ELECTRIC POWER RESEARCH INSTITUTE

Distributed Energy Resources and Management of Future Distribution

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EPRI Project Manager
J. Hughes

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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Utility Consulting International
4340 Stevens Creek Blvd. Suite 288
San Jose, CA 95129

Principal Investigator
N. Markushevich

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PRODUCT DESCRIPTION

The Electric Power Research Institute's (EPRI's) Smart Grid demonstration initiative is a collaborative research effort focused on the design, implementation, and assessment of field demonstrations to address challenges with integrated distributed resources in grid and market operations as well as system planning.

The main objective of this study is to identify approaches to interoperability and integration that can be used on a systemwide scale to help standardize the use of distributed energy resources (DER) as part of overall system operations and control.

Results and Findings

The study includes discussions on advanced distribution automation applications in the Smart Grid environment with integration of DER as active participants of power system operations. In addition, the potential benefits of integrating DER into dynamic optimization are analyzed and existing and future requirements for information exchange with DER are addressed. Views on the actors, logical interfaces, and object models involved in this information exchange are also presented. The gaps between the current and future states of the information exchange with DER are described, and the migration strategy to overcome the gaps is outlined. The report concludes with recommendations for future work.

Challenges and Objectives

The objectives of this study are as follows:

- Develop an end-to-end model depicting the data and information exchange required to manage the large-scale deployment of DER between systems involved in regional system operations, transmission, distribution, and customer service down to end-use energy systems and on-site resources.
- Characterize the current baseline state of typical existing "legacy" systems for managing DER equipment.
- Define the future state of these systems, including the functions and requirements necessary to scale up and manage widely deployed DER.
- Identify the gaps between the current and future states.
- Identify the benefits associated with the future state, including the benefits of a mature management infrastructure that covers interoperability and security.
- Define a strategy for migrating from a legacy system to the future state and associated architecture considerations.

The challenges of the study lie in the transition state of Smart Grid and its components. Among these challenges are DER and the renewable energy-based components.

Applications, Value, and Use

This study can serve as a reference for feasibility studies in Smart Grid operations and for the development of a Smart Grid data management system, object model, and information exchange designs. The material presented in this report should be used for the selection, expansion, integration, and harmonization of interoperability standards.

EPRI Perspective

This project takes a future view of a few advanced distribution automation (DA) functions and uses these to further the development of the open standards necessary to enable these forward-looking applications. This study addresses the use of multiple distributed energy resources as dependent, as well as independent, variables in the dynamic optimization of power system operations. Because there are no precedents of such optimization in real utilities, this study represents a new step into future grid operations.

Approach

The study is based on the conceptual design of major advanced DA applications introduced in the IntelliGrid project and related studies and updated in accordance with the most recent development in the Smart Grid area, including the National Institute of Standards and Technology (NIST) Interoperability Roadmap. The study addresses the information support and controlling capabilities of DA applications available under the current conditions and the possible development of information support and controls by integrating DER as information sources and as controllable variables in the DA applications. Prior work performed by Utility Consultants International was used in the development of this report.

Keywords

Distribution automation
Distributed energy resources
Electric storage
Microgrids
Operation models
Smart Grid

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IDENTIFICATION OF THE BENEFITS ASSOCIATED WITH END-TO-END INFORMATION EXCHANGE BETWEEN SYSTEM OPERATIONS AND DISTRIBUTED ENERGY RESOURCES

The following achievements characterize the Smart Grid [1]:

Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.

- Dynamic optimization of grid operations and resources, with full cyber- security.
- Deployment and integration of distributed resources and generation, including renewable resources.
- Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
- Deployment of `smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
- Integration of `smart' appliances and consumer devices.
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
- Provision to consumers of timely information and control options.
- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

With the advances of the Smart Grid the distribution system will transition from a passive sub-system of the power system into an Active Distribution Network (ADN). As defined in [2], "Active Distribution Networks are distribution networks that have systems in place to control a combination of distributed energy resources (generators, loads and storage). Distribution system operators (DSO) have the possibility of managing the electricity flows using flexible network topology. Distributed Energy Resources (DERs) take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement".

Significant penetration of DERs in distribution systems provides basic benefits due to their impact on the power system infrastructure. In addition to these long-term benefits, there are potential benefits from the dynamic optimization of the operations of the ADNs. However, the existence of significant DERs in the distribution systems also presents some challenges for power system operations. In this study, we will discuss the information support needed for obtaining the operational benefits of DER, as well as for overcoming the operational challenges.

Before we approach the benefits associated with end-to-end information exchange between system operations and distributed energy resources, we need to define the role of DERs in the operations of the Active Distribution Networks.

The concept of the Smart Grid is based on a close integration of different active elements present in the ADNs, including customer systems with a variety of choices. Therefore, the integration of DER into dynamic optimization of the power system operations in the Smart Grid environment cannot be considered without the interrelationships and interactions of other active power system components, such as:

- different kinds of demand response, which also can be considered as DER
- discrete and continuous (dynamic) sources of reactive power, and
- Voltage regulating devices.

On the other hand, the dynamic operations of a significant portion of power system resources in the customer and distribution domains considerably impact the operations of the transmission and bulk generation systems and vise versa. Aggregated DERs, including the demand response portion of it, will also become a significant participant in the energy and ancillary markets. Hence, strong relationships between all major domains of power system operations are expected due to the significant presence of DERs in distribution and due to the need in dynamic optimization of the power system operations in a holistic manner to provide the best reliability, quality, and efficiency of electric services to the modern society Figure 1-1.

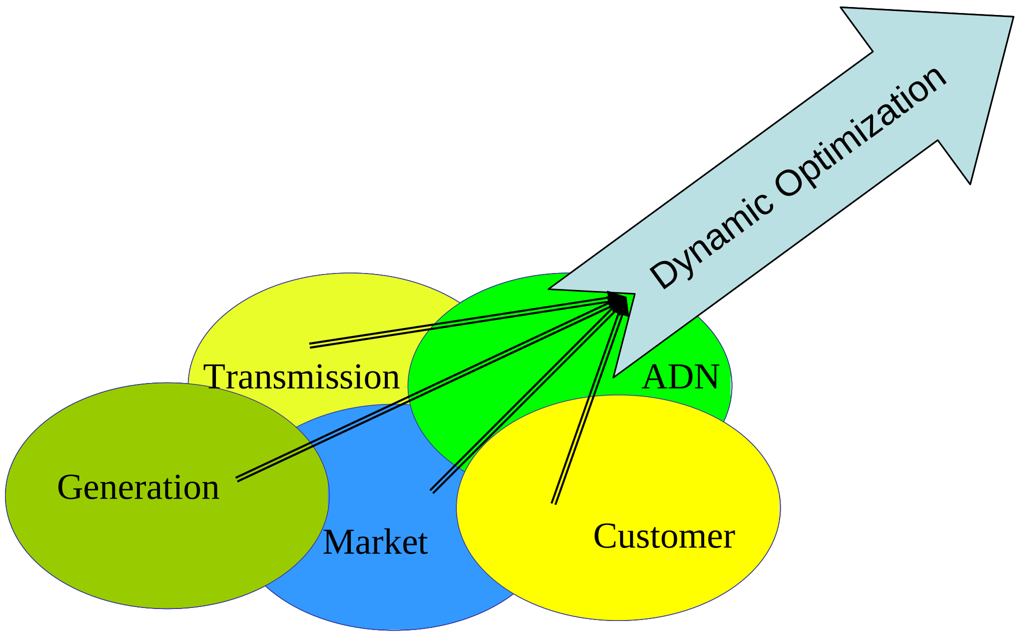

Figure 1-1
All major domains of power system operations will be interrelated with the Active Distribution Networks.

The main activities in managing distribution operations are as follows:

- Under normal operating conditions—
  - Provide near-real-time and short-term look-ahead situational awareness of the normal operating conditions of the distribution system
  - Control distribution operations, providing quality power to the customers in a reliable and efficient manner
  - Prepare for probable contingencies
  - Manage planned maintenance
  - Support market operations
  - Coordinate distribution operations with bulk power system operations, including information support for Wide Area Situational Awareness.
  - Provide information storage for reports and retrospective analyses of operations
- Under emergency operating conditions—
  - Provide urgent situational awareness for the emergency operating conditions (fault location and emergency assessment)

  - Limit the spread of the emergency to a minimum customer domain (isolation and restoration in space and time)
  - Adjust the operations to the new conditions (prepare for other contingencies, re-coordinate, adjust Volt/Var/Watt Optimization)
  - Manage forced outages
  - Inform the customers
  - Provide information storage for reports and retrospective analyses of operations
- Under restorative operating conditions—
  - Provide fast situational awareness for the restorative operating conditions
  - Restore services to the de-energized customers and to the customers served under abnormal conditions in coordination with the near-real-time and short-term look-ahead operational margins
  - Provide information storage for reports and retrospective analyses of operations.

Situational Awareness of the Normal Distribution Operating Conditions with Significant DER

Situational awareness of the operations of an Active Distribution Network shall provide answers to the following questions [3]:

- What are the current states of the distribution system components and of the components of other associated systems?
- What are the capabilities and behavior of the power system components? How does each relate to the entire power system state as a whole?

In regards to DER, the information needed to answer these questions cannot be limited to the DERs only. The states, the behavior, and the relation of DER to the system state may strongly depend on the state and behavior of other components of the ADN and on other factors influencing DER behavior. For instance, there will be many small DERs located at the customer premises, which are weather-dependent. The current and the short-term look-ahead states of these DERs can be assessed based on the local weather conditions collected from a weather information system. Another example relates to a customer, which has both a DER that can be turned On or Off and a Demand Response means. The choice of the customer for starting the DER, or applying the Demand Response, or doing both may be different even under the same price signals and different other conditions impacting the use of these means. Hence, to be aware about the current or shortly expected state of the DER, the situational awareness function should also be informed about the expected behavior of the Demand Response under the particular expected conditions.

In general, to have comprehensive end-use information about the DERs as components of the operation model of the ADN the data model cannot be considered in isolation from the full distribution operation model.

The main Advanced Distribution Automation (ADA) applications providing the situational awareness of the distribution operations are the following:

- Distribution Operation Model and Analysis (DOMA)
- Distribution Contingency Analysis (DCA), which can be a part of DOMA.

Distribution Operation Model and Analysis

The objectives of DOMA application are as follows:

- Generate and analyze the distribution operation model that is adequate for the near real-time monitoring of the essential behavior of the distribution system.
- Provide situational awareness of the distribution system operations by submitting concise and essential information to the operators.
- Generate component and aggregated behavioral object/data models for the use by other advanced DA and EMS applications.
- Determine dynamic operational limits to be used by DA and EMS applications.
- Analyze the operations of the distribution system from the standpoints of adequacy, power quality, and economic efficiency.

Component Models of DOMA

Below is a brief description of the component models of the basic Distribution Operation Model and Analysis application [3-8].

In the Smart Grid environment, the multifunctional Advanced Metering Infrastructure (AMI) system, customer Energy Management System (CEMS), DER and microgrid controllers in the Point of Common Coupling (PCC), and the market and weather IT systems will become significant sources of information support for the ADA applications. DOMA will processes these various input data into a near-real- time and short-term look-ahead comprehensive models of distribution operations to be used as a base for other ADA applications and to provide the operators with the situational awareness of the ADN operations. A high level illustration of the information flow for DOMA application is presented in Figure 1-2.

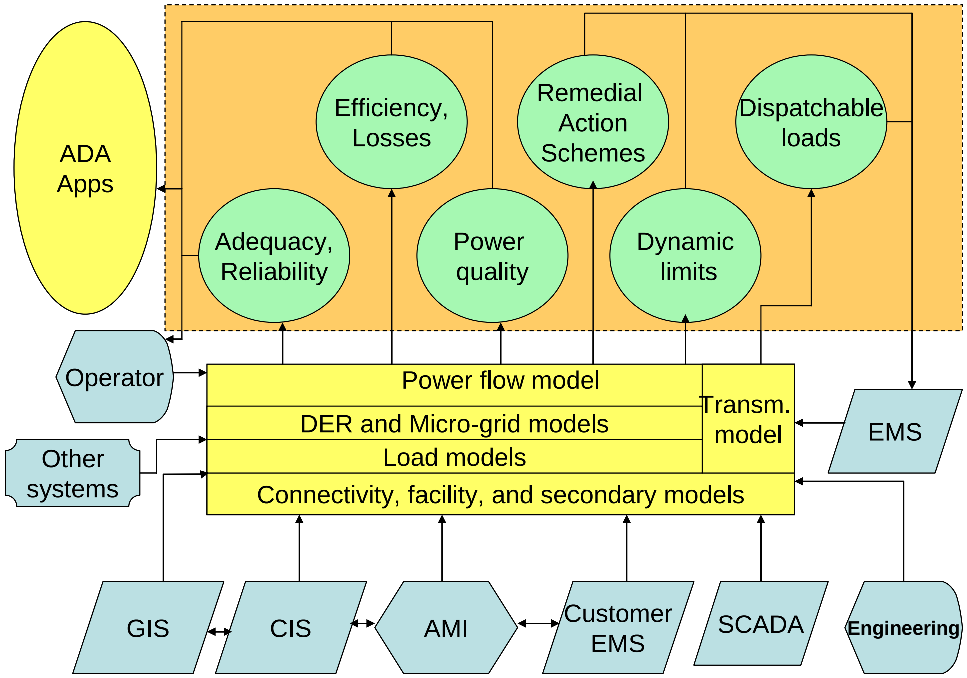

Figure 1-2
Data sources, models, and analyses in DOMA

The function is based of the following component models:

- *Model of transmission/sub-transmission system* needed to account for the impact of the distribution operations on transmission operations. With high penetration of DER in distribution, the power flows, the voltages and voltage angles [9] in transmission will significantly depend on the aggregate state and operations of the DERs. The Locational Marginal Prices (LMP) at the buses feeding the distribution system will depend on the DER operations and will impact their operations. This model provides topology and electrical characteristics of those substation transformers and transmission/sub-transmission portions of the system, where loading and voltage levels significantly depend on the operating conditions of the particular portion of the distribution system. The model also includes substation transformers and transmission/sub-transmission lines with load and voltage limits that should be respected by the application. The model of the rest of the bulk transmission system is included as sensitivity functions determined by the Energy Management System (EMS) Network Sensitivity application. The transmission related information exchange is accomplished over the EMS—Distribution Management System (DMS) interface.

- *Model of distribution circuit connectivity.* This model provides a topological model of distribution circuits, starting from the distribution side of the substation transformer and ending with the equivalent secondary circuits between the distribution transformer and either a load centers with an aggregated load model, or point of connection of an individual customer or a DER. A topological consistency check is performed every time the connectivity changes. Presently, the model input comes from AM/FM/GIS, from SCADA/EMS, Distribution SCADA, from Distribution System Operator (DSO)), from the Outage Management System, and from field crews (typically through the DSO). In the Smart Grid environment, additional information may come from processing outage detections by AMI and from secondary equivalents derived based on AMI-processed data. At the present time, the AM/FM/GIS databases lack many objects and attributes needed for DA applications. Most of these databases do not include or do not update timely the data on the secondary distribution circuits. If the model of a DER connected to the secondary circuit is not embedded in the nodal load model, or if the DER is used for control by a local controller or by an ADA application, the DER should be represented as a separate object model, and its connectivity to the distribution transformer should be explicitly modeled. This explicit model can be represented by an equivalent derived based on the AMI-supported data and other component of DOMA [10].The impact of DER operations on the operational parameters in distribution is highly dependent on the connectivity of the distribution circuits. Under some connectivity, the DER may unload the distribution circuit, while under another it can overload some segments of the feeder. The voltage profile along the feeder supported by the DER is also different under different connectivity.
- *Models of distribution nodal loads*. At the present time, the nodal load modeling in distribution is based on 'typical' real load shapes and expert estimates of the power factors for a number of load categories and on the monthly billing data. In the Smart Grid environment, the concept of 'typical' load shape is not applicable due to the variety of possible behavior of the many small distributed generators, electric storage devices, and plug-in electric vehicles, and demand response means scattered among many customers. The real and reactive load models, individual or aggregated, shall reflect the behavior of these composite loads depending on the known weather, prices, voltage, time of day, and other factors. In many cases, the models of the DER embedded in the customer systems can be considered as component of the behavioral load model. For instance, the model of a customer load with solar panels (passive, non-controllable, DER) would be a function of the sunlight (or time of day) and cloudiness, while the model of a customer load with a passive DER and with Demand Response would be, in addition, a function of the Demand Response conditions, e.g., energy price. However, if the DER is partially or fully controllable, it is preferable that its object model is separated from the load model.

  With the penetration of the weather-sensitive DER in the customer domain, the nodal loads will become irregular due to the fluctuations of the embedded generation caused by variable cloudiness or wind changes. These fluctuations are random, however some of their statistics can be modeled based on their known parameters and weather forecast. Based on these statistics, the random component of the load should be accounted for in a way that is minimally detrimental to the optimization process. The maximum and minimum possible fluctuations can be derived from the nominal output of the DER under the predicted weather conditions at the particular times. The probability distribution of the fluctuations can be assessed based on historic data. Figure 1-3 and Figure 1-4 present illustrations of a customer load with an embedded PV DER. As seen in the figures, the load shapes are significantly different at a sunny day and at a clouded day.

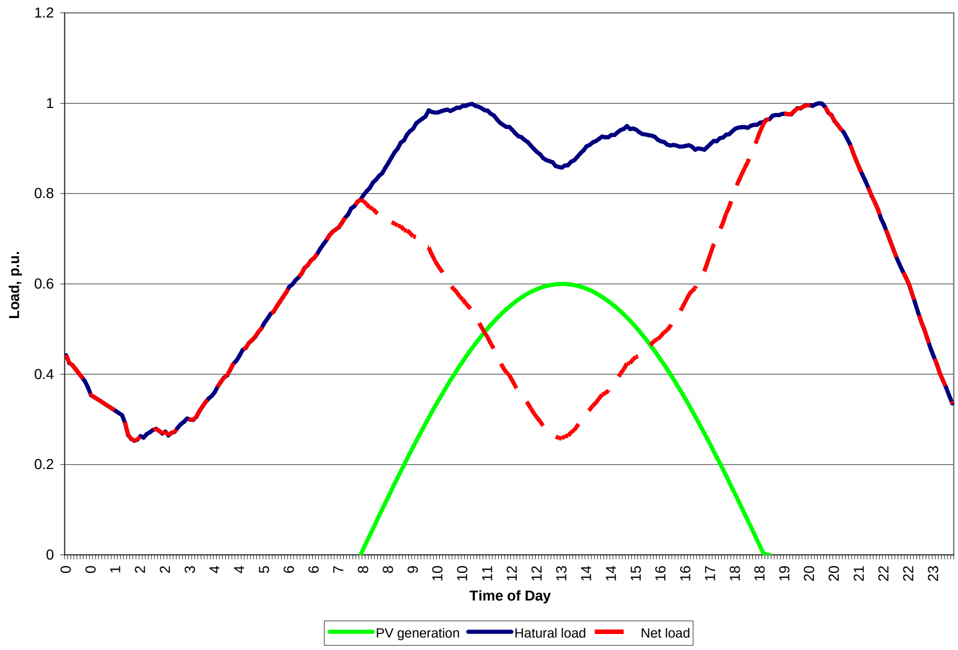

Figure 1-3
Load shapes with PV generation, full sun

When the cloudiness is changeable the net load may be at any value within the area a-b-c-d-a Figure 1-4.

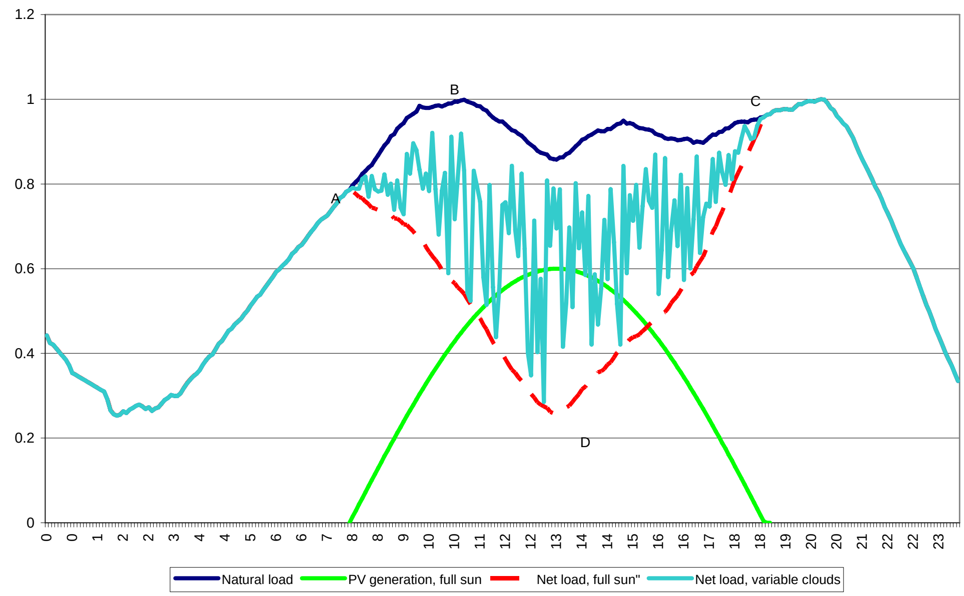

Figure 1-4
Load shapes with PV generation with and without variable clouds

Figure 1-5 presents an illustration of possible voltage fluctuations at the customer terminals due to the fluctuations of the net load in a day with variable clouds. Hence, in general, the weather-dependent DER should be represented by probabilistic data models, which, in turn, depend on the weather forecast and times. Actually, the passive loads also have a significant random component. The base of their behavioral models [10] can be also represented in a probabilistic way. With such a significant probabilistic input base, the distribution operation model should be built on the probabilistic methodology. In such a case, the optimizing ADA application, will maximize the probability of meeting its objective and will minimize the probability of violating the operational limits. The solution will depend on the current statistics and roles of different nodal load and DERs, on the weather forecast, and other dominant factors. Figure 1-6 illustrates a sample of net-load fluctuation during the times of variable clouds. If the load models with embedded weather-dependent DER are represented by the average load shapes, and by the standard deviations, the overall operation model and its operational tolerances can be defined more accurate than by a deterministic model. Hence, the savings will be greater and the power quality will be better.

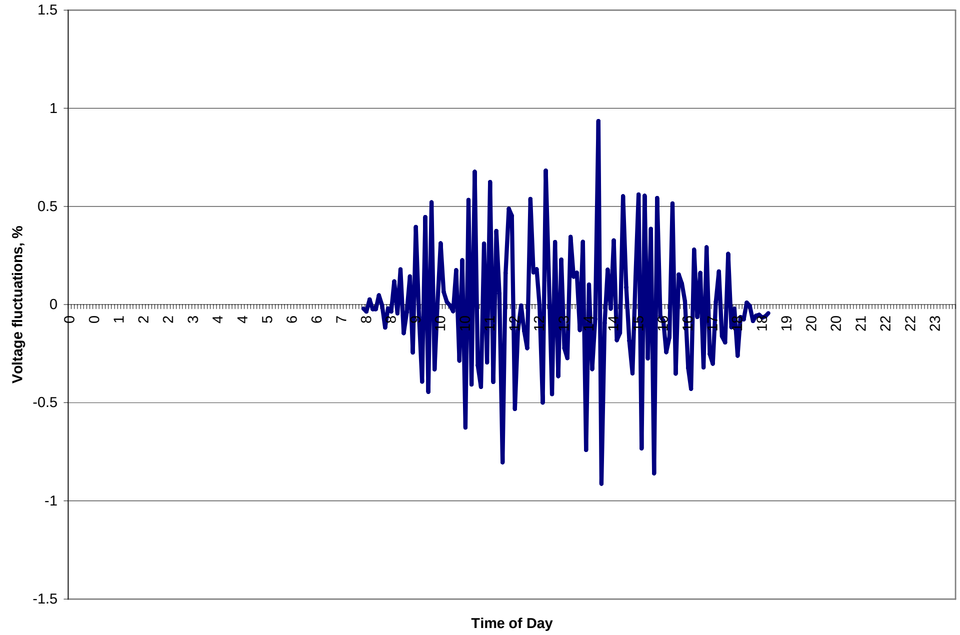

Figure 1-5
Local voltage fluctuations due to varying PV output

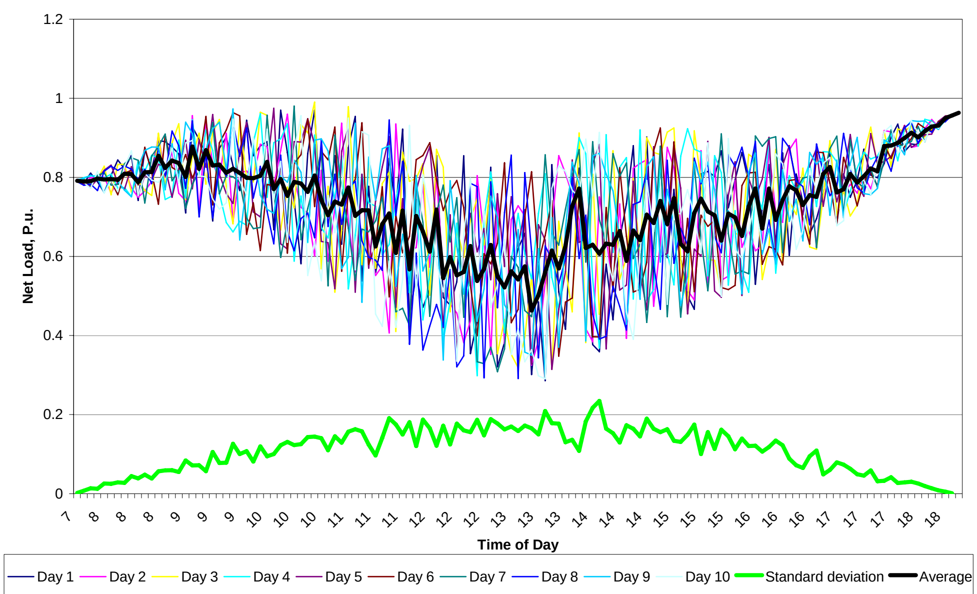

Figure 1-6
Fluctuations of net load during times with variable clouds

The load-to-voltage dependences are critical attributes of the nodal load models in distribution. The presence of embedded DERs in the customer loads creates another level of complexity and variations of the net load-to-voltage dependency. This issue will be discussed in more details in the next item.

- *Modeling Distributed Energy Resources (DER) and microgrids*. This sub-function provides characteristics of real and reactive load generated by DER, connected to the secondary side of distribution transformer or to primary distribution circuits. These characteristics shall be sufficient to estimate the generated kW and kvars at a distribution node at any given time and shall include the generation schedules for short-term look-ahead timeframes, the current and possible modes of operation, the setpoints of automatic control, the availability of remote control, and the corresponding financial attributes. They also shall include capability curves.

  The ability of controlling the DER reactive power in different modes of control increases the variety of reactive load-to-voltage dependences at the terminals of DER and consequently in the Point of Common Coupling (PCC). Several illustrations of the possible differences in the DER generation of reactive power are presented in Figure 1-7 through Figure 1-11. As seen in the figures, the differences are significant. Hence, corresponding information should be collected to define the applicable dependency at the specific time and under specific conditions.

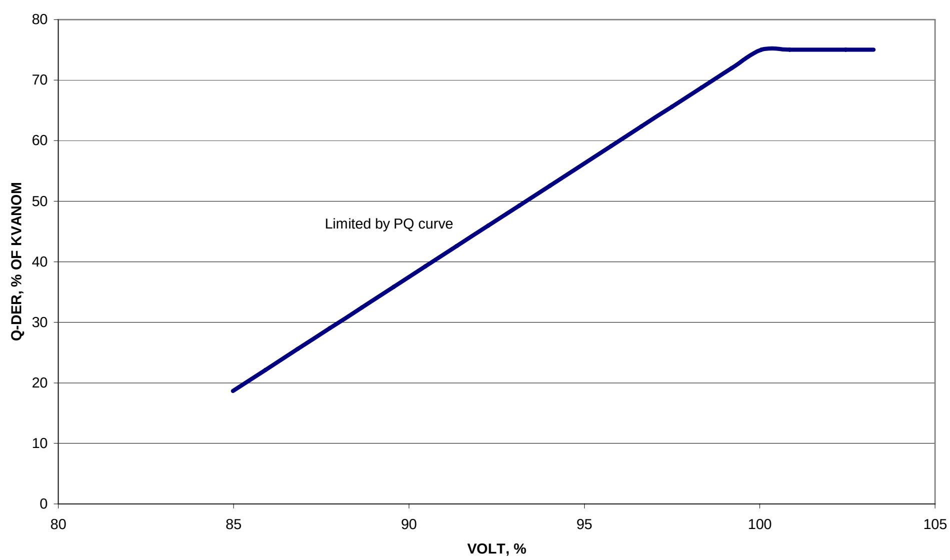

Figure 1-7
Illustration of dependency of kvar generation by a DER (Q-DER) in PQ-mode on voltage (in % of nominal) at the DER terminals. DER kW (P-DER) = 80% of nominal DER kVA (KVANOM).

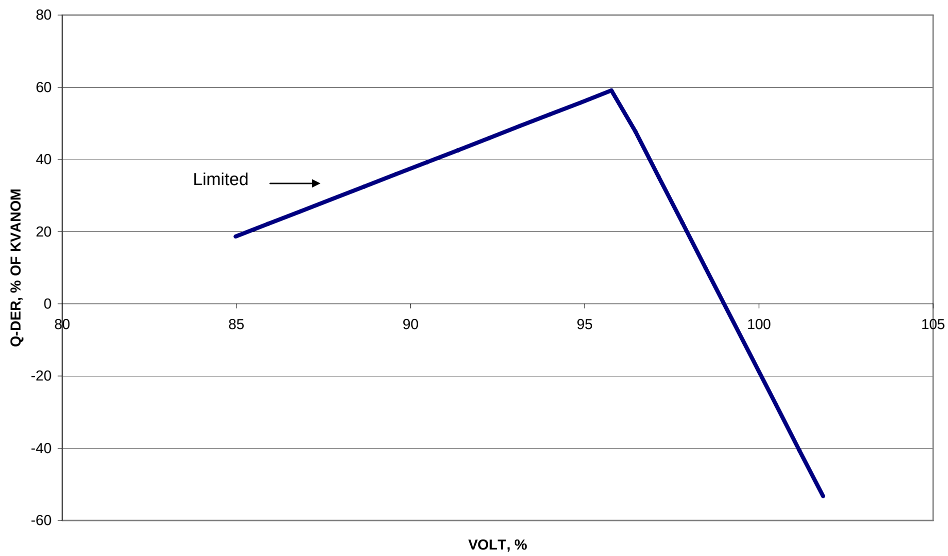

Figure 1-8
Illustration of dependency of kvar generation by a DER in PV-mode on voltage at the DER terminals.

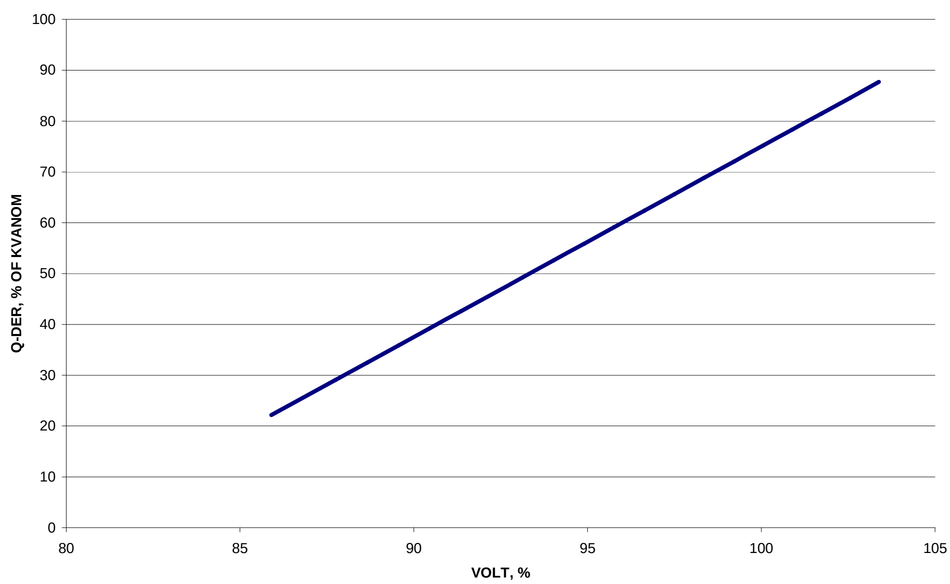

Figure 1-9
Illustration of dependency of kvar generation by a DER in maximum kvar mode on voltage at the DER terminals.

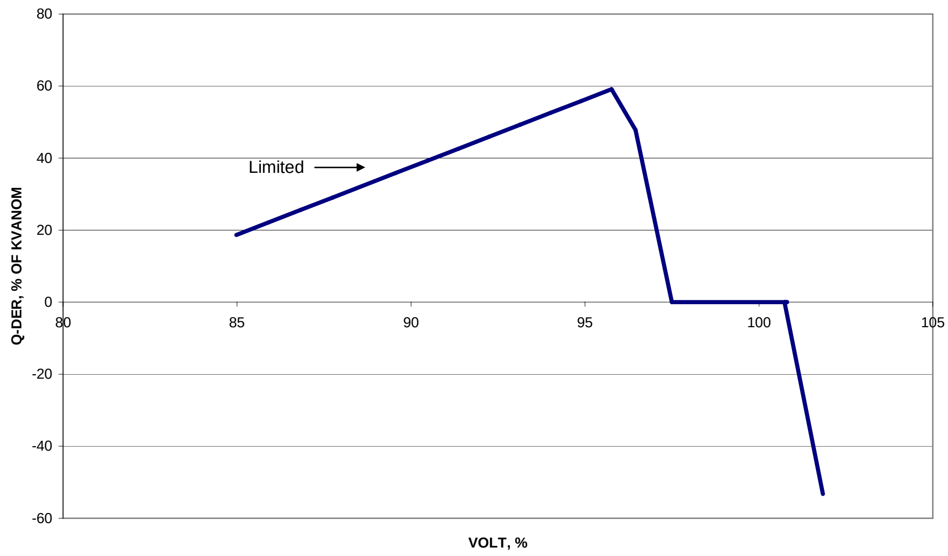

Figure 1-10
Illustration of dependency of kvar generation by a DER in voltage-override mode on voltage at the DER terminals.

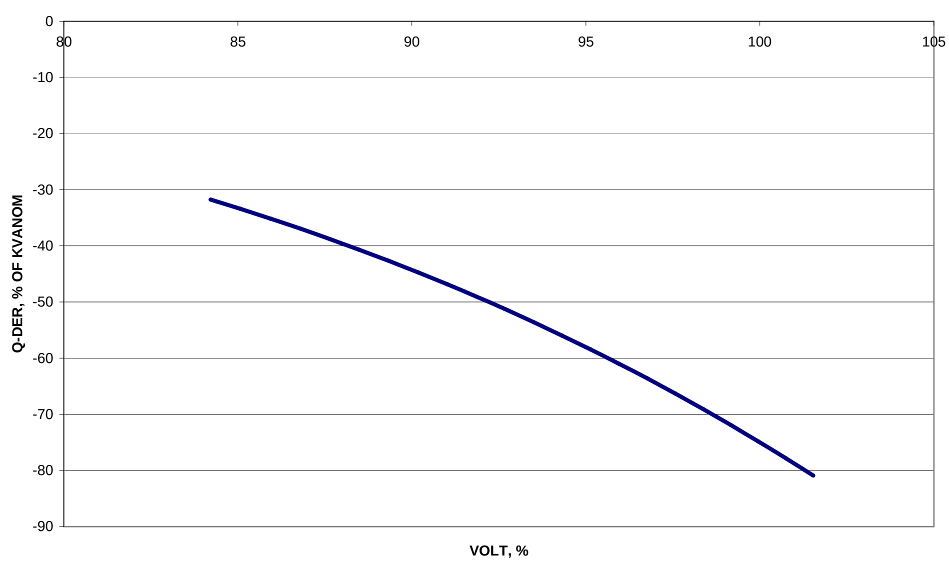

Figure 1-11
Illustration of dependency of kvar generation by an induction-generator based DER on voltage at the DER terminals.

Modeling microgrids is a more complex task. Microgrids are small power systems embedded in a utility grid. A micro-grid has one or more distributed energy resources and loads and can operate either in parallel with the utility grid, or independently of the utility as an intentionally created electric island. The micro-grid is connected to the utility grid via an interconnection switch, which may be supplemented with a control system. Individual controllers with different functionalities can be installed for each of the distributed energy resources. The loads within the micro-grid may participate in different demand response programs and may be connected to different load shedding schemes. When the micro-grid operates in parallel, its object/data models are a part of the utility information infrastructure. The models of the micro-grids are different depending on the operational conditions.

The micro-grid can be viewed by the utility as an aggregated object behind the PCC. Then, the object models of the micro-grid shall represent the behavior of the net real and reactive powers flowing through the PCC under different normal and emergency conditions. The aggregated model is comprised of many micro-grid-internal component models representing the behavior of the loads, distributed generation, and electric storage. If the interior of the micro-grid is supposed to be transparent to the utility, then information infrastructure of the utility shall include the individual models of loads and DER devices the same as for other distribution system objects. However, even when utility performs individual monitoring and control of the micro-grid components, the behavior of the aggregated at the PCC model shall be known to the utility. The micro-grid can be disconnected from the utility at any moment and under different conditions, and the utility should know the aggregated impact of such separation on both the utility and on the micro-grid.

- *Models of distribution circuit facilities.* These models, in addition to the conventional facility models, include the models of local controllers and of the secondary circuit equivalents. The local controllers of the DER are considered as a part of the DER object model. Currently, the most common controllable devices in distribution operating under the steady-state conditions are the locally controlled capacitors and voltage regulators. In the future, the different types of the DER may become automatically controlled devices operating under different contractual or user-defined conditions. For instance, the stand-alone DER may operate in a PQ mode, or in a PV mode, or in constant Power Factor mode, or in maximum reactive power generation mode, etc. The DER located in a micro-grid may operate under individual conditions or can be controlled by an energy management system of the micro-grid following similar to the above net values. These controllable devices are component models of DOMA and shall be used in accord with the iterative results of the power flow calculations. The secondary circuit equivalent models are critically important for modeling the impact of the DERs connected to the secondaries on the local voltages and on other operational parameters. Presently, these models are developed based on expert estimates. Currently, the models of the secondary equivalents are predominantly determined based on expert estimates and may significantly differ from the real objects, resulting in large errors of voltage modeling and, consequently, in reducing the operational tolerances. Based on the voltages and powers measured by Smart Meters and other DER gateway means, adequate secondary equivalents can be derived.
- *Model of distribution power flow/state estimation.* Under conditions of the Smart Grid, the power flow/state estimation will need to additionally model the price- dependent events, and solve radial and meshed networks with multiple generation busses in different modes of operation. The models discussed above, including the models of large DERs, will increase

the accuracy of the power flow model, thus supporting a better utilization of the distribution systems.

The analysis part of the DOMA application includes the following analyses:

- *Analysis of adequacy of distribution system operations.* The adequacy of the operations is defined by the loading of the distribution elements, by the transfer capacity of normally open ties, and by the consistency of the fault currents with the capabilities of distribution facilities and protection settings. Under the Smart Grid conditions, the transfer capacity analysis shall take into account the availability, impacts, and cost of involvement of DER, microgrids, DR, PEV, ES, and Feeder Reconfiguration and Volt/Var/Watt control applications. Other measures for eliminating overload should take into account the reaction of DER to these measures (e.g., feeder reconfiguration with DER can change coordination of relay protection, islanding conditions, and Volt/Var control capabilities).

  The fault analysis will also estimate the impact of the fault on the status and operations of the DER and the impacts of DERs on operations of relay protection schemes. These issues are described in detail in [11].

- *Distribution Contingency Analysis.* The objective of the Distribution Contingency Analysis application is to monitor the reliability of the operations in the near-real-time and short-term look-ahead timeframe. The application informs the operator on the status of real-time distribution system reliability and shall be used for short-term look-ahead operational decisions and for operational planning. For each contingency, the application returns optimum restoration solution based on the short-term forecast of the operating conditions covering the expected time of repair, thus preparing dynamically optimal fault isolation and service restoration solutions. In the case of an absence of a satisfactory solution, the application provides the violations of the operational limits, which assists the operator in the decision making. In the Smart Grid environment, the application shall be able of handling of the Distributed Energy Resources, Demand Response, Electric Storage, and Electric Transportation as generation resources available for backup of the load, when needed; and of using the capability for intentionally created microgrids to maximize the amount of energized loads.

  With significant penetration of DER, there will be a new kind of contingencies associated with a loss of a significant DER or with a loss of several DERs. The loss of several DERs or microgrids may happen due to a significant distortion of the operating conditions in the adjacent transmission systems. IEEE 1547 defines the voltage and frequency distortions, under which the DER shall be automatically disconnected. These distortions can propagate to a large number of DER connected to the affected distribution system. The disconnection of these DERs may cause overloads and under-voltages in distribution and can worsen the situation in the transmission system. The severity of the contingency depends, among other conditions, on the DER protection settings, on the point of disconnection, and on balance between generation and loads in the point of disconnection. The transmission static contingency analysis or dynamic security analysis will defined the possible distortions caused by contingencies in transmission system. If the distortion can cause changes in distribution operations, which may include disconnection of DER and/or Microgrids, or certain reactions of other controlling devices, these changes shall be accounted for in the transmission contingency analyses. Therefore, the aggregated at the buses of the transmission model characteristics of the emergency behavior of DER and other controlled devices shall be made known to Wide Area Situational Awareness function. On the other hand, the expected distortions of transmission operations shall be made known to the ADA for the distribution contingency analysis application to analyze the possible consequences.

The partial restoration and the return to normal portions of the DCA will also heed to consider the re-synchronization aspects of the multiple disconnected DERs. In addition to the information about the synchronization capabilities at the Point of Common Coupling (PCC), information about other points of synchronization, which can be used for reconnection of the intentional island with DERs, should be made available to the application. In some cases, when the DERs can support load upstream of the PCC, the intentional island created for this purpose should be separated from the rest of distribution system by switches equipped with synchronization devices to avoid customer interruption during restoration of normal connectivity.

Hence, the results of the DCA can be used for pre-arming the point of separation of microgrids and for the relay protection re-coordination. If there are DER installation capable of ride-through under particular conditions, but cannot withstand other contingencies, the protection setting can be adjusted based on the results of DCA. The benefits obtainable from the additional information collected from the DER are better preparedness for possible contingencies and more reliable services during planned maintenance.

- *Power quality analysis.* Presently, the power quality analysis of the DOMA application analyzes the voltage deviations and voltage imbalance calculated by the power flow model. In the Smart Grid environment, this sub-function will retrospectively analyze the voltage deviations, sags and swells measured and collected by the AMI system, will analyze the correlations between higher harmonic levels and operations of shunt devices and power electronics, including converter-based DER devices.

  In the real-time environment, sudden disconnection or significant fluctuations of a DER power and loss of excitation for synchronous machines can cause significant voltage deviation, which should be corrected by other voltage regulating means. These corrections may take time, depending on the design of voltage and var control in the particular distribution system. If the loss of a DER or its excitation causes a sufficient change in the operating conditions and activates compensation from the local controllers of other dynamic Volt/Var devices, then the voltage deviation will have approximately the same duration as the controllers' delay (e.g., from milliseconds to tens of seconds). In many cases, it may not be recognized by other local controllers, and the ADA Volt/Var control application should be involved. To invoke the Volt/Var Control (VVC) function, the loss of DER or its excitation should be determined as a sustained one and should become a triggering event for this function (i.e. in addition to status for the interconnection and transfer switches, the state of a significant DER excitation should be a part of the DER model.) The duration of voltage deviations caused by the loss of a significant DER or its excitation depends on the performance of SCADA, DA applications, and devices used for control execution.

  If the loads of DER fluctuate frequently, then the sags and swells become flicker. Also, some DER, by their nature (e.g. windmills that experience wind gusts, photovoltaic systems subject to changing cloud cover without back-up batteries), can be significant sources of flicker. Flickers are defined by their magnitudes and corresponding frequencies. They are limited by magnitude versus frequency (time in cycles). For an example, refer to the CBEMA curve. Respecting the CBEMA curve for each individual DER PCC does not mean that the combined impact of several DERs will not generate unacceptable flickers in other points of the circuits.

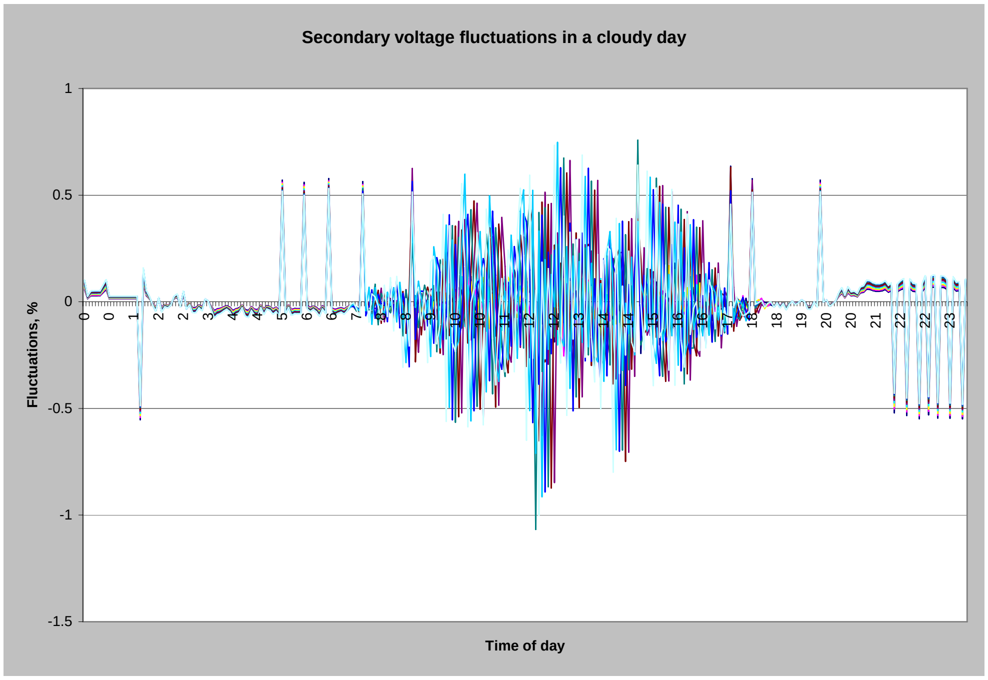

Figure 1-12
Cloudy Day Secondary Voltage Fluctuations

A greater penetration by converter-based DER will be observed in the Low Voltage (LV) networks due to their usually smaller sizes. This means that there will be multiple sources of power quality distortion in LV circuits. This implies the need for more on-site measurements of power quality characteristics, which can be accomplished by the Smart Meters.

IEEE standard P1547 specifies individual and total demand distortion for DERs. Also, the DC current component is limited to 0.5%. DER contribution to power quality distortion will be defined first at the stage of acceptance tests. The conditions of field operations can be different from the test conditions, and regular monitoring of power quality at the PCC may be needed. Again, respecting the standard requirements for higher harmonic distortion at each DER PCC does not mean that the combined impact of the higher harmonics generated by DER and other sources of higher harmonics along circuits will not violate power quality limits at other circuit points, especially under resonance conditions.

To provide a complete analysis of the power quality, the power quality characteristics should be monitored and evaluated also during the islanding of DERs with load into micro-grids.

- *Analysis of the economic efficiency.* The economic efficiency can be determined in different ways depending on the utility business environment and objectives. The following components of the economic efficiency of distribution operations can be suggested: 1) Evaluation of the incremental cost of delivered energy by components, one of which is the cost of energy losses, and 2) Evaluation of the incremental benefits due to a particular change in distribution operations implemented in the utility. The incremental cost may include the cost of supply from both bulk energy sources and distributed energy sources, the incremental cost of demand response incentives, the cost of losses, the penalties for limit violations, if any, etc. For large non-renewable DER the following information may be needed: cost of fuel, cost of maintenance (e.g., $/hour of on-line), cost of start, cost of stop, cost of ramping under different conditions, the real-time efficiency factor of the DER, which depends on the operating conditions, etc.

Energy loss analysis can be of a special interest in the analysis of economic efficiency of the operations. The loss analysis should be performed by the following components: losses in the distribution feeders, core and coil losses in the distribution transformers, loss estimates in the secondaries, losses in T&D substation transformers, and loss increments in the transmission system due to the distribution load. When there is an island, especially an intentional one, which may include a portion of the distribution system, the loss analysis program should be able to calculate losses in the elements of the island and integrate them with losses in the same elements calculated for other operating conditions. The change of losses due the operations of DER can also be of interest to the utility, customers, and integrators. These losses can be determined by running the what-if analysis concurrently with the near-real-time Distribution Operation Analysis.

- *Determining the operational voltage tolerances at T&D buses.* The operational tolerances include transmission bus voltage tolerances of the T&D substations for meeting distribution operation requirements and voltage angles tolerances for feeder paralleling capabilities. Presently, in many cases, the T/D bus voltage limits are constant for an extended time interval. The dynamic optimization of the distribution system operations results in different optimum voltages at the distribution side of the T&D substation. These voltages can be supported within a certain range of the transmission-side voltages. This range defines the transmission-side voltage limits at the time of optimization. There may be another set of dynamic voltage limits: the power quality limits, when the voltage at the buses shall satisfy the standard voltage tolerances at the customer terminals. The dynamic voltage limits defined by DOMA should be submitted to the transmission domain for use in the Wide Area Situational Awareness applications. The presence of significant DER in the distribution system impacts the levels and the dynamics of the optimal and standard voltage requirements at the T&D buses. It also changes the capability of the transmission system to satisfy these requirements. The greater is the generation of real and reactive power by the DERs in distribution, there lower can be the voltage at the feeding substation buses, and the less is loaded the transmission system, which means that higher voltage can be provided at the transmission side. However, if the majority of the DER generation is weather-dependent, the more changeable are the T&D bus limits.

  The difference in voltage magnitudes and angles at the adjacent buses, as well as the loading of critical segment in the temporary distribution loop may prevent feeder paralleling needed for feeder reconfiguration, which, in turn, is needed for service restoration, reliability improvement, loss reduction, and load swapping between buses with different LMPs [9, 12]. At the present time, the paralleling of distribution feeders, performed by the distribution system operators, is based on conservative expert estimates. Such an approach may significantly limit the benefits of feeder paralleling.

The magnitude of the voltages at the distribution busses can be changed by changing the transformation ratios of the transmission-to-distribution transformers, by changing the statuses of substation and feeder capacitors, by changing the transformation ratios of feeder voltage regulators, and by changing the reactive and real power of distributed energy resources. These changes, in turn, are limited by the available regulation ranges of the devices and by the voltage quality limits.

The resulting current through the critical segments of the distribution loop depends on the initial load flow through these segments. This load flow can be changed by changing the statuses of feeder capacitors, the output of DER, and by applying demand response as a temporary means to accommodate feeder paralleling.

- Determining the available dispatchable real and reactive load at the T&D buses. .
  The significant penetration of DER, Demand Response, and Plug-in Electric Vehicles (PEVs) in combination with Volt/Var/Watt control and Feeder Reconfiguration applications will provide wide ranges of dispatchable loads at the T&D buses. These loads will be dependent on a number of conditions, such as real-time energy prices, reliability signals (can be price also), ancillary service conditions, temporary voltage limit for peak load reduction, weather, statuses and modes of DER operations, etc. With significant DERs in the distribution system, there are a variety of possible additional situations, such as, available or unavailable real and reactive power from DER, with or without the ability to remotely control the real power and with the following controls of reactive power:
  - remotely controlled settings for reactive power in PQ mode
  - remotely controlled settings for reactive power in PV mode
  - remotely controlled settings for reactive power with voltage
  - locally controlled reactive power in different modes.

  These different modes of operations will result in different changes of the aggregated reactive power of the DERs and in different load dependencies on voltage at the T&D buses.

- *Determining the aggregated at the T&D buses remedial action schemes parameters.* In case of disturbances in the bulk power system, many DERs can disconnect from the utility according to their protection settings and operational constraints. The DER can be disconnected at the PCC together with some load or they can be disconnected by the individual DER switching device, or they can just stop generating temporarily or for an extended time interval. At any given moment, the aggregated result of probable disturbances in the bulk power system should be determined for each T&D bus by the ADA application. To derive these aggregated results the information on the current operations of the DERs and on their reaction to different disturbances should be known. The Wide Area Measurement and Control System (WAMCS) should take into account this aggregated models and correspondingly adjust the arming of the RAS.

The additional benefits of DOMA due to information exchange with DER are presented in Table 1-1.

Table 1-1
Additional benefits of DOMA due information exchange with DER

Objective	Benefits
Generate and analyze the distribution operation model that is adequate for the near real-time monitoring of the essential behavior of the distribution system.	Supports more accurate and timely the situational awareness of distribution operations by preventing from inaccuracies due to unknown behavior of DER. Results in better reliability, efficiency, and quality of service.
Provide situational awareness of the distribution system operations by submitting concise and essential information to the operators.	Makes the operators work more efficient, providing the operator with information on actual behavior of DER and their capabilities, improves the service reliability; reduces the operation and maintenance cost.
Generate component and aggregated behavioral object/data models for the use by other advanced DA and EMS applications.	Support more accurate distribution operation models, including the behavioral models of passive and active DERs, resulting in more efficient optimization of the distribution and transmission operations.
Determine dynamic operational limits to be used by DA and EMS applications	Support more accurate operational tolerances, including the impact of DER in these tolerances, resulting in more efficient optimization of the distribution and transmission operations.
Analyze the operations of the distribution system from the standpoints of adequacy, power quality, and economic efficiency.	The object models of DER used by DOMA provide more accurate information about the impact of DER on distribution system adequacy, power quality, and economic efficiency.

Voltage, Var, and Watt Optimization (VVWO)

VVWO is a major multi-objective and multi-faceted advanced DA application performing dynamic optimization of the distribution operations taking into account all significant impacts of the application on the operations in different domains [4,7,12-25].

In the Smart Grid environment, in addition to the current control of voltage controller settings and feeder capacitor statuses, the application should be able to control the reactive power of DER and other dynamic sources of reactive power. Under some objectives, the application should be able to control the Demand response means [12, 18, and 19] and the real power of DER. Therefore, the Volt/Var optimization becomes a Volt/Var/Watt Optimization (VVWO).

The function predominantly operates in the power distribution domain and its outcome predominantly materializes in the customer domain, where it impacts one of the basic power quality parameter—voltage deviations. It also impacts operations in the distribution, transmission, and generation domains by changing the loading of elements, power losses, and real and reactive loads. In turns, these changes may result in changes of Locational Marginal Prices (LMP), as seen in Figure 1-13.

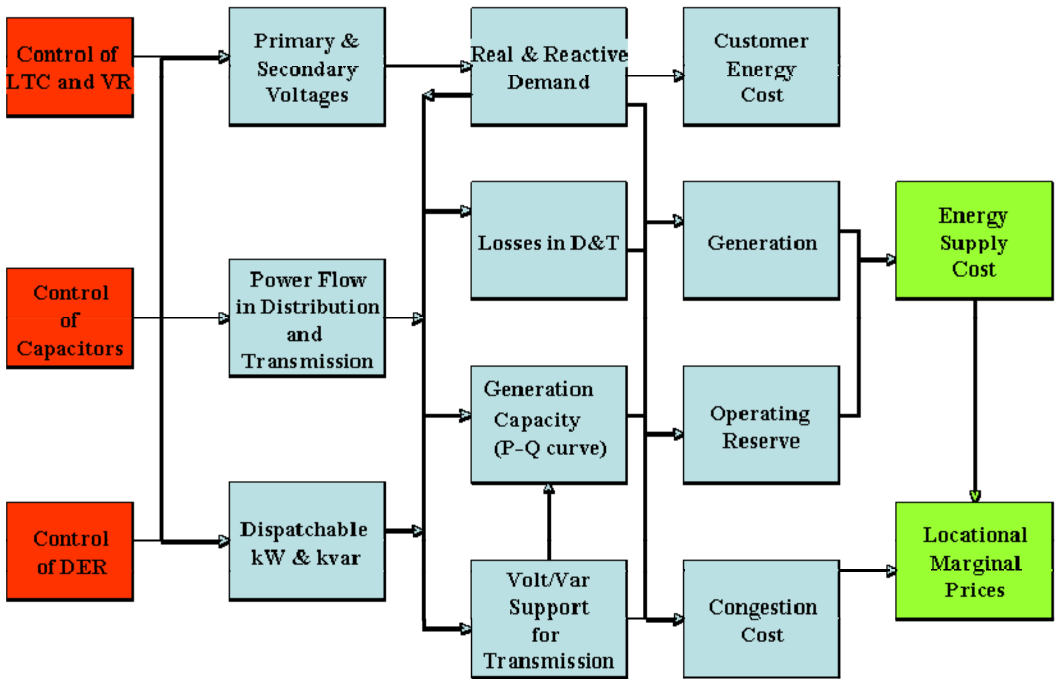

Figure 1-13
Impact of VVWO on operations in different power system domains

Due to the multifaceted nature of the voltage and var control in distribution, there are multiple objectives for the function. The major objectives are the following:

- Ensure standard (or better) voltages at customer terminals
- Reduce load at particular times;
- Conserve energy (includes loss component)
- Reduce or eliminate overload in transmission lines
- Provide reactive power support for transmission/distribution bus
- Provide spinning reserve support
- Reduce cost of energy;
- Reduce energy losses
- Expand the operational tolerances for generation/transmission operations
- Provide compatible combinations of above objectives.

The constraints, within which the optimization should be performed, are as follows:

The VVWO application is constraint by the following limits:

- Loading limits of model elements
- Voltage limits at the equivalent customer terminals.
- Voltage limits in selected point of distribution primaries, including the distribution bus of the T&D substation
- Loading and voltage limits of selected transmission facilities
- Reactive power or power factor limits at selected busses in T&D
- Capability limits of distributed energy resources
- Operating reserve limits, if included in the model
- Limits of controllable devices:
  - LTC limits
  - Voltage regulator limits
  - Capacitor control limits
  - Demand response limits
  - Electric storage limits
  - Distributed generation control limits
  - Power electronics limits

The controllable variables of the VVWO are as follows:

- Voltage controller of Load Tap Changers (LTCs),
- Voltage regulators,
- DER controllers,
- Demand Response controllers
- Power electronic device controllers
- Capacitor controllers
- Electric Storage controllers
- Electric Vehicle controllers
- M5
- Microgrid controllers

It is expected that the signals to the controllable variables will be either price-based or direct commands.

The information support base for the VVWO application is the same as for DOMA. There will be additional information sources, such as: AMI-supported Data Management System; Demand response (DR) management system; DER management system; Customer EMS; microgrid controllers.

To fully meet the Smart Grid requirements the current design of the application will need significant upgrades to take advantage and overcome the challenges of the new Smart Grid technology. The upgraded function will be much more involved in the customer domain, and the optimization of voltages and vars will be significantly more integrated with the control of real power through DER and DR control.

The objective functions of the application are different for different objectives. The provision of standard voltages is ensured by respecting the voltage limits, when the application follows any other objective, except when the objective is to provide the best voltages. This objective can be met, for instance, by maximizing the consumption in the close vicinity to the nominal voltage. The control of reactive power sources, including the DERs, takes a significant part in this optimization, which, in turn, impacts the losses in distribution and transmission. This objective can be closely met in a number of ways, and therefore the loss component should be added to the objective function.

The load (generation) reduction objective also can be met in different ways. The least intrusive way is to apply the load-reducing voltage and var optimization, which minimizes the sum of the demand and losses in both distribution and transmission systems within the standard voltage limits. Under emergency conditions, the load minimization is performed within lower than standard limits. If the DERs, which may include electric storage, and demand response means are available for minimization of the total distribution load, their participation with their corresponding costs (or lost customer values) should be included in the objective function. The cost of their participation will compete with the benefits of load reduction, which should be expressed in comparable units. Sometimes, the optimization cannot be completed by considering the operating conditions at one particular time. For instance, an electric storage discharged at one time will need to be recharged at another time and for another cost, or the load reduction due to demand response may have a payback time and value. In these cases, the objective function should cover a prolonged time cycle.

The operations of the DER in distribution, which in general, include electric storage, impact voltages in distribution by contributing or absorbing the real and reactive powers. As a minimum, the voltage and var optimization by other than DER means should be coordinated with the operations of DER. It is expected that in the Smart Grid environment certain control of DERs by ADA applications will be available. For instance, the utility-own DER can be under direct status and setpoint control from the VVWO applications. The customer-own DER can be controlled via price signals or other mutually agreed triggers within contractual constraints. The gateways to the customer-own DER can be individual DER or micro-grid controllers in the points of common coupling, or customer EMS, or AMI meters.

If the nodal load model in distribution is an aggregated load model, all DER model components of the individual loads should also be aggregated into one equivalent DER model connected to the secondary equivalent. In some cases, the DER models can be incorporated in the behavioral load model, however, it may significantly complicate the load model and present challenges in representing the cost and capability curves of the DER models.

The impact of DER connected to the secondary circuits on the voltage in the point of connection is significant due to the upstream impedances of the secondary circuits and the distribution transformer. While the ability to control the real power of a customer DER for the purpose of integrated Volt/Var/Watt may be limited, the control of the reactive power may be more available [14]. It may require retrofitting some installed converters and special orders for new installations. There is an increase of the cost for the converters with reactive power control capability. In many cases, this additional investment returns greater benefit due to unloading upstream circuits [15]. In addition, if this source of controllable reactive power is included in the dynamic VVWO, it may increase the voltage tolerance for overall optimization of voltage and provide a local means for voltage adjustment [16]. For better utilization of the controllable reactive power, the DER converters, in addition to generating, should be able to absorb the reactive power.

The objective function of VVWO should include these variables with their value factors, and the VVWO application should be able of providing specific triggers or setpoints to enable the controls in the appropriate nodes.

All kinds of DER have electrical constraints expressed as capability curves presenting interdependencies of relevant operational parameters, e.g., Watt, var, and Volt. These capability curves are also operational constraints for the VVWO application. In the three-phase circuits, the voltage imbalance should be taken into account when checking against the constraints. For these purpose, the symmetrical components of the DER impedance must be known.

Numerical examples, illustrating what has been discussed above are presented below.

The example below address a simple case of voltage and var control by a voltage regulator and a number of small var-controllable customer-side photovoltaic DERs. The circuit diagram used for this example is presented in Figure 1-14. For the clarity of the illustrations, all the loads are nominally of the same value and the same daily profiles, and are fed through the identical distribution transformers and secondary circuits. The maximum capacity of the DERs is 60% of the corresponding customer peak load. These simplifications always make the node in the end of the feeder the voltage-critical points with the lowest voltage. In reality, the load, the distribution transformers, and the secondary circuits are different, which makes the operation model much more complex and may make any node along the feeder the voltage-critical one, and the critical points may move along the feeder at different times.

Three conditions were considered in the example:

1. No PV are generating any real and reactive power (No PV)
2. All PV are generating full power according to the sun irradiation (Sunny Day)
3. All PV are generating intermittent power due to a cloudy weather (Cloudy day).

Another assumption is that the PV converters can operate in one of the following three mode of reactive power control:

1. Power Factor PF=1
2. Maximum reactive power generation with PF = 0.9
3. Maximum reactive power absorption with PF = 0.9.

The objective function of the Volt/Var control is Energy Conservation.

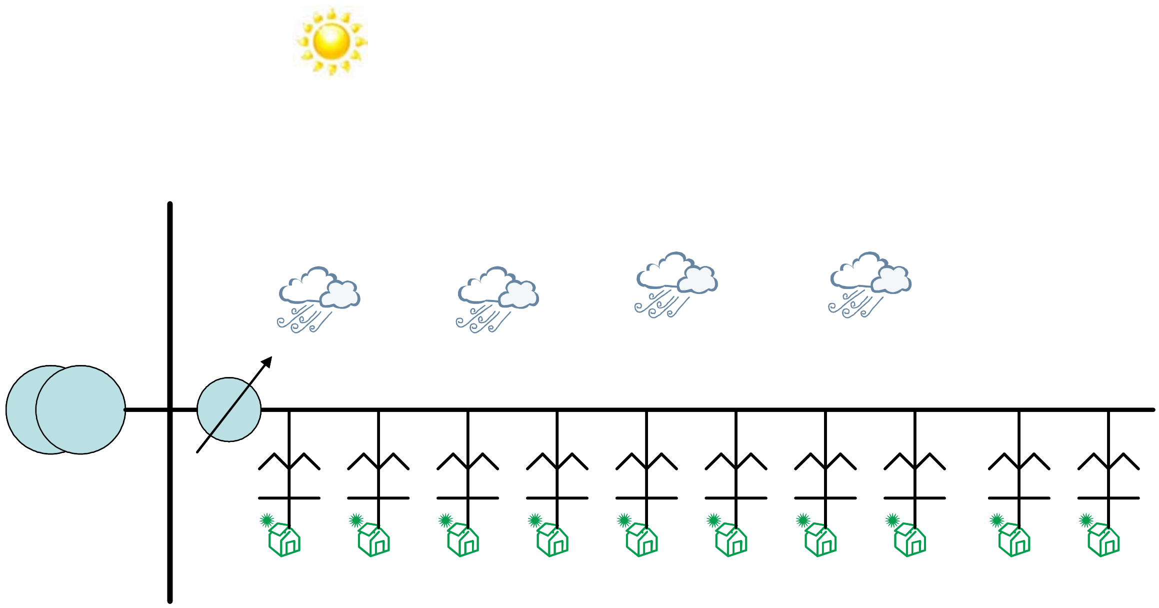

Figure 1-14
Example distribution circuit with feeder voltage regulator.

The Volt/Var Optimization (VVO) applications controls the setpoints of the voltage regulator and the modes of var control at the DERs to minimize the sum of energy consumption and losses with the load-side minimum voltages limit equal to 0.95 of the nominal voltage. The preliminary analysis of the behavior of the VVO application shows that the optimal bus voltage during the cloudy days significantly fluctuated (see Figure 1-15), which may increase the number of operations of the voltage regulator beyond acceptable value. Therefore, the voltage control bandwidth for the voltage regulator during cloudy days should be increased, as seen in Figure 1-16

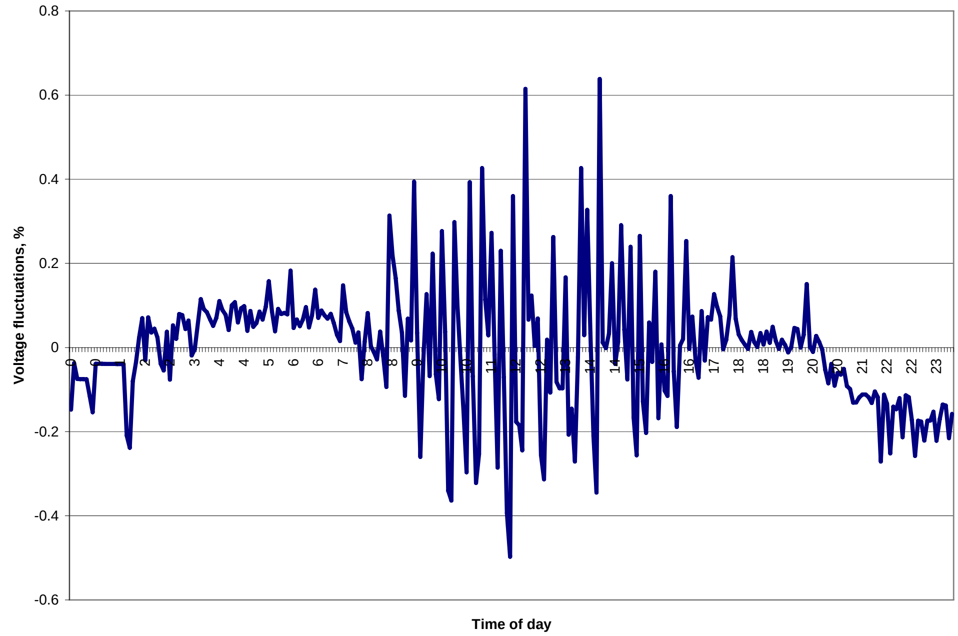

Figure 1-15
Optimal bus voltage fluctuations in a cloudy day

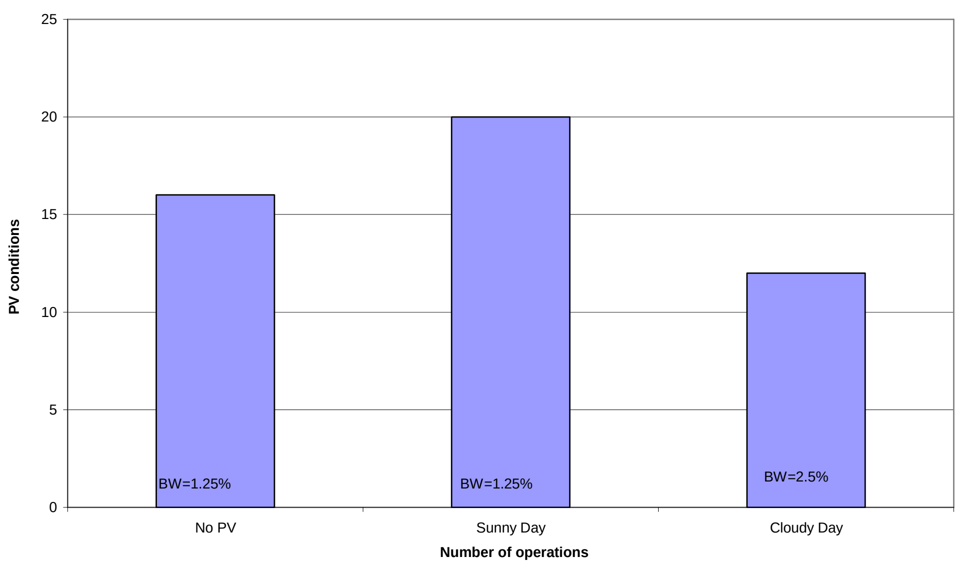

Figure 1-16
Number of LTC operations

The first scenario was considered under the assumptions that the converters of the PV DERs do not generate or absorb reactive power (PF=1). The optimal daily bus voltage profile for the three different weather conditions are presented in Figure 1-17 through Figure 1-19. The continuous lines in the figures represent the optimal voltages, while the step-wise lines represent the voltages executed by the step-wise voltage regulator. As seen in Figure 1-19, the executed voltage differs from the optimal voltage more than in other cases due to the greater voltage control bandwidth. Figure 1-18 presents the optimal bus voltage for the case without DER generation. Figure 1-18 and Figure 1-19 represent the optimal bus voltages with DER at a sunny day and at a cloudy day respectively. As seen in these figures, the bus voltages at the time of sunshine are lower, than in the case without DER generation, due to lower voltage drops in the distribution circuits because of the real power generation by the DERs. The individual load models for the cloudy days were based on a representative sample of a cloudy day. These samples can be derived based on statistics of a number of similar cloudy days corrected by the near-real-time distribution state estimation. The average optimal voltage profiles at the customer terminals along the feeder during the sunshine times are presented in Figure 1-20. As seen in the figure, in all three cases, the lowest voltage approaches 0.95, with the minimum voltage at cloudy days slightly higher than 0.95. This is because there are instances during the cloudy days, when the voltage-critical point is not in the end of the feeder due to the loss of uniformity of the net loads. The voltages at the nodes different from the critical ones are higher than 0.95, which leaves room for further local voltage and load reduction. However, this additional room for optimization cannot be utilized in this case, due to the absence of other controllable voltage and var means.

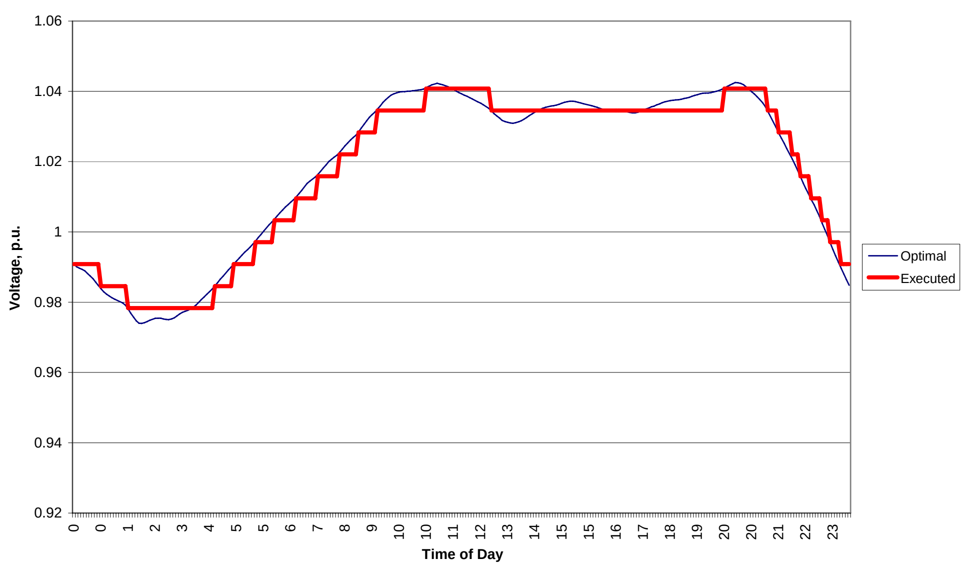

Figure 1-17
Optimal and executed bus voltage, no PV

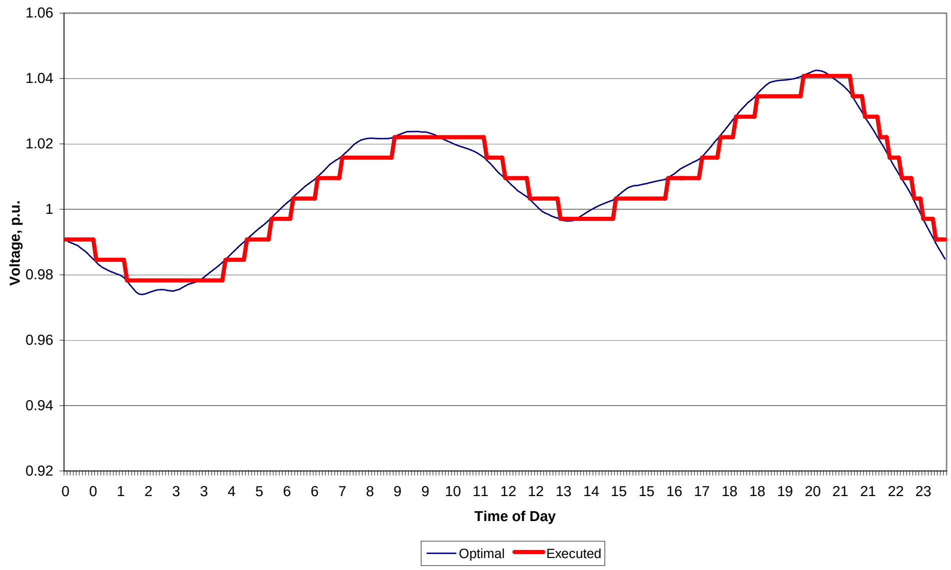

Figure 1-18
Optimal and executed bus voltage, with PV PF=1, sunny day

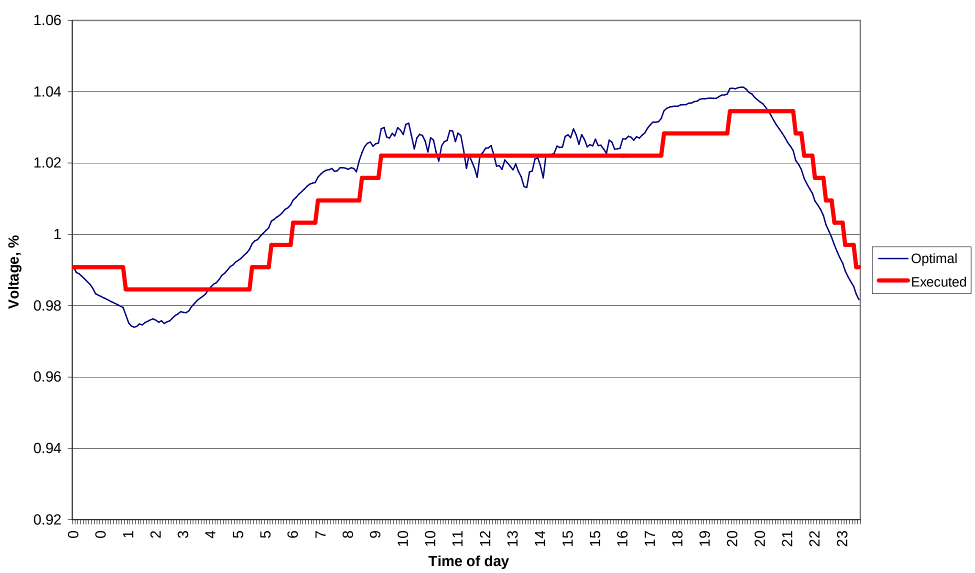

Figure 1-19
Optimal and executed bus voltage, with PV PF=1, cloudy day

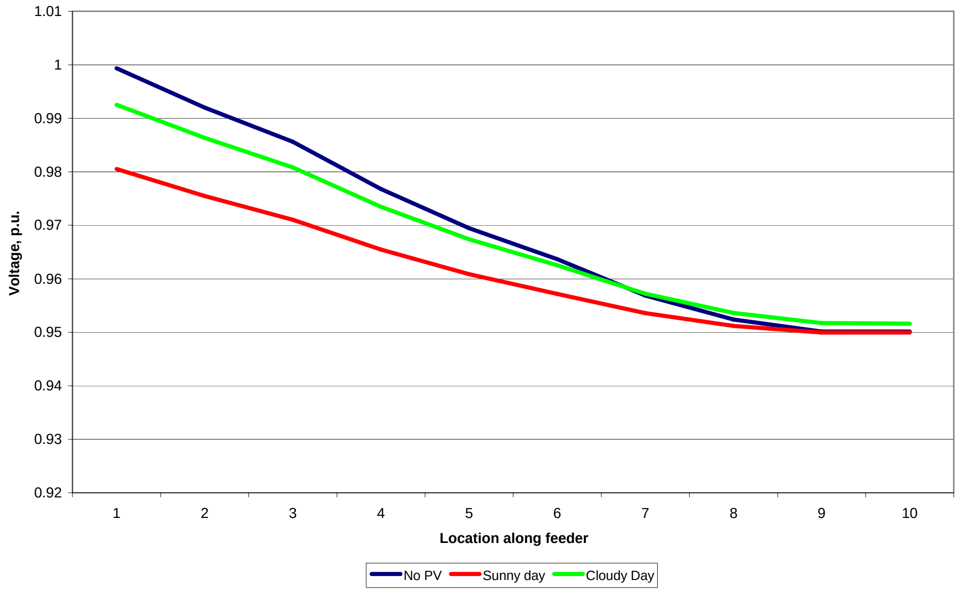

Figure 1-20
Average secondary voltage profiles along feeder, PV PF=1

The second scenario considered included the PV DER with maximum generation of vars. The pattern of operations of the voltage regulator is different, but it still requires a greater voltage control bandwidth during cloudy days (see Figure 1-21). The optimal bus voltages and the average voltage profiles along the feeder for the sunny and for the cloudy days are presented in Figure 1-22 through Figure 1-24. As seen in the figures, the bus voltages during the sunshine are lower than in the case with PF=1, due to even smaller voltage drops in the distribution circuits because of additional generation of reactive power by the DERs. The average voltage profiles at the customer terminals along the feeder again approach the minimum voltage limit of 0.95 in the critical point, with the voltage at the cloudy day slightly higher. The voltages at the customer terminals in other than critical points are lower than they were, when the DERs did not generate reactive power. By the way, as seen in Figure 1-25, the executed voltage profile differs from the optimal due to the voltage control bandwidth (especially for the cloudy days). Again, there is still room for local voltage reduction. This reduction can be achieved by adjusting the modes of local reactive power control differently for different DER along the feeder.

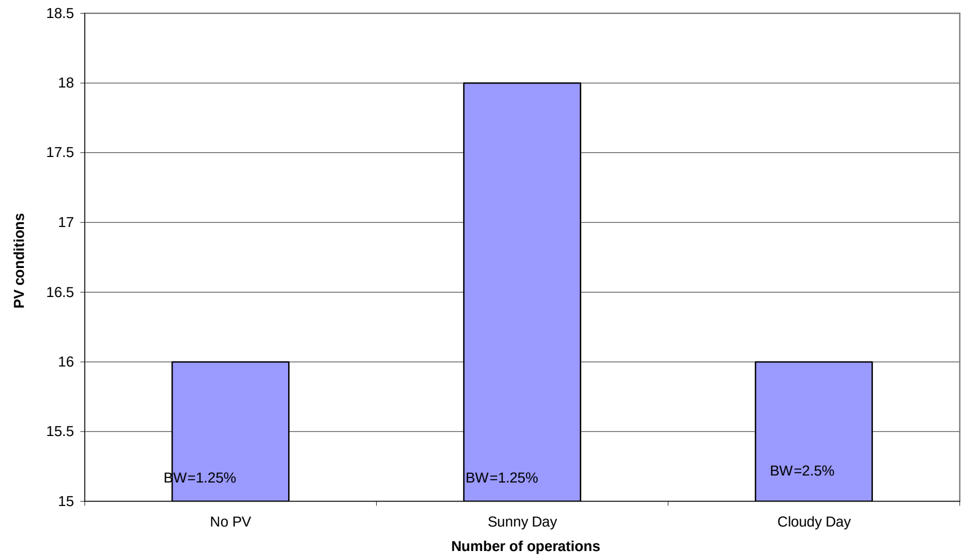

Figure 1-21
Number of Load Tap Changer (LTC) operations with DER with Q-max

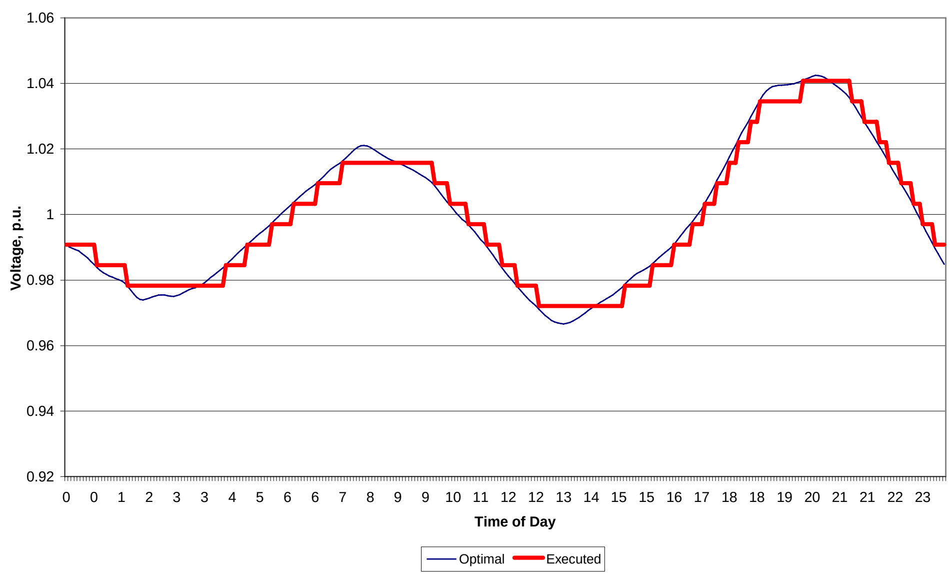

Figure 1-22
Optimal and executed bus voltage, with PV Q-max, sunny day. Compare with Figure 1-18

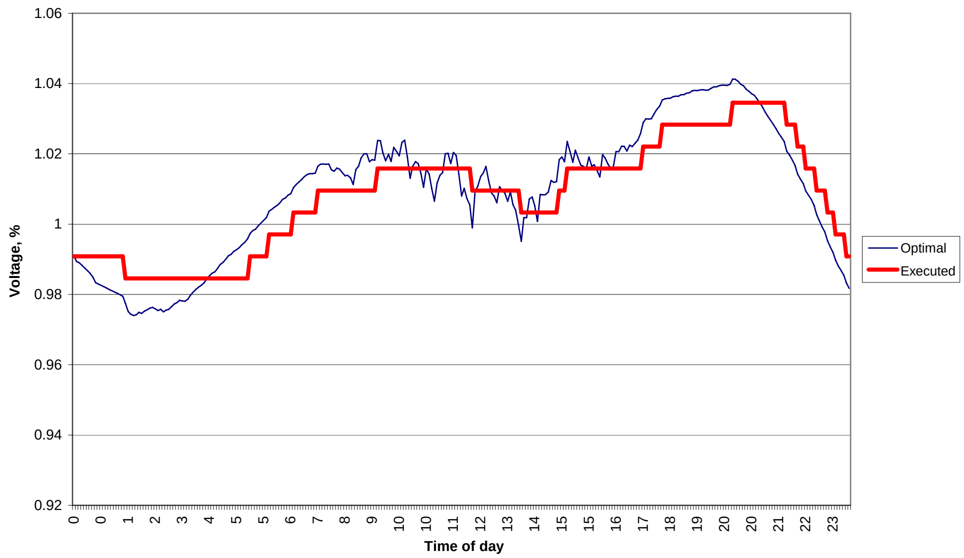

Figure 1-23
Optimal bus voltage with PV Q-max, cloudy day. Compare with Figure 1-19

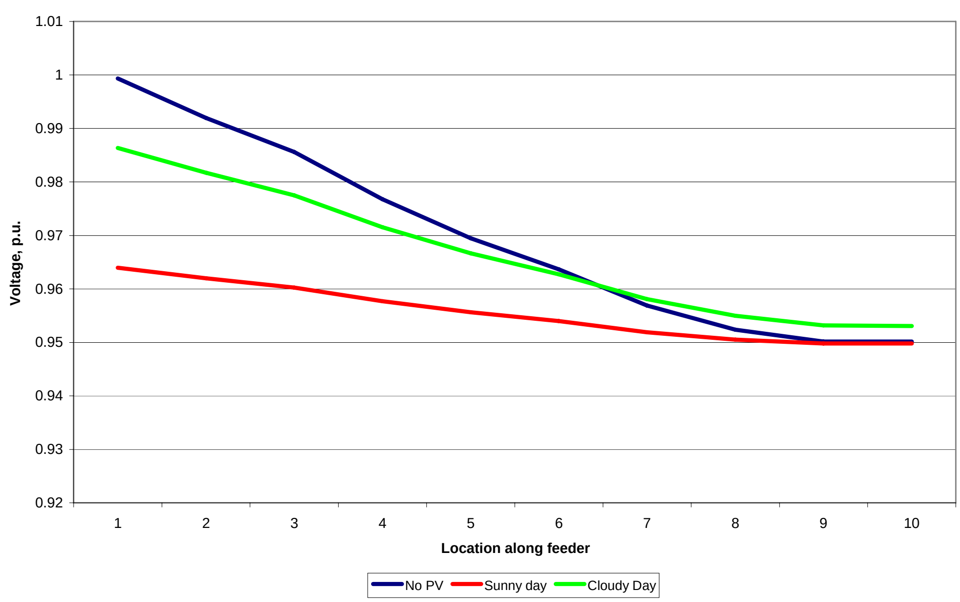

Figure 1-24
Average secondary voltage profiles along feeder, PV Q-max

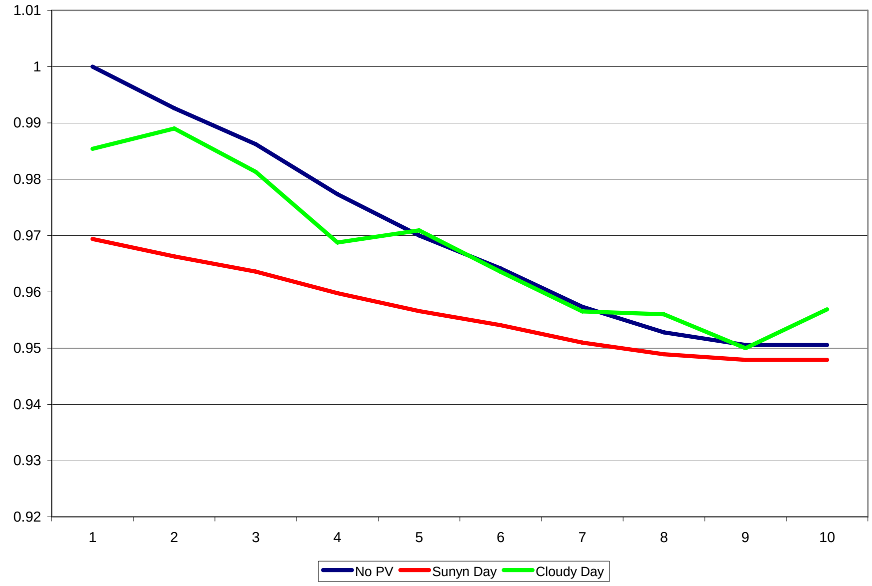

Figure 1-25
Average executed secondary voltage profiles along feeder, PV Q-max

In this example, the modes of reactive power control were adjusted as follows:

- Load #1 through #3 – Absorbing maximum vars (PF=0.9 – absorbing)
- Load #4 through #6 – PF = 1
- Load #7 through #10 Generating maximum vars (PF=0.9 – generating).

The results with the adjusted modes of reactive power control are presented in Figure 1-26 through. Figure 1-28. As seen in the figures, the bus voltages during the sunshine are slightly higher than in the case with Q -max, due to slightly larger voltage drops in the distribution circuits because of reduced total generation of reactive power by the DERs. The average voltage profiles at the customer terminals along the feeder again approach the minimum voltage limit of 0.95 in the critical point, with the voltage at the cloudy day slightly higher. But, in this case the secondary voltages along the feeder are significantly lower than in the previous case, especially for the sunny days, when they are close to 0.95 almost along the entire feeder.

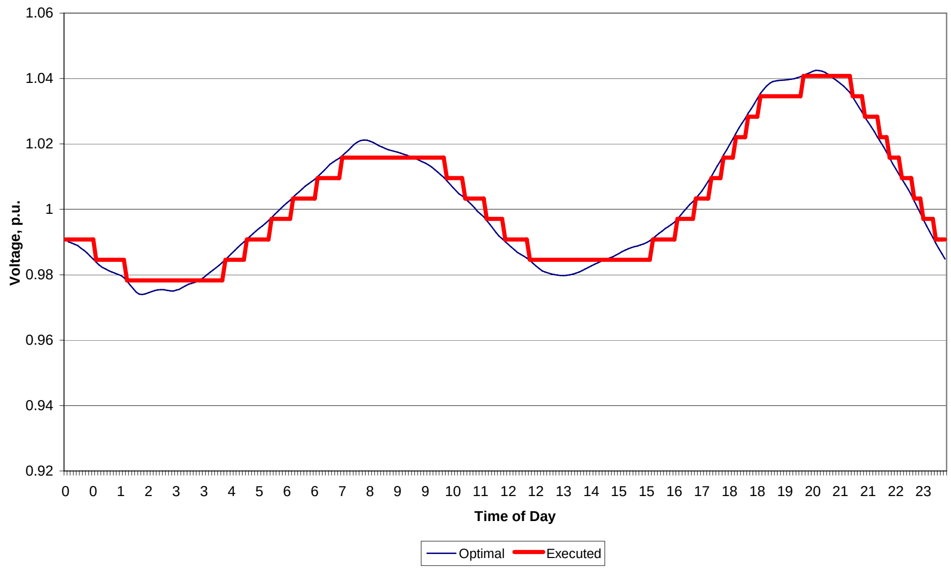

Figure 1-26
Optimal and executed bus voltage, with PV Q-adjusted, sunny day. Compare with Figure 1-22.

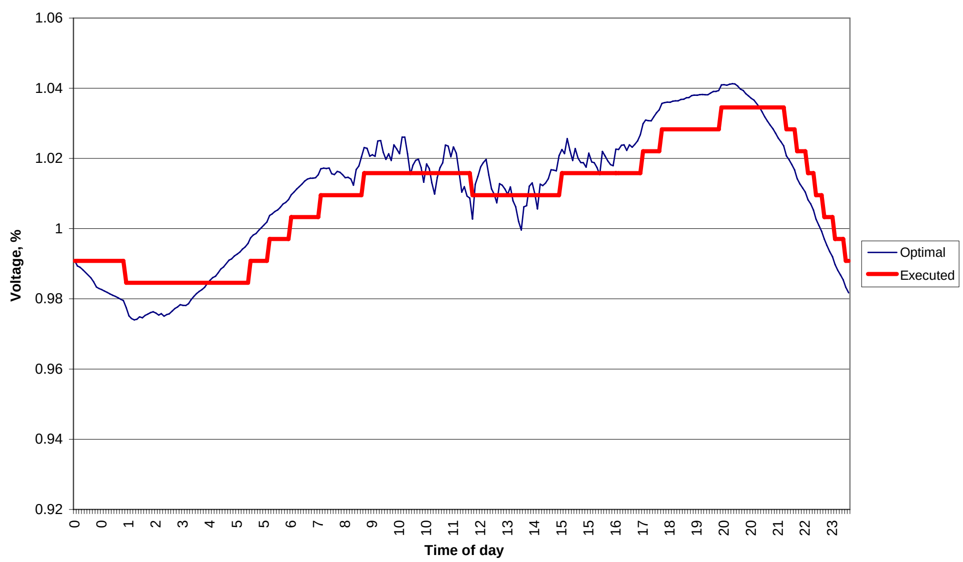

Figure 1-27
Optimal and executed bus voltage, with PV Q-adjusted, cloudy day. Compare with Figure 1-23.

Figure 1-28
Average secondary voltage profiles along feeder, PV Q-adjusted.

It must be noted, that changing the voltage and the reactive power along the feeder, changes the power flow and the losses. The objective is to minimize the sum of the load and losses, i.e. to minimize the total generation needed to cover the load. The analysis of the impact of the described above Volt/Var optimization alternatives is presented in the following figures. Figure 1-29 shows that the maximum reduction of the natural load is achieved, when the modes of reactive power control is different at different nodes, as described above, and this is true for both sunny and cloudy days. However, changing the modes of reactive power control also changes the losses. The reduction of losses due to deployment of the DERs and due to Volt/Var optimization is presented in Figure 1-30. As seen in the figure, the maximum loss reduction is achieved, when all DERs generate maximum reactive power. So, from the loss reduction standpoint, the optimal mode of reactive power control is different than from the load reduction standpoint. If the objective is minimization of the total generation, then the optimal mode of reactive power control is the maximum reactive power mode for the sunny days, and the different adjusted modes of reactive power control for the cloudy days.

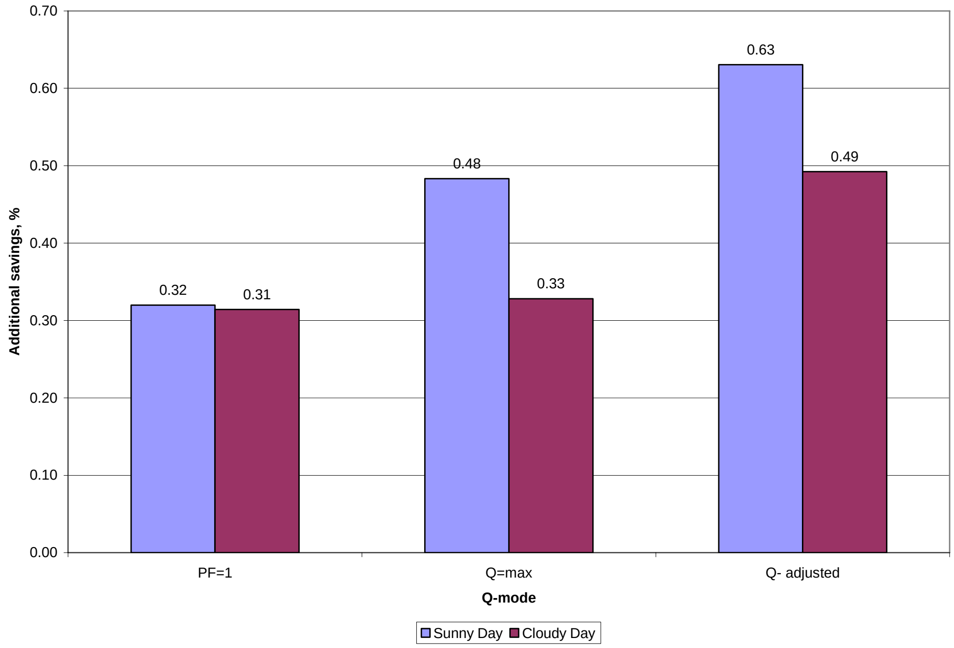

Figure 1-29
VVO energy conservation benefits in comparison with no PV

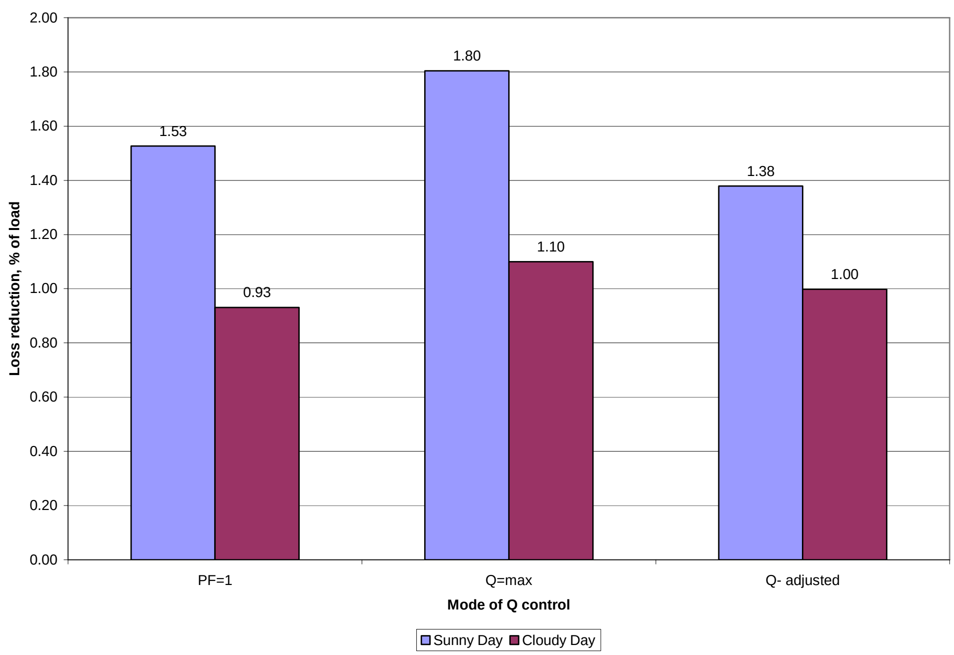

Figure 1-30
Loss reduction due to PV and VVO

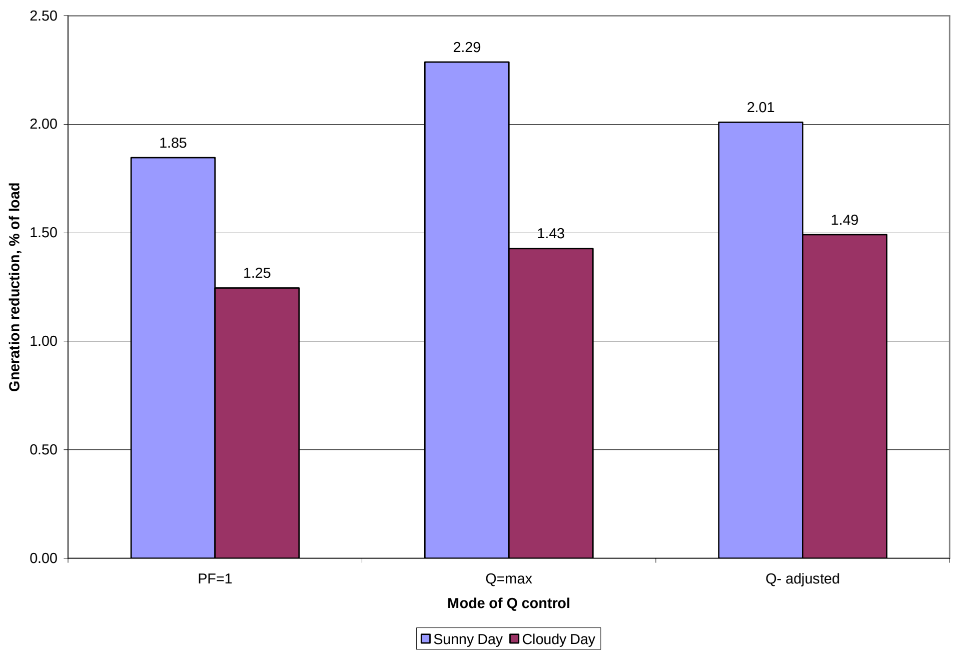

Figure 1-31
Generation reduction due to loss and load reduction.

Another example distribution circuit is presented in Figure 1-32. This example presents a case, where the bus voltage is optimized for two feeders by controlling the common LTC and the DER vars on both feeders. It is assumed, in this example, that Feeder 1 is always the voltage critical feeder, i.e. the voltage drops in feeder 2 are always smaller that the voltage drops in Feeder 1. Hence, the bus voltage is defined by the requirements of the critical points in Feeder 1.

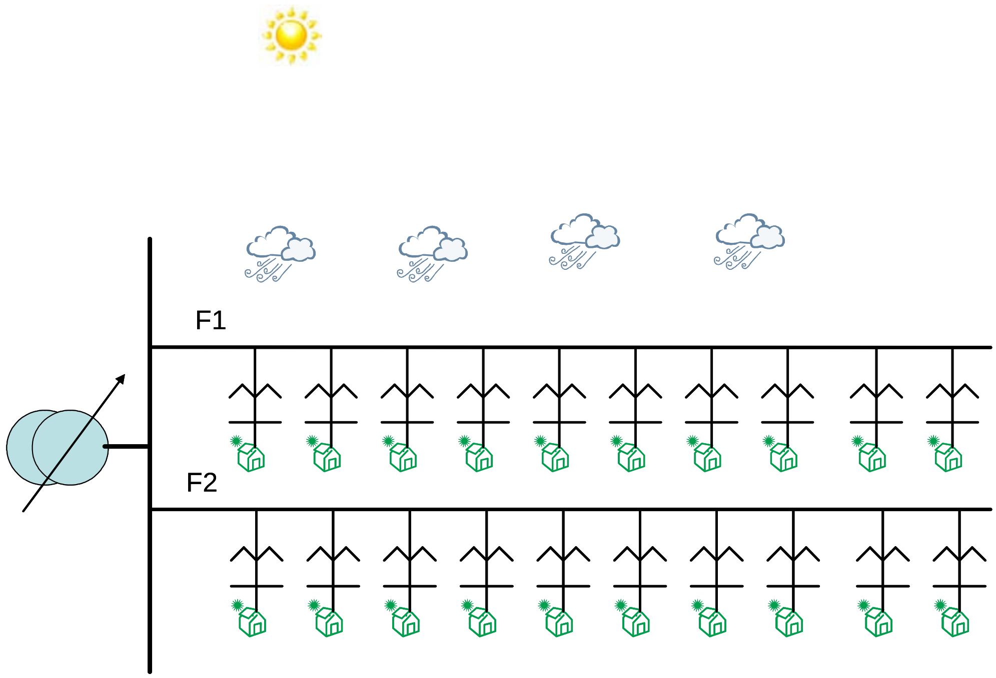

Figure 1-32
Example distribution diagram with two feeders and common LTC control

Figure 1-33 presents the best achievable average voltage profiles along Feeder 2, when the mode of reactive power control on Feeder 1 is PF = 1. In this case, the modes of reactive power control at all DER in Feeder 2 are minimum reactive power, i.e., PF = 0.9 absorbing.

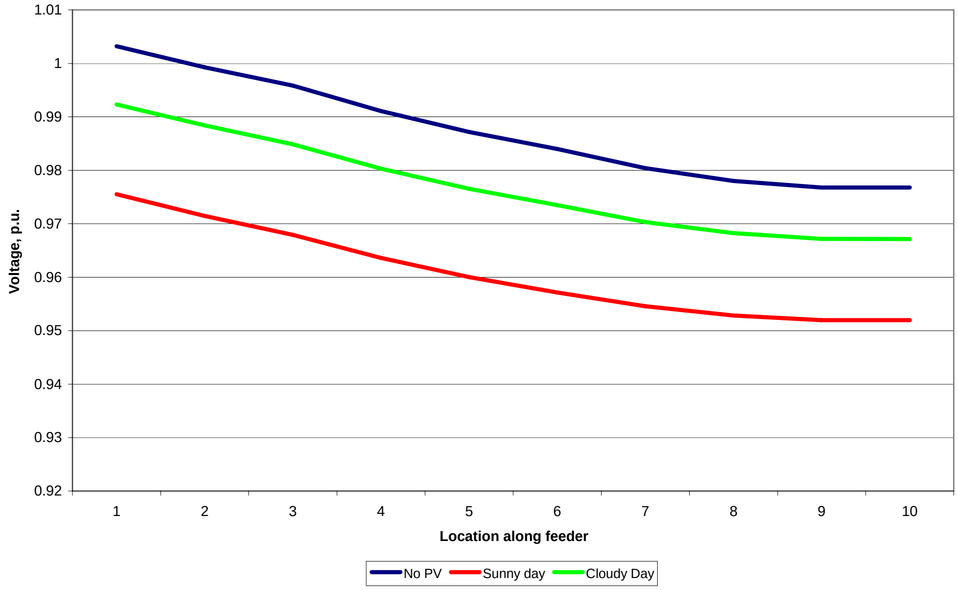

Figure 1-33
Average optimal secondary voltage profiles along Feeder 2, when the modes of Q control in Feeder 1 are PF= 1

When the modes of reactive power control at all DERs in Feeder 1 are maximum reactive power, i.e., PF = 0.9 generating, the best modes of reactive power control at DERs in Feeder 2 are as follows:

- Load # 1 through # 3 – PF = 0.9 absorbing
- Load # 4 through # 10 – PF=0.9 generating.

The average voltage profiles for this case are presented in Figure 1-34.

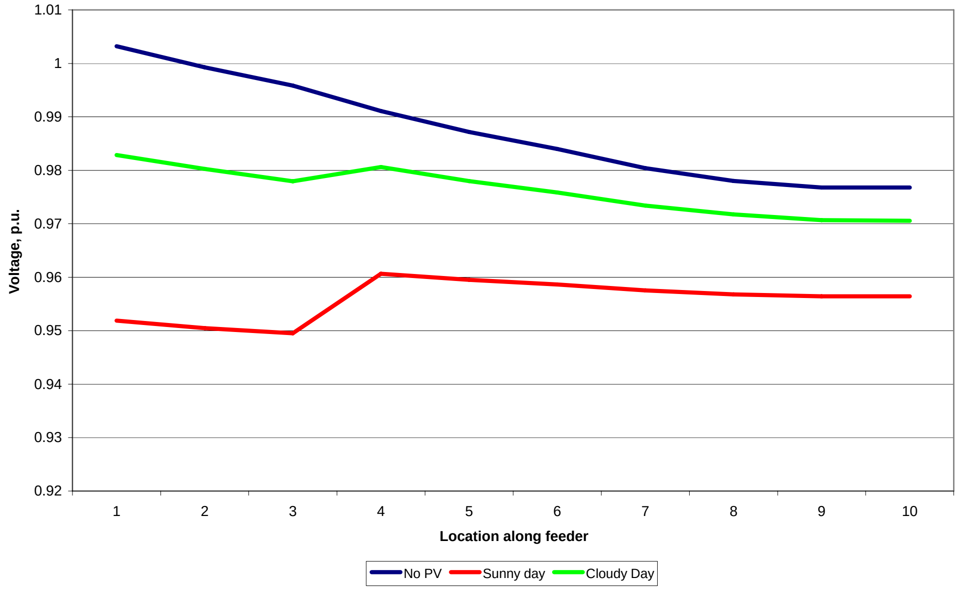

Figure 1-34
Average optimal secondary voltage profiles along Feeder 2, when the modes of Q control in Feeder 1 are Q-max

When the modes of reactive power control at DERs in Feeder 1 are differently adjusted, the best modes of reactive power control at DERs in Feeder 2 are as follows:

- Load # 1 through # 4 – PF = 0.9 absorbing
- Load # 5 through # 10 – PF= 1.

The average voltage profiles for this case are presented in Figure 1-36.

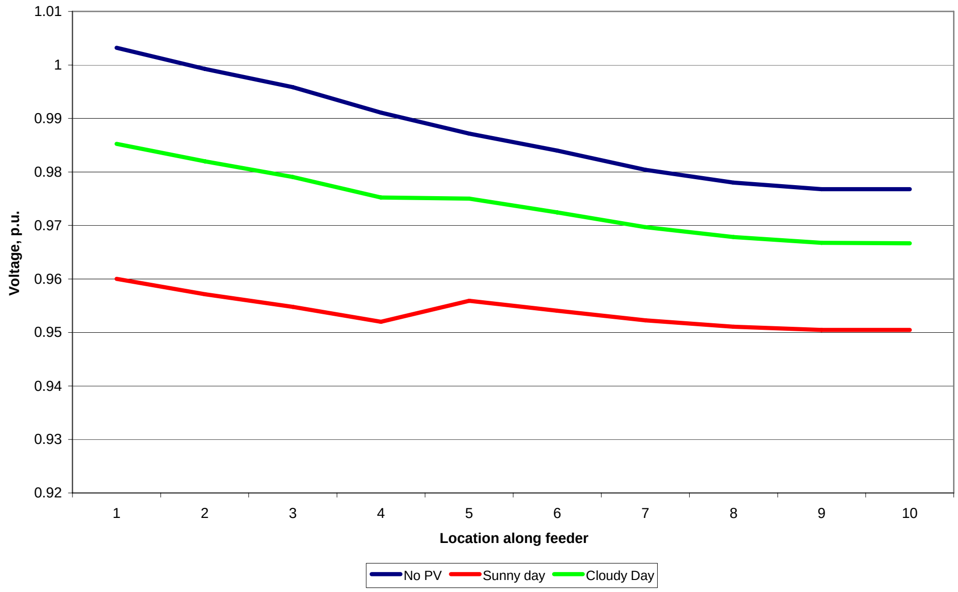

Figure 1-35
Average optimal secondary voltage profiles along Feeder 2, when the modes of Q control in Feeder 1 are differently adjusted

The consumption savings in Feeder 2 for the three alternatives presented above are shown in Figure 1-36. As seen in the figure, the best alternative for Feeder 2 is the differently adjusted modes of reactive power control. From the loss minimization standpoint (see Figure 1-37), the best alternative, when the modes of reactive power control in feeder 1 is Q-max, and from the generation standpoint, the best alternative is Q-max for the sunny days and the differently adjusted modes for the cloudy days (see Figure 1-38)

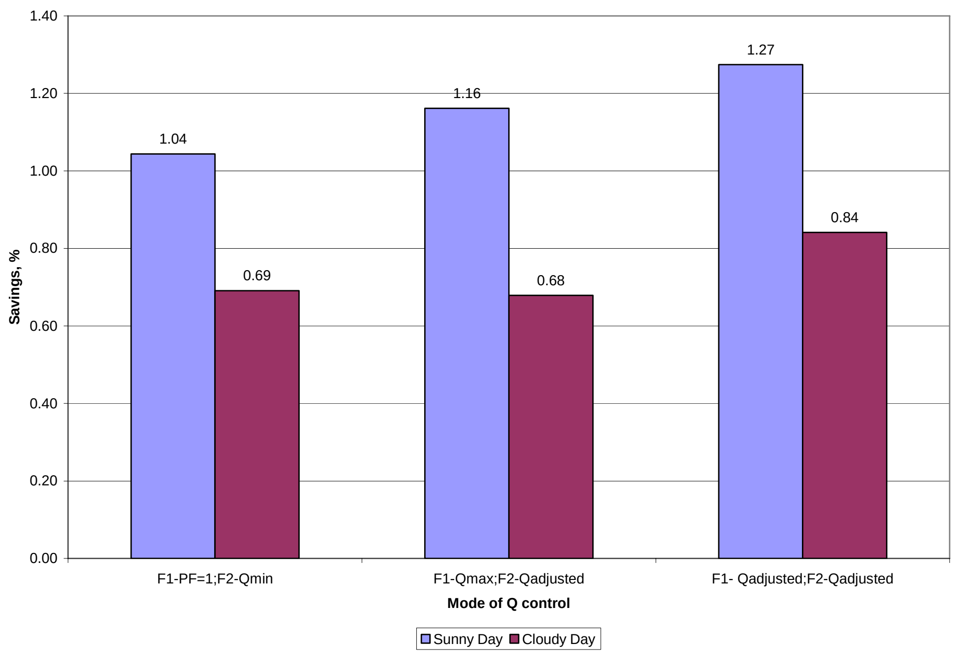

Figure 1-36
VVO energy conservation benefits in comparison with no PV for Feeder 2

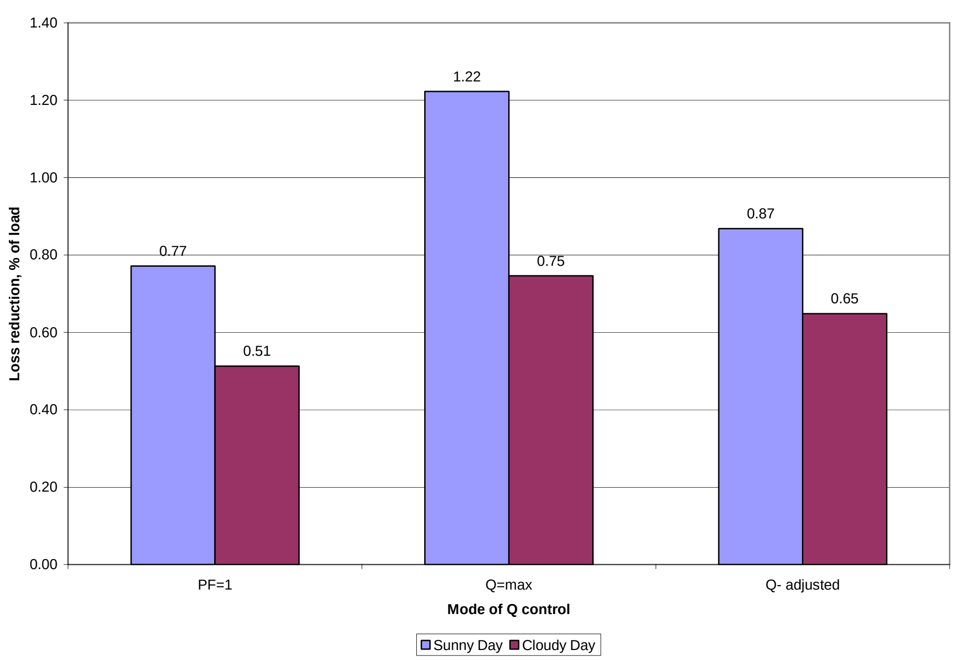

Figure 1-37
Loss reduction due to PV and VVO for Feeder 2

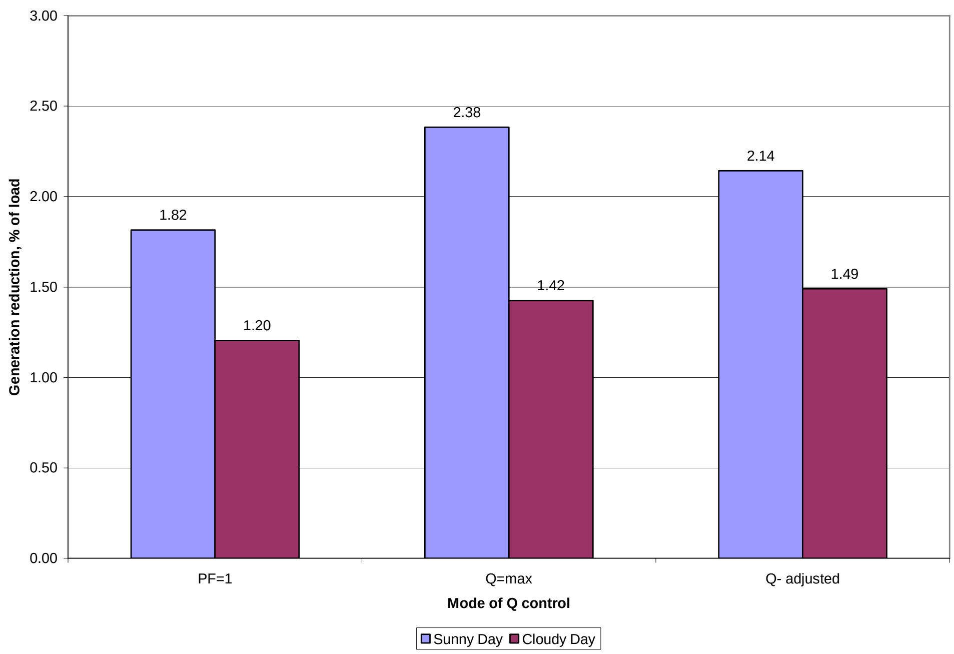

Figure 1-38
Generation reduction due to loss and load reduction for Feeder 2

The final selection of the optimal modes of operations should be based on the total benefits for both feeders. Those are presented in Figure 1-39 through Figure 1-41. As seen in the figures, from the standpoint of consumption minimization, the best alternative is the differently adjusted modes of reactive power control. From the loss minimization standpoint it is the Q-max modes, and from the generation standpoint, it is Q-max for the sunny days, and the differently adjusted modes for the cloudy days.

As it follows from the above discussion, even for uniformly distributed loads and DER capacities the optimal modes of reactive power control may be different for different locations along the same feeder and in different feeders. Hence, the optimal modes of reactive power control by DERs able to change the modes of operations should be issued by the ADA application to individual DER controllers, or to changeable groups of DERs combined by the same mode of operation.

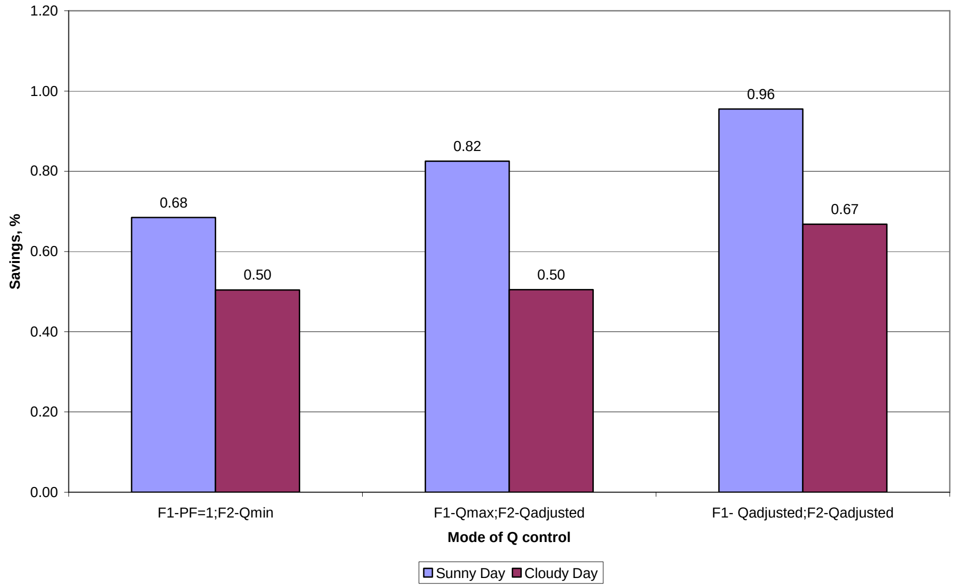

Figure 1-39
VVO energy conservation benefits in comparison with no PV for Feeders 1 and 2

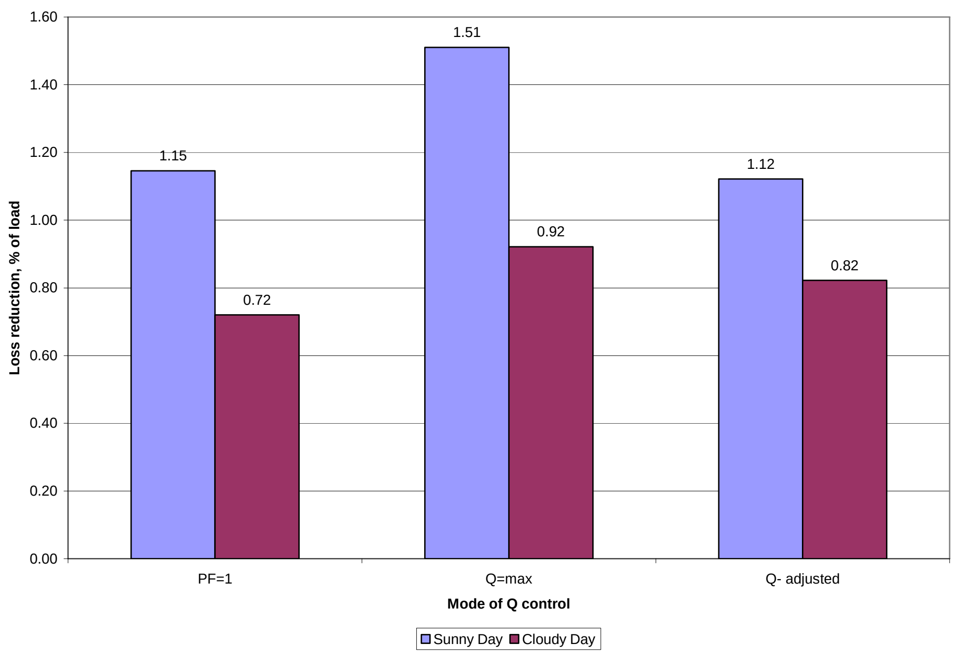

Figure 1-40
Loss reduction due to PV and VVO for Feeders 1 and 2

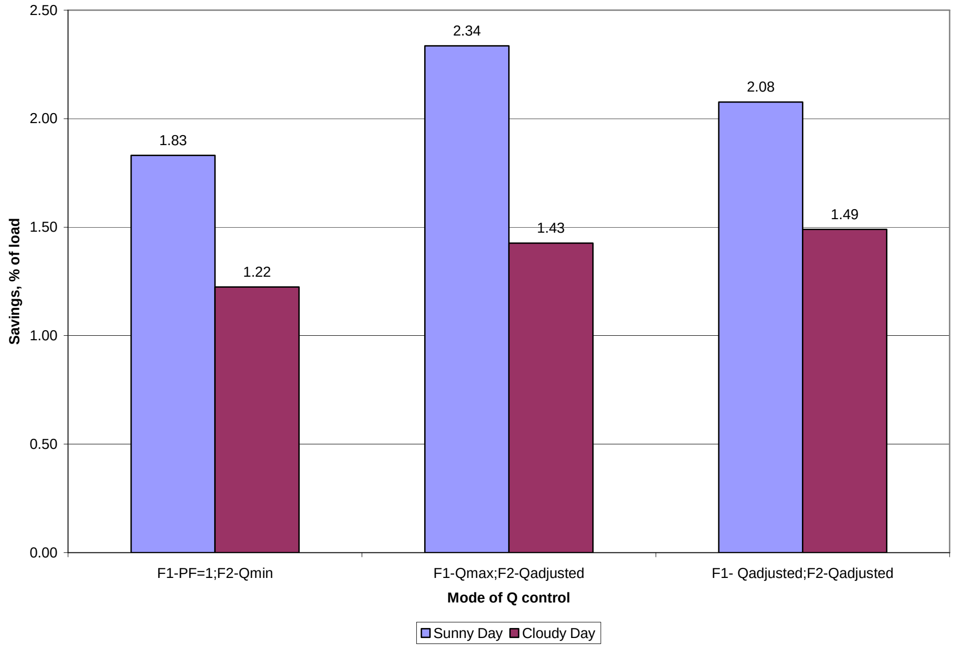

Figure 1-41
Generation reduction due to loss and load reduction for Feeders 1 and 2

Although, typically, utilities limit customer generation below their existing capacity, (see, e.g., [26, 27], there are concerns about the voltage control issues in distribution, when the DER generation exceeds the load, and the voltage profiles along the feeders are increasing toward the end of the feeders. Such an example is considered below. The maximum capacity of the individual DERs, in this example, is 150% of the corresponding customer peak load (see Figure 1-42). As seen in the figure, the net power, which flows from the customer terminals into the distribution system may exceed 50% 0f the peak load. The example diagram of the distribution circuit is the same as in Figure 1-14. If the mode of reactive power control is Q-max at all DERs along the feeder, the desired bus voltage that provides minimum voltages at the customer terminals drops to a very low level, as is seen in the dotted line of Figure 1-43. Such bus voltage may be either not acceptable, or not achievable. Assume that the low bus voltage limit is presented by the broken line in Figure 1-43. In this case, the optimal average voltage profile along the feeder is as presented in Figure 1-44. As seen in the figure, the voltage is the highest at the end of feeder and almost reaches the maximally acceptable level (1.05). The lowest secondary voltage is far above the low voltage limit.

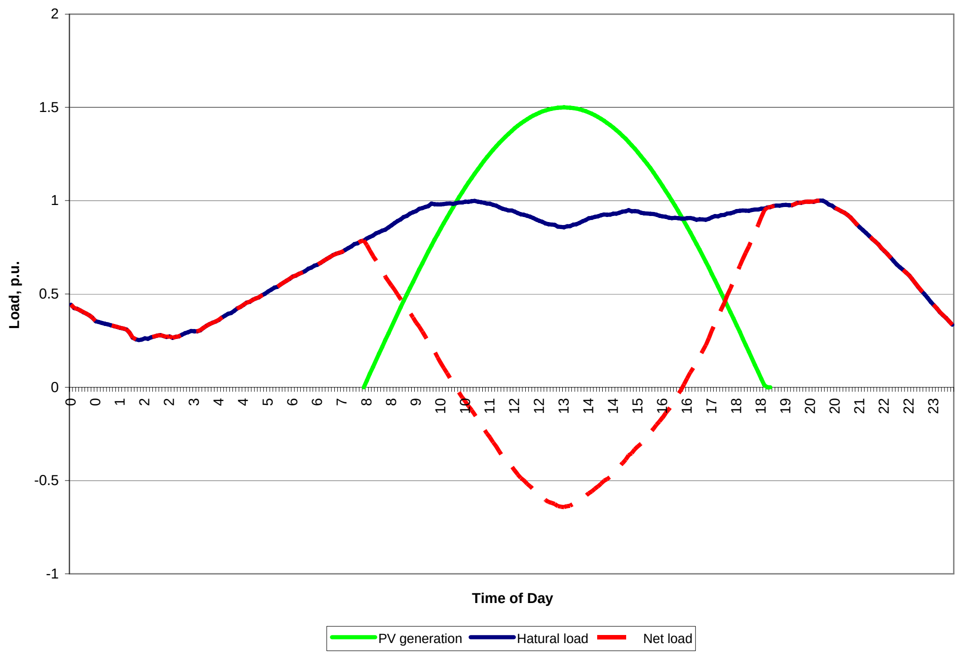

Figure 1-42
Load and generation in the example with the DER generation exceeding the load.

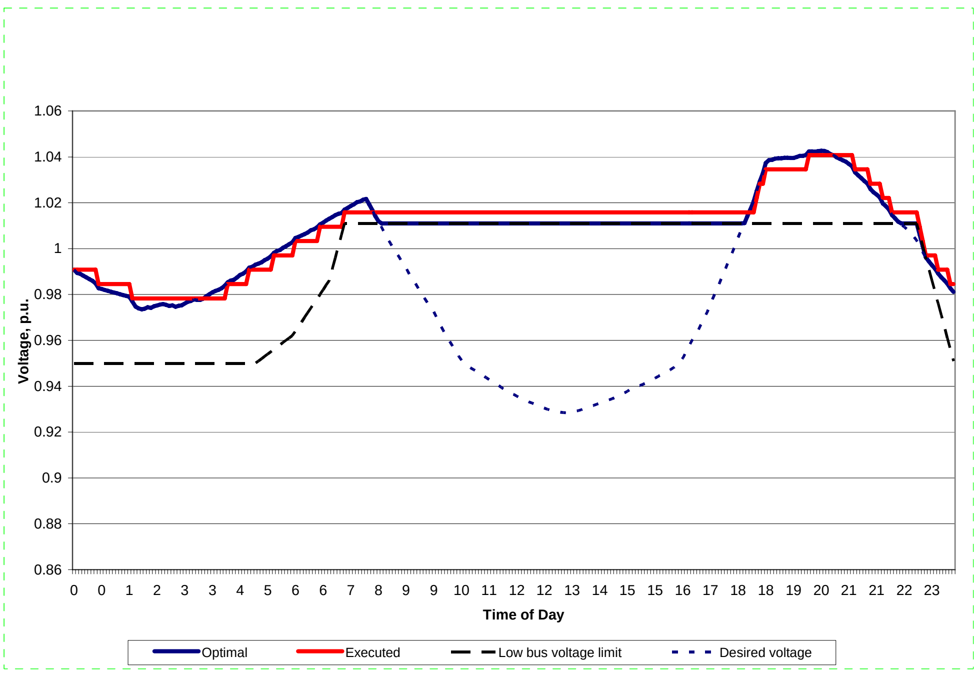

Figure 1-43
Bus voltages for the Q-max mode of DER control along the feeder.

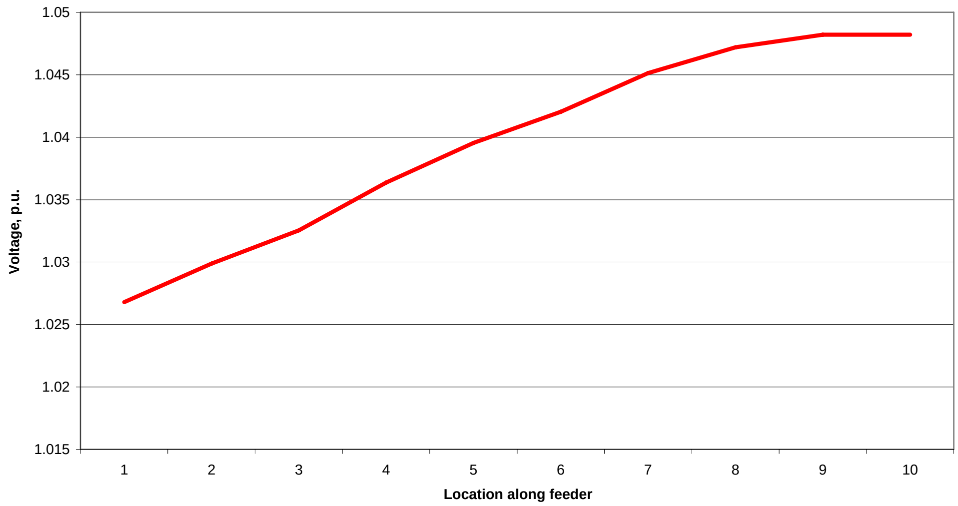

Figure 1-44
Average secondary voltage profile along the feeder for the Q-max mode of DER control.

In order to lower the secondary voltages, the modes of DER reactive power control was changed to PF = 1. The voltage profile is presented in Figure 1-45, and the bus voltages are presented in Figure 1-46. Now, the secondary voltage profile is lower, but still above the minimum limit, and the desired bus voltage is still below the lower bus voltage limits.

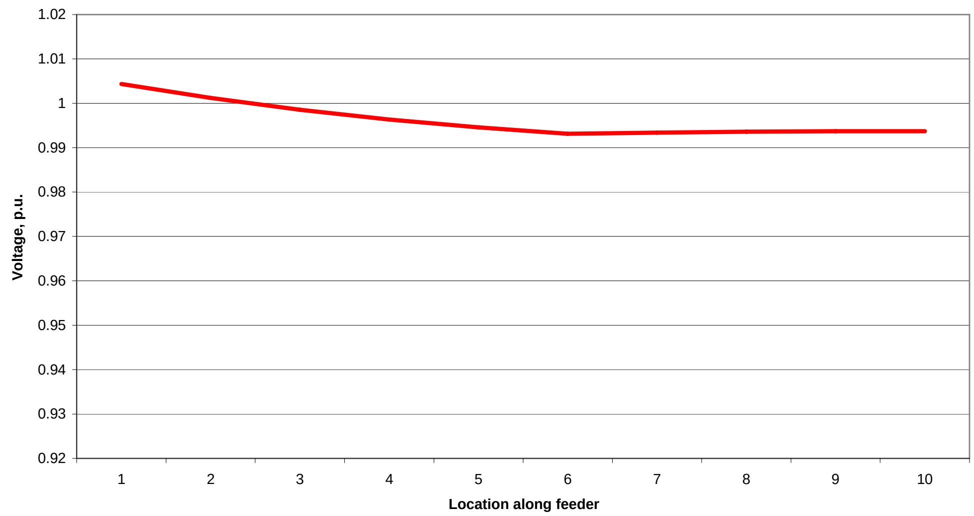

Figure 1-45
Average secondary voltage profile along the feeder for the PF = 1 mode of DER control.

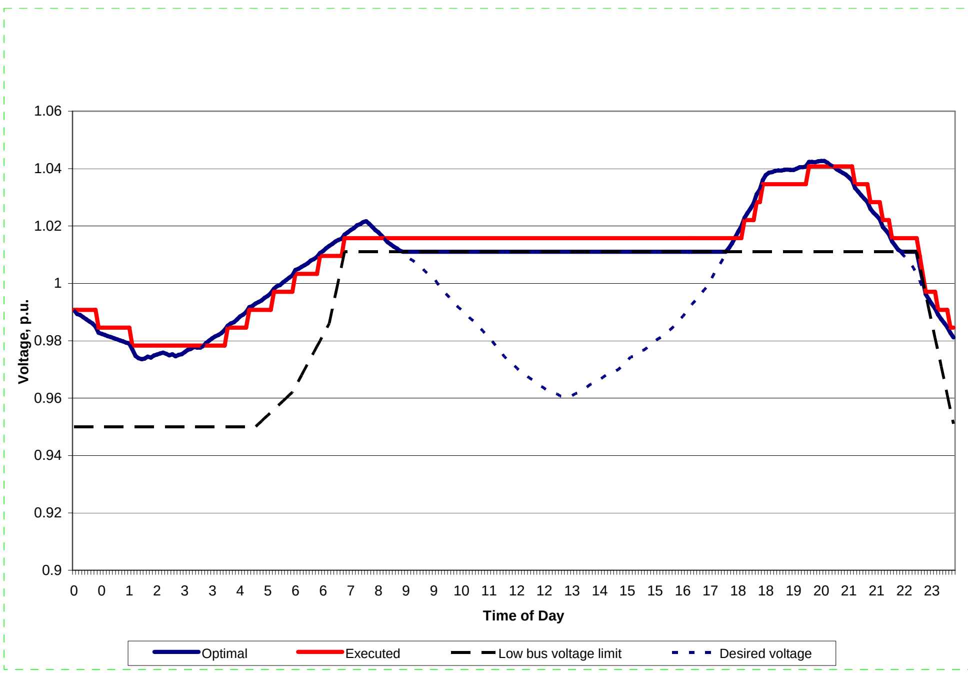

Figure 1-46
Bus voltages for the PF =1 mode of DER control along the feeder.

In order to further lower the secondary voltages, the modes of DER reactive power control was changed to Q- min (absorbing). The voltage profile is presented in Figure 1-47, and the bus voltages are presented in Figure 1-48. Now, the secondary voltage profile reaches the lower limit in the end of the feeder, and the desired bus voltage is slightly above the lower bus voltage limits. In order to utilize the remaining room for voltage reduction at the substation bus, the voltage drop along the feeder should be reduced. This can be achieved, e.g., by changing the mode of reactive power control of the remote DER from Q-min to PF=1. The results of such a change are presented Figure 1-49 and Figure 1-50. As seen in the figures, the voltage was increased in the remote node, thus increasing the consumption in this node, but the voltages in all other nodes were reduced due to the additional voltage reduction at the substation bus, which reduced the consumptions in these nodes. From the local standpoint, there was no reason to increase the voltage in the remote node: it was already at the minimum limit. But, from the standpoint of overall load reduction, the increase of the load in the remote point might result in a greater reduction of the total load.

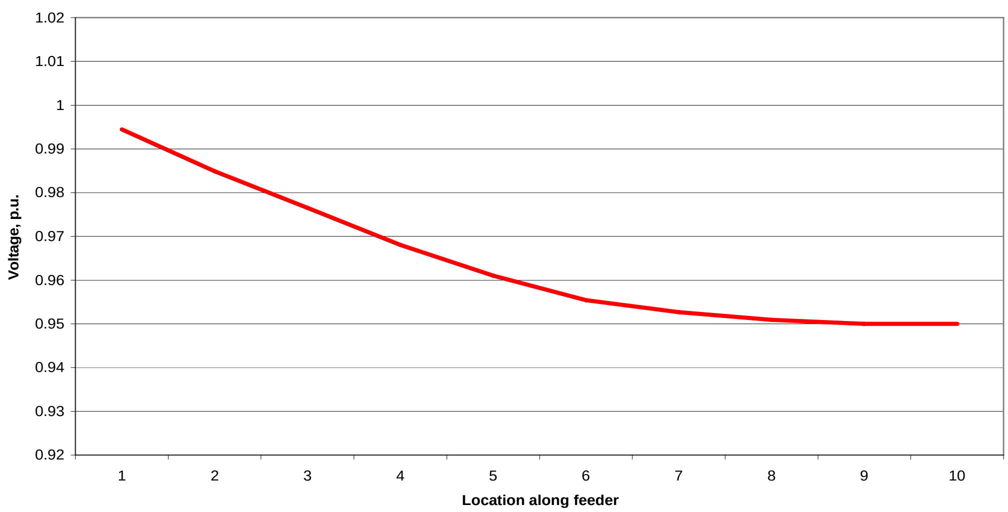

Figure 1-47
Average secondary voltage profile along the feeder for the Q-min mode of DER control.

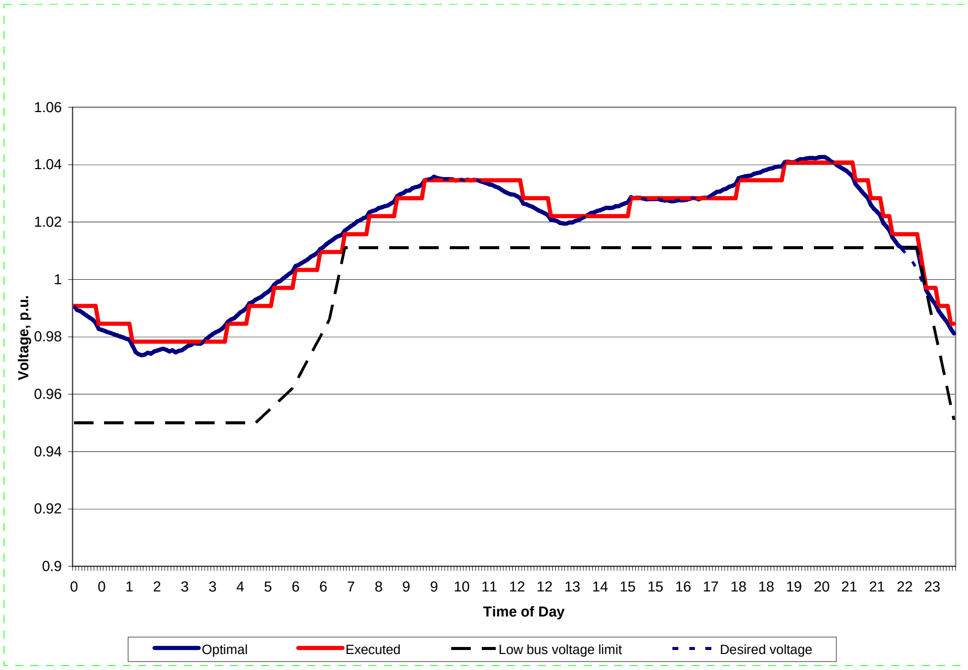

Figure 1-48
Bus voltages for the Q-min mode of DER control along the feeder

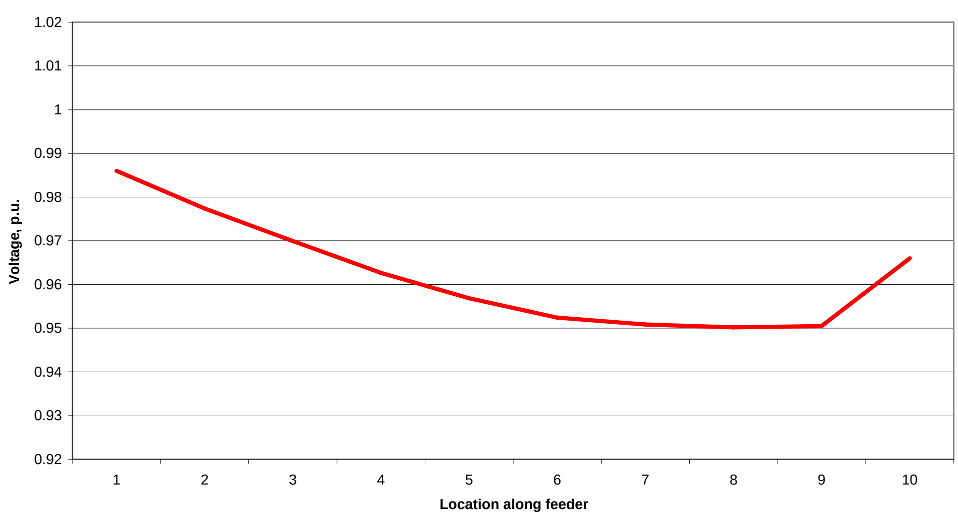

Figure 1-49
Average secondary voltage profile along the feeder for the Q-min mode of DER control, except the remote node with the mode PF =1.

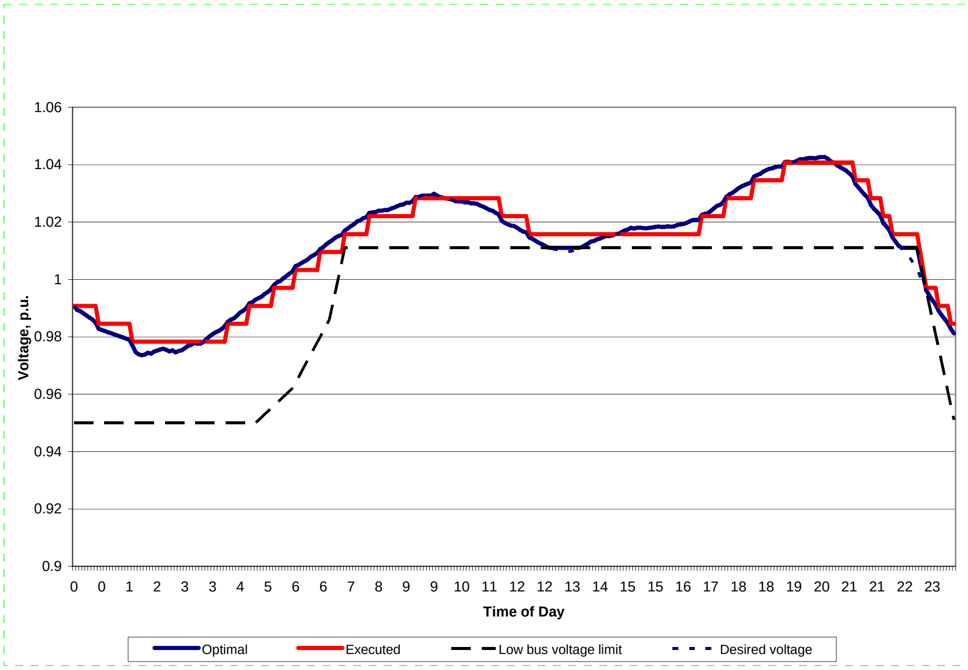

Figure 1-50
Bus voltages for the Q-min mode of DER control along the feeder, except the remote node with the mode PF =1.

The benefits of Volt/Var control, in the example with excessive DER generation, are presented in Figure 1-51. As seen in the figure, the savings in energy consumption are minimal in the last case with the PF =1 mode in the remote node. However, the behavior of losses is different. The minimum losses are in the case with the Q-max mode of control. The minimum generation is in the case with the PF=1 mode of control.

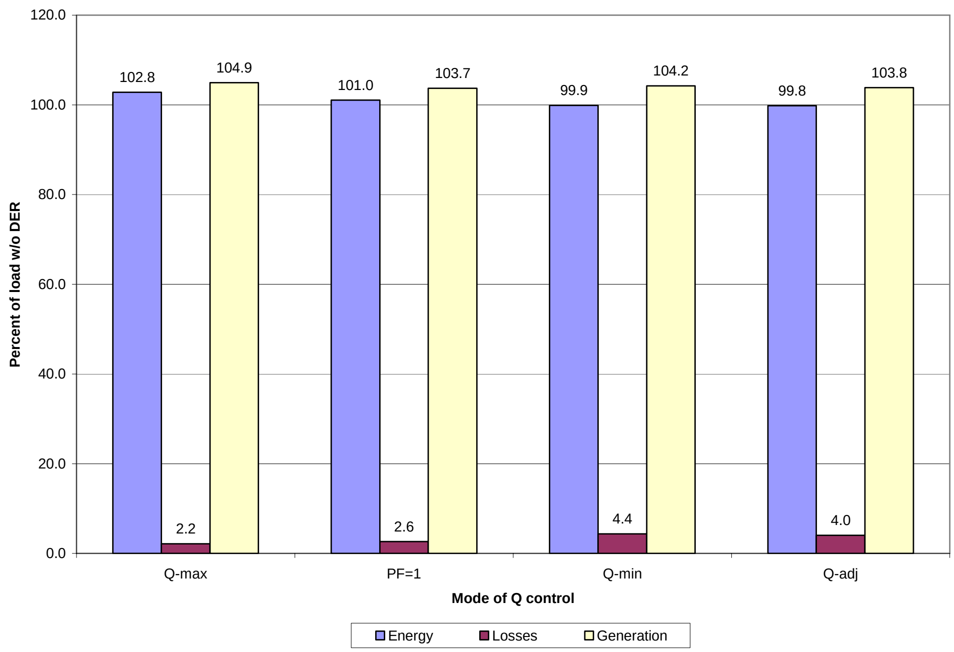

Figure 1-51
Benefits of Volt/Var optimization in the case of excessive DER generation.

The above examples were based on simple distribution circuits and only on LTC and DER var control capabilities. In the Smart Distribution systems, there will many different controllable devices, which will complicate the optimization models, and the optimization will even more depend on data unavailable locally. A more complex example is illustrated below.

The model for the illustrations is based on the IEEE 123-bus model. The IEEE model was expanded by adding distribution transformers, nodal load models with different load shapes, real and reactive load-to-voltage dependencies, simplified models of passive DER, demand response component models, secondary circuits and transmission equivalents.

The examples illustrate the results of VVWO with the load reduction objective [12]. Figure 1-52 presents the secondary and primary voltages, when the DERs are off. The settings of the voltage regulator in the feeder head (LTC) and along the feeder, as well as the statuses of the feeder capacitors were optimized. The lowest voltages in the secondaries are close to the low voltage limit, 114 V, in several nodes.

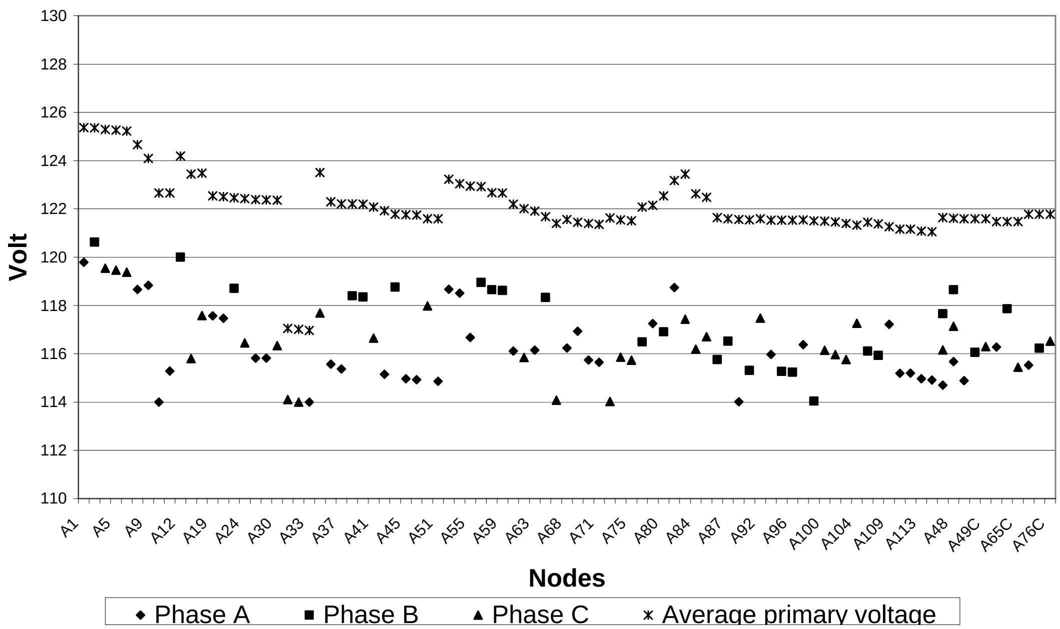

Figure 1-52
Secondary and primary voltages, no DER, optimization of LTC, feeder capacitors, and voltage regulators

Figure 1-53 illustrates the results of optimization, when the DERs are generating real power only. The VVWO optimized the setpoints of all voltage regulators and the statuses of feeder capacitors. As seen in the figure, the coordinated optimization of the voltage regulators and feeder capacitors provides a flatter voltage profile along the feeder and additional VVWO benefits.

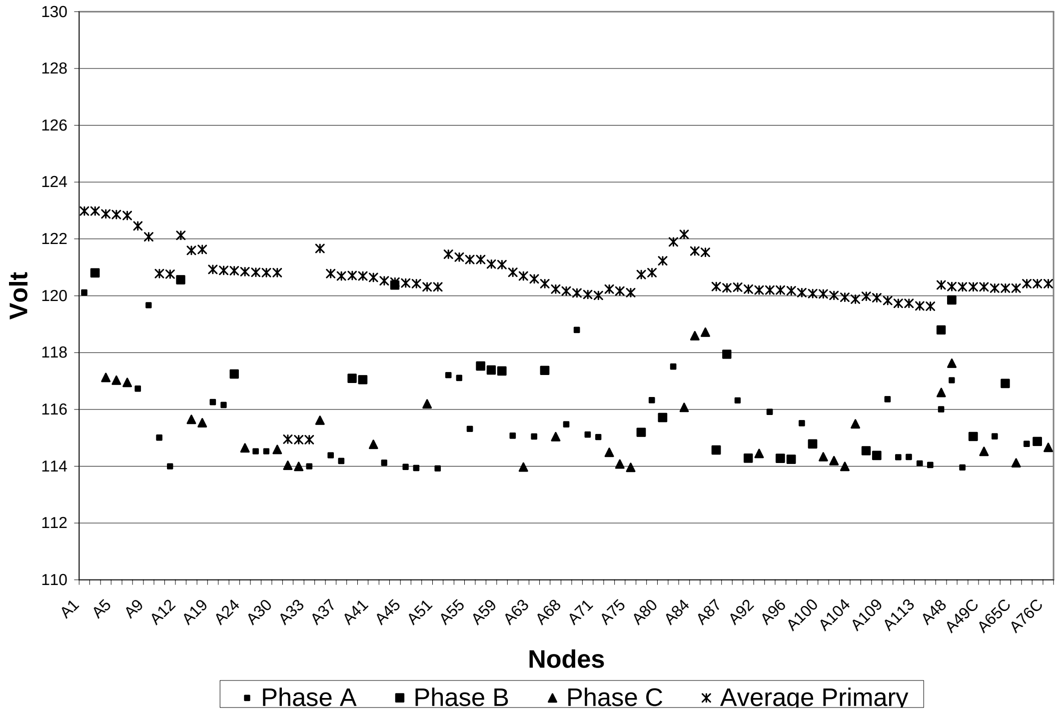

Figure 1-53
Secondary and primary voltages, with DER PF=1, optimization of LTC, feeder capacitors, and VR

Figure 1-54 illustrates the results of optimization, when the DERs are ON generating real power and are able to generate and absorb reactive power. The lowest secondary voltages are close to 114 V. Some of the DERs generated reactive power, while other absorbed it.

Generation of the reactive power reduced the voltage drops and provided additional room for Volt/Var optimization. Absorbing the reactive power in the nodes with higher voltages increased the voltage drops and mainly lowered the voltages locally. However, in other nodes, where the local voltage could be reduced, the DER did not absorb the reactive power, because it would also reduce the voltages in other nodes, where voltages were already on the low limit.

It means that the ‘local” control of voltage by regulating the local reactive power should take into account the impact on the voltages in other nodes and should be coordinated with other control means in the same distribution circuits.

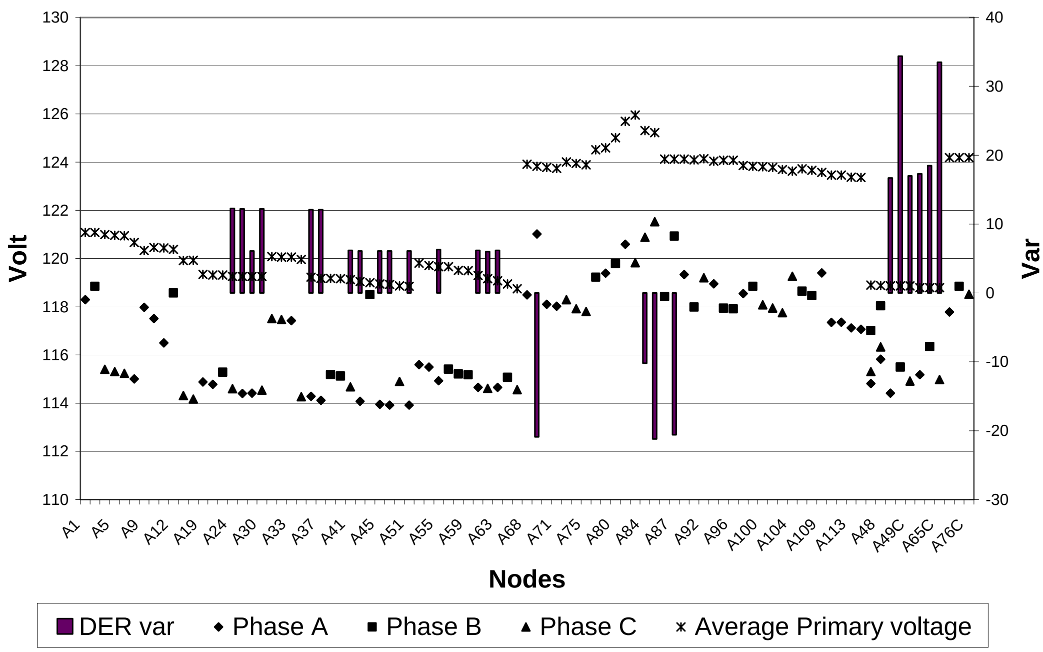

Figure 1-54
Secondary and primary voltages, with LTC, Capacitors, and variable vars of DER

Figure 1-55 illustrates the case when all voltage regulators, feeder capacitors, and the reactive power of DER are optimized. This optimization provides the largest benefits.

The summary results of the optimization for the last three cases and their comparison with the optimization of the LTC and feeder capacitors only are presented in.

The assumed penetration of DER in the sample circuit is about 30% of the peak feeder load. Change of the participation of the DER from full to zero required a significant increase of the bus voltage at the feeder head (about four steps of the LTC), which is manageable if such change happens not too often and not very fast. If such changes occur frequently, e.g., due to frequent weather variations and predominantly weather-dependent DER, the electro-mechanical devices will not be able to compensate for the voltage fluctuations [17], and many more dynamic voltage and var controlling and electric storage devices will be needed. The modes of operations, and the setpoints of these devices will need to be determined by the VVWO application, or another ADA application, depending on load and weather forecasts, expected behavior of the DER, and other operational characteristics.

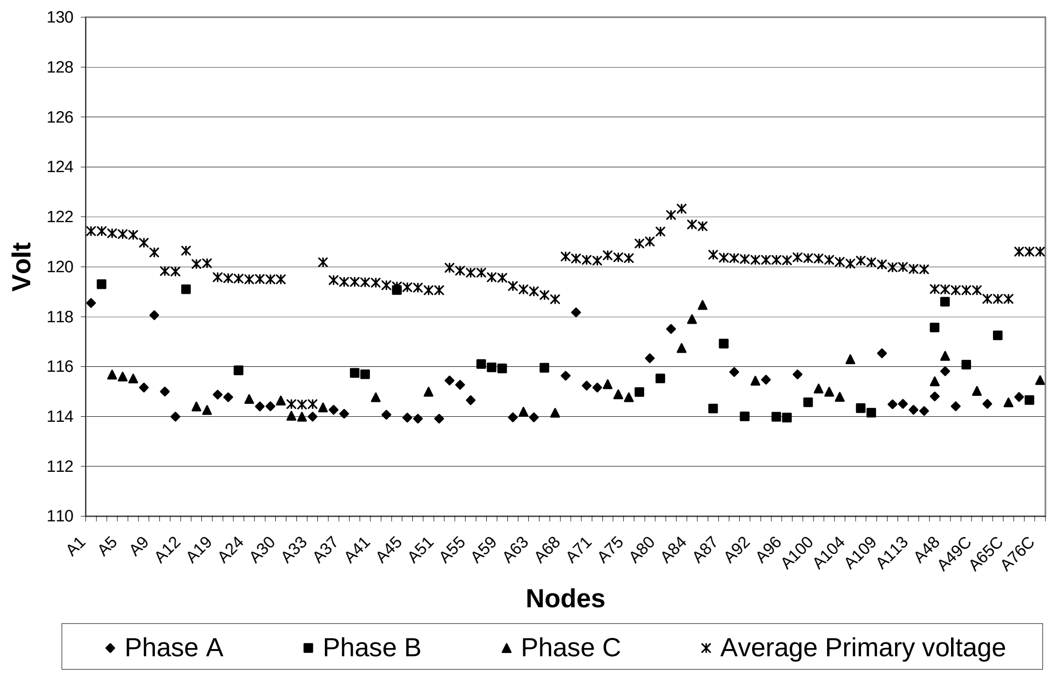

Figure 1-55
Secondary and primary voltages, with LTC, Capacitors, variable vars of DER, and VR

Table 1-2
Summary of optimization results with DER

Parameter	Optimization of			
	LTC and Capacitors	LTC, Capacitors, var of DER	LTC, Capacitors, and VR	LTC, Capacitors, var of DER, and VR
Bus Volt	124.1	121.7	123.7	122.1
Average primary voltage	122.49	121.45	120.5	119.84
Total load, kW	3279	3265	3243	3236
Feeder kW	3488	3470	3449	3436
Feeder kvar	432	274	589	472
Feeder Losses, kW	208	204	205	199
Transmission losses, kW	264	262	261	259
Generation, kW	3751	3732	3710	3695
Generation reduction, kW		20	42	56
Generation reduction, %		0.53	1.1	1.50

As follows from the above discussions, the presence of the capabilities of DER to generate and absorb reactive power may provide significant added benefits of VVWO in comparison with the no-var DERs.

It also suggests that the optimum selection of the DER var control depends on the configuration and parameters of the distribution circuits, on the load and DER distribution among customers and along feeders, on weather conditions, on the utility objectives of Volt/Var optimization, on operational constraints in the distribution and transmission systems, and on the impact of distribution operations on transmission operations (accounting for transmission losses and Volt/Var support), and other global factors. This conclusion suggests that, in general, optimal var control by DERs based on local parameters cannot be accomplished. Besides, with significant penetration of DER, the local controls may cause control stability problems.

The optimal control of var by DERs, can be provided by a Volt/Var/Watt control application of ADA, based on a comprehensive distribution operation model, including behavioral models of loads and DERs, and on a communication system capable of timely delivery of the setpoints (modes of operations) to the DER controllers.

The potential benefits of VVWO due to information exchange with DER associated with the objective of the VVWO application are presented in Table 1-3.

Table 1-3
Objectives and benefits of Volt/Var/Watt optimization application due to information exchange with DER

Objective	Benefits
Ensure standard (or better) voltages at customer terminals	Prevention of miss-coordination between DER operations and Volt/Var control by other than DER means; obtaining additional power quality improvement due to coordinated control of DER vars, reduction of power quality related complaints and expenses.
Reduce load while respecting given voltage tolerance (normal and emergency)	Additional load reduction by load-reducing Volt/Var/Watt optimization due to coordinated control of DER vars and Watts, if needed, resulting in additional reduction of energy cost, deferral of new generation; and reduction of pollution.
Conserve energy	Additional conservation of energy by energy-conservation Volt/Var optimization due to coordinated control of DER vars, if needed, resulting in additional reduction of energy cost, and reduction of pollution.
Reduce or eliminate overload in transmission lines	Additional reduction of the congestion component of Locational Marginal Prices and improvement of reliability due to coordinated control of DER vars and Watts.
Provide reactive power support for transmission/distribution bus	Additional reduction of losses and the loss component of the Locational Marginal Prices and improvement of reliability due to coordinated control of DER vars.
Provide spinning reserve support	Additional reduction of energy cost and improvement of reliability due to coordinated control of DER vars and Watts.
Minimize cost of energy	Reduction of cost of energy by optimization of consumption, energy and var resources due to combined real and reactive optimization of distribution operations.
Reduce energy losses	Included in reduction of cost of energy
Expand the operational tolerances for generation/transmission operations	Additional improvement of transmission operation efficiency due to wider tolerances provided by coordinated control of DER vars and Watts; additional increase of generation capacity corresponding to the generator capability curve due to coordinated optimization of DER vars, resulting in additional reduction of cost of energy.

The following conclusions can be derived from the above discussion on VVWO:

- The Integration of Voltage and var optimization in distribution with the controls of the Distributed Energy Resources enhances the efficiency of distribution operations
- The dynamic Volt/Var/Watt optimization involving DERs even more impacts the operational parameters across the customer, distribution, transmission, and generation domains, which definitely should be taken into account in the design and implementation of the application
- Integration of controls of reactive power generated or absorbed by distributed energy resources into VVWO provides additional benefits, which depend on their interaction with other controllable variables and on their impacts on the voltages in other nodes in the same distribution circuits
- Integration of controls of demand response and of real power of DER into combined voltage, real and reactive power optimization selects the most effective means for load management.

Multi-level Feeder Reconfiguration (MFR)

The application performs a multi-level feeder reconfiguration to meet one of the following objectives or a weighted combination of these objectives [4, 5, 9, 28, and 29]:

- Optimally restore service to customers utilizing multiple alternative sources. The application meets this objective by operating as part of Fault Location, Isolation and Service Restoration.
- Optimally unload an overloaded substation transformer or feeder segment. This objective is pursued if the application is triggered by the overload alarm from SCADA, or from the Distribution Operation Modeling and Analysis application.
- Unload congested transmission lines or reduce high Locational Marginal Prices (LMPs) by swapping loads from high-LMP substations to other substations with smaller LMPs [30].
- Minimize losses
- Minimize exposure to faults
- Equalize voltages.

The function deals with a very large number of variables [28]. Two kinds of DER will be included in the operation model for the MFR application: the multiple passive DER, which are either On or Off depending on weather or other non-utility imposed conditions, and the active DER, which can be controlled by the utility. The presence or absence, or the behavior of the passive DER will increase the number of initial operating conditions for the MFR application. The number of active DER will increase the dimension of the optimization.

Theoretically, the number of possible combinations to consider during the search of the best solution is equal $2^{n,}$ where n is the number of switching devices in the interconnected circuits. With active DERs connected to the distribution circuits, the circuit configuration solution may be different. Just by adding the two states of DER: ON or OFF, the number of combinations for searching the configuration solution increases to 2^{n+m}, where m is the number of DERs connected to the subject circuit. Different modes of operation and different load schedules of DER can also change the solution. Hence, the number of combination may increase even more. If the optimal configuration is sought for a long-term interval (season, year), the application should take into account the probable schedules of the DERs during the entire time interval for which the configuration solution is sought and find a configuration which is the best for this time interval.

Furthermore, DERs introduce additional constraints to the configuration and to the migration from one configuration to another. For instance, when the distribution circuits are reconfigured, customers with DERs may move from being electrically connected to one substation bus to being connected to another bus, and this may be unacceptable by the DER owner due to, e.g., a change of the DER capability to provide ancillary services, or due to an increase in exposure to faults. The input data describing such kind of conditions should be made available to the reconfiguration application. Other constraints can be imposed by the transient process during switching operations while implementing the new configuration, which consist of paralleling and breaking. The change in voltage magnitude and phase angle during the switching operations will present some kind of disturbance for the DER and in some instances may be unacceptable. Such parameters as acceptable rate of voltage and angle changes may be needed for deciding whether the configuration with a DER connected to the circuit can be accomplished. In some cases, a temporary intentional islanding during the transition from one configuration to another can be included in the reconfiguration solution.

Relay Protection Re-coordination (RPR)

This application adjusts the relay protection settings to real-time conditions based on the preset rules. This is accomplished through analysis of relay protection settings and operational mode of switching devices (i.e., whether the switching device is in a switch or in a recloser mode), while considering the real-time connectivity, tagging, and severe weather conditions. The application is called to perform after feeder reconfiguration, and, in case, when conditions are changed and fuse saving is required [4, 11, 31].

The relay protection coordination application without DER [8] analyzes the coordination of a group of settings along distribution feeders and selects the mode of operation of the switching devices (protective device mode/switch mode) and the group of settings to respect the requirements for coordination. No fault calculations are needed in this application.

With DERs in distribution, the situation is much more complex, especially when supporting the fuse-saving protection policy. There are a variety of relationships between fault currents through the protective devices and through fuses. The room for adjustment of the settings of the protective devices is limited. Hence, it is possible, that under some conditions, the coordination for the fuse saving protection cannot be provided. Therefore, the relay protection coordination application should include a fault calculation routine determining probable fault currents through the protective devices and through the fuses. The range of these fault currents should be compared with the corresponding settings, and a decision about the coordination should be made. If the coordination with existing settings cannot be provided, and changes of settings of the protective devices are possible, then the recommended changes should be implemented. The assumption here is that the future protective devices will be available for remote change of their settings.

The situation is different when the coordination of several protective devices along the feeder should be coordinated, and there are DERs connected to the circuits between the protective devices. In this case, the fault current through the protective device downstream from the DER will be greater than the fault current upstream from the DER, and it is easier to provide coordination. But, if the DER disconnects before the fault is cleared due to low voltage, then the margin for coordination becomes smaller. This relationship between the residual voltage at the DER PCC, timing of the relay protection, and relay protection setting should be taken into account in the relay protection coordination application. Issues related to behavior and coordination of relay protection in distribution with DER, as well as the information support requirements, are addressed in [11].

Pre-arming of Remedial Action Schemes (RAS)

This application receives pre-arming signals from an upper level of control and changes the settings (tuning parameters) of distribution-side remedial action schemes (RAS), e.g., load-shedding schemes (a component of self-healing grid) or intentional islanding of DER and loads into microgrids. The protection settings of the DER leading to unintentional separation of the DER with or without loads shall be taken into account.

To meet the Smart Grid requirements, the application shall provide coordination of remedial action schemes with Distributed Energy Resources, Demand Response, Electric Storage, Electric Transportation, and microgrids. In a case of a significant disturbance, some of the DERs will disconnect almost immediately without load, some with load (micro-grids), where the load is smaller than the DER generation, and some with a greater load. If the RAS can separate a portion of load, which can be later reconnected with a disconnected DER, which can carry the load, the total lost kWh will be smaller. The micro-grids, which separated with excessive load, should have their RAS tuned to balance the micro-grids. This load can be shed either before the micro-grid disconnects, or after, depending on a number of conditions. These conditions include the severity of the initial disturbance and the ability to balance the real and reactive loads and generation in the micro-grids. The fast-acting RAS don't have to restore the frequency and voltage to the nominal levels. If these parameters are restored to a level, which is acceptable for some time, then other slow-acting and less intrusive means can be implemented. These means include connection of disconnected standby DER and emergency VVWO.

Short-term Load and Energy Forecast

The short-term distribution load forecast is needed for the look-ahead ADA applications and for the bus-load forecast EMS application. For different applications and for different objectives of the applications different degrees of load aggregation are needed.

In the Smart Grid environment, the historic data on loads, which is the current base of load forecast, will be significantly influenced by the operations of embedded passive and active DER, by the Demand Response activities, by the use of Electric Storage, and by the use of PEVs. Therefore, before forecasting it is expected that the historic data will be normalized to a pre-defined base, and the dependencies on a number of dominating factors will be derived from the relevant samples of historic data, provided by AMI, DER, and DR Data Management Systems and by historic weather data. When such behavioral load models exist, the load forecast mostly turns into the forecast of the dominating factors.

For the forecast of the load aggregated at feeder heads or at the feeding substation bus, the forecasts of the operations of significant DER, which were not an embedded part of the load models, shall be provided. One possibility is the use of DER schedules and modes of reactive power control, if this information is available. The operations of the renewable DER can be forecasted based on weather forecast and maintenance schedules, if any.

Distribution Outage Scheduler

The Distribution Outage Scheduler is an operation planning application, which analyzes and coordinates the outage requests. The input data for this function includes load forecast and data about active and authorized planned outages. The presence of DER in distribution adds to this application the outage requests or outage schedules of significant DERs and the data about the future operations of DERs. The outage requests or the outage schedules from the DER owners should be made available to the distribution operation planners. The request or schedule should include tolerances for the outage time and the emergency restoration (recall) time for different stages of maintenance. Scheduling the use of the Electric Storage and Demand Response may be needed to accommodate some of the outage requests.

Asset Management, AM/FM/GIS, and CIS Databases

The Asset Management Systems (AMS) perform recording of asset data, up-front data consistency checking, updating records, adding and cloning new assets, submitting defaults, asset tracking, sorting, filtering, finding required information about assets, identifying trends in asset usage and replacement, monitoring maintenance periodicity, contract progress, and life cycles of assets, alarming and announcement about asset conditions, generating reports, providing total and incremental extracts for different users, output data consistency checking, preparing forms for different input data providers, etc. Typically the AMS uses AM/FM/GIS (Automated Mapping/Facility Management/Geographic Information System) databases associated with Customer Information Systems (CIS).

With Significant DER in distribution, the Asset Management Systems should include the DER-related information of the Distribution Company (DISCO)-owned DERs in their databases and process this data in accordance with the asset management rules of DISCO. The available information of DER owned by customers and IPP should be also included in the databases. This information should be sufficient for building the complete model of the distribution system used for ADA applications. It should include as a minimum the following nominal data:

- Type of DER
- Connectivity
- Synchronization points
- Rated kVA, PF, and kV
- P-Q-V constraints

- Electric characteristics for calculating fault currents

Recognizing and Controlling the Abnormal Distribution Operation

The analysis of abnormal conditions cannot be limited to distribution operations only. Significant penetration of DER in distribution also means that a significant component of the demand-supply equilibrium is allocated among a big number of distributed generators connected to distribution circuits. These generators have different from the bulk generators operational constraints, rules of control and interconnection with the utility. In case of a significant disturbance in the bulk power system, the behavior of the many distributed generators may play a critical role in the development of the emergency operating conditions.

Certainly, the abnormal operating conditions in the distribution system with significant DER will also develop differently than without DER and should be analyzed from the standpoint of dynamic optimization of the reliability of service under emergency conditions.

The following cases of abnormal operating conditions are considered below:

- Fault location, isolation and service restoration with DER and microgrids
- Significant frequency and/or voltage deviations in bulk power systems
- Coordination of emergency actions
- Coordination of restorative actions

Fault Location, Isolation and Service Restoration

The Objectives and Benefits

The fault location objective is most accurately identifying, in minimum time, the location of the fault.

The fault isolation objective is de-energizing the faulted element of the distribution system with minimum de-energized load. It may involve opening of remotely controlled switching devices first and later, when the crew arrives, opening of locally controlled switches. With DER in distribution the fault isolation requires automatic disconnection of DERs feeding the fault [IEEE 1547]. If the directed relay protection is implemented, the faulted section can be isolated, while the DER connected to the healthy sections of the feeder remain connected to an electric island. The behavior of the DER in the island depends on the load-generation balance. The island situation should be recognized by ADA applications and by the operators. Measurements of frequency and voltages from the islanded portion of the system are needed to recognize the island situation [32, 33].

The service restoration objectives are as follows:

- Minimum number and duration of customer interruptions due to the fault
- Minimum switching operations
- Minimum losses after reconfiguration

The Constraints

FLIR is constrained by the following operational parameters:

- Loading of distribution facilities
- Voltages at customer terminals
- Loading of transmission facilities
- Voltage angle differences for adjacent transmission buses
- Demand response limitation
- DER operational limitations
- Electric storage discharge limitations

The Controllable Variables

In the Smart Grid environment, the controllable variables for FLIR are as follows:

- Switching devices within T&D substations
- Switching devices in distribution feeders
- Switching devices in DER Points of Common Coupling
- Switching devices of individual DER
- Demand response direct control triggers
- Setpoints of DER controllers
- Setpoints of micro-grid controllers
- Setpoints of customer EMS
- Reliability price signals.
- Synchronization switching devices

It is assumed here that the VVWO application will be automatically involved by FLIR, if needed for Volt/Var and phase angle support.

The function is initiated by the Fault Indication sub-function. Then, it performs fault location based on available information, a significant portion of which can be provided by the AMI applications, and DER information gateways. Based on the fault location, it performs fault isolation, after which it derives the best solutions for partial service restoration for the time of repair. After the completion of repair, the application provides the solution for return to normal. The solutions provided by the application can be executed either in authorized close-loop mode, or by the operator based on the advisory mode of the application.

The generated switching orders are based on considering the availability of remotely controlled switching devices, feeder paralleling, DER involvement, and creation of intentional islands supported by distributed energy resources. The solutions are dynamically optimized based on the expected operating conditions during the time of repair. When considering the alternatives for service restoration sustainable during the time of repair, the load-generation balance in the created electric islands should be analyzed. In some islands, in some times, load shedding may be required. The application should analyze the sustainability of the island, the amount of the shed load and compare it with other alternatives, which may have less disruptive implications. The information support for such analysis should include the load forecast for the islanding portions of the systems, the parameters of the automatic load shedding and/or load controlling schemes [34, 35].

The benefits of FLIR corresponding to the FLIR objectives are presented in Table 1-4.

Table 1-4
Objectives and benefits of Fault Location, Isolation, and Service Restoration application

Objective	Benefits
Most accurately identifying, in minimum time, the location of the fault.	Reduction of outage time, resulting in reduction of customer losses due to the fault and in reduction of utility expenditures on SAIDI reduction by other more expensive means.
Fault isolation by de-energizing the faulted element of the distribution system with minimum de-energized load.	Reduction of the number of de-energized customers and the duration of interruptions, resulting in reduction of customer losses due to the fault and in reduction of utility expenditures on SAIDI reduction by other more expensive means. Increased safety.
Minimum increase of the number and duration of customer interruptions due to the fault.	Reduction of the number of de-energized customers and the duration of interruptions, resulting in reduction of customer losses due to the fault and in reduction of utility expenditures on SAIDI reduction by other more expensive means; and deferral of distribution upgrades. Involving DER and Microgrids in service restoration reduced the number and duration of customer interruptions.
Minimum switching operations	Increased reliability of service, reduction of duration of interruptions. Involvement of DER and Microgrids into service restoration prevents from load transfers to remote feeders and reduces the number of switching operations.
Minimum losses after reconfiguration	Increase of efficiency of operations. Generating power by DER closer to the load reduces the losses in the abnormal topologies.

Significant Frequency and/or Voltage Deviations in Bulk Power Systems

By significant frequency and voltage deviations in the bulk power system we mean here frequency and voltage distortions that can happen, when a portion of an interconnected power system is islanded during a developing emergency situation in the interconnection. The self-healing concept of the Smart Grid implies intentional islanding in bulk power systems. When such an island is created, it may not have an exact match between the load and generation. In this case, the frequency and the voltages will deviate from normal, which may cause the disconnection of DERs in distribution. Significant penetration of DER in distribution may account for 15-20% of the island load. If such amount of generation is lost, the frequency and voltage can drop to unacceptable levels, and the entire island may experience a very severe emergency situation, resulting is significant loss of load. To foresee such situations, when considering the islanding option, the corresponding EMS application should include the expected behavior of the DER and microgrids during the alleged contingency. The information needed to analyze the behavior of the DER and microgrids is as follows:

- Expected power mismatch in islands without separation of DER and micro-grids
- Characteristics of the frequency dynamics in the islands
- Characteristics of the voltage dynamics in the islands
- Load characteristics in the islands
- Generation tolerances in the islands
- Transmission tolerances in the islands
- Distribution tolerances
- Current DER injections
- DER capacity under emergency conditions
- Placement, real-time status, and settings of protection of DER devices for parallel and island operations , including
  - Under-frequency
  - Over-frequency
  - Under-voltage
  - Over-voltage
  - Over-saturation
  - Rate of change of frequency
  - Other
- Conditions of DER islanding (contractual agreements)
- Expected power mismatch in DER-based islands
- Characteristics of frequency dynamics in DER-based islands
- Characteristics of voltage dynamics in DER-based islands
- Load characteristics in DER-based islands

Coordination of Emergency Actions

This application recognizes the emergency situation based on changes of the operating conditions or on reaction of some RAS to operational changes and coordinates the objectives, modes of operation, and constraints of other Advanced Distribution Automation applications. For example, Under-frequency Load Shedding Schemes trigger emergency load reduction mode of Volt/Var/Watt control, or the under-frequency protection of Distributed Energy Resources triggers the pre-armed intentional islanding. These are post-disturbance activities [4, 5].

The application shall include coordinating emergency actions between the RAS, DA applications, Distributed Energy Resources, Demand Response, Electric Storage, Electric Transportation, and microgrids.

Coordination of Restorative Actions

This application coordinates the restoration of services after the emergency conditions are eliminated. For example, advanced DMS changes the order of feeder re-connection, after they have been disconnected by the RAS, based on current customer priorities or inhibits return to normal voltage until there are disconnected feeders [4, 5].

The application shall include the following:

- Restoration of loads disconnected by RAS coordinated with the dynamically changing availabilities provided by the transmission, generation and distribution systems.
- Restoration of loads changed by DA applications and Demand Response to normal levels based on the dynamically changing restorative operating conditions
- Re-synchronization of Distributed Energy Resources and micro-grids based on the post-contingency operating conditions.

There is a number of planning function involving DA applications. Implementing the advanced DA functions to their maximum extent will require optimal allocation and prioritization of controllable equipment in the distribution system (automated switching devices, controllable capacitors, voltage regulators, demand response installations, DER installations with specific capabilities, etc.). These planning activities cannot be accomplished without knowing what is expected from the DA applications, because different stakeholders may have different dominant objectives and other requirements for these applications. The benefits of such comprehensive planning will materialize through better coordinated utilization of all means of distribution operations optimization.

Functional Integration of ADA Applications with EMS

The ADA applications can provide the EMS Bus Load Forecast application with information including the impacts of DER on the components of the model, as it is presented in the description of the DOMA application. The available at the T&D bus dispatchable real and reactive loads due to all available means in the distribution, which include active DERs, Electric Storage, Demand response, and VVWO, with the associated incremental cost of these means, can be used by the EMS OPF, Security Constrained Dispatch, Contingency Analysis, and other applications. [36]. A high-level illustration of the information exchange between the ADA and EMS is presented in Figure 1-56 [4].

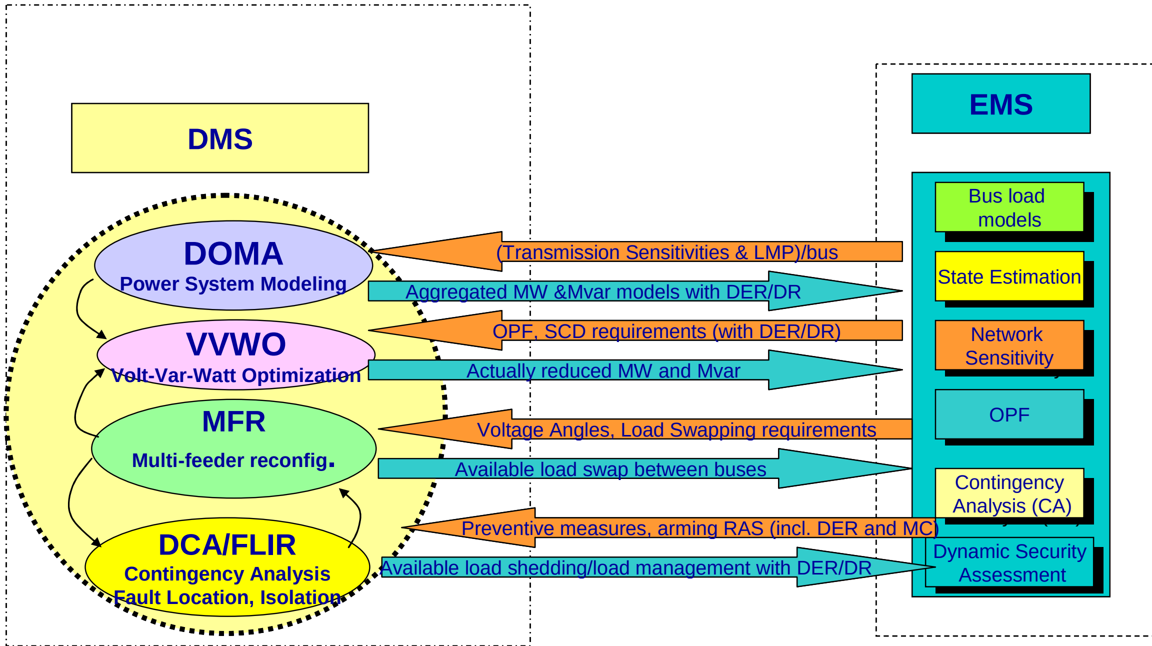

Figure 1-56
Information exchange between DMS and EMS for dynamic optimization of power system operations

2
THE EXISTING SYSTEMS AND THE INFORMATION EXCHANGE BETWEEN OPERATIONS AND END-USE SYSTEMS

In the discussion on the information exchange between the utility and other parties and DER systems, we will focus on the attributes of the object models needed for monitoring and control of system operations with significant DER. There are many other attributes of the DER object models addressing the designs and a number of internal properties of the DER system used for other than operational purposes.

The existing state of information exchange between the utility and DER will be addressed in this Chapter on the conceptual level. The existing attributes of the object/data models will be presented in the next Chapter side by side with the future attributes for better comparison and realization of the gaps between the existing and the future states.

Information Exchange with Stand-alone DER

Comparatively large DER (e.g., 250kVA and larger) can be either utility, or customer owned.

Utility Owned DER

As required by IEEE 1547, each DR unit of 250 kVA or more, or DR aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output and voltage at the point of DR connection. These are the currently minimum requirements. They may be not sufficient for the Smart Grid operations. Therefore, when many utilities are evolving into the Smart Grid environment, the existing state of information exchange between different utility entities (predominantly TransCos, and DisCos) and utility owned DERs is rapidly changing. There are utilities, where no real-time information exchange is implemented, and there are utilities, where the large DERs are treated almost the same as other generators of small sizes. The existing metering and communication technology does not prevent from providing information exchange between the utilities and large utility-owned DERs like the designs described in [37, 38].

In these designs, the DER Gateways (RTU, DER controller or Smart Meter) selectively provide the following near-real-time data to the utilities:

- KW in
- KW out
- Kvar in
- Kvar out
- Volt
- Wind speed
- Wind direction
- Pressure
- Humidity
- Ambient temperature
- Global horizontal radiance
- Direct radiance
- Panel temperature
- Breaker/inverter status
- Solar panel strings monitoring
- On-site energy storage status
- Command and control status
- System and component failure alarm notification
- KWh in, in given time intervals
- KWh out, in given time intervals
- Kvarh in, in given time intervals
- Kvarh out, in given time intervals
- Sag, swell, flicker, harmonics, in given time intervals.

All data should be accompanied with data-quality indicators. In addition the DER Gateway provides on-site historic data storage. The Aggregate Reactive Capability Curve (D-Curve) should be provided.

The following control can be executed in the "Command and Control" fashion:

- Command and control of statuses with synchronization, if needed
- Volt/Var control
- Ancillary service
- On-site energy storage control

Presently, the information exchange is supported by DNP 3.0 or ICCP [38] with a 10 sec or less periodicity. The work on development and implementation of IEC 61850, IEC 61970/61968 for the information exchange with DER and about DER in the future is in progress in a number of Standard Development Organizations.

The following additional requirements for information support are currently specified for the existing wind farms in [38]:

- Ramp-up and ramp-down times
- The Wind Power Forecaster requires several data points from the wind farms to accurately forecast the wind power.
- General Turbine Information
- Class of turbine
- Capacity of turbine
- Power Generation Threshold Rates (i.e. minimum / maximum wind speed)
- Manufacture Power Curves of individual wind turbines
- Geographic location (longitude and latitude) of wind farm site or each turbine if available
- Hub height of wind power facility
- Aggregate Historic data (measured MW output, outage information, and wind speed at hub height)
- Ambient Temperature Operating Limits.

Large Customer-owned DER

If a large customer-owned DER participates in the energy or ancillary service markets, the information support requirements are the same as for a utility-owned DER. The procedures for the control of the customer-owned DER may be different and may involve a third party (Aggregators). If the DER is not a market participant, then the minimum requirements of IEEE P1547 apply. In addition to the real-time measurements, if any, the owner of the DER provides the utility with the operation and maintenance schedules of the DERs. The nominal operations of the large customer-owned DER are typically defined by the contract between the DER owner and the utility, with provisions for deviations of the nominal operations in extreme situations. The "Inform and Motivate" style of control is the most probable agreement between the utility and the customer. The customer may have its objective for operating the DER, which may be different from the utility objectives. In this case, the customer will compare the value of the local objective with the utility motivation. With the evolvement of real-time pricing, the customer-owned DER may operate dependent on price, if so agreed upon with the utility. Therefore, the forecast of the operations of the customer-owned DER has a high degree of uncertainty.

In many cases, the customer-owned DER (as some of the utility-owned) nave limited, or not at all, capabilities for remote control of reactive power and do not support an adequate object model of the DER needed for the flexibility of operations in the Smart Grid environment.

Technology-wise, all available information from the DER controllers or other data concentrators can be obtained at the present time through SCADA or other available interfaces, if supported by the owner. In the most of the cases, the DER gateways are not compatible with the interoperability standards.

Information Exchange with In-load-embedded DER

Passive DER Without Var Control

Passive DERs are the ones, which generated kW depend on external conditions and cannot be controlled by the user, except by switching the DER ON or OFF. Typically, these are small DERs, like residential photovoltaic installations. The common case of current information exchange with these DERs is defined by the interconnection contract. The periodic (monthly) readings of the net energy through the meter at the customer terminals are the most common source of information. Some utilities install bi-directional meters for customers with the PV system size above 10 kW [27]. With installation of the Smart Meters, there are greater possibilities of information exchange between the customer and the utility.

Passive DER With Var Control

At the present time it is not common to install small converter-based DER with var-controlling capabilities.

Active DER (Combined With DR)

Customer-owned active DER (e.g., micro-turbines, fuel cells) can change both real and reactive power. The active DERs are mostly used in commercial and industrial installations and are controlled for the customer external use. The information exchange between the utility and the DER owners is typically limited to the energy measurements at the common point of connection. The operations of the DERs in response to utility "Inform and Motivate" message are often combined with Demand Response measures based on the customer preference.

Information Exchange With Microgrids.

Currently, the micro-grids are in the stage of demonstration projects, and no established procedures for the information exchange exist. The IEEE P1547.4 standard governs the current interconnection requirements for micro-grids.

3
THE FUTURE STATE OF THE SYSTEMS AND INFORMATION EXCHANGE BETWEEN OPERATIONS AND END-USE SYSTEMS

In this chapter, we will discuss the object models, major actors, and logical interfaces pertinent to the information exchange with DER.

The Object Models

In this section we will address the load models with embedded DER, the Demand Response model due to their close association with DER, and the DER/microgrid models. The discussion will include the current possibilities for modeling these objects and the requirements for the models to be used in the Smart Grid environment. The expected impact of the recommendation on the benefits is also presented.

Most of the data objects models involved in the ADA applications are described in [4, 5, 7 and 10]. In this section we will discuss data objects, for which the use of information exchange with DER may significantly increase the accuracy of the monitoring applications and the efficiency of controlling applications.

It must be noted that the models for advanced DA applications must reflect not only the current state of the object under current conditions, which can be measured. The models must support the states of the objects in the look-ahead timeframes and the changes of the states dependent on changing conditions. These future states under different from current conditions cannot be measured. However, the models of the 'what-if" states can be derived a) from the historic data measured by DER and microgrid controllers and collected by DSCADA, by Customer EMS, and by the Smart Meters; b) from DER object/data models stored partially in the DER controllers, in the DER Data Management System, in the Asset Management System, and other corporate databases; c) forecasts of external dominant factors like weather systems, market conditions, etc.

Table 3-1
Nodal load model requirements pertinent to the information exchange with DER

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Number of customers connected to the node	Provided by GIS/CIS	Provided by GIS/CIS/AMI/DER Data Management Systems, aggregated at the PCC of microgrids. In case of DER separation from the utility with customers (micro-grids or pseudo micro-grids) the estimated number of de-energized customers is needed.	More accurate assessment of the service reliability
Load category/cluster	Based in the dominant load category defined by experts	Assuming that AMI is implemented, there will be more and better refined load clusters based on aggregation of similar individual load profiles and impacting factors. Customers with DER generation and/or storage embedded in the customer loads should be defined in sub-categories/clusters with the behavioral dependencies of the DERs.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications
Typical load shapes for different times	Generalized load shapes per load category	Assuming that AMI is implemented, there will be more accurate representative load shapes dependent on impacting factors, which will include the factor impacting the operations of embedded DERs.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications
Scaling factors	Monthly average based on billing data for shifted monthly intervals	With the DER embedded in the customer loads, the scaling factors will be derived from the net load measurements for smaller time intervals. More accurate scaling factors will be derived from data provided by smart meters, if the load and DER generation is measured separately.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications
Power factor shapes or reactive load shapes	Expert estimates, typically constant values across the load profile	Similar to real load models with embedded DERs	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications

Table 3-1
Nodal load model requirements pertinent to the information exchange with DER (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Confidence factor for State Estimation	Expert estimates, based on load category	Confidence factors will be assigned based on the estimated accuracy of the methodology for load modeling taking into account the confidence levels of the component input data. For instance, load models dependent on the weather forecast, which will include the uncertainty of cloudiness and/or wind forecasts will have lower confidence factors.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications
Schedules of load-to-voltage dependencies separate for real load and reactive loads	Expert estimates based on field tests for a small number of selected buses or feeders	The dependency of the net load with embedded DERs on voltage will consist of two components: the base real and reactive load dependencies and the DER real and reactive generation dependencies. The DER dependencies will be different for different modes of reactive power control (PQ, PV, Q-max, Q=0, V-override, etc.) and for different positioning of the initial operating point of DER relative to the capability curve.	More accurate specific and aggregated load-to-voltage dependences; More accurate assessments of DA application benefits; more accurate optimization of voltages, vars, and Watts; more accurate assessment of dispatchable load.

Table 3-1
Nodal load model requirements pertinent to the information exchange with DER (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Incremental rate	Based on average rates for the load category	With the embedded DER in the customer loads, the individual incremental rates may be dependent on the operations of the DERs. In a case of a progressive rate schedule, the rates can be lower when the DER is generating power, and higher, when it is not. Also, it can be assumed, that if a DER is able to generate and/or absorb reactive power, and the utility provides incentive to the customer to control the reactive power for the dynamic optimization of the distribution operations, the price may be different.	More accurate assessment of the cost of operations; more accurate optimization of operating conditions
Power quality requirements	Standard voltage tolerances for different load categories; No higher harmonics, voltage sags; momentary interruptions addressed	Individual voltage quality requirements associated with the customer choices of power quality, if approved by the utility, including the power quality requirements at the PCC of the DER or Microgrid. These requirements include higher harmonic limits, DC component limit, sags and swells. Voltage deviations, higher harmonics, voltage sags/swells, and momentary interruptions can be monitored by Smart Meters, customer EMS, and DER controllers, if so designed. The challenge for the power quality monitoring and analysis at the PCC is determining whether the violation of the power quality is caused by the DER embedded in the load behind the PCC, or it is propagated from the utility side, or both.	More accurate assessment of power quality and its sources of distortion. Better voltage quality due to better optimization of the operating conditions based on more comprehensive information; better customer satisfaction.
Penalties (cost) for power quality violations to be used in the assessment of power quality and in the dynamic optimization of the operating conditions.	Expert estimates based on the utility policy on power quality	Individual contractual agreement between the utility and the customers, including the obligations of the owner of the DER according to the rules of interconnection and the particular requirements of the DER for proper operations, if any. For instance, significant imbalance of voltages in a three-phase PCC may reduce the capability of the DER	Better customer satisfaction; safer use of Volt/Var control for load reduction; more accurate assessment of power quality; additional benefits from relaxed power quality requirements.

Table 3-2
Attributes of Demand Response model related to DER embedded in the customer loads

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Demand Response capacity function for loads with embedded DER	An expert estimate of the percentage of initial load at the moment of application of the Demand Response dependent on triggering (price) signal	With embedded passive DER, the customer's base for demand response depends on whether the DER is generating and how much. With an embedded active DER, including electric storage, the demand response base is also dependent on the initial operations of these devices, and the demand response capacity is dependent on the ability of additional generation from the active DER and willingness of the customer to include it in the demand response commitment. These conditions can be defined in the contract between the utility and the customer and exercised in near-real time depending on the current conditions. Under a particular condition, the Demand Response can be executed by starting a DER or by discharging an Electric Storage. Under another condition, the Demand Response can be executing by controlling the thermostat and changing the cycling of an appliance. The patterns of these cases will be different: In the former case, the load reduction will be a continuous value, while in the latter case it will impact the diversification of many cycling loads in the neighboring area. There may be a combination of both cases. The actual execution of the Demand Response can be monitored by Smart Meters connected to appliances via HAN, by the customers EMS, and by the DER controller. For load model of the distribution transformer feeding several customers, the individual models shall be aggregated.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications with integration of DER.

Table 3-2
Attributes of Demand Response model related to DER embedded in the customer loads (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Demand Response Triggers	Different "price" levels can be associated with different percentage of aggregated load under demand response	The triggers (price signals) for enabling the Demand Response may be different for starting a DER, discharging an Electric Storage, or for changing the cycling of a load. These triggers can be different under different conditions of the composite customer demands. The ADA applications should be informed about the near-real-time and short-term look-ahead triggers, which are capable of enabling a particular amount of Demand Response. The individual demand response programs and current specifics of the program can be made known to ADA through the AMI and customer EMS information interchange with ADA; if aggregated load models are used, corresponding aggregated demand response models shall be developed. These models can be built based on collected individual information, presenting the aggregated demand response as a function of different triggers.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications.
Demand Response time delay	From experience with direct load control, if any.	The behavioral model of demand response shall also include the time delay of execution after the trigger is issued. The time delays for changing load cycling are different from the time delay to start a DER, which, in turn, may be different from starting discharge of an Electric Storage. These time delays should be associated with currently available combination of the committed components of Demand Response. These attribute can be derived from the contractual agreements and verified from the statistics collected via AMI/EMS during the actual utilization of the Demand Response with DER.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications.

Table 3-2
Attributes of Demand Response model related to DER embedded in the customer loads (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Cost of implementation of Demand Response	N/A	The behavioral model of demand response shall also include the cost (incentives) of the demand response. The incremental cost components of every controllable variable are included in the objective functions of the ADA applications performing the dynamic optimization. With the variety of execution of Demand Response with embedded DER, the price (inconvenience) of the demand Response will be different for different patterns of execution. These incremental costs of composite Demand Response, if any, can be derived from the Demand Response and DER Data Management Systems, supported by interactive communications between the customers, the utility, and other relevant parties. Sometimes, the cost of execution of a particular component of Demand Response at a particular time may depend on the expected operations at another time. For instance, if the Electric Storage is discharged at the present time, and the probability to recharge it for a low cost, or at all, before it will be needed again, is small, the current cost of it usage should be higher.	More accurate assessment of the cost of operations and of the benefits from implemented demand response; better justified optimizations of the use of Demand response and DER by ADA applications.
Controllability of Demand Response with embedded DER by ADA applications	N/A	The triggers for enabling the demand response of a particular amount in selected nodes should be generated by ADA applications depending on the trigger thresholds for different portions of demand response. For instance, the cost of enabling the Electric Storage is ‘x,’ and it provides ‘X’ kW, and the cost of starting the DER is ‘y’ > ‘x’, and the DER can provide ‘Y’ kW. The utility needs ‘Z’ kW, where ‘Z’ > ‘X’. Hence, the trigger ‘z’ should be greater than ‘y’.	Greater benefits of the optimizing DA applications due to integration of Demand response with embedded DER into the applications.

Table 3-2
Attributes of Demand Response model related to DER embedded in the customer loads (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Contractual constraints of Demand Response with embedded DER	N/A	The behavioral model of demand response with embedded DER shall also include the conditions under which the DER can be used for the Demand Response purposes. For greater certainty of the behavioral models, the operational conditions should be included in the contracts between the customer and the utility or other relevant party to the maximum extent. This information can be made available to the ADA from the Demand Response and DER Data Management Systems, also supported by AMI.	More accurate load models; more accurate results of power flow; more accurate optimization of the operations by DA applications.

Table 3-3
Attributes of Distributed Energy Resources and Microgrids Models

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Type of DER	Available in Asset Management or in Customer System or in Customer Information System	Available from DER Data Management System or DER object model embedded in the DER controller	No difference
DER rating information, including capability curves and droop characteristics for voltage and frequency control.	Available for utility-owned DER from the corporate databases. Limited knowledge of customer-owned DERs	Can be made available for customer-owned DER from the DER Data Management System supported by AMI and from customer (CEMS) or DER controllers	More accurate results of state estimation and power flow; more accurate models of micro-grids and more accurate optimization.
Cost curves for real power generation, if any	Input/Output curves, efficiency factor curves for fuel-based DERs	Incremental cost or price curves, if applicable. Opportunity cost (if the utility constraints the generation of real power by a DER, the customer loses some benefits of DER)	More accurate optimization of the distribution and customer operations
Cost (loss) curve for reactive power generation/absorption	N/A	Cost of losses due to reactive power and opportunity cost of reactive power, if constrained by required vars.	More accurate optimization of the distribution and customer operations
Generator status, ON/OFF	Available for utility-owned DER from the corporate databases, sometimes from SCADA. Limited knowledge of customer-owned DERs	Can be made available for customer-owned DER from the DER Data Management System supported by AMI and customer EMS (CEMS). For large DER can be made available from DER controllers.	More accurate results of state estimation and power flow; more accurate models of micro-grids and more accurate optimization.
Generator status control, available/unavailable	Sometimes available for utility-owned DER through SCADA	Can be made available via AMI and CEMS, based on contractual conditions between the utility and the customer, or based on agreed trigger (price) signals. For large DER can be made available from DER controllers.	Additional benefits of optimization due to integration of DER into DA applications.

Table 3-3
Attributes of Distributed Energy Resources and Microgrids Models (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Statuses of main interconnection switches of a microgrid	Can be made available if the switch is monitored by Distribution SCADA	Can be made available through AMI or CEMS via SCADA and through DER Data Management System. For large microgrids can be made available from microgrid controllers.	More accurate results of state estimation and power flow; more accurate models of micro-grids and more accurate optimization.
Ability to control statuses of main interconnection switches of a microgrid	Can be made available if the switch is monitored and controlled by Distribution SCADA	Can be made available through AMI or CEMS via SCADA and through DER Data Management System. For large microgrids can be made available from microgrid controllers.	Additional benefits of optimization due to integration of DER into DA applications
Actual power and energy flows through DER switches or main interconnection switches of microgrids	Can be made available if the switch is monitored by Distribution SCADA	Can be made available through AMI or CEMS via SCADA and through DER Data Management System. For large DERs and microgrids can be made available from DER and micro rid controllers.	More accurate results of state estimation and power flow; more accurate models of micro-grids and more accurate optimization.
Availability of controlling kW and kvar through the interconnection switches	N/A	Can be made available through AMI or CEMS (DER or Micro-Grid Controllers) and through DER Data Management System	Additional benefits of optimization due to integration of DER into DA applications
Actual Mode of operations and available modes of operations	Available for utility-owned DER from the corporate databases. Limited knowledge of customer-owned DERs	Can be made available from the CEMS (controllers) and from the DER Data Management System	More accurate results of power flow; more accurate models of micro-grids and more accurate optimization.
Availability of controlling actual mode of operations	N/A	Can be made available through AMI or CEMS (controllers) and through DER Data Management System	Additional benefits of optimization due to integration of DER into DA applications

Table 3-3
Attributes of Distributed Energy Resources and Microgrids Models (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Storage data, such as: Nominal capacity Current capacity Charge rate Discharge rate Time delay for connection/ DER-ES ramp rate Characteristics of ES controller Current cost of discharge	Pre-defined nominal data in corporate databases. Operational data estimated during calculations by the DA application	Can be made available from AMI, CEMS (controllers) and from the DER Data Management System	More accurate load and power flow models. More accurate prediction of DER-ES behavior during transient weather conditions [20].
Higher harmonic and THD at the DER terminals or at the PCC of a microgrid; sags, swells, flicker, in given time intervals	Based on interconnection requirements and selective surveys.	Can be made regularly available via AMI, or CEMS, or DER (microgrid) controller.	More accurate power quality analysis and more efficient mitigation of power quality violations. Higher harmonics characteristics as dependencies of operating conditions can be developed based statistics collected from DER information sources.
Relay Protection settings	Available for utility-owned DER from the corporate databases. Limited knowledge of customer-owned DERs	For the customer-owned DER, the object models including relay protection settings should be made available from the sites, where the object models reside, e.g., from the CEMS and/or from the DER Data Management System	More accurate results of contingency analyses, better reliability.
Indicators of relay protection actions	N/A	Available in near-real-time from the CEMS, DER information gateways.	More accurate results of fault location, better safety procedures

Table 3-3
Attributes of Distributed Energy Resources and Microgrids Models (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Auto-synchronizer parameters	Available for utility-owned DER from the corporate databases. Limited knowledge of customer-owned DERs	Can be made available from the CEMS (controllers) and from the DER Data Management System.	More accurate results of service restoration application, better reliability
Available points of synchronization	Available from SCADA database	Can be made available from CEMS, microgrid controllers, DER Data Management Systems	More accurate service restoration solutions
Contractual requirements, such as: Constraints imposed by non-electric parameter Limit on export Limit on import Power factor to provide by DER Distribution system voltage tolerance Obligations to provide ancillary services through other entities (aggregators) Penalties for violation of contractual agreements Other	Based on interconnection contract	Can be made available from the CEMS and from the DER Data Management System	More accurate power flow results, more accurate constraints of optimization, more accurate assessment of cost of production.
Incremental cost of DER production dependency on significant factors, such as: KW output Heat production Ambient temperature Other	Pre-defined cost curve dependent on kW output	Can be made available from the CEMS and from the DER Data Management System	More accurate optimization and more accurate assessment of cost of production

Table 3-3
Attributes of Distributed Energy Resources and Microgrids Models (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
DER kW, PF and Maintenance schedules	Can be defined for utility-owned and large customer DERs	Can be made available from the DER Data Management System and from CEMS	More accurate models and optimization for look-ahead conditions.
Weather conditions, such as: sun radiations, ambient temperature, wind speed, wind direction, humidity, atmospheric pressure	Can be defined for utility-owned and large customer DERs	Can be made available from the DER controller, CEMS, Smart Meters	More accurate behavioral models based on information from external systems
For PV DER: panel temperature; inverter status; solar panel strings state; on-site energy storage status	Available from utility DER if monitored by DSCADA	Can be made available from AMI and CEMS directly or through the DER Data Management System	More accurate behavioral models based on information from external systems
For wind farms: Ramp-up and ramp-down times; general turbine information; class of turbine; capacity of turbine; power generation threshold rates; manufacture power curves of individual wind turbines; geographic location (longitude and latitude) of wind farm site; hub height of wind power facility; ambient temperature operating limits.	Available from utility DER if monitored by DSCADA	Can be made available from AMI and CEMS directly or through the DER Data Management System	More accurate behavioral models based on information from external systems

Table 3-3
Attributes of Distributed Energy Resources and Microgrids Models (continued)

Attribute	Current State	Solution with Significant DER (Future State)	Possible Impact on the Benefits
Alarms and data-quality indicators	Available from utility DER if monitored by DSCADA	Can be made available from AMI and CEMS directly or through the DER Data Management System	More accurate alarm processing and higher reliability
Pre-processed data for microgrid object models: This information should support the modeling of the transient and sustained operations of the microgrid after and during separation from the utility network. The data should include the current generation and its dynamic characteristics; the generation reserves and its dynamics, the current loads and its dynamic characteristics; the available load management means and their characteristics; the parameters of the frequency, voltage, and other load shedding schemes, etc.	N/A	The non-real time information can be made available from the DER Data Management System. The real-time data can be derived from AMI and CEMS measured data.	More accurate modeling of distribution operations with connected microgrids. Better justified solutions for intentional islanding under abnormal operating conditions. Better relay protection coordination.

Major Actors

The major actors involved in the integration of DER with Distribution Automation are presented in Table 3-4.

Table 3-4
Major Actors

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
1	Distribution Operator	Person	Person in charge of distribution operations during the shift	The operator sets up the ADA applications, defining the objectives, the modes of operations, the contents of application results presented to the operator, provides certain input data, monitors the results of ADA applications, requests additional information, when needed, authorizes the ADA recommendations, makes decisions based on ADA recommendations, etc. Normally, the operator defines the options for the close-loop control in advance, but does not take a part in the close-loop control.
2	Distribution SCADA	System	DSCADA collects data from IEDs beyond the fence of the T&D substation and supports remote control of controllable devices in the field either in supervisory or close-loop modes. The field IEDs include utility DER and microgrid controllers, may include customer EMS.	Distribution SCADA database is a major source of input data for the ADA applications. It is updated via remote monitoring and operator inputs. DSCADA is used for execution of ADA application solutions either in supervisory, or in close-loop modes.
3	Transmission SCADA/EMS	System	SCADA/EMS collects data from IEDs within the T&D substation and supports remote control of controllable devices in the substation. The EMS runs the applications for analysis and control of the transmission and generation systems.	Transmission and generation management system providing ADA with transmission/generation-related objectives, constraints, and input data. EMS system contains the transmission power system model, and can provide the transmission connectivity information for facilities in the vicinity of the distribution power system facilities and with outputs from other EMS applications.

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
4	Aggregator/ Energy Services Company	Company	A person or company combining two or more customers into a single purchasing unit to negotiate the purchase of electricity from retail electric providers, or the sale to these entities. The transaction may include electricity consumption and demand, DER/microgrid generation, Demand Response "Nega-watts", and ancillary services. Aggregators also combine smaller participants (as providers or customers or curtailment) to enable distributed resources to participate in the larger markets.	The agreement between the customers and the Aggregators, if approved by the utility, define the conditions under which the DERs will operate during pre-defined times, and the operational tolerances for control of these devices, if any.
5	3rd Party, External Systems (e.g. Weather)	Systems	Public information systems outside the utility, provides the utility with information on weather and major event relevant to utility operations.	The information obtained from these systems is used by the modeling components of ADA for adjustment of the behavioral models. This information is most important for the development of the models of weather-dependent DERs.
6	DMS	System	A set of integrated IT systems and ADA applications supporting the operations, maintenance, and planning of the electric distribution system	ADA applications are a central component of DMS, being supported by DMS corporate databases, such as AM/FM/GIS, and interfaced with other IT systems, such as OMS and WMS.
7	DMS Gateway	Sub-system	Computer-based system consisting of Graphic User Interface, interface with distribution SCADA, and ADA applications	Accepts, checks, and organizes information obtained from DSCADA, Operators and other authorized personnel and triggers ADA applications according to the given setups. Accepts output information from ADA applications and initiates execution of their instructions.

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
8	Customer EMS	System	A customer supplied system for monitoring and managing energy use at their residence or business. It includes human interface displays for interacting with the system and allows the customer to program functions, control loads, and display energy costs, usage, and related information. It can be programmed to take action based upon price inputs or event messages from the utility, or changes to customer's load. Interfaces with Home Area Network (HAN) or Building Automation devices and may integrate with the Smart Meter [37]	Measurements and storage of aggregated data from Smart Meters: kW and kvar kWh Load profiles Interval average voltages Instantaneous voltages Instantaneous frequency Weather data. Services: DER monitoring and control functions Demand Response functions Information for customers and third parties Communications with HAN and Smart Meters
9	DER controller/gateway	Device	Measures, stores and communicates current generation, generation schedules, capability curves, protection settings, mode of operations and Volt/Var control settings, and other data needed for current and predictive model of DER operations	Communicates with DER Data Management System or other systems dedicated to manage DER and with DA applications. Supports control of frequency and voltages if included in an intentionally created electric island.
10	Microgrid interconnection controller in PCC	Device	Calculates, stores, and communicates aggregated load, Demand Response, Generation data for the microgrid, Protection settings and settings for frequency and voltage control for connected and for autonomous modes of operations, other data needed for current and predictive model of microgrid operations.	Communicates with Data Management System or other systems dedicated to manage microgrids and with DA applications. Supports control of frequency and voltages in autonomous mode of operations.

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
11	Smart Meter	Device	Advanced electric revenue meter capable of two-way communications with the utility. Smart meters may also serve as an internetworking gateway between the utility, customer site, and customer's load controllers. Measures, records, displays, and transmits data such as energy usage, generation, text messages, and event logs to authorize systems and provides other advanced utility functions [37].	Measurements and storage of: kW and kvar kWh Load profiles Interval average voltages Instantaneous voltages Instantaneous frequency Weather data. Services: Last Gasp/AC Out Demand Response functions Information for customers and third parties Communications with HAN
12	Customer appliances, with embedded controls integrated with customer premises networks	Devices	Equipment and systems at the customer site that could participate in demand response and other programs	Components of behavioral load models for ADA applications

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
13	DER, PEV, and Electric Storage embedded in customer premises	Devices	Equipment and systems at the customer site that could participate in supply of the local load, in demand response, and other programs	Components of behavioral load models for ADA applications
14	AM/FM/GIS	System	Repository of distribution system assets, their relationships (connectivity), ownerships, nominal states, and links to associated objects.	AM/FM system contains the geographical information of the distribution power system circuit connectivity, as well as the parameters describing the power system facilities, including all electric characteristics of distribution transformers, as well as circuit connectivity and parameters of secondary circuits between the distribution transformers and customers or their equivalents consistent with voltage drops and power losses. Conceptually, the AM/FM/GIS database can contain transmission connectivity and facility data and relevant to distribution operations customer-related data. AM/FM/GIS databases is interfaced with the Customer Information System for linkage between the customer data and point of connection, with AMI, DER, and DR Data Management Systems for updates of secondary circuit equivalents, and behavioral models of load, DER, ES, and DR. Alternative interfaces between these Data Management Systems and ADA are possible. AM/FM/GIS databases are also accessible to field crews via mobile computing for updates on facility connectivity and parameters. The AM/FM/GIS databases shall be updated, proof-tested and corrected in a timely manner to provide a high probability of preparedness for supporting near-real-time ADA applications.

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
15	Connectivity and facility parameters validation processor	Process	GIS information should be validated on two levels: 1) validation of connectivity and distribution transformer loading, and 2) integrated validation on operational reasonability.	The first level of validation can be performed by analyzing the consistency of connectivity (de-energized elements, loops, wrong phasing, etc.) and by analyzing the consistency of customer association with the distribution transformers and of its loading. The second level of validation is based on the consistency of the power flow and contingency analysis results with the utility policies.
16	Customer Information System (CIS)	System	Customer information including billing data, customer types, links to distribution circuits	CIS communicates with AMI, DER, and DR Data Management Systems. It contains consumption and demand data on per customer basis for pre-defined time intervals of measurements by the Smart Meters, as well as composite data for billing periods. It also contains information on other customer properties, like customer type, rate schedules, etc.
17	DER Data Management System	System	A specific database for DER attributes, behavioral models, contracts, and performance associated with the owner.	DER Data Management System is interfaced with AMI Data Management System, Aggregators, with the Load Management System, and with the ADA applications providing DER behavioral models.
18	AMI Data Management System	System	Gathers, validates, estimates, and permits editing of meter data such as energy usage, generation and meter logs. Stores this data for a limited amount of time before it goes to the Meter Data Warehouse and makes the data available to authorized systems [11]. Includes load model processor and secondary equivalent processor.	Derives aggregated at the distribution transformer load profiles Communicates either directly or through a network Management system [11] with the Smart meters Communicates with DA applications Provides ADA with behavioral load models.

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
19	Load Management/Demand Response System	System	Executes and monitors requested demand response resources. Sends out demand response event notifications to Smart Meters and customers [37]. Controls DR, DER, PEV and ES charging/discharging.	Executes ADA commands for aggregated load control, is interfaced with the Aggregators, and ensures execution of the market-related contracts.
20	Demand Response Data Management System	System	Stores and processes data on load management/Demand Response programs, contracts, relevant historic information, creating behavioral models for Demand Response.	Is interfaced with AMI Data Management System. Communicates with Load model processor; Communicates with ADA applications.
21	DOMA	Application	Distribution Operation Model and Analysis is an advanced DA application. It runs periodically and by event; models near real-time power flow; Provides situational awareness of distribution operations; Provides background models for other ADA applications.	Utilizes behavioral nodal load, DER microgrid, and PV models and secondary equivalents. Communicates with AMI, DER, and DR Data Management Systems.
22	VVWO	Application	Volt/Var/Watt Optimization is an ADA application. It runs periodically and by event; optimizes states of voltage, var, DER, microgrid controllers, and Demand response means;	Communicates with DOMA, Demand Response/Load Management System, Customer EMS, and with interconnection controllers at the PCCs.
23	FLIR	Application	Fault Location, Isolation, and Service Restoration. An ADA application. Identifies and locates the fault, isolates the faulted element from healthy sections and restores services to the customers connected to the healthy sections. Assesses, for the duration of repair, the situation with loads, DER, Demand response and microgrids	Communicates with DOMA, Demand Response/Load Management System, Customer EMS, and with interconnection controllers at the PCCs.

Table 3-4
Major Actors (continued)

#	Actor	Actor Type	Description	Functionality Related to ADA Applications
24	Field Crew	Persons	Manual operations of field devices, repair, construction work, patrolling and other assignment in the field	Field crews are able to communicate with the distribution system operator and with GIS management via mobile communications and computing
25	Market Operation System (MOS)	System	Wide-area energy market management system providing high-level market signals for DisCos	Market for energy products, including bulk generation, distributed generation, electric storage, electric transportation, and demand response.
26	ISO/RTO	Systems	ISO: An independent entity that controls a power grid to coordinate the generation and transmission of electricity and ensure a reliable power supply. RTO: An independent organization that coordinates, controls, and monitors the operation of the electrical power system and supply in a particular geographic area; similar to Independent System Operator.	Issues aggregated load management requirement to EMS/DMS/Operators;
27	Engineering	Person	Planning, and DMS maintenance personnel, power quality and reliability engineers, etc.	Recommends setups of ADA applications, monitors performance of ADA applications, troubleshoots applications, reviews report, etc.

Logical interfaces supporting DER-related information exchange

Meeting the Smart Grid requirements will require development of standard object models and interfaces between different information sources. High level interface diagrams were developed in the Report to NIST on the Smart Grid Interoperability Standards Roadmap (see Figure 3-1). The more detailed diagram of logical interfaces between actors involved in ADA applications with DER is presented in Figure 3-2. This diagram includes all interfaces and aggregated actors presented in the Figure 3-1 and additional disaggregated actors and interfaces reflecting the information exchanges in more details.

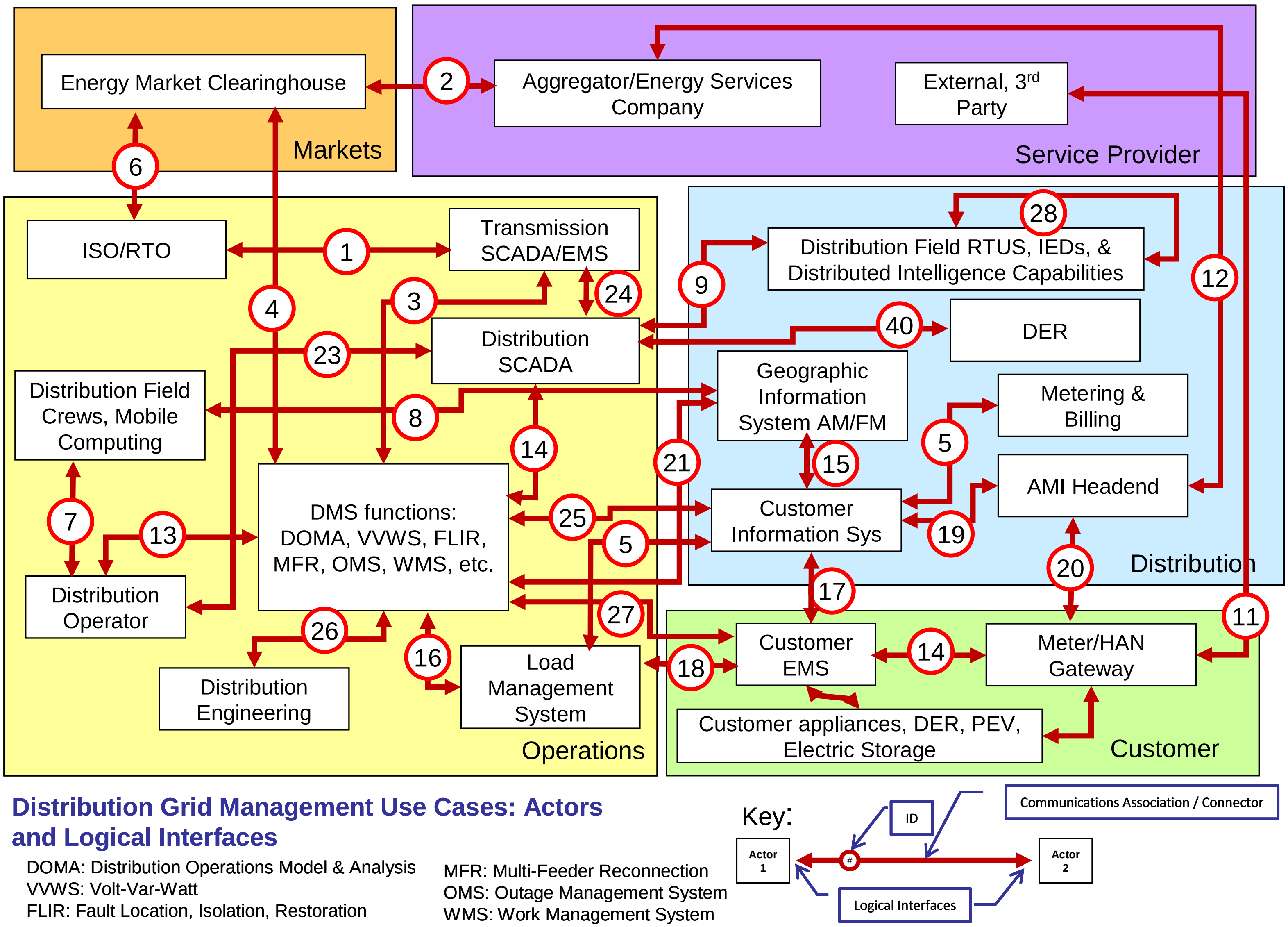

Figure 3-1
Logical Interfaces and Aggregated Actors for Distribution Grid Management with customer and utility DER

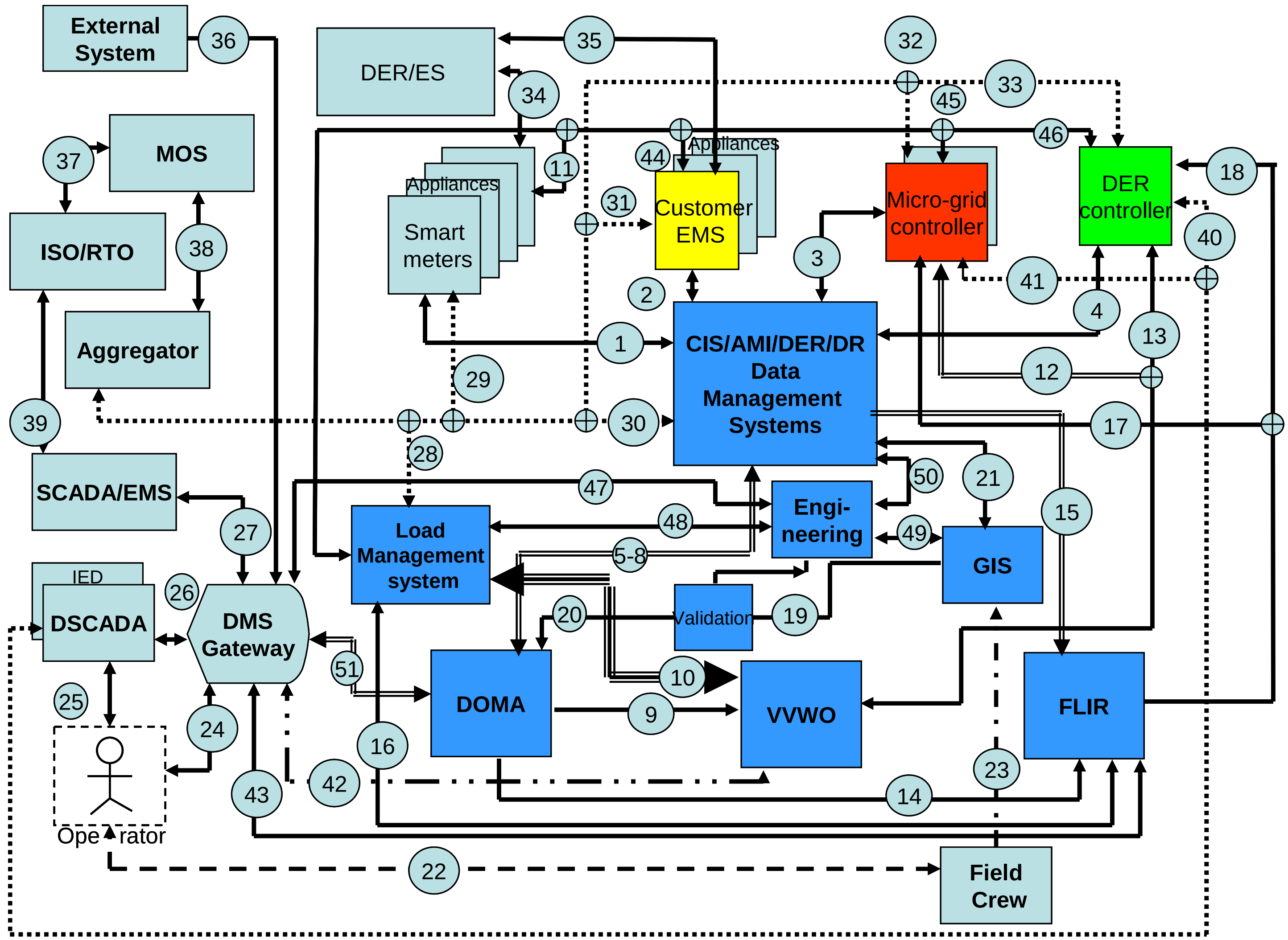

Figure 3-2
Major actors and interfaces involved in information exchanges between ADA and DER.

Table 3-5
Attributes of Information Exchange Between Major Actors

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
1	Smart Meter	AMI Data Management System (including Last Gasp service)	kW and kvar kWh Load profiles Interval average voltages Weather data Demand response triggers received with timestamps; Commands issued for Demand Response (thermostat, appliances, DER, Storage).	Large	Once a day	Revenue accuracy for kW and kvar; 0.5%-0.2% accuracy for Voltages
1	Smart Meter	AMI Data Management System	Instantaneous voltages Instantaneous frequency from dedicated meters in autonomous mode of microgrid Last Gasp/AC Out	Small to average	Last gasp - immediately from selected first-reporters; Instantaneous voltages within minutes after fault; Instantaneous frequency from dedicated meters – report by exception	0.5%-0.2% for Volt; 0.1% for Hz

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
1	AMI Data Management System	Smart Meter	Real-time prices Demand response triggers and amount Data requests	Small to average	Immediately after change	
2	Customer EMS	AMI Data Management System	Aggregated from Smart Meters: kW and kvar kWh Load profiles Interval average voltages Weather data. Demand response triggers received with timestamps; Commands issued for Demand Response (customers' Smart Meters, thermostat, appliances, DER, Storage).	Small to average	Once a day	Revenue accuracy for kW and kvar; 0.5%-0.2% accuracy for Voltages
2	Customer EMS	AMI Data Management System (including Last Gasp service)	Lowest instantaneous voltages from included Smart Meters Instantaneous frequency Last Gasp/AC Out from selected Smart Meters	Small to average	Last gasp - immediately from selected first-reporters; Instantaneous voltages within minutes after fault; Instantaneous frequency – report by exception	0.5%-0.2% for Volt; 0.1% for Hz

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
2	AMI Data Management System (including Last Gasp service)	Customer EMS	Real-time prices Demand response triggers and amount Data requests	Small to average	Immediately after change	
3	Microgrid interconnection controller in PCC	AMI Data Management System	Aggregated for microgrid, Net, load and generation kW and kvar Net, load and generation kWh Net, load and generation load profiles Interval average voltages from selected Smart Meters Weather data. Demand response triggers received with timestamps; Commands issued for Demand Response (customers' Smart Meters, thermostat, appliances, DER, Storage) Protection settings and settings for frequency and voltage control for connected and for autonomous modes of operations, Operational limits O&M cost functions Other data needed for current and predictive model of microgrid operations.	Small to average	Once a day	Revenue accuracy for kW and kvar; 0.5%-0.2% accuracy for Voltages

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
3	Microgrid interconnection controller in PCC	AMI Data Management System	Lowest instantaneous voltages from included Smart Meters Instantaneous frequency Last Gasp/AC Out from selected Smart Meters	Small to average	Last gasp - immediately from selected first-reporters; Instantaneous voltages within minutes after fault; Instantaneous frequency – report by exception in autonomous mode of operations.	0.5%-0.2% for Volt; 0.1% for Hz
3	AMI Data Management System	Microgrid interconnection controller in PCC	Real-time prices Demand response triggers and amount Disconnection command for intentional islanding Desired kW and kvar setpoints Desired voltage setpoints Data requests	Small to average	Immediately after change	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
4	DER &Controller	AMI Data Management System	Generation kW and kvar Generation kWh Generation profiles Interval average voltages Weather data. Generation change triggers received with timestamps; Active protection settings and settings for voltage control in the connected mode of operations and voltage and frequency control settings for island mode of operations, Capability curve Synchronization settings O&M cost functions	Small to average	Once a day	Revenue accuracy for kW and kvar; 0.5%-0.2% accuracy for Voltages
4	DER &Controller	AMI Data Management System	Lowest instantaneous voltages before disconnection Instantaneous frequency in island mode Last Gasp/AC Out or protection actions	Small	Immediately after change	0.5%-0.2% for Volt; 0.1% for Hz
4	AMI Data Management System	DER &Controller	Real-time prices Desired kW and kvar setpoints Desired voltage setpoints Data requests Synchronization commands	Small	Immediately after change	
5	AMI Data Management System	Load model Processor	kW and kvar profiles for every day Impacting factors with time stamps Weather Demand response with start and stop times Other related events with timestamps	Large	Once a day	
6	Load model Processor	DOMA	List of nodes in clusters Name of clusters Representative nodal load models for clusters of similar loads	Average	Once a day	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
7	AMI Data Management System	Secondary Equivalent processor	Daily kW and kvar load profiles from individual Smart meters and aggregated at the distribution transformer load profiles Daily profiles of interval-average voltages	Large	Once a day	
8	DOMA	Secondary Equivalent processor	Modeled voltages at the secondary buses of distribution transformers	Large	On request by Secondary Equivalent processor (once a month or less frequent)	
8	Secondary Equivalent processor	DOMA	Dependencies of critical voltages on nodal loads Dependencies of losses in secondaries on nodal loads	Large	After significant change (once a month or less frequent)	
9	DOMA	VVWO	All component of operation models (can be integrated in VVWO)	Large	Every run of DOMA and VVWO (e.g., every 5-15 min.)	
10	VVWO	Load Management System	Triggers of Demand response for selected nodes Desired amount of Demand Response in selected nodes	Low	Up to every run of VVWO. Immediately after successful execution of previous steps.	
10	Load Management System	VVWO	Available Demand Response per node Constraint of Demand Response per node	Average	After significant change	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
11, 44, 45, 46	Load Management System	Smart Meters; Customer EMS; microgrid controller; DER controller	Triggers of Demand response for selected nodes Desired amount of Demand Response in selected nodes Triggers of Demand Response for aggregated loads of Micro-Grid to microgrid controllers Triggers of Demand Response for aggregated loads to Customer EMS Information on assigned emergency voltage limit (In case of emergency load-reducing VVWO)	Small	Immediately after receiving solution.	
11, 44, 45, 46	Smart Meters; Customer EMS; microgrid controller; DER controller	Load management system	Customer choices, contractual conditions, and DER/ES attributes.	Small to Medium	After significant changes	
12	VVWO	Microgrid interconnection controller in PCC	Triggers of Demand response for selected nodes in connected mode Desired amount of Demand Response in selected nodes Desired net kW and kvar exchange Desired settings or mode of operation for var or voltage control	Small	Up to every run of VVWO. Immediately after successful execution of previous steps.	
12	Microgrid interconnection controller in PCC	VVWO	Available Demand Response per PCC Constraint of Demand Response per PCC Constraints of kW and kvar exchange Constraints on voltage control	Small	After significant change	
13	VVWO	DER controller	Desired state of DER (On/Off) Desired kW and kvar generation Desired settings or mode of operation for var or voltage control	Small	Up to every run of VVWO. Immediately after successful execution of previous steps.	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
13	DER controller	VVWO	Actual state of DER Actual kW and kvar Schedule of kW and kvar for look-ahead times Actual settings and mode of operation for var and voltage control	Small	Up to every run of DOMA	
14	DOMA	FLIR	All component of operation models (can be integrated in FLIR)	Large	Every run of DOMA (e.g., every 5-15 min.)	
15	AMI Data Management System	FLIR	Last Gasp/AC Out Instantaneous voltages	Small to average	Last Gasp – immediately after lock out Instantaneous voltages – within minutes after fault	
16	FLIR	Demand Response System	Triggers of Demand response for selected nodes Desired amount of Demand Response in selected nodes	Small	After fault, and after repair. Up to every run of FLIR.	
16	Demand Response System	FLIR	Available Demand Response per node Constraint of Demand Response per node	Small to average	After significant change	
17	FLIR	Microgrid interconnection controller in PCC	Desired state of microgrid (Connected or autonomous) Triggers of Demand response per microgrid Desired amount of Demand per microgrid Desired net kW and kvar exchange	Small	After fault and after repair. Up to every run of FLIR	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
17	Microgrid interconnection controller in PCC	FLIR	Available Demand Response per PCC Constraint of Demand Response per PCC Constraints of kW and kvar exchange	Small	After significant change	
18	FLIR	DER controller	Desired state of DER (On/Off) Desired kW and kvar generation	Small	After fault and after repair. Up to every run of FLIR	
18	DER controller	FLIR	Actual state of DER Actual kW and kvar Schedule of kW and kvar for look-ahead times Protection settings	Small	After significant change	
19	GIS	Validation	Circuit connectivity, facility parameter, customer association with the network data;	Large volume initially, medium volume for updates	Initially before commissioning DMS, and regularly after significant changes (once a day, or more frequently) and after corrections	High
19	Validation	GIS	Reports on inconsistent data	Small to Medium	Initially before commissioning DMS, and regularly after significant changes (once a day, or more frequently)	N/A

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
20	Validation	DOMA	Validated data on circuit connectivity, facility parameter, and customer association with the network	Large volume initially, medium volume for updates	Immediately after full validation	
21	GIS	Data Management Systems	Connectivity and parameter data on DER, ES, DR	Small to Medium	After significant change	
21	Data Management Systems	GIS	Data to be associated with the topology and facility parameters	Medium	Upon the change	High, subject to validation before inserting in GIS
22	Field Crew	Operator	Work-related information according to the ticket	Small	According to safety and maintenance rules	
22	Operator	Field Crew	Work-related information according to the ticket	Small	According to safety and maintenance rules	
23	Field Crew	GIS	States and parameters of the corresponding equipment observed in the field according to pre-defined instructions (template)	Small	During the presence at the subject in the field	Verified information
24	Operator	DMS	Setup of the ADA applications, requests for particular information	Small	As needed	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
24	DMS	Operator	Pre-defined output data and messages from ADA applications,	Small	On pre-defined periodicity for normal output; immediate after an alarming/warning event and on operator's demand	
25	Operator	DSCADA	Supervisory control commands, requests for particular information, setup of SCADA functions	Small	Minimum response time	
25	DSCADA	Operator	Analog and Status data in predefined screens of the graphical user interface, output of SCADA functions	Medium to Large	Minimum reporting and response times	According to efficient utilization
26	DSCADA	DMS	Near real-time analog and status information from the observable portions of the distribution power system	Medium to Large	Minimum exchange times	According to efficient utilization
26	DMS	DSCADA	Control commands from ADA applications executable by DSCADA	Small to Medium	Minimum exchange times	
27	SCADA/EMS	DMS	Near real-time analog and status information from the observable portions of the transmission and generation systems	Medium to Large	Minimum exchange times	According to efficient utilization
27	DMS	SCADA/EMS	Dynamic limits, multi-attribute aggregated bus load models	Medium to Large	After each run of ADA application	<=1% for voltage
28	Aggregator	DR System	Market/Contractual conditions for participation in capacity, ancillary service markets and related information	Medium	According to market rules	
28	DR System	Aggregator	Individual and aggregated customer choices, contractual agreement, etc.	Medium	According to market rules	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
29	Aggregator	Smart Meters	Information relevant to participation in the market	Medium	According to market rules	
29	Smart Meters	Aggregator	Information relevant to participation in the market	Medium	According to market rules	
30	Aggregator	Data Management Systems	Contractual information needed for development of behavioral models	Medium	According to market rules	
30	Data Management Systems	Aggregator	Historic information relevant to performance of market participants	Medium	According to market rules	
31	Aggregator	Customer EMS	Information relevant to participation in the market	Medium	According to market rules	
31	Customer EMS	Aggregator	Information relevant to participation in the market	Medium	According to market rules	
32	Aggregator	Microgrid controller	Information relevant to participation in the market	Medium	According to market rules	
32	Microgrid controller	Aggregator	Information relevant to participation in the market	Medium	According to market rules	
33	Aggregator	DER controller	Information relevant to participation in the market	Medium	According to market rules	
33	DER controller	Aggregator	Information relevant to participation in the market	Medium	According to market rules	
34	Smart meters	Customer Appliances	Control commands for Demand response and Energy Efficiency	Small		
34	Customer Appliances	Smart meters	Statuses of appliances	Small		
35	Customer Appliances	Customer EMS	Control commands for Demand response and Energy Efficiency	Small		

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
35	Customer EMS	Customer Appliances	Statuses of appliances	Small		
36	External Systems	DMS	Environmental data by locations; Other information impacting the behavior of the customer loads	Medium to Large	Periodically and by significant changes.	
37	MOS	ISO/RTO	Price signals and other market-related information	Medium		
37	ISO/RTO	MOS	Authorization of transactions and other relevant information	Medium		
38	MOS	Aggregator	Price signals and other market-related information	Medium		
38	Aggregator	MOS	Information on behalf of customers	Medium		
39	ISO/RTO	SCADA/EMS	Prices and congestion related information, aggregated load management requirements	Medium	Day-ahead, hour-ahead; 5-15 minute-ahead	
39	SCADA/EMS	ISO/RTO	Near-real time operation models, reports on load management, available dispatchable load by areas, etc.	Large	Very short update times (~ 1sec)	
40	DSCADA	DER	Control commands for start, stop, change of kW and kvar, change of mode of operations, change of setpoints.	Small	1-2 sec.	
40	DER	DSCADA	Analog and status of DER elements, alarms, setpoints of control and protection, etc.	Small to Medium	1-2 sec	
41	DSCADA	Microgrid controller	Control commands for open/close of PCC switches, change of net kW and kvar, change of mode of operations, change of setpoints.	Small	1-2 sec	
41	Microgrid controller	DSCADA	Analog and status of microgrid elements, alarms, setpoints of control and protection, etc.	Small to Medium	1-2 sec	

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
42	DMS Gateway	VVWO	VVWO options	Small	1 - 2 sec after change	
42	VVWO	DMS Gateway	Optimal setpoints and statuses, heartbeats, summary output data for the user	Small	1- 2 sec after VVWO solution	
43	DMS Gateway	FLIR	FLIR options, fault indicators, lock-out signals, Fault location,			
43	FLIR	DMS Gateway	Switching sequences	Small	1-2 sec after the lockout signal	
47	ADA Gateway	Engineering	Selected information for review based on authorization of the results of case studies	Small		
47	Engineering	DMS Gateway	Request and input data for case studies, review of case studies results. Setup of ADA applications according to authorization.	Small	1-2 seconds respond times.	
48	Engineering	Load Management System	Engineering conditions for load management; Plans for load management	Small		
48	Load Management System	Engineering	Reports on load management and other relevant information for engineering designs and planning	Small to Medium		
49	Engineering	GIS	Information on future installation; Correction and update on existing information	Small to Medium		
49	GIS	Engineering	Diagrams, connectivity, parameters, associated loads for design, studies and planning purposes	Medium		
50	Engineering	Data Management Systems	Software and relevant input data for Data Management Systems	Medium		
50	Data Management Systems	Engineering	Reports and selective extracts on Data Management System performance			

Table 3-5
Attributes of Information Exchange Between Major Actors (continued)

#	Source	Recipient	Contents of Information	Volume	Timing	Accuracy
51	DMS Gateway	DOMA	DSCADA/SCADA/EMS analog and status snapshots; operators options for ADA applications	Medium to Large	1-2 seconds updates	
51	DOMA	DMS Gateway	Results of DOMA for the operators and for SCADA/EMS	Small to Medium	1-2 sec after DOMA run	

4

PREVAILING INFORMATION EXCHANGE GAPS AND THE CHALLENGES IN MIGRATING TO THE FUTURE STATE

The specific gaps between the existing and the ultimate information exchange with Distributed Energy Resources are listed in the tables of Chapter 3. In this chapter we will summarize the conceptual gaps to overcome to successfully migrate to the Smart Grid environment. The Smart Grid concept is based on digital monitoring and control techniques and on dynamic optimization of the power system operations. Hence, the most challenging requirements for the information exchange with DER, as well as with other devices of the Smart Grid, are the requirements imposed by the real-time monitoring and controlling applications.

Information Exchange with Stand-alone DER

The required level of information exchange with the large utility-owned DER will ultimately approach the level of current information exchange with bulk generation. The prevailing gaps between the current state of available information exchange with the utility-owned DER and the future state are as follows:

- Some DER controllers do not have all the needed capabilities for automatic (local or remote) control. For instance, there are no capability curves embedded in the controllers, preventing the overloads of the electric components on per phase basis. Without such protection, the controlling function should relay on the DER and power flow models and conservatively limit the operational tolerances and options. Not all DER controllers have the capability to execute different modes of reactive power control, such as Qmax, Qmin, PQ with voltage override, etc., and all of them within the capability curves.
- Controllers (or other DER gateways) should confirm to standards object models and to interoperability standards for information exchange.

The required level of information exchange for large customer-owned DER, in general, is not different from the requirements for the utility-owned ones. The difference is that some of the required information can be limited to the internal use, while other information needs to be provided to the utility. The most challenging gap is the uncertainty of the DER reaction to the "Inform and Motivate" message coming from the utility. To overcome this gap, adequate behavioral operation models of the DERs of particular customers should be developed. The point of information exchange with the customer-owned DER is typically the Point of Common Coupling of the customer circuit with the utility circuit. The scope of information needed from PCC for the dynamic optimization will, most likely, exceed the current scope, defined by IEEE P1547. Therefore, the information gateway at the PCC of customers with significant DER will need to be able provide the extended information either in DER-specific scope, or in aggregated scope. For instance, in addition to current net measurements, the characteristics of available dispatchable real and reactive loads will be needed. The aggregated available load may include DER reserves and Demand Response (DR) capacity. The contractual conditions for utilization of the DER or the DR may be different, and it may be not indifferent for the utility which of the available means for load control to use at the particular time. Therefore, the gateway at the PCC of a customer with DER should confirm to the standard object models of such interconnection and to the interoperability standard.

Information Exchange with Small In-load-embedded DER

The prevailing challenge of information exchange with small embedded in load DER is the adequate modeling of their behavior under different conditions and the timely delivery of the control requests to the changeable clusters of customers. Depending on the available historic data, either the aggregated models of the net powers, or the separate models of the loads and DER power will be developed. The most likely gateways for such customers will be the Smart Meters. For the customers with capability of DER var and/or Watt control, the Smart Meter should be capable of transmitting the request for the modes of reactive /real power control to the DER converter. The aggregated or separate object models supported by the Smart Meters should confirm to interoperability standards.

Information Exchange with Microgrids

The gateways of the microgrids are the most complex intelligent devices in the PCCs. In addition to the combination of all of the mentioned above requirements valid for the interconnected mode of microgrid operations, the microgrid controller should support the monitoring control of operations of the separated islands. The details of such control (e.g., [34, 35]) are beyond the scope of this study. The near-real-time information needed for dynamic optimization of the normal and emergency power system operations with significant penetration of micro-grids comprises, in addition to directly measurable data, a set of pre-processed data needed to model the behavior of the microgrid after an intentional or forced separation. The attributes of such an object model are presented in Table 3-3 in Chapter 3.

5 MIGRATION STRATEGY

- Advanced Distribution Automation applications are based on near real-time computer-aided models of distribution operations supported by corporate databases and scarce SCADA measurements. With the implementation of the Smart Grid, the distribution system migrates from a passive network to an Active Distribution Network (ADN). The ADN will have a high level of penetration of different kinds of Distributed Energy Resources. The DERs will differ not only by their technologies, but by their ownership, accessibility, controllability, functionalities, and by the benefits to the owners and to the utilities.
- The benefits of DER to the utility and its customers depend on the location, sizes, and functionality of the DER. Therefore, the migration to the future integration of DER into the Smart Grid should start from system planning stage. On this stage, the feasibility studies of the future states of the power system should determine the optimal combination of all available components of grid development, including DER's impact on the power system infrastructure and operations. It means that even on the early stages of system planning, the DER should be represented by their adequate object models. Based on comprehensive planning studies, the utility will determine not only the preferred DER types, sizes, and sites, but also the required functionalities. For instance, the studies may show whether it is efficient to encourage the distribution utilities or the customers in particular areas to install the converter-based DERs with the var and/or Watt control capabilities, or whether microgrids should be developed in particular areas with particular generation-load balances and operational capabilities, etc. Hence, the migration to the future state of information exchange with DER should start from the inclusion of the DER operations in the system planning studies. It also means that the system planning applications should be upgraded for inclusion of optimization procedures for selection of the kinds, sizes, locations, and functionalities of DER.
- Another step in migration to the future efficient use of DER is the enhancement of the DER controllers with the embedded capabilities for the utilization of DER in dynamic optimization of the Smart Grid operations. The requirements for such enhancement should come from the power system industry.
- The object models of DER include the design data of the DERs, their nominal places in the topology model of the utility, the characteristics of protection and control, the contractual conditions of the interconnection and operations within the utility, a variety of operational behavior dependent on the near-real-time internal and external conditions, and on a set of near-real-time data. The constant and the conditionally constant data can be stored and updated in some kind of DER Data Management System associated with other corporate IT systems, e.g., like GIS, CIS, and AMI. The measured and the pre-processed near-real-time data can reside in the DER and microgrid controllers or corresponding customer EMS. Hence, the migration to the Smart Grid information exchange with DER should include the development of the following two critical components of the information exchange system:

- The DER Data Management System, or its equivalent
- The DER object models for different kinds of DER devices.

These models should include the local controller models, nodal load models with embedded distributed energy resources, stand-alone DER models, including Electric Storage, and aggregated and detailed microgrid models. The models should be predictive and behavioral. The customer-owned DER models, especially the embedded ones, can be developed by utilizing the AMI-supported data. The accuracy of the DER models is essential for the overall optimization of the power system operations. The injections of real and reactive powers from significant DER or from many small DERs are components of the state estimation and power flow modeling procedures. Information from these sources should be provided either from corresponding IEDs, or from the behavioral models of these objects. If this information is not available or is significantly erroneous, the efficiency of the high accuracy from other information sources, e.g., from AMI devices, will be diminished. In the Smart Grid environment, when many loads become "active" loads, due to embedded DERs and Demand Response capabilities, the behavioral load models depending on different triggers and conditions can be developed based on data collected from the Smart Meters, including data collected via in-building networks, if permitted, customer EMS devices, from different sources of operational triggers, such as real-time pricing sources, reliability trigger sources, weather sensors and systems, contractual agreements with customers, DER schedules and characteristics, field test results, etc. Based on these conditions and historic data, the composite load models should be normalized to the nominal conditions, and dependencies of the load on the changes of these conditions should be derived. Therefore, a sophisticated pre-processing of AMI data along with other associated information will be needed to migrate to the future information exchange with DER [11].

- The advance applications of EMS and DMS to be used for the dynamic optimization of the power system operations should be upgraded to include the different DERs and their capabilities as the operation model components and as controllable variables for the near-real-time, as well as for the short-term look-ahead optimization. Significant additional benefits of the optimizing DA applications can be expected due to the opportunity of integration of the controls of DER and microgrids. Inclusion of DER Watt and var control in voltage-critical points provides additional room for load-reducing Volt/var optimization in a much bigger distribution grid. To utilize such opportunities, the Volt/Var/Watt Optimization (VVWO) application should be capable of issuing triggering signals to the DER gateways to enable the corresponding control modes in the selected nodes. Inclusion of DER and microgrids into controllable variables of the Service Restoration function reduces the number and duration of customer interruptions and defers upgrades of the distribution facilities. To optimally utilize this potential, the behavioral models of these components should be made available to the DA application, and the application should be capable of issuing triggering and operational signals to the DER systems. The Service Restoration is based on a number of "what-if" power flow calculations. The 'what-if" scenarios include alternatives involving feeder reconfiguration, sometimes with intermediate feeder paralleling for unloading backup feeders; DER starts or ramping, micro-grids management, intentional islanding, and Demand Response. The difference in applying the DER, microgrids, and Demand Response for service restoration is that the recommendations, which become a portion of the switching order, should be made for the future time, for which the restoration problem is to be solved.

Corresponding predictive models of the controllable systems will be needed for the look-ahead times.

- According to the current standard IEEE 1547, all DER shall be disconnected in the case of a fault on the corresponding circuits, and their support of the utility load will be lost. Some of the DER can be disconnected from the utility grid together with the load downstream from the interconnection switch at PCC, creating electrical islands (Micro-Grids). If the available capacity of the DER in the Micro-Grid is greater than the load, and the control system of the Micro-Grid is capable of maintaining the balance between the demand and supply within the quality tolerances, then the service of the load will continue uninterrupted, but part of the generation support will be lost for the load connected to the utility grid. If the load of the Micro-Grid exceeds the generation capacity, and the control system of the Micro-Grid is capable of managing the load to provide the balance between the demand and supply within the quality tolerances, part of the load will be disconnected and part will be reduced by demand-based frequency and voltage control systems. In some cases, there will not be sufficient dispatchable load available for keeping the balance with the generation, and then the entire Micro-Grid may shot down. The misbalance may happen immediately after he fault occurred, and may happen later during the time of repair. The possibility of this happening should be foreseen by the DA application. The Data Management system, in addition to supporting updated behavioral composite load models on the distribution transformer levels and on the PCC levels, shall support predictive models of the balancing capabilities of the micrograids and intentional islands for the expected time of repair. To support these models and the autonomous operations of the microgrids, the gateways in the PCC shall be able to accurately measure the frequency and voltage, monitor the states of the appliances via the HAN and control them based on the pre-armed settings.
- The production of DERs of different kinds is provided by a multitude of different manufactures; the applications involving DER are and will be developed by different vendors, and they will be used by different utility and customer users. Hence, all components of the information exchange with DER should be based on international interoperability standards. As seen from the above discussions, the information exchange with DERs involves corporate utility IT systems, field IEDs in the utilities and in customer premises, AMI infrastructure, and Home Area Networks. It means that different interoperability standards will be involved in this information exchange. These standards include but are not limited to: IEC 61850, IEC 61968/61970, IEEE 1547, DNP3, ANSI C12.19-22, Open ADR, and ZigBee/HomePlug. Being involved in the same information exchange, these standards should be harmonized or integrated on a common fundamental level such as object structure.

6
FUTURE WORK

The recommended future work is based on the strategy for the migration to the Smart Grid information exchange with the Distributed Energy Resources. In addition, the following action could be recommended:

1. Develop case studies for specific utilities on benefits of integration of DER into dynamic optimization of the power system
   – Identify the existing and planned implementation of Demand Response, DER, and microgrids
   – Identify the objectives of existing and planned DA applications
   – Develop object/data models for DERs and micro-grids. Validate the model based on field tests
   – Optimize the selection of future DERs
   – Develop the operational models for the case study reflecting the properties of the legacy systems.
   – Simulate and optimize the virtual operations under different alternatives of utilization of DER. Assess the potential benefits of DER embedded in DA application for the existing, planned, and optimized conditions
   – Identify areas of improvement
   – Specify requirements for DER object models and controllers
2. Develop a virtual demonstration project of an active distribution network with monitoring and controlling ADA applications.
3. Conduct a demonstration project of an actual active distribution network with advanced DMS applications and with an information exchange based on interoperability standards.
4. Further development of key use cases and requirements for DER communications and control.
5. Development of necessary extensions to existing DER communications logical nodes and object models with subsequent contributions to IEEE and IEC Standards as appropriate.

7
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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com