ANL/ESD-15/18

# Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

*High-Level Use Cases for DMS*

**Energy Systems Division**

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ANL/ESD-15/18

# Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization

*High-Level Use Cases for DMS*

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## FOUNDATIONAL REPORT SERIES

## DISTRIBUTION MANAGEMENT SYSTEMS FOR GRID MODERNIZATION

This is one of seven reports on distribution management systems (DMS), their functions, implementation, and importance for grid modernization.

The reports on DMS in this numbered series of Argonne reports are as follows:

1. Importance of DMS for Distribution Grid Modernization (ANL/ESD-15/16)
2. DMS Functions (ANL/ESD-15/17)
3. High-Level Use Cases for DMS (ANL/ESD-15/18)
4. Business Case Calculations for DMS (To Be Published)
5. Implementation Strategy for DMS (To Be Published)
6. DMS Integration of Microgrids and DER (To Be Published)
7. DMS Industry Survey (To Be Published)

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# LIST OF ACRONYMS

| | |
|---|---|
| AM | Asset Management |
| AMI | Advanced Metering Infrastructure |
| AOR | Area of Responsibility |
| | |
| CLPU | Cold Load Pickup |
| CPMS | Charge Point Management System |
| CVR | Conservation Voltage Reduction |
| | |
| DA | Distribution Automation |
| DAC | Data Acquisition & Control |
| DCC | Distribution Control Center |
| DER | Distributed Energy Resources |
| DERMS | Distributed Energy Resources Management System |
| DG | Distributed Generation |
| DMS | Distribution Management System |
| DR | Demand Response |
| DRMS | Demand Response Management System |
| DSCADA | Distribution Supervisory Control and Data Acquisition |
| DSE | Distribution State Estimation |
| DSO | Distribution System Operator |
| DTS | Dispatcher Training Simulator |
| | |
| ELS | Emergency Load Shedding |
| EMS | Energy Management System |
| EV | Electric Vehicle |
| | |
| FCI | Faulted Circuit Indicator |
| FLISR | Fault Location Isolation and Service Restoration |
| | |
| GIS | Geospatial Information System |
| | |
| IAP | Intelligent Alarm Processing |
| IED | Intelligent Electronic Device |
| IPP | Independent Power Producer |
| IT | Information Technology |
| | |
| KPI | Key Performance Indicator |
| | |
| LTC | Load Tap Changer |
| | |
| MW/MX | Active/Reactive Power |

| | |
|---|---|
| OLPF | On-Line Power Flow |
| OMS | Outage Management System |
| ONR | Optimal Network Reconfiguration |
| PFL | Predictive Fault Location |
| PV | Photovoltaic |
| SA | Substation Automation |
| SCA | Short-Circuit Analysis |
| SCADA | Supervisory Control and Data Acquisition |
| SOM | Switch Order Management |
| STLF | Short-Term Load Forecasting |
| VVO | Volt-VAR Optimization |

# OVERVIEW

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# 1 OVERVIEW

## 1.1 INTRODUCTION

Many distribution management systems (DMS) projects have achieved limited success because the electric utility did not sufficiently plan for actual use of the DMS functions in the control room environment. As a result, end users were not clear on how to use the new application software in actual production environments with existing, well-established business processes. An important first step in the DMS implementation process is development and refinement of the "to be" business processes. Development of use cases for the required DMS application functions is a key activity that leads to the formulation of the "to be" requirements. It is also an important activity that is needed to develop specifications that are used to procure a new DMS.

In the future, with the expected growth of distributed generation (DG) resources (including intermittent renewables) and the introduction of significant new loads such as electric vehicle (EV) charging, coupled with increasing customer expectations, a DMS is expected to become essential to maintain efficient and reliable electric service to all customers under all loading and environmental conditions. The predicted emergence of DMS as a mission-critical system will require a clear understanding about how the DMS application functions will actually be used by the DMS stakeholders.

Because DG resources significantly challenge the operations of local utilities, the main focus of this report is how DMS can be used to manage DG units and coordinate them with other components in the distribution system. In particular, this report contains high level "use cases" for each of the DMS application functions that were identified in the *DMS Functions* report (ANL/ESD-15/17). The use cases contained in this report identify how the DMS stakeholders will actually use the DMS application functions in a real-time operating environment.

These high-level use cases identify:

- The stakeholders who will use each function,
- The purpose of each function,
- The situations under which each function will be used,
- Information that is required to run each application,
- Application function outputs that will be provided to the stakeholders,
- Required actions by the stakeholders in response to functional outputs, and
- Other information that is needed to determine how each application will run in actual production mode.

These high-level use cases should be considered preliminary use cases insofar as they are written prior to selecting a DMS vendor and developing software that is compatible with current and

planned operating practices. The use cases can be used to identify application and integration requirements to support business processes.

## 1.2 SCOPE OF THIS REPORT

This report contains high-level use cases for each of the DMS application functions described in the *DMS Functions* report. The use cases will identify the principal users of each function, summarize the work activities that will be accomplished by the DMS application function, and briefly explain how the DMS application will change current practices in managing the electric distribution system.

The use cases do not include specific, detailed workflows. Rather, they present an overview that will enable the reader to gain a high-level understanding of DMS as a new way of serving customers in a modernized grid.

The functional descriptions and high-level use cases establish a framework for predicting the benefits that an electric distribution utility can achieve by deploying a DMS. Each use case identifies the stakeholders for whom the function applies; states the purpose of the function; identifies situations under which the function will be used; and provides information required to run each application. Application function outputs identify a range of benefits (low and high estimates) expressed in functional terms, such as labor savings, reliability improvement, electrical loss reduction, and other items that contribute to an electric utility's bottom line.

## 1.3 ORGANIZATION OF THIS REPORT

This report contains the following sections:

- **Section 1 – Overview**
  - Provides background information for the DMS use cases
  - Describes the scope and organization of this report
  - Identifies the major users of DMS and describes their overall responsibilities and how they use DMS
  - Summarizes the high-level use cases presented in Section 2
- **Section 2 – Use Cases**
  - Contains the high-level use cases for each DMS application function's stakeholders. Identifies required actions by the stakeholders in response to functional outputs and other information needed to determine how each application will run in production mode.

## 1.4 DMS STAKEHOLDERS

This section identifies the intended users (stakeholders) of the DMS, describes their overall responsibilities (at a high level), and provides an overview of how the stakeholders will interact with the DMS. Interaction with the DMS includes how stakeholders will access DMS information and use the information presented to make business decisions.

### 1.4.1 Distribution System Operators

Among the most important DMS stakeholders are distribution system operators (DSOs). They are the primary users of the system. DSOs are responsible for ensuring that the electrical distribution system is operating normally (adequately protected and within established ratings) while maintaining safe conditions for the field work force and the general public. The DSOs use multi-display DMS consoles (workstations) installed in the Distribution Control Center (DCC) for viewing DMS information, responding to alarms produced by the DMS, interacting with the DMS application functions, and initiating DMS control actions as needed.

### 1.4.2 Trouble Dispatching Personnel

Trouble dispatchers are responsible for detecting possible outages to one or more electric distribution customers and managing the response of electric utility personnel during such incidents. The primary software tool used by the trouble dispatchers is the outage management system (OMS). Given the current industry trends toward a combined DMS-OMS system, the trouble dispatchers are now becoming one of the principal user groups and a key category of DMS stakeholders. DMS information required by the trouble dispatchers includes changes of state of any high-voltage switch that would produce an outage for one or more customers, along with information to send to trouble crews to help locate the root cause of any power system event resulting in customer outages.

### 1.4.3 Field Operations Personnel

Field operations personnel include persons who are responsible for substation and feeder switching, executing switching instructions from the DSOs, providing fault investigation and troubleshooting, and performing other field activities. The field operations group is, for the most part, a mobile workforce that relies heavily on communication facilities for interacting with DSOs and other utility company personnel. Field operations personnel usually do not have direct access to the DMS; however, they can receive data and interact with the DMS using email, text messages, and/or mobile data terminals. A growing number of electric distribution utilities have equipped field operations personnel with smart phones and tablets that can display DMS and power system information and enable interactions with control center personnel.

### 1.4.4 Planning and Design Engineers

Planning and design engineers are responsible for developing specifications and ratings of electrical power apparatus, handling long-term (five years and beyond) capacity planning. In addition, they ensure that the electric distribution system maintains acceptable voltage, equipment loading, and power quality under all operating conditions.

They are also responsible for conducting DG connection studies that are needed to ensure that proposed DG installations comply with company standards and that all abnormal operating conditions caused by DG (reverse power, dynamic voltage fluctuations, etc.) are properly mitigated.

Planning and design engineers will often assist with post-mortem analysis of information supplied by the DMS following major system disturbances to ensure that all protection and control systems performed as expected during the disturbance.

With the advent of advanced DMS applications (such as On-Line Power Flow [OLPF] and Volt-VAR Optimization [VVO]) in the DCC, planning and design engineers are playing a larger role supporting the DCC. Most modern DCCs that include advanced DMS applications will include operational support engineers whose role, in part, is to assist the operators in using the advanced distribution applications.

### 1.4.5 Asset Management Group

This group includes persons responsible for tracking the health and operating status of the energized power apparatus and for managing the maintenance activities for this equipment. The Asset Management (AM) group relies on near-real-time data received from the DMS pertaining to the operation of electric distribution equipment. This information is used during routine and abnormal operations to determine whether the equipment is operating correctly and, if not, whether additional inspections, maintenance activities, and corrective action may be needed.

### 1.4.6 Protective Relaying Group

This group includes persons knowledgeable about protective systems for the distribution system (including substations and feeders) in terms of different aspects, including:

- Protection coordination
- Adaptive relaying applications, for example, cold load pickup (CLPU) and “fuse saving”
- Impacts of using microprocessor-based relays for data acquisition and control (DAC)
- Information requirements for “post mortem” studies, for example, oscillography waveforms, sequence of events, etc.

Protective relaying engineers will play a key role in the design, development, and testing of all software, faulted circuit indicators (FCIs), and switchgear used by the Fault Location Isolation and Service Restoration (FLISR) application. Protective relaying personnel may be called upon following a power system emergency to review the sequence of events, especially in cases where relay or control misoperation is suspected. In such cases, the protective relay personnel require access to sequence-of-events reports, fault current and voltage magnitude, distance-to-fault calculations, oscillography waveforms, and other information computed by the DMS.

### 1.4.7 Communication Engineering Group

This group includes persons knowledgeable about corporate networks for handling communications between enterprise-level data processing systems, remote data centers, and existing and planned facilities that can be used for communicating with field personnel (including mobile dispatch, if applicable) and power apparatus in substations and outside the substation. This group is responsible for ensuring that the proposed distribution automation (DA) facilities located outside the substations make effective use of existing and planned telecommunication facilities.

### 1.4.8 Security Group

This group includes persons who are familiar with the electric utility's practices and standards for physical and cyber security, and the applicability of Critical Infrastructure Protection (CIP) requirements to DMS/DA facilities.

### 1.4.9 Information Technology and Standards Group

This group includes persons responsible for information technology (IT) networks, integration standards, service-oriented architecture, enterprise service buses for system integration, current IT systems, and plans for major system additions and enhancements. This group should include persons who are familiar with the DMS technology, including the operation and maintenance of all DMS application functions and interfaces between the DMS and other corporate systems.

### 1.4.10 Geospatial Information System Group

This group includes persons who are familiar with the Geospatial Information System (GIS) used to build and maintain the distribution system model used by DMS. This group helps to resolve data quality and completeness concerns. Some data quality concerns include phasing errors, incorrect field asset data, and missing or inaccurate construction details. The GIS group is also responsible for developing business processes to update the electrical model, practices of using redlining and hand-drawn map updates, and requirements for including "planned" updates and load profiles required by the DMS advanced applications.

### 1.4.11 Supervisory Control and Data Acquisition Engineering Group

This group includes persons who are knowledgeable about supervisory control and data acquisition (SCADA) systems used to perform continuous monitoring and control of distribution system equipment located in substations and past the feeder breaker. In addition, Energy Management System (EMS) SCADA will be used for DMS/DA purposes.

### 1.4.12 Feeder Automation Group

This group includes persons who are knowledgeable about existing or planned facilities (including stand-alone, decentralized DA systems) for FLISR (self-healing), VVO/Conservation Voltage Reduction (VVO/CVR), and other such applications that may be separate from the "centralized" DMS.

### 1.4.13 Planning Group

This group includes engineers and technicians who manage the capital expansion budgets, which are used to expand or reinforce the system to meet load growth, as well as initiate projects and programs to improve reliability. They are also key technical resources for the development of DA/FLISR and VVO/CVR configurations and settings.

### 1.4.14 Advanced Metering Group

This group includes persons who are familiar with the electric utility's revenue metering facilities, which may include Advanced Metering Infrastructure (AMI) facilities. While many utilities have installed AMI on their electric distribution systems, few utilities have really fully utilized the amount of new information supplied by the microprocessor-based meters for purposes other than billing. As AMI systems and their associated communication infrastructure become more mature, it is expected that additional and innovative uses will be found for AMI data. The DMS will rely on availability of AMI data for operational purposes (i.e., near-real-time data such as voltage measurements for CVR feedback), use of AMI infrastructure for DA communications, last-gasp messages and pinging of individual meters, and use of AMI data for up-to-date load profiles.

### 1.4.15 Distributed Generation Connections Group

This group includes persons knowledgeable about existing and planned DG and energy storage facilities, requirements for monitoring and control of distributed energy resources or distributed energy resources (DERs) (e.g., transfer tripping of larger units, use of smart inverters), need for a DER Management System (DERMS) separate from or part of DMS, interfaces with DG aggregators (virtual power plants), and planned microgrids. This group includes persons who are knowledgeable about existing and planned DERs, the electric utility's role (if any) in managing

controllable loads for providing ancillary services, and use of fast demand response (DR) for DA applications.

### 1.4.16 Local Media Personnel

This group of DMS stakeholders is responsible for keeping the general public, government officials, emergency response officials, and other agencies informed about the current status of events that are having an impact on electric utility service delivery. An example of the activities performed by this group is keeping local media (television, radio, printed media, etc.) informed about widespread outages that are expected to last more than a few minutes. At a growing number of electric distribution utilities, the local media personnel will also rely on social media (Facebook, twitter, etc.) to disseminate information about electric utility activities and incidents that are having a significant impact on the general public.

The role of each DMS stakeholder is summarized in Table 1.

TABLE 1 Summary of DMS Stakeholders

| DMS Stakeholder | Role |
|---|---|
| Distribution System Operator | • Ensures that the electrical distribution system operates normally<br>• Maintains safe conditions for the field workforce and general public |
| Trouble Dispatching Personnel | • Detect possible outages to electric distribution customers<br>• Manage the response of electric utility personnel during outages |
| Field Operations Personnel | • Provide field services, including performing substation and feeder switching, executing switching instructions from the DSOs, providing fault investigation and troubleshooting, and performing other field activities |
| Planning and Design Engineers | • Develop specifications and ratings of electrical power apparatus<br>• Handle long-term capacity planning<br>• Ensure that the electric distribution system maintains acceptable voltage, equipment loading, and power quality under all operating conditions<br>• Conduct DG connectivity study<br>• Assist with post-fault analysis |
| Asset Management Group | • Tracks the health and operating status of the energized power apparatus<br>• Manages the maintenance activity for the equipment |
| Protective Relaying Group | • Assigns protection schemes for distribution circuits<br>• Applies adaptive relaying applications as necessary<br>• Performs “post mortem” studies after events |

TABLE 1 (Cont.)

| DMS Stakeholder | Role |
|---|---|
| Communication Engineering Group | • Ensures that the proposed DA facilities located outside the substations make effective use of existing and planned telecommunication facilities |
| Security Group | • Ensures the security of the facilities in coupled cyber and physical systems |
| Information Technology and Standards Group | • Operates and maintains all DMS applications and interfaces between DMS and other corporate systems |
| Geospatial Information System Group | • Resolves data quality and completeness concerns related to geospatial information<br>• Develops business processes to update the electrical model, practices of using redlining and hand-drawn map updates and requirements for including planned updates and load profiles |
| Supervisory Control and Data Acquisition Engineering Group | • Performs continuous monitoring and control of distribution system equipment<br>• Participates in DA |
| Feeder Automation Group | • Handles the existing or planned facilities for FLISR, VVO/CVR, and other applications that may locate outside DMS |
| Planning Group | • Manages the capital expansion budgets<br>• Initiates projects and programs to improve reliability<br>• Supports the development of FLISR and VVO/CVR configurations and settings |
| Advanced Metering Group | • Handles and manages AMI data |
| Distributed Generation Connections Group | • Participates in the management of existing and planned DG and energy storage facilities<br>• Participates in managing controllable loads for providing ancillary services<br>• Participates in using fast demand response for DA applications |
| Local Media Personnel | • Keeps the general public, government officials, emergency response officials, and other agencies informed of current status of distribution system(s) |

## 1.5 USE CASES FOR CORE DMS FUNCTIONS FOR HIGH PENETRATION OF DG

### 1.5.1 Data Acquisition and Control

The purpose of the DAC function is to provide continuous monitoring of the distribution assets and DERs (DG including intermittent renewables, energy storage, and controllable loads) from a central location (such as the DCC). The DAC function also enables the DSOs to remotely control these assets as needed during normal and energy conditions.

### 1.5.2 Distribution State Estimation

The DMS Distribution State Estimation (DSE) application function 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 busses, sections, and transformers; active and reactive power losses in all sections and transformers; and other such electrical quantities. DSE is also used for estimating the output of DERs (DG including intermittent renewables, energy storage, etc.) that are not equipped with SCADA facilities for direct monitoring and control.

### 1.5.3 Distribution System Model/Load Model

These models allow the DMS to compute electrical conditions at feeder locations that do not have instrumentation. These models encompass the entire distribution system from the point of connection to the transmission system down to (and including) the distribution service transformer.

The distribution system model is necessary to represent the connectivity of the distribution system, which is further used to determine the optimal location and planning of DGs. Meanwhile, precise load models (profiles) can be used to facilitate the accurate sizing of renewable energy sources and energy storage.

### 1.5.4 On-Line Power Flow

The DMS OLPF program enables its users to determine the electrical conditions on the distribution feeders in near-real time. The OLPF provides the control center personnel with calculated current and voltage values in place of actual measurements and alerts 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 Switch Order Management (SOM), VVO, and FLISR, use the OLPF results to accomplish their specified functionality.

### 1.5.5 Intelligent Alarm Processing

The DMS Intelligent Alarm Processing (IAP) function alerts DSOs and other stakeholders to abnormal conditions, such as to DMS system and communication equipment failures and other abnormal DMS conditions requiring attention, on the power system. The DMS includes a variety of distinct alarm priorities that determine the manner and priority in which each alarm is announced, acknowledged, and recorded.

### 1.5.6 Tagging, Permits, and Clearances

The DMS manages 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.

### 1.5.7 Short-Circuit Analysis

The DMS Short-Circuit Analysis (SCA) function enables 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 calculates and compares fault currents against switchgear current-breaking capabilities and device fault-current limits; this capability is useful for conducting post mortem studies following a power disturbance for which protective relay misoperation is suspected. The SCA function also enables users to identify estimated fault location using measured fault magnitude, pre-fault loading, and other information available at the time of the fault.

The SCA function should consider the different characteristics of inverter and rotation-based DERs. Compared to rotation-based DERs, the fault-current limits of power electronic inverter-based DERs are much lower (e.g., ~2to 3 times the rated current). The SCA function should reflect this difference for further analysis in other applications to facilitate the implementation of coordinated protection schemes.

### 1.5.8 Switch Order Management

The SOM function assists the DSO 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 assists the user in generating switching orders that comply with applicable safety policies and work practices. The SOM function 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.

### 1.5.9 Volt-VAR Optimization

The VVO function automatically determines and initiates optimal control actions for voltage and VAR control devices (e.g., substation load tap changers [LTCs], midline voltage regulators, switched capacitor banks) to achieve user-specified volt/VAR "operating objectives" while maintaining acceptable voltage and loading at all feeder locations. The VVO function should not violate operating constraints, such as daily limits on the number of voltage regulator and capacitor bank operations.

### 1.5.10 Fault Location Isolation and Service Restoration

The purpose of the FLISR function is to restore power to as many customers as possible following a permanent fault of the distribution feeder. If backup sources with sufficient spare capacity exist, FLISR will be able to restore power to some or all customers connected to healthy (unfaulted) sections of the feeder in less than one minute, versus restoration in one hour or longer with conventional restoration procedures. The result is a significant improvement in service reliability as measured by the System Average Interruption Duration Index and System Average Interruption Frequency Index.

### 1.5.11 Predictive Fault Location

The Predictive Fault Location (PFL) application 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 Intelligent Electronic Devices (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 a fault current that matches the measured fault current are "candidate" fault locations.

### 1.5.12 Optimal Network Reconfiguration

The Optimal Network Reconfiguration (ONR) application function identifies ways in which the utility can reconfigure an interconnected set of distribution feeders without violating any loading or voltage constraints on the feeder in order to achieve selected operating objectives (e.g., reduce losses, reduce peak demand on specified facility, and accommodate a higher penetration of DG on the interconnected set of feeders). ONR, in effect, evaluates all plausible switch position combinations using load flow and SCA to determine which combination of switching actions provides the most benefit.

### 1.5.13 Short-Term Load Forecasting

The Short-Term Load Forecasting (STLF) function uses historical load and weather data to forecast the system load automatically every hour for a 168-hour (7-day) rolling period. The STLF

results support outage planning and other DMS application functions that require an estimate of expected peak loading in the near term, such as FLISR, SOM, and ONR.

### 1.5.14 Dynamic Equipment Rating

The Dynamic Equipment Rating function calculates thermal ratings (real-time ampacities) of substation transformers and distribution feeders (underground cables and overhead lines) on the basis of actual loading and ambient conditions rather than worst-case weather and load assumptions.

### 1.5.15 DMS Control of Protection Settings

The DMS includes 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. Potential uses of this application include Fuse-Saving Enable/Disable and CLPU Enable/Disable.

### 1.5.16 Distributed Energy Resources Management

As the penetration level of DERs (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 DERs may be needed. The current industry direction for DER monitoring and control is a separate DERMS that handles the direct interface to DERs for monitoring and control purposes, rather than Distribution Supervisory Control and Data Acquisition (DSCADA). The DMS will obtain DER-related information as needed via enterprise system integration techniques such as Enterprise Service Bus.

### 1.5.17 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 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.

### 1.5.18 Emergency Load Shedding

The DMS includes an Emergency Load Shedding (ELS) function whose objective 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 should be able to initiate load shedding only for loads that are included in the user's assigned Area of Responsibility (AOR).

### 1.5.19 Electric Vehicle Charge Management

The DMS EV Charge Management function includes 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 during peak hours and to take advantage of off-peak charging benefits. The EV Charge Management function enables the user to 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.

### 1.5.20 Asset Management

The DMS AM application function enables the electric utility to track the current operating condition of each piece of electric power apparatus (transformers, switches, voltage regulators, etc.). The AM function collects real-time and near-real-time information that enables 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.

### 1.5.21 Engineering Analysis

The DMS should include a suite of applications that engineers can use for planning and design purposes and for conducting post-mortem analysis following unusual operating events, such as protective relay misoperation. 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.

### 1.5.22 Dispatcher Training Simulator

The DMS should include a dispatcher training simulator (DTS) that can 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 DTS should include a complete replica of the real-time DMS user interface plus the operating model which should simulate the real-time analog telemetry and status changes (elements' models should be the same).

# USE CASES

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# 2 USE CASES

This section contains the high-level use cases for each DMS application function. Each use case identifies:

- Stakeholders who will use each function
- Purpose of each function
- Situations under which each function will be used
- Information that is required to run each application
- Application function outputs provided to the stakeholders
- Required actions by the stakeholders in response to functional outputs
- Other information needed to determine how each application will run in production mode

## 2.1 DATA ACQUISITION AND CONTROL

This section contains the high-level use case for the DAC application function of the DMS. The foundation on which DMS is based is the DSCADA system (see Figure 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 one 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.

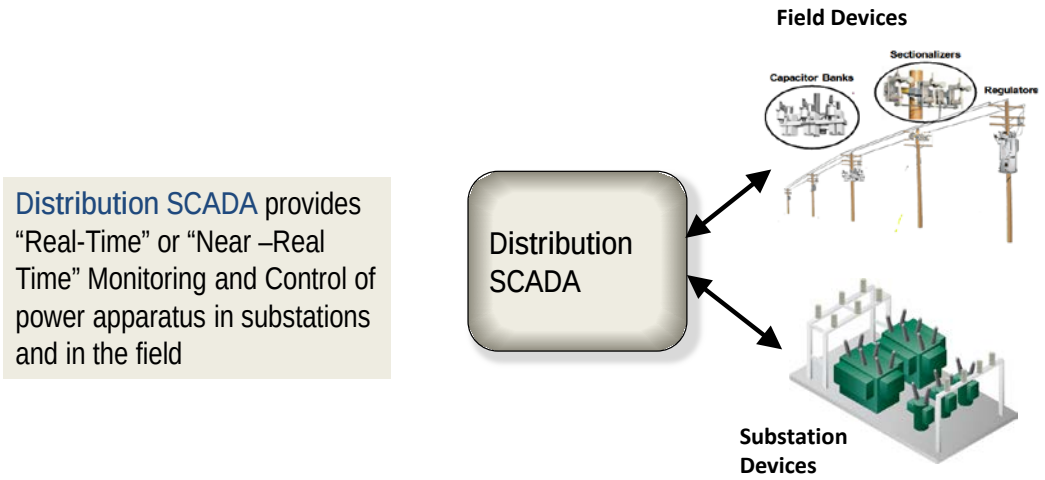



FIGURE 1 Distribution SCADA Conceptual Diagram

The DAC function should be used based on continuous data flow obtained from remote measurement units. It is implemented using a centralized controller architecture to monitor and manage the operation of distribution system in both normal and abnormal conditions. The purpose of this function is to provide continuous monitoring of the distribution assets and DERs (DG, intermittent renewables, energy storage, and controllable loads) from a central location (such as the DCC). The DAC function also enables the DSOs to remotely control these assets as needed during normal and energy conditions.

### 2.1.1 Stakeholders

The control room operators use near-real-time data and alarm information supplied by the DAC function to monitor the loading, performance, and operating status of the distribution assets. Control room operators also use the DAC facilities to remotely operate the controllable assets (circuit breakers, line recloser, and other electrically operable switches), voltage regulators, switched capacitor banks, etc. The DSOs may also be able to control DERs (remote on/off, set point control, etc.) using the DAC function. In most (if not all) cases, the DSOs are the only stakeholders authorized to use the control functions of the DMS.

The DMS DAC function also serves DMS stakeholders who require information about the operating status of the electric distribution system (including information about out of service equipment), system loading and performance, and health of the distribution system primary and secondary assets.

The health of distribution system assets is also of concern to most of the other stakeholders identified in the Overview section of this report to support various forms of analysis and computer-assisted decision-making. These stakeholders often do not receive real-time or near-real-time data. Rather, this information is generally accessed “after the fact” via a data historian function or other DMS data storage facilities.

In almost all cases, DAC stakeholders other than the DSOs are ***not*** authorized to execute control actions and do not have access to the DMS control functions.

The major stakeholders for the DAC function are as follows:

- **DSOs** use the DAC function to continuously monitor the performance of the electric distribution system, detect abnormal conditions that may require corrective action, and initiate remote control actions to support normal and emergency operations when necessary.
- **AM personnel** use information from the DAC function to determine the overall health and performance of the distribution assets so that suitable maintenance, inspection, and repair work can be scheduled for equipment that is in most need of such activities (i.e., to support a condition-based maintenance program).
- **Planning and design engineers** use peak load information from DAC for capacity planning purposes. DAC information would also be used by planning and design engineers

to perform system loss studies and for conducting DG connection studies to determine whether distribution system design changes (voltage regulation, protection, feeder reconductoring, etc.) are needed to accommodate a proposed DG unit. Planning and design engineers can use DAC information to determine the impact of adding public EV charging stations to an existing feeder. Information acquired from DAC is also used by planning and design engineers assessing load growth and planning irrespective of DG, and the necessity of circuit reconfigurations are determined from load studies.

### 2.1.2 Situations in Which This Function Should Be Used

The DAC function should be used under the following circumstances:

- **Normal operations:** The DAC function is used continuously under normal and emergency conditions. DSOs will use the DCA function on a continuous basis to monitor the status of the distribution assets. DAC information is especially valuable during peak load conditions when electrical conditions (voltage, loading, etc.) may approach the equipment rating thresholds (high/low operating limits) and the American National Standards Institute (ANSI) voltage limits. On distribution circuits that have high penetration of DERs which are sufficient to produce reverse power flow (back toward the substation), close attention may need to be given to voltages approaching the established high voltage limits for the feeders. It is especially important to monitor high voltage limits during off-peak conditions if DG resources are running during these conditions.
- **Power system alarm occurrence:** When an alarm indicates that a change of state of a switch has occurred or an operating constraint (limit) has been violated, the DSO will receive the alarm message, determine what the required action should be (all alarms should be actionable), and forward the information to the person(s) responsible for follow-up action.

### 2.1.3 Information That Is Required to Run the Application

The DAC function does not require any additional information to run the application. The DAC function runs automatically on a specified schedule and when “significant” changes occur on the distribution circuits and at distribution substations. Parameters that trigger DAC functionality (high/low alarm limits, significant change threshold, etc.) are established when the DAC database is built.

### 2.1.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the DAC function to the stakeholders:

- **Dynamically updated variables:** Some commonly used outputs supplied by the DAC function include multiple types of continuously varying measurements, such as:

- Current
- Voltage
- Active power
- Reactive power
- Ambient and internal equipment temperatures
- Oil level in a transformer
- Tap position of a voltage regulator
- Other “analog” values that are provided on a real-time or near-real-time basis
- Other “analog” values whenever changed by a specified significant amount (or percentage) since the last time the parameter was reported

Meanwhile, DA also supplies information on the operating status of various pieces of distribution equipment, such as the open/closed status of a high-voltage device (circuit breaker, line recloser, load break switch, etc.) and the on/off status of substation transformers’ forced cooling systems. Dynamically updated variables are presented to the DSO and other stakeholders in the form of tabular reports, trend lines, and graphical displays. These variables also serve as inputs to other advanced DMS application functions such as On-Line Power Flow, FLISR, and VVO. Key variables are usually stored in a data historian so this information can be accessed by stakeholders outside the DCC for studies, performance tracking, and other “off-line” activities that do not rely on continuous data flow in real-time.

- **Alarm messages:** The DAC system furnishes alarm messages when a measured variable is outside its normal operating range or the status of a piece of equipment changes from its normal position to an abnormal state at the request of a protective relay, automatic controller, or other automated device. State changes that occur as a result of an intentional human action are usually not alarmed. Ideally, every alarm message should be actionable by the stakeholders.

### 2.1.5 Required Actions by the Stakeholders in Response to Functional Outputs

Identifying all the possible actions by stakeholders in response to significant changes in potentially thousands of measurements and alarm messages is not practical for a general use case and is, therefore, beyond the scope of these high-level use cases. This section includes a few general actions that should be taken with respect to the two main functional outputs: significant change in the measured load on a feeder and alarm message pertaining to exceeding a high load operating limit on a substation transformer.

**DAC Scenario Number 1: Significant change occurs in measured value of load on a distribution feeder.**

The operation procedure of this DAC scenario is shown in the flow chart in Figure 2.

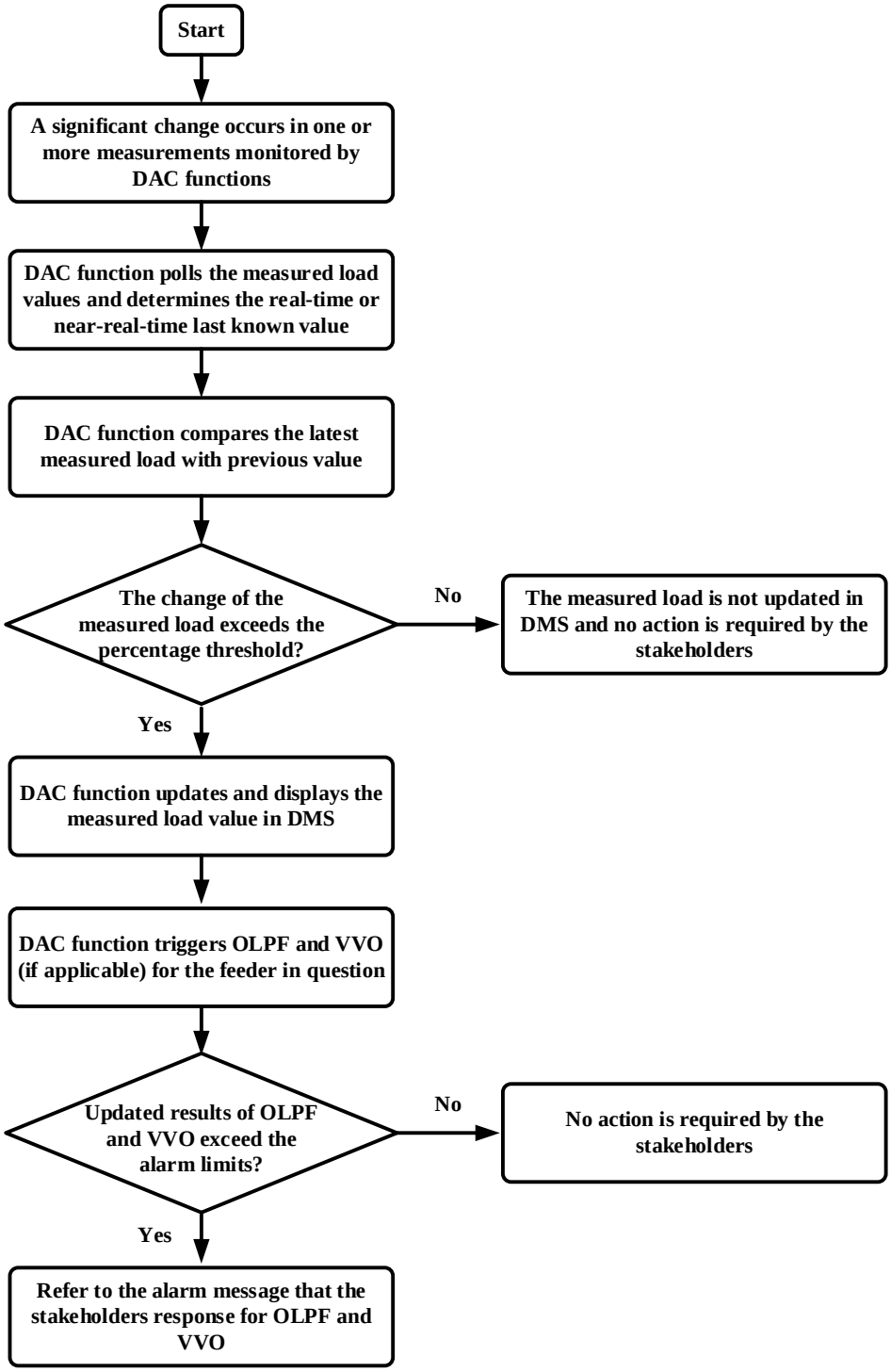



FIGURE 2 Flow Chart of the Operation Procedure of DAC Scenario #1: Significant Change Occurs in Measured Value of Load on a Distribution Feeder

**DAC Scenario Number 2: Alarm message warning indicates that substation transformer load has exceeded its high operating limit.**

The operation procedure of this DAC scenario is shown in the flow chart in Figure 3.

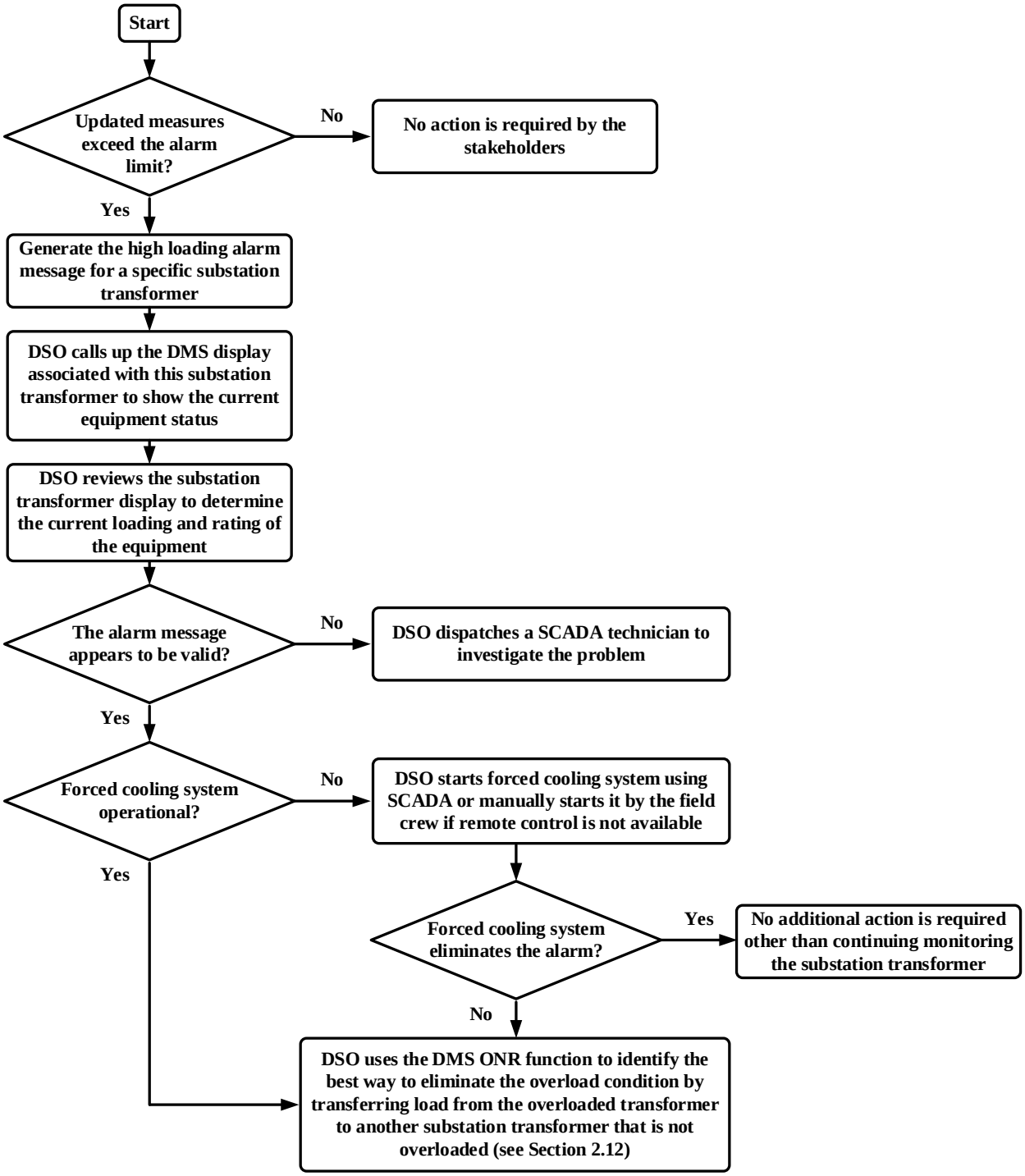



FIGURE 3 Flow Chart of the Operation Procedure of DAC Scenario #2: Alarm Message Warning Indicates That Substation Transformer Load Has Exceeded Its High Operating Limit

## 2.2 DISTRIBUTION STATE ESTIMATION

This section contains the high-level use case for the DMS DSE application function. An accurate insight into the distribution network's current state under normal and emergency conditions is essential to enable the DSO and other stakeholders to manage the distribution networks in a reliable and efficient manner. Typical SCADA deployments only cover the high-voltage/medium-voltage substations. Even though more measurement devices/sensors are installed on distribution circuits, there are still insufficient measurements available nowadays outside the substation fence. The lack of distribution data is the primary motivation for the application of DSE.

The DSE application should be used based on the existing but limited measurements of distribution system to estimate the status of the required busses.

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, transformers, and other such electrical quantities.

DSE is also used for estimating the output of DERs (DG including intermittent renewables, energy storage, etc.) that are not equipped with SCADA facilities for direct monitoring and control.

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 and power supplied by DG sources, many of which are not monitored by the SCADA system (DAC function).

### 2.2.1 Stakeholders

There are no direct users of the DSE function. Like DAC, DSE has many stakeholders that rely on it as an "enabling" function for other DMS application functions, such as OLPF. DSE stakeholders include the following:

- **DSOs** use this function to continuously monitor the performance of the electric distribution system, detect abnormal conditions that may require corrective action, and, when necessary, initiate remote control actions to support normal and emergency operations.
- **AM personnel** use information from the DSE function to determine the overall health and performance of the distribution assets so that suitable maintenance, inspection, and repair work can be scheduled for equipment that is in most need of such activities (i.e., to support a condition-based maintenance program).

- **Planning and design engineers** use peak load information from DSE for the following purposes: (1) capacity planning; (2) system loss study; (3) long-term load forecasting for an area, substation, or feeder; (4) DG connection study; and (5) determination of the impact of adding public EV charging station to an existing feeder.

### 2.2.2 Situations in Which This Function Should Be Used

DSE is continually and automatically running in the background to ensure that the measured data is as accurate as possible and that missing data (such as real-time customer loading and DG output) can be estimated as needed by the OLPF program and other applications.

Under normal circumstances, the stakeholders do not have to perform any specific actions in response to results from the DSE function. However, when data inconsistencies are detected by the DES function, follow-up action may be required by the DSO or other stakeholders to resolve the issue.

For example, if a sensor indicates that there is non-zero power flow through an open switch, the measurement sensor could be malfunctioning or the detected state of the switch is incorrect. In either case, the cause of the inconsistent data must be identified and corrected to avoid corrupting the results of other DMS application functions (e.g., OLPF).

Another example of data inconsistency can occur in cases when redundant measurements of the same power system parameter are available; if the redundant measurements are not the same (within a specified tolerance), then data inconsistency occurs and this condition will be flagged by DSE for further investigation.

### 2.2.3 Information That Is Required to Run the Application

Besides the physical and electrical parameters of network elements, real-time data required by the DSE function includes the following:

- Feeder topology, transformer, and voltage regulator tap changer position.
- Voltage magnitudes at the head end (substation end) of the feeder.
- Current magnitudes (active and reactive power) at the head end of the feeder and at midline points along the feeder.
- Solar radiation, wind speed, and direction monitors for estimating the output of DERs whose output is not directly monitored by the DMS.

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

- Daily load profiles (current magnitudes and power factors, or active and reactive powers) for the following categories, i.e., (1) load classes/type (e.g., industrial, commercial, and

residential), (2) seasons (i.e., winter, spring, summer, and autumn), and (3) types of days (i.e., Saturdays, Sundays, and holidays).

- Peak-loads for all distribution transformers and/or consumers (peak-currents and/or peak power).

### 2.2.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the DSE function to the stakeholders:

- Estimated real and reactive power consumption by each customer.
- Estimated output of DERs (photovoltaic [PV], wind power, etc.) that are not directly monitored by SCADA. For a smaller DG unit that is not required to have SCADA, DSE estimates DG output in one or both of the following ways: by using a sensor (e.g., solar radiation monitor) to estimate the power output of solar PV units, or by using the output of larger DG units (with SCADA monitoring) to estimate the proportional output of smaller DG units.
- List of measurements that have been flagged as possibly invalid on the basis of checks performed by DSE.

### 2.2.5 Required Actions by the Stakeholders in Response to Functional Outputs

Under normal circumstances, no action is required by the stakeholders in response to outputs from the DSE function. However, when inconsistent measurements and/or status indications are detected by DSE, the DSO must take action to correct the problem and thus avoid corrupting the results of other DMS applications, such as OLPF.

**DSE Scenario Number 1: Inconsistent measurement data detected.**

The operation procedure of this DSE scenario is shown in the flow chart in Figure 4.

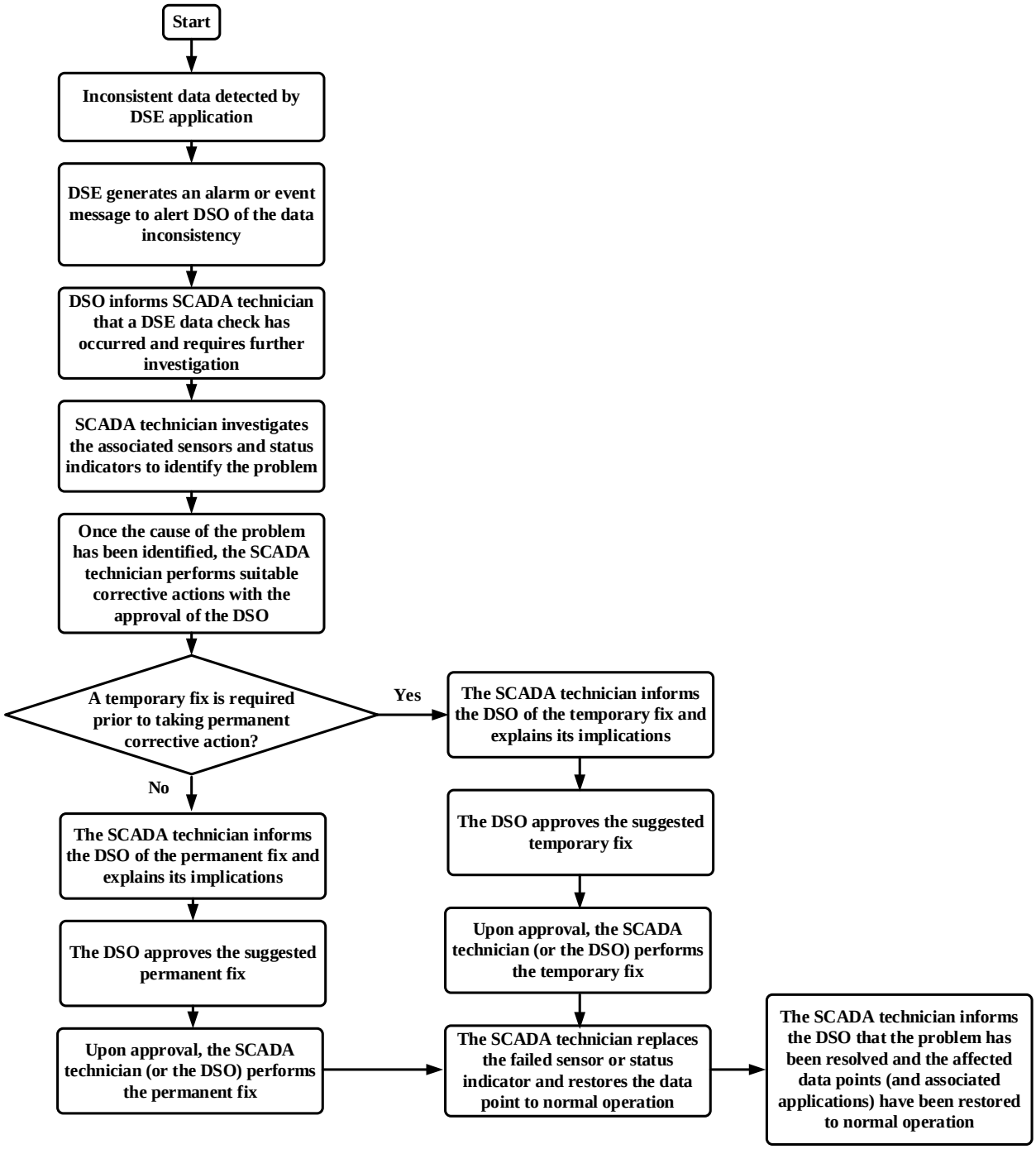



FIGURE 4 Flow Chart of the Operation Procedure of DSE Scenario #1: Inconsistent Measurement Data Detected

## 2.3 DISTRIBUTION SYSTEM MODEL/LOAD 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 encompasses the entire distribution system from the point of connection to the transmission system down to (and including) the distribution service transformer). Meanwhile, it provides the electrical connectivity necessary to support an integrated OMS system and is used for power flows.

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 zero to minimal manual 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 DSO.

The application of distribution system model/load model is used based on the geographic or other system information. It plays a significant role in assisting the other model-based applications in DMS.

### 2.3.1 Stakeholders

The following stakeholders use this function:

- **DSOs** use this function to ensure that all feeder maps, displays, and models reflect the current “as operated” state of the electric distribution system.
- **Field engineers** and **line crews** use the maps and models to identify and locate the specific pieces of equipment they need to work on and for troubleshooting outages and other distribution system problems.
- **Planning and design engineers** use the system and load models for effective maintenance and expansion planning, as well as for understanding connected load on a circuit.
- **GIS personnel** are responsible for maintaining the latest information within the GIS that is used for building the models and displays that are used by DMS.

### 2.3.2 Situations in Which This Function Should Be Used

The maps, models, and other information produced by this function are fundamental items that enable the operation of most DMS application functions. This function runs continuously in the background and ensures that all model-driven DMS applications have the models and displays needed to operate correctly.

The modeling/mapping application should be used under the following circumstances:

- **Significant changes and additions are made to the electric distribution system that affect the overall configuration of a feeder.** For example, an existing line is extended, shortened, reconfigured, etc., and/or new equipment (capacitor bank, transformer, etc.) is added.
- **A temporary change is made that affects the configuration of the electric distribution system.** Examples include changing the position of a switch that is normally open to normally closed and vice versa, and installing temporary cuts and jumpers.

In each situation, existing models and displays must be modified as needed to support the specific situation that has occurred.

### 2.3.3 Information That Is Required to Run the Application

The following information is needed to run the modeling application:

- Description of changes that are needed to the "as operated" model to reflect the different distribution system configuration for the situation in question.
- Time and date for which the changes apply. Note that this may be the current date and time, a date and time in the past (for post-mortem analysis), or a date and time in the future (for outage planning).

### 2.3.4 Outputs That Will Be Provided to the Stakeholders

Outputs provided by the modeling software to the stakeholders include an "as operated" model for the time and date in question. This model includes the as-operated physical characteristics of the distribution system, as well as the load estimates for the time and date in question.

### 2.3.5 Required Actions by the Stakeholders in Response to Functional Outputs

The required actions for the stakeholders for each of the identified scenarios for this function are identified below.

**Modeling Scenario Number 1: Significant changes and additions are made to the electric distribution system that affect the overall configuration of a feeder.** For example, an existing line is extended and/or new equipment (capacitor bank, transformer, etc.) is added.

The operation procedure of this modeling scenario is shown in the flow chart in Figure 5.

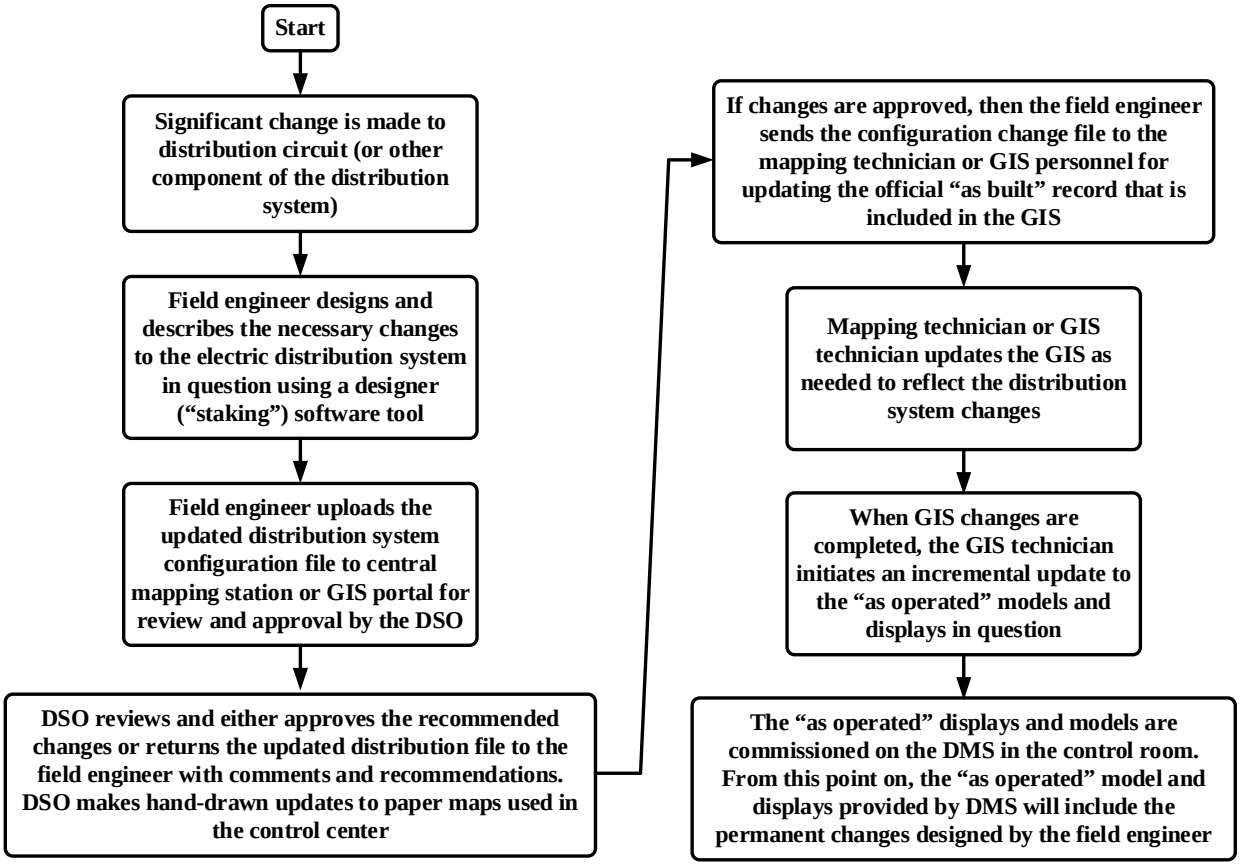



FIGURE 5 Flow Chart of the Operation Procedure of Modeling Scenario #1: Significant Changes and Additions Are Made to the Electric Distribution System That Affect the Overall Configuration of a Feeder

**Modeling Scenario Number 2: A temporary change is made by a DSO or field crew that affects the configuration of the electric distribution system.** A temporary change is one that will remain in effect for less than a specified time period (e.g., less than one month). Examples include changing the position of a switch that is normally open to normally closed and vice versa, and installing temporary cuts and jumpers.

The operation procedure of this modeling scenario is shown in the flow chart in Figure 6.

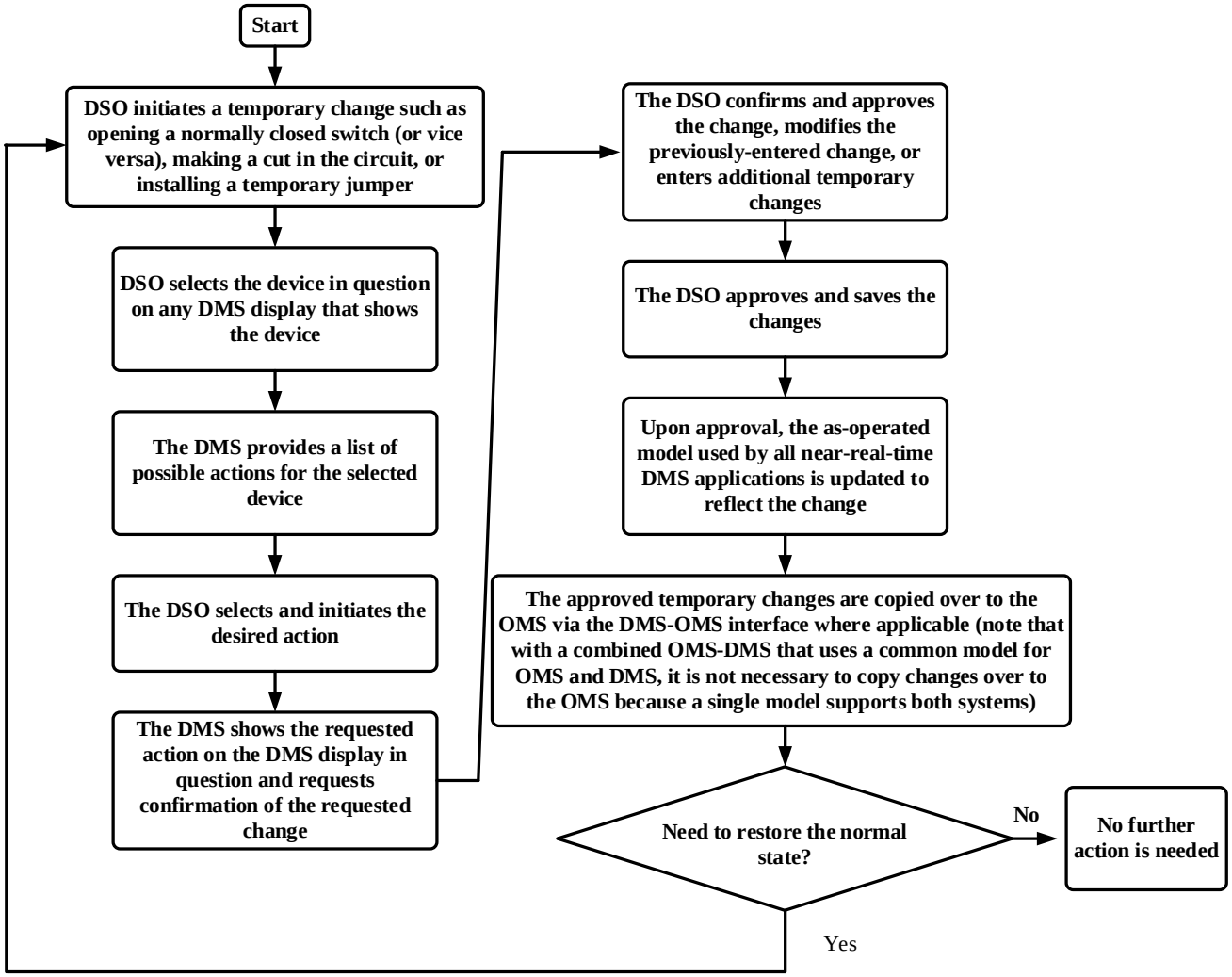



FIGURE 6 Flow Chart of the Operation Procedure of Modeling Scenario #2: A Temporary Change Is Made by a DSO or Field Crew That Affects the Configuration of the Electric Distribution System

## 2.4 ON-LINE POWER FLOW

The DMS OLPF program enables its users to determine the electrical conditions on the distribution feeders in near-real time. The OLPF provides the control center personnel with calculated current and voltage values in place of actual measurements and alerts 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, use the OLPF results to accomplish their specified functionality.

The calculation of OLPF is implemented based on system model and estimated data of distribution system. In particular, the OLPF uses the distribution system model and load estimate provided by load allocation and estimation functions in its calculations, along with available real-time statuses from the substation and feeder devices. The OLPF uses voltages and phase angles obtained from the EMS state estimator at the injection points (usually placed on high-voltage transformer buses in distribution substations).

The OLPF program calculates current and voltage magnitudes and phase angles as well as real and reactive power flows and injections for the entire distribution system and presents the results in various formats automatically and on demand.

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

Convenient mechanisms should be provided for viewing the OLPF results on schematic and geographic displays. The following display mechanisms are available for viewing OLPF results:

- Sections of the feeder that are overloaded or experiencing under/over voltage conditions are automatically highlighted 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”) results in the display of current flow and phase-neutral voltage at that point on the feeder.

Figure 7 illustrates how voltage violations identified by OLPF can be shown on a feeder map display. Areas where voltage violations exist are highlighted with a violet “halo.”

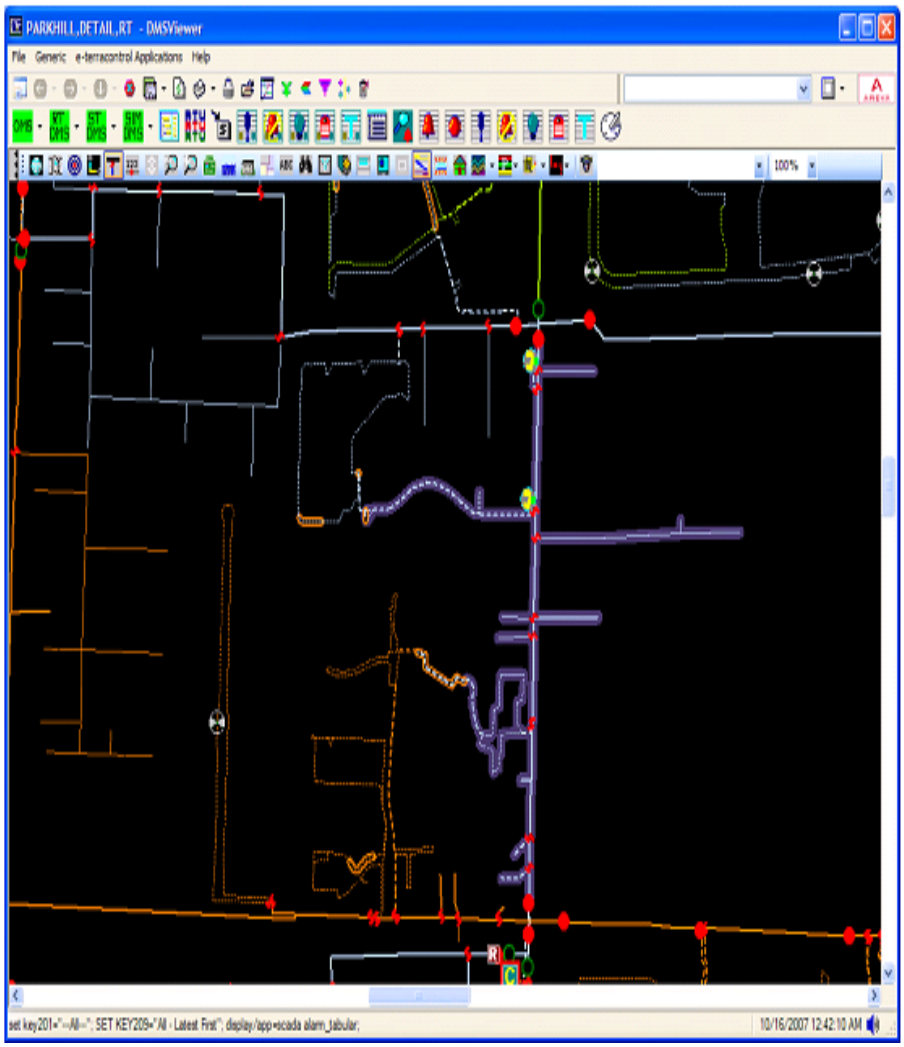



FIGURE 7 Highlighting Section of Feeder with Voltage Violation

The OLPF includes a “study mode” feature that enables engineers and control center personnel to perform “what if” studies using the OLPF program without affecting the actual live operation of the electrical distribution system.

### 2.4.1 Stakeholders

Following are the primary stakeholders for the OLPF function:

- **DSOs** use the OLPF program to compute the estimated conditions at distribution system locations that do not have sensors for continuous remote monitoring.
- **Planning and design engineers** use the OLPF program to compute equipment loading, electrical losses, and effectiveness of voltage regulation strategy and to perform DG connection studies.

### 2.4.2 Situations in Which This Function Should Be Used

The OLPF runs periodically (e.g., once every 15 minutes) on a continuous basis to determine electrical conditions at feeder locations that do not have sensors for direct measurement. Periodic execution of the OLPF DMS application does not require any manual intervention.

The OLPF program should also be used under the following circumstances:

- **A significant change occurs in the configuration or loading of the feeder:** The OLPF program will be triggered when a significant change occurs in the electric distribution (e.g., measured load on the feeder changes by a utility-specified threshold [x %] since the last time OLPF ran, or any switch on a feeder changes position). OLPF can also be triggered manually at any time.
- **"What If" study required:** An engineer or other stakeholder needs to run a power flow study to determine whether unacceptable electrical conditions will result if a proposed distribution system change is made. In this scenario, OLPF will run in study mode.

### 2.4.3 Information That Is Required to Run the Application

The following information is required to run the OLPF program:

- Near-real-time measurements of real and reactive power and voltage at the head-end (substation end) of the feeder (as a minimum) and at other strategic feeder locations (e.g., midline recloser and voltage regulator locations). Providing additional real-time measurements from sensors located on the feeder will improve the overall accuracy of the OLPF calculations.
- "As operated" model of the portion of the electric distribution system that is being analyzed.
- Load profiles for all of the loads that are connected to the feeder. Alternatively, near-real-time load measurements can be used instead of load profiles if this information is available in near-real time from an advanced metering system.
- Real and reactive power output of DG units and energy storage facilities that are connected to the distribution facilities being analyzed. For larger (utility-scale) generating units (usually having a capacity of at least 100 kilowatts), these quantities may be available via SCADA in accordance with the connection agreement. The output of smaller DG units that do not have SCADA can be determined (if needed) by the DSE function.

### 2.4.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the DMS OLPF program to the stakeholders:

- **Real and reactive power flow, current, and voltage** at all points on the feeder.

- **Electrical losses** calculated by OLPF.
- **Warnings and alarms** about abnormal conditions anywhere on the feeder (under/over voltage, overload, etc.).

### 2.4.5 Required Actions by the Stakeholders in Response to Functional Outputs

The specific use cases for the two OLPF scenarios are described below.

**OLPF Scenario Number 1: Significant change occurs.** The OLPF program will be triggered when a significant change occurs on the electric distribution (e.g., measured load on the feeder changes by a utility-specified threshold [x %] since the last time OLPF ran, any switch on a feeder changes position) and can also be triggered manually at any time.

The operation procedure of this OLPF scenario is shown in the flow chart in Figure 8.

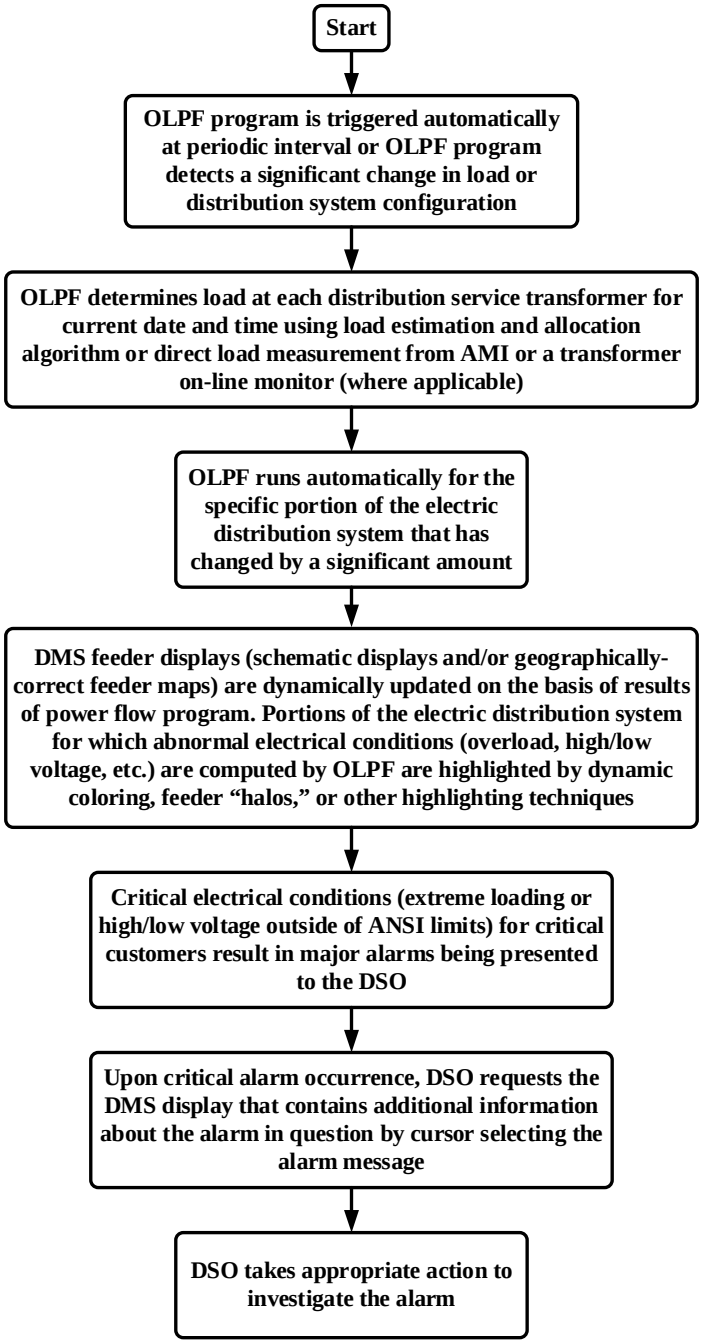



FIGURE 8 Flow Chart of the Operation Procedure of OLPF Scenario #1: Significant Change Occurs

**OLPF Scenario Number 2: "What if" study is required.** Engineer or other stakeholder needs to run a power flow study to determine whether unacceptable electrical conditions will result if a proposed distribution system change is made. In this scenario, OLPF will run in study mode.

The operation procedure of this OLPF scenario is shown in the flow chart in Figure 9.

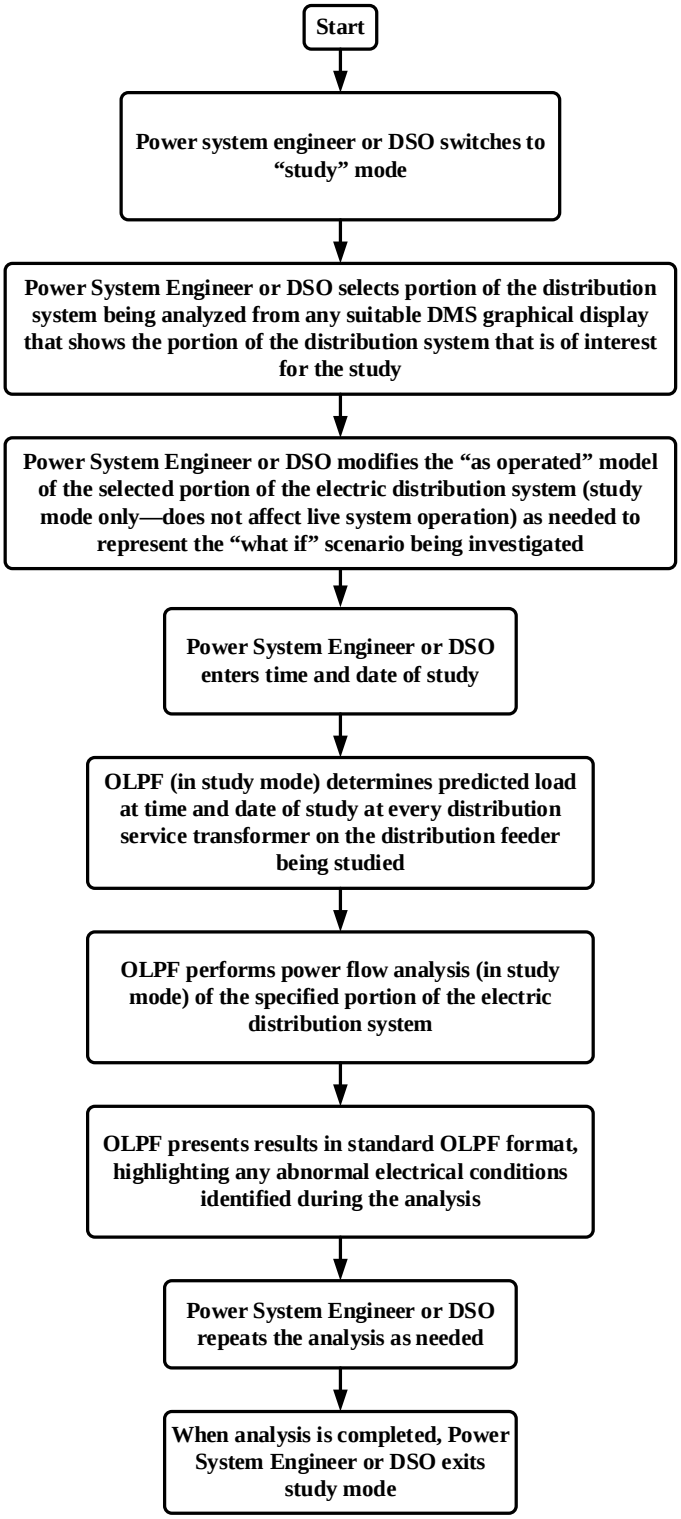



FIGURE 9 Flow Chart of the Operation Procedure of OLPF Scenario #2: "What if" Study Is Required

## 2.5 INTELLIGENT ALARM PROCESSING

The IAP function will alert DSOs and other stakeholders to abnormal conditions on the power system. The IAP function will also alert DSOs to DMS system and communication equipment failures and other abnormal DMS conditions requiring attention. The DMS includes a variety of distinct alarm priorities that determine the manner and priority in which each alarm is announced, acknowledged, and recorded.

The application of IAP is realized based on data acquisition. It generates alarm messages when abnormal operation is detected. The DMS should perform IAP to assist the operator in managing "bursts" of alarms that can occur during an emergency or combinations of alarms related to a single event. As a minimum, IAP will include the following:

- Operating dependent alarms for which alarming of specified points should be enabled or disabled on the basis of the status or values of another related data point.
- Preventing repetitive alarms for the same alarm condition.
- Combining related alarm messages; for example, a single alarm message "feeder ABC tripped" can be provided instead of 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 on the basis of 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 a measurement instrument transformer failure.

The IAP function includes "time-sensitive alarming." The DMS should monitor and track time-sensitive ratings on substation transformers, cables, and other equipment with time-sensitive ratings. The time-sensitive alarm function should track the amount of time by which 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 four-hour emergency rating for a user-specified period (e.g., 3.5 hours), the DSO should be alerted.

### 2.5.1 Stakeholders

Following are the key stakeholders and primary users of the IAP function:

- **DSOs** use the IAP function to alert the operators to abnormal operating conditions that require their attention. Alarms produced by the IAP should be actionable, not just support information that requires no follow-up action.
- **Maintenance personnel and other stakeholders** who are responsible for responding to the incident that produced the intelligent alarm use the IAP function.

### 2.5.2 Situations in Which This Function Should Be Used

The IAP application runs continuously. Action is required when a valid alarm condition is detected.

### 2.5.3 Information That Is Required to Run the Application

The following information is needed to run the IAP application:

- Real-time measurement or computed variable (pseudo point) that exceeded some alarm limit or status point that transitioned to an abnormal (alarm) state.
- Alarm limit that was exceeded.
- Algorithm on which the intelligent alarm is based, including analysis performed on the alarm inputs to determine that the alarm is valid.
- Rules and procedures that describe follow-up action, including the person or persons responsible for performing the follow up action.

### 2.5.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the IAP to the major stakeholders:

- **Alarm message** containing information about the abnormal condition that has been detected.
- **Links to additional information** that can be used by the DSO to interpret the message and perform the necessary actions. Links may include more detailed information about the "intelligent" alarms (individual alarms and alarm dependencies that comprise the "intelligent" alarm, supporting displays, operator notes and procedures for responding to the alarm, and other supporting information).

### 2.5.5 Required Actions by the Stakeholders in Response to Functional Outputs

The specific required actions depend on the specific alarm in question. Because there may be hundreds of different (intelligent) alarms on the system, all having different types of actions in response, it is not practical to provide use cases for all of these items in this report. This section identifies the general list of required actions when an (intelligent) alarm occurs.

The following steps should be performed in response to the functional outputs received from IAP:

**IAP Scenario Number 1: An actionable alarm is generated by the IAP function.**

The operation procedure of this IAP scenario is shown in the flow chart in Figure 10.

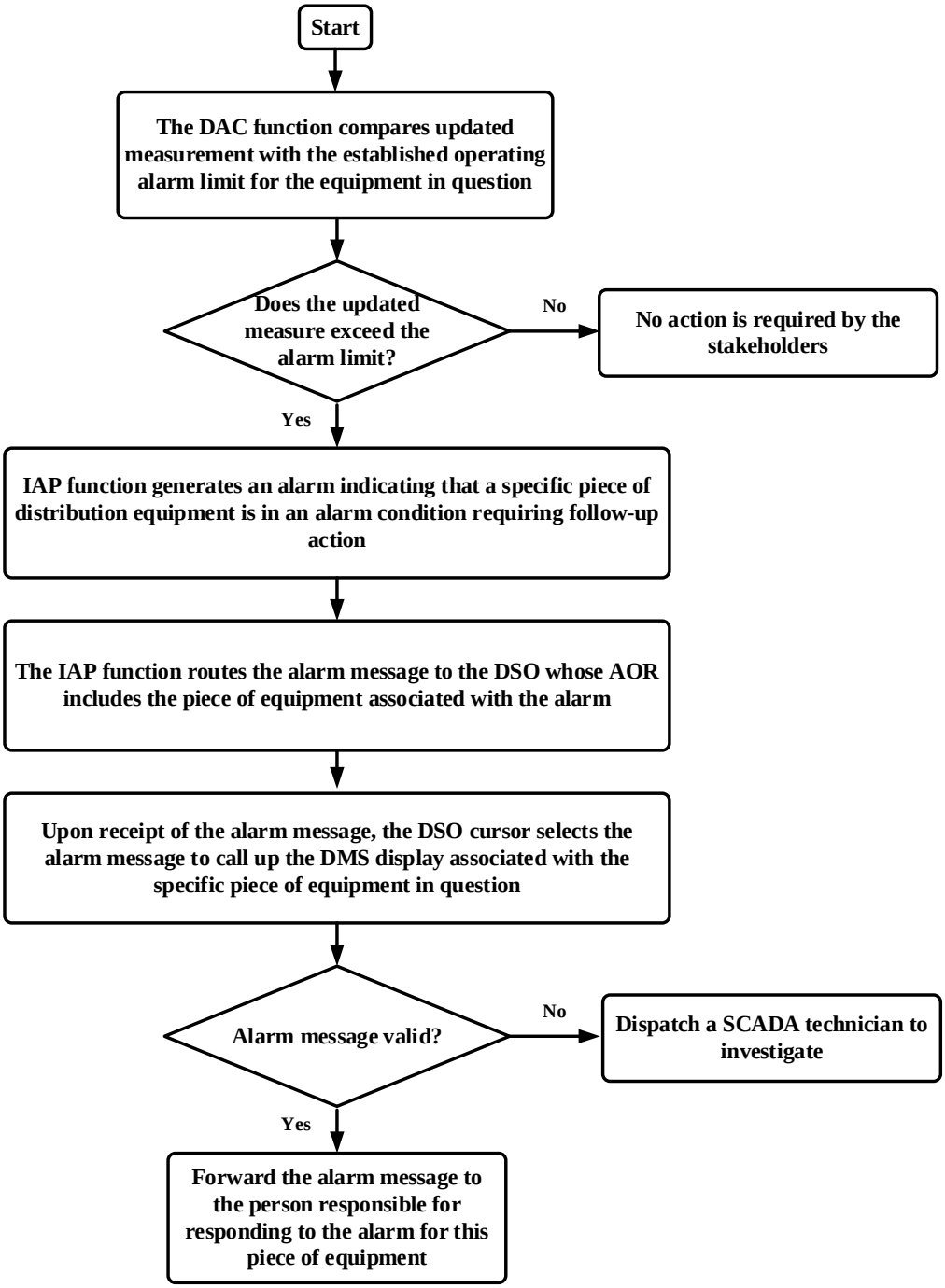



FIGURE 10 Flow Chart of the Operation Procedure of IAP Scenario #1: An Actionable Alarm Is Generated by the IAP Function

## 2.6 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 (tagging, permits, clearances, etc.), 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 will 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.

This application is used to generate, receive, and manage the safety messages to ensure the reliable operation of distribution system. The DMS should use tagging to call the DSO's attention to exception conditions for field devices and to inhibit supervisory control actions. As such, special precautions should be taken to ensure that no supervisory control action can be performed using a control-inhibited device. In addition, special precautions should 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 should only be confirmed to the user applying the tag after it has been committed to the standby processor of the active control system.

Special precautions should be made to ensure that workers are protected against inadvertent or intentional energization by DERs (DG, storage, etc.) of power apparatus that should be de-energized. The tagging and clearance process should ensure that the distribution field workers are protected against such occurrences.

### 2.6.1 Stakeholders

Key stakeholders for the tagging and permits function include the following:

- **DSOs** who have overall responsibility (person-in-charge duties) for maintaining safe working conditions for field workforce and the general public. This responsibility includes ensuring that work areas on or near electrical power apparatus are properly safeguarded to protect the workforce and general public, in accordance with established safety rules.
- **Field workforce, construction personnel, switchmen, first responders, line crews,** and **other personne**l who work in proximity to the energized power apparatus.
- **External parties (contractors, emergency response personnel [fire, police])** that depend on having safe access to selected facilities that are protected against coming in contact with energized electrical components.

### 2.6.2 Situations in Which This Function Should Be Used

The tagging and permits application function should be used under the following circumstances:

- **When construction work needs to be performed in proximity to electrical power apparatus.**
- **When emergency response personnel (fire, police) need to gain access to facilities where energized components are present.**

### 2.6.3 Information That Is Required to Run the Application

The following information is required to run the tagging and permits application function:

- List of facilities being worked on.
- Description of work being performed on nearby facilities (including permits, tags, and clearances associated with nearby work).
- Proposed time and date of the work.
- Requested operating conditions while work is being performed.
- Persons responsible for performing the work.
- Person responsible for placing and removing the tags.

### 2.6.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the tagging and permits application function to the stakeholders:

- Approved permits and clearances, as needed.
- Physical tags.
- Switching orders associated with the work.

### 2.6.5 Required Actions by the Stakeholders in Response to Functional Outputs

The following steps should be performed in response to a request for permits and clearances:

**Tagging Scenario Number 1: Permit or clearance is requested by field crew.**

The operation procedure of this tagging scenario is shown in the flow chart in Figure 11.

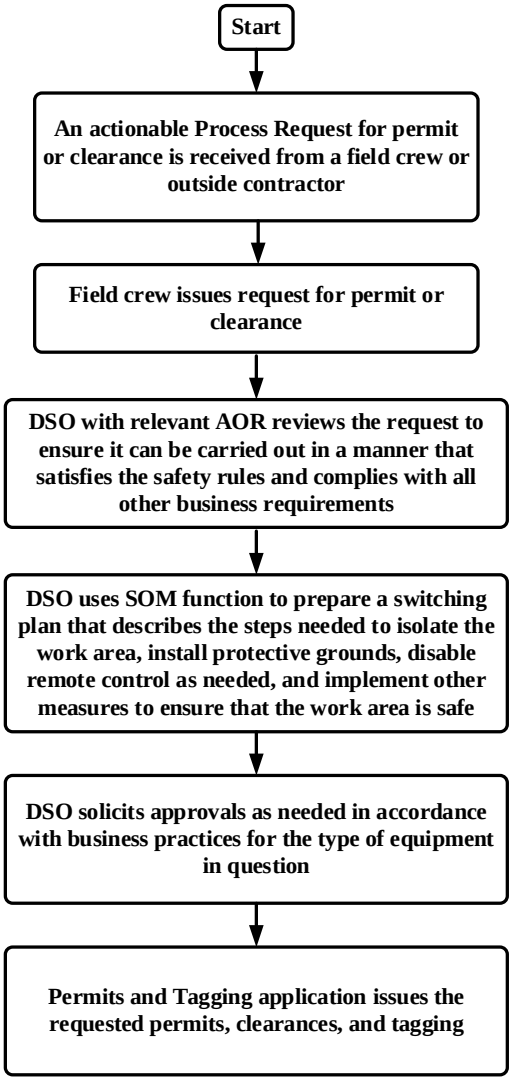



FIGURE 11 Flow Chart of the Operation Procedure of Tagging Scenario #1: Permit or Clearance Is Requested by Field Crew

## 2.7 SHORT-CIRCUIT ANALYSIS

The DMS SCA function enables 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 calculates and compares fault currents against switchgear current-breaking capabilities and device fault-current limits; this capability is useful for conducting post-mortem studies following a power disturbance for which protective relay misoperation is suspected. The SCA function also enables users to identify estimated fault location using measured fault magnitude, pre-fault loading, and other information available at the time of the fault.

The application of SCA is used based on the system model and field measurements. It is used for fault analysis, including fault location, influence assessment, post-fault study, etc.

### 2.7.1 Stakeholders

The following are the principal stakeholders for the DMS SCA function:

- **Protective relay engineers** can use the DMS SCA function to investigate power system events in which relay misoperation is suspected.
- **The DMS PFL application function** uses the DMS SCA function to determine the location of a distribution system fault.

### 2.7.2 Situations in Which This Function Should Be Used

The DMS SCA function should be used under the following circumstances:

- **Fault investigation:** There is a need to determine approximate location of a permanent fault that has occurred so the repair and restoration activities can proceed.
- **Post-mortem analysis of fault event:** A power system disturbance has occurred in which misoperation of a protection and control system is suspected (including incorrect fault location and isolation by FLISR).

### 2.7.3 Information That Is Required to Run the Application

The following information is required to run the SCA application:

- As-operated power system model (positive, negative, and zero sequence), including models of DERs (e.g., DG units) that are able to produce a significant level of fault current contribution.
- Fault magnitude measured by microprocessor-based protective relay during the fault (where applicable).

- Thevenin-equivalent impedance of transmission system at the point of connection of the portion of the distribution system that is being analyzed. Note that impedance varies on the basis of the operating status of centralized generating facilities and transmission lines. This information should be obtained from the EMS.
- Operating status of utility-scale DG units on the feeder in question that are able to produce a significant amount of fault current.

### 2.7.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the DMS SCA application function to the stakeholders:

- Fault current magnitude at any position on the feeder (e.g., at the head end [substation end] of the feeder) for a fault at any given fault location.

### 2.7.5 Required Actions by the Stakeholders in Response to Functional Outputs

Following are the specific processes to be used by the SCA stakeholders for each situation:

**SCA Scenario Number 1: Fault location.**

The operation procedure of this SCA scenario is shown in the flow chart in Figure 12.

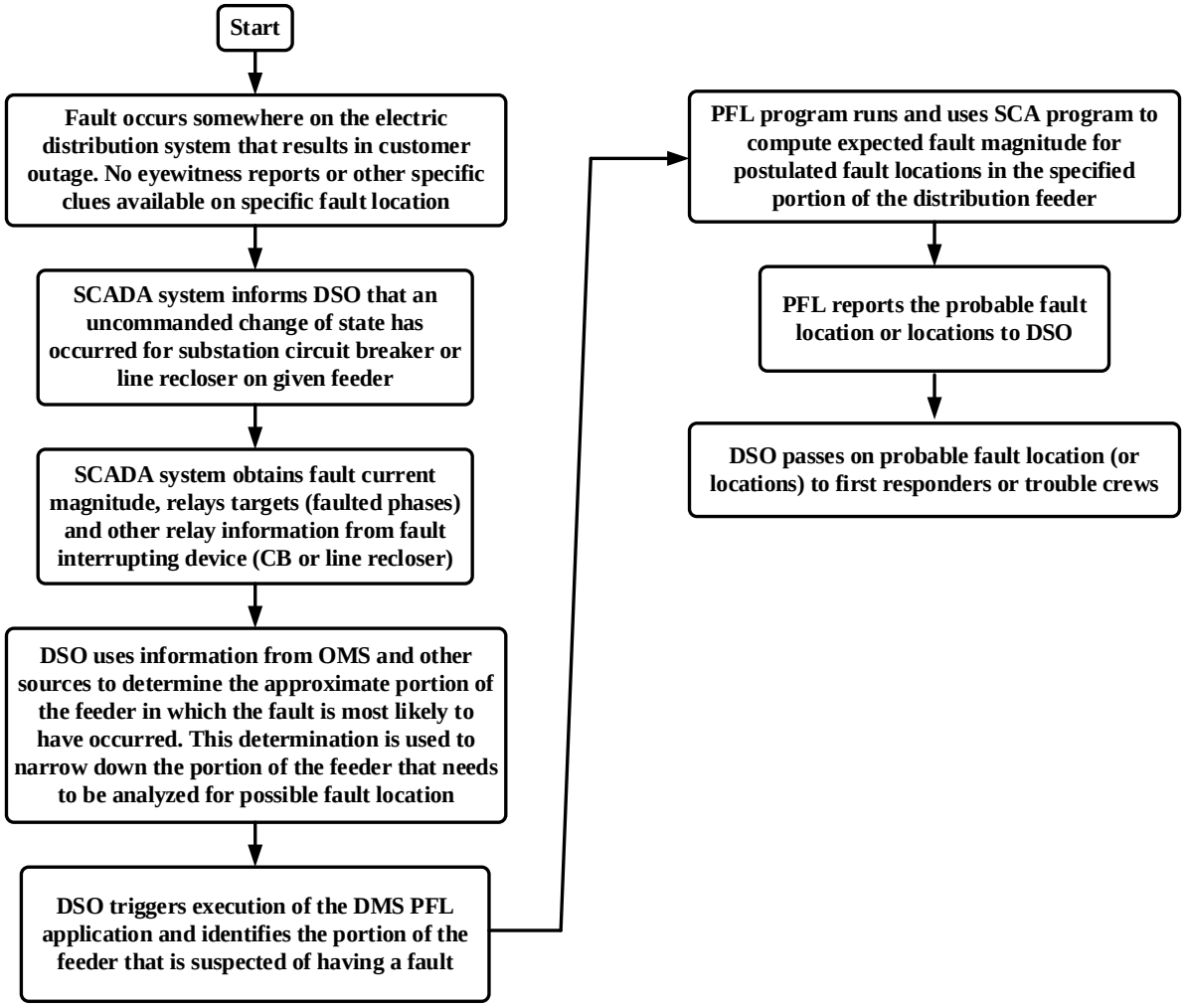



FIGURE 12 Flow Chart of the Operation Procedure of SCA Scenario #1: Fault Location

**SCA Scenario Number 2: Post-mortem analysis.**

The operation procedure of this SCA scenario is shown in the flow chart in Figure 13.

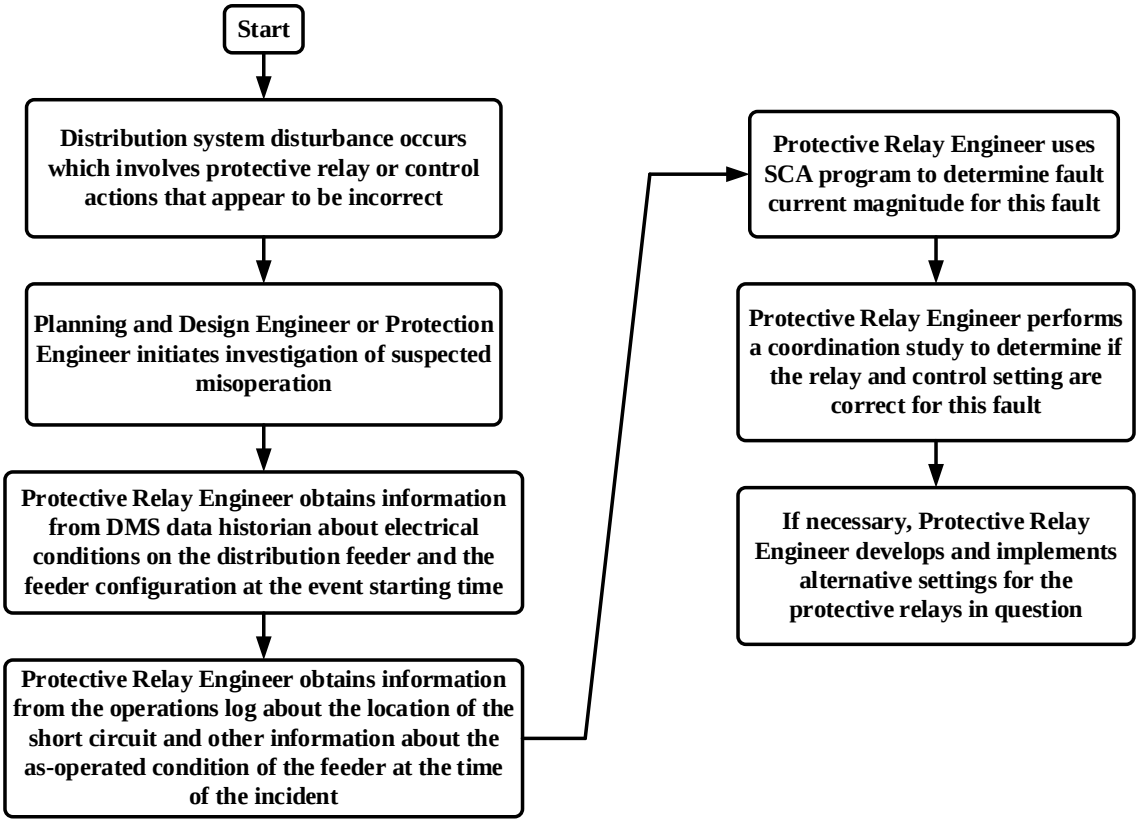



FIGURE 13 Flow Chart of the Operation Procedure of SCA Scenario #2: Post-Mortem Analysis

## 2.8 SWITCH ORDER MANAGEMENT

The DMS SOM function is used to provide detailed a switching procedure in the distribution system. It is realized based on scheduled switching plan and an assessment of affected equipment. It assists the DSOs 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 assists the user in generating switching orders that comply with applicable safety policies and work practices. Figure 14 shows an example of a paper switching order: the DMS should include an electronic version of this switching order. The SOM function 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.

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 |
|---|---|---|---|---|---|
| | | | | | |

RETURN FIELD SWITCHING ORDER SHEET WITH TAGS TO LOCAL SUPERVISION FOR REVIEW
RETAIN LOCALLY FOR THREE (3) YEARS

Figure 14 Switching Order

The DMS is able to automatically generate switching orders. With this auto-generate feature, the dispatcher selects the power system device or portion of the system ("large area restoration") to be isolated and worked on. Figure 15 shows a typical DMS display screen that is used to select the area for which a switching order is needed.

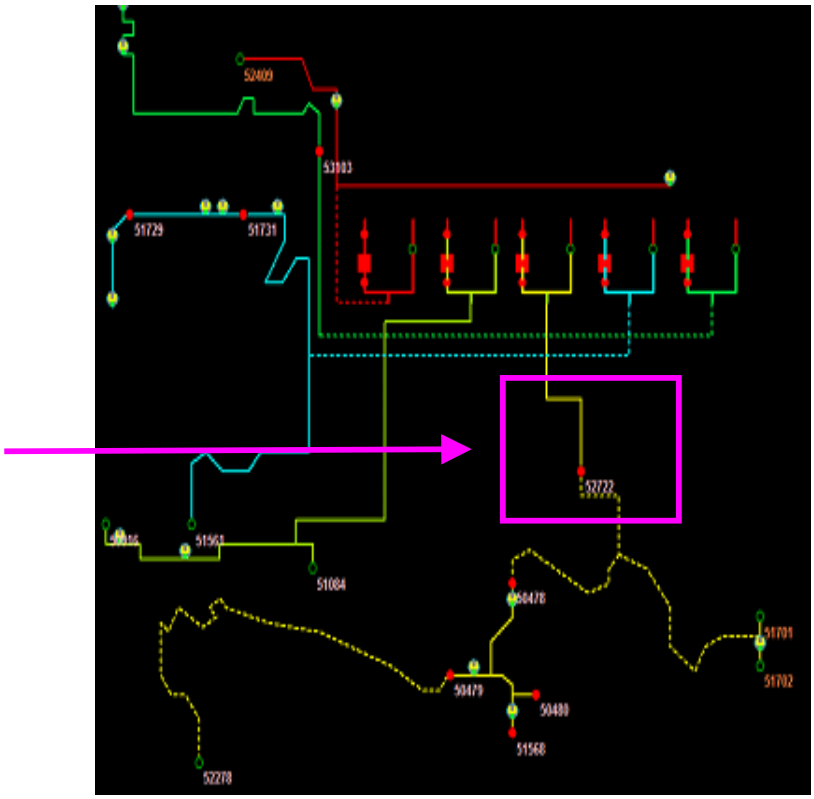



FIGURE 15 Selecting an Area for Automatic Switch Order Creation

The DMS SOM function is able 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 will alert the dispatcher if any violations are detected during study mode execution of the switching order.

### 2.8.1 Stakeholders

Following is a list of key stakeholders for the DMS SOM function:

- **DSO** determines the switching steps that are needed to isolate equipment being worked on from energized power apparatus.

- **Field crew (switchers).**
- **Construction crews.**

### 2.8.2 Situations in Which This Function Should Be Used

The DMS SOM function should be used under the following circumstances:

- **Equipment isolation to support planned work:** Need to isolate a specified piece of equipment being worked on to guarantee the safety of the workers. Isolation should be consistent with established safety standards.
- **Power restoration to a de-energized portion of the feeder:** Need to restore power to a section that has become de-energized because of upstream fault or upstream work being performed.

### 2.8.3 Information That Is Required to Run the Application

The following information is required to run the SOM function:

- Description of planned work: this information is usually provided in the form of an approved permit or clearance.
- Affected equipment, such as a specific piece of power apparatus, all or part of a feeder, or an entire substation.
- Date and time of the proposed work.

### 2.8.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the SOM program to the stakeholders:

- Switching order containing the steps required to isolate a specified portion of the electric distribution system.

### 2.8.5 Required Actions by the Stakeholders in Response to Functional Outputs

This section identifies the specific steps required by the various stakeholders for each of the situations in which the SOM program is used.

**SOM Scenario Number 1: Equipment isolation to support planned work.**

The operation procedure of this SOM scenario is shown in the flow chart in Figure 16.

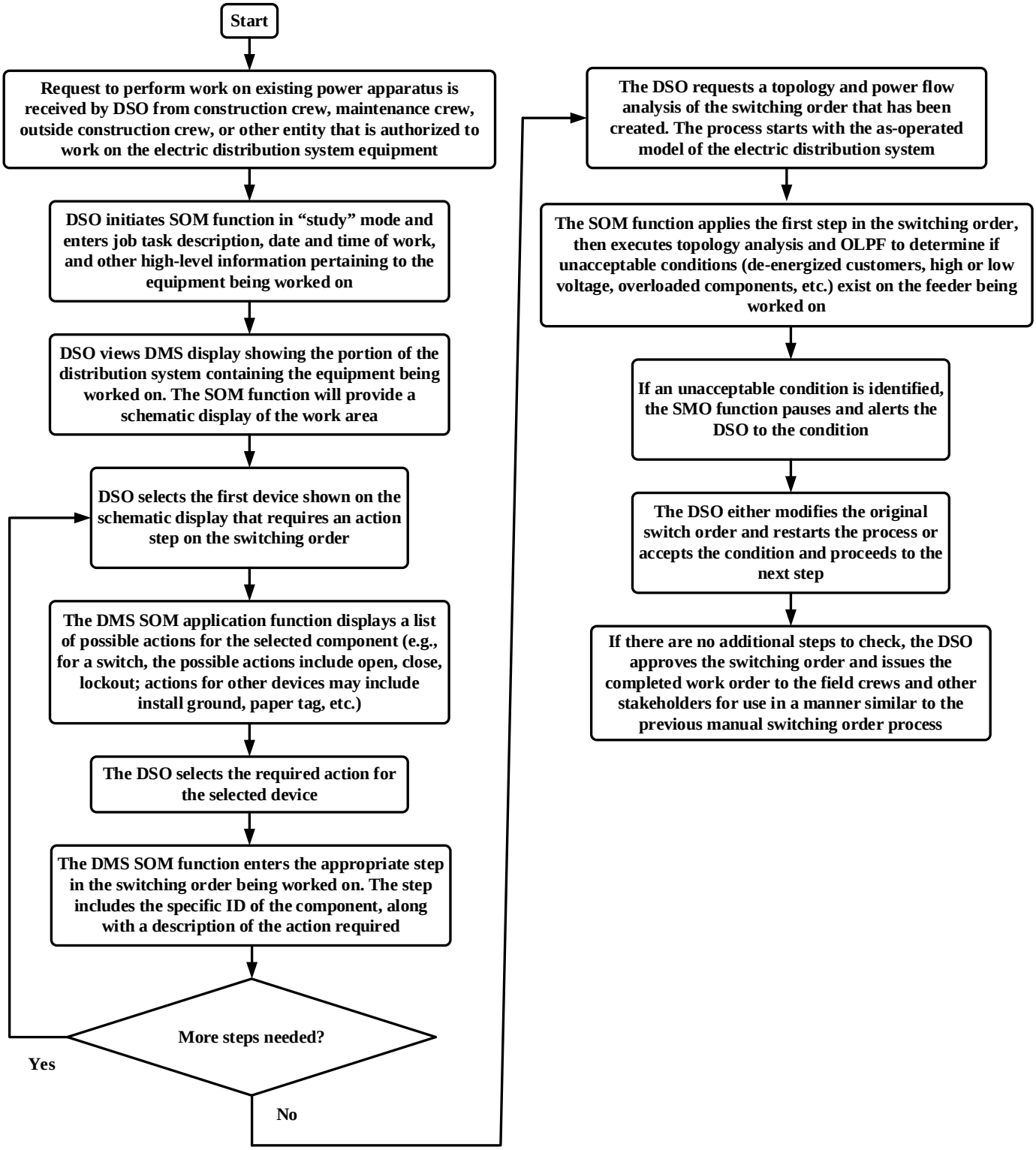



FIGURE 16 Flow Chart of the Operation Procedure of SOM Scenario #1: Equipment Isolation to Support Planned Work

**SOM Scenario Number 2: Restore service to isolated (de-energized) customers.**

The operation procedure of this SOM scenario is shown in the flow chart in Figure 17.

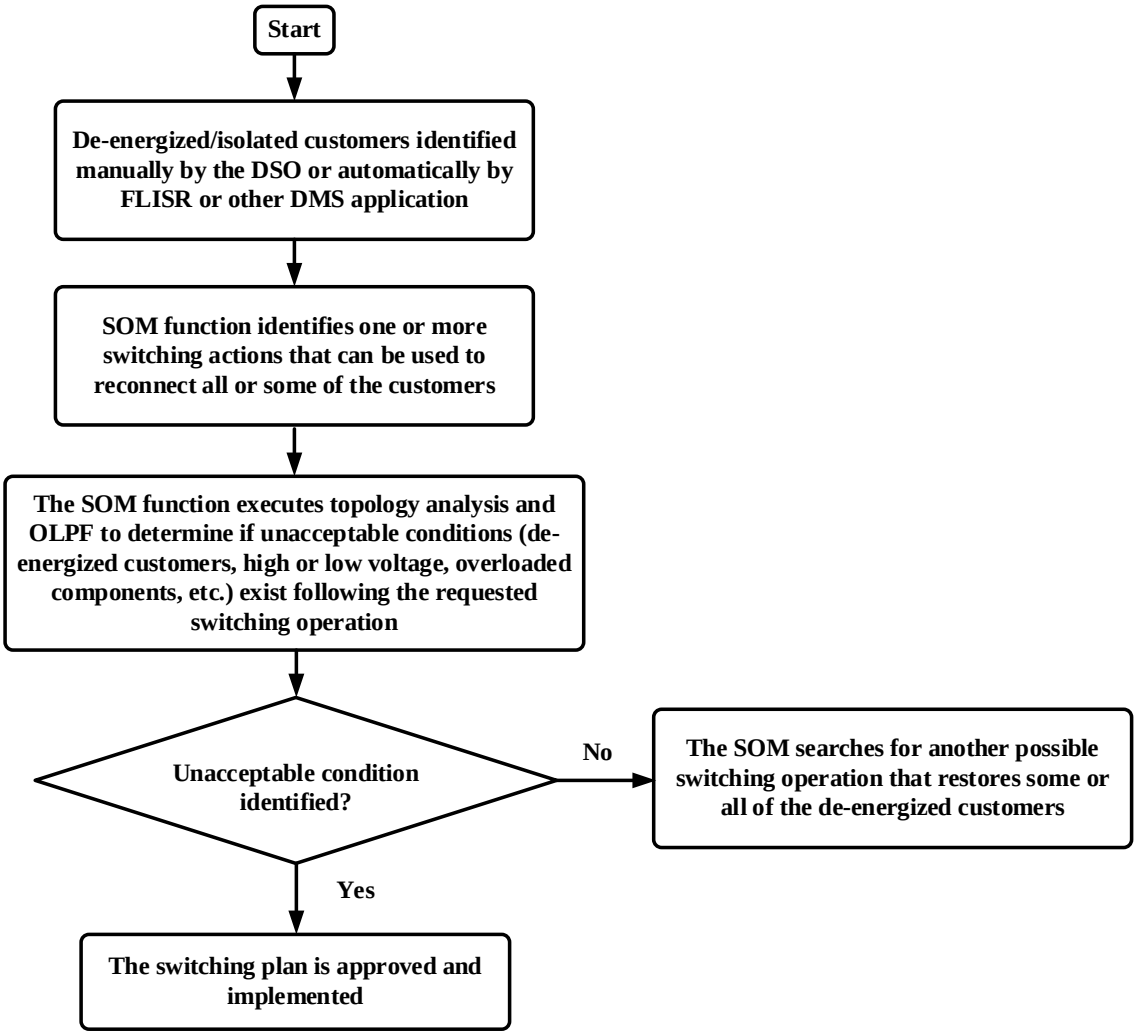



FIGURE 17 Flow Chart of the Operation Procedure of SOM Scenario #2: Restore Service to Isolated (De-energized) Customers

## 2.9 VOLT-VAR OPTIMIZATION

The DMS VVO function automatically determines and initiates optimal control actions for voltage and VAR control devices (e.g., substation LTCs, midline voltage regulators, switched capacitor banks) to achieve user-specified volt/VAR "operating objectives" while maintaining acceptable voltage and loading at all feeder locations. The VVO function should not violate operating constraints, such as daily limits on the number of voltage regulator and capacitor bank operations.

VVO is used based on the model of distribution system. Meanwhile, the control signals generated by the Volt-VAR optimization engine work on the devices that are capable of regulating the voltage profile based on controllable reactive power injection.

VVO should include the following utility-selectable operating objectives:

- Reduce electric demand
- Reduce energy consumption
- Improve feeder voltage profile
- Maximize revenue
- Minimize energy loss/improve power factor
- Implement a weighted combination of the above

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 can 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 (significant change in the distribution system such as significant load transfer or topology change), or when requested by the user (on demand).

The DMS should obtain near-real-time voltage measurements from a small number of (i.e., between 10 and 20) 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 if a feeder outage has occurred.

The VVO function should have a "fail-safe" 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 for any other reason. IEDs used on feeder devices should possess a "heartbeat" 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 "heartbeat" 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 (stand-alone) control. When a VVO component is out of service for any reason (controller failure, loss of communications, controller manually bypassed, blown capacitor fuse, etc.), the DMS should continue to operate in these

abnormal situations, if possible, without producing unacceptable voltage and loading conditions, using the remaining DMS components.

### 2.9.1 Stakeholders

The following are the principal stakeholders for the VVO function:

- **The DSO** is a key stakeholder who is responsible for ensuring that the VVO function is operating properly and is not producing control actions by Volt-VAR control devices that would cause unacceptable voltage and loading conditions anywhere on the circuit. The DSOs are responsible for ensuring that the voltage profile is acceptable at all points on the feeder under all loading conditions in the presence of high penetration of DERs (especially DG units and intermittent renewables that are able to produce reverse power conditions).
- **Planning and design engineers** are the primary stakeholders for the VVO function because they are responsible for efficiency improvement functions like power factor correction and CVR. The planning and design engineers are responsible for determining that VVO programs are providing the expected efficiency improvements.

### 2.9.2 Situations in Which This Function Should Be Used

The VVO program runs continuously at specified intervals (e.g., every 10 minutes).

The VVO program should also be used under the following circumstances:

- Whenever a significant change occurs on the distribution system:
  - **Load on the feeder changes** by more than 3–5% since the last time the VVO program ran.
  - **Feeder reconfiguration has occurred** for any reason.
- If the operating objective for VVO includes voltage reduction during peak load conditions, the program would be used **when peak load conditions are expected.**
- VVO can also be called upon to run **when a system emergency is declared**: emergency load reduction, call for reactive power support, etc.

### 2.9.3 Information That Is Required to Run the Application

The following information is required to run the VVO application:

- As-operated feeder model of the distribution circuit in question (includes the normal [as-built] model plus changes that have occurred to the normal configuration).
- Real-time feeder measurements, especially real and reactive power flow at the head end of the feeder.

- Near-real-time voltage feedback from feeder extremities.
- Current operating status of all Volt-VAR regulating/control devices.

### 2.9.4 Outputs That Will Be Provided to the Stakeholders

The VVO function includes an audit function that enables the planning engineer to review the VVO switching actions and associated analysis that resulted in each control action.

VVO provides a switching plan for voltage and VAR control devices, including switched capacitor banks; voltage regulators (substation LTCs and midline voltage regulators); smart inverters; DERs that can supply Volt-VAR support; power electronic-based, edge-of-network-based devices; and other devices that enable distribution Volt-VAR control.

### 2.9.5 Required Actions by the Stakeholders in Response to Functional Outputs

Descriptions of required user actions for each of the VVO scenarios are described below:

**VVO Scenario Number 1: Significant change occurs on electric distribution system** (feeder reconfiguration, load change exceeds threshold established by the utility).

The operation procedure of this VVO scenario is shown in the flow chart in Figure 18.

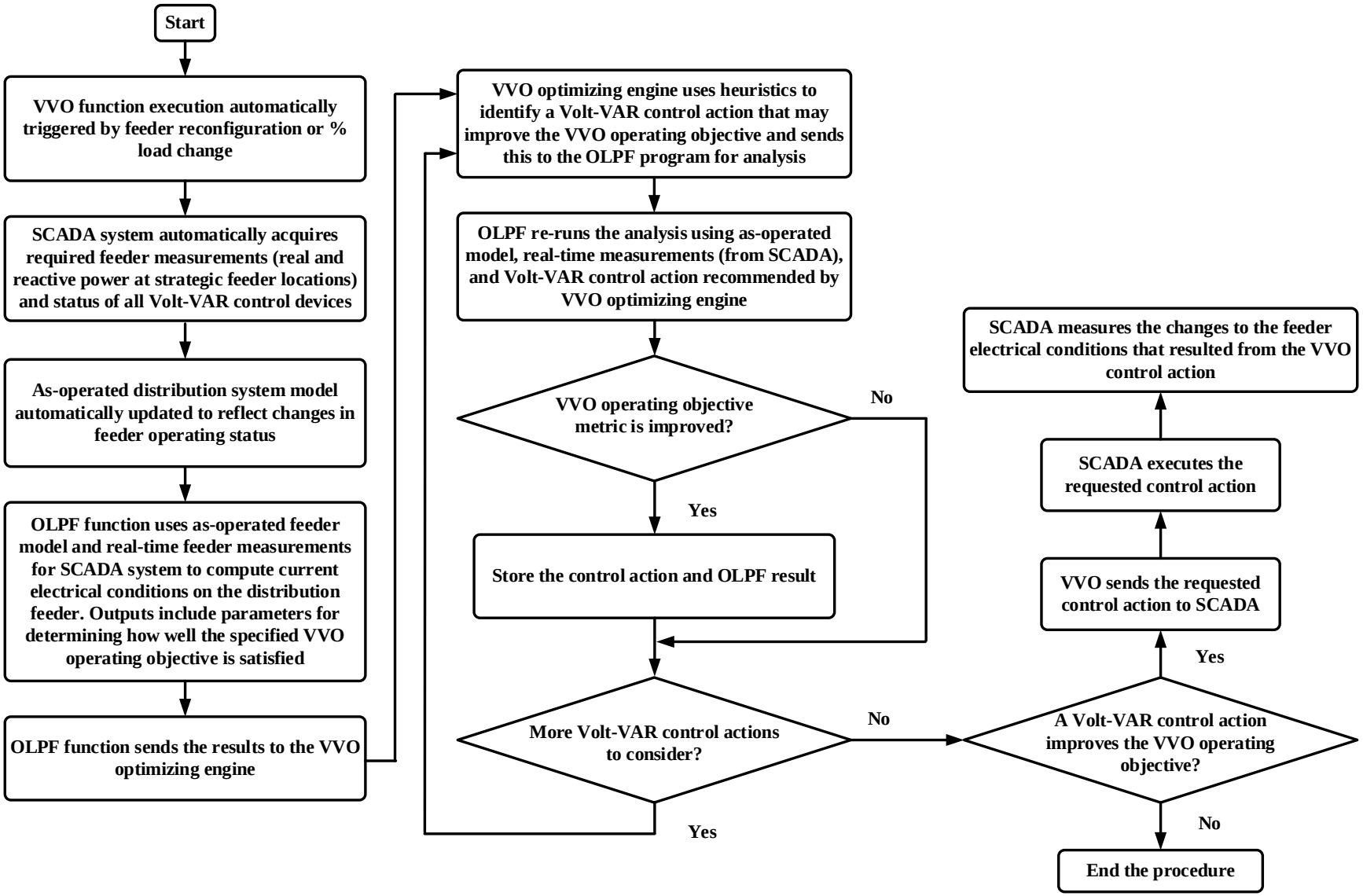



FIGURE 18 Flow Chart of the Operation Procedure of VVO Scenario #1: Significant Change Occurs on Electric Distribution System

**VVO Scenario Number 2: ISO requests VAR support to address system emergency.**

The operation procedure of this VVO scenario is shown in the flow chart in Figure 19.

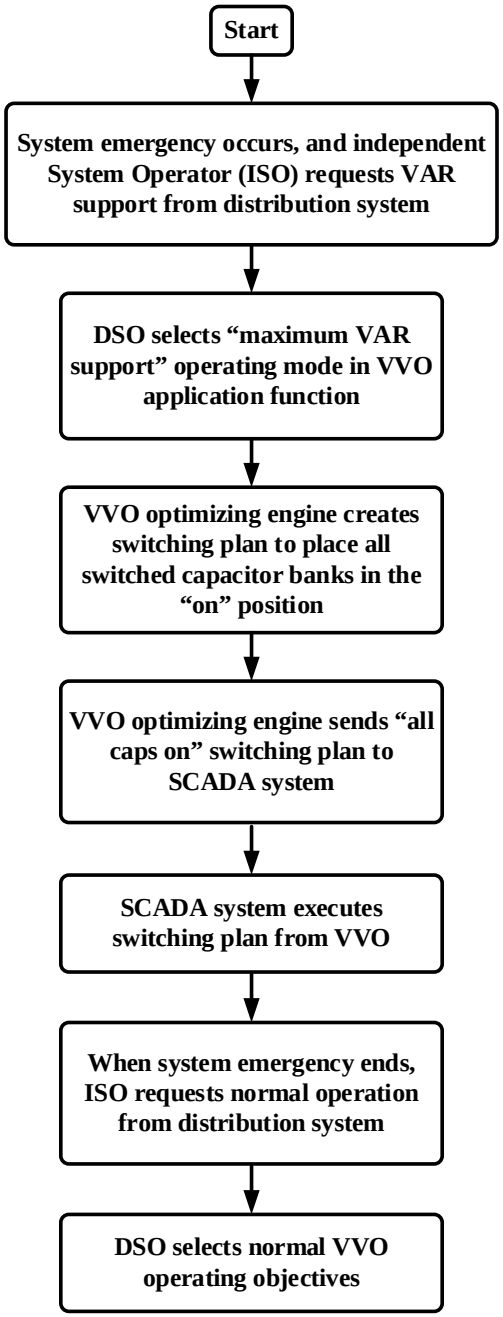



FIGURE 19 Flow Chart of the Operation Procedure of VVO Scenario #2: ISO Requests VAR Support to Address System Emergency

**VVO Scenario Number 3: ISO requests voltage reduction to address system emergency.**

The operation procedure of this VVO scenario is shown in the flow chart in Figure 20.

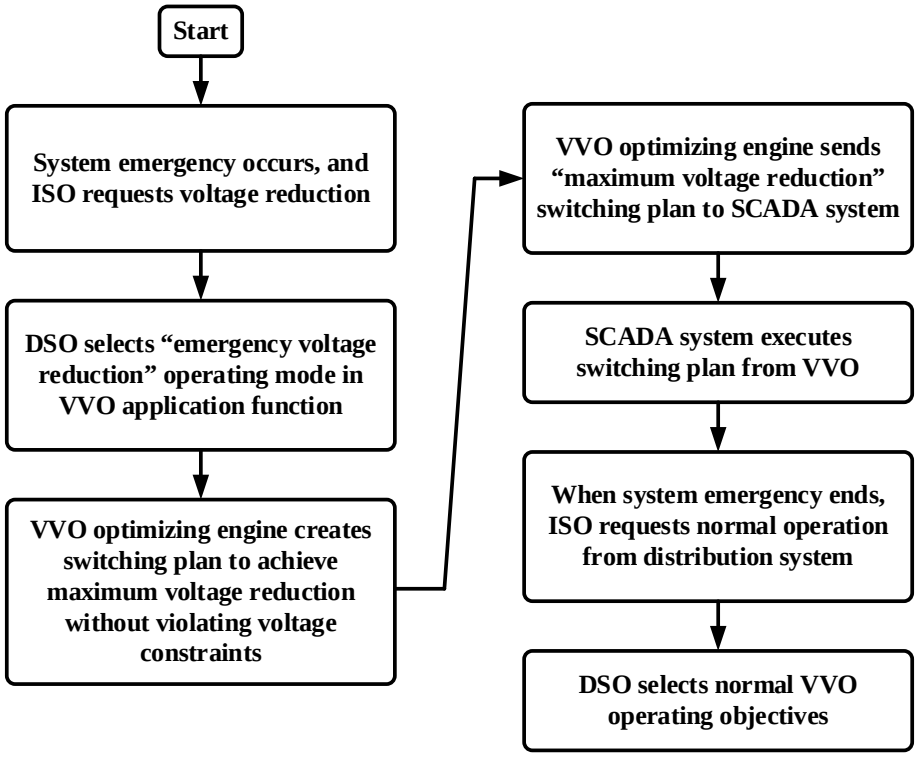



FIGURE 20 Flow Chart of the Operation Procedure of VVO Scenario #3: ISO Requests Voltage Reduction to Address System Emergency

## 2.10 FAULT LOCATION ISOLATION AND SERVICE RESTORATION

The purpose of the FLISR function is to restore power to as many customers as possible following a permanent fault of the distribution feeder. If backup sources with sufficient spare capacity exist, FLISR will be able to restore power to some or all customers connected to healthy (unfaulted) sections of the feeder in less than one minute, versus restoration in one hour or longer with conventional restoration procedures. The result is a significant improvement in service reliability as measured by the System Average Interruption Duration Index and System Average Interruption Frequency Index.

The DMS FLISR application function, also referred to as "self-healing," is one of the major application functions associated with grid modernization. It is implemented based on the knowledge of system model and measured data, and it is used to isolate the fault and restore the service in the post-fault period. The FLISR main logic will automatically do the following:

- Detect permanent faults (faults that are not self-clearing) out on the distribution feeder;
- Determine the approximate location of the fault (i.e., the faulted section of the feeder that is bounded by two or more feeder switches);
- Isolate the faulted section of the feeder; and
- Close normally open tie switches to transfer loads that are downstream (further from the normal supply substation) of the faulted section to an adjacent backup.

The following example of a DMS FLISR incorporating single-phase automation is presented in Figure 21 for illustration. In this example, the feeder is broken into three sections starting from the left with a substation breaker, with single-phase operating reclosers as the mainline sectionalizing device, and normally open three-phase reclosers at ties. The phases should be interpreted as Aφ on top, Bφ in the middle, and Cφ at the bottom.

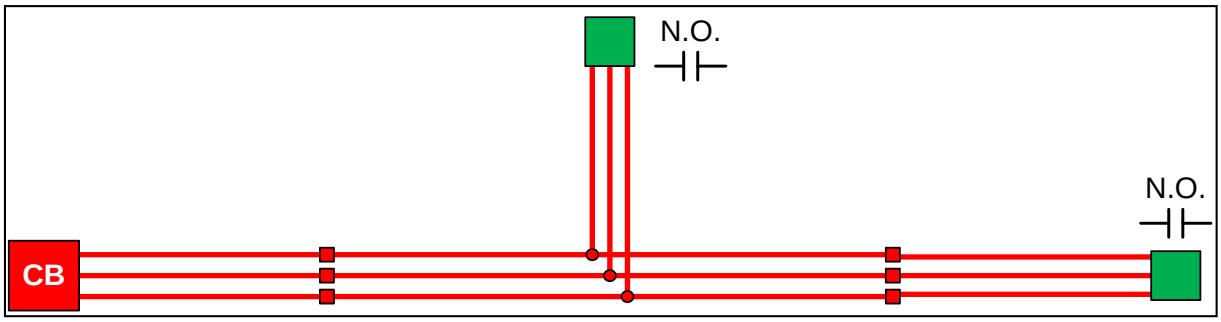



FIGURE 21 Example of FLISR with Single-Phase Automation – Initial Condition

When a fault occurs on Aφ, the Aφ recloser goes through its trip cycle. Customers upstream of the recloser, as well as those on Bφ and Cφ, are not affected. If the fault is permanent, the Aφ recloser goes to lock out (Figure 22).

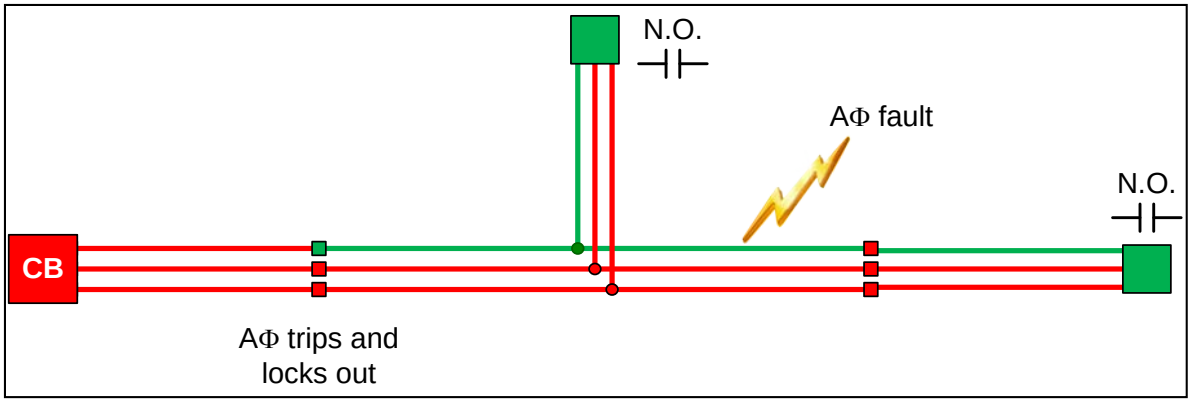



FIGURE 22 Example of FLISR with Single-Phase Automation – Fault Occurs and Recloser Locks Out

The downstream recloser opens to sectionalize all three phases and isolate the fault (Figure 23). This decision-making logic may take place locally, using just the information available to the recloser, or it may be directed from the DMS. In either case, the important decision points are that the recloser experienced a sustained loss of potential on one or more phases and that it did not experience any fault current. All three phases are tripped to avoid the potential of having different phases fed from different directions on the same section.

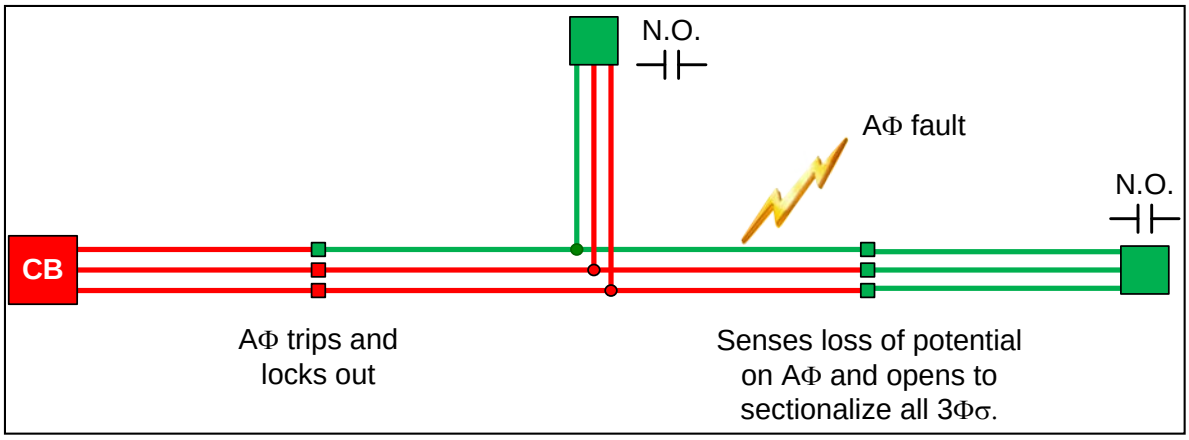



FIGURE 23 Example of FLISR with Single-Phase Automation – Fault Isolated

Once the fault has been isolated between the first and second recloser, control logic directs the closing of the 3φ tie switch, restoring all customers downstream of the second recloser. At the end of this operation, only 1/9 of the feeder experiences a sustained outage (Figure 24). A similar FLISR event with three-phase switching would have resulted in one-third of the feeder experiencing a sustained outage.

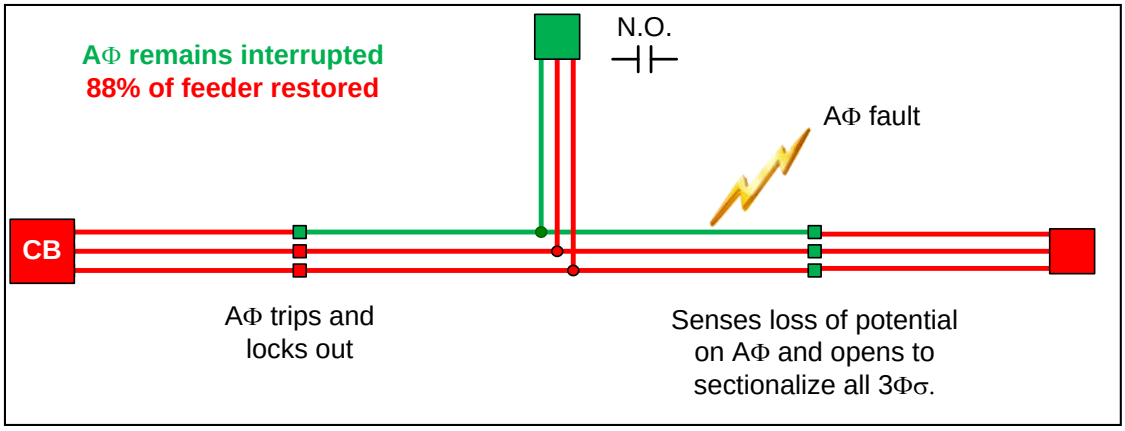



FIGURE 24 Example of FLISR with Single-Phase Automation – Restoration

### 2.10.1 Stakeholders

FLISR stakeholders include DSOs, trouble dispatchers, and field crews.

### 2.10.2 Situations in Which This Function Should Be Used

The FLISR application should be used when a permanent fault occurs out on the feeder that is not cleared following automatic reclosing. (Event-driven) FLISR should **not** be used when the circuit is intentionally de-energized by manual switching (ELS) and when the circuit is de-energized by under-frequency load shedding and/or under-voltage load-shedding relays (i.e., stakeholders should not attempt to restore feeders that have been tripped to mitigate a bulk power grid emergency).

### 2.10.3 Information That Is Required to Run the Application

The following information is needed to run the FLISR application function:

- Trip status and available relay targets from the protective relays associated with circuit breakers, line recloser, and other protective devices on the feeder.
- Open/closed status indications for circuit breakers and line reclosers on the feeder, plus all tagging and other operating restrictions (e.g., do-not-operate tags) for all circuit breakers and reclosers.
- FCI status indications or other means of detecting that a fault has occurred “downstream” (further from the normal supply substation) of the device. This information is used for locating the fault. FCIs or other fault-detecting devices are required at each automated switch that is present on the feeder in question.

- “Hot-line tag” status indication (indicates that live line work is being performed on the feeder). When the hot-line tag is set for the feeder, no switches should be closed by FLISR (opening switches that do not have “do not operate” tags is permitted).
- Near-real-time load measurements are required on the affected feeder at every circuit breaker, line recloser, load break switch, and other automated switching device used by FLISR. This information is used to determine the load that is connected to every feeder segment (portion of feeder bounded by FLISR switches), which, in turn, FLISR uses to determine whether the load can be transferred to a backup feeder without causing overloads or under-voltage conditions.
- Near-real-time load measurements are required for all feeders that are connected to the affected feeder via normally open automated tie switches, along with the maximum loading capacity on each potential backup feeder. This information is used to determine the maximum amount of load that can be transferred to the backup feeder without producing unacceptable electrical conditions (under-voltage, overload, etc.).
- Operating status and loading of all DERs that are connected to the feeder. This information is needed to determine the “net load” (actual load minus DER facilities that will trip off when the line goes dead) on each feeder section. It also can be used to determine what DERs can be brought back on line to enable restoration of downstream feeder segments that cannot otherwise be restored because of loading constraints on backup feeders.

### 2.10.4 Outputs That Will Be Provided to the Stakeholders

The FLISR application function will generate a switching plan for isolating the faulted section of the feeder and restoring service to customers that are served from a feeder location that is not “downstream” of the faulted feeder. The FLISR application will also produce a switching plan for transferring load that is downstream of the faulted feeder section to an adjacent feeder that has sufficient spare capacity to accept the additional load.

The FLISR application function will identify the faulted section of the feeder, which is bounded by the switches used to isolate the faulted feeder segment. This information should be forwarded by the trouble dispatcher or DSO to the first responder and/or trouble crews to identify the portion of the faulted feeder that needs to be patrolled.

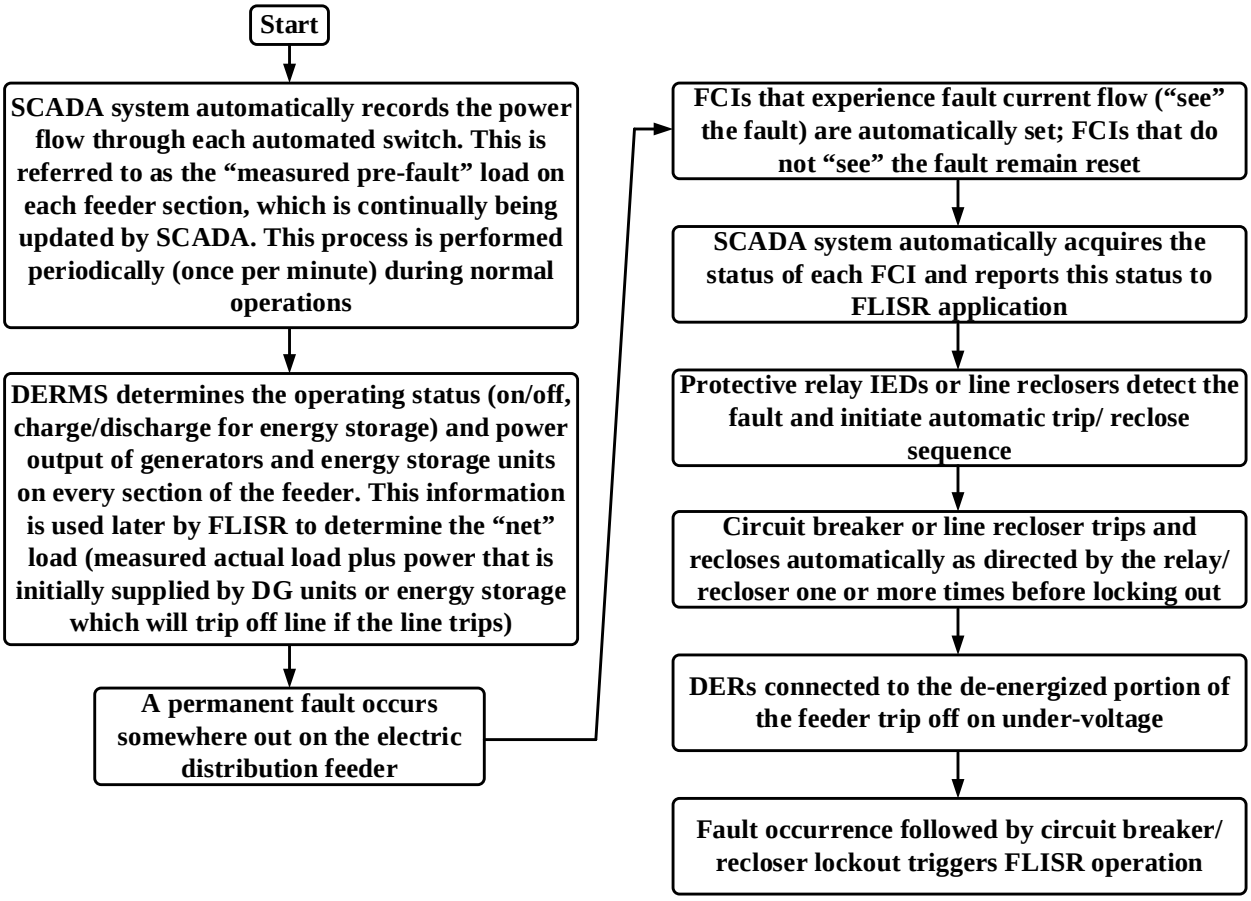
### 2.10.5 Required Actions by the Stakeholders in Response to Functional Outputs

FLISR can operate in fully automatic mode, semi-automatic mode, or manual (supervisory) mode. The use case varies depending on what mode FLISR is operating in. In “fully automatic” mode, the FLISR application runs without manual intervention and automatically initiates the switching actions identified by FLISR for switches controlled by SCADA. In semi-automatic mode, some activities (e.g., detection, location, isolation, and upstream restoration) are performed automatically with no human intervention, and other activities (e.g., downstream restoration) are performed manually by the operator and/or field crews. In manual (supervisory) mode, all switching actions are initiated by the DSO and field crews using a switching plan supplied by

FLISR. *[Note: For the purposes of this high-level use case, it is assumed that FLISR is operating in semi-automatic mode, meaning that FLISR handles fault detection, isolation, and upstream restoration with no manual intervention and downstream restoration requires operator approval.)*

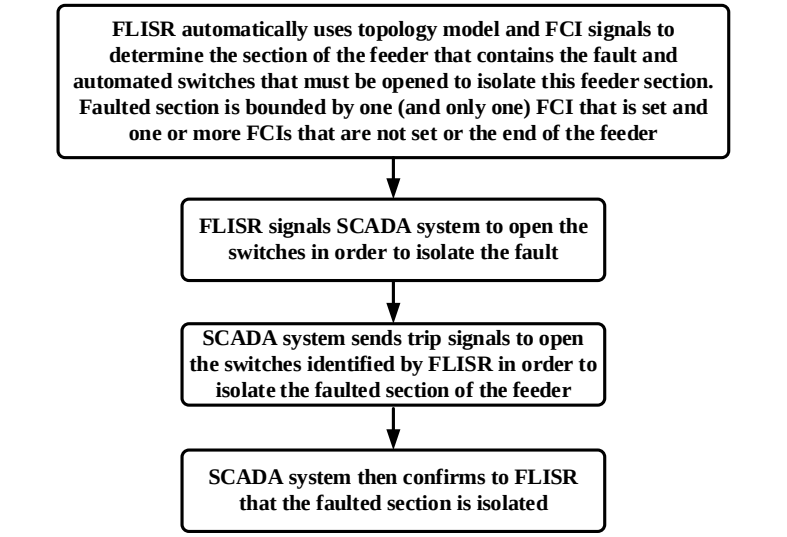
**FLISR Scenario Number 1: Permanent fault occurs out on the main line portion of the distribution feeder (not protected by fuse).**

The operation procedure of this FLISR scenario is shown in the flow chart in Figure 25.

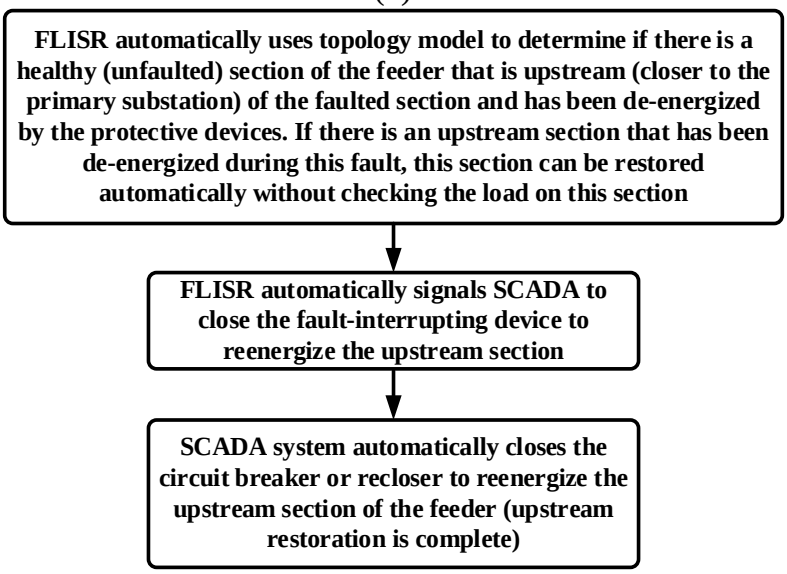



(a)

FIGURE 25 Flow Chart of the Operation Procedure of FLISR Scenario #1: Permanent Fault Occurs Out on the Main Line Portion of the Distribution Feeder: (a) Pre-procedure, (b) Step 1: Fault Isolation, (c) Step 2: Upstream Restoration, (d) Step 3: Downstream Restoration, (e) Step 4: Microgrid Operation

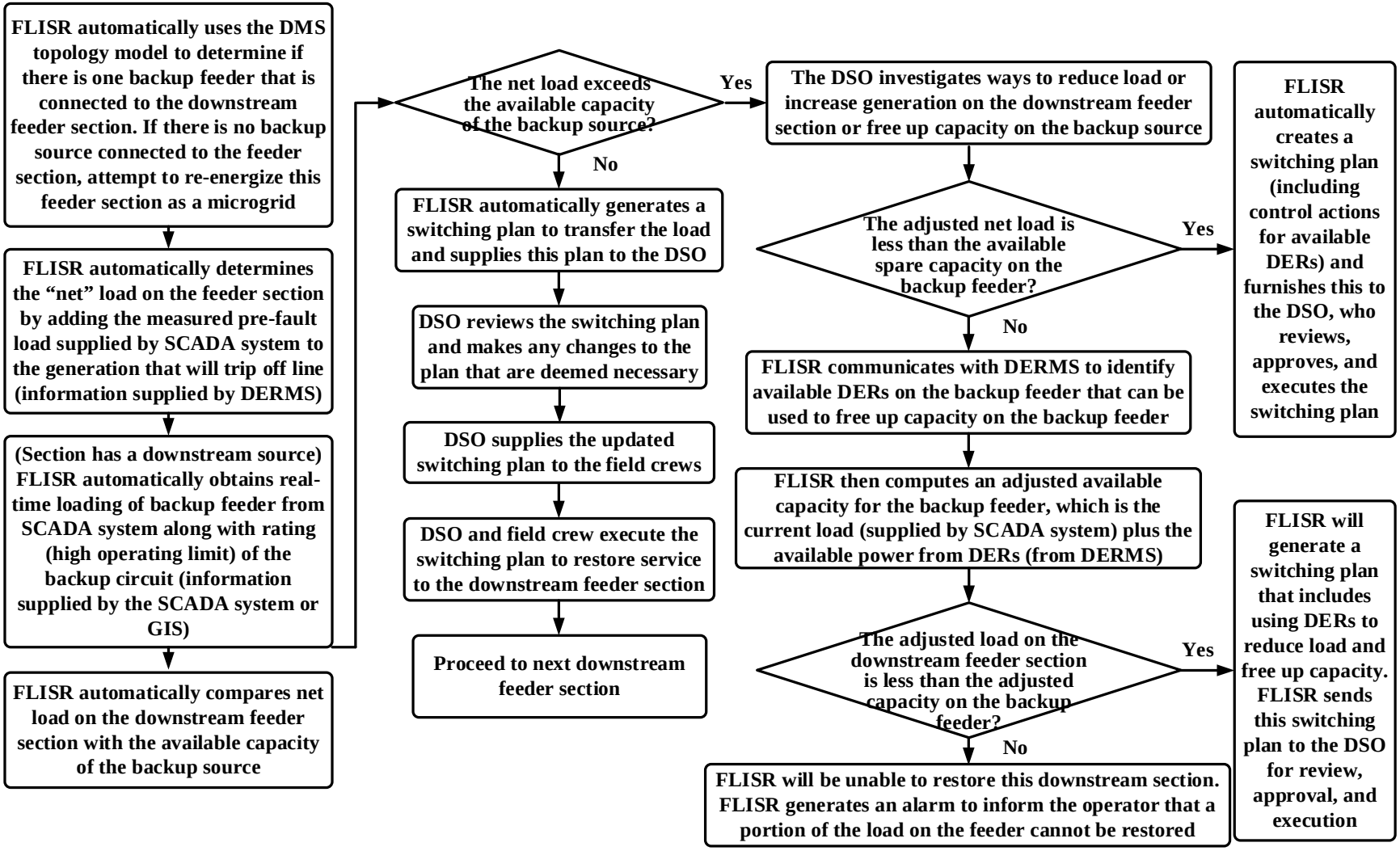



(b)



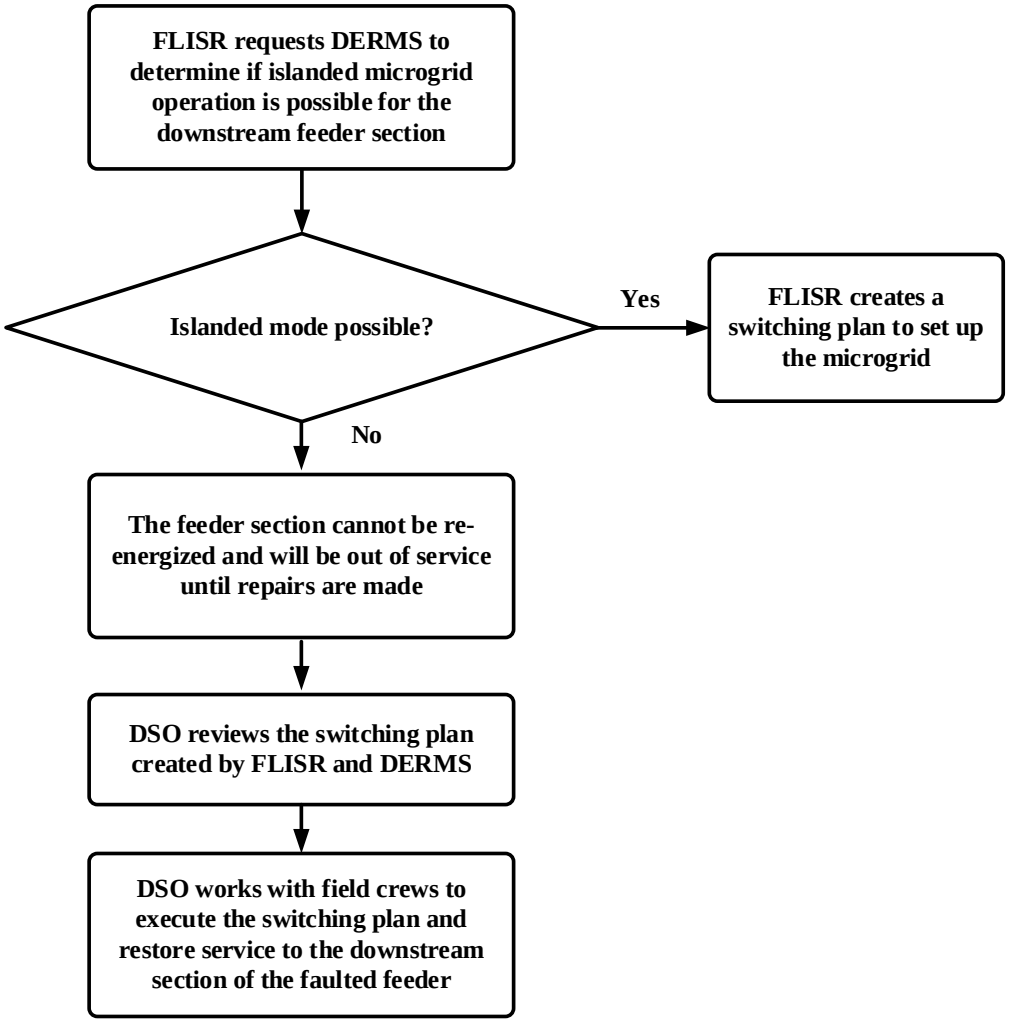

(c)

FIGURE 25 (cont.) Flow Chart of the Operation Procedure of FLISR Scenario #1: Permanent Fault Occurs Out on the Main Line Portion of the Distribution Feeder: (a) Pre-procedure, (b) Step 1: Fault Isolation, (c) Step 2: Upstream Restoration, (d) Step 3: Downstream Restoration, (e) Step 4: Microgrid Operation




(d)

FIGURE 25 (cont.) Flow Chart of the Operation Procedure of FLISR Scenario #1: Permanent Fault Occurs Out on the Main Line Portion of the Distribution Feeder: (a) Pre-procedure, (b) Step 1: Fault Isolation, (c) Step 2: Upstream Restoration, (d) Step 3: Downstream Restoration, (e) Step 4: Microgrid Operation




(e)

FIGURE 25 (cont.) Flow Chart of the Operation Procedure of FLISR Scenario #1: Permanent Fault Occurs Out on the Main Line Portion of the Distribution Feeder: (a) Pre-procedure, (b) Step 1: Fault Isolation, (c) Step 2: Upstream Restoration, (d) Step 3: Downstream Restoration, (e) Step 4: Microgrid Operation

## 2.11 PREDICTIVE FAULT LOCATION

The DMS PFL application (Figure 26) is realized based on the information obtained from system model and other fault-related applications. In particular, it uses short-circuit analysis 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 short-circuit analysis program with simulated faults at all plausible fault locations for the given fault current. Fault locations that result in a fault current that matches the measured fault current are "candidate" fault locations.

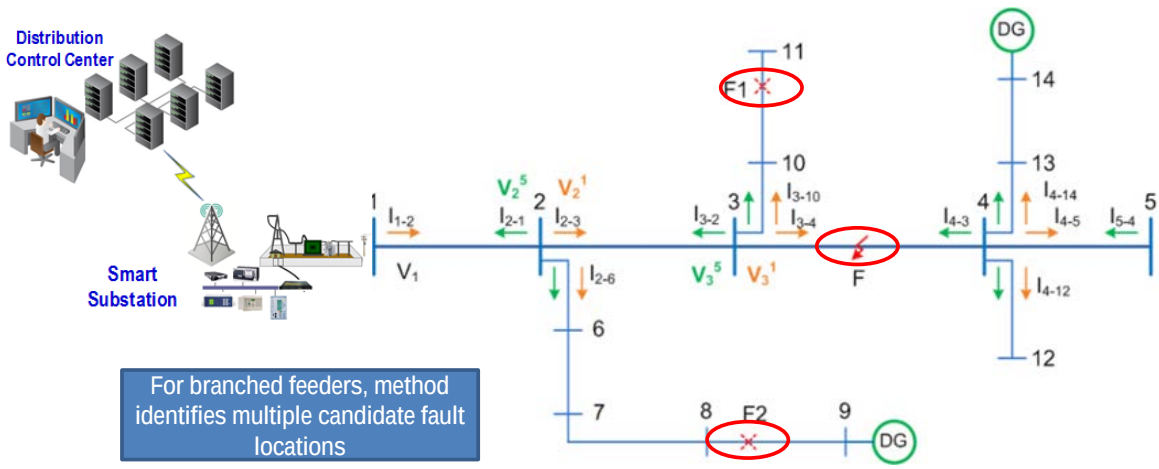



FIGURE 26 Predictive Fault Location

The purpose of the PFL function is to help identify the specific location of a short circuit out on the distribution feeder that has caused the feeder to trip. Other means of fault location are much less accurate and therefore require that a larger portion of the feeder be patrolled to determine the location and cause of the problem. The benefits of improved fault location include reliability improvement (faster service restoration) and labor savings (less time spent to investigate fault).

### 2.11.1 Stakeholders

The following are the principal stakeholders for the PFL application function:

- **Trouble dispatchers** or **DSOs** use the results of the PFL application function to direct the field crews to the most likely location of a fault that has occurred.
- **Field crews (first responders** or **trouble crews)** use the predicted fault location information to identify the portion or portions of the feeder that need to be patrolled to locate the damaged equipment.

### 2.11.2 Situations in Which This Function Should Be Used

PFL is an event-driven function that is used when an outage occurs out on the distribution feeder and the exact location of the damage (street address, pole number, etc.) is unknown. The function is triggered upon receipt of information indicating that an outage event has occurred. Event-triggering information includes uncommanded circuit breaker or recloser change of state (from SCADA), customer outage calls (from the OMS), and AMI power outage ("last gasp") messages.

If an exact outage location is reported by an eyewitness, it is not necessary to run the PFL application.

### 2.11.3 Information That Is Required to Run the Application

The following information is needed to run the PFL application function:

- Event-triggering information includes uncommanded circuit breaker or recloser change of state (from SCADA), customer outage calls (from the OMS), and an AMI power outage ("last gasp") message (from AMI head end system).
- Predicted fault interrupting device (circuit breaker, line recloser, or fuse) from the OMS prediction algorithm.
- Fault current magnitude at the time of the fault and associated relay targets reported by the protective relay IED associated with the circuit breaker or line recloser that tripped. This information will be obtained via SCADA or called in by field personnel who can manually read the data from the display on the front face of the relay IED.
- Status inputs from available FCIs out on the feeders. If the FCI is set, then the fault is downstream of the FCI (further from the substation). If the FCI is not set, then the fault is not downstream of the FCI.
- Fault current contribution from DG units that are connected to the feeder. This information can be acquired from an IED associated with the DG unit or computed by the DMS short-circuit program using a model of the DG unit.

### 2.11.4 Outputs That Will Be Provided to the Stakeholders

The PFL application will identify one or more possible locations for the fault. For feeders that have several main line branches and/or numerous lateral taps, the PFL application can identify more than one feeder location at which the fault may have occurred. Figure 26 illustrates a case where PFL identified three possible fault locations.

The OMS outage prediction algorithm will identify the fault-interrupting device (circuit breaker, line recloser, or fuse) that most likely operated to clear the fault. This information is most helpful for fault-interrupting devices that are not monitored by SCADA (for example, a branch line fuse). Operation of devices that are monitored by SCADA will already be known. The predicted

interrupting device information from OMS indicates that the fault is located somewhere downstream of the predicted fault-interrupting device.

FCI status indications provide information to help identify the section of the feeder containing the fault. The damaged section of the feeder is bounded by an FCI that detected the fault and either one or more FCIs that did not detect the fault or the end of the feeder. If DG units that are able to produce significant fault current are present on the feeder, the FCI settings must be set above the maximum fault current contribution from the DG unit to prevent an FCI that is downstream of the fault from being picked up because of the fault current contribution from a DG unit that is downstream of the FCI.

### 2.11.5 Required Actions by the Stakeholders in Response to Functional Outputs

The following steps will be performed by the DSO or trouble dispatcher upon receipt of outage event-triggering information (circuit breaker or recloser uncommanded change of state, OMS outage prediction, or FCI status indications):

**PFL Scenario Number 1: Outage caused by distribution feeder fault occurs.**

The operation procedure of this PFL scenario is shown in the flow chart in Figure 27.

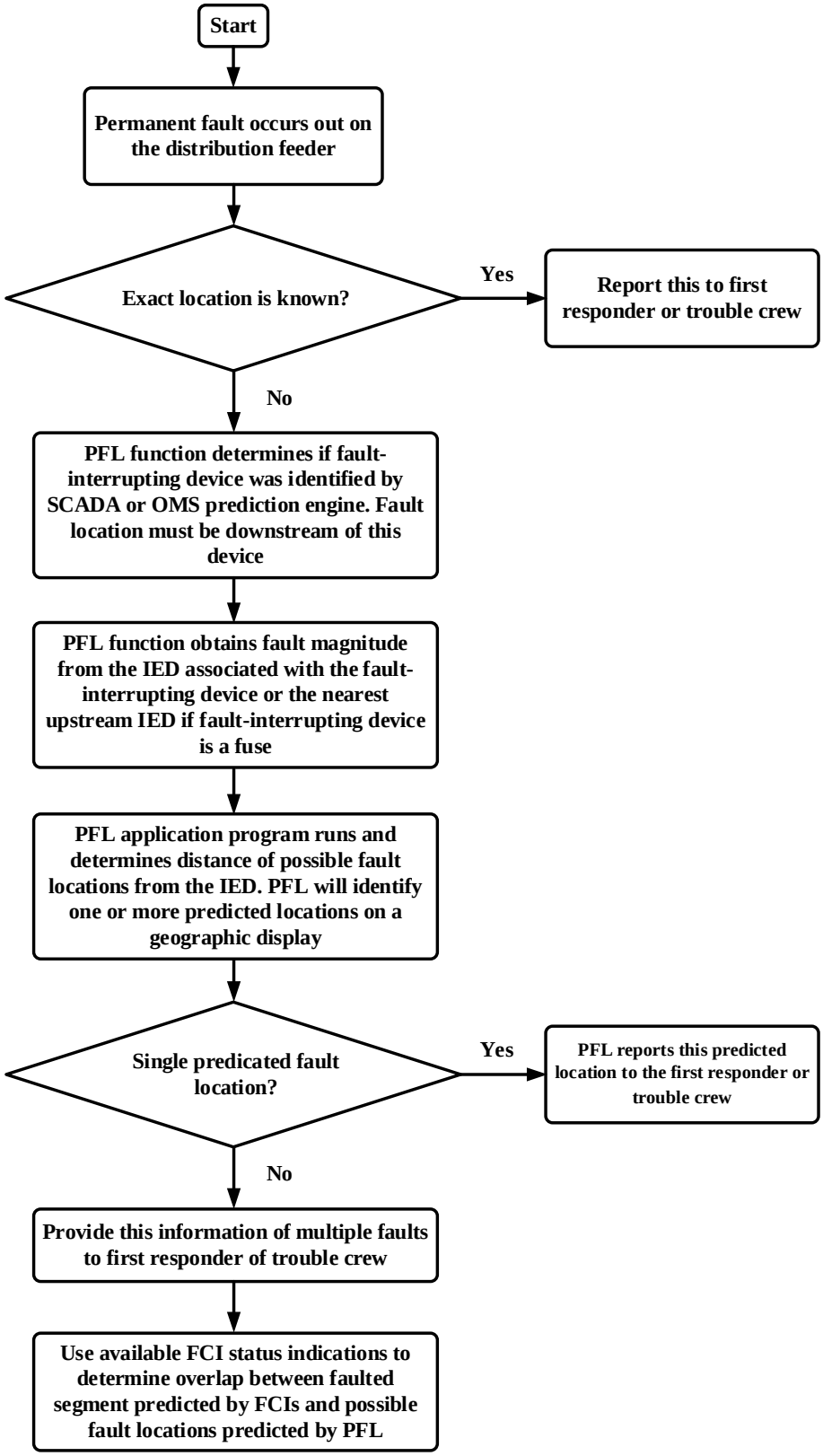



FIGURE 27 Flow Chart of the Operation Procedure of PFL Scenario #1: Outage Caused by Distribution Feeder Fault Occurs

## 2.12 OPTIMAL NETWORK RECONFIGURATION

The ONR function is implemented based on the specific objection functions without violating the operation constraints. It identifies ways in which the utility can reconfigure an interconnected set of distribution feeders without violating any loading or voltage constraints on the feeder in order to achieve selected operating objectives (e.g., reduce losses, reduce peak demand on specified facility, and accommodate a higher penetration of DG on the interconnected set of feeders). ONR, in effect, evaluates all plausible switch position combinations using load flow and SCA to determine which combination of switching actions provides the most benefit.

The purpose of the ONR function is to identify ways in which a set of interconnected distribution feeders can be reconfigured to accomplish a specified operating objective without violating any established operating constraint (voltage, equipment loading, all customers served, etc.). The objective is to identify how the normally open and normally closed connection points between distribution circuits can be changed to achieve valuable business benefits. Objective functions for this application include (as a minimum) attempting to:

- 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) over the specified time period.
- Accommodate a higher penetration of DG (including intermittent renewables [solar PV, wind]). ONR can be used to balance the amount of DG among the interconnected set of feeders to avoid equipment overload and voltage regulation difficulties.

### 2.12.1 Stakeholders

The following are the principal ONR stakeholders:

- **Planning and design engineers** use this application periodically (e.g., once a season) to evaluate circuit configuration changes that would provide benefits as seasonal load changes occur and/or when major circuit changes and additions are planned.
- **Engineers** and **DSOs** can use this application when a major piece of equipment (e.g., a substation transformer or an entire substation) must be taken out of service for maintenance, repair, or replacement.

### 2.12.2 Situations in Which This Function Should Be Used

The ONR function should be used under the following circumstances:

- **On a periodic basis (annually or seasonally) to identify circuit changes that would provide specified benefits** owing to naturally occurring changes (e.g., change of load balance due to seasonal load variations, annual load growth) on the interconnected set of feeders.
- W**hen circuit additions/extensions are planned:** in this case, ONR should evaluate whether some load should be transferred from the expanded feeder to another feeder as part of the circuit extension.
- **When a major component (substation transformer or entire substation) must be taken out of service for maintenance, repair, or replacement:** identify temporary circuit reconfiguration activities that should be performed to best meet the selected business objective while the major component is out of service.
- **When significant growth in penetration of DG (including intermittent renewables) has occurred:** ONR can identify circuit reconfiguration that will spread the DG more evenly over the feeders to prevent voltage regulation and loading problems.

### 2.12.3 Information That Is Required to Run the Application

The following information is needed to run the ONR application function:

- The group of interconnected feeders that needs to be analyzed: the user should select feeders that are interconnected via existing normally open or normally closed switches that may be closed or opened to accomplish the selected objective function.
- Time period of interest: The ONR user must specify a time period over which the objective function should be improved. For example, ONR can identify the best overall configuration for an entire year, a season, and/or the duration of a major equipment outage.
- Selected objective function: the user must input the selected objective function.
- Existing operating constraints (load limits, acceptable voltage range, no isolated [de-energized] components, no loops, maximum number of DG units or intermittent renewables that can be installed on a given feeder, etc.) that must be satisfied in all cases. Feeder reconfiguration scenarios that produce violations are not valid and will be discarded by the ONR program.

### 2.12.4 Outputs That Will Be Provided to the Stakeholders

The ONR function will furnish 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). The list will be prioritized, with switching actions that produce the maximum benefits at the top of the list.

### 2.12.5 Required Actions by the Stakeholders in Response to Functional Outputs

The following steps will be performed by the planning and design engineer or DSO in response to the ONR functional output:

**ONR Scenario Number 1: Seasonal review of distribution system configuration.**

The operation procedure of this ONR scenario is shown in the flow chart in Figure 28.

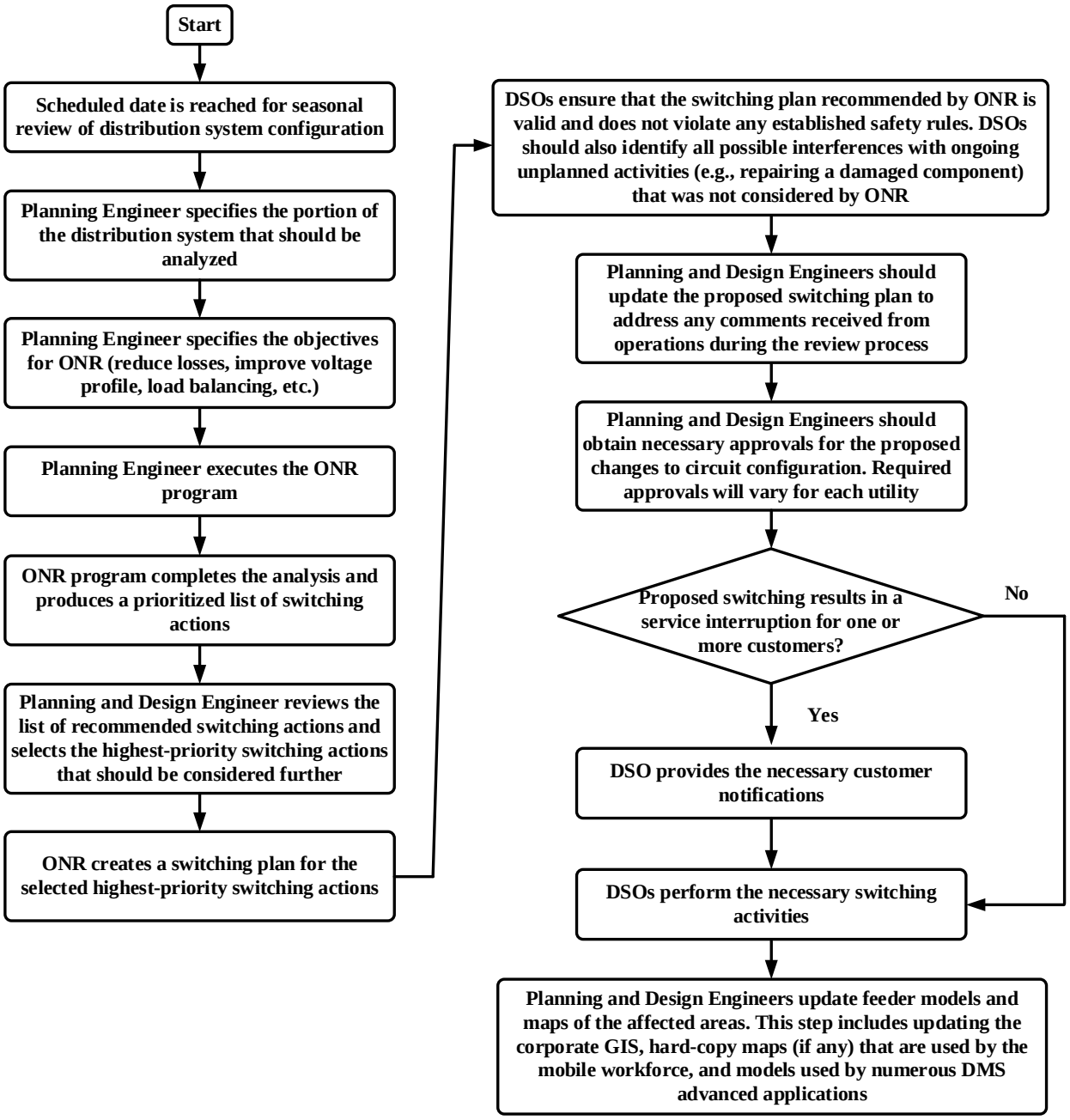



FIGURE 28 Flow Chart of the Operation Procedure of ONR Scenario #1: Seasonal Review of Distribution System Configuration

## 2.13 SHORT-TERM LOAD FORECASTING

The DMS STLF function uses load and weather data inputs to predict the load characteristics hours/days ahead. It uses historical load and weather data to forecast the system load automatically every hour for a 168-hour (7-day) rolling period. STLF results support outage planning and 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.

### 2.13.1 Stakeholders

The primary stakeholders for the STLF function are:

- **DSOs** and other persons who are responsible for outage planning. STLF enables the user to determine what the load will be when outage work is needed. STLF helps determine whether the customers affected by planned outage work can be transferred to another nearby feeder.
- **Planning and design engineers** who are responsible for doing studies on the electric system. STLF is needed to determine what the load will be at the proposed study time.

### 2.13.2 Situations in Which This Function Should Be Used

STLF should be used under the following circumstances:

- **Outage planning:** STLF determines the expected load at the time of the proposed planned outage. This information is needed to ensure that customers who will be affected by the planned outage work can be transferred to another feeder that is not affected by the planned outage work.
- **Engineering analysis in "study mode":** Load estimates supplied by the STLF program are needed to support engineering analysis applications running in study mode.

### 2.13.3 Information That Is Required to Run the Application

The following information is needed to run the STLF application:

- Substation, feeder, or other portion of the electric distribution system that is of interest to the user.
- Date and time for which the forecast is needed.

- Weather forecast for the required date and time (temperature, humidity, precipitation, wind speed, etc.) to enable the STLF program to find a "similar day" from archives upon which the forecasted load is based.

### 2.13.4 Outputs That Will Be Provided to the Stakeholders

The following outputs are provided by the STLF:

- Real and reactive power for the specific date and time identified by the user.

### 2.13.5 Required Actions by the Stakeholders in Response to Functional Outputs

Following are the user actions that are required to run the program in each situation:

**STLF Scenario Number 1: Determine load forecast for outage planning purposes.**

The operation procedure of this STLF scenario is shown in the flow chart in Figure 29.

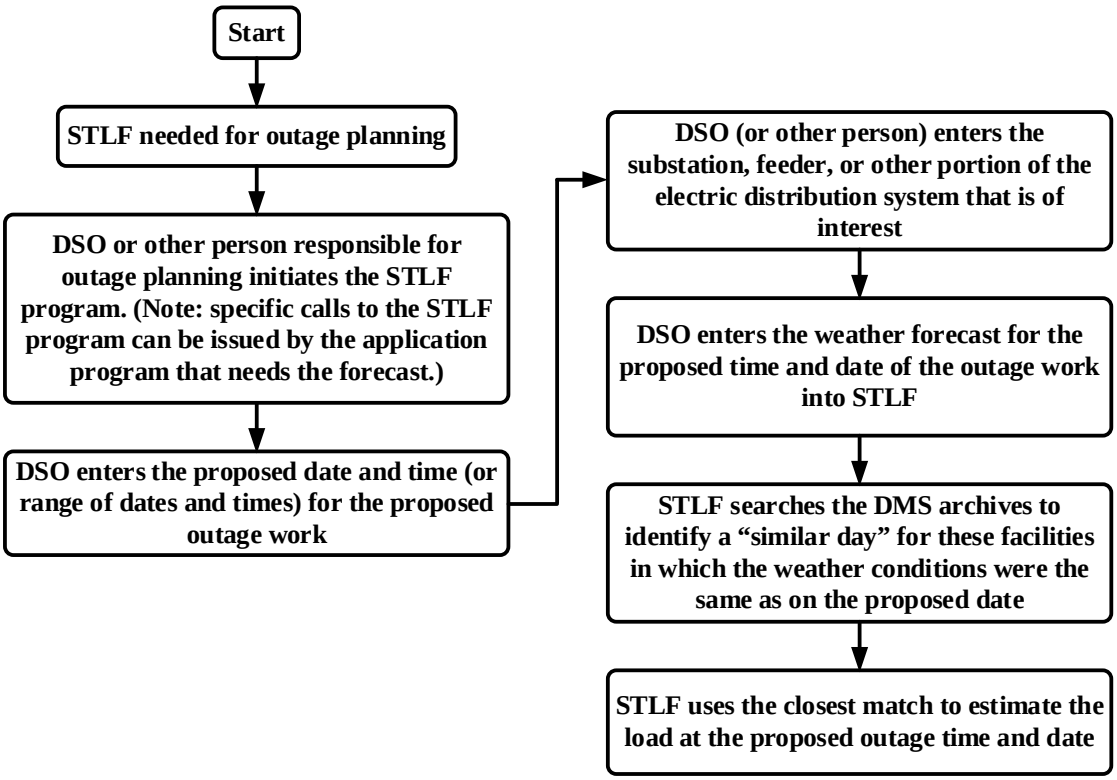



FIGURE 29 Flow Chart of the Operation Procedure of STLF Scenario #1: Determine Load Forecast for Outage Planning Purposes

## 2.14 DYNAMIC EQUIPMENT RATING

The DMS dynamic equipment rating function calculates thermal ratings (real-time ampacities) of substation transformers and distribution feeders (underground cables and overhead lines) on the basis of actual loading and ambient conditions rather than worst-case weather and load assumptions. It uses the thermal measurements and historical loading data to determine the ratings dynamically.

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

### 2.14.1 Stakeholders

Following are the key stakeholders for the dynamic equipment rating function:

- **DSOs**
- **Planning and design engineers**
- **Asset managers**

All of these stakeholders use the function to determine whether a critical piece of equipment (substation transformer, critical underground cable, etc.) is able to carry load that exceeds its normal rating during an unusually high peak load period that may include one or more contingencies.

### 2.14.2 Situations in Which This Function Should Be Used

The dynamic equipment rating function should be used under the following circumstances:

- **Equipment in question has exceeded its normal operating limit** and further load increase is possible because of extremely high demand (nearing annual peak or new peak load). This situation is coupled with the loss of a redundant component that normally shares the load with the equipment in question.

### 2.14.3 Information That Is Required to Run the Application

The following information is required to run the dynamic equipment rating application:

- 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.

### 2.14.4 Outputs That Will Be Provided to the Stakeholders

The dynamic equipment rating function provides the following information to the stakeholders:

- Emergency rating of the equipment in question based on ambient conditions, recent loading, and other factors (rather than normal operating limit that is based on worst-case seasonal assumptions).
- Amount of time the emergency load can be carried by the equipment without significant loss of life of the equipment.

### 2.14.5 Required Actions by the Stakeholders in Response to Functional Outputs

Following are the user actions that are required to run the program in each situation:

**Dynamic Equipment Rating Scenario Number 1: Critical substation transformer or underground cable close to exceeding its operating rating.**

The operation procedure of this dynamic equipment rating scenario is shown in the flow chart in Figure 30.

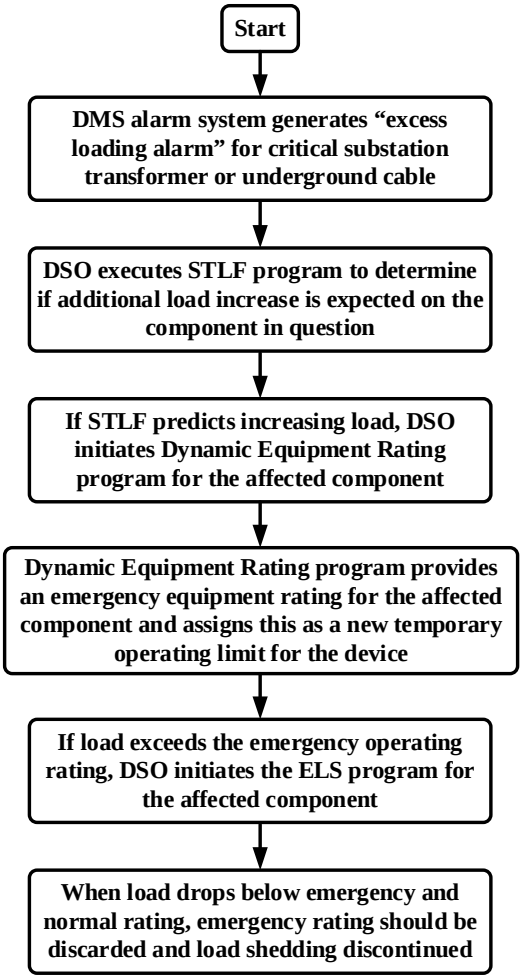



FIGURE 30 Flow Chart of the Operation Procedure of Dynamic Equipment Rating Scenario #1: Critical Substation Transformer or Underground Cable Close to Exceeding Its Operating Rating

## 2.15 DMS CONTROL OF PROTECTION SETTINGS

The DMS includes 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. It updates the protection settings as needed in order to ensure the safe operation of the distribution system. Several potential uses of this application are summarized below.

### 2.15.1 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 Fuse-Saving function 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.

#### *2.15.1.1 Stakeholders*

The key stakeholders for this function are:

1. **Field crews (switchmen)** who are responsible for performing switching actions to restore service to customers that have been without power because of a planned or unplanned outage.
2. **Protective relay engineers** who are responsible for determining the protective relay settings to be used under "fuse-saving" conditions.
3. **DSOs** who are responsible for determining if inclement weather conditions exist that warrant changeover to fuse-saving settings.

#### *2.15.1.2 Situations in Which This Function Should Be Used*

The fuse-saving function should be used under the following circumstances:

**Fuse-Saving Scenario Number 1: Inclement weather conditions, especially high wind.**

- The fuse blowing settings should be used whenever inclement weather conditions (especially high wind) exist. Under such circumstances, temporary (self-clearing) faults can occur as a result of tree branches contacting energized lines. In such conditions, it is usually desirable to prevent branch line (lateral) fuses from blowing and causing a permanent outage requiring field crew intervention (to replace the blown fuse). To prevent these blown fuses, feeder protective relay settings are switched to low-set instantaneous settings that cause the feeder circuit breaker or recloser to trip before the fuse blows. Upon reclosing, the normal settings (fuse blowing) are used, so that if the fault still exists, the fuse will blow. The benefit is elimination of field trips to replace fuses that have blown unnecessarily because of temporary faults.

#### *2.15.1.3 Information That Is Required to Run the Application*

The following information is required to run the fuse-saving application:

- Indications of inclement weather conditions (especially high winds).

#### *2.15.1.4 Outputs That Will Be Provided to the Stakeholder*

The following outputs are supplied by the fuse-saving function:

- Indication (alarm message) that circuit breaker settings have been changed to fuse-saving settings.
- Indication (alarm message) that circuit breaker settings have been changed to normal (fuse-blowing) settings.

#### *2.15.1.5 Required Actions by the Stakeholders in Response to Functional Outputs*

Procedures for using the fuse saving application are described below:

**Fuse-Saving Scenario Number 1: Manual operation for inclement weather conditions, especially high wind.**

The operation procedure of this fuse-saving scenario is shown in the flow chart in Figure 31.

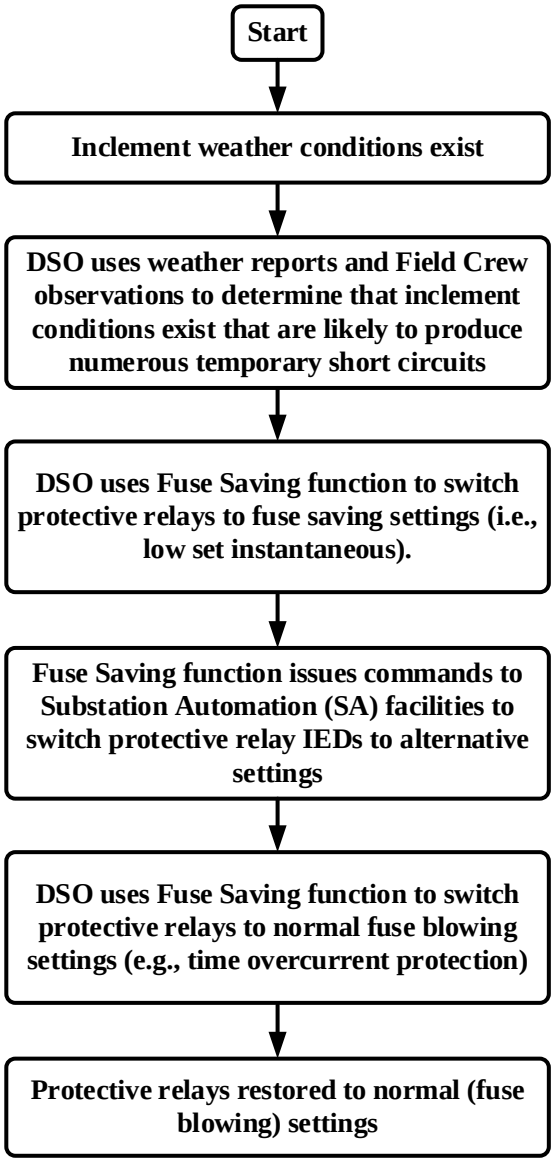



FIGURE 31 Flow Chart of the Operation Procedure of Fuse Saving Scenario #1: Manual Operation for Inclement Weather Conditions

**Fuse Saving Scenario Number 2: Automatic Operation based on inclement weather conditions, especially high wind.**

The operation procedure of this fuse-saving scenario is shown in the flow chart in Figure 32.

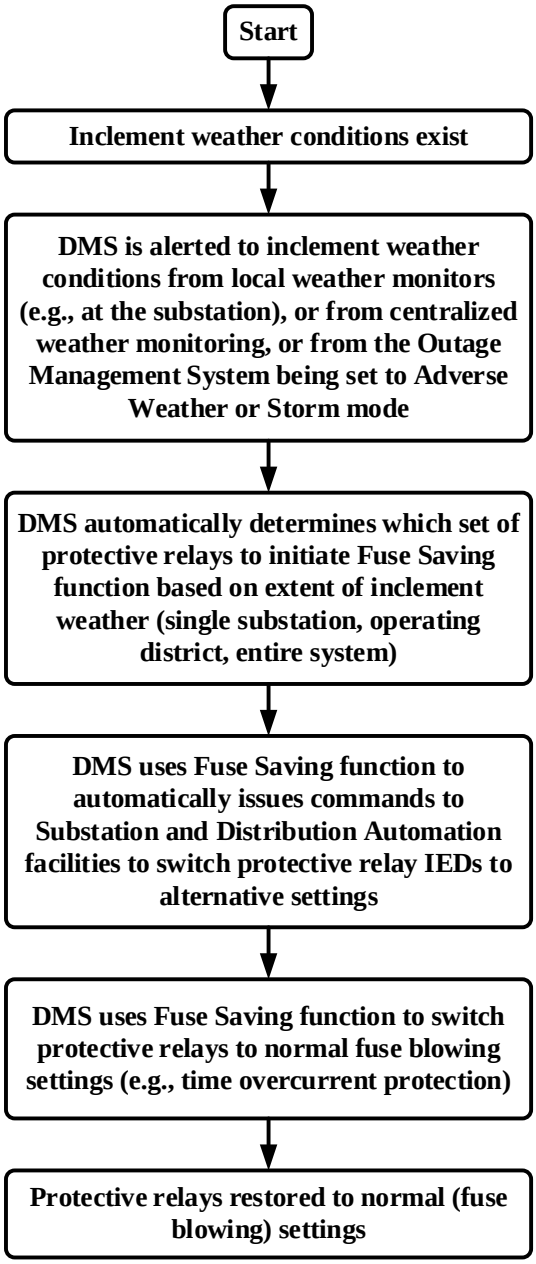



FIGURE 32 Flow Chart of the Operation Procedure of Fuse Saving Scenario #2: Automatic Operation Based on Inclement Weather Conditions, Especially High Wind

### 2.15.2 Cold Load Pickup Enable/Disable

Circuit breaker protective relays and reclosers include user-selectable setting groups for handling normal service restoration and CLPU. CLPU 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 includes a CLPU function to enable the user to

switch between the normal setting group and the CLPU setting group for user-selected circuit breaker protective relays and reclosers located in substations and reclosers located out on the distribution feeders.

#### *2.15.2.1 Stakeholders*

The key stakeholders for this function are:

1. **Field crews (switchmen)** who are responsible for performing switching actions to restore service to customers that have been without power due to a planned or unplanned outage.
2. **Protective relay engineers** who are responsible for determining the protective relay settings to be used under "cold load" conditions.
3. **DSOs** who are responsible for determining whether cold load conditions exist on the feeder.

#### *2.15.2.2 Situations in Which This Function Should Be Used*

The CLPU function should be used under the following circumstances:

**CLPU Scenario Number 1: Feeder re-energization following extended outage.**

- The CLPU settings should be used whenever a significant portion of a distribution feeder has been de-energized for an extended period. Under such circumstances, the naturally occurring diversity between loads on the feeder is lost, resulting in load upon re-energization that exceeds the normal pickup setting of feeder overcurrent relays. This situation is further aggravated by inrush currents that occur naturally when electromagnetic components (transformers, motors) and capacitive elements (line charging, capacitor bank charging, etc.) are first energized. The purpose of the CLPU function is first to recognize that CLPU conditions exist and then to switch to alternative CLPU settings on the protective relays for the affected feeder.

#### *2.15.2.3 Information That Is Required to Run the Application*

The following information is required to run the CLPU application:

- Identifier of feeder that has experienced an outage.
- Pre-fault load on the affected feeder.
- Estimated output of DG on the feeder just prior to the fault. (This generation will usually trip off-line [per IEEE 1547] when feeder tripping occurs, resulting in higher net load on the feeder.)
- Length of time that the feeder has been de-energized.

- Ambient temperature in the region covered by the feeder in question.
- Time of day and load level.
- Rules, established by the utility company, for determining that CLPU conditions exist.

#### *2.15.2.4 Outputs That Will Be Provided to the Stakeholder*

The following outputs are supplied by the CLPU function:

- Indication (alarm message) that cold load conditions exist on the feeder in question.
- Command to switch feeder protective relays to alternative (CLPU) settings.

#### *2.15.2.5 Required Actions by the Stakeholders in Response to Functional Outputs*

Procedures for dealing with CLPU conditions on a feeder that has experienced a lengthy de-energization period are described below:

**CLPU Scenario Number 1: Feeder re-energization following extended outage.**

The operation procedure of this CLPU scenario is shown in the flow chart in Figure 33.

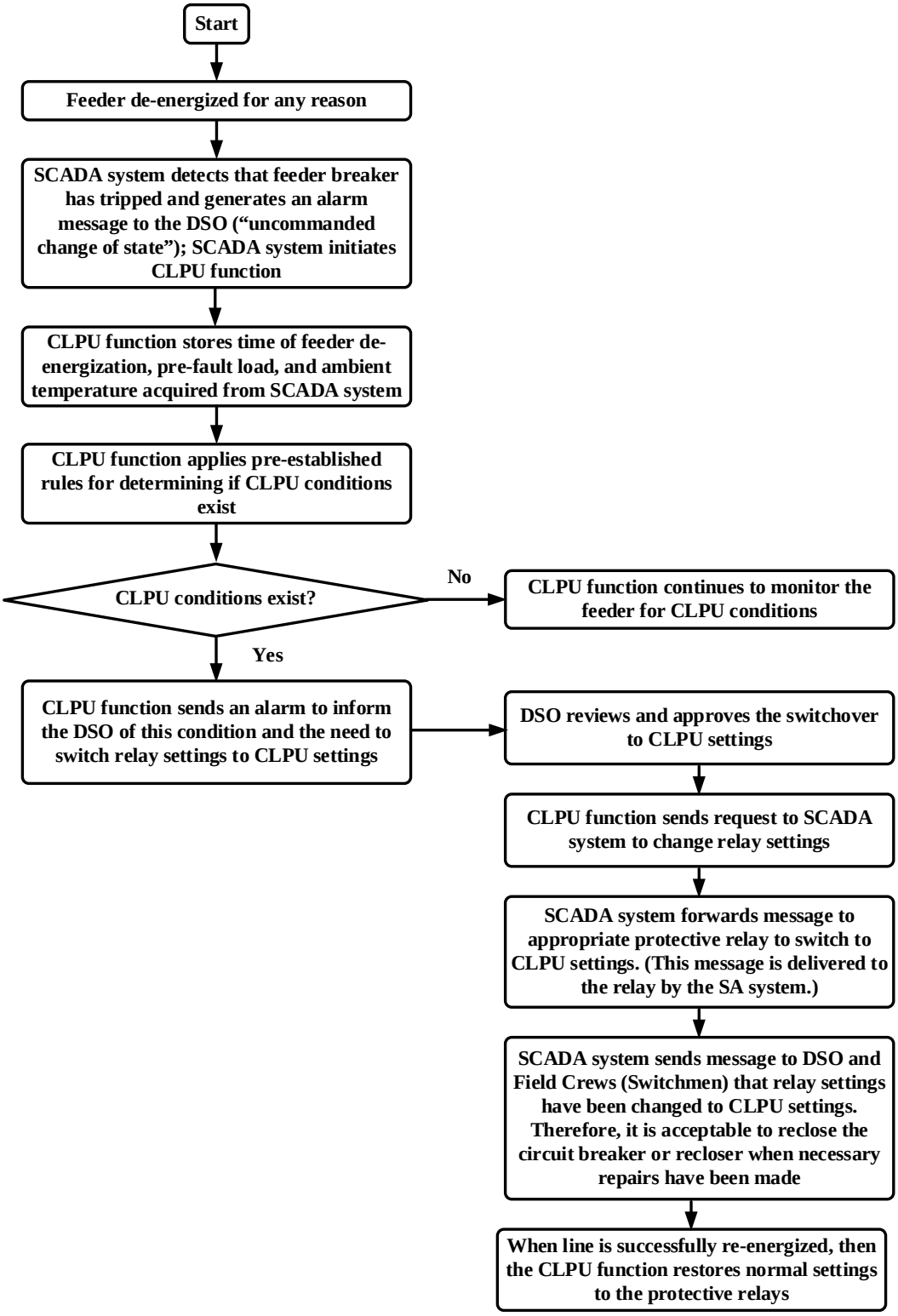



FIGURE 33 Flow Chart of the Operation Procedure of CLPU Scenario #1: Feeder Re-energization Following Extended Outage

## 2.16 DISTRIBUTED ENERGY RESOURCES MANAGEMENT

As the penetration level of DERs (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 DERs may be needed. The current industry direction for DER monitoring and control is use of a separate DERMS that handles the direct interface to DERs for monitoring and control purposes, rather than use of DSCADA. The DMS will obtain DER-related information as needed via enterprise system integration techniques such as Enterprise Service Bus. Figure 34 illustrates the separation of DSCADA and DERMS functionality for field device monitoring and control.

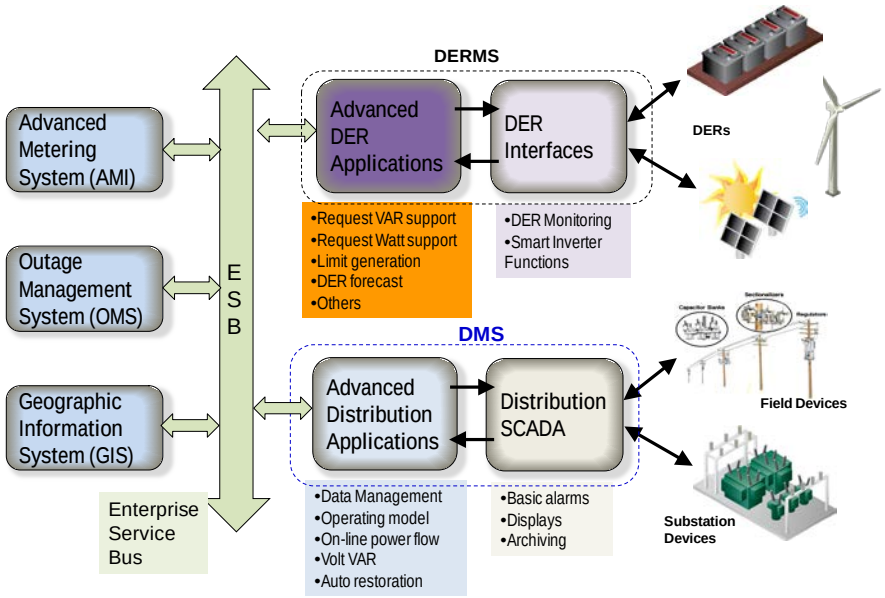



FIGURE 34 Separation of DSCADA and DERMS Functionality

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

The DMS should include facilities to enable the utility to incorporate IPPs into real-time generation dispatch and control. The DMS should 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) should monitor energy flow at the metering point to determine customer response. The DMS should be able to control generation of active/reactive power (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 should 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 should dispatch through SCADA.

The DMS should include monitoring and distributed control of temporarily isolated ("islanded") portions of the distribution system powered by generating resources owned by IPPs and the utility company. This approach 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 online power flow, should 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 behaviors 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 34, the function of managing the DER devices is shown as an enterprise application called a DERMS. DERMS is commonly used for DER management by controlling the outputs of DERs in a specific system. In actual implementations, DERMS functionality may or may not be embodied in 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 DERs and other utility systems can be identified and supporting information standards developed.

### 2.16.1 Stakeholders

The principal stakeholders of the DMS DER Management function include:

- **DSOs** who are responsible for maintaining acceptable operating conditions on the distribution system at all times and for responding to potential overloads via control actions such as “surgical” peak shaving using DERs.
- **Customer care personnel** who are responsible for maintaining relationships with key customers that own and operate DERs.

### 2.16.2 Situations in Which This Function Should Be Used

The DMS DER Management function should be used under the following circumstances:

- **Scenario Number 1: Surgical or system-wide peak shaving required.**
  The electric distribution utility needs to perform targeted (surgical) peak shaving for any reason. For example, the FLISR application may need to reduce load to free up capacity on a backup source or reduce load on a feeder section that needs to be transferred to another feeder. In this case, the DMS signals the DERMS to free up capacity on the specified portion of the electric distribution system. The DERMS is responsible for ensuring that the requested DER control actions are allowed under the terms of the connection agreements. The DERMS is responsible for issuing direct control commands to the DERs.
- **Scenario Number 2: Volt-VAR control and optimization.**
  The DMS VVO application uses all available resources on the electric distribution system to achieve the specified VVO objective (reduced losses, peak shaving, energy conservation, etc.). Each time the VVO application executes (every 15 minutes, when significant change occurs to distribution feeder or substation, on demand, etc.), the DMS VVO program works with the DMS DERMS to determine the potential impacts and opportunities of using DERs for accomplishing the VVO business objective. When VVO runs, the DMS DERMS identifies resource availability and forecast, which are then considered by VVO. If VVO determines that DERs can contribute to achieving the VVO objective, then suitable control commands are sent to the DERs via DERMS.
- **Scenario Number 3: Microgrid management (grid-connected mode).**
  When the ISO declares a frequency response event, the DMS DERMS determines the availability of DERs to respond to this event. If resources are available, the amount is reported by the DMS to the ISO. When the ISO actually requests that the service be delivered, the DMS sends the frequency response request to DERMS, which actually issues the control commands to the individual generating units and energy storage devices.
- **Scenario Number 4: Microgrid management (islanded mode).**
  This scenario is triggered when a portion of the distribution system (feeder or portion of a feeder, entire substation, etc.) becomes isolated from the main power grid. In this case, the DMS determines the load (from SCADA) and available DERs (from DERMS) on the isolated portion of the distribution system. If the load is smaller than what available resources can provide, a transition to microgrid islanded mode is triggered.

### 2.16.3 Information That Is Required to Run the Application

The following information is required to run the DMS DERMS:

- Current output of all DERs (measured or estimated);
- Short-term (15-minute) forecast of DER output;
- Available capacity (kilowatts and kWh) of DERs on a specified portion of the distribution system (feeder or portion of a feeder, substation, microgrid, etc.); and
- Available reactive power capacity (kVAR and kVARh) of DERs on a specified portion of the distribution system (feeder or portion of a feeder, substation, microgrid, etc.).

### 2.16.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the DMS DERMS:

- Required changes to the set points of selected DERs on the facilities in question. These set point changes are communicated to the actual DERs by DERMS.

### 2.16.5 Required Actions by the Stakeholders in Response to Functional Outputs

The specific use case scenarios for DERMS are described below:

**DERMS Scenario Number 1: Surgical or system-wide peak shaving required.**

The electric distribution utility needs to perform targeted (surgical) peak shaving for any reason. For example, the FLISR application may need to reduce load to free up capacity on a backup source or reduce load on a feeder section that needs to be transferred to another feeder. In this case, the DMS signals the DERMS to free up capacity on the specified portion of the electric distribution system. The DERMS is responsible for ensuring that the requested DER control actions are allowed under the terms of the connection agreements. The DERMS is responsible for issuing direct control commands to the DERs (generation and storage).

The operation procedure of this DERMS scenario is shown in the flow chart in Figure 35.

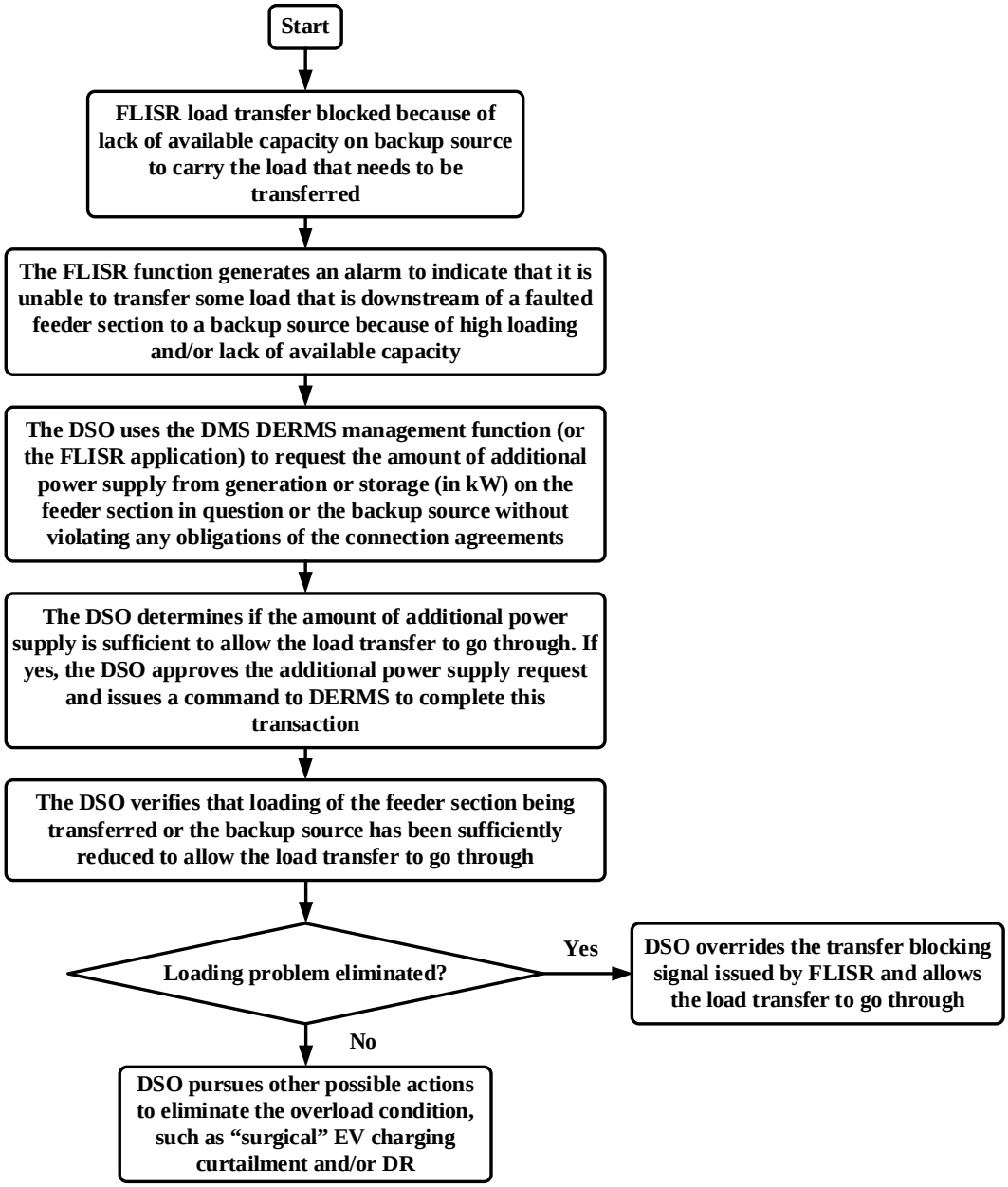



FIGURE 35 Flow Chart of the Operation Procedure of DERMS Scenario #1: Surgical or System-wide Peak Shaving Required

**DERMS Scenario Number 2: Volt-VAR control and optimization.**

The DMS VVO application uses all available resources on the electric distribution system to achieve the specified VVO objective (reduced losses, peak shaving, energy conservation, etc.). Each time the VVO application executes (every 15 minutes, when significant change occurs to distribution feeder or substation, on demand, etc.), the DMS VVO program works with the DMS DER Management function to determine the potential impacts and opportunities of using DERs for accomplishing the VVO business objective. When VVO runs, the DERMS

management function identifies resource availability and forecast, which are then considered by VVO. If VVO determines that DERs can contribute to achieving the VVO objective, then suitable control commands are sent to the DERs via DERMS.

The operation procedure of this DERMS scenario is shown in the flow chart in Figure 36.

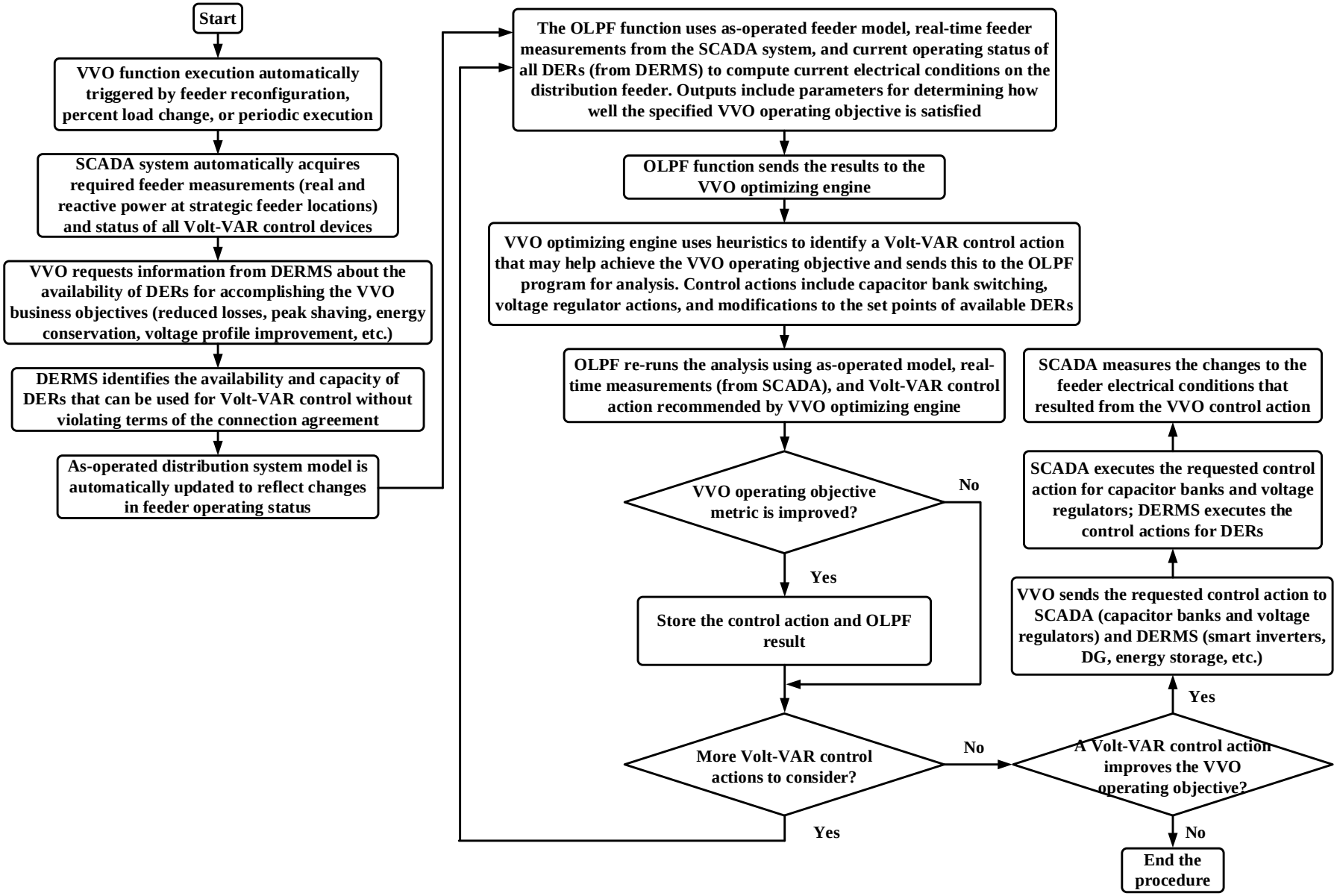



FIGURE 36 Flow Chart of the Operation Procedure of DERMS Scenario #2: Volt-VAR Control and Optimization

**DERMS Scenario Number 3: Microgrid management (grid-connected mode).**

When the ISO declares a frequency response event, the DMS DERMS management function determines the availability of DERs to respond to this event. If resources are available, the amount is reported by the DMS to the ISO. When the ISO actually requests that the service be delivered, the DMS sends the frequency response request to DERMS, which issues the control commands to the individual generating units and energy storage devices.

The operation procedure of this DERMS scenario is shown in the flow chart in Figure 37.

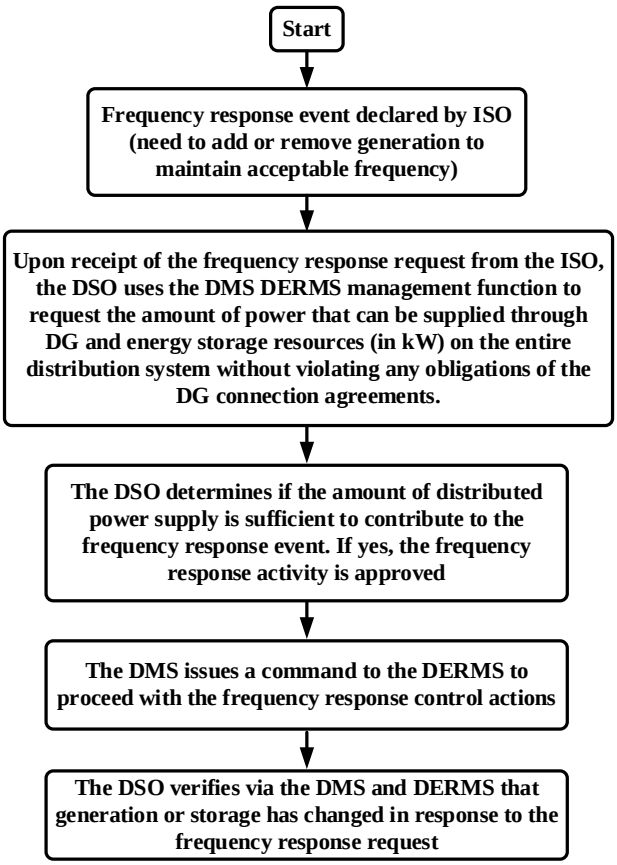



FIGURE 37 Flow Chart of the Operation Procedure of DERMS Scenario #3: Microgrid Management (Grid-Connected Mode)

**DERMS Scenario Number 4: Microgrid management (islanded mode).**

This scenario is triggered when a portion of the distribution system (feeder or portion of a feeder, entire substation, etc.) becomes isolated from the main power grid. In this case, the DMS determines the load (from SCADA) and available DERs (from DERMS) on the isolated portion of the distribution system. If the load is smaller than what available resources can provide, transition to microgrid islanded mode is triggered.

The operation procedure of this DERMS scenario is shown in the flow chart in Figure 38.

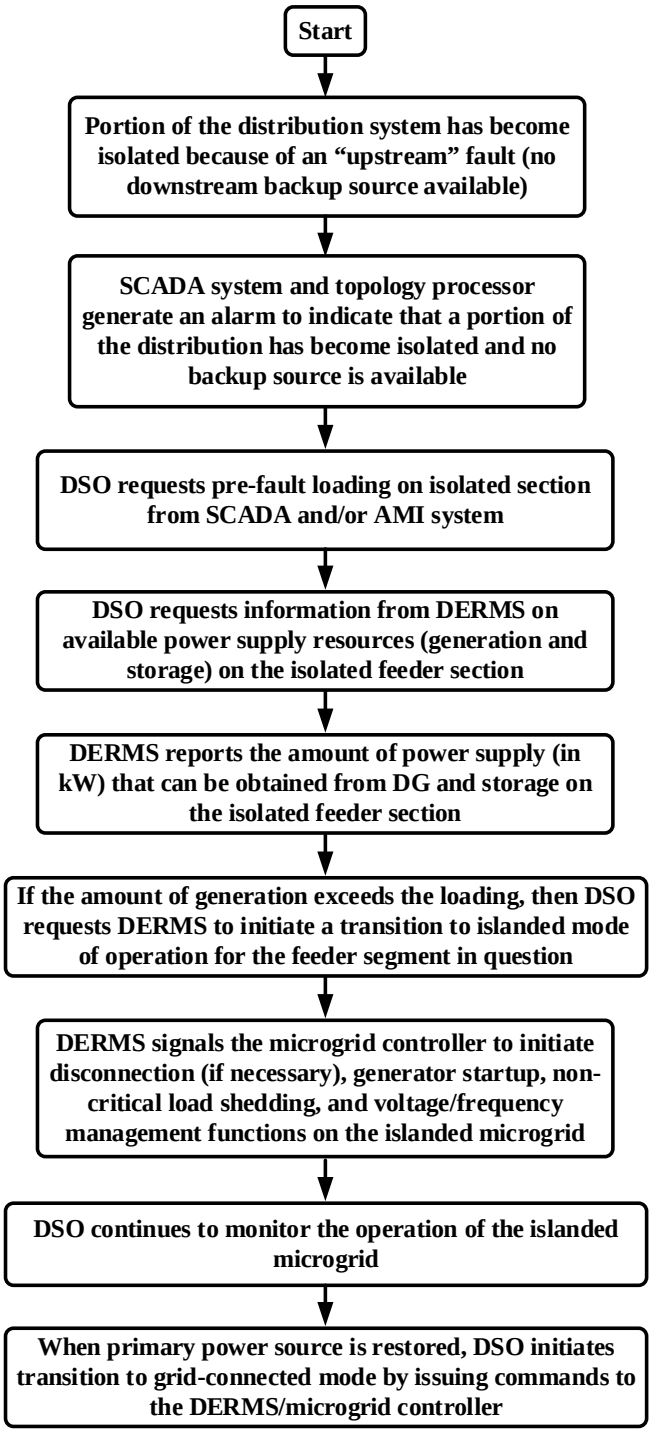



FIGURE 38 Flow Chart of the Operation Procedure of DERMS Scenario #4: Microgrid Management (Islanded Mode)

## 2.17 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 programs. 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 can compete equally with generation in these markets.

For the use of DR, 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 and verification of the end customer's response to a DR event (i.e., a 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 because of 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.

### 2.17.1 Stakeholders

The principal stakeholders of the DR function include the following:

- **DSOs** who are responsible for monitoring the condition or the distribution system and for responding to potential overloads via control actions such as "surgical" DR.
- **DR personnel** who use load curtailment as a means of lowering the peak load at a given time.
- **Customer care personnel** who are responsible for maintaining relationships with key customers that participate in the DR programs.

### 2.17.2 Situations in Which This Function Should Be Used

The DMS DR function should be used under the following circumstances:

- **Scenario Number 1: Surgical load shedding required.**
  The electric distribution utility needs to perform targeted (surgical) load shedding for any reason. For example, the FLISR application may need to reduce load to free up capacity on a backup source or reduce load on a feeder section that needs to be transferred to another feeder. In this case, the DMS signals the Demand Response Management System (DRMS) to reduce demand on the selected portion of the distribution system. The DRMS is

responsible for ensuring that the load curtailment activity is allowed under the terms of the DR contractual obligations of the utility. The DRMS is also responsible for curtailing the load, using building EMSs and other resources that can support DR activities.

- **Scenario Number 2: System-wide load-shedding activity.**
  The electric distribution utility needs to perform load shedding during a system-level emergency. In this case, the DMS signals the DRMS to curtail the load by a specified amount using its DR capabilities. The DRMS is responsible for ensuring that the load curtailment activity is allowed under the terms of the DR contractual obligations of the utility. The DRMS is also responsible for curtailing the load, using building EMSs and other resources that can support DR activities.

### 2.17.3 Information That Is Required to Run the Application

The following information is required to run the DR application:

- The specific portion of the electric distribution system for which surgical DR is needed. This can be one or more substations, one or more feeders, a feeder section, and/or one or more distribution service transformers.
- Loading on the portion of the distribution system in question. Alarm limits for entre feeders or substations are part of the standard SCADA alarm package. However, alarm detection for specified portions of the electric distribution system is generally not available without additional analysis. This use case assumes that loading and alarming of specified portions of an electric distribution feeder can be determined from line sensors installed at strategic locations (e.g., the portion of a feeder between two DA switches that are used by the DMS FLISR application).

### 2.17.4 Outputs That Will Be Provided to the Stakeholders

The following information is supplied by the DR management function:

- Amount by which the load can be curtailed using DR on a specified portion of the distribution system (feeder or portion of a feeder, substation, etc.) without violating obligations of the DR agreement.

### 2.17.5 Required Actions by the Stakeholders in Response to Functional Outputs

The specific use case scenarios for DR management are described below.

**DR Scenario Number 1: Surgical Load Shedding Required.**

The electric distribution utility needs to perform targeted (surgical) load shedding for any reason. For example, the FLISR application may need to reduce load to free up capacity on a

backup source or reduce load on a feeder section that needs to be transferred to another feeder. In this case, the DMS signals the DRMS to reduce demand on the selected portion of the distribution system. The DRMS is responsible for ensuring that the load curtailment activity is allowed under the terms of the DR contractual obligations of the utility. The DRMS is also responsible for curtailing the load, using building EMSs and other resources that can support DR activities.

The operation procedure of this DR management scenario is shown in the flow chart in Figure 39.

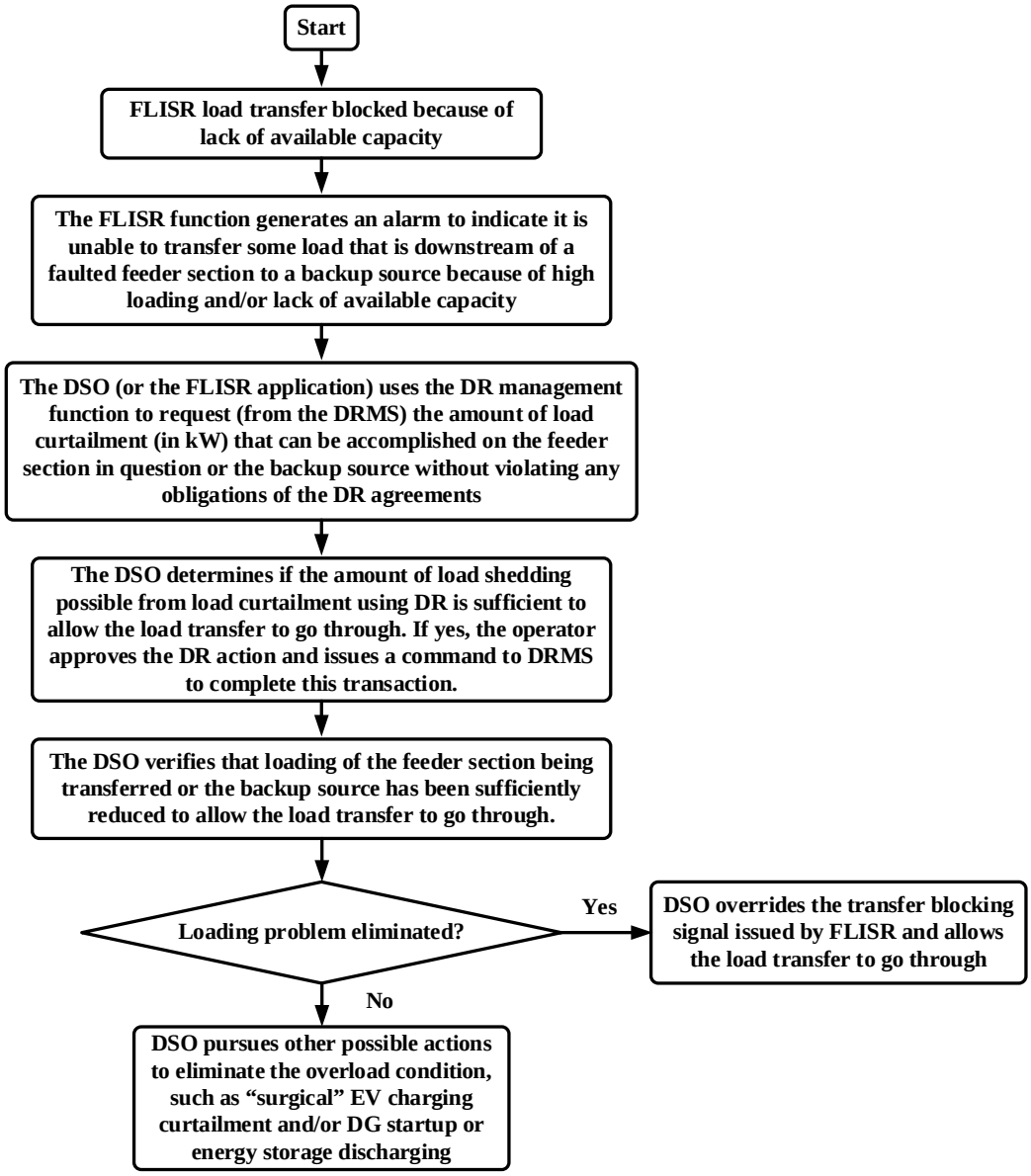



FIGURE 39 Flow Chart of the Operation Procedure of DR Management Scenario #1: Surgical Load Shedding Required

**DR Scenario Number 2: System-wide load-shedding activity.**

The electric distribution utility needs to perform load shedding during a system-level emergency. In this case, the DMS signals the DRMS to curtail the load by a specified amount using its DR capabilities. The DRMS is responsible for ensuring that the load curtailment activity is allowed under the terms of the DR contractual obligations of the utility. The DRMS is also responsible for curtailing the load, using building EMSs and other resources that can support DR activities.

The operation procedure of this DR management scenario is shown in the flow chart in Figure 40.

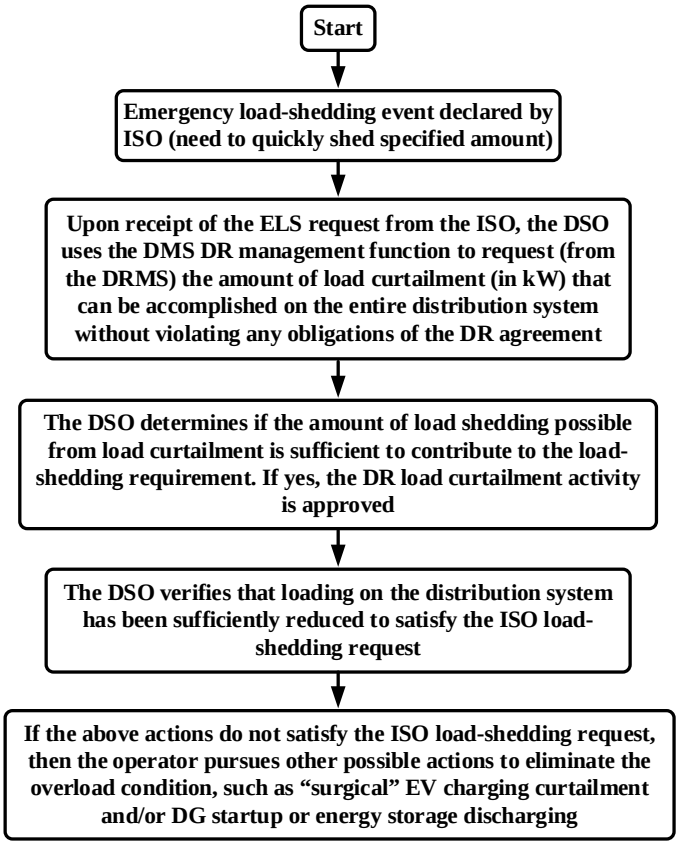



FIGURE 40 Flow Chart of the Operation Procedure of DR Management Scenario #2: System-wide Load-Shedding Activity

## 2.18 EMERGENCY LOAD SHEDDING

The DMS should include an ELS function. 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 should be able to initiate load shedding only for loads that are included in the user's assigned AOR.

The ELS function is activated and used by entering the amount of load to be shed. The ELS should then determine which switching devices to operate to accomplish the load-shedding objective. ELS should allow the user to shed load using the following load-shed facilities:

1. Remote connect/disconnect and direct load control features for meters at specified individual customers (E+ rate customers). The actual load shedding of these customers should be accomplished by the SMI system upon receipt of a command from DMS.
2. Remote-controlled line reclosers, load break switches, and sectionalizers located in the field (outside the substation fence). These remote-controlled switches should enable the DMS to shed the load served by a portion of the distribution feeder.
3. Feeder circuit breakers and reclosers located in the substations. These devices should be used to shed an entire feeder.
4. Substation transformer switches located on the high side (supply side) of the substation transformers. These switches should be used to shed all of the load served by the affected transformer.

The DMS should initiate transfers to microgrid operation on portions of the distribution system that have this capability in order to provide additional load relief. It should also be possible for the ELS to initiate a return to normal operation when the requirement for ELS ceases.

The DMS should also be able to change the VVO objective function to "reduce demand" when the need arises to shed load during an emergency. The command by ELS to switch over to "reduce demand" should override whatever VVO objective function is currently in place. It should also be possible to restore the original VVO objective function when the need for ELS ends.

The load that is shed by the ELS function should **not** be restored automatically by the FLISR function and other DMS automatic load restoration functions. Automatic load restoration should be blocked on feeders where ELS has initiated load shedding.

The DMS should determine the recommended control actions that should be performed to accomplish the desired load shedding effect, and should display the facilities to be tripped to the user. The dispatcher should be able to add facilities to or delete facilities from the list of load-shed actions recommended by ELS. The user should be able to confirm that load shedding should proceed. Following confirmation by the user, the DMS should initiate tripping of the recommended facilities.

The DMS should issue the load shed control commands to the appropriate external system (EMS or AMI) that is responsible for executing the command within five (5) seconds after the ELS-

recommended control actions have been confirmed by the user. The DMS should also initiate direct load shed commands to field devices controlled by DMS (as needed) within five (5) seconds. “Select before execute” processing should be bypassed during ELS operations. That is, it should not be necessary for the user to confirm proper device selection (other than the device confirmation step described earlier) before the DMS trips the device.

Selection of which facilities to trip should be based on a load-shedding priority scheme specified by the DSO and the current loading of each facility. Each facility that can be used for ELS should be pre-assigned by the electric utility to an ELS load-shedding priority group. Within each load-shedding priority group, facilities should be listed in the preferred order of tripping. Facilities having the highest load-shedding priority should be shed first, followed by the next-highest priority feeders, and so on until the load-shedding requirement is satisfied. At least ten (10) separate load-shedding priority groups should be supported by the DMS.

Following execution of the ELS function, the preferred order of tripping within each load-shedding priority group should be changed so that the same feeders are not tripped first for subsequent load-shedding operations.

The ELS function should assist the user in restoring power following the emergency. Partial restoration and full restoration should be supported. In partial restoration, the user should specify the amount of load to be restored, and the ELS function should restore the load, one facility at a time, in the reverse order of tripping until the load restoration target is achieved. For full restoration, all facilities that were shed should be restored in the reverse order of tripping.

During system emergencies that result in severe power shortages, it may be necessary to shed rapidly (i.e., in less than one minute) a block of load (specified in MW) to avoid loss of bulk power grid integrity and stability. Load shedding must be performed in a manner that does not interrupt any critical essential loads (hospitals, government agencies, police/fire, and other critical infrastructure).

Non-critical load should be shed in a fair and equitable manner; that is, different feeders should be selected for load shedding during each occurrence so that the burden of load shedding is not imposed on the same customers for every event.

The DMS should include an ELS function that should be executed in real time on request. This function should 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 should be able to initiate load shedding only for loads that are included in the user’s assigned AOR.

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

### 2.18.1 Stakeholders

The principal stakeholders of the DMS ELS function include the following:

- **ISOs** are responsible for declaring that "xx" amount of MW should be shed. They are also responsible for declaring that the ELS event is over.
- **DSOs** execute the ELS function that performs load shedding; they also use this function to implement rolling blackouts when needed.

### 2.18.2 Situations in Which This Function Should Be Used

The DMS ELS function should be used under the following circumstances:

- **ISO declares load shed emergency:** Function is run when ISO requests ELS of a specified amount.
- **Rolling blackout period expired:** After the specified time period for a rolling blackout, the feeders that are shed must be changed: one feeder must be taken off line and service must be restored to one of the original feeders. The ELS application is responsible for rotating the feeders being shed to distribute the burden among all customers.
- **ISO declares emergency event is over:** The ELS function is run when the ISO requests that load that was shed be restored (load should be restored gradually to avoid the additional shock of in-rush current).

### 2.18.3 Information That Is Required to Run the Application

The following information is required to run the DMS ELS function:

- List of feeders (or portions of feeders) that are available for ELS: these are feeders (or portions of feeders) that can be switched off under remote-control SCADA.
- Current net load on each feeder (from SCADA; equivalent to actual load minus DG output).
- Penetration of DG on the feeder, if possible.
- Status input; that is, ISO requests ELS of a specified amount.
- Declaration by ISO that ELS is no longer required.

### 2.18.4 Outputs That Will Be Provided to the Stakeholders

The ELS function will supply the DSO with a list of feeders or portions of feeders that

- Have SCADA for remote control purposes.

- Are able to operate in islanded microgrid mode.
- Do not serve critical customers.
- Have the highest load.
- Do not have a high penetration of DG resources that would not be available when the feeder is tripped and therefore are eligible for load shedding.

The list will include the current loading on the feeder, prioritized by amount of time the feeder has been shed in the past (feeders that have never been shed are highest priority), current loading (feeders that have the highest load are higher priority), and then random ordering.

### 2.18.5 Required Actions by the Stakeholders in Response to Functional Outputs

**ELS Scenario Number 1: ISO declares load shed emergency.**

The operation procedure of this ELS scenario is shown in the flow chart in Figure 41.

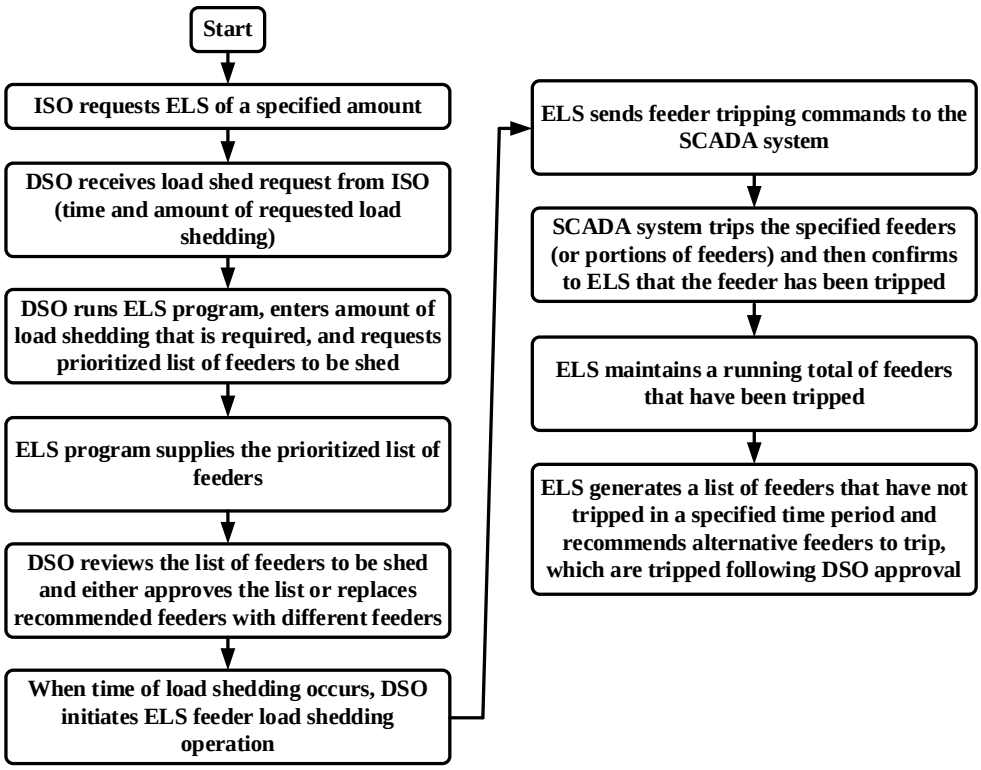



FIGURE 41 Flow Chart of the Operation Procedure of ELS Scenario #1: ISO Declares Load Shed Emergency

## 2.19 ELECTRIC VEHICLE CHARGE MANAGEMENT

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 function of EV charge management can be used as a complement of demand response. It includes 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 during peak hours and to take advantage of off-peak charging benefits. The EV charge management function enables the user to 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.

Note that some EV charging functions such as billing are usually performed by a system that is separate from the DMS, such as a Charge Point Management System (CPMS).

### 2.19.1 Stakeholders

The principal stakeholders of the DMS EV charge management function include:

- **DSOs** who are responsible for monitoring the condition or the distribution system and for responding to potential overloads via control actions such as "surgical" control of EV charging.
- **DR personnel** who use the EV charge management function as a means of lowering the peak load at a given time.
- **Customer care personnel** who are responsible for maintaining relationships with key customers such as the owner/operators of public EV charging stations and ensuring that the electric utility company is meeting its obligations to customers that use EV charging facilities.

### 2.19.2 Situations in Which This Function Should Be Used

The DMS EV charge management function should be used under the following circumstances:

- **EV Charge Management Scenario Number 1: Distribution service transformer serving EV charging station is overloaded.**
  The electric distribution utility needs to reduce the loading on an overloaded distribution service transformer or associated secondary circuit that services an EV charging station or cluster of EV charging stations. In this case, the DMS signals the CPMS to curtail the amount of charging that is currently taking place on the charging station or stations that are

served by this transformer. The CPMS is responsible for ensuring that the charging curtailment activity is allowed under the terms of the EV charging contractual obligations of the utility.

- **EV Charge Management Scenario Number 2: Surgical load shedding.**
  The electric distribution utility needs to perform targeted (surgical) load shedding for any reason (e.g., needs to free up capacity on a portion of the electric distribution system that includes a high penetration of EV charging stations). In this case, the DMS signals the CPMS to curtail the amount of charging that is currently taking place on the selected portion of the distribution system. The CPMS is responsible for ensuring that the charging curtailment activity is allowed under the terms of the EV charging contractual obligations of the utility. The CPMS is also responsible for curtailing the EV charging load on the basis of commands from the DMS.
- **EV Charge Management Scenario Number 3: System-wide load-shedding activity.**
  The electric distribution utility needs to perform load shedding during a system-level emergency. In this case, targeted (surgical) load shedding is performed on a portion of the electric distribution system that includes a high penetration of EV charging stations. The DMS signals the CPMS to curtail the amount of charging that is currently taking place on the selected portion of the feeder. The CPMS is responsible for ensuring that the charging curtailment activity is allowed under the terms of the EV charging contractual obligations of the utility. The CPMS is also responsible for curtailing the EV charging load on the basis of commands from the DMS.

### 2.19.3 Information That Is Required to Run the Application

The following information is required to run the DMS EV charge management application:

- The specific portion of the electric distribution system for which charge management is needed. This can be one or more substations, one or more feeders, a feeder section, and/or one or more distribution service transformers.
- Loading on the portion of the distribution system in question. Alarm limits for entire feeders or substations are part of the standard SCADA alarm package. However, alarm detection for distribution service transformers and other specified portions of the electric distribution system is generally not available without additional analysis. This use case assumes that:
  - Loading and alarming of individual distribution service transformers is available via a dedicated monitor installed on the distribution transformers that serve pockets of EV chargers.
  - Loading and alarming of specified portions of an electric distribution feeder can be determined from line sensors installed at strategic locations on the distribution feeder that serves EV charging stations (e.g., the portion of a feeder between two DA switches that are used by the DMS FLISR application).
- Specific locations of charging stations on the electric distribution system.

### 2.19.4 Outputs That Will Be Provided to the Stakeholders

The following outputs will be supplied by the EV charge management application function to the stakeholders:

- Current loading on EV charging stations located in a specified portion of the electric distribution system.
- Amount by which the EV charging can be curtailed at a specified charging station without violating obligations of the EV charging contract.

### 2.19.5 Required Actions by the Stakeholders in Response to Functional Outputs

Usage of the EV charge management function under various scenarios is described below.

**EV Charge Management Scenario Number 1: Distribution service transformer serving EV charging station is overloaded.**

The electric distribution utility needs to reduce the loading on an overloaded distribution service transformer or associated secondary circuit that services an EV charging station or cluster of EV charging stations. In this case, the DMS signals the CPMS to curtail the amount of charging that is currently taking place on the charging station or stations that are served by this transformer. The CPMS is responsible for ensuring that the charging curtailment activity is allowed under the terms of the EV charging contractual obligations of the utility.

The operation procedure of this EV charge management scenario is shown in the flow chart in Figure 42.

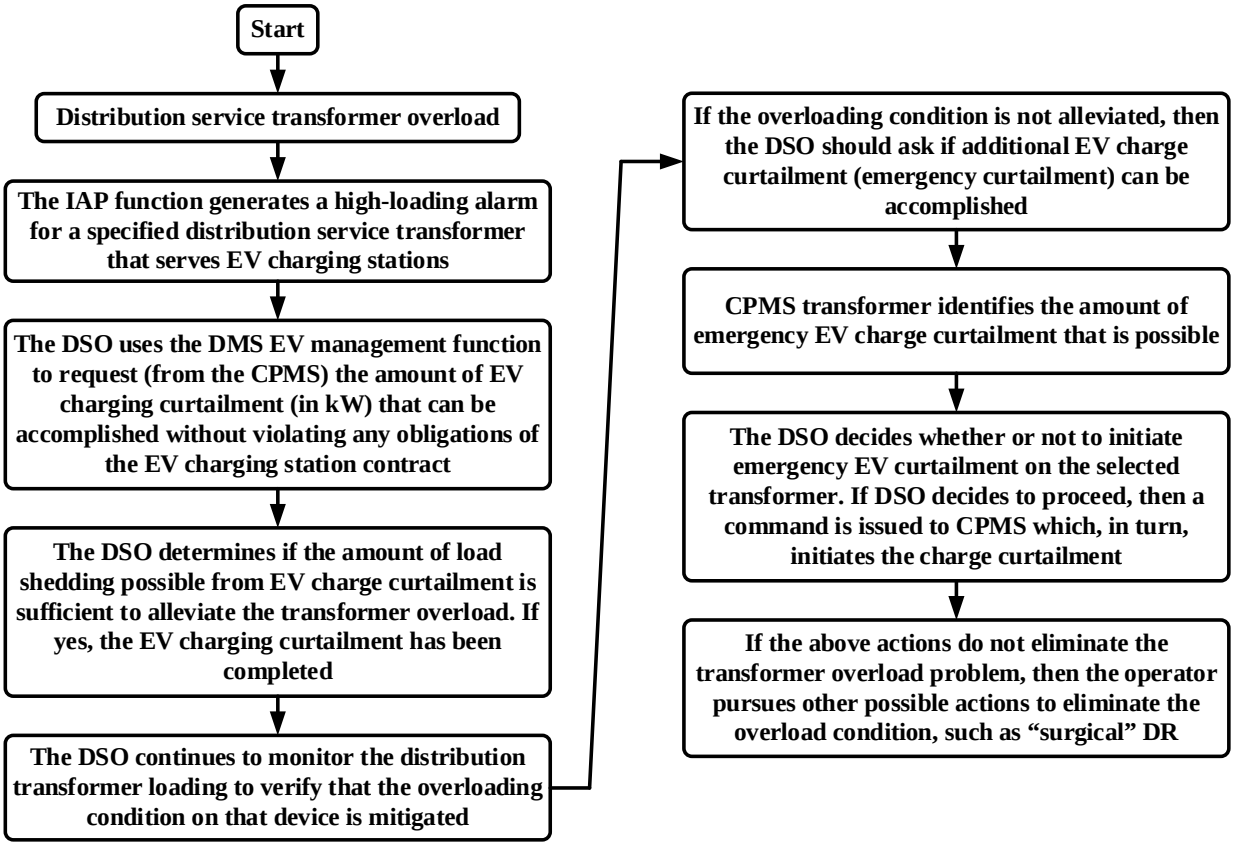



FIGURE 42 Flow Chart of the Operation Procedure of EV Charge Management Scenario #1: Distribution Service Transformer Serving EV Charging Station Is Overloaded

**EV Charge Management Scenario Number 2: Surgical load shedding required.**

The electric distribution utility needs to perform targeted (surgical) load shedding for any reason (e.g., needs to free up capacity on a portion of the electric distribution system that includes a high penetration of EV charging stations). In this case, the DMS signals the CPMS to curtail the amount of charging that is currently taking place on the selected portion of the distribution system. The CPMS is responsible for ensuring that the charging curtailment activity is allowed under the terms of the EV charging contractual obligations of the utility. The CPMS is also responsible for curtailing the EV charging load on the basis of commands from the DMS.

The operation procedure of this EV charge management scenario is shown in the flow chart in Figure 43.

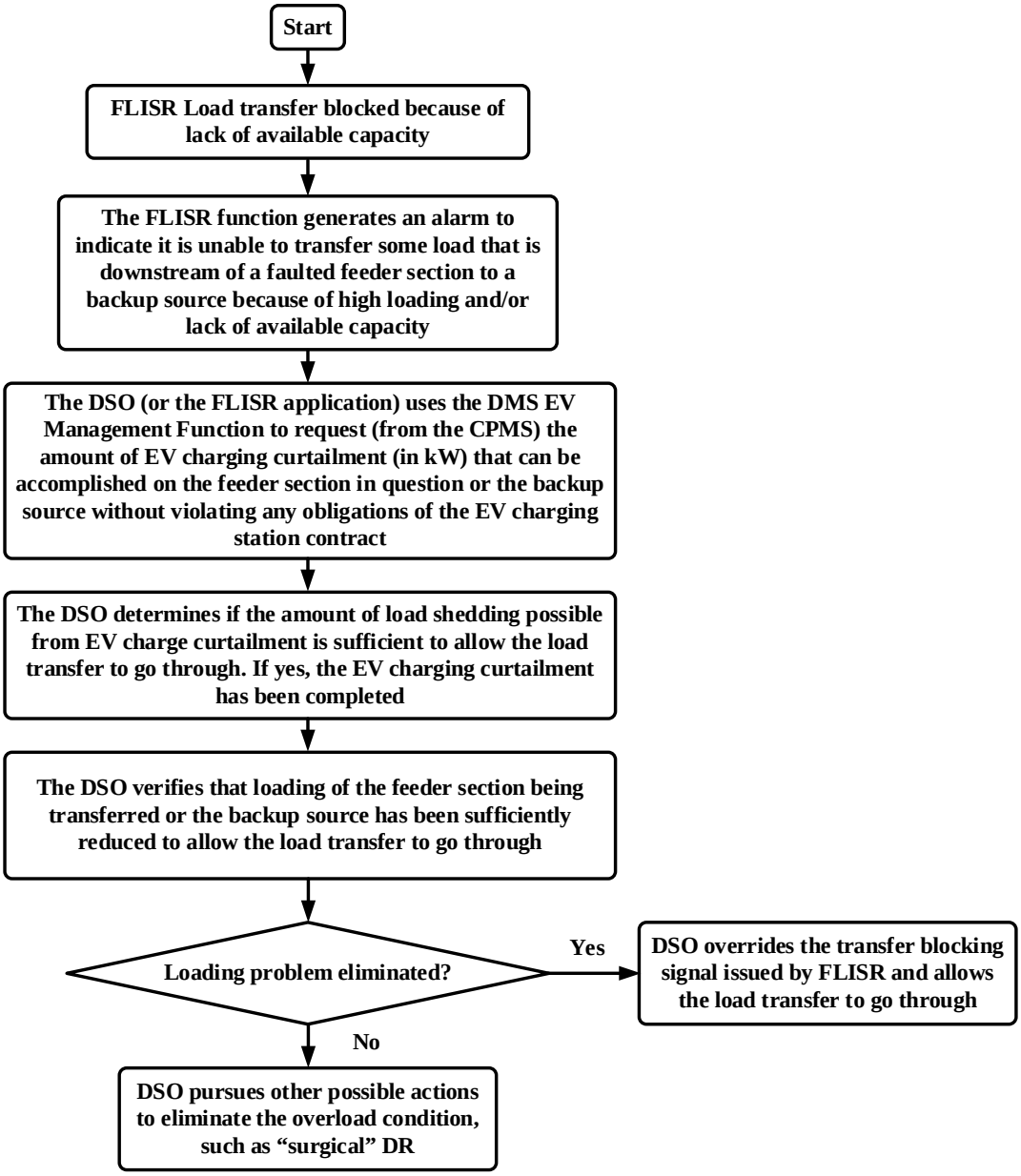



FIGURE 43 Flow Chart of the Operation Procedure of EV Charge Management Scenario #2: Surgical Load Shedding Required

**EV Charge Management Scenario Number 3: System-wide load-shedding activity.**

The electric distribution utility needs to perform load shedding during a system-level emergency. In this case, targeted (surgical) load shedding is performed on a portion of the electric distribution system that includes a high penetration of EV charging stations. The DMS signals the CPMS to curtail the amount of charging that is currently taking place on the selected portion of the feeder. The CPMS is responsible for ensuring that the charging curtailment activity is allowed under the terms of the EV charging contractual obligations of

the utility. The CPMS is also responsible for curtailing the EV charging load based on commands from the DMS.

The operation procedure of this EV charge management scenario is shown in the flow chart in Figure 44.

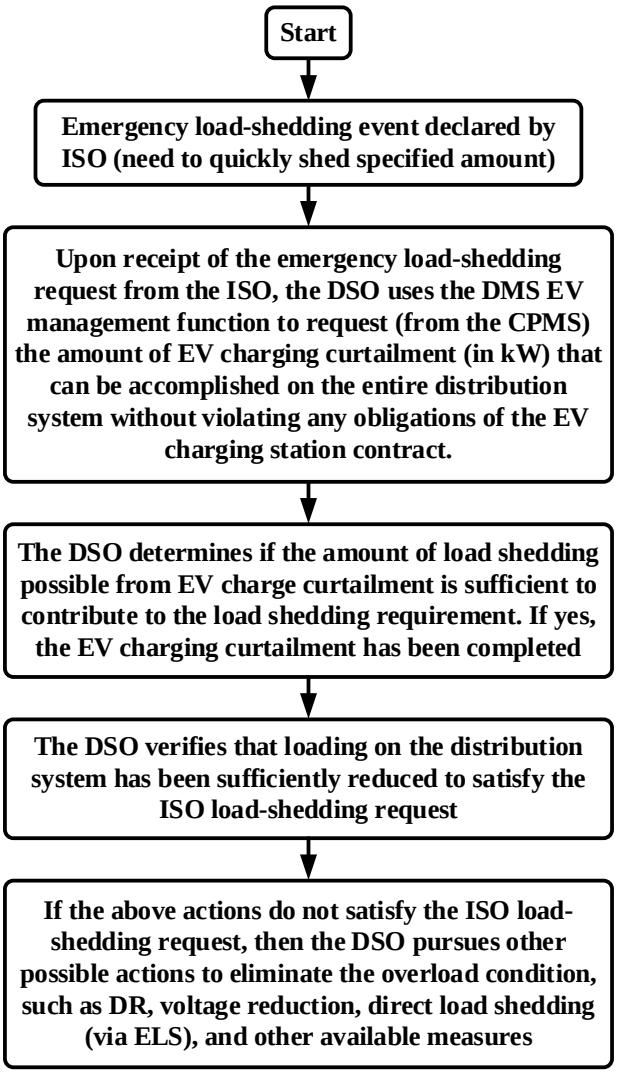



FIGURE 44 Flow Chart of the Operation Procedure of EV Charge Management Scenario #3: System-wide Load-shedding Activity

## 2.20 ASSET MANAGEMENT

The DMS AM application function enables the electric utility to track the current operating condition of each piece of electric power apparatus (transformers, switches, voltage regulators, etc.). The AM function is used by collecting real-time and near-real-time information that should 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 enables the utility to implement a "condition-based" maintenance program in which maintenance activities are performed on the basis of the amount of duty performed by the device rather than calendar time between maintenance activities.

### 2.20.1 Stakeholders

The major stakeholders for the AM function are:

- **AM personnel:** This group includes persons responsible for tracking the health and operating status of the energized power apparatus and for managing the maintenance activities for this equipment. The AM group relies on near-real-time data received from the DMS pertaining to the operation of electric distribution equipment. This information is used, during routine and abnormal operations, to determine whether the equipment is operating correctly and, if not, whether additional inspections, maintenance activities, and corrective action may be needed.

### 2.20.2 Situations in Which This Function Should Be Used

The AM function should be used under the following circumstances:

- The AM function runs continuously without manual intervention to track the performance and operating status of the distribution system equipment, including circuit breakers and other switchgear, voltage regulators and LTCs, secondary equipment (e.g., substation batteries), and other distribution components that require periodic inspections and maintenance activities. During the continuous tracking process, key performance indicators (KPIs) are developed for each power system component that indicate the amount of "wear and tear" on each component, which can be used to determine if inspection and maintenance activities are warranted.
- **KPI threshold exceeded:** When any given KPI exceeds a specified threshold, the DSO or AM personnel responsible for the type of power apparatus in question will trigger additional investigation that may result in inspections and additional maintenance activities.

### 2.20.3 Information That Is Required to Run the Application

The following information should be used by the DMS to support the AM calculations:

- Equipment counters for all power apparatus that are 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.
- Quantity and magnitude of through-fault events for each device.

In addition to the performance measurements listed above, the AM function requires a set of performance thresholds for each type of equipment. If a threshold is exceeded, this reading indicates that the particular piece of equipment may require attention in the form of maintenance or replacement.

### 2.20.4 Outputs That Will Be Provided to the Stakeholders

The output of the AM application function is a set of KPIs that indicate the overall performance and health of power system components. These KPIs indicate whether a component should be scheduled for tear-down inspections, maintenance activities, and/or possible replacement.

### 2.20.5 Required Actions by the Stakeholders in Response to Functional Outputs

Following is a summary of the actions required by stakeholders in response to the functional outputs of the AM function:

**AM Scenario Number 1: Maintenance threshold exceeded for specific piece of equipment.**

The operation procedure of this AM scenario is shown in the flow chart in Figure 45.

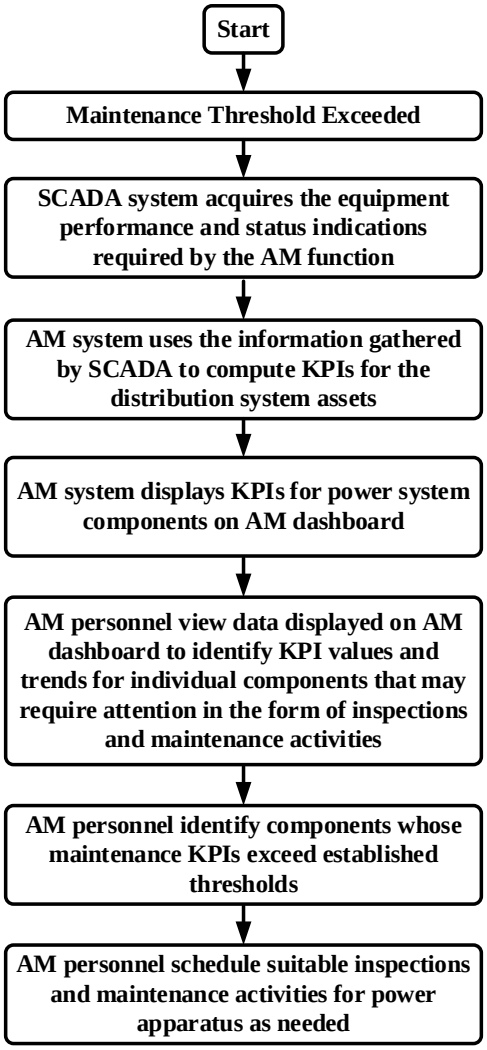



FIGURE 45 Flow Chart of the Operation Procedure of AM Scenario #1: Maintenance Threshold Exceeded for Specific Piece of Equipment

## 2.21 ENGINEERING ANALYSIS

The DMS should include a suite of applications that engineers can use for planning and design purposes and for conducting post-mortem analysis following unusual operating events, such as protective relay misoperation. DMS engineering analysis tools are 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.

The application of engineering analysis can be used in real time or off-line. Although these 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 can 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 following:

- The same distribution system model is 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 recreating 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" because of feeder reconfiguration that takes place during the year.

As a minimum, the following engineering analysis functions should be available in the DMS for performing "off-line" engineering analysis:

- OLPF and state estimation
- Short-circuit analysis
- Protective relay analysis and coordination
- Reliability analysis
- Energy loss calculations
- Optimal network reconfiguration
- Voltage regulator/tap changer settings
- Short-term/long-term load forecasting
- Capacity planning
- Thermal monitoring
- Capacitor placement
- Motor start

The DMS should 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 should 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 should 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 should enable operators and engineers to examine "what if" scenarios. (For example, "What if a portion of feeder 'A' load is transferred to feeder 'B'?") Study mode operation should be executed upon demand.

### 2.21.1 Stakeholders

The major stakeholders for the engineering analysis function are as follows:

- **Planning and design engineers** use the engineering analysis software to compute equipment loading and electrical losses, evaluate effectiveness of voltage regulation strategy, conduct DG connection studies, and perform other analysis.

### 2.21.2 Situations in Which This Function Should Be Used

The engineering analysis software is used when the planning and design engineer needs to conduct "what if" studies on the electric distribution system and when it is necessary to do post-mortem analysis of a recent event in which relay/control misoperation was suspected. The engineering analysis scenarios are listed below:

- **Scenario Number 1: "What if" study is required.**
  Engineer or other stakeholder needs to run a power flow study to determine whether unacceptable electrical conditions will result if a proposed distribution system change is made. In this scenario, the engineering analysis software will run in study mode.
- **Scenario Number 2: Post-mortem analysis is required.**
  Engineer needs to analyze a recent event to verify that the protection and control equipment operated correctly during that event.

### 2.21.3 Information That Is Required to Run the Application

The following information is required to run the engineering analysis program:

- Near-real-time measurements of real and reactive power and voltage at the head end of the feeder (as a minimum) and at other strategic feeder locations (e.g., midline recloser and voltage regulator locations). *[Note: providing additional real-time measurements from sensors located on the feeder will improve the overall accuracy of the engineering analysis calculations.]*

- “As operated” model of the portion of the electric distribution system that is being analyzed.
- Load profiles for all of the loads that are connected to the feeder. Alternatively, near-real-time load measurements can be used instead of load profiles if this information is available in near-real time from an advanced metering system.
- Real and reactive power output of DG units that are connected to the distribution facilities being analyzed. For larger (utility-scale) generating units (usually having a capacity of at least 100 kW), these quantities may be available via SCADA in accordance with the connection agreement. The output of smaller DG units that do not have SCADA will be determined as needed by the DSE function.

### 2.21.4 Outputs that Will Be Provided to the Stakeholders

The following outputs will be supplied by the engineering analysis software to the stakeholders:

- Real and reactive power flow, current, voltage at all points on the feeder.
- Electrical losses calculated by OLPF
- Warning about abnormal conditions anywhere on the feeder (under/over voltage, overload).

### 2.21.5 Required Actions by the Stakeholders in Response to Functional Outputs

The specific use cases for the engineering analysis scenario are described below:

**Engineering Analysis Scenario Number 1: “What if” study is required.**

Engineer or other stakeholder needs to run an engineering analysis study to determine whether unacceptable electrical conditions will result if a proposed distribution system change is made. In this scenario, the engineering analysis software will run in study mode.

The operation procedure of this engineering analysis scenario is shown in the flow chart in Figure 46.

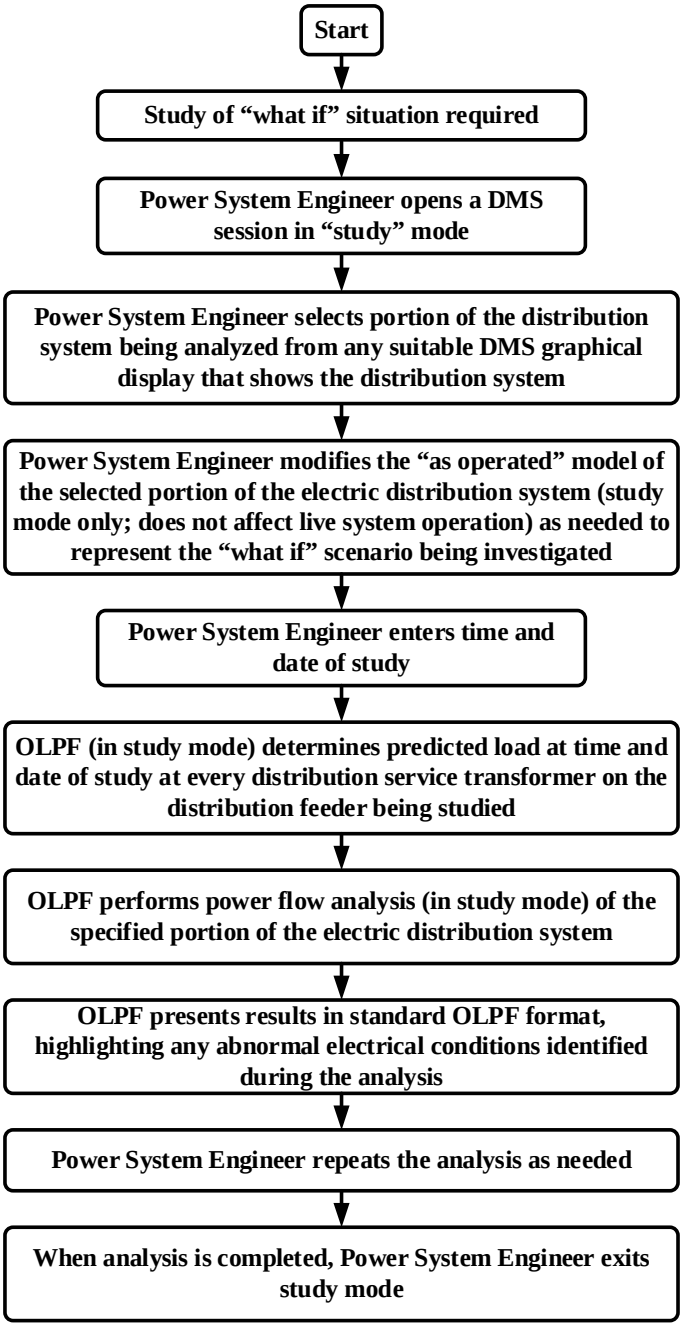



FIGURE 46 Flow Chart of the Operation Procedure of Engineering Analysis Scenario #1: "What If" Study Is Required

**Engineering Analysis Scenario Number 2: Post-mortem analysis required.**

Engineer needs to analyze a recent event to verify that the protection and control equipment operated correctly.

The operation procedure of this engineering analysis scenario is shown in the flow chart in Figure 47.

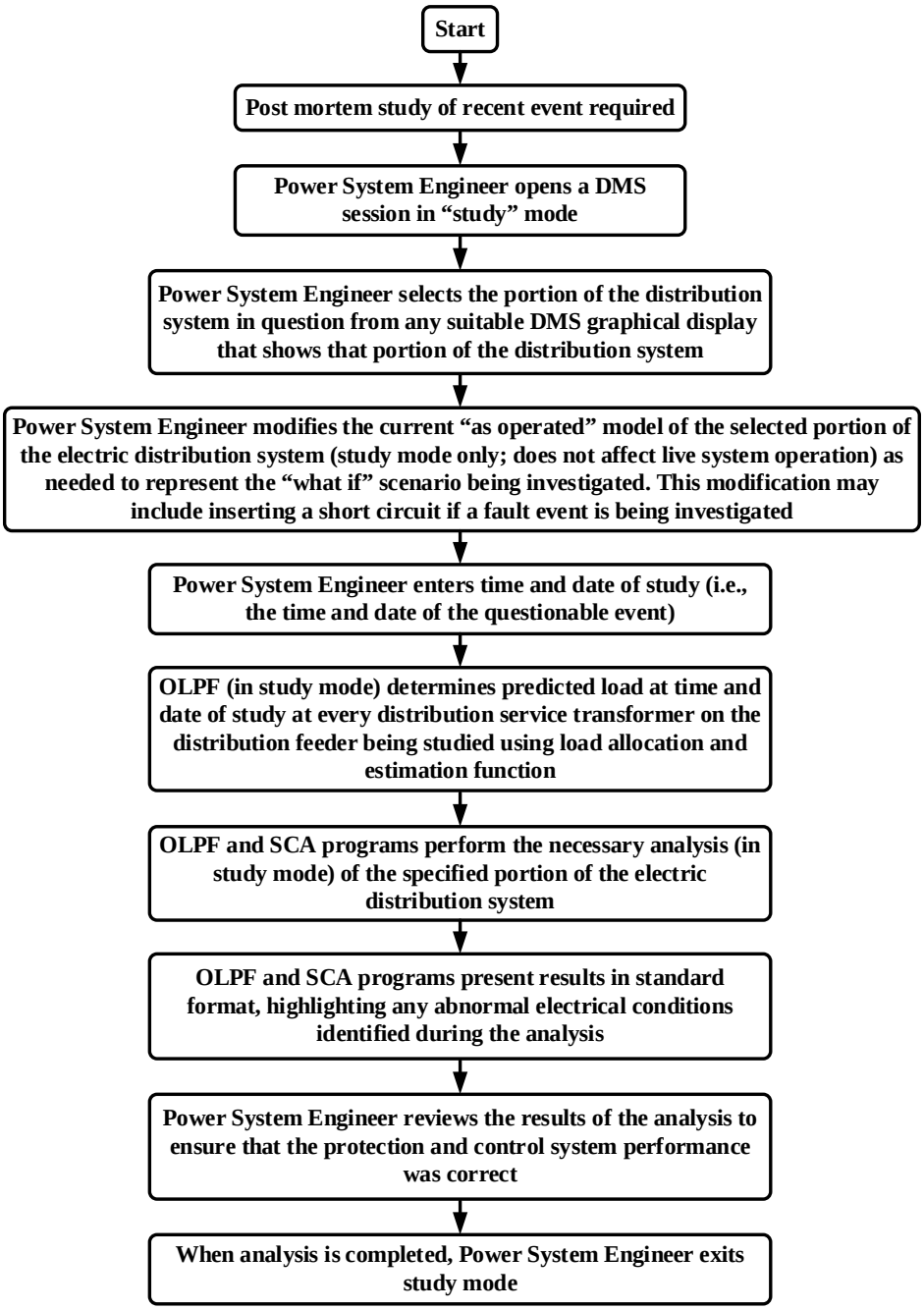



FIGURE 47 Flow Chart of the Operation Procedure of Engineering Analysis Scenario #2: Post-Mortem Analysis Required

## 2.22 DISPATCHER TRAINING SIMULATOR

The DMS should include a DTS that should 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 DTS should include a complete replica of the real-time DMS user interface plus the operating model, which should simulate the real-time analog telemetry and status changes (elements' models should be the same).

The DTS serves two main purposes:

- Allows utility personnel to become familiar with the DMS system and its user interface without affecting actual substation and feeder operations.
- Allows 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 is used as an interactive tool to train the operators for different conditions that could be encountered in real operation. It should be considerably more than a simple data "playback" facility. The DTS should 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 should automatically go to zero. The event should be properly reflected on the trainee's screen as an open switch with the coloring of the non-energized state. In other words, the distribution system model at the trainee's console should respond to all dynamic changes caused by the instructor. The DTS should fully emulate all monitoring and control capabilities of the real-time the system such as alarming, tagging, and AOR functionalities.

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

The DTS should enable the user (instructor) to introduce equipment and control failures into the system, whereupon the simulator should calculate the expected result and present it to the trainee. The instructor should be able to place simulated single- and multiphase faults at any location along the feeder using the DTS supervisor console, and the DTS should (in turn) calculate and display the expected fault current magnitude and resultant protective device operation(s).

It should 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 should 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).

### 2.22.1 Stakeholders

The main stakeholders for the DTS include:

- **DSOs** who use the DTS for training new operators and conducting refresher training for experienced operators (including trainees and trainers).
- **Human resource personnel** who manage the training program for DSOs and support personnel.

### 2.22.2 Situations in Which This Function Should Be Used

The DTS simulator should be used when a new operator requires training or when a more experienced operator requires refresher training.

### 2.22.3 Information That Is Required to Run the Application

The following information is required to run the DTS:

- "As operated" model of the electric distribution system (copied from production DMS used for live operation).
- Sequence of power system events that are included in the training scenario (e.g., a permanent fault occurs at a specified location on the distribution feeder).

### 2.22.4 Outputs That Will Be Provided to the Stakeholders

The DTS provides DMS displays of simulated power system information that matches what would be displayed to operators on DMS screens if the event occurred in live operation.

### 2.22.5 Required Actions by the Stakeholders in Response to Functional Outputs

Following is a sample scenario that illustrates how the DTS would be used for a typical training scenario.

**DTS Scenario Number 1: Permanent fault occurs on main line portion of the distribution feeder.**

The operation procedure of this DTS scenario is shown in the flow chart in Figure 48.

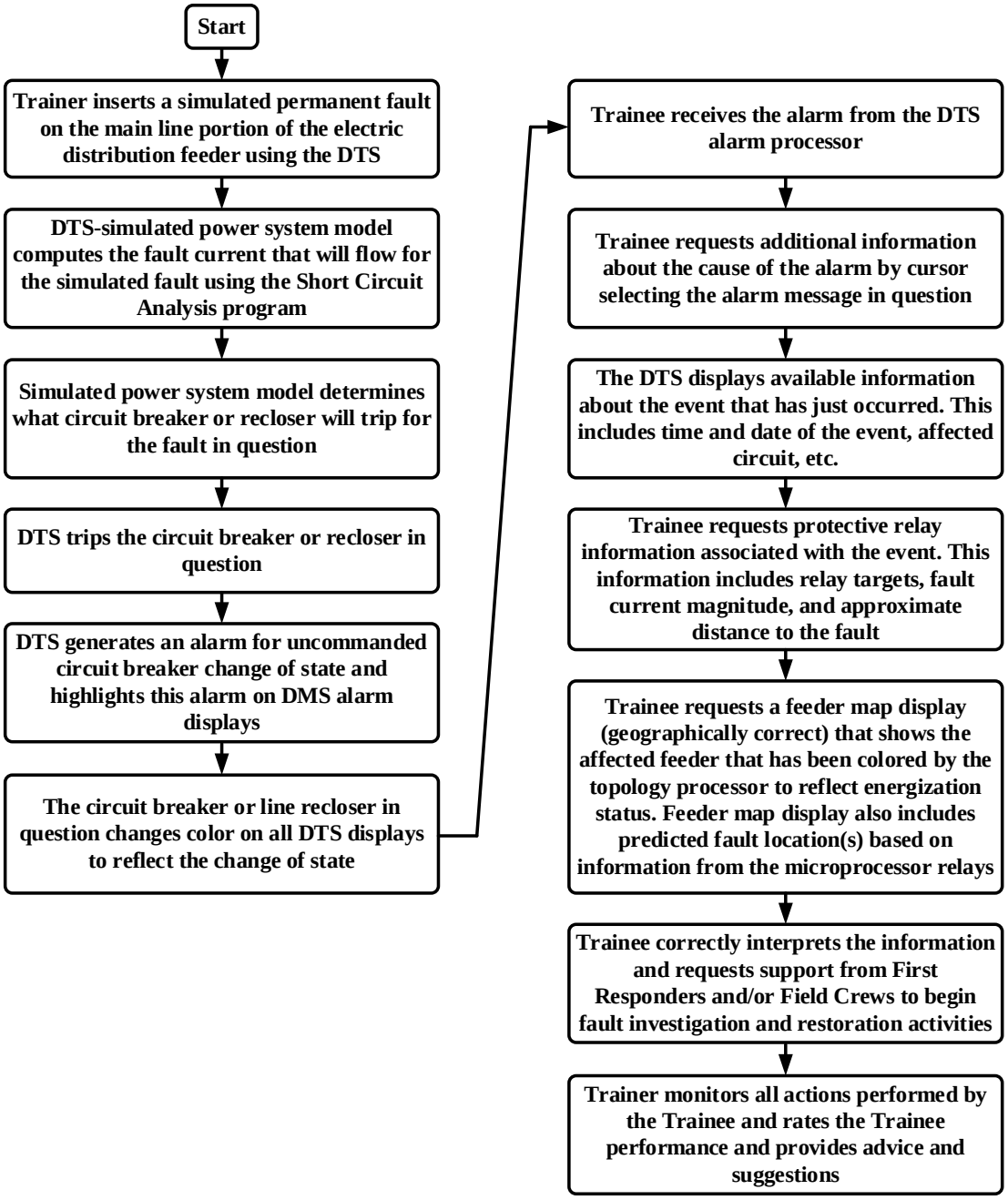



FIGURE 48 Flow Chart of the Operation Procedure of DTS Scenario #1: Permanent Fault Occurs on Main Line Portion of the Distribution Feeder

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