimize the impact in the longer term. Some steps in power quality processing include:

- Utility measures power quality parameters, transmits them to central location, processes data, and stores data in PQ database in real time.
- Real time power quality state estimation system calculates power quality characteristics based on limited monitoring information from substations, distribution systems, and customer systems and models (pseudo-measurements) supplementing to the needed redundancy
- Utility correlates data from utility operations database, lightning database, and other operations related database with PQ event database and generates reports and/or stores analysis results for future reporting.
- The utility PQ evaluation system analyzes PQ events, trends, and profiles of power quality levels of the supply system against planning limits and operation objectives. The system is used to generate recommendations and priorities for system improvements.
- The power quality management system analyzes PQ events and profiles to identify causes of PQ problems and possible equipment problems that could be corrected. Detailed recommendations are developed and automatic responses are implemented where possible.
- Utility generates various reports from PQ database for operation, management, engineering, and customer consumption via e-mail and web interfaces.
- Utility exposes historical and real-time power quality data to customers
- The power quality information is evaluated with respect to specific customer Description on the specific system. Coordination with equipment and power conditioning equipment within customer facilities is implemented to improve productivity and reliability of customer systems.
- Utility accesses PQ database and generates bill/refund/penalty statement for events that exceed contract limits.

8.2 Customer Demand Response

8.2.1 Customer Response to Demand Response Signals

Type/Dependency: Secondary, dependent on AMI and new types of tariffs

Purpose:

Customers can respond to power system reliability situations and the actual costs of energy through pricing signals linked to the customer tariffs. Although many of these demand response relate to the cost of energy, others are linked to distribution system reliability and power quality.

Description:

Customers respond to reliability and/or pricing signals, which may be provided months, days, or hours ahead.

These demand response pricing signals can affect different tariff arrangements that customers might have:

- Time of Use
- Net Metering
- Programmable Communicating Thermostats (PCTs)
- Real-Time Pricing
- Microgrids
- Backup Power
- Priority Maintenance
- Power Quality

8.2.2 Analysis of Demand Response

Type/Dependency: Secondary, dependent on AMI and new types of tariffs

Purpose:

Distribution systems need to take into account the results of customer demand response as it affects distribution planning and operations. These assessments include the impact of demand response on:

- Time of Use (TOU)
- Net metering
- Direct load control (PCTs and/or cycling of appliances)
- Opt-in load control

- Real-Time Pricing (RTP)

Description:

Both aggregated demand responses and specific customer demand responses (typically of larger customers) are used for short term operational planning, and ultimately for longer term distribution planning. These demand responses would be included in functions based on the DSPF.

8.2.3 Demand Response Interactions with Home Automation Networks

Type/Dependency: Secondary, dependent on AMI and existence of home automation networks

Purpose:

Demand response can best work when customers can establish their responses ahead of time, and then allow automated actions to respond to the signals. Home automation networks can provide energy information and respond to requests to modify energy usage for reliability and/or financial purposes, including:

- Customer home automation system manages the building environment, based on preset parameters (security settings, temperature, appliances, lighting management, etc.)
- Utility sends demand response reliability or pricing signals which causes the home automation system to take preset actions
- Customer EMS bids into power market using both DER generation/storage and controllable load

Description:

Demand response signals would be used by home automation networks to manage thermostats, cycle appliances, and take other pre-planned actions, without direct intervention by the customer at the time of the signal.

8.3 Customer Use of DER Generation/Storage

8.3.1 Customer Use of DER for Self-Supply

Type/Dependency: Secondary, dependent on AMI

Purpose:

Distribution operations must increasingly monitor information on the profile of DER usage by customers in order to manage the distribution system in a reliable and efficient manner. This information is critical for distribution operations, power quality management, as well as distribution planning.

Description:

Commercial customers, industrial customers, residential customers, and communities can use DER units for different purposes. These purposes include:

- DER units used as automatic backup for key internal load if main power is lost or may be lost (e.g. diesel generator). The DER system undertakes automatic start of DER device, disconnects Area EPS, synchronizes and interconnects DER to local EPS, and performs generation control to meet changing load Description.
- DER units base-loaded to provide a set level of generation (e.g. to offset load, to provide local generation for reliability and/or demand-response, to shave peaks).
- DER, specifically Combined Heat and Power (CHP), units make use of excess heat to generate electricity
- DER units used to maintain import/export levels for compliance with tariff requirements
- DER units used in permanent building/campus microgrid where the utility power is only for backup

8.3.2 Electric Vehicle as Combined DER Generation and Storage

Type/Dependency: Secondary, dependent on AMI and the availability of significant numbers of plug-in electric vehicles

Purpose:

Plug-in electric vehicles could in the long term provide a significant method for improving efficiency by shifting electric loads so that the overall load factor could be closer to 1. Conceptually, these electric vehicles would be charged up over night when the load is low, and then used to provide additional generation during peak daytimes.

Since they are mobile, they could be used in a limited way for mobile electric storage, able to be sent to areas needing local energy support. They might also be used during the emergency establishment of microgrids, since electric storage (batteries) can provide the most rapid response to sudden changes in electric power.

Electric vehicles could also be used for storage that would balance the generation of electricity by renewable sources which are driven by weather, sunlight, and other uncontrollable natural forces.

Description:

A number of issues would have to be resolved for this capability to take place:

- Significant numbers of plug-in electrical vehicles would need to be available and purchased by customer
- Equipment for managing charging and discharging as desired by the customer would have to be available
- Tariffs would need to reflect appropriate rates and constraints for both charging and generating power.

- Methods would need to be developed for correct billing to the customer for electricity usage and generation where the vehicle might be in any location
- Electric distribution system would need to be able to handle uncertain loads and generation

8.3.3 DER Units Bid into Market Operations

Type/Dependency: Secondary, dependent on electric energy and ancillary services market

Purpose:

Distribution operations must increasingly monitor information on the profile of DER usage by customers in order to manage the distribution system in a reliable and efficient manner. This information is critical for distribution operations, power quality management, as well as distribution planning.

Description:

Customers bid their DER units into the electricity market for:

- Energy
- Ancillary services, such as reserve, local generation, storage for balancing renewables, etc.
- Carbon trading

9. Secondary DA Functions – Distribution Planning

9.1 Operational Planning

Operational planning for distribution systems involves analyzing the expected state of the system from 1 day to 1 week ahead.

9.1.1 Assessing Planned Outages

Type/Dependency: Secondary, dependent on the DSPF model

Purpose:

Outages, even when planned, can be disruptive to customers, particularly if they cause unexpected problems such as tripping of DER units during switching operations. Scheduling these planned outages can be difficult, since unintended consequences can occur if not well scheduled.

Description:

Planned outages have to take into account many different aspects, including work management scheduling of field crews, power system reliability needs, access to required assets, etc. DA functions can provide some of this assessment through the use of the DSPF model of the distribution system, where the impacts of potential outages can be studied ahead of time to determine how best to avoid unintended consequences.

The approach would include:

- Work management and/or maintenance personnel prepare outage requests based on time and condition criteria
- Operations staff review and approve outage requests based on the results of the DSPF assessment of the distribution system
- Outage request analysis and scheduling, taking into account the capabilities of real-time DA functions
- Planners/operators perform load analysis of substation equipment using the DSPF
- Multi-level feeder reconfiguration is executed if it appears overloads might occur
- Contingency analysis/reliability assessment is performed to determine the degree of risk of unintended consequences
- DER system operators are notified and possibly re-scheduling for contingency support
- Protection coordination analysis is performed to ensure that the affected protection schemes are correct
- Switching orders are determined for undertaking the planned outages and for the return to normal

9.1.2 Storm Condition Planning

Type/Dependency: Secondary, dependent on the SCADA system and the DSPF model

Purpose:

Storms can cause many outages, some of which cause momentary short circuits due to wind gusts. Often these cause fuses to blow, even though no permanent problem exists. If recloser settings could be changed to minimize blown fuses, then many of these outages would just cause momentary power losses, while avoiding the need to send crews out to replace the fuses.

Description:

Operators plan and prepare for storm conditions by using the DSPF to analyze the impact of historical storm situations on different feeders, and using the SCADA system to identify and change recloser settings.

- Change recloser settings
- Change alarm thresholds to avoid cascading of multiple alarms from the same cause
- Use the DSPF to study possible contingency actions for different types of storm damage to different feeders

9.2 Short-Term Distribution Planning

Short-term planning for distribution systems involves analyzing the expected state of the system from 1 week to 1 year ahead.

9.2.1 Short-Term Load Forecast

Type/Dependency: Secondary, dependent on the DSPF model

Purpose:

The DSPF model can be used in study mode to perform short term load forecasts for different feeders with different levels of loads and DER generation/storage.

Description:

Some of the tasks that the DSPF could perform include:

- Load forecast for existing loads based on historical loads for comparable days and weather conditions
- Forecast the location and amount of new loads
- Forecast DER generation and storage based on historical generation for comparable days and weather conditions
- Forecast the location and capabilities of new DER generation and storage
- Assessing impact of different demand response levels

9.2.2 Short-Term DER Generation and Storage Impact Studies

Type/Dependency: Secondary, dependent on the DSPF model

Purpose:

The DSPF model can be used in study mode to perform short term impact studies of DER generation and storage. In these studies, different generation levels can be modeled to determine not only the impact on feeder loads but also the variability impact on these loads.

Description:

Some of the tasks that the DSPF could perform include:

- Load forecast for existing loads based on historical loads for comparable days and weather conditions
- Forecast the location and amount of new loads
- Forecast DER generation and storage based on historical generation for comparable days and weather conditions
- Forecast the location and capabilities of new DER generation and storage
- Assessing impact of different demand response levels

9.3 Long-Term Distribution Planning

Long-term planning for distribution systems involves analyzing the expected state of the system from 1 year to 5 years ahead.

Although the same term, DSPF, is used for the distribution system model, often the DSPF model used for long-term planning is different from the DSPF model used in operational and short-term planning. This difference is due mostly because simplified DSPF models have been used for a long time for the long-term modeling, but also because the details such as 3-phase models that are required for day-to-day operations are not needed in long-term planning. Therefore the "DSPF" in this section can be a different software application than that used in other DA functions, but it does not have to be different.

9.3.1 Long-Tem Load Forecasts by Area

Type/Dependency: Secondary, dependent on the long-term DSPF model

Purpose:

The long-term DSPF model can be used in study mode to perform long term load forecasts for different areas with different levels of loads and DER generation/storage.

Description:

Some of the tasks that the DSPF could perform include:

- Load forecast for existing areas based on historical loads for comparable days and weather conditions
- Forecast the location and amount of new loads
- Forecast DER generation and storage based on historical generation for comparable days and weather conditions
- Forecast the location and capabilities of new DER generation and storage
- Assessing impact of different demand response levels

9.3.2 Optimal Placements of Switches, Capacitors, Regulators, and DER

Type/Dependency: Secondary, dependent on the long-term DSPF model

Purpose:

The long-term DSPF model can be used in study mode to determine the optimal placement of sectionalizer and tie switches, capacitor banks, voltage regulators, and DER generation and storage.

Description:

The assessment of the optimal placement of distribution equipment can provide a goal for this placement, even if not all placements are feasible. This optimization could use different criteria, such as small numbers of larger capacitor banks versus larger numbers of smaller capacitor banks. For switches, the criteria could also include the expected number of times the switches might be used during normal operations to offset possible overloads, and/or the number of switches versus the number of customers on faulted segments.

In particular, DER generation and storage placement is often at the discretion of the DER owners, and can be very dependent upon the type of DER and the contractual arrangements with the DER owners. For instance, PV and wind would need balancing DER storage in order to provide energy when needed. CHP could be used by its owners to respond to their own needs first, and thus might not be reliably available.

9.3.3 Distribution System Upgrades and Extensions

Type/Dependency: Secondary, dependent on the long-term DSPF model

Purpose:

The long-term DSPF model can be used in study mode to assess the need for and location of distribution system upgrades and extensions, including substations, feeders, feeder segments, and distribution equipment. This study can also use the optimal placement assessment to best determine the placement of distribution equipment.

Description:

Distribution system upgrades and extensions can be assessed in conjunctions with the long-term transmission plan, through the use of the DSPF model and a transmission power flow model. Distribution assets to study would include:

- New transmission and distribution substations
- New distribution circuits and conductors
- New distribution transformers
- New DER generation and storage, including both utility-owned and customer-owned
- New circuit boundaries
- New switch allocation
- New capacitor allocation

9.3.4 Distribution Financial Planners

Type/Dependency: Secondary, dependent on the long-term DSPF model

Purpose:

The long-term DSPF model can be used in study mode to assess the impact of different potential contractual arrangements with transmission companies, DER providers, and customers.

Description:

The long-term DSPF can be used to:

- Assess contracts with transmission companies covering mutual obligations for the T&D interfaces, operation coordination, and information exchange.
- Assess contracts with DER generation and storage providers
- Assess customers contracts/tariffs regarding service reliability and power quality, demand response, interruptible, etc

10. Secondary DA Functions – Distribution Maintenance, Engineering, and Construction

10.1 Distribution System Equipment Maintenance

Maintenance is an area that can benefit significantly from distribution automation. In particular, DA can provide better locational information of problems and can provide more information on the health and status of equipment.

10.1.1 Predictive Maintenance Application Assesses Distribution Equipment

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

Predictive maintenance allows maintenance personnel to focus on equipment with the highest need of maintenance, rather than just relying on periodic maintenance cycles.

Description:

The health and operational history of field equipment is monitored, including trends or peaks in temperature, pressure, vibration, and other characteristics of the equipment. Maintenance staff can then analyze this history and determine which equipment requires maintenance in which time-frames. In addition, the results of different predictive maintenance algorithms can be compared to determine which are the most accurate in predicting failures.

10.1.2 Management of Maintenance Assets

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

Although asset management per se is beyond the scope of distribution automation functions, the DSPF model can be used to track maintenance activities, often by identifying anomalies in the data that may indicate that the model no longer reflects the actual status of the power system after some maintenance activities.

Description:

The approach would include:

- Maintenance staff identifies assets and work crew
- Work crew carries out maintenance, coordinating with operators for switching
- Work crew logs activities and results of tests
- Work crew identifies assets removed and/or installed

- DSPF is used to determine if the model still reflects the status of the power system after the assets are removed and/or installed

10.1.3 Scheduling of Maintenance and Equipment Replacement

Type/Dependency: Secondary, dependent on historical SCADA data and the DSPF model

Purpose:

Scheduling of maintenance activities can be influenced by historical SCADA data on equipment actions, as well as the results of DSPF study-mode executions to determine any potential changes. For instance, if more automated switching is done for efficiency purposes or for managing DER generation and storage, then changes may be necessary for the maintenance of these switches.

Description:

The approach would include:

- Calculate system utilization based on forecast load and nameplate ratings
- Schedule maintenance operations - time-based
- Schedule maintenance operations - predictive, based on data and models
- Schedule equipment replacement - based on age of equipment
- Schedule equipment replacement - predictive, based on data and models
- Schedule equipment replacement - based on contingency scenarios
- Schedule spare distribution, ensure sufficient at each site

10.1.4 Maintenance Updates to Documentation and Maps

Type/Dependency: Secondary, dependent on the DSPF model and accurate, consistent, and timely data

Purpose:

Although documentation and mapping updates per se are beyond the scope of distribution automation functions, the DSPF model can be used to identify errors in these updates if they affect the distribution system operations, often by identifying anomalies in the data that may indicate that the model no longer reflects the actual status of the power system after some maintenance activities.

Description:

The approach would include:

- Maintenance staff identifies errors in documentation and maps
- Maintenance staff identifies marks up documentation ("red/green")
- Maintenance staff indicates permanent versus temporary changes

10.1.5 Maintenance of DSPF Model and Other DA Applications

Type/Dependency: Secondary, dependent on the DSPF model

Purpose:

The DSPF model and DA applications need to be maintained and updated as the distribution system changes and operational requirements are modified.

Description:

These updates include:

- Updating the topology of the distribution model
- Updating the load profiles and DER generation/storage profiles
- Updating distribution equipment asset parameters as these assets are added and/or removed
- Updating electrical connectivity of the distribution model where this is not monitored from the field
- Setting parameters for different DA applications as operational objectives change, including:
  - Closed-loop control of service restoration function
  - Use emergency limits for service restoration
  - Provide volt/var support for transmission
  - Provide Peak Load reduction within voltage quality limits
  - Provide Peak Load reduction within voltage emergency limits

10.2 Distribution System Design and Engineering

10.2.1 Design and Engineering of Substations and Feeders

Type/Dependency: Secondary, dependent on SCADA data and the DSPF model

Purpose:

DA SCADA and DSPF-based functions can provide significant amounts of information that can be used in the design and engineering of substations and feeders.

Description:

Using the DSPF model, historical SCADA data, and other sources, the impacts of different designs and engineering solutions can be studied on the distribution system. The DSPF model can either be used to apply "peak seasonal" data sets, as is often done now, or can be used to study alternatives with demand response and DER generation/storage as off-setting the peak energy requirements.

10.2.2 Specification of Distribution Equipment

Type/Dependency: Secondary, dependent on SCADA data and the DSPF model

Purpose:

New distribution equipment should have additional capabilities to meet the requirements of DA functions.

Description:

Particularly if pilot projects and initial implementations have been used to determine the best equipment requirements and beneficial DA functions, the results of these implementations should be used to identify what capabilities any new distribution equipment should have in order to best meet the needs.

10.3 Construction Management

Most of construction management lies outside of DA functions, other than the actual installation of DA equipment and communications. But a few construction aspects exist that benefit from DA functions.

10.3.1 Asset Tracking and Updating

Type/Dependency: Secondary, dependent on SCADA data and asset databases

Purpose:

If SCADA systems can access not only normal distribution system data, but also asset identification data for assets in the field, then asset databases can be automatically updated.

Description:

Asset databases can be updated by SCADA information from assets that have been installed in the field.

10.3.2 Planning Construction Projects

Type/Dependency: Secondary, dependent on SCADA data and the DSPF model

Purpose:

Planning of construction projects can be aided by sets of SCADA data and results from running DSPF models.

Description:

Some of construction project steps might result in planned outages, which can benefit from determining the impact on the distribution system, DER generation/storage, and its customers. Other construction steps could include testing of new construction before it is interconnected with the distribution system, which could benefit by using the SCADA capabilities to check monitored values and parameters, and the DSPF to validate the consistency of the data.