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Guidelines for Assisting Understanding and Use of IntelliGrid Architecture Recommendations: Distribution Operations

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PRODUCT DESCRIPTION

The Initial IntelliGrid Architecture documents were prepared by a team of experts from several companies and many stakeholder groups. The initial project was titled "The Integrated Energy and Communications Architecture" (IECSA), sponsored by the Electric Power Research Institute (EPRI) in a public private partnership.

The objective of the guidelines presented in this report is to assist power system personnel in using the ideas and concepts presented in the IntelliGrid Architecture documents.

Results & Findings

These guidelines address strategic visions for the planning system, systems approach to the functional requirements of the monitoring and controls systems, and understanding of the information flows needed for advanced distribution systems. In addition the configuration, quality of service, security, and data management requirements for the information exchange involved in the operations of these systems are addressed. The guidelines described in this report are based on a specific application for distribution operations and is used as a representative example. The example used here is the Distribution Operation Model and Analysis (DOMA) application for a Distribution Management System (DMS).

Action items at different stages of system development are presented. Future work for development of monitoring and control system for power utilities based on a system approach and standardization is outlined.

Challenges & Objectives

These guidelines represent a stepping stone in the development of an industry-level architecture for intelligent equipment and systems. The standards that will comprise these systems are still working toward a level of maturity for real equipment. Several challenges are ahead including the resolution of some technical issues and details remaining within the key standards and defining key elements necessary for management and security within the systems.

Applications, Values & Use

These guidelines can be used to better understand how to describe and specify systems that make use of the standards and recommended practices that comprise the IntelliGrid Architecture documents. Using these guidelines will also provide an understanding of the state of the development of the critical portions of the architecture. Using these guidelines can contribute to a utility's own set of requirements development processes for specifying equipment that makes use of the recommendations within the IntelliGrid Architecture

EPRI Perspective

The IntelliGrid Architecture represents on going work to establish an industry level architecture for intelligent equipment that interoperates. To assist the ultimate deployment and cost effectiveness of intelligent systems it is important to develop and understand the infrastructures that will enable the integration of equipment. The development of open systems will assist in competitive procurement of intelligent equipment and assist in the long term ability to cost-effectively build and maintain systems that meet both today's and tomorrows demands for power system operations. These guidelines can serve to provide a better understanding of the tasks involved in reaching these goals as an industry.

Approach

These guidelines build upon the initial systems engineering approaches taken by the original team in developing the IntelliGrid Architecture documents. These methods will be augmented by linkage within the EPRI IntelliGrid Architecture website.

Keywords

Distribution Management System, Distribution Operation Model and Analysis, Distributed Energy Resources, IntelliGrid Architecture, Distribution Operations

IEC 61850, IEC 61968, Common Information Model, Application Guidelines

CONTENTS

1. INTRODUCTION

The objective of this document is to show how the information presented in the IntelliGrid Architecture (http://intelligrid.info/IntelliGrid_Architecture/Overview_Guidelines/index.htm) can be applied to the implementation of the Distribution Management System (DMS). The DMS application Distribution Operation Modeling and Analysis (DOMA) will be used as an example (see section *Distribution Operation Modeling and Analysis: http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*). It is understood that DOMA is only a first step in implementing Advanced Applications of Distribution Management Systems. DOMA stands as an example set of functions, other functions will ultimately need to be developed to attain DMS's full potential. The document's presentation is constructed to follow a path that a utility planning/project engineer may pursue in studying IntelliGrid Architecture information to understand the issues and the ways to address them. This is accomplished by navigating the reader through the sections of the IntelliGrid Architecture relevant to DOMA function. (All references to other sections and figures, found in this document, refer to IntelliGrid Architecture.) This document is not intended to replace IntelliGrid Architecture with a user-friendlier publication nor is it a version of "IntelliGrid Architecture for Dummies". On the contrary, the document shows the use and the significance of the IntelliGrid Architecture information, without repeating it, for identifying and addressing the (sometimes subtle) issues arising in the process of the DOMA (and DMS) implementation. These issues are formulated in a form of action items, thereby showing how IntelliGrid Architecture information can be used as a guide for action. A reasonable level of familiarity with the information and general user guidelines presented in the IntelliGrid Architecture is assumed. The key steps in using the IntelliGrid guidelines for implementing the DOMA function are as follows:

1. Determine the business needs for DMS and its functions. Develop an understanding of *DMS functions* through the review of the DMS functions described in the IntelliGrid Architecture (see section *Distribution Operations – Overview of Advanced Distribution Automation: http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_ADA_Overview.htm*).
2. Review the IntelliGrid Architecture strategic concepts, and establish your utility's strategic vision for the overall deployment of advanced applications of DMS and for modern information infrastructures (see section *IntelliGrid Vision: http://intelligrid.info/IntelliGrid_Architecture/High_Level_Concepts/HLC_Strategic_Vision.htm*).
3. Study implementation issues through the review of DOMA's capabilities as described in the IntelliGrid Architecture (see section *Distribution Operation Modeling and Analysis: http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*) and action items outlined in this document.
4. Understand information flow through reviewing the flow charts presented in the IntelliGrid Architecture; by identifying all the actors involved in the process and the types and significance of data in the flow (see section *DOMA Steps*).

5. Study issues associated with communication environments described in the IntelliGrid Architecture, specifically the configuration, performance and security requirements associated with communication channels employed by DOMA (see section *IntelliGrid Architecture Environments:* *http://intelligrid.info/IntelliGrid_Architecture/Environments/Environments.htm*).
6. Select communication technologies based on the options described and recommended by IntelliGrid Architecture (see section Technologies: http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/H1_Technology_List.htm).
7. Prioritize the action items in accordance with the company's near- and long-term goals. This should be done considering the existing utility infrastructure, the projects in progress, the budget a well as other priorities.

2. STRATEGIC VISION FOR DISTRIBUTION MANAGEMENT SYSTEMS

The power industry exceedingly relies on the real-time information to operate the power systems. As a result, there are two infrastructures - power delivery and "distributed computing". Distributed computing encompasses "real-time" automation with field equipment, as well as information systems. It should be noted that both of these technical domains are evolving, requiring a parallel development and support. Therefore, the DMS implementation necessitates understanding and investment in both infrastructures. This investment should be identified by first assessing the present state of the "as built" distribution system, followed by the establishment of the system's future target states for both power systems and the supporting distributed computing infrastructure. The former is accomplished through evaluating the present levels of adequacy, power quality, security, economic efficiency and the functionalities employed to maintain them. The latter may include the future levels of power quality and reliability (indices), reduction in the cost of assets per delivered unit of power, penetration of real-time pricing/distributed generation in distribution, etc. Evaluating the journey from the present state to the future targets will identify the extent and the needed functionality of DMS as well as the associated investment. This approach allows for the decisions, made along the way to implementing the DMS, to be checked against and, if possible, linked with the future power system design, functional/performance requirements, forthcoming power system control functions and emerging technologies. Recognizing all that, and having the prudence for planting the seeds and leaving the space for futures to come, will turn out to be a significant contribution towards building a smarter power system of the future.

Action items:

1. Reaffirm utility's present performance criteria:
   - Reliability (e.g., System Average Interruption Duration Index - SAIDI, System Average Interruption Frequency Index - SAIFI, etc.).
   - Efficiency (Energy losses; Load elasticity/Available demand response; Utilization of facilities/Loading of circuits, transformers; operation and maintenance expenses, etc.)

- Power quality criteria (Voltage deviation beyond standard limits; higher harmonics; Voltage sags and swells; Voltage imbalance; etc.)
- Customer satisfaction

2. Identify the functionalities presently used in the company to maintain/improve reliability, efficiency, power quality, and customer satisfaction. Estimate the cost of these functionalities
3. Determine utility's future reliability, efficiency, power quality, and customer satisfaction targets (5-10 years)
4. Determine existing capabilities for achieving the targets (DMS-readiness degree). Estimate needed upgrades for achieving the targets. For example, consider the following:
   - Reserves in circuit capacity and backup capabilities
   - Degree of sectioning of circuits
   - Number of load-breaking switches, feeder reclosers, remotely controlled switching devices, automated fault detecting, isolation and service restoration means, etc.
   - Voltage and var control means; utilization of voltage deviation tolerance
   - Availability of real-time monitoring and controlling in distribution
   - Other.
5. Perform a feasibility study to determine cost-efficient upgrades of the distribution system and the degree of automation of the distribution operations (DMS). In the study consider DMS as a means for the following:
   - Enhancement distribution operations (reliability, power quality, efficiency)
   - Controlling energy resources (demand response, distributed energy resources, support of real-time pricing)
   - Provision of real-time information for transmission operations (substation bus load models; dynamic voltage-quality based limits at transmission buses; aggregated load-to-voltage dependencies; available value of demand response, etc.)
   - Support of real and reactive power balances and voltage support in bulk power system.
6. Based on the feasibility study and on affordability of resources select the degree of upgrade and automation. The upgrade may include actions like the following:
   - Installation of automated switching devices
   - Installation of automated capacitors
   - Replacement of critically limiting facilities
   - Installation of remotely-controlled voltage and var controllers.

   The automation may include the following actions:
   - Modernization and cleanup of the Automated Mapping, Facility Management, and Geographic Information System (AM/FM/GIS) and Customer Information system (CIS) databases
   - Expansion or installation of Distribution Supervisory Control and Data Acquisition system (SCADA)
   - Implementation of DMS integrated with other Information Technology (IT) systems, such as:
     - AM/FM/GIS/CIS

- Outage Management System (OMS)
- Work Management System (WMS)
- Energy Management System (EMS)
- Other
- Implementation of advanced DMS Applications, such as:
  - Distribution Operation Model and Analysis (DOMA)
  - Coordinated Optimal Voltage and Var control (OVVC)
  - Fault Location, Isolation, and Service Restoration (FLIR)
  - Multi-Feeder Reconfiguration (OFR)
  - Other

The Distribution Operation Model and Analysis function is used as an example for applying the ideas of the integrated energy and communication infrastructure presented in the Intelligrid documents when planning and implementing Distribution Management Systems.

3. INTRODUCTION TO DOMA

The following subsections identify and expand on the DOMA function related issues arising from reviewing the section *Distribution Operations – Overview of Advanced Distribution Automation -* (http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_ADA_Overview.htm)

3.1 DOMA's Role in DMS

The DOMA function is identified as one of DMS actors. DMS's primary objectives - to enhance reliability of power system service, power quality, and power system efficiency - are accomplished by automating:

- Near real-time data preparation
- Optimal decision making
- Control of distribution operations in coordination with transmission and generation

To support these objectives, the DOMA function performs the following activities/services:

- Analysis of real-time operating conditions based on the power flow and state estimation calculations
- Provision of aggregated bus load models for transmission operation
- Issue of alarming/warning messages to the operator
- Generation of distribution operation reports and logs

The flow diagram (see Figure 4: *Information Flows within Advanced Distribution Automation*) illustrates that DOMA is a monitoring function providing pseudo-measurements and concise results of operational analysis. It allows evaluating the distribution system present state by identifying load and voltage violation, room for optimization, etc. These parameters demonstrate, in part, the system's readiness for DMS implementation. Other DMS functions, such as Multi-

Feeder Reconfiguration, Volt-var-Watt Control, Fault Location Isolation and Service Restoration, are decision-making functions using components of DOMA for information support needed to deliver their designated functionality. Therefore, it is natural that DOMA is the first function to be implemented as part of the DMS project. Furthermore, examples of real-time data required for controlling distribution operations (see Figure 3: *What Do We Need to Know to Optimally Control Distribution?*) show the need for parameters like load of individual distribution transformers, status of capacitor switches, voltage imbalances, feeder segment power flow, which can not be measured to the needed extend and, therefore, need to be estimated in real-time. Thus, a function, with DOMA capabilities, is guaranteed a "full-time", i.e., 24 hours and 7 days a week of real-time, employment.

Action items: Develop an understanding of DOMA objectives and its role in the automation of information support for real-time operations, as well as for studies evaluating the systems readiness for DMS implementation based on information in section *Overview of Advanced Distribution Automation (http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_ADA_Overview.htm).*

3.2 Distribution and Distributed Energy Resources (DER) Contracts

Discussion in section Contractual Relationships: *Contracts between DISCO and DER owners* (http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_ADA_Overview.htm) raises issues associated with the presence of distributed generation in distribution. To properly account for DER presence, DOMA (along with many other parameters in DER Object Model) requires the knowledge of DER schedule and the power flow constraints (if any) at the point of common coupling. *Standard 1547* and EPRI publication *Studies of Distribution Operations to Aid in Determining Object Models for Distributed Energy Resources* will serve as useful resources in search for needed DER information.

Action items:

- Determine/confirm the schedules and commitments of relevant DERs as well as power flow constraints at points of common coupling.
- Develop the mechanism for updating schedules and commitments of relevant DERs for this data may change. As part of DER Object Model (OM), this data is used as DOMA function input data. Verify whether DER OM can be communicated through SCADA in the timeframe of the project. If not, define the information flow for providing data about DER operations.

3.3 Distribution and Customer Contracts

Discussion in section Contractual Relationships: *Contracts between DISCO and customers (*http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_ADA_Overview.htm) raises power quality and load management issues. Specifically, DOMA determination of dispatchable real and reactive power, dynamic voltage limits, detection of voltage violations at customer terminals, etc., requires the knowledge of relevant customer terminals quality/emergency limits.

Action items:

- Identify customers (if any) with quality/emergency customer terminals voltage limits that differ from the standard limits (i.e., +/- 5/10%).
- Identify customers participating in various types of load management, including:
    - Real-time pricing (RTP)
    - Direct load control (DLC)
    - DER
    - Storage
    - Emergency load shedding/ Interruptible load

4. FUNCTIONAL REQUIREMENTS OF DOMA APPLICATION

In Section *Distribution Operation Modeling and Analysis (DOMA) - (http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm)*, a brief description of the function and its modes of operation provide an introduction into the function's capabilities as well as the challenges of implementing and maintaining this function. Each of the following subsections expands upon the respective topic in the IntelliGrid narrative. The action items in each subsection identify the types of discussions and actions that the power engineering staff should initiate after studying the narrative.

4.1 Integration of Distribution Operations with Adjacent Transmission and Sub-Transmission Operations

In considering the need and locations for modeling transmission and sub-transmission (see section *Modeling Transmission/Sub-Transmission System Immediately Adjacent to Distribution Circuits-http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*), a number of questions should be answered. These questions are formulated in the following action items.

Action items:

Determine:

- Which power system areas have transmission loading and voltage levels that significantly depend on the operating conditions in distribution?
- Which substation transformers and transmission/sub-transmission lines have load and voltage limits that should be respected by distribution?
- What are contractual relationships between transmission and distribution companies? These should be reviewed for they define the operational boundaries between the two. If the boundaries are at the feeder circuit breaker level, then DOMA has no direct access to the status of substation capacitors and switches, analogs of bus voltage and transformer loading.

Therefore, access to transmission SCADA, to ensure that the above parameters are available, needs to be addressed.

- Is the company ready to consider steps needed for a functional integration of distribution, transmission and market operations? The latter will require access to EMS, to ensure that energy pricing is available in real time.

4.2 The Extend of Modeling the Low Voltage (LV) Distribution System

Most of the changes in distribution operating conditions impact the operational parameters on the customer sites: the amount of electric energy consumed the power quality, and the service reliability. Therefore, the Distribution Operation Model should cover the distribution system as close to the points of energy consumption as possible. The model should definitely include the distribution transformers (transforming the medium voltage into low voltage) and some kind of a model of the LV circuits. Ideally, the full model of the LV circuits with the loads connected to the point of service is desirable. Practically, in most of the utilities, it is currently impossible to built and support such a mode due to the lack of such operational databases. The most urgent need of such LV models can be seen for large LV networks, where the power flow in the LV network is highly dependent on the connectivity in the primary system feeding the LV networks. Outages of the primary feeders can lead to dangerous overloads in the LV network resulting in cascading contingencies.

In the cases with radial LV circuits fed from a single distribution transformer or from a transformer group, the LV circuit can be represented by equivalent (reduced) circuit and by an aggregated load model. The important parameters, which should be equivalently represented in such models, are the aggregated loads in the load centers and the voltage drop between the distribution transformer and the load centers. In addition, a model of the demand response characteristics of the load, if any, should be embedded in the aggregated load model.

Large customers can be individually represented by their object models, which need to be developed. The attributes of aggregated loads associated with a distribution transformer or a group of parallel transformers and containing components with special demand response means can be developed in pre-processing procedures within Customer Information Systems and be transferred to DMS databases. A standard object model of such aggregated load would be helpful for easier implementation of DMS based on different platforms.

The advances of Advanced Metering Infrastructure (AMI) raise an issue about integration of DMS with AMI. The degree of integration depends on the scope of AMI. If the AMI system collects energy consumption data, this information can be used for obtaining more accurate (synchronized) aggregated per distribution transformer billing data, which is used for generating distribution transformer load models. If the AMI system is collecting load data for several time intervals during days, this data can be used to develop more accurate typical load shapes for different load categories. This data is also used to generate distribution transformer load models.

If the AMI system collects load data in ‘real-time”, this data can be used for more accurate “real-time” load models. In order to use this data in aggregated load models, the individual measurements should be synchronized in time. If multi-functional meters are used in AMI, the power factors and voltages can be measured. The use of this data depends on the accuracy of the measurements, on the frequency of its transmission to data concentrators or databases, and on the ability to process this data for the purpose of nodal load modeling. It must be noted, that these measurements can assist in more accurate power flow, but they do not replace the power flow. In most of the DMS computing applications, “what-if” calculations are involved. These calculations simulate the impact of controllable variables on the end results. For instance, even if the voltages at the customer service points are known, it is not enough to determine the optimizing actions for voltage and var control in the distribution system, especially for system-wide objectives, such as demand response, transmission volt/var support, etc. In order to determine the actions for optimizing the voltages and vars in the distribution system, the impact of changing the voltages and vars on the voltages at the customer terminals, on the loading of distribution and transmission facilities, on the losses in distribution and transmission, on the power capacity of generators should be calculated.

Action items:

1. Determine the extent of the existing and planned AMI in the utility. If significant Automated Meter Reading (AMR) exists or is expected, define the functionality of the AMR and verify whether and how the data collected via AMR is utilized for distribution nodal load modeling.

2. Address the issue about interfacing the AMI with DMS applications. Consider the scope of automated metering, the accuracy of each parameter, the frequency of collecting data and updating the relevant databases.

4.3 DMS Database Update

The DMS database provides information support for the DOMA function (and other DMS functions) making the issue of database management crucial for the successful operation of the function. There are several sources of information used by the DMS database. These include AM/FM/GIS database, CIS database, and the real-time updates coming from field crews and/or operators, and SCADA. The following subsections identify the issues arising from relevant material presented in IntelliGrid Architecture.

4.3.1 Updating AM/FM/GIS Database

The AM/FM/GIS database provides nominal connectivity information as well as the facility parameters to the DMS database (see section *Data Management Issues between AM/FM/GIS and*

DMS Distribution Connectivity Database). The quality and completeness of AM/FM/GIS information is relied upon to make decisions affecting the real-time distribution operations. Therefore, the questions about the AM/FM/GIS database readiness to participate in this process should be raised.

Action items:

Determine:

- Determine whether the AM/FM/GIS database have all the information required by DMS. For example, data needed for distribution transformers are as follows: installed kVA, nominal voltages, tap positions, core/coil losses, impedance; step-down transformer tap positions and impedance; substation transformer data, etc. If this data is not in the database, the missing data should be acquired from other sources and added to the database.
- How frequent and complete is the AM/FM/GIS database update? All significant changes should be incorporated into the database without delay. If this is not the current practice, measures should be suggested to change the procedures for database update to minimize the time delay between the change in the field and the change in the DMS database.
- Determine the validity of data in the AM/FM/GIS database and develop a process for maintaining the consistency of data in the database.

Addressing the above issues should ultimately result in a procedure for a regular update of the AM/FM/GIS database by qualified personnel.

4.3.2 Updating CIS Database

The quality of CIS data, specifically the billing data, will be enhanced if CIS is supported by data from Automated Meter Reading System (see section *Data Management Issues between CIS and AM/FM/GIS and DMS Distribution Connectivity Database*). This, by extension, will positively impact the quality of DOMA's recommendations as well.

Action items:

- Take steps to ensure that the presence of the Advanced Metering Infrastructure (AMI) or Automated Meter Reading system (AMR), if one already exists at the utility, is taken advantage to improve the quality of the billing data used by DOMA. Specifically, using the billing data from CIS (supported by AMR) for regular DMS database updates, the loading of individual distribution transformers will be modeled more accurately, thus increasing precision of the power flow calculations. This, in turn, impacts the integrity of DOMA output data/recommendations as well as of other DMS functions that rely on DOMA for input information.
- Take steps to ensure that AMR implementation approach does not conflict with DMS needs. An example could be consolidated bills, in some of the present AMR systems, where the load data of individual distribution transformers at different sites becomes unavailable outside of CIS.

4.3.3 Updating DMS Database with CIS and AM/FM/GIS Data

Updating the DMS database with the AM/FM/GIS and CIS data is not a trivial exercise, and it requires a conversion and validation process similar to one shown in section *DOMA Data Conversion*. The issues associated with the interface between the AM/FM/GIS/CIS and DMS that need to be addressed are presented as the following action items.

Action items:

- Consider the applicability of Common Information Model (CIM) – http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_IEC_61970_Part_3_-_Common_Information_Model_(CIM).htm to the presentation of data residing in corporate databases and used in DMS
- Develop the process and the format for data retrieval from CIS and AM/FM/GIS databases
- Develop the process for CIS and AM/FM/GIS data conversion and validation before the DMS database update takes place
- Develop the process for DMS database update. Consider the availability and applicability of industry standards for the subject information exchange.

4.3.4 Updating DMS Database with Real-Time Data

The changes in the real-time connectivity are entered into the DMS database (see section *Modeling Distribution Circuit Connectivity*) either through SCADA for the remotely monitored points, or by the field crew directly (via mobile computing), or by the operator, who receives them from the field crew. The timing and the accuracy of this information is essential due to their potential impact on the real-time distribution operations.

Action items:

Address issues raised in the following questions:

- Does the technology allow for the field crew to enter changes in connectivity directly into the DMS database? If yes, should it require operator's authorization? Should the operator be in the loop at all? What kind of cyber-security measures should be provided?
- If the technology is not available, does the field crew have the means to communicate this information to the operator reliably and in a timely manner?
- Does the operator have the time to deal with entering this information into the DMS database?
- Are the operators ready and willing to accept the responsibility for handling this information?
- Modeling distribution connectivity requires not only establishing the communication links to all the actors, expected to provide the connectivity data, but also conveying to them the importance of ensuring the quality of their contribution. This issue should be addressed in discussions with both the field crews and the operators.
- The connectivity issue is also closely related to the requirements for SCADA capabilities. Not only SCADA should be able of carrying the information

related to many new parameters, but also, under some circumstance, the speed of that communication is drastically increasing. For example, during the storm conditions, DOMA may be running every 2 min. Therefore, the timing of DMS database update should comply with the 2-min time interval, thus placing a new speed requirement on SCADA. This should be considered while evaluating/upgrading SCADA.

Furthermore, steps should be taken to include in SCADA (unless already available) the real-time data required for modeling and control. This data includes real-time information about the modes of operation, states, and operational parameters from DER devices and from a number of Intelligent Electronic Devices (IED), such as Remote Terminal Units (RTU), recloser controllers, capacitor controllers, voltage regulator controllers, etc.

The method of information exchange with these devices depends on the availability of the standard object models for these devices and on the capability of these IEDs to communicate over standard communication protocols.

Action items:

1. Take steps to include in SCADA the following operational parameters:
    - Feeder and station capacitors status and mode of operation
    - Feeder and bus analogs
    - Switching device status, mode of operation, protection settings, as well as lock-outs and fault indications (whichever is applicable)
    - Transmission line status and operating limits
    - Transmission reactive power source schedule
    - LTC, voltage regulator, and DER controllers' statuses, settings and modes of operation
    - DER Object Model (OM) parameters required by DMS, e.g., mode of operation, capability curves , status of operation, schedule of operation, output analog measurements, etc. (see EPRI publication *Studies of Distribution Operations to Aid in Determining Object Models for Distributed Energy Resources* for more information on DER OM)
    - Settings, statuses, modes of operation, commands, recommendations, and output data associated with DOMA.
2. Define the existing object models for the participating field devices and the ability of the IEDs to adhere to the standard communication protocols. Select the communication technology that meets the utility objectives and is consistent with utility resources. Consider the conformity of the selected technology with the tendency of the industry toward using International Standards in the Communication Infrastructure. For example, the industry is moving into expansion of the use if IEC61850 for distribution and transmission operations. Learn whether standard object models consistent with the IEC61850 exist for the devices, with which DMS should be interfaced and whether the corresponding logical nodes ant attributes are included in the standard to accommodate the requirements of DMS.

4.4 Distribution Nodal Load Modeling

The following issues associated with nodal load modeling should be addressed (see section *Modeling Distribution Nodal Loads in* *http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*).

Action items:

- Review the existing load shape data for each customer category (residential, industrial, commercial, etc.). The origin of that data and its accuracy should be determined. If need to, a load survey study (e.g., using AMR capabilities) should be performed to update the load shape data for all relevant customer categories.
- Determine via field tests the load-to-voltage dependencies (both kW and kvar) for typical customer categories
- Confirm whether the accuracy of the real-time field measurements (kW, kvar, Amps, kV) meets DMS requirements. If need to, the upgrades and/or replacement of relevant measuring units should be undertaken.
- Take steps to include in relevant databases additional information required by nodal load modeling. This information includes actual and forecasted environmental data and data pertinent to demand response means.

4.5 Evaluation of Transfer Capacity

The DOMA's report on transfer capacity (see section *Evaluation of Transfer Capacity in* *http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*) can be used for support/validation of service restoration and optimum reconfiguration solutions, or for making any decisions associated with changes in connectivity, load balancing, etc.
Action items: Arrange for DOMA's report on transfer capacity to be issued to the operator and the engineering staff.

4.6 Power Quality Analysis

The results of DOMA's power quality analysis can substantially enhance the existing utility's practice of evaluating power quality (see section *Power Quality Analysis in* *http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*). To take advantage of these results, the newly available real-time power quality parameters should be incorporated into the various procedures presently used by the company as outlined in the following action items.

Action items:

Include results of DOMA power quality analysis into the following:

- Scheduled power quality evaluation procedures – e.g., the monitoring of minimum and maximum customer terminal voltages, voltage quality index and voltage imbalance helps to evaluate the impact the changes, taking place on the system, have on the quality of power received by the customers.

- Procedures used to investigate customer complaints – e.g., the possible reasons for the problem, if not already reported by DOMA in real time, can be studied with DOMA in the study mode before the investigation begins in the field. Furthermore, the voltage/overload violations, as reported by DOMA, can be investigated right away, thus potentially preventing/foreseeing customer complaints.
- Procedures used to evaluate the impact on power quality from new facilities, changes in connectivity and reactive power compensation – e.g., the evaluation is done before the changes are implemented through the off-line studies and observed in real time after implementation.

4.7 Loss Analysis

The results of DOMA's loss analysis can substantially enhance the utility's existing practice of evaluating losses (see section *Loss Analysis in* http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm). These results contain components of technical losses, including transmission, substation transformer core/coil, feeder, and distribution transformer core/coil losses.
Action items: Arrange for DOMA's report with results on loss analysis to be available to other departments within the company.

4.8 Fault Analysis

The DOMA's fault analysis provides an opportunity to determine the fault current under a multitude of operating conditions (see section *Fault Analysis in* http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm). The changes, taking place in distribution operating conditions, continuously impact the level of the expected fault current. Therefore, the maximum fault current should be periodically determined to verify whether it could be interrupted given the rating of existing switching devices. Moreover, the minimum fault current should be periodically determined to check the sensitivity of the protective relaying. In case the fault current is inconsistent either with the interruption capability of switching devices, or with the sensitivity of relay protection, DOMA should alarm the operator. In addition, such information should be conveyed to other relevant parties.
Action items:

- Arrange for DOMA's report on fault analysis (i.e., minimum fault current) to be reported to protective relaying personnel for protective relaying settings update.
- Arrange for DOMA's report on fault analysis (i.e., maximum fault current) to be reported to system planners and circuit breaker experts to be used in studying the feasibility of various operating conditions.

4.9 Evaluation of Operating Conditions

The evaluation of operating conditions benefits the operators by detecting in real time the critical voltages, and voltage and overload violations (see section *Evaluation of Operating Conditions in http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm*). Using the violations reported by DOMA, the operator can initiate problem investigations before the customer complaints come through. Furthermore, DOMA, by reporting the available demand response for real and reactive power, will guide the operator in making load reduction decisions. The parameters aggregated at transmission-to-distribution busses serve as operational limits used by functions controlling transmission. These parameters include dynamic voltage limits and dispatchable load.

Action items:

- Arrange for reporting violations to relevant departments
- Arrange for information exchange between Distribution Companies (DISCO) and Transmission Companies (TRANCO).

5. UNDERSTANDING INFORMATION FLOW

5.1 Introduction

An understanding of the information flow is essential to determine the communication requirements needed for DMS information support. The flow charts in section *DOMA Steps* identify the communication links between the key actors involved in DMS, the type of data transmitted by each link as well as communication environments associated with each link.

Action items:

- The DMS Historic Database will be receiving daily a massive amount of data; therefore, the issues of data selection, storage, archiving, security, back-up, retrieval, maintenance, manpower, authorized access, web access, ownership, sharing with interested parties, and usage, should be addressed.
- As diagrams and the narrative show, a number of DOMA output parameters are suggested to be made available for the operator. Each of these parameters should be reviewed to determine whether to permanently display them for the operator or to make them available upon request from the control room.
- Before DOMA calculations begin, the distribution model is checked for inconsistencies, e.g., it is checked whether the distribution network connectivity is consistent with the analog measurements. In case the answer is negative, and the integrity of the distribution model is in question, as section *DOMA Steps* show, several actions are undertaken. The inclusion of the message on the operator's display should be discussed. Furthermore, the course of action in case this message is displayed should be developed and

agreed with all the parties involved. Specifically, the issues to resolve may include the following:

- Who is responsible for investigating the causes of inconsistency?
- What is the methodology for determining the cause of inconsistency?
- Who is responsible for taking the necessary steps for restoring distribution model's integrity?

For example, if the inconsistency is caused by the operator omitting to change on time the status of a locally-operated switch – although the field crew had informed him/her of changes in the field – the resolution is quite simple and is implemented by the operator. If the operator was not informed about the field changes, then communications with the field crew are involved. The field crew is also involved if the integrity of the field analog measurement is a suspect and a particular measuring device ought to be investigated. It will also be prudent to inform all the parties, relying on DOMA's data, about the significance and the reasons behind the inconsistency messages.

The understanding of information flows prepares the user for dealing with communication environments.

5.2 Concept of IntelliGrid Environments

The concept of Intelligrid Environments and their attributes (configuration, performance, security and data management) are presented in the Section Environments of the Intelligrid documents (http://intelligrid.info/IntelliGrid_Architecture/Environments/Environments.htm).

In summary, IntelliGrid Architecture defines an ***Environment*** based on a logical grouping of information support requirements that could be addressed by a similar set of distributed computing technologies. Within a particular environment, the information support requirements are divided in the following components:

- Configuration requirements (Who interacts with whom)
- Quality of service requirements (Availability, timing)
- Security requirements (Confidentiality, integrity, availability, and non-repudiation)
- Data management requirements (Network Management, volumes of data flows, data up-to-date, data validation, synchronization, multiple users, frequency of changes, specific or standard object models, support of unstructured data formats, conversion of data, mapping, etc.)

Procedure for Performing Security Risk Assessment and Mitigation

The procedure for performing security risk assessment and mitigation are described in the following steps, and are illustrated in Figure 5-1 of the IntelliGrid document (see also http://intelligrid.info/IntelliGrid_Architecture/Technology_Analysis/Anl_Security_Risk_Assessment.htm). It is recommended that the North American Electric Reliability Council (NERC) Critical Infrastructure Protection standard is used as a guideline for security risk assessment and mitigation (see http://www.nerc.com/~filez/standards/Reliability_Standards.html#Critical_Infrastructure_Protection):

1. **Describe the Function** as a narrative and basic steps, along with drawings to help identify the locations of data and the flows of information. These descriptions do not need to be detailed, but should cover the function from end to end. This should be done by "Domain Experts": people who understand the functions and the equipment, but do not necessarily need to understand security technologies.
2. **Identify the Critical Information Assets** that must be secured: specifically databases, data exchanges, applications, and hardware. This should be done by "Domain Experts".
3. **Determine the Configuration and Performance Constraints** of these information assets by using the Configuration and Performance Questions. This should be done by "Domain Experts".
4. **Assess the Security Requirements of Confidentiality, Integrity, Availability, and Non-Repudiation** by using the Security Questions for each of the information assets. This should be done by "Domain Experts".
5. **Identify the IntelliGrid Environments that most closely match the Configuration and Performance Constraints.** Using the Configuration and Performance questions, identify the most appropriate IntelliGrid Environments (see http://intelligrid.info/IntelliGrid_Architecture/Environments/Environments.htm). This should be done by "Communications Experts": people who understand communications, including security, but do not necessarily understand the function. However, interaction with the Domain Experts is vital to ensuring that the function is truly understood and the correct Environments selected.
6. **Equate IntelliGrid Environments to Security Domains.** Using the IntelliGrid Environments identified as the most relevant to the function, treat them as security domains. This matching may not be exact, but can provide significant support to ascertaining what security services are needed. This should be done by "Communications Experts".
7. **Identify Security Technologies and Techniques** based on IntelliGrid Environment / Security Domain recommendations and modified by the Security Questions which identified which security requirements must be met. This should be done by "Communications Experts".
8. **Select Actual Security Products and Procedures.** Company security policies and existing security products should be used to determine what actual security products and

procedures should be implemented. This should be done by "Utility Communications Experts".

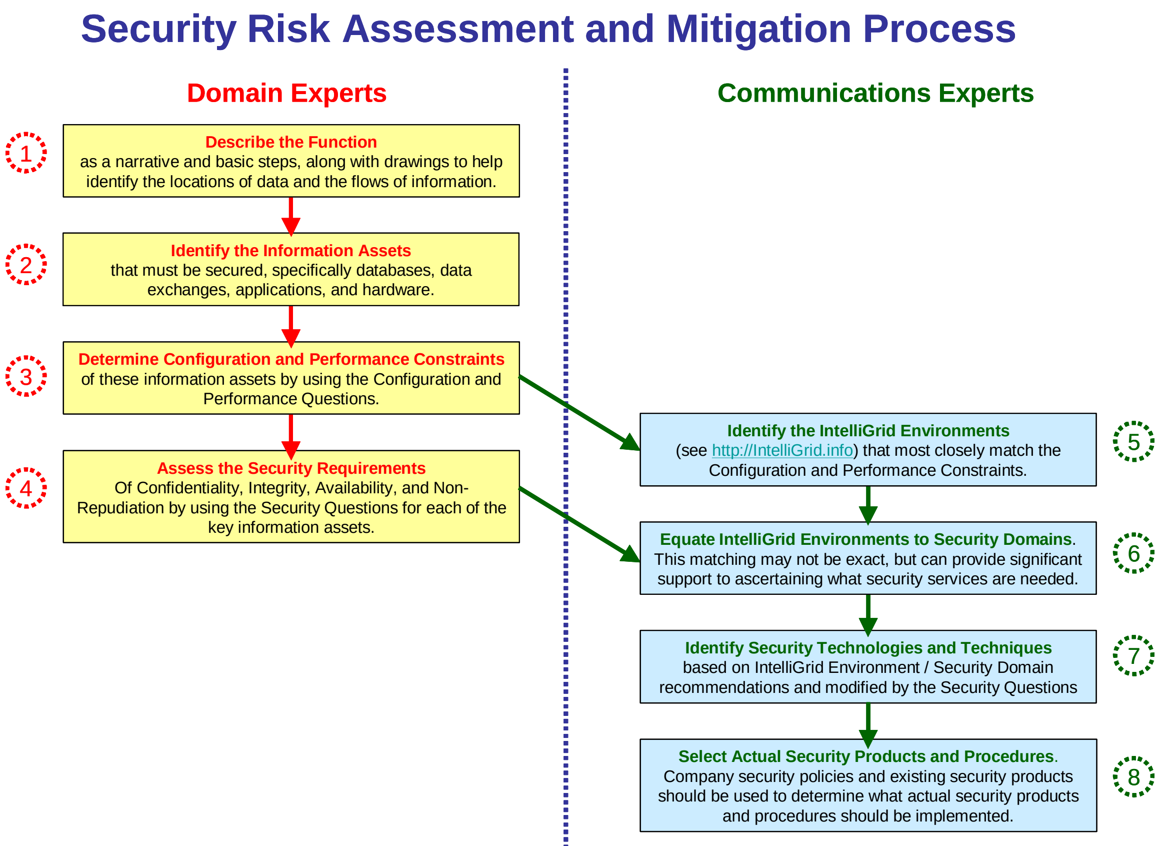

Figure 5-1: Security Risk Assessment and Mitigation Process

5.3 Intelligrid Environments for DMS (based on Distribution Operation Model and Analysis information flow)

As follows from the information flow of DOMA (see Section Distribution Operation Model and Analysis of the Inteelligrid Documents – http://www.intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm), the information exchange needed for DOMA directly involves the SCADA/EMS, DMS and corporate databases. The support of these databases needs information exchanges with field devices and personnel. These environments are described in Section Data Acquisition and Control (DAC) Function (http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DAC_Use_Case.htm) and mainly represent the Critical Operations DAC and SCADA Environment #5 (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env5_Critical_Operations_DAC.htm) and DER Monitoring and Control Environment # 15 (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env15_DER_Monitoring_and_Control.htm). If data acquisition and control for DMS is partially accomplished through Substation Automation (SA), then the Deterministic Rapid Intra-substation Environment #1 (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env1_Deterministic_Intra-Substation.htm) and the Critical Operations Intra-Substation Environment - #3 (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env3_Critical_Operations_Intra-Substation.htm) are involved.

Hence, specifically for DOMA, which resides in the Control Center realm, the following Intelligrid environments are involved:

1. Environment #7. Intra-Control Center**:** Within one control center between DMS and SCADA/EMS

2. Environment #13. Intra-Corporation Environment**:** Within corporate utility (e.g. between DMS and planning, engineering, DMS access to AM/FM and customer information systems)

3. Environment # 11. Control Center to Customers: Between the DMS and large customers with their own Energy Management Systems or equipped with Automatic Meter Reading systems.

The choices of technologies for these Environments are listed in Sections Recommended Technologies (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env7_Intra-Control_Center.htm in (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env13_Intra-Corporation.htm), and in (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env11_Control_Center_to_Customers.htm).

These sections cover the following topics:

- Energy Industry-Specific Technologies
- Communications Industry Technologies
- Security Technologies
- Network and Enterprise Management Technologies

They also cover Recommended Common Services, including the following issues:

- Security Services
- Network and System Management Services
- Data Management Common Services
- Common Platform Services

Section Best Practices covers the following issues:

- Data Management Best Practices
- Security Best Practices.

From these sub-sections, one can navigate to the more detailed description of the technologies.

5.3.1 Intra-Control Center Environment #7

Most steps of the DOMA function take place within the ***Intra-Control Center Environment (#7)*** ((http://intelligrid.info/IntelliGrid_Architecture/Environments/Env7_Intra-Control_Center.htm). The following are the DOMA requirements within this environment.

5.3.1.1 Configuration Requirements

The configuration requirements are characterized by the following:

- Connection configuration: support networked interactions
- Single or broadcast configuration: provide for single source and destination per message
- Client-Server configuration: provide interactions between a few “servers” and many “clients” (e.g., central application server with many users accessing it)
- Internal-External Configuration: provide interactions within a contained environment (i.e., control center and facilities of the operation planner and DMS support personnel)
- Media configuration: use fixed communications (e.g., wire, fiber optic cables, fixed wireless systems)
- Equipment constraints: no equipment or media constraints
- Moves and changes: infrequent changes of equipment or communication

5.3.1.2 Quality of Service Requirements

- Messaging speed: high speed for high priority messages requiring response in the order of 1 second and medium speed for other messages with response requiring within an order of 10 seconds
- Availability: requires medium availability of information flows of 99.0+ (~3.5 days per year)
- Time criticality: requires contractual timeliness (due to operational requirements, regulations or contracts, data must be available at a specific time or within a specific window of time)
- Time synchronization: time synchronization within one minute
- Data traffic pattern: large amount of data processing within the computers and low traffic levels over the interfaces the majority of time

5.3.1.3 Security Requirements

The DMS applications within the IntelliGrid ***Intra-Control Center Environment*** are characterized by the following security requirements for the four security issues of Confidentiality, Integrity, Availability, and Non-Repudiation:

Confidentiality (preventing the unauthorized access to information):

- Significant direct financial losses from data seen by unauthorized entities: **some financial losses are possible in a competitive market environment**
- Suffering from social or regulatory impacts from data seen by unauthorized entities: **unlikely**
- Significant decrease in safety of employees, customers, or the public from data seen by unauthorized entities: **unlikely**
- Another entity benefiting financially from seeing the data: **it is possible in a competitive market environment**
- Another entity benefiting socially or politically from seeing the data: **unlikely**

Integrity (preventing the unauthorized modification or theft of information):

- Suffering significant direct financial losses from data being modified, deleted, or stolen by unauthorized entities: **it is possible due to incorrect operational decisions because of wrong or missing data**
- Suffering from social or regulatory impacts from data being modified, deleted, or stolen by unauthorized entities: **it is possible due to incorrect operational decisions because of wrong or missing data resulting in reduction of customer satisfaction**

- Significant decrease in safety of employees, customers, or the public from data being modified, deleted, or stolen by unauthorized entities: **it is possible due to incorrect operational decisions because of wrong or missing data.**
- Another entity benefiting financially from data being modified, deleted, or stolen by unauthorized entities: **it is possible in a competitive market environment**
- Another entity benefiting socially or politically from data being modified, deleted, or stolen by unauthorized entities: **it is possible.**

Availability (preventing the denial of service and ensuring authorized access to information):

- Suffering significant direct financial losses from data being unavailable within the required time window: **it is possible due to delayed reactions to emergency massages.**
- Suffering from social or regulatory impacts from data being unavailable within the required time window: **it is possible due to delayed reactions to emergency massages.**
- Significant decrease in safety of employees, customers, or the public from data being unavailable within the required time window: **it is possible due to delayed reactions to emergency massages and therefore wrong operational decisions.**
- Another entity benefiting financially from data being unavailable within the required time window: **it is possible in competitive market environment.**
- Another entity benefiting socially or politically from data being unavailable within the required time window: **it is possible in competitive market environment.**

Non-Repudiation (preventing the denial of an action that took place or the claim of an action that did not take place):

- Suffering significant direct financial losses from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible due to wrong operational decision, e.g., because of an unknown rejection of a significant input message**.
- Suffering from social or regulatory impacts from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible due to wrong operational decision, e.g., because of an unknown rejection of a significant input message**.
- Significant decrease in safety of employees, customers, or the public from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible due to wrong operational decision, e.g., because of an unknown rejection of a significant input message**.
- Another entity benefiting financially from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible in competitive market environment.**

- Another entity benefiting socially or politically from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible in competitive market environment.**

Resulting Security Services

Based on the results from Confidentiality, Integrity, Availability, and Non-Repudiation requirements, the following security services are needed:

- Provide Identity Establishment Service (you are who you say you are). See Section Identity Establishment Service – (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Identity_Establishment_Service.htm)
- Provide Authorization Service for Access Control (resolving a policy-based access control decision to ensure authorized entities have appropriate access rights and authorized access is not denied. See Section Authorization for Access Control - http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Authorization_for_Access_Control.htm)
- Provide Audit Service (responsible for producing records, which track security relevant events. See Section Audit Common Service – http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Audit_Common_Service.htm)
- Provide Security Policy Service (concerned with the management of security policies. See, e.g., Section Security Policy Issues – http://intelligrid.info/IntelliGrid_Architecture/Technology_Analysis/Anl_Security_Policies.htm)
- Provide User Profile and User Management according to Section Profile Service – http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Profile_Service_(User_Profile_Service).htm)

5.3.1.4 Data Management Requirements

The general requirements for data management are described in Section Data Management in the IntelliGrid Architecture - (http://intelligrid.info/IntelliGrid_Architecture/Technology_Analysis/Anl_Data_Management.htm).

An example of specific requirements for DMS applications within the IntelliGrid Intra-Control Center Environment is presented below.

- Support integration of sources of real-time data with sources of corporate data. Consider application of IEC standards, such as IEC 61970 Part 3 (CIM) - (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_IEC_61970_Part_3_-_Common_Information_Model_(CIM).htm) and IEC 61850.

- Provide Information Network Management (management of communication nodes. See, e.g., Section Network management Technologies - (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/H3_Network_Management_Technologies.htm)
- Provide System Management (management of DMS applications)
- Support the management of large volumes of data processing
- Support keeping the data up-to-date
- Support extensive data validation procedures (the real-time operational model should be continuously checked on integrity)
- Support keeping data consistent and synchronized across systems and/or databases
- Support timely access to data by multiple different users
- Support changes in types of data exchanged (e.g., after integration with a new AMI)
- Support specific standardized or de facto object models of data (e.g., DER object models based on IEC61850)
- Support the exchange of unstructured or special-format data (e.g. text, documents, oscillographic data)
- Provide conversion and protocol mapping.

5.3.2 Intra Corporation Environment #13

A few but very important steps of the DOMA function take place within the ***Intra Corporation Environment (#13)*** **-** (http://intelligrid.info/IntelliGrid_Architecture/Environments/Env13_Intra-Corporation.htm).

DOMA interfaces with the AM/FM/GIS and CIS databases. The AM/FM/GIS database is the source of information about the nominal connectivity, geographic locations, and electric parameters. The same database can be the source of information about the customer consumption, if the CIS is interfaced with the AM/FM/GIS database and the consumption data is associated with the relevant distribution transformers. If the CIS database is used as an independent source of information about the customer consumption, then the association with the distribution transformers should be represented in the CIS database. If the consumption data is collected on a monthly basis, the update of the DMS database in regard with consumption is performed also on a monthly basis. If the CIS database is fed from an AMR system, and the data is collected more frequently, then there are several alternatives for utilizing the data by DMS. One alternative is that the data is collected in a intermediate information system (e.g., load survey system) where it is used to 1) derive representative load shapes for different groups of customers and for different timeframes and 2) aggregate the load on distribution transformer levels. Then, the load shapes, the average or peak demand associated with the corresponding distribution transformer are stored either in the CIS or in the GIS databases for the use by DMS. The frequency of updates of the DMS database for consumption data is, practically, the same – monthly. Another alternative for utilizing the AMR data by DMS applications is the near-real-time update of the DMS load models. In this case the data collected by the AMR system should be processed by the AMI processor in near-real-time fashion.

The data processing should include data synchronization in time, aggregation of data on distribution transformer basis (per phase), and determination of the lowest and the highest voltage measurements, if any, in each phase.

The requirements for DMS applications within this environment are described below

5.3.2.1 Configuration Requirements

- Connection configuration: support network interactions
- Single or broadcast configuration: provide for single source and destination per message
- Client-Server configuration: provide interactions between a few “servers” and many “clients”
- Internal-External Configuration: Provide interactions across widely distributed sites (e.g., Interfaces between DMS and AM/FM/GIS/CIS, OMS, and WMS)
- Media configuration: use fixed communications (e.g., wire, fiber optic cables, fixed wireless systems)
- Equipment constraints: no equipment or media constraints
- Moves and changes: infrequent changes of equipment or communication

5.3.2.2 Quality of Service Requirements

- Messaging speed: medium speed with message requiring on the order of 10 seconds
- Availability: requires medium availability of information flows of 99.0+ (~3.5 days per year)
- Time criticality: requires contractual timeliness (due to operational requirements, data must be available at a specific time or within a specific window of time)
- Time synchronization: requires time synchronization of data for age and time-skew information
- Data traffic pattern: low traffic levels the majority of time, except if the near-real-time interface with AMI systems is implemented.

5.3.3 Security Requirements

Confidentiality

- Significant direct financial losses from data seen by unauthorized entities: **some financial losses are possible in a competitive market environment (e.g., data on large customers)**

- Suffering from social or regulatory impacts from data seen by unauthorized entities: **unlikely**
- Significant decrease in safety of employees, customers, or the public from data seen by unauthorized entities: **unlikely**
- Another entity benefiting financially from seeing the data: **it is possible in a competitive market environment**
- Another entity benefiting socially or politically from seeing the data: **unlikely**

Integrity

- Suffering significant direct financial losses from data being modified, deleted, or stolen by unauthorized entities: **it is possible due to incorrect operational decisions because of wrong or missing data**
- Suffering from social or regulatory impacts from data being modified, deleted, or stolen by unauthorized entities: **it is possible due to incorrect operational decisions because of wrong or missing data resulting in reduction of customer satisfaction**
- Significant decrease in safety of employees, customers, or the public from data being modified, deleted, or stolen by unauthorized entities: **it is possible due to incorrect operational decisions because of wrong or missing data.**
- Another entity benefiting financially from data being modified, deleted, or stolen by unauthorized entities: **it is possible in a competitive market environment**
- Another entity benefiting socially or politically from data being modified, deleted, or stolen by unauthorized entities: **it is possible.**

Availability

- Suffering significant direct financial losses from data being unavailable within the required time window: **it is possible due to delayed updates of significant changes.**
- Suffering from social or regulatory impacts from data being unavailable within the required time window: **it is possible due to delayed updates of significant changes.**
- Significant decrease in safety of employees, customers, or the public from data being unavailable within the required time window: **it is possible due to delayed updates of significant changes and therefore wrong operational decisions.**
- Another entity benefiting financially from data being unavailable within the required time window: **it is possible in competitive market environment.**
- Another entity benefiting socially or politically from data being unavailable within the required time window: **it is possible in competitive market environment.**

Non-Repudiation

- Suffering significant direct financial losses from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible due to wrong operational decision, e.g., because of an unknown rejection of a significant change update**.
- Suffering from social or regulatory impacts from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible due to wrong operational decision, e.g., because of an unknown rejection of a significant change update**.
- Significant decrease in safety of employees, customers, or the public from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible due to wrong operational decision, e.g., because of an unknown rejection of a significant change update**.
- Another entity benefiting financially from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible in competitive market environment.**
- Another entity benefiting socially or politically from a transaction being repudiated or from lack of solid proof that a transaction did not take place: **it is possible in competitive market environment.**

Resulting Security Services

Based on the results from Confidentiality, Integrity, Availability, and Non-Repudiation requirements, the following security services are needed:

- Provide Identity Establishment Service (you are who you say you are). See Section Identity Establishment Service – (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Identity_Establishment_Service.htm)
- Provide Authorization Service for Access Control (resolving a policy-based access control decision to ensure authorized entities have appropriate access rights and authorized access is not denied. See Section Authorization for Access Control - http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Authorization_for_Access_Control.htm)
- Provide Information Integrity Service (data has not been subject to unauthorized changes or these unauthorized changes are detected). See Section Information Integrity Service – (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Information_Integrity_Service.htm)
- Provide Confidentiality Service (only authorized access to information, protection against eavesdropping). See Section Confidentiality (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Confidentiality.htm)

- Provide Security Assurance Service (determine the level of security provided by another environment, e.g., by Environment #11 – Control Center to Customers, if AMR is involved in providing data for DMS). See Section Security Assurance Management – (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Security_Assurance_Management.htm)

- Provide Audit Service (responsible for producing records, which track security relevant events). See Section Audit Common Service – (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Audit_Common_Service.htm)
- Provide Security Policy Service (concerned with the management of security policies). See Section Security Policies – (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Security_Policies.htm)
- Provide Firewall Transversal (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_Firewall_Traversal.htm)

5.3.3.1 Data Management Requirements

- Support integration of sources of real-time data with sources of corporate data. Consider application of IEC standards, such as IEC 61970 Part 3 (CIM) - (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/Tech_IEC_61970_Part_3_-_Common_Information_Model_(CIM).htm) and IEC 61850.
- Provide Information Network Management ((management of media, transport, and communication nodes). See, e.g., Section Network Management Technologies - (http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/H3_Network_Management_Technologies.htm)
- Provide System Management (management of DMS applications)
- Support the management of large volumes of data processing
- Support keeping the data up-to-date
- Support extensive data validation procedures (AM.FM/GIS and CIS data need intensive data consistency checking)
- Support keeping data consistent and synchronized across systems and/or databases
- Support timely access to data by multiple different users
- Support changes in types of data exchanged (e.g., after integration with a new AMI)
- Support specific standardized or de facto object models of data (e.g., large customer object models based on IEC61850)

- Provide conversion and protocol mapping (Consider application of IEC 61970 and IEC 61850)
- Support the management of data across departmental boundaries (e.g., Operations and Information Services department)

5.4 DOMA Steps

This section describes the information flow for DOMA application broken into steps according to the IntelliGrid use case for DOMA. The descriptions are given for the information flow associated with data conversion and validation process (see section *DOMA Data Conversion - http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm#DOMA%20Setup*) and with the process that takes place when DOMA run is triggered by the event (see section *DOMA Runs due to Events - http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm#DOMA%20Event%20Run*). The description explains the main purpose of each step, the type of information exchanged, the source and the recipient of the information, and the communication environment involved. Although, a perfect match for the communication environment may not be found, the IntelliGrid Environments serve as a significant support for ascertaining what services are required by DOMA information flow. Also, the flows of information, shown in tables and UML flow diagrams, are only examples (although every effort was made to include every known possibility). The implementation of communication infrastructure should use IntelliGrid as a guide while reviewing the information flow on the actual system.

The actions items related to communication environments are as follows:
Action items:

- Identify information flow links required by DOMA implementation in your company
- Determine if the existing communication infrastructure meets configuration and performance requirements necessary for DOMA
- Assess the security requirements (confidentiality, integrity, availability, and non-repudiation)
- Identify security technologies and techniques that would bring existing communication infrastructure to the level required by DOMA

5.4.1 DOMA Data Conversion and Validation

5.4.1.1 DOMA Step 1.1.1: Authorization to Conversion and Validation

The DMS Database Administrator authorizes the Conversion and Validation sub-function to extract, convert and validate circuit connectivity, electric parameter data, and distribution transformer loading data. This step starts Stage 1 validation. This authorization enables the Conversion and Validation sub-function either to sent out a request for an incremental data extract from the AM/FM/GIS/CIS database, or to acknowledge a standing message that the incremental extract from the source databases are ready for transmittal. In the former case, the requirements for this step match those of IntelliGrid Intra-Corporation Environment #13, and in the latter case the requirements for this step match those of the Control Center Environment #7.

5.4.2 DOMA Step 1.1.2: Real-Time Data from DMS SCADA Database

The data in the latest download of DMS SCADA data is checked by DOMA function for changes in topology and is used to obtain the latest relevant analog data. This step is independent from Conversion and Validation process and is shown to indicate that it is taking place during this process and should be taken into account. It means that the DOMA application continues operating based on the real-time data and previous AM/FM/GIS/CIS data. In case of inconsistencies between the real-time data and the connectivity/parameter/nominal loading data, the application should report the invalidity of the current model and trigger default behavior embedded in the design of the application. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.3 DOMA Step 1.1.3: Changes in Connectivity

The Topology Update function prepares changes in connectivity for updating DMS database based on the latest DMS SCADA data. This step is independent from Conversion and Validation process and is shown to indicate that it is taking place during this process and should be taken into account. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.4 DOMA Step 1.1.4: DMS Database Update

The Topology Update function updates DMS database based on the changes detected in the latest snapshot of DMS SCADA. This step is independent from Conversion and Validation process and is shown to indicate that it is taking place during this process and should be taken into account. In case of inconsistencies between the real-time analog data and the real-time connectivity data, the application should report the invalidity of the current model and trigger default behavior embedded in the design of the application. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.5 DOMA Step 1.1.5: Extraction of Initial AM/FM/CIS Data

The Conversion and Validation function receives initial incremental (i.e., before any corrections) connectivity, billing and facility parameter data. This incremental data is integrated in the previous database. The requirements for this step match those of IntelliGrid Intra-Corporation Environment #13.

5.4.6 DOMA Step 1.1.6: Initial Stage 1 Validation and Report

Stage 1 analysis checks data on reasonability and consistency with pre-defined rules. For instance, stage 1 analysis reveals incorrect phasing of circuit segments, distribution transformers, incorrect voltage classes, reenergized elements, loops in radial distribution systems, unreasonably loaded distribution transformers, etc. After, the Conversion and Validation function completes Stage 1 analysis; it issues a report with the discovered inconsistencies. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.7 DOMA Step 1.1.7: Authorization for Stage 1 Corrections

After reviewing the Stage 1 report, the DMS Database Administrator issues an authorization to perform Stage 1 corrections. The report with inconsistencies should be transmitted to the source database administrators, and the erroneous or missing data should be corrected in the original database. The requirements for this step match those of IntelliGrid Intra-Corporation Environment #13.

5.4.8 DOMA Step 1.1.8: Stage 1 Corrections

The AM/FM/CIS database is corrected based on the Stage 1 report after DMS Database Administrator authorized the procedure. This action takes place in the communication environment in which the source databases reside.

5.4.9 DOMA Step 1.1.9: Extraction of AM/FM/GIS Data after Stage 1

The Conversion and Validation function receives incremental connectivity; billing and facility parameter data after Stage 1 corrections have been implemented. The requirements for this step match those of IntelliGrid Intra-Corporation Environment #13.

5.4.10 DOMA Step 1.1.10: Report Requiring no Further Database Corrections after Stage 1

After Conversion and Validation function completes Stage 1 analysis, which may require repetition of steps 1.1.6 through 1.1.9, it issues a report showing that no further corrections associated with connectivity, billing or facility parameter data are required, and the incremental changes of the nominal data can be implemented in the DMS test database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.11 DOMA Step 1.1.11: Update of DMS Test Database after Stage 1

After Stage 1 corrections produce a report with no connectivity and transformer loading problems, the Conversion and Validation function updates the DMS Test Database, which sets the stage for

Stage 2 validation. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.12 DOMA Step 1.1.12: Authorization to Start Stage 2

The DMS Database Administrator authorizes the Conversion and Validation function to validate facility parameters via load flow and load transfer analyses. This is referred to as Stage 2 validation. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.13 DOMA Step 1.1.13: Extraction from DMS Test Database after Stage 1

The Conversion and Validation function extracts incremental changes from DMS Test Database (after they were updated with Stage 1 corrections) to perform Stage 2 analyses. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.14 DOMA Step 1.1.14: Extraction of Data from DMS Database after Stage 1

The Conversion and Validation function receives the latest statuses and measurements from DMS Database (which in turn is updated by DMS SCADA Database) to perform Stage 2 analyses. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.15 DOMA Step 1.1.15: Report after Stage 2 Initial Validation

Stage 2 analysis checks the validity of data based on the reasonability of the state estimation and contingency analysis procedures. After performing Stage 2 analyses, Conversion and Validation function issues a report for DMS Database Administrator. The report includes information on unreasonable load and voltage violations, corresponding facility parameters, results of comparative analyses and correction of inconsistencies. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.16 DOMA Step 1.1.16: Authorization for Stage 2 Corrections

After reviewing the Stage 2 report, the DMS Database Administrator transmits the report to the administrators of the source databases and issues an authorization to perform Stage 2 corrections. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7 and Intra-Corporation Environment #13.

5.4.17 DOMA Step 1.1.17: Stage 2 Corrections

The AM/FM/CIS database is corrected based on the Stage 2 report after DMS Database Administrator authorized the procedure. This action takes place in the communication environment in which the source databases reside.

5.4.18 DOMA Step 1.1.18: Extraction of AM/FM/GIS Data after Stage 2

The Conversion and Validation function receives connectivity; billing and facility parameter data after Stage 2 corrections have been implemented. The requirements for this step match those of IntelliGrid Intra-Corporation Environment #13.

5.4.19 DOMA Step 1.1.19: Update of DMS Test Database after Stage 2

The Conversion and Validation function updates the DMS Test Database after Stage 2 corrections of AM/FM/GIS database are completed. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.20 DOMA Step 1.1.20: Extraction from DMS Test Database after Stage 2

The Conversion and Validation function receives excerpts from DMS Test Database (after they were updated with Stage 2 corrections) to perform the next round of Stage 2 analyses. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.21 DOMA Step 1.1.21: Extraction of Data from DMS Database after Stage 2

The Conversion and Validation function receives the latest statuses and measurements from the DMS Database (which in turn are updated by DMS SCADA Database) to perform the next round of Stage 2 analyses. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.22 DOMA Step 1.1.22: Report Requiring no Further Database Corrections after Stage 2

After the Conversion and Validation function completes Stage 2 analysis, it issues a report showing that no further corrections associated with unreasonable load and voltage violations, or corresponding facility parameters are required. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7 and Intra-Corporation Environment #13 (delivering the report to AM/FM/GIS/CIS database administrators).

5.4.23 DOMA Step 1.1.23: Permission to Update DMS Database

After reviewing the Stage 2 report requiring no further corrections, DMS Database Administrator authorizes the update of DMS database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.24 DOMA Step 1.1.24: Extraction of Data from DMS Test Database

After permission to update DMS database is given, the DMS database administrator receives the needed update from DMS Test database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.4.25 DOMA Step 1.1.25: Update of DMS Database

The DMS database administrator updates DMS database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5 DOMA Runs due to Events

5.5.1 DOMA Step 1.3.1: Real-Time Data from DMS SCADA Database

In this step, DOMA function receives the latest scan of DMS SCADA database to be checked for relevant changes or events. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.2 DOMA Step 1.3.2: Real-Time Data from EMS SCADA Database

In this step, DOMA function receives the latest scan of EMS SCADA database to be checked for relevant changes or events. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.3 DOMA Step 1.3.3: Changes in Connectivity

In this step, DOMA, after detecting changes in connectivity, transfers relevant data to Topology Update function. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.4 DOMA Step 1.3.4: DMS Database Update

In this step, the Topology Update function updates DMS database with changes in connectivity detected by DOMA function and with the latest analog measurements. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.5 DOMA Step 1.3.4a: DMS Database Update

After completing the switching in the field, the field crew uploads the change in connectivity into the SCADA database as pseudo-SCADA data. This step has the same requirements as the IntelliGrid Field Equipment Maintenance Environment #20 (presently, this step is not shown in IntelliGrid). DOMA, in turn, will receive these changes from the SCADA database within Environment #7.

5.5.6 DOMA Step 1.3.5: Check Distribution Model Integrity

In this step, the Topology Update function checks the DOMA function to analyze the distribution model integrity based on pre-defined criteria. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.7 DOMA Step 1.3.7a: Permission to Start State Estimation and Power Flow Calculations

In this step, after the distribution model integrity is confirmed, DOMA gives the permission for performing state estimation and power flow calculations. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.8 DOMA Step 1.3.8a: Excerpts from DMS Database

In this step, the DOMA function receives the data from DMS database (facility data and real-time data) needed for state estimation and power flow calculations. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.9 DOMA Step 1.3.9a: Data for FLIR

Upon completion of the state estimation and power flow calculations, the DOMA function makes the connectivity, facility (including controllers), load and transmission data available to Fault Location, Isolation, and Restoration (FLIR) function. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.10 DOMA Step 1.3.10a: Data for VVC

Upon completion of state estimation and power flow calculations, DOMA function makes the connectivity, facility (including controllers), DER, load and transmission data available to Volt/Var Control function. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.11 DOMA Step 1.3.11a: Power Flow and State Estimation Results for Analysis

The DOMA function makes results of power flow calculations available for analysis. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.12 DOMA Step 1.3.12a: Power Flow & Analysis Results for DMS Historic Database

DOMA issues a report with results of analysis of state estimation and power flow calculations for storage in historic DMS database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.13 DOMA Step 1.3.13a: Selected Power Flow & Analysis Results for Operator, EMS, and Distributed Intelligence Schemes

In this step, the selected results of analysis of state estimation and power flow calculations are made available for the operator, EMS, and distributed intelligence schemes. These results are delivered to the SCADA database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.14 DOMA Step 1.3.14a: Initiation of VVC

In this step, if analysis of state estimation and power flow calculations detect a voltage or overload violation, the signal is sent to initiate the Volt-var Control function (VVC). The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.15 DOMA Step 1.3.7b: Model Inconsistency Message Stored in DMS Database

If checking the distribution model integrity identifies a model inconsistency, a message describing the inconsistency is issued for storage in DMS database. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.16 DOMA Step 1.3.8b: Model Inconsistency Message Issued to Operator

If checking the distribution model integrity identifies a model inconsistency, a message describing the inconsistency is issued for the operator. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.17 DOMA Step 1.3.9b: Command to Switch VVC to Default Settings

If checking the distribution model integrity identifies a model inconsistency, a command to switch VVC to default settings is issued. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

5.5.18 DOMA Step 1.3.10b: Command to Switch FLIR to Default Settings

If checking the distribution model integrity identifies a model inconsistency, a command to switch FLIR to default performance is issued. The requirements for this step match those of IntelliGrid Intra-Control Center Environment #7.

6. SUMMARY OF ACTION ITEMS

The following summarizes the action items identified in the above discussions:

6.1 Planning stage

1. Reaffirm utility's present performance criteria:
   - Reliability (e.g., SAIDI, SAIFI, etc.).
   - Efficiency (Energy losses; Load elasticity/Available demand response; Utilization of facilities/Loading of circuits, transformers; operation and maintenance expenses, etc.)
   - Power quality criteria (Voltage deviation beyond standard limits; higher harmonics; Voltage sags and swells; Voltage imbalance; etc.)
   - Customer satisfaction
2. Identify the functionalities presently used in the company to maintain/improve reliability, efficiency, power quality, and customer satisfaction. Estimate the cost of these functionalities
3. Determine utility's future reliability, efficiency, power quality, and customer satisfaction targets (5-10 years)
4. Determine existing capabilities for achieving the targets (DMS-readiness degree). Estimate needed upgrades for achieving the targets. For example, consider the following:
   - Reserves in circuit capacity and backup capabilities
   - Degree of sectioning of circuits

- Number of load-breaking switches, feeder reclosers, remotely controlled switching devices, automated fault detecting, isolation and service restoration means, etc.
- Voltage and var control means; utilization of voltage deviation tolerance
- Availability of real-time monitoring and controlling in distribution
- Other.

5. Perform a feasibility study to determine cost-efficient upgrades of the distribution system and the degree of automation of the distribution operations (DMS). In the study consider DMS as a means for the following:
    - Enhancement distribution operations (reliability, power quality, efficiency)
    - Controlling energy resources (demand response, distributed energy resources, support of real-time pricing)
    - Provision of real-time information for transmission operations (substation bus load models; dynamic voltage-quality based limits at transmission buses; aggregated load-to-voltage dependencies; available value of demand response, etc.)
    - Support of real and reactive power balances and voltage support in bulk power system.
6. Based on the feasibility study and on affordability of resources select the degree of upgrade and automation.

    The upgrade may include actions like the following:
    - Installation of automated switching devices
    - Installation of automated capacitors
    - Replacement of critically limiting facilities
    - Installation of remotely-controlled voltage and var controllers.

    The automation may include the following actions:
    - Modernization and cleanup of the AM/FM/GIS and CIS databases
    - Expansion or installation of Distribution SCADA
    - Implementation of DMS integrated with other IT systems, such as:
        - AM/FM/GIS/CIS
        - Outage Management System (OMS)
        - Work Management System (WMS)
        - Energy Management System (EMS)
        - Other
    - Implementation of advanced DMS Applications, such as:
        - Distribution Operation Model and Analysis (DOMA)
        - Coordinated Optimal Voltage and Var control (OVVC)
        - Fault Location, Isolation, and Service Restoration (FLIR)
        - Multi-Feeder Reconfiguration (OFR)
        - Other

6.2 Procurement Stage

7. Develop DMS Functional Requirements (See Section Distribution Operations – Power System Functions - http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_Distribution_Use_Cases.htm)

8. Develop DMS specifications (See Sections: Distribution Operations – Power System Functions - http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_Distribution_Use_Cases.htm; Environments - http://intelligrid.info/IntelliGrid_Architecture/Environments/Environments.htm; Security Issues - http://intelligrid.info/IntelliGrid_Architecture/Technology_Analysis/Anl_Security_Overview.htm; Technologies - http://intelligrid.info/IntelliGrid_Architecture/New_Technologies/H1_Technology_List.htm and http://intelligrid.info/IntelliGrid_Architecture/Technology_Analysis/Technology_Analysis_Overview.htm)

6.3 Implementation Stage

1. Determine/confirm the schedules and commitments of relevant DERs as well as power flow constraints at points of common coupling.
2. Develop the mechanism for updating schedules and commitments of relevant DERs for this data may change. As part of DER Object Model (OM), this data is used as DOMA function input data. It is assumed that DER OM is communicated through SCADA.
3. Identify customers (if any) with quality/emergency customer terminals voltage limits that differ from the standard limits (i.e., +/- 5/10%).
4. Identify customers participating in various types of load management (demand response), including:

   - Real-time pricing

   - Direct load control

   - DER

   - Storage

   - Emergency load shedding
5. Determine:
   - Which power system areas have transmission loading and voltage levels that significantly depend on the operating conditions in distribution?
   - Which substation transformers and transmission/sub-transmission lines have load and voltage limits that should be respected by distribution?
   - What are contractual relationships between transmission and distribution companies? These should be reviewed for they define the operational boundaries between the two. If the boundaries are at the feeder circuit breaker level, then DOMA has no direct access to the status of substation capacitors and switches, analogs of bus voltage and transformer loading. Therefore, access to transmission SCADA, to ensure that the above parameters are available, needs to be addressed.
   - Is the company ready to consider steps needed for a functional integration of distribution, transmission and market operations? The latter will require access to EMS, to ensure that energy pricing is available in real time.
6. Determine:

- Does AM/FM/GIS database have all the information required by DMS? For example - distribution transformer: tap positions, core/coil losses, impedance; step-down transformer tap positions and impedance; substation transformer data, etc. If it does not, the missing data should be acquired from other sources and added to the database.
- How frequent and complete is the AM/FM/GIS database update? All significant changes should be incorporated into the database without delay.
- If there is no process to validate the AM/FM/GIS information, one should be developed?

7. Develop a procedure for a regular update of the AM/FM/GIS database by qualified personnel.
8. Take steps to ensure that the presence of the Automated Meter Reading system (AMR), if one already exists at the utility, is taken advantage to improve the quality of the billing data used by DOMA. Specifically, using the billing data from CIS (supported by AMR) for regular DMS database updates, the loading of individual distribution transformers will be modeled more accurately, thus increasing precision of the power flow calculations. This, in turn, impacts the integrity of DOMA output data/recommendations as well as of other DMS functions that rely on DOMA for input information.
9. Take steps to ensure that AMR implementation approach does not conflict with DMS needs. An example could be consolidated bills, in some of the present AMR systems, where the load data of individual distribution transformers at different sites becomes unavailable outside of CIS.
10. Develop the process for data retrieval from CIS and AM/FM/GIS databases
11. Develop the process for CIS and AM/FM/GIS data conversion and validation before the DMS database update takes place
12. Develop the process for DMS database update
13. Address issues raised in the following questions:
    - Does the technology allow for the field crew to enter changes in connectivity directly into the DMS database? If yes, should it require operator's authorization? Should the operator be in the loop at all?
    - If the technology is not available, does the field crew have the means to communicate this information to the operator reliably and in a timely manner?
    - Does the operator have the time to deal with entering this information into the DMS database?
    - Are the operators ready and willing to accept the responsibility for handling this information?
    - Modeling distribution connectivity requires not only establishing the communication links to all the actors, expected to provide the connectivity data, but also conveying to them the importance of ensuring the quality of their contribution. This issue should be addressed in discussions with both the field crews and the operators.
    - The connectivity issue is also closely related to the requirements for SCADA capabilities. Not only SCADA should be able of carrying the information related to many new parameters, but also, under some circumstance, the speed of that communication is drastically increasing. For example, during the storm conditions, DOMA may be running every 2 min. Therefore, the timing of DMS database update

should comply with the 2-min time interval, thus placing a new speed requirement on SCADA. This should be considered while evaluating/upgrading SCADA.

14. Determine whether existing SCADA can accommodate the requirements associated with the data needed by DMS. If yes, take steps to include in SCADA the following operational parameters:
    - Feeder and station capacitors status and mode of operation
    - Feeder and bus analogs
    - Switching device status, mode of operation, protection settings, as well as lock-outs and fault indications (whichever is applicable)
    - Transmission line status and operating limits
    - Transmission reactive power source schedule
    - LTC, voltage regulator, and DER controllers' statuses, settings and modes of operation
    - DER Object Model (OM) parameters required by DMS, e.g., mode of operation, P-Q-V constraints, status of operation, schedule of operation, output analog measurements, etc. (see EPRI publication *Studies of Distribution Operations to Aid in Determining Object Models for Distributed Energy Resources* for more information on DER OM)
    - Settings, statuses, modes of operation, commands, recommendations, and output data associated with DOMA.
15. Review the existing load shape data for each customer category (residential, industrial, commercial, etc.). The origin of that data and its accuracy should be determined. If need to, a load survey study (e.g., using AMR capabilities) should be performed to update the load shape data for all relevant customer categories.
16. Determine via field tests the load-to-voltage dependencies (both kW and kvar) for typical customer categories
17. Confirm whether the accuracy of the real-time field measurements (kW, kvar, Amps, kV) meets DMS requirements. If need to, the upgrades and/or replacement of relevant measuring units should be undertaken.
18. Take steps to include in SCADA additional information required by nodal load modeling. This information includes the real-time environmental data forecast and statuses of the load management means.
19. Arrange for DOMA's report on transfer capacity to be issued to the operator and the engineering staff.
20. Include results of DOMA power quality analysis into the following:
    - Scheduled power quality evaluation procedures – e.g., the monitoring of minimum and maximum customer terminal voltages, voltage quality index and voltage imbalance helps to evaluate the impact the changes, taking place on the system, have on the quality of power received by the customers.
    - Procedures used to investigate customer complaints - e.g., the possible reasons for the problem, if not already reported by DOMA in real time, can be studied with DOMA in the study mode before the investigation begins in the field. Furthermore, the voltage/overload violations, as reported by DOMA, can be investigated right away, thus potentially preventing/foreseeing customer complaints.
    - Procedures used to evaluate the impact on power quality from new facilities, changes in connectivity and reactive power compensation – e.g., the evaluation is

done before the changes are implemented through the off-line studies and observed in real time after implementation.

21. Arrange for DOMA's report with results on loss analysis to be available to other departments within the company.
22. Arrange for DOMA's report on fault analysis (i.e., minimum fault current) to be reported to protective relaying personnel for protective relaying settings update.
23. Arrange for DOMA's report on fault analysis (i.e., maximum fault current) to be reported to system planners and circuit breaker experts to be used in studying the feasibility of various operating conditions.
24. Arrange for reporting violations to relevant departments
25. Arrange for information exchange between DISCO and TRANCO
26. The DMS Historic Database will be receiving daily a massive amount of data; therefore, the issues of data selection, storage, archiving, security, back-up, retrieval, maintenance, manpower, authorized access, web access, ownership, sharing with interested parties (free or fee-based), and usage, should be addressed.
27. As diagrams and the narrative show, a number of DOMA output parameters are suggested to be made available for the operator. Each of these parameters should be reviewed to determine whether to permanently display them for the operator or to make them available upon request from the control room.
28. Before DOMA calculations begin, the distribution model is checked for inconsistencies, e.g., it is checked whether the distribution network connectivity is consistent with the analog measurements. In case the answer is negative, and the integrity of the distribution model is in question, as section *DOMA Steps* show, several actions are undertaken. The inclusion of the message on the operator's display should be discussed. Furthermore, the course of action in case this message is displayed should be developed and agreed with all the parties involved. Specifically, the issues to resolve may include the following:
    - Who is responsible for investigating the causes of inconsistency?
    - What is the methodology for determining the cause of inconsistency?
    - Who is responsible for taking the necessary steps for restoring distribution model's integrity?
29. Validate the Distribution Operation Model by statistically comparing the results of modeling with measurements in the primary and secondary points of the modeled distribution system. Use remote monitoring points and temporary portable devices installed in critical points of the secondary distribution system. If the comparison shows unacceptable result, find the inconsistency in the model and correct it (The most likely inconsistency is erroneous AM/FM/GIS/CIS data).

6.4 Operation and Maintenance Stage

1. Typical patterns of DOMA operations are described in the DOMA use-case steps (http://intelligrid.info/IntelliGrid_Architecture/Use_Cases/DO_DOMA_Use_Case.htm).
2. The maintenance of DOMA involves the following activities:
    - Regularly review the application logs. Pay attention to messages regarding inconsistencies of the model, loading and voltage violations.
    - Timely adjust the conditionally-constant data. For example, the incremental cost of energy for the customers, which is a component used for calculations of the

cost of operations, changes with the change of electricity rates. If this data is not automatically updated from the CIS database, the maintenance personnel should take care about it.

- Monitor the displays for maintenance personnel and review all messages related to the performance of the application. In case of violations of operational limits, determine whether the violations are caused by the model inconsistency (incorrect connectivity, input data or measurement) or by the actual operating conditions. In the former case take steps to correct the model, and in the latter case contact the relevant personnel (e.g., power quality engineer or operation planner) and inform them about the problem.
- Contact relevant personnel for fixing revealed problems, e.g., contact corporate database administrators in case of delay of updates or errors in data.
- Provide timely updates of the DMS databases.

7. FUTURE WORK

The Intelligrid project defined the concept of the Integrated Energy and Communications Infrastructure. In every attempt of implementing this concept in real utility projects, one will find answers to a number of practical questions in the Intelligrid documents and will not find answers to a number of other questions. By accepting the philosophy of a systems approach to the self-healing power system operations, which requires a symbiosis of energy and information infrastructure, one will come up with the essential practical requirements for the integrated infrastructure. These practical requirements will encourage the IT developers to produce the products required by the industry. The bottom-line basis for development the requirements for an information infrastructure for self-healing power systems is good understanding of the power system operations, the mutual interdependencies between different operational components, and the dynamics of these interrelationships. Modern power systems are very complex technological objects to control. There are very strong technological relationships between different components of the system, between the generators, transmission system, distribution systems, and customer systems. All these components are subjected to deterministic and random influences. The issues become much more complicated in the open energy marker environment, when critical components of the power system, strongly tied technologically, become economically unbundled. This relative economic “independence” results in additional constraints imposed on the controllability of the critical components and on the exchange of information needed for reliable and efficient control of the entire power system. At the same time, the customer requirements for reliability and quality of energy services become more demanding growing along with the development of the technology in different industries and in people’s homes.

In all these complexities, the timely and adequate exchange of information is vital for reliable operations of power systems. The questions are - how timely and how adequate the information exchange should be to provide the needed level of power system reliability and efficiency. To answer these questions, a very good understanding of the technological and economic phenomena in the power industry should be developed. Based on this understanding, the requirements for the information infrastructure, including the contents of the information, the security of information, and the information technology can be developed.

An initial attempt in developing such an understanding of the power system behavior took place in the Intelligrid Project. This understanding was defined in the descriptions of the use cases for different domains of the power system operations. Some efforts in linking different domains among themselves were made in the project, but they cannot be considered as comprehensive enough.

Development of an interrelated functional model of power system operations covering the technological and market operations of customer systems, distribution systems, and interconnected transmission and generation systems would serve as a solid basis for development of a corresponding information infrastructure. Such a model, revealing important dependencies between operations of different power system entities, would set a ground for some new business relationships between different market participants.

After learning the operational essence of different power components, standard object model of the components, which deem to be critical for power system operations, can be developed. One cannot develop an adequate object model without understanding the critical roles and capabilities of the object.

Consider some examples related to distribution operations and to the DOMA application. The distribution systems are not just passive "wire companies". There are many "active" elements in the modern distribution systems: automatically or remotely controlled transformer Load Tap Changers (LTC), automatically or remotely controlled voltage regulators, automatically or remotely controlled shunt capacitors operating in different control modes, large and small Distributed Energy Resources (DER) of different kinds and operating in different modes, static var compensators (SVC), automatically or remotely controlled protective and load-breaking switching devices, etc.

The customer loads connected to the distribution systems change all the time due to the time and technology cycles, weather conditions, and other public events. The random component of the load may be significant. The operations of distribution system are highly dependent on the behavior of the load. At the present time and even more in the future, the load is considered as a power resource due to the Demand Response (DR) concept. There are different means of DR, such as Real-Time Pricing programs (RTP), Direct Load Control (DLC), Voltage Reduction, etc. With active Demand Response program in place, the controllable variables for distribution operations significantly grow in numbers.

Another important issue in distribution operations is that the controllable variables in distribution systems impact not only the distribution operations but also the customer-site values, the transmission operations, and the generation capabilities. Therefore, these variables are controlled for different objectives: for distribution operation objectives, for customer-focused objectives, and for transmission and generation objectives. When a group of variables is controlled for the benefits of a particular power system entity, it may cause additional cost in another power system entity. In these cases, there should be a way for accounting the benefits and costs, and a financial mechanism providing adequate incentives to make the actions mutually beneficial should be developed.

Consider a specific example. Suppose the transmission operations require an additional volt/var support from distribution systems for congestion management. In order to provide this support, the distribution system turns ON all reserve capacitors and lowers the voltage within standard voltage limits, which additionally reduces the reactive (and real) load, creating overcompensation of reactive load in distribution. These actions may increase losses in distribution and reduces the sales of energy to the customers, reducing the revenues. Hence, the transmission operations will improve due to congestion relief, but the efficiency of the distribution operations may reduce, and the entity benefiting from energy sales will incur some financial losses. In order to account for these phenomena, corresponding information exchange between involved power system entities is required and an accurate model simulating the phenomena should be in place. DOMA is such kind of model, if it is supported by adequate models of the distribution connectivity, facility parameters, and adequate object models of the controllable devices in distribution.

Another example. Many operational decisions in power system operations are made based on the results of Security Analysis for the transmission and generation systems. A critical component of the models used for this analysis is the bus load model under conditions of the contingency. Most of the contingencies are accompanied by significant distortions of the voltages and/or frequencies. In turn, the behavior of the bus load reflects the aggregated reaction of the loads connected to the distribution system and the reaction of the automatically controlled variables in distribution. For instance, when the voltage at the substation bus drops, all voltage related controllers in distribution react. The voltage reduction by itself and the operations of the voltage-dependent devices change the real and reactive power flow in distribution. Hence, the power-flow dependent devices react on this change, etc. As a result, the bus load dependency on voltage may be very different under different real-time conditions, and so the results of the Security Analysis may be also different. Therefore, a near-to-real-time computing application should be employed to provide the Security Analysis application with concurrent bus load models. This application should be able to simulate the behavior of the loads connected to the distribution system and of all controllable devices in distribution under significant voltage and/or frequency distortions. DOMA is such an application, if it is supported with adequate models of the distribution system connectivity, facility parameters, nodal load models, and by object models of significant controllable devices.

As follows from the above discussion and examples, a consideration should be given to development of the following standard object models:

- Bus load model supported by DOMA
- Voltage controller model
- Significant DER models
- Aggregated DER model
- Capacitor controller model

- Switching device controller model
- SVC model
- Customer Load model
- DMS application models

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