# Guidelines for Implementing Substation Automation using UCA-SA (Utility Communications Architecture-Substation Automation)

*Technical Report*

# Guidelines for Implementing Substation Automation Using UCA-SA (Utility Communications Architecture—Substation Automation)

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# REPORT SUMMARY


This report provides guidelines for substation engineers, information technologists, and utility managers on the information issues related to substation automation, in particular when UCA-SA (Utility Communications Architecture – Substation Automation IEC61850) standards are used. Substation automation is a new challenge for the utility industry, and these guidelines provide the overall vision as well as the specific steps that should be taken for successful implementation of this new enabling capability.

## Results & Findings

These guidelines are organized according to the stages involved in undertaking substation automation: planning, specifying, implementing, deploying, and operations/maintenance. It is expected that most readers will start with the section called "Vision for Substation Automation," an introduction to the broader issues of power system management, information technologies, and automation of systems, and then jump to the section covering their area of interest, such as planning or deployment. Each section has been designed to stand alone.

The 2003 funding for this project allowed for the development of the full structure of the Guideline and the completion of approximately 50% of the content. This research effort continues into 2004 with the expectation that 2004 funding will permit completion of the Guidelines. In this interim version, the structure of the complete work can be seen in the section headings and some bullet items within the sections.

## Challenges & Objectives

Substation automation is far more than the automation of substation equipment. It is one of the first steps toward the creation of a highly reliable, self-healing power system that responds rapidly to real-time events with appropriate actions and supports the planning and asset management necessary for cost-effective operations. Automation does not just replace manual procedures: it permits the power system to operate in an entirely new way, based on accurate information provided in a timely manner to the decision-making applications and field devices.

Substation automation would not have been feasible a few years ago. Communications technologies simply were not available to handle the kinds of demands put on them by the complexity of substation automation requirements. However, communication standards have now been developed that can address many of these demands. In particular, UCA-SA, formally called IEC61850, provides solutions to automation issues using state-of-the-art object modeling technologies.

## Applications, Values & Use

The IEC61850 documents are not easy to interpret. This guideline was designed to help the users of substation automation by describing the UCA-SA standards in more "user friendly" terms and identifying what options are available. Even though most users will rely on the vendors of equipment to implement the actual UCA-SA standards, it is important for users to have at least a basic understanding of the options available and how the different object models work with each other.

Additional capabilities are being added to the IEC61850 series of standards, including configuration language standards and conformance testing planning. Once these are finalized as standards, they should be included in later updates to these guidelines.

## EPRI Perspective

International standards organizations, such as the IEC, are excellent in developing standards; but their strengths do not lie in describing to potential users exactly how best to use those standards. EPRI has a key role in translating these standards into understandable language, and discussing the different options and issues related to the standards.

## Approach

The guidelines were developed first to describe the overall vision of substation automation to help ensure that the paradigm shift provided by this new enabling technology is better appreciated by the utility industry. The guidelines then describe the steps required in each phase of implementing substation automation with UCA-SA.

## Keywords

Substation automation
Utility Communications Architecture (UCA)
IEC61850
UCA-SA
object modeling
abstract modeling
UML

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# 1 EXECUTIVE SUMMARY

## 1.1 Introduction

This report, "***Guidelines for Implementing Substation Automation using UCA-SA***", provides guidelines for substation engineers, information technologists, and utility managers on the information issues related to substation automation. Substation automation is a new challenge for the utility industry, and the full range of new capabilities that it enables is not yet well understood.

These guidelines were developed first to describe the overall vision of substation automation to help ensure that the paradigm shift provided by this new enabling technology is better appreciated by the utility industry. The guidelines then describe the steps required in each phase of implementing substation automation with UCA-SA.

The report is organized by the different stages of undertaking substation automation: planning, specifying, implementing, deploying, and operations/maintenance. It is expected that most readers will start with the section called "Vision for Substation Automation" as an introduction to the broader issues of power system management, information technologies, and automation of systems. Then each reader will determine their area of interest, such as planning or deployment, and jump directly to that section. The document, therefore, is designed so that each section is relatively stand-alone.

In this interim report, the 2003 funding allowed for the development of the full structure of the Guideline and the completion of approximately 50% of the content. This research effort continues into 2004 where the expectation is that 2004 funding will permit completion of the Guidelines. In this document the structure of the 2004 work can be seen under the section headings and some bullet items within the sections. This way the readers can understand what the completed document will contain.

## 1.2 Vision for Substation Automation

Gunpowder, the printing press, commercial generation of electricity, the personal computer, and the Internet – what do these and innumerable other past developments have in common? They were all major paradigm shifts.

Information has become the driving necessity in power system operations. As stated by Kurt Yeager, the CEO of EPRI, during in an interview on the August 14th East Coast Blackout[1]:

***"The first, the most important factor that we have to apply to the power system today is to make it a digitally controlled system."***

Substation automation is more, far more, than just the automation of substation equipment. It is one of the first steps toward the creation of a highly reliable, self-healing power system that responds rapidly to real-time events with appropriate actions, and that supports the planning and asset management necessary for cost-effective operations. Automation does not just replace manual procedures; it permits the power system to operate in an entirely new way, based on accurate information provided in a timely manner to the decision-making applications and devices.

Substation automation would not really have been feasible a few years ago. Communications technologies simply were not available to handle the kinds of demands put on them by the complexity of substation automation requirements. For instance, one of the main enablers of substation automation was the recognition that the vast bundles of point-to-point wiring between the control house and the equipment in the substation yard could be eliminated through the use of Ethernet networks. However, communication standards have now been developed that can address many of these demands. In particular, UCA-SA (formally called IEC61850) provides solutions to automation issues using state-of-the-art object modeling technologies.

The vision for substation automation over the next years is presented in Section 2.

## 1.3 Planning for Substation Automation – Benefits of Abstract, Model-Based Distributed Computing Technologies

Planning for substation automation requires a different approach than substation engineers have typically done in the past to construct new substations. In addition to the design of physical and electrical requirements, substation automation also requires the design of the information requirements.

The most effective way to analyze information requirements, determine information flows, and develop specifications for these information needs, is to develop abstract models of the functions and their data requirements. Substation engineers will probably need support from specialists in information modeling, but an overview of the abstract modeling process is presented in Section 3.

[1] http://www.pbs.org/newshour/bb/fedagencies/july-dec03/blackouts_08-25.html

## 1.4 Specifying UCA-SA: Standards and Options

The IEC61850 documents are not easy to read or to comprehend how all the pieces work together. This guideline is therefore designed to help the users of substation automation by describing the UCA-SA standards in more “user friendly” terms and identifying what options are available. Even though most users will rely on the vendors of equipment to implement the actual UCA-SA standards, it is important for users to at least have a basic understanding of the options available and how the different object models work with each other.

These UCA-SA specification standards and options are described in Section 4.

## 1.5 Implementing Substation Automation

Until substation automation becomes the norm, rather than the exceptions, implementation of substation automation requires more effort and different expertise than just implementing a new substation using the traditional approaches. It is therefore very important for a substation engineer to fully appreciate the different steps required, even though these must be tailored to their individual situations.

The basic steps are:

1. Find a “champion” who recognizes that substation automation will be cost effective, despite some of the learning pains, requirements for different skills and approaches, and inevitable “glitches”.

2. Develop functional requirements, by reaching out to other groups to determine what they need from substation information.

3. Develop technical specifications that truly capture the functional requirements, but do not over-specify by identifying specific hardware. The specifications must cover the substation equipment as well as the communications systems – and UCA-SA.

4. Evaluate bidders and selecting vendors to provide the equipment and systems

5. Monitor and manage the system development efforts, both in-house and by the vendors

6. Review and comment on documentation, which is vital to ensure the equipment and systems are developed as specified

7. Factory, field, and acceptance testing

8. Field installation, validation, and commissioning

9. Planning for future upgrades and extensions

These implementation steps are discussed in Section 5.

## 1.6 Deployment of UCA-SA in Different Types of Substations

Section 6 describes different deployment strategies and issues:

1. Deployment in Legacy Transmission Substations

2. Deployment in New Transmission Substations

3. Deployment in Distribution Substations

4. Repositories and Clients

## 1.7 Operations and Maintenance with UCA-SA in Substations

UCA-SA is particularly beneficial as operations and maintenance efforts start coping with the large amounts of data generated by substation automation. Different information-flow configurations and processes are discussed in Section 7.

# 2

# VISION FOR SUBSTATION AUTOMATION

## 2.1 Thinking Outside the Box – Paradigm Shift of Substation Automation

Gunpowder, the printing press, commercial generation of electricity, the personal computer, and the Internet – what do these and innumerable other past developments have in common? They were all major paradigm shifts.

Not surprisingly, they all swept away current practice or modified it significantly. Not instantly, but quickly enough to indicate something rather important had occurred. In each case, there was a confluence of technologies, present need, and a vision of how to put them together for economic gain and unprecedented advantage.

***Substation automation is not just automating a substation – it is part of a major paradigm shift for all of power system operations.***

Perhaps electric power transmission and distribution networks are ready for such a change. They represent the largest and most capital-intensive system devised by man. Yet utilities leverage remarkably little information from this lifeblood of their business. As recent and past events have already demonstrated, the urgency to improve this situation is increasing: We need to ensure a secure national grid. We need to accommodate higher grid complexity, as will occur with the growth of distributed energy resources. And we need improved efficiency, better power quality, and deterministic power flow in support of a more competitive business climate. Technical, legal, and financial models of the power system need to reinforce one another to ensure accountability.

Mainstream technologies can already extract a wealth of information from the power delivery system, selectively delivering it to multiple utility departments according to need. This technological infrastructure is shared, so that all stakeholders have common access to station data and functionality, subject to security safeguards, regulations, and corporate policy. Modern devices and controllers can easily and cost-effectively provide exhaustive measurements of power system data with all its nuances. They can detect and measure system events and conditions, and control the flow of power. They support traditional protection of individual equipment, as well as the development of strategies for protection of the system as a whole against contingencies.

This integration of data and functionality, once accomplished, sets the stage for one additional huge benefit: the implementation of local and system-wide automation, delivering economic gains on many fronts. These include the reduction of non-productive effort, the operation of equipment assets at higher power levels, while also monitoring them for operational safety under current operating conditions, and the interactive use of equipment assets to effect voltage and VAr control strategies. There are literally tens of applications that can be deployed to economic and operational advantage.

***"The first, the most important factor that we have to apply to the power system today is to make it a digitally controlled system."***

Substation automation is more, far more, than just the automation of substation equipment. It is one of the first steps toward the creation of a highly reliable, self-healing power system that responds rapidly to real-time events with appropriate actions, and that supports the planning and asset management necessary for cost-effective operations. Automation does not just replace manual procedures; it permits the power system to operate in an entirely new way, based on accurate information provided in a timely manner to the decision-making applications and devices.

Why should an organization tolerate semi-informed decisions that may eventually cost tremendous time and money, when the means are available to tightly justify (or discredit) proposed improvements? These guidelines enable decentralized access to the station resources. This approach allows each department to gain access to those allowed resources that are most valuable for improving its process, cutting its cost, and exploiting new opportunities that open up. It lets each group meet its own responsibilities, applying innovation to the area it knows most intimately. If the corporate staff meets its responsibilities to provide direction and leadership, there is no doubt that the whole utility enterprise can achieve significant advancement. To summarize, use these advantages to transform how you *conduct* your business.

Information has become the driving necessity in power system operations. The passage below reinforces these views. It quotes comments by Kurt Yeager, the CEO of EPRI, during in an interview August 25, 2003 on the Lehrer News Hour. The program addressed the August 14th East Coast Blackout[2]:

> "The first, the most important factor that we have to apply to the power system today is to make it a digitally controlled system. We have a digital economy and we're still trying to provide power to it through a mechanical design system that was designed over 50 years ago. It's a marvelous system, but we've been effectively borrowing against the future to pay for the present, and the future has caught up with us; we need to build the system to serve the digital society of the 21st century. So that's the first step.
>
> In so doing we can increase the efficiency and the capacity of the system we have. It will not eliminate the need for some new lines, but certainly we, if we do it technically,

[2] http://www.pbs.org/newshour/bb/fedagencies/july-dec03/blackouts_08-25.html

> capacity expansion, we can reduce the amount of new lines that have to be put in place. So it really fundamentally improves the efficiency.
>
> And it's then the controllability of that system. Once we have those digital controls in, we can instantaneously manage the power system so it is self-healing, that is it can detect instantaneously a difficulty and correct for it locally so that cascading effects can be eliminated and fundamentally improve the reliability of the system so that computers and other sensitive equipment that has come in over the last decade is not upset by power disturbances."

Substation automation basically consists of implementing Intelligent Electronic Devices (IEDs) using microprocessors to monitor and control the physical power system devices. These IEDs can make more data available in digital format. In and of itself, having lots of data (in whatever format) is not particularly good or bad. However, this data can be turned into ***information*** that is available at the right places at the right times. It is this information that is the true benefit of substation automation.

### 2.1.1 Enabling Information Technologies That Enhance Substation Automation Capabilities

Substation automation would not really have been feasible a few years ago. Communications technologies simply were not available to handle the kinds of demands put on them by the complexity of substation automation requirements.

For instance, one of the main enablers of substation automation was the recognition that the vast bundles of point-to-point wiring between the control house and the equipment in the substation yard could be eliminated through the use of Ethernet networks. But Ethernet was only practical once the higher speed, switching technologies were developed. Once networking became standardized with highly reliable products available from multiple vendors, automation became feasible because data could be collected from multiple devices without the added expense of running new wires.

***One of the main enablers of substation automation was the recognition that vast bundles of point-to-point wiring could be eliminated through the use of Ethernet networks.***

With this basic communications capability in place, all of a sudden other technologies commonly used in other industries could be easily adapted to the substation environment. Instead of just replacing the wires with Ethernet networks, the door opened to taking advantage of additional technologies to improve the management of data, the security of information, and the simplification of hardware and software maintenance. Some examples of the state-of-the-art technologies that could now be applied include:

1. **Industry-standard Interface Technology:** TCP/IP can be used over the Ethernet network to provide full routing capabilities can also be used for engineering stations providing direct

access over logical paths to IEDs (Intelligent Electronic Devices) in the substation for remote configuration and setting of parameters without the need of separate physical links.

2. **Security through Role-Based Access:** Control centres have individual access rights to the information objects of the substation and can subscribe for information objects published by the directly from the information object or from a proxy.

3. **Consolidation of Hardware:** Conversion of protocols and formats is avoided because the communication platform for local communication within the substation (substation bus) and telecontrol is the same. Instead of a gateway a proxy is used within the substation to present the information objects to the control centre.

4. **Object Modeling – Establishing Standardized Self-describing Object Names:** Using object modeling technologies, substation automation information has been organized with self-describing names instead with numerical addresses (for crucial reports an optimized addressing is defined). The IEC61850, which is called UCA-SA, provides this object modeling framework.

***UCA-SA (IEC61850), using object modeling technology, has established standardized, self-describing object names for substation information.***

5. **Standardized Naming and Mapping to Proprietary Databases in Proxy Servers:** The device-oriented names of information objects can be mapped in the proxy server to process-oriented proprietary names and databases, because the control centre application is process oriented and logical devices of the substation are therefore hidden.

6. **Metadata Management:** Essential parts of the metadata can be exchanged, e.g., technological name, information type, dimension, unit, range of values, and dead band value for reporting (self-describing objects) are inherent part of the communication.

7. **Designing toward a Seamless Architecture:** In general a seamless architecture leads to potential less cost for design, configuration, installation, operation, and maintenance combined with higher performance compared with current solutions. Although much work still needs to be done, the steps taken by

### *2.1.2 Benefits of Substation Automation to Different Users*

However, just have some information technology available does not necessarily mean that automation is useful or justifiable. Therefore, it is vital to determine the true benefits of substation automation to all its stakeholders or users. In fact, not all benefits are cost-justified under all conditions, so that each situation must be evaluated individually. Nonetheless, many benefits which were not initially obvious, have become increasingly cost-justified as automation has moved from simple replacement of existing processes to more sophisticated

***For better or worse, automation leads to powerful new capabilities for users, which in turn lead to the need for more automation.***

interactions among processes, and the development of new functions that would have been impossible before automation. For better or worse, automation leads to powerful new capabilities for users, which in turn lead to the need for more automation.

Some examples of the benefits of substation automation to different users are described briefly below:

1. Substation automation offers implementation benefits:

   a. **Reduced quantities of equipment** through use of shared technology for data sourcing, control, protection, station metering, processing, and communication … all for the benefit of multiple utility departments and other clients.

   b. **Replacement of discrete station wiring with flexible communication networks,** which can accommodate continual system change and migration.

   c. **Networks implemented with fiber optic cable,** mutually isolating pieces of connected equipment to limit collateral equipment damage under adverse electrical conditions, such as faults and close-proximity lightning strikes.

   d. **Integration of digital information and functionality** in disparate devices that currently operate in separate realms: fault recorders, protective relays, sequence of event recorders, fault locators, network transducers, regulators, controllers, etc.

   e. **Gradual displacement of analog devices**, which are typically less flexible in use, more difficult to diagnose, and more costly to maintain.

   f. **New digital equipment capabilities**, such as distance-to-fault locators and sag detectors, can easily be integrated with the other station equipment to provide new functionality and more comprehensive system information.

   g. **Station HMI consoles**: Station information can be locally consolidated, including power system data, status of the local electrical network infrastructure, and the diagnostic status of IEDs, networks, and other technology. This approach enables the displacement / replacement of traditional station panels.

2. Substation automation benefits utility staff:

   a. **Maintenance staff** can remotely isolate and diagnose problems. This requires fewer trips to the station, saving time and money, resulting in typically shorter outages. This capability is provided by microprocessor-based equipment supporting self-monitoring and self-diagnosis.

   b. **Planners, engineers, and asset management personnel** can monitor and capture the operational behavior of feeders and line equipment over time, profiling their service characteristics against independent factors such as temperature, season, time of day, and time of week. Statistical analysis can used to distill useful information for planning.

c. **Operators and operational planners**: Additional real-time information for use in operational planning (within the next hour or so)

d. **Operators**: Additional alarming capabilities and alarm management (how important are what alarms under what conditions, and who should see them)

e. **Operators**: Multiple sources for data and alarms to ensure no critical information is lost or unavailable to operators

f. **Protection engineers**: oscillographic information available for capture in real-time during normal operations;

g. **Protection engineers**: ability to change settings remotely in anticipation of changing conditions

h. **Operations engineers**: additional information available for contingency analysis and identification of potential problems, management during emergency conditions, emergency recovery, and post-emergency analysis

3. Substation automation benefits control center operations:

a. **SCADA/EMS systems**: Additional data is available to be monitored if it is needed by operators and/or SCADA/EMS applications. Alternatively, if the SCADA/EMS system does ***not*** need some data that is required by another group, then the other group can collect the data directly from the substation master without burdening the SCADA/EMS system.

b. **Contingency Analysis (Security Analysis):** Additional data from multiple sources for redundancy, thus increasing the reliability of the results

c. **Intelligent Alarm Processing:** With the additional data, intelligent alarm processing can filter out the less important alarms from the more important ones, and also analyze this data to determine the true issue causing the alarm. These more important alarms can then notify operators, and/or cause additional applications to execute, such as contingency analysis

d. **Emergency Response:** Control commands, whether issued locally or remotely, can respond rapidly to emergency situations in a coordinated manner, not only within a substation, but also between substations and between utilities

## 2.2 Power System Functions That Drive the Requirements for Substation Automation

***In the future, it is crucial that utility engineers design substations to accommodate power system functions that have not been part of their focus in the past.***

The automation of substations must be based on clearly defined utility requirements; otherwise the automation is not needed. Therefore, it is the utility requirements that drive the needs for substation automation. This understanding is vital to the design and implementation of substation automation in any utility.

The requirements for substation automation must reflect all of the utility requirements, not just protective relaying or SCADA monitoring. Therefore, it is crucial that, in the future, the substation engineers designing the automation of a substation be aware of functions that have not been part of their focus in the past.

The Integrated Energy and Communications Systems Architecture (IECSA) project sponsored by E2I (see www.iecsa.org) developed a comprehensive list of power system functions required for transmission operations (additional lists of functions were developed for other "domains"). Most of these functions would benefit from the access to information, the response to events, and the ability for dynamic management of power system settings that is provided by substation automation.

Clearly not all functions will require information within the same time frames. For instance, protective relaying will need "instantaneous" data (with 4 ms), while control center operations rely on "real-time" interactions on the order of a few seconds, and many of the planning functions will need statistical information derived from the raw data over various time periods and under various circumstances. Other post-operational functions, such as reading of the revenue meters, require the information only over long periodicities.

Some functions listed do not exist today in utilities to any significant degree. For instance, the setting of protection and recloser parameters is usually performed off-line by protection engineers, and then either manually entered or remotely downloaded. In the future, settings could be dynamically determined and automatically downloaded, or even dynamically set within the substation, based on actual conditions.

***The key idea to gain from the following tables is that substation automation impacts far more than the substation; it impacts planning, protection engineering, daily operations, emergency responses, market operations, maintenance, and even executives.***

The following table lists the key transmission operations functions and illustrates their interactions with substation equipment. The purpose of this table is show just how varied the uses of the substation information will be within transmission operations; it should not be viewed as being the only mapping of functions to substation information. The key idea to gain from the following tables is that substation automation impacts far more than the substation; it impacts planning, protection engineering, daily operations, emergency responses, market operations, maintenance, and even executives.

The codes for the table entries are:

- **B = before real-time**; this means the information can be gathered at any time for future use
- **I = instantaneous signaling**; this means monitoring and control signals transmitted on the order of 4 ms. This signaling is within and between substations.
- **M = real-time monitoring**; this means the information is gathered in "real-time" (defined here as being on the order of 1 to 10 seconds) by the control center as well as by substation equipment
- **C = real-time control or settings**; this means control commands are issued from the control center or from a substation master, either as direct commands or as setpoint changes for immediate or future actions
- **A = after real-time monitoring**; this means the information is gathered on past conditions and behavior. Although this could be seen as identical to the code B (both being gathered at some non-critical time), the implication is that this data will be used for capturing explicit past behavior, rather than for analyzing data for future use
- **S = statistical analysis**; this means the individual data is not important except as input to specific statistical calculations performed under different scenarios (e.g. max and min voltage during each 24 hours, average power factor, etc.)
- **P = power flow analysis** (or other sophisticated analysis); this means that more sophisticated analysis is performed on the data, such as power system flows, state estimation, contingency analysis, etc.
- **L = Logging**; this means that the actions and data are logged and archived for future auditing, planning, and analysis

### 2.2.1 Transmission Planning Functions

**Table 2-1**
**Transmission Operations Functions Requirements for Transmission Planning**

**Codes:** B = before real-time; I = instantaneous signaling; M = real-time monitoring; C = real-time control or settings; A = after real-time monitoring; S = statistical analysis; P = power flow analysis; L = Logging

| Information / Substation Automation / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Long term transmission planning (1 year to 5 years)** | | | | | | | | | | | | |
| 1. Long term load forecast | S | | | | | | | | S | | | |
| 2. Forecast alternatives for generation sources (Probable market conditions) | S | | | | | | | | S | | | |
| 3. Plan transmission upgrades and additions (e.g. participation in ISO/RTO expansion plan) | S,P | S | S | S | S | S | S,P | S,P | S | A | B | |
| 4. Plan automation of transmission system for SCADA, equipment monitoring, and EMS | S,P | S | S | S | S | S | S,P | S,P | S | A | B | |
| 5. Prepare long-term contracts with distribution utilities: | | | | | | | | | | | | |
| a. Transmission voltage management | S,P | S | S | S | S | S | S,P | S,P | S | | | |
| b. Distribution reactive power support (power factor) in the T&D interface | S,P | S | S | S | S | S | S,P | S,P | S | | | |
| c. T&D information exchange | S,P | S | S | S | S | S | S,P | S,P | S | | | |
| 6. Prepare emergency response planning, e.g. ice storm, hurricane, local outages, system-wide blackouts | S,P | S | S | S | S | S | S,P | S,P | S | A | B | |
| 7. Ensure copies of all schematics, diagrams, relay settings are available to field personnel | | | | | | B | B | | | | B | |
| 8. Prepare inventory and personnel plans based on neighboring load, tie point capacity, etc. | S,P | | | | | | | | S | | B | |

| **Substation Automation** / **Information** / **Transmission Operations Functions** | **Electric Power Measurements** | **Circuit Breakers** | **Reclosers** | **Load Tap Changers and** | **Capacitor Controllers** | **Protection** | **Fault Indication & Location** | **SOE & Disturbance Fault Recording** | **Metering** | **Logging & Archiving** | **Substation Configuration** | **Other** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Medium-term planning (1 month to 1 year)** | | | | | | | | | | | | |
| 1. Forecast annual load | S | | | | | | | | S | L | | |
| 2. Consider probable generation sources | S | | | | | | | | S | | | |
| 3. Equipment and line maintenance plans | A,S | A,S | A,S | A,S | A,S | A,S | A,S | A,S | A,S | A | B | |
| 4. Calculate system utilization based on forecast load and equipment nameplate ratings | S | S | S | S | S | | | | S | | | |
| 5. Schedule maintenance operations – time-based | | | | | | | | | | | B | |
| 6. Schedule maintenance operations – predictive, based on data and models | S | S | S | S | S | S | S | S | S | | B | |
| 7. Schedule equipment replacement – based on age of equipment | A | A | A | A | A | A | A | A | A | | | |
| 8. Schedule equipment replacement – predictive, based on data and models | S | S | S | S | S | S | S | S | S | | B | |
| 9. Schedule equipment replacement – based on contingency scenarios | S,P | S,P | S,P | S,P | S,P | S,P | S,P | S,P | | | B | |
| 10. Schedule spare parts distribution, ensure sufficient at each site | | | | | | | | | | | B | |
| 11. Revise contracts with distribution utilities using actual costs as partial input | S | S | S | S | S | S | S | S | S | | B | |
| **Operational *planning (1 hour to 1 month)*** | | | | | | | | | | | | |
| 1. Short-term load forecast | B,S | | | | | | | | B,S | L | B | |
| 2. Short-term generation alternatives based on annual maintenance plan and market conditions | B,S | | | | | | | | B,S | | | |
| 3. Planned outage management | | | | | | | | | | | | |
| a. Operators determine needed transmission outages | | | | | | | | | | L | B | B |
| b. Contingencies are analyzed | B,P | B,P | B,P | B,P | B,P | B,P | | | | L | B | |
| c. Planners/operators perform load analysis of | B,P | B,P | B,P | B,P | B,P | B,P | | | | L | B | |

| Information / Substation Automation / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| substation equipment based on data | | | | | | | | | | | | |
| d. Operators submit transmission outages and constraints to RTO/ISO | B,P | B,P | B,P | B,P | B,P | B,P | | | | L | B | |
| e. Dynamic equipment capacity – change write-up | | | | | | | | | | L | | |
| f. Protection engineer, to alter relay settings | B,S | B,S | B,S | B,S | | B,C | | | | L | | |
| 4. Meter parameters are updated as per any market contracts | | | | | | | | | C | | | |

### *2.2.2 Normal Real-Time Transmission Operations*

**Table 2-2**
**Transmission Operations Functions Requirements for Normal Real-time Operations**

**Codes:** B = before real-time; I = instantaneous signaling; M = real-time monitoring; C = real-time control or settings; A = after real-time monitoring; S = statistical analysis; P = power flow analysis; L = Logging

| Information / Substation Automation / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Real-time normal operator actions (using SCADA/EMS)** | | | | | | | | | | | | |
| 1. SCADA system monitors transmission system | | | | | | | | | | | | |
| a. Monitor equipment state (open/close/alarm) | | M | M | M | M | M | M | M | | L | | |
| b. Monitor system activity and load (current, voltage, frequency, energy) | M | | | M | | | | M | | L | | |
| c. Monitor equipment condition (overheat, overload, battery level, capacity) | M | M | M | M | M | M | M | M | M | L | | |

| Substation Automation Information / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| d. Monitor environmental (fire, smoke, temperature, sump level) and Monitor security (door alarm, intrusion, cyber attack) | | | | | | | | | | L | M | M |
| e. Monitor security records (audio/video recording) | | | | | | | | | | | | M |
| 2. SCADA announces alarms to operators | M | M | M | M | M | M | M | M | | L | | |
| 3. Alarms are analyzed by Intelligent Alarm Processing | M,P | M,P | M,P | M,P | M,P | M,P | M,P | M,P | | L | | |
| 4. Distribution of alarms to non-operators: | | | | | | | | | | | | |
| a. Overloads and replacement issues to maintenance engineer | A | A | A | A | A | A | A | A | | L | | |
| b. Automated work management system | A | A | A | A | A | A | A | A | | L | | |
| c. Fault records and SOEs to protection engineers | | A | A | | | A | A | A | | L | | |
| d. Info to billing dept. re: possible refunds or reliability contract | A | A | A | A | A | A | A | A | | L | | |
| e. External security or emergency response teams | M | M | M | | | | | | | L | | |
| 5. Operators perform supervisory control of switching operations | | | | | | | | | | | | |
| a. Manual switching | | | | | | | | | | L | | |
| b. Supervisory control | M | M,C | M,C | M, C | M,C | | | | | L | | |
| 6. Automation applications control voltage, var and power flow based on objectives set by operators, using algorithms, real-time data, and network-linked capacitive and reactive components | M | M,C | M,C | M, C | M,C | M,C | | | | L | | |
| 7. Automation applications perform normal load management, e.g. for "peak shaving" or alleviating temporary overloaded equipment | M | M,C | M,C | M, C | M,C | M,C | | | | L | | |
| 8. Operators changes setup/options of EMS functions | | | | | | | | | | | | M |

| Information / Transmission Operations Functions \ Substation Automation | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| a. Periodicity of real-time sequence/cold Initiation | | | | | | | | | | L | | |
| b. Event triggers | M | M | M | M | M | M | M | M | | L | | |
| c. Manual initiations | | | | | | | | | | L | | |
| d. Contingency list | | | | | | | M,S | M,S | | L | | |
| e. Application tuning parameters | | | | | | | | | | L | | |
| f. Other | | | | | | | | | | L | | |
| 9. Operators prepare for storm conditions, based on weather data and history, and change recloser and protection settings | M | M | M,C | M, C | M,C | M,C | | S | | L | | M |
| 10. Operators prepare for storm conditions based on weather data and history and change alarm thresholds | M | M | M | M | M | M | | | | L | | |
| 11. Prepare for transformer clipping (e.g. solar wind/solar magnetic disturbance raising ground DC offset) | | | | | | | | | | L | | |
| **Power System Analysis during normal real-time operations** | | | | | | | | | | | | |
| 1. EMS system performs Real-Time Sequence of Model Update, State Estimation, Bus Load Forecast | M | M | M | M | M | | M | | | L | | |
| 2. EMS system performs Contingency Analysis, recommends preventive and corrective actions, and executes upon operator authorization | M | M | M,C | M, C | M,C | M,C | M | M | | L | | |
| 3. EMS system perform real-time Voltage Stability Analysis of network conditions | M | M | M,C | M, C | M,C | M,C | M | M | | L | | |
| 4. EMS system performs Optimal Power Flow analysis, recommends optimization actions, and executes upon operator authorization | M | M | M,C | M, C | M,C | M,C | M | M | | L | | |
| 5. EMS system perform real-time Transient Stability Analysis of network conditions | M | M | M,C | M, C | M,C | M,C | M | M | | L | | |

### 2.2.3 Emergency Real-Time Transmission Operations

**Table 2-3**
**Transmission Operations Functions Requirements for Emergency Real-time Operations**

**Codes:** B = before real-time; I = instantaneous signaling; M = real-time monitoring; C = real-time control or settings; A = after real-time monitoring; S = statistical analysis; P = power flow analysis; L = Logging

| Substation Automation Information / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Emergency Control System Emergency/Prevention Operations** | | | | | | | | | | | | |
| 1. Real-time assessment of power system tolerances and margins | | | | | | | | | | | | |
| a. Generator withstand capabilities for over- and under-frequency conditions | M | | C | | | C | | | | | | M |
| b. Transmission dynamic limits: stability, thermal, & voltage | M | M | M | M | M | M | | S | | L | | |
| c. Distribution dynamic limits: load stability & emergency voltage quality limits | M | M | M | M | M | M | | S | | L | | M |
| 2. Real-time Fast Simulation and Modeling (FSM) | | | | | | | | | | | | |
| a. Real-time security assessment | M | M | M | M | M | | | | | L | | M |
| b. Generation and load balance assessment | M | M | M | M | M | | | | | L | | M |
| c. Inter-area power flow analysis | M | M | M | M | M | | | | | L | | M |
| d. Power flow optimization | | | | | | | | | | | B | |
| e. Generation dispatch optimization | | | | | | | | | | | | M |
| f. Integration with market models | | | | | | | | | | | | M |
| 3. Real-time determination of Remedial Action load and generation shedding upon insecure transmission operating conditions | | | | | | | | | | | | |
| a. Determination of triggers for fast load/generation shedding (FSM study) | B | | | | | | | | | L | M | M |

| Information \ Substation Automation — Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| b. Pre-arming of fast load/generation shedding for different triggers (real-time) | | | C | | | C | | | | L | | |
| c. Protection actions for fast load/generation shedding (immediate time) | | I | I | | | I | I | I | | L | | |
| d. Secure, adaptive restoration of loads and generation (real-time) | M | M,C | M,C | M, C | M,C | | | M | | L | | |
| 4. Real-time determination of remedial islanding upon insecure transmission operating conditions | | | | | | | | | | | | |
| a. Coordination of load-generation balances with generation tolerances | M | | | | | | | M | | L | | |
| b. Time synchronization of separation operations | | I | I | | | I | I | I,M | | L | | |
| c. Respecting the time-frequency zone constraints and voltage limits | M | | | M | M | | | | | | | |
| d. Load and generation balancing in islands: adaptive under-frequency load shedding, adaptive load restoration, & fast and accurate generation balancing | M | I,M,C | I,M,C | M, C | M,C | I,M, C | I | I | | L | | |
| 5. Restoration of power system integrity | | | | | | | | | | | | |
| a. Determination of the conditions for restoration | M | M | M | M | M | M | M | M | | M | M | |
| b. Determination of synchronization points | M | M | M | | | C | M | M | | M | | |
| c. Return to normal | M | M,C | M,C | M, C | M,C | C | M | M | | L | C | |
| **Substation protection system emergency operations** | | | | | | | | | | | | |
| 1. Power system protection reacts to power system faults | | | | | | | | | | | | |
| a. Protection actions within a substation | | I | I | | | I | I | | | L | | |
| b. Protection actions between substations | | I | I | | | I | I | | | L | | |
| 2. Emergency operations performs under/over-frequency load/generation shedding (both from | M | I,M,C | I,M,C | | | I | I | M | | L | | |

| **Substation Automation** / **Information** / **Transmission Operations Functions** | **Electric Power Measurements** | **Circuit Breakers** | **Reclosers** | **Load Tap Changers and** | **Capacitor Controllers** | **Protection** | **Fault Indication & Location** | **SOE & Disturbance Fault Recording** | **Metering** | **Logging & Archiving** | **Substation Configuration** | **Other** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| relaying or operator control) | | | | | | | | | | | | |
| 3. Emergency operations performs under/over-voltage load shedding (both from relaying or operator control) | M | I,M,C | I,M,C | | | I | I | M | | L | | |
| 4. Emergency operations performs conditional localized load shedding in response to: | | | | | | | | | | | | |
| a. Recovery from voltage or frequency-based load shedding | M | I,M,C | I,M,C | | | I | I | M | | L | | |
| b. LTC control/blocking | M | I,M,C | I,M,C | I,C | | I | I | M | | L | | |
| c. Shunt control | M | I,M,C | I,M,C | | | I | I | M | | L | | |
| d. Series compensation control | M | I,M,C | I,M,C | | | I | I | M | | L | | |
| e. System separation detection | M | I,M,C | I,M,C | | | I | I | M | | L | | |
| f. Wide area real time instability recovery | M | I,M,C | I,M,C | | | I | I | M | | L | | |
| **Control center emergency operations** | | | | | | | | | | | | |
| 1. Operators respond manually to emergency alarms | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 2. SCADA/EMS aids operators in locating fault | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 3. Operators dispatch field crews for restoration | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 4. SCADA system performs intelligent alarm processing | | | | | | | | | | | | |
| a. Local alarm reduction within substation | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| b. Centralized alarm reduction based on events from multiple substations | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 5. SCADA system performs disturbance monitoring analysis (including fault location) | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 6. SCADA/EMS performs dynamic limit calculations | M | M,C | M,C | M, | M,C | M | M | M | | L | | |

| Information / Substation Automation / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| for transformers and breakers based on real time data from equipment monitors | | | | C | | | | | | | | |
| 7. SCADA/EMS performs pre-arming of fast acting emergency automation | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 8. SCADA/EMS generates signals for emergency support by distribution utilities (according to the T&D contracts): | | | | | | | | | | | | |
| a. Emergency voltage and var control for providing dispatchable real and/or reactive loads | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| b. Emergency load re-balancing between T/D substations by feeder reconfiguration | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| c. Activation of interruptible/curtailable load | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| d. Activation of direct load control | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| e. Activation of distributed resources | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| f. Activation of other load management functions | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |
| 9. Operators performs system restorations based on system restoration plans prepared (authorized) by operation management | M | M,C | M,C | M, C | M,C | M | M | M | | L | | |

### 2.2.4 Post Real-Time Transmission Operations

**Table 2-4**
**Transmission Operations Functions Requirements for Post Real-time Operations**

**Codes:** B = before real-time; I = instantaneous signaling; M = real-time monitoring; C = real-time control or settings; A = after real-time monitoring; S = statistical analysis; P = power flow analysis; L = Logging

| Substation Automation<br>Information<br>Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Post operations** | | | | | | | | | | | | |
| 1. All systems archive logs and reports in searchable databases | | | | | | | | | | L | | |
| 2. Engineers and auditors research information from these logs and reports | | | | | | | | | | M | | |
| 3. Meters are read | A | | | | | | | | M | L | | |
| **Power system equipment maintenance** | | | | | | | | | | | | |
| 1. Substation and line maintenance including operation blocking | | | | | | | | | | | | |
| a. Periodic (time-based) maintenance | S | S | S | S | S | S | S | S | S | S | S | |
| b. Based on age of equipment | S | S | S | S | S | S | S | S | S | S | S | |
| c. Based on predictive models driven by real-time data | A | A | A | A | A | A | A | A | A | A | A | |
| 2. Maintenance staff maintain transmission lines | | | | | | | | | | | | |
| a. Request that operator block reclosing for maintenance purposes | | M | M | | | | | M | | L | | |
| b. Maintenance staff provides information for updating relevant databases | | | | | | | | | | L | | |
| c. Maintenance staff access substation drawings electronically | | | | | | | | | | | A | |

| Substation Automation Information / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **SCADA/EMS Maintenance** | | | | | | | | | | | | |
| 1. SCADA/EMS personnel update SCADA/EMS databases | A | A | A | A | A | A | A | A | A | A | A | |
| 2. SCADA/EMS personnel update EMS applications | | | | | | | | | | | A | |
| 3. SCADA/EMS personnel update operator interfaces | | | | | | | | | | | A | |
| 4. SCADA/EMS personnel update interfaces with other systems | | | | | | | | | | | A | A |
| 5. SCADA/EMS personnel perform diagnostics of the SCADA/EMS systems | | | | | | | | | | | | A |
| **Operator and SCADA/EMS personnel training** | | | | | | | | | | | | |
| 1. Operators and SCADA/EMS personnel perform periodic training by using the Operator Training Simulator | A | A | A | A | A | A | A | A | A | A | A | A |
| 2. Operators and SCADA/EMS personnel participate in advanced education programs | A | A | A | A | A | A | A | A | A | A | A | A |
| **Engineering** | | | | | | | | | | | | |
| 1. Protection engineers perform protection engineering | | | | | | | | | | | | |
| a. Duties: base case, fault studies, relay settings, protection coordination, fault analysis | A | A | A | A | A | A | A | A | A | A | A | A |
| b. Needs data: line/equipment capacity, relay specs, PT/CT ratios, fault records, SOE data, event info (relay 'targets' - which element picked up) | A | A | A | A | A | A | A | A | A | A | A | A |
| 2. Substation engineers perform substation engineering | S | S | S | S | S | S | S | S | S | S | S | S |
| 3. Transmission engineers perform transmission line | S | S | S | S | S | S | S | S | S | S | S | S |

| Substation Automation / Information / Transmission Operations Functions | Electric Power Measurements | Circuit Breakers | Reclosers | Load Tap Changers and | Capacitor Controllers | Protection | Fault Indication & Location | SOE & Disturbance Fault Recording | Metering | Logging & Archiving | Substation Configuration | Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| engineering | | | | | | | | | | | | |
| 4. Engineering staff provides information for updating relevant databases - from site / online | | C | C | C | C | C | C | C | C | C | C | |
| **Construction management** | | | | | | | | | | | | |
| 1. Construction managers manage assets | A | A | A | A | A | A | A | A | A | A | A | |
| 2. Construction managers plan construction projects | | | | | | | | | | | A | |
| 3. Construction managers manage crew assignments | | | | | | | | | | | | A |
| 4. Construction personnel provides information for updating relevant databases - from the site / online | A | A | A | A | A | A | A | A | A | A | A | |
| 5. Construction personnel access substation drawings electronically | | | | | | | | | | | | A |
| **Black Start** | | | | | | | | | | | | |
| 1. To be determined in 2004 research | | | | | | | | | | | | |

## 2.3 Information Technology Requirements That Drive Substation Automation Designs

Power system operations can no longer be viewed as a single infrastructure; in addition to the power system infrastructure, there is now an information infrastructure that overlays the power system.

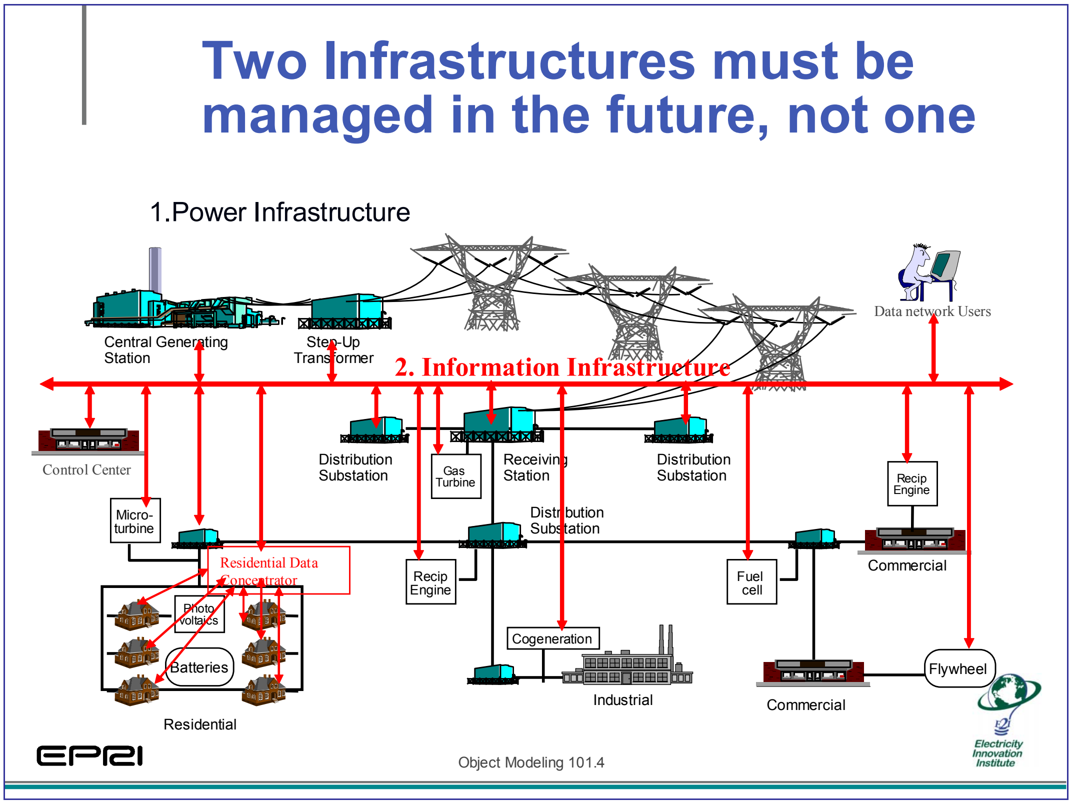



**Figure 2-1**
**Power System Infrastructure and the Information Infrastructure**

The extraordinarily complex power system, sometimes viewed as the largest machine in the world, can not function without this information infrastructure. However, this information infrastructure is not only a tremendous enhancer of power system operations, but also a new burden, since it too needs to be designed, implemented, and managed.

> ***Not only must the power system be designed and managed, but also the information infrastructure must be designed and managed.***

The information infrastructure must be designed with its main focus on supporting power system operations. If this were the only criteria for developing the information infrastructure, many different information designs could be (and have been) used. However, within recent years, information technologies have been evolving so that they are not only better at supporting power system operations, but they are also better at managing their own infrastructure. Although these information technologies are still evolving, it is crucial to use what technologies are available and to plan for incorporating new concepts as they are solidified and standardized.

The IECSA project mentioned above also developed a list of information infrastructure issues, which is shown below in shortened form.

### 2.3.1 Data Management

**_In automation systems, data management vital to ensuring the right information is available in the right place at the right time._**

The purpose of data management is to meet the power system operational requirements for data quality (integrity, accuracy), flexibility, scalability and availability, while also providing the information infrastructure for managing this data. This task includes management of many large databases, with data exchanges across organizational boundaries, requiring frequent and timely access and updates.

1. **Management of Databases**, includes functions such as capacity planning, tablespace management, permissions, access control and quotas

2. **Data Design and Modeling**, includes functions such as indexing, development and use of object modeling techniques, data modeling for typical data objects, data modeling for non standard data such as geographical information system maps, images, video, and oscillographic data

3. **Data Recovery**, includes development and use of automated and manual techniques for data replication, management of alternate sources of data, logging and archiving, backup, offline storage, disaster recovery

4. **Data Integrity**, includes development and use of data management techniques for data synchronization across interfaced systems, consistency checking, validation and data correction, handling logs and auditing, data cleansing, data anonymity, data purging

5. **Management of Database Operations**, includes development and use of techniques for data editing and updating policies and procedures, database population, report generation and data collection forms, handling data across organizational boundaries ( consistency, integrity), data transformation and mapping, database mediation and integration, development of forms and schedules for providing raw data by other departments (planners, engineering, maintenance, construction, etc.), discovery and automated interfacing with non-utility data objects, such as the methodology proposed by ebXML, storage, retrieval and streaming of video and audio data, two stage commit and rollback

6. **Data mining and retrieval**, includes development and use of techniques for on line transaction processing (OLTP) which involves real-time processing and retrieval of data and

may extend data bases across organizational boundaries, on line analytical processing (OLAP) which involves retrieval and processing and presentation of data from different points of view, sorting/selecting, and retrieving large amounts of historical data, data warehouse, data mining, ad hoc querying, knowledge management, and document management

7. **Data object modeling**, includes developing object models, instantiating object models, mapping of instantiated object models, data self-discovery, object browsing capabilities, automated data discovery, developing data exchange models, and validating object models and instantiations

### 2.3.2 Information Security Planning and Management

***Security by obscurity is no longer a safe bet.***

Information or cyber security has become an enormously hot topic over the last few years. Not only are there threats from Internet kiddie-script hackers (which rightly were ignored by substation engineers), but there are now more pertinent threats from sophisticated "crackers", industrial espionage, disgruntled employees, well-paid insiders, and terrorists.

The purpose of information security planning is to meet the security requirements of the user community, network, data and applications, including security policies, security technologies, and security management for:

1. **Security Requirements Assessment**, including techniques for determining the types and levels of security required by each asset, prevention techniques, vulnerability assessment, and interdependency analysis:
    a. Systematically identify critical assets;
    b. For each asset, conduct assessments on attractiveness to attackers, impact of successful attack, and vulnerability to attacks;
    c. Carry out critical consequence analyses; and evaluate the public health and safety, economic, and social impacts of infrastructure disruptions
    d. Security Policy management, including the development of security policies, the establishment of policies for corrective action when vulnerability is discovered, the establishment of policies for granting and revoking authority, the security training of employees, the security monitoring of employees, the repercussions for employees for not following security policies, and the assessment of information exposure to ensure compliance with security policies and procedures
    e. Periodic re-assessment of security requirements

2. **Security policies and techniques** for determining requirements and implementing **physical security countermeasures**:

a. Surveillance systems for buildings, substations, and other facilities, including motion detection cameras, video cameras, digital video recording equipment, matrix switching and control, and remote video transmission

b. Alarm system (sensors and control panels)

c. Access control and staff identification, including locks, guards, fences, guard dogs, lights, biometrics, smart card, RFID, electronic keys and locking devices, fiber optic vibration sensor, motion sensor and others

d. Backup and alternative paths, including backup control center, backup systems and bunker sites, backup data at physically different sites, alternative communication paths, alternative communications media, and alternative communications interfaces

3. **Security policies and techniques** for determining requirements and implementing **information security countermeasures**

   a. Assessment of possible countermeasures for each type and level of security vulnerability

   b. Assessment of most cost-effective techniques across groups of assets

   c. Handling of legacy systems and applications in implementing security

   d. Data authentication, integrity, confidentiality

   e. Supervisory computer security and firewalls

   f. Key management and certification

   g. Secure communication architectures and protocols

   h. Secure internet (SSL, IPsec)

4. **Intrusion detection, mitigation, and recovery** plan and techniques

   a. Intrusion detection methodologies

   b. Integrate and analyze data and information from different sensors, detectors, and other sources to make rapid determinations of the magnitude of an emergency, either physical or cyber and implement contingency plan to reduce the impacts of disruptions on the grid

   c. Spare parts database management

   d. Development and execution of methods for Distributed Denial of Service attacks (DDOS)

   e. Recovery plans

   f. Security management techniques to mitigate impacts during a security attack, including detection of intrusion, detection of attack, methods for countering attacks in progress, and methods for ameliorating the impact of a security breach

   g. Security managers respond and mitigate the physical and cyber disruptions

h. Security management techniques after a security attack, including assessment of damage, assessment and correction of security vulnerabilities, and determination of legal and financial processes against attackers

i. Security techniques to collect and distribute threat information

5. **Investigation and prosecution of a security attack**

   a. Logging, recording, and audit trails

   b. Security issues for legal procedures

### *2.3.3 System/Application Management*

***Systems and applications need to be actively managed, as much as the power system does.***

The purpose of system and application management is to provide the technological infrastructure and managerial policies that are designed to support the availability, reliability, performance, scalability and economics required by applications and systems. These include applications and systems within the substations, the control center, engineering and planning departments, the corporate departments, and, as much as possible, across to external entities.

1. End system and application requirements development. Collect and analyze computation, storage, and management requirements.

2. End system technology and architecture/platform planning. Specify appropriate computing, and system management technologies and architectures for applications, middleware, operating systems, and hardware. The task includes establishment and use of IT standards for:

   a. Inter-application interfacing and communications technologies such as message brokers and RPC oriented infrastructures.

   b. System implementation, validation, and certification

   c. Maintenance of systems

   d. Monitoring systems and applications

3. Installation, deployment and certification of systems and applications

4. System Integration

   a. Application integration (internal)

   b. Integration with eCommerce interfaces (external)

5. Real-time system and application monitoring and management for applications, middleware, operating systems, and hardware. This includes development and use of techniques for
   a. Monitoring the status of systems and applications,
   b. Detection and recovery from failures and performance problems,
   c. Disaster recovery and business continuity,
   d. Logging and recording of status and problems.

6. End System/application maintenance (planned and emergency)
   a. Testing and diagnosis
   b. Technician scheduling and repair
   c. Report generation

7. Customer care, help desk and user support

8. Business object management. This includes management of SW constructs associated with real world objects such as a circuit breaker or a purchase order. Tasks include:
   a. Design and development of business objects and management systems
   b. Monitoring and reporting of status of business objects.

9. Workflow management. This includes design and development of workflow management systems as well as execution of management functions: monitoring, diagnosis and reporting.

### 2.3.4 Communication Network Management

The purpose of network management is to meet the requirements for communications network accessibility, reliability, availability, resiliency, performance, manageability, and economics, covering:

***Communications networks also need to be actively managed in order to provide the required reliability.***

1. User/business network requirement (QoS, availability, backup, bandwidth, response time) development.
2. Network technology and architecture/platform planning. It includes establishment and use of new technologies for network architecture, network management, network signaling and control, data/payload delivery mechanisms, implementation, validation, and certification of networks
3. Network design and configuration. The task is to specify the logical network design and configuration that meet the architecture specifications and forecasted network demand growth.

4. Installation, deployment and certification of networks
5. Real-time network monitoring and management. This includes establishment and use of IT techniques for monitoring the status of networks, responding to failures, performance problems, logging and recording status and problems, collecting and analyzing measurements for network reengineering, and capacity planning
6. Network element management, including performance management, fault management and recovery, maintenance (planned and emergency), including testing/diagnostics, technician scheduling, repair, report generation, and process management, and disaster recovery/business continuity
7. Network engineering, including addressing and routing, policy management, configuration management, traffic and QoS engineering
8. Customer care and user support

### 2.3.5 Telecommunications Management

**_Telecommunications media need to be actively managed in order to provide the required reliability._**

The purpose of telecommunications management is to meet the requirements demanded by power system operations for the telecommunications infrastructure.

In this discussion, the term "Telecommunications" covers both the physical media and the media-specific protocols. The media includes leased lines, fiber optic systems, microwave systems, spread spectrum radio systems, power line carrier, wire cables, use of cellular and wireless service providers, Internet and internet service providers, telecommunication service providers, data service providers, etc.

The management of telecommunications covers the configuration and networking of different media, accessibility to telecommunication channels, reliability of the media channels, availability of the networks, resiliency of the infrastructure to planned and unplanned telecommunications outages, performance parameters, manageability of maintenance and changes, and economics of maintenance and upgrades.

Telecommunications management can be categorized as:

1. User/business telecommunications and data networking requirement development, including Service Level Agreements development and oversight of externally provided telecommunications and networking facilities
2. Telecommunications infrastructure technology and architecture planning, including the establishment and use of standards for designing, purchasing, installing, and implementing different media
3. Real-time monitoring and management techniques for monitoring the status of the telecommunications network infrastructure, and providing resiliency and recovering from failures, performance problems, etc.

4. Telecommunications infrastructure management, including monitoring and measurement for capacity planning, performance management, fault management and recovery, inventory/asset and order management, maintenance (planned and emergency), and disaster recovery/business continuity.

# 3
# PLANNING FOR SUBSTATION AUTOMATION – BENEFITS OF ABSTRACT, MODEL-BASED DISTRIBUTED COMPUTING TECHNOLOGIES

Planning for substation automation requires a different approach than substation engineers have typically done in the past to construct new substations. In addition to the design of physical and electrical requirements, substation automation also requires the design of the information requirements.

The most effective way to analyze information requirements, determine information flows, and develop specifications for these information needs, is to develop abstract models of the functions. Substation engineers will probably need support from specialists in information modeling, but an overview of the abstract modeling process is presented in this section.

## 3.1 Abstract, Model-Based Distributed Computing Background

***Abstract modeling allows the designs of complex systems to be decomposed into their individual, simpler components in an organized manner.***

One of the most powerful technologies that has taken a leading role in the information industry is ***abstract modeling***. Abstract modeling allows the designs of complex systems to be decomposed into their individual, simpler components in an organized manner, with methodologies to help capture all requirements, from contractual issues, to human idiosyncrasies, to performance, and to the increasingly time-consuming maintenance issues. Once all of these components are identified, the system can be built up from them.

Multitudes of applications, scattered throughout distributed computers and tied together by meshes of networks, would be hopeless to design, operate, and manage without modeling

### *3.1.1 Problems of Historical Concepts and Technologies*

As can be seen from the discussions in the previous sections, the automation of substations provides many benefits to utility operations. However, not all information technologies provide the same benefits toward supporting substation automation.

First of all, if different vendor proprietary protocols are used within a single substation and possibly between the substation and the control center, the exchange of information becomes difficult and limited. This polyglot of communication languages means that translators (gateways and protocol converters) must be scattered through out the substation so that the different devices can understand each other, a complex and costly proposition.

***Historically, the polyglot of different communications protocols has created a terrible management problem.***

Secondly, even if one communications protocol is selected, many difficulties still arise if it is not object-oriented. For instance, many substation automation projects try to use DNP 3 or Modbus as their single communications protocol. These protocols use "plain vanilla" hard-wired data descriptions. For instance, the voltage at a bus could be "analog point 39 on I/O card 5". This cryptic identification is difficult enough to validate when first installed, but after some data "maintenance" or modifications to the substation, this same data point could become "analog point 198 on I/O card 3 in RTU ABC". Multiply this change in identity by the frequency of data maintenance activities and substation modifications and expansions, to say nothing of multiple utilities monitoring the same data point, and it can be seen that this becomes a nightmare for ensuring validity of data information.

Thirdly, different information is needed by different entities (humans, applications, and systems) for different purposes at different times. The traditional approach has been to require the SCADA system in the control center to acquire all data that might be needed by anyone – except for the data it can't handle (e.g. oscillographic data) or for the times the SCADA system is too limited to handle the many new requirements for data, particularly from automated substations. In these cases, jury-rigged solutions are applied, which only add to the chaos of the information infrastructure.

### *3.1.2 Benefits of Modeling Technologies*

***UCA-SA (alternately or officially known as IEC61850)*** provides the most advanced standardized capabilities of all the substation automation technologies. This superiority stems from its object-oriented approach to data design and management, the use of modeling not only for objects but also for services, and the fact that it is now an international standard that is, or will shortly be, supported by most major vendors.

***UCA-SA (IEC61850) is an international standard based on object modeling technologies which are crucial to achieving true interoperability.***

First, as of 2003, the key elements of UCA-SA are an international standard. This means that all substation devices will support UCA-SA in the near future, even if they do not already do so. Proprietary protocols and data designs will become obsolete as both users and vendors demand the use of standards. Users are becoming more cognizant of the problems with proprietary protocols as they struggle to interface them once the vendors have left. At the same time, vendors are anxious to support and maintain over many years as few different protocols as possible.

Second, UCA-SA defines standard object models for all substation devices, thus giving every data point a unique and permanent name. The voltage on the bus would always have the same standard name, regardless of how it was physically connected or who was reading its information. Just this one fact alone improves the accuracy of initial installations and can simplify the on-going maintenance by orders of magnitude. These standardized object models provide the stability of source data that permits the rigorous management and yet flexible use of this data by different users and systems.

Third, because it is object-oriented, UCA-SA does not require that all data be collected by a SCADA system. Certainly some of the substation data is needed for SCADA operations, but other applications and systems could access this self-defining data directly (or indirectly through a secure gateway server) without loading down the SCADA system with collecting non-SCADA data. This capability off-loads the SCADA system and frees it up to manage only the data that is necessary for real-time operations.

## 3.2 Use of Abstract Modeling Tools to Develop Requirements

Information technology has taken many leaps in concepts over the last few years (and is one of the major reasons that these UCA-SA models were a long time in design). The key conceptual requirements that drove the design of UCA-SA object models include:

### *3.2.1 Abstract Modeling*

Organizing information abstractly allows it to be understood more completely before it is turned into a physical (or cyber) form. These abstract models can not only model data (like a circuit breaker status), but also services or actions (such as “send status upon change”). Once information is modeled abstractly, it can be mapped (or “instantiated”) into a specific cyber item – format, protocol, etc. Thus an abstract model of a circuit breaker gives it a name and a structure – this name and structure can then be mapped into any format, while the abstract models of services can be mapped to communications protocol, including MMS, DNP, XML, or even a flock of carrier pigeons.

### *3.2.2 Information Exchange Interoperability*

Interoperability in a substation is the ability of two or more IEDs from the same vendor, or different vendors, to exchange information and use that information for correct co-operation. Vital as it is, this level of “interoperability” still does not guarantee that the business content (e.g. the usefulness of the exchanged information) is understood by both entities.

### *3.2.3 Interworkability*

At a higher level, applications interworkability is defined as the ability to have functions work together over a distributed system. Thus, in addition to having information exchange interoperability, the applications must understand the information that is exchanged and be able to complete their functions. Interoperability involves technologies above the communications system layers, and involves not just the "hard-coding" of what data means and where it is stored, but the ability of applications, using standardized names and procedures, to seek out the information they need. A very common example of this is the ability of Microsoft Windows™ operating systems to detect new hardware, query the hardware (actually firmware) to determine what it is, then load automatically the appropriate drivers. This concept could (eventually) be facilitated in substation automation through the use of the **Substation Configuration Language (SCL),** using the concepts promulgated by the ebXML methodologies. For instance, if new equipment is installed in a substation, or a new substation is commissioned, the EMS Network Analysis functions could use SCL to determine what equipment has been installed, and automatically add it to the power flow topology data.

### *3.2.4 Interchangeability*

Interchangeability is defined by the IEC as the ability to replace a device from the same vendor, or from different vendors, utilizing the same communication interface, with the same functionality, and with no impact on the rest of the system. Interchangeability moves from the partially manual implementations of interworkability to completely automated implementations. Using the previous Windows example, very often the hardware detection process requires manual intervention to "find the driver", install upgrade patches, and to otherwise "tweak" the operating system and the "new hardware" to truly work together. Eventually, the systems and interface standards should become so robust that they determine exactly what is needed, possibly find the drivers and patches automatically over the Internet, and install the systems automatically.

## 3.3 Unified Modeling Language (UML)

The Unified Modeling Language (UML) was developed to provide the abstract modeling needed to ensure top-down understanding of the entire system, as well as to provide mechanisms for translating those abstract models into actual computer code. A more complete description of the UML constructs can be found in Appendix B.

### *3.3.1 Abstract Modeling in UML*

***Abstraction, the focus on relevant details while ignoring others, is a key to learning and communicating. Modeling is a method of visualizing that abstraction.***

Abstraction, the focus on relevant details while ignoring others, is a key to learning and communicating. Modeling is the process of abstracting from the morass of stuff to develop a coherent, multi-faceted vision. Because of this:

- Every complex system is best approached through a small set of nearly independent views of a model. No single view is sufficient.

- Every model may be expressed at different levels, ranging from highly abstract to the concrete.
- The best models are connected to reality.

The generally accepted methodology for software modeling is the Unified Modeling Language (UML), which has been endorsed by the Object Management Group (OMG), the leading industry standard for distributed object programming. UML is the standard language for visualizing, specifying, constructing, and documenting the artifacts of a software-intensive system. It can be used with all processes, throughout the development life cycle, and across different implementation technologies. UML combines the best of the best from Data Modeling concepts (Entity Relationship Diagrams), Business Modeling (work flow), Object Modeling, and Component Modeling

***The key benefit of using UML is that it provides structured methods for visualizing complex interactions that must be implemented in an invisible cyber world.***

Vendors of computer-aided software engineering products are now supporting UML and it has been endorsed by almost every maker of software development products, including IBM and Microsoft (for its Visual Basic environment). UML is a standard notation for the modeling of real-world objects as a first step in developing an object-oriented design methodology, and is used as the language for specifying, visualizing, constructing, and documenting the artifacts of software systems, as well as for business modeling and other non-software systems. UML represents a collection of the best engineering practices that have proven successful in the modeling of large and complex systems.

The UML modeling methodology is very powerful in that it can be used from the highest overview levels to actual implementation code, and from the largest global project to a tiny enhancement project. The key benefit of using UML is that provides methodologies for visualizing the complex interactions that must be implemented in an invisible cyber world. It consists primarily of structured diagrams that are designed to illustrate different aspects of cyber behavior. A number of CASE tools exist for developing these UML models as well-structured diagrams. The different UML modeling concepts and types of diagrams are described below.

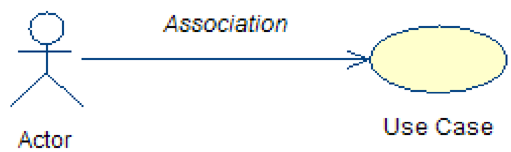
### *3.3.2 Use Cases*

***Use Cases are usually the first (and often the only) description of a function, because these Use Cases draw pictures of the interrelationships of the key elements at the highest levels.***

Use Cases are modeling constructs which focus on the interactions between functions and actors from a user's point of view. These are usually the first (and often the only) description of a function, because these Use Cases draw pictures of the interrelationships of the key elements at the highest levels. The basic idea for a Use Case is to capture the requirements of these actors in relationship to the function. "Actors" are defined as the ultimate sources or users of information for a particular Use Case scenario, and do not need to be humans. For instance, the power system can be seen as an Actor when it provides the source data for a SCADA system, while a billing system can be the user of metering data from an Automatic Meter Reading system.

Use Cases are layered or iterative in concept. For instance, in a Use Case diagram, a function is defined as a Use Case itself (which sometimes leads to confusion, but does emphasize the layered nature of Use Cases). As an example, in one Use Case diagram, the function "Distribution Automation Functions" could be defined as a single entity within distribution operations, while this same function could be expanded into its own Use Case, showing the individual functions as separate entities.

Therefore, the scope of a particular Use Case is entirely a function of what needs to be defined. In a broad picture Use Case, distribution system operations can be one function within utility operations. In a detailed picture Use Case, the Distribution Automation Volt/Var Optimization application can be the primary function. Therefore, often Use Cases are used first to define the overall Business Processes, and then are utilized to take each function within a Business Process and drill down to more detailed levels.




Modeling implies diagrams. Use Case Diagrams consist of Actors (often represented as little stick people) and Use Cases (ovals) linked by lines which indicate relationships, such as "is associated with", "is an aggregation of", or "is a generalization of". An association, which is represented as a line with one or two arrows, provides a pathway for communication. The communication can be between use cases, actors, classes or interfaces. Associations are the most general of all relationships and consequentially the most semantically weak. If two objects are usually considered independently, the relationship is an association. Other relationships include "generalization" and "dependency".

An example of a Use Case for the function “Implementing Substation Automation” is shown in Figure 3-1.

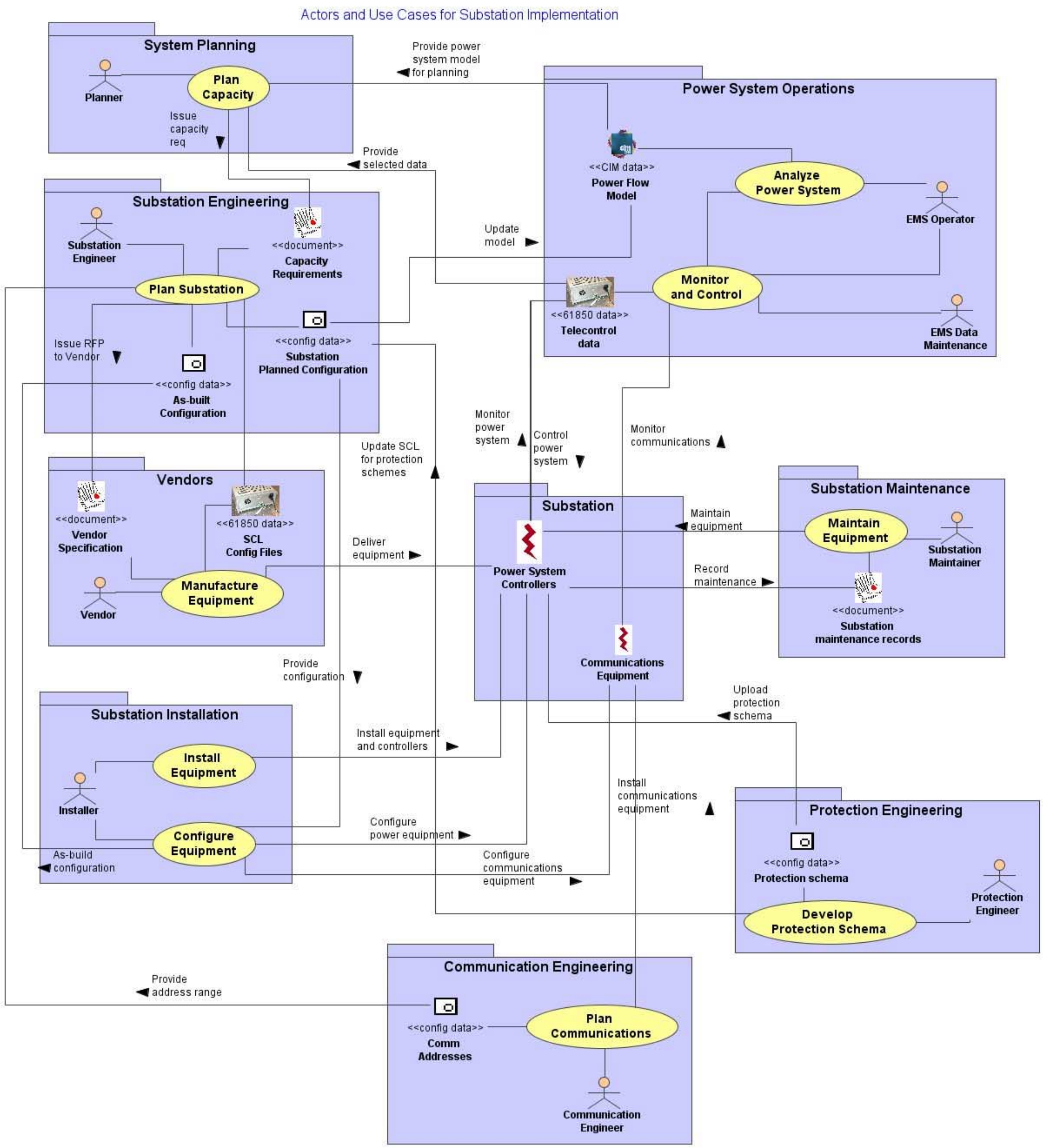



**Figure 3-1**
**UML Use Case of Implementing Substation Automation**

The benefits of Use Cases include:

- Visualizing processes and interactions which otherwise might be obscure or lost in the complexity of a system

- Capturing requirements from user's perspective
- Users are not only involved in providing requirements, but can actually understand and validate what is being designed
- A good way to start identifying information which will be exchanged among the functions and actors
- One way of estimating the percentage of requirements captured
- Categorizing functions and determining which impact the others particularly if a "phased delivery" implementation is planned
- A better way of estimating the percentage of requirements completed during development.
- Test plan can be immediately generated based on use cases
- Helps technical writers in structuring the overall work on the users manuals at an early stage
- Better traceability throughout the system development process
- Quality of the software is improved by identifying the exception scenarios earlier in the development process

### 3.3.3 UML Methodology

The methodology for using UML can be summarized as follows:

1. Develop Business Processes, using Use Cases
   a. Pick a business process, e.g. Day-ahead Submittal of Energy Schedules by Scheduling Coordinators
   b. Determine all the Actors, e.g. Scheduling Coordinator and Time Line Manager
   c. Determine the Use Case functions or systems involved, e.g. Market Interface Web Server, Format Validation Procedures, Database of Energy Schedules, and Congestion Management function. Since business processes are usually at a higher and broader level than individual functions, these Use Cases are do not focus on a single function to show basically its inputs and outputs, but show the "forest" rather than the "trees".
   d. Describe all performance requirements, pre- and post-conditions, and other assumptions, e.g. responses to submittals will be within 5 seconds or at pre-specified times, Scheduling Coordinators are all registered, post-condition is that schedule is accepted or rejected
   e. Draw and describe the interactions between the Actors and Use Cases, including sequences of steps and decisions affecting information flows, e.g. Sequences for error checking, ability of Scheduling Coordinator to withdraw schedule, etc. These can be documented in Activity Diagrams, Sequence Diagrams, Collaboration Diagrams, and State Diagrams, along with text to clarify the interactions.

2. Develop Data and/or Messages Contents, using Class Diagrams
   a. Identify the Data or Message Type for each interaction in the business process: Message Type consists of a noun (the data) and a verb (how/when/under what conditions is the message sent)
      – There are many, many Nouns, e.g. New energy schedule or update to an existing energy schedule
      – There are very few Verbs, e.g. Send, Request, Acknowledge Response, Error Response
   b. Organize and list all elements required by each Data or Message Type
      – "Organize" means identify specific parts of a message that are probably re-usable for other messages, e.g. Message Header, Scheduling Coordinator information, RTO information, E-tagging information (so that format can be used), Time and Date information, Other
      – Indicate if there is a one-to-one or a many-to-one correspondence between a part and the message, e.g. only one Scheduling Coordinator, but one or more schedules
      – List all elements for each part, e.g. Scheduling Coordinator Corporate name, Scheduling Coordinator ID, individual sending schedule, etc.

3. Translate Classes into Component Models
   a. Convert the classes into Document Type Definitions (DTD), using IDL or, as is becoming more common, using XML-DTD.
   b. These components can be translated into actual software code if so desired.

4. Register these DTDs so that all users of the information can access them. XML Registries can be public (e.g. ebXML uses OASIS XML Registry) or can be private. This step is not actually part of UML, but is becoming a powerful means to publish, maintain, and update information exchange templates among large groups of users.

## 3.4 Reference Model for UCA®, UCA-SA, IEC61850, CIM, and Substation Communications

***UCA-SA (IEC61850) is an international standard based on many of the object modeling technologies described above.***

UCA stands for Utility Communications Architecture, and was the brainchild of EPRI starting in the early 90's. It was a magnificent vision, and was greeted by the utility industry with great enthusiasm, but has run into problems over its lifetime. Put bluntly, the term "UCA" has acquired some negative baggage over the years while it was (and still is) being developed. This is due to the length of time it has taken for UCA to go from its original concept as the "overall architecture for utility communications", through the UCA version 2 documents of GOMSFE, CASM, and the MMS-based profiles, to the international IEC standard, IEC61850.

However, IEC61850 has now become an excellent standard that is accepted world-wide. It is being implemented by vendors into their products and is specified by utilities for their systems. However, since humans are not very good at remembering numbers, an effort is underway to provide a new set of human-friendly names that clarify what the suite of UCA components has become over time. Figure 3-2 provides a diagram of the UCA components within the Utility Communications Architecture. As can be seen, one component is UCA-SA, which comprises the substation automation object models defined in IEC61850-7-3 and 7-4. Although the naming effort has not been finalized, it is this term, UCA-SA, which will be used through the rest of this document.

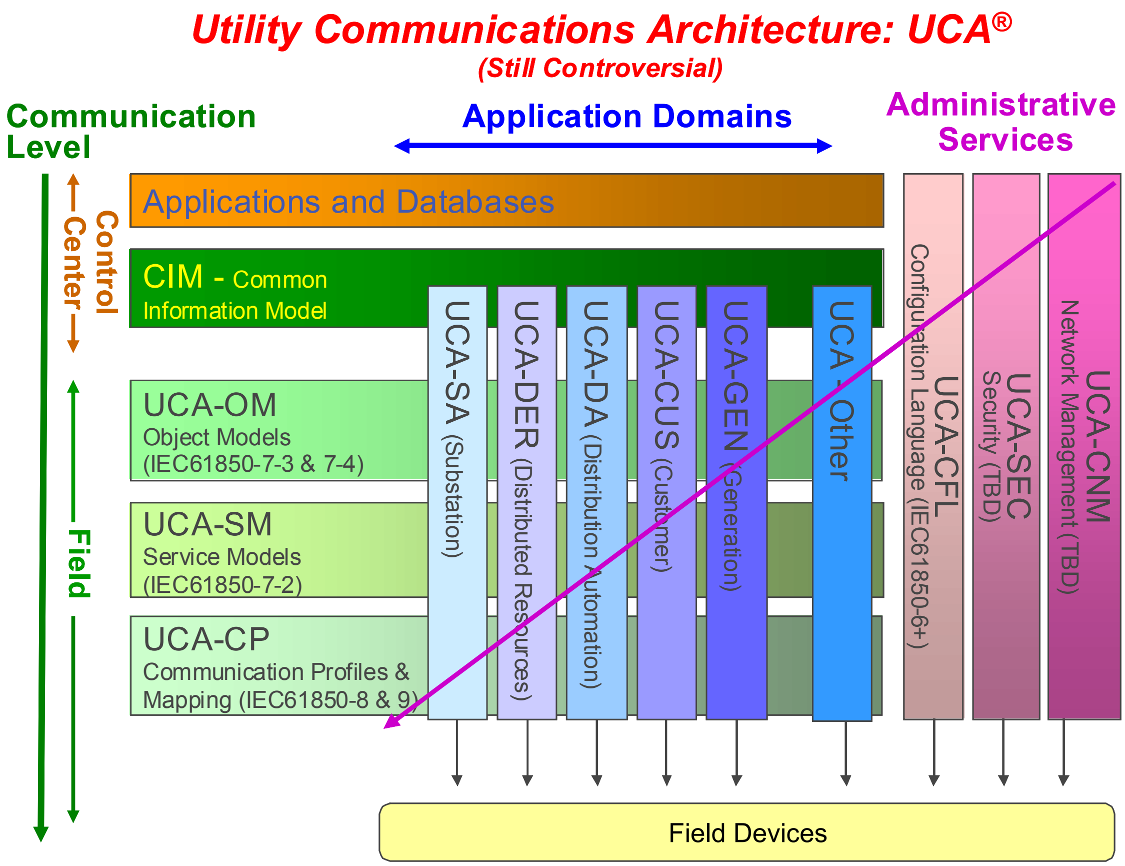



**Figure 3-2**
**Suite of UCA Components within the Utility Communications Architecture, with UCA-SA used for Substation Automation**

### *3.4.1 Object Modeling – UCA-OM*

Object Models are ***Nouns.*** They are the data that is exchanged among different devices and systems. Figure 3-3 illustrates the object hierarchy used for developing UCA-SA object models. The process from the bottom up is described below:

***Object Models are Nouns: the models of the data that will be exchanged. UCA-SA defines the object models for substations.***

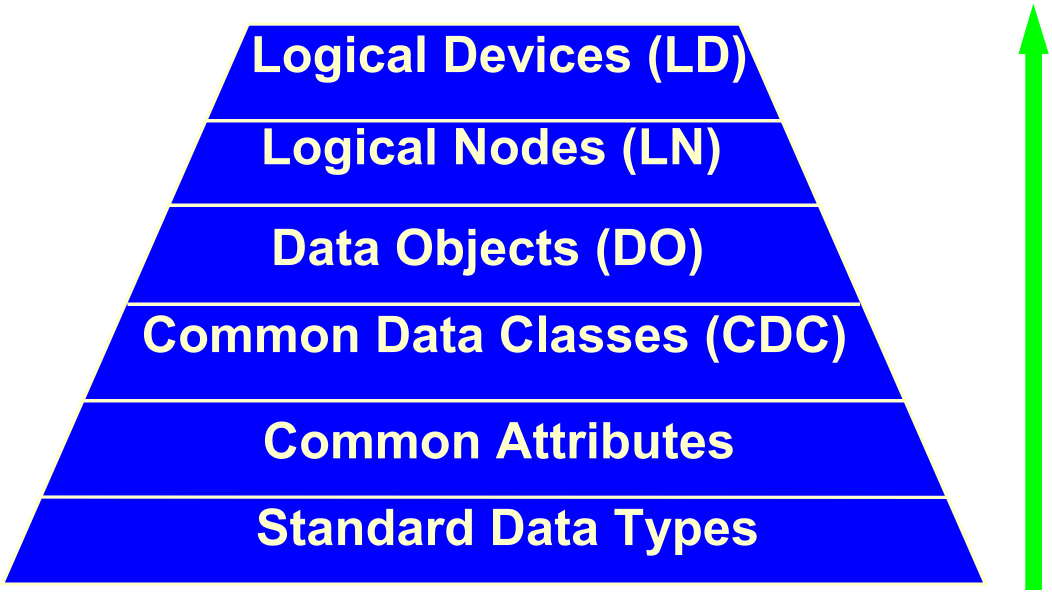



**Figure 3-3**
**Object Model Hierarchy**

1. **Standard Data Types**: common digital formats such as Boolean, integer, and floating point

2. **Common Attributes**: predefined common attributes that can be reused by many different objects, such as the Quality attribute. These common attributes are defined in IEC61850-7-3 clause 6.

3. **Common Data Classes (CDCs)**: predefined groupings building on the standard data types and predefined common attributes, such as the Single Point Status (SPS), the Measured Value (MV), and the Controllable Double Point (DPC). In essence, these CDCs are used to define the type or format of Data Objects. These CDCs are defined in IEC61850-7-3 clause 7.

4. **Data Objects (DO)**: predefined names of objects associated with one or more Logical Nodes. Their type or format is defined by one of the CDCs. They are listed only within the Logical Nodes. An example of a DO is “Auto” defined as CDC type SPS. It can be found in a number of Logical Nodes. Another example of a DO is “RHz” defined as a SPC (controllable single point), which is found only in the RSYN Logical Node.

5. **Logical Nodes (LN)**: predefined groupings of Data Objects that serve specific functions and can be used as “bricks” to build the complete device. Examples of LNs include MMXU which provides all electrical measurements in 3-phase systems (voltage, current, watts, vars, power factor, etc.); PTUV for the model of the voltage portion of under voltage protection; and XCBR for the short circuit breaking capability of a circuit breaker. These LNs are described in IEC61850-7-4 clause 5.

6. **Logical Devices (LD)**: the device model composed of the relevant Logical Nodes. For instance, a circuit breaker could be composed of the Logical Nodes: XCBR, XSWI, CPOW, CSWI, and SMIG. Logical Devices are not directly defined in any of the documents, since different products and different implementations can use different combinations of Logical Nodes for the same Logical Device. However, many examples are given

IEC61850 Logical Device servers (a server being a hardware device such as a computer) contain Logical Device models within them (a model being software and database constructs which act as if they were the physical device they are modeling). These Logical Device models consist of one or more Physical Device models, along with some general information about device identity and global capabilities.

Physical Device models, in turn, are constructed of multiple functional modules called Logical Nodes (LNs). Logical Nodes are standard groupings of Data Objects that have been organized to serve a specific function. Therefore a Logical Device Server can be diagrammed as shown in Figure 3-4.

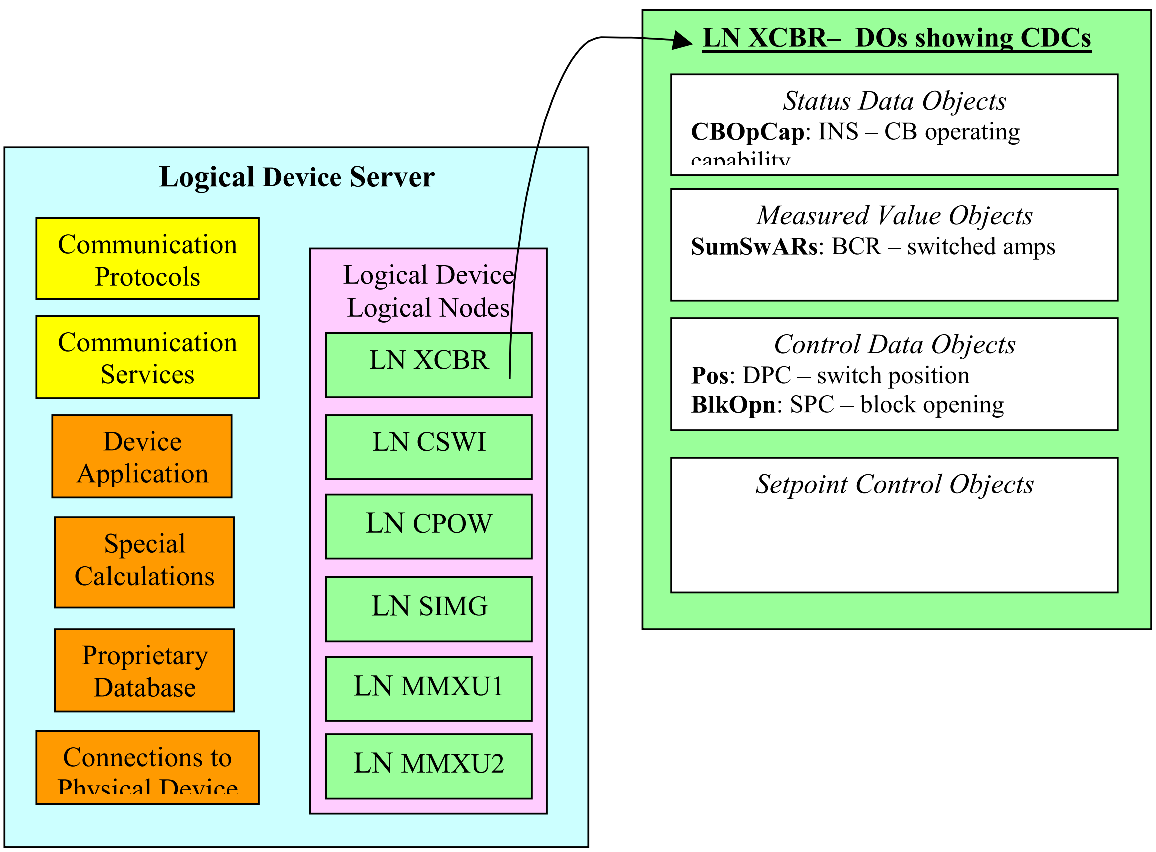



**Figure 3-4**
**Example of Relationship of Logical Device, Logical Nodes, Data Objects, and Common Data Classes**

### 3.4.2 Communication Services Modeling – UCA-SM

**_Communication Services are Verbs: the actions that actually perform the exchanges of data._**

Communication Services are the ***Verbs.*** They provide the actions, such as sending and receiving data, reporting data when some event occurs, logging data, and other "actions". In UCA-SA, there are two types of communication services: Abstract Communication Services, which must be mapped to a particular protocol (such as MMS or OPS); and PICOM, which is a unique set of services for protection relaying.

#### 3.4.2.1. ACSI – Abstract Communication Services Interface

IEC61850-7-2 defines a set of abstract communication services that addresses the basic requirements for the process of exchanging information. These services include:

1. **Association services**, where a logical connection is made between two entities, such as a substation master with a new IED. In addition, multi-cast associations are also handled. This group of services handles establishing connections, deliberate breaking connections, aborting connections (usually due to some error condition), and managing unexpected broken connections.

2. **Get**, which requests information to be sent, including Get Logical Device Directory, Get Logical Node Directory, Get Data Values, Get Data Values Directory, and others. This service is used to monitor information.

3. **Set**, which sends information to be used or stored, including Set Data Values. This service is used for control commands, setting parameters, and writing descriptions

4. **Data Sets**, where data values are grouped into sets for efficient transmittal. Data Sets can be manually created as well as automatically created and deleted.

5. **Report Control**, which manages the reporting of Data Sets upon request, at a particular periodicity (e.g. integrity scan), and upon the occurrence of pre-specified events, such as data change (e.g. closed to tripped status), quality change (e.g. a problem causes data to be invalid), data update (e.g. an accumulator value is "frozen" periodically), or integrity scan mismatch (e.g. the integrity scan indicates a different status value from the value that was last reported).

6. **Log Control**, which manages logging and journaling of information, such as sequence of events

7. **Substitution Values**, which manages the substitution of values if these are indicated in the Data Object classes

8. **GSE Messages**, which handle special ultra-high-speed messaging to multiple destinations, typically for protective relaying.

9. **Select-Before-Operate Control**, which implements the safety mechanisms used by most switch-related control commands. This procedure basically consists of: an originator of the control command first issuing a select of the control point, the receiver then performing a select and reporting the results back to the originator, the originator then issuing an execute command which the receiver performs only if it receives the execute command within a pre-specified time from the originator.

10. **Time Management,** which handles the synchronization of time across all interconnected nodes.

11. **File Transfer,** which handles the transfer of files between entities, without treating them as data objects. This capability supports the uploading of new applications into the IEDs and other servers.

Of these services, most are taken care of automatically by the basic communications software. The key services that are important for the substation engineer to become involved with are the Data Sets. Basic Data Sets are pre-defined: each Logical Node has an associated Data Set of all its data. However, these may not be appropriate for all users, therefore, the substation engineer should help define the data groupings, based on substation requirements as well as other user and software application requirements.

Although clearly initial Data Sets must be defined, they can be changed at any time. Therefore, one of the requirements from the vendors must be an HMI (human-machine interface) tool that permits the easy definition and modification of these Data Sets (see Section 5.4.5).

#### 3.4.2.2 PICOM

Piece of Information for COMmunications (PICOM) is a term defined by CIGRE WG34.04 to describe the information passed between Logical Nodes. The components of a PICOM are:

1. Data, meaning the actual data items sent from one LN to another LN

2. Type of data, meaning its format

3. Performance of the information exchange

The PICOMs are used primarily to define what data needs to be exchanged between protective relaying IEDs. The detailed exchange parameters of PICOMs should be part of a protective relaying vendor's package; however, the substation engineer will need to specify very precisely what protection events should trigger what actions.

### 3.4.3 Mapping to Protocol Profiles – UCA-CP

The abstract objects and communication services have to be "mapped" to real-world bits and bytes, in other words, to actual communication protocols.

***Abstract objects and services must be "mapped" to real-world bits and bytes, in other words, into actual communication protocols.***

IEC61850 currently has two protocol mapping specified, namely, the GSE protocol for transmissions between very high speed devices (such as protection relays) and MMS over the TCP/IP suite of protocols. However, the UCA-SA object models can also be transmitted using some other mappings to protocol profiles, although some protocols can manage objects better than others. For instance, MMS and XML (over any lower layer network protocols) can utilize the object models completely. However, XML does not specify the communication services (when to send, triggered by what, etc.). So an underlying service capability must be added, most of which do not handle some of the more powerful services like data sets.

### 3.4.4 Substation Configuration Modeling – UCA-CFL

***Abstract configuration languages provide a mechanism for describing how real-world components are actually connected to each other. Two such configuration languages have been defined to date in the utility industry: UCA-CFL and CIM.***

Abstract configuration languages provide a mechanism for describing how real-world components are actually connected to each other. Two such configuration languages have been defined to date in the utility industry:

1. Substation Configuration Language UCA-CFL for the configuration of equipment within substations

2. Common Information Model (CIM) for the overall configuration of the power system, from corporate ownership through the lines, substations, and feeders, down to the customer sites.

The concept of a ***configuration language*** is that the configuration of the substation can be modeled electronically using object models, not just the data in the substation. This model of the substation configuration allows applications to "learn" how all the devices within a substation are actually interconnected both electrically and from an information point of view.

This configuration language is described in IEC61850-6. However, the document is not yet complete, and is still being developed. However, Figure 3-1 does provide a Use Case of how the configuration language might be constructed.

The configuration language is also planned to be compatible with the Common Information Model (CIM) standard (see Section 3.4.5). The work to do this is also still under development through the IEC. However, when it is completed, it may become very important in future more sophisticated functions that would benefit from having substation configuration information available and updated electronically.

Even if this configuration language is not immediately used within a utility's operations, it should be required from the appropriate substation automation vendor, probably the vendor of the substation master.

### 3.4.5 Power System Configuration Modeling – CIM

The Common Information Model (CIM) is an abstract model that represents all the major power system objects in an electric utility enterprise, including some organizational and ownership aspects, but focusing on power system connectivity. The "instantiation" of a CIM power system model (conversion from an abstract model into a specific configuration of a specific utility's power system) provides the information that is typically needed by power flow topology models used by multiple applications, such as the EMS and DMS Network Analysis applications. This model includes public classes and attributes for these objects, as well as the relationships between them.

***The Common Information Model (CIM) is an abstract model that represents all the major power system objects in an electric utility enterprise, including some organizational and ownership aspects, but focusing on power system connectivity.***

The CIM was initially developed under the aegis of EPRI as the Control Center API (CCAPI) research project (RP-3654-1) project. It is currently undergoing standardization through the IEC TC57 WG13, as the document IEC 61970. The following descriptions of the CCAPI concepts are derived from excerpts from the introduction to the IEC document and other submissions to the IEC.

The principle objectives of the EPRI CCAPI project were to:

- Reduce the cost and time needed to add new applications to an EMS.
- Protect the investment in existing applications that are working effectively in an EMS.
- Provide an integration framework for interfacing existing systems to an EMS.

The principal task of the EMSAPI Project (to develop and standardize IEC 61970) is to develop a set of guidelines and standards to facilitate the integration of applications developed by different suppliers in the control center environment - similar to a plug-in application. A plug-in application is defined to be a piece of software that may be installed on a system with minimal effort & no modification of source code; i. e., the way software packages are installed on a desktop computer.  The EMSAPI Project goal is to at least approach that ideal by reducing the often significant efforts currently required to install third-party applications in an EMS.

The scope of these specifications includes other transmission systems as well as distribution and generation systems external to the control center that need to exchange real-time operational data with the control center. Therefore, another related goal of these standards is to enable the integration of existing legacy systems as well as new systems built to conform to these standards in these domains of application.

The complete set of standard documents includes the following parts:

- Part 1: Guidelines and General Requirements
- Part 2: Glossary
- Part 3xx: Common Information Model (CIM)
- Part 4xx: Component Interface Specification (CIS), Level 1
- Part 5xx: CIS, Level 2 (the CIM defined as XML, using RDF)

The goal of the CCAPI standards is to encourage the independent development of reusable software components and facilitate their integration in the construction of control center systems through the development of component interface standards. The software industry, including the major Energy Management System (EMS) vendors and suppliers of application software for an EMS, has undergone an evolution from basing software engineering concepts on top down modular software design to object-oriented approaches to the latest refinement using component-based architectures. The component models embraced by the Common Object Request Broker Architecture (CORBA), Enterprise Java Beans (EJB), and Distributed Common Object Modeling (DCOM) best exemplify this trend.

One of the primary on-going efforts is the development of Application Program Interfaces (APIs) for interfacing between the CIM and applications. These component-based approaches facilitate the integration of software from various sources. The goal is not to develop standard interfaces for middleware. In fact, the goal is just the opposite – *to be independent of any particular set of middleware services*. This allows integrators to select the right type and scale of infrastructure for each system. It allows service designs to evolve and innovate, and it simplifies component development as well. The selected protocol is the Generic Interface Definition (GID).

The following two examples illustrate this independence of components:

- CORBA components specifically do not require the use of CORBA Notification (or any particular service) as its event system.
- COM+ components are written exactly the same way whether they are deployed in an environment with or without Distributed Transaction Coordinator (DTC) and/or a Microsoft Message Queue (MSMQ).

The CIM model is defined using UML tools, and has been exported into XML for use in implementations.

# 4

# SPECIFYING UCA-SA: STANDARDS AND OPTIONS

## 4.1 UCA-SA Object Models Specifications

IEC61850-7-4 clause 5 lists Logical Nodes in alphabetic order within type of LN. For those experts who have been involved in the development of the standard and who have the LN names burned in their brains, this organization makes sense since they can quickly find the LN they are looking for to get the details. But this organization doesn't help those people who don't even know what LN to look for. IEC61850-5 clauses 12-2 and 12-3 provide a few examples, but no definitive descriptions of how to model a circuit breaker or Load Tap Changer for different requirements. This is understandable for a "normative" standard that is oriented toward "you shall" rather than "you could". That is where this guideline can help the users of substation automation – even if ultimately it is the IEC experts who implement the LNs into their products.

The following sections discuss the optional implementations of the different Logical Nodes for the different substation equipment. Generally, no single option is "better" than another; they are simply designed for different capabilities and requirements. Different vendors may also choose to implement functions using somewhat different arrangement of LNs, depending upon their products. However, along with the tables of functions described in Section 2.2, the issues described in these following sections can assist substation engineers and planners determine the range and functionality of the required substation equipment.

### *4.1.1 Electric Power Measurements*

Electric power measurements can be captured by many controllers and many locations in substations, often in conjunction with equipment for which these measurements are not particularly relevant. For instance, the primary purpose of a circuit breaker controller is to respond to the trip command from protective relaying devices or supervisory control command from a control center, and it may need frequency measurements to perform point-on-wave switching. However, it often also captures electric power measurements just because it is convenient to include this capability in the controller. Therefore electric power measurement Logical Nodes are often included within many different Logical Devices. Which LNs to include in a Logical Device, should depend upon the electric power measurement requirements for the location that is connected to the controller.

Table 4-1 describes the different electric power measurement Logical Nodes. The first rows describe the basic contents of each Logical Node, while the last row shows a typical implementation of Logical Nodes for one device, such as a switch. The numbers indicate how many Logical Nodes might be implemented. For instance, if the device is a switch, then 2 instances of the MMXU 3-phase measurements might be implemented, one for each side of the switch.

**Table 4-1**
**Electric Power Measurement Logical Nodes**

| Electric Power Measurements | TVTR | TCTR | MMXU | MMXN | MDIF | MHAI | MHAN | MSQI |
|---|---|---|---|---|---|---|---|---|
| **Voltage Transformer:** measurement of voltage at the PT | X | | | | | | | |
| **Current Transformer:** measurement of current at the CT | | X | | | | | | |
| **3-Phase Electrical Measurements**: 3-phase watts, vars, volt-amps, voltage, amps, power factor, impedances, and frequency, by phase-to-phase and phase-to-ground (as appropriate) | X | X | X | | | | | |
| **Single Phase Electrical Measurements:** Single phase watts, vars, volt-amps, voltage, amps, power factor, impedances, and frequency, by phase-to-phase and phase-to-ground (as appropriate) | X | X | | X | | | | |
| **Amps Measured on "Other" Side:** amps measured on the other side of an open switch or breaker | X | X | | | X | | | |
| **3-Phase Harmonics Measurements:** 3-phase harmonics | X | X | | | | X | | |
| **Single Phase Harmonics Measurements:** single phase harmonics | X | X | | | | | X | |
| **Sequence and Imbalance Measurements:** sequence and imbalance measurements across phases | X | X | | | | | | X |
| **All 3-Phase Measurements:** all 3-phase measurements at one location, on both sides of a device | 6 | 6 | 2 | | 1 | 1 | | 2 |

### *4.1.2 Switches, Circuit Breakers, and Reclosers*

Different types of switches are built from the different Logical Nodes, based on the requirements and capabilities of the equipment. The Logical Nodes used in some of the more common switch and circuit breaker-related capabilities are shown in Table 4-2.

**Table 4-2**
**Switch, Circuit Breaker, and Recloser Logical Nodes**

| Switches, Circuit Breakers, and Reclosers | XSWI | XCBR | CSWI | RREC | RBRF | RSYN | CILO | SIMG | SARC | SPDC | CPOW | TCTR | TVTR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Switch:** switches with no short circuit breaking capability, such as disconnects, grounding switches, etc | X | | | | | | | | | | | | |
| **Switch with Supervisory Control:** switches which can be operated through supervisory control | X | | X | | | | | | | | | | |
| **Circuit Breaker with No Supervisory Control:** circuit breaker can only be tripped and reset by protection devices | | X | | | | | | | | | | | |
| **Circuit Breaker with Supervisory Control**: circuit breaker can be tripped by protection devices, and can also be opened and closed by supervisory control commands | | X | X | | | | | | | | | | |
| **Circuit Breaker with SF6 gas:** insulating gas is monitored | | X | X | | | | | X | | | | | |
| **Circuit Breaker with alarm monitoring:** arcs, partial discharges, and breaker failures are monitored | | X | X | | X | | | | X | X | | | |

| **Switches, Circuit Breakers, and Reclosers** | XSWI | XCBR | CSWI | RREC | RBRF | RSYN | CILO | SIMG | SARC | SPDC | CPOW | TCTR | TVTR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Circuit Breaker with Lockout:** lockout prevents or enables switching operation | | X | X | | | | X | | | | | | |
| **Circuit Breaker with Point-on-Wave tripping capability:** circuit breaker operates only at a specific point on the waveform | | X | X | | | | | | | | X | X | X |
| **Circuit Breaker with synchronization checking:** circuit breaker operation is enabled only if voltage phasor difference across the open switch is within specified limits | | X | X | | | X | | | | | | | |
| **Recloser:** circuit breaker with multi-cycle auto recloser capability | | X | X | X | | | | | | | | | |
| **Circuit Breaker with all capabilities:** circuit breakers can include all capabilities | | X | X | X | X | X | X | X | X | X | X | X | X |

In addition to these circuit breaker LNs, the IED controller for a circuit breaker could also include other LNs, since the current transducer (CT) and power transducer (PT) sensors are usually located at the breaker site. So, additional LNs that could be included in the circuit breaker IED are:

- MMXU or MMXN – 3-phase or single phase electric measurements
- MDIF – amps on the "other" side of the breaker
- MHAI or MHAN – harmonics in 3-phase or single phase system
- MSQI – sequence and imbalance measurements
- CALH – grouping of alarms
- RFLO – fault locator

### *4.1.3 Transformers and Tap Changers*

Transformers and their tap changing controllers are modeled by multiple Logical Nodes, which can be combined to form different capabilities to meet the various different requirements

The Logical Nodes used in some of the more common transformer and load tap changer-related capabilities are shown in Table 4-3.

**Table 4-3**
**Transformer and Tap Changer Logical Nodes**

| **Transformers and Tap Changers** | **YPTR** | **YLTC** | **YPSH** | **YEFN** | **ATCC** | **AVCO** | **ARCO** | **ANCR** |
|---|---|---|---|---|---|---|---|---|
| **Power Transformer:** the characteristics of the transformer | X | | | | | | | |
| **Load Tap Changer:** status and measurements of the load tap changer | | X | | | | | | |
| **Power Shunt:** controller for controlling the power shunt | | | X | | | | | |
| **Earth Fault Neutralizer:** controller for the earth fault neutralizer coil | | | | X | | | | |
| **Automatic Tap Changer controller:** controller for the automatic control of tap changers | | | | | X | | | |
| **Voltage Controller:** control characteristics based on voltage | | | | | | X | | |
| **Reactive Power Controller:** control characteristics based on reactive power | | | | | | | X | |
| **Neutral Current Regulator:** regulator for the neutral current | | | | | | | | X |
| **Automatic Load Tap Changer controller:** LTC controller combining many characteristics | X | X | | | X | X | X | X |

In addition to these tap changer LNs, the IED controller for tap changer could also include other LNs, since the current transducer (CT) and power transducer (PT) sensors are usually located at the breaker site. So, additional LNs that could be included in the tap changer IED are:

- MMXU or MMXN – 3-phase or single phase electric measurements
- MDIF – amps on the “other” side of the breaker
- MHAI or MHAN – harmonics in 3-phase or single phase system
- MSQI – sequence and imbalance measurements
- CALH – grouping of alarms

### *4.1.4 Capacitor Bank Switch Logical Nodes*

Capacitor bank switch controllers are modeled by a few Logical Nodes used together. The only choice is whether the switch is manually operated or can be controlled through supervisory control actions.

The Logical Nodes used for the capacitor bank switch are shown in Table 4-4.

**Table 4-4**
**Capacitor Switch Logical Nodes**

| **Capacitor Switch** | **XCAP** | **XSWI** | **CSWI** |
|---|---|---|---|
| **Capacitor Bank:** the characteristics of the capacitor bank | **X** | | |
| **Capacitor Switch:** status and control over capacitor switch | | **X** | |
| **Switch Controller:** switch with supervisory control capability | | | **X** |
| **Capacitor Bank Control:** capacitor bank with supervisory control capability | **X** | **X** | **X** |

In addition to these capacitor switch LNs, the IED controller for a capacitor switch could also include other LNs, since the current transducer (CT) and power transducer (PT) sensors are usually located at the breaker site. So, additional LNs that could be included in the capacitor switch IED are:

- MMXU or MMXN – 3-phase or single phase electric measurements
- MDIF – amps on the “other” side of the breaker
- MHAI or MHAN – harmonics in 3-phase or single phase system
- MSQI – sequence and imbalance measurements
- CALH – grouping of alarms
- RFLO – fault locator

### *4.1.5 Protection Logical Nodes*

Protection functions are probably the most complex and extensive of the Logical Nodes in IEC61850. The first table below shows the Logical Nodes associated with specific protection functions, then the tables in the subsections 4.1.5.1-6 show typical combinations of these protection functions for common purposes.

The Logical Nodes used for the protection functions are shown in Table 4-5.

**Table 4-5**
**Protection Functions Logical Nodes**

| Protection Functions (IEEE C37.2 Ref) | PTEF | PZSU | PDIS | PSCH | PVPH | PTUV | PDOP | PDUP | PTUC | PTOC | PTOV | PTTR | PIOC | PVOC | POPF | PUPF | PHIZ | PPAM | PTOF | PTUF | PFRC | PDIF | PDIR | PHAR | PMRI | PMSS | RDIR | RPSB | PZSU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Transient earth fault | X | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Zero speed and under speed (14) | | X | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Distance (21) | | | X | X | | | | | | | | | | | | | | | | | | | | | | | X | | |
| Volt per Hz (24) | | | | | X | | | | | | | | | | | | | | | | | | | | | | | | |
| Under voltage (27) | | | | | | X | X | X | | | | | | | | | | | | | | | | | | | | | |
| Undercurrent/ under power (37) | | | | | | | | X | X | | | | | | | | | | | | | | | | | | | | |
| Loss of field / Under excitation (40) | | | | | | | | X | | | | | | | | | | | | | | | | | | | | | |
| Reverse phase or phase balance current (46) | | | | | | | | | | X | | | | | | | | | | | | | | | | | | | |
| Phase sequence voltage (47) | | | | | | | | | | | X | | | | | | | | | | | | | | | | | | |
| Thermal overload (49) | | | | | | | | | | | | X | | | | | | | | | | | | | | | | | |
| Rotor thermal overload (49R) | | | | | | | | | | | | X | | | | | | | | | | | | | | | | | |
| Stator thermal overload (49S) | | | | | | | | | | | | X | | | | | | | | | | | | | | | | | |
| Instantaneous overcurrent or rate of rise (50) | | | | | | | | | | | | | X | | | | | | | | | | | | | | | | |
| AC time overcurrent (51) | | | | | | | | | | X | | | | | | | | | | | | | | | | | | | |
| Voltage controlled/dependent time overcurrent (51V) | | | | | | | | | | | | | | X | | | | | | | | | | | | | | | |
| Power factor (55) | | | | | | | | | | | | | | | X | X | | | | | | | | | | | | | |
| Time Overvoltage (59) | | | | | | | | | | | X | | | | | | | | | | | | | | | | | | |
| DC Overvoltage (59DC) | | | | | | | | | | | X | | | | | | | | | | | | | | | | | | |
| Voltage or current balance (60) | | | | | | X | | | | | X | | | | | | | | | | | | | | | | | | |

| Protection Functions (IEEE C37.2 Ref) | PTEF | PZSU | PDIS | PSCH | PVPH | PTUV | PDOP | PDUP | PTUC | PTOC | PTOV | PTTR | PIOC | PVOC | POPF | PUPF | PHIZ | PPAM | PTOF | PTUF | PFRC | PDIF | PDIR | PHAR | PMRI | PMSS | RDIR | RPSB | PZSU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Earth fault / Ground detection (64) | | | | | | | | | | | | | | | | | X | | | | | | | | | | | | |
| Rotor earth fault (64R) | | | | | | | | | | X | | | | | | | | | | | | | | | | | | | |
| Stator earth fault (64S) | | | | | | | | | | X | | | | | | | | | | | | | | | | | | | |
| Intertum fault (64W) | | | | | | | | | | X | | | | | | | | | | | | | | | | | | | |
| AC directional overcurrent (67) | | | | | | | | | | X | | | | | | | | | | | | | | | | | X | | |
| Directional earth fault (67N) | | | | | | | | | | X | | | | | | | | | | | | | | | | | X | | |
| DC time overcurrent (76) | | | | | | | | | | X | | | | | | | | | | | | | | | | | X | | |
| Phase angle or out-of-step (78) | | | | | | | | | | | | | | | | | | X | | | | | | | | | | | |
| Frequency (81) | | | | | | | | | | | | | | | | | | | X | X | X | | | | | | | | |
| Differential (87) | | | | | | | | | | | | | | | | | | | | | | X | | | | | | | |
| Phase comparison (87P) | | | | | | | | | | | | | | | | | | | | | | X | | | | | | | |
| Differential line (87L) | | | | | | | | | | | | | | | | | | | | | | X | | | | | | | |
| Restricted earth fault (87N) | | | | | | | | | | | | | | | | | | | | | | X | | | | | | | |
| Differential transformer (87T) | | | | | | | | | | | | | | | | | | | | | | X | | X | | | | | |
| Busbar (87B) | | | | | | | | | | | | | | | | | | | | | | X | X | | | | | | |
| Motor differential (87M) | | | | | | | | | | | | | | | | | | | | | | X | | | | | | | |
| Generator differential (87G) | | | | | | | | | | | | | | | | | | | | | | X | | | | | | | |
| Motor startup (49R,66,48, 51LR) | | | | | | | | | | | | | | | | | | | | | | | | | X | X | | | |
| Power swing detection/blocking | | | | | | | | | | | | | | | | | | | | | | | | | | | | X | |
| Zero speed or under speed | | | | | | | | | | | | | | | | | | | | | | | | | | | | | X |

In addition to the specific protection Logical Nodes, relays can also include other Logical Nodes, such as:

- CALH – grouping of alarms
- RFLO – fault locator
- RDRE, RDRS, RBDR, RADR – Disturbance recording
- RSYN – Synchronization checking

#### 4.1.5.1 Typical Protection Logical Nodes for a Transformer Relay

Table 4-6 shows a typical set of Logical Nodes used in transformer relays. As can be seen, there can be multiple instances of the same Logical Node, used for different purposes.

**Table 4-6**
**Typical Protection Logical Nodes for a Transformer Relay**

| IEEE | Function | Logical Node | Logical Node |
|---|---|---|---|
| 24 | Volts Per Hertz | PVPH | |
| 27 | Phase Undervoltage | PTUV | |
| 27X | Auxiliary Undervoltage | PTUV | |
| 50/87 | Instantaneous Differential Overcurrent | PIOC | PDIF |
| 50G | Ground Instantaneous Overcurrent | PIOC | |
| 50N | Neutral Instantaneous Overcurrent | PIOC | |
| 50P | Phase Instantaneous Overcurrent | PIOC | |
| 51G | Ground Time Overcurrent | PTOC | |
| 51N | Neutral Time Overcurrent | PTOC | |
| 51P | Phase Time Overcurrent | PTOC | |
| 59N | Neutral Overvoltage | PTOV | |
| 59P | Phase Overvoltage | PTOV | |
| 59X | Auxiliary Overvoltage | PTOV | |
| 67N | Neutral Directional Overcurrent | PTOC | |
| 67P | Phase Directional Overcurrent | PTOC | |
| 81O | Overfrequency | PTOF | PFRC |
| 81U | Underfrequency | PTUF | PFRC |
| 87G | Restricted Ground Fault | PDIF | |
| 87T | Transformer Differential | PDIF | |

### 4.1.5.2 Typical Protection Logical Nodes for a Line Distance Relay

Table 4-7 shows a typical set of Logical Nodes used in line distance relays.

**Table 4-7**
**Typical Protection Logical Nodes for a Line Distance Relay**

| IEEE | Function | Logical Node | Logical Node |
|---|---|---|---|
| 21G | Ground Distance | PDIS | PSCH |
| 21P | Phase Distance | PDIS | PSCH |
| 25 | Synchrocheck | RSYN | |
| 27P | Phase Undervoltage | PTUV | |
| 27X | Auxiliary Undervoltage | PTUV | |
| 50BF | Breaker Failure | PIOC | |
| 50DD | Current Disturbance Detector | PIOC | |
| 50G | Ground Instantaneous Overcurrent | PIOC | |
| 50N | Neutral Instantaneous Overcurrent | PIOC | |
| 50P | Phase Instantaneous Overcurrent | PIOC | |
| 50_2 | Negative Sequence Instantaneous Overcurrent | PIOC | |
| 51G | Ground Time Overcurrent | PTOC | |
| 51N | Neutral Time Overcurrent | PTOC | |
| 51P | Phase Time Overcurrent | PTOC | |
| 51_2 | Negative Sequence Time Overcurrent | PTOC | |
| 52 | AC Circuit Breaker | ????? | |
| 59N | Neutral Overvoltage | PTOV | |
| 59P | Phase Overvoltage | PTOV | |
| 59X | Auxiliary Overvoltage | PTOV | |
| 59_2 | Negative Sequence Overvoltage | PTOV | |
| 67N | Neutral Directional Overcurrent | PTOC | |
| 67P | Phase Directional Overcurrent | PTOC | |
| 67_2 | Negative Sequence Directional Overcurrent | PTOC | |
| 68 | Power Swing Blocking | RPSB | |
| 78 | Out-of-Step Tripping | PPAM | |
| 79 | Automatic Recloser | RREC | |

#### 4.1.5.3 Typical Protection for Feeder Relay

Table 4-8 shows a typical set of Logical Nodes used in feeder relays.

**Table 4-8**
**Typical Protection Logical Nodes for a Feeder Relay**

| IEEE | Function | Logical Node | Logical Node |
|---|---|---|---|
| 25 | Synchrocheck | RSYN | |
| 27P | Phase Undervoltage | PTUV | |
| 27X | Auxiliary Undervoltage | PTUV | |
| 32 | Sensitive Directional Power | PDOP | PDUP |
| 50BF | Breaker Failure | PIOC | |
| 50DD | Current Disturbance Detector | PIOC | |
| 50G | Ground Instantaneous Overcurrent | PIOC | |
| 50N | Neutral Instantaneous Overcurrent | PIOC | |
| 50P | Phase Instantaneous Overcurrent | PIOC | |
| 50_2 | Negative Sequence Instantaneous Overcurrent | PIOC | |
| 51G | Ground Time Overcurrent | PTOC | |
| 51N | Neutral Time Overcurrent | PTOC | |
| 51P | Phase Time Overcurrent | PTOC | |
| 51_2 | Negative Sequence Time Overcurrent | PTOC | |
| 52 | AC Circuit Breaker | ????? | |
| 59N | Neutral Overvoltage | PTOV | |
| 59P | Phase Overvoltage | PTOV | |
| 59X | Auxiliary Overvoltage | PTOV | |
| 59_2 | Negative Sequence Overvoltage | PTOV | |
| 67N | Neutral Directional Overcurrent | PTOC | |
| 67P | Phase Directional Overcurrent | PTOC | |
| 67_2 | Negative Sequence Directional Overcurrent | PTOC | |
| 79 | Automatic Recloser | RREC | |
| 81O | Over frequency | PTOF | |
| 81U | Under frequency | PTUF | |

### 4.1.5.4 Typical Protection for Generator Relay

Table 4-9 shows a typical set of Logical Nodes used in generator relays.

**Table 4-9**
**Typical Protection Logical Nodes for a Generator Relay**

| IEEE | Function | Logical Node | Logical Node |
|---|---|---|---|
| 21P | Phase Distance | PDIS | PSCH |
| 24 | Volts Per Hertz | PVPH | |
| 25 | Synchrocheck | RSYN | |
| 27P | Phase Undervoltage | PTUV | |
| 27TN | Third Harmonic Neutral Undervoltage | PTUV | |
| 27X | Auxiliary Undervoltage | PTUV | |
| 32 | Sensitive Directional Power | PDOP | PDUP |
| 40 | Loss of excitation | PDUP | |
| 46 | Generator Unbalance | PTOC | |
| 50G | Ground Instantaneous Overcurrent | PIOC | |
| 50N | Neutral Instantaneous Overcurrent | PIOC | |
| 50P | Phase Instantaneous Overcurrent | PIOC | |
| 50/27 | Accidental Energization | PIOC | PTUV |
| 51G | Ground Time Overcurrent | PTOC | |
| 51P | Phase Time Overcurrent | PTOC | |
| 59N | Neutral Overvoltage | PTOV | |
| 59P | Phase Overvoltage | PTOV | |
| 59X | Auxiliary Overvoltage | PTOV | |
| 59_2 | Negative Sequence Overvoltage | PTOV | |
| 64TN | 100% Stator Ground | PTOC | |
| 67N | Neutral Directional Overcurrent | PTOC | |
| 67P | Phase Directional Overcurrent | PTOC | |
| 68 | Power Swing Blocking | RPSB | |
| 78 | Out-of-Step Tripping | PPAM | |
| 81O | Over frequency | PTOF | |
| 81U | Under frequency | PTUF | |
| 87S | Stator Differential | PDIF | |

#### 4.1.5.5 Typical Protection for Bus Differential Relay

Table 4-10 shows a typical set of Logical Nodes used in bus differential relays.

**Table 4-10**
**Typical Protection Logical Nodes for a Bus Differential Relay**

| IEEE | Function | Logical Node | Logical Node |
|---|---|---|---|
| 27 | Undervoltage | PTUV | |
| 50 | Instantaneous Overcurrent | PIOC | |
| 50/74 | CT Trouble | PIOC | CALH |
| 50/87 | Unrestrained Bus Differential | PIOC | PDIF |
| 50BF | Breaker Failure | PIOC | |
| 51 | Time Overcurrent | PTOC | |

#### 4.1.5.6 Typical Protection for Motor Relay

Table 4-11 shows a typical set of Logical Nodes used in motor relays.

**Table 4-11**
**Typical Protection Logical Nodes for a Motor Relay**

| IEEE | Function | Logical Node | Logical Node |
|---|---|---|---|
| 27P | Phase Undervoltage | PTUV | |
| 27X | Auxiliary Undervoltage | PTUV | |
| 32 | Sensitive Directional Power | PDOP | PDUP |
| 46 | Generator Unbalance | PTOC | |
| 47 | Phase Sequence Voltage | PTOV | |
| 49 | Thermal Overload | PTTR | |
| 50G | Ground Instantaneous Overcurrent | PIOC | |
| 50P | Phase Instantaneous Overcurrent | PIOC | |
| 51G | Ground Time Overcurrent | PTOC | |
| 59N | Neutral Overvoltage | PTOV | |
| 59P | Phase Overvoltage | PTOV | |
| 59X | Auxiliary Overvoltage | PTOV | |
| 59_2 | Negative Sequence Overvoltage | PTOV | |
| 87S | Stator Differential | PDIF | |

### 4.1.6 Disturbance Recording Logical Nodes

Disturbance Recording Logical Nodes handle the collection and storage of analog and status changes during disturbances. These Logical Nodes may be part of other devices, since they capture information from the same current transducer (CT) and power transducer (PT) sensors that are used by the other functions.

These are shown in Table 4-12. The code "M" means "multiple instances in different devices".

**Table 4-12**
**Disturbance Recording Logical Nodes**

| **Disturbance Recording** | **RDRE** | **RADR** | **RBDR** | **RDRS** |
|---|---|---|---|---|
| **Disturbance Recorder Source Management:** Manages the triggers, timing of triggers, memory for recording, and other aspects of disturbance handling at the source. | X | | | |
| **Disturbance Recorder Analog Data:** Handles the input of analog data in COMTRADE format. | | X | | |
| **Disturbance Recorder Binary Data:** Handles the input of binary data in COMTRADE format. | | | X | |
| **Disturbance Record Handling:** Handles the storage of records at another location, such as the substation master. | | | | X |
| **Disturbance Recording System:** | M | M | M | 1 |

### 4.1.7 Metering Logical Nodes

Metering Logical Nodes handle the reading of meters.

These are shown in Table 4-13.

**Table 4-13**
**Metering Logical Nodes**

| **Metering** | **MMTR** | ***M???*** | **MSTA** |
|---|---|---|---|
| **3-Phase Metering:** Calculation of energy in a 3-phase system | X | | |
| **Single Phase Metering:** Calculation of energy in a single phase system. *This Logical Node has not yet been defined, but will be in the near future.* | | X | |
| **Metering Statistics:** Statistical information derived from metered values | | | X |

### *4.1.8 Archiving, HMI, and Alarming Logical Nodes*

Archiving, HMI, and alarming Logical Nodes handle user interface issues.

These are shown in Table 4-14.

**Table 4-14**
**Archiving, HMI, and Alarming Logical Nodes**

| **Archiving, HMI, and Alarming** | **IARC** | **IHMI** | **CALH** |
|---|---|---|---|
| Archiving: Management of archival records | X | | |
| Human-Machine Interface: Management of the HMI. | | X | |
| Alarm Handling: Individual alarms can be grouped together to create group warnings and alarms. | | | X |

### *4.1.9 Power Quality*

There are currently no power quality object models in IEC61850 yet, but there is on-going work to modify the GOMSFE objects into 61850 objects.

## 4.2 UCA-SA Information Exchange Configuration

The UCA-SA concept of the information exchange configuration for substation automation consists, in its basic form, of the following parts:

1. **Substation Logical Devices** (acting as "Servers" in Client-Server terminology), which provide data and respond to commands. These servers contain one or more Logical Nodes for the devices being accessed. They can be simple electronic controllers each linked to a single device, more capable Intelligent Electronic Devices (IED) each managing a single device but providing additional functionality, or local servers which manage multiple devices and support many additional functions. Examples of the latter include substation automation masters and Distributed Energy Resources (DER) management systems.
2. **Ultra High Speed Network** that interconnects Logical Devices requiring ultra high speed exchange of information (on the order of 4 milliseconds), in particular the protection relays. These high speed networks can be physically separate point-to-point media links or logical channels within a network. For protection Logical Devices, the communication protocol used would be GSE or GOOSE to ensure that performance requirements are met.
3. **Substation Network** that interconnects Logical Devices not requiring the ultra high speeds of protection relays. These networks are physically within a substation, thus requiring a design to avoid electromagnetic interference noise, but possibly needing less protection against information security threats due to its isolation and the physical boundary of the substation (although this is an on-going debate).
4. **Substation Automation Master** that acts as a gateway between the substation and the external users of the substation information. This substation master can also store logs and archives, collect maintenance information, perform statistical calculations, provide a local human-machine interface, coordinate activities between Substation Logical Devices, and other functions.
5. **SCADA Communications Network** that provides external access to the substation Logical Devices, possibly directly but more likely through the Substation Automation Master. It may also include security measures in the form of firewalls, encryption devices, key management, role-based access measures, etc. In addition it may include network management capabilities.
6. **Data Acquisition and Control (DAC) subsystem,** acting as a "Client" to the Logical Devices and/or Substation Automation Master, and acting as a "Server" to control center SCADA systems and other Users. Specifically, these DAC subsystems can provide "mapping" between UCA-SA objects and internal representations of this data, such as to a SCADA real-time database. These DAC subsystems can also provide the security and network management capabilities.
7. **Multiple Users** who need to access the information in the Logical Device servers and, as authorized, issue data updates and control commands to the Logical Device servers. These Users can be systems, applications, databases, and/or humans, including power system operators, protection engineers, maintenance personnel, database administrators, planners, and even executives. Most Users will access the Logical Device servers via the DAC subsystem, but some may be UCA-SA Users with direct access to the Logical Devices. These UCA-SA Users could be vendors, communication technicians, or systems of the future which do not require data object mapping. Appropriate role-based access security measures would be required for all Users.

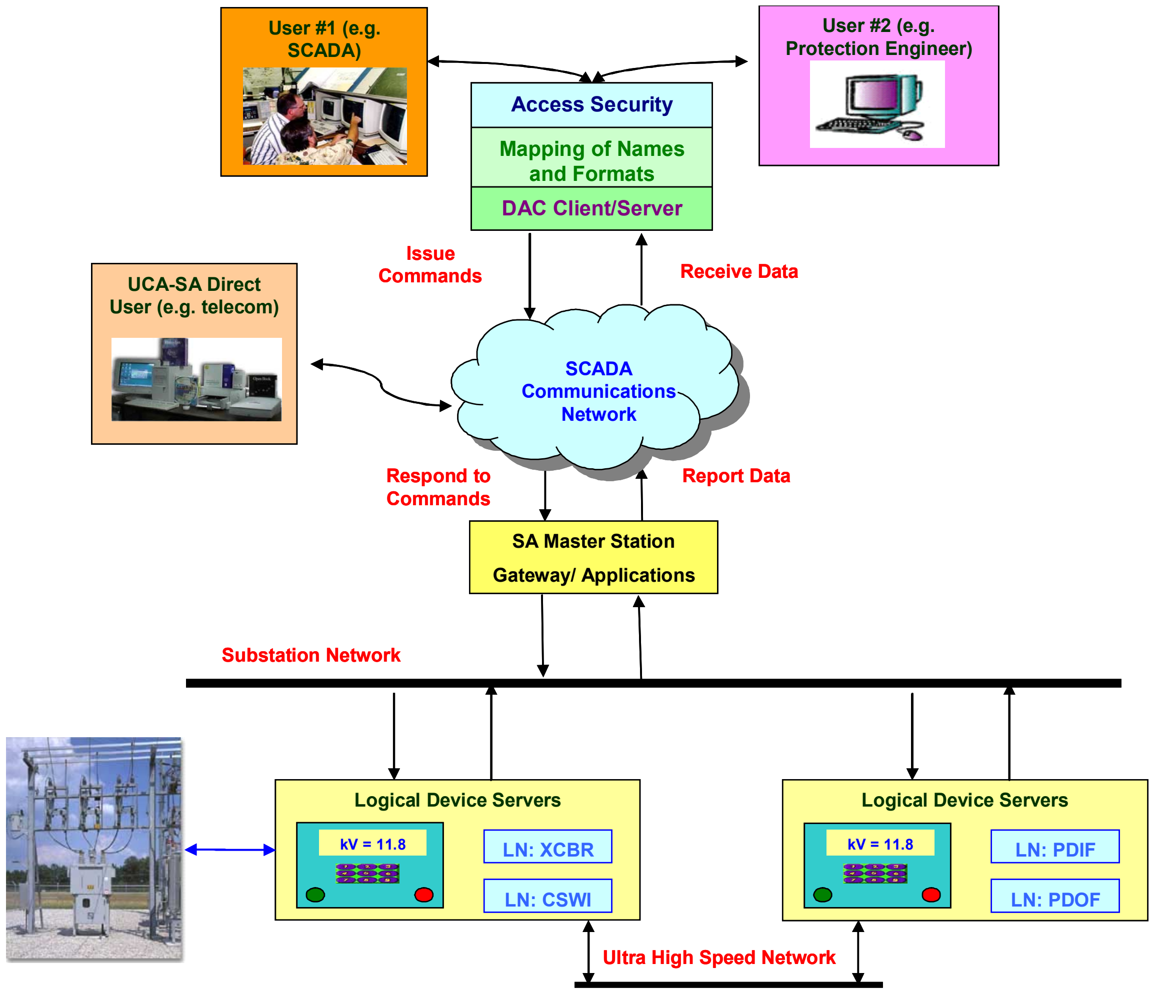



**Figure 4-1**
**Basic Communications Services Concepts Model**

## 4.3 Procedure for Specifying UCA-SA

The general procedures for specifying substation automation are described in Section 1. This section addresses only the procedure for specify UCA-SA.

The procedure for specifying UCA-SA consists of the following steps:

1. Step 1 – Determine functional requirements
2. Step 2 – Determine UCA-SA Logical Nodes and the data available within the LN
3. Step 3 – Develop UCA-SA data exchanges within the substation
4. Step 4 – Develop UCA-SA data exchanges with external systems

5. Step 5 - Specify Conformance Testing

6. Step 6 – Specify UCA-SA Configuration Tools

### 4.3.1 Step 1 – Determine Functional Requirements

Determining the functional requirements is the most critical step, and the one that must be performed by utility substation engineers. After this step, the results may be passed to vendors or integrators to do the detail work, including the implementation of the UCA-SA technologies. These functional requirements should indeed be "functional" and not oriented toward a specific vendor's product (even if the vendor's product is a foregone conclusion). The detailed process for developing functional requirements is discussed in greater detail in Section 1, but are covered briefly here as the necessary first step before the UCA-SA requirements can be determined. The requirements would include:

1. Layout of the substation from an electrical point of view

2. Identification of the types of equipment – CTs, PTs, circuit breakers, capacitor banks, transformers and tap changers, etc

3. Identification of what data is available or needed at each

4. Protection schemes – what events will cause what actions by what equipment

5. SCADA requirements – what information will be needed in real-time by the substation master and/or the control center SCADA system, and what control/setpoint/parameter capabilities will be needed

6. Information flow requirements – what information is required from each substation device and what information should be sent to each substation device. This includes information exchanges within the substation and between the substation and the rest of the utility. Specifically, the information in the Transmission Operations tables in Section 2.2.1 should be reviewed to determine what data could be needed.

7. Information security requirements – which data assets require what levels of security.

8. System and network management requirements – what capabilities are needed for monitoring, alarming, controlling, automating, diagnosing, maintaining, repairing, and auditing the information infrastructure

### 4.3.2 Step 2 – Determine UCA-SA Logical Nodes and the Available Data

This step could be performed by the utility substation engineers, based on this guideline. However, it could also be performed by vendors or system integrators, so long as the results are verified as conforming to the functional requirements by the utility substation engineers. The Logical Node determination includes:

1. Based on the functional requirements, determine which logical nodes are needed for which devices. Although vendors and/or integrators may choose to "instantiate" (turn into actual data) different Logical Nodes in different controllers or IEDs, the list of Logical Nodes should be the same for meeting the same functional requirements.

2. Select which optional data items need to be instantiated in the Logical Nodes, again based on the functional requirements.

### *4.3.3 Step 3 – Determine UCA-SA Data Exchanges within the Substation*

The data to be exchanged between devices in the substation must be defined, particularly between the protection devices and the circuit breakers, but also other closed-loop automated functions within the substation, as well as monitoring, alarming, reporting, and logging of information to the substation master.

This step should most likely be performed jointly between the utility substation engineers and the vendors/implementers of the substation equipment. The functional requirements in Step 1 describe the types of data to be exchanged; this step defines explicitly what UCA-SA data items are sent, where and under what conditions, within the substation.

In UCA-SA terminology, these data exchange definitions are PICOMs (Pieces of Information for COMmunication). Annex A of the IEC61850-5 document lists the most common PICOM source and sink Logical Nodes. In Annex B, these PICOMs are also categorized by the most common performance requirements. The PICOM descriptions are not normative, however, meaning that they are there for convenience and as examples. Therefore, it is important to ensure that the actual data exchanges are clearly defined as to average and maximum transfer times, average and maximum response times, average and maximum size of messages, security, availability, backup and/or redundancy, and other performance criteria.

### *4.3.4 Step 4 – Determine UCA-SA Data Exchanges with External Systems*

To be determined in 2004 research

### *4.3.5 Step 5 – Specify Conformance Testing*

Requiring that a vendor pass a UCA-SA conformance test is vital to ensuring interoperability. The conformance test procedures are going to become standards in 2004.

### 4.3.6 Step 6 – Specify UCA-SA Configuration Tools

The only constant thing is the world is change. It is vital that the vendor provide tools for managing the object models, communication services, protocols, and information services such as network management and security.

# 5
# IMPLEMENTING SUBSTATION AUTOMATION

*{This section is planned for development in the 2004 phase of the project. The headings and bullet points are shown to allow the reader to understand what the entire guideline will contain.}*

Until substation automation becomes the norm, rather than the exceptions, implementation of substation automation requires more effort and different expertise than just implementing a new substation using the traditional approaches. It is therefore very important for a substation engineer to fully appreciate the different steps required, even though these must be tailored to their individual situations.

The basic steps are:

1. Find a "champion" who recognizes that substation automation will be cost effective, despite some of the learning pains, requirements for different skills and approaches, and inevitable "glitches".

2. Develop functional requirements, by reaching out to other groups to determine what they need from substation information.

3. Develop technical specifications that truly capture the functional requirements, but do not over-specify by identifying specific hardware. The specifications must cover the substation equipment as well as the communications systems – and UCA-SA.

4. Evaluate bidders and selecting vendors to provide the equipment and systems

5. Monitor and manage the system development efforts, both in-house and by the vendors

6. Review and comment on documentation, which is vital to ensure the equipment and systems are developed as specified

7. Factory, field, and acceptance testing

8. Field installation, validation, and commissioning

9. Planning for future upgrades and extensions

## 5.1 Project Leadership & Management

### *5.1.1 Finding a Champion*

### *5.1.2 Involvement of Stakeholders and Users*

### *5.1.3 Project Management and it's Responsibilities*

#### 5.1.3.1 Managing the Implementation Process

- Planning -
    - Convening a team
    - Defining objectives
    - Choosing a deployment site
    - Establishing and maintaining the schedule
    - Establishing and maintaining the budget
    - Developing functional requirements
    - Developing technical specifications
    - Selecting equipment and suppliers
- System integration and testing
- Commissioning
- System maintenance until the project is commissioned
- Scoping future upgrades and extensions

#### 5.1.3.2 Keeping the Project on Track

- Maintaining a demonstration scale to avoid logistical headaches
- Preventing expansion of scope after objectives have been set
- Exercising judgment and influence to manage risk

#### 5.1.3.3 Vetting Solutions for –

- Effectiveness
- Reliability
- Project reusability
- Scalability
- Flexibility

#### 5.1.3.4 Building teamwork

- Among departments
- Between the utility & its principal suppliers
- Identifying experts & leaders

#### 5.1.3.5 Fostering good communication & problem solving

- Keeping participants engaged
- Promoting ownership
- Anticipating and managing problems
- Mediating differences

#### 5.1.3.6 Defining and Managing Project Documents

*Types of Documents*

- List of capabilities / applications and subscribers
- List of station data and functionality to be supported
- List of access privileges & reasons
- List of mandated access restrictions -
  - To comply with government regulations
  - To comply with utility policy
  - To mitigate risk
- Information flow diagrams
- Block diagrams
- Functional Requirement documents
- Technical Specification documents
- Application documents
  - Description of functionality
  - Description of system interface
  - Resources required
  - Input data required
  - Output data provided

*Document Management Processes*

- Ensuring documents communicate clearly
- Document distribution
- Document revisions
- Managing feedback

## 5.2 Developing a Consensus

### *5.2.1 Convening a Team*

- Representing departmental stakeholders -
  - Transmission operations
  - Protective relaying
  - Station metering
  - Facility planning and asset management
  - Station engineers
  - Operations & maintenance
  - Transmission planning
  - Market operations
  - Auditors and historians
  - Corporate users
- Possessing technology & integration skill sets
- Project champion
- Project Manager
- Consultant(s)

### *5.2.2 Defining Objectives*

#### 5.2.2.1 Deciding Who Needs What

- Access to data and functionality
  - Real-time data and functionality
  - Historical real-time data
  - Calculated or filtered data (e.g. min / max /avg / statistical values)

   - Time-tagged events
   - Pseudo-alarms (e.g. communications and device health status)
- SA applications and capabilities –
   - Archiving
   - Automatic bus sectionalizing
   - Automatic feeder sectionalizing
   - Automatic reclosing (enable/disable and monitoring)
   - Automatic transfer sequencing
   - Breaker failure protection
   - Breaker health monitoring
   - Bus fault protection
   - Digitally-filtered "smart" alarms
   - Downed conductor protection
   - Fault distance reporting
   - Feeder deployment switching
   - Line protection
   - Logging
   - Shunt reactor protection
   - Synchronism check
   - Event summaries, time-correlated
   - Time-overcurrent and instantaneous-overcurrent protection
   - Transformer load balancing
   - Transformer load monitoring
   - Transformer protection
   - Underfrequency protection
   - Voltage and VAr control (e.g. LTC control, cap bank control)

*Constraints*

   - Timing constraints
   - Delivery constraints
   - Presentation constraints

#### 5.2.2.2 Defining Expectations and Outcomes

- Staking out the project boundaries –
  - What's off-limits
  - What's essential
  - Identifying low-hanging fruit
- Specific capabilities to be realized –
  - Beneficiaries
  - New value to be realized
  - Savings to be realized
  - Cost to realize
  - Impact on present practice
- Qualitative attributes to be realized –
  - Reliability
  - Reusability
  - Scalability
  - Flexibility

#### 5.2.2.3 Deciding on Common Utility Infrastructure and Technology

- Traditional utility equipment –
  - Buses , lines, and feeders
  - Transformers
  - LTCs
  - Breakers
  - Switches
  - Capacitor banks
  - Reactors
- IEDs –
  - Relays
  - LTC controllers
  - Cap bank controllers
  - Station meters / network transducers
  - RTUs / PLCs

- Communications technology –
  - Legacy protocol gateway, protocol translation
  - Fiber and copper
  - Switches
  - Redundant access
- Processing technology –
  - Local client / protocol translator / repository / proxy server
  - Local application processing
  - User interface
- Technology tools –
  - Configuration
  - Data management
  - Network management
  - System Administration
  - Diagnostic & maintenance
- Legacy equipment to be integrated –
  - Traditional point I/O
  - Digital fault recorders

### *5.2.3 Choosing a Deployment Site*

- Consider suitability, accessibility, availability, and constraints
- Document pro's and con's

### *5.2.4 Establishing a Schedule*

- Recognition of other projects competing for resources
- Recognition of special constraints (e.g. summer or winter peaks)
- Availability of qualified personnel & other resources
- Staging successive phases

### *5.2.5 Determining a Budget*

- Budget for capital expense (e.g. equipment, software, tools)
- Budget for labor
  (e.g. management, engineering, installation, documentation, maintenance)

- Factor in deployment site pro's & con's
- Budget for low efficiency in new tasks
- Budget for consultation
- Budget conservatively, because this is a new experience

## 5.3 Developing Functional Requirements

### *5.3.1 Determining the Users of SA*

- Determine the SA functions to be supported

### *5.3.2 Involving the Users in Developing Functional Requirements*

### *5.3.3 Use of Modeling Tools for Utility Applications and Information Flows*

## 5.4 Developing Technical Specifications

- These define the solutions to be realized.

### *5.4.1 Formal Specification of Functional Requirements for Substation Automation*

#### 5.4.1.1 Responsibility for System Integration

- Who is responsible? Utility? One vendor? System integrator?

#### 5.4.1.2 Implementation Scheduling and Coordination

- Scheduling of multiple vendor milestones and delivery dates
- Interface Control Document to formalize interfaces between different vendors

### *5.4.2 Communication System Planning*

- Network and communications design within substation, interface with control center, interfaces with other users
- Network hardware, protocols, and technologies
- Network management
- Network installation

### 5.4.3 One or More Specifications of Any New Hardware Equipment

### 5.4.4 One or More Specifications of Any New Controller Equipment (IEDs)

- For new equipment
- Retrofit controllers for existing equipment when necessary

### 5.4.5 Specification of Substation Master

- Monitoring requirements
- Control requirements
- Protocol conversion requirements
- Performance requirements
- Security requirements
- Network management requirements
- Backup and recovery requirements
- Substation configuration requirements

### 5.4.6 Specification of Information Flows and Interactions

- Between IEDs and substation master
- Among IEDs
- Between substation master and SCADA
- Between substation master and non-SCADA systems (e.g. Database for non-SCADA access, protection engineering systems, PI historian, etc.)
- Between UCA-based items and CIM databases
- Protocol conversion requirements

### 5.4.7 Specification of Performance, Backup, and Recovery Requirements

### 5.4.8 Specification of Documentation, Testing, Project Management

### 5.4.9 Specific UCA Requirements for Servers and Clients

- UCA browsing requirements
- Abstract Communication Services required

- Special or new Logical Nodes and/or Objects required (beyond those needed to fulfill the functional requirements specified above)
- UCA logging requirements
- UCA laboratory and field testing requirements

## 5.5 Evaluating / Selecting Equipment and Suppliers

### *5.5.1 Support for Functional Requirements*

#### 5.5.1.1 General

- Request suppliers to provide comprehensive documentation (e.g. data sheets, user guides, drawings, application guides) in the areas of your interest. This information is commonly available on CDs or websites, which provide a convenient way to manage redistribution of and access to such information within your utility organization.
- Expect your principal suppliers to take time to understand your project requirements.
- Expect suppliers to provide personalized application guidance and review concerning use of their products within your project.
- In response to your bid specification, invite suppliers to submit alternative approaches they believe offer cost or functional benefits for your project.
- Be considerate of suppliers, realizing that their time is generally uncompensated beyond the products that you actually purchase.

#### 5.5.1.2 Application Functionality

- This includes all functionality related to supporting utility applications in support of the electric power system.

#### 5.5.1.3 Product Tools

- Client programs for (as applicable) –
  - Creating logic governing product behavior
  - Configuring the product
  - Downloading/uploading programs, configuration files, and data files
  - Testing communication capabilities
- Diagnostic and maintenance aids
- Expect your supplier to explain and demonstrate his product tools.

### 5.5.2 Support for UCA-SA Communication Objectives

- Request a PICS document (Protocol Implementation Conformance Specification) for UCA. This describes the specific functional support that is provided within the product.

#### 5.5.2.1 Network Support

- Support for TCP/IP over Ethernet.
- Support for connection-oriented clients.
- Support for multicast/connectionless messaging (i.e. 'goose messages'), if applicable.

#### 5.5.2.2 Support for Utility-Specified Object Models

- The earlier models were specified in GOMSFE, a part of EPRI's UCA 2.0 specifications. These are presently being reviewed and codified within the IEC 61850 standard (Parts 7-3, 7-4).

#### 5.5.2.3 Support for Utility-Specified Communication Services

- These services were specified in CASM, a part of EPRI's UCA 2.0 specifications. These are presently being reviewed and codified within the IEC 61850 standard (Part 7-2)

### 5.5.3 Support for Collateral Communications

- Concurrent network support for other protocols (e.g. Modbus, DNP, FTP), as required, over the same network connection used by UCA-SA, but using other logical port numbers.
- Support for other protocols over serial ports, using IEEE interface standards (e.g. RS-232, RS-485)
- Request a PICS document (Protocol Implementation Conformance Specification) for the protocols of interest. These describe the specific functional support that is provided within the product.

### 5.5.4 Technical Support & Commitment

- Suppliers that claim compliance with UCA specifications for a product must adhere to the prevailing specifications and undergo compliance testing to ensure interoperability with other equipment.
- A product may legitimately support only a subset of total UCA functionality and features. Even within that scope, they are only obligated to implement the mandatory portions, not the optional ones. For better or worse, what a supplier elects to include represents their marketing judgment.

- Your project specifications need to spell out your expectations. If you choose to require UCA/SA functionality and features beyond your anticipated project requirements, you may artificially limit the number of candidate products.
- Suppliers may implement extensions to the content found in UCA specifications, as long as those extensions don't contradict or replicate the standard content.

## 5.6 Monitoring and Managing System Development

### *5.6.1 Project Management*

### *5.6.2 Meetings*

### *5.6.3 Scheduling*

### *5.6.4 Change Order Management*

## 5.7 Documentation

### *5.7.1 System Design Documents*

### *5.7.2 Detailed Design Documents*

### *5.7.3 Drawings*

### *5.7.4 User Guides and Manuals*

## 5.8 System Integration and Testing

### *5.8.1 System Integration of Multiple Vendor Products*

### *5.8.2 Bench Testing for Performance and Interoperability*

### *5.8.3 Formal Factory Testing*

## 5.9 System Maintenance

### *5.9.1 UCA-SA Technologies for System Maintenance*

#### 5.9.2 Planning System Maintenance Procedures and Technologies with UCA-SA

## 5.10 Field Installation, Validation, and Commissioning

### 5.10.1 Planning for Installation of Equipment

### 5.10.2 End-to-End Operational Validation

5.10.2.1 Communication functions

5.10.2.2 Data acquisition

5.10.2.3 Control functions

5.10.2.4 Application functionality and performance

### 5.10.3 Validation of Local/Remote Control

5.10.3.1 Station Control: Level 1

5.10.3.2 Equipment Group Control (e.g. related to a specific breaker): Level 2

5.10.3.3 Equipment Control: Level 3

### 5.10.4 Validation of Loss and Recovery Scenarios

5.10.4.1 Loss of Station Service

5.10.4.2 Loss of IED Power

5.10.4.3 Loss of Primary Communications

5.10.4.4 Loss of an IED Network Connection

5.10.4.5 Loss of Station Processing (e.g. local client)

## 5.11 Planning for Future Upgrades and Extensions

# 6
# DEPLOYMENT OF UCA-SA IN DIFFERENT TYPES OF SUBSTATIONS

# 7
# OPERATIONS AND MAINTENANCE WITH UCA-SA IN SUBSTATIONS

## 7.1 Data Acquisition and Control (DAC) Interface Server

## 7.2 Operations: A New Substation Environment: Enterprise Access

### *7.2.1 A Decentralized System Model*

### *7.2.2 Multiple Clients*

### *7.2.3 Proxy Servers*

## 7.3 Managing Information for Continual Improvement

- How clients (e.g. utility departments) benefit
- Cutting the costs and risks of strategic initiatives

### *7.3.1 Objectives*

### *7.3.2 ServerViews*

### *7.3.3 ClientViews*

## 7.4 Information Technology Services

### *7.4.1 Data Management*

### *7.4.2 System Administration*

### *7.4.3 Security*

## 7.5 Equipment Maintenance Issues

### 7.5.1 Diagnostic Tools

### 7.5.3 Maintenance Procedures

# A
# UCA-SA OVERVIEW

## Background of Utility Communications Architecture (UCA®)

### *History of UCA and IEC61850*

The following subsections on the history of UCA have been extracted from *Introduction to UCA Version 2.*

#### UCA Version 1.0

Advancements in computer and communications technology have been successfully applied by utilities in the development of information systems. Many of these systems are dedicated to meeting the specific needs of particular utility functions. These systems, however, have evolved based on the proprietary and/or utility-developed communications protocols. As a result, this process has created "islands of information" optimized for various vendor-specific platforms only. These islands make communications difficult between them and within, as well as complex, and costly - or impossible due to lack of available specifications and experts. The problems associated with integrating these platforms are becoming more acute as the need for communications systems within a utility grows.

In order to promote and facilitate interoperability between computer systems supplied to the utility industry, EPRI initiated the Integrated Utility Communication (IUC) program. The Utility Communications Architecture (UCA) project began in November 1988 as the first of a series of projects under this program. The project, conducted in conjunction with Pacific Gas and Electric (PG&E) and Houston Light and Power (HL&P), resulted in the development of a standard communications architecture, the UCA Version 1.0, to meet the communications needs of the electric utility industry. The UCA Version 1.0 was based on information exchange requirements identified during interviews with representatives from 14 electric utility companies, including approximately 100 utility personnel from PG&E and HL&P. A number of deliverables were created to help develop and support UCA.

As part of the UCA Version 1.0 effort, a detailed information exchange requirements analysis was performed based on extensive interviews with utility representatives. Based on the results of the requirements definition, a standards assessment was performed to review relevant international standards, from which a suite of protocols was selected, and a set of profiles was defined. For most real time data acquisition and control applications, the standard ISO 9506 - Manufacturing Message Specification (MMS) was adopted.

While the UCA Version 1.0 profiles supplied a great deal of functionality, industry adoption was limited. One of the most significant barriers to adoption was in the lack of detailed specification of how the protocols would actually be used in utility field devices. The rich functionality and broad generality of MMS in particular meant that without further specification, field devices could implement utility applications using a variety of services and procedures, resulting in a continued lack of interoperability.

### UCA Version 2.0 for Real-time Database Exchange

While the adoption of UCA Version 1.0 was limited, the needs for improved standardization within the utility industry became more acute. In particular, the moves toward a deregulated utility environment have significantly increased the requirements for communications standards both within and between utilities.

The first major move to address these heightened requirements was in the area of communications between control centers. Three primary standards were in use for inter-control center communications:

- Western States Coordinating Committee (WSCC), used in the western North America,
- Inter-Utility Data Exchange Consortium (IDEC), used in eastern North America, and
- Elcom 83 and Elcom 90, used throughout Europe

As the need for a unified standard became clear, the International Electrotechnical Commission (IEC) solicited member bodies for contributions to be considered for international standardization. The lack of a consensus standard in the US, as well as the perceived limitations of all of the existing candidate protocols, led to the formation of a utility/vendor task force sponsored by EPRI, WSCC, IDEC, and a number of utilities. This task force led the development of the Inter-Control Center Communications Protocol (ICCP). The name was later changed to Telecontrol Application Service Element 2 (TASE.2) to conform to IEC TC57 WG07 taxonomy.

The TASE.2 specification defines a standardized use of MMS in UCA Version 2.0 compliant networks for real-time exchange of data within and between control centers, power plants, and SCADA masters. TASE.2 is being standardized as *IEC 870-6-503: TASE.2 Services and Protocol, IEC 870-6-802: TASE.2 Object Models,* and *IEC 870-6-702: TASE.2 Application Profile*. The documents are published independently of the rest of UCA, but included by reference in UCA Version 2.0. Each of these documents have been defined in close coordination with the UCA working groups, been balloted as IEC Committee Drafts (CD), revised, and are currently being circulated as Draft International Standards (DIS). TASE.2 has considerable global vendor support, and is currently either deployed or is being deployed in a number of utilities and power pools throughout the world.

TASE.2 is focused on the exchange of real-time data between EMS and SCADA databases, as well as power plant DCS, and large-scale substation hosts (perhaps even RTU level system). The object models supported by TASE.2 include SCADA points (such as status, analog, accumulator, and control), generation and exchange schedules, availability and forecast reports, accounting information, power plant curves, and general message and file data. TASE.2 does not (as currently defined) directly include formal field device models; data is instead represented in the traditional form of points lists of each of the various point types, independent of the actual physical device at which the data originated. This representation is consistent with standard practice within most systems within and between control centers. Often in such data exchange arrangements, the details of how data is acquired (including the type and physical interconnection of field devices) are not known to the receiving party, particularly in data exchange between utilities.

### UCA Version 2.0 for Field Devices

The direct data acquisition and control of field devices (either substation, feeder, customer interface, and power plant controls) is an area which has been undergoing significant transition. Traditionally, the end field devices were directly connected to Remote Terminal Units (RTUs), which provided a network interface and performed initial processing of the acquired data. The introduction of microprocessor technology has led to the development of Intelligent Electronic Devices (IEDs), effectively allowing for the direct network access to the devices, as well as more processing being performed at the end device. As the end devices have become more complex, the cost of integrating the devices has increased. Within the UCA framework, the definition of the data and control functions made available by the device, along with the associated algorithms and capabilities, is known as the *device object model*.

As part of the EPRI sponsored activities leading up to the publication of UCA Version 2.0, a number of efforts were initiated to develop detailed object models of common field devices, including definitions of their associated algorithms and communications behavior visible through the communication system. Most notable of these efforts are the EPRI sponsored MMS Forum Working Groups, the Substation Integrated Protection, Control, and Data Acquisition (RP3599) project, and the Distribution Automation Pilot Project (DAPP) for City Public Service of San Antonio. The results of these efforts are contained in the *Generic Object Models for Substation and Feeder Equipment (GOMSFE)*. Agreement has been reached for a number of basic field devices. Examples include basic RTU, Switch, Voltage Regulator/Tap Changer, Recloser, and Capacitor Bank Controllers. The development of models for other substation and feeder automation field devices will be ongoing.

Modeling efforts within the customer interface area are in progress. These efforts include metering and interfaces to residential and commercial customer devices. There has been active industry participation in the customer interface modeling efforts. Significant work has been accomplished as part of several UCA pilot projects, and preliminary results are available in draft form. The development of models of power plant devices is underway.

The device models developed within the UCA 2.0 effort make use of a common set of services to describe the communications behavior of the devices. A standard mapping of these services onto the UCA application layer protocol (MMS), when used in conjunction with the device models, completely specifies the detailed interoperable structure for utility field devices. The services and mapping to MMS are defined in *UCA Common Application Service Models (CASM)*. The use of the CASM services within all UCA device models simplifies the integration efforts across functional areas of the utility. An added benefit is that CASM allows device models to be specified independent of the underlying protocol. This protocol independence has encouraged active participation of groups outside the UCA activities, and will simplify migration through the construction of gateways to older existing protocols. In addition, it may allow for the future expansion of the UCA protocol suite to other application protocols such as CORBA. Finally, the UCA Profiles have been revised to meet the requirements of a number of new operating environments. The new profiles include a fully detailed reduced stack (3-layer) for use with low bandwidth and/or very small field devices, as well as additional profiles for operating in a TCP/IP network environment. The revised UCA Profiles are defined in *UCA Profile Specification, Version 2.0*.

### *Benefits of Developing UCA Device Object Models*

The following discussion describes the role of object models within communication protocols.

The design of a new communication protocol can be viewed as reflecting four aspects:

1. The ***communications network configurations*** and ***media characteristics*** form the physical basis of the communications system (referred to in communication terminology as Layer 1 of the OSI reference model – see UCA documents listed in Section 1.3 for a discussion of the OSI reference model), and determine the fundamental capabilities that the communication protocol must have, such as routing ability, traffic management, speed ranges, and sizes of data blocks. The configuration basically defines ***where*** one can go.

   From an analogous point of view, this can be seen as equivalent to the network of turnpikes, freeways, highways, roads, streets, alleyways, dirt roads, railways, waterways, and hiking trails that make up the United States transportation system. The characteristics of these roads determine what type of traffic they will bear: tractor-trailers should not typically use alleyways and dirt roads; backpackers and cowboys on horses should avoid freeways.

2. The ***transport protocol profile*** determines the means for getting data from one location to another. In communication terminology, the transport profile defines which of the protocols in Layers 2 through 4 of the OSI reference model will be used. The transport profile basically answers the question of ***how*** to get from one place to another.

   As an analogy, the transport profile can be seen as the vehicle (car, truck, boat, train, horse) for getting from one location to another. A parcel delivery service could establish a combination of truck and train for getting overnight parcels delivered between two major cities.

3. The ***application protocol profile*** determines the characteristics for ***when*** the data will go and in what ***form*** the data will be in. In communication terminology, the application profile defines which of the protocols in Layers 5 through 7 of the OSI reference model will be used.

   As an analogy, the application profile can be seen as decisions by a manufacturer to send a product on Tuesday morning, packaged in wooden crates, for overnight delivery by a parcel delivery service.

4. The ***object definitions*** determine the meaning of the data being sent. Object definitions basically answer the question of ***what*** the data means. ***Object models*** are groups of objects used to define all relevant aspects of the entity that is being modeled. These object models are not defined in the OSI reference model, and can therefore be viewed not as strictly part of communication protocols but more as part of data protocols.

   As an analogy, object definitions can be seen as the information on the product sent by the manufacturer: what the product is used for, its size and weight, its version number, its default factory settings, the associated manuals, etc. The object model is the entire group of objects describing the product.

Object models are a relatively new concept in the field of communication protocols, and, in fact, go beyond the typical understanding of what a communication protocol covers. In the past, only the bits and bytes necessary for *transmitting* data between locations were standardized; no one considered standardizing the *meanings* of the data. Essentially, it was too complex an undertaking to develop models of devices before even the communications protocol infrastructures were developed. Therefore, until recently, most of the effort in developing communication protocols has focused on the first three aspects: namely the infrastructure and basic mechanisms for sending data between systems; very little effort went into defining what the data represented: after all, if you can't get the data there in the first place, it doesn't matter what it means.

But now, many communication protocol standards do exist for the transport and application profiles, which can handle most network configurations. New profiles are usually just variations on existing profiles to handle specific situations. Therefore, the standardization efforts are increasingly on developing methods for determining ***what*** the data means – i.e. developing the data protocols.

In the utility SCADA world, traditionally, data was separated into status points, analog point, and control commands, but no attempt was made to standardize the ***meaning*** of the data. However, during the development of UCA, the developers realized that it was equally, if not more, important to define the meaning of the data being exchanged, so that systems could start communicating without lengthy and often error-prone manual entry of data meanings on each side of a communications link.

In the mean time, object-oriented technology has evolved to the point that it is now better-understood, more efficient, and very effective for describing data. Therefore, the developers of UCA expanded from the original scope of defining only the UCA communications profiles, to defining an object-modeling scheme for devices.

Some of the key benefits of object-oriented device modeling include:

1. ***Self-Defining Capability*** – In traditional SCADA systems, the SCADA subsystem that is responsible for data acquisition and control (DAC subsystem), expects to retrieve groups of undefined status and analog points from remote devices, and therefore expects to define the data itself, and map it to the SCADA real-time database. However, in the UCA model, UCA devices are self-describing. Each device, and each item of data within a device, has a standardized, "well-known", unique name, thus making it understandable by any DAC subsystem. This self-defining capability leads to the following potential benefits:
   a. ***Rapid Installation*** – When a new device is connected to the communications network, the DAC subsystem can immediately establish connection, ask the device who it is, download the list of names of objects, and set up all reporting parameters – without human intervention.
   b. ***Minimize Manual Intervention and Transcription Errors*** – Since the devices are self-describing, no manual effort is needed to copy names or link database entries to data points in the field.
   c. ***Minimize Maintenance Efforts*** – The SCADA database can use the same names as in the remote devices, therefore eliminating the need for a Data Administrator to laboriously map all the data items.
   d. ***Plug and Play Installation*** – When a new type of device is connected, the DAC subsystem can automatically run a "Wizard" (a program supplied with the device to aid in installation) to request any device-type specific data – or even download it from the device.

2. ***Interoperability*** – The use of UCA as a standard communication protocol permits:
   a. ***Integration of Different Vendor Equipment*** – Different equipment from different vendors to be integrated over the same mainstream communications network.
   b. ***Second Sourcing*** – Similar products from different vendors to be installed, thus assuring utilities of second sources.

3. ***Distributed Processing*** – Multiple DAC subsystems can access the UCA devices over the communications network, thus permitting:
   a. ***Direct Access by (Authorized) Applications*** – Other systems and applications can establish their own direct communications with field devices, without having to go through the administrative and technical hassles of requesting data from the SCADA system.

b. ***Off-loading of SCADA systems*** – The SCADA system can remain dedicated to its task of monitoring and controlling the power system, and not be tied up with passing data to other systems and applications.

c. ***Security*** – UCA provides security, so no unauthorized applications can access information or issue controls.

4. ***Enterprise-wide Integration*** – Since UCA is object oriented, device objects can be exchanged through-out the enterprise:

   a. ***Conformance with Object Oriented Technology*** – UCA objects can be exchanged among control center systems, and other enterprise systems, using state-of-the-art object-oriented technologies, including conformance with the Common Information Model (CIM).

   b. ***Conformance with Data Exchange Messaging Technology*** – UCA conforms to the publish-subscribe concepts of integration bus technologies, such as CORBA, Enterprise Java Beans, and Microsoft's COM.

   c. ***Conformance with Communication Standards*** – UCA utilizes standard communication profiles, thus ensuring long term support by utility and telecommunications vendors.

# B

# UNIFIED MODELING LANGUAGE (UML)

The Unified Modeling Language (UML) was developed to provide the abstract modeling needed to ensure top-down understanding of the entire system, as well as to provide mechanisms for translating those abstract models into actual computer code.

## Abstract Modeling in UML

Abstraction, the focus on relevant details while ignoring others, is a key to learning and communicating. Modeling is the process of abstracting from the morass of stuff to develop a coherent, multi-faceted vision. Because of this:

- Every complex system is best approached through a small set of nearly independent views of a model. No single view is sufficient.
- Every model may be expressed at different levels, ranging from highly abstract to the concrete.
- The best models are connected to reality.

***Abstraction, the focus on relevant details while ignoring others, is a key to learning and communicating. Modeling is a method of visualizing that abstraction.***

The generally accepted methodology for software modeling is the Unified Modeling Language (UML), which has been endorsed by the Object Management Group (OMG), the leading industry standard for distributed object programming. UML is the standard language for visualizing, specifying, constructing, and documenting the artifacts of a software-intensive system. It can be used with all processes, throughout the development life cycle, and across different implementation technologies. UML combines the best of the best from Data Modeling concepts (Entity Relationship Diagrams), Business Modeling (work flow), Object Modeling, and Component Modeling

***The key benefit of using UML is that it provides structured methods for visualizing complex interactions that must be implemented in an invisible cyber world.***

Vendors of computer-aided software engineering products are now supporting UML and it has been endorsed by almost every maker of software development products, including IBM and Microsoft (for its Visual Basic environment). UML is a standard notation for the modeling of real-world objects as a first step in developing an object-oriented design methodology, and is used as the language for specifying, visualizing, constructing, and documenting the artifacts of software systems, as well as for business modeling and other non-software systems. UML represents a collection of the best engineering practices that have proven successful in the modeling of large and complex systems.

The UML modeling methodology is very powerful in that it can be used from the highest overview levels to actual implementation code, and from the largest global project to a tiny enhancement project. The key benefit of using UML is that provides methodologies for visualizing the complex interactions that must be implemented in an invisible cyber world. It consists primarily of structured diagrams that are designed to illustrate different aspects of cyber behavior. A number of CASE tools exist for developing these UML models as well-structured diagrams. The different UML modeling concepts and types of diagrams are described below.

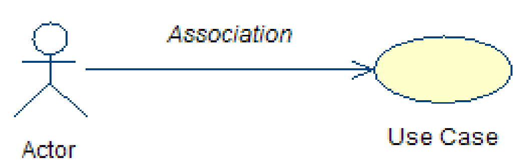
## Use Cases

***Use Cases are modeling constructs which focus on the interactions between functions (Use Cases) and "Actors" from a user's point of view.***

Use Cases are modeling constructs which focus on the interactions between functions and actors from a user's point of view. The basic idea for a Use Case is to capture the requirements of these actors in relationship to the function. "Actors" are defined as the ultimate sources or users of information for a particular Use Case scenario, and do not need to be humans. For instance, the power system can be seen as an Actor when it provides the source data for a SCADA system, while a billing system can be the user of metering data from an Automatic Meter Reading system.

Use Cases are layered or iterative in concept. For instance, in a Use Case diagram, a function is defined as a Use Case itself (which sometimes leads to confusion, but does emphasize the layered nature of Use Cases). As an example, in one Use Case diagram, the function "Distribution Automation Functions" could be defined as a single entity within distribution operations, while this same function could be expanded into its own Use Case, showing the individual functions as separate entities.

Therefore, the scope of a particular Use Case is entirely a function of what needs to be defined. In a broad picture Use Case, distribution system operations can be one function within utility operations. In a detailed picture Use Case, the Distribution Automation Volt/Var Optimization application can be the primary function. Therefore, often Use Cases are used first to define the overall Business Processes, and then are utilized to take each function within a Business Process and drill down to more detailed levels.




Modeling implies diagrams. Use Case Diagrams consist of Actors (often represented as little stick people) and Use Cases (ovals) linked by lines which indicate relationships, such as "is associated with", "is an aggregation of", or "is a generalization of". An association, which is represented as a line with one or two arrows, provides a pathway for communication. The communication can be between use cases, actors, classes or interfaces. Associations are the most general of all relationships and consequentially the most semantically weak. If two objects are usually considered independently, the relationship is an association. Other relationships include "generalization" and "dependency".

The benefits of Use Cases include:

1. Visualizing processes and interactions which otherwise might be obscure or lost in the complexity of a system

2. Capturing requirements from user's perspective

3. Users are not only involved in providing requirements, but can actually understand and validate what is being designed

4. A good way to start identifying information which will be exchanged among the functions and actors

5. One way of estimating the percentage of requirements captured

6. Categorizing functions and determining which impact the others particularly if a "phased delivery" implementation is planned

7. A better way of estimating the percentage of requirements completed during development.

8. Test plan can be immediately generated based on use cases

9. Helps technical writers in structuring the overall work on the users manuals at an early stage

10. Better traceability throughout the system development process

11. Quality of the software is improved by identifying the exception scenarios earlier in the development process

## Behavior Diagrams

Behavior Diagrams are used to model the behavior of entities. Two primary types of diagrams can be used: the Activity Diagram and the State Chart Diagram.

**Activity Diagrams** provide a way to model the workflow of a business process. Activity diagrams are very similar to a flowchart because the workflow can be modeled from activity to activity. An activity diagram is basically a special case of a state machine in which most of the states are

***Activity Diagrams are similar to flowcharts and provide a way to model the workflow of a business process.***

activities and most of the transitions are implicitly triggered by completion of the actions in the source activities.

These diagrams should not replace the original Use Cases, although there is sometimes a tendency to bypass the Use Case process as unnecessary and jump right to the Activity Diagrams. However, the Use Case is vital to capturing the views of the user, which is often overlooked or assumed if the business process analysis starts with the Activity Diagram.

An Activity Diagram illustrating portions of the same energy schedule submittal process shown in the Use Case above are shown in the Activity Diagram figure.

**State Chart Diagrams** define the States and the dynamic behavior for going between States for a particular function (Use Case) or object (Class). These diagrams show the sequences of states that an entity goes through, the events that cause a transition from one state to another, and the actions that result from a state change. State Chart diagrams are closely related to Activity diagrams. The main difference between the two diagrams is that State Chart diagrams are state centric, while activity diagrams are activity centric. A State Chart diagram is typically used to model the discrete stages of an entity's lifetime, whereas an activity diagram is better suited to model the sequence of activities in a process.

***State Chart Diagrams define the States and the dynamic behavior for going between States for a particular function (Use Case) or object (Class).***

Each state represents a named condition during the life of an entity during which it satisfies some condition or waits for some event. A State Chart diagram typically contains one start state and multiple end states. Transitions connect the various states on the diagram. As with activity diagrams, decisions, synchronizations, and activities may also appear on State Chart diagrams.

## Interaction Diagrams

Interaction Diagrams, consisting of Sequence Diagrams and Collaboration Diagrams, focus on the interactions between entities. These diagrams are particularly important in the development of Information Exchange Models (IEMs).

**Sequence Diagrams** specify the precise sequence of information flows between functions, including acknowledgments, error handling, and other details. A sequence diagram is a graphical view of a scenario that shows object interaction in a time-based sequence, i.e., what happens first, what happens next. This type of diagram is best used during early analysis phases in design because they are simple and easy to comprehend. A sequence diagram has two dimensions: typically, vertical placement represents time and horizontal placement represents different objects. Sequence diagrams are normally associated with Use Cases, since they can be used to focus on the interactions between Actors and the functions they interact with.

Sequence diagrams are closely related to collaboration diagrams and both are alternate representations of an interaction. There are two main differences between sequence and collaboration diagrams: sequence diagrams show time-based object interaction while collaboration diagrams show how objects associate with each other.

***Collaboration diagrams and sequence diagrams really are alternative representations of the same interaction.***

**Collaboration Diagrams** illustrate how entities interact with each other. Collaboration diagrams and sequence diagrams really are alternative representations of the same interaction, in which a collaboration diagram shows the order of messages that implement an operation or a transaction, while a sequence diagram shows object interaction in a time-based sequence. In some CASE tools, the capability is provided to create a Collaboration diagram from a Sequence diagram and vice versa. Collaboration diagrams show objects, their links, and their messages. They can also contain simple class instances and class utility instances.

## Class Diagrams

***Class Diagrams visually describe the structures and relationships of data entities, explicitly showing their contents (attributes) and their actions (operations)***

Class Diagrams visually describe the structures and relationships of data entities, explicitly showing their contents (attributes) and their actions (operations). The word "entity" is used rather than "object" because Class Diagrams can be used to describe both objects models of individual data items and metadata models of definitions of data items and their relationships. The Figure shows a Class Diagram of a metamodel of an Energy Schedule.

Visually, Class Diagrams contain icons representing classes, interfaces, and their relationships, and can be multi-level and nested through the use of Packages. Packages are used to group similar Class Diagrams.

For utilities, the best known set of Class Diagrams is the Common Information Model (CIM) which is a metadata model of the power system (primarily) with additional Packages describing other aspects of power system operations. This CIM model is being expanded to encompass distribution operations, asset management, and other areas.

For Information Exchange Modeling purposes, Class Models can be used both to define the metamodels of the data to be exchanged, as well as the structure of the information messages themselves.

***Implementation Diagrams take the abstract information and convert it into more physical views, using one of many software languages, such as C++, Java, JavaScript, Corba, Microsoft's COM, DTD, and XML.***

## Implementation Diagrams

Implementation Diagrams take the abstract information of the other types of diagrams and convert it into more physical views, using one of many software languages, such as C++, Java, JavaScript, Corba, Microsoft's COM, and others. Alternatively, the conversion can be into a data language, such as Document Type Definition (DTD) or XML.

## Component Diagrams

**Component Diagrams** provide a physical view of the current model. A component diagram shows the organizations and dependencies among software components, including source code components, binary code components, and executable components. These diagrams also show the externally-visible behavior of the components by displaying the interfaces of the components. Calling dependencies among components are shown as dependency relationships between components and interfaces on other components. Note that the interfaces actually belong to the logical view, but they can occur both in class diagrams and in component diagrams.

Component diagrams contain Component packages, Components, Interfaces, and Dependency relationships. A Component Package Specification enables you to display and modify the properties of a component package. Similarly, a Component Specification and a Class Specification enables you to display and modify the properties of a component and an interface, respectively. The information in these specifications is presented textually. Some of this information can also be displayed inside the icons representing component packages and components in component diagrams, and interfaces in class diagrams.

In some CASE tools, the properties of, or relationships among, component packages, components, and interfaces can be changed by editing the specification or modifying the icon on the diagram. The affected diagrams or specifications are automatically updated. An additional capability of some CASE tools is to reverse engineer a set of objects which are already in another language (such as C++ or XML) and convert them back into abstract Classes with all attributes and relationships where possible.

## Deployment Diagrams

Deployment Diagrams show processors, devices, and connections, in other words, the physical location where each of the component models will be implemented. Therefore, each model contains a single deployment diagram which shows the connections between its processors and devices, and the allocation of its processes to processors.

## UML Methodology

The methodology for using UML can be summarized as follows:

1. Develop Business Processes, using Use Cases
    a. Pick a business process, e.g. Day-ahead Submittal of Energy Schedules by Scheduling Coordinators

b. Determine all the Actors, e.g. Scheduling Coordinator and Time Line Manager

c. Determine the Use Case functions or systems involved, e.g. Market Interface Web Server, Format Validation Procedures, Database of Energy Schedules, and Congestion Management function. Since business processes are usually at a higher and broader level than individual functions, these Use Cases are do not focus on a single function to show basically its inputs and outputs, but show the "forest" rather than the "trees".

d. Describe all performance requirements, pre- and post-conditions, and other assumptions, e.g. responses to submittals will be within 5 seconds or at pre-specified times, Scheduling Coordinators are all registered, post-condition is that schedule is accepted or rejected

e. Draw and describe the interactions between the Actors and Use Cases, including sequences of steps and decisions affecting information flows, e.g. Sequences for error checking, ability of Scheduling Coordinator to withdraw schedule, etc. These can be documented in Activity Diagrams, Sequence Diagrams, Collaboration Diagrams, and State Diagrams, along with text to clarify the interactions.

2. Develop Data and/or Messages Contents, using Class Diagrams

   a. Identify the Data or Message Type for each interaction in the business process: Message Type consists of a noun (the data) and a verb (how/when/under what conditions is the message sent)

   b. There are many, many Nouns, e.g. New energy schedule or update to an existing energy schedule

   c. There are very few Verbs, e.g. Send, Request, Acknowledge Response, Error Response

3. Organize and list all elements required by each Data or Message Type

   a. “Organize” means identify specific parts of a message that are probably re-usable for other messages, e.g. Message Header, Scheduling Coordinator information, RTO information, E-tagging information (so that format can be used), Time and Date information, Other

   b. Indicate if there is a one-to-one or a many-to-one correspondence between a part and the message, e.g. only one Scheduling Coordinator, but one or more schedules

   c. List all elements for each part, e.g. Scheduling Coordinator Corporate name, Scheduling Coordinator ID, individual sending schedule, etc.

4. Translate Classes into Component Models

   a. Convert the classes into Document Type Definitions (DTD), using IDL or, as is becoming more common, using XML-DTD.

   b. These components can be translated into actual software code if so desired.

5. Register these DTDs so that all users of the information can access them. XML Registries can be public (e.g. ebXML uses OASIS XML Registry) or can be private. This step is not actually part of UML, but is becoming a powerful means to publish, maintain, and update information exchange templates among large groups of users.

    a. Named, hierarchical components

    b. Self-description

*Program:*
Transmission Substations

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EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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