Electricity Innovation Institute

Utility Communications Architecture (UCA®)

Object Models for Distributed Energy Resources (UCA-DER)

Final Report, December 2003

E2I Project Manager
F. R. Goodman, Jr.

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Utility Consulting International (UCI)

NettedAutomation GmbH

Tamarack Consulting, Inc

CITATIONS

This report was prepared by

Utility Consulting International (UCI)
20370 Town Center Lane, Suite 211
Cupertino, CA 95014

Principal Investigators

F. Cleveland
R. Ehlers

NettedAutomation GmbH
Im Eichbaeumle 108
D - 76139 Karlsruhe, Germany

Principal Investigator

K. Schwarz

Tamarack Consulting, Inc
2311 Shelby, Unit 105
Ann Arbor, MI 48103

Principal Investigator

G. Schimmel

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REPORT SUMMARY

Background

Spurred by deregulation and the availability of new technologies, there has been a sharp increase in the number of implementations of a large variety of distributed energy resources (DER) interconnected with electric utility distribution systems for many different purposes. At the same time, automation of the distribution systems has become not only feasible, but increasingly cost effective, leading to a vision of advanced distribution automation (ADA) that can respond to utility and customer needs more rapidly and efficiently.

As a result of these changes, distribution utilities and their customers are evaluating DER devices to determine what benefits they might bring. Some of the DER uses being evaluated include generation capacity, load following, peak shaving, spinning reserve, emergency backup generation, voltage and VAr support, intentional islanding, pollution credits, green power, and deferred construction of distribution facilities.

Objectives & Scope

This report is part of the DER/ADA project to specify object models of DER data. These object models define the template for data to be exchanged between DER devices and any systems that monitor, control, maintain, audit, and operate the DER devices. This first draft includes draft object models for reciprocating engines (diesel engines) and for fuel cells.

Approach

This draft document describes the functional requirements for these DER object models, the basics of object modelling technologies, the overall structure of the object modelling for DER, and finally the actual draft object models for two DER devices: reciprocating engines and fuel cells. These object models are being reviewed by DER vendors, utilities, and integrators, and will be refined and validated in the future.

Results

This 2003 final report is the first draft of these DER object model specifications and will be added to over the next few years. The object models in this document are ready for trial use by vendors in order to provide feedback and updates. However, it must be understood that these are still draft object models and are subject to change. Vendors are encouraged to report any experience they have in trying these models to E2I to help in their further development.

Future work

Plans for next year include development of a validation process and then validation of the reciprocating engine and fuel cell object models through laboratory testing. The laboratory work will be followed by field tests. When ready, the models will be promulgated as international standards. Work with standards organizations is going on concurrently. Also, the results of the ongoing parallel project work to study the impact of DER on future distribution operations and ADA will be incorporated into the object models. A separate report of the first phase of that work in 2003 is being concurrently published by E2I.

Using the object model outline presented in this document, object models for other DER devices will be developed over the next few years. The work could also be extended to other intelligent devices used in ADA devices, besides DER. The choice of which devices to model will be largely dependent on willingness of vendors to participate with E2I in their development.

Keywords

Distributed Energy Resources (DER)
DER object models
Advanced Distribution Automation (ADA)
IEC61850
Reciprocating engine
Diesel generator
Fuel cell

EXECUTIVE SUMMARY

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Distribution utilities and their customers are evaluating DER devices to determine what benefits they might bring. Some of the DER uses being evaluated include generation capacity, load following, peak shaving, spinning reserve, emergency backup generation, voltage and VAr support, intentional islanding, pollution credits, green power, and deferred construction of distribution facilities.

This document on ***Utility Communications Architecture® (UCA) – Object Models for Distributed Energy Resources (UCA-DER)*** specifies the object models of DER information that can be exchanged between DER devices and any systems which monitor, control, maintain, audit, and generally operate the DER devices. Basically, "object models" are standardized formats or templates for exchanging data between different pieces of equipment or systems. Standard object models, combined with standard service models (methods for sending the data) and standard protocols (the bits and bytes actually send over the communication channel), permit different systems to interact with minimal customization. The combination of object model, service model, and protocol profiles can be termed the "information model".

This 2003 final report is the first draft of these DER object model specifications and will be added to over the next few years. This draft describes the functional requirements for these DER object models, the basics of object modelling technologies, the overall structure of the object modelling for DER, and finally the actual draft object models for two DER devices: reciprocating engines (predominantly diesel generators) and fuel cells. These object models are being reviewed by DER vendors, utilities, and integrators, and will be refined and validated in the future.

Plans for next year include development of a validation process and then validation of the reciprocating engine and fuel cell object models through laboratory testing. The laboratory work will be followed by field tests. When ready, the models will be promulgated as international standards. Work with standards organizations is going on concurrently. Also, the results of the ongoing parallel project work to study the impact of DER on future distribution operations and ADA will be incorporated into the object models. A separate report of the first phase of that work in 2003 is being concurrently published by E2I.

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CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION TO UCA-DER

The rapid advances of digital technologies have enabled the automation of electric power operations, providing utilities and customers with both new capabilities and new challenges. Many, particularly those involving increased interactions with distributed energy resources (DER) and utility customers through Advanced Distribution Automation (ADA), are barely being thought of today. As Kurt Yeager, the CEO of EPRI stated on August 25, 2003 in an interview on the Lehrer News Hour about the August 14 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. 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 is 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, 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."*

This is the challenge being faced by utilities, customers, vendors, and the electricity marketplace: how can the information infrastructure be implemented to meet the expanded needs of the power system, while not becoming part of the problem itself. Part of that challenge can be met by UCA-DER, the standardized communications interface for DER devices.

The far ranging impact of DER on the electric power operations is illustrated in Figure 1-1 below.

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

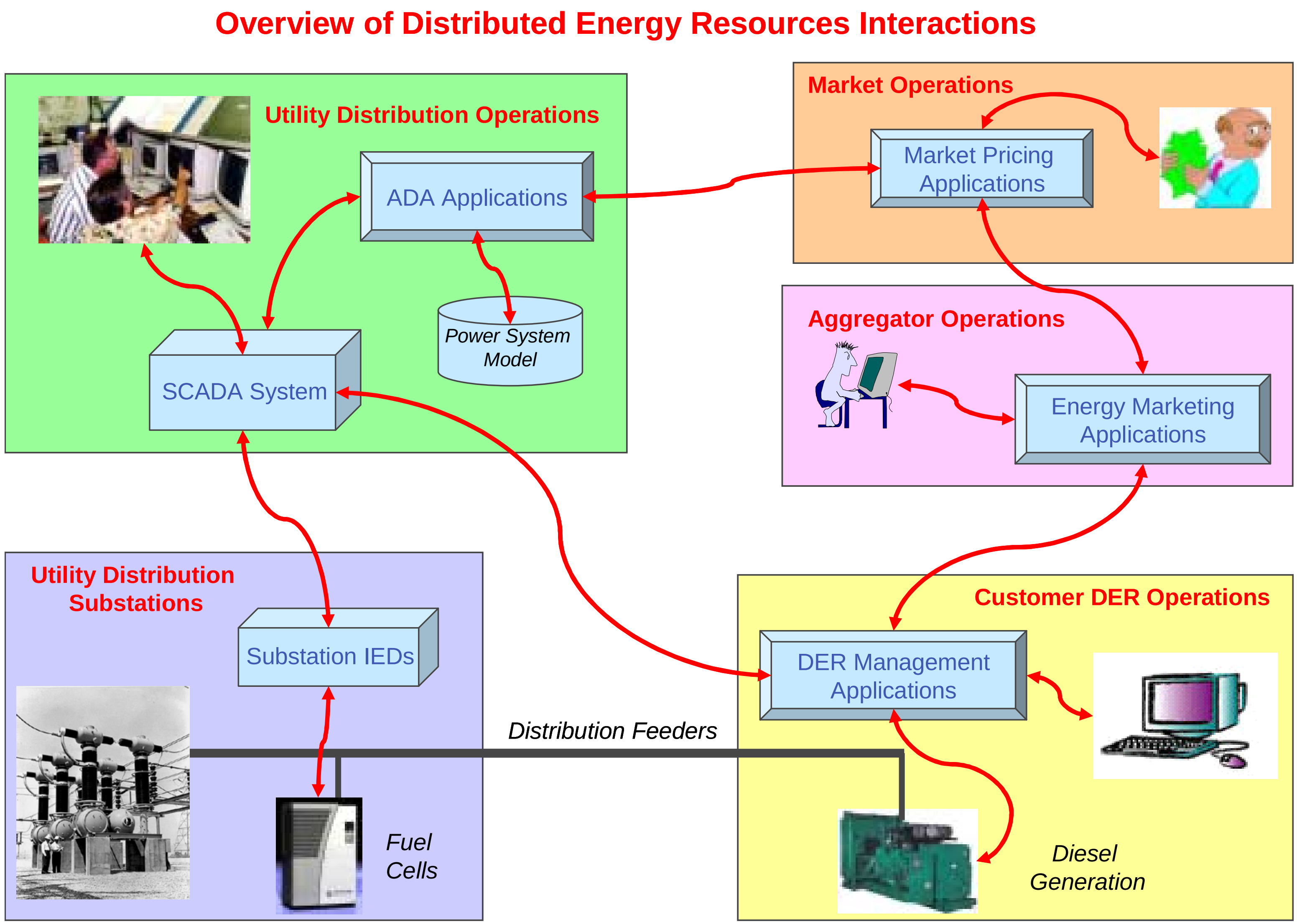

Figure 1-1: Interactions involving Distributed Energy Resources (DER) in Electric Power System Operations

1.1 Overview of DER/ADA Project

The development of UCA-DER object models is part of the CEIDS project "***Open Communication Architecture for Distributed Energy Resources (DER) in Advanced Distribution Automation (ADA)***", also known as the DER/ADA Project. The DER/ADA Project is described in detail in the "***Open Communication Architecture for Distributed Energy Resources (DER) in Advanced Distribution Automation (ADA) Project Work Plan***".

The purpose of the DER/ADA Project is to develop object models for exchanging data with DER devices. **DER** devices are generation and energy storage systems that are connected to the distribution power system. The DER devices must be actively managed by users and by many different types of automation functions. These functions include using DER devices for customer backup power, for utility peak shaving, for combined heating and power, for market demand responses, and for advance distribution automation.

The principle goal of the project is to develop DER object models that are of suitable quality to be submitted to the IEC and the IEEE for eventual standardization, a process that will be supported by EPRI/E2I. This quality can only be obtained by using the expertise of vendors, utilities, DER owners, and other DER stakeholders. In particular, utilities will need to manage increasing amounts of DER within their distribution systems, and will increasingly use automation to handle the challenges and opportunities posed by DER. In particular, advanced distribution automation (ADA) will need to incorporate DER into its automated management of the distribution system.

ADA is the concept of actively managing the distribution system to further different goals. Traditionally, distribution systems are designed to perform one function—distribute power to end-users. However, with ADA, the distribution system can be used to support different purposes, such as demand response in the electricity marketplace, automated fault isolation and service restoration, peak shaving, and emergency responses to power system failures.

Therefore, a two-pronged approach is being used, by developing object models for two to three DER devices at a time, while at the same time developing a clearer understanding of the functional requirements for ADA. With this approach, the basic, well-established data exchanges can be codified into object models first and rapid progress can be made. As the ADA functional requirements are determined and more complex information exchanges are identified, then extensions to these basic object models can be developed.

The development of object models for different DER devices overlap, so that new object models are being developed as others are being refined through review by vendors and other domain experts.

The results of this project may lead to additional projects, particularly in the realm of advanced distribution automation.

1.2 Scope of UCA-DER

The scope of this document on ***Utility Communications Architecture® (UCA) – Object Models for Distributed Energy Resources (UCA-DER)*** is the specification of the object models of DER information that can be exchanged between DER devices and any systems which monitor, control, maintain, audit, and generally operate the DER devices. Simply put, “object models” are standardized formats or templates for exchanging data between different equipment or systems. Standard object models, combined with standard service models (methods for sending the data) and standard protocols (the bits and bytes actually send over the communication channel), permit different systems to interact with minimal customization. The combination of object model, service model, and protocol profiles can be termed the “information model”.

These UCA-DER information models are based on open-system language, semantics, services, protocols, and architecture, which have been standardized by IEC61850, but they include some extensions to IEC61850. The UCA-DER object models will eventually be provided to the IEC as a draft set of object models for international standardization. In order to ensure the standardization process is simplified, these UCA-DER information models are compatible with IEC61850 (UCA-SA), IEC61970 (CIM), IEC60870-5 (telecontrol protocol, which also formed the base for DNP), and IEC60870-6 (ICCP/TASE.2) standards.

The object models in this draft document are ready for trial use by vendors in order to provide feedback and updates. However, it must be understood that these are still draft object models and are subject to change.

1.3 Purpose of UCA-DER

There is a growing interest in implementing DER devices throughout the world. As the DER technology evolves, nations recognize the economic, social, and environmental benefits of integrating DER technology within their electric infrastructure. The manufacturers of DER devices are facing the age-old issues of what communication standards and protocols to provide to their customers for monitoring and controlling DER devices, in particular when they are interconnected with the electric utility system. In the past, DER manufacturers developed their own proprietary communication technology. However, as utilities and other energy service providers start to manage DER devices which are interconnected with the utility power system, they are finding that coping with these different communication technologies present major technical difficulties, implementation costs, and maintenance costs. Therefore, utilities, DER manufacturers, and the customers they serve are increasingly interested in having one international standard that would define the communication and control interfaces for all DER devices. Such standards, along with associated guidelines and uniform procedures would simplify implementation, reduce installation costs, reduce maintenance costs, and improve reliability of power system operations.

At the same time, the object modeling technology has developed within the last few years to become well-established as the most effective method for managing information exchanges. In particular, the UCA object models for the exchange of information within substations (UCA-SA) have moved through the standardization process, and are now formally designated as the

IEC61850 International Standard. Many of the components of this standard can be reused for object models of other types of devices. Some new components are also needed, but these can follow the rules for creating these new components, thus making them compatible with the existing UCA-SA standards.

Therefore, the object models in this document are part of the umbrella Utility Communications Architecture (UCA) and are designated as UCA-DER object models, pending eventual numbering as an IEC or IEEE standard. This concept is illustrated in Figure 1-2. This illustration shows as horizontal layers the three components to an information exchange model for retrieving data from the field, namely, the communication protocol profiles, the service models, and the object models (labeled UCA-CP, UCA-SM, and UCA-OM, respectively). Above these layers is the information model of utility-specific data, termed the Common Information Model (CIM), as well as all the applications and databases needed in utility operations. Vertically, different areas are shown: substation automation, DER, distribution automation, customer services, generation, etc.

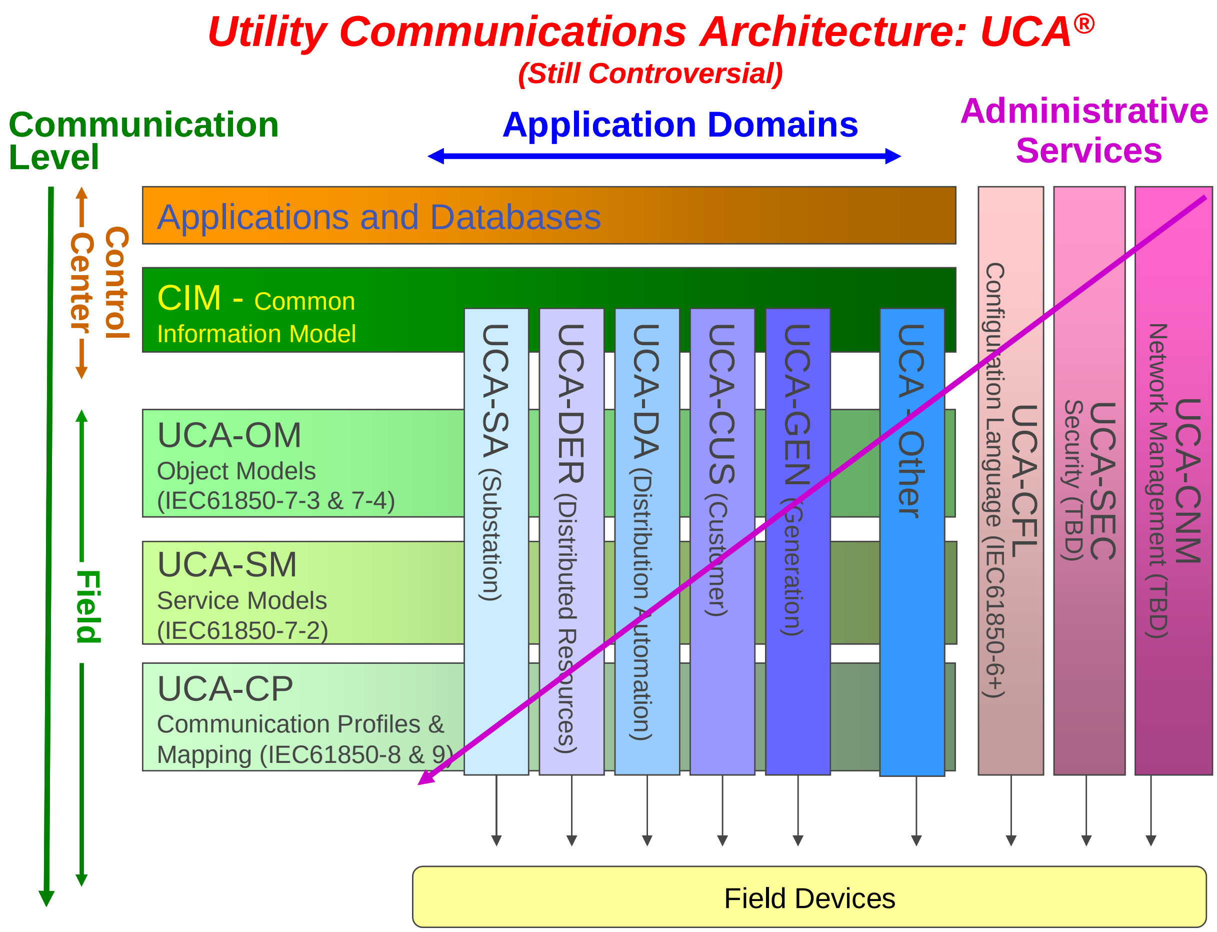

Figure 1-2: Overview of UCA Constructs

1.4 Status of DER Object Model Report

This report is a draft of certain DER object models, with a focus on reciprocating engines and fuel cells, along with the peripheral object models required by these DER devices, such as batteries. These object models have gone through one review cycle but have not been tested in any implementation. Therefore, they could be used for validation trials and preliminary testing, but may change significantly before they are standardized.

In addition, there are some object models that reflect work in progress on additional DER devices, such as photovoltaics. These are the initial drafts for the next DER object models being undertaken during 2004, and should be viewed as very preliminary.

1.5 Normative References

The following referenced documents are valuable for understanding the DER object models described in this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

- ISO/IEC 7498-1:1994, Information technology -- Open Systems Interconnection – Basic Reference Model: The Basic Model

- IEC 61850-7-1, Communication networks and systems in substations – Part 7-1: Basic communication structure for substations and feeder equipment – Principles and models

- IEC 61850-7-2, Communication networks and systems in substations – Part 7-2: Basic communication structure for substations and feeder equipment – Abstract communication service interface (ACSI)

- IEC 61850-7-3, Communication networks and systems in substations – Part 7-3: Basic communication structure for substations and feeder equipment – Common data classes

- IEC 61850-7-4, Communication networks and systems in substations – Part 7-4: Basic communication structure for substations and feeder equipment – Compatible logical node classes and data classes

- ISO 1000, *SI units and recommendations for the use of their multiples and of certain other units*

- IEC CDV 61850-6:2003, Communication networks and systems in substations – Part 6: Substation automation system configuration description language

- IEC 61850-8-1, Communication networks and systems in substations – Part 8-1: Specific Communication Service Mapping (SCSM) – Mapping to MMS (ISO/IEC 9506 Part 1 and Part 2) and to ISO 8802-3 [2]

- IEC 60870-5-101 Ed. 2:2002 (57/605/FDIS), Telecontrol equipment and systems - Part 5-101: Transmission protocols – Companion standard for basic telecontrol tasks

- IEC 60870-5-104:2000, Telecontrol equipment and systems – Part 5-104: Transmission pro-tocols – Network access for IEC 60870-5-101 using standard transport profiles

- OPC XML-DA Specification Version 1.0; Release Candidate 2.1; June 11, 2003

- W3C, Extensible Markup Language (XML) 1.0, http://www.w3.org/TR/2000/REC-xml-20001006

[2] To be published.

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- W3C, XML Schema Part 0: Primer, http://www.w3.org/TR/2001/REC-xmlschema-0-20010502
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- DNP V3.00 Subset Definitions, Edition 2.00, November 1995, DNP Users Group; Document Nr.: P009-0IG.SUB
- DNP V3.00 Data Object Library, Edition 0.02, July 1997, DNP Users Group; Document Nr.: P009-0BL
- DNP V3.00 Application Layer, Edition 0.03, May 1997, DNP Users Group; Document Nr.: P009-0PD.APP
- DNP V3.00 Transport Functions, Edition 0.01, May 1997, DNP Users Group; Document Nr.: P009-0PD.TF
- DNP V3.00 Data Link Layer, Edition 0.02, May 1997, DNP Users Group; Document Nr.: P009-0PD.DL
- Transporting DNP V3.00 over Local and Wide Area Networks, Edition 1.0, December 1998. DNP Users Group

2. FUNCTIONAL REQUIREMENTS FOR DER INFORMATION

2.1 Overview of DER Environment

2.1.1 Distribution Utility Opportunities with DER in the Future

Spurred by deregulation and the availability of new technologies, there is a sharp increase in the number of implementations of a large variety of Distributed Energy Resources (DER) systems interconnected with distribution systems (which have been termed the Area Electric Power Systems (EPS) in the IEEE 1547 Distributed Resources Interconnection standard) for many different purposes.

Regardless of how a particular utility meets the challenge of deregulation and what role it plays in the electricity marketplace, all utilities are focusing on their customers to a degree unthought of in the past. To help stay competitive, many utilities are examining new technologies and exploring new customer services. At the same time, they are trying to find ways to cut operational costs without jeopardizing the security of the power system. Caught in the middle of this dichotomy, distribution utilities in particular are concerned with improving power quality for customers, deferring construction costs, and developing new business ventures involving energy services.

As a result of this pressure from both sides, DER technologies are increasingly being evaluated by distribution utilities to determine what benefits they might bring. Some benefits could be "soft", such as increased customer satisfaction, while other benefits could be "hard" or quantifiable monetary benefits which either reduce costs or increase revenue. Some of the DER uses being evaluated include:

a. **Generation capacity**. DER devices have generation capacity that can provide energy to offset load within a customer site, to support local load on a distribution feeder, and/or to provide energy within a substation.

b. **Load following**. DER devices can be used to follow load, not necessarily second by second (as needed by automatic generation control), but over short time frames or to counteract the large non-conforming loads of the DER owner. Distribution utilities could benefit from improved power quality (e.g. more stable voltages, lower voltage spikes) on the feeder serving this load.

c. **Peak shaving**. DER devices can be scheduled, manually controlled, or remotely controlled to turn on or provide more power during peak load times.

d. **Spinning reserve**. DER devices which are on-line or have a short start-up and synchronization time, can be counted as spinning reserve. This spinning reserve comes in small increments and can be scheduled by utilities to avoid starting up much larger units.

e. **Emergency backup generation**. The same DER devices which could provide spinning reserve can also provide emergency power to customer sites.

f. **Voltage support**. Feeders drop in voltage from the source substation to the end of the feeder. Typically voltage regulators along the feeders are installed to boost voltage and prevent low voltage conditions for customers at the end. DER devices could provide the same voltage support. If many DER devices are located along a feeder, voltage support could be achieved with more but smaller increments, thus permitting the feeder voltage at the distribution substation to have a wider range for the load tap changer. This wider range could be translated into lower feeder voltage at the substation during peak loads, and vice versa during low loads.

g. **Var support**. Some DER devices could provide var support in place of capacitor banks with similar benefits as for voltage support.

h. **Intentional islanding**. Sections of distribution feeders with significant amounts of available DER energy could be designed to become self-supporting islands if outages shut off the primary source of electricity. Campuses, isolated developments, or groups of hotels could be candidates.

i. **Pollution credits**. DER devices, particularly the renewables (wind, solar, etc.), usually cause less pollution than the larger coal and oil plants. Utilities which want or need to minimize their pollution levels could purchase more power from these DER devices, while customers concerned with pollution could either purchase or contract to use these DER devices.

j. **Green power**. A growing area of the electricity marketplace is the Green Power market. Many customers are willing to pay extra for green power. Although most green power today comes from hydro power, DER based on renewables could provide additional support, particularly whenever access to the hydro power (usually far away from most loads) is unavailable or curtailed due to power system problems.

k. **Defer construction of distribution facilities**. DER devices which act as negative load, provide peak shaving, and support voltage and vars on the feeder, also implicitly can defer the construction or upgrade of distribution facilities. Deferral of these capital expenditures can significantly off-set the costs associated with DER equipment.

l. **DER products for sale**. Utilities could provide DER devices for sale, using utility expertise and equipment for consulting on different DER alternatives, for installing the DER devices, and for testing the monitoring and control facilities.

m. **DER services**. Utilities could provide operation and maintenance services for DER equipment, again using their expertise and facilities as a marketing advantage.

2.1.2 DER Monitoring and Control Requirements

Installing DER devices presents distribution utilities with multiple challenges. The main challenge is the connection of the DER devices to radial distribution systems that were not designed for two-way real and reactive power flows. This technical challenge has been complicated by the organizational challenges of the deregulation process in the utility industry. For instance, which utility and non-utility organizations will be permitted to own and operate generation and energy storage devices at the distribution level? Which organizations and/or customers can benefit from DER? How will costs and benefits be allocated to participating organizations and customers?

Whichever organizations do become involved with implementing DER devices, the key for distribution utilities and other organizations to utilize DER effectively will be the timely and efficient exchange of critical and relevant information. For instance, some information may be collected once a month, such as meter reads of DER usage, and maybe perfectly adequate. However, other information, such as the on-off state of a DER device, or its remaining energy generation capacity, or its availability to provide backup power, must be known in "real-time" (seconds) for it to be truly useful. Without the ability to remotely monitor and control the DER devices in real-time, utilities will be blind and inefficient in using these DER resources.

In order to determine what types of communications, control, and management technologies are needed for DER, it is first necessary to determine the information and timing requirements of all of the stakeholders involved with DER. Once the stakeholder requirements are determined, then the flow of information can be assessed. With the information flows understood, then the technology requirements can be addressed.

2.1.3 DER Stakeholders

DER Stakeholders are the roles that different people or companies play in relation to each other with respect to the DER devices, particularly in the deregulated electricity marketplace. These roles determine what information they have and what information they need. In some cases, the same person or company may actually play two different roles at one time, but conceptually that one person or company is still two different stakeholders.

The stakeholders in the use of DER devices (see Figure 2-1) consist of the following:

a. **DER Owner:** The DER Owner owns the DER device. This owner could be viewed as a small ***GenCo***: the owner profits from using the DER either for serving his own load or from selling products: energy capacity or ancillary services. These services could be spinning reserve, peak shaving, emergency backup, voltage support, var support, etc.

b. **Marketer or Energy Services Provider:** The Marketer wishes to purchase energy or other services from the DER device for servicing his customer loads. In the terms of deregulation, he can be viewed as an **Energy Service Provider (ESP),** or possibly an ***ESCo*** if he is providing more services than just energy. He negotiates with the DER Owner for the type of product (e.g. capacity, spinning reserve, and voltage support), the schedule of the product (e.g. next hour, on peak for the next month, etc.), and the price. The marketer could be serving only himself; however, more generally, the marketer will have collected a number of customers for whom he is acting as the broker for purchasing energy and services.

c. **Distribution System Operator:** The distribution system operator is responsible for operating the distribution system safely and efficiently with DER: implementing all DER schedules in his control area, monitoring the DER devices (either directly or indirectly), and ensuring that all DER devices have tripped off in an emergency, while in general ensuring the secure and economic operation of the power system. The operator is also, generally, responsible for directing all maintenance and emergency activities on the power system.

d. **DER Operator:** The DER Operator is responsible for turning the DER device on and off during normal operations, based on the needs of the DER Owner for his own use of the DER device, as well as on the requirements of any contractual DER schedule. Since this is clearly not a complex task, the DER Operator may be a person pushing a button on the DER device, or an automated controller/synchronizer with a built-in scheduler, or the Distribution System Operator with a remote control capability. The DER device will have the built-in capability to shut down or not turn on if it is unsafe for the device to operate.

e. **Distribution System Maintenance:** The field crews responsible for distribution system maintenance (under the direction of the distribution system operator) are also usually responsible for ensuring that DER devices are off and/or locked out of connecting to the power system. At other times, these field crews must be aware of the impact of their maintenance activities on DER and vice versa.

f. **DER Device Maintenance:** The person responsible for DER device maintenance is responsible for ensuring that the DER devices and their security shut-offs, are operating correctly.

g. **DER Device:** The DER device itself must provide real-time data on its condition when queried, and respond to local and/or remote control commands, as well as protective relaying commands.

h. **Distribution Power System Protection:** If needed for security, the distribution power system protection devices issue long distance protection commands.

i. **Telecommunications Maintenance:** Telecommunications maintenance ensures the reliability and availability of the telecommunications capability. This function may be under utility control or may be the responsibility of a third party.

These DER Stakeholder roles are shown in Figure 2-1: DER Stakeholders.

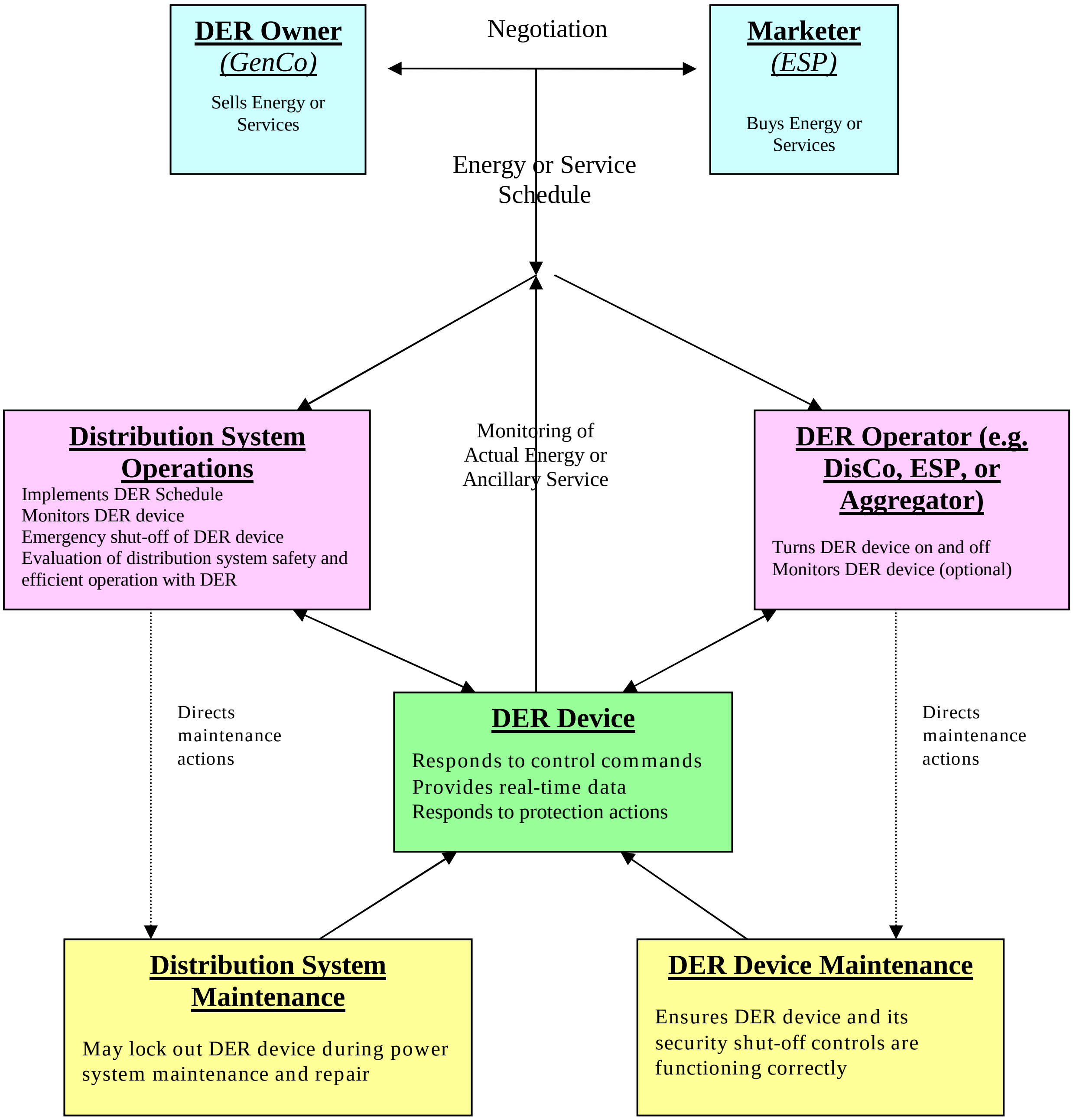


Figure 2-1: DER Stakeholders

2.2 Functions Involving DER

Information exchanges are determined by the functions that are required for monitoring, controlling, maintaining, and managing DER devices and installations. Therefore, the only way to ensure that all information exchange requirements are met is to exhaustively analyze all functions that could be implemented.

That said, much of the information to be exchanged will be the same for different functions, and the availability of different types of information will be determined by the equipment capabilities, the installation choices, and the degree of precision that the functions necessitate. Therefore, a more practical approach entails listing all functions (to ensure completeness), and then selecting a few that most likely cover all key information exchange requirements. These selected functions can be assessed in detail to determine both the minimum, mandatory information exchange requirements, as well as the maximum, optional information exchange requirements.

The same function can vary in scope significantly, depending upon the purpose of the DER devices in a particular installation. In addition, functions that are barely feasible today could become typical in the future. For instance, for the basic monitoring and control function, possible purposes could include:

1. Occasional use for backup for the local EPS (within a customer site). It is never interconnected to the area EPS (utility-owned distribution power system).
2. Occasional use for additional generation for the local EPS. It is never interconnected to the area EPS. This could be for reducing load that is served by the area EPS.
3. Occasional use for additional generation while local EPS is interconnected with the area EPS. This could be for peak shaving or other situation necessitating reduction in load.
4. Full-time use as additional generation interconnected with the area EPS. This generation could be run independently by the DER owner, loosely coordinated with distribution operations, or tightly integrated and controlled by utility operations. The DER generation would typically be larger combined heating and power (CHP) or other co-generation systems.
5. Full-time use as market-driven generation interconnected with the area EPS. This could include responses to real-time pricing signals, requirements of distribution automation scenarios, formation of microgrids, etc.
6. Emergency use as part of an overall plan for prevention of power system outages and blackouts, as well as the recovery from outages and blackouts.

Because of this large range of different purposes, the types of data that are exchanged can vary significantly for the same function. Therefore, careful attention must be paid to what data is mandatory and what data is optional, as well as how the data is organized in the object models.

Some of the key functions are described in the following sections. The functions in ***bold-italic*** are (will be) described in Use Cases in the next draft.

2.2.1 Local Functions (by DER Owners/Operators, which include Commercial Customers, Industrial Customers, Residential Customers, and Distribution Utilities)

The DER can be located at a customer site or at a utility site, such as in a substation. The DER owner/operator owns and operates the DER directly (no third party).

1. ***DER owner/operator uses DER as automatic backup for key internal load if main power is lost or may be lost (e.g. diesel generator). The DER system undertakes automatic start of DER device, disconnects Area EPS, synchronizes and interconnects DER to local EPS, and performs generation control to meet changing load requirements.***
2. DER owner/operator sets DER at a specific setpoint to provide a set level of generation (e.g. to offset load, to provide local generation for reliability and/or demand-response, to shave peaks).
3. DER owner/operator establishes a permanent building/campus microgrid (e.g. utility power as backup)
4. ***DER owner/operator uses DER for internal loads following with import/export interconnection to Area ESP, set for fixed import/export***
5. ***CHP or other factors drive the use of DER with net zero import/export, so Area EPS is used strictly as backup, so heat information is also required***
6. ***Heat is main purpose for heating hospitals – feed power back to the networked distribution grid in downtown New Orleans. Monitored for power flow when it is on.***
7. ***Contractual establishment possibility of microgrids during power outage or peak shaving. The DER owners are responsible for actually establishing the microgrid. Although no data exchanges now, in the future they will want far more data and possible control over the process.***
8. ***Greenpower demonstration house with net revenue and instantaneous metering on residential (up to 25 kW and small commercial up to 100 kW) – developing load curves from load monitoring, including after an outage.***
9. DER owner plans the scheduling/bidding of DER generation in electricity marketplace, for energy, as ancillary services, as contracted, as per real-time pricing, etc. The DER operator then executes the schedules as required.
10. DER operator manages DER system maintenance, including DER generator, prime mover, local EPS switching and protection, communications system, and the monitoring and control system
11. DER system collects information, logs, and statistics, including operational information, performance, efficiency, emissions, environmental parameters, green power %, etc. This information may be available in real-time as well as historical.

2.2.2 Third-Party Remote Operator or Aggregator Functions (by ESP or DisCo or Other e.g. RTO/ISO)

The DER can be located at a customer site or at a utility site, such as in a substation. The DER is operated by a third party from a remote site. The third party could be an Aggregator, and Energy Services Provider, a utility, or other entity.

1. Remote operator monitors generator status only (on/off)
2. ***Remote operator monitors instantaneous metering (status, alarms, kW output, voltage, amps, statistics, etc.)***
3. ***Remote operator monitors DER environment (prime mover, weather, emissions, protective relays, switches, etc.)***
4. Remote operator or Aggregator dispatches a local operator to manually control the DER device.
5. ***Make-before-break DER system picks up local load, then disconnects from the Area EPS; diesel recips; startup, isolation, verification, real-time metering, revenue metering both at the PCC and at the DER, as well as submetering, stop***
6. ***Dispatch pricing signal – DisCo dispatches DER on (to run at full power) or off***
7. Remote operator or Aggregator sets DER at a specific setpoint to provide a fixed amount of generation (e.g. to offset load, to provide local generation for reliability and/or demand-response, to shave peaks).
8. ***AGC – Remote operator (e.g. RTO/ISO or utility) or Aggregator controls DER operations through automatic control to meet specified operational needs and contracts (e.g. power quality, emissions, economic dispatch, energy schedules, ancillary service contracts, real-time pricing, local backup, interconnection with distribution system)***
9. Remote operator dispatches field crew to perform manual switching operations on feeders with DER present
10. Remote operator performs supervisory control of switching operations on feeders with DER present
11. Remote operator performs supervisory control of load tap changers and/or voltage controllers with DER present
12. Remote operator aggregates multiple DER device information for DisCo SCADA system
13. Remote operator provides DER owners, DisCo, and/or market operators with the results and other information on DER operations
14. Remote operator manages local microgrid operations with DER
15. ***Net metering – ESP or DisCo manages and reads revenue meters for DER and loads***
16. ESP or DisCo handles settlements and billing for DER owner
17. Regulators and auditors monitor compliance of DER operations with contractual and environmental commitments

2.2.3 Automated Distribution Operations (ADO) Functions (by Distribution Utility) Supported by Advanced Distribution Automation (ADA)

The DER can be located at a customer site or at a utility site, such as in a substation. Multiple points of common coupling (PCCs) of multiple DRs along a feeder need to be taken into account. The DER is operated by a distribution utility specifically to meet its normal operational needs, particularly if there is significant penetration of DER on some of its feeders or in its substations. These operational needs can include power system reliability, power system efficiency, power quality assessment, outage management, market operations, and maintenance.

1. ADO collects and analyzes distribution operations with significant DER penetration (multiple PCCs), including basic SCADA, distribution state estimation and operational analysis, status estimation of controllable devices, load modeling and analysis, reliability assessment, dynamic limit calculations, power quality analysis, etc.
2. ***ADO operates a DER system in a substation or other utility facility for additional local generation and ancillary services.***
3. ***ADO, supported by ADA, provides quality power to customers under normal conditions and/or as a result of predicted adverse conditions, based on coordinated volt-var control, contingency analysis, multi-level feeder reconfiguration, relay protection re-coordination, feeder phase load and voltage balancing, etc.***
4. ***ADO manages DER and distribution facilities planned outages, using Advanced Distribution Automation (ADA) applications in study/look-ahead mode, covering distribution operations analysis, DER availability analysis, multi-level feeder reconfiguration, coordinated volt-var control, reliability assessment, cold load pickup, work order creation.***
5. ADO, supported by ADA, supports market operations for DisCo, through load forecasting with DER availability and dispatchable load analysis, look-ahead distribution system analysis, contract-oriented loss calculations, coordinated volt-var with real-time pricing, etc.
6. ADO supports distribution and DER maintenance, by providing performance and historical statistics of DER and distribution equipment, as well as risk assessments based on these statistics
7. ADO, supported by ADA, coordinates distribution and DER operations with bulk power system operations, including real and reactive load/DER management, load shedding, load/DER transfer to different feeders, etc.
8. ADO, supported by ADA, supports customer services, through power quality assessment and management, real-time pricing analysis, and performance analysis
9. ADO, supported by ADA, manages DER interconnected with the utility grid, through DER forecasting and scheduling, microgrid creation and management, injection and storage management, interconnection design, and performance monitoring

10. ADO supports database management through asset management, database consistency management, and database validation management.

2.2.4 Emergency Operations Functions

The DER can be located at a customer site or at a utility site, such as in a substation. The DER is operated by a distribution utility specifically to meet its emergency operational needs, particularly if there is significant penetration of DER on some of its feeders or in its substations. These emergency needs can include protection schemes and actions, load shedding, alarm management, disturbance monitoring, emergency switching, and establishment of microgrids.

1. Protection equipment performs system protection actions on DER interconnections – fault detection, clearing, and reclosing
2. ***Distribution operator directly trips or verifies trip of interconnected DER on loss of feeder power***
3. Distribution operators manage emergency alarms from DER devices
4. SCADA system performs disturbance monitoring analysis, including DER responses
5. ***ADO, supported by ADA, manages forced outages of DER and distribution facilities, by supporting automated fault clearing (protective devices), fault indication, fault location, fault isolation, dynamic limit calculation, service restoration (manual or closed-loop switching), volt-var adjustment, DER control, microgrid creation, cold load pickup, paralleling check, relay re-coordination, etc.***
6. Operators dispatch field crews to troubleshoot system and customer power problems
7. Operators dispatch field crews to troubleshoot communication system and customer communication problems
8. Operators perform switching operations involving DER interconnections
9. Operators shed loads and/or DER devices intentionally
10. Outage management systems collect trouble calls and generate outage information
11. Microgrids of DER devices matched to loads are formed, operated, and eventually connected back into the distribution system

2.2.5 Planning, Installation, Commissioning, and Maintenance Functions (by DER Owners, Energy Service Providers (ESP), and DisCos)

Planning and implementation of DER involves longer term activities, with multiple parties involved to design, test, and audit DER systems.

1. DER sizing, technology, configuration, and installation is planned and coordinated with DisCo, by providing ratings, configurations, planned usage, etc.

2. Distribution planners study the impact of planned DER installations on the distribution system, and integrate these results with other distribution upgrades and additions, as well as ADA settings
3. Installer installs and tests DER devices in the local EPS
4. Distribution utility tests DER installation with interconnection to area EPS
5. Distribution utility interacts with DER owner on DER installation physical and electrical configuration, contractual arrangements, planned operations, and/or other information
6. DER operator tests DER communications system performance and management
7. Vendors of different equipment (including DER systems, switches, protection, and communications system) gather real-time data and statistics, and perform troubleshooting of their own equipment.
8. ***DER maintainer maintains DER system***
9. ***DER environmental monitoring***
10. Energy Service Provider meets contractual obligations for managing the DER system.

2.3 Alternative DER System Information Flow Configurations

DER devices can be implemented using many different configurations and with many different purposes and modes of being operated. Table 2-2 provides examples of what types of data may be exchanged for these configurations as they are used for different functions, but ultimately the information flows specified for any specific implementation must reflect the actual requirements for that installation.

Examples of the range of configurations are described in the following subsections.

2.3.1 Configuration #1 – Single DER Device with Manual Controls

The simplest configuration is a single DER device with manual controls. In this configuration, the DER device can be considered a "black box", and no communications are involved. See

Figure 2-2: Configuration #1 – Manual

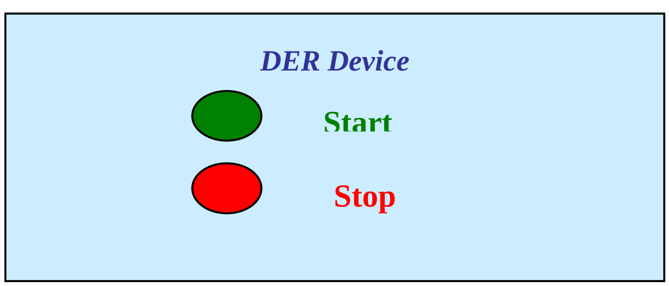


Figure 2-2: Configuration #1 – Manual DER System

2.3.2 Configuration #2 – Standalone DER Device Connected to a Local Controller

A very common configuration is a single, standalone DER device connected to a local controller that provides a simple HMI (human-machine interface) for local interactions with the DER device. The communications links between the DER device and the local controller are currently vendor proprietary. Since the HMI and these links are usually packaged as a unit, it may not be necessary or beneficial at this time to standardize the information flows on these links. See

Figure 2-3: Configuration #2 – Standalone DER with Local Controller/HMI.

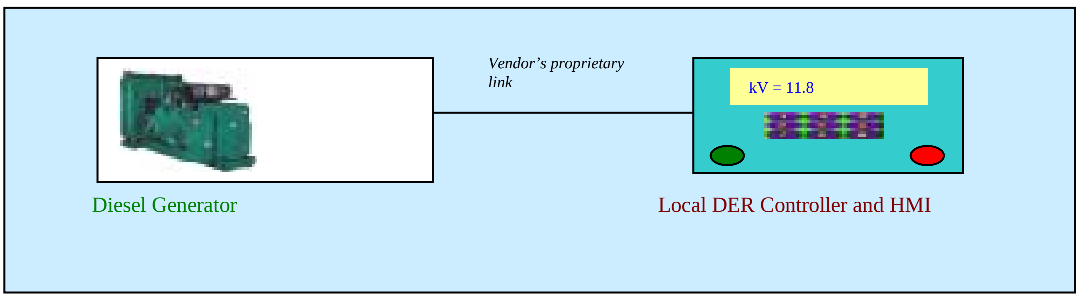
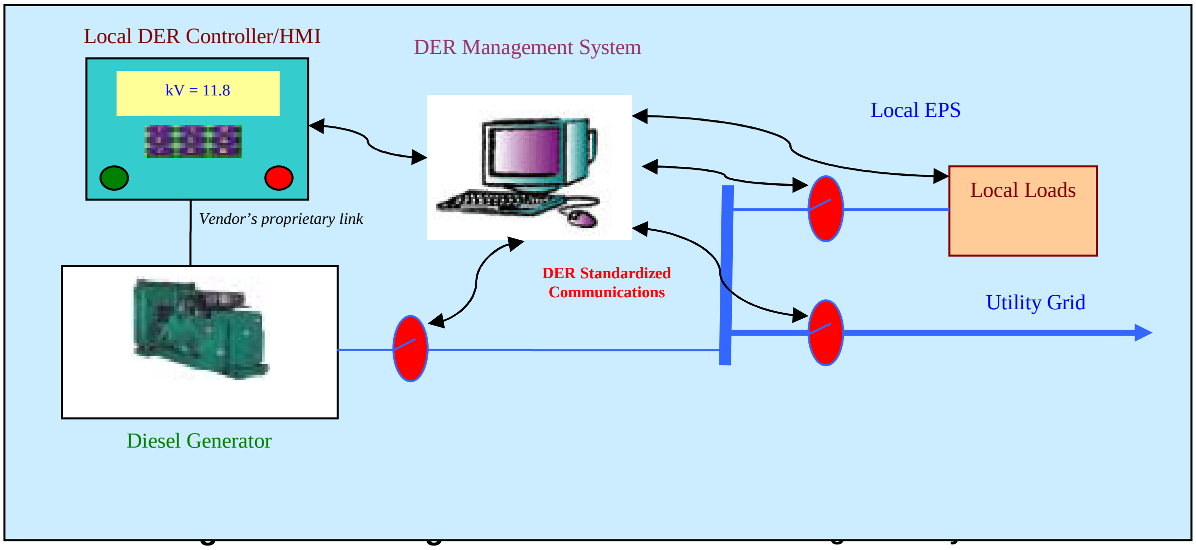


Figure 2-3: Configuration #2 – Standalone DER with Local Controller/HMI

2.3.3 Configuration #3 – Local DER Management System

Another configuration is a local DER Management System controlling to a single or multiple DER devices. The DER Management System also monitors, controls, and maintains the local Electric Power System (EPS), supporting switching operations of DER devices and local loads. This DER Management System may be a system that handles the scheduling and running of DER devices only or it could be a part of a Building Automation System (BAS). The BAS would combine the scheduling and management of the loads within a customer's site with the scheduling and management of the DER generation. See Figure 2-4: Configuration #3 – Local DER Management System.

Since this configuration requires communications between systems and power system devices that are very likely to be manufactured by different vendors, the need for information exchange standards becomes critical. Specifically, these interfaces would be between the DER Management System and the Local Controller/HMI, the local loads, the local EPS switches, and the local EPS protective relays. These interfaces are shown as curved pointers in the figure.



2.3.4 Configuration #4 – Remote DER Master Station for DER System

A more complex configuration involves the use of a Remote DER Master Station to monitor and control one or more DER systems. This Remote DER Master Station could be an Aggregator System, an Energy Management System, or a Campus Management System that handles multiple DER installations, providing different levels of monitoring, control, statistics-gathering, and maintenance support. See Figure 2-5: Configuration #4 – Remote DER Master Station.

The information exchange requirements for this configuration expand from management of the local EPS to the management of multiple EPS's with different local environments and contractual relationships with the remote system. Although the communications would most likely be with DER Management Systems, alternates could require communications directly to the Local DER Controller/HMI.

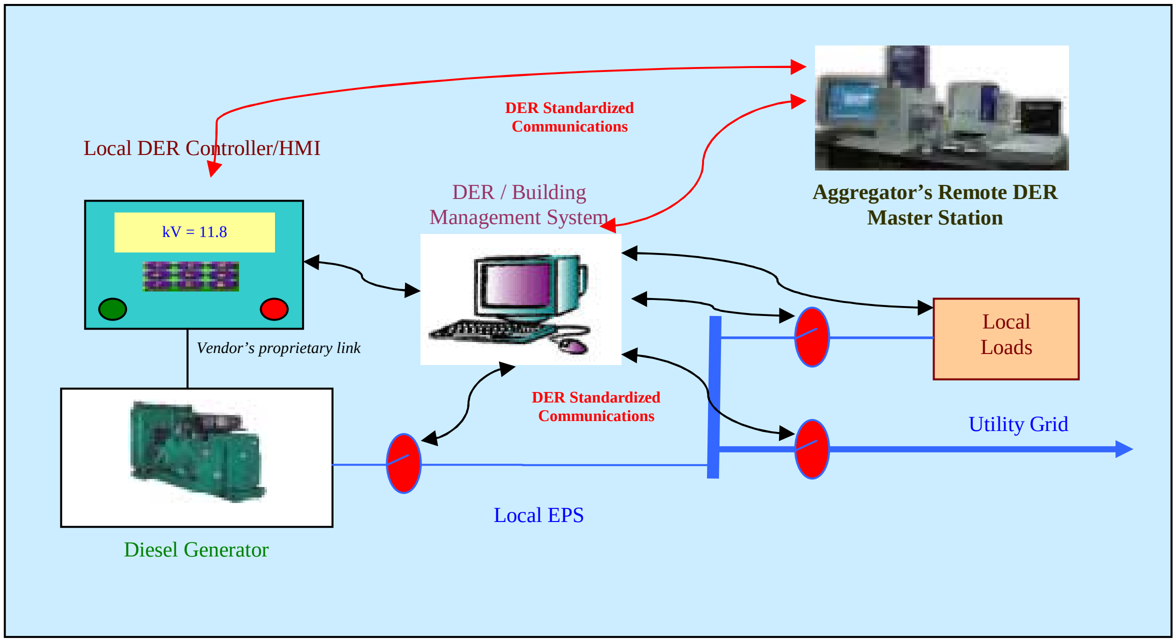


Figure 2-5: Configuration #4 – Remote DER Master Station

2.3.5 Configuration #5 – Distribution Operations Managing DER Systems

Another configuration involves the utility distribution operations directly managing multiple different DER systems as part of distribution operations, possibly including market operations. At a simple level, the distribution operations could simply monitor these DER systems; while at more complex levels, the distribution operations could manage the DER systems as an integral part of Advanced Distribution Automation (ADA). For instance, ADA could use DER systems for volt/var control, schedule the DER systems for energy and ancillary services in the energy marketplace, utilize DER systems for emergency responses, and initiate deliberate islanding of the power system into "microgrids" for economic or emergency reasons. Figure 2-6: Configuration #5 – Distribution Operations Managing DER Systems.

The information exchange requirements for this scenario involve many different systems with many variations on what information will be needed by what system, and when and how. Standards are therefore crucial.

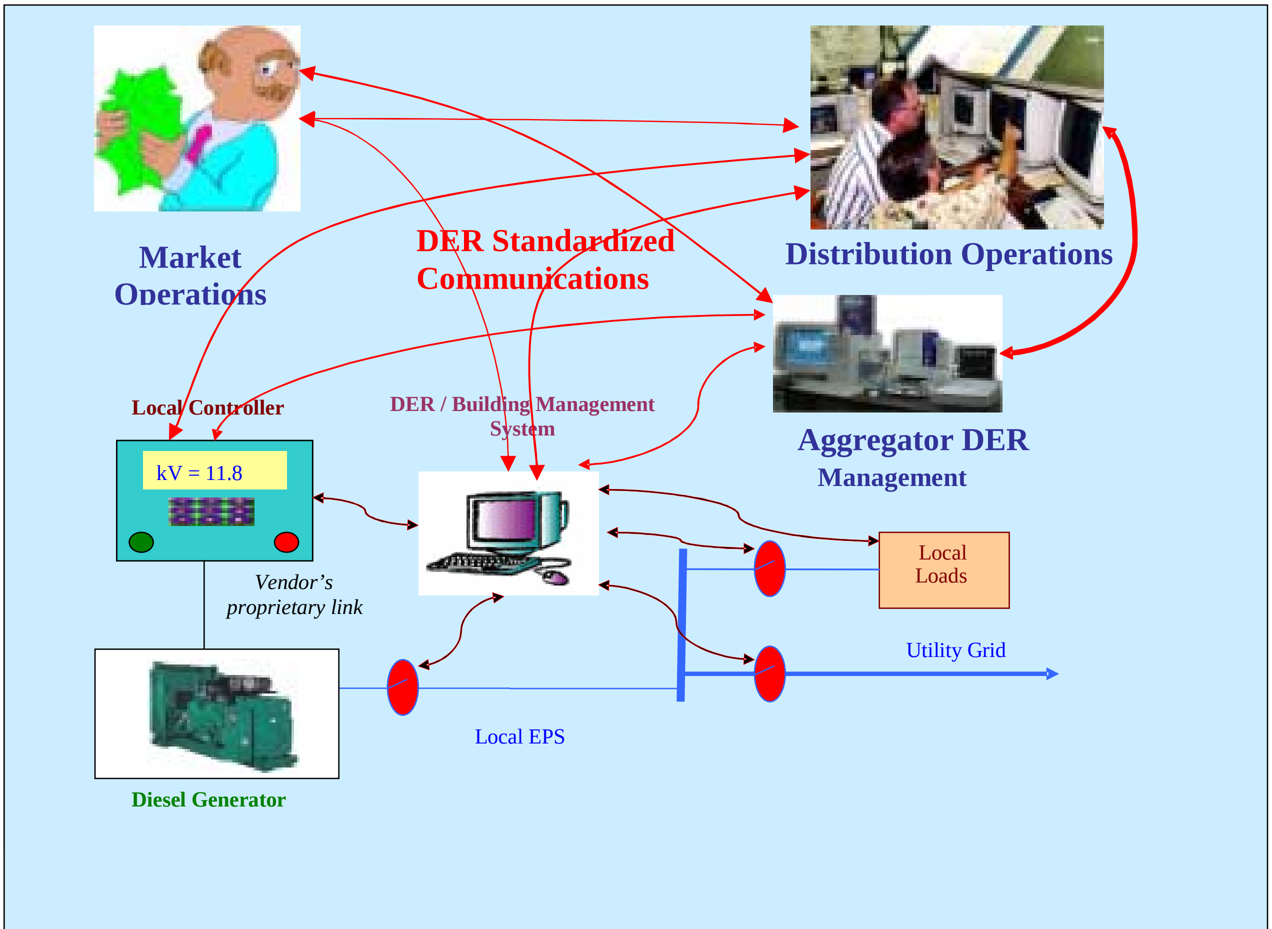


Figure 2-6: Configuration #5 – Distribution Operations Managing DER Systems

2.4 Generic DER Installation Configuration

As can be seen from the different configurations above, DER systems can be implemented in many different ways. In addition, DER systems themselves are made up of different modules, some of which are similar between types of DER and others of which are unique to each DER type. As will be seen during the information modeling sections, this decomposition into modules is very important.

Figure 2-7: Block Diagram of a Generic Distributed Energy Resources (DER) System shows a block diagram of a generic DER system, including the following modules:

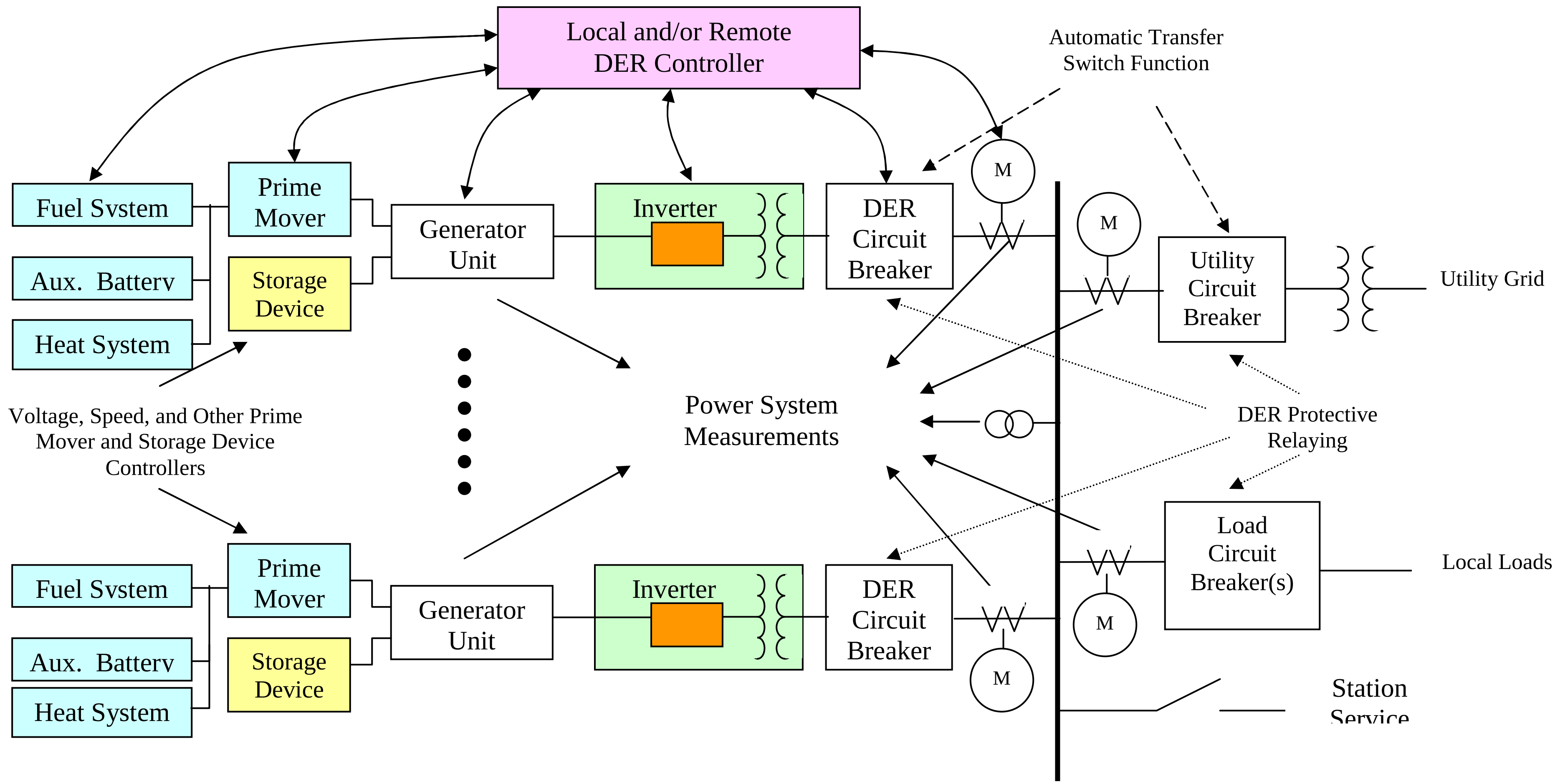
1. DER Units

   a. Prime Mover or Storage Device (for some technologies, prime movers or storage devices are integral with the generator and/or converter equipment. However, conceptually they can be viewed as having separate functions, and are therefore shown as separate blocks.)

   b. Generator
   c. Converter equipment
   d. Fuel system and auxiliary batteries
2. Power System measurements
   a. Volt, var, amp measurements from many locations
   b. Metering from different locations and power flow directions
3. Protective Relaying elements
   a. Circuit breakers
   b. Relays
4. Automatic Transfer Switch function
   a. Circuit breakers
   b. ATS controllers

The modules shown in white are common to all DER systems. The modules shown in non-white are specific to the type of DER prime mover used in the system.

Figure 2-7: Block Diagram of a Generic Distributed Energy Resources (DER) System



Prime Mover = Microturbines, Fuel Cell, Photovoltaic System, Wind Turbines, Diesel Generators, Combustion Turbines

Storage Device = Superconducting Magnetic Energy Storage, Battery, Pumped Hydro, Flywheels, Micro-flywheels

Inverter = DC to AC Power

2.5 DER Modules Required by Different DER Prime Mover Technologies

Table 2-1 shows the mandatory (M) and optional (O) DER modules needed by each of the different DER prime mover technologies. Mandatory implies that the module is needed in all circumstances; optional implies it may be needed in different configurations. Blank implies the module is not needed.

Table 2-1: DER Modules Required by DER Prime Movers

DER Modules / *DER Prime Mover Technology*	Prime Mover or Storage Module	DER Controller	Generator Characteristics	Frequency control	Converter/ Inverter if needed by prime mover	Fuel System or Equivalent	Battery System
Diesel Generators	M	M	M	O		O	O
Fuel Cells	M	M	O	O	M	O	O
Photovoltaics Systems	M	M	M	O	M	O	O
Wind Turbines	M	M	M	O	O	O	O
Combustion Turbines	M	M	M	O		O	O
Microturbines	M	M	M	O		O	O
SMES	M	M	M	O	M	O	O
Batteries	M	M	M	O	M	O	O
Pumped Hydro	M	M	M	O		O	O
Flywheels	M	M	M	O	M	O	O

2.6 Example of Information Requirements of DER Functions from DER System Modules

The functions described in Section 2.2 require different information flows from the different DER modules. This table is an example only, since different implementations will have different detailed requirements. In addition, this table only indicates which modules are involved in the information exchanges, but does not indicate the actual flows of information from one module to another. It also does not include details as to what data from within a module should be exchanged. That said, however, the table does indicate the complexity of the information flows and gives a rough idea of the scope that should be envisioned when the DER systems are designed.

Validation of the information requirements illustrated in this table should be performed through the development of Use Cases, using the Unified Modeling Language (UML) and/or RM-ODP modeling techniques.

Table 2-2: Example of Information Requirements of DER Functions from DER System Modules

Codes*: B = before real-time; P = protection signalling; M = real-time monitoring; C = real-time control or settings; A = after real-time monitoring; S = statistical analysis; L = Logging*

DER System / *Modules* / *Functions*	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
A. Local Functions (by DER Owners/ Operators)																				
1. Backup for key internal load if main power is lost	M,C	B			B	B	B				M				P	M		A	L	

Modules / DER System / Functions	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
2. Offset load to shave peak (no export)	M,C	B			B	B	B				M					M		A	L	
3. Permanent building/campus microgrid with no export but possible import	M,C	M	M,C		M	M	B	M	M			C,P			P	M		A	L	
4. Continuous power for internal loads continuously with interconnection	M,C	M	M,C		M	M	B	M	M			C,P			P	M		A	L	
5. Scheduling/bidding of DER generation in electricity marketplace	S	S			S	S		S											S	
6. DER system maintenance	A	A	A	A	A	A	A				A	A			A				A	
7. Logs and statistics gathering	S	S	S	S	S	S	S	S			S	S			S	S		S	A	S
B. Remote Operator Functions																				
1. Remote operator monitors generator status only (on/off)																				
2. Remote operator monitors generator operations																				
3. Remote operator monitors DER environment																				

Modules / DER System / Functions	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
4. Remote operator controls DER operations																				
5. Remote operator performs manual switching operations on feeders with DER present																				
6. Remote operator performs supervisory control of switching operations on feeders with DER present																				
7. Remote operator performs supervisory control of load tap changers and/or voltage controllers with DER present																				
8. Remote operator uses SCADA system to aggregate multiple DER device information to be sent to the DisCo SCADA system																				
9. Remote operator manages and/or coordinates local microgrid operations with DER																				

Functions / Modules / DER System	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
10. ESP or DisCo installs, calibrates, sets parameters, and reads revenue meters for DER and loads																				
11. ESP or DisCo handles settlements and billing for DER owner																				
12. Regulators and auditors monitor compliance of DER operations with contractual and environmental commitments																				
C. Automated Distribution Operations (ADO) Functions (by DisCo)																				
1. ADO collects and analyzes information about distribution operations with significant DER penetration																				
2. ADO provides reliable services and quality power to customers under normal conditions																				

DER System / Modules / Functions	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
3. ADO manages DER and distribution facilities planned outages																				
4. ADO manages DER and distribution facilities forced outages																				
5. ADO supports market operations for DisCo																				
6. ADO supports distribution and DER maintenance																				
7. ADO coordinates distribution and DER operations with bulk power system operations																				
8. ADO supports customer services																				
9. ADO and DisCo operations manage the DER systems interconnected with the utility grid																				
10. ADO supports database management																				

Modules / DER System / Functions	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
D. Emergency Operations Functions																				
1. Protection equipment performs system protection actions on DER interconnections																				
2. DisCo directly trips or verifies trip of interconnected DER on loss of feeder power																				
3. Operators manage emergency alarms from DER devices																				
4. SCADA system performs disturbance monitoring analysis, including DER responses																				
5. Operators dispatch field crews to troubleshoot system and customer power problems																				
6. Operators perform switching operations involving DER interconnections																				

Modules / DER System / Functions	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
7. Operators shed loads and/or starts DER devices intentionally																				
8. Outage management systems collect trouble calls and generate outage information																				
9. Microgrids (islands) of DER devices matched to loads are formed, operated, and eventually connected back into the distribution system																				
E. Planning and Installation Functions (by DER Owners, ESPs, and DisCos)																				
1. DER sizing, technology, configuration, and installation is planned and coordinated with DisCo																				
2. Distribution planners study the impact of planned DER installations on the distribution system																				

Modules / DER System / Functions	DER Controller	Generator Characteristics	DER Frequency control to Load	Converter/ Inverter	Prime Mover or Storage	Fuel System	Battery/UPS System	Generator Electrical Mmt	Local EPS Electrical Mmt	Area EPS Electrical Mmt	Automatic Transfer Switch	Circuit Breaker at DERs	Circuit Breakers at Load	Circuit Breaker on Area EPS	Protective Relaying	Metering at DER	Metering at Load	Metering at PCC	Alarming and Logging	Configuration Mgmt
3. Installer installs and tests DER devices in the local EPS																				
4. DisCo tests DER installation with interconnection to area EPS																				
5. DER operator tests DER communications system performance and management																				
6. Vendors of different equipment gather real-time data and statistics, and perform troubleshooting of their own equipment																				

3. DEVELOPMENT PROCEDURES FOR UCA DEVICE OBJECT MODELS

3.1 Background of Utility Communications Architecture (UCA®)

3.1.1 History of UCA and IEC61850

The history of UCA can be found in the *Introduction to UCA Version 2*, which is part of IEEE TR1550.

3.1.2 Motivation for 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.

3.2 IEC61850 Device Modeling Constructs and Processes

IEC61850 device modeling constructs and processes are not for the faint of heart. Their main purpose is to make the specification and implementation of information exchanges easier for the user. Therefore, these object models take on the complexity themselves and bury that complexity in the software developed by the vendors. Once the complex underlying software is developed, the vendors can present a simple interface for all implementations.

For a person who is "object-modeling-challenged", the most important part of the modeling process is the defining of Data Objects so that they reflect the real-world, as described in Section 3.2.4.

3.2.1 IEC61850 Communication Constructs

The IEC61850 concept of communications consists, in its basic form, of the following:

1. A **Logical Device** (acting as "Servers" in Client-Server terminology), which provides data and responds to commands. This server contains one or more Logical Nodes for the devices being accessed. It can be a simple electronic controller linked to a single device, a more capable Intelligent Electronic Device (IED) managing a single device but providing additional functionality, or a local server which manages multiple devices and supports many additional functions. Examples of the latter include substation automation master stations and DER management systems.

2. A **Communications Network** that provides network access to the Logical Device server. 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.

3. One or more **Data Acquisition and Control (DAC) subsystems,** acting as "Clients" to the Logical Device servers and acting as "Servers" to other Users. Specifically, these DAC subsystems can provide "mapping" between IEC61850 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.

4. **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. Most Users will access the Logical Device servers via the DAC subsystem, but some may be IEC61850 Users with direct access to the Logical Devices. These Users could be vendors, maintenance personnel, or systems of the future which do not require data object mapping. Obviously appropriate security measures would still be required.

These concepts are illustrated below as

Figure 3-1**: Basic Communications Services Concepts Model**.

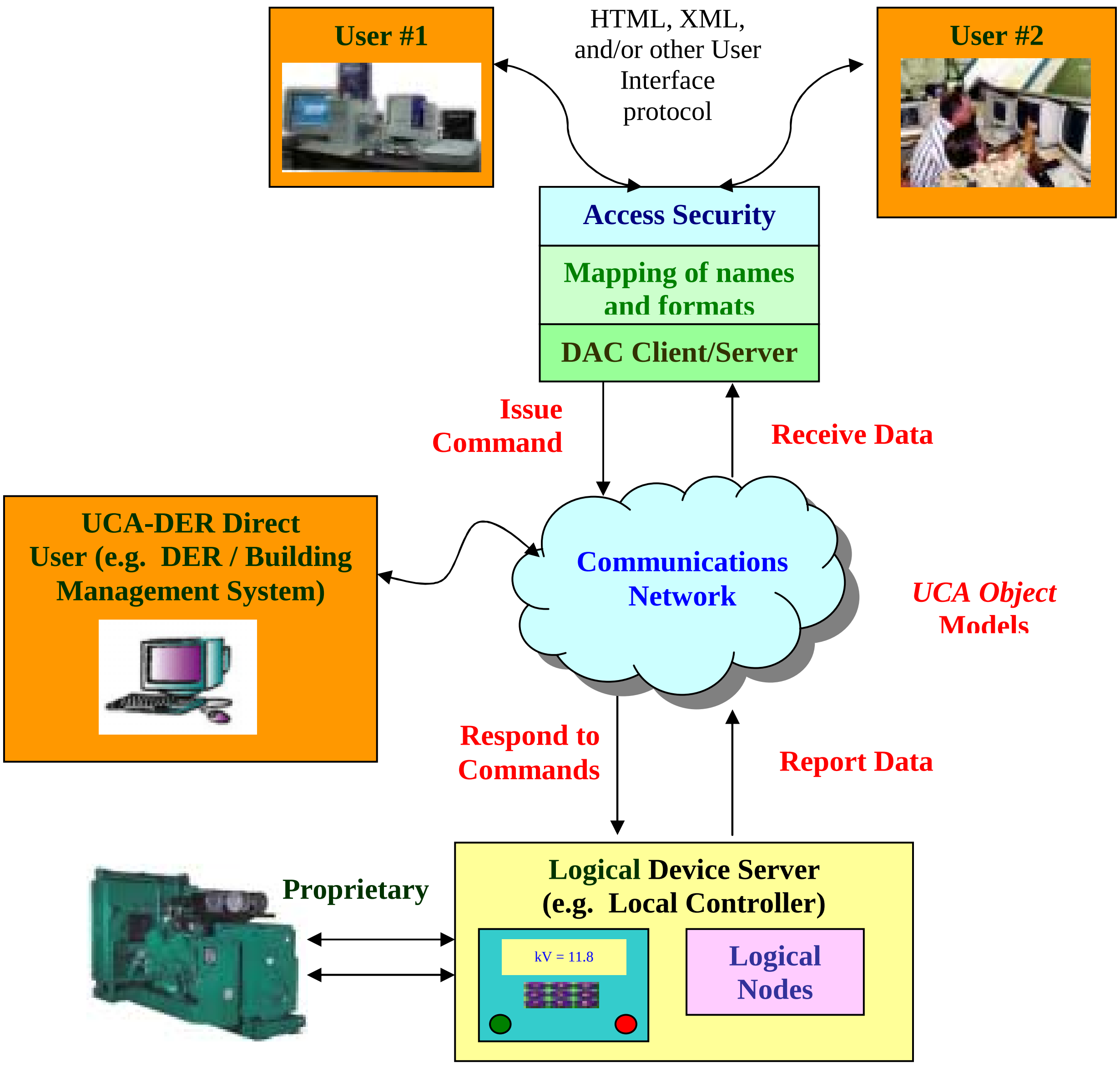


Figure 3-1: Basic Communications Services Concepts Model

3.2.2 IEC61850 Logical Device Modeling Constructs

IEC61850 Logical Device servers (a server being a hardware device such as a computer) contain one or more 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 three parts:

- Information from and commands to the equipment being modeled (e.g. the running/stopped status of the generator, control command to start the generator). This part consists of one or more Logical Nodes.

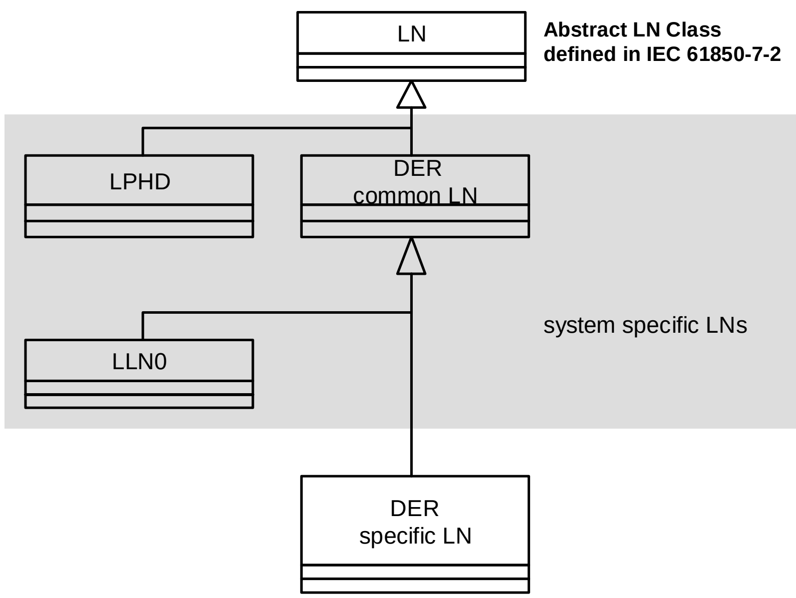
- Information about the Controller itself (not what it controls) (e.g. controller nameplate information, controller health). This part is called the LPHD Logical Node.

- Information from and commands to the Logical Device model (e.g. operation time, run diagnostics). The Logical Device is treated as a separate entity from the Controller, since there may be more than one Logical Device within a single Controller, or vice versa, there may be more than one Controller handled by a single Logical Device. This part is called the LLN0 Logical Node.

3.2.3 IEC61850 Logical Nodes

The relationships between these abstract Logical Node constructs are shown in Figure 3-2, using UML diagramming constructs. This figure does require knowledge of class diagramming rules to be understood.

Figure 3-2: Relationships between Abstract Constructs of Logical Nodes



A more user-friendly diagram of the relationship between logical nodes and physical devices is illustrated in Figure 3-3.

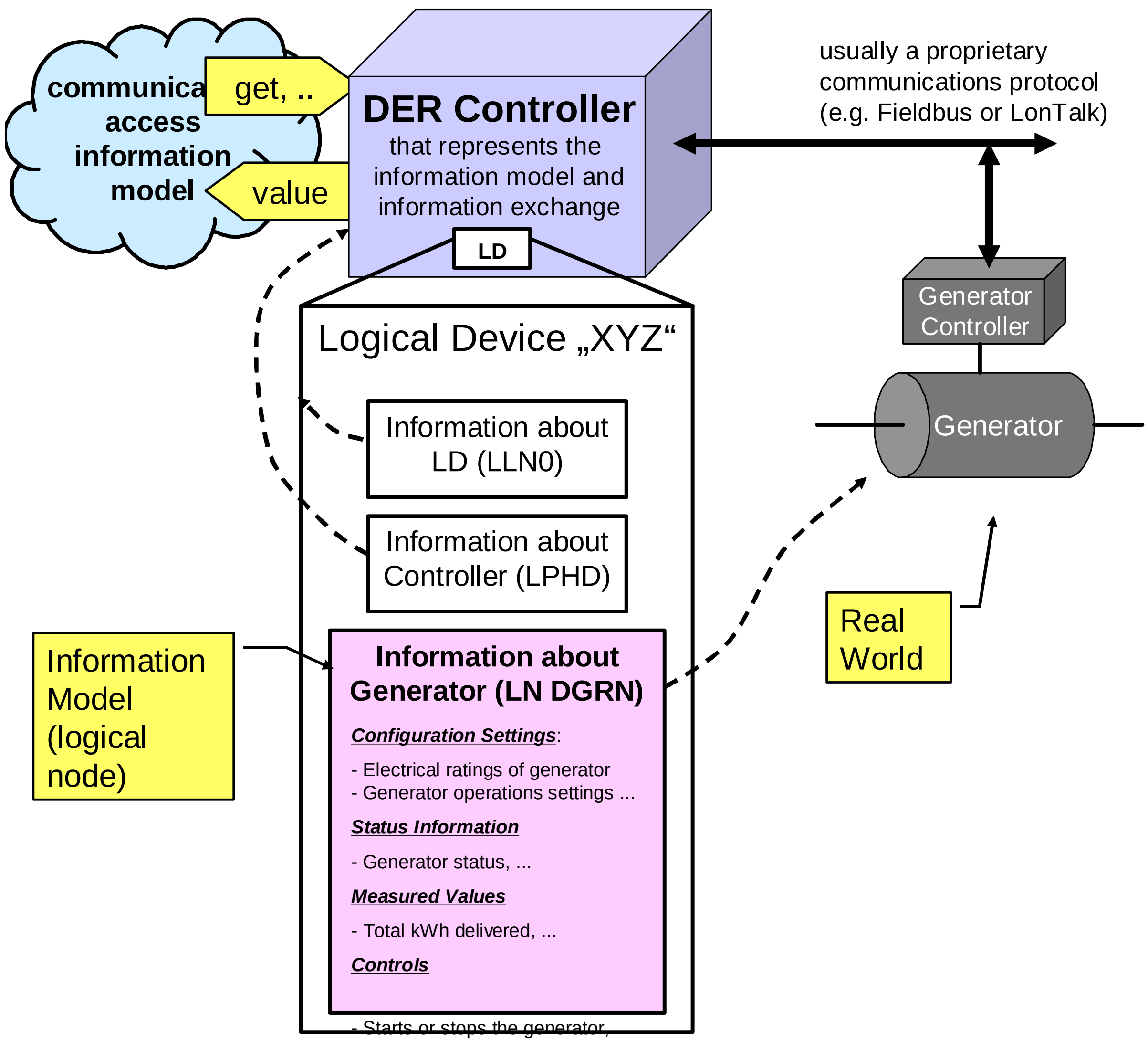


Figure 3-3: Relationship between Logical Nodes and Physical Devices

3.2.4 IEC61850 Data Objects – The Actual Data

As mentioned above, the first part of the Logical Device models 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, showing what Logical Nodes are required to fulfill a particular capability. As can be seen, there are usually many Logical Nodes in one Logical Device server.

Logical Nodes are made up of many Data Objects. These Data Objects provide "well-known" names for the actual data that will be exchanged. ***Most of the effort in modeling goes into defining these Data Objects so that they truly reflect the real-world information***.

Examples of Data Objects are GenSt (generator status showing on or off), TotalkWh (showing total kWh that the generator has generated), and GntCtl (control command to the generator to turn it on or off).

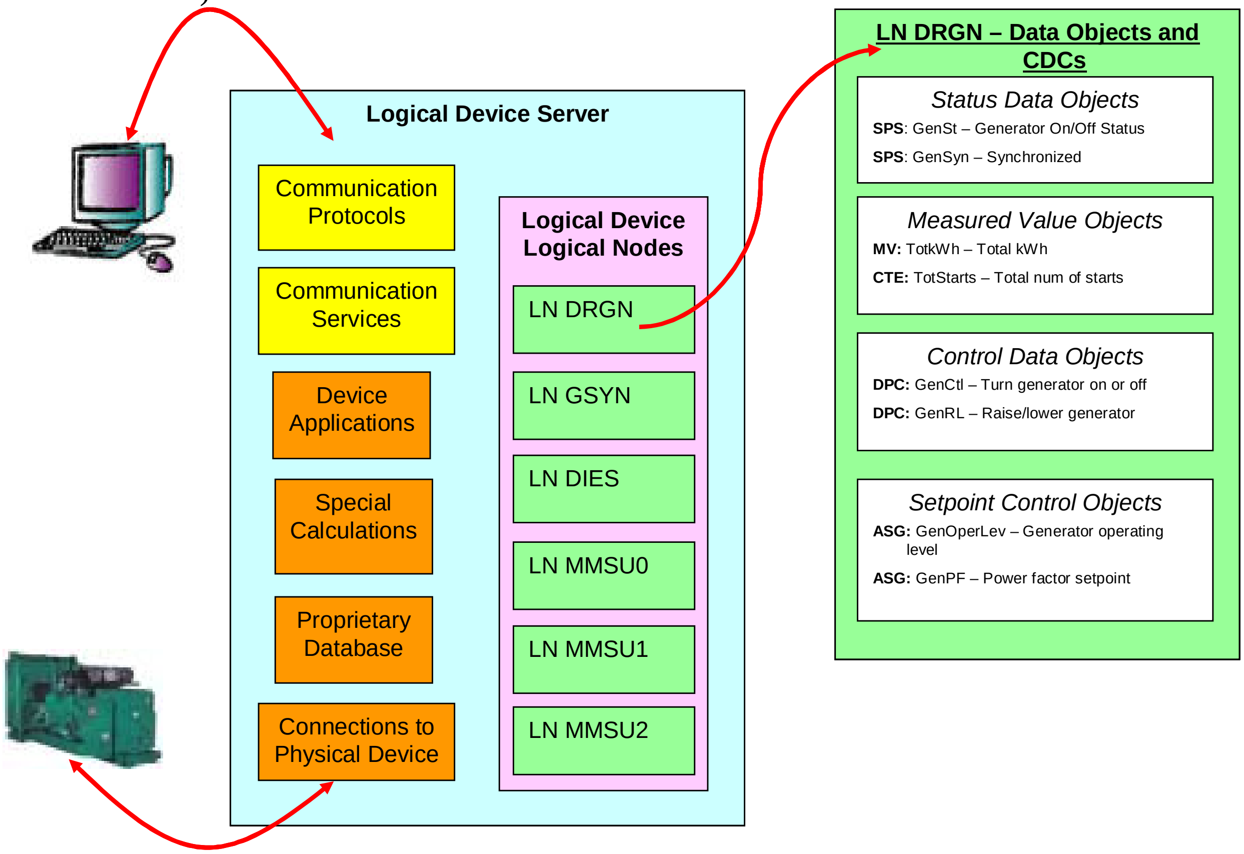


Figure 3-4: Relationships between Logical Node Server, Logical Nodes, Data Objects, and Common Data Classes (CDCs)

3.2.5 IEC61850 Common Data Classes – The Format of the Actual Data

As illustrated in the figure above, the Data Objects in the Logical Nodes are categorized by type of data, and assigned to use one of many Common Data Classes (CDCs). A CDC consists of a structured set of attributes, which are used to define the characteristics of each data object. Each CDC is also defined by a name and a type (format). The format can itself be complex, involving multiple attributes and different attribute types.

Examples of CDCs are:

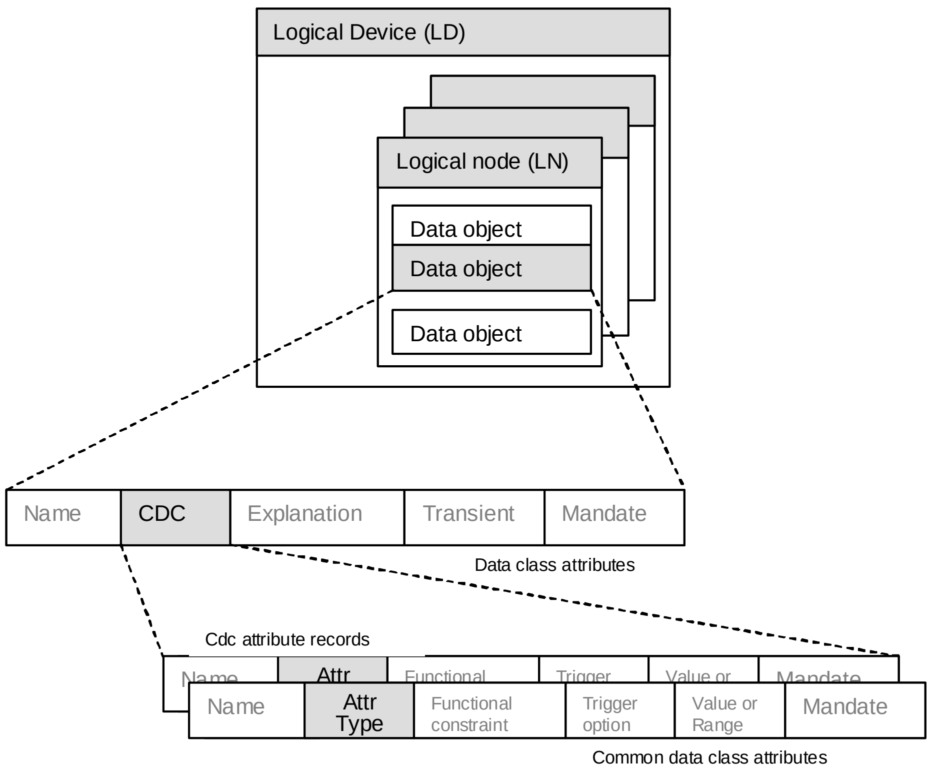
- **SPS (single point status)**, which contains stVal (the actual status being reported), the quality code of that status point, a time stamp of when the status was read, a description, and some other attributes.

- **MV (measured value**), which contains instMag (the instantaneous magnitude of a measured value), mag (the magnitude over some pre-specified time), range (an indication if the magnitude is higher or lower than some pre-specified amounts), quality, time stamp, and some other attributes.

- **DPC (double point control**), which contains ctlVal (the actual controllable point), operTim (the time stamp when the control command was executed), stVal (the status of the point associated with the controlled point), and other attributes.

The relationship between Logical Nodes, Data Objects, and Common Data Classes is illustrated in Figure 3-5.

Figure 3-5: Relationship between Logical Devices, Data Objects, and Common Data Classes



Some of the key types and examples of their most common CDCs are as follows (see IEC61850-7-2 for a complete list of types of data, and IEC61850-7-3 for a complete list of CDCs used in Substations):

1. Reported Data

   a. **Type ST** – status and alarm objects, which are defined as one or more bits that generally change in real-time due to external events. These objects can be read, substituted, reported, and logged, but not written. Common CDCs are defined for Single Point Status (SPS) (e.g. for a simple alarm), Double Point Status (DPS) (e.g.

for status of open/closed or off/on states), and Status Indication Group (SIG) (e.g. for multiple alarms).

b. **Type MX –** measurement objects, which are defined as integers, floating point values, or other analog formats that generally change in real-time due to external changes. These objects can be read, substituted, reported, and logged, but not written. Common CDCs are defined as Measurement Value (MV) (e.g. for measuring voltage or current), and Harmonic Value (HV) (e.g. for measuring power quality harmonics)

2. Commands

   a. **Type CO –** single bit control commands, generally resulting in a change between two states. These objects may be operated (written to in control mode) and read. Common CDCs are defined as Single Point Control (SPC) (e.g. for resetting a fault indicator), and Double Point Control (DPC) (e.g. for issuing an open or close command).

   b. **Type SP –** setpoint control commands, where an analog value is used to define where in a range the device is being commanded to go. The device is then expected to automatically take whatever actions it can to go to or maintain that setpoint value. These objects may be operated (written to in control mode) and read. Common CDCs are defined as Analog Setpoint (ASP) (e.g. for setting a voltage level that the device must operate to), and Analog Input Setpoints (AISP) (e.g. for setting high and low limits that, if exceeded, will cause some action).

3. Descriptive Information

   a. **Type CF –** configuration information whose value may be written as well as read. This information may be used to affect processes. Common CDCs include the Device Name Plate (DPL) and Logical Node Name Plate (LPL).

   b. **Type DC –** descriptions, providing human-readable descriptions of objects. This information is not generally used by any processes.

4. Reporting Objects

   a. **Types BR and RP –** unsolicited reporting of data by the Server as buffered or unbuffered reports. A Report Control Block is associated with a Data Set containing a list of Data Objects to be reported upon event, periodically, by exception, etc. The only common Class is the basic Report Control Block (basRCB).

   b. **Type LG –** logging of timestamped objects upon event, for historical purposes. A Log Control Block indicates how logging is to be done.

3.2.6 IEC61850 Data Object Naming Conventions

As defined in IEC61850, Data Object names consist of different parts, each with a maximum number of characters. To make the naming convention harmonized with the IEC61970 Common Information Model (CIM), the following structure has been proposed {***comment***: IEC61850-7-2 shows a different breakdown for the Data Name}, see Figure 3-6:

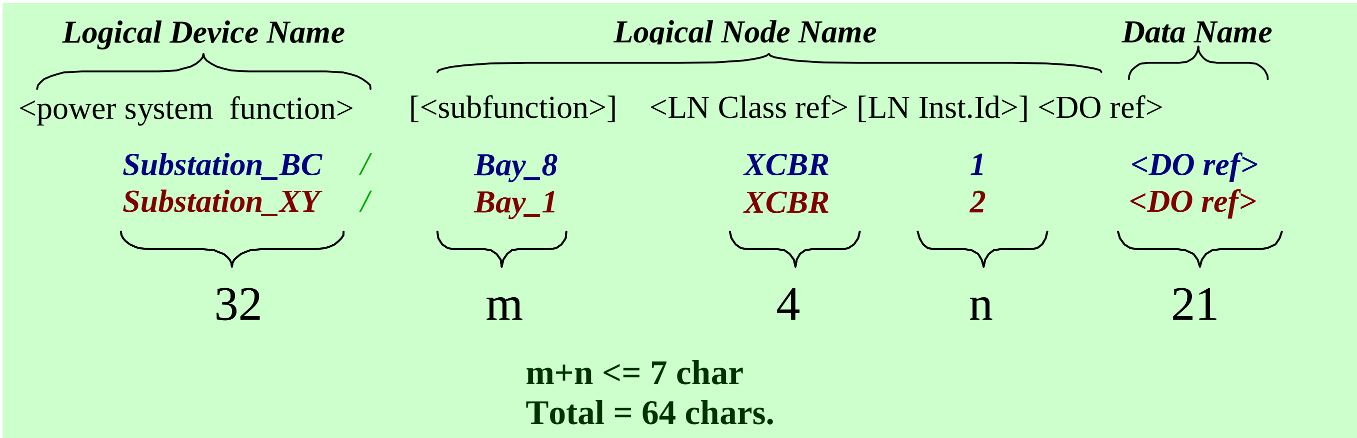


Figure 3-6: Structure of names of objects in instantiated IEDs using the Configuration Language

The data names are further defined as follows:

DataName[.DataName[…]].DataAttributeName[.DAComponentName[…]]

Notice that neither the Functional Component nor the Common Data Class is contained in the name of a Data Object. This is because the Data Objects, once they are standardized, are unique within a Logical Node and are thus "well-known", meaning that they can have only one structure, the structure defined in the standard.

3.2.7 IEC61850 Abstract Services, Reporting, and Data Sets

Object models can be characterized as "**nouns**"; abstract services can be characterized as "**verbs**". They establish the rules for what information is sent, when it is sent, to whom it is sent, and what happens when it does (or does not) get there.

The object models include everything that could be wanted from a device. However, usually only a small fraction of the information needs to reported, and often that reporting should be done only under special conditions. IEC61850-7-2 defines the abstract services needed to establish what does get sent and under what conditions.

Briefly, these abstract services perform the following key tasks (among others):

- Establish and manage associations between a "client" and a "server"
- Permit Data Objects (and the selected attributes within the Data Object) to be grouped into Data Sets so they can be sent as one time without having to send the name of each Data Object every time.
- Establish conditions when Data Sets are sent, such as every 10 seconds, or upon change of a status point, or upon the significant change of an analog measurement.

3.3 General Device Model Development Procedures

When a device object model is created, the following steps are used:

1. The information exchange requirements are developed from the functional requirements, as described in *Section 2 - Functional Requirements for DER Information.*
2. A block diagram is created of the device, showing its different logical parts and functions, focusing on the information exchange requirements.
3. These logical parts or functions are further separated into one or more Logical Nodes (LNs). A Logical Node is a logical grouping of objects required by a particular function, which could be reused by many different devices. Many Logical Nodes already exist in the IEC61850-7-4; these should be used if they meet the device requirements. However, new Logical Nodes must be created to meet new needs, such as those for the Distributed Resources environment.
4. Each logical piece of data that may be exchanged between the Server and a Client is defined as a ***data object***. Many data objects have already been defined in the IEC61850-7-4, and should be used as defined. New data objects must be defined when no existing IEC61850-7-4 objects can serve. Data objects may be simple (e.g. open/close status of a switch), complex (e.g. all ratings and static characteristics of a device), or an array (e.g. an array of bits defining alarm reasons). Discussion among experts is sometimes required to determine exactly what constitutes a particular data object.
5. Existing IEC61850 Logical Nodes have their data objects already assigned to them. A new IEC61850 Logical Node must have new and existing data objects assigned to it, based on their logical role within the device model. Sometimes a data object could be assigned to more than one Logical Node: therefore, a decision must be made as to where it most logically lies.
6. Each type of data object is also assigned to one of the ***Functional Component*** categories (e.g. the open-close status of a water valve is assigned to the ST functional component category).
7. Each data object is given a unique ***object name***, which must follow certain guidelines, but should be relatively self-explanatory (e.g. the open-close status of a switch is called SwDS, where DS stands for Device State). This name is critical: it is the way that Clients and Servers can recognize what data is being transmitted.
8. Each data object is assigned a ***Common Data Class***, which defines what format the data is in (e.g. SwDS is assigned to the CDC *SPS*, which is defined as a two-bit binary, plus quality code, plus timestamp, plus description). A CDC can be defined to be a single item, or, more usually, as a structure of items (such as the SPS CDC, which consists of 4 items). If no existing CDC can meet the requirements of the data element, then a new CDC must be developed, following the procedures established for IEC61850.
9. Each data object is defined as ***mandatory*** or ***optional*** or ***conditional*** (m/o/c column).

10. The meaning of the ***values*** for each data object are defined; some are implicitly defined by the type of Class, but certain Classes have flexibility in what values might mean, so these must be clarified for each data element (e.g. for SwDS, the two-bit status has the following meanings: 00 = between (in transit), 01 = closed, 10 = open, 11 = invalid).
11. The ***reporting objects*** are defined, based on the conditions under which each client needs to receive data (e.g. SwDS should be reported to Client 1 anytime the two-bit value or the quality code changes), and what groups (***Data Sets***) of data objects should be reported. The actual rules for the reporting procedures are defined in the IEC61850-7-2 standard. Once Data Sets are established on either side of a link, then only the data (not the long names) can be sent over the communications network.

4. DER LOGICAL NODES

4.1 Procedure for Determining Object Modeling Requirements for DER Devices

The following steps were undertaken to develop the UCA object models for the DER devices and were based on the generic steps described in Section 3.2.7:

1. The preliminary functional requirements for information exchanges between DER devices and the stakeholders in DER operations and maintenance were extracted from the 1998 EPRI report: ***Integration of Distributed Resources in Electric Utility Systems: Functional Definition for Communication and Control Requirements***, EPRI TR-111491, Final Report, October 1998.
2. A list of possible functions involving DER devices was developed, partially from the current “Integrated Energy and Communications Systems Architecture (IECSA)” project sponsored by E2I. This list was enhanced and expanded upon through Task 2 of the CEIDS DER/ADA Project: “***Studies to Determine the Impact on DER Object Models of Distribution Operation with Significant DER***”.
3. Lists of relevant data elements were derived from many sources, including ***Straw-man Device Object Models for Distributed Resources in Utility Communications Architecture (UCA™)*** EPRI WO 5782-01, Final Report, November 1999, as well as DER vendor device specifications, utility distribution system operations requirements, and previous UCA modeling efforts. These data elements were then categorized according to their purpose and type.
4. The information requirements outlined in Table 2-2 were used as a guide for the modules needed and the types of information needed from each module.
5. A block diagram of DER functions in a generic installation was developed. The components common to all DER devices were identified, along with those which are unique to different DER technologies.
6. A set of UCA “Logical Nodes” or modules was developed, reflecting the DER functions in the block diagram.
    a. Almost all Logical Nodes are common to all DER installations, e.g. Generation, Protective Relaying, Measurements, Metering, Circuit Breakers, and Automatic Transfer Switch, although not all would be needed in every installation. For instance, the converter/inverter Logical Node is not needed for diesel generators, and not all installations require Automatic Transfer Switches.

b. One function is interchangeable, depending upon the DER technology; the Prime Mover or Storage Device function is modeled as multiple Logical Nodes, reflecting the different technologies. Examples of these Logical Nodes are:

- Diesel-Generator (DIES)
- Fuel Cell (DFCL)
- Photovoltaics Systems (DRPV)
- Microturbine (DRMT)
- Combustion Turbine Generator (DCTG)
- Wind Turbine (DWTB)
- Flywheel (DRFW)
- Micro-flywheel (DRFW)
- Battery (DBAT)
- Super magnetic energy storage (DSMS)
- Electronic power converters (DEPC)

7. Each Logical Node was expanded to show the objects within it, using the lists of the data elements derived earlier to ensure all data exchanges were covered.

   a. Some Logical Nodes, covering previously established object models (e.g., the protective relaying Logical Nodes), are used "as is" from the existing set of Logical Nodes described in the IEC61850-7-2, 7-3, and 7-4 standards.

   b. Other Logical Nodes were developed to meet the unique DER requirements. For these Logical Nodes, existing objects were used as much as possible: these existing objects are shown in regular typeface in the Logical Node definitions. New objects were developed only when no existing objects could meet the DER requirements.

8. The Common Data Classes (CDCs) were defined for each new object.

   a. Most new objects used existing CDCs (as defined in IEC 61850-7-3 document).

   b. A few DER objects required new CDCs or extensions to existing CDCs. These new CDCs were therefore developed to reflect the DER requirements.

4.2 Logical Nodes Involved in a DER Installation – LN Group: D

The following Figure 4-1 defines the Logical Nodes for DER devices. The shaded LNs are specific to DER; the unshaded LNs are specified in IEC61850. The relationship between logical nodes and DER systems is illustrated in Figure 4-2: LNs in a Generic Distributed Energy Resources (DER) System.

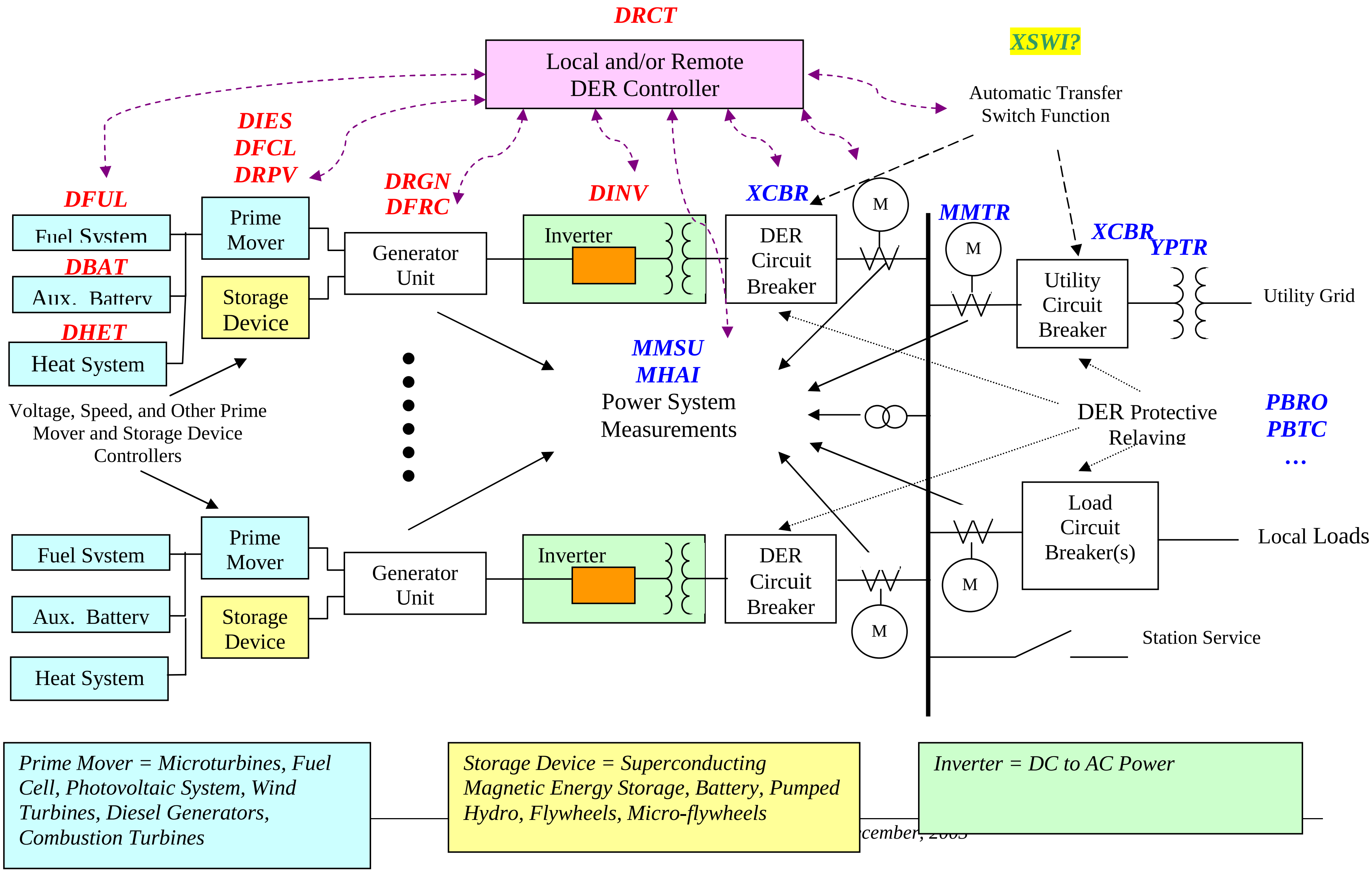
Figure 4-1: Distributed Energy Resources (DER) Logical Nodes

Logical Node	Description
	DER Device Characteristics
DRCT	*DER Controller*
DRGN{n}	*DER Generator Characteristics and Control (units 0 – n)*
DFRC{n}	*DER Frequency Control: DFRC0-n = Generator Unit*
{Multiple LNs} Prime Mover or Storage	*DER Prime Mover or Storage Device Characteristics and Control (e.g. DIES, DFCL). This LN varies, depending upon the DER technology*
DINV{n}	*DER Inverter Characteristics: DINV0-n = Inverter Unit. This LN varies, depending upon the need for an inverter*
DFUL	*Fuel Systems for DER*
DBAT	*Battery Systems for DER*
DHET	*Heating Systems combined with DER (e.g. CHP)*

Logical Node	Description
	Electrical Power System Measurements
MMSU{n}	DER voltage, current, frequency, & var measurements: e.g. MMSU0 = DER Alternator; MMSU1 = local power; MMSU2 = utility power. This LN is similar to MMXU, but contains additional attributes related to statistics
MMXU{n}	DER voltage, current, frequency, & var measurements without statistical information. Alternative to MMSU. (MMXN if single phase)
MHAI{n}	Power System Harmonics (MHAN if single phase)
MMTR{n}	DER Energy Meters: MMTR0 = Total generation; MMTR1 = Net generation; MMTR2 = Transferred to power system; MMTR{m} = submetering
YPTR{n}	Transformers
	Circuit Breakers
XCBR{n} **CSWI{n}**	DER Circuit Breakers: XCBR0 = Load Breaker; XCBR1 = Common Coupling Breaker; XCBR2 = Interface Point Breaker; XCBR3-n = DER Generator Unit Breakers
	Protection Function
PBRO{n}	DER Protective Relaying base logical node: for PUVR, POVR, PTOC, PDPR, PFRQ
PBTC{n}	DER Protective Relaying timing logical node: for PUVR, POVR, PTOC
RREC{n}	Reclosing relay for circuit breakers
PRCF{n}	*DER Rate of Change of Frequency Relaying*
Pxxx {n}	*Other protection functions (TBD)*

Logical Node	Description
	Automatic Transfer Switch
ATSC{n}	DER Automatic Transfer Switch Characteristics (TBD)
SWIT{n}	DER Automatic Transfer Switch (ATS) status
SDRV{n}	DER ATS Control
AUTO{n}	DER ATS Automatic Control Logic
FIND{n}	DER ATS Fault Indicator
	Administrative Function
DMIB{n}	SNMP Management Information Base for DER Installations

Figure 4-2: LNs in a Generic Distributed Energy Resources (DER) System – Red LNs are new for DER; Blue LNs already exist



4.3 Logical Nodes for DER Device Electrical Interconnection Characteristics

In the following tables, the Logical Nodes for each new component of DER devices is defined. For each LN implemented by a vendor, all Mandatory items must be included (those indicated as an M in the M/O column).

4.3.1 LN: DER Controller Name: DRCT

The DER Controller Logical Node defines the characteristics of the environment of one DER device, and its connection into the local and (optionally) the utility Electric Power System (EPS).

Table 4-1: DER Controller LN (DRCT)

		DRCT Class		
Attribute Name	**CDC**	**Explanation**	**SI Units and Meanings**	**M/O**
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	Mod, Beh, Health, NamPlt)	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Controller Nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DERType	INS	Type of DER device	List of DER Types	M
DEROwn	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
CktID	ING	Circuit Id		O
CktPhs	ING	Circuit phases	3 phase or single phase: A, B, C, Delta, Wye, Wye-grounded, Other	O
EPSConn	ING	Interconnection with Area EPS	Local EPS only or interconnected with Utility EPS, thru transformer, thru universal transformer	O
Status Information				
EPSConn	SPS	DER is connected to Utility EPS, or to Local EPS	Standalone; Utility EPS connected	M
GenConn	SPS	DER is connected to or disconnected from load	Disconnected; Connected	M
LocEPSSw	SPS	Status of disconnect switch for starting device in Local EPS only	Contact open; Contact closed	O
AutoMan	SPS	Automatic or Manual mode	Automatic; Manual	M

		DRCT Class		
Attribute Name	**CDC**	**Explanation**	**SI Units and Meanings**	**M/O**
GenMode	INS	Operational or in test/off-line mode,	1 = in test 2 = off-line 3 = available	O
GenReady	SPS	Generator is ready to be connected to load	Not ready; Ready;	O
LoadMode	SPS	Base load or load following	Possible modes: Base load; Load following; Available energy, Fixed export	O
DCPowStat	SPS	DC Power Status	Power not on; Power on	O
Measured Values				
ContTime	TMS	Controller on time	Value = hours on	O
Controls				
AutoManCtl	SPC	Sets operations mode to automatic or manual	Automatic; Manual	O
GenMode	SPC	Sets generator into test mode or operational mode	Test; Operational	O
GenConn	DPC	Connects generator to load, or disconnects generator from load	Disconnect; Connect	M
LoadMode	SPC	Sets generator mode as base load or as load following	Base load; Load following	O
GenSync	SPC	Starts synchronizing generator to EPS	True = start synchronization process	O
EmgStop	DPC	Remote emergency stop	Stop	O
FaultAck	SPC	Acknowledge fault clearing	True = Reset	O
EPSConn	DPC	Connects generator to the EPS, or disconnects generator from the EPS	Disconnect; Connect	O
Control Settings				
DerateTar	ASG	Derated load target %		O
LdGovW	ASG	Load kW target		O
LdGovVar	ASG	Load kVar target		O
LdGovVarMx	ASG	Max load kVar		O
RampLd	ASG	Ramp Load or Unload rate		O
LdShutDown	ASG	Load Shut Down: Stop/Don't Stop		O
LdShareRamp	ASG	Load Share/Don't share		O
AltAppkW	ASG	% load kW		O
ImExLev	ASG	The setpoint for maintaining constant import/export to EPS	kW value at the EPS connection	O
PowerFact	ASG	The setpoint for maintaining fixed power factor	Power factor value	O
FreqLvl	ASG	The setpoint for maintaining fixed frequency	Frequency value {offset?}	O

		DRCT Class		
Attribute Name	**CDC**	**Explanation**	**SI Units and Meanings**	**M/O**
VoltLvl	ASG	The voltage setpoint for maintaining fixed voltage level	Voltage value {% offset?}	O
StartCnt	ASG	Time before starting	Seconds	O
StopDly	ASG	Time delay before stopping	Seconds	O

4.3.2 LN: DER Generator Name: DRGN

The following Logical Node defines the DER generator characteristics. Each DER unit has a generator. Although each type of DER provides different prime movers for its generator, thus requiring different prime mover logical nodes, the general operational characteristics of these generators are the same across all DER types. Therefore, only one UCA DER generator model is required.

Table 4-2: DER Generator LN (DRGN)

		DRGN Class		
Attribute Name	**Attr. Type**	**Explanation**	**SI Units and Meanings**	**M/O**
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	Mod, Beh, Health, NamPlt)	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Generator Nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DEROwn	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
ConnectType	INS	Type of connection	3-phase or single phase, Delta, Wye	M
VoltRt	MV	Voltage level rating	Voltage in volts	M
AmpRt	MV	Continuous current rating	Current in amps	M
HzRt	MV	Nominal frequency	Frequency in Hz	M
TempRt	MV	Max temperature rating	Temperature in Centigrade	O
FltCurRt	MV	Max fault current rating	Amps	O
FltDurRt	INS	Max fault duration rating	Seconds	O
VolAmpRt	MV	Max volt-amps rating	Volt-Amps	O
VolAmprRt	MV	Max var rating	VArs	O
PwrFactRt	MV	Power factor rating	Cosθ	O

		DRGN Class		
Attribute Name	**Attr. Type**	**Explanation**	**SI Units and Meanings**	**M/O**
VTPhs	ING	Voltage transformer phases	A, B, C, Delta, Wye in volts	O
CTPhs	ING	Current transformer phases	Amps	O
MaxLodRampRt	INS	Max load ramp rate	Watts per second	O
MaxUnlodRampRt	INS	Max unload ramp rate	Watts per second	O
EmgRampRt	INS	Emergency ramp rate	Watts per second	O
MaxWattOut	MV	Max Watt output	Watts	O
RtdWatt	MV	Rated Watts	Watts	O
MinWattOut	MV	Min Watt output	Watts	O
MaxVarOut	MV	Max VAr output	VArs	O
RotDir	INS	Rotation direction	ABC or CBA	O
GenDisconLvl	INS	Generator disconnect level	Watts	O
GenLodDrpSet	INS	Generator load droop setting	Volts per amp (ohms) or Hz per Watt	O
RaiseLodSetRt	INS	Raise baseload setpoint rate	Watts	O
LowerLodSetRt	INS	Lower baseload setpoint rate	Watts	O
CostRamp	MV	$ for ramping	Cost	O
CostStart	MV	$ for starting generator	Cost	O
CostStop	MV	$ for stopping generator	Cost	O
CostOper	MV	$ for operating	Cost	O
GenPID	PID	Proportional, integral, and derivative gain parameters for automatic voltage regulator (AVR)	Proportional gain Integral gain Derivative gain	O
GenPQV		Real Power-Reactive Power-Voltage dependency curve	Curve parameters	O
Status Information				
GenSt	SPS	Generator is on or is off	Off: On	M
GenOpSt	INS	Generation operational state: starting up, shutting down, ramping, at disconnect level,	1 = Starting up 2 = Shutting down 3 = At disconnect level 4 = kW ramping 5 = kVar ramping	O
GenSync	SPS	Generator is synchronized to EPS, or not	Not synched; Synched	O
GenExcit	SPS	Excitation state	Excitation off; Excitation on	
ParlSt	SPS	Paralleling status	Standby; Paralleling	O
GenAlarm	ALM	Generation alarms: high/low voltage, high/low current, high/low frequency, emergency trip, etc.	1 = High voltage alarm 2 = Low voltage alarm 3 = High current alarm 4 = Low current alarm 5 = High frequency alarm 6 = Low frequency alarm 7 = Emergency trip alarm	M
VoltDroop	SPS	Voltage droop status	Droop not enabled; Droop enabled	O

		DRGN Class		
Attribute Name	**Attr. Type**	**Explanation**	**SI Units and Meanings**	**M/O**
RampLdSw	SPS	Ramp Load/Unload Switch	Unload; Load	
DCPowStat	SPS	DC Power Status	Power not on; Power on	O
OperTim	INS	Total time generator has operated	Accumulated time in seconds since the last time the counter was reset	O
GenOnCnt	INS	The number of times that the generator has been turned on	Count of "generator on" times, since the last time the counter was reset	O
Measured Values				
TotkWh	MV	Total kWh delivered	Value = kWh	O
PerkWh	MV	kWh in period since last reset	Value = kWh	
TotStarts	CTE	Count of total number of starts	Value = counts	O
PerStarts	CTE	Count of starts since reset	Value = counts	O
GenOprTim	MV	Time in msec as the generator becomes ready after the GenOnOff command was issued	Value = Elapsed milliseconds max = maximum time before issuing a start-failure alarm	O
GenStbTmr	MV	Timer for stabilization time	Value = Elapsed milliseconds max = maximum time before issuing a stabilization-failure alarm	O
GenCoolDn	MV	Timer for generator to cool down	Value = Elapsed milliseconds min = minimum time for cool down	O
AVR	MV	% Duty Cycle	Value = % duty cycle of ???	O
Controls				
GenCtl	DPC	Starts or stops the generator	Stop; Start	M
GenRL	DPC	Raises or lowers the generation level by steps	Raise; Lower pulses	O

4.3.3 LN: DER Frequency Control Name: DFRC

The DFRC logical node compares various voltages to ascertain whether or not they are synchronized with each other. When a synchronous condition exists between the compared voltages, closing of the generator breaker is permitted.

Table 4-3: DER Frequency control LN (DFRC)

Attribute Name	**Attr. Type**	**Explanation**	**SI Units and Meanings**	**M/O**
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Frequency control Nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DEROwn	DOO	Owner and operator of device	See Section 5.1.1	
DERLoc	GPS	GPS location of device		
Measured Values				
GenHz	MV	Frequency at generator	Value = frequency at generator	O
EPSHz	MV	Frequency on utility or local EPS	Value = frequency at EPS	O
GenV	MV	Generator voltage		O
RunV	MV	The reference utility voltage for synchronism check logic	Value = Voltage on utility grid	O
InV	MV	V compared with RunV by the sync check logic	Value = Voltage at the generator	O
AngDiff	MV	Difference in phase angle between the RunV and the InV	Value = difference in phase Max = Maximum difference in phase between utility and generator phases	O
SyncV	MV	Difference in voltage magnitude between RunV and InV	Value = difference in voltage Max = Maximum difference in voltage between utility and generator voltage levels	O
SyncHz	MV	Difference in frequency between RunV and InV	Value = difference in frequency Max = Maximum difference in frequency between utility and generator frequency levels	O
GnSynDur	MV	*Time interval that the sync process is in progress.*	*Value = time of sync process* *Max = Maximum time before alarm*	O
Status Information				
SyncSt	INS	Status of the synchronization logic.	TBD	O
SynchEna	SPS	Synchronization enabled	*Synch not enabled; Synch enabled*	O
Controls				
StartSynch	DPC	Start synchronization	Start synchronization process	M
EnaHzSync	SPC	Enable slip frequency synchronization	Enable; Disable	O
EnaDdBus	SPC	Enable generator breaker to close on dead bus	Enable; Disable	O
Control Settings				
SetFreqLvl	ASG	The setpoint for maintaining fixed frequency	*Frequency value {offset?}*	O
SetVoltLvl	ASG	The voltage setpoint for maintaining fixed voltage level	*Voltage value {% offset?}*	O

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Configuration Settings				
SyncTol		Tolerances for synchronization	%	O
FreqCInertia	ASG	Torque	Radians/second^2-newton-meter	O
FreqCLimHi	ASG	Hard high frequency control limit	Hz	O
FreqCLimLo	ASG	Hard low frequency control limit	Hz	O
FreqCAlmHi	ASG	Hard high frequency alarm limit	Hz	O
FreqCAlmLo	ASG	Hard low frequency alarm limit	Hz	O
FreqCShutdownHi	ASG	Hard high frequency shutdown limit	Hz	O
FreqCShutdownLo	ASG	Hard low frequency shutdown limit	Hz	O
FreqCPID	PID	Configuration parameters for proportion-integral-derivative algorithms for frequency control	proportion-integral-derivative	O

4.3.4 LN: DER Inverter Name: DINV

DINV defines the characteristics of the inverter, which converts generator output dc power to ac power. The different prime mover LNs and the MMSU LN handle the actual measurements of inverter inputs and outputs.

Table 4-4: DER Converter/Inverter LN (DINV)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Converter/Inverter Nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DEROwn	DOO	Owner and operator of device	See Section 5.1.1	
DERLoc	GPS	GPS location of device		O
Commute	ING	Type of commutation	Line commutated Self commutated	O

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Isolation	ING	Type of isolation	Low frequency transformer isolat'd Hi frequency transformer isolated Non-isolated, grounded Non-isolated, isolated DC source	O
SwitchFreq	ASG	Switching frequency	Hz	O
SwitchType	ING	Switch type	Field Effect Transformer Insulated Gate Bipolar Transistor Thyristor Gate Turn Off Thyristor Silicon Controlled Rectifier Other ….	O
OperMode	ING	Operating Modes	Grid connect only Stand-alone only Multi-mode	O
GridMode	ING	Grid Connect Modes	Current control (Norton model) Voltage droop control (Thevenin model) Combined	O
Status Information				
Status	SPS	Status of inverter	Off; On	M
HeatSinkTemp	SPS	Heat sink temperature	? Why is temp a status point?	O
EnclTemp	SPS	Enclosure temperature	?	O
AmbAirTemp	SPS	Ambient outside air temperature	?	O
FanSpeed	SPS	Fan speed setting	?	O
MeasFanSpeed	SPS	Measured fan speed	Tach or vane ??	O
SmokDetect	SPS	Smoke detector	?	O
StatOperMode	SPS	Actual operating mode	Grid export Stand-alone/ island Off	O
Measured Values				
InpAmp	MV	Input current	Amps, DC	M
InpV	MV	Input voltage	V	O
OutAmp	WYE	Output current (rms)	Amps	M
OutV	WYE	Output voltage (rms)	Volt	O
OutFreq	MV	Output frequency	Hz	O
OutW	MV	Output power	Watts	O
OutPF	MV	Output power factor	$\cos\theta$	O
OutVar	MV	Output reactive power	Vars (*need sign convention*)	O
Control Settings				
SetOperMode	ASG	Set operating mode	Off Export Stand-alone Bypass	M

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
OutWLvl	ASG	Output power setpoint	W	O
OutVArLvl	ASG	Output reactive power setpoint	VAr	O
PFLvl	ASG	Power factor setpoint	Cosθ	O
FreqLvl	ASG	Frequency setpoint	Hz	O
AmpLimit	ASG	Input current limit	Amps	O
VLimit	ASG	Input voltage limit	V	O

4.4 Logical Nodes for Prime Movers

4.4.1 LN: Diesel Engine Name: DIES

The diesel engine characteristics covered in the DIES logical node reflect those required for remote monitoring of critical diesel engine functions and states. The DIES LN attributes contain strictly non-electrical objects, even though typically a diesel genset consists of a combined diesel engine and generator.

Table 4-5: DER Diesel Engine LN (DIES)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Diesel engine nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DiesOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
DiesFuel	ING	Type of fuel		O
DiesAvgCalFuel	ASG	Average calorie content of fuel		O
DiesMaxTurPres	ASG	Max turb pressure		O
DiesMaxInletTemp	ASG	Max inlet temperature		O
Dies MaxOutTemp	ASG	Max outlet temperature		O
DiesMinSpeed	ASG	Min speed		O
DiesMaxSpeed	ASG	Max speed		O
DiesHeatRtCurves	CSD	Heat rate curves	From IEC61850-7-3 Clause 7.9.4	O

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
DiesFuel	ING	Type of fuel used by diesel engine		O
Status Information				
DiesOnOff	SPS	Diesel is on or is off	Off; On	M
DiesMode	INS	Operational or in test/off-line mode,	1 = in test 2 = off-line 3 = available	O
SpdDroop	SPS	Speed droop status	Disabled; enabled	O
OilPresSt	SPS	Oil pressure status	Normal; Abnormal	O
CoolPresSt	SPS	Coolant pressure status	Normal; Abnormal	O
CustSw1	SPS	Status of customer switch 1	Off; On	
CustSw2	SPS	Status of customer switch 2	Off; On	
DiesAlm	ALM	Diesel engine alarms	TBD	O
Measured Values				
OilPres	MV	Oil pressure	Pressure, in Pascals	O
DiesTemp	MV	Engine temperature	Temperature in degrees K	O
DiesRPM	ANV	Diesel engine speed	Speed in revolutions per minute	O
GenFrq	MV	Diesel engine gen frequency	Hz	O
EngTrq	MV	Engine torque	Metric equivalent to ft-lbs	O
EngTim	MV	Engine timing	Degrees BTDC?	O
EngFuel	MV	Engine fuelling ??Set or MV?	Mm3s ???	O
AirPres	MV	Air pressure	Metric equivalent to InHg	O
CoolPres	MV	Coolant pressure	Metric equivalent to psi	O
CoolTemp	MV	Coolant temperature	Deg C	O
ManiPres	MV	Intake manifold pressure	Metric equivalent to psi	O
ManiTemp	MV	Intake manifold temperature	Deg C	O
WaterTemp	MV	Aftercooler water temperature	Deg C	O
BlowFlow	MV	Blowby flow	CFM ??	O
BatVolt	MV	Battery voltage	volts	O
FuelPres	MV	Fuel Rail pressure	Metric equivalent to psi	O
TimPres	MV	Timing Rail pressue	Metric equivalent to psi	O
FuelTemp	MV	Fuel temperature	Deg C	O
FuelAmp	MV	Fuel Rail actuator current	amps	O
TimAmp1	MV	Timing rail actuator current	amps	O
TimAmp2	MV	Timing rail actuator current	amps	O
PumpAmp	MV	Fuel pump actuator current	amps	O
BatVolt	MV	Battery charger alt flash volts	volts	O
TotCumFuel	MV	Cumulative fuel consumption	Fuel in liters	O
CumFuel	MV	Cumulative fuel since reset	Fuel in liters	O
EngRunTim	TMS	Engine running time	Hours	O
FuelRate	MV	Fuel usage rate	Fuel usage rate liters/hr	

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
FuelCal	MV	Calorie content of fuel	Calorie content of fuel	O
FuelLvl1	MV	Fuel level in tank #1	Fuel level in one tank	O
FuelLvl2	MV	Fuel level in tank #2	Fuel level in second tank	O
Controls				
DiesCtl	DPC	Start / stop diesel engine	Stop; Start	M
Crank	DPC	Crank relay driver command	Off; On	O
FuelShut	DPC	Fuel shutoff valve driver command	False; True	
Emerg Ctl	DPC	Emergency start / stop diesel engine	Stop; Start	O
DiagEna	DPC	Diagnostic mode enable	Fault flashout	O
Control Setpoints				
TrgSpd	SPV	Final target engine speed	rpm	O
DiesFreq	APC	Diesel generator frequency	Hz	O
EngTrqSet	APC	Desired engine torque	Metric equivalent to ft-lbs	O
DrpAdj	APC	Droop adjustment	%	O

4.4.2 LN: Fuel Cell Name: DFCL

The fuel cell characteristics covered in the DFCL logical node reflect those required for remote monitoring of critical functions and states of the fuel cell itself. The electrical measurements of the power system it is connected to uses the MMXU LN.

Table 4-6: DER Fuel Cell LN (DFCL)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Fuel cell nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DfclOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
DfclWGrInRt	ASG	Fuel cell Watt grid-independent rating	Watt	O
DfclWGrDeRt	ASG	Fuel cell Watt grid-dependent rating	Watt	O
DfclVARt	ASG	Fuel cell Volt-Amp rating	VA	O
DfclVoltRt	ASG	Fuel cell voltage rating	Volt	O

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
DfclHzRt	ASG	Fuel cell frequency rating	Hz	O
DfclPhRt	ING	Fuel cell phase rating	Single phase or 3 phase	O
DfclFuelType	ING	Fuel cell type of fuel		O
DfclFuelConsump	ASG	Fuel cell fuel consumption rating	Cubic meters per second	O
DfclEffic	ASG	Fuel cell efficiency	Percent	O
Status Information				
DflcOnOff	SPS	Fuel cell is on or is off	Off; On	M
DflcMode	INS	Operational or in test/off-line mode,	1 = in test; 2 = off-line 3 = available	M
WaterSol	INS	State of water makeup solenoid	Units?	O
NitPurg	INS	State of nitrogen purges	Units?	O
DflcAlm	ALM	Fuel cell alarms	TBD	O
NumCellVTrips	INS	Number of cell low voltage trips	Count	O
NumSysRestart	INS	Number of system restarts	Count	O
NumReconnect	INS	Number of grid reconnections	Count	O
Measured Values				
DCVolt	MV	DC volts at stack	DC volts	M
DCAmp	MV	Fuel cell DC amps	Amp	M
CoolTemp	MV	Coolant temperature	Temperature	M
HydrPres	MV	Hydrogen pressure	Pressure	O
HydrFlowRate	MV	Hydrogen (or reformate) flow rate	Rate	O
AirFlowRate	MV	Air or oxygen flow rate	Rate	O
FuelFlowRate	MV	Fuel (non-hydrogen) flow rate	Rate	O
WaterLvl	MV	Water level	Linear measure	O
ReformTemp	MV	Reformer temperature	Temperature	O
HydroAvail	MV	Hydrogen available	Linear measure	O
FuelCellLdTim	MV	Accumulated fuel cell load time	Seconds	O
MaintTim	MV	Time until next maintenance	Seconds	O
WaterConduct	MV	Water conductivity	Units?	O
StackRunHrs	MV	Daily stack run hours	Seconds	O
SysRunHrs	MV	Daily system run hours	Seconds	O
LifeSysRunHrs	MV	Lifetime system run hours	Seconds	O
TotStackRunHrs	MV	Total stack run hours	Seconds	O
CumkWHrs	MV	Cumulative kWHrs	Seconds	O
Efficiency	MV	Efficiency	Units?	O
FuelConsump	MV	Fuel consumption	Units?	O
Controls				
FuClCtl	DPC	Start / stop fuel cell	Stop; Start	M
FuelShut	DPC	Fuel shutoff valve driver command	False; True	

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Emerg Ctl	DPC	Emergency start / stop fuel cell	Stop; Start	O
Control Setpoints				
SetOperMode	ASG	Set operating mode	Off Export Stand-alone Bypass	M
OutWLvl	ASG	Output power setpoint	W	O
OutVArLvl	ASG	Output reactive power setpoint	VAr	O
PFLvl	ASG	Power factor setpoint	Cosθ	O
FreqLvl	ASG	Frequency setpoint	Hz	O
AmpLimit	ASG	Input current limit	Amps	O
VLimit	ASG	Input voltage limit	V	O

4.4.3 LN: Photovoltaics System Name: DRPV

The photovoltaics system characteristics covered in the DRPV logical node reflect those required for remote monitoring of critical photovoltaic functions and states. *{This LN may be split into three LNs, e.g. LN for Array information, LN for Module information, and LN for PV system} {Work in Progress}*

Table 4-7: DER Photovoltaic Systems LN (DRPV)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Photovoltaics system nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DfclOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
DphvRtg		Ratings of the photovoltaic system	???	O
ArrayArea	ASG	Array area	M^2	O
ArrayWRating	ASG	Array power rating	W (W peak – W p)	O
ArrayAzimuth	AZM	Array azimuth	Degrees from true north, Elevation	O

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
ArrayShading	AZM	Array of obstruction elevations vs azimuth		O
ModMaterial	ING	Module material	Silicon Cadmium Telluride Copper Indium Diselenide	O
ModType	ING	Module type	Single crystal Amorphous Other ….	O
ModConfig	ING	Module configuration	Flat plate Concentrating	O
TrackType	ING	Tracking type	Fixed Single axis Two axes	O
NumMod	ING	Number of modules per series string	Count	O
NumParallel	ING	Number of parallel strings	Count	O
ModWRating	ASG	Module rated power	W peak; W p	O
ModVmax	ASG	Module voltage at max power	V	O
ModAmax	ASG	Module current at max power	Amp	O
ModOpenCir	ASG	Module open circuit voltage	V	O
ModShortCir	ASG	Module short circuit current	Amp	O
ModTempDerate	ASG	Module temperature/power derate	%/DegC above 25C	O
ModFuseRating	ASG	Module series fuse rating	Amp	O
Status Information				
PVOnOff	SPS	PV system is on or is off	Off; On	M
PVMode	INS	Operational or in test/off-line mode,	1 = in test; 2 = off-line; 3 = available	O
PVAlm	ALM	PV alarms	TBD	O
Measured Values				
PVAmp	MV	PV amps input to inverter	Amp	O
PVDCvolt	MV	DC volts at PV input to inverter	DC volts	O
Controls				
PVCtl	DPC	Start / stop PV	Stop; Start	M
Control Setpoints				
				O
				O

4.5 Logical Nodes for Auxiliary DER Components

4.5.1 LN: Fuel Systems Name: DFUL

The fuel system characteristics covered in the DFUL logical node reflect those required for remote monitoring and control of critical fuel system functions and states. These may vary significantly based on the type of DER. *{Work in Progress}*

Table 4-8: Fuel Systems LN (DFUL)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Fuel system nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DfclOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
FuelRtg		Ratings of the fuel system	???	O
Status Information				
FuelOnOff	SPS	Fuel system is on or is off	Off; On	M
FuelAlm	ALM	Fuel system alarms	TBD	O
Measured Values				
FuelLvl	MV	Fuel level	Level	O
FuelPres	MV	Fuel pressure	Pressure	O
FuelRate	MV	Fuel flow rate	Rate	O
FuelEffCoef	MV	Fuel efficiency coefficient	Fuel efficiency coefficient	O
FuelCost	MV	Cost of fuel	$ per unit fuel	O

4.5.2 LN: Battery Systems Name: DBAT

The battery system characteristics covered in the DBAT logical node reflect those required for remote monitoring and control of critical auxiliary battery system functions and states. These may vary significantly based on the type of DER. *{Work in Progress}*

Table 4-9: Battery Systems LN (DBAT)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Battery/UPS nameplate information	Vendor and Device nameplate	M
Configuration Settings				
DfclOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
BattRtg		Ratings of the battery system	???	O
Status Information				
BattOnOff	SPS	Battery system is on or is off	Off; On	M
BattAlm	ALM	Battery system alarms	TBD	O
Measured Values				
BattVolt	MV	Internal battery voltage	Volts	M
BattAmp	MV	Internal battery current	Amps	M
BattTemp	MV	Internal battery temperature	Temperature	O

4.5.3 LN: Environmental Conditions Name: ENVR

The characteristics of the environment of the DER system cover meteorological parameters, emissions, and other key environmental items. In addition, many of the environmental sensors may be located remotely from the instantiated logical node. This logical node may therefore represent a collection of environmental information from many sources. The need for different objects may vary significantly based on the type of DER. *{Work in Progress}*

Table 4-10: Environmental Conditions LN (ENVR)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Configuration Settings				
DfclOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
CarbonTrade	ING	Involved in carbon trading	Yes No	O
CarbCred	ASG	Carbon production credit value	$/W	O
GreenTag	ING	Green tag information	??	O
Status Information				
IntrusionAlm	ALM	Intrusion alarms	??	O
Measured Values				
CO2Emiss	MV	CO2 emissions		O
COEmiss	MV	CO emissions		O
NOxEmiss	MV	NOx emissions		O
SOxEmiss	MV	SOx emissions		O
SoundEmiss	MV	Sound emissions	dBA	O
WindVel	MV	Wind velocity		O
AmbTemp	MV	Ambient temperature		O
Humidity	MV	Humidity		O
CloudCvr	MV	Cloud cover level		O
WaterLvl	MV	Water level	Meters	

4.5.4 LN: Heat Systems Name: DHET

The heat system characteristics covered in the DHET logical node reflect those involved in Combined Heat and Power (CHP) systems. *{Work in Progress}*

Table 4-11: Heat Systems LN (DHET)

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
EEName	DPL	Battery/UPS nameplate information	Vendor and Device nameplate	M
Configuration Settings				
Status Information				
Measured Values				
InWatTemp	MV	Inlet water temperature	Degrees C	O
OutWatTemp	MV	Outlet water temperature	Degrees C	O
WatFlowRate	MV	Water flow rate	Meters per second	O
Controls				
PumpOnOff	DPC	Start / stop pumps	Stop; Start	M

4.6 References to IEC61850-7-4 Logical Nodes

4.6.1 Electrical Power System Measurements

1. MMXU – 3-Phase Electrical Measurements: See IEC61850-7-4, section 5.10.7.
2. MMXN – Single Phase Electrical Measurements: See IEC61850-7-4, section 5.10.6.
3. MHAI – 3-Phase Harmonics: See IEC61850-7-4, section 5.10.3.
4. MHAN – Single Phase Harmonics: See IEC61850-7-4, section 5.10.4.
5. MMTR – 3-Phase Metering: See IEC61850-7-4, section 5.10.5.
6. MMXN – Single Phase Metering: See IEC61850-7-4, section 5.10.6.
7. MSTA – Metering Statistics: See IEC61850-7-4, section 5.10.9.

4.6.2 Protective Relaying

See the protection LNs defined in IEC61850-5 and IEC61850-7-4, Sections 5.4 and 5.5.

4.6.3 Switchgear

1. **XCBR – Circuit Breaker**: See IEC61850-7-4, section 5.12.1.
2. **XSWI – Circuit Switch**: See IEC61850-7-4, section 5.12.1.
3. RREC

4. RBRF
5. RSYN
6. CILO
7. CPOW
8. CSWI
9. SIMG

4.7 References to IEC61400-25 Logical Nodes

1. MMSU – 3-Phase Electrical Measurements with Statistics: Under development in IEC61400-25.

5. DER COMMON DATA CLASSES (CDC)

5.1 Proposed New CDCs

The following are additional Common Data Classes, which are required for DER device models.

5.1.1 Device Ownership and Operator (DOO)

Clause 7.9.2 of IEC61850-7-3 defines the device name plate information, including the vendor, the device, and its location. However, for DER devices, the ownership of the device is also important, along with the entity(ies) responsible for operations. This CDC could be used for general information as well as part of access management.

DOO Class				
Attribute Name	**Attribute Type**	**FC**	**Value/Value Range**	**M/O/C**
DataName				
DataAttribute				
Description				
Owner	Visible String 255	DC	Owner of device	M
OwnerSite	Visible String 255	DC	Site where device is located	O
EPSName	Visible String 255	DC	Name of Electric Power System device is connected to	O
Role	Visible String 255	DC	Role of device	O
PrimeOperator	Visible String 255	DC	Primary operator of device	O
SecondOperator	Visible String 255	DC	Secondary operator of device	O

5.1.2 Geographical Positioning System (GPS)

The *GPS* class defines the location of the physical device as defined by GPS equipment.

GPS Class				
Attribute Name	**Attribute Type**	**FC**	**Value/Value Range**	**M/O/C**
DataName				

DataAttribute				
Description				
Latitude	FLOAT32			
Longitude	FLOAT32			
Altitude	FLOAT32			
GPS Time	BTIME6			

5.1.3 Proportional-Integral-Derivative Configuration (PID)

The *Proportional-Integral-Derivative Configuration* class defines the PID response parameters for control actions.

PID Class				
Attribute Name	**Attribute Type**	**FC**	**Value/Value Range**	**M/O/ C**
DataName				
DataAttribute				
Description				
Bias	FLOAT32			
ClampLowr	FLOAT32			
ClampUppr	FLOAT32			
dbLower	FLOAT32			
dbUpper	FLOAT32			
DerivAct	FLOAT32			
ErrorTerm	FLOAT32			
Kgain	FLOAT32			
Krate	FLOAT32			
Ktime	FLOAT32			
MaxRate	FLOAT32			
PIDAlg	ENUM8			
PolarFrwd	BOOL			
Override	BOOL			
smpRate	INT16U			

5.2 References to IEC61850-7-3 CDCs

1. Single point status (SPS)
2. Double point status (DPS)
3. Integer status (INS)
4. Measured value (MV)
5. Complex measured value (CMV)

6. Wye-connected phase measurements (WYE)
7. Controllable single point (SPC)
8. Controllable double point (DPC)
9. Controllable integer status (INC)
10. Integer status setting (ING)
11. Analog setting (ASG)

5.3 References to 61400-25 (Wind Turbines) CDCs

1. Alarm list (ALM)

6. TERMS AND REFERENCES

6.1 Terms and definitions

For the purpose of this document, the following definitions apply.

3.1
actor
Term used in the Unified Modeling Language (UML) to designate the role a human, application, or system plays in the function being modeled.

3.2
alarm
Change of state information that is important enough to warrant notifying a person or system.

3.3
characteristic values
Statistical information based on monitored values, such as min, max, avg, dev, etc.

3.4
command
Controllable point used to change system behaviour (enable/disable).

3.5
communication function
Used by an actor to configure, perform and monitor the information exchange with functions, e.g. operational and management function.

3.6
conditional
Information shall be provided by an implementation of this standard if a certain condition corresponding with the information is true.

3.7
control
Operational function used for changing and modifying, intervening, switching, controlling, setting parameters, and optimizing of generation

3.8
counting value
Statistical information on the total number of occurrences of a specific event

3.9
data retrieval
Operational function used for monitoring, archiving, and exporting data.

3.10
diagnostics
Management function used to set up and provide for self-monitoring of components.

3.11
electrical system
Component of a DER system responsible for transporting electrical energy from its source generation to the load

3.12
event
State information indicating the occurrence of an event, such as a change in status, an alarm indication, or a command execution

3.13
function
A function is a task, usually automated but with possible actions by human users, that is performed in the control center or DER system

3.14
IED
Intelligent Electronic Device - An IED may have connections as a client, or as a server, or both, with other IED. An IED is, therefore, any device incorporating one or

more processors, with the capability to receive data from an external sender or to send data to an external receiver.

3.15
information
Content of communication. The material basis are raw data, which must be processed into relevant information. DER device information categories: source information (analogue and state information), derived information (statistical and historical information).

3.16
information exchange
Communication process between two systems, such as component and actor, with the goal to provide and to get relevant information. Requires specific communication functions (services).

3.1
information
Information is defined as data and meta-data describing the data.

3.17
log
Historical information of a DER device. Chronological list of source information for a period of time.

3.18
logging and reporting
Operational function used for analyzing, reporting and evaluating DER devices

3.19
management function
Required for the higher-level management of the information exchange. Used by certain actors to define general rules for the monitoring and control of DER devices and to monitor their compliance. Types are, e.g., user/access management, time synchronization, diagnostics, setup.

3.20
mandatory
Information shall be provided by an implementation of this standard.

3.21
measured value
DER device analogue information. Sampled value of a process quantity.

3.22
meteorological system
Component of a DER device responsible for the measuring of the wind conditions, e.g. the wind speed. It is installed at a reference location and supplies the data required to correlate the produced power output of individual wind turbines to the useable wind potential.

3.23
monitoring
Operational function used for local or remote observing of the status and changes of states (indications) for DER devices.

3.24
operational function
Used by actors for the normal daily operation of DER devices to obtain information on DER devices and to send instructions to it. Types: monitoring, logging and reporting, data retrieval, control.

3.25
optional
Information may be provided by an implementation of this standard.

3.26
parameter
DER device analogue information. Controllable value for system behavior (adjustment).

3.27
performance curves
DER device historical information. Log containing analogue information for XY graphing (PV-curve) for a long period of time.

3.28
polled data transfer
Data transfer initiated by a (client) application, e.g., a control center.

3.29
processed value
DER device analogue information. Measured value, which has been, processed (10m-average/…).

3.30
report
DER device historical information. Event-driven or periodical notification of information comprising also statistical information and total performance.

NOTE The term report (reporting) is also used for the communication service to send spontaneous data from a server to a client.

3.31
signal
In monitoring direction: a set comprising a process value (e.g., status), a time stamp, and quality information.

In control direction: a set comprising a process value (e.g., open), a time stamp, and additional information.

NOTEThe engineering unit of a measured value is not a signal in this sense.

3.32
status
DER device state information. Condition of a component or system (st1/st2/..stn).

3.33
setpoint
DER device analogue information. Controllable target (demanded) value for a process quantity.

3.34
setup
Management function used for configuration of DER device components.

3.35
spontaneous data transfer
Unsolicited data transfer (called a "communication" report) initiated by a server application process upon events or change of data.

3.36
timing value
DER device statistical information. Total time duration of a specific state.

3.37
three phase value
DER device analogue information. Measured value of a three phase electric power quantity.

3.38
transient log
DER device historical information. Event triggered chronological list of high resolution source information for a short period of time (event driven report).

3.39
user / access management
Management function used for setting up, modifying, deleting users (administratively), assigning access rights (administratively) and monitoring access.

3.40
DER device
Complete system consisting of any number of technical subsystems referred to in this standard as DER device components. The main task of DER devices is to generate electrical energy and to provide it for consumption. Operation concepts: individual and integrated operation.

3.41
DER device analogue information
Continuous information concerning the actual condition or behaviour of a component or system. Types are, e.g., measured value, processed value, three phase value, setpoint, parameter.

3.42
DER device component
Technical system employed in the operation of DER devices, such as wind turbine, meteorological, electrical and wind farm management system.

3.43
DER device historical information
Derived information. Previous information. Types: log, transient log, report, performance curves.

3.44
DER device management system
Component of a DER device responsible to ensure that the complete system adapts itself to the static and dynamic conditions and requirements of the electrical power connection (substation, utility network).

3.45
DER device state information
Source information. Discrete information concerning the actual condition or behaviour of a component or system. Types are, e.g., status, alarm, command, event.

3.46
DER device statistical information
Derived information. Cumulative information for a period of time. Types are, e.g., timing value, counting value, characteristic values.

3.47
wind turbine
Main component of a wind power DER device. It is responsible for generating energy and meets the task of using the wind potential of a certain location that converts kinetic wind energy into electric energy.

6.2 General Abbreviated Terms

ACSI	Abstract Communication Service Interface (defined e.g. in 61850-7-2)
ADA	Advanced Distribution Automation
ASN.1	Abstract Syntax Notation One
CDC	Common Data Class
CHP	Combined Heating and Power
CIM	Common Information Model (IEC61970)
DER	Distributed Energy Resources, including generation and storage
DisCo	Distribution utility company
EPS	Electric Power System
IEC	International Electrotechnical Commission
IEEE	International Electrical and Electronic Engineers
IOA	Information Object Address
ISO	Independent System Operator
LD	Logical Device
LN	Logical Node
MMS	Manufacturing Message Specification
O&M	Operations and Maintenance
SCADA	Supervisory Control and Data Acquisition
SCL	Substation (System) Configuration Language (defined in IEC 61850-6)
SCSM	Specific Communication Service Mapping (defined for MMS in 61850-8-1)
SNMP	Simple Network Management Protocol
SOAP	Simple Object Access Protocol
UCA	Utility Communications Architecture
XML	Extended Markup Language

6.3 Data Classes Abbreviated Terms

Abbreviated terms used to build names of Data Classes found in LNs shall be as listed in Table 6-1: Data Classes Abbreviated Terms

EXAMPLE RotPos is constructed by using two names "Rot" which stands for Rotor and "Pos" which stands for "Position". Thus the concatenated name represents a "Rotor Position".

Table 6-1: Data Classes Abbreviated Terms

Term	Description
Ack	Acknowledge
Acs	Access
Act	Actual
Al	Alarm
An	Analogue
Ang	Angle
At	Active (real)
Atv	Activate
Avg	Average
Avl	Availability
Bec	Beacon
Bl	Blade
Blk	Blocked
Brg	Bearing
Brk	Brake
Cab	Cable
Ccw	Counter clockwise
CDC	Common Data Class
Ch	Characteristic
Chg	Change
Chk	Check
Chrg	Charge
Cl	Cooling
Cm	Command
Cnv	Converter
Ct	Counting
Ctl	Control
Cur	Current
Cw	Clockwise
D	Description
Dat	Data
Db	Deadband
Dcl	Dc-link
Dec	Decrease
Det	Detection
Dir	Direction
Dly	Daily

Term	Description
Dmd	Demand
Drv	Drive
Dwn	Down
Egy	Energy
Elev	Elevator
Emg	Emergency
Ent	Entrance
Ety	Empty
Evt	Event
Exc	Excitation
Flsh	Flash
Flt	Fault
Frq	Frequency
Ftr	Filter
Gbx	Gearbox
Gd	Grid
Gn	Generator
Gs	Grease
Hi	High
Hly	Hourly
Ht	Heating
Hum	Humidity
Hy	Hydraulic
Id	Identifier
Idl	Idling
Inc	Increase
Inj	Injection
Inst	Instantaneous
Lev	Level
Lg	Log
Lim	Limit
Lo	Low
Lum	Luminosity
Man	Manual
Max	Maximum
Met	Meteorological
Min	Minimum

Term	Description
Mly	Monthly
Mod	Mode
Ms	Measurement
Mul	Multiplier
N	Number (size)
Nac	Nacelle
Op	Operation
Ov	Over
Per	Period
Ph	Phase
Pmp	Pump
Pol	Pollution
Pos	Position
Pres	Pressure
Prod	Production
Pt	Pitch
Ptr	Pointer
Pwf	Power factor
Pwr	Power
q	Quality
Rdy	Ready
Rep	Report
Rms	Root-mean-square
Rng	Range
Rot	Rotor (windturbine)
Rs	Reset
Rt	Reactive
Rtr	Rotor (generator)
Sdv	Standard deviation
Seq	Sequence
Shf	Shaft
Smk	Smoke
Smp	Sampled
Sp	Setpoint
Spd	Speed
St	Status
Sta	Stator

Term	Description
Stdby	Standby
Stp	Stop
Str	Start
Stt	State
Sw	Switch
t	Timestamp
Tm	Timer
Tmp	Temperature
Tot	Total
Tow	Tower
Tr	Transient
Trf	Transformer
Trg	Trigger
Trq	Torque
Tur	Turbine
Un	Under
Urg	Urgent
Val	Value
Vals	Values
Vib	Vibration
Vis	Visibility
Vtg	Voltage
W	Wind (power)
Wup	Windup
Xdir	X-direction
Ydir	Y-direction
Yly	Yearly
Yw	Yaw

6.4 References to IEC61400-25 CDCs

The following CDCs are similar to some IEC61850 CDCs, but include additional statistical information and/or other specializations

1. Characteristics and historical information (CHA)
2. Analogue value (AMV)
3. Setpoint value (SPV)
4. Status value (STV)
5. Alarm (ALM)
6. Command (CMD)
7. Event counting (CTE)
8. State timing (TMS)