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Guidelines for Implementing Advanced Distribution Management Systems

Requirements for DMS Integration with DERMS and Microgrids

Energy Systems Division

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Table of Contents

Figures

Tables

List of Acronyms

AM	Asset Management
AMI	Advanced Metering Infrastructure
AOR	Area of Responsibility
CBM	Condition-Based Maintenance
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CSM	Cyber Security Manager
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DMM	Data & Model Management
DMS	Distribution Management System
DNP3	Distributed Network Protocol, Version 3
DOE	U.S. Department of Energy
DR	Demand Response
DRM	Demand Response Management
DRMS	Demand Response Management System
DSCADA	Distribution Supervisory Control and Data Acquisition
DTS	Dispatcher Training Simulator
EEDR	Energy Efficiency and Demand Reduction
ESB	Enterprise Integration Bus
ELS	Emergency Load Shedding
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
EVMS	Electric Vehicle Management System
FAN	Field Area Network
FCI	Faulted Circuit Indicator
FLISR	Fault Location, Isolation, and Service Restoration
GIS	Geographical Information System
GUI	Graphical User Interface
HIS	Historical Information System
HV	High-Voltage
MV	Medium-Voltage

IAP	Intelligent Alarm Processing
ICCP	Inter-Control Center Protocol
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IEEE PES	IEEE Power & Energy Society
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IT	Information Technology
kVA	kilovolt-ampere
kW	kilowatt
LTC	Load Tap Changer
MC	Microgrid Controller
MDMS	Meter Data Management System
M&V	Measurement & Verification
ms	millisecond
NUG	Non–Utility Generator
OC	Overcurrent
OLPF	On-Line Power Flow
OMS	Outage Management System
ONR	Optimal Network Reconfiguration
OV	Overvoltage
PCC	Point of Common Coupling
PEV	Plug-in Electric Vehicle
PFL	Predictive Fault Location
PV	Photovoltaic
QoS	Quality of Service
RDBMS	Relational Database Management System
RF	Radio Frequency
RFP	Request for Proposal
RTU	Remote Terminal Unit
s	second
SAIDI	System Average Interruption Duration Index
SCA	Short-Circuit Analysis
SCADA	Supervisory Control and Data Acquisition
SE	State Estimation
SI	System Integrator

SOM	Switch Order Management
STLF	Short-Term Load Forecasting
TP	Topology Processor
UI	User Interface
UV	Undervoltage
V	volt
VGU	Virtual Generation Unit
VVC	Volt/VAR Control
VVO	Volt/VAR Optimization

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1 Introduction

Grid modernization calls for distribution management systems (DMS) that meet fundamental challenges to distribution grid operations from high-penetration distributed energy resources (DER), behind-the-meter generation, two-way power flows, and microgrids. This modernization effort requires enhanced DMS functionality that interacts with distributed control systems — an advanced DMS.

With the development of the smart grid in recent years, advanced measurement and control devices, such as automated distribution circuit reclosers and sectionalizers, are being installed in utility distribution networks to improve reliability under both normal and event-driven operations. With advances in grid telemetry, enabling two-way information exchange between utilities and consumers, it is now possible for grid operators to have access to near-real-time data measurement for control of distribution circuits, substations, transformers, switches, and relays.

On the consumer side, the fast-growing development and deployment of smart grid solutions, such as advanced metering infrastructure (AMI), demand response (DR), aggregated DER, and microgrids, create challenges for distribution management and control. For example, the output of behind-the-meter DER may not be visible to distribution system operations. The inherent uncertainty and variability of energy sources such as distributed photovoltaic (PV) may cause voltage control issues on the feeders of the distribution system.

Grid modernization requires advanced DMS that can integrate and further enhance existing customer information systems (CIS); geographic information systems (GIS); outage management system (OMS); energy management system (EMS); and other information and control systems available at utilities to improve their visibility, control, and support analytics. An advanced DMS can realize comprehensive and optimal monitoring and control of distribution systems, which are critical to taking full advantage of smart grid investments and enhancing the value of both utility-owned and customer-owned assets. (Common, emerging, and/or required DMS functions are discussed in Section 2 and in Appendix A).

The implementation of DMS varies across utilities (see *Distribution Management System Industry Survey*, Appendix B). While some utilities have just begun planning for DMS implementation, others are already far along in the process. Some DMS applications such as fault location isolation and service restoration (self-healing), Volt/VAR optimization (VVO), on-line power flow (OLPF), and switch order management (SOM) have gained wide acceptance. There is a growing consensus on the need for new applications for control and management of distribution systems with high-penetration DER and microgrids. This need requires an advanced DMS that integrates the functionality and capabilities of the DMS with those of DER management systems (DERMS) and microgrid controllers (MC).

1.1 Overview

Conventionally, distribution grids are generally passive networks with power flows that travel solely in one direction from source substations down to individual passive consumer loads. In addition, the distribution networks are largely configured to operate radially, which further ensures that power flow takes a single path between the source and a consumer load in either normal operation or a faulted condition. When DER and microgrids are connected to the distribution network, the conventional features mentioned above no longer exist, even though a network would still be configured radially. This result occurs because distribution grids generally become active networks, and power flows become two-way flows. The actual flow directions of individual circuit sections will depend on load distributions and the output contributions of dispersed DER and microgrids from time to time.

With high-level penetration of DER in a distribution grid, it may be necessary to have a DERMS to aggregate, control, and manage the operation of the DER dispersed widely in the network. A DERMS can be mainly responsible for aggregating the dispersed DER into different energy resource groups, achieving energy optimization for the overall distribution grid, and also possibly participating in energy transaction bidding at the transmission level of energy trading. Individual DER connected to a distribution grid may be broadly classified by a DERMS/DMS as either a *directly* monitored/controlled DER or as an *indirectly* monitored/controlled DER. The same classification rule may also apply to microgrids connected to the distribution grid. For example, indirectly monitored DER may have small capacities (e.g., 10 kW or less) and may be represented simply as negative loads, allowing them to be merged with the ordinary loads in a DMS. However, a larger microgrid or a major DER, especially an aggregated DER in a DERMS, may have considerable capacity, and its operation may have impacts on distribution grid operation that cannot be ignored and may need to be well modeled, monitored, controlled, and coordinated with the DMS for reliable operation and control in providing quality power delivery to consumers in the distribution grid.

This guideline focuses on the integration of DMS with DERMS and microgrids connected to the distribution grid by defining generic and fundamental design and implementation principles and strategies. It starts by addressing the current status, objectives, and core functionalities of each system, and then discusses the new challenges and the common principles of DMS design and implementation for integration with DERMS and microgrids to realize enhanced grid operation reliability and quality power delivery to consumers while also achieving the maximum energy economics from the DER and microgrid connections.

1.2 Functional Scopes and Responsibilities of DMS, DERMS, and Microgrids

A distribution system is generally considered to be part of an electric power grid and is usually extended from the primary (high-voltage [HV]) buses of distribution substation transformers all the way to distribution service transformers through distribution feeder circuits. It may cover a large geographical area with many distribution substations or a small area with one or a few substations. It may also be extended to cover a certain part of the sub-transmission network, if it exists, that supplies the primary buses of the distribution substation transformers and/or by being extended down further to the lower voltage network on the secondary side of the distribution service transformers. A distribution system may be owned by a single power utility or by more than one, with each owning part of the system; or there may be mixed ownership may that is shared among utilities and customers, or independent energy/service providers, etc.

A distribution system may be operated under a single DMS's monitoring and control, or it may be partitioned into several subsystems geographically, with each subsystem having a dedicated DMS. A DMS may be assigned to control and manage a single distribution system, multiple systems, or multiple subsystems; however, a single system or a subsystem should be under only one DMS at a time, although it may have one or more backup DMS for fail-over in actual operation.

Traditionally, a **DMS** is fully responsible for overall operation reliability, power delivery quality, grid economics (minimum energy losses), and all of the normal and emergency controls of the distribution system or subsystem, including maintaining an acceptable voltage profile. A DMS may operate in an integrated environment with other associated systems (e.g., the advanced metering infrastructure [AMI] and demand response management system [DRMS]); however, the other systems do not interfere with the tasks of the DMS within the scope of the overall distribution grid operation assigned to the DMS.

A **microgrid** is a small and local distribution grid having its own energy resources and loads. It may operate independently as an islanded grid or be connected to the utility distribution grid (i.e., grid-connected mode). Similar to utility distribution grids, a microgrid may be owned by a utility or a customer or both with each one owning part of the microgrid. Regardless of how its ownership is allocated, the microgrid generally has a unique controller or control system that is located at the site of the microgrid and is fully responsible for the operation of the microgrid. The controller or control system should also be responsible for ensuring an acceptable voltage profile and maintaining continuous power exchange at the point of common coupling (PCC) connecting it to the utility distribution grid. In the island mode, the MC has to maintain the energy balance and frequency within the allowable deviation. It should be noted that the concept of an MC can be limited to a regional system with a relatively smaller scale. However, it also applies to larger systems. In this case, the MC can be used as a fully functional control unit. Particularly in the case of islanding operation, it can be regarded as a local DMS.

A **DERMS** is designed to manage and control widely dispersed DER in the distribution system. As discussed in the report by the Electric Power Research Institute (EPRI) [1], DER management is achieved by using a DERMS. Meanwhile, the interactive operation of an MC and a DERMS is investigated in [1]. Providing four main functions, a DERMS:

- **Aggregates:** A DERMS takes the services of millions of individual DER and presents them as a smaller, more manageable number of aggregated virtual resources.
- **Simplifies:** A DERMS handles the complex and granular details of DER settings and presents DER capabilities as simple, grid-related services that are consistent with DMS needs.
- **Optimizes:** A DERMS optimizes the utilization of DER within various groups to obtain the desired outcome at minimal cost, maximum utilization, and best possible power quality.

- **Translates:** Individual DER may “speak” different languages, depending on their type and scale. A DERMS handles these diverse languages and presents the information to the DMS (or other upstream calling entity) in a cohesive way.

The optimal schedules may be allocated to the individual DER through disaggregation for actual execution. A DERMS may directly monitor and control the individual DER or may coordinate through shared supervisory control and data acquisition (SCADA), AMI, field area network (FAN), or other communication-capable applications.

Like a demand response application server (DRAS), a DERMS may be a utility-operated application or a third-party system that provides DER management services to the utility. In either case, a DERMS is a tool for the distribution operator and a “slave” to the DMS. A DERMS may cover the service area of the DMS, or multiple DERMS systems together may cover the entire service area of the DMS. This latter structure means that the DMS may integrate with multiple DERMS, which is similar to how it may be structured with microgrids.

A DER may or may not participate in the management of a DERMS, regardless of how large its capacity, where it is located, and its ownership structure. If it does not participate in a DERMS, it may be under direct control of the DMS using another architecture or following proprietary operation rules, which may not follow the guideline defined in this document.

1.3 Relationships among DMS, DERMS, and Microgrid Controllers

In the integration of the DMS with microgrids and DERMS, the DMS may play the leading role, with the others mainly occupying supporting positions, although each of the systems has its own responsibilities, functionalities, and tasks.

The functions of an MC or control system may be implemented in a physically independent device or a processor located in a control room or somewhere in the local area of the microgrid, or they may be implemented as a subsystem or a subfunction of the DMS or a system in parallel to the DMS. However, the functionality of the MC or control system should depend on relatively independent logic, regardless of where and how it is implemented. The guidelines defined in this document largely focus on the functional logic and common integration features that would be applicable to various implementations as long as the microgrids follow the industry standards such as those defined in the Institute of Electrical and Electronics Engineers (IEEE) 1547 standard [2].

Similarly, the integration of a DMS with a DERMS may be accomplished in many different ways. A DERMS may be fully independent of the DMS and may be located in a substation, in an engineering office, a local or remote control center, or, in the case of a third-party DERMS, in a cloud server on the Internet. It may also be implemented as a subfunction or a dedicated application in the DMS. However, the basic functionality of a DERMS and its integration logic with the DMS should have similar features. This guideline will focus on the fundamental common functionalities and integration logic between the DMS and DERMS that are generally applicable to various implementation options.

In some cases, a microgrid may be managed directly by a DERMS rather than by communicating directly to the DMS. In such cases, the microgrid may be treated in the same way as the other DER, and all of its features and functionalities as a microgrid to DMS integration would be omitted. Its operation should be modeled and managed as an aggregated DER rather than as a microgrid when connected to the grid.

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2 DMS – Current Status and New Challenges

DMS is regarded as one of the most critical components for the modernization of today's distribution system with automatic control and management. As a fully functional unit, a DMS may have dozens of individual applications, such as fault location, isolation, and service restoration (FLISR); VVO; and OLPF. An industry survey on DMS, as shown in Appendix B, has been conducted to investigate the interests and current practices of different stakeholders so that trends regarding the future development of DMS can be documented. Meanwhile, the main technical barriers can be identified. This survey, which consists of 20 multiple choice questions, was sent to more than 300 participants. Based on the results of the survey, a growing number of entities have DMS running in their systems given that the available DMS products are becoming more mature and field proven. However, participants also indicated that challenges remain in developing a highly reliable and functional DMS in different respects (e.g., system integration, communication). It is fair to conclude that the wide adoption of DMS means it is significantly welcome in field applications, although there are still some technical barriers to overcome.

Considering the integration of DMS, the MC, and DERMS, which is the main topic of this guideline, the most relevant applications in DMS can be summarized as FLISR, VVO, OLPF, outage management, state estimation (SE), DER management, network configuration, DR, short-circuit analysis (SCA), intelligent alarm processing (IAP), emergency load shedding (ELS), and short-term load forecasting (STLF). The integration of the MC and DERMS with DMS should consider the compatibility of the above functionalities. For the rest of the applications that may be performed by a DMS, because they are not highly related to the integration of the above three systems, they will not be addressed in detail in this guideline but discussed in the Appendices.

Most of the DMS in operation today are designed to meet the operational requirements for the automation and management of traditional distribution grids. The key common features of the traditional distribution grids are that they are largely passive networks that are usually configured in a radial operation topology for distribution feeders. A typical DMS consists of or coordinates with several subsystems and major software modules, including a SCADA system, a GIS, a Data & Model Management (DMM) module, a set of advanced applications, and a User Interface (UI) module. Figure 2-1 shows a high-level layout and structure of the subsystems and key components in a typical DMS.

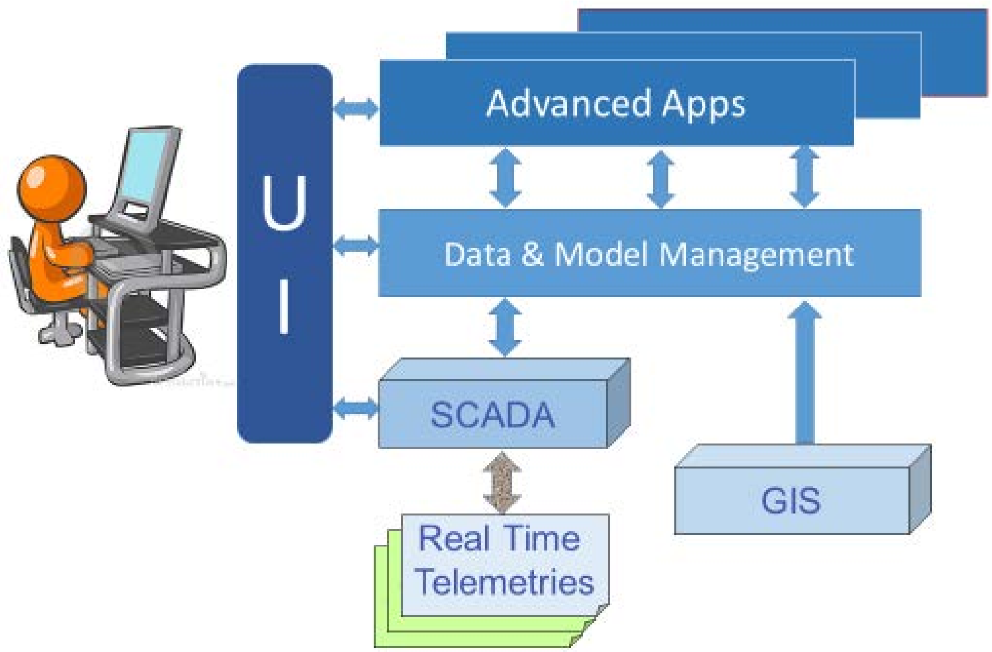

Figure 2-1 Reference Layout and Structure of a DMS

In Figure 2-1, the SCADA subsystem is responsible for acquiring real-time operational data from distribution substations and remote intelligent electronic devices (IEDs) or remote terminal units (RTUs) installed along the feeder lines. The SCADA system provides the "field-facing" interface that enables the DMS to monitor the distribution field equipment in real-time (measurements made and reported in 1 minute or less on average) or near-real-time (measurements made and reported every 10 to 15 minutes on average). The SCADA subsystem is also responsible for issuing control commands to the remote IEDs to operate switch devices, change voltage regulator taps, turn on/off capacitor banks, issue set points to various device controllers, and download configuration parameters or settings to the individual IEDs and RTUs. The GIS provides the overall distribution grid models, including the feeder connectivity models, the electrical parameters, and the geographical locations of the feeder line equipment and devices. The DMM module manages the internal data and models converted from the raw network information from the GIS and the real-time data from the SCADA system in a format that can effectively and efficiently support the real-time operation and management of the advanced applications and the UI. The advanced applications are the intelligence of a DMS that conducts the analysis and optimization for decision-making either manually or automatically and proposes or executes control actions.

An actual DMS used at a specific utility may include more or fewer components and advanced applications. The specific integration of the individual components may also be quite different. For instance, the interface to the GIS may be through an Enterprise Service Bus (ESB) in one utility's implementation but through a direct and proprietary connection in another utility's implementation. A similar situation exists for the SCADA interface and integration with other components. In some cases, different interface/integration approaches may also be applied to individual advanced applications. For example, one or more typical applications may be provided by different vendors, and the integration may occur at the ESB or may go through a dedicated proprietary interface to the DMM. Figures 2-2 and 2-3 show two sample integrations via an ESB, and Figure 2-4 shows a sample integration through a direct/proprietary interface.

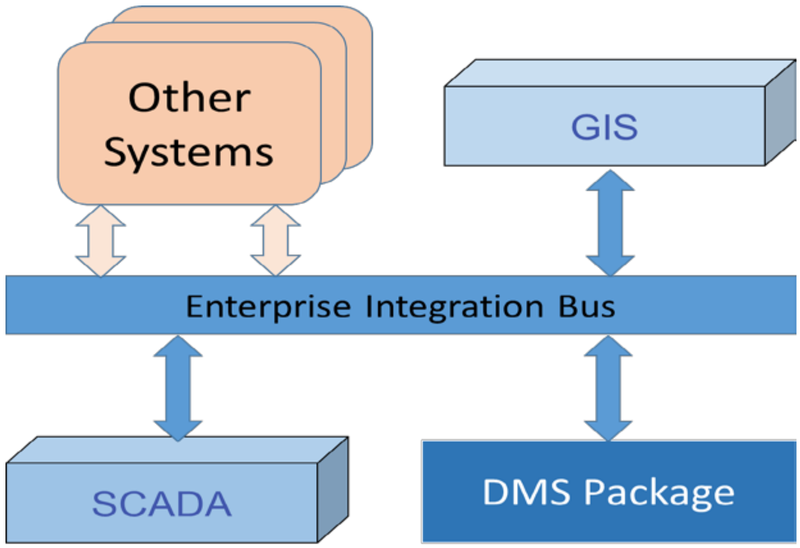

Figure 2-2 Example of Full Integration of DMS via ESB

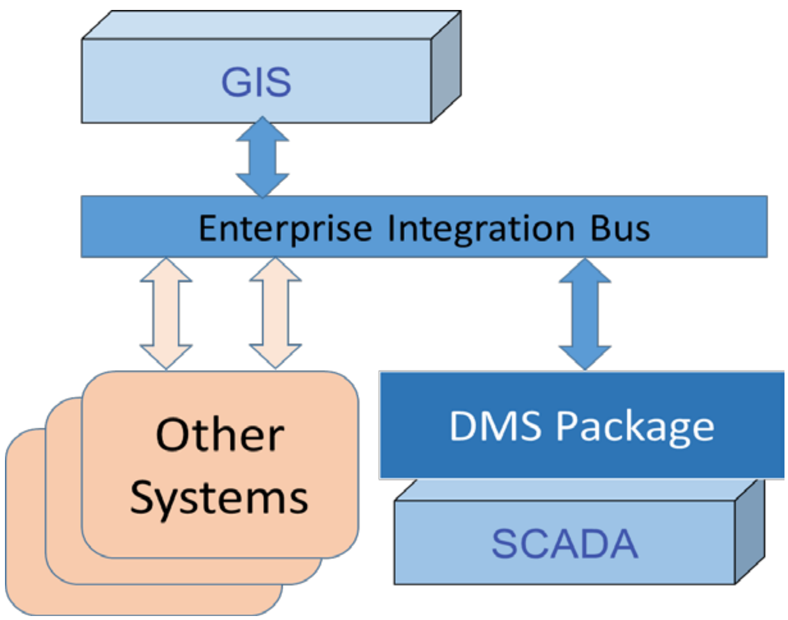

Figure 2-3 Example of Partial Integration of DMS via ESB

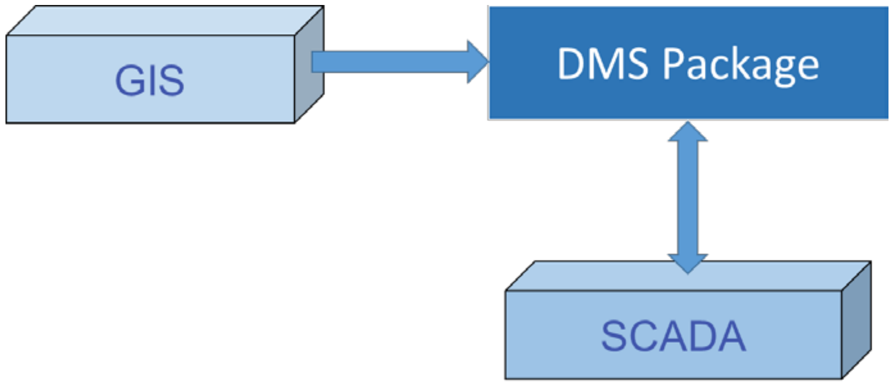

Figure 2-4 Integration of DMS via Direct Connection

2.1 Current Status of DMS Development

The basic functionalities of a typical DMS in operation today include real-time monitoring and control through a SCADA system and individual advanced applications, such as the following:

- Topology processor (TP);
- Intelligent alarm processing (IAP);
- On-line power flow (OLPF);
- Short-circuit analysis (SCA);
- State estimation (SE);
- Fault location, isolation, and service restoration (FLISR);
- Volt/VAR optimization (VVO);
- Optimal Network Reconfiguration (ONR);
- Switch order management (SOM);
- Emergency load shedding (ELS); and
- Short-term load forecasting (STLF).

The listed applications are the key advanced functions in a DMS and are generally designed for controlling and managing distribution grids with passive networks. They are all facing fundamental challenges from the high penetration of DER that make the distribution grids no longer passive but highly active networks. The basic functionalities and features of the individual applications will be discussed in the following subsections, and the specific impacts from the DER penetration on the individual applications will be discussed in Subsection 2.3.3.

2.1.1 Passive and Radial Distribution Network with One-Way Power Flow

Traditionally, distribution grids are largely passive networks in which each of the feeder circuits is supplied by a distribution substation as its sole energy source. It is generally assumed that no other energy resources or devices are connected to the feeder circuit except passive shunt devices like capacitor banks and loads of the individual end users that are modeled as pure energy consumers, as schematically shown in Figure 2-5. There may be tie switches that connect the feeder to a nearby feeder that can serve as a backup source; however, these tie switches are normally open.

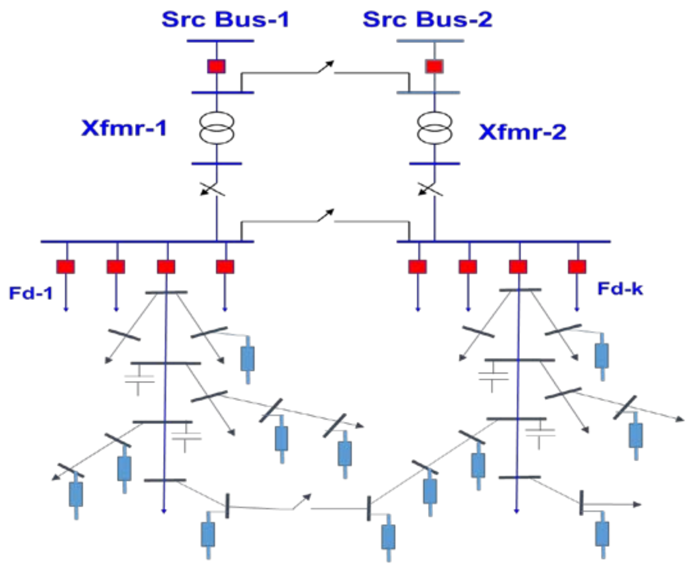

Figure 2-5 Schematic Diagram of a Conventional Feeder Circuit

Figure 2-5 shows that a conventional distribution grid can consist of many feeder circuits, each one of which extends from a distribution substation all the way to the individual end users through the feeder circuits. Power flow direction is predetermined by the configured radial circuit topology and is not dependent on the voltage profiles along the feeder circuits.

Moreover, distribution feeder circuits are generally configured as a radial network, according to which power flow to each end user is single sourced and delivered on a single path according to the operational topology of the network. Such a configuration makes all issues associated with grid planning and operation much simpler, including those having to do with distribution feeder circuit design and planning; operation and management; and more importantly, much easier implementation of protection, control, and voltage regulation schemes.

The one-way power flow and radial network configuration are two key characteristics of traditional distribution systems and are fundamental to the existing DMS design, implementation, and operation.

2.1.2 Advanced Applications in DMS

In addition to supporting subsystems such as GIS and SCADA that provide overall system models and real-time data acquisition, respectively, a DMS also includes many advanced applications for various functionalities. The following subsections introduce a few widely used advanced applications in a typical DMS [3–7]:

2.1.2.1 Topology Processor

TP is usually a background processor that accurately determines the distribution network topology based on the static connectivity model and the dynamic status of switch devices, and it also displays feeder circuit colorization signifying energization status, supplying paths, and so forth. In case a non-intentional loop is being formed, TP can detect the loop condition and issue an alarm to alert operators. Once the topology is determined, power flow direction is as well because of the radial configuration. The topology data are the basis of many other DMS applications. It is also used to support IAP (Section 2.1.2.2) based on the topology structure. In some cases, a distribution grid may have intentional looped operation scenarios. TP is responsible for tracing the looped circuits and can make special marks to highlight them upon operators' requests. In general, the TP function can perform the following functions:

- Locate an element of the distribution network (e.g., transformer, section) by name or ID,
- Locate and mark supply paths of network elements,
- Determine and highlight the energization status of network elements,
- Locate and highlight network loops,
- Locate and highlight all network elements for the downstream of a selected element,
- Locate and highlight neighboring feeders of a selected feeder that can serve as an alternate supply for the feeder,
- Color individual feeders,
- Color by voltage level,
- Color line segments with voltage magnitudes less than specified thresholds,
- Color line segments with loading greater than specified thresholds, and
- Locate and highlight portions of the distribution feeder that are isolated from the utility's power grid and are being energized by microgrids or DER.

In addition to requiring correct connectivity models, it is also essential to have accurate phase information in the connectivity model for TP to provide correct topology information for the UI displays and other advanced applications. This is because distribution networks generally operate in unbalanced conditions, including unbalanced networks (e.g., single-phase and two-phase laterals) and unbalanced power flow among the three phases. Incorrect phase information will lead to topology and power flow "solutions" that are completely wrong.

2.1.2.2 Intelligent Alarm Processing

The conventional alarm mechanism has been based on the basic SCADA functions where the data are organized with independent data points. When an event occurs in the distribution grid, the associated data points will be used to trigger an alarm for the abnormal condition independently, which can result in many unnecessary annoying alarm messages being presented to the system operator. The IAP function is designed with sufficient intelligence to generate concise and root cause alarm messages to alert the system operators about abnormal conditions by filtering the unnecessary alarms. It includes a variety of distinct alarm priority logics that can determine the manner and priority in which each alarm is announced, acknowledged, and recorded.

The IAP function can effectively assist the operators in managing “bursts” of alarms that may occur during an emergency or combinations of alarms related to a single event. Generally, an IAP function should include the following functionalities and features:

- Dependent alarms for which alarming of specified points should be enabled or disabled based on the status or values of another related data point,
- Prevention of repetitive alarms for the same alarm condition,
- Combining of related alarm messages (e.g., a single alarm message “feeder ABC tripped”) provided instead of multiple messages that convey the same information (breaker tripped, loss of voltage, loss of current),
- Prioritizing of alarm messages and highlighting of the most urgent messages,
- Combining of the alarm states of two or more alarms to produce a higher-priority alarm message, and
- Suppression of alarms based on related conditions (i.e., suppressing or enabling the alarm based on the value or state of another system variable).

The IAP function may also include “time-sensitive alarming.” It monitors and tracks time-sensitive ratings on substation transformers, cables, and other equipment’s time-sensitive ratings. The time-sensitive alarm function can track the amount of time that the short-term emergency loading on a substation transformer or cable has been exceeded and alert the operator when the time limits are being approached. For example, if a substation transformer has exceeded its 4-hour emergency rating for a user-specified period (e.g., 3.5 hours), the system operator will be alerted.

2.1.2.3 On-line Power Flow

OLPF is a very important application in a DMS. It solves the three-phase unbalanced power flow of the distribution network, either in a pure radial configuration or weakly meshed network with a few loops. OLPF is one of the core applications in a DMS. Power flow results from OLPF are used by many other DMS applications to set initial conditions and validate performance or to show hypothetical impacts, such as in VVO, FLISR, and SOM.

The OLPF also provides the control center personnel with calculated line section current and power flow values and node voltage values in place of actual measurements and alerts the operators to abnormal conditions out on the feeders, such as low voltages at feeder extremities and overloaded line sections.

In solving power flow problems, the OLPF uses the distribution system model and load estimate provided by load allocation and estimation functions in its calculations. It may also use the available real-time status from the substation and feeder devices and the voltages and phase angles obtained from the EMS state estimator used by the transmission operator at the injection points (usually placed on a high-voltage transformer bus in distribution substations). More detailed OLPF results include the calculated current and voltage magnitudes and phase angles, the real and reactive power flows and injections for the entire distribution system, and all technical losses. All of the detailed results may be presented in various formats automatically or on demand on convenient graphical displays for viewing power flow summaries for a large area of the distribution system and/or viewing (on demand) the detailed results for the individual points or sections of the distribution system.

2.1.2.4 Short-Circuit Analysis

SCA is an analysis tool in DMS that operates upon the operator's or a user's request. It calculates the short-circuit current distribution for hypothetical fault types and pre-fault operation conditions to evaluate the possible impacts of the fault on the distribution grid. SCA results can be used to verify the relay protection settings and operation, as well as the circuit breaker and fuse ratings, and propose more accurate relay settings or a better feeder circuit configuration from the viewpoint of circuit protection.

The SCA function enables users to calculate the three-phase voltages and currents on the distribution system that could occur as a result of postulated fault conditions and pre-fault loading conditions. It can calculate and compare fault currents against switchgear current-breaking capabilities and device fault-current limits. It may also enable users to identify estimated fault location using measured fault magnitude, pre-fault loading, and other information available at the time of the fault.

2.1.2.5 Fault Location, Isolation, and Service Restoration

FLISR is designed to improve distribution grid reliability. It can detect a fault on a feeder section based on real-time telemetries from the field RTUs or IEDs installed along the feeder line, and can quickly isolate the faulted feeder section by opening the adjacent automatic switches. FLISR then restores services to the healthy upstream of the faulted section by the same source prior to the fault occurring and then to the downstream sections by connecting to an alternative source. If a single alternative source lacks sufficient capacity to pick up all healthy feeder sections that are downstream of the faulted section, multiple alternative sources may be utilized to share the load, depending upon their available capacities. FLISR can significantly reduce the outage time, generally from several hours to less than a minute, considerably improving distribution system reliability and service quality, for example, in terms of System Average Interruption Duration Index (SAIDI) because of reduced outage duration and System Average Interruption Frequency Index (SAIFI) because some customers can be restored to service in less time than the threshold for permanent outages (usually 1 minute).

The main FLISR logic includes the following features:

- Automatically detects faults,
- Automatically determines the approximate location of the fault (i.e., the faulted section of the feeder that is bounded by two or more feeder switches),
- Automatically isolates the faulted section of the feeder, and

- Automatically restores service to as many customers as possible in less than 1 minute following the initial circuit breaker or recloser tripping.

The FLISR can analyze all available real-time information acquired from field devices, including fault detector outputs, fault magnitude at various locations on the feeder, feeder segment or even the customer meter energization status, and protective relay targets, to detect faults and other circuit conditions for which service restoration actions are required. All control actions identified by FLISR are executed by issuing supervisory control commands to substation circuit breakers, reclosers, and various feeder switching devices (reclosers, load breakers, and sectionalizers that are equipped with supervisory control capabilities).

The FLISR function is normally only responsible for dealing with permanent faults occurring out on the main three-phase portion of the feeder and those substation faults that cause the sustained loss of one or more feeders at the substation. Temporary faults that are cleared without sustained loss of service by standard automatic reclosing schemes are included in FLISR logic. FLISR function is not responsible for restoring service loss that occurs because of blown fuses on feeder laterals, ELS activities, and manual feeder tripping.

The FLISR generally considers all possible ways to restore as much of the load as possible without creating such undesirable conditions. The following service restoration strategies are commonly used for service restoration by FLISR, such that it:

- Does not cause undesirable electrical conditions on any distribution feeder,
- Restores electrical service to the maximum number of customers, and
- Requires the fewest number of switching actions.

2.1.2.6 Volt/VAR Optimization

VVO adjusts the feeder voltage profile and VAR flow. It generally has the following three key objectives and the weighted combination of them as it seeks to.

- Minimize network losses by switching the available switched capacitor banks "on" or "off."
- Ensure a desired voltage profile along the feeder circuit during normal and emergent operation conditions.
- Reduce peak loads through conservation voltage reduction (CVR) by controlling transformer tap positions in substations and voltage regulators on feeder sections. Advanced optimization algorithms are employed to optimally coordinate the controls of the capacitor banks, voltage regulators, and transformer tap positions.

The VVO function can operate either in closed-loop or advisory (open-loop) mode. In advisory mode, VVO provides advisory control actions that can be reviewed and then either approved by the dispatcher for execution or rejected. In closed-loop mode, VVO will automatically execute the optimal control actions without operator verification. The VVO function can be executed periodically at a user-adjustable interval, upon occurrence of a specified event (e.g., significant change in the distribution system such as significant load transfer or a topology change) or when requested by the user (on demand) manually.

In addition to the real-time data from the field IEDs, VVO may also use the near-real-time voltage measurements from a small number of AMI meters if available. These voltage measurements can be continuously monitored by VVO to verify that voltage constraints are not violated at these locations.

2.1.2.7 Optimal Network Reconfiguration

ONR is designed to provide better recommendations of switch operation sequences to reconfigure the distribution feeder circuits from the existing state to the optimal one in order to achieve the objectives of minimizing network energy losses in operation by maintaining desired feeder voltage profiles and balancing the loading condition among substation transformers, the feeders, and the three phases. ONR can also be utilized to develop planned outage plans for feeder circuit maintenance or fieldwork for service expansion. Common objectives of the ONR function are to:

- Minimize total electrical energy losses on the selected group of feeders over a specified time period,
- Minimize the peak demand among the selected group of feeders over a specified time period,
- Balance the load between the substation transformers or selected groups of feeders (i.e., transfer load from heavily loaded feeders to lightly loaded feeders), and
- Implement a weighted combination of the above.

The ONR function output is presented with a list of recommended switching actions and a switching plan to accomplish these actions, along with a summary of the expected benefits (e.g., amount of loss reduction).

2.1.2.8 Switch Order Management

The SOM function is to assist system operators in preparing and executing switching procedures for various elements of the distribution system, including both substation and field devices (outside the substation fence). It can assist the user in generating switching orders that comply with applicable safety policies and work practices. It supports the creation, execution, display, modification, maintenance, and printing of switching orders containing lists of actions that are needed to perform the switching, such as opening/closing various types of switches, implementing cuts and jumpers, blocking, grounding, and tagging. It is also able to help in viewing a portion of the feeder being worked on in either geographic form or schematic form that may be automatically created from the geographic view.

In addition to the computer-assisted switch order generation facility described above, the SOM can automatically generate switching orders, with which the dispatcher can select the distribution system device or portion of the system to be isolated and worked on. The defined switching orders may be executed in real-time mode or in study mode. The real-time executions will involve supervisory control commands, while study mode execution allows the dispatcher to check out the switching order's potential impact on the distribution grid, including possible current and voltage violations, at a specified time and date using the OLPF function prior to actual execution. SOM can alert the dispatcher if any violations are detected during study mode execution of the switching order.

2.1.2.9 Emergency Load Shedding

The ELS function is executed in real time on request for the quick shedding of load in the distribution system. This function is usually synchronized with the load-shedding functions that are executed in EMS (under frequency, under voltage load shedding). The objective of ELS is to minimize the manual effort that is required to shed a specified amount of load and restore the previously shed load when the initiating problem is corrected. The user is allowed to initiate the load shedding only for loads that are included in the user's assigned Area of Responsibility (AOR). When ELS is required, the user can activate the ELS function and enter the amount of load to be shed. The ELS will then determine which switching devices to operate to accomplish the load-shedding objective.

The loads that participate in the emergency load-shedding program may be assigned different priorities corresponding to various shedding strategies. The loads at the same priority level may be rotated dynamically for equal chance and duration of out of service.

2.1.2.10 Short-Term Load Forecasting

STLF in DMS is a function that predicts the distribution system load based on the historical load and the historical and forecasted weather data on an hourly basis for up to a 168-hour rolling forecast period. The STLF results should be available for viewing and outage planning and should also be used by other DMS application functions that require an estimate of expected peak loading in the near term, such as OLPF, FLISR, SOM, and ONR.

STLF in DMS usually provides the load forecast for the entire system or on a substation basis. The forecast load is then allocated to individual feeders or even individual consumer transformers based on certain allocation rules, such as using hourly or daily peaks or averages of the feeders or consumer transformers as the allocation factors.

STLF may use both a weather-adaptive and a similar-day forecast methodology to obtain the best accurate prediction. The forecasting model is updated based on the difference between the previous forecast and the actual load value at the time when it becomes available. Because the actual load consumption measured reflects the real consumption that excludes the loads out of service and other manually manipulated portions of loads (e.g., ELS) during the hour, it is necessary for the model updating mechanism to take into account such load adjustments. The load forecast accuracy may be significantly enhanced in advanced DMS by incorporating actual meter readings obtained from AMI for the specified feeder, where AMI is integrated with the DMS.

2.1.3 Protection Schemes

The protection schemes used in distribution grids are less complex than those in the transmission grids, mainly because distribution grids are generally passive networks and, more importantly, mainly arrayed in a radial configuration. In fact, the reason why existing distribution systems have generally been configured as radial networks is predominantly for the benefits of simple and cost-effective protection schemes, as well as because this arrangement completely eliminates the possibility of wheeling power flow between two substations through one or more loops among the distribution feeders. In most cases, the distribution circuits can be well protected with time-inverse overcurrent (OC) protection and, in some special cases, with over/undervoltage (OV/UV) protections, as well. Moreover, because of the characteristics of one-way power flow and the single supply path from the energy source to an end user, relay protection coordination between an upstream device and a downstream device also becomes very easy, just by simply setting a different time delay and/or different trigger settings. For example, an upstream OC should have a longer pickup time than its immediate downstream OC but have the same pickup current. This setting also allows the upstream OC to play the role of the backup protection for the downstream OC. However, in some cases, the upstream OC may be set with a higher pickup current, depending on the load condition between the two OCs and the short-circuit current level at the maximum fault impedance considered for downstream OC, which can be well coordinated based on SCA results from various hypothetical fault scenarios. There is no need to involve other expensive or more sophisticated protection schemes, such as directional protections, differential protections, and impedance protections, as are commonly used in the transmission grid protections.

Figure 2-6 depicts the basic concept of feeder circuit protection coordination. When adding microgrids into conventional distribution systems, the protection schemes become more complex considering the two-way power flow, distributed generation (DG), and so forth. For example, the settings of directional relays may need to be adjusted to accommodate two-way power flows.

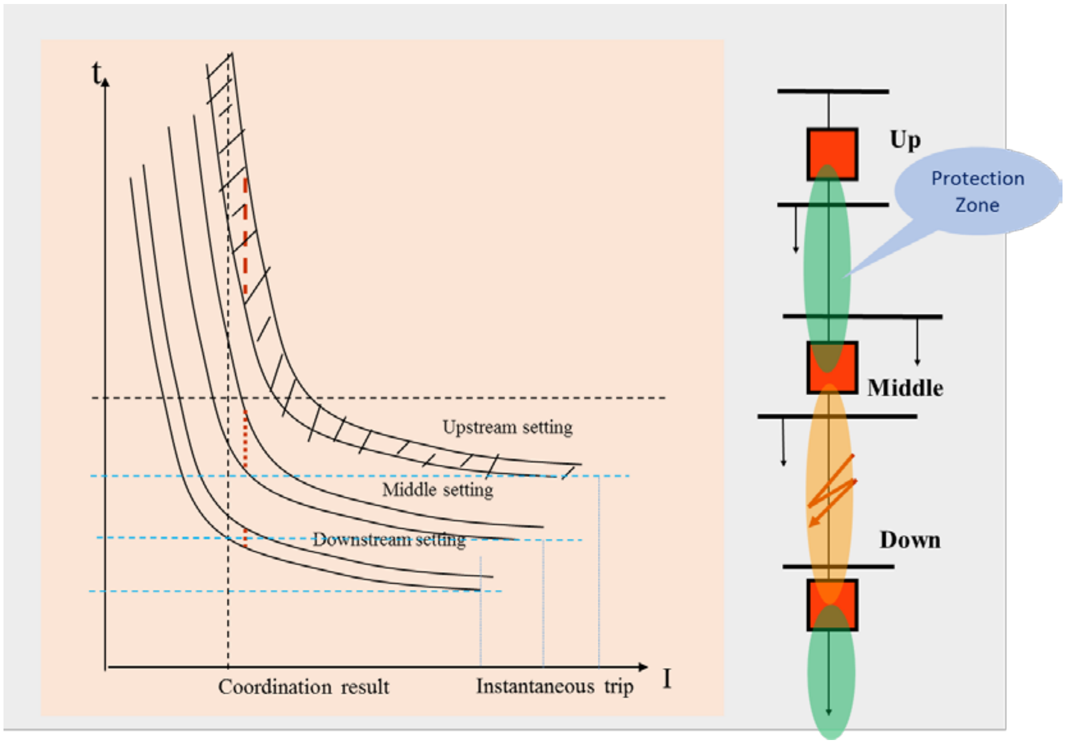

Figure 2-6 Feeder Circuit Protection Coordination

2.1.4 Simplified Implementations – Expansion from SCADA System

The term DMS still lacks a unique or an industry-standard definition regarding its exact scope, standard components, and implementations. In many cases, a DMS in a utility has been created by combining many legacy systems or subsystems. One typical example involves expanding from a legacy distribution SCADA system by incrementally adding more features, components, and applications toward achieving a system with more and more DMS functionalities. It is common in such implementations that the system lacks a good initial design and that all of the new features or added applications resemble patches attached to the SCADA system. This approach may reach its performance or capability limit when adding more applications and results in a very high cost to migrate to the level of a well-designed DMS compared with the cost of completely replacing it with a new system.

2.2 Advanced DMS

The advanced DMS not only contains the full features and advanced applications of a DMS, but is also well integrated with other associated systems, such as the OMS, AMI, and Demand Response Management (DRM).

2.2.1 Enterprise Integration with OMS, AMI, and DRM

Figure 2-7 depicts a high-level chart of DMS integration with OMS, AMI, and DRM through an Enterprise Integration Bus.

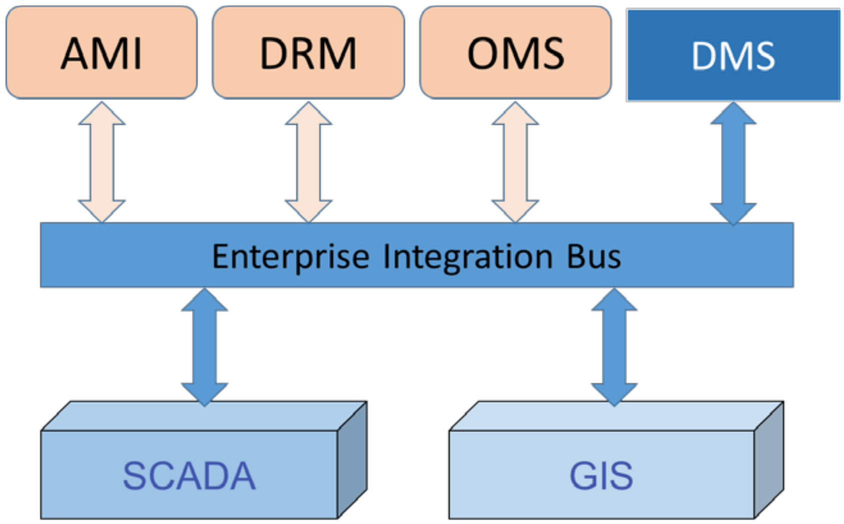

Figure 2-7 Advanced DMS System Integration

In most utilities, an OMS is a separate system developed rather independently of the DMS and SCADA systems. OMS is responsible for tracking outages from all available information channels, including trouble calls, public media, real-time data from SCADA or DMS, or other dedicated field or home devices, as well as other sources. Based on the information collected, OMS does its best to find out the faulted areas and possible root causes and, more importantly, to propose troubleshooting and/or restoration plans based on the best estimation of the amount of work, resources needed, and how quickly the problem can be fixed; it also organizes and dispatches crews to deal with the outages.

Similar to OMS, AMI has been developed independently for the purposes of energy metering and billing to individual consumers. However, the data collected directly from consumer consumption levels can also be useful for developing enhanced DMS functions. An AMI system generally manages consumer energy meters directly, without modeling the distribution circuits. Some AMI systems may include a simple model of user transformers feeding individual consumers. The distribution system modeling in a DMS usually stops at the user transformers in a feeder. Therefore, the user transformer is the common device through which a linkage can be established between the distribution system model in a DMS and the energy consumption model of the individual users in AMI.

In the meantime, DRM has received considerable attention for direct management of the individual loads in recent years, which can be well coordinated with DMS to optimize both normal operation and emergency load balancing for enhanced operation reliability and power delivery quality.

2.2.2 Data Communication between DMS and OMS, AMI, and DRM

The data communication between DMS and OMS, AMI, and DRM are presented in Figures 2-8, 2-9, and 2-10, respectively.

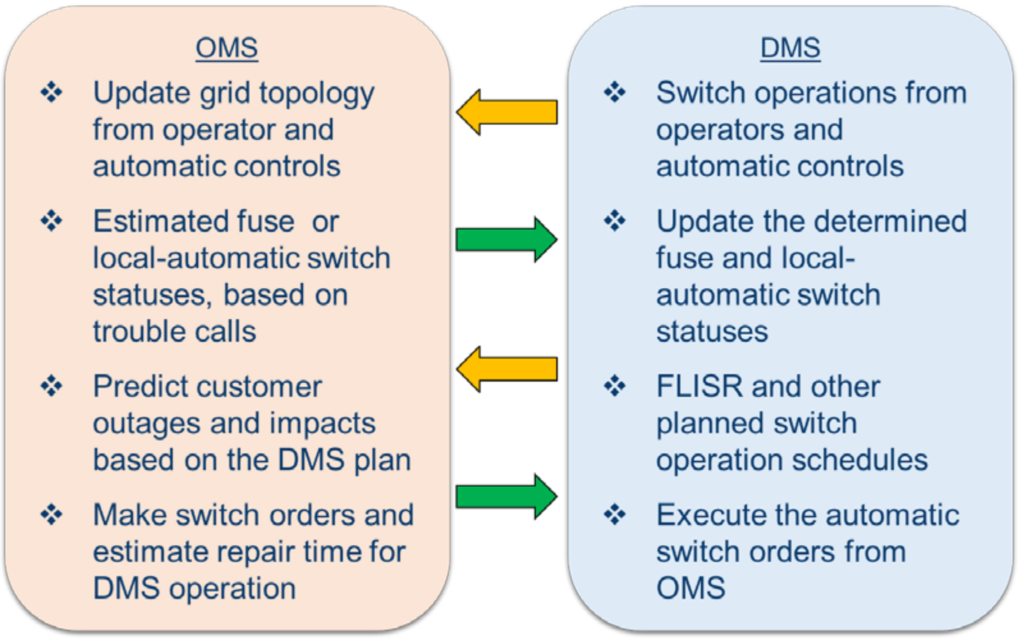

Figure 2-8 Data Communication between DMS and OMS

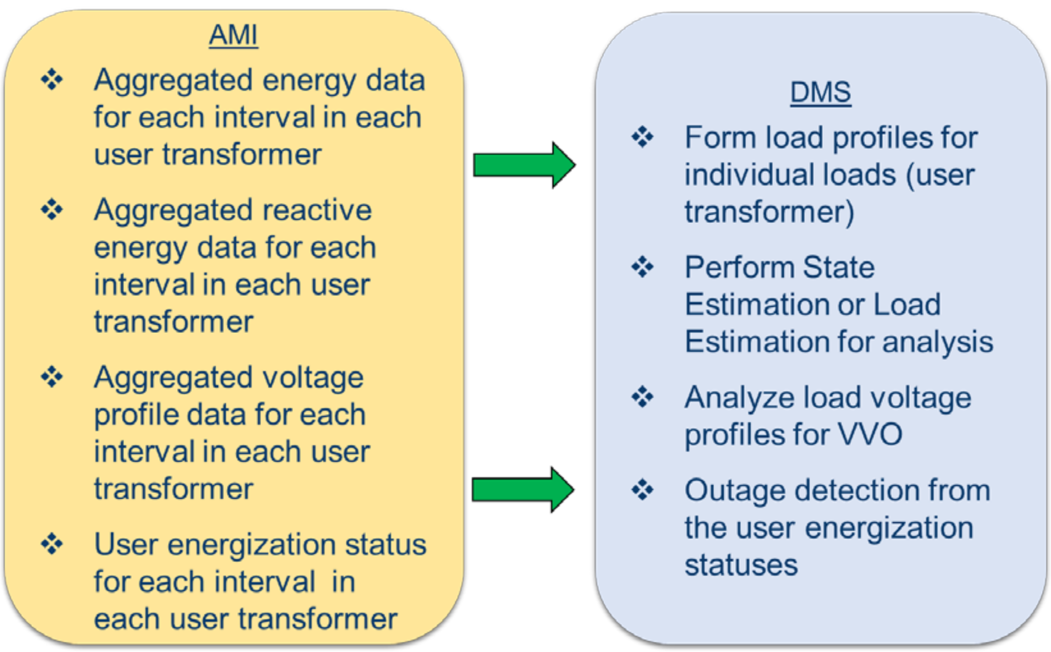

Figure 2-9 Data Communication between DMS and AMI

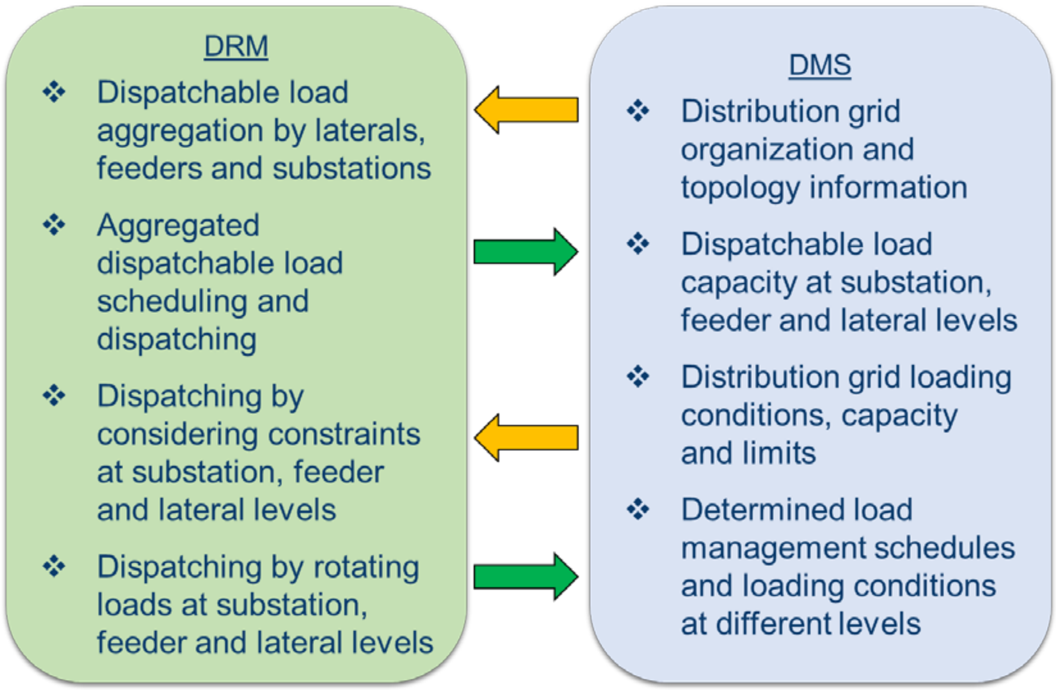

Figure 2-10 Data Communication between DMS and DRM

As shown in Figures 2-8, 2-9, and 2-10, data communication between DMS and OMS and between DMS and DRM can be two-way, whereas that between DMS and AMI is one-way. This is because the data from DMS can also be useful for enhancing OMS and DRM operation, whereas AMI, based on its original design, needs no data from DMS. However, in some special cases, DMS may skip DR and directly use the "Remote Disconnect" feature of the AMI for ELS.

2.3 Penetration of DER

High penetration of DER introduces a series of challenges to distribution grids. The following subsections address a few of the important issues.

2.3.1 Impacts of DER on Distribution Grid Operation

As mentioned in the previous sections, the traditional distribution grid is passive and radially configured with one-way power flow. Because of the connections of DER along the distribution feeder circuits, distribution networks will become active and may involve two-way power flow. The network topology may still be radial or may be weakly meshed depending on how a utility manages and configures its feeders—in other words, the same as what has been done before. Therefore, the voltage profiles and power flow directions in the individual feeder circuits will not be obviously observed from the topology and will need to be dynamically determined from real-time measurements and/or periodic load-flow or state-estimation calculations. The static and dynamic operational characteristics of individual DER, as well as their connection/disconnection to/from the grid, will have direct impacts on operational reliability and power delivery quality. All these factors introduce considerable challenges to the DMS, including the proper modeling of the DER in the DMS, the impacts on advanced application functionalities and algorithms, and issues associated with the DERMS and overall integration.

2.3.2 DER Modeling in DMS

Many different types of DER may be defined based on their energy sources and technologies, including solar, wind, hydro, biogas, fuel cell, combined heat and power (CHP), battery storage, and other forms of energy storage. However, DER can be categorized into two classes from an electrical perspective: (1) inverter-based generation (e.g., PV), and (2) rotational machine-based generation (e.g., CHPs). The energy storage technologies, regardless of whether they are inverter based, like battery storage, or rotational machine based, like pump storage, have to be modeled differently because they can operate in either the generation mode or load mode. Accordingly, the proper DER models should be defined in a DMS for each different class and operation mode.

2.3.3 Impacts on DMS Advanced Applications

The connections of DER will have significant impacts on the functionalities and algorithms used by advanced DMS applications. This is not only because the distribution grids become active networks and power flow may become two-way, but also because the static and dynamic characteristics of the individual DER can lead to very different conditions of overall system operation. The following subsections discuss the issues for a few typical advanced applications in DMS.

As mentioned, a fully functional DMS unit commonly has multiple applications. Considering the penetration of DER, its impact on some applications should be further studied to ensure the reliable integration of the MC, DERMS, and DMS. As stated previously, the most relevant applications to meet the challenges of grid modernization are (1) FLISR, (2) VVO, (3) OLPF, (4) SE, (5) DER management, (6) ONR, (7) DRM, (8) SCA, (9) IAP, (10) ELS, and (11) STLF.

The following subsections discuss the issues for the typical advanced applications in DMS.

2.3.3.1 Topology Processing

In addition to offering its own functionalities, TP is the base function in the DMS and supports several other key applications. A few key points introduced to TP by DER connections are as follows:

1. The status of DER and microgrids at the PCC needs to be included,
2. Network topology alone does not enable determination of flow direction,
3. The power flow or SE results need to be combined to determine the direction of power flow of the individual feeder sections and devices, and
4. Portions of the distribution feeders that are isolated from the utility's power grid and are being energized by microgrids or DER need to be located and highlighted.

2.3.3.2 Intelligent Alarm Processing

With the connection of DER and microgrids, the logic of IAP may have to be adjusted significantly. For example, the voltage profile will no longer be uniformly distributed along a feeder, and a low voltage at a point does not mean all of the downstream points will also be of low voltage as in the conventional passive network. Therefore, the old alarm-processing logic for the dependent low-voltage profile will no longer be valid. The similar rule applies to the overload conditions. The other situation is that the opening of a switch that would cause the entire downstream sections to be de-energized in the passive network and the IAP could effectively suppress all of the dependent alarms for the downstream devices. If the downstream sections are connected with DER and/or microgrids, the switch operation may be deliberately directing the feeder sections to the microgrids, along with the DER, for islanded operation. The switch operation will not cause any feeder section to be de-energized but brings about a status change only to the switch itself.

2.3.3.3 On-line Power Flow

OLPF solutions are based on specified power injections to individual buses and a slack bus with a voltage that is constant in magnitude and phase angle, with generation being treated as positive injections and load as negative injections. In conventional passive distribution networks, there is no generation in the distribution circuits, and the substation source is the only energy source that is defined as the slack bus, which is the source of the power that feeds loads and network losses. With DER connected, however, the positive power injections to the DER connection buses have to be specified. For single-phase DER, the injections are given to individual phases based on their phase connections. For three-phase DER, however, it may be the three-phase total rather than individual phases, especially for rotational machine-based generation in which power allocations to individual phases are determined by terminal bus voltages of individual phases. The unbalanced condition of three-phase terminal bus voltages, in turn, is not determined by the local DER alone, but by the overall load and generation injections in the grid. On the other hand, the distribution load-flow algorithm requires that power injections at each bus be specified for each phase. Therefore, special generation models have to be included when dealing with the three-phase power injections from DER.

2.3.3.4 State Estimation

DSE has been studied extensively over the last two decades but has not been widely implemented in DMS so far. SE is essentially a data consolidation process to obtain the more accurate values from many inaccurate and redundant data and models. SE has been very successful in EMS for transmission networks because of the sufficient redundancy (generally more than 1.5) of real-time measurements. Distribution systems, however, lack such redundancy and, sometimes, even lack sufficient real-time data to perform power-flow calculations.

In recent years, with the development of the Smart Grid, distribution automation (DA) has been greatly improved, and more and more field IEDs are being installed in feeder circuits for remote monitoring and control. Plus, with the integration with AMI and DRM, more real-time or quasi real-time measurements have become available, which make the application of DSE possible. Similar to OLPF, DSE needs to include DER models to deal with power injections from the DER.

It has to handle the allocation of three-phase power injections if the values from individual phases are not available.

2.3.3.5 Short-Circuit Analysis

When a fault occurs in a distribution circuit, each DER connected to the circuit will contribute short-circuit current to the fault. SCA has to include dynamic models of the DER generators in the calculations, especially for rotational machine-based DER. For inverter-based DER, their short-circuit current contributions may be ignored because power electronic devices in the DER can respond quickly to effectively limit the fault current contribution.

2.3.3.6 Fault Location, Isolation, and Service Restoration

The connection of DER may have significant impacts on the logic of fault detection and the strategy of service restoration in FLISR. This result occurs because the fault current will take multiple paths to all connected energy sources, rather than a single path in a conventional passive network. After the faulted segment is determined and isolated, achieving service restoration will not be as simple as it is for the passive feeders. It may have to account for the presence of the associated DER in the feeder sections in addition to the de-energized loads, the reliability requirements, the service priorities, and other constraints applied to FLISR. In general, the connection of DER and microgrids may not cause much change to the fault isolation logic, but it may require more advanced algorithms for effectively detecting the faulted feeder section and providing the best effective restoration plan.

2.3.3.7 Volt/VAR Optimization

The Volt/VAR control and management in VVO will also face a few challenges from the DER connections. The voltage profiles of a feeder circuit will not be determined only by the transformer taps, voltage regulators, and capacitor bank status, but also by the real and reactive power outputs from the DER and microgrids at different locations along the feeder circuits. The VAR outputs of DER can generally be changed continuously, not like the VAR outputs from capacitor banks that are in integers, which are either “on” or “off” with an approximately fixed amount of VAR. Some of the DER may be schedulable by VVO, forming a mixed-integer programming problem in VVO optimization. The real algorithm will be more complicated when combined with other objectives and constraints, such as multi-interval, look-ahead optimization and operation limits of the capacitor and voltage regulator operations. The VVO may have to involve a two-stage optimization process, with the first stage dealing with the discrete control variables (capacitor bank on and off status and the tap positions of substation transformers and feeder voltage regulators), and the second stage dealing with the continuous control variables of the DER and microgrid VAR generations. The two stages can go through cycles iteratively to converge to the optimal solution.

2.3.3.8 Optimal Network Reconfiguration

There may still be significant technical and economic advantages to keeping the distribution feeders operating in radial configuration even with the high penetration of DER. However, the DER connections will introduce additional complexities to the ONR, because it has to account for the generation distributions to the individual feeder sections from the DER, rather than the load distributions alone in the conventional passive distribution networks.

It is well known that the ONR can use the load forecasting results to optimize the feeder reconfiguration for the next few hours, days, or even weeks for the traditional passive distribution networks. With the connections of DER and microgrids, it has to include the DER forecasts and microgrid schedules for the same objective. This task is very challenging. Effective and realistic algorithms may need to be developed to cope with the new challenges.

2.3.3.9 Switch Order Management

The SOM process will also be largely affected by the penetration of DER and microgrids where the switch operation sequences to be developed or executed have to take into account the associated DER and microgrids connected at the corresponding feeder sections. An improper switch operation may cause overload or voltage violations on the other feeder sections that do not appear to be of direct correlation to the switch operation. Therefore, it may be necessary to study each operation with a power flow analysis for the hypothetical operation of the switch.

2.3.3.10 Emergency Load Shedding

ELS can shed load in various granular levels, for example, a substation, a feeder, or partial feeder level. The presence of DER and microgrids will further complicate load-shedding logic, especially for the partial feeder level. This complication occurs because feeder sections may have both loads and DER/microgrids, and disconnecting a section will not only disconnect the loads but also the DER and microgrid generations that will involve a series of local actions in responding to the disconnection. It would be necessary to consider all of the consequences when planning the ELS strategies and executing the ELS plans.

2.3.3.11 Short-Term Load Forecasting

The key feature of the STLF is its accuracy, which is dependent on the forecast model being updated periodically based on the forecast error calculated when the actual system load becomes available. With the connection of DER and microgrids, the total system load is not only what is measured at the substations but also the sum of the generation from all DER and microgrid injections. Correspondingly, the allocation methods used in the conventional passive distribution systems for shares of the forecast to the individual feeders and loads may have to be adjusted accordingly.

2.3.4 Impacts on the Protection Scheme

The existing protection schemes for distribution grids are generally designed on the basis of having a single source of fault current, passive networks, one-way power flow, and radial configuration. The DER connections will cause significant impacts on the existing schemes in the distribution system protection. The situation will gradually become more severe when DER penetration increases. Faster protection schemes may be needed on the electric system to clear faults before associated voltage sags cause DER to drop off because of low-voltage ride through (LVRT) requirements.

If the distribution system can still maintain the radial configuration with the DER penetration, the impacts can be limited to that of the two-way power flow and the multiple paths of fault current contribution to the faulted point. The issues mainly relate to the coordination with the directional OCs, as well as the coordination of the grid protection schemes with the protection of individual DER.

2.4 Connection of Microgrids

A microgrid, as its name implies, is considered to be a small and local area distribution power grid with both the generation resources and the loads connected. It can operate in either islanded mode (grid-disconnected mode) or connected mode (grid-connected mode) while being connected to the utility distribution grid.

2.4.1 Connection Modes

In the islanded or grid-disconnected mode, a microgrid can operate independently to supply power to its individual loads using the local energy resources. In this operation mode, the MC needs to maintain the grid frequency and voltage profile at standard levels within the deviations allowable by its own resources. The MC needs to ensure effective load following and voltage regulation performance for both normal operation and emergency conditions.

When connected to the utility distribution grid, the microgrid should be able to maintain the scheduled power transaction and participate in maintaining the voltage profile at the PCC.

2.4.2 Interface at the PCC

A PCC is the coupling point between a microgrid and the utility distribution grid. Although a microgrid may have more than one PCC configured to it, the controls would be simpler with only one active PCC in normal operation. A microgrid may connect to the distribution grid through multiple active PCC, especially when the microgrid needs more support from the distribution grid or vice versa. The microgrid may split into multiple internal islands, with each island being connected to the distribution grid through a PCC. In such a case, the microgrid is actually split into multiple sub-microgrids, and each one has its own active PCC.

2.4.3 Power Exchange

A microgrid may be scheduled to exchange power to/from the utility distribution grid when it is operating in the grid-connected mode. In such situations, it is usually the microgrid's responsibility to maintain the target power transaction by following the schedule.

2.4.4 Mutual Support in an Emergency

Under emergency conditions, either occurring in the microgrid or the distribution grid, additional voltage and energy support may be requested from the other party. For instance, when a generation resource in the microgrid is shut off because of an internal fault, an emergency energy schedule may be activated immediately to deliver more power from the utility grid through the PCC. In some other cases, however, the utility circuit may need support from a microgrid to provide additional power to restore service to normal, unfaulted feeder sections resulting from a feeder fault. A microgrid may be requested to energize some of the isolated feeder sections through a PCC, forming a wheeling path between the utility and the microgrid; that is, the distribution grid supplies power to the microgrid through one PCC, and the microgrid supplies power to the isolated part of the utility grid through another PCC.

2.4.5 Protection Scheme

As a power grid, a microgrid has its own internal protection schemes that must perform correctly in grid-connected and islanded modes. However, when it is in the connection mode, a microgrid becomes an integrated part of the grid as an active entity at the PCC from the distribution grid's point of view, and it must follow the utility's protection rules and policies, similar to those for individual DER. It should be able to isolate itself from the distribution grid at the PCC for either the internal or external faults. For an internal fault, it may clear the fault as fast as possible and recover to its normal operation before disconnecting from the distribution grid. However, it may need to disconnect itself quickly from the distribution grid in some fault conditions that are not effectively cleared by its local protection mechanism within the allowable time period. Once disconnected because of a fault, it should restore its service in the disconnected mode before requesting a reconnection to the distribution grid. For an external fault, it should follow a similar process and, if disconnected, should maintain its operation in the disconnected mode until the external distribution grid is ready for its reconnection.

3 Microgrid Operation

As briefly discussed in the previous chapter, a microgrid is a small and local distribution power grid that can operate either in the connected mode to the utility distribution grid or as an islanded grid while disconnected from the utility distribution grid. As a power grid, no matter how large its size, there are some basic features and operation-related performance requirements that are commonly shared, such as the voltage and frequency quality, load-following characteristics, synchronization, and power exchange fluctuations when connected to the grid. A microgrid generally has its own local distribution circuit, local loads, and energy resources that are directly connected to its local grid. It may be implemented with multiple PCC to the distribution grid. Under some specific topology conditions, it may form wheeling paths to the utility distribution grid if more than one PCC is active. Some special restrictions may be needed in reconfiguring the microgrid's internal topology in order to avoid possible wheeling paths to the utility grid when operating in the connected mode.

In the disconnected mode, a microgrid should be able to maintain voltage quality and frequency and effective load-following characteristics, as well as prepare for reconnecting to the grid through the synchronization process.

It should be noted that for the operation and management of DER or the aggregated DER, the basic concepts and requirements can be found in the existing IEEE standards. Some of the data shown in Sections 3 and 4 can be found in IEEE Std. 1547 [2].

3.1 Basic Concepts of Microgrid Operation

In either a grid-connected or -disconnected operation mode, a microgrid should meet specific operation requirements, such as maintaining an acceptable voltage profile, grid frequency, synchronization, and load following. In the grid-connected mode, a microgrid can exchange energy with the local utility of the distribution grid following a predefined schedule between the DMS and the microgrid in normal operation and can provide mutual support in abnormal conditions. In the disconnected mode, the microgrid should be able to balance its internal load demand by its own energy resources and maintain the same level of voltage quality and grid frequency. It should also be able to reconnect to the distribution grid when requested, which involves the resynchronization process to the grid.

3.2 Basic Requirements for a Microgrid Connecting to a Distribution Grid

3.2.1 Response to Normal Conditions

A microgrid should be able to perform proper operation functions under normal operating conditions. The following subsections introduce some basic requirements, which are mainly based on the IEEE 1547 standard.

3.2.1.1 Voltage Regulation

A microgrid should be able to regulate the voltage within a certain range at the active PCC as requested by the DMS and should not cause a voltage violation at the PCC or any other point in the distribution grid, as defined in the American National Standard Institute's C84.1-1995, Range A standard.

3.2.1.2 Coordinated Grounding with the Distribution Grid

A microgrid must have a proper grounding scheme that should be well coordinated with the distribution grid to avoid the occurrence of any possible overvoltage or safety issues in the microgrid or the distribution grid. Meanwhile, the grounding scheme in the microgrid may also coordinate with the protection scheme in the distribution grid to avoid any possible interference with the existing ground fault protection logic.

3.2.1.3 Synchronization

In the grid-connected mode, a microgrid may operate in parallel with the distribution grid through a single active PCC or multiple PCC. For the synchronization between the microgrid and the distribution grid at each PCC, the voltage fluctuations should be within ±5% of the prevailing voltage level. Meanwhile, the requirements for limiting voltage flicker should also be fulfilled.

When multiple active PCC co-exist, wheeling paths among the PCC may be formed that are more likely to remain unnoticed by the distribution grid operators. Such a situation should be eliminated. Voltage fluctuation imposed by circulating power among PCC should also be avoided.

3.2.1.4 Inadvertent Energization of the Distribution Grid

The microgrid must cease to energize the distribution grid at any PCC when the grid is de-energized.

3.2.1.5 Monitoring Provisions

If the capacity of the interfacing device at each PCC is greater than 250 kVA, the monitoring of its connection status may be performed, including the monitoring of real power output, reactive power output, and voltage at the PCC.

3.2.1.6 Isolation Device

When required by the distribution grid, isolation devices may be equipped with the circuit breaker at each PCC of the microgrid.

3.2.1.7 Interconnect Integrity

The microgrid should be able to withstand electromagnetic interference (EMI) environments in accordance with the IEEE C37.90.2-1995 standard.

Meanwhile, it should also be able to withstand voltage and current surges as defined in the IEEE C62.41.2-2002 or IEEE C37.90.1-2002 standards.

3.2.2 Response to Abnormal Conditions

Apart from the responses to normal conditions, the microgrid should perform proper operation during abnormal conditions, as shown in the subsections below. This guidance also mainly follows the requirements presented in the IEEE 1547 standard.

3.2.2.1 Distribution Grid Faults

In case of distribution grid faults, the microgrid should cease to energize the grid at any PCC. Meanwhile, power balancing inside the microgrid should be performed.

3.2.2.2 Distribution Grid Reclosing Coordination

When a microgrid operates in the islanded mode, it may be energizing a portion of the isolated distribution grid through a PCC. The microgrid should cease to energize the isolated portions of the distribution grid at any PCC prior to reclosing. Power balancing inside the microgrid should be achieved prior to reclosing, and zero power exchange should be maintained after reclosing until it is ready to start transaction schedules.

3.2.2.3 Voltage Requirements

The voltage at the PCC of the microgrid should be monitored in case a fault occurs. If the voltage at the PCC is within a range shown in Table 3-1, the microgrid should cease to energize the distribution grid at the PCC. The clearing times for each of the different fault voltages are also shown in Table 3-1. At a PCC with a capacity greater than 30 kW, the voltage set point should be field adjustable, and the clearing time shown in Table 3-1 is the default value. If the microgrid is disconnected from the distribution grid, the power balance inside the microgrid should be maintained.

Table 3-1 Interconnection System Response to Abnormal Voltages [2]

Voltage Range (% of Base Voltage)	Clearing Time (s)
$V < 50$	0.16
$50 \leq V < 88$	2.00
$110 < V < 120$	1.00
$V \geq 120$	0.16

3.2.2.4 Frequency Requirements

When the system frequency falls within a range listed in Table 3-2, the microgrid should cease to energize the distribution grid at the PCC. The clearing time for different faulted frequencies is shown in Table 3-2. If the microgrid is disconnected from the distribution grid, the power balance inside the microgrid must be maintained.

Table 3-2 Interconnection System Response to Abnormal Frequencies [2]

Capacity at PCC	Frequency Range (Hz)	Clearing Time (s)
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< 59.8–57.0 (adjustable set point)	0.16 to 300
	< 57.0	0.16

3.2.2.5 Reconnection to Distribution Grid

Reconnection of the microgrid can take place when the voltage is within the range of 88% to 110% of the base voltage and the frequency is within the range of 59.3 Hz to 60.5 Hz.

The reconnection at the PCC should include an adjustable or a fixed delay (e.g., 5 minutes). Power balance inside the microgrid should be guaranteed after reconnection during this time period. Potential wheeling paths when multiple PCC are reconnected may be allowable.

3.3 Point of Common Coupling

Point of coupling refers to the connecting points of the microgrid to the distribution grid. For integrating microgrids into the distribution grid, multiple PCC can co-exist. In this situation, that is, when the microgrid is connected to the distribution grid through multiple PCC, the wheeling paths should be noted in order to avoid circulating power.

3.4 Generation Resources and Types

Diverse types of generation resources can be deployed in a microgrid, including synchronous machines, induction machines, and power-electronic-converter-interfaced renewable energy sources (e.g., PV, wind turbine, and fuel cell).

Energy storage units are also commonly employed in a microgrid, if applicable. Different types of energy storage can be used, including batteries, flywheel, and super-capacitors.

3.5 Voltage/VAR, Frequency, and Load Following

A microgrid should have sufficient capability to maintain the standard voltage profile and frequency range, which requires that the microgrid has sufficient energy resources for both real and reactive power generation to balance its load demands in normal operation, especially for the disconnected operation mode in which it has no external assistance but only its own resources.

3.6 Connection to and Disconnection from the Distribution Grid

Microgrids should have the capability of connecting to and disconnecting from the distribution grid. As stated in Section 3.2.2, microgrids should disconnect from the distribution grid when encountering non-timely cleared faults in the distribution grid. Power balance inside the microgrids should be ensured after the disconnection. Meanwhile, in the case where there are multiple PCC, the microgrid should disconnect from the distribution grid at all PCC when the distribution grid is in a severe fault condition, so that the microgrid can completely cease to energize the faulted distribution grid. In case a fault occurs inside the microgrid and the local protection mechanism fails to clear the fault within the allowable time frame, the microgrid should also disconnect from the distribution grid at the PCC to avoid further impacts on the distribution grid.

When the fault is clear, the microgrid can reconnect to the distribution grid. Sufficient delay time is required to ensure the normal status of the grid. As stated in Section 3.2.2.6, this delay time can be either adjustable or fixed (e.g., 5 minutes).

3.7 Intentional and Unintentional Disconnection

Intentional disconnection occurs when the microgrid responds to a command from the distribution grid or requests to operate in the islanded mode. Intentional disconnection should not induce large voltage and frequency fluctuations and should maintain power balance after disconnection. It is common practice to ramp-down power exchanges at the PCC to near zero to help ensure that there will be minimum impacts on both the distribution grid and the microgrid during the transition to disconnection. Control or additional hardware devices can be deployed to alleviate voltage and current surge during disconnection.

Unintentional disconnection occurs when unintentional islanding is detected. The MC should be capable of detecting the unintentional islanding operation. Power balance after the disconnection should be ensured, just as in a case with intentional islanding.

The transient process of unintentional islanding should be accomplished within 2 seconds, according to the IEEE 1547 standard.

3.8 Internal Protection

An MC should be capable of detecting any internal fault occurring anywhere in its internal grid. When an internal fault is detected, the faulted circuit, or the PCC, should be tripped to ensure that the fault will not cause an operation problem to the distribution grid; at the same time, the faulted circuit section should be isolated for the microgrid to restore service for the healthy sections of the faulted circuit. Power balancing within the microgrid should be fulfilled after isolating the faulted section or disconnecting from the distribution grid.

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4 Distributed Energy Resources

DER connections to the distribution grid involve many challenges to both the DER and the distribution grid. The basic concepts of DER connecting to the distribution grid are addressed in the following subsections, including their energy sources, rotating machine or inverter-based generation, real and reactive power outputs, voltage/VAR and frequency characteristics, impacts on the grid voltage, harmonics, phase unbalance, fluctuations and intermittency, and low-/high-voltage ride-through capability, as well as the overall benefits and impacts on the grid operation reliability.

4.1 Basic DER Types

DER are the energy sources connected to a distribution grid in a dispersed manner, such as PV, wind turbine, small hydro, and fuel cell, as well as distributed energy storage units (e.g., batteries, flywheels, and ultra-capacitors).

4.2 Basic Requirements for DER Connecting to the Distribution Grid

The basic requirements for DER connecting to distribution grids are similar to those for microgrids. As indicated in the IEEE 1547 standard, a single DER or aggregated group of DER can be connected to the grid at a single PCC. From the perspective of grid connection, a microgrid is similar to an aggregated DER, although it can be presented with either a positive (as a generator) or negative (as a load) power injection to the grid and, hence, both DER and microgrids follow the same rules and requirements as defined in the IEEE 1547 standard. The basic requirements have been discussed in Section 3, and characteristics dedicated to DER will be highlighted in this section.

For DER under normal operation conditions, the requirements regarding voltage regulations, integration with the distribution grid, synchronization, inadvertent energization of a distribution grid, isolation devices, and interconnection integrity should be the same as those for microgrids. For monitoring provisions, as required by the IEEE 1547 standard, only DER at 250 kVA or more should have provisions for monitoring their connection status, real and reactive power outputs, and voltages at a DER connection PCC.

For abnormal operation conditions, the requirements regarding distribution grid faults, reclosing coordination, loss of synchronization, and reconnection to the distribution grid should be the same as those for microgrids.

For abnormal voltage conditions, if a DER is greater than 30 kW in peak capacity, the requirements should be those shown in Table 3-1, where the clearing time is the default value, and it should be field adjustable. If the DER is less than 30 kW in peak capacity, the requirements should also be those shown in Table 3-1; however, the clearing time should be the maximum value, and it should be either fixed or field adjustable. When the aggregated capacity of grouped DER connected to a single PCC is less than or equal to 30 kW, the voltage should be detected at either the PCC or the point of DER connection.

For abnormal frequency conditions, if the DER is greater than 30 kW in peak capacity, the requirements should be the same as those shown in Table 3-2. The clearing time shown in Table 3.2 is the default value, and it should be field adjustable. If the DER is less than 30 kW in peak capacity, it should also follow the requirements in Table 3-2. However, the clearing time should be the maximum value, and the frequency set-points and clearing time should be either fixed or field adjustable.

4.3 Communication Requirements

Two-way communication capabilities may be required for effective monitoring and control of the DER operation. Many communications and networking technologies can be used to support these applications, including traditional twisted-copper phone lines, cable lines, fiber optic cable, wireless cellular, satellite, power line carrier, and wireless short-range networks such as Wi-Fi and ZigBee. Choice of the proper communication technologies for DER monitoring and control is determined based on an analysis for a specific system's communication requirements and mainly depends on the type of applications, locations, and topologies of the system. When designing communication networks for DER monitoring and control, the basic requirements presented in the following subsections should be considered.

4.3.1 Scalability

The integration of large-scale, dispersed DER may require that communication networks be scalable as the number of DER connected to the network increases to meet the needs of various applications. The architecture of the network should be designed to cope with this challenge. In general, a hierarchical network architecture is desirable because of its flexibility and expandability in incorporating new types of data and applications. This network design can enable "near-user" data processing and distributed control, which significantly reduces the communication and computation burden at the control center or data center for DER integration.

4.3.2 Bandwidth

The bandwidth requirements for a communication network refer to data traffic speed, that is, how many data packets per second are needed, and the data traffic pattern, that is, the periodicity or burst (event-based) for each application. The U.S. Department of Energy (DOE) guidance on bandwidth requirements for DER monitoring and control is 9.6 kbps to 56 kbps [8]. This defines an acceptable range, which an actual design should consider based on its specific application needs, requirements, and constraints for DER integration.

4.3.3 Quality of Service

Because of various aspects of DER connections (e.g., protection, monitoring and control, energy management, and post-event analysis), the quality of service (QoS) requirements may differ in terms of data quality and communication latency. The DOE guide provides a communication latency range required by DER connections between 20 ms and 15 s [8]. The data quality (accuracy) can be increased by utilizing error correction and acknowledgement feedback mechanisms for data transmission. The communication latency can be lowered by increasing the transmission priority. The communication protocols should have mechanisms to adjust the accuracy and latency of data transmission to accommodate the various QoS requirements for DER connections.

4.3.4 Data Quantity and Storage

The quantity of data flow varies among different applications, and thus data storage (buffer) in communication networks should be properly designed to account for data flow requirements. For example, in protection and control, the quantity of data transmitted is usually very low for a fast response, so little data storage is needed. On the other hand, for forecasting or post-event analysis, a large volume of data may be required and thus sufficient data storage is needed.

4.3.5 Data Content

When designing the data packet of the communication protocol, the fields of each packet corresponding to the specific measurements or control signals should be well defined. The data contents depend on the inputs/outputs of the various DER applications.

4.3.6 Cybersecurity

Cybersecurity is essential in communication network design for DER connections, since high penetration of DER would have significant impacts on the distribution grid operation. As a result, a cyber-attack on DER communication networks can result in severe consequences to power grid operation. According to the DOE's guide [8], the cybersecurity requirements for DER communications should generally be high. The general technical security requirements for information technology (IT) should be tailored to the unique features of the DER connections. The general cybersecurity requirements for a Smart Grid can be found in [9], and a detailed mapping of cybersecurity requirements tailored for DER connections can be found in [10].

4.3.7 Interoperability

The communication protocols for DER should also comply with the existing standards for distribution systems, including Modbus, SEP2, DNP3, and International Electrotechnical Commission (IEC) 61850. Special attention should be paid to Part 90-7 of IEC 61850, which describes the information model for inverter-based DER in the communication networks [11]. The design of the communication protocols should be interoperable with these widely accepted standards.

4.4 Volt/VAR Characteristics

Each DER should be configured with specific voltage and VAR characteristics, as shown in Figure 4-1 [12].

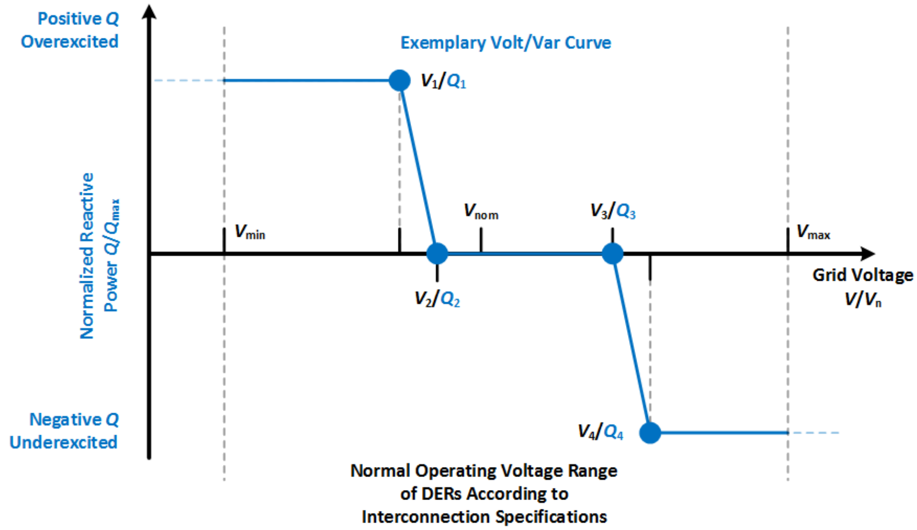

Figure 4-1 Voltage/VAR Characteristics of a DER

As shown in Figure 4-1, a DER can maintain its normal and constant VAR output within the normal voltage range and will increase or decrease if the voltage drops or increases, respectively. Once it reaches its reactive power capacity limit, the VAR output will remain constant even though the voltage drops or increases further.

4.5 Real and Reactive Power Characteristics and Control

The real and reactive power capacities of a DER are generally not constant values, but depend on its operation conditions and the relative values between these capacities. Figure 4-2 depicts the operation range of a DER's real and reactive capacities [12]:

At a normal voltage level, the apparent power capacity of a DER is constant; when the kVAR output increases, the kW capacity will be reduced accordingly. The set points for the voltage control, VAR control, and real power control should be within the capacity range, each of which depends on the other.

4.6 Fluctuation and Intermittency

Because of the natural characteristics of distributed energy resources, the power output of a DER may not be able to remain constant at all times. For example, a PV-based DER may have a significant drop in power output, with sudden cloud coverage changes at the PV site. A similar situation can occur with wind-based DER when the wind speed varies significantly in a short period of time. A large DER may require special measures to avoid very short-term fluctuations and intermittency (e.g., by installing energy storage devices to smooth out the fluctuations). However, small-sized DER may not have mechanisms to address such fluctuations. It is the distribution grid's responsibility to be robust enough to handle the intermittency and deliver quality electric energy to the end consumers.

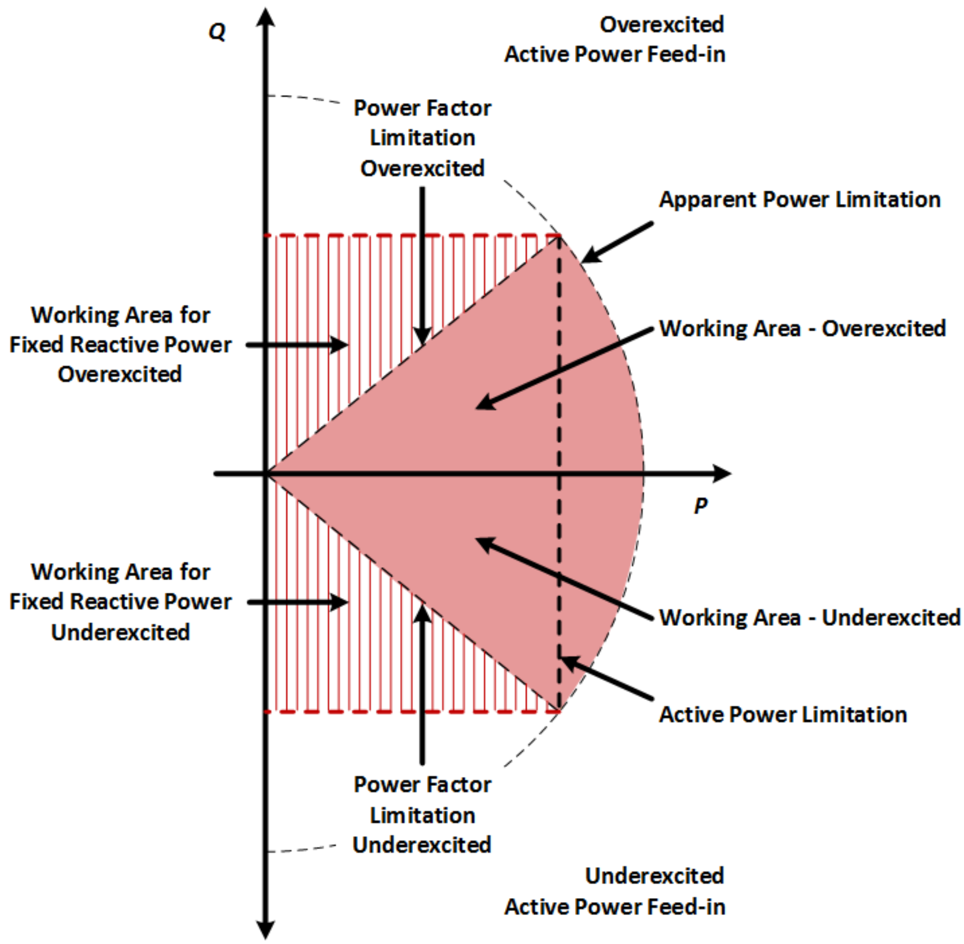

Figure 4-2 kW and kVAR Operation Range of a DER

4.7 Harmonics

When a DER serves balanced linear loads, the harmonic currents injected into the distribution grid should not exceed the values shown in Table 4-1. Any harmonic current induced by harmonic voltage distortions present in the distribution grid without DER connections should be fully excluded.

Table 4-1 Maximum Harmonic Current Distortion in Percentage of the Fundamental Current [2]

Individual Harmonic Order h (odd harmonics)	$h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	Total Demand Distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

Note that the current should be one of the following values, whichever is greater:

- Maximum load current integrated demand (15 or 30 minutes) in the distribution grid without DER units, or
- Rated current capacity of the DER unit.

Even harmonics are limited to 25% of the odd harmonic limits shown in Table 4-1.

5 Distributed Energy Resources Management System

DERMS is a relatively a new concept to the distribution industry. Its key objectives and functionalities mainly consist of effectively organizing, managing, optimizing, and controlling DER resources for maximum grid economic benefits, enhanced grid operation reliability, and service quality. This functionality includes how the DER are aggregated or grouped, for example, at the substation level, feeder level, or even at the feeder section level, as well as in other ways, such as by generation types, capacities, response rates, or other characteristics. The aggregated groups may be modeled as virtual generation units (VGUs), which can be optimally scheduled with targeted operation schedules hourly or by a fraction of hourly intervals for hours one day ahead. The resultant VGU schedules can be further distributed to the individual physical DER through disaggregation as their operation base points for the DER operating in real time.

5.1 Objectives and Functionalities

DERMS should effectively manage, optimize, and control the DER dispersed along the distribution feeder circuits in order to maximize the economic benefits of DER, enhance grid operation reliability, improve power supply quality, and minimize possible negative impacts (if any).

5.2 Group Structures and Aggregation Policies

The group structures and aggregation policies are the core features of DERMS. DER can be physically dispersed anywhere on the distribution grid. They also have very diversified characteristics, for example, in terms of energy sources (solar, wind, biogas, hydro, fuel cell, and battery storage), generation types (inverter-based or rotational machine-based), physical locations in the feeder circuits or feeder sections, power capacities, dynamic response performance to voltage and frequency changes, controls (local or remote), connection status, and many other features. It may be necessary for the DERMS to organize or group them properly in different aspects based on their features or specific characteristics to manage and optimize the resources effectively. Therefore, a single DER can be a member of several featured groups; for example, a remotely controllable solar DER can be a member of the solar group, a member of the remote control group, and a member of the fast-response group for a specific feeder circuit or section where the DER is connected. The grouped DER based on their specific characteristics or features may be organized as VGUs that can be the main base unit to participate in the optimal resource scheduling in the DERMS. The optimized operation schedules for the individual groups may be disaggregated to the individual physical DER as the set points to guide their operation around the committed schedules.

5.3 Operation Rules and Resource Optimization

A DERMS may need to consider the network constraints of distribution grid operation while optimizing the DER operation schedules based on their energy availabilities and the demands at different levels (e.g., substation, feeder, and feeder sections). It should communicate with the DMS to obtain the real-time operation condition and the committed operation plans to define the network constraints. Before committing to a schedule, it may be necessary for the DMS to verify that such a schedule will not cause any issue to the overall grid operation reliability and service quality. The DMS, in turn, may accept or reject the schedule, or counter offer a better schedule for the DERMS to review or consider. Once a schedule is accepted, it becomes a committed schedule, and both systems have to follow it closely. Under emergency conditions, temporary schedules may be provided, or the DMS may take emergency actions by shedding loads and/or the generation of some DER.

5.4 Controls and Monitoring of Individual DER

A DERMS may directly monitor the operations of the individual DERs remotely, or go through the DMS system and indirectly collect the operation data. It may also directly issue controls to the individual DER to download the set point values to the DER under remote control with the real power (kW) and reactive power (kVAR) generations or the voltage and real power (kW) settings based on the committed operation schedules. For those DER not under remote monitoring and control, DERMS may estimate their generation profiles based on their historical patterns and weather forecasts, or use the near-real-time data from AMI or other systems integrated with DERMS.

5.5 Generation Forecasting of DER

The optimization in scheduling an individual DER would be based on the available energy resources. However, a big portion of the DER may be from renewable energy sources, such as wind and solar, which are highly weather-condition-dependent and cannot be fully dispatchable to meet the demands. Therefore, it is necessary to have a good forecast of the available generation for the individual DER based on the weather forecast and other conditions. The generation forecast can either be an independent module to provide the forecasts to DERMS or be part of DERMS as an application.

5.6 Impacts of DERMS on DMS

The installation of a DERMS may help DMS operation. It may significantly reduce the uncertainties caused by the dispersed DER that may not follow a unified or coordinated operation pattern. With a DERMS, the DMS can obtain not only the real-time generation values of grouped VGUs, but also their operation schedules for look-ahead time intervals. This capability can be very effective in enabling the DMS to make predictive operation, control, and management decisions to further enhance operation reliability.

6 DMS Integration with Microgrids

Microgrids can operate in either a grid-connected or a grid-disconnected (islanded) mode. The integration of DMS and MCs needs to ensure that both the distribution grid and the microgrids are maintaining reliable operation for normal operation and contingency conditions, as well as making seamless transition from one mode to the other.

A microgrid may be independently owned by a customer, an energy provider, or the distribution utility that runs the distribution grid. The MC or control system can be physically located either locally or remotely, or even virtually in a cloud server on the Internet, regardless of its ownership. It may also be implemented as a subfunction or an advanced application in the DMS. This case would most likely occur when the microgrid is owned by the same utility that runs the distribution grid.

Regardless of the ownership structures and the controller locations, and how they are actually integrated with the DMS, the integration of microgrids with the DMS should follow common principles and rules as long as they respect the common definition of microgrids and the operation principles. The following subsections focus on the common principles and features in the integration.

6.1 Data Communication between the DMS and Microgrid

When connected to the distribution grid, a microgrid should have the necessary data communication for operation coordination under both normal operation and emergency conditions.

Under normal operation, the DMS needs to receive information on the energy interchange and voltage/VAR support schedules between the microgrid and the distribution grid at the PCC. In addition, it needs to receive real-time data in terms of phase voltages, currents, kWs, and kVARs at the active PCC. The microgrid may also provide a simplified internal operation topology to the DMS to indicate whether it forms wheeling paths to the distribution grid in case there is more than one PCC in active status. The wheeling paths may generate hidden loops to the distribution grid, which can cause considerable operation difficulties for the DMS and the distribution grid while system operators would remain unaware or lack acknowledgment. Figure 6-1 depicts a wheeling path in a microgrid.

Figure 6-1 shows that when the microgrid has both of the PCCs (PCC-1 and PCC-2) activated and its internal tie switch (S-1) closed, a hidden loop is formed to the distribution feeder that the DMS will not be aware of because it does not have the internal operation topology of the microgrid.

The situation could be even worse if the DMS were to transfer some loads from one feeder to another, as shown in Figure 6-2.

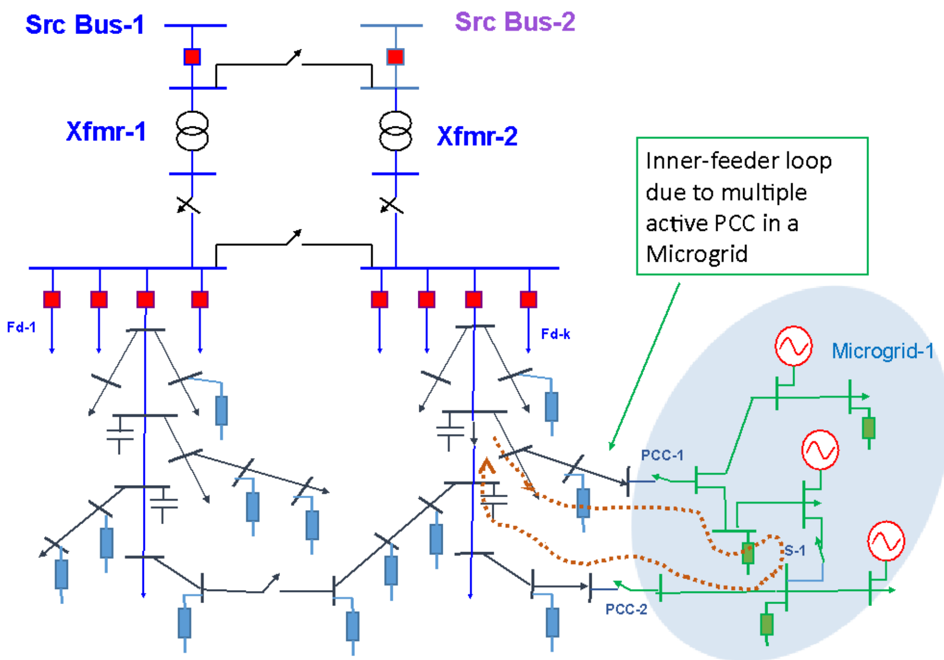

Figure 6-1 Wheeling Path in a Microgrid – Inner-Feeder Loops

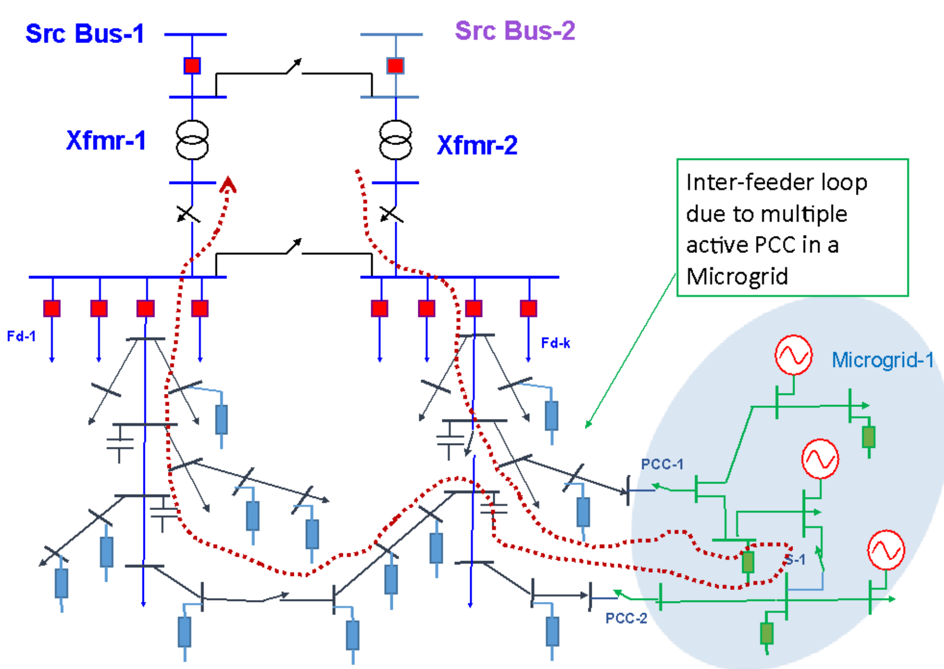

Figure 6-2 Wheeling Path in a Microgrid – Inter-Feeder Loop

Such hidden loops could cause significant operational difficulties or even catastrophic consequences in DMS control and management.

Under emergency conditions, either initiated from a microgrid or from the distribution grid in the grid-connected mode, support may be needed from the other party, including emergency energy interchange and voltage/VAR support. The request for emergency support should be forwarded to the other party and be confirmed quickly for effectively relieving the emergency problems. Under severe fault conditions, either occurring in the distribution grid or the microgrid, the PCC should be disconnected by the relay protections. This type of disconnection is classified as unintentional disconnection.

For unintentional disconnection, regardless of the root causes, both the DMS and the MC should take quick actions first, such as FLISR or other emergency measures, to isolate the problem at the troubled side, followed by recovering actions to restore load balancing and voltage profile recovery (e.g., increase real and reactive power generation in the microgrid, shed load or increase local DER generation, and activate the VVO to re-optimize the voltage profile in the DMS of the distribution grid).

For intentional disconnection, either by the MC or the DMS, depending upon which one requests the disconnection, the other party should be notified to prepare for the disconnection, including reducing the energy interchange to be near zero at the PCC and re-optimizing the grid voltage profiles. These steps can be done by balancing the real and reactive demands in their respective grids.

For reconnection to the grid, the microgrid should notify the DMS, and it sometimes may need to receive a confirmation notice before starting the reconnection process. Once confirmation is received, the microgrid can start the resynchronization process, which requires that (1) the grid frequency and voltage level closely match the distribution grid values across the PCC, and (2) the voltage angle difference between the two grids at the PCC is near zero. Once connected and stabilized, the energy exchange and mutual support functions can be activated.

Figure 6-3 is a summary of data communication and function mapping between an MC and a DMS to highlight the different functions of each under both normal and fault conditions. As shown in Figure 6-3, in both operation modes, the functions in the MC and DMS are coordinated with each other to ensure effective integration between the two control systems.

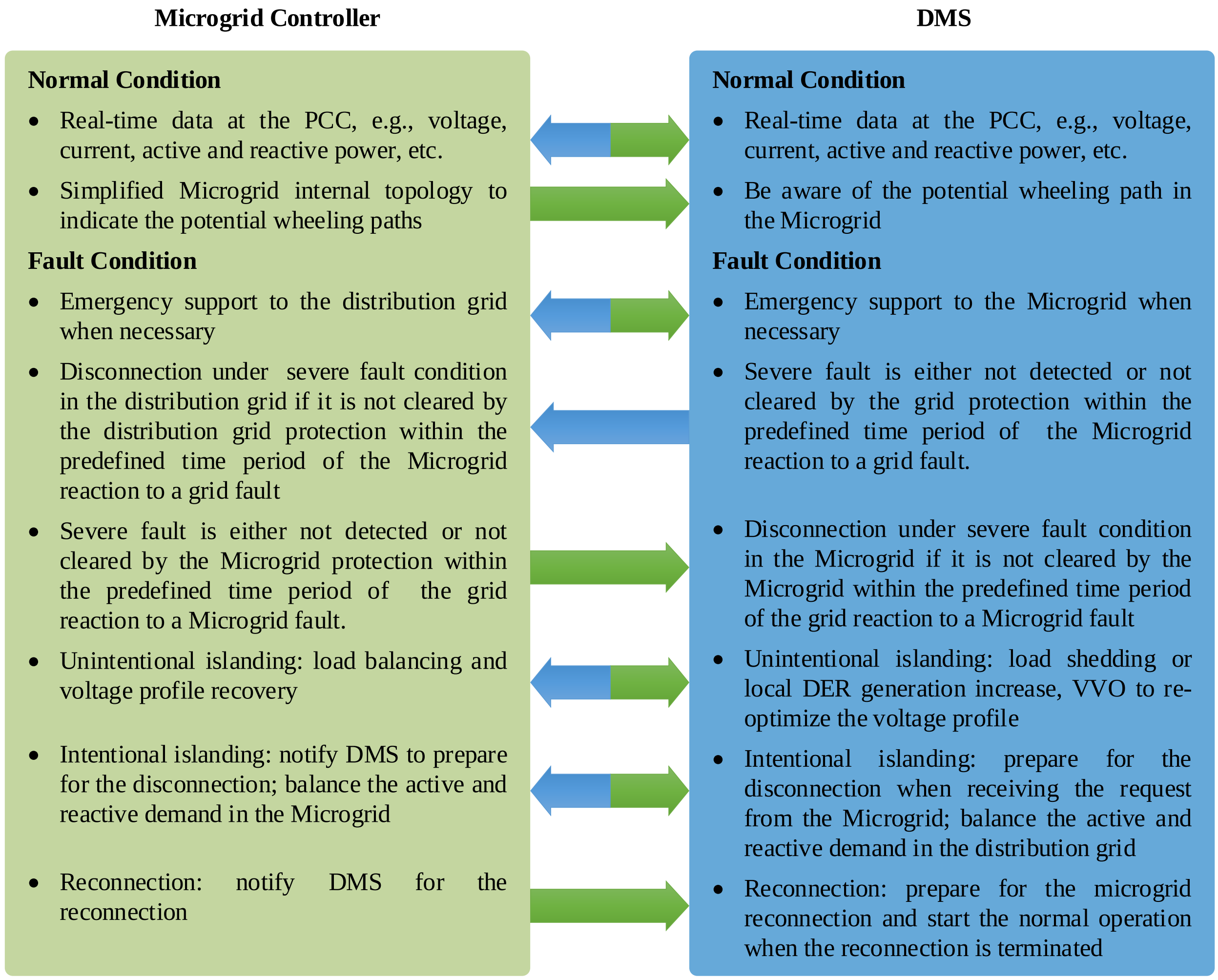

Figure 6-3 Data Communication and Function Mapping between a Microgrid Controller and a DMS

Considering the data communication and interactive control functions between an MC and a DMS, the microgrid can be seamlessly integrated and treated as an energy asset to improve the operation of distribution grids. The control signals are generated by different advanced applications in DMS to change the status of the microgrid according to the operation condition and requirements, as shown in Figure 6-4.

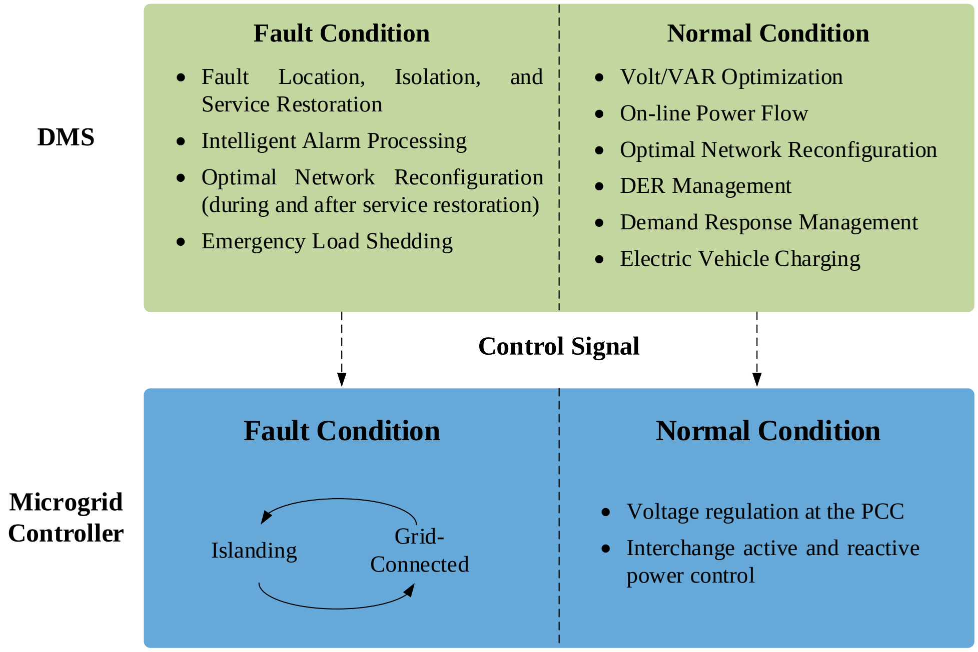

Figure 6-4 Control Signals Generated by the Advanced Applications to Adjust the Operation of the Microgrid

6.2 Operation Rules for Both the DMS and the Microgrid

A microgrid is generally an independent entity having its own operation rules and regulations. However, when connected to the distribution grid, it should also follow the operation rules of the distribution grid at the PCC, including those of the DMS responsible for the control and management of the distribution grid. Although the DMS may not be granted the control access to penetrate into the internal operation of a microgrid, it should enforce rules such that the microgrid cannot cause operational difficulties for the distribution grid owing to its own internal improper topology configuration, circuit faults, voltage control, or load-following problems. For instance, the DMS may request internal circuit topology from a microgrid that has more than one active PCC to the distribution grid, from which the DMS can detect whether the microgrid is forming a wheeling path or a parallel loop to the distribution grid, as shown in Figure 6-5.

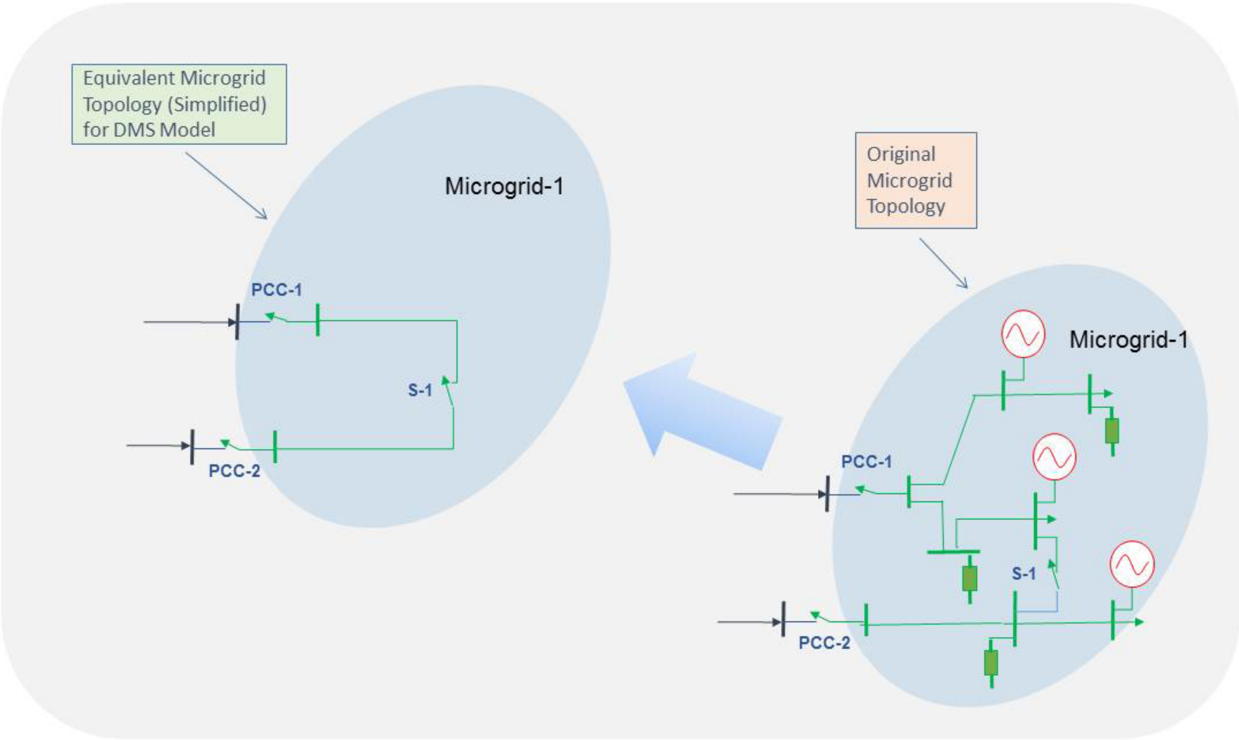

Figure 6-5 Simplified Microgrid Topology in DMS

As Figure 6-5 makes evident, with the simplified topology, system operators can easily determine what impact the microgrid has on the overall operation topology of the DMS when the microgrid has multiple PCCs activated.

The microgrid should disconnect from the grid if any fault or event occurs internally that will jeopardize the operation of the distribution grid. If a fault occurs in the distribution grid, the protection schemes in the DMS will be activated, but the related microgrids are also responsible for protecting themselves from any harm the fault may cause. Microgrids in the grid-connected mode should disconnect from the grid if a fault causes the corresponding distribution circuit to trip and become de-energized. The microgrids should also have the capability to ride through certain levels of low voltage owing to temporary fault conditions, as defined in the standards (e.g., the IEEE 1547 standard) during a fault time period that does not cause the circuit trip.

The microgrid should contribute to maintaining the healthy voltage profiles of the distribution grid at the active PCC when connected to the grid.

6.3 Synchronization and Connection/Disconnection

When a microgrid is to connect to the distribution grid, it should go through the synchronization process (that may be automatically checked by the synchronization relay) to ensure that its voltage level, frequency, and phase angle across the reclosing switch meet the synchronization criteria before closing the connection switch. No voltage or power disturbances to the distribution grid may be tolerated during the synchronization process. In other words, the synchronization process should be aborted if any severe disturbance occurs during the process. Upon the completion of the synchronization process, the energy exchange may be ramped to the committed target at a predefined ramping rate.

For intentional disconnections, the microgrid may ramp the energy exchange at the active PCC to near zero before disconnecting from the grid, regardless of which party initiated the disconnection.

For unintentional disconnections, both the distribution grid and the microgrids may need to have sufficient resources and proper control strategies in place to absorb the impacts and quickly recover to normal operation by complying with the operation standards, such as the corresponding sections defined in the IEEE 1547 standard.

6.4 Microgrid Control while Integrated with DMS

A microgrid's local energy resources and load management should have sufficient monitoring and control capabilities to do the following: (1) maintain the synchronization with the distribution grid, (2) maintain the desirable voltage profile at the PCC and its internal grid, and (3) quickly respond to the changes in internal load and generation and the disturbances from the distribution grid or the internal grid. Its operation conditions at the PCC should be monitored or visible to the DMS of the distribution grid. The connection switch at the PCC may also be controllable by the DMS for emergent disconnection.

6.4.1 Frequency Control and Load Following

A microgrid is generally not powerful enough to influence the frequency of the distribution grid significantly; however, it should maintain synchronization at the PCC with constant power exchange by following the committed transaction schedules with minimum deviation and minimum accumulated inadvertent energy exchange. The DMS should closely monitor the voltage profiles and power fluctuations at the PCC in real-time operation. The microgrid should be able to respond quickly to its internal load and generation changes or disturbances so there will be minimum impacts on the distribution grid at the PCC. In case of significant generation shortage or surplus, a new power exchange between the distribution grid and the microgrid should be scheduled, or the action of load or generation shedding may be launched in order to maintain the load balancing.

6.4.2 Volt/VAR Control

The DMS of the distribution grid should maintain healthy voltage profiles for the feeder circuits where one or more microgrids may be connected. In addition, a microgrid is responsible for assisting the DMS in maintaining the desirable voltage at the PCC. The microgrids may offer their additional reactive capacities and resources to the DMS for the overall voltage/VAR optimization of the distribution grid. The DMS can also provide or recommend the optimal voltage or VAR settings for the individual PCC of each microgrid.

The conventional VVC algorithms in the DMS are designed for controlling the on/off states of the capacitor banks at the feeder circuits and distribution substations, the substation transformer tap positions, and the voltage regulator taps at the feeder circuits, all in binary or discrete quantities. With the microgrid and DER connections, the reactive power and voltage controls may be continuously adjustable quantities within certain ranges. This arrangement will introduce new challenges to the VVC algorithms because they have to handle mixed control variables, some in binary and others in continuous (adjustable) quantities.

6.4.3 Emergency Support

Under emergency conditions, regardless of where the emergency starts, the DMS and microgrids should be able to support each other with only minimum negative impacts felt by either party. An emergency support policy may be established between the two parties, including emergency voltage/VAR and real power supplies from one to the other with specific levels and conditions.

6.5 Resource Optimization in Microgrid

The energy resource optimization of a microgrid is actually the internal issue of the microgrid and does not have much to do with the DMS of the distribution grid. However, the DMS may define constraints on the microgrid at the PCC (e.g., the operation ranges of the voltage, VAR, and the allowable real power exchange at the individual PCC for different time periods). The individual microgrids may optimize their resources by taking into account all of the constraints to maximize their overall benefits, including taking advantages of peak/off-peak energy price differences of the distribution grid so they can use their internal energy resources and storage capacities intelligently.

6.6 Energy Transactions and Wheeling between the Distribution Grid and Microgrid

Power exchanges, or energy transactions, between the distribution grid and a microgrid should be fully monitored by both the DMS and the microgrid and be directly controlled by the microgrid to follow the committed transaction schedules.

The energy transactions between the distribution grid and a microgrid are counted as net quantities from any active PCC of the microgrid. When more than one active PCC is involved, energy wheeling will be more likely to occur. An example of this occurrence is when one party delivers a certain amount of power to another through one PCC and receives some amount of power from another PCC. Operators may need to avoid such wheeling in normal operation, although it may be needed in emergency support and therefore must be well coordinated between the two parties.

A wheeling path through a microgrid will form a looped operation condition for both the distribution grid and the microgrid, which may result in operation difficulties if the grids are configured to operate in radial configuration, including impacts on the protection mechanism, voltage and VAR control, and the load flow distribution.

However, under emergency conditions, such wheeling can be useful in providing alternative paths to deliver power to consumers and helpful in maintaining voltage profiles for the grid.

When microgrids are owned by the utility that owns/operates the distribution grid, the microgrid control systems may be embedded into the DMS as subfunctions or applications. This structure permits the scheduling of energy exchanges to be optimized in the same domain as the entire distribution grid. In this case, there may be no need for independent optimization of individual microgrids.

6.7 DMS Function Enhancement with Microgrid Integration

A microgrid can be considered as an energy resource just as a DER. Under some circumstances, it can be considered as a controllable load to the distribution grid. Therefore, it should be properly modeled in the DMS as a special entity with variable generation and load capacities. Microgrid connections can be very helpful in further enhancing the operation reliability and power supply quality of the distribution grid by optimally utilizing their potentials. The corresponding operation strategies in DMS may be adjusted to meet the operation rules and the natural characteristics of microgrids, including those for power transactions, voltage/VAR optimization, emergency support, etc., as discussed in Sections 6.4.1 through 6.4.3.

6.8 Protection Schemes

Similar to instances of DER penetration, microgrid connections will result in two-way power flows on the distribution grid. The protection scheme in the distribution grid should be adjusted accordingly to cover the multisource contributions of short-circuit currents from different directions to the point of faulting. It is a minimum requirement for the distribution grid to implement a directional over-current protection scheme, which can support different short-circuit current settings for different fault directions. It is important to note that the protection scheme must be defined in the planning stage. With increasing DER penetration, operators are required to modify the protection scheme accordingly to ensure the successful integration of the MC and the DERMS into DMS.

The distribution grid will generally be an active network with the connections of DER and microgrids. These local generation resources will introduce significant dynamic changes, conventional static protection schemes, and settings that sometimes may not cover all possible scenarios. For this reason, modifications should be made during operations to mitigate the impact of DER. For example, some of the DER may be on and off occasionally, and the rest of the DERs in connection may or may not be significant short-circuit current sources, depending upon their energy conversion types (inverter-based DER may not be significant fault current contributors). Moreover, the operation topology of the distribution grid may also be dynamically adjusted or reconfigured owing to changes in dynamic operation conditions. The protection schemes and settings should be adjusted accordingly so as to adapt closely to operation condition changes. These settings will not only require more reliable remote relay-setting mechanisms but also higher cybersecurity requirements for the protection schemes.

In addition, it may also be necessary to strengthen the original protection mechanisms at the PCC to isolate the faults occurring in the internal circuit of a microgrid and keep them from resulting in severe impacts on the distribution grid.

Another modification of the existing protection scheme is the synchronization at the PCC. A microgrid should implement a synchronization scheme at the PCC for connecting to the distribution grid, in addition to the protection schemes isolating the faults occurring at the grid side or at the internal circuit. The synchronization logic should automatically control the corresponding energy resources to adjust the microgrid frequency and voltage to levels matching that of the distribution grid at the PCC. The synchronization relay can lead to reconnection to the grid by automatically checking the differences in voltage, frequency, and phase angle across the connection switch at the PCC.

6.9 Responsibilities of Microgrids and DMS in Integrated Operation

6.9.1 Responsibilities of Microgrids

An MC is responsible for maintaining constant real and reactive power exchanges and healthy voltage profiles at the active PCC when connected to the distribution grid. It may provide a simplified operation topology to the DMS when more than one PCC is activated. A microgrid should be able to disconnect automatically from the distribution grid under any severe distribution grid fault condition, beyond the threshold of fault-ride-through, occurring either within the distribution grid or the microgrid.

6.9.2 Responsibilities of DMS

The DMS should provide operation guidance to the microgrids, including the operating voltage ranges and power exchange fluctuation tolerances around the scheduled targets at the active PCC. The DMS can also initiate emergency requests to microgrids with clearly defined and specific emergency support requirements, including for support through wheeling if there is more than one active PCC.

7 DMS Integration with the DERMS

The DERMS is responsible for organizing, managing, and controlling the dispersed DER in a distribution system that could be directly managed and controlled under a DMS. Therefore, it should be properly integrated with the DMS to perform its functions by mutually sharing the available data in both systems, which sets the fundamental basis for both systems to work in a coordinated way in controlling and managing the corresponding parts of the distribution system.

Similar to the microgrids, a DER may be owned by an independent customer, an independent energy provider, or the same distribution utility that runs the distribution grid. In addition, the DERMS may be located in a local area, in a substation, in the control center, or even on a cloud server. It may also be implemented as a subfunction or application embedded in the DMS. Moreover, the distribution grid may have more than one DERMS, each one managing a portion of the DER in part of the distribution grid. These differences may lead to variations in the actual implementation of the integration but should not lead to different principles and rules as long as they respect the common definition and operation objectives of the DERMS. The following sections focus on the common principles and features of the DERMS integration with the DMS.

7.1 Data Communication between the DMS and the DERMS

7.1.1 Model Sharing

Generally, the DMS will have a fairly detailed model of the entire distribution system, usually with full coverage from the distribution substations all the way to the end user transformers. The model may also cover the DER, but it may not cover their characteristics in full detail, including only basic features like the capacities, operation limits, etc., and more likely in terms of the aggregated VGUs at the user transformer level.

In addition to the detailed parameters of the individual DER, the DERMS can also have a model of the distribution network defining where the DER are connected (e.g., through the user transformers at the PCC). Figure 7-1 shows a typical connection of DER at an end-user transformer in a feeder circuit. The individual DER in one nearby location may share one user transformer or may be aggregated as one or more VGUs based on their specific characteristics and grouping rules.

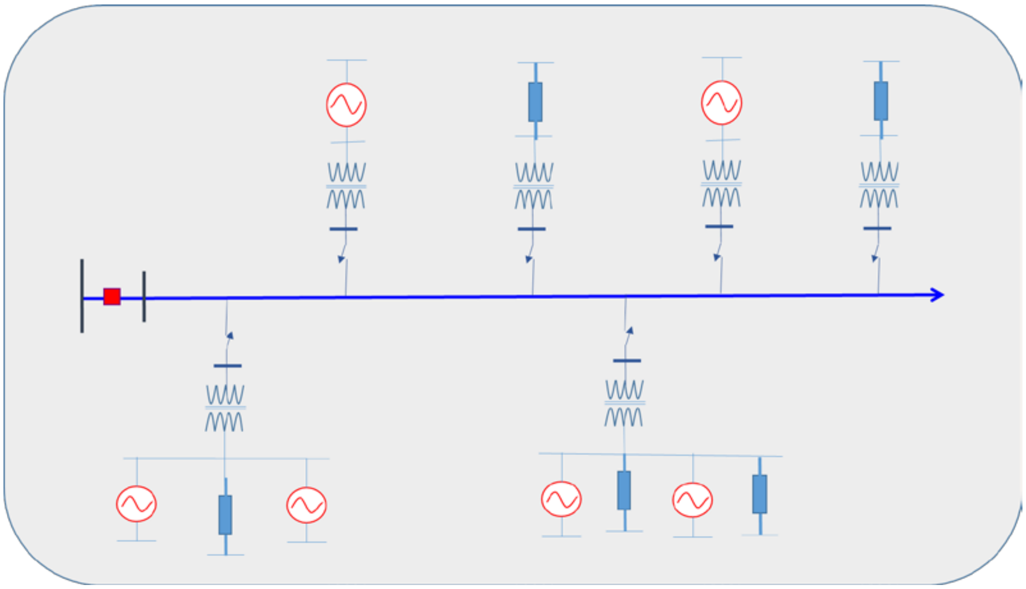

Figure 7-1 A Typical Connection of DER at a Feeder and User Transformers

Once the physical connection to the distribution circuit or feeder is defined, it may not be necessary for the DERMS to include a full distribution network model that is the same as what the DMS uses; rather, it can include a simplified hierarchy of the distribution grid organization defining the specific feeder section, feeder circuit, and substation where each of the DER is connected or belongs, as shown in Figure 7-2.

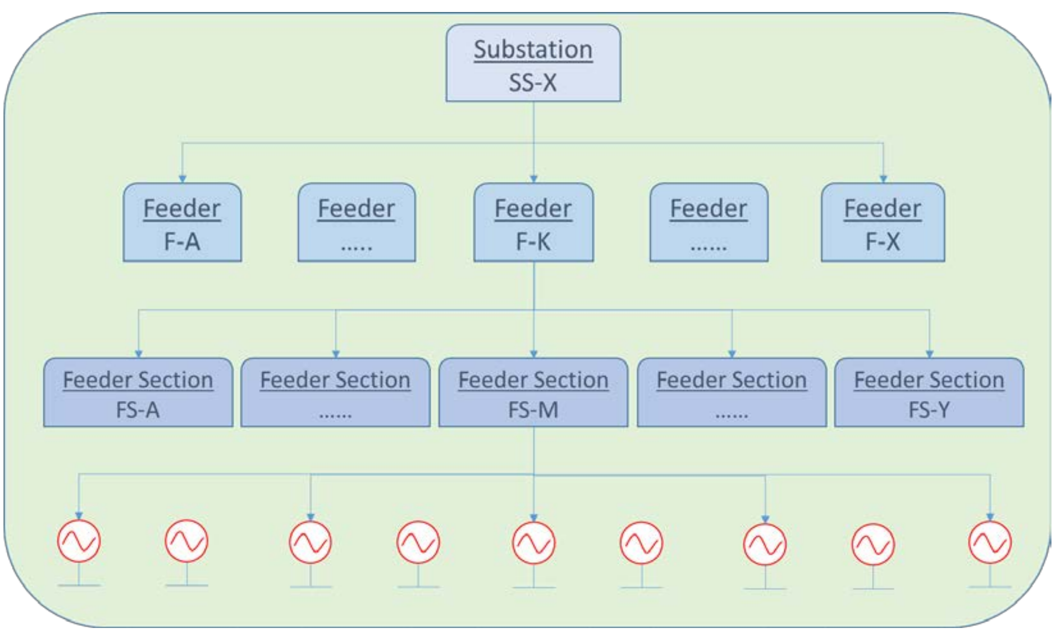

Figure 7-2 An Organizational Hierarchy of Individual DER

The organization hierarchy is a dynamic structure that may change as the distribution topology changes owing to switch operations and network reconfiguration for load transferring, load balancing, planned outage services, service restoration, or periodic network reconfigurations. However, a feeder section can be modeled as the basic topology component, and any topology change can be easily adapted by reassigning the corresponding feeder sections to the new target feeders, or, in some cases, the entire feeder circuit may be assigned to another target substation.

7.1.2 Operation Data Communication

The DERMS may take into account the dynamic changes of distribution network topology in its operation model while organizing its dynamic DER groups and optimizing the operation schedules of the groups. The resultant schedules of DER groups or VGUs are then disaggregated to the actual individual DER as their base operation settings. The schedules of DER groups or VGUs should be forwarded to the DMS in either whole-group quantities or break-down quantities by smaller groups, depending on how the DER are modeled in the DMS. The operation data exchanges between the DERMS and DMS in the integrated environment can be presented as shown in Figure 7-3.

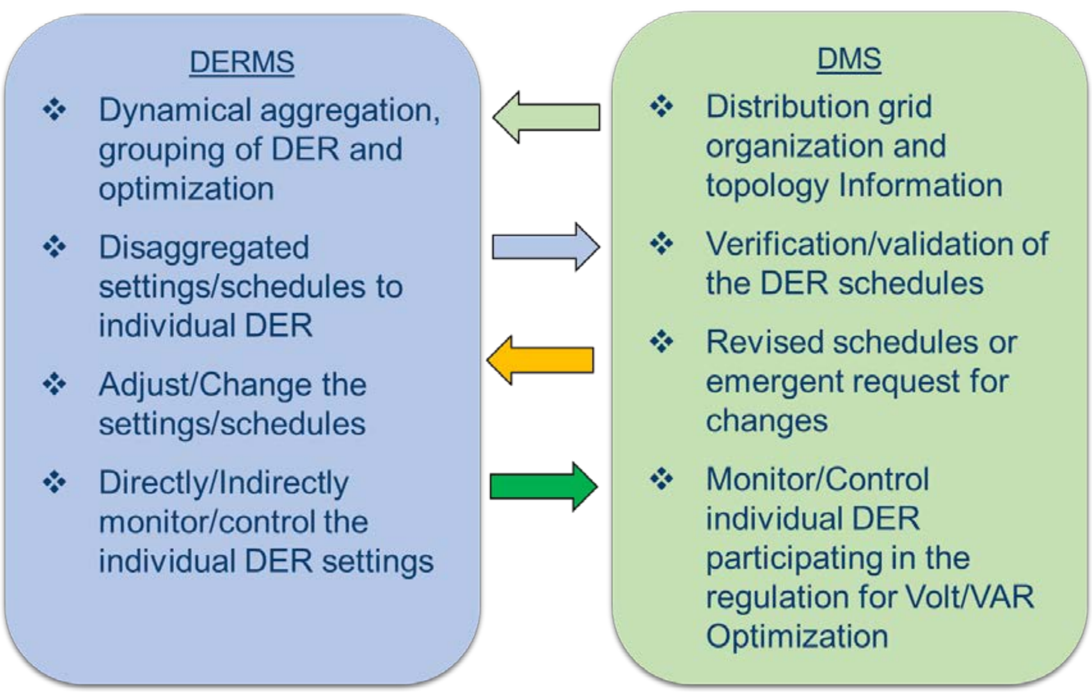

Figure 7-3 Data Communication between the DMS and DERMS

The data exchange may be back and forth for a few iterations in real-time operation for reviewing, validating, and rejecting or revising before the operation schedule is finalized, accepted, and committed. The committed schedules can also be revised, suspended, or cancelled when the operation condition changes; and emergent schedules may be developed and applied under emergency conditions.

The DERMS may directly monitor and control individual DER or forward the set points and target operation schedules of the individual DER to the DMS for actual execution in case the DER are under direct control of the DMS. In either case, the DMS should also monitor the operation of the aggregated DER, which is similar to what the DERMS does. It would be recommended that both the DERMS and the DMS may share available real-time measurements from the DER, regardless of which system directly collects and owns the data.

7.2 Responsibilities of the DERMS for DMS

The DERMS is the system that is responsible for performing the overall management and control of the individual DER, including grouping the DER based on their energy sources, maximum and available real and reactive capacities, availability in timeframes, dynamic response performance, voltage-VAR and frequency characteristics, and physical locations in the distribution circuits, etc. The individual DER may be organized in small groups as VGUs based on their electricity distance and operation characteristics in the optimization and scheduling process. However, the DMS may not need to receive detailed information about the DER for its operation objectives. It is the DERMS's responsibility to simplify and aggregate the resultant information at the level that the DMS needs for integrated operation. For instance, the DMS may be interested only in information at the aggregated VGU level in performing the DMS control and management functions.

The DERMS should provide tentative operation schedules of the DER or VGUs for the DMS to evaluate or validate in advance. The DERMS is also responsible for quickly responding to any emergency request from the DMS for emergency operation schedules for certain DER when the DMS encounters emergency conditions and looks for external supports (e.g., increasing generation, providing more kVARs from some DER, or shedding some generation).

The DERMS may also include a generation forecasting function for the various types of DER.

7.3 Responsibilities of the DMS for the DERMS

In addition to providing the real-time operation condition of the distribution grid, the committed operation schedule, the associated constraints, and the available margins for the DERMS's optimization, the DMS may also validate the tentative operation schedules of the DER and provide feedback to indicate the acceptance, rejection, or revision of a suggested schedule. It should also initiate emergency requests to the DERMS with clearly defined and specific demands for support.

7.4 Operation of DER under the DERMS Connecting to the Distribution Grid

The aggregated DER groups can be modeled as VGUs, which may be optimally scheduled with target operation schedules on an hourly or subhourly basis for a day or a few hours ahead. The resultant VGU schedules can be further distributed to the individual DER as their operation base points that may be directly downloaded to the individual DER through the remote controls or command messages, depending upon what levels of remote monitoring and control capabilities are implemented on the DER.

Prior to finalizing the operation schedules to the VGUs or individual DER, it may be necessary for the DERMS to obtain a validation or approval status from the DMS as to the tentative schedule. The DMS may approve, disapprove, or revise the proposed schedule based on the actual grid condition. On the other hand, the DMS may request an urgent change in a committed operation schedule to the DERMS or may directly change the schedule in emergency conditions in real-time operation while notifying the DERMS of the change at the same time or later.

7.4.1 Impacts of DER on Distribution Power Quality

Intermittency in DER outputs in terms of real and reactive power will have considerable impact on power quality of the distribution grid. It can induce significant power fluctuations and frequency/voltage oscillations. Meanwhile, harmonic currents generated by the DER inverters can penetrate into the distribution grid through the PCC.

To guarantee that the DMS can effectively monitor and evaluate the impacts of the DER, it should be capable of gathering information from the DERMS indicating power quality status of each DER. Effective approaches for eliminating power quality problems from DER should be deployed in the DMS to alleviate the DER’s influences based on the requirements of related standards (e.g., the IEEE 1547 standard). Meanwhile, as a hybrid solution, the DERMS should have the capability of mitigating the impact of power quality issues by itself.

7.4.2 Volt/VAR Support and Control

Based on the available VAR resources of DER provided by the DERMS, the DMS may request additional volt/VAR support from some DER through the DERMS in addition to the normal settings for the individual DER. The DERMS should include such demands into its overall optimization process and provide updated DER operation schedules to the DMS. Once accepted and committed, the new set points to the individual DER should be updated, and each of the DER involved should operate around its new set points for volt/VAR control.

7.5 Strategies and Policies for Emergency Control and Management

The DERMS should actively participate in emergency control and management to assist the DMS in relieving operational difficulties during emergency conditions as much as possible. It may dynamically update the DMS with the available resources of DER. Based on the availability of resources, it is the DMS’s responsibility to initiate requests for emergency support. These requests may be in terms of real power increase or decrease in kW, reactive power increase or decrease in kVAR, or generation shedding within a certain time period. The DERMS should quickly respond to the request by either using its reserve margin or performing a fast resource optimization by taking the emergency demands into account. The confirmed emergency schedule should be forwarded to the DMS while controls are issued to the affected DER at the same time.

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8 DMS Design Principles for Integration with DERMS and Microgrids

As discussed in the previous chapters, conventional DMS are generally designed for passive distribution networks, where the energy sources are the primary buses of distribution substation transformers and where power flows in one direction from the sources to the end consumers through the distribution circuits. However, with the penetration of DER and microgrids, the distribution networks are becoming highly active, with more and more DER and microgrid connections. DER and microgrids generally have their own control and management systems, including the DERMS for DER and the MCs for individual microgrids. The challenges for the DMS are not only dealing with the active distribution networks but also integrating with the DERMS and MCs. Meeting these challenges requires new principles and guidelines for designing the new generation of DMS in order to achieve effective control and management of the active distribution systems and seamless integration with DERMS and microgrids. As a brief introduction, different approaches for integrating MCs and DERMS are shown in Figure 8-1. The figure shows that MCs and DERMS can be flexibly integrated into the existing control system of distribution grids. For example, an MC can be integrated into the DMS or connected to it as a separate system. Meanwhile, a DERMS can also be integrated into an MC or become a separate system.

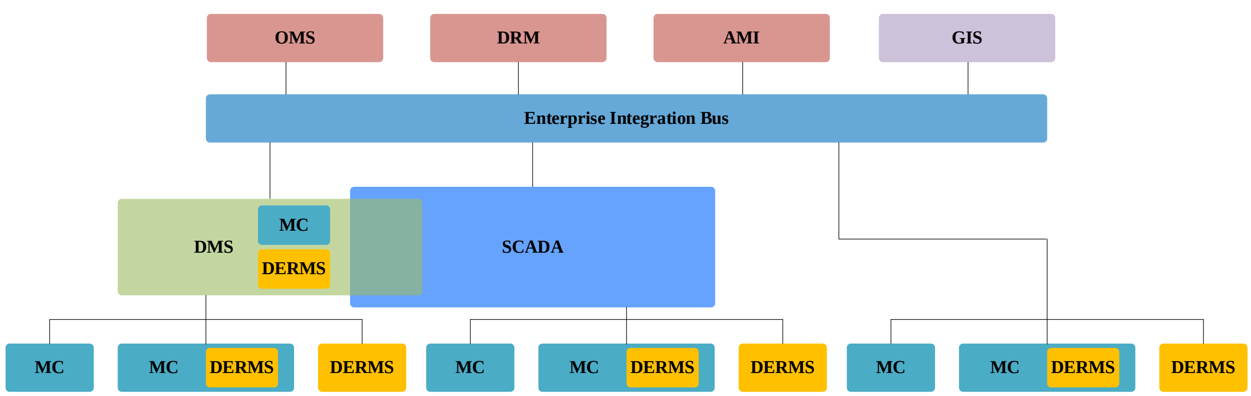

Figure 8-1 Integration of Microgrid Controllers and DERMS into the Existing Control Systems of Distribution Grids

8.1 DER and Microgrid Modeling in DMS

DER and microgrids are considered new components of DMS when compared with conventional distribution grid operations. They need to be properly modeled first before they are included in DMS functions and DMS integration.

8.1.1 DMS Model

The distribution network model itself may have no changes that are considered significant when compared with the conventional passive network; however, it may need to include the connection models of the DER and the microgrids.

8.1.2 Modeling DER in DMS

Individual DER may be presented in two different formats in the DMS, depending on the DER's size or capacity. Large DER (e.g., a major DER with a capacity of 30 kW or more), may be presented as independent DER and have a dedicated or shared PCC. Smaller DER, such as residential PV generators with capacities of less than 30 kW, may be aggregated at the user transformer level. This model is similar to the conventional model of loads in the DMS, where individual loads sharing the same user transformer are usually aggregated as a single load in the DMS model. Each DER included in the DMS model, regardless of whether it is an independent DER or an aggregated one, should be modeled at a sufficient level of detail so that both its static and its dynamic operational characteristics are represented. The details would include the operational limits on the voltage range, real and reactive power outputs, internal impedance, phase connection types (delta/Y with or without grounding), and response rate (power ramping).

8.1.3 Modeling Microgrids in DMS

The generation resources, loads, and distribution network of a microgrid are directly controlled and managed by its internal controller and may not be visible to the DMS in terms of individual components. However, the DMS may model microgrids as special energy entities that can be either equivalent loads or equivalent energy resources at the PCC, including their real and reactive power limits as loads and energy resources, their available capacities in real-time operation, the response rates, etc. The DMS may also obtain a simplified network topology model along with the status of the tie-switches if more than one active PCC is involved in a microgrid when it is connected to the distribution grid. By using the simplified topology model and tie-switch status, the DMS can find out if the active PCC would form parallel power flow paths or hidden loops to the distribution grid. The interconnections between two or more microgrids may also form hidden loops, although each of them may have only one active PCC to the distribution grid. In such cases, the DMS may also include a simplified topology model for the interconnections among the microgrids.

8.2 Data Exchange Requirements

The communication integration of the DMS with microgrids and DERMS can be implemented in many ways; examples include peer-to-peer communication that uses a proprietary data exchange format or a connection to the ESB through standard data exchange, such as IEC 61970/61968.

8.2.1 Data Exchange between DMS and Microgrids

The data exchange needs for integrating the DMS with microgrids are mainly at the PCC and include the following.

8.2.1.1 Connection Status

Both the DMS and the microgrid should receive information about the connection status at the PCC.

8.2.1.2 Voltages

Both the DMS and the MC should receive information on the target and actual voltages at each active PCC when the microgrid is connected to the distribution grid. The microgrid may need to receive information on the voltages at both sides of a PCC when it is disconnected and there is an intention to reconnect.

8.2.1.3 Power Exchanges

Both the DMS and the MC should receive information on the actual real and reactive power exchanges at each active PCC and the net target power exchanges between the two parties. Each system should be alerted if any significant unintentional wheeling exists, and the microgrid should take action to keep it from occurring.

8.2.1.4 System Frequency

The microgrid should monitor the distribution grid frequency when it is disconnected and there is an intention to reconnect it to the grid. Once connected, the system frequency would be the same on both sides.

8.2.1.5 Power Exchange Schedules

Power exchanges between the distribution grid and the microgrid may be prescheduled so that the available energy resources can be optimally shared. Both parties may negotiate iteratively over tentative schedules before finalizing a formal schedule for commitment. Once both parties are committed, they should follow the schedule as closely as possible; adopting this approach may mainly be the responsibility of the microgrid, which can effectively control its energy resources to balance its internal demands and the exchanges through the PCC. The committed schedules may be cancelled or terminated at any time under emergency conditions, and new emergency schedules may be added in some cases.

8.2.1.6 Simplified Operation Topology of the Microgrid

When more than one PCC is activated, the microgrid should provide a simplified operation topology to the DMS for its monitoring of possible loops formed by the PCC, plus also provide alerts of possible wheeling.

8.2.1.7 Connection/Disconnection Requests

The microgrid may request permission from the DMS to connect to or disconnect from (intentional disconnection) the distribution grid, and the DMS may approve or reject the connection request and accept a disconnection request right away or ask for a short time delay. On the other hand, the DMS may also request the microgrid to connect to or disconnect from the distribution grid, and the microgrid may accept or reject the connection request and ask for a short time delay for a disconnection request. Under emergency conditions, each party may initiate the process of disconnection without asking for approval. (For example, the DMS may send a transfer trip command to the tie-switch of a PCC if the corresponding feeder is tripped because of a contingency.)

8.2.2 Data Exchange between the DMS and DERMS

The data exchange between the DMS and DERMS may occur at a high level when compared with the exchange between the DMS and the microgrids.

8.2.2.1 Distribution System Model

A DERMS can use exactly the same distribution grid model to perform its functions as that used by the DMS. It may also use simplified models in its internal processing, like the hierarchical model discussed in Section 7.1.1 and shown in Figure 7-2. These models may be a good compromise between the complexity and the capabilities needed for DERMS functionalities and objectives, such that the DER are effectively organized and aggregated from different aspects while the basic topological information is also taken into account.

8.2.2.2 Aggregated DER Groups (VGUs)

The DERMS may pass the aggregated DER groups (VGUs) to the DMS for proper modeling of the DER in the DMS and its advanced applications, including the aggregated capacities in real and reactive power operation ranges, fault current contribution, internal impedances, and their availabilities from time to time.

8.2.2.3 Grid and DER Operational Conditions

DERMS may need to understand the current and predicted operational conditions of the distribution grid based on the committed operation schedules and the forecasted demands from the DMS, including the field loading conditions and voltage profiles. At the same time, the DERMS may directly monitor and control the individual DER, monitoring its operational conditions in terms of the PCC status, terminal voltages, and real and reactive power outputs. Monitoring may also be performed indirectly, by relying on the DMS to carry out the direct monitoring and control and forwarding the information to it.

8.2.2.4 DER (VGU) Operational Schedules

The DERMS may provide the committed operational schedules of the individual DER groups (VGUs) to the DMS to obtain the benefit of overall distribution system operation. Before a schedule is finalized, a few iterations between the DERMS and DMS may be needed for mutual validation and confirmation.

8.2.2.5 Emergency Requests

The DMS may make an emergency request to DERMS for increasing or decreasing the real and/or reactive power outputs from some dedicated VGUs, or it may request a certain amount of generation shedding in the scope of a feeder section, feeder, group of feeders, substation, or group of substations.

8.3 Advanced DMS Applications for Active Distribution Networks

As described in the previous sections, the distribution grid is becoming highly active with a higher penetration of DER and microgrid connections. Advanced applications in the DMS are facing completely new environments that are not like the traditional passive networks that were the basis of conventional applications, and the result is a series of challenges. The most important challenge comes from the bidirectional power flow in the grid, which may change from time to time depending on the real-time dynamics of the load and the DER generation distributions. The second challenge comes from the additional uncertainties associated with DER generation, in that most of the generation may come from renewable resources. DMS applications may thus need to be sufficiently robust and able to respond quickly in order to cope with dramatic changes in conditions. Some of the key applications may need to be able to look ahead when providing predicted operational schedules and strategies, including VVO, FLISR, and ONR. The following text discusses sample features for a few typical DMS applications.

8.3.1 Topology Processor

The TP will no longer be able to determine flow directions purely on the basis of network connectivity. The flow directions of the individual feeder sections may have to be determined from power flow results for the OLPF based on the actual network topology, load, and DG distributions. The directions of real and reactive power flows at each phase may not be the same.

8.3.2 On-line Power Flow

Although distribution grids may become highly active with bidirectional power flows, they may also still remain in a radial configuration, sometimes with a few loops, which is similar to what is found in conventional passive networks. Therefore, fundamental changes to power flow solution algorithms or methods may or may not be required just because of the DER and microgrid connections.

Some of the DER may be rotational machine-based and others may be inverter-based. With regard to rotational machine-based DER (usually with three phases), their internal source voltages would be well balanced among the three phases; however, their power outputs among the three phases may vary significantly depending on grid operational conditions, even though the total output from the three phases may be a given and fixed quantity. It is not possible to specify power outputs for the individual phases for a rotational machine-based generator, so it would thus naturally share the unbalanced loads proportionally. With regard to an inverter-based DER, however, its power output can be specified both for the total output and for the individual phases. If it is specified for the total power injection to the grid, one may assume that its internal three-phase voltages would be balanced and that the output power at each phase would be determined by the grid operational condition, a situation that is similar to that associated with rotational machine-based generators. If power output is specified for the individual three phases, that may mean that it has chosen to balance the unbalanced local loads.

8.3.3 Short-Circuit Analysis

Similar to the OLPF, SCA may or may not require fundamental changes to the solution algorithms. But some of the DER may be strong contributors to the fault currents, leading to multiple fault current contribution sources, a situation that is quite different from that of conventional passive networks. On the other hand, the inverter-based DER generally are not strong contributors to the fault current, even though they may still play important roles during the first couple of cycles. Special attention to inverter-based DER may be needed on a case-by-case basis.

8.3.4 Fault Location, Isolation, and Service Restoration

The penetration of DER and microgrids may introduce significant challenges with regard to FLISR. This challenge is the result because conventionally, FLISR was generally designed to consider only the restoration of load service; no DER generation was in the scope of consideration. The objectives, algorithms, and approaches of FLISR may need to be reconsidered by taking into account the impacts of DER and microgrids in restoration plans, including the restoration of both load and DER generation. The transition in which load is restored first and then generation is restored later may occur because the DER may have been disconnected during de-energization and will not reconnect right away when the feeder is energized again.

8.3.5 Volt/VAR Optimization

VVO is generally designed to control capacitor banks and substation transformer taps and feeder voltage regulators. These are all binary control variables. The connections of DER and microgrids may provide additional VAR resources for voltage and VAR control and optimization in VVO. These resources will be continuous control variables, resulting in more complicated mixed-integer programming problems in VVO optimization. Moreover, fluctuations in the DER outputs may have additional impacts on VVO operation that may have to be considered in revised solution approaches.

8.3.6 Optimal Network Reconfiguration

ONR is generally designed to minimize network energy losses while maintaining good voltage profiles in the grid within a given time period. Similar to other DMS applications, it is built on the basis of passive distribution networks. The connections of DER and microgrids will also introduce great challenges for the ONR. It may have to include the DER and microgrid operational schedules in its optimization process and apply a look-ahead logic. It may also have to include some of the DER and microgrids as dispatchable resources in its optimization. Such a design will allow ONR to generate the optimal overall configuration, which results in better use of DER resources and optimal recommended schedules being submitted to DERMS and DMS for consideration and validation.

8.4 Monitoring and Control Requirements

In addition to addressing conventional monitoring and control functions, integrating DMS with microgrids and DER will extend the functionalities in its monitoring, control, and management of the distribution system. There will be more “knowing” and less “guessing” based on the understanding of the current operational condition that is gained and also based on the look-ahead knowledge of conditions provided via the availability of the operational schedules of the DER and microgrids provided by DERMS and the microgrids, respectively. However, this integration also means that the DMS would need to extend its operational scope to include the monitoring and tracking of the committed operational schedules from DERMS and the microgrids and the validation or verification of the proposed schedules prior to formal commitment.

8.5 Communication System Requirements

The underlying communication system to support the monitoring and control of the integration of DER and microgrids into the DMS needs to be properly designed. As discussed in Section 4.3, many communications and networking technologies provide available options for such a design, including traditional twisted-copper phone lines; cable lines; fiber-optic cable; wireless cellular, satellite, and power line carriers; and wireless short-range networks such as Wi-Fi and ZigBee. For each technology, several standards and protocols can be chosen, and the communication network topology parameters need to be designed properly, as well. For the integration of DER and microgrids into the DMS, the communication system requirements should be based on the architectural design and supported applications. The criteria are discussed in the following sections.

8.5.1 Bandwidth

The bandwidth requirements of communication systems for integrating DER and microgrids into the DMS depend on the control architecture and the applications to be supported. For example, if the DMS needs to receive information on all of the details of the DER managed by DERMS, the communication link between DERMS and the DMS needs to be stronger than it is for a case that only requires aggregated information to be exchanged between DERMS and the DMS. A similar case also applies to the communication link between the MC and the DMS. The more applications there are to be supported, the more bandwidth requirements there will be. Therefore, the bandwidth requirements of the communication system should cover all of these aspects.

8.5.2 Quality of Service

To specify the QoS requirements of the communication system in terms of communication latency and data accuracy, each individual application related to the integration of DER/microgrids with the DMS should be investigated in order to properly specify the latency and accuracy requirements. The communication protocols need to have the mechanisms to adjust the accuracy and latency of data transmission in coping with the various QoS requirements for different applications.

8.5.3 Data Storage

This requirement also depends on the applications related to the integration of DER/microgrids with the DMS. The data storage (buffer) in the communication networks needs to be designed properly to account for the data flow features. For example, in protection and control, the quantity of data is usually very small for a fast response, so a very limited amount of data storage may be needed. On the other hand, for prediction or post-event analysis, a large volume of data may be required, and a sufficient amount data storage would thus be needed.

8.5.4 Cybersecurity

The cybersecurity requirements for the communication system can refer to the EPRI report [10] that specifies the cybersecurity requirement for the hierarchical control architecture of DER systems. The DER and microgrids may need to be compatible with the hierarchical control architecture presented in the report.

8.5.5 Interoperability

It is recommended that the new communication protocols to be used comply with the existing standards for distribution systems, including Modbus, SEP2, and IEC 61850. Special attention should be paid to Part 90-7 of standard IEC 61850, which describes the information model for inverter-based DER in the communication networks [11].

8.5.6 Other Requirements

In addition to the requirements discussed above, some others should also be considered. For instance, the communication distance between the individual DER and DERMS determines whether a low-cost, short-range wireless local area network (WLAN) or a high-cost wireless wide area network (WWAN) should be used when the wireless communication medium has been chosen already. Budget constraints will play an important role in choosing which communication medium should be used. This consideration is because wire-based communication has a huge infrastructure cost, whereas a wireless solution may have a large spectrum cost. The physical locations of the DER and DERMS determine the topology of the communication network between the DER and DERMS. In this regard, the communication requirements largely depend on a specific implementation of the DER/microgrid integration with the DMS.

8.6 Integrated Operation of DMS with Microgrids, DER, and DERMS

In the integrated operation of the DMS with DER and microgrids, the objective is not only to enable mutual data sharing for better functionality and performance of tasks but also to achieve better coordination in how the various functions operate in the relatively independent systems. It may be the responsibility of the DMS to set operational guidelines and track the performance of the other systems by monitoring real-time system operational conditions and analyzing the committed operational schedules of the DER and microgrids. Suggestions or warnings may be generated and passed to the corresponding systems for their alerts. Under emergency conditions, the DMS may undertake immediate control actions based on its operational rules in order to contain the problem and keep damage to a minimum before other parties are notified.

The subsections below discuss a few typical issues and approaches to such integration.

8.6.1 Integration Approaches

The integration of the DMS with the DERMS and microgrids can be implemented in many different ways. Listed here are a few sample integration approaches.

8.6.1.1 Integration through ESB

Similar to the integration of the DMS with other connected systems (e.g., OMS, AMI, DRMS), the DMS integration with the DERMS and microgrids can be implemented through an ESB, as shown in Figure 8-2.

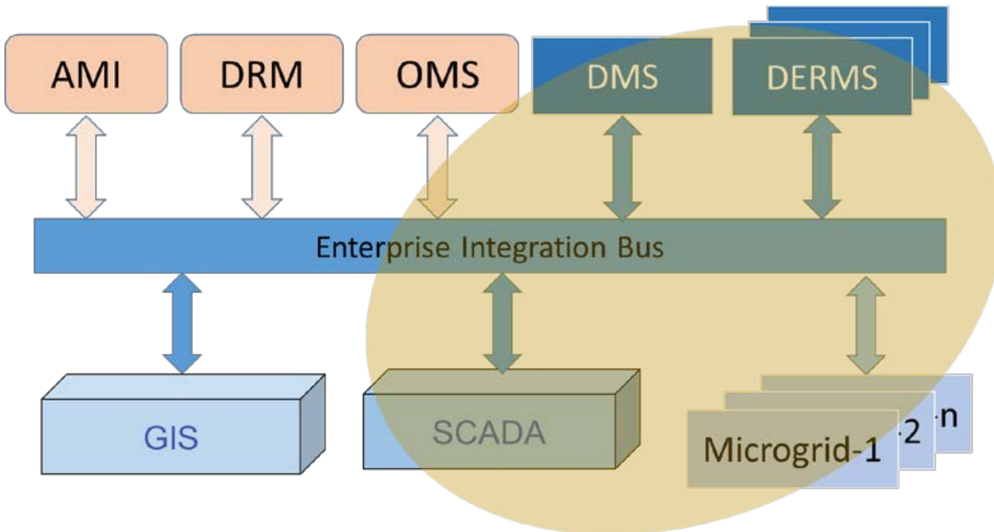

Figure 8-2 DMS Integration with DERMS and Microgrids through ESB

As shown in Figure 8-2, the DMS, microgrids, and DERMS are treated equally from an ESB standpoint, because each system connects to the ESB through its communication system, and because all of the data communication among the systems is through the ESB, with all of the data needed from other systems being available at the ESB.

The MCs and DERMS, as well as the other systems, may not necessarily be in the same physical location as the DMS. As a matter of the fact, the MCs may be installed in the physical locations of the microgrids or be located somewhere else. It may also be the case that one MC controls several microgrids that are far away from each other. Similarly, the DERMS may also be located somewhere other than where the DMS is, such as in a substation, in another city, or even in a cloud server. There could also be more than one DERMS for one DMS. In other words, multiple DERMS could be integrated with one DMS. For example, one DERMS may cover only one substation or a few substations, with each one being independent of the others. On the other hand, one DERMS may partially cover the scope of two or more DMS, assuming that these DMS have no coverage overlaps within the distribution grids.

8.6.1.2 Peer-to-Peer Integration

The integration of the DMS with DERMS and microgrids can also be implemented in a peer-to-peer format through proprietary data communication. In this case, DERMS and microgrids may appear like clients to the DMS, and they may be invisible at the ESB level where the DMS may integrate with the other systems.

8.6.1.3 Embedded Integration

As mentioned in the introductory chapter of this document, the functions of microgrid control systems and/or DERMS may be embedded in the DMS as subfunctions or applications in some implementations. In such cases, the MCs and/or DERMS may be invisible to the external systems. However, the data communication and the base operation rules of the microgrids and

DERMS would remain in the embedded modules. The only difference would be that the physical communication medium would be different. In the embedded case, the physical communication medium may be just simply memory function calls.

8.6.2 More Than One Active PCC in a Microgrid

A microgrid may have more than one active PCC connected to the distribution grid. It may also directly connect to other adjacent microgrids that may have one or more PCC to the distribution grid. The PCC may be on the same feeder circuit, or they may be on different feeder circuits in the same substation or in different substations in the grid. They may form unintentional wheeling paths and hidden loops to the distribution grid if the DMS has not received sufficient information about the internal topologies of the microgrids. It is strongly recommended that microgrids with more than one PCC provide their simplified operation topologies, if not their complete ones, to the DMS to avoid the possible lack of awareness of hidden loops formed by these PCC.

8.6.3 Phase Balancing of DER

As briefly mentioned in Section 8.3.2, inverter-based DER may have their phase power output dispatchable; their power output at each phase can be allocated within the phase limits. This feature can be used to balance some unbalanced local loads. However, it may also cause a further unbalanced condition if the feature is not properly used. For example, if every DER is specified with balanced three-phase power output, and if the loads are actually not well balanced in the feeder circuits, the DER will transfer the total unbalanced portion of the loads up to the distribution substation transformer, resulting in a more unbalanced operation condition. Therefore, it is important to allocate the unbalanced loads properly to the DERs. It may be better to take default settings in order for the DER to behave like the rotational machine-based generators if no good unbalance control logic is available for properly dealing with phase balancing. This approach means that the inverter-based DER are set to operate with balanced three-phase voltages internally.

8.7 Protection Schemes for Microgrids/DER and the Distribution Grid

As discussed in Subsections 2.3.4, 3.8, and 6.8, the penetration of DER and microgrids will have a significant impact on the existing protection schemes in the distribution systems. The following subsections discuss the requirements of protection schemes for maintaining operational reliability with regard to the connections of the DER and microgrids to the distribution grids.

8.7.1 Faults in Microgrids

The protection scheme of a microgrid should be able to detect its internal fault and isolate it quickly before it causes significant impacts on the operation of its internal grid and then on the distribution grid if it is in grid-connected mode. It should disconnect itself from the distribution grid if the fault is observed at the PCC and reaches the predefined criteria for disconnection (e.g., fault direction, current magnitude, and time duration for the directional time-inverse protection scheme).

A backup protection scheme may also be applied by the distribution grid to ensure that the faults that occur in a microgrid can be effectively isolated at the PCC in case its internal protection scheme fails.

8.7.2 Faults in DER

Although DER generally do not have their own local grids, they may have internal circuit faults, and they should have corresponding protection schemes to detect such faults and disconnect themselves from the grid at the PCC when such faults occur.

8.7.3 Faults in the Distribution Grid

The protection schemes in the distribution grid should isolate the faults that are occurring in that grid. However, the microgrids and the DER should also protect themselves from the impacts of grid faults. They should be able to detect the faults that occur at the grid side. The microgrids and DER may implement advanced schemes that can intelligently determine whether they should disconnect from the grid right away or try to "ride though" first before disconnecting.

The grid protection scheme may actively disconnect the microgrids and DER through transfer trips when the corresponding part of the distribution circuits is de-energized. This scheme ensures that the related microgrids and DER are not able to energize the isolated part of the distribution circuits. Of course, the microgrids and DER connected to that part of the distribution circuits should have protection schemes to detect the de-energization and disconnect themselves from the grid automatically.

8.7.4 Distribution Grid Protection with Microgrids and DER Connected

When the microgrids and DER are connected, the fault current contribution will no longer be from a single source but instead from multiple sources and multiple paths spread across the entire distribution grid. The protection schemes have to adapt to this change with corresponding strategies and effective approaches.

The schemes may need to relate to directional protection functionalities, because the fault current at a feeder section could travel in either direction and may need different settings for different directions.

Also, protection coordination in different locations along the distribution feeder circuits may be dynamic or may depend on operational conditions, which could add more complexities to the protection coordination in addition to the directional schemes.

In addition, the protection settings may have to be based on the topology configurations, where a topology change due to a contingency or operational request may result in significant changes to the relay settings.

Moreover, the DER may have significantly different fault characteristics, which largely depend on their energy conversion schemes. Generally, a rotational machine-based DER may have a much higher fault-current contribution than that of an inverter-based DER. Therefore, for the same fault location and the same fault impedance, the fault current at the fault point and the fault current distribution in the distribution grid may vary significantly, depending on what types of DER are active when the fault occurs, where they are located in the grid, and what the grid topology configuration is. These are serious concerns for protection engineers when it comes to distribution grid protection that requires practical solutions.

8.8 Use Cases for the Integration of Microgrid Controller, DERMS, and DMS

Various use cases can be employed to test the integration of the MC, DERMS, and DMS (e.g., frequency regulation, voltage control in grid-connected or islanding operational modes, load management). Some of the use cases can be found in EPRI's report in [1].

9 Summary and Conclusion

This document provides general and practical guidelines for integrating the DMS with microgrids and DER. The fundamental challenges to distribution grid operation posed by penetration of the use of DER and microgrids, the current status of DMS, the basic concepts of microgrids and DERMS, and finally the fundamental principles and strategies for DMS integration with microgrids and DERMS are discussed.

9.1 Challenges and Objectives

Distribution power grids are becoming highly active networks with more DER and microgrid connections. Power flow is no longer static and flowing one way from the substation transformers to the end users, but instead is dynamic and flowing two ways. The changes in power flow direction depend on the operational dynamics of the dispersed DER and microgrids and the distribution of loads along distribution circuits. The microgrids are generally small, independent, local grids with their own loads and generation resources and dedicated controls and operational rules and regulations. Microgrids can operate in a grid-connected mode or an islanded mode with respect to the distribution grids. The individual DER can operate in a way similar to the way that the microgrid operates, but they can also be under a centralized control and management system through a DERMS, which performs aggregated control, management, and optimization of the widely dispersed DER in the distribution circuits. All these features introduce a variety of challenges to be addressed by the DMS, which is responsible for managing and controlling the overall operation of a distribution grid. In order for the various functions to work in harmony to achieve the same operational objectives as those of the distribution grid, there should be common guidelines for implementing and integrating the relatively independent systems by following the same principles and rules for data sharing and information exchange, as well as functional boundaries and responsibilities.

9.2 Current Status of DMS and New Challenges

A DMS may cover an entire distribution grid or only a subset of the system, such as a group of substations of the distribution grid. The DMS generally has full responsibility for the overall operation of the entire grid or part of the grid.

Most of the DMS in operation today are designed to meet operational requirements for the automation and management of traditional distribution grids. The fundamental features of the traditional distribution systems include passive networks and radial configurations. These features are the basic foundation for today's DMS designs and implementations; they include the grid modeling, data structures, and advanced application algorithms. A typical DMS generally consists of several subsystems and software modules. The overall architecture of a DMS with these components may still work fine for a new distribution grid with a high penetration of DER and microgrids; however, the contents of these components may need to be extended significantly or updated by incorporating the impacts of the transition from passive networks to the active networks of the distribution grids.

9.3 DMS Integration with Microgrids

The physical interfaces of a distribution grid and microgrids are at the PCC, which is the boundary between the two types of grids. The DMS is fully responsible for the operation of the distribution grid, and an MC or a control system is fully responsible for its own internal grid. Both parties are responsible for the operation of the PCC when the microgrid is in the grid-connected mode and the transitions from one mode to the other; the responsibilities include maintaining desired voltage profiles, constant power exchange, intentional disconnection and re-connection, mutual emergency support, and protection coordination.

A microgrid may be owned by customers, independent energy providers, the local electric utility, or jointly by any combination of the above. The MC or microgrid control system may be implemented as an independent entity located in a local or remote area (e.g., in a substation, in a remote office, in the DMS control room, or even on a cloud server). It may also be implemented as a subfunction or application of the DMS as a physical part of the DMS. However, the MC or microgrid control system has its own responsibilities, tasks, and functionalities, regardless of where it is located and how it is implemented. Similarly, although the integration of the DMS and microgrid control systems may differ in actual implementations because of their locations and the various implementation approaches, the basic principles and strategies would generally apply, as long as the microgrids were classified as standard microgrids following industry standards as defined in IEEE 1547.

9.4 DMS Integration with DERMS

DERMS is designed to manage and control the individual DER through the aggregation of the dispersed DER that are participating in DERMS management across the distribution grid. It may be that more than one DERMS covers the entire territory of a DMS, with each DERMS being responsible for part of the distribution grid.

Similar to microgrids, a DERMS may be implemented in a substation, in a remote office, in a control room, or even on a cloud server. It may also be implemented as a subfunction or application of the DMS. However, these differences in location and how a DERMS is actually implemented should not lead to different principles or strategies being applied in the implementations. In fact, all of them should follow the common fundamental principles and strategies.

9.5 Protection Schemes

The transition from a passive network to an active network can have significant impacts on and result in challenges to conventional protection schemes, which have largely been based on the features of passive networks and radial configurations of conventional distribution grids.

The new schemes have to deal with two-way power flows that dynamically change from time to time depending on the operational conditions of the DER and the load distributions.

When integrating DMS with DERMS and microgrids, each party needs to account for the corresponding coordination schemes while implementing the tasks and responsibilities of its own scope of protection.

9.6 Design Principles of DMS Integration

This document provides a set of general and fundamental principles for designing how a DMS integrates with DERMS and microgrids. It is based on the key features, characteristics, and impacts of active distribution networks with a high penetration of DER and microgrids. These include the relationships among the systems and their corresponding responsibilities and boundaries in the integration, system modeling, data structures, and advanced algorithms in advanced DMS applications, as well as the coordination of the protection schemes.

The principles and strategies proposed in the guidelines are generic and independent of the physical locations and actual implementation approaches of DERMS and microgrid control systems. They should be applicable to most of the integration implementations, as long as the implementation and operation of the DERMS and microgrid systems follow the industry standards defined in IEEE 1547.

Because DMS applications are being enhanced continuously, there have been some commercial products in the marketplace. For instance, Siemens has proposed a solution for enhancing the performance of the DMS by using three complete sets of advanced power system applications. These can be configured as a stand-alone system or integrated with the existing SCADA/DMS. These three suites of power system applications are called Information Model Manager (IMM), Cyber Security Manager (CSM), and Distribution Network Application (DNA) [13]. Alstom has developed an integrated tool for achieving smart distribution and making critical and timely decisions called the Integrated Distribution Management System (IDMS). In this tool, multiple functions are combined in a single, integrated environment, and a complete solution is provided that covers modeling, secure integration, operations, reliability, awareness, optimization, and other features [14]. Schneider Electric has proposed an advanced DMS solution to consolidate three basic and conventional parts (SCADA, DMS, and OMS). This solution has the advantage of being a single version that can be shared among the three systems; it includes a unique security system, a unique user interface, complete functionalities, closed-loop control and management, advanced protection, and other features [15]. ABB has developed Network Manager SCADA/DMS as a distribution management solution. It achieves the seamless integration of a DMS and an enterprise information system, and it provides a complete model of the electrical network under control. Network Manager SCADA/DMS can effectively manage the operation of a distribution network, and it enhances the information exchange between operators and customers [16].

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10 References

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Appendix A: Distribution Management System Functions

Advanced Distribution Management Systems for Grid Modernization

Distribution Management System Functions

August 2015

Appendix A — Table of Contents

Figures

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A.1 DMS Functions

This report lists the major distribution management system (DMS) application functions and provides a description of each. This list of DMS application functions is based on survey responses submitted by electric utilities that have implemented or are planning to implement a DMS. The list of DMS functions also considers survey responses received from vendors, consultants, research organizations, and academic institutions.

The description of each DMS application includes a list of functional requirements, along with key features and characteristics of each application that are needed in current and future DMS deployments. The description also summarizes major benefits provided by each function to the various stakeholders (e.g., customers, shareholders), with due consideration of the fact that the realizable benefits of each function may be different for each type of utility (e.g., investor-owned utility [IOU], cooperative, and municipal).

The results of this subtask are sufficient to define the functional requirements of each application for system procurement (Request for Proposal [RFP]) purposes and for developing preliminary high-level use cases for each function. However, the document is not a detailed design document that will enable a vendor or software developer to actually design and build the application.

A.1.1 What Is a DMS?

Because there is no widely accepted industry definition for DMS, the IEEE Power and Energy Society (PES) DMS task force has adopted the following definition:

> "A DMS is a decision support system that is intended to assist the distribution system operators, engineers, technicians, managers and other personnel in monitoring, controlling, and optimizing the performance of the electric distribution system without jeopardizing the safety of the field workforce and the general public and without jeopardizing the protection of electric distribution assets."

The following are several key points pertaining to this definition:

- The DMS should be viewed as a tool that assists the distribution system operators in the control center and in the field in performing their duties. The DMS is not intended to replace human judgment and decision-making.
- DMS users are not limited to distribution system operators in the control center and in the field. DMS stakeholders and users also include engineers who may use the DMS for engineering analysis and studies, technicians who may use the DMS for troubleshooting and maintenance, and managers who may use the DMS for oversight and overall decision making support.
- The DMS should play a key role in improving (optimizing) the efficiency, reliability and overall performance of the electric distribution system. Optimizing distribution system performance is often the primary motivator for DMS deployment. Advanced applications that assist in determining operating actions needed for improved performance are one of the key distinguishing factors of the DMS.

- The two most fundamental operating objectives—safety and asset protection—must never be compromised by the desire to improve performance. In fact, the major driving factors for DMS deployment often include *improving* safety and asset protection.

A.1.1.1 DMS Basic Building Blocks

The DMS concept is best described by looking at the component parts or basic building blocks that make up the DMS.

A.1.1.1.1 Distribution SCADA System

The foundation on which DMS is based is the distribution supervisory control and data acquisition (DSCADA) system (see Figure A-1). The DSCADA system provides the "field-facing" interface that enables the DMS to monitor the distribution field equipment in real-time (measurements made and reported in 1 minute or less on average) or near-real-time (measurements made and reported every 10 to 15 minutes on average). DSCADA also enables the DMS to initiate and execute remote control actions for controllable field devices in response to operator commands or application function control actions. Examples of control actions include opening/closing a medium voltage line switch, raising/lowering a voltage regulator tap-setting, and switching a capacitor bank on or off.

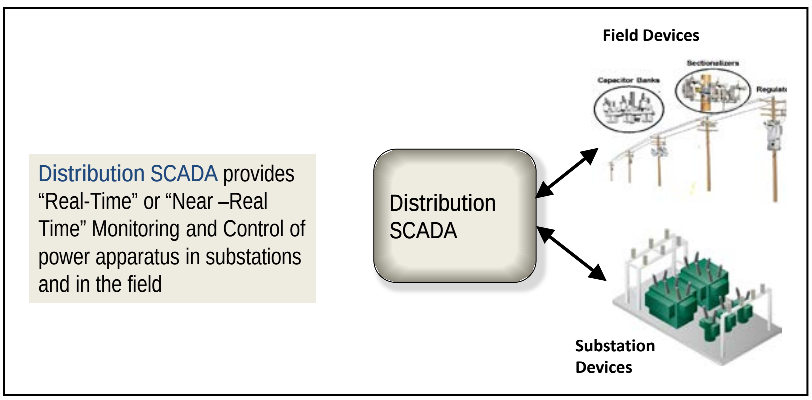


Figure A-1 Distribution SCADA System

The degree to which distribution field devices are monitored and controlled by DSCADA varies widely from utility to utility. Many utilities have implemented DSCADA facilities for their electric distribution substations. However, far fewer utilities have implemented continuous monitoring and control of power apparatus that is installed out on the feeders themselves (outside the substation fence). A growing number of electric distribution utilities are currently implementing DSCADA for feeder devices as part of their grid modernization strategy. The ability to monitor and control feeder devices, such as automated line switches and reclosers, switched capacitor banks, and voltage regulators, and the ability to continuously monitor stand-alone distribution sensors (e.g., faulted circuit indicators [FCIs], current/voltage sensors) are seen as essential for improving the overall performance of the distribution system.

As the penetration level of distributed energy resources (DER) (distributed generators, energy storage devices, and controllable loads) continues to grow, these devices will have a significant impact on overall distribution system performance. As a result, continuous monitoring and control of these DER may be needed. An approach to DER monitoring and control that is being researched by the Electric Power Research Institute (EPRI) and other research organizations is the concept of a DER management system (DERMS) which handles the direct interface to DER rather than DSCADA for monitoring and control purposes. The DMS will obtain DER-related information as needed via enterprise system integration techniques such as enterprise service bus (ESB). Figure A-2 illustrates the separation of DSCADA and DERMS functionality for field device monitoring and control.

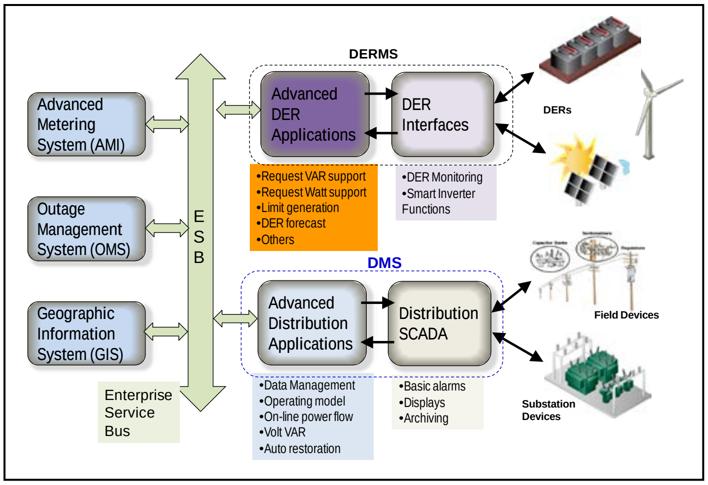


Figure A-2 Separation of DSCADA and DERMS Functionality

Field-facing interfaces to other grid modernization devices, such as plug-in electric vehicles (PEVs) and advanced metering infrastructure (AMI), are expected to be handled in much the same manner as DER. That is, the interface to advanced customer meters will most likely be handled by a meter data management system (MDMS), which exchanges data as needed with DMS via ESB or other integration technique. Similarly, the interface to PEV charging infrastructure may be handled by an electric vehicle management system (EVMS).

The DSCADA building block may also include some additional basic functionality, such as simple alarm checking, graphical user interface (GUI) for viewing data (tabular and schematic displays), and data archiving. However, more advanced functionality, such as geographic displays and distribution system modeling, are usually not considered part of DSCADA.

A.1.1.1.2 Advanced Distribution Applications

The next major DMS building block includes the advanced distribution applications which use the information acquired by DSCADA to improve overall distribution system performance. Advanced applications build on DSCADA monitoring and control capabilities to provide electronic decision-making and automatic control capabilities for system “optimization.”

Advanced distribution system applications that determine control actions needed to optimize distribution system performance execute control actions via DSCADA. Adding advanced distribution applications provides a clear distinction between DMS and DSCADA. Figure A-3 shows the interaction between the advanced applications and DSCADA building blocks.

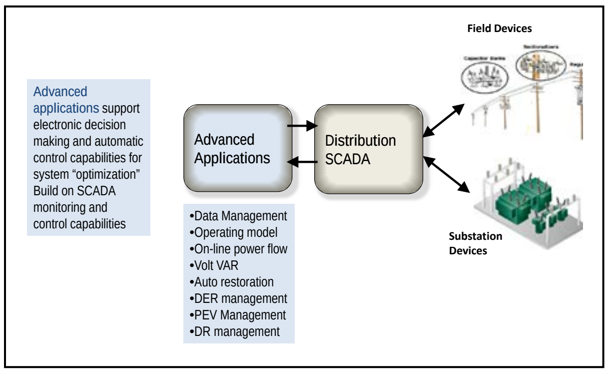


Figure A-3 Interaction between Advanced Distribution Applications and DSCADA

Examples of advanced distribution applications that are often included in this DMS building block are listed below. Note that this is just a partial list of the DMS advanced application suite. More detailed descriptions of these application functions are provided later in this report.

- ***Distribution System Model***. An electrical representation of the physical characteristics and topology (connections between devices) of the electric distribution system. The distribution system model may also include customer loading characteristics. The distribution system model is a key application that enables many of the other DMS applications.
- ***Geographical User Interface***. The DMS application suite almost always includes a geographically correct GUI. For example, the DMS is usually able to show feeder map style displays with dynamically updating real-time and near-real-time information superimposed on the map displays.
- ***On-Line Power Flow***. The on-line power flow (OLPF) advanced application uses the distribution system model and available DSCADA data to compute the electrical conditions at any point on the feeder, including points that are not equipped with physical monitoring facilities. The OLPF is one of the most important DMS application functions because it enables numerous other applications, such as switch order management and Volt-VAR optimization, to operate.

- ***Switch Order Management (SOM).*** SOM enables the distribution system operators and operations support staff to create and validate switching orders needed to isolate portions of the distribution system that are being repaired or maintained while providing electrical service to as many customers as possible.
- ***Volt-VAR Optimization (VVO)***. This application identifies a coordinated set of control actions for distribution voltage regulators and VAR control devices that are needed to achieve utility-specified operating objectives (e.g., improve voltage profile, reduce electrical losses, lower demand, and promote energy conservation).
- ***Optimal Network Reconfiguration (ONR)***. This application identifies a set of line switching actions that will enable the electric utility to achieve better load balance between interconnected feeders, improved voltage profile, or other utility-specified objective functions.
- ***Predictive Fault Location (PFL)***. This application uses fault magnitude from substation intelligent electronic devices (IEDs), along with the distribution system model, to predict the probable fault location, thus enabling more precise dispatching of field crews, reduced fault investigation time, and faster service restoration.

A.1.1.1.3 Interfaces to External Systems

Another important DMS characteristic is the integration of advanced distribution applications and DSCADA facilities with other corporate enterprise systems, such as the geographic information system (GIS) and the outage management system (OMS). Figure A-4 shows the addition of corporate enterprise integration facilities to the set of DMS building blocks.

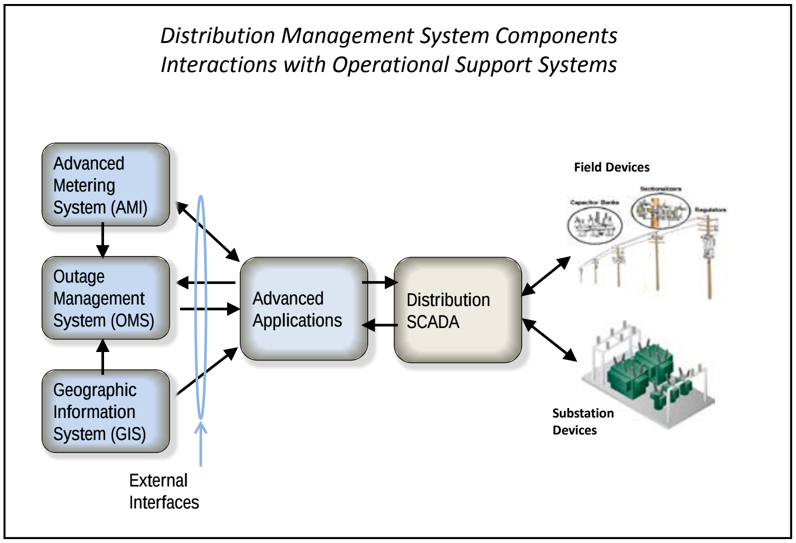


Figure A-4 Corporate Enterprise System Integration

The purpose of each interface is summarized briefly below:

- ***Geographic Information System (GIS).*** The GIS is a data repository containing detailed information about the electric distribution "physical" assets (e.g., poles, conductors, transformers, line switches, capacitor banks, and voltage regulators). The detailed information typically includes information about the physical characteristics and electrical characteristics (e.g., electrical impedance, efficiency) of each device along with the geographic location (latitude and longitude) of each device. This information is used to construct and maintain the distribution system model used by many advanced DMS functions. The GIS is also used to build and maintain a similar model used by the OMS. Note that the OMS version of the model usually contains only the feeder topology, not the electrical impedance and other information needed to run a load flow.
- ***Outage Management System (OMS).*** The OMS performs many essential functions to assist distribution system dispatchers when customers are experiencing service interruptions. One of the key OMS functions is "fault location prediction." The OMS applies individual customer outage telephone calls (or, more recently, "last gasp" messages from AMI meters) to its distribution system model to determine which calls/messages appear to be related to the same outage event. After the calls/messages have been grouped, the OMS uses the model to search "upstream" (closer to the substation) to determine which fault interrupting device operated for this event. This information is used to direct field crews to the approximate location of the root cause of the outage event. The OMS often includes facilities for dispatching first responders and field crews to the outage location for fault investigation, damage assessment, and repairs.
- ***Meter Data Management System (MDMS).*** The MDMS is responsible for acquiring and processing readings from AMI meters. MDMS is primarily intended to support the revenue billing process. However, MDMS may support a myriad of additional functions such as theft detection, outage detection ("last gasp" messages), service restoration verification, and transformer load management (TLM). DMS advanced applications have many potential uses for AMI data, such as accurate determination of customer loading on a near-real-time basis. The AMI system may also be used to implement DR actions and execute other customer load control actions. To date, AMI data resources are, for the most part, a largely untapped resource for advanced applications beyond revenue billing.

Note that GIS, OMS, and MDMS are just a few of the corporate enterprise systems that are included in the DMS architecture.

A.1.2 DMS Application Functions

The following DMS application functions are included in this report:

- Data acquisition and control
- State estimation (SE)
- Graphical user interface (GUI)
- Historical information system (HIS)

- Distribution system model
- Load models
- Topology processor (TP)
- On-line power flow (OLPF)
- Intelligent alarm processing (IAP)
- Tagging, permits, and clearances
- Short-circuit analysis (SCA)
- Switch order management (SOM)
- Volt-VAR optimization (VVO)
- Fault location, isolation, and service restoration (FLISR)
- Predictive fault location (PFL)
- Optimal network reconfiguration (ONR)
- Short-term load forecasting (STLF)
- Dynamic equipment rating
- DMS control of protection settings
- DER management
- Demand response management (DRM)
- Emergency load shedding (ELS)
- Electric vehicle charging
- Asset management (AM)
- Engineering analysis
- Dispatcher training simulator (DTS)

A.1.3 Data Acquisition & Control

The foundation on which DMS is based is the DSCADA system (see Figure A-1). The DSCADA system provides the "field-facing" interface that enables the DMS to monitor the distribution field equipment in real-time (measurements made and reported in 1 minute or less on average) or near-real-time (measurements made and reported every 10 to 15 minutes on average). DSCADA also enables the DMS to initiate and execute remote control actions for controllable field devices in response to operator commands or application function control actions. Examples of control actions include opening/closing a medium voltage line switch, raising/lowering a voltage regulator tap-position, and switching a capacitor bank on or off.

The DMS should be able to acquire analog inputs (continuously varying signals) and status inputs (signals that have a limited number of valid states). At a minimum, the following types of analog input points should be implemented:

- Voltage magnitude measurements,
- Current magnitude measurements,
- Active power measurements,
- Reactive power measurements, and
- Transformer load tap changer (LTC) position.

The following types of status input points should be implemented (at a minimum):

- Circuit breaker, recloser, and switch status (open or closed), and
- Shunt capacitor switch statuses.

The DMS data may be acquired from a variety of data sources, including (but not limited to):

- ***Substation SCADA Remote Terminal Units (RTUs).*** The DMS may acquire information about substation equipment (e.g., transformers, circuit breakers, and voltage regulators) via a direct connection to substation RTUs, data concentrators, or equivalent devices.
- ***SCADA facilities Associated with Field Devices***. Some field devices located outside the substation fence may be equipped with local controllers, RTUs, and/or internal SCADA communication cards that can support DMS data acquisition functions.
- ***Distributed Line Sensors.*** The DMS should be able to acquire real-time information from stand-alone sensors located out on the distribution circuits. Examples of stand-alone sensors include FCIs, line post sensors, and bellwether meters.
- ***AMI Meters.*** Some DMS information may be acquired from AMI meters installed at selected field locations (such as the substation end of the feeder) and selected customer premises.

The DMS should use a report-by-exception philosophy. Only the specified data that have changed by a stated amount should be transferred at any given time. The DMS should also include an “integrity check” feature that transfers the entire dataset at specified intervals.

The DMS should be able to control power system apparatus located at distribution substations and field locations (out on distribution feeders). The controlled power apparatus should include substation circuit breakers and reclosers, field reclosers, switched capacitor banks, voltage regulators, and other primary and secondary voltage equipment. The DMS should also be able to initiate load shedding of selected customers via the AMI system or a separate load management system.

The degree to which distribution field devices are monitored and controlled by DSCADA varies widely from utility to utility. Many utilities have implemented DSCADA facilities for their electric distribution substations. However, DSCADA is often not available at small (single transformer, single feeder) substations, especially substations that are very remote and lack suitable communication facilities.

Far fewer utilities have implemented continuous monitoring and remote control of power apparatus that is installed out on the feeders themselves (outside the substation fence). The ability to monitor and control feeder devices such as automated line switches and reclosers, switched capacitor banks, and voltage regulators, and the ability to continuously monitor stand-alone distribution sensors (e.g., FCIs, current/voltage sensors) are seen as essential for improving the overall performance of the distribution system. As a result, a growing number of electric distribution utilities are currently implementing DSCADA for feeder devices as part of their grid modernization strategy.

Real-time or near-real-time monitoring and control of distribution assets are essential for implementing many of the advanced DMS functions, thus DSCADA should be added to most (if not all) of the distribution substations. Furthermore, monitoring and control of assets located out on the feeders themselves will be needed by many applications. Phased implementation of these facilities is recommended because it is not practical to deploy DSCADA at all locations all at once due to limited technical and financial resources. To maximize payback of the investment, many electric distribution utilities implement DSCADA facilities on “worst performing” feeders first (i.e., highest losses, less than average reliability, etc.), followed by the remaining feeders.

The AMI system is also expected to be a key source of near-real-time data, such as voltage measurements and alarms, which will supply valuable feedback to DMS applications such as VVO/conservative voltage reduction (CVR). Load measurements will also be needed to build and maintain load profiles that are used for load allocation and estimation; however, these data are not required on a near-real-time basis.

Implementing the necessary facilities for data acquisition and control is essential for DMS implementation success. This will be an important element of the DMS Roadmap.

A.1.4 State Estimation

An accurate insight into the distribution network’s current state under normal and emergency (outage) conditions is essential for managing the distribution networks. Typical DSCADA deployments only cover the high-voltage/medium-voltage (HV/MV) substations. As stated in the previous section of this report, few (if any) measurements are available for out on the feeders themselves (outside the substation fence). The lack of distribution data is the primary motivation for the application of distribution SE.

DSE is used for determining approximate values of the loads at all network nodes and assessment of other state variables, including voltage and current phasors (magnitude and angle) for all distribution circuit buses, sections, and transformers, active and reactive power losses in all sections and transformers, and other such electrical quantities.

The load estimation or calibration DMS application function evaluates the symmetrical (per phase) and asymmetrical (three-phase) load of all nodes in the distribution network that are not remotely monitored by the DSCADA system. Then, a standard load flow calculation can be performed.

DSE is a basic (“enabling”) DMS function, because practically all other DMS analytical functions require the DSE results to perform their calculations. DSE computes the “unobservable” load of the actual network, which is not directly covered by the DSCADA system.

The DSE function should use an algorithm specially designed for distribution networks, which have low redundancy of real-time, remotely monitored data. In addition to the physical and electrical parameters of network elements, the real-time data required by the DSE function should include:

- Feeder topology, transformer, and voltage regulator tap changer position,
- Voltage magnitudes at the head end (substation end) of the feeder, and
- Current magnitudes (active and reactive power) at the head end of the feeder and at mid-line points along the feeder.

Because real-time measurements are not available at all points on the feeder, historical data may be used to compensate for the lack of real-time data. The historical data consist of:

- Daily load profiles (current magnitudes and power factors, or active and reactive powers) for all load classes (industrial, commercial, and residential), for all seasons (winter, spring, summer, and autumn), and for four types of days (weekday, weekend, and holiday).
- Peak-loads for all distribution transformers and/or consumers (peak-currents and/or peak power).

The DSE function should be available in both real-time and study mode. In real-time mode, the function is used to estimate the current state. In the study mode, the function is used to estimate the desired state (e.g., any state selected from the saved cases).

A.1.5 Graphical User Interface (GUI)

Distribution system operators and other authorized personnel should be able to interact with the DMS via PC-based workstations installed at the system control centers and various offices. Figure A-5 depicts typical control center workstations.

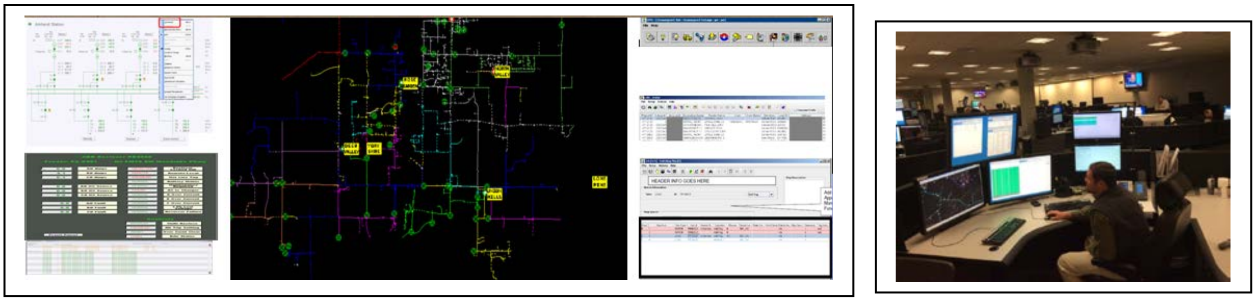


Figure A-5 DMS User Workstation

The DMS user interface should allow authorized personnel to view measured and calculated real-time, near-real-time, and historical data values to initiate control actions (with suitable security limits and controls) and to interact with the DMS applications as needed. The DMS should also include facilities to provide secure, view-only capability to authorized users located outside the control center.

The DMS user interface should be a workstation-based, full-graphic display product. Full GUI features should include panning, zooming, and declutter levels to allow the user to control the viewable area of the "world space" on the display.

The DMS should include areas of responsibility (AORs) that should provide the means to route alarms, restrict supervisory control, and restrict data entry to those personnel having the associated responsibility and authority for the respective area. It should be possible to assign responsibility for portions of the distribution system to individual consoles by pre-defining groups of AORs and assigning them to different consoles in the control room.

Convenient mechanisms should be provided to enable the user to request specific displays and navigate between displays. The amount of typing and the number of mouse clicks (e.g., cursor target selections) needed to request any specific display should be minimized.

The DMS should include a variety of display types to support the visualization requirements of the DMS applications. At a minimum, the DMS displays should include:

- One-line ("schematic") diagrams showing the configuration, status, and loading of the distribution feeders, substations, and other power system facilities.
- Substation one-line ("schematic") diagrams showing the configuration, status, and loading of the utility's internal substation configuration.
- Schematic diagrams for distribution field equipment (outside the substation fence). These displays should be generated automatically by the DMS on demand using geographically formatted displays of field information obtained from the GIS.
- Map-style displays showing properly scaled and geographically correct depictions of the utility's distribution lines overlaid on street maps. It should be possible to view dynamic data, such as the open/closed position of each switch, the energization status of each

device, and the loading of all equipment, on these displays. Figure A-6 contains a comparison of traditional “schematic” displays with todays “geographically correct” map style displays.

- Switch-gear one-line (“schematic”) diagrams showing the fusing and switching configuration, status, and loading of the internal switchgear configuration.

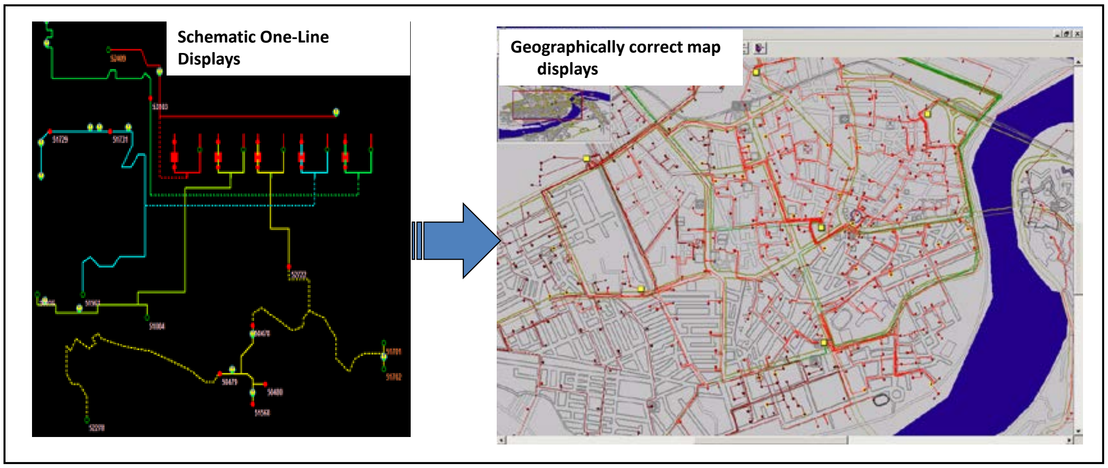


Figure A-6 DMS Graphical Displays

A.1.6 Historical Information System (HIS)

The DMS should include a HIS to store and retrieve system variable values, alarm and event messages, power system disturbance reports, and other calculated or acquired information. Real-time information shall be stored in the HIS on a periodic basis at user-specified intervals and also on an “exception” basis when a variable changes by a user-specified amount since the last time it was stored. Information associated with events, such as an alarm or power system disturbances, shall be stored whenever such events occur.

As a minimum, the following types of data shall be stored in the HIS:

- A complete set of all system variables stored at least once per hour and on exception;
- All supervisory and automatic control actions initiated via the DMS;
- All alarm messages and return-to-normal messages;
- Sequence of events logs;
- DMS event messages, such as processor restarts and communication error messages; and
- System journals that record security-related events, including changes in permissions as defined by the system administrator

The stored data should be time/date stamped to enable the historical retrieval functions to select the desired subset of data. Data quality and alarm condition tags should also be stored along with the value of each system variable.

The DMS should include two storage media for historical data—on-line data storage and off-line (archive) storage. Data retrieval functions should be capable of accessing the data from on-line and archive storage. All historical data should initially be stored in on-line storage. Data should be automatically transferred from on-line storage to archive storage on a periodic basis at a user-specified interval. It should also be possible to transfer the contents of on-line storage to archive storage on demand. The DMS should be capable of archiving at least 1 year of HIS data.

The HIS should enable users to access the HIS database via ad hoc queries and to produce reports using standard relational database management system (RDBMS) report software.

Users should be able to retrieve selected data items for specified time/date intervals and display the retrieved data in a variety of formats, including tabular reports and trend charts. It should be possible to perform user-specified calculations on any historical data item that has been retrieved from the HIS database.

The DMS vendor is often able to furnish its own HIS. However, it is common industry practice to use a commercially available software package (e.g., OSIsoft PI) for this purpose.

A.1.7 Distribution System Model

Many of the advanced DMS applications require an accurate three-phase electrical model of the distribution system that represents the exact physical and load characteristics of the distribution grid. This model allows the DMS to compute electrical conditions at feeder locations that do not have any instrumentation. The model should encompass the entire distribution system from the point of connection to the transmission system down to the customer meter (Figure A-7).

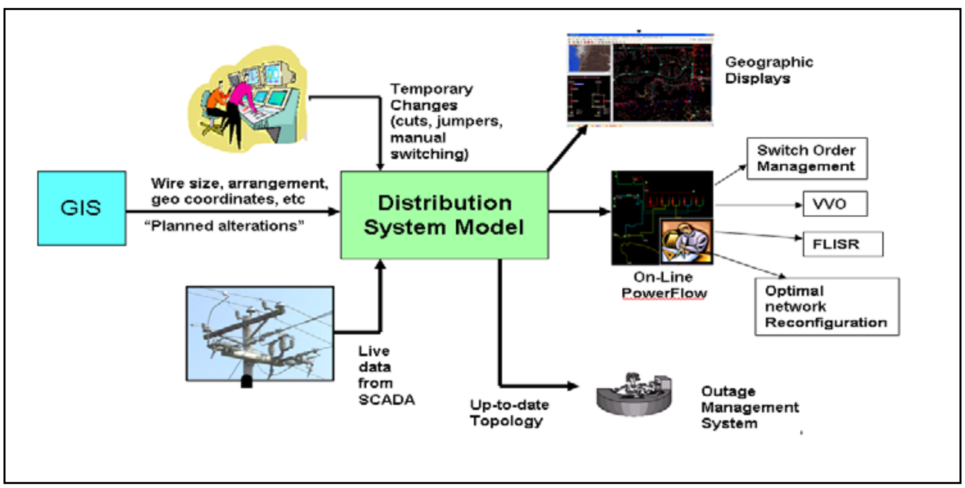


Figure A-7 Distribution System Model

The distribution system model must accurately represent the unbalanced characteristic of electric distribution systems (i.e., different impedance, load, and generation on each phase of the three-phase distribution system). This model also must enable analysis of radial (single source) and networked (multi-source) distribution systems.

Several variations of the model are needed:

- An *as-built* model that represents the normal configuration of the system;
- An *as-operated* model that represents the current configuration of the system, including any temporary modifications (e.g., temporary switching, cuts, and jumpers); and
- An *as-planned* version of the model to ensure that planned facilities are quickly added to the model when the utility company energizes these devices.

The DMS should include facilities for seamlessly importing this model from corporate GIS data. The incremental update process to bring model changes into the DMS should be handled via electronic transfers with no manual copying and hand-drawn updates. In addition, the model changes should be brought into the DMS with no downtime for the system in a manner that is transparent to the distribution system operator.

The DMS should include a detailed, up-to-date electrical and connectivity model of the electric distribution system as required by the DMS applications. There should be only one DMS model of the system used by all DMS advanced applications, such as OLPF and short-circuit analysis (SCA).

The DMS distribution system model should represent the entire distribution network that includes distribution feeders and distribution substation devices from the high-voltage side of the substation transformer (including the high side circuit breaker) down to the low-voltage (secondary) side of the distribution service transformers. The DMS distribution system model should be a three-phase model that fully represents the unbalanced nature of the distribution system. The electrical model should include the entire distribution primary circuit, including main line portions of the circuit, feeder laterals, and underground loops that are tapped off the main trunk of the feeder. The distribution system model should accommodate three phase portions of the feeder as well as single-phase and two-phase line segments and laterals.

The distribution model should include the "physical" characteristics of the circuit and the loading characteristics, as described below. The DMS shall provide proper handling of "underbuilds" identified by GIS. Underbuilds occur when:

- Distribution lines are on the same poles as transmission wires (which are not modeled in the same distribution GIS database), and
- Two or more distribution primary lines are on the same pole (parallel circuits).

While most feeders are radial in nature (i.e., there is one and only one path leading from a single feeder source to any point on the feeder), the DMS distribution system model and associated application software shall be able to handle looped and weakly meshed feeder configurations, circuits operating in parallel, as well as secondary networks.

Some electric distribution utilities have considered modelling the secondary portion of the distribution circuit between the distribution transformer and the customer meter. By explicitly modeling the secondary (120/240 V) circuits, the electric utility is able to accurately determine the voltage drop from the load side of the distribution transformer to the load. Some DMS vendors estimate the voltage drop based on the estimated loading of the distribution transformer and then look up the voltage drop using an optional pre-defined schedule (for each load category). For example, if the distribution transformer is currently loaded to 80% and a voltage drop schedule has been provided, the voltage drop schedule may indicate that the voltage at the customer service entrance (load) is 1.5% lower than the OLPF-solved transformer secondary voltage. The ability to calculate voltage down to the meter/service entrance of the customer is most important with respect to not over-stepping VVO voltage reduction for demand minimization or CVR.

The transmission or subtransmission source(s) at each distribution substation may be represented by an infinite bus with dynamic source voltage angle and magnitude supplied by the EMS state estimator function used by the transmission operator. The equivalent impedance of the external network, as seen from the high-voltage buses of distribution substation buses, should be provided. Note that the equivalent impedance of the transmission grid is not a fixed number; it varies with generating unit commitment and status of key transmission system components. Therefore, in order to obtain accurate SCA results (required for predictive fault location [PFL]), the equivalent impedance of the external network must be dynamically updated as system conditions vary.

Generators such as co–generators, non–utility generators (NUGs), independent power producers (IPPs), and other similar units should be modeled. Generators should be designated as either constant real power/constant voltage units (PV units) or constant real power/constant power factor units (PQ units). Generator active and reactive power limits should be modeled by generator capability curve. In addition to synchronous reactance, the generator model should also include sub-transient and transient reactances required for SCA.

To the fullest extent possible, the distribution system model should be created and maintained with little or no manual intervention. The primary source of field (outside the fence) information for the model should be the GIS. The sources of information for the distribution substation portion of the distribution system model may include other non-GIS sources. Manual entry may be needed to build the necessary substation models if this information is not available via an accessible electronic mechanism.

The GIS should provide some basic “physical” information about each circuit, such as wire size and type, arrangement of conductors, height of conductors above ground, and section length. The DMS, in turn, should calculate resistance and reactance (including all significant mutual impedances) from these basic physical parameters. The GIS should also provide information about the sizing and physical characteristics of other field components such as line capacitor banks, voltage regulators, and distribution service transformers. Underground cables should be modeled to include the cable impedance as well as charging admittance. The position of the individual cable in the ducts and manholes should be provided from the GIS.

The DMS should support incremental model changes. That is, when a small permanent change to the distribution system occurs, it should be possible to update only those portions of the distribution system model that are affected by the change. It should not be necessary to rebuild the entire model for each change in equipment and configuration. The DMS should be able to perform incremental builds on a per-feeder basis.

The DMS should provide a convenient mechanism for installing temporary changes to the electrical model. It should be possible to change the open/closed position of a switch whose status is not automatically telemetered ("pseudo" point). In addition, the DMS should support the addition of temporary cuts and jumpers (including jumpers between individual phases; must be able to temporarily jumper between conductors that are normally connected to different phases). The DMS should allow an operator to change the network model to show a feeder being cut, grounded, or attached (jumpered) to another feeder or phase.

When the repair is completed, it should be possible to back the change out and return the network model to its original state. All such changes should be automatically reflected in the DMS model. The DMS should provide information about all such temporary changes to the utility's OMS.

A.1.7.1 Modeling the Transmission System

A portion of the transmission grid that supplies each substation may also be modeled, especially if the utility company that owns and operates the substation and distribution resources also owns and operates the supply lines. However, in most case, the transmission grid is not modelled to any great extent.

Typically, the transmission grid is modeled with an impedance that represents the Thevenin equivalent of the transmission grid, including all generators that are currently connected to the grid and running. The accuracy of the transmission equivalent impedance is very important because it is needed to compute the short circuit current for faults that occur on the distribution system. Short circuit current is (in turn) used by the PFL application that runs in the DMS.

The equivalent impedance is not a fixed value; it is different for every point of connection to the transmission system. The transmission system equivalent impedance at any point of connection may vary with time as central generators are committed and decommitted. When a large central generator is taken off line, the equivalent impedance will increase because the short circuit contribution of that large generator is removed and as major transmission line switching occurs.

The distribution system model shall include an equivalent impedance for each transmission point of connection that is obtained from the transmission operator. The equivalent impedance values must be dynamically updated to reflect changes in major generator status and transmission line status.

A.1.7.2 Modeling the Substations

The electrical characteristics of each substation component and the connections between components must be accurately represented in the electric distribution model. Substation assets are usually not in the electric utility's GIS. Therefore, the substation models required by DMS must be obtained from a different source, such as the electric utility's EMS, or must be built from scratch using the DMS vendor's model-building software. Fortunately, changes to substation assets are much less frequent than distribution feeder changes, so it is usually practical to manually build and maintain the substation models.

A.1.7.3 Modeling the Distribution Secondary Circuits

Most electric distribution companies elect not to model the secondary portion of their electric distribution feeders from the low side of the distribution service transformer down to the customer meters. This practice is mostly due to the lack of accurate information about this portion of the circuit.

Despite the lack of an accurate model of the secondary portion of the circuit, analysis of the secondary circuit is important, especially for utilities that are planning to implement CVR. To gain the maximum possible CVR benefit without causing low-voltage violations for any customer, it is necessary to determine the service delivery voltage at each meter. Ideally, voltage feedback would be provided in the form of instantaneous voltage measurement provided by smart meters. However, it is not practical to obtain near-real-time voltage measurements from every meter due to the enormous burden this would place on the AMI meters and associated communication infrastructure.

It is possible to obtain near-real-time measurements from a subset of meters that are located at sites that are likely to have the lowest voltage on the feeder. These locations include feeder extremities that are farthest from the substation, end points of heavily loaded branches, and the source side of midline voltage regulators. However, research has shown that the lowest voltage along a feeder varies widely with time, and that the number of meters that have the lowest voltage on the feeder at least one time during the course of the year numbers in the hundreds. While the number of metered points is less than monitoring all meters in near real time, this approach will still place an enormous burden on the AMI meters and associated communication infrastructure. Furthermore, if the feeder is reconfigured for any reason, hundreds of different metered locations may suddenly become candidates for the lowest voltage on the feeder.

Without an accurate measurement or calculation of the lowest feeder voltage at any time, the utility company will need to provide more operating margin to ensure that the voltage does not go below the minimum at any location on the feeder. From the standpoint of CVR, this will limit the amount of voltage reduction that can be performed, and therefore reduce the maximum possible savings.

Many electric utilities have elected to approximate the voltage drop between the modeled portion of the distribution feeder and the customer meter. The simplest approach is to assume a default voltage drop on the secondary circuit. But the assumed value of voltage drop can be very approximate, because this voltage drop may vary between 2 and 6 V (on a 120-V basis). So once again, the method is not that accurate and, accordingly, a bigger operating margin must be used to prevent violating the minimum voltage level.

A refinement of this approach is to estimate the voltage drop based on the OLPF-calculated loading of the distribution transformer and then look up the voltage drop using a pre-defined voltage drop schedule (for each load category). For example, if the distribution transformer is currently loaded to 80% and a voltage drop schedule has been provided, the voltage drop schedule may indicate that the voltage at the customer service entrance (load) is 1.5% lower than the OLPF-solved transformer secondary voltage. This approach improves the voltage drop calculation but is still only an approximation that requires a bigger operating margin.

Since it is not practical to measure and report instantaneous voltage at every smart meter, the next best accuracy can be obtained by modeling the secondary portion of the distribution circuit from the low side of the distribution service transformer down to each customer meter. By explicitly modeling the distribution circuits, the voltage drop from the load side of the distribution transformer to the load is more accurate, and the operating margin on voltage reduction can be smaller resulting in more voltage reduction benefits.

Calculation of voltages on the secondary circuit will provide a clear view of effects on any Volt or volt/VAR control. The secondary circuit model will enable the utility to analyze the effects of performing load control applications through AMI, such as turn on/off air-conditioners, water heaters, and pool pumps.

Modeling the secondary portion of the distribution feeder can significantly improve possibilities for more accurate fault location following trouble calls. The benefit in this case would be reduction in fault investigation time which, in turn, translates to reliability improvement and labor savings.

Another possible benefit of modeling the secondary circuit is the analysis of the effects of rooftop solar on power flow and secondary circuit voltage. While many utilities do not expect a high penetration of DG on their distribution feeders in the near future, it is possible to have clusters of DG units in certain areas that can produce unacceptable electrical effects.

Modeling the secondary circuit will also provide more accurate calculation of electrical losses. This information can be used to target worst-performing feeders for circuit improvements. More accurate loss calculations can also help identify feeders where a significant amount of electricity theft is occurring.

At a minimum, the utility company should model the secondary circuit in areas where high penetrations of rooftop solar are expected, and also in areas where high deployment of EV charging vehicles are expected.

A.1.7.4 Load Models

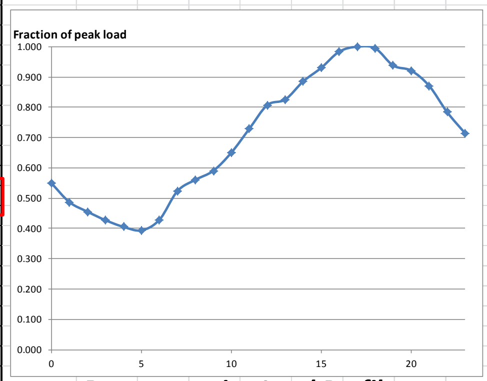
The DMS should include a mechanism to estimate the load on each distribution service transformer at a particular point in time. The Load Allocation and the Load Estimation functions should provide the best estimate of kW and kVAR levels to the OPLF program. It should be possible to use the Load Allocation and the Load Estimation function in both real-time and study mode.

The DMS load allocation function should support the use of historical load curves (“load profiles”) that represent the characteristics of load types served by the utility. The load profile for each load type should include the percentage of peak load at 15-minute intervals throughout the day plus a peak-load value for this customer type. Figure A-8 shows a representative load profile. To calculate the estimated load at any time of day, the percentage of peak-load at that time of day taken from the load profile is multiplied times the peak-load.

For the sample load profile shown in Figure A-8, to determine the load at 10 a.m., the percentage of peak-load at that time (0.650) should be multiplied times the peak-load for the day (1.753 kW) to determine an estimated load of 1.14 kW.

Hour of Day	Fraction of peak load
0	0.549
1	0.487
2	0.455
3	0.427
4	0.405
5	0.394
6	0.429
7	0.523
8	0.561
9	0.590
10	0.650
11	0.729
12	0.807
13	0.826
14	0.886
15	0.930
16	0.983
17	1.000
18	0.995
19	0.938
20	0.921
21	0.871
22	0.784
23	0.714

Peak Load 1.753 kW



Representative Load Profile

Figure A-8 Representative Load Profile

Load types supported by the DMS should include different “conforming” loads (i.e., loads with a profile that matches the utility’s load survey data) and “non-conforming” loads (i.e., loads with a unique profile that is significantly different than the utility’s “standard” load profiles). Conforming load classes should include numerous load types that go well beyond the basic residential, commercial, and industrial load types. For example, supported load types may include:

- Agriculture – Commercial
- Agriculture – Residential
- Mining

- Educational Service
- Residential – High-Rise Apartment Common (electric heat)
- Residential – High-Rise Apartment Common (non-electric heat)
- Residential – High-Rise Apartment Suites (electric heat)
- Residential – High-Rise Apartment Suites (non-electric heat)

Load profiles should consist of a pair of real power and power factor (or reactive power) for each load interval (15 minutes). Load interval size should be configurable (e.g., 5, 15, or 30 minutes). The DMS should interpolate between load survey points to determine load values at intermediate points between points on the curves. For example, with hourly load survey data, half hourly data points should be the average of the two adjacent hourly points. The DMS should include a different set of load profiles for each season (winter, spring, summer, and fall) and for different types of days (weekday, weekend, and holiday). The number of seasons and day types should be configurable to satisfy the utility's specific needs.
Traditionally, load profiles have been built by performing statistical load surveys for each rate class, and these load profiles remain fixed until the next load survey. Utilities that have implemented AMI should use actual billing data from AMI meters to construct load profiles that will be considerably more accurate than the traditional load profiles. The DMS should update its load profiles on a monthly basis or more often using AMI data.

The DMS should be capable of using actual near-real-time distribution transformer loading measurements acquired from an AMI system or a TLM system in place of allocated values.

The power flow algorithm should treat each load value as *voltage dependent*. Active and reactive loads should be determined as a function of voltage at the bus where the load is connected. A polynomial representation, which is a combination of constant power, constant current, and impedance characteristics, should be used to compute the voltage-adjusted load.

The load estimation application should determine the best estimate of each distribution transformer load (kW and kVAR) based on the available real-time measurements, load profiles, and real-time network topology. Load estimation should use the accuracy class information assigned to each real-time measurement to discriminate between measurements based on the measurements' errors. Thus, load estimation should match more closely the measurements which are more accurate (smaller errors assigned) then those measurements which are deemed less accurate (i.e., have larger errors defined in the assigned accuracy class) while determining kW and kVAR values of each load. Load estimation should also perform measurement consistency checks and validation by fully exploring measurements redundancy wherever available in order to identify potentially bad measurements.

A.1.7.5 Electronic Map/Model Updates

Having an up-to-date "as operated" representation (maps and models) of the electric distribution system at all times is essential for safe and efficient operation of the electric distribution system. At many electric utilities, a considerable amount of manual effort is needed to update the existing records. Thus there is a significant amount of delay in updating the maps, displays, and other records used by operating personnel. Hand-drawn markups (see Figure A-9) are often used as the main source of information until the official map updating is done.

Some changes to the electric distribution system are only made in a single system (e.g., the OMS) and are, therefore, not available to other applications. This will become even more of a problem as the DMS is introduced due to the number of model-driven applications that are contained in the DMS.

The DMS must include suitable mechanisms to streamline the records update process by eliminating manual copying between systems and hand-drawn updates to maps. The one distribution system model should be accessible by all computing systems that require this information (i.e., should not have to duplicate information on multiple systems).

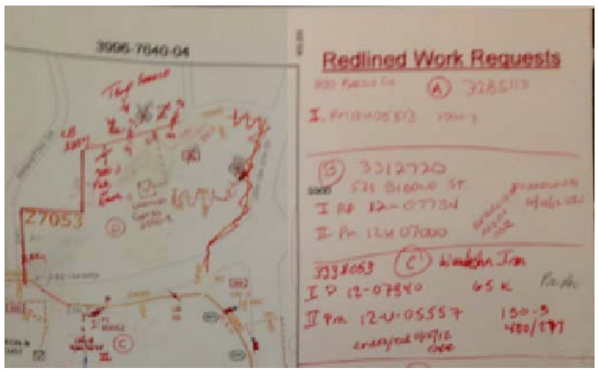


Figure A-9 Hand-Drawn Map Update (Red lines)

A.1.8 Topology Processor

The DMS shall include a topology processor (TP) for performing various analyses of the distribution network configuration. The DMS TP function shall maintain static and dynamic connectivity models. Static connectivity shall define relationships such as static node-device relationship and organizational entities groupings. Dynamic connectivity shall account for switch statuses, device energization statuses, and loops. The DMS TP function shall be able to:

- Locate an element of the distribution network (e.g., transformer, section) by name or ID,
- Locate and mark supply paths of network elements,
- Determine and highlight the energization status of network elements,
- Locate and highlight networks loops,
- Locate and highlight all network elements downstream of a selected element,
- Locate and highlight neighboring feeders of a selected feeder that can serve as an alternate supply for the feeder,
- Color individual feeders,

- Color by voltage level,
- Color line segments with voltage magnitudes less than specified thresholds,
- Color line segments with loading greater than specified thresholds, and
- Locate and highlight portions of the distribution feeder that are isolated from the utility's power grid and are being energized by IPPs and other distributed generating resources.

Figure A-10 shows a network of feeders with each individual feeder drawn with a different color by the TP.

Figure A-10 Colorization of Individual Feeders by the Topology Processor

For the TP to work correctly, it is essential to have accurate phasing information in the connectivity model used by this application. At many electric utilities, existing distribution models often contain many phasing errors (e.g., transformers connected to the wrong phase, single-phase laterals modelled incorrectly) that must be corrected before this information can be effectively used by the TP. Some electric utilities have been able to identify many of these errors by lowering the voltage using single-phase voltage regulators and observing the corresponding voltage reduction on single-phase meters connected to the associated feeder. However, if the voltage regulation strategy for the feeder in question includes three-phase regulators or a substation LTC, this approach is not possible. Often, this problem can only be corrected via field inspections. Once all phasing errors have been corrected, business processes must be put in place to ensure that new phasing errors are not introduced during future line work (especially during reconstruction following storm damage).

A.1.9 On-Line Power Flow

The DMS should include an OLPF program that is able to determine the electrical conditions on the utility's distribution feeders in near-real time. The OLPF should provide the control center personnel with calculated current and voltage values in place of actual measurements and should alert the operators to abnormal conditions out on the feeders, such as low voltage at the feeder extremities and overloaded line sections. In addition, other DMS application functions, such as SOM, VVO, and FLISR, should be able to use the OLPF results to accomplish their specified functionality.

The OLPF should use the distribution system model and load estimate provided by load allocation and estimation functions in its calculations. The OLPF should also use the available real-time statuses from the substation and feeder devices. The OLPF should use voltages and phase angles obtained from the EMS state estimator used by the transmission operator at the injection points (usually placed on a high-voltage transformer bus in distribution substations). The OLPF program should calculate current and voltage magnitudes and phase angles as well as real and reactive power flows and injections for the entire distribution system and should present the results in various formats automatically and on demand. Convenient mechanisms should be provided for viewing power flow summaries for a large area of the distribution system. It should also be possible to view (on demand) the power flow results for a single point or section of the power distribution system.

The OLPF should calculate all technical electrical losses (load and no-load losses), and real and reactive power flows and consumption in the distribution system.

The OLPF should be designed specifically for electric distribution systems. It should provide a full three-phase unbalanced calculation, accommodating single-phase, two-phase, and three-phase circuits and loads (balanced and unbalanced). The OLPF solution method should be able to handle both radial and weakly meshed configurations and the wide range of X/R ratios encountered on distribution networks where mixtures of overhead lines and underground cables are commonplace.

Convenient mechanisms should be provided for viewing the OLPF results in schematic and geographic displays. As a minimum, the following display mechanisms should be provided for viewing OLPF results:

- Automatically highlight sections of the feeder that are overloaded or experiencing under/over voltage conditions using color coding (e.g., sections of the feeder that are overloaded are color-coded red) or an equivalent highlighting technique.
- Positioning the cursor on any feeder section ("mouse over") should result in the display of current flow and phase-neutral voltage at that point on the feeder.

Figure A-11 illustrates how voltage violations identified by the OLPF can be shown on a feeder map display. Areas where voltage violations exist are highlighted with a violet "halo."

A.1.10 Intelligent Alarm Processing

The DMS should include an intelligent alarm processing (IAP) function to alert system operators to abnormal conditions on the power system. The IAP function should also alert system users to DMS and communication equipment failures and other abnormal DMS conditions requiring attention. The DMS should include a variety of distinct alarm priorities that determine the manner and priority in which each alarm is announced, acknowledged, and recorded.

The IAP function should assist the operator in managing “bursts” of alarms that may occur during an emergency, or combinations of alarms related to a single event. At a minimum, IAP should include:

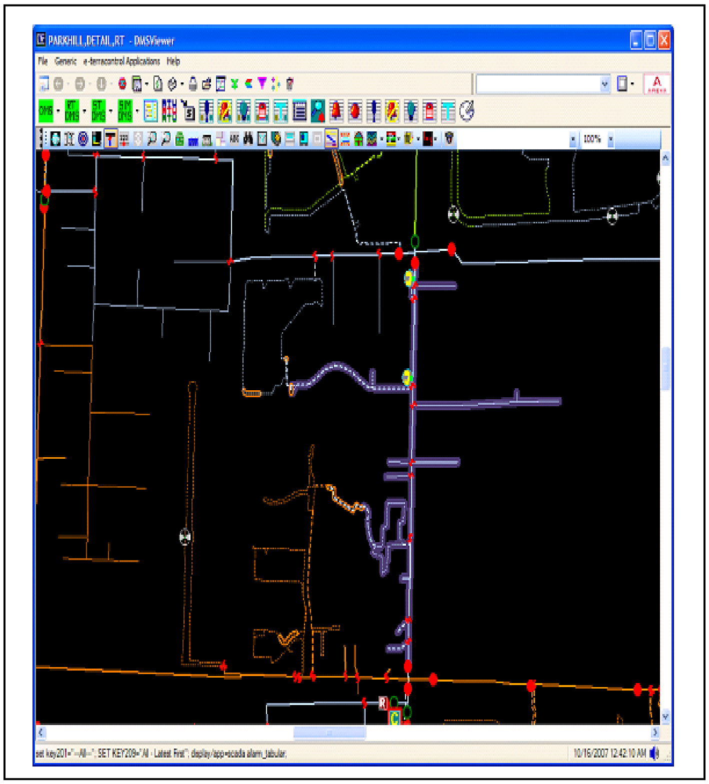


Figure A-11 Voltage Violation Highlighting

- Dependent alarms for which alarming of specified points should be enabled or disabled based on the status or values of another related data point.
- Preventing repetitive alarms for the same alarm condition.
- Combining related alarm messages (e.g., a single alarm message “feeder ABC tripped” may be provided rather than multiple messages that convey the same information (breaker tripped, loss of voltage, loss of current).
- Prioritizing alarm messages and highlighting the most urgent messages.
- Combining the alarm states of two or more alarms to produce a higher priority alarm message. For example, the DMS should be able to generate a single major alarm if two or more specified minor alarms exist at the same time.
- Suppressing alarms based on related conditions (i.e., suppressing or enabling the alarm based on the value or state of another system variable). For example: if equipment associated with a voltage measurement is de-energized and that voltage value is approximately 0.0 kV, the DMS should consider that to be normal and should not raise any alarm. If the same equipment is energized and that voltage value is approximately

0.0 kV, the DMS should produce an alarm to indicate the possibility of an instrument transformer failure.

The IAP function should include "time-sensitive alarming." The DMS should monitor and track time-sensitive ratings on substation transformers, cables, and other equipment time-sensitive ratings. The time-sensitive alarm function should track the amount of time the short-term (e.g., 4-hour) emergency loading on a substation transformer or cable has been exceeded and should alert the operator when the time limits are being approached. For example, if a substation transformer has exceeded its 4-hour emergency rating for a user-specified period (e.g., 3.5 hours), the system operator should be alerted.

A.1.11 Tagging, Permits, and Clearances

Maintaining the safety of the electric utility workforce and the general public is a fundamental and essential business objective that applies to all electric distribution utilities. The DMS should strictly enforce safety rules (e.g., tagging, permits, and clearances), improve operator awareness and facilitate rapid detection of potential safety hazards, provide mechanisms to enable rapid detection of potential safety rule violations, and provide mechanisms such as remote monitoring and control to perform some hazardous operations from a safe distance. The DMS should manage the business processes for issuing, tracking, and enforcing all safety tags, permits, and clearances in accordance with established safety procedures and will help to ensure that all users and systems are aware of all such operating restrictions.

The DMS shall use tagging to call the system operator's attention to exception conditions for field devices and to inhibit supervisory control actions. As such, special precautions shall be taken to ensure that no supervisory control action can be performed using a control inhibited device. In addition, special precautions shall be taken to ensure that tags are not lost during system failover or switchover, even when these events occur simultaneously with tag application or removal. The tag application shall only be confirmed to the user applying the tag after it has been committed to the standby processor of the active control system.

A.1.12 Short-Circuit Analysis

The DMS should include a SCA function to enable users to calculate the three-phase voltages and currents on the distribution system due to postulated fault conditions with due consideration of pre-fault loading conditions. The SCA function should be able to calculate and compare fault currents against switchgear current-breaking capabilities and device fault-current limits. The SCA function should also enable users to identify estimated fault location using measured fault magnitude, pre-fault loading, and other information available at the time of the fault.

The results of SCA should be used for other applications like PFL, which uses the SCA results to identify fault locations that could produce the fault current magnitude measured by protective relay IEDs during a fault.

A.1.13 Switch Order Management

The DMS should include a SOM function to assist system operators in preparing and executing switching procedures for various elements of the power system, including both substation and field devices (outside the substation fence). The DMS SOM function should assist the user in generating switching orders that comply with applicable safety policies and work practices. Figure A-12 shows an example of a paper switching order—the DMS should include an electronic version of this switching order. The SOM function should support the creation, execution, display, modification, maintenance, and printing of switching orders containing lists of actions that are needed to perform the switching, such as opening/closing various types of switches, implementing cuts and jumpers, blocking, grounding, and tagging.

A valuable feature that should be included in the DMS to support creation of switching orders is the ability to view a portion of the feeder being worked on in either geographic form or schematic form. Figure A-13 shows a geographically correct display alongside a schematic view of the same distribution feeder. The system should be able to create a schematic view automatically from the geographic view—it should not be necessary to build a separate schematic view of a feeder manually.

Field Switching Order - Distribution Control Center

NGRID Logo Placeholder
Printed Copy Only

Page X of Y

Switching Location(s)________________

Work to be performed and why________________ TOA#________

Section________________ Operator ID______ Latest Job State__________ Date/Time Stamp____________

Remember the Six Basic Steps of Switching

1. Carry the Field Switching Order with you.
2. Verify the switching order for correct location and correct sequence.
3. Identify and ensure yourself of the device you are about to operate.
4. Verify the device position and anticipated status (i.e. the closed switch is about to open).
5. Operate the device.
6. Verify the device has operated properly as anticipated.

When in doubt of any switching step, STOP, and notify the System Operator.

FIELD SWITCHING ORDER

Step #	TIME Issued	TIME Executed	Performed By	Location / Switching Description	Comments

Figure A-12 Switching Orders

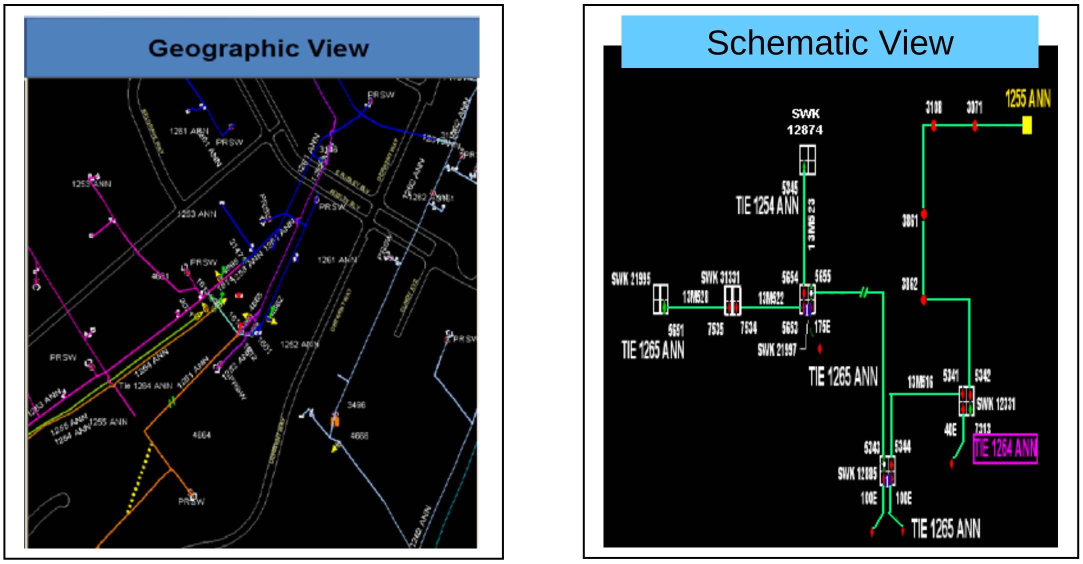


Figure A-13 Geographic versus Schematic View

In addition to the computer-assisted switch order generation facility described above, the DMS should be able to automatically generate switching orders. With this auto-generate feature, the dispatcher should select the power system device or portion of the system ("large area restoration") to be isolated and worked on. Figure A-14 shows a typical DMS display screen that is used to select the area for which a switching order is needed.

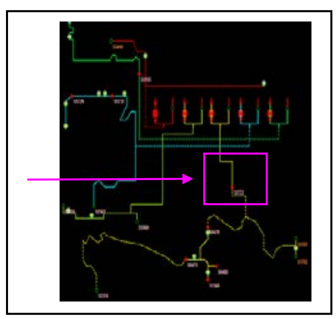


Figure A-14 Selecting an Area for Automatic Switch Order Creation

It should be possible to execute defined switching orders in real-time and in study mode. Real-time execution should be provided for switching orders that involve supervisory control commands. Study-mode execution should allow the dispatcher to check out the switching order's potential impact on the power system, including possible current and voltage violations, at a specified time and date using the DMS OLPF program prior to actual execution. The DMS should alert the dispatcher if any violations are detected during study-mode execution of the switching order.

A.1.14 Volt-VAR Optimization

The DMS should include a VVO function that should automatically determine optimal control actions for voltage and VAR control devices (e.g., substation LTC, midline voltage regulator, and switched capacitor banks) to achieve specified volt/VAR "operating objectives" while maintaining acceptable voltage and loading at all feeder locations. In addition to the basic voltage and loading constraints, the VVO function should not violate other constraints established by the utility, such as daily limits on the number of voltage regulator and capacitor bank operations.

The VVO application should include a set of displays for managing the operation of VVO, viewing VVO results, and viewing a tabulation of estimated benefits. Figure A-15 depicts a representative DMS model-driven VVO solution.

VVO should include the following utility-selectable operating objectives:

- Reduce electric demand,
- Reduce energy consumption,
- Improve feeder voltage profile,
- Maximize revenue,
- Energy loss minimization/power factor improvement, and
- Weighted combination of the above.

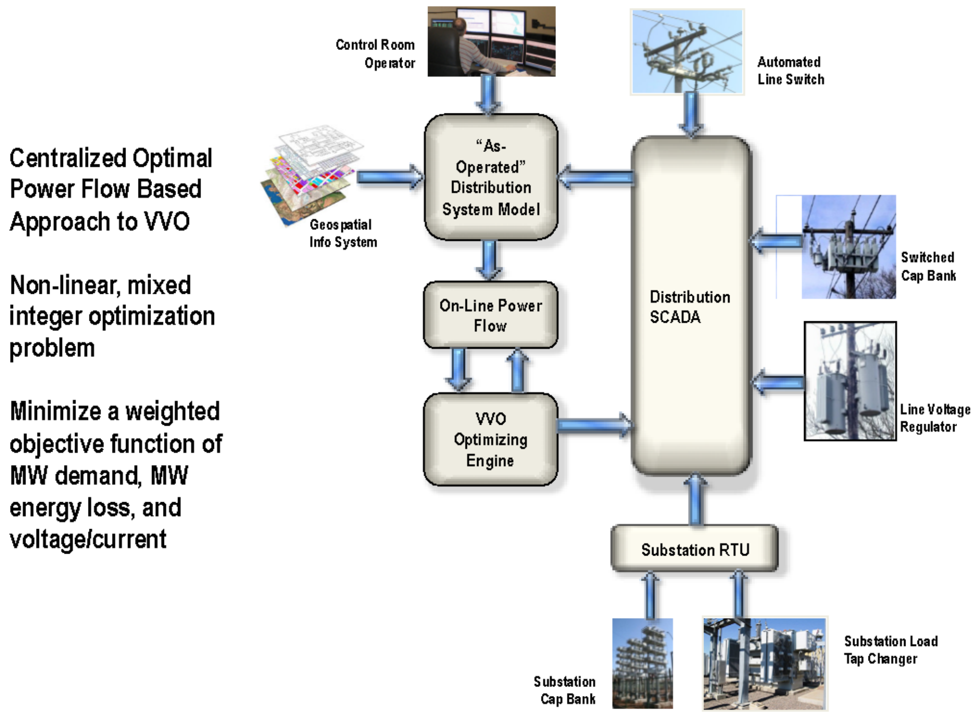


Figure A-15 VVO DMS-Based Model-Driven Solution

The VVO function should operate either in closed-loop or advisory (open-loop) mode. In advisory mode, the VVO function should generate advisory control actions that may then be implemented by the dispatcher. In closed-loop mode, the VVO program should automatically execute the optimal control actions without operator verification. The VVO application function should be executed periodically at a user-adjustable interval, upon occurrence of a specified event (e.g., significant change in the distribution system such as significant load transfer, topology change) or when requested by the user (on demand).

The DMS should obtain near-real-time voltage measurements from a small number (between 10 and 20) of AMI meters. These voltage measurements should be continuously monitored by the DMS to verify that voltage constraints are not violated at these locations and to determine whether a feeder outage has occurred.

The VVO function should have a "failsafe" design. That is, no control action that would produce unacceptable voltage or loading conditions should be requested by the DMS as a result of the failure of any DMS component or any other reason. IEDs used on feeder devices should possess a "heart beat" function to detect loss of communication with the master station within 10 minutes. This time period should be programmable. The VVO application should periodically check that the feeder IEDs are under VVO monitoring using the "heart beat" functionality of the controller. If the local controller fails to communicate with the VVO central processor for a specified time period, the controller should revert to local (standalone) control. When a VVO component is out of service for any reason (e.g., controller failure, loss of communications, controller manually bypassed, or blown capacitor fuse), the DMS should continue to operate in these abnormal situations, if possible, without producing unacceptable voltage and loading conditions, using the remaining DMS components.

A.1.15 Fault Location, Isolation, and Service Restoration

The DMS should include a FLISR function that should be used to reduce outage duration (i.e., improve the System Average Interruption Duration Index (SAIDI]). FLISR may also improve the System Average Interruption Frequency Index (SAIFI) because some customers will be restored to service in less time than the threshold for permanent outages (usually 1 minute). FLISR should provide SAIDI improvement benefits for a wide variety of feeder configurations with various levels of protection and automation, ranging from feeders in which the substation circuit breaker is the only controllable device and source of information, to feeders that are equipped with automated line switches, tie switches, fault detectors, and other facilities for monitoring and control.

The FLISR main logic should:

- Automatically detect faults,
- Automatically determine the approximate location of the fault (i.e., the faulted section of the feeder that is bounded by two or more feeder switches),
- Automatically isolate the faulted section of the feeder, and
- Automatically restore service to as many customers as possible in less than 1 minute following the initial circuit breaker or recloser tripping.

The DMS should analyze all available real-time information acquired from field devices, including fault detector outputs, fault magnitude at various locations on the feeder, feeder segment and customer meter energization status, and protective relay targets, to detect faults and other circuit conditions for which service restoration actions are required. All control actions identified by centralized FLISR should be executed by issuing supervisory control commands to substation circuit breakers and reclosers and various feeder switching devices (reclosers, load breaker switches, and sectionalizers that are equipped with supervisory control capabilities). The DMS FLISR function shall only operate for permanent faults occurring out on the main three-phase portion of the feeder and for substation faults that cause the sustained loss of one or more feeders at the substation. Temporary faults that are cleared without sustained loss of service by standard automatic reclosing schemes shall *not* result in FLISR control actions being executed. The FLISR function shall not attempt to perform control actions to restore service loss resulting from blown fuses on feeder laterals, emergency load shedding activities, and manual feeder tripping.

Before executing any downstream service restoration actions, the DMS shall confirm that the alternative source is energized (available) and is able to accommodate the additional load being switched. Service restoration actions performed or recommended by the DMS shall not produce undesirable electrical conditions, such as low voltage or equipment overloads, on any of the utility's feeders. The DMS shall analyze pre-fault loading on the faulted feeder and available capacity on the alternative source feeders to determine whether such undesirable electrical conditions would occur on the backup feeder if proposed switching actions are performed. The available capacity on alternative source feeders shall be determined by comparing the pre-fault loading on the alternative source feeder with the feeder rating.

The DMS shall consider all possible ways to restore as much of the load as possible without creating such undesirable conditions. The preferred service restoration strategy shall be the switching strategy that:

1. Does not cause undesirable electrical conditions on any distribution feeder,
2. Restores electrical service to the maximum number of customers, and
3. Requires the fewest number of switching actions.

If any portion of the interrupted load cannot be restored by the DMS due to loading or other undesirable electrical effects, the DMS shall inform the operator of this condition via an alarm/event message.

A.1.16 Predictive Fault Location

When a short circuit occurs on the distribution feeder, modern protective relay IEDs are able to capture the fault current magnitude and the voltage magnitude at the time of the fault. Dividing the voltage magnitude by the current magnitude at the time of the fault yields the impedance to the fault (in ohms) seen by the relay. Dividing the impedance to fault seen by the relay by the conductor ohms-per-mile yields the approximate distance in miles from the distribution substation to the fault. While electric distribution utilities have had some success in using this approach, distance-to-fault supplied by the protective relay IED has several limitations that usually decrease the overall accuracy of the approach:

- The relay usually assumes a homogeneous wire size/arrangement. If the wire or cable size is not uniform across the feeder, the calculations will be inaccurate.
- The fault impedance is unknown. Fault impedance increases the apparent distance to the fault, so if not properly accounted for, the results will be inaccurate. This is less of a problem for underground feeders, because fault impedance is often negligible for underground cable circuits. On overhead lines, it is a common approach to determine the reactive ohms distance to fault because fault impedance tends to be resistive in nature. Alternatively, default fault impedance may be assumed.
- The protective relay IED does not account for fault current in-feed from distributed generating units. Failure to account for DG will result in a predicted fault location that is farther downstream than the actual fault location.

The DMS should include a PFL application that uses SCA and the as-operated short circuit model of the electric distribution system to determine feeder locations where a fault would produce the current magnitude observed at the head end of the feeder by protective relay IEDs. The distance-to-fault software repeatedly executes the SCA program with simulated faults at all plausible fault locations for the given fault current. Fault locations that result in fault current that matches the measured fault current are "candidate" fault locations.

This approach has several advantages compared with the protective relay distance-to-fault information:

- It is not necessary to assume homogeneous conductor sizing, because the calculations use an as-operated short circuit model of the electric distribution. As a result, the conversion of fault impedance to actual distance is far more accurate than the relay IED approach.
- It is possible to account for the short circuit in-feed from distributed generating units if these units are properly modeled in the as-operated short circuit model of the electric distribution system. The short circuit calculations used in this method will properly account for the short circuit contributions of DG units.

The effects of fault impedance are handled in a similar manner to the protective relay IED (e.g., use default value for fault impedance, use short circuit reactance to determine distance to fault).

PFL may identify multiple candidate fault locations on branched (bifurcated) feeders (see Figure A-16). The electric utility should be able to narrow down the possible fault locations by combining distance-to-fault data with OMS fault interrupting device predictions and AMI voltage measurements at the time of the fault.

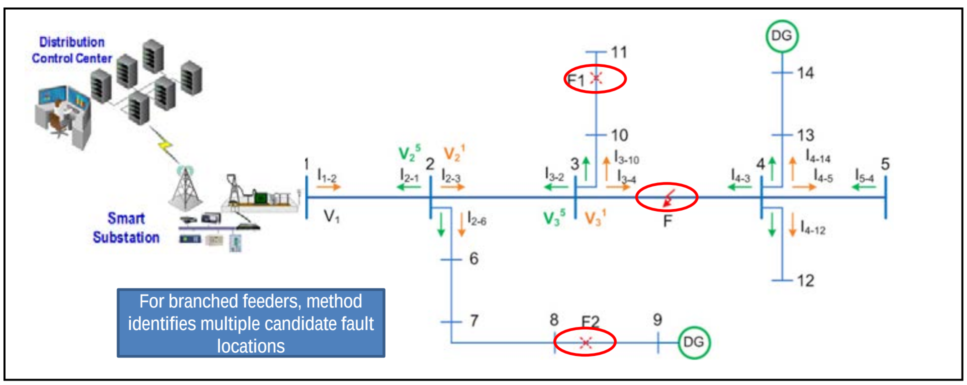


Figure A-16 Predictive Fault Location

A.1.17 Optimal Network Reconfiguration

The DMS should include an optimal network reconfiguration (ONR) function that should identify ways in which the utility can reconfigure a user-selected interconnected set of distribution feeders to accomplish a user-specified objective function without violating any loading or voltage constraints on the feeder. At a minimum, the DMS ONR function should enable the user to achieve the following objective functions:

- Minimize total electrical losses on the selected group of feeders over a specified time period,
- Minimize the largest peak demand among the selected group of feeders over a specified time period,
- Balance the load between the selected group of feeders (i.e., transfer load from heavily loaded feeders to lightly loaded feeders), or
- A combination of the first three objectives with a weighting factor for each objective function.

The ONR function output should include a list of recommended switching actions and a switching plan to accomplish these actions along with a summary of the expected benefits (e.g., amount of loss reduction).

A.1.18 Short-Term Load Forecasting

The DMS should include a short-term load forecast (STLF) function that should use historical load and weather data to forecast the system load automatically every hour, for a 168-hour (7-day) rolling period. The STLF results should be available for viewing and outage planning and should also be used by other DMS application functions that require an estimate of expected peak loading in the near term, such as FLISR, SOM, and ONR.

STLF should use both a weather-adaptive and a similar-day forecast methodology to obtain the most accurate prediction. It should be possible to assign weighting factors to the results of each methodology to obtain a weighted average forecast. The load forecast should be based on historical load measurements or, in the future, actual meter readings obtained from AMI for the specified feeder on a "similar day" during the most recent past years. At a minimum, "similar" days should be selected based on day of week (weekday, weekend, and holiday) and month or season.

A.1.19 Dynamic Equipment Rating

The DMS should include a dynamic equipment rating function that should calculate thermal ratings (real-time ampacities) of substation transformers and distribution feeders (underground cables and overhead lines) on a real-time basis. The objective of this function should be to calculate variable ratings based on actual loading and ambient conditions rather than worst-case weather and load assumptions.

Substation transformer ratings should be based on:

- Recent loading history,
- Internal temperature measurements (e.g., top oil, bottom oil, and hot spot temperatures for substation transformers),
- Status of forced cooling systems (e.g., pumps and fans on substation transformers),

- Ambient temperature, and
- Season.

Underground cable ratings should be based on duct temperature measurements (where available), position in the duct bank.

A.1.20 DMS Control of Protection Settings (Adaptive Protection)

The DMS should include application functions to assist the operators in switching between pre-established setting groups that are installed in the utility's protective relays and reclosers when the need arises. Several potential uses of this application are summarized below:

- ***Fuse Saving Enable/Disable:*** Circuit breaker reclosing relays and line reclosers used by many electric utilities include user-selectable setting groups for "fuse saving" and "fuse blowing." The DMS should include a function that enables the user to switch between the "fuse saving" setting group and the "fuse blowing" setting group for user-selected circuit breaker reclosing relays located in substations and reclosers located in substations and out on the distribution feeders.
- ***Cold Load Pickup Enable/Disable***: Circuit breaker protective relays and reclosers may include user-selectable setting groups for handling normal service restoration and "cold load" pickup. Cold load pickup settings include additional time delays and higher pickup settings to prevent re-tripping when re-energizing the feeder or portion of the feeder following a lengthy (sustained) outage. The DMS should include a function to enable the user to switch between the normal setting group and the "cold load pickup" setting group for user-selected circuit breaker protective relays and reclosers located in substations and reclosers located out on the distribution feeders.

A.1.21 Distributed Energy Resource Management

As the penetration level of DER (distributed generators, energy storage devices, and controllable loads) continues to grow on the electric distribution system, these devices will have a significant impact on overall distribution system performance. As a result, continuous monitoring and control of DER may be needed. The current industry direction for DER monitoring and control is a separate DERMS which handles the direct interface to DER for monitoring and control purposes rather than DSCADA. The DMS will obtain DER-related information as needed via enterprise system integration techniques such as ESB. Figure A-17 illustrates the separation of DSCADA and DERMS functionality for field device monitoring and control.

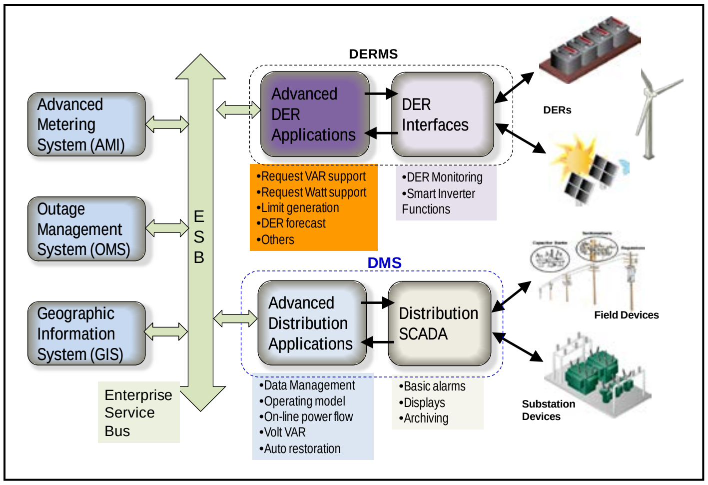


Figure A-17 Separation of DSCADA and DERMS Functionality

The DMS shall use available DER, both customer-owned and utility-company-owned, to help control real and reactive power requirements on the distribution system. The DMS shall be able to request DG power factor modifications and remote generation disconnection. The DMS shall also monitor in real time, actions taken by the IPPs, such as verification that requested load reduction has actually taken place. The DMS shall also enable the utility to monitor the performance of customer-owned power generators.

The DMS shall include facilities to enable the utility to incorporate IPPs into real-time generation dispatch and control. The DMS shall be able to use a customer's DG unit to help control real or reactive power imbalance on a distribution circuit. The DMS (or AMI system) shall monitor energy flow at the metering point to determine customer response. The DMS shall be able to control generation MW/MX output using SCADA in a manual mode and perform power balancing and generation dispatch in an automatic mode. In manual mode, the dispatcher shall be able to specify the amount of MW/MX and send that through SCADA. In automatic mode, generator control will be placed in AUTO, and the DMS application shall dispatch through SCADA.

The DMS shall include monitoring and control of temporarily isolated ("islanded") portions of the distribution system powered by distributed generating resources owned by IPPs and the utility company. This is commonly referred to as "microgrid" operation, which is the intentional islanding of selected portions of the distribution system to enhance reliability and provide high power quality to customers with sensitive loads. All applications, including OLPF, shall be capable of solving the islands energized by generators provided that islands are feasible (i.e., there is enough generation to supply loads and losses in those islands).

Industry activities to create DER standards have thus far focused almost exclusively on the behaviours of individual DER units and the communication protocols over the field networks that connect directly to these devices. The functions include, for example:

- Intelligent Volt-VAR control
- Intelligent Volt-Watt control
- Reactive power/power factor
- Low-voltage ride through
- Load and generation following
- Storage systems charge/discharge management
- Connect/disconnect dynamic reactive current injection (responding to changes in voltage dV/dt)
- Max generation limiting
- Intelligent frequency-watt control
- Peak limiting function for remote points of reference

In Figure A-17, the function of managing the DER devices is shown as an enterprise application called a DERMS. In actual implementations, DERMS functionality may or may not be a dedicated software. Stand-alone DERMS products could be developed and deployed, or DERMS functionality could be integrated into DMS, EMS, SCADA, or other applications. Nevertheless, it is beneficial at this early stage of industry consideration to think of a DERMS as a separate logical entity so that the interactions between DER and other utility systems can be identified and supporting information standards developed.

A.1.22 Demand Response Management

One of the key challenges for today's electric utilities is mitigating the demand growth before it has to be met with heavy investments in new infrastructure capacity. The primary mitigating measures are considered to be energy efficiency and demand reduction (EEDR) programs. Demand response (DR, also known as load response) enables end-use customers to reduce their use of electricity in response to power grid needs, economic signals from a competitive wholesale market, or special retail rates. Wholesale electricity markets provide opportunities for end-use customers to realize value for reducing their demand for electricity. DR is an integral part of markets for energy, ancillary service, and capacity. DR may compete equally with generation in these markets.

Achieving DR goals will require additional metering and communication facilities that will enable the utility to send signals about electricity prices and system grid reliability directly to the customers over networks such as the Internet. Facilities are also needed to enable measurement & verification (M&V) of the end customer's response to a DR event (call for demand reduction).

The DMS should be able to use these DR facilities for implementing "surgical" load reduction when needed. For example, if a load transfer operation by the FLISR application is blocked due to high load, then the DMS should be able to call upon DR where possible to reduce the load and therefore enable the load transfers to go through.

A.1.23 Emergency Load Shedding

The DMS shall include an emergency load shedding (ELS) function that shall be executed in real time on request. This function shall be synchronized with load shedding functions that are executed in EMS (under frequency, under voltage load shedding). The objective of ELS is to minimize the manual effort that is required to shed a specified amount of load and restore the previously shed load when the initiating problem is corrected. The user shall be able to initiate load shedding only for loads that are included in the user's assigned AOR.

When emergency load shedding is required, the user will activate the ELS function and enter the amount of load to be shed. The ELS shall then determine which switching devices to operate to accomplish the load shedding objective.

A.1.24 Smart EV Charging

Widespread deployment of EVs is not expected in the near term on the electric distribution system of many utility companies. However, there may be some areas with pockets of high EV deployment. Even low levels of EV adoption will have a significant impact on utilities and the grid—a single EV plugged into a fast charger can double a home's peak electricity demand.

The DMS should include suitable mechanisms for managing EV charging in a manner that is optimized for grid load while guaranteeing that drivers' schedules and range requirements are met. Unmanaged EV charging will add to peak grid load and would require additional generation capacity. EV charging must be scheduled intelligently in order to avoid overloading the grid peak hours and to take advantage of off-peak charging benefits. With a DMS, the utility can manage when and how EV charging occurs while adhering to customer preferences, collect EV-specific meter data, apply specific rates for EV charging, engage consumers with information on EV charging, and collect data for greenhouse gas abatement credits.

A.1.25 Asset Management

The DMS shall include an Asset management (AM) application function that shall enable the electric utility to track the current operating condition of each piece of electric power apparatus (e.g., transformers, switches, and voltage regulators). The AM function shall collect real-time and near-real-time information that shall enable the electric utility to determine the operating duty performed by each device and the amount of "wear and tear" that has occurred on each piece of power apparatus since the last time the equipment was thoroughly inspected and/or repaired.

The DMS AM information shall enable the utility to implement a "condition-based" maintenance program in which maintenance activities are performed based on the amount of duty performed by the device rather that calendar time between maintenance activities.

At a minimum, the DMS shall automatically track the information listed below and use this information for determining if an inspection (visual or "tear down"), repair, or equipment replacement is needed. The following information shall be used by the DMS to support the AM calculations:

- Equipment counters for all power apparatus that is equipped with counters;
- Contact wear indicators on all circuit breakers;
- Alarms and alerts generated by special purpose sensors such as partial discharge detectors, on-line oil/gas analyzers, and moisture detectors; and
- Quantity and magnitude of through-fault events for each device.

A.1.26 Engineering Analysis Tools

The DMS should include a suite of applications that engineers may use for planning and design purposes and for conducting “post mortem” analysis following unusual operating events, such as protective relay misoperation. The DMS engineering analysis tools should be similar in function to the “off-line” analytical software that electric utility engineers have used for decades for capacity planning, protective relay coordination, electrical loss studies, and other functions pertaining to the planning and design of electric distribution systems.

While the DMS engineering analysis tools are primarily intended to handle near-real-time operational problems, such as verifying that proposed switching activities do not produce unacceptable electrical conditions, the DMS tools may also support other “off-line” engineering analysis. In fact, some utilities have considered using the DMS software tools for engineering applications and eliminating separate “off-line” tools altogether. The benefits achieved by using a single set of software tools include:

- The same distribution system model can be used for operational purposes and for engineering analysis. There is no need to build and maintain separate models for operational needs and engineering needs.
- Engineers will have better access to the “as-operated” model of the electric system. This will simplify post-mortem studies performed by the engineers because engineers will not have to spend time re-creating the circumstances that existed when the unusual event occurred.
- Having access to the as-operated model at all times will simplify capacity planning because engineers will spend much less time “scrubbing” the load measurement data to ensure that load measurements are not “double counted” due to feeder reconfiguration that takes place during the year.

At a minimum, the following engineering analysis functions should be available in the DMS for performing “off-line” engineering analysis:

- OLPF and SE
- SCA
- Protective relay analysis and coordination
- Reliability analysis
- Energy loss calculations

- ONR
- Voltage regulator/tap changer settings
- Short-term/long-term load forecasting
- Capacity planning
- Thermal monitoring
- Capacitor placement
- Motor start

The DMS shall also include "study" mode for all applications, which allows users to simulate the operation of the distribution system for performing "what if" studies, outage planning, and other such activities. Study mode shall provide the operators and engineers with voltage, current, real power flow, and reactive power flow at any point on the distribution feeders at a specified date and time (i.e., not real time). This mode of operation shall enable the utility to model electrical conditions on the feeder at specified times (during peak-load and off-peak periods) before and after proposed changes to the feeder. Study-mode execution shall enable operators and engineers to examine "what if" scenarios. (e.g., "What if a portion of feeder 'A' load is transferred to feeder 'B'?"). Study-mode operation shall be executed upon demand.

A.1.27 Dispatcher Training Simulator (DTS)

The DMS shall include a dispatcher training simulator (DTS) that shall provide a realistic environment for hands-on dispatcher training under simulated normal, emergency, and restorative operating conditions. The training should be based on interactive communication between instructor and trainee. The DMS training simulator shall include a complete replica of the real-time DMS user interface plus the operating model which shall simulate the real-time analog telemetry and status changes (elements' models shall be the same).

The DMS training simulator shall serve two main purposes:

- Allow utility personnel to become familiar with the DMS system and its user interface without impacting actual substation and feeder operations, and
- Allow utility personnel to become familiar with the dynamic behavior of the electric distribution system in response to manual and automatic actions by control and protection systems during normal and emergency conditions.

The DTS shall be considerably more than a simple data "playback" facility. The DTS shall predict (compute) the behavior of the power system under normal load circumstances and during simulated disturbances. For example, when a switch is opened by the instructor, the current through the switch shall automatically go to zero. The event shall be properly reflected on the trainee's screen as open switch and coloring for non-energized state. In other words, the distribution system model at the trainee's console shall respond to all dynamic changes caused by the instructor. The DTS shall fully emulate all monitoring and control capabilities of the real-time system such as alarming, tagging, and AOR functionalities.

To support this sophisticated functionality, the DMS training simulator shall include a dynamic model of the distribution system that shall simulate the expected behavior of the electric distribution system in response to disturbances introduced by a training supervisor. The DMS training simulator shall include either the same real-time model of the distribution system as it is in the control center, or from selected saved cases that represent the distribution system at a specific date and time. The training simulator shall include dynamic load models (profiles), together with forecast total feeder load, that shall be used to determine current and voltage values along the feeder during normal conditions. This information shall be displayed on the simulator operator consoles as though the simulated values were actual field measurements.

The training simulator shall enable the user (instructor) to introduce equipment and control failures to the system, and the simulator shall calculate and present the expected results to the trainee. The instructor shall be able to place simulated single- and multi-phase faults at any location along the feeder using the simulator's supervisor console, and the simulator shall (in turn) calculate and display the expected fault current magnitude and resultant protective device operation(s).

It shall also be possible to introduce events into the DTS to simulate equipment failures, faults, or other anomalies. Following the introduction of the event, the DTS shall automatically simulate the operation of the actual automatic control equipment, such as protective relays and reclosers that are installed in distribution substations and in the field (outside the substation fence).

Appendix B: Distribution Management System Industry Survey

Advanced Distribution Management Systems for Grid Modernization

Distribution Management System Industry Survey

August 2015

Appendix B — Table of Contents

Figures

B.1 DMS Industry Survey

Arguably, no portion of the electric power grid has been affected more by grid modernization than the electric distribution system. The so-called "smart grid" has transformed the electric distribution system from mostly manual, paper-driven business processes to electronic, computer-assisted decision making with a high degree of automation. At the heart of this transformation is the distribution management system (DMS), which is a set of integrated computer and communication systems whose purpose is to assist the distribution system operator, engineers, and other electric utility personnel in monitoring and controlling the distribution system in an optimal manner without compromising safety or asset protection.

This document contains the results of a literature search and survey conducted on behalf of Argonne National Laboratories (Argonne) and the IEEE PES DMS Task Force to identify and document trends in DMS applications by North American electric utilities and to document the results achieved by utilities that have several years of DMS operating experience "under their belts."

B.1.1 Challenges to Successful DMS Implementation

Utilities that are contemplating implementing a DMS face numerous challenges. The first and foremost challenge is developing a business case that demonstrates that the benefits achieved by implementing a DMS outweigh the costs to implement and sustain the new system. Unlike its counterpart on the transmission system — the energy management system (EMS) — a DMS is not considered at this time to be an essential, mission-critical system. As a result, a solid business case is needed to determine the economic merits of DMS implementation. In many cases, the economic payback of implementing a new DMS is positive but is not sufficient to justify immediate investment. The lack of a solid business case often results in piecemeal implementation of advanced applications for worst-performing circuits.

Another common barrier to successful DMS implementation is the lack of mature, field-proven products. The DMS is still a relatively new concept, and vendors and utilities alike do not have many years of operating experience for these applications. As a result, the early implementers of DMS are still gaining experience, such as identifying and correcting errors as new operating conditions are encountered.

B.1.2 The Market for DMS

Despite significant barriers to faster DMS uptake, this market will likely see steady growth over the next several years. According to a new report from Navigant Research, the worldwide DMS market will grow from $507 million in 2013 to $935 million in 2020.

Utilities of all sizes have installed management systems such as supervisory control and data acquisition (SCADA), outage management systems, DMS, or a combination of the three. Smaller utilities must often fit their modernization efforts into tight operational expenditure budgets, whereas the bigger utilities typically have larger capital expenditure budgets. In either case, according to the report, utility managers must strike a balance between the benefits provided by a DMS and the cost of procuring, installing, operating, and maintaining the system.

B.2 Survey Results

As part of this summary of industry trends, we conducted a survey to benchmark current practices for DMS implementation that can serve as a guide for future system implementations. This survey sought information on current plans to implement DMS, DMS functions of interest, implementation challenges, functional benefits achieved, and other relevant information. These survey results were combined (where possible) with similar surveys conducted by the IEEE DMS Task Force in the previous three years so that trends over the years could be observed.

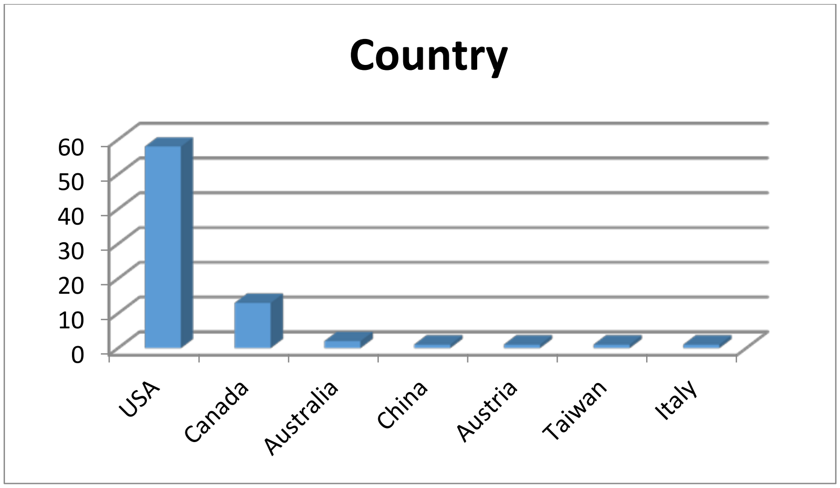
The survey, consisting of 20 multiple-choice questions, was sent by email to more than 300 members of the IEEE PES DMS Task Force with the permission of officers of that group. Because all members of that group have expressed interest in DMS, readers should not consider the group surveyed to be a completely random sampling of the industry (i.e., this group is not a statistically valid sampling of the overall industry). Organizations that are not interested in DMS generally are not members of this group. Hence, the survey only represents the views of entities that are contemplating DMS. Despite the relatively small sample size, and lack of truly random polling, we believe that the survey provides valuable insights into important issues pertaining to DMS implementation.

While most of the survey participants work for electric utilities, the survey also includes some inputs from individuals who are not employees of electric utilities (e.g., academic institutes, research organizations, vendors, consultants), the objective being to capture the valuable insights possessed by representatives of these entities. Non-utilities were requested to answer the questions from their own points of view regarding the market, including about DMS features and research areas on which their clients are requesting information.

The survey was conducted with a promise of strict confidentiality. Therefore, all responses are treated with anonymity. The results of the survey are summarized in this report and were also presented at the next DMS Task Force meeting, held in July 2015 in Denver, Colorado. Results will also be sent to survey participants following the completion of the survey.

B.2.1 Survey Demographics

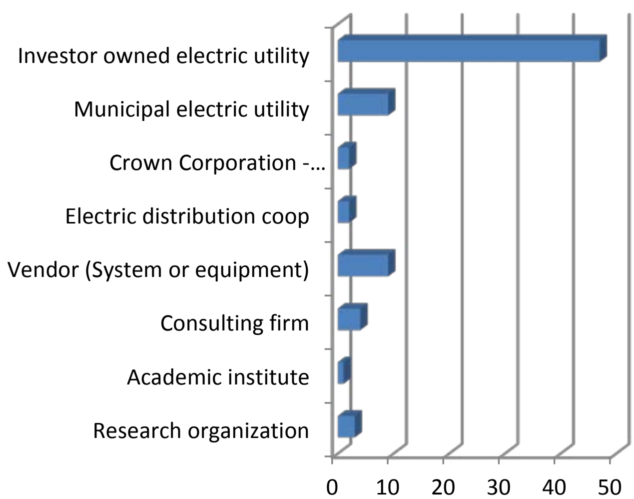
Individuals representing 77 entities responded to the survey. As Figure B-1 shows, most responses were received from entities located in North America (the United States and Canada). However, a small number of responses were received from participants located outside of North America (China, Taiwan, Australia, Italy, and Austria).



Country	#
USA	58
Canada	13
Australia	2
China	1
Austria	1
Taiwan	1
Italy	1

Figure B-1 Survey Responses by Country

Most survey responses were supplied by electric utilities of various types, including investor-owned utilities (IOUs), Crown corporation provincial utilities, municipals, and electric distribution cooperatives (co-ops). Results were also received from vendors, consultants, academic institutes, and research organizations. Figure B-2 shows the number of responses in each of these categories.



Company Type	#
Investor owned electric utility	47
Municipal electric utility	9
Crown Corporation - Provincial Utility	2
Electric distribution coop	2
Vendor (System or equipment)	9
Consulting firm	4
Academic institute	1
Research organization	3
Total	77

Figure B-2 Responses by Organization Type

B.2.2 State of DMS Deployment

Participants were asked to select the item that best describes their current state of DMS deployment. Participants were able to choose <u>one</u> of the items listed below. A ninth choice, “Other,” was available to enable participants to type in something other than the eight standard selections. The following choices available to survey participants were these:

- **No plans** to implement DMS.
- **Just thinking** about DMS; have not yet decided whether to proceed; project is on hold.
- **Planning stage**, including conducting a needs analysis, developing a business case, developing general implementation strategy.
- **Procurement stage**, developing detailed specifications, bid evaluation, contract negotiation.
- DMS **design and test** stage.
- System **installation, integration, and commissioning** stage.
- DMS **up and running** and being used for live system operation.
- Doing DMS **“midlife”** assessment.
- Other.

Figure B-3 summarizes the responses to the question about current state of deployment. Sixty (60) of the 77 survey participant responded to this question. The length of the bars shows the percentage of responses that indicated each state of deployment. The responses show that a significant number of utilities, just under 38% of the survey participants (23 respondents), report that they are in the “thinking about it” and “planning” stages of DMS deployment. This result indicates that the interest in DMS is strong and that a significant number of new DMS will be implemented in the near future. Having a growing number of operational DMS is important, because electric utilities are gaining valuable experience into the significant benefits and new opportunities afforded by a DMS implementation. Along with that, vendor products are gaining maturity, which will simplify future deployments.

DMS Status	#
No Plans	3
Just Thinking	7
Planning	16
Procuring	4
Design and Test	2
Up and Running	25
“mid life” assessment	3

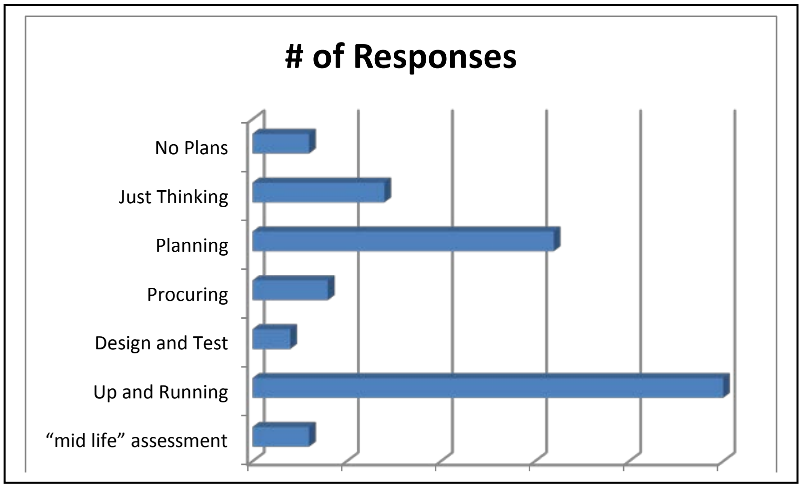


Figure B-3 DMS Implementation Status

A significant result is that almost 42% of the survey participants reported that their DMS is “up and running.” This result represents an increase of about 17% from last year’s survey. It is important to note that most utilities implement their systems in phases, with early phases including basic functions (SCADA, geographic displays, etc.) and later phases including more advanced functions (voltage/VAR optimization [VVO], FLISR [fault location, isolation, and service restoration], etc.). Some utilities consider their systems to have “gone live” when the initial basic phases are completed, even though there is still a long road to travel before they are really done. Six of the respondents reporting that they had gone live indicated that the DMS was partially implemented: one utility indicated that DMS was running without any advanced applications, and two of the respondents indicated that their DMS included only distribution automation (DA) and Voltage/VAR control (VVC).

Several respondents indicated that they were doing a “midlife” assessment of a DMS that had been in service for a number of years.

One of the respondents (a vendor) indicated that the organization is experiencing movement from “first-generation” DMS to DMS products from a new (different) vendor. It was stated that the original system did not live up to expectations and that the planning and procurement stages of the DMS implementation project require improvement. This type of transition points to an area where better industry guidelines are needed.

B.2.3 DMS Applications in the Process of Being Implemented

The next survey question asked survey participants to identify the major application functions they are implementing or planning to implement in their DMS. Sixty-eight (68) of the 77 survey participants answered this question. The chart shown in Figure B-4 is ordered by the percentage of survey participants indicating that they are implementing the specific application. The four most popular items are (1) FLISR, a.k.a. self-healing, (2) VVO, (3) on-line power flow (OLPF), and (4) switch order management (SOM) — this ranking is the same as in last year’s (2014) survey. This result reflects the continued interest in improving efficiency and reliability within the electric utility community.

2014	2015	DMS Function	#	%
1	1	FLISR	60	88%
2	2	VVO	58	85%
3	3	On-line power flow	57	84%
4	4	Switching orders	54	79%
7	5	Training simulator	50	74%
6	6	Outage management	48	71%
5	7	Tagging & Permits	47	69%
8	8	Intelligent alarming	42	62%
11	9	Distribution state est	40	59%
9	9	Engineering analysis	40	59%
10	10	Electronic map updates	39	57%
12	11	DER Management	36	53%
13	12	ONR	33	49%
14	13	Emerg load shedding	28	41%
15	14	Contingency analysis	19	28%
17	15	DRmanagement	18	26%
16	16	Load forecasting	17	25%
18	17	Asset management	6	9%
18	18	EV Management	6	9%

Figure B-4 DMS Applications Being Implemented

Several applications moved up by more than one spot compared to the 2014 ranking (higher percentage of utilities seeking to deploy):

- **Training simulator.** Its increased popularity indicates growing interest in using the DMS as a training tool for new operators; as refresher training for experienced operators; and for engineering simulation and emergency preparedness drills.
- **Distribution state estimation.** More utilities are seeking to use information from advanced metering infrastructure (AMI) and other near-real-time measurement data to improve the quality of their OLPF calculations.
- **Demand Response (DR) Management.** There is growing interest in using "surgical" demand response managed by the DMS as part of the distribution operations strategy.

Figure B-5 shows a comparison of the application ranking for IOUs versus distribution coops/municipals. Significant differences are listed below:

- IOUs showed considerably higher interest in VVO and emergency load shedding than did the coop/municipal group.
- Coops/municipals showed more interest in optimal network reconfiguration, load forecasting, permits/tagging, and engineering analysis.

Application	Rank	
	Coop, Muni	IOU
Intelligent alarm processing	9	8
Electronic map updates	13	12
Switching order management	4	4
Permits, tagging	3	7
Distribution state estimation	8	10
On-line power flow	2	3
Outage management	12	6
VVO	7	2
FLISR	1	1
Optimal Network Reconfiguration	11	14
Asset management	19	19
Management of DERs	10	11
Management of EV charging	18	18
DR management	16	16
Emergency load shedding	17	13
Contingency analysis	15	15
Load forecasting	14	17
Engineering analysis	6	9
Training simulator	5	5

Figure B-5 Application Ranking Comparison

B.2.4 Architecture for DMS and OMS

Today's electric utilities are showing considerable interest in outage management systems (OMS), which have many synergies with DMS:

- Both types of systems are important operational support tools that are used by operating, engineering, and management personnel throughout the electric utility organization.
- OMS and DMS both require an accurate "as operated" model of the electric distribution. While the modeling requirements for DMS and OMS are different (DMS requires a full "power flow" model that contains topology and electrical impedances; OMS requires connectivity and customer counts), it is essential that common portions of these models be in synchronism.
- Some applications, like switch order management, are usually offered by DMS vendors and OMS vendors. While the DMS version includes power flow validation of switching steps, the two variations of the applications are very similar.

As a result of the commonalities listed above, a key industry trend is the combination of OMS and DMS in a single platform.

Survey participants were asked if their DMS strategy includes both DMS and OMS functionality. If a DMS/OMS strategy was planned, participants were asked to identify which of the following items best describes the strategy to integrate the DMS and OMS functionality:

- **Separate Systems – No Interface.** DMS and OMS functionality is implemented on two completely separate systems that do not share information in digital fashion.
- **Separate Systems with Digital Interface for Data Sharing.** DMS and OMS are implemented on different systems that share data via a digital network.
- **Single System – Separate Models.** DMS and OMS are implemented on a single system, but separate models are used by OMS and DMS.
- **Single System – Shared Model.** DMS and OMS are implemented on a single system, and a single model is shared by OMS and DMS.

The results are summarized in Figure B-6. As this figure shows, an integrated approach to DMS/OMS is strongly preferred by the survey participants, with more than 80% preferring a solution architecture that allows the DMS and OMS to exchange data in digital fashion. Fifty-two percent (52%) of the survey participants expressed a preference for a single platform that supports both DMS and OMS applications. Survey participants that use separate systems for DMS and OMS often do so because an existing legacy OMS cannot be expanded to include the required DMS application function, or because an existing DMS does not support OMS functionality. When determining a suitable strategy for DMS, the need for OMS functionality should be carefully examined and taken into account during vendor selection.

Approach to DMS - OMS Integration	% of Responses
DMS and OMS are implemented on a single system, and a single model is shared by OMS and DMS	52%
DMS and OMS implemented on different systems that share data via a digital network	29%
DMS and OMS are implemented on a single system, but separate models used by OMS and DMS	6%
DMS and OMS functionality implemented as two completely separate systems that do not share information in digital fashion	3%
Other	10%
- Currently evaluating options	
- Prefer maximum integration, but client legacy systems may need accommodation	
- DMS and OMS implemented on different systems and a single model is shared by OMS and DMS	

Figure B-6 Approaches to DMS-OMS Integration

B.2.5 Benefits Achieved by Implementing DMS

This survey question requested information on the general types of benefits that have been achieved by survey respondents who have already implemented all or part of a DMS. Responders were given a list of potential DMS benefits (see the list that follows) and were asked to select all that apply to their specific implementation. Survey respondents were also given the selection choice “Other” to enable respondents to enter benefits that were not included in the suggested list. Potential benefits specified on the survey were these:

- Improved reliability of customer service
- Field workforce productivity improvement
- Control center personnel productivity improvement
- Deferred or eliminated significant capital expenditure
- Reduced electrical losses
- Reduced peak electrical demand
- Reduced overall energy consumption (energy conservation)
- Voltage profile improvement
- Power quality improvement
- Deployment enabled of condition-based maintenance (CBM)
- Accommodation for growing penetration of DER
- Deployment enabled of grid-connected or “islanded” microgrids
- Other (please specify)

Figure B-7 shows the percentage of respondents who indicated that the specified benefit was achieved by implementing DMS.

If you have already implemented DMS, what general benefits have been achieved (check all that apply)	
Answer Options	Response Percent
Control center productivity improvement	70.8%
Voltage profile improvement	66.7%
Improved reliability of customer service	62.5%
Field workforce productivity improvement	54.2%
Reduced peak electrical demand	50.0%
Power quality improvement	50.0%
Reduced electrical losses	45.8%
Reduced energy consumption	37.5%
Deferred capital expenditure	29.2%
Accommodation of DER	25.0%
Condition-based maintenance (CBM)	20.8%
Microgrids	16.7%
Improved workforce safety	8.3%
Outage communication to customers	8.3%

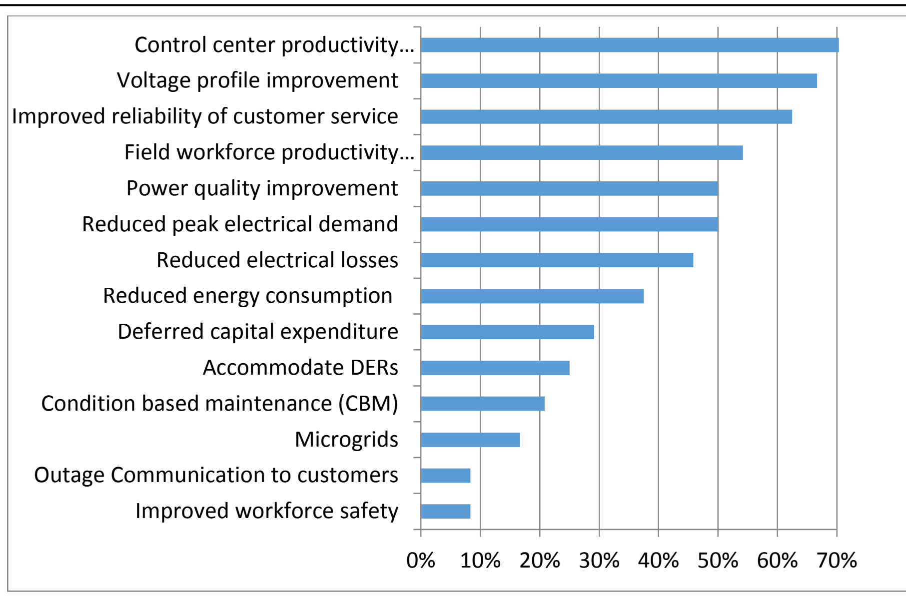


Figure B-7 Benefits Attributable to DMS

The benefits attributed to DMS appear to be well aligned with the DMS functions that have been implemented by the respondents. DMS functions that can contribute to each of the benefit categories are listed below (examples given for benefits that were listed on more than 50% of the responses):

- Control center personnel productivity improvement:
  - Electronic mapping will eliminate many hand-drawn map updates, which is a tedious, time-consuming process for control room operators.
  - SOM will automate many of the business processes that are used by control room personnel to generate switching orders.
  - Training simulators will reduce the amount of senior operator time dedicated to on-the-job training of new system operators.
- Voltage profile improvement:
  - VVO will play a key role in ensuring that service delivery voltage is well within acceptable range for all customers under all loading conditions.
  - DER management will help ensure that the output of DER (including intermittent renewables) does not produce high- or low-voltage conditions.
- Improved reliability of customer service; improved customer outage communications:
  - FLISR will restore service rapidly (in 1 min. or less) to customers connected to "healthy" portions of a faulted distribution feeder.
  - Optimal network reconfiguration is an application that identifies manual switching that can be performed to reconfigure the distribution network in a manner that minimizes service restoration time.
  - Predictive fault location is an application that can be used to pinpoint fault location (within a few spans) using short-circuit analysis and fault magnitude information from intelligent electronic devices (IEDs).
- Field workforce productivity improvement:
  - The permits tagging and clearances function streamlines the process of requesting and receiving permits, tagging instructions, clearances, and other safety protection guarantees. Having this capability will minimize the amount of time field crews spend waiting for information.
  - Switch order management will reduce the time needed to prepare switching orders that are required to enable field personnel to work in a safe and efficient manner.
  - FLISR and predictive fault location will provide more accurate fault locations, which, in turn, will reduce the amount of time spent by field crews on fault investigation.
- Reduced electrical losses, peak demand, and energy consumption:
  - VVO will enable the electric utility to operate voltage regulators, substation load tap changers (LTCs), switched capacitor banks, and other voltage and VAR control

devices to achieve various operating objectives including reduce losses, lower peak demand, and overall energy conservation.

- Optimal network reconfiguration will enable the electric utility to identify manual switching actions that can be performed to configure the feeder for minimal losses and overall improved efficiency.

Figure B-8 contains a "DMS opportunity matrix" that identifies monetary and strategic benefits that can be achieved by implementing various DMS application functions.

DMS Functional Requirements	Enabling Function	Safety	Reliability	Asset protection	Efficiency	Peak shaving	Asset Utilization	Manage DERs	Manage Evs
Data Acquisition & Control	X	X							
State Estimation	X								
Graphical User Interface	X								
Historical Information System	X								
Distribution System Model	X								
Load Models	X								
Topology Processor	X								
On-Line Distribution Power Flow	X								
Intelligent Alarm Processing			X	X			X		
Tagging, Permits and Clearances		X	X	X	X				
Short Circuit Analysis			X	X					
Switch Order Management		X	X	X			X		
Volt-VAR Optimization					X	X	X	X	
FLISR		X	X						
Predictive Fault Location			X						
Optimal Network Reconfiguration			X		X	X	X		
Short Term Load Forecasting			X		X	X		X	X
Dynamic Equipment Rating				X			X		
DMS Control of Protection Settings			X	X					
DER Management			X	X	X	X		X	
Demand Response Management			X			X			
Emergency Load Shedding						X			
EV Charging						X			X
Dispatcher Training Simulator		X	X	X	X	X	X	X	X

Figure B-8 DMS Opportunity Matrix

B.2.6 DMS Data Acquisition and Control Strategy

The decision support and automatic control advanced applications that are included in the DMS require real-time and near-real-time measurements from various strategic locations throughout the electric distribution system. As a minimum, measurements are required from the following strategic locations:

- Substation end ("head end") of feeder.
- Feeder extremities, including feeder end points that are located furthest from the substation end of the feeder.
- Heavily loaded lateral branches.

- Locations near midline voltage regulators and switched capacitor banks.

The DMS should be able to remotely control various components of the electric power apparatus (switches, voltage regulators, switched capacitor banks, etc.) as required by the DMS applications being implemented.

Survey participants were asked to identify the ways in which an existing or planned DMS performs real-time data acquisition and control. Participants were asked to identify one or more approaches being used (or planned). The following multiple-choice selections were provided in the survey question:

- **SCADA facilities that are an integral part of the DMS.** That is, the monitoring and control facilities were supplied by the same vendor that supplied the DMS itself.
- **Distribution SCADA system that is separate from the DMS.** The DMS uses continuous monitoring and remote control facilities for the distribution system that were supplied by a vendor other than the DMS supplier. In most cases, distribution SCADA facilities that were in place prior to the DMS project are used. These facilities were interfaced to the DMS through inter-control center protocol (ICCP) or other standard interface.
- **SCADA facilities that are part of a separate EMS.** It is common for equipment located in primary substations (high-/medium-voltage [HV/MV]) to be monitored and controlled via an existing EMS that is primarily used to manage transmission and centralized generation facilities. Utilities that used this approach interfaced EMS and DMS facilities via a secure ICCP link or similar facilities.
- **Advanced metering infrastructure (AMI).** AMI facilities are used in some cases to supply near-real-time information from customer endpoints to the DMS applications.
- Other (please specify).

Thirty-five (35) of the participants responded to this question. The results are shown in Figure B-9. As this table shows, almost two-thirds of the survey participants indicated that remote monitoring and control would be provided (at least in part) by SCADA facilities supplied by the DMS vendor (an integral part of DMS). It should be noted that more than 82% of the survey participants reported that more than one mechanism was used to handle the DMS data acquisition and control requirements.

It is encouraging to see that almost half (49%) of the survey participants were using (or planning to use) AMI data as a major source of near-real-time information for the DMS applications. This response level clearly indicates that the participating utilities are planning to leverage AMI information for operational purposes other than customer billing.

DMS Data Acquisition and Control Strategy	% of Responses
SCADA facilities that are an integral part of the DMS	63%
Distribution SCADA system that is separate from the DMS	26%
SCADA facilities that are part of a separate energy manage	34%
Advanced metering infrastructure (AMI)	49%
Other (please specify)	11%
- DA Pilot Project	3%
- multiple data streams including some exclusive to DMS	3%
- Load and generation forecasting systems	3%
- SCADA integration with OMS/DMS & stand-alone FLISR	3%
- SCADA this integral part of EMS, DMS and OMS	3%
- AMI voltage alerts for End-of-Line (EOL) voltage input.	3%

Figure B-9 DMS Data Acquisition and Control Strategy

The survey also asked if participants plan to use available AMI communication infrastructure to support the DMS data acquisition and control functions. The answers are summarized in Figure B-10.

Use AMI to support DMS Comms?	% of Responses
Yes	66%
No	34%

Figure B-10 Use of AMI for DMS Communications

In addition to the simple Yes/No answers to this question, survey participants also provided the following comments pertaining to this topic:

- AMI communication was not fast and reliable enough.
- Respondents plan to use AMI communications for DMS where systems share same geography.
- Volt/VAR application uses AMI voltage alerts in real time as input to the application.
- There are some concerns about bandwidth and latency for any use that requires real-time or near real-time data and alarms — particularly for anything in scale beyond limited pilots (and not just from the communications network, but also through an AMI/meter data management system (MDMS) [versus direct distributed network protocol or DNP3 communications to SCADA/DMS]). For example, respondents have heard of delays of 15–60 min. for voltage data, which would render the data useless or misleading for volt/VAR applications.

- Respondents plan to use AMI to gather voltage data from endpoints and feed data to state estimation.

B.2.7 Distributed Energy Resources Monitoring and Control

This section of the report presents survey results pertaining to the deployment and use of DER by the electric distribution utility.

B.2.7.1 DER Monitoring

Survey participants were asked to identify the types of DER that are currently monitored on a continuous basis. Participants were asked to check all that apply. This survey question elicited a total of 35 responses. The results are summarized in Figure B-11.

DER Monitored	% Responses
Distributed generation (including intermittent renewables)	54%
Energy Storage	11%
Controllable Loads (Demand Response)	14%
None of the above	29%

Figure B-11 DER Monitoring

As indicated in Figure B-11, more than half of the entities that responded to this question are currently monitoring DER that are connected to the distribution feeders. Fewer survey participants are monitoring energy storage and controllable loads (DR facilities).

B.2.7.2 DER Control

Survey participants were asked to identify the types of distributed energy resources that are currently controlled by the electric distribution utility. Once again, survey participants were asked to check all that apply. Approximately one-half of the entities that responded to this question indicated they plan to control distributed generating resources (Figure B-12). Only a small percentage of respondents indicated they are controlling, or plan to control, energy storage for DR facilities.

DER Controlled	% Responses
Distributed generation (including intermittent renewables)	50%
Energy Storage	15%
Controllable Loads (Demand Response)	15%
None of the above	35%

Figure B-12 DER Control

B.2.7.3 DER Communications

The survey included several questions pertaining to the mechanisms used to handle communications with the distributed energy resources located out on electric distribution feeders.

The first question seeks information on the general mechanism used to handle communications between a DMS and DER located at customer sites. Respondents were asked to select one or more approaches based on their current approach to DER communications.

Figure B-13 summarizes the results of this question. As this chart shows, more than two-thirds of the respondents indicated that they communicate directly from the DMS to the DER. Slightly more than one-third of the respondents indicated that the DMS communicates (or will communicate) with the DER via a separate, stand-alone DER management system (DERMS). A smaller percentage (approximately 15%) intends to communicate with DER via an aggregator or similar service provider.

Method of Communicating with DERs	% of Responses
Communicate directly from DMS or SCADA to DER	69%
Communicate from DMS or SCADA to a separate DER management system (DERMS) which connects to the DERs	35%
Communicate with a DER aggregator/service provider who manages the direct interface to the DER	15%

Figure B-13 General Approach to DER Communications

Survey participants were also asked to identify the specific types of communication media that are used or will be used to handle communications between DMS and DER that are located in the field. Figure B-14 summarizes the results of the responses to that question.

Communication Media	% of Responses
wireless cellular communication (3/4 G, LET, etc)	71%
ethernet	49%
RF radio	49%
microwave communication	23%
wireless local network (Wi-Fi, Zigbee,etc.)	17%
power line communication	14%
Other (please specify)	20%
- Fiber network	
- fibre, satellite	
- MAS radiio	
- Micro grid	
- under study at this time	
- Utilty provided communications	

Figure B-14 Communication Methods for IEDs and DER

As the chart shows, most survey participants plan to use the available cellular communication facilities for handling communications between DMS and DER located in the field. Approximately one-half of the participants (49%) indicated that they will use either Ethernet or radio frequency (RF) communication facilities. Lower percentages of survey participants plan to use microwave, wireless local network (Wi-Fi, ZigBee), and power line communication.

B.2.7.4 DMS Communication Infrastructure Functions

Survey participants were queried regarding the types of supporting communication functions that are included or will be included in communication facilities used by the distribution management system. Figure B-15 summarizes the responses received to this question.

Communication Infrastructure Functions	% of Responses
encryption	50%
quality of service (QOS) support (e.g.,different communication delays for	44%
authentication	44%
different connection modes (e.g., direct peer to peer ad hoc mode and ce	36%
Unsure	6%

Figure B-15 DMS Communication Infrastructure Functions

B.2.7.5 Standards for Monitoring and Control of DER

A significant amount of effort is being expended by various industry standardization groups to identify suitable standards for communicating with distributed energy resources. Because the communication mechanism for distributed energy resources involves some new monitoring and control functions that are not commonly implemented in a traditional power system's electrical apparatus (switches, capacitor banks, etc.), there may be a need to develop new standards or to expand on existing standards (such as DNP3 and International Electrotechnical Commission [IEC] 61850) to support the evolving needs for DER communications.

Survey participants were asked what standards they plan to implement for monitoring and control of DER in DMS. The results are summarized as follows in Figure B-16:

Comm Standards for DERs	% of Responses
DNP 3	67%
IEC 61850	31%
SunSpec Modbus	11%
Smart energy profile (SEP 2)	6%
develop customize standard	3%
not sure	19%
Other (please specify)	8%
- 104	
- internal legacy protocol standard	
- Seems to us that IEC 61850 is not being adopted in North America for distribution.	

Figure B-16 Communication Standards Used for DER

As this chart shows, most survey participants identified DNP3 and IEC 61850 as their communication protocol/standard of choice. This result is most likely attributable to the basic familiarity of the electric utility industry with these established communication standards. As new DER-specific standards continue to be developed, it is expected that use of standards that have been developed specifically for DER will grow in popularity among the electric utility community.

B.2.7.6 Microgrids

This portion of the survey included several questions pertaining to the use of microgrids, which are relatively small portions of the electric power grid that can be connected or disconnected from the main portion of the power grid and operate autonomously if desired. There is growing interest within the industry and its associated regulating bodies in building electric distribution systems that are capable of operating in island mode (completely separated from the main power grid) or in "grid-connected" mode. In grid-connected mode, the internal DER are controlled in a manner that makes the most effective use of these resources.

Figure B-17 below summarizes the response to a question about the number of microgrids that are currently implemented on the electric distribution system. As this chart shows, the vast majority of survey participants indicated that they do not have any microgrids, do not plan to have any microgrids, or have one microgrid.

How many micro-grids do you currently have in your system?	# Responses
zero but plan to have more	13
zero, and do not plan to have any	11
more than one	3
one	2

Figure B-17 Number of Microgrids Deployed

Entities that either have or plan to have one or more microgrids on the system were asked to identify the microgrid functionality they plan to implement. A total of 16 responses were received; Figure B-18 summarizes the results to this question. A large percentage of survey participants indicated that they are planning to deploy both island operation and grid-connected applications. The most popular microgrid application is fault detection and isolation, in which the microgrid may be converted to island mode upon loss of the supply from the main electric utility.

Microgrid Controller Objectives	% of Responses
islanding operation	88%
grid connected operation	94%
power quality enhancement, including harmonics unbalance	25%
fault detection and isolation	69%
reclosing to external utility grid	50%
Other (please specify)	13%
- end of line voltage support	
- Customer cost minimization	

Figure B-18 Microgrid Controller Objectives

B.2.8 Security — Critical Infrastructure Protection (CIP) Compliance

Security is a major concern of information technology (IT) managers and others who are contemplating the implementation of a DMS. Much experience in this area has been gained with EMS that are being used to manage the operation of the bulk power grid, including transmission lines and centralized generation. The EMS and its associated applications and data acquisition and control facilities are, for the most part, classified as critical infrastructure and are therefore subject to critical infrastructure protection (CIP) compliance.

The question of whether DMS monitoring and control facilities should also be classified as critical infrastructure is a matter of much debate within the electric utility industry. Entities that are in favor of classifying distribution facilities as critical infrastructure cite the capability of the DMS user to rapidly shed load, including critical loads (hospitals, government offices, fire and police facilities, municipal infrastructure such as sewage treatment, etc.), as a reason that DMS should be classified as critical infrastructure. Integration of DMS with other IT systems that are generally classified as business related is a factor that greatly complicates the conversion to a CIP-compliant facility.

Survey participants were asked to indicate whether they considered their DMS facility to be a CIP-compliant facility. The results are shown in Figure B-19.

to what extent is your DMS critical infrastructure protection (CIP) compliant?	% of Responses
Not sure at this point	52%
Portions of the DMS, such as control of substation assets, are treated as CIP facilities	22%
DMS facilities are not CIP compliant	7%
DMS is completely CIP compliant	7%
Other (please specify)	11%
- Capability to add go to CIP compliance exists within system	

Figure B-19 CIP Compliance

As this chart indicates, the majority of survey participants (more than 50%) are uncertain at this time whether their proposed DMS facility should be CIP compliant. Some utilities (approximately 22% of the surveyed participants) indicated that portions of the system, such as facilities to control substation equipment that is classified as transmission, are often classified as critical infrastructure. A smaller portion of the participants (7% or less) have declared their DMS to be compliant.

Clearly, the industry needs guidance on how to proceed with DMS security.

B.2.9 Power Quality

There is growing interest within the electric utility community in online power quality monitoring and analysis that will enable the utilities to collect high-resolution voltage and power quality data and perform forensic engineering analysis on this data. Reasons for this increased emphasis on power quality include the growing penetration of electrical and electronic devices whose operation may be adversely impacted by the presence of harmonics and nonlinear voltage waveforms. As a result, new power quality sensors may be added at critical equipment locations along with analytical tools for processing the data provided by the sensors and providing actionable information.

To address these issues, the survey included several questions pertaining to power quality analysis and architecture. Responses to these questions are described in the following two subsections.

B.2.9.1 Power Quality Enhancements

Survey participants were asked to identify aspects of power quality assessment that are of most interest. Figure B-20 contains a summary of the responses to this question.

Power Quality Enhancements of Interest	% of Responses
harmonics	44%
high frequency resonance (over 20 times line frequency)	8%
frequency and voltage amplitude deviation	42%
Other (please specify)	6%
- Voltage quality measured at End of Line (EOL)	
- Tracking momentaries and other disturbances indicative of potential failures (predictive maintenance)	

Figure B-20 Power Quality Enhancements

As Figure B-20 shows, survey participants are most interested in monitoring and analyzing harmonics and frequency/voltage amplitude deviation. The DMS may include applications to support various power quality analysis needs, such as waveforms and fault recorder capabilities, flicker analysis, and the derating of substation transformers owing to high harmonic content.

B.2.9.2 Preferred Architecture

Survey participants were asked to identify their preferred architecture for "power quality enhancement." The results of this question are shown in Figure B-21. As this chart shows, most survey participants indicated that the power quality data acquisition and analysis system would use a hybrid architecture in which some components are decentralized (e.g., the sensors) and some components are centralized (e.g., waveform and fault recorder functions, flicker analysis).

Prefered Architecture for Power Quality Enhancements	% of Responses
hybrid (centralized plus decentralized)	50%
centralized in DMS	29%
decentralized and micro-grid controller or the controller for distributed sources	21%

Figure B-21 Preferred Architecture for Power Quality Enhancement

B.2.10 Significant Challenges

The last question in the survey asked survey participants to identify the topics that are of most interest to them. These are the topics that have posed a challenge to utilities that have implemented a DMS or are planning to do so. It would be beneficial to have some form of industry guidebook that would enable utilities to exchange information on dealing with the challenges of each step. These topics should be reviewed as areas in which the industry research organizations, academic institutions, and the IEEE DMS Task Force should focus their efforts. Figure B-22 summarizes the responses to this question.

Which of the following items do you consider to be a significant challenge in deploying a DMS (please check all that apply)?		
Answer Options	Response Percent	Response Count
Planning a new system	25.0%	9
Developing the business case	50.0%	18
Preparing Detailed specifications	30.6%	11
Soliciting and evaluating vendor proposals	19.4%	7
System design and test activities	36.1%	13
DMS integration with external systems	61.1%	22
Debugging DMS advanced software	44.4%	16
Installing, testing, and commissioning	33.3%	12
Training and change management	58.3%	21
Determining the benefits (Measurement and Verification)	38.9%	14
Other (please specify)	13.9%	5

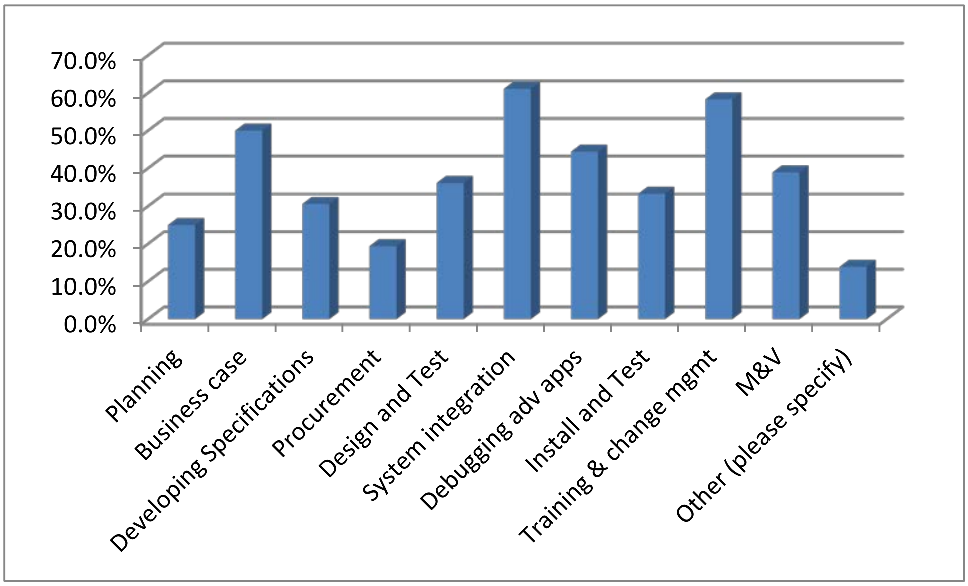


Figure B-21 Significant Challenge of DMS Implementation

As has been the case in previous year's surveys, the biggest challenge that utilities have faced in DMS deployment has been in the area of system integration. The DMS requires many interfaces to existing corporate computing systems, including the geographic information system (GIS), engineering analysis, AMI, OMS, and others. This activity requires an extensive collaborative effort between IT and OT staff members, the DMS vendor, and possibly an external system integrator (SI). Often expenditures on system integration activities greatly exceed the cost to purchase and configure the actual DMS. As a result, there is great incentive to perform these activities in an effective and efficient manner.

Training and change management is also a major concern, as has been the case in past years. Implementing new DMS applications can have great impact on existing business processes as manual paper-driven processes are supplanted by electronic computer-assisted decision making. DMS implementation cannot be successful if end users are not trained to use the new system software and if well-established business practices are not updated to address this new functionality.

Developing a business case and then actually verifying that the benefits have been achieved has been another major challenge for electric utilities including those utilities that have responded to the survey. As stated elsewhere in the survey report, DMS projects generally do not proceed and at full-scale without a sound business case that shows that the benefits that will be achieved by implementing the DMS significantly outweigh the costs to deploy the system. Utilities are also facing pressure to demonstrate after the system has been implemented that promised benefits have been realized.

B.3 Summary of Survey Findings

This section summarizes the responses to the DMS survey questions.

- In terms of demographics, most responses were received from North American IOUs. However, the survey participants included municipal and coop utilities, as well as vendors, consultants, academic institutes, and research organizations.
- As for the current state of DMS deployment, a growing number of utilities have at least partially deployed a DMS, and because of this trend, the DMS products available to the industry are becoming more mature and field proven. However, there are still a significant number of electric distribution utilities that are thinking about a DMS or identify that they are in the planning stages for the deployment of such a system.
- The four most popular items are fault location isolation and service restoration (FLISR, a.k.a., self-healing), volt-VAR optimization (VVO), online power flow (OLPF), and switch order management (SOM). However, there is growing interest in the training simulator, distribution state estimation, and demand response (DR) management.
- An integrated approach to DMS/OMS is strongly preferred by the survey participants, with more than 80% preferring a solution architecture that allows the DMS and OMS to exchange data in digital fashion.
- Key benefits that have been achieved by deploying a DMS include the following:
    - Control center personnel productivity improvement.
    - Voltage profile improvement.
    - Improved reliability of customer service; improved customer outage communications.
    - Field workforce productivity improvement.
    - Reduced electrical losses, peak demand, and energy consumption.
- Almost two-thirds of the survey participants indicated that remote monitoring and control would be provided (at least in part) by SCADA facilities supplied by the DMS vendor (an

integral part of DMS). More than 82% of the survey participants reported that more than one mechanism was used to handle the DMS data acquisition and control requirements.

- Almost half (49%) of the survey participants were using (or planning to use) AMI data as a major source of near-real-time information for the DMS applications. Roughly two-thirds of the survey respondents indicated that they plan to use AMI communication infrastructure to support the needs of the DMS.
- Slightly more than one-half of survey participants indicated that they plan to monitor and control distributed energy resources. In particular, these utilities plan to control distributed generating resources; lower percentages planned to control available energy storage and controllable loads (demand response).
- More than two-thirds of the respondents indicated that they plan to communicate directly from the DMS to the DER. Slightly more than one-third of the respondents indicated that the DMS communicates (or will communicate) with the DER via a separate, stand-alone DER management system (DERMS). Approximately one-half of the participants (49%) indicated that they will use or plan to use either Ethernet or radio frequency (RF) communication facilities for this purpose.
- Most survey participants identified DNP3 an IEC61850 as their communication standards of choice. This result is most likely attributable to the basic familiarity of the electric utility industry with these established communication standards. As new DER-specific standards continue to be developed, it is expected that use of these standards that have been developed specifically for DER's growing popularity among the electric utility community will increase.
- The vast majority of survey participants indicated that they have no microgrid or plan to have no microgrids or only one microgrid. A large percentage of survey participants indicated that they are planning to deploy both island operation and grid-connected applications. The most popular microgrid application is fault detection and isolation, in which the microgrid may be converted to island mode upon loss of the supply from the main electric utility.
- The majority of survey participants (more than 50%) are uncertain at this time whether their proposed DMS facility should be CIP compliant. Some utilities (approximately 22% of the surveyed participants) indicated that portions of the system, such as facilities to control substation equipment that is classified as transmission, are often classified as critical infrastructure.
- Survey participants expressed interest in monitoring and analyzing harmonics and frequency/voltage amplitude deviation. The DMS should include applications to support various power quality analysis needs, such as waveforms and fault recorder capabilities, flicker analysis, and substation transformer derating that results from high harmonic content.
- The biggest challenge that utilities have faced in DMS deployment has been in the area of system integration. The DMS requires many interfaces to existing corporate computing systems, including GIS, engineering analysis, AMI, OMS, and others. There is great incentive for performing these activities in an effective and efficient manner.

- Training and change management are also major concerns, as has been the case in past years. DMS implementation cannot be successful if end users (system operators) are not trained to use the new system software and if well-established business practices are not updated to address this new functionality.
- Keen interest was expressed during this survey in developing a business case and then actually verifying that the benefits have been achieved. It is increasingly important to show that the benefits that will be achieved by implementing the DMS significantly outweigh the costs.

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