

Advanced Power System Management Functions and Information Exchanges for Inverter-based DER Devices, Modelled in IEC 61850-90-7

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These advanced functions for inverter-based distributed energy resources (DER) were originally developed through an EPRI Project (bseal@epri.com) and submitted to the IEC through the NIST Priority Action Plan (PAP) 7 on Energy Storage and DER (allen.hefner@nist.gov). The information exchange requirements of these functions are currently being mapped to IEC 61850-7-420 object models as the IEC 61850-90-7 Technical Report (fcleve@xanthus-consulting.com).

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Advanced Power System Management Functions for Inverter-based DER Devices

1. Executive Summary of inverter-based DER functions

1.1 Introduction

The numbers of interconnected DER systems are increasing rapidly. The advent of decentralized electric power production is a reality in the majority of power systems all over the world, driven by many factors:

- The need for new sources of energy to mitigate the heavy reliance on externally-produced fossil fuels.
- The requirements in many countries and US states for renewable portfolios that have spurred the movement toward renewable energy sources such as solar and wind, including tax breaks and other incentives for utilities and their customers.
- The development of new technologies of small power production that have made, and are continuing to improve, the cost-effectiveness of small energy devices.
- The trend in deregulation down to the retail level, thus incentivizing energy service providers to combine load management with generation and energy storage management.
- The increased demand for electrical energy, particularly in developing countries, but also in developed countries for new requirements such as Electric Vehicles (EVs).
- The constraints on building new transmission facilities and increasing environmental concerns that make urban-based generation more attractive.

These pressures have greatly increased the demand for Distributed Energy Resources (DER) systems which consist of both generation and energy storage systems that are interconnected with the distribution power systems.

DER systems challenge traditional power system management. These increasing numbers of DER systems are also leading to pockets of high penetrations of these variable and often unmanaged sources of power which impact the stability, reliability, and efficiency of the power grid. No longer can DER systems be viewed only as “negative load” and therefore insignificant in power system planning and operations. Their unplanned locations, their variable sizes and capabilities, and their fluctuating responses to both environmental and power situations make them difficult to manage, particularly as greater efficiency and reliability of the power system is being demanded.

At the same time, DER devices could become very powerful tools in managing the power system for reliability and efficiency. The majority of DER devices use inverters to convert their primary electrical form (often direct current (dc) or non-standard frequency) to the utility power grid standard electrical interconnection requirements of 60Hz (or 50Hz) and alternating current (ac). Not only can inverters provide these basic conversions, but inverters are also very powerful devices that can readily modify many of their electrical characteristics through software settings and commands, so long as they remain within the capabilities of the DER device that they are managing and within the standard requirements for interconnecting the DER to the power system.

DER systems are becoming quite “smart” and can perform autonomously according to pre-established settings. They can “sense” local conditions of voltage levels, frequency deviations, and temperature, and can receive broadcast emergency commands and pricing signals, which

allow them to modify their power and reactive power output. They can also operate according to schedules or in response to direct control commands.

Given these ever more sophisticated capabilities, utilities and energy service providers (ESPs) are increasingly desirous (and even mandated by some regulations) to make use of these capabilities to improve power system reliability and efficiency.

1.2 Inverter configurations and interactions

Inverter-based DER functions range from the simple (turn on/off, limit maximum output) to the quite sophisticated (volt/VAR control, frequency/watt control, and low-voltage ride-through). They also can utilize varying degrees of **autonomous capabilities** to help cope with the sophistication.

To support and enhance this autonomous behaviour that utilizes local conditions like voltage and frequency to make decisions, at least **three levels of information exchanges** are envisioned:

- **Tightly-coupled interactions** focused on direct monitoring and control of the DERs with responses expected in “real-time”.
 - Tightly-coupled commands assume relatively detailed knowledge of the status and capabilities of the DER system.
 - Tightly-coupled interactions would more likely be needed for grid reliability but could also be associated with grid efficiency.
 - Common scenarios for tightly-coupled interactions are controllers that directly manage one or more inverters, such as a home PV system, a building with multiple PV systems, a wind farm, or a solar farm.
 - Additional scenarios include an ISO/RTO managing a large storage device through Automatic Generation Control (AGC) or requesting a specific power factor at the PCC of a wind farm
 - A microgrid scenario would include a microgrid management system tightly managing the formation of the microgrid and controlling the combined generation, storage, and load elements to maintain microgrid stability.
- **Loosely-coupled interactions** which request actions or “modes” that are interpreted by intelligent DER systems for undertaking **autonomous reactions** to local conditions or externally provided information. Information is then sent back on what actions they actually performed.
 - Autonomous behaviour is defined as DER devices utilizing pre-set modes and schedules that respond to locally sensed conditions, such as voltage, frequency, and/or temperature, or to broadcast information, such as pricing signals or requests for using specific modes. These pre-settings are updated as needed (not in real-time), possibly through the Internet or through other communication methods.
 - Loosely-coupled interactions would be more likely associated with grid efficiency than with grid reliability, but could also be used for emergency commands.
 - Common scenarios for loosely-coupled interactions include a campus DER management system coordinating many DER systems on different buildings or an energy service provider managing disparate DER systems within a community.
- **Broadcast/multicast** essentially one-way requests for actions or “modes”, without directly communicated responses by large numbers of DERs.

- These broadcast or multicast requests are interpreted by the DER systems for undertaking **autonomous reactions** to local conditions or externally provided information.
- Broadcast/multicast requests would be more likely associated with grid efficiency than with grid reliability because of the uncertainty of DER responses, but could also be used for emergency commands.
- Broadcast/multicast can be used to request actions without necessarily knowing which DER systems can or will respond, thus setting the expectation that only a certain number will respond without a direct measure of how much each responded (at least in real-time – metering information can provide after-the-fact measures). The amount of response would be determined by monitoring the power system to see whether
- Common scenarios include an energy service provider broadcasting a pricing signal, which is then reacted to by the individual DER systems, or a utility multicasting a reduction in generation to all DER systems on a constrained feeder that cannot handle reverse power flows.

These different DER management interactions are shown in Figure 1.

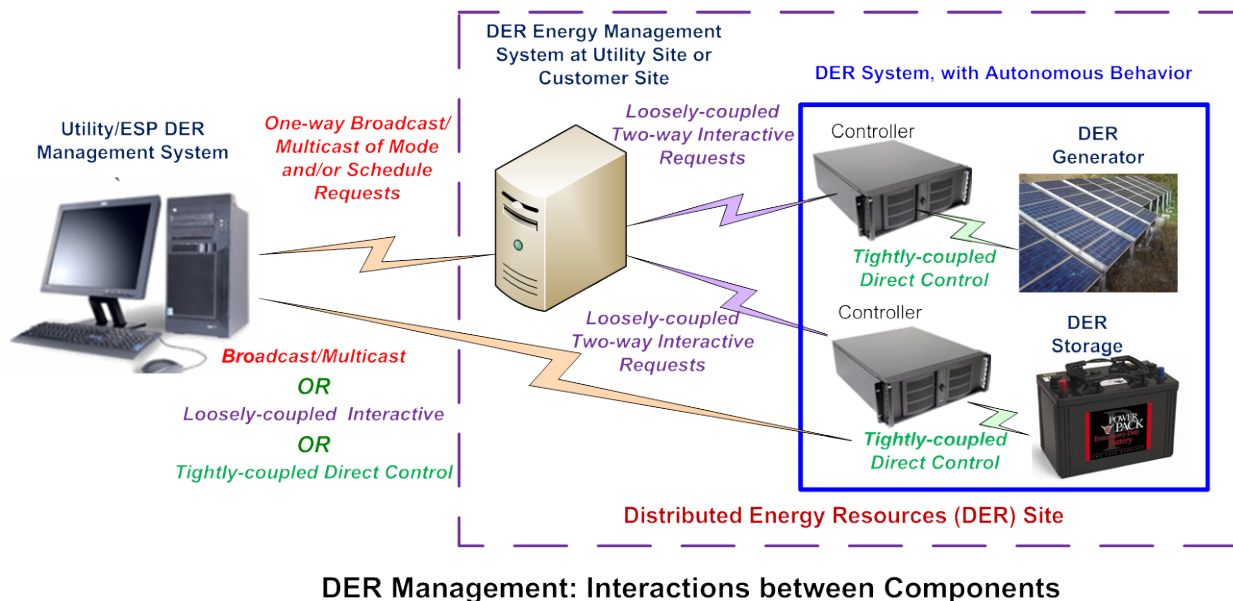


Figure 1: DER management interactions

1.3 Inverter methods

The methods for inverters to manage autonomous behaviour according to preset parameters include the following:

- **“Modes”** consist of pre-established groups of settings that can enable autonomous DER behaviour, where the DER senses local conditions, and, using those mode settings, responds appropriately. This approach minimizes the communications requirements and permits more rapid responses. "Modes" can be established for volt/VAr control, frequency-watt control, charging/discharging storage, and some other complex actions, where the arrays and parameters for each mode are sent ahead of time - maybe once a year or season, and then "go to mode" commands/requests can be broadcast/multicast.

- **Schedules** can also be established, which can operate for a specific time period or indefinitely (once initiated) completely autonomously. For instance, a schedule can establish what modes to use during weekday mornings, versus mid-afternoon, versus weekends.
- **Temperature-based curves and pricing-signal curves** provides settings for what actions to take based on the current temperature or pricing signal. A pricing signal curve can indicate which mode(s) to go to, based on the pricing signal level (can be \$\$, but can also be tiers, or H-M-L, or other signal). When a new pricing signal is broadcast, the DERs can ramp to the specified modes. There can even be a schedule of pricing signals so that they do not need to be broadcast, unless an emergency calls for a different level.
- **Ramp rates and parameters based on "% of capability"** (rather than absolute amounts) are also included. In addition there is a **time-window randomization** that requires DERs to respond to commands using a random number within the time window to actually initiate the command. This prevents sharp jumps whenever a new command/request/pricing signal is broadcast. (Obviously the time window can be set to zero if immediate emergency action is required.)

Although the DER generator and storage inverter functions do not directly cover loads, the same mechanisms of modes, schedules, graphic curves, arrays, timing constraints, etc. could be very readily applied to loads. The actual modes would be different (lighting cannot create VARs, but could dim slightly), but the mechanisms would be the same.

1.4 Inverter functions

This document covers many of the key inverter functions, including:

- **Immediate control functions** for inverters
 - Function INV1: connect / disconnect from grid
 - Function INV2: adjust maximum generation level up/down
 - Function INV3: adjust power factor
 - Function INV4: request real power (charge or discharge storage)
 - Function INV5: request action through a pricing signal
- **Volt-VAr management modes**
 - Volt-VAr mode VV11: normal energy conservation mode
 - Volt-VAr mode VV12: maximum VAr support mode
 - Volt-VAr mode VV13: static inverter mode
 - Volt-VAr mode VV14: passive mode
- **Frequency-watt management modes**
 - Frequency-watt mode FW21: high frequency reduces active power
 - Frequency-watt mode FW22: constraining generating/charging by frequency
 - Frequency-watt mode FW23: watt generation/absorption counteractions to frequency deviations
- **Dynamic grid support during abnormally high or low voltage levels**
 - Dynamic grid support TV31: volt-var support during abnormally high or low voltage levels
- **Curves for “must disconnect” and “must stay connected”**
 - “Must disconnect” MD curve
 - “Must stay connected” MSC curve
- **Watt-power factor management modes**
 - Watt-power factor WP41: feeding power controls power factor

- **Voltage-watt management modes**
 - Voltage-watt mode VW51: smoothing voltage deviations by watt management
 - Voltage-watt mode VW52: charging by voltage
- **Non-power-related modes**
 - Temperature-function mode TMP: ambient temperature indicates function
 - Pricing signal-function mode PS: pricing signal indicates function to execute
- **Parameter setting and reporting**
 - Function DS91: modify inverter-based DER settings
 - Function DS92: event/history logging
 - Function DS93: status reporting
 - Function DS94: time synchronization

1.5 Control mechanisms for interactions with inverters

There are a number of different control mechanisms for interactions with inverters:

- **Immediate control commands**, in which the action is started immediately. Examples include:
 - Disconnect inverter from grid
 - Get current status of inverter
 - Retrieve event log
 - Activate normal energy conservation mode, using specific pre-established volt-VAr arrays
 - Activate specific schedule
- **Individual settings**, which can influence subsequent actions, but are not explicit commands. Examples include:
 - Maximum discharge rate for a storage system
 - Power factor convention (IEC or IEEE)
 - Voltage offset to be used in voltage calculations
- **Modes with pre-established settings**, which may be sent to the inverter at any time, but which are only initiated by an immediate or scheduled control command. Examples include:
 - Volt-VAr modes
 - Frequency-watt modes
 - Temperature-VAr modes
- **Scheduled commands**, in which a schedule is sent to the inverter with commands scheduled for particular times. These commands can also invoke pre-established parameters. Examples include:
 - Week-day schedule for volt-VAr actions
 - Weekly schedule for frequency-watt actions

These different mechanisms can be intermingled, or only a specific type used, depending upon the requirements of implementations and configurations.

1.6 Differing DER architectures

1.6.1 Conceptual architecture: electrical coupling point (ECP)

Some inverter-based DER systems may be directly connected to the utility grid, while others may be part of a site microgrid. In either case, the inverter-based DER systems will have a point of electrical connection, which is defined as:

“The electrical coupling point (ECP) is the point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS). Each DER (generation or storage) unit has an ECP connecting it to its local power system; groups of DER units have an ECP where they interconnect to the power system at a specific site or plant; a group of DER units plus local loads have an ECP where they are interconnected to the utility power system.

1.6.2 Conceptual architecture: point of common coupling (PCC)

For those ECPs between a utility EPS and a plant or site EPS, this point is identical to the point of common coupling (PCC) defined as “the point where a Local EPS is connected to an Area EPS” in the IEEE 1547 “Standard for Interconnecting Distributed Resources with Electric Power Systems” (see clause **Error! Reference source not found.** for additional definitions).

This concept is illustrated in Figure 2.

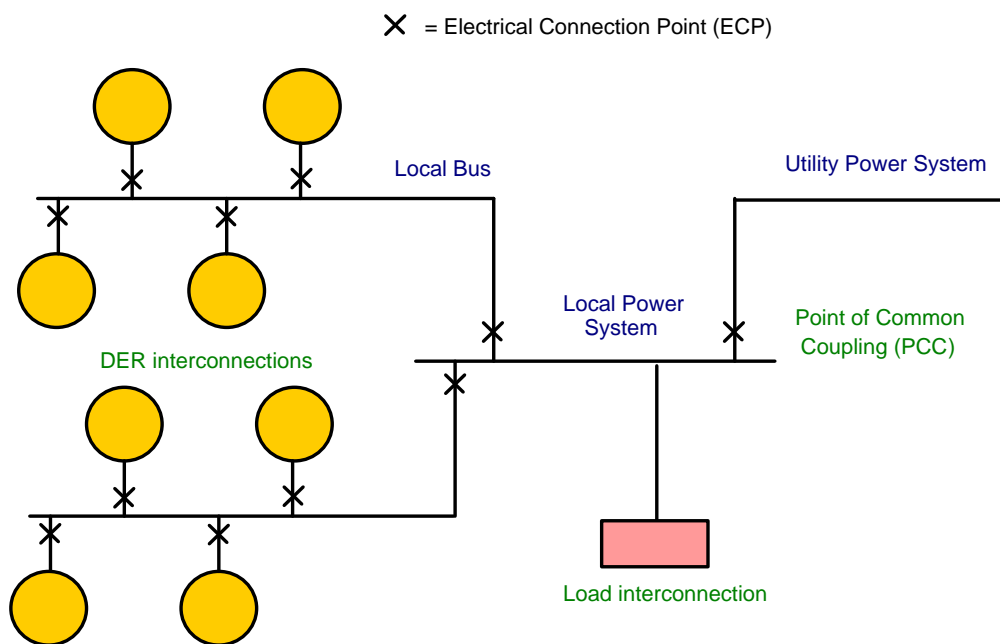


Figure 2: Electrical Connection Points (ECP) and Point of Common Coupling (PCC)

1.6.3 Utility interactions indirectly with inverters via a customer EMS

Utilities/ESPs can interact with inverter-based DER systems using different architectures. The following diagram illustrates the use of a Customer EMS to help manage inverter-based DER

device responses to the broadcast utility request, with the idea that this Customer EMS will possibly be managing multiple inverter-based DER devices, customer appliances, other types of distributed generators and storage devices, and plug-in electric vehicles.

For instance, if the utility broadcasts a specific mode request for inverter-based DER device actions, then these can be passed directly or indirectly (through explicit commands) to the inverter-based DER devices. If the utility broadcasts Demand Response signals or more generic volt/VAr requests, then the Customer EMS could use other devices in addition to inverter-based DER devices to meet these requests. With this approach, the Customer EMS could manage responses locally to meet the requests with the most effective mix of devices.

From a communications perspective, the utility broadcast to the customer site, between the utility and the “Customer EMS”, could use different technologies at different layers, for example:

- Object models: IEC 61850
- Application protocols: Mapping of IEC 61850 objects to Web services, XML-based, ANSI C12.22, DNP3, and/or MMS
- Transport / media layers: Public Internet, GPRS cellphone network, AMI network, utility private network, leased services from telecommunication providers

1.6.4 Utility interactions directly with inverter controllers

Alternatively, utilities/ESPs can communicate requests directly with inverter-based DER device controllers. These requests are then interpreted by the inverter-based DER device controllers.

From a communications perspective, the utility broadcast to the customer site, between the utility and the inverter-based DER device, could use different technologies at different layers, for example:

- Object models: IEC 61850
- Application protocols: Web services, XML-based, ANSI C12.22, DNP3, MMS
- Transport layers: Internet, GPRS, AMI network, private network

1.7 General Sequence of interactions

The (generic) sequence for interactions between a utility/ESP and inverter-based DER devices is:

1. **The utility determines what types of services** are desired from inverter-based DER devices within a region, on a feeder, or in some other area. This determination will be based on assessments of the power system status, abilities of other equipment to perform the required actions (e.g. capacitor banks for VAr control), market considerations, etc.
2. **The utility broadcasts a general request** that inverter-based DER devices (within a region or feeder or other area) go into a specific mode or that certain parameters are set. This request may be sent either to individual inverter-based DER device controllers, or to more general “Customer EMSs” that know how to interpret such requests for the inverter-based DER device controllers that they are managing. In either case, the utility does not necessarily need to know anything about the inverter-based DER device capabilities, current PV status, market or tariff agreements on using the inverter-based DER system, or desires of the PV owner.

3. At each customer site or other facility, the **inverter-based DER device controller OR a Customer “energy management system” (EMS)** receives and interprets this broadcast utility request.
4. **If a Customer EMS is used:**
 - a. **The Customer EMS interprets the utility request.** It determines whether it will take any action, and what the command(s) will be to the inverter-based DER device controller(s) under its control, including responding to any customer overrides or changes. These actions could be explicit commands to each inverter-based DER device it is managing, or could be a schedule of commands if the inverter-based DER device has the ability to handle schedules.
 - b. **The Customer EMS then issues specific commands to the inverter-based DER device(s):** First it requests (or already has) the current status of the inverter-based DER device(s), modifies the command if necessary to reflect the status, and then issues the appropriate command.
 - c. **The inverter-based DER device(s) respond to the Customer EMS command,** indicating success or rejection, as well as any error codes. In addition, the current status of the inverter-based DER device could be sent if either explicitly requested by the Customer EMS or if it is “automatically” sent as part of the sequence.
 - d. **The Customer EMS may or may not be required to respond** to the utility request.
 - If the utility does not expect a direct response, it may both monitor conditions to determine if enough power system changes have occurred and/or read the meter (or meter event log) to determine if the inverter-based DER device responded appropriately.
 - If it does respond, it will acknowledge receipt of the command and returning the appropriate information.
5. **If an inverter-based DER device controller directly receives the broadcast request from the utility:**
 - a. **The inverter-based DER device controller determines internally how best to respond,** and performs those actions.
 - b. **The inverter-based DER device controller may or may not respond** to the command from the utility with an acknowledgement and any appropriate information.
 - If the utility does not expect a direct response, it may both monitor conditions to determine if enough power system changes have occurred and/or read the meter (or meter event log) to determine if the inverter-based DER device responded appropriately.
 - If it does respond, it will acknowledge receipt of the command and returning the appropriate information.
6. **The inverter-based DER device(s) are metered either individually or via net metering,** with their output (in response to the command) captured as part of the metering data. If electric storage is part of the inverter-based DER system, then it could be metered separately or the inverter-based DER system as a whole could just be metered. (Metering is out of scope for this document).
7. **If communications are lost, the inverter-based DER device goes to a default mode,** possibly after a timeout period. The default mode, the timeout period, and other parameters for this situation would be established ahead of time.
8. **Customers can override or modify commands,** at any time if they desire.

2. Concepts and constructs for managing inverter functions

2.1 Basic settings of inverters

2.1.1 Nameplate values versus basic settings

Nameplate values are expected to be fixed, based on the type, model, and capabilities of the inverter. However, installation-specific requirements may require modifications to the nameplate values, so long as these basic settings remain within the constraints of the nameplate values. These basic settings are usually established upon installation and start-up, and are usually due to varying inverter configurations, power grid environments, desired inverter capabilities, and DER owner preferences.

Basic inverter settings are needed for several functions and include power and voltage settings. These basic settings will be applied to power adjusting functions. At the beginning of this clause the power settings will be described and afterwards voltage settings. The basic setting functions assume a tightly coupled interaction between the inverter-based DER devices and a controlling entity (utility, energy service provider, or customer EMS).

2.1.2 Power factor and inverter quadrants

Figure 3 shows the possible working areas of a DER inverter: the 1st and 4th quadrants are for delivering power to the grid (VARs either lagging (overexcited) or leading (underexcited), respectively), while the 2nd and 3rd quadrants are for receiving power from the grid (VARs either leading (overexcited) or lagging (underexcited), respectively). DER inverters can work in any of these four quadrants, depending upon their capabilities and the desired functions. Historically, there are two conventions: IEC and IEEE. Another convention is Excitation. These conventions are shown in Table 1:

Table 1: IEC, IEEE, and Excitation power factor conventions

Quadrant	IEC	IEEE	Excitation
Q1	Lagging	Supply	Overexcited
Q2	Leading	Demand	Overexcited
Q3	Lagging	Demand	Underexcited
Q4	Leading	Supply	Underexcited

Along with an indication of which convention is being used, the sign of the power factor (PF) value plus a leading/lagging indication, a supply/demand indication, or an overexcited/underexcited indication would clearly specify which quadrant was being referenced. Either as nameplate or basic setting, the IEC/IEEE/Excitation convention indicator (PFSign) must be set for that installation.

If the inverter does spontaneously change between charging and discharging without an explicit command, it can continue to maintain the VARs according to what it was previously doing, either providing VARs or absorbing VARs, or the reverse. The spontaneous change action (reversing or maintaining VAR direction) is set either as nameplate or basic setting (VARAct).

All commands for PF must include the other two elements: signed PF value (OutPFSet) and VAR characterization as overexcited/underexcited, leading/lagging, or supply/demand binary indicator (PFsign), and if excitation characterization is used, then PFExt identifies under or over excited.

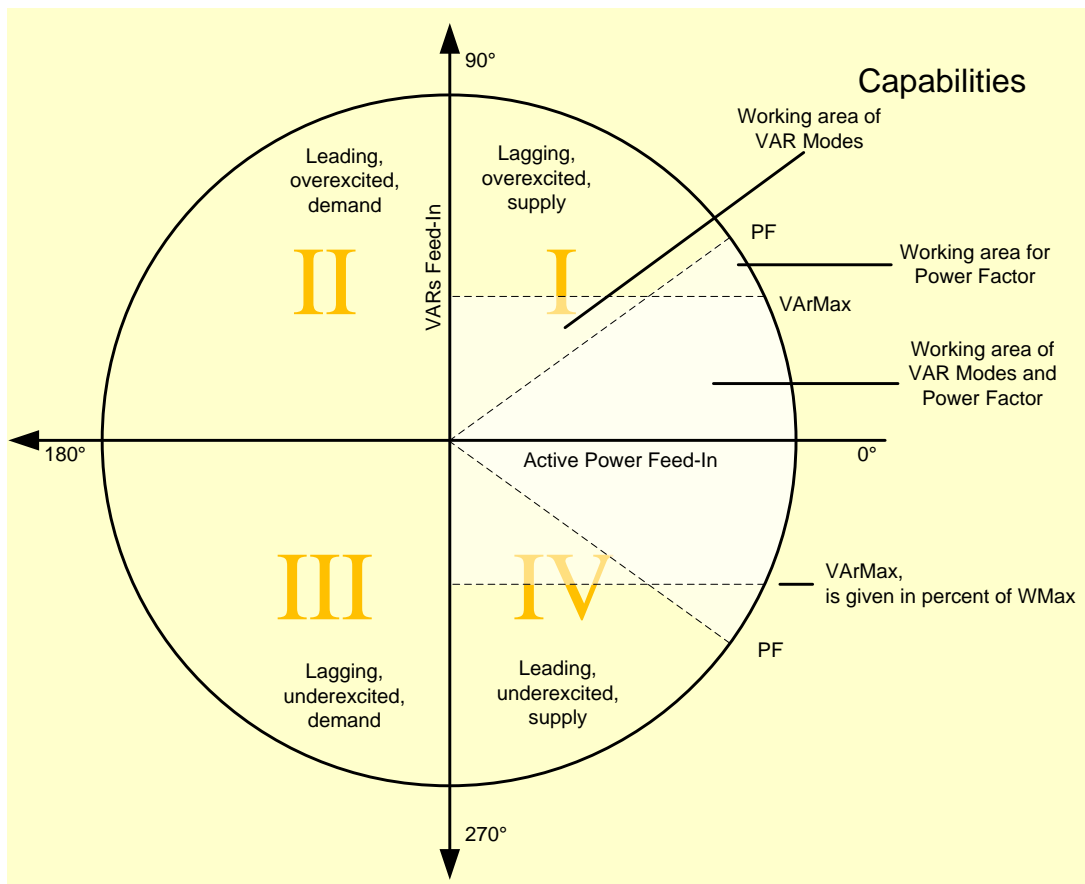


Figure 3: Four-quadrant view of inverter-based DERs

2.1.3 Maximum watts and volt-amp settings

Each inverter's power connection to its local grid is called its electrical connection point (ECP). If there are multiple inverters within a site, they may all contribute to the interconnection of the site to the main grid at the point of common coupling (PCC).

The inverter quadrant areas can be constrained in order to meet specified limits at its ECP or at the PCC. In order to determine the limits at the PCC, all inverters must have two parameters, called WMax (for active power) and VAMax (for apparent power) that establish their limits at the ECP of each inverter. The sum of all ECP limits provides the limits at the PCC.

WMax and VAMax are these settable limits that may be the same as the nameplate values, or may be (typically) lower values reflecting actual implementation limits. They would normally be set at the initial deployment time, although they could be modified occasionally to reflect changes to the implementation.

The parameter WMax is the critical value: it is used as the reference value for power requests, including both active and reactive power. Control commands can then be issued as a percentage

of WMax: each inverter can then calculate for its own actual values from its own WMax value. This approach allows the reduction of a DER's power level by relative values in an unlimited range and provides a consistent way to set reactive power by setting its value as relative to the active power.

For a facility with multiple inverters, the maximum continuous power output capability of the facility is given by the sum of parameter WMax of all inverters. The maximum continuous reactive power output capability is given in percents of WMax. Furthermore, in some cases it can be an advantage to set the maximum continuous reactive power output capability in same manner as WMax. However, the basic settings for power do not intend to limit the energy flow to be one directional.

An example is shown in Figure 4 for the 1st and 4th quadrant (assuming the arrows indicate a producer reference system (the producer reference arrow system)).

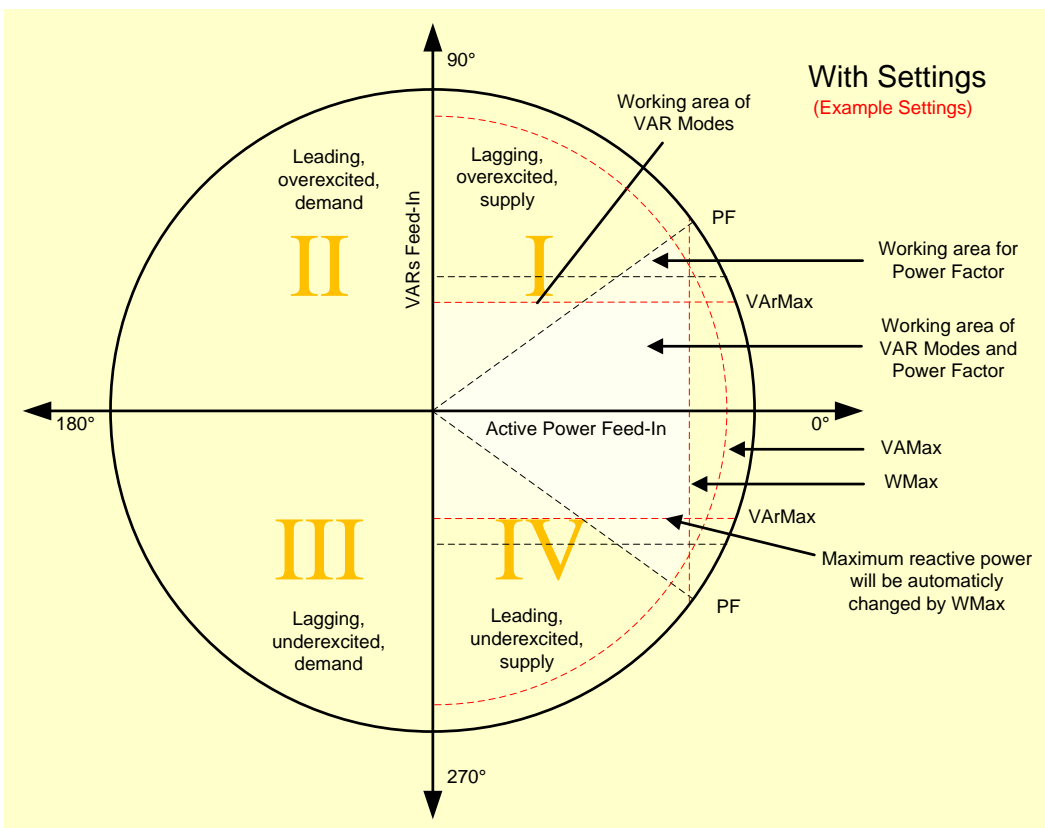


Figure 4: Working areas for different modes

The different hatched areas show the different working areas and working area limits. The red hatched lines show the maximum values for active power WMax, reactive power VARMax and apparent power VAMax.

Possible power factor settings may range from a minimum PF (OutPFSet) (leading, supply, underexcited) in quadrant 4, going through the maximum value of 1 to a minimum power factor (lagging/supply/overexcited) in quadrant 1. Possible VAR settings (see function INV2 below) are limited by VARMax which is a percentage value of WMax.

Since some possible settings are limited by regulations or device capabilities, more than one boundary may apply to a selected DER management function for inverters, resulting in zones limited by more than one hatching type.

2.1.4 Active power ramp rate settings

The default ramp rate of change of active power is provided by the parameter WGra. This parameter sets the change of active power due to either a change by a command or by an internal action such as the release of power reduction by use of the hysteresis in the function Active Power Reduction by Frequency. This ramp rate (gradient) does not intend to replace the specific ramp rates that are set by the commands or schedules, but acts as the default if no specific ramp rate is specified. WGra is defined as a percentage of WMax per second.

2.1.5 Voltage phase and correction settings

In the case of single phase inverters, the voltage value used in the inverter functions is based on whichever phase circuit (A, B, or C) the inverter is connected to. The identity of the phase can be set in the inverter as a basic setting. In the case of three-phase inverters that do not act independently, the mean value of A, B, and C is to be used.

For functions using voltage parameters (like the volt-var modes, volt-watt modes, and Dynamic Grid Support), a reference voltage (VRef) and a correction voltage (VRefOfs) are additionally introduced to the previously mentioned parameters, WMax, VAMax and WGra. All inverters behind one PCC have a common reference voltage, but differ in the voltage between their own ECP and the PCC due to configuration differences within a plant. These differences can be corrected by the parameter VRefOfs that will be applied to each inverter, as can be seen in Figure 5, where a positive value means that voltage at the ECP is higher than the voltage at the PCC. This correction voltage will be applied to the voltage-based modes and will allow a homogenous setting and broadcasts for the plant.

The equation for the effective percent voltage is:

$$\text{Effective Percent Voltage} = 100 * (\text{local voltage} - V_{\text{RefOfs}}) / (V_{\text{Ref}})$$

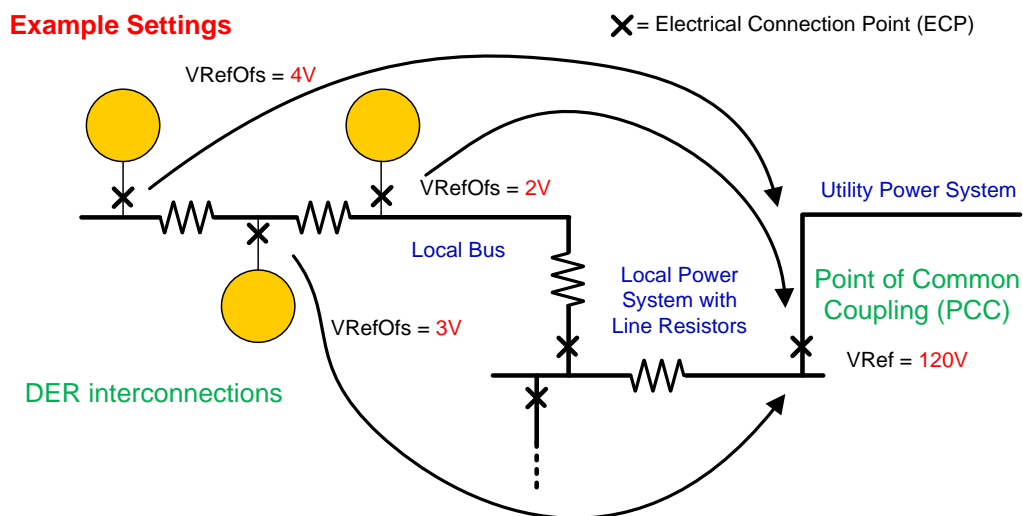


Figure 5: Example of voltage offsets (V_{RefOfs}) with respect to the reference voltage (V_{Ref})

2.1.6 Charging settings

For those inverters that manage storage DER units that can both deliver power (discharging in quadrants 1 and 4) and absorb power (charging in quadrants 2 and 3), additional parameters are needed if the maximum discharge limits are different from the maximum charge limits: WChaMax, VChaMax, and WChaGra.

2.1.7 Example of basic settings

An example of settings for an inverter is shown in Table 2.

Table 2: Example basic settings for a storage DER unit

Parameter	Example Values
PFsign	1 = IEC; 2 = IEEE; 3 = Excitation
PFExt	Under excited = False; Over excited = True
VArAct	1 = reverse VAr leading/lagging characterization when changing between charging and discharging) 2 = maintain VAr characterization
WMax, delivered	14500W
WChaMax, received	-14500W
VAMax	16000VA
VChaMax	16000VA
VArMax	12000VAR
VRef	120V
VRefOfs	2V
WGra	20% WMax/second
WChaGra	15% WChaMax/second

2.1.8 Basic setting process

The settings described above are expected to only be set once or infrequently over the life time of the system. The utility/ESP or the customer EMS would take the following actions:

1. **(Optional) Request status of inverter-based DER device:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
2. **Issue command or mode to modify inverter-based DER settings:**
 - a. Data element to be modified (e.g. WMax, VAMax, VArMax, VRef, VRefOfs, WGra, mode)
 - b. New value for that data element
3. **Receive response to the command:**
 - a. Successful (plus new value of data element)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

2.2 Modes for managing autonomous behaviour

2.2.1 Benefits of modes to manage DER at ECPs

“Modes” are methods for managing DER devices by pre-setting desired parameters and curves that describe desired behaviour in response to local conditions (e.g. voltage, frequency, power factor, temperature, and pricing signal). Many different mode settings can be defined once and updated only infrequently. Utilities and/or ESPs can then invoke a specific mode by a single command whenever they wish the DER to follow the behaviour defined by that mode.

The use of modes allows the DER to act autonomously without moment-by-moment commands, thus both simplifying the tasks of the utilities/ESPs, as well as minimizing the necessary communications burden. Utilities and ESPs can either monitor the behaviour of the DERs or can simply monitor the power system to determine how well their mode requests are affecting the power system.

Generally, modes will be applied to one inverter or groups of inverters that are connected at different levels of ECPs (see Figure 6 for examples).

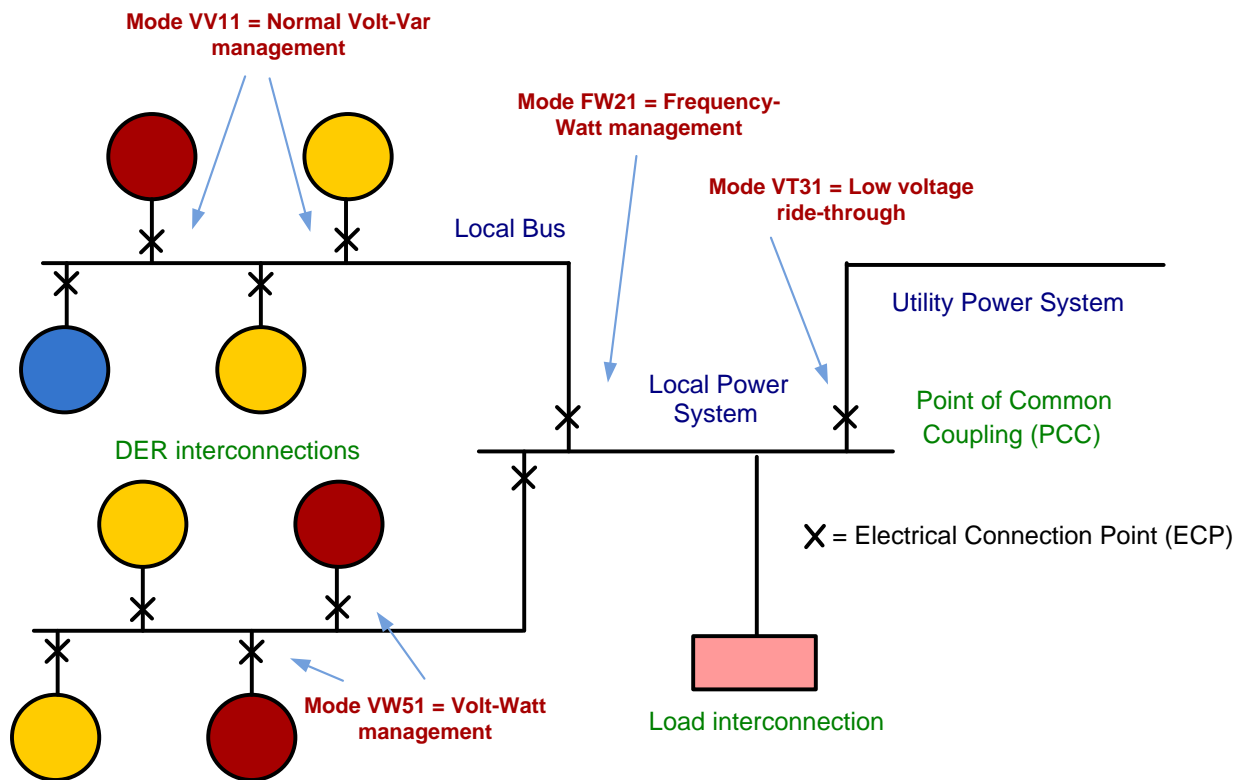


Figure 6: Example of modes associated with different ECPs

2.2.2 Modes using curves to describe behaviour

Modes are defined as using curves to describe autonomous behaviour. These curves correlate a measured or triggering value (the independent variable) with a requested response by the DER (dependent variable).

In order to generate a curve, two-column arrays are used, with the first column containing monotonically increasing triggering values (x-axis) and the second column containing the

response values (y-axis). These arrays are combined into a piecewise linear curve by interpolating each response values to correspond with each triggering value.

When an operational mode is invoked, the real-time measured value or stipulated external value of the triggering parameter is used to derive the interpolated response value.

Examples include the following modes, although others could be added. The first four modes are power-related modes, while the last two modes utilize non-power-related triggering values:

- Volt-Var Mode: Voltage values to determine what VARs the inverter should produce at each voltage level
- Frequency-Watt Mode: Frequency values to determine what watts the inverter should produce for each frequency value
- Dynamic Grid Support Mode: Apply volt-VAR management during short times of abnormally low or high voltage values to support the grid until either the voltage returns within its normal range or the inverter must disconnect.
- Volt-Watt Mode: High-voltage values to determine what watts the inverter should produce if the voltage is above a certain level
- Temperature-Var Mode: Temperature values to determine what VARs or what volt-VAR mode the inverter should produce within each temperature range
- Pricing Signal Mode: Pricing signal values to determine what watts, VARs, power-related mode, or other ancillary service the inverter should produce for each range of pricing signals.

In most of these modes, the real-time triggering values (voltage, frequency, etc.) are measured locally. In some modes, the triggering value might be received from external sources, such as regional average temperature or energy pricing signal.

Unlike direct control commands, modes indicate behaviour that the inverter should follow autonomously without further intervention. This approach alleviates the need for continuous control commands being sent out to large numbers of inverters.

Because autonomous behaviour must take into account the current capabilities of the DER device, these inverter modes are designed to request DER devices to provide the needed mode support as best as their capabilities allow them. For this reason, the curve settings are generally in percentages of nominal or nameplate values, rather than absolute values. That approach permits both small and large inverter-based DER devices to respond within their limits.

An example of a curve used in a volt-VAR mode is shown in Figure 7.

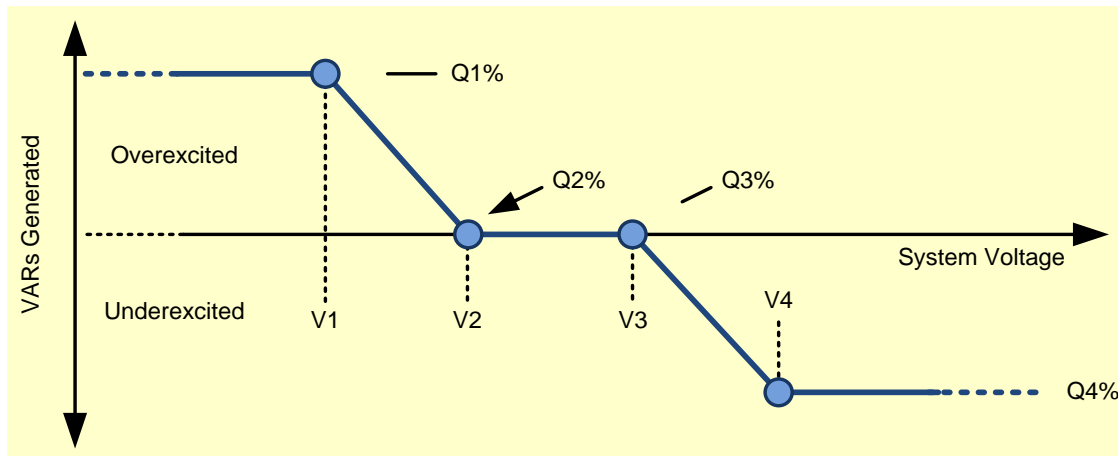


Figure 7: Example of a volt-VAr mode curve

2.2.3 Paired arrays to describe mode curves

Each mode curve is described by a two-column array of pairs of values: the first column in the array contains the breakpoints of the independent variable values, while the second column contains the dependent variable values at those breakpoints. These two columns of values can be used to derive a piece-wise linear curve.

The independent variables are typically values which may be measured locally or calculated from locally available measurements or values. For instance, when a DER controller receives a mode curve which uses voltage as the independent variable, the DER may determine its current location along the curve by averaging the three voltage phase values at the ECP and applying the appropriate voltage offset. The independent variable may be an absolute value (e.g. frequency value) or may be a percentage of nominal (e.g. % of nominal voltage).

The dependent variables are typically (but not exclusively) percentages of a nominal value. These dependent variables are used to calculate what behaviour the DER is being requested to follow. For instance, if the dependent variable is the percentage of the maximum watts (W_{max}) and the independent variable is % of nominal voltage, the DER controller can determine its desired watts based on its measured voltage.

The paired arrays therefore consist of the breakpoints of the independent variables, the breakpoints of the dependent variables, and the units (either SI units or percentage of SI units).

2.2.4 Percentages as size-neutral parameters: voltage and var calculations

As noted previously, because broadcast/multicast commands cannot necessarily know the size or capabilities of an inverter, the curve settings are generally in percentages of nominal or nameplate values, rather than absolute values. That approach permits both small and large inverter-based DER devices to respond within their limits.

In particular, given this size-neutral and connection-point-neutral approach, inverters will need to calculate an effective percent value for the locally measured voltage as follows:

$$EffectiveLocalVoltage = \left(\frac{LocallyMeasuredVoltage - VrefOffset}{Vref} \right) * 100$$

An inverter would then compare this *EffectiveLocalVoltage* to the voltage percentages (X-Values) in the configuration curve, so the X-Values of the curve points would be calculated as follows:

$$PercentVoltage = \left(\frac{DesiredVoltageValue}{Vref} \right) * 100$$

These definitions allow the same *PercentVoltage* values to be used in the configuration curves of many different inverters without adjusting for local conditions at each inverter. Such adjustments can be made by setting the global Reference Voltage (VRef) or Reference Voltage Offset (VRefOfs) when the device is first commissioned or occasionally thereafter, without affecting the curve settings.

In similar fashion, the requested VAR (Y-Values) to be written for each curve point would be a percentage calculated as follows:

$$PercentVARs = \left(\frac{DesiredVARValue}{VARmax} \right) * 100$$

The percentage of VARs is a signed value, so that it can represent VARs generated (positive) or absorbed (negative).

2.2.5 Hysteresis as values cycle within mode curves

Although the simplest curve is a piece-wise linear curve, hysteresis can be added to provide different return routes. This hysteresis adds stability to the inverter responses to possibly fluctuating primary curve values by not following the minor fluctuations, but by maintaining a constant level until the trend of the primary curve value stabilizes.

There are two modes available (*parameter names are shown in the example Figure 8*):

- By specifying a hysteresis path or
- Via a deadband path to simulate hysteresis

A ramp rate can be configured by RmpTmsPT1 for getting of system voltage to this function. This parameter is configured in seconds. This is the time this function requires reaching 95% of the grid voltage change (3 times the RC time constant).

Examples of volt-VAR curves with hysteresis are shown in Figure 8 and Figure 9.

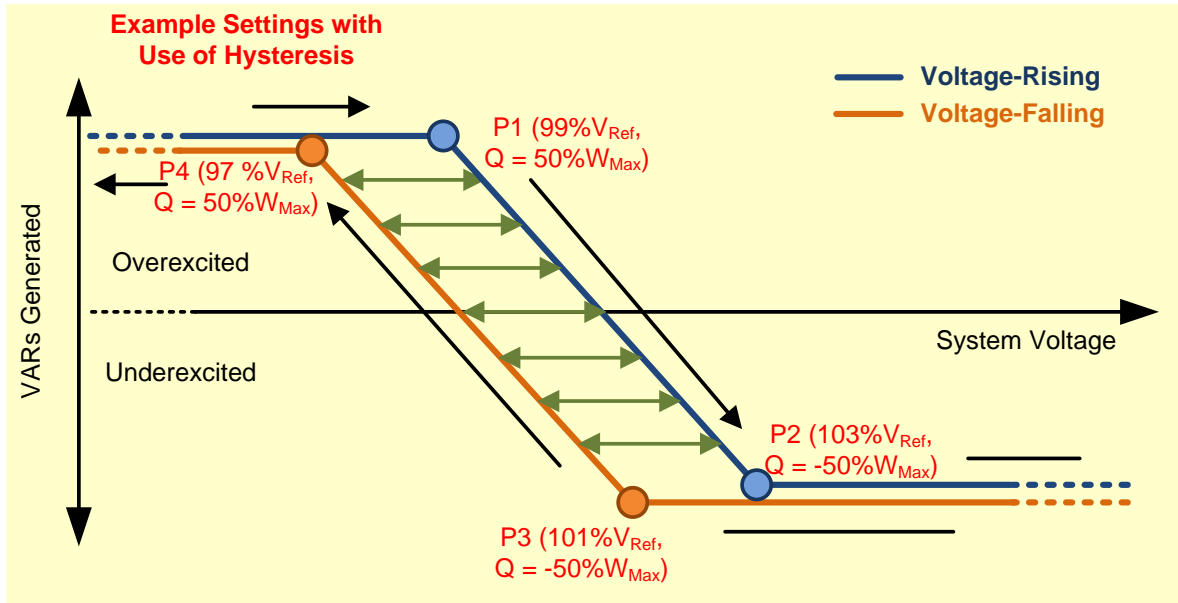


Figure 8: Example of hysteresis in volt-VAR curves

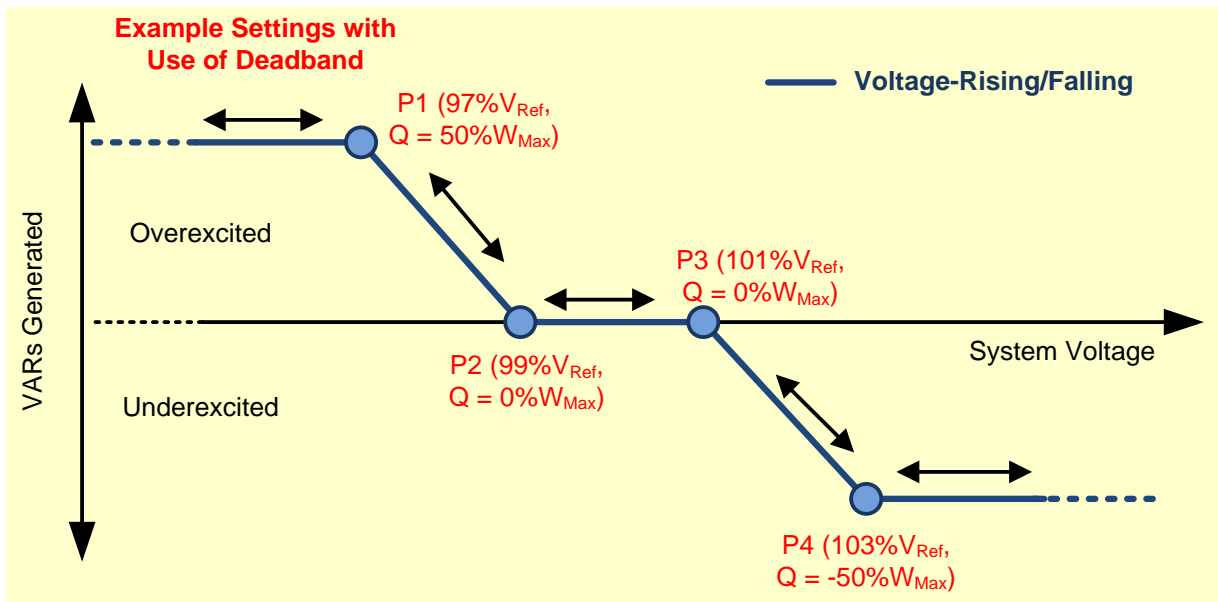


Figure 9: Example of deadband in volt-VAR curves

2.2.6 Low pass exponential time rate

The local function block diagram in Figure 10 shows the topology for Low Pass, Utility Defined Curve Shapes and Linear Gradient (ramp rates). The Utility Defined Curve Shape can be assumed to be the any function defined by paired arrays.

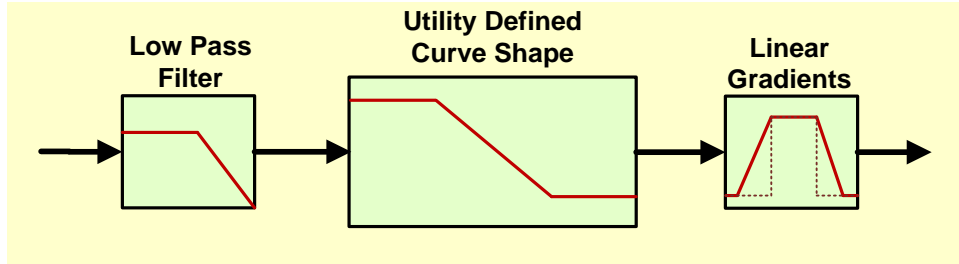


Figure 10: Local function block diagram

The Low-Pass filter is a simple first-order filter with a frequency response magnitude given by:

$$\left| \frac{\text{Output}}{\text{Input}} \right| = \frac{1}{\sqrt{1 + (\omega\tau)^2}}$$

Where $\omega = 2\pi \cdot \text{frequency}$ and $\tau = \text{the time constant of the filter}$.

The time-response of such a filter to a step change in the input is as illustrated in Figure 4.

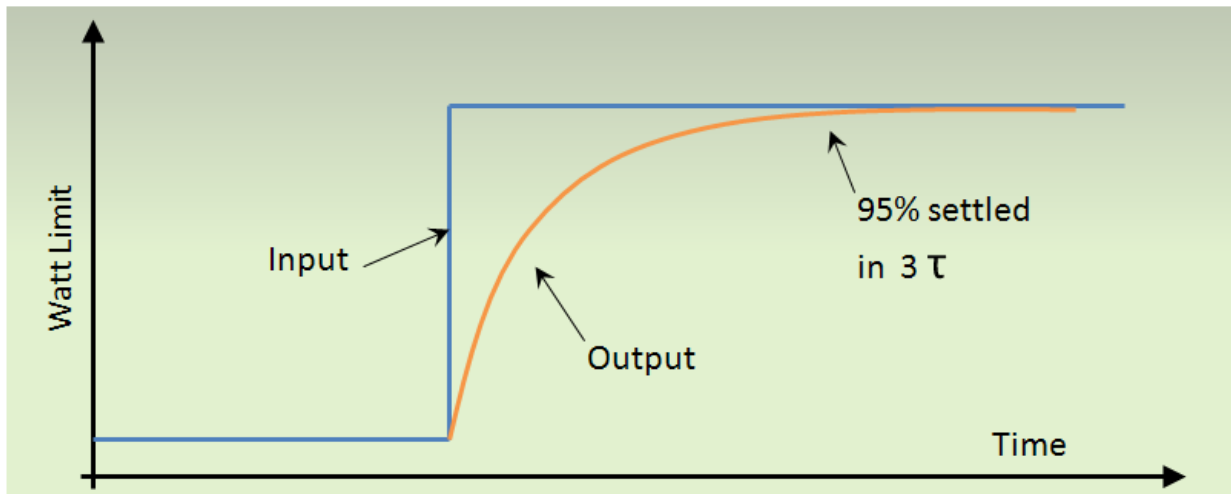


Figure 11 – Time domain response of first order low pass filter

The configuration parameter for this filter is a time, in seconds, in which the filter will settle to 95% of a step change in the input value. This is equivalent to 3τ .

2.2.7 Ramp rates

To avoid sharp shifts at the breakpoints of the piecewise linear curve, a ramp rate is included for each transition in order to smooth and stabilize the responses of large numbers of inverter-based DER devices. In order to distinguish the decrease and increase of the independent output value two ramp rates are in use, called RmpTmmDec and RmpTmmInc.

2.2.8 Randomized response times

Since mode requests will (most likely) be broadcast or multicast to large numbers of DER devices at the same time, it may be beneficial to stagger the responses. This is achieved by providing a time window within which a random “start” time actually triggers the execution of the mode.

2.2.9 Timeout period

A timeout period is available for reverting to a default state of the DER device, to ensure that a missed or lost command does not impact normal operations beyond that timeout period. If the mode is the default state, then the timeout period would be set to infinite.

2.2.10 Multiple curves for a mode

Each type of operational mode could have multiple curves with different settings. For instance, a volt-VAR mode could have different curves that could be invoked during colder days or hotter days. The pricing signal mode could have different curves for weekdays and for weekends. The low-voltage-ride-through mode could have different curves for non-islanded situations versus islanded situations.

2.2.11 Multiple modes

Multiple modes may be in effect at any one time, so long as they are not mutually exclusive. Modes may also be overridden by immediate control commands, such as for emergency situations. For instance, DER systems that are executing a volt-VAR mode under normal circumstances could be triggered by a high temperature to execute a temperature-VAR mode to provide or absorb more VARs.

Multiple pricing signal modes could be effect. For instance there could be different pricing signal modes for energy, for VARs, for frequency response, or for other ancillary services. When actual pricing signals are received for each type, then an assessment would be performed to determine which may be mutually exclusive, which of those may be the preferred mode, and which modes might co-exist at the same time. For instance, a high pricing signal for VARs might out-weigh a lower pricing signal for watts, while frequency-watt mode might co-exist with either.

2.2.12 Use of modes for loosely coupled, autonomous actions

Inverter mode requests to inverter-based DER devices are examples of decentralized coordination of generation or loosely-coupled generation control. Loosely-coupled interactions also cannot expect complete compliance from all DER devices. For instance, inverter-based DER devices may not be able to respond completely for any number of reasons: the sun is behind a cloud, the customer has overridden the mode setting, local situations are impacting what response the inverter-based DER device can provide, etc.

Therefore the expectation for issuing mode requests is that an aggregated response will be gotten from many or most inverter-based DER devices, but not necessarily all. Any financial ramifications will be determined by the metering results.

Since these mode requests maybe broadcast (multicast) to specific groups of inverter-based DER devices and since the responses from the inverter-based DER devices will generally not be explicit, the utility may not know what the actual responses will end up being, and could require subsequent interactions not only with these inverter-based DER devices but possibly with

distribution grid capacitor controllers, load tap changers, voltage regulators, storage devices, and other types of DER.

2.3 Schedules for establishing time-based behaviour

2.3.1 Purpose of schedules

Larger inverter-based DER systems and large aggregations of small inverter-based DER systems have significant influence on the distribution system and have local volt/VAR characteristics that may vary throughout the day. As a result, a single function or operational mode such as a specific volt/VAR curve may not be suitable at all times. Yet sending many control commands every few hours to many different DER systems may impact bandwidth-limited communications systems or may not be received in a timely manner, leading to inadequate DER system responses. However, if schedules can be established that the DER systems can follow autonomously, then these communication impacts can be minimized.

Schedules establish what behaviour is expected during specified time periods. A schedule consists of an array of time periods of arbitrary length, with each time period associated with a function or mode.

Schedules use relative time, so that increasing time values are the delta seconds from the initial time value. The actual start date/time replaces the initial time value when the schedule is activated. A ramp rate sets the rate at which the function or mode in one time period moves to the function or mode in the subsequent time period, while the ramp type indicates how the ramp is to be understood. A stop time indicates when the schedule is deactivated.

Schedules can be used to allow even more autonomous control of the behaviour of DER equipment. They may be sent ahead of time, and then activated at the appropriate time.

2.3.2 Schedule components

The interrelationship of schedule controllers, schedules, and schedule references, along with some example settings are shown in Figure 12. These components are described as:

- **Electrical Connectivity Point (ECP) manager:** An ECP manager handles one or more DER unit controllers that provide energy through that ECP. It is expected that the ECP manager will handle the schedule controllers for its interconnected DER units.
- **Schedule controllers:** One or more schedule coordinators may be available at the ECP. Each schedule controller can control multiple schedules so long as they are not running at the same time. The schedule controller indicates which schedule is currently ready-to-run or running. For one schedule controller, only one schedule can be running.
- **Schedules:** Each schedule must have a non-zero identifier that is a unique schedule identity within the ECP. A schedule consists of time periods of arbitrary length that reference delta time from the initial entry.
- **Schedule references:** Each entry in a schedule references a specific value, a mode, or a function. Configuration parameters indicate the units and other characteristics of the entries.
 - **Values** are direct settings, such as maximum watt output. These are absolute values or a percentage, to be used primarily where specific values are needed.
 - **Modes** are the settings and arrays of independent and dependent variables that manage output through algorithmic calculations, such as the volt-var modes

- **Functions** are the combination of settings for immediate control commands, such as INV3, adjust power factor. These usually involve percentages of maximum to allow inverters with different capabilities to respond appropriately.

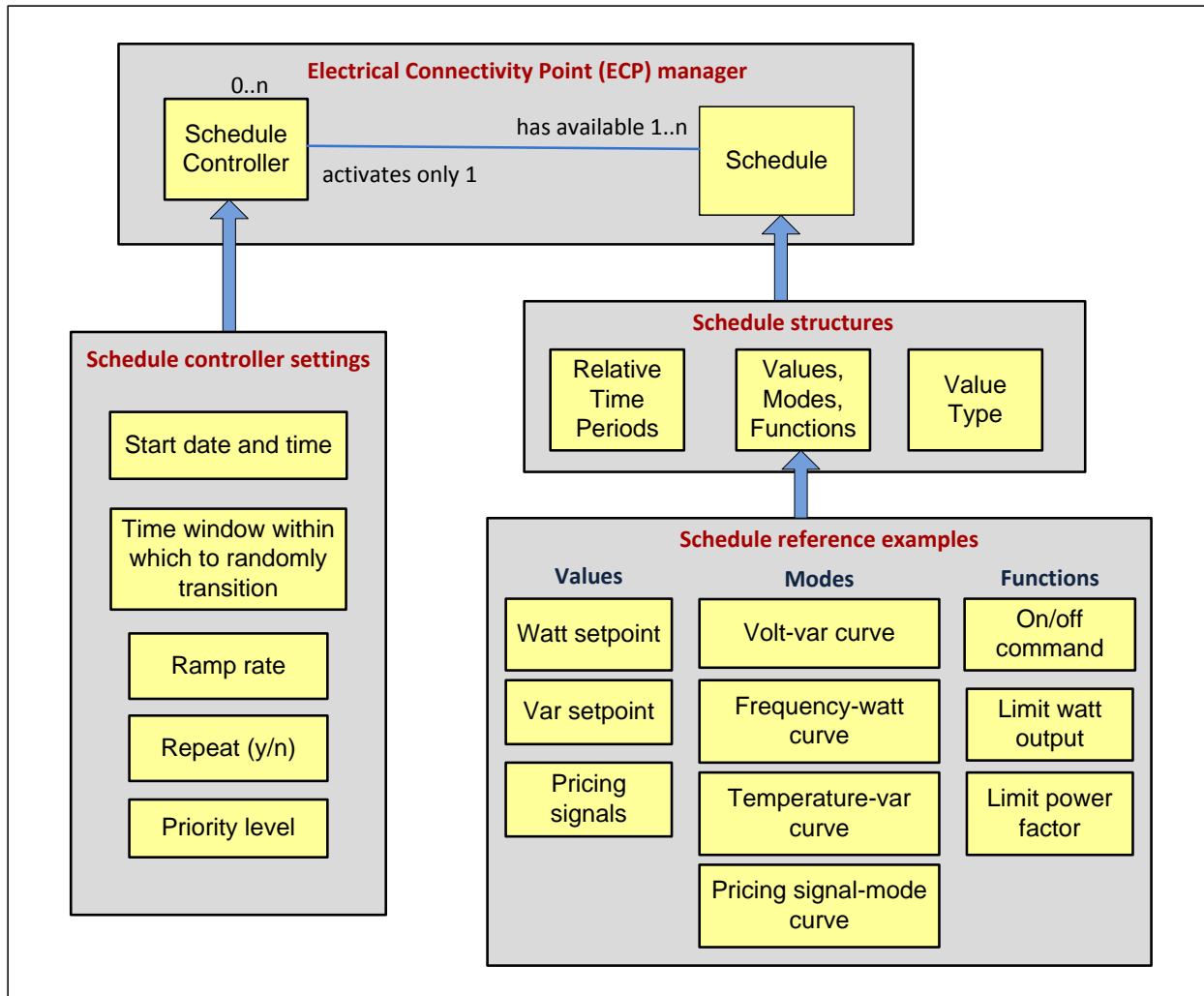


Figure 12: Interrelationships of schedule controllers, schedules, and schedule references

2.3.3 Schedule structure

Schedules may be used to establish:

- A direct setpoint value (e.g. active power value for each time period)
- A function (e.g. watt output limits) for each time period
- A mode (e.g. a volt/VAR mode or pricing signal mode) for each time period. Since modes may have more than one curve associated with them, the actual curve to be used is also established

Schedules contain the following information:

- Three correlated arrays:
 - Relative time ($t_{0..n}$): the initial entry will be added to the start date and time when the schedule is activated, the remaining entries are seconds from the initial entry, with the final entry acting as the stop time
 - Scheduled activity ($val_{0..n}$): value/function/mode to start (mode identifies which curve to use)
 - Value type ($valTyp_{0..n}$) across the time period between this entry and the next entry.
- Length of the 3 correlated arrays (length= $n+1$)
- Units of the Action. For example,
 - Direct setting value units like watts or VArS
 - Function identifier (reference to the function, such as INV2)
 - Mode identifier (reference to the mode, such as VV11)
- Descriptions and other optional information

2.3.4 Value types within schedules

Value types describe how the value in the schedule actually indicates what occurs during the time period. The types are “fixed” (no ramping), “ramp” (straight line ramp rate), and “average” (average of the value across the time period). See Figure 13 for examples of these value types.

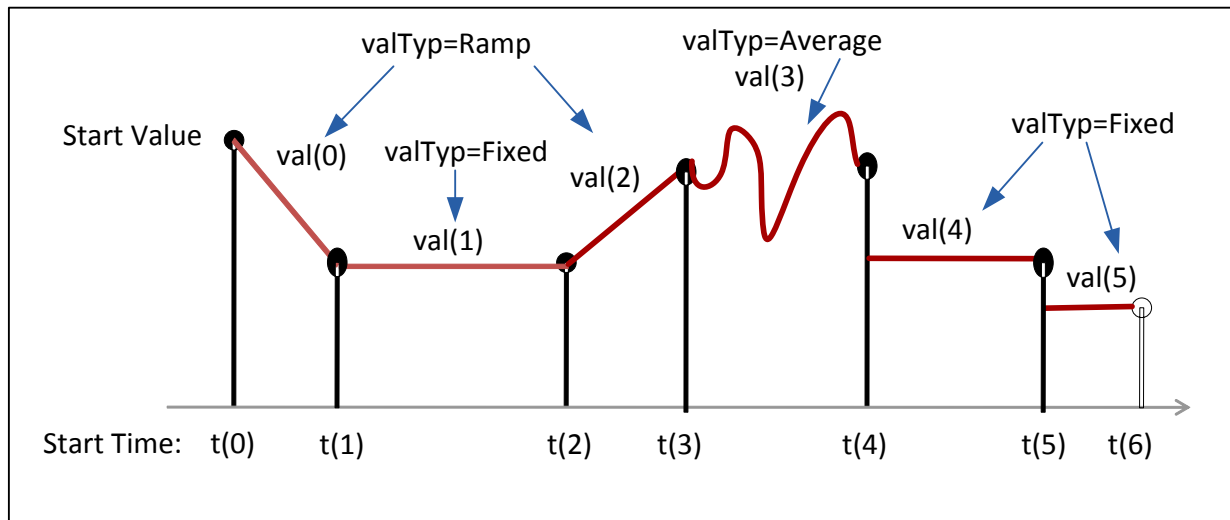


Figure 13: Schedule value types

Using the figure above, an example of a schedule using values is shown in Table 3:

Table 3: Schedule example using values (direct settings)

Time Period	Relative Time	Value/Function/Mode	valTyp	Description
t0	0 (start time)	val(0) = 40 kW	Ramp	At the start date & time + 0 seconds, ramp over 10 minutes (t1-t0) from wherever the inverter is to 40 kW

Time Period	Relative Time	Value/Function/Mode	valTyp	Description
t1	600 seconds	val(1) = 40 kW	Fixed	At the start date & time + 10 minutes, stay at 40 kW
t2	14400 seconds	val(2) = 60 kW	Ramp	At start date & time + 4 hours, ramp to 60 kW over 20 minutes (t3-t2)
t3	15600 seconds	val(3) = 60 kW	Average	At start date & time + 4h 20m, stay at 60 kW for 2h 20m (t4-t3), but allow average output over that time period.
t4	24,000 seconds	val(4) = 50 kW	Fixed	At the start date & time + 6h 40m, jump to 50 kW and stay there for 2h 20m (t5-t4)
t5	32,400 seconds	val(5) = 40 kW	Fixed	At start date & time + 9h 0m, jump to 40 kW and stay there for 1h 0m (t6-t5)
t6	36,000 seconds (stop time)			Stop schedule at start date & time plus 10 hours. Revert to default (unless repeated, or another schedule or command is initiated)

Another schedule example using modes rather than absolute values is shown in Table 4.

Table 4: Schedule example using modes

Time Period	Relative Time	Value/Function/Mode	valTyp	Description
t0	0 (start time)	val(0) = VV11, Curve 2	Ramp	At the start date & time + 0 seconds, ramp over 10 minutes (t1-t0) from wherever the inverter is to the VV11 (normal energy mode), using Curve 2
t1	600 seconds	val(1) = VV11, Curve 2	Fixed	At the start date & time + 10 minutes, use VV11 (normal energy mode), Curve 2 for 3h 50m (t2-t1)
t2	14400 seconds	val(2) = VV12, Curve 1	Ramp	At start date & time + 4 hours, use VV12 (max VAr mode), Curve 1 and ramp over 20 minutes (t3-t2)
t3	15600 seconds	val(3) = VV12, Curve 1	Average	At start date & time + 4h 20m, use VV12 (max VAr mode), Curve for 2h 20m (t3-t2), allowing average output over that time period.
t4	24,000 seconds	val(4) = VV11, Curve 4	Fixed	At the start date & time + 6h 40m, use VV11 (normal energy mode), with Curve 4 for 2h 20m (t5-t4)
t5	32,400 seconds	val(5) = VV11, Curve 2	Fixed	At start date & time + 9h 0m, use VV11 (normal energy mode), Curve 4 for 1h 0m (t6-t5)
t6	36,000 seconds (stop time)			Stop schedule at start date & time plus 10 hours. Revert to default (unless repeated, or another schedule or command is initiated)

2.3.5 Schedule controllers

Each schedule is associated with schedule controller which manages its state and run-time parameters. Schedule controllers may be associated with more than one schedule, but may have only one active schedule at a time.

The schedule controller can activate a schedule by providing:

- Start time and date which is added to the first time period: e.g. February 23, 2011, 6:30 + 0 seconds
- Time window within which to randomly start each change in the schedule, e.g. 300 seconds
- Repetition: none, daily, weekly, seasonally, or other periodicity
- Priority level: higher value takes precedence over lower value

2.3.6 Activation states of schedules

Schedules are in one of the following four states:

- Not available: the schedule is not available to be run. When first received, all schedules are placed in this state.
- Inactive: the schedule has been validated and determined to be ready for use, but does not yet have a start time and is not necessarily associated with a schedule controller. For instance, a schedule needs to be validated for consistency and reasonability, and the times must be monotonically increasing. The processes for determining readiness are outside the scope of this document.
- Ready-to-Run: a schedule controller has been associated with the schedule and has activated it by establishing the parameters for the schedule, including a start time. However, the start time has not yet arrived. Only one schedule can be ready-to-run for a schedule controller.
- Running: the start time of a ready-to-run schedule has arrived and/or passed, so the schedule is currently being executed. The associated schedule controller indicates which schedule is currently running and can provide information about its status.

Although a schedule controller can manage only one schedule at a time, an implementation may contain more than one schedule controller, so that multiple ready-to-run and running schedules may be in effect. Which of these has precedence depends on its priority and on what settings or functional modes are in effect in each of the running schedules. Priority settings are local issues.

2.3.7 Activating and running schedules

The process for activating schedules (making them ready-to-run) and running schedules is as follows:

- A command is received that identifies the schedule controller and the schedule that is to be made ready-to-run through it. The schedule controller will be provided at least the start time; other optional parameters, such as the time window, may be provided or may use default values. The schedule must be in the “inactive” state. If a command is received to activate a schedule that is “not available”, a negative “not ready” response must be returned.
- A ready-to-run schedule is set to the “running” state when the start time and date is reached.
- To start a ready-to-run schedule immediately, the start time is set to the current time.
- If a schedule is set to the “ready-to-run” state later than the start time, the schedule will start running immediately. The ramp type will be applied from the current time.

- If schedules which are mutually exclusive and which have the same priority overlap in time, the schedule with the more recent start time will become the effective one and will enter the “running” state. For instance, a volt/VAr mode that was more recently activated with the current time will pre-empt a volt/VAr mode that was already running.
- If schedules which are mutually exclusive and which are at different priorities overlap in time, the schedule with the highest priority will become the effective one and will enter the “running” state.
- If multiple compatible (not mutually exclusive) schedules are in the “running” state, those with the higher priority become effective if there is a conflict. For instance, a schedule may be running a volt/VAr mode, while a schedule using a temperature-based mode has its first temperature value at a high value. So long as the temperature is below that high value, the volt/VAr schedule is in effect. Above that temperature, the settings/mode in the temperature schedule pre-empts the volt-VAr schedule.
- If a running schedule reaches its stop time, another ready-to-run schedule which had been pre-empted will become effective again. Although the maximum number of such “layers” of schedules is not explicitly defined, it is expected that no more than 3 layers are reasonable for most implementations.

2.3.8 Deactivating schedules

A schedule that expires will automatically go to the “inactive” state.

A schedule can be directly set to “inactive” at any time through the schedule controller, whether it is in the “ready-to-run” or “running” states. This is done either by setting another regular schedule or graphic curve to running or by setting the value for the value/function/mode to the ID 0.

If a schedule that is running repeatedly is set to “inactive”, it will not only cease running, but it will not repeat.

2.3.9 Combinations and precedence of schedules

Combinations of schedules may build on each other so long as the types of requests are not mutually exclusive (for instance, volt/VAr mode schedules may be overlapping with watt/frequency mode schedules).

Combinations of schedules and immediate commands can also be used to build on each other or pre-empt each other for critical periods. For instance, a normal schedule of volt/VAr modes could be combined with a temperature-VAr mode which requests “max VAr output” if the temperature is above a critical high value. Or it could be combined with a pricing signal mode which could request power factor = 1 for a very high pricing signal during a power peak.

The priority of a schedule is set through the schedule controller. Precedence of different types of schedules is determined by their priority level value: the higher the value, the higher the priority. The actual setting of these priority levels is not standardized, but is determined locally during implementation.

3. DER management functions for inverters

3.1 Immediate control functions for inverters

Immediate control functions assume a tightly coupled interaction between the inverter-based DER devices and a controlling entity (utility, energy service provider, or Customer EMS). This implies that the controlling entity has knowledge about the capabilities of the inverter-based DER devices, can request updates on their current status, can expect the inverter-based DER device to follow the command to the best of their capabilities, and will receive a direct response from the inverter-based DER devices on the results from following the command.

Basic commands will supersede each other and any inverter mode commands in effect, based on the time they were issued by the controlling entity.

Basic commands also imply communication channels with high availability between the controlling entity and the inverter-based DER devices, since the controlling entity must maintain direct knowledge of the inverter-based DER device status and capabilities. Nonetheless, it is expected that inverter-based DER devices will revert to “default” states if communications are unavailable for some pre-specified length of time (implementation dependent).

It is expected that, in general, utilities will use direct controls with larger, utility-owned inverter-based DER devices, while ESPs could use direct commands with groups of inverter-based DER devices, and Customer EMSs could use direct controls with those inverter-based DER devices belonging to the customer. However, other interactions are possible, depending upon business decisions and specific implementations.

3.1.1 Function INV1: connect / disconnect from grid

This function causes the inverter-based DER device to immediately physically connect or disconnect from the grid via a disconnect switch at the inverter-based DER device’s ECP to the grid.

The utility/ESP or the Customer EMS takes the following actions:

1. **(Optional) Request status of inverter-based DER device:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
2. **Issue Connect/Disconnect Command to inverter-based DER device:**
 - a. Binary command to open or close a switch.
 - b. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately (optional – if not included, then default time window for this function will be used). The connection may be delayed due to necessary safety functions.
 - c. Timeout period, after which the inverter-based DER device will revert to its default status, such as closing the switch to reconnect to the grid (optional – if not included, then default timeout period for this function will be used)
3. **Receive response to the command:**
 - a. Successful (plus resulting switch position)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.2 Function INV2: adjust maximum generation level up/down

This function sets the maximum generation level at the electrical coupling point (ECP) as a percentage of set capacity (WMax). This limitation could be met by limiting PV output or by using the excess PV output to charge associated storage.

In addition, a ramp rate (power versus time) and a delay time before starting will be included so that not all inverter-based DER devices change state abruptly at the same time.

A timeout period is included for reverting to the default state of the inverter-based DER device, to ensure that a missed or lost command does not impact normal operations beyond that timeout period.

The utility/ESP or the Customer EMS takes the following actions:

1. **(Optional) Request status of inverter-based DER device:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
2. **Issue command to adjust power setpoint:**
 - a. Command to adjust the power setpoint to the requested generation level
 - b. Requested ramp time for the inverter-based DER device to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate: WGra)
 - c. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
 - d. Timeout period, after which the inverter-based DER device will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)
3. **Receive response to the command:**
 - a. Successful (plus actual maximum power setpoint)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.3 Function INV3: adjust power factor

Fixed power factor will be managed through issuing a power factor value. In addition, a ramp rate (change versus time) and a delay time before starting will be included so that not all inverter-based DER devices change state abruptly or at the same time.

A timeout period is included for reverting to the default state of the inverter-based DER device, to ensure that a missed or lost command does not impact normal operations beyond that timeout period.

The utility/ESP or the Customer EMS takes the following actions:

1. **(Optional) Request status of inverter-based DER device:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
2. **Issue command to adjust power factor setpoint:**
 - a. Command to adjust the power factor

- b. Requested ramp time for the inverter-based DER device to move from the current setpoint to the new setpoint (optional – if not included, then use previously established default ramp rate)
 - c. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
 - d. Timeout period, after which the inverter-based DER device will revert to its default status, such as resetting the power factor setpoint to its default value (optional – if not included, then default timeout period for this function will be used)
3. **Receive response to the command:**
- a. Successful (plus actual output power factor value)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.4 Function INV4: request real power (charge or discharge storage)

Inverter-based DER systems which can manage energy production through additional generation reserve and/or storage capabilities can also respond to requests to increase or decrease this energy production, although it is understood that they will always be in ultimate control of what actions they take and that these functions are “requests” to perform certain actions if feasible within pre-specified constraints. For example, a storage system cannot charge when the storage element is full nor can it discharge if at the storage reserve limit.

This function requests the storage system to charge or discharge at a specific rate (% of max charging or discharging rate). A controller might use this command frequently, in conjunction with reads of the battery charge level, to achieve a desired daily charge / dump characteristic.

To account for diversity in the size of storage systems, the function requests a percentage quantity based on the capacity of the system. For real power out requests (storage discharging), the percent is relative to the present maximum discharge rate (WMax, delivered). For real power in requests (storage charging), the percent is relative to the present maximum charging rate (WMax, received). It is acknowledged that the discharging capacity of the inverter and the charging capacity of the charger may differ.

A timeout period is included for reverting to the default state of the inverter-based DER device, to ensure that a missed or lost command does not impact normal operations beyond that timeout period.

The inverter-based DER system may also determine if only inverter-based DER device output is used for charging or whether grid power can be used.

The utility/ESP or the Customer EMS takes the following actions:

1. **(Optional) Request status of inverter-based DER system:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
2. **Issue command to request real power (charge/discharge) setpoint for the storage system:**
 - a. Command to adjust the real power charge/discharge setpoint for the storage system
 - b. Requested ramp time for the inverter-based DER system to move from the current setpoint to the new setpoint (optional – if not included, then use previously established default ramp rate)

- c. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
 - d. Timeout period, after which the inverter-based DER system will revert to its default status (optional – if not included, then default timeout period for this function will be used)
 - e. Storage charge from grid setting (yes/no)
3. **Receive response to the command:**
- a. Successful (plus actual real power setpoint)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

3.1.5 Function INV5: pricing signal for charge/discharge action

This function provides a pricing signal (actual price or some relative pricing indication) from which the inverter-based DER system may decide whether to charge the storage or discharge the storage, and what rate to charge or discharge.

The utility/ESP or the Customer EMS takes the following actions:

1. **Issue pricing signal (*the actual form or content of the pricing signal will be established by the utility/ESP and is outside the scope of this specification*):**
 - a. Pricing signal
 - b. Requested ramp time for the inverter-based DER system to move from its current output to any new output (optional – if not included, then use previously established default ramp rate)
 - c. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
 - d. Timeout period, after which the inverter-based DER system will revert to its default status (optional – if not included, then default timeout period for this function will be used)
2. **Receive response to the command:**
 - a. Successful (plus actual real power setpoint)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

3.2 Modes for volt-VAr management

3.2.1 Var management modes using volt/VAr arrays

Since utilities (and/or other energy service providers) will be requesting VAr support from many different inverter-based DER devices with different capabilities, different ranges, and different local conditions, it would be very demanding of the communications systems, unnecessary, and ultimately impossible for the utilities to issue explicit settings to each inverter-based DER device every time a change is desired.

Volt-VAR behaviours are configured into an inverter using arrays that establish a volt-VAR relationship or curve. Each volt-VAR behaviour is associated with a volt-VAR mode, and requests can be made to change modes by simply specifying the desired mode. This allows DER inverters to be addressed in groups, with each having tailored volt-VAR behaviours, and yet all able to be switched from one mode to another with minimal communication overhead.

Key inverter modes are described below, with the understanding that additional modes may be defined at a later date. In any of these modes, the inverter-based DER device would still be limited to what it can safely or physically provide, and will log its actions.

3.2.1.1 Volt-VAR modes

A number of examples of inverter modes have been defined (see *Modes VV11 – VV14*) for typical types of VAR support requests. For each inverter mode, one to a few volt/VAR arrays of settings can be associated (the maximum number that may be configured into an inverter is limited only by the device itself). Controlling entities (utility or other) may choose what kind of volt-VAR behaviour is desired for each mode and may configure inverters accordingly.

Each volt/VAR array consists of volt/VAR pairs: a set of voltage levels and their corresponding VAR levels that will be treated as a piecewise linear function. These arrays can be of variable length, depending upon the number of volt/VAR pairs. Utilities can pre-establish these volt/VAR arrays initially and update them when necessary.

3.2.1.2 Invoking volt-VAR modes

There are three ways a utility can invoke a volt-VAR mode:

- Direct requests to specific inverter-based DER devices
- Broadcasts or multicasts to all inverter-based DER devices in a selected area (region, feeder, substation) to use a particular volt/VAR array.
- Scheduling volt-VAR modes using different criteria.

Multiple volt-VAR modes may be ready-to-run at any one time. The most recently activated mode will take precedence over other modes. If the most recent mode is deactivated, the next most recent will take effect.

3.2.2 Volt-VAR mode VV11: normal energy conservation mode

As one example of Volt-VAR modes, the Normal Energy Conservation mode reflects the calculation of the most efficient and reliable VAR levels for inverter-based DER devices at specific distribution points of common coupling (PCC). This mode could also help compensate for local high voltage due to PV kW back flow on the circuit.

In this mode, inverter-based DER devices will be provided with a double array of setpoints: a set of voltage levels and their corresponding VAR levels as % of available VARs. The voltage levels will range between V1 and Vx in increasing voltage values. Values between these setpoints will be interpolated to create a piecewise linear volt/VAR function. The corresponding VAR levels define the percent of WMax requested for the voltage level.

Figure 14 provides one example of volt/VAR settings for this mode. It is assumed that the VAR value between VMin and V1 is the same as for V1 (VARMax, which is assumed to be 50%WMax, in this example). The equivalent is true for the VAR value between V4 and VMax (-VARMax, which is assumed to be 50%WMax, in this example).

Example Settings

Voltage Array (% VRef)	VAR Array (% WMax)
V1 97	Q1 50
V2 99	Q2 0
V3 101	Q3 0
V4 103	Q4 -50

VAR Ramp Rate Limit – fastest allowed decrease in VAR output in response to either power or voltage changes	50 [%WMax/second]
VAR Ramp Rate Limit – fastest allowed increase in VAR output in response to either power or voltage changes	50 [%WMax/second]
The time of the PT1 in seconds (time to accomplish a change of 95%).	10 seconds
Randomization Interval – time window over which mode or setting changes are to be made effective	60 seconds

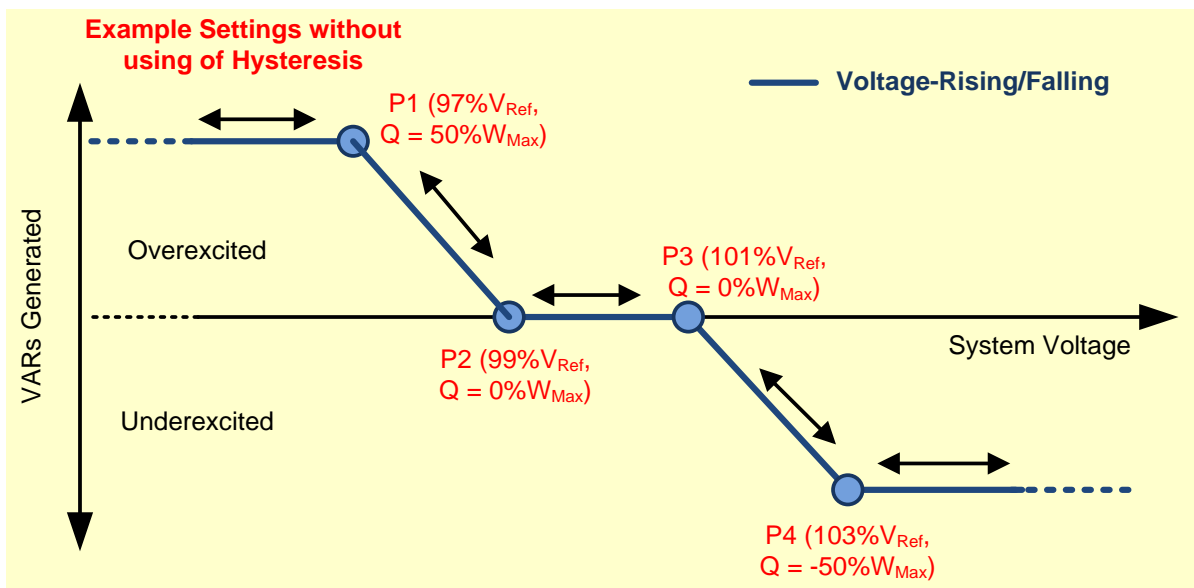


Figure 14: Volt-VAr mode VV11 – Normal Energy Conservation Mode

The steps to invoke the VV11 Mode are as follows:

1. Issue request to go into VV11 Mode:

- a. Request to go into VV11 Mode
- b. Array of volt/VAr of setpoints (optional – if not included, then use previously established default array)
- c. Requested ramp time for the inverter-based DER device to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
- d. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)

- e. Timeout period, after which the inverter-based DER device will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

3.2.3 Volt-VAr mode VV12: maximum VAr support mode

As another Volt-VAr example, inverter-based DER devices provide the maximum VArS currently available (VArMax available = is assumed to be 50%WMax) without reducing kW output or exceeding VMax. This mode would typically be invoked by the utility to support transmission VAr emergencies.

This function would essentially be represented as a straight horizontal line at VArMax = 100% (which is 50%WMax), until the IEEE 1547 low voltage limit or ANSI C84.1 high voltage limit is reached or the inverter protective limits are hit (although the actual VAr value of VArMax itself could vary at different voltage levels).

Figure 15 provides one example of how a VV12 mode may be configured. In this example, the inverter generates maximum capacitive VArS for reduced voltages down to the cut-off limit VMin. As voltage increases above configuration point V1, VAr generation is ramped down, reaching zero at V2, so as not to drive the local system voltage too high.

The ramp rates and/or the randomized time-constant settings are also required.

Example Settings

Voltage (%VRef)	Array	VAr Array (%WMax)	
V1	101	Q1	50
V2	103	Q2	0

VAr Ramp Rate Limit – fastest allowed decrease in VAr output in response to either power or voltage changes	50 [%WMax/second]
VAr Ramp Rate Limit – fastest allowed increase in VAr output in response to either power or voltage changes	50 [%WMax/second]
The time of the PT1 in seconds (time to accomplish a change of 95%).	10 seconds
Randomization Interval – time window over which mode or setting changes are to be made effective	60 seconds

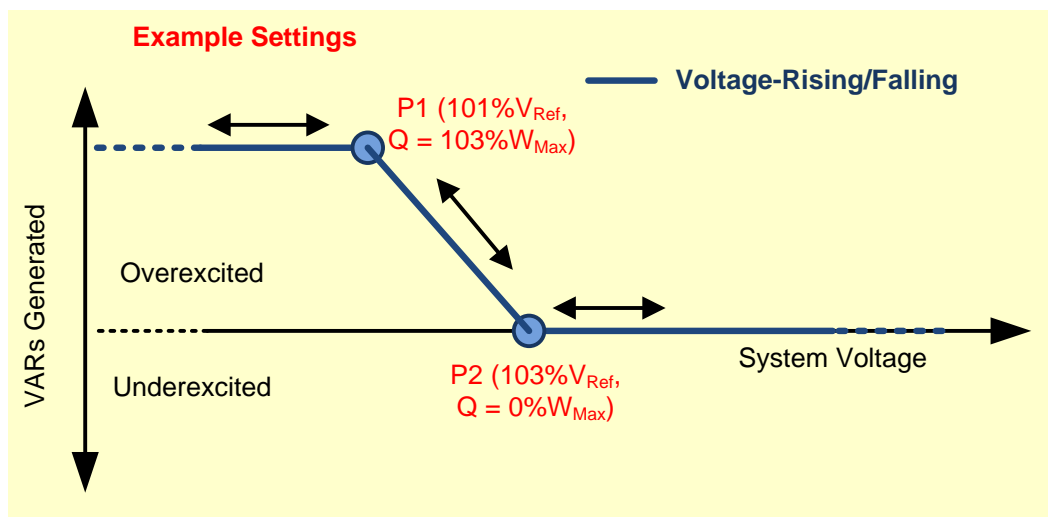


Figure 15: Inverter mode VV12 – VAr support mode

The steps to invoke the VV12 Mode are as follows:

1. Issue request to go into VV12 Mode:

- a. Request to go into VV12 Mode
- b. Array of volt/VAr of setpoints (optional – if not included, then use previously established default array)
- c. Requested ramp time for the inverter-based DER device to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
- d. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
- e. Timeout period, after which the inverter-based DER device will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

3.2.4 Volt-VAr mode VV13: static inverter mode

Another example mode, VV13, establishes fixed VAr settings for inverters.

This function can be typically represented as a straight horizontal line at a Q percentage value between +/-100% until the IEEE P1547 VMin/VMax levels or the inverter protective limits are reached. It is distinguished from mode VV14 only in that the Var level is assumed to be non-zero.

This mode is likely to be of interest in cases where a separate inverter-based DER system controller is managing the PV site. In such a case, the controller would be the point of intelligence, monitoring system voltage and communicating with the utility, then managing the local inverters moment by moment to achieve the desired results.

Figure 16 illustrates a case where mode VV13 is configured using two voltage points with the same VAr setting for each. This results in a flat VAr generation across the entire inverter operating range because of the previously defined flat behaviour above the highest voltage configuration point and below the lowest.

The ramp rates and/or the randomized time-constant settings are also required.

Example Settings

OutVArNomSet	50%WMax
Randomization Interval – time window over which mode or setting changes are to be made effective	60 seconds

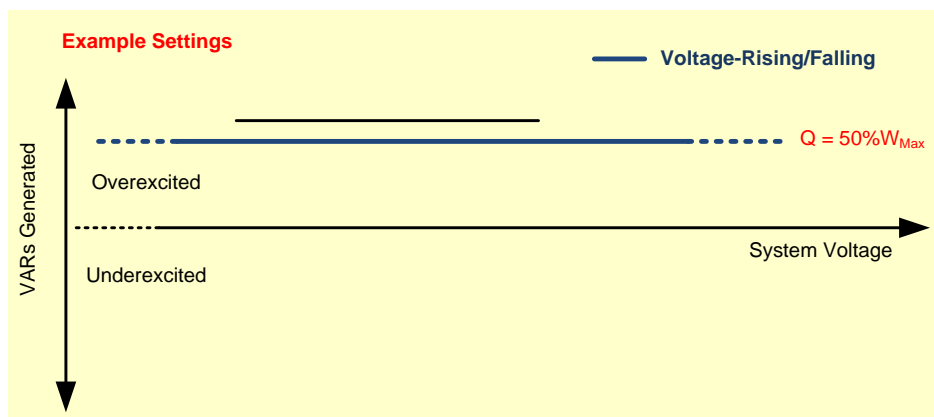


Figure 16: Inverter mode VV12 – VAr support mode

The steps to invoke the VV13 Mode are as follows:

1. **Issue request to go into VV13 Mode:**
 - a. Request to go into VV13 Mode
 - b. Adjust setpoint OutVArNomSet

- c. Requested ramp time for the inverter-based DER device to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
- d. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
- e. Timeout period, after which the inverter-based DER device will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

3.2.5 Volt-VAr mode VV14: passive mode

This example mode is the same as mode VV13 above, except that the VAr levels are zero. In this mode, inverters will follow the system voltage levels within their capability range, presumably at their most efficient settings. This would be the same as current UL 1741/IEEE 1547 compliant product.

This mode will serve as the default mode for inverter-based DER devices upon power up, when schedules expire, or if no communications have been received within a defined period (e.g. if no additional signals have been received over x hours or if the schedule has run out without further updates).

Utilities could switch some or all inverters to this mode if other modes presented unexpected difficulties.

The steps to invoke the VV14 Mode are as follows:

1. Issue request to go into VV14 Mode:

- a. Request to go into VV14 Mode
- b. Requested ramp time for the inverter-based DER device to move from the current setpoint to the new setpoint if either it is now being constrained or it is now being released from a constraint (optional – if not included, then use previously established default ramp rate)
- c. Time window within which to randomly execute the command. If the time window is zero, the command will be executed immediately, (optional – if not included, then default time window for this function will be used)
- d. Timeout period, after which the inverter-based DER device will revert to its default status, such as resetting the maximum power setpoint to its default value (optional – if not included, then default timeout period for this function will be used)

3.3 Modes for frequency-related behaviours

3.3.1 Frequency management modes

Frequency management modes are used to mitigate frequency deviations by countering them with reduced or increased power. These modes can be used for emergency situations involving very large frequency deviations, but can also be used continuously to smooth minor frequency changes. These modes also include the addition of hysteresis.

The curve shapes shown in *Figure 17* provide a generic example of the operating areas that could be specified. The vertical axis would be percent of WMax, and the horizontal axis is frequency, with nominal frequency (ECPNomHz) shown in the middle.

Utility-Defined Curve Shape

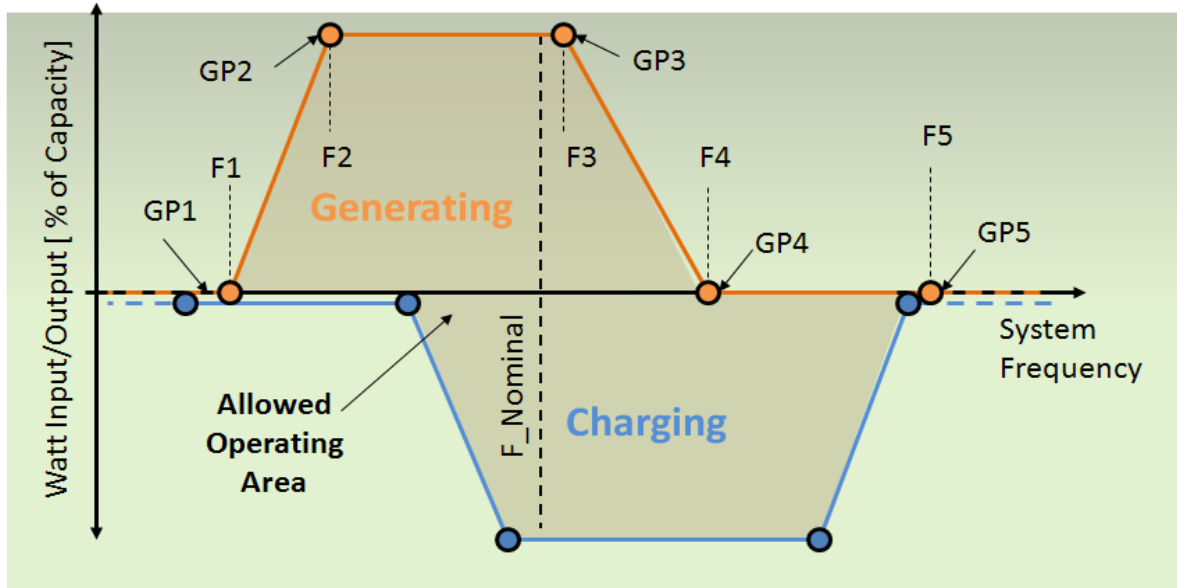


Figure 17: Frequency-watt mode curves

3.3.2 Frequency-watt mode FW21: high frequency reduces active power

This frequency-watt mode addresses the issue that high frequency often is a sign of too much power in the grid, and vice versa. These extreme deviations from nominal frequency can cause grid instability, particularly if they cause significant amounts of generating equipment to trip off-line.

One method for countering this over-power problem is to reduce power in response to rising frequency (and vice versa if storage is available). Adding hysteresis provides additional flexibility for determining the active power as frequency returns toward nominal. Figure 18 shows the necessary settings for the active power reduction by frequency.

The parameters for frequency are relative to nominal grid frequency (ECPNomHz). The parameter HzStr establishes the frequency above nominal at which power reduction will commence. If the delta grid frequency is equal or higher than this frequency, the actual active power will be “capped” at its current output level, shown as P_M . If the grid frequency continues to increase, the power cap will be reduced by following the gradient parameter (WGra), defined as percent of P_M per Hertz.

The parameter HystEna can be configured to activate or deactivate hysteresis. Without hysteresis (HystEna is deactivated), the power curve follows the same gradient back up as frequency is reduced (see top left graph in Figure 18). With hysteresis (HystEna is activated), the power curve remains capped at the lowest power level reached until the delta grid frequency reaches the delta stop frequency, HzStop (see top right graph and example in Figure 18).

For generation, the output power could be decreased to zero; for combinations of generation and storage, the output power may shift from decreasing generation to absorbing power (charging).

Whether or not hysteresis is active, the actual power will be uncapped when the delta grid frequency becomes smaller than or equal to the parameter HzStop. In order to prevent abrupt power increases after this uncapping of the actual power, an active power gradient is used as a time-based recovery ramp rate. This power gradient parameter, HzStopWGra, is defined in Wmax/minute. The default could be around 10% Wmax/minute.

Example Settings

Name	Description	Example settings
WGra	The slope of the reduction in the maximum allowed watts output as a function of frequency	40% P _M /Hz
HzStr	The frequency deviation from nominal frequency (ECPNomHz) at which a snapshot of the instantaneous power output is taken to act as the “capped” power level (PM) and above which reduction in power output occurs	0.2Hz
HzStop	The frequency deviation from nominal frequency (ECPNomHz) at which curtailed power output may return to normal and the cap on the power level value is removed.	0.05Hz
HystEna	A boolean indicating whether or not hysteresis is enabled	On
HzStopWGra	The maximum time-based rate of change at which power output returns to normal after having been capped by an over frequency event.	10% Wmax/minute

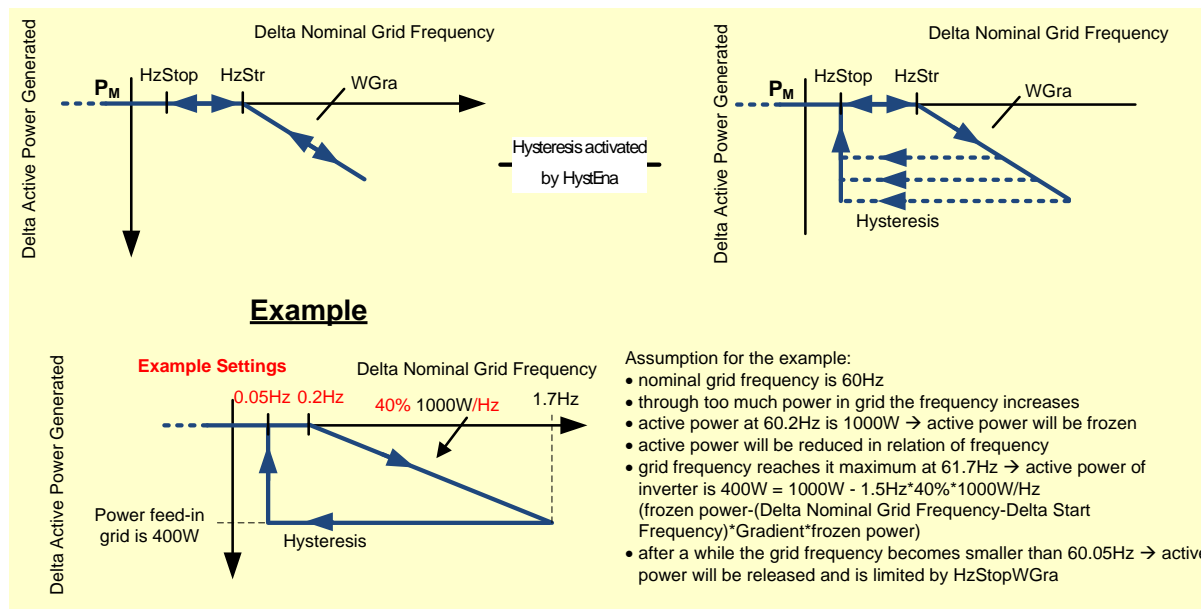


Figure 18: Frequency-based active power reduction

This frequency-watt mode is specifically designed for emergency situations involving grid stability concerns, and thus is expected to be rarely invoked. However, like all modes, it could be

activated in conjunction with other modes, including frequency-watt modes that respond to minor frequency deviations, such as FW22 and FW23.

The frequency-watt mode settings can be pre-specified at installation to act in all high/low frequency situations or can be modified and activated at a later time via the following actions:

Issue command to modify frequency-watt settings:

- Frequency-watt mode
- Triggering settings for frequency
- Hysteresis activation setting
- Gradient values
- Recovery ramp rate

Receive response to the command:

- Successful (plus new value of data element)
- Rejected (plus reason: equipment not available, message error, overridden, security error)

3.3.3 Frequency-watt mode FW22: constraining generating/charging by frequency

If more general response to minor frequency deviations is desired, particularly if both generation and charging of storage is included, then frequency-watt arrays need to be used, rather than the individual parameters defined in the FW21 mode.

There can be multiple frequency-watt modes configured into an inverter. For example, the desired frequency-watt settings might be different on-peak versus off-peak, or different when islanded (in isochronous mode) versus grid connected. A simple mode change broadcast could move the inverters from one pre-configured frequency-watt mode to another

The settings for this mode would include a frequency-watts-delivered curve (generation) and/or a frequency-watts received curve (storage), ramps for changing power, time of the input filter, and as with other functions, a time window, ramp rate, and timeout.

As another example, Figure 19 shows an equivalent approach to frequency-watt mode FW21, but using frequency-watt curves instead of individual parameters.

Example Settings

RmpTms for P1	10s
RmpTmmDec	100% Wmax/minute
RmpTmmInc	40% Wmax/minute
RmpRsUp	10% Wmax/minute

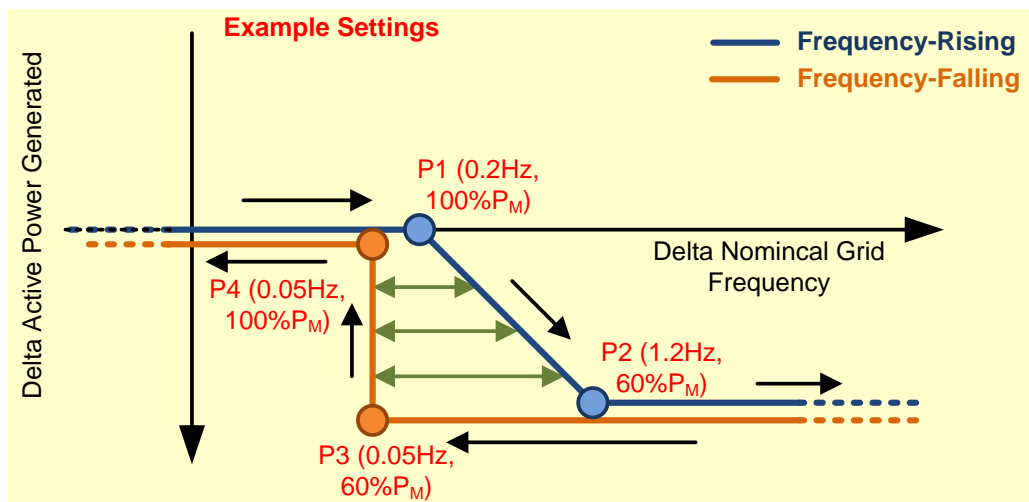


Figure 19: Frequency-based active power modification with the use of an array

Modes

As with the volt-var modes, there could be multiple frequency-watt modes configured into an inverter. For example, the desired frequency-watt settings might be different on-peak vs. off-peak or different when islanded vs. grid connected. A simple mode change broadcast could move the inverters from one pre-configured frequency-watt mode to another.

Basic Concept

The basic idea is illustrated in Figure 20.

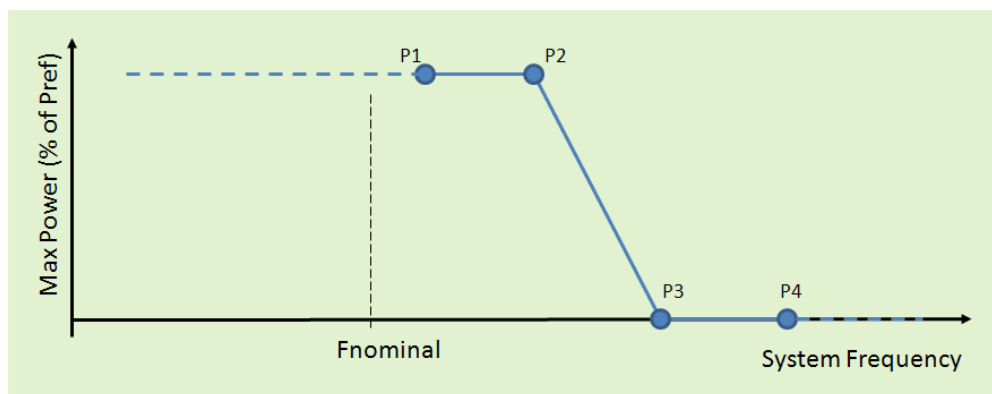


Figure 20: Example of a Basic Frequency-Watt Mode Configuration

The desired frequency-watt behaviour is established by writing a variable-length array of frequency-watt pairs. Each pair in the array establishes a point on the desired curve such as

those labelled in Figure 2 as P1-P4. The curve is assumed to extend horizontally to the left below the lowest point and to the right above the highest point in the array. The horizontal X-axis values are defined in terms of actual frequency (Hz). The vertical Y-axis values are defined in terms of a percentage of a reference power level (PRef) which is, by default, the maximum Watt capability of the system, Wmax (defined in prior work, may differ from the nameplate value). As will be explained later in this document, these Y-axis values are signed, ranging from +100% to -100%, with positive values indicating real power produced (delivered to the grid) and negative values indicating power absorbed.

Setting a Snap Shot Power Reference (PRef) Value

In some cases, it may be desirable to limit and reduce power output relative to the instantaneous output power at the moment when frequency deviates beyond a certain frequency. To enable this capability, each frequency-watt mode configuration will include the following parameters, in addition to the array.

Snapshot Enable (SnptW): A Boolean, which when true, instructs the inverter that the PRef value is to be set to a snapshot of the instantaneous output power at a certain point. When Snapshot is enabled, no reduction in output power occurs prior to reaching the PRef Capture Frequency (PRefHz).

PRef Capture Frequency (PRefStrHz): The frequency setting, in hertz, at which the PRef value is established at the instantaneous output of the system at that moment. This parameter is only valid if Snapshot Enable is true.

PRef Release Frequency (PRefStopHz): The frequency setting, in hertz, at which the PRef value is released, and system output power is no longer limited by this function. This parameter is only valid if Snapshot Enable is true.

Optional Use of Hysteresis

Hysteresis can be enabled for this frequency-watt function in the same way as with the Volt-Watt function defined previously. Rather than the configuration array containing only points incrementing from left to right (low frequency to high frequency), as indicated in Figure 2, hysteresis is enabled by additional points in the configuration array which progress back to the left. Figure 21 illustrates this concept.

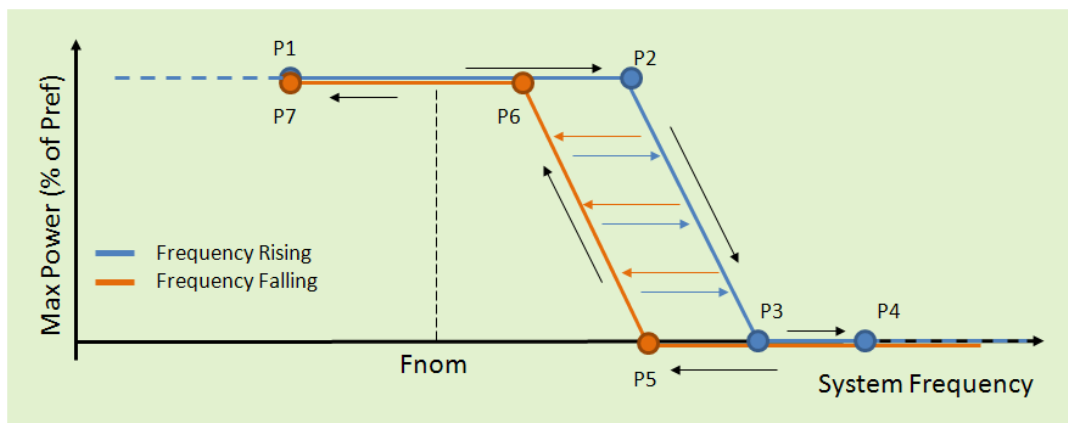


Figure 21: Example Array Settings with Hysteresis

In this case, the points in the configuration array can be thought-of as the coordinates for an X-Y plotter. The pen goes down on the paper at the first point, then steps through the array to the last point, tracing out the resulting curve. As with any configuration (including those without hysteresis), inverters must inspect the configuration when received and verify its validity before

accepting it. The hysteresis provides a sort of dead-band, inside which the maximum power limit does not change as frequency varies. For example, in Figure 3, if frequency rises until the max power output is being reduced (somewhere between points P2 and P3), but then the frequency begins to fall, the maximum power setting would follow the light orange arrows horizontally back to the left, until the lower bound is reached on the line between points P5 and P6.

The return hysteresis curve does not have to follow the same shape as the rising curve. Figure 22 illustrates an example of such a case.

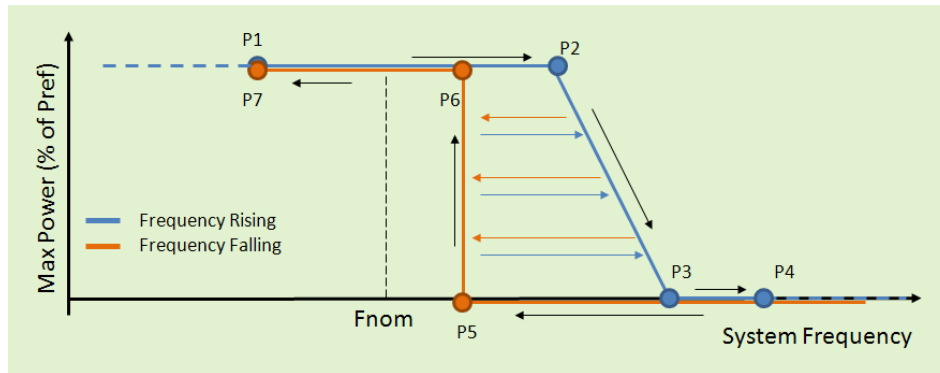


Figure 22: Example of an Asymmetrical Hysteresis Configuration

Controlling Ramp Time

It may be desirable to limit the time-rate at which the maximum power limit established by these functions can rise or fall. To enable this capability, each frequency-watt mode configuration will include the following parameters, in addition to the array.

Ramp Time Increasing and **Ramp Time Decreasing**: The maximum rates at which the maximum power limit established by this function can rise or fall, in units of %Wmax/second.

Supporting Two-Way Power Flows

Some systems, such as battery storage systems, may involve both the production and the absorption of Watts. To support these systems, a separate control function is defined, which is identical to that described above, except the vertical axis is defined as maximum watts absorbed rather than maximum watts delivered. This allows for battery storage systems to back-off on charging when grid frequency drops, in the same way that photovoltaic systems back-off on delivering power when grid frequency rises. Figure 23 illustrates an example setting.

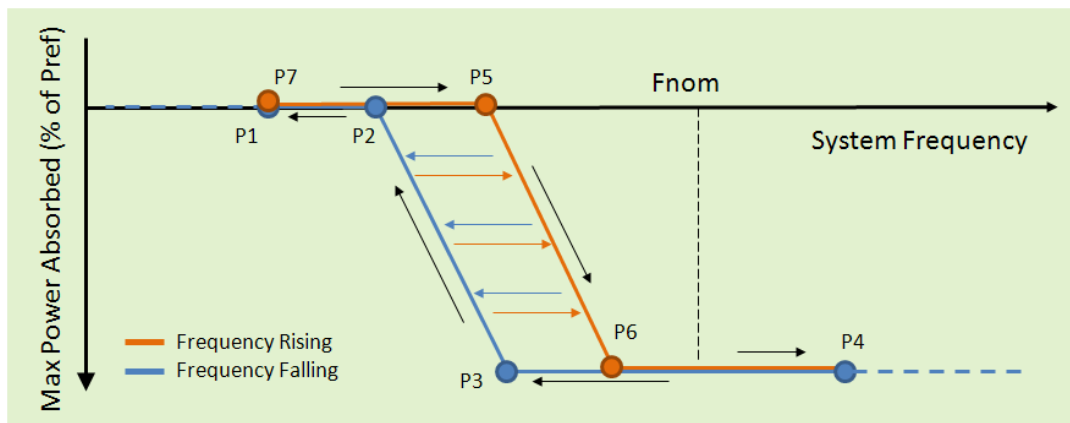


Figure 23: Example Array Configuration for Absorbed Watts vs. Frequency

A further characteristic of systems capable of two-way power flows is that the maximum power curtailment illustrated in Figures 2 through 4 need not stop at 0%. It may pass through zero, changing signs, and indicating that power must flow in the opposite direction (unless prevented from doing so by some other hard limitation).

For example, a battery storage system may be in the process of discharging, delivering power to the grid. If the grid frequency then rises above normal, the maximum delivered power level may begin to be curtailed. Once it has been curtailed to zero, if the frequency keeps rising, the system could be required to absorb watts, taking power out of the grid. Likewise, a battery storage system could curtail charging if the grid frequency drops too low, and begin discharging if frequency continues to drop further. These array configurations would utilize the signed nature of the array Y-values, as mentioned above.

3.4 Dynamic grid support during abnormally high or low voltage levels

The dynamic grid support function defines the requirements for inverters to support the grid during short periods of abnormally high or low voltage levels by feeding reactive current to the grid until the voltage either returns within its normal range or the inverter is forced to disconnect. This function is required in some regions in order to meet international laws and regulations¹.

3.4.1 Dynamic grid support mode TV31: dynamic grid support during abnormally high or low voltage levels

During abnormally high and low voltage levels, dynamic grid support by inverter-based DER systems can and/or must be taken to counter these abnormal conditions. These dynamic grid support actions are based on a combination of the actual voltage levels and the duration of these abnormal voltage dips/spikes.

The two zones (high abnormal voltage and low abnormal voltage) within which the inverter must support the grid are defined by two curves plotting abnormal voltage levels versus time. Within these abnormal voltage zones, specific volt-VAr modes of operation then take effect, overriding any other volt-VAr modes. The zones specified by this curve do not indicate where a disconnect must or must not take place – that is left up to the inverter, based on other settings and situations.

The same types of volt-VAr modes as used in other inverter functions can be used to define the volt-VAr actions during abnormal voltage conditions. This document provides the communications capability to set those curves, but does not specify what those settings actually are, since those may vary by country, region, or specific environment.

An example of the voltage dip curve is shown in Figure 24 as the B₂ zone; an equivalent but opposite curve could be developed for a voltage spike in the B₁ zone.

¹ The function may contain a description of the relevant European Standard EN 50549 law that is being met. Event logging will show when a law and its parameters have been changed.

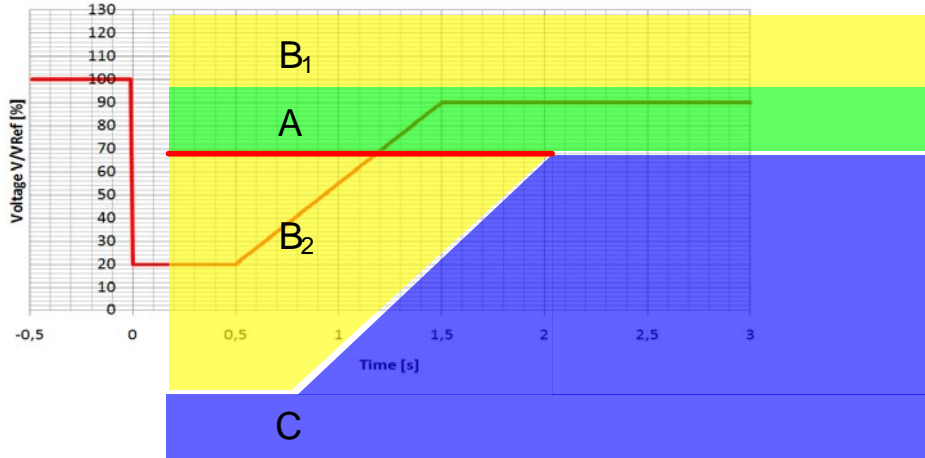


Figure 24: Dynamic grid support zones for Fault Ride Through²

Where the zones A, B₁, B₂, C are defined below:

A	Operation within this area must not cause instability or separation from the grid
B ₁	Injection of inductive reactive current (absorbing vars) to support the grid, until the fault is resolved (Over-voltage would be described in a separate curve so behaviour above 130% voltage is not shown in this diagram). The DER must stay connected in this zone.
B ₂	Injection of capacitive reactive current (supplying vars) to support the grid, until the fault is resolved. The DER must stay connected in this zone.
Lines between A and B ₂ and between B ₂ and C	Boundary of zone within which volt-VAr management is desired or required
C	Generating unit may disconnect or may stay connected depending upon the “must stay connected” and/or the “must disconnect” curves

3.4.2 Example of dynamic grid support capabilities

An example of dynamic grid support using 5 zones is shown in *Figure 26*, where each zone has been previously defined by voltage versus time curves or settings.

The voltage vs. time domain figure is separated in 5 sections.

- A. **Normal operation**, no disconnection from grid
- B. **B₁ and B₂ feeding reactive current** according to *Figure 26* “Feeding in reactive current”
- C. **Power output** disabled through blocking and/or disconnection from the grid
- D. **Device dependent low limit** of output disabling

² Based on EN 50549

E. **Hysteresis** which is applied between two zones to support Schmitt-Trigger behaviour for supplying power to the grid

In order to fulfil requirements of different countries the following settings can be applied. As shown in Figure 15, certain areas in the voltage vs. time domain are configurable. These areas are for blocking of the feed-in of power and can be configured as follows.

It can be assumed that every inverter has a limit of supplying power to grid during a fault and this area is called Fix Block Zone. The information (V_{BlockFix} , t_{BlockFix}) describing this zone should be provided as primary information. Above this area a hysteresis is applied which realizes a Schmitt-Trigger behaviour for supplying power to the grid. Additional to the Fix Block Zone the Adjustable Block Zone will be configured by a voltage and time set point as needed. The reference voltage for this function (see Figure 25) is V_{Ref} .

Figure 26 illustrates the volt-VAr modes that could be defined for the B_1 and B_2 Feed-In Zones as shown in Figure 25. I_B is the feed-in reactive current and I_N is the nominal active current determined by the reference active power and the nominal grid voltage. The centre point of voltage is the moving average voltage. The “deadband” reflects Zone A where these dynamic grid support curves are not applicable.

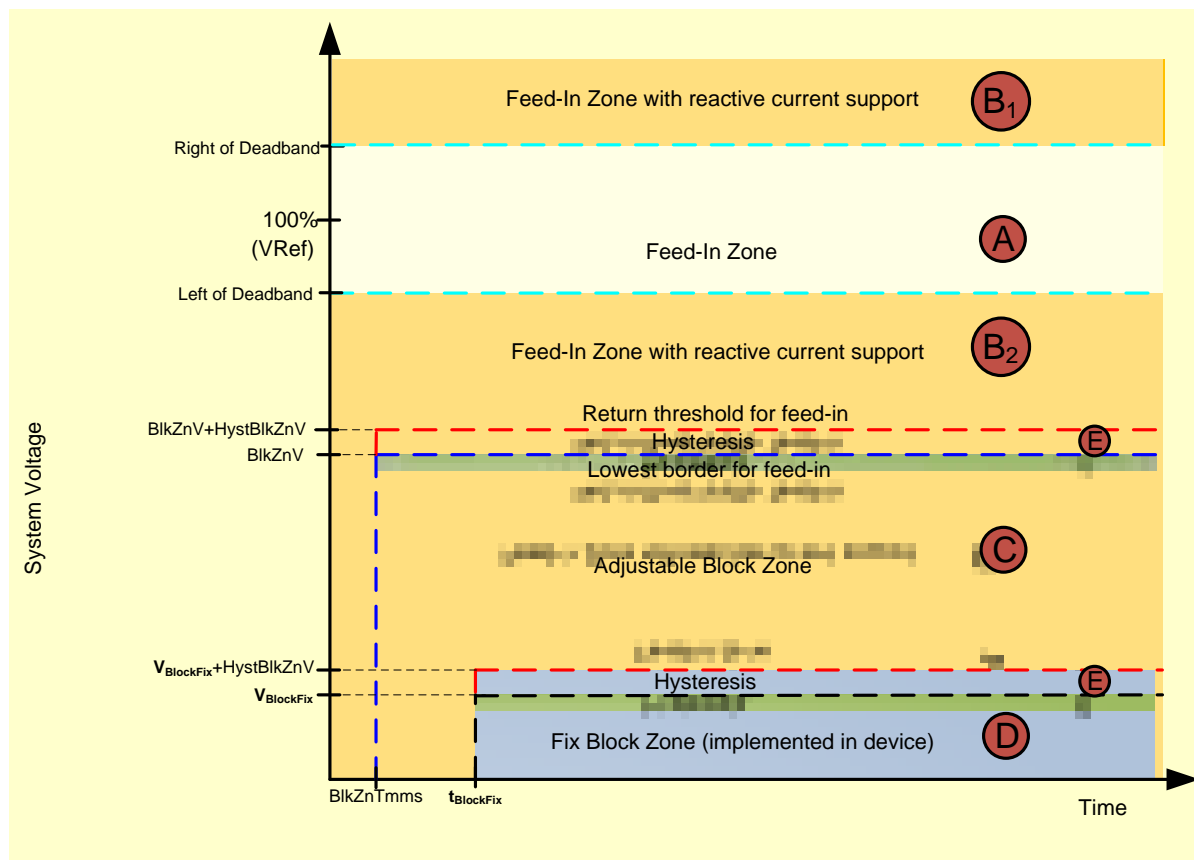


Figure 25: Dynamic grid support settings

Example Settings

HystBlkZnV	5% VRef
BlkZnV	70% VRef
BlkZnTmms	50ms

Figure 26 also illustrates the two possible methods: either the use of an additional reactive current (see top illustration) or specifying an absolute current (see bottom illustration). There is a setting, ArGraMod, which allows switching between these two methods. The delta current can be specified by the volt-var modes.

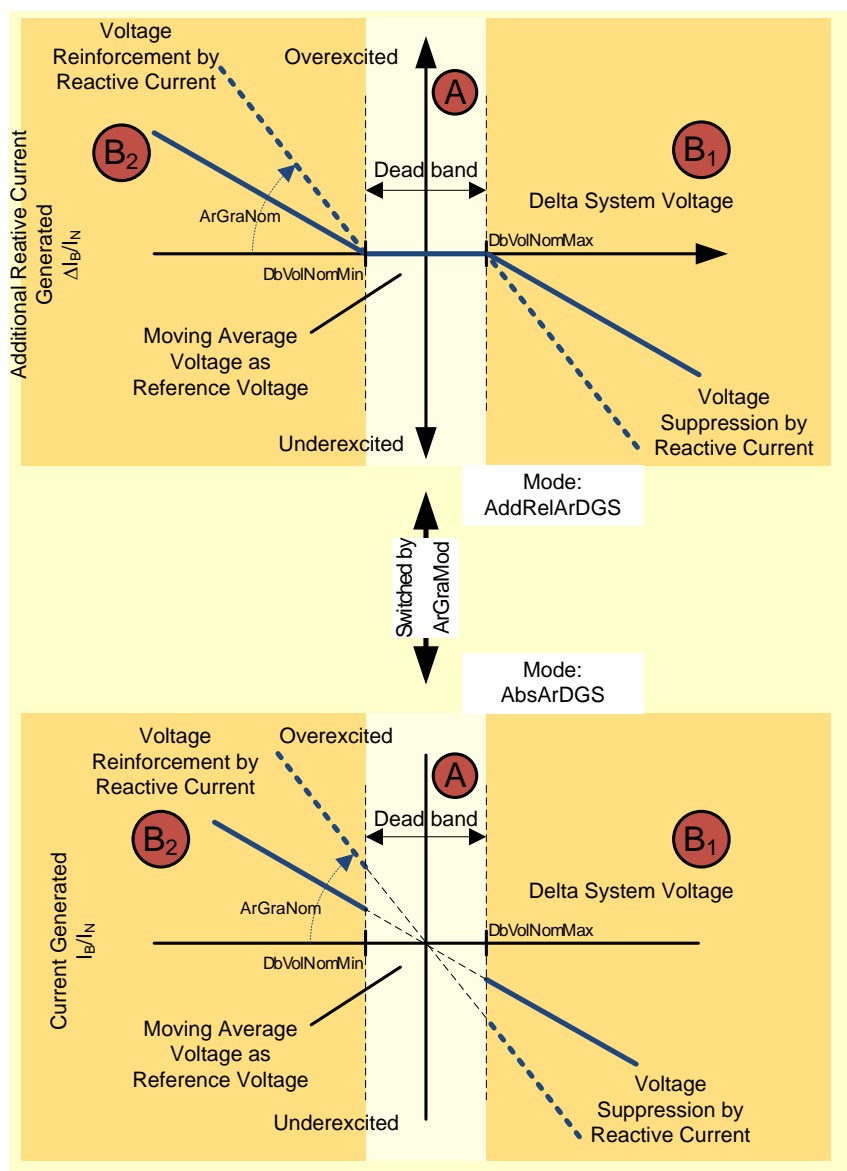


Figure 26: Feeding in reactive current

Example Settings

AGraMod	False = Relative current; True = Absolute current
ArGraNom	2
DbVMax	10% VRef
DbVMin	-10% VRef

3.5 Functions for “must disconnect” and “must stay connected” zones

Curves can also be used to define the “must disconnect” and “must stay connected” zones:

- **“Must disconnect”** zone of voltage levels versus time. This zone is defined by a combination of the inverter safety constraints, local regulatory requirements, and any specific operational situations (anti-islanding requirement).
- **“Must remain connected”** zone of voltage levels versus time. This curve is also defined by a combination of the inverter safety constraints, local regulatory requirements, and any specific operational situations (e.g. microgrid creation requirement).

3.5.1 “Must disconnect” MD curve

Some “must disconnect” curves are defined in standards like IEEE 1547. In addition, inverters have their own must-disconnect settings for safety reasons and/or to prevent possible damage to the equipment. This can be modelled by the existing over and under voltage protection functions.

The IEEE 1547 maximum clearing times for DER ≤ 30 kW (and default for DER > 30 kW) due to abnormal voltage levels are shown in *Figure 27*. These focus on the “must disconnect” aspects of voltage anomalies.

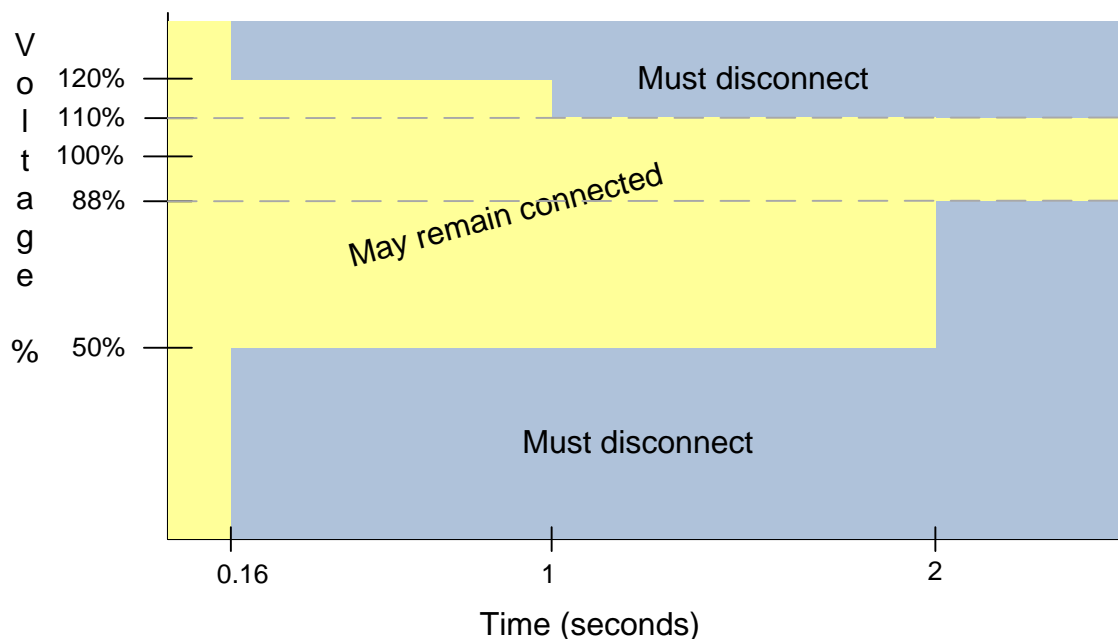


Figure 27: IEEE 1547 Abnormal voltage clearing times

3.5.2 “Must stay connected” MSC curve

Increasingly regulations are requesting DER system to remain connected during voltage anomalies, so long as they are not too long in duration. As described in the TV31 function, these “must stay connected” curves may be the same as those defined by regulations for that function, but may also be different. For instance, these curves may be modified by individual inverter sensitivities, since the safety of the equipment overrides any general regulations. Examples of some “must stay connected” curves are shown in *Figure 28*.

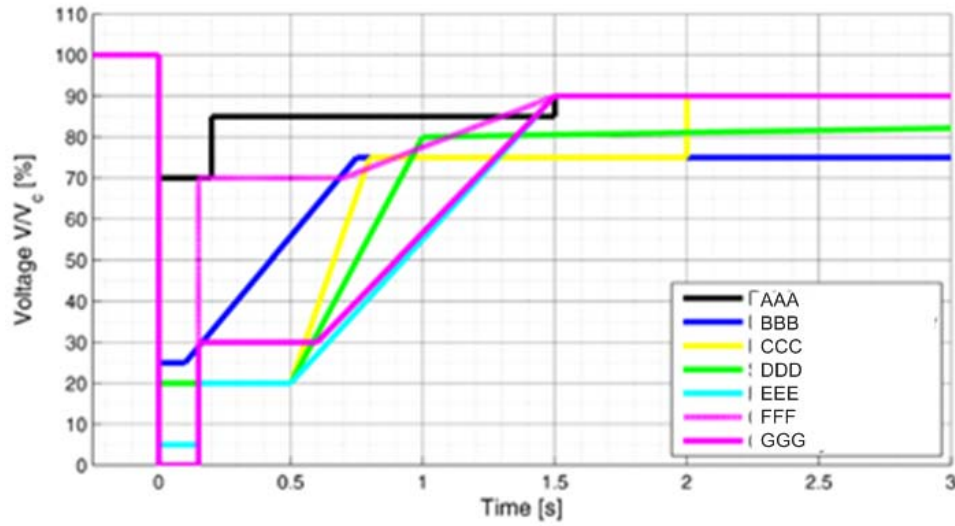


Figure 28: Examples of “must stay connected” requirements for different regions

3.5.3 Low/High Voltage Ride-Through (L/HVRT)

The Low/High Voltage Ride-Through (L/HVRT) functions will use configurable arrays. The arrays of X-Y points allow the user to define a piece-wise linear “curve” which defines the desired behaviour or operating bounds.

For LVRT, it is proposed that two curves may be defined, creating three regions as illustrated in Figure 29, including:

- Must Remain Connected
- Remaining Connected or Disconnecting is Allowed
- Must Disconnect

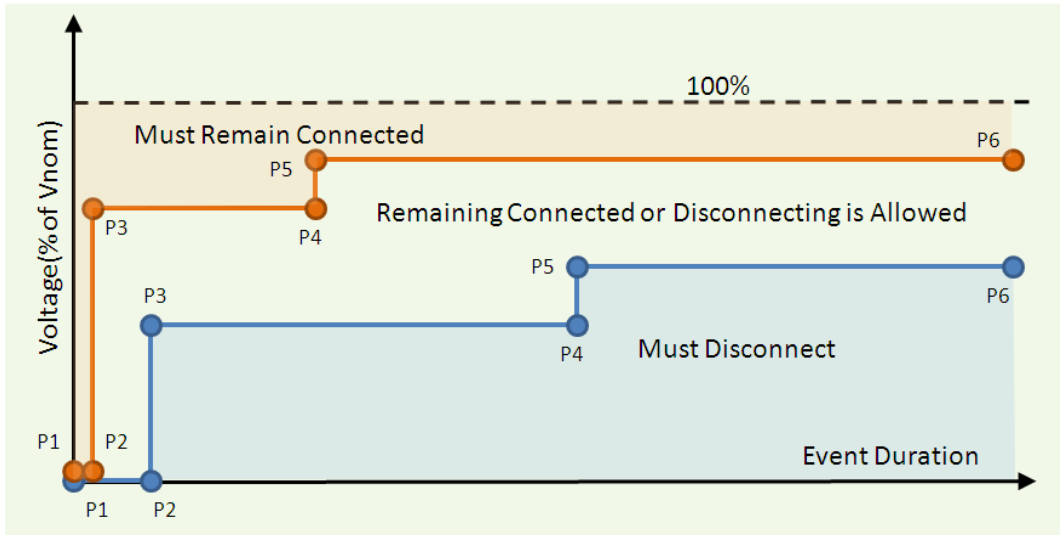


Figure 29: LVRT Areas Created by Two Configured Curves

These curves are illustrated with each using the same point label names (P1 through P6), because each will be configured separately, using independent x,y arrays.

Definition of the “Must Disconnect” curve is required for the LVRT function. If the “Must Remain Connected” curve is not defined, it is assumed to be the same as the “Must Disconnect” curve such that the middle area does not exist except as provided by hysteresis as described below.

All LVRT and HVRT curves are assumed to extend horizontally to the left to zero seconds below the first point in the array and to the right horizontally above the right-most point in the array. For example, in the blue curve in Figure 1, the configuration would have the same effect if point P1 and point P6 were removed from the configuration array. This interpretation is consistent with the other functions that have been managed by curves in this body of smart inverter communication work.

Although the example shown in Figure 1 shows only stair-step transitions, diagonal or sloping settings are also supportable using this array mechanism. Examples of such settings have been presented in other array-based functions such as the Volt-VAR modes.

3.5.3.1 Interpreting the Voltage-Time Curves

During voltage anomalies, measure the actual voltage level is complex. The following discussion identifies methods for interpreting voltage-time curves, particularly during tests. Certain voltage waveforms may be drawn in which the amplitude rises and falls, crossing over the set-boundaries one or more times (e.g. what if the voltage drops below the curve, but then rises again to a higher level, then falls again below the curve?). The settings relate to testing done with square-pulse conditions. Each test “event” will have an amplitude and a duration, as illustrated in Figure 30.

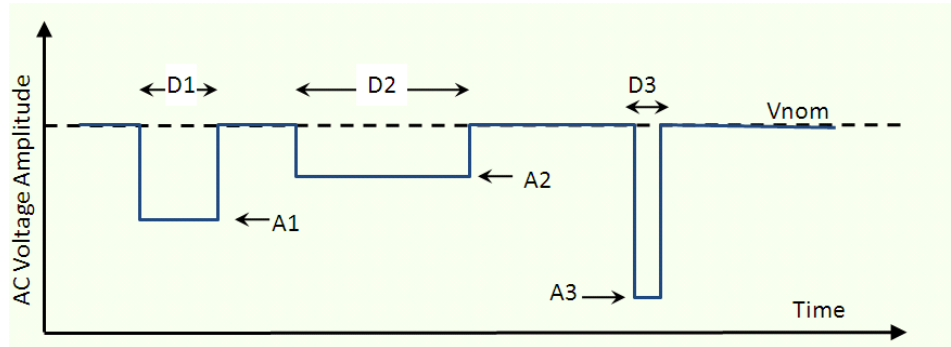


Figure 30: Example Low Voltage Test Events

Each test event amplitude and duration (e.g. (D1, A1), (D2, A2) or (D3, A3)) may be thought-of as an X,Y point that could be plotted on the graph of Figure 1. The configuration of Figure 1 is to thus be interpreted as establishing the boundaries for square-pulse event tests that a device should pass, either disconnecting or remaining connected accordingly. The test events are intended to be sufficiently separated in time so as to not interact. Each is a single event test, returning to Vnominal in between.

The specific techniques by which smart inverters may filter, average, or otherwise respond to time-varying voltage signal amplitudes are outside the scope of this communication specification. The square-pulse test description is included here only to provide clarification on the meaning of the curves established by the LVRT and HVRT configuration arrays.

3.5.3.2 Defining Voltage in Three Phase Systems

This communication document does not specify how three phase systems are to interpret L/HVRT settings relative to the three voltages they may measure. It is recognized that many scenarios exist, including the use of the highest of the three, the lowest of the three, or some combination or average. However, it is considered to be the purview of other codes and standards, such as those that may be produced by the IEEE, national governments, or other entities to define how L/HVRT settings are to be interpreted by poly-phase systems.

3.5.3.3 Pre-Clearing Behaviour During Voltage Events

During high or low voltage events, before disconnecting (clearing) occurs, it is intended that devices will continue to operate, delivering (or receiving in the case of storage devices) power to the grid to the best of their ability. Note that this L/HVRT function is accompanied by a “Dynamic VAR Support” function (documented separately) which, if used, may result in VAR support during low and high voltage events, in addition to continuance of Watt production as possible. It is acknowledged that solar and other variable sources are not predictable. It is also acknowledged that inverters have current limits, VA limits, or thermal limits that may prevent full power output at reduced or elevated voltage levels. Reductions in output in this regard are considered normal and acceptable, as long as devices continue to support the grid with real and reactive power as possible.

It is also recognized that this L/HVRT function may work in conjunction with the Dynamic Volt-Var Function, which is noted below and documented separately.

3.5.4 High Voltage Ride Through

It may be desirable to disconnect in response to high voltage events as well as low voltage events. This will be handled in the same way as LVRT using two additional curves as illustrated in Figure 31.

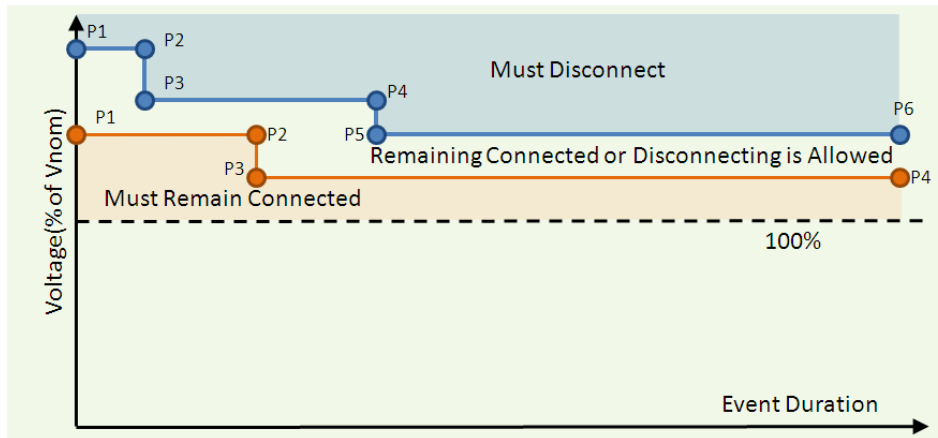


Figure 31: Areas for High Voltage Ride Through

As with the LVRT function, if the “Must Remain Connected” curve is not defined for the high voltage events, it is assumed to be the same as the “Must Disconnect” curve. If both LVRT and HVRT functionality is used, and each employs both the “Must Disconnect” and “Must Remain Connected” curves, then a total of four configured curves are used.

3.5.5 Providing for Hysteresis

Consistent with prior functions, each “curve” for LVRT and HVRT may include points that begin at the left (at or near time = 0), increase to a maximum time at the right side of the curve, then decrease back to the left (as illustrated in Figure 32) in order to define a hysteresis.

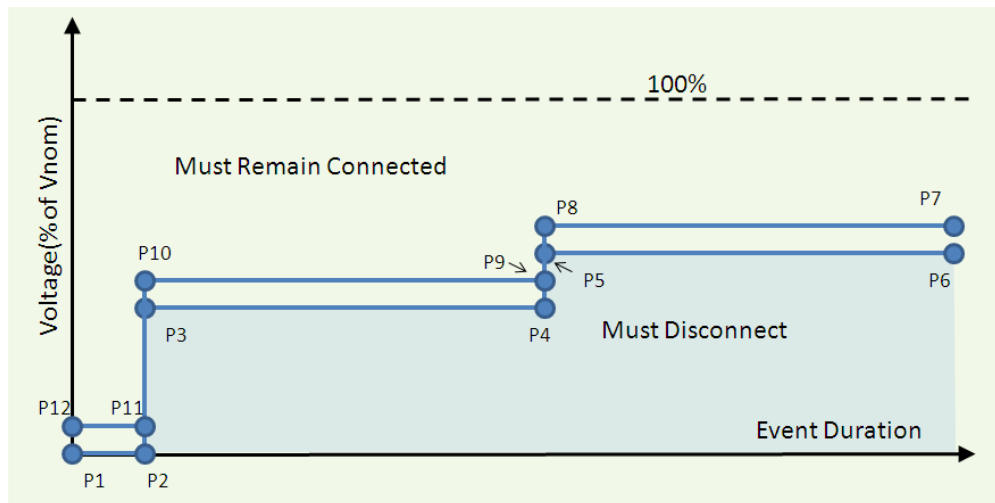


Figure 32: Example Curve with Hysteresis Included

Each of the four curves (two for LVRT and two for HVRT) may optionally be defined with hysteresis. As indicated in Figure 4, this is accomplished by configuring an array of points that begin at left most point (shown as P1), progress along the line defined by P2 through P5 to the maximum value (shown occurring at P6 and P7), then returning by a different path defined by P8 through P12.

As with other functions, hysteresis is indicated by any configuration curve in which the X-values decrease back toward the point of origin after reaching a maximum value.

When hysteresis is used, the curves are assumed to extend horizontally to the left (to zero seconds) below the first and last points in the array and to extend horizontally to the right above the highest X-value points in the array. The two points furthest to the right (P6 and P7 in this example) must have the same X-value.

3.5.6 Defining Parameters for Reconnect Behaviour

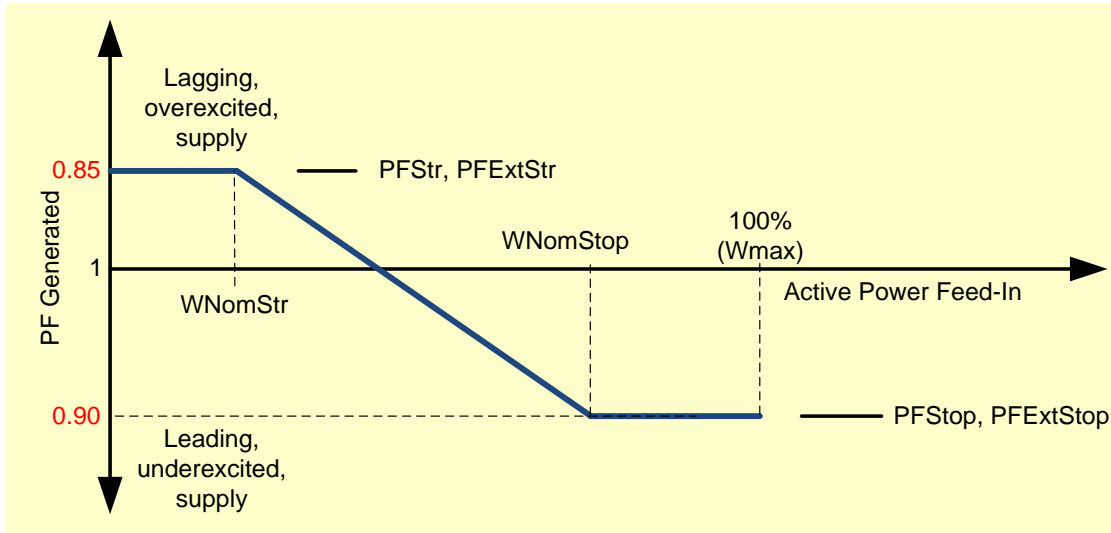
The settings defined above are intended to affect only the disconnect behaviour of the DER. Reconnecting may be managed by the following parameters:

Name	Description
VMaxReconnect	The maximum level of the service voltage before reconnecting may occur. In other words, the service voltage must be below this level before the DER may reconnect.
VMinReconnect	The minimum level of the service voltage before reconnecting may occur. In other words, the service voltage must be above this level before the DER may reconnect.
TInterruptLimit	The maximum duration of what may be considered a short-term interruption. Is also equal to the minimum duration of what may be considered a long-term interruption.
TDelayShortReconnect	Following a short term interruption, the minimum time delay after the service voltage is between VMaxReconnect and VMinReconnect, before reconnection may occur.
TWindowShortReconnect	A randomization window, after TDelayShortReconnect that is applied before reconnection occurs. In other words, after the service voltage is between VMaxReconnect and VMinReconnect, the DER will wait TDelayShortReconnect + Rnd(TWindowShortReconnect) before reconnecting.
TDelayLongReconnect	Following a long term interruption, the minimum time delay after the service voltage is between VMaxReconnect and VMinReconnect, before reconnection may occur.
TWindowLongReconnect	A randomization window, after TDelayLongReconnect that is applied before reconnection occurs. In other words, after the service voltage is between VMaxReconnect and VMinReconnect, the DER will wait TDelayLongReconnect + Rnd(TWindowLongReconnect) before reconnecting.

3.6 Modes for watt-triggered behaviours

3.6.1 Watt-power factor mode WP41: feeding power controls power factor

The amount of watts provided at the ECP can be set to gradually modify the power factor. This watt-power factor mode WP41 is shown in Figure 33. The power factor will be set in relation to the feeding power, in this example ranging from .85 overexcited (lagging) to .90 underexcited (leading).



Example Settings

Power (% WMax)		Power Factor		Power Factor with convention defined by PFsign. If Excitation convention is used, then the over or under excitation object is needed	
WStr	20	PFStr	0.85	PFEExtStr	Under excited -> False
WStop	40	PFStop	0.90	PFEExtStop	Under excited -> True

Figure 33: Power factor controlled by feeding power

These settings are not expected to be updated very often over the life time of the system. The utility/ESP or the Customer EMS takes the following actions:

- **(Optional) Request status of inverter-based DER device:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
- **Issue command to modify watt-PF settings:**
 - Watt-PF paired array to create the curve
 - Additional parameters
- **Receive response to the command:**
 - Successful (plus new value of data element)
 - Rejected (plus reason: equipment not available, message error, overridden, security error)

3.7 Modes for voltage-watt management

3.7.1 Voltage-watt mode VW51: voltage-watt management: generating by voltage

Similar to the frequency-watt mode FW22 a voltage-watt management can be used for smoothing voltage deviations.

There can be multiple voltage-watt modes configured into an inverter. For example, the desired frequency-watt settings might be different on-peak versus off-peak, or different when islanded versus grid connected. A simple mode change broadcast could move the inverters from one pre-configured voltage-watt mode to another.

Figure 34 shows one example for maximum watts generated versus voltage.

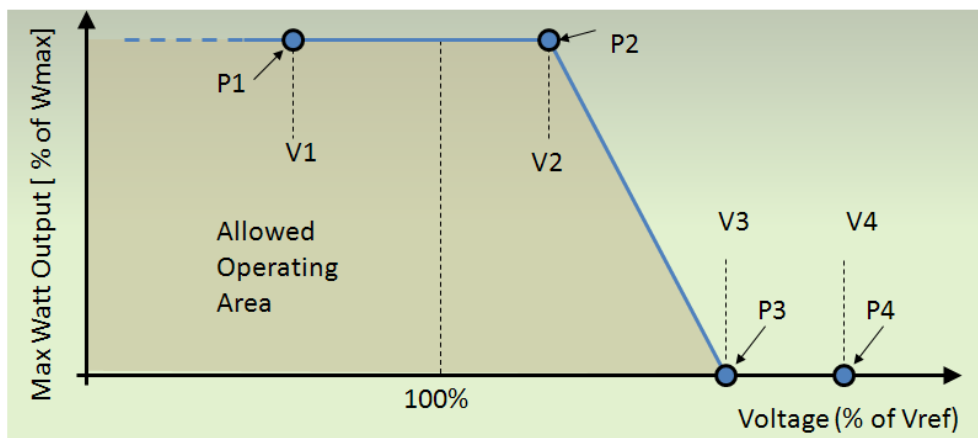


Figure 34: Example configuration curve for maximum watts vs. voltage

3.7.2 Voltage-watt mode VW52: voltage-watt management: charging by voltage

In addition to voltage-based management of generation, charging of storage units also can be affected by voltage-watt management. Figure 35 illustrates maximum watts absorbed by a storage device versus voltage.

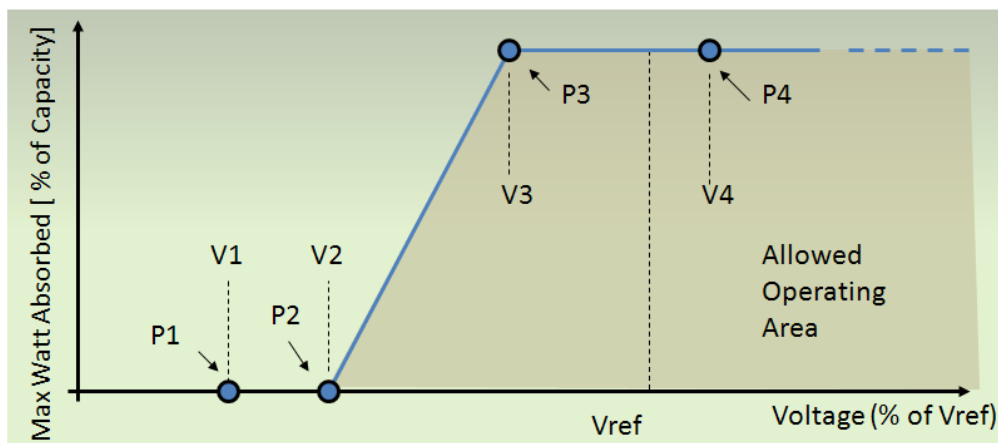


Figure 35: Example configuration curve for maximum watts absorbed vs. voltage

The settings for this mode would include a voltage-watts-delivered curve (generation) and/or a voltage -watts received curve (storage), ramps for changing power, time of the input filter, and as with other functions, a time window, ramp rate, and timeout.

The curve shapes shown in Figure 35 above are one example. The vertical axis would be percent of WMax, and the horizontal axis is voltage, with reference voltage (VRef) shown in the middle.

3.8 Modes for behaviours triggered by non-power parameters

3.8.1 Temperature mode TMP

The temperature mode invokes the temperature curve. In the temperature curve, the temperature is the primary value of the curve, while the secondary value identifies the action to take. Actions to take when the temperature is within one of the specified ranges can include functions, such as adjust power factor (IN3), or other modes, such as maximum VAr support mode (VV12).

A typical use would be for the inverter to respond with additional vars during very high temperatures, similar to a feeder's capacitor bank that is set to respond to temperature.

3.8.2 Pricing signal mode PS

The pricing signal mode invokes the pricing signal curve. In the pricing signal curve, the pricing signal is the independent variable of the curve, while the dependent variable identifies the action to take. Actions can include functions, such as adjust maximum generation level (IN2), or other modes, such as frequency-watt mode (FW21).

Multiple pricing signal curves can be established to reflect different energy and ancillary services. For instance, one pricing signal curve could be for watts, another for VAr support, and a third for frequency support. So long as they are not contradictory (e.g. two curves for watts), these modes can be activated for the same time periods.

The actual pricing signal would be received from an external source (e.g. broadcast by the utility/ESP) or from a schedule (e.g. pricing signal between 6 am and 2 pm, between 2 pm and 4:30 pm, and between 4:30 pm and 6 am). This pricing signal would be used with the activated curve to determine the DER response.

3.9 Setting and reporting functions

In addition to functions which directly control functions, many individual parameters can be set to different values in order to change the inverter's behaviour. Some of these settings are described below.

3.9.1 Establishing settings DS91: modify inverter-based DER settings

This function permits the utility, energy service provider, customer EMS, and/or other authorized entities to dynamically modify or update various parameters for inverter-based DER systems. This list of parameters may be expanded, but will include:

- **Intermittency Ramp Rate Limit.** This setting will limit the rate that watts delivery to the grid can increase or decrease in response to intermittent PV generation. The configuration will be in units of "percent of WMax per minute". A single setting will be applied to both increasing and decreasing power output. This ramp rate limit does not apply to output power changes in response to commands that are received. Such

commands contain their own ramp limits. Inverter-based DER systems must manage the details of their battery charging such that the rate of change in power delivery to and from the grid remains below this limit – even when the PV generation is intermittent.

- **Storage Reserve** (Minimum energy charge level allowed, % of maximum charge level). This level may be set by the vendor, asset owner, or system operator for a variety of purposes. In some cases, depth of discharge may be limited in order to extend battery service life. In other cases, a minimum reserve may be desired to provide some carryover during outage. It is intended that reserve settings be maintained even while managing intermittency ramp rate limits as described above. For example, a system with a 20% minimum reserve setting may charge up to 40% before beginning to generate to the grid so that a sudden loss of the PV source can be covered by a controlled ramp-down of generation, and yet without dropping below 20% charge.
- **Maximum Storage Charge and Discharge Levels.** These settings establish the maximum charge and discharge rates for storage elements that might be part of the DER. These settings are expressed in terms of a percentage of WMax, delivered and WMax, received, and by default are equal to 100% of these settings. Charge/Discharge commands, as described in INV4, are expressed in terms of a percentage of these settings.

The utility/ESP or the Customer EMS takes the following actions:

1. **(Optional) Request status of inverter-based DER device:** Request a pre-defined set of the status information, including the status values, the quality flag, and the timestamp of the status (see Function DS93 for details of status points).
2. **Issue command to modify inverter-based DER settings:**
 - a. Data element to be modified
 - b. New value for that data element
3. **Receive response to the command:**
 - a. Successful (plus new value of data element)
 - b. Rejected (plus reason: equipment not available, message error, overridden, security error)

3.9.2 Event logging DS92: log alarms and events, retrieve logs

3.9.2.1 Event log concepts

Event/history logs are maintained by the inverter-based DER systems to record key time-stamped events. The event log can be queried by selecting time ranges.

Different users of inverter-based DER systems will need varying timeframes for retrieving event log information and different types of information from these event logs:

- Utility operations will typically only need key operations-related information, possibly infrequently or only under special circumstances.
- Owners/managers (including utility owners) will want more detailed information, probably periodically or after certain types of events.
- Energy management systems with tightly-coupled interactions will need complete event logs relatively frequently.

- Larger PV plants are different from large numbers of small inverter-based DER systems: more types of event data may be collected from these larger plants, while only basic event data may be collected from the smaller inverter-based DER systems. Larger plants may also aggregate and/or amalgamate events from multiple individual inverter-based DER devices.

In general the following types of events will be logged, but decisions on exactly which ones are logged or which ones are retrieved by any specific user, will be determined on an implementation basis by DataSets, Logs, and LogControlBlocks:

- All errors or failures (service tracking and logging)
- All startup and shutdown actions (logging)
- All control actions (service tracking and logging)
- All responses to control actions (service tracking and logging)
- All limit violations, including returns within limits (logging)

Note: Service tracking is a new service defined in IEC 61850-7-2 Edition 2.

3.9.2.2 Event Log Fields

All event logs will contain the following 4 fields:

1. **Date and time stamp:** The accuracy of this timestamp will be determined by the frequency of time synchronization and the innate precision in keeping time of the inverter-based DER system, and is therefore outside the scope of this specification. Zeros can be used to pad any timestamp if the accuracy does not match the format.
2. **Data reference:** the reference to the data item that triggered the event log entry. For instance, if it is a voltage-related event, the Data reference will be to that data object. If it is an inverter mode event, the Data Reference will be to the inverter mode data object.
3. **Value:** Value field of the Data reference field that is triggering the event, including commands, state changes of monitored values, quality code changes, mode setting, etc. For instance, the request to go into a specific inverter mode will be logged with the Value containing the inverter mode identity.

To enable the filtering of events so that different users can select different types of events to retrieve, different logs can be used. These different logs may be set up to differentiate different types of events, such as:

- Communications (for communication-related events)
- Grid power (for power system events)
- Device asset (for time and asset-related events)
- Security (for security-related events)
- Inverter-based DER system (for inverter-based DER device events, as well as other PV events)
- Storage system (for storage inverter events, as well as other storage events)

Table 5 shows some examples of events that are logged.

Table 5: Event Codes

Domain	Part	Type	Attribute	Description
Communications	Messaging	Status	Success	Request received successfully. Value field identifies the request as a "demand response"

Domain	Part	Type	Attribute	Description
	Messaging	Status	Success	Command received successfully. Value field identifies the command as a "Direct command"
	Messaging	Status	Acknowledged	Response – acknowledgment sent
	Messaging	Alarm	Message failed	Response – alarm invalid message. Value field contains type of error.
	Network interface	Alarm	Comm. failed	Alarm communications error. Value field contains type of error.
PV System	Inverter	Command	Success	Action taken successfully (details are provided in Mode and Command events)
	Inverter	Command	Failed	Requested action failed. Value field contains type of error.
	Inverter	Command	Deviation	Action taken is a deviation from the requested action. Data Reference and Value fields contain indication of this deviation
	Mode	Status	Inverter mode	Inverter is in one of the inverter modes, as indicated in the Value field
	Inverter	Command	INV Command	Inverter responded to one of the INV commands, as indicated in the Value field
	Inverter	Status	Limit exceeded	Inverter status changed due to internal control threshold exceeded. Data Reference and Value fields provide details
	Schedule	Schedule change	Success	Action was successfully taken in response to the scheduled requirement
	Schedule	Schedule change	Failed	Action failed in response to the scheduled requirement. Value field indicates the type of error
	Power	Status	Power out	Inverter power turned off
	Power	Status	Power on	Inverter power turned on
	Power	Alarm	Power out	Power tripped off due to internal situation
	Power	Alarm	DC voltage	Inadequate DC bus voltage, Value field provide measured value
	Power	End alarm	DC voltage	DC bus voltage within limits. Value field provide measured value

Domain	Part	Type	Attribute	Description
	Temperature	Alarm	Limit exceeded	Temperature limit exceeded. Value field contains type of error.
	Temperature	End alarm	Limit exceeded	Returned within temperature limit. Value field contains type of error.
Grid Power	ECP Switch	Status	Connected	Switch at the ECP between inverter and the grid is connected
	ECP Switch	Status	Disconnected	Switch at the ECP between inverter and the grid is disconnected
	Voltage	Alarm	Limit exceeded	Voltage limit exceeded. Value field contains voltage measurement.
	Voltage	End alarm	Limit exceeded	Returned within voltage limit. Value field contains voltage measurement.
	Voltage	Alarm	Limit exceeded	Voltage distortion limit exceeded. Value field contains voltage distortion.
	Voltage	End alarm	Limit exceeded	Returned within voltage distortion limit. Value field contains voltage distortion.
	Current	Alarm	Limit exceeded	Current limit exceeded. Value field contains current measurement.
	Current	End alarm	Limit exceeded	Returned within current limit. Value field contains current measurement.
	Power quality	Alarm	Limit exceeded	Harmonic limit exceeded. Value field contains harmonic measurement.
	Power quality	End alarm	Limit exceeded	Returned within harmonic limit. Value field contains harmonic measurement.
	Other 1547 parameters	Alarm	Limit exceeded	High/low limit exceeded
	Other 1547 parameters	End alarm	Limit exceeded	Returned within high/low limit
Device asset	Logs	Status	Almost full	Log is almost full. Value contains percentage full.
	Logs	Alarm	Full	Log full: new events to overwrite unread events
	Time	Alarm	Clock failed	Clock failure. Value contains error information.
	Time	Alarm	Synch failed	Synchronization failed. Value contains error information

Domain	Part	Type	Attribute	Description
	Time	Setting	Synchronized	Synchronized. Value contains delta between new time and old time
	Time	Setting	Daylight adjust	Daylight time or Standard time adjustment. Value indicates Daylight of Standard
	Firmware	Alarm	Data error	Data error detected in firmware. Value indicates type of error

The retrieval of the event log consists of the following command and response:

1. Retrieve event log

- a. Event log retrieval command
- b. Retrieval criteria: event codes to be retrieved, with “wildcard” capabilities
- c. Start time/ stop time (start time = 0 means start from beginning of log; stop time = 0 means include through the final log entry)

2. Receive response to the command:

- a. Requested log entries
- b. Success/Failure (plus reason: no log event fulfils the retrieval criteria, log not available, message error, security error, request type not supported, etc.)

Additional event log interactions can include:

- Notification if event log is almost full or completely full without having been retrieved
- Notification of an event log error

3.9.3 Reporting status DS93: selecting status points, establishing reporting mechanisms

Many functions require the status of the inverter-based DER device either periodically, on significant change of a value, or upon request.

Examples of status information that is standardized in the corresponding Logical Nodes are listed in *Table 6*. These status information points and any other information (standardized and extended Logical Nodes and Data Objects) can be used to configure DataSets that were used by ReportControlBlocks. The ControlBlocks can be configured to get the required reporting behaviour (periodic, sequence of events, or general interrogation).

Table 6: Standardized status points

Status Point	Description
Primary information	
Connect status	Whether or not the device is currently connected at its ECP.
PV output available	Yes/No
Storage output available	Yes/No
Status of VAr capability	Yes/No

Status Point	Description
Inverter active power output	Present real power output level (Watts). This is an instantaneous (minimum averaging) reading.
Inverter reactive output	Present reactive power output level (VARs, underexcited (leading) or overexcited (lagging)). This is a signed quantity.
Current inverter mode	Identity of mode or function that the inverter-based DER is in, including "owner mode" (Enumeration with range left open for proprietary vendor)
Detailed information	
Inverter status	Inverter is switched on (operating), off (not able to operate), or in stand-by mode (capable of operating but currently not operating)
DC Current level available for operation	Indicates whether or not there is sufficient DC current to allow operation. – Value, not yes/no
Inverter active power output	Present real power output level (Watts). This is an instantaneous (minimum averaging) reading.
DC inverter input power	Use for determining efficiency of inverter
Local/Remote control mode	Inverter is under local control or can be remotely controlled
Real power setpoint	Value of the real power setpoint
Reactive power setpoint	Value of the output reactive power setpoint
Power factor setpoint	Value of the power factor setpoint
Power measurements	
Active power	Active power value, plus high and low limits
Reactive power	Reactive power value, plus high and low limits
Phase to ground voltages	Voltage values per phase, plus high and low limits
Power factor	Power factor value, plus high and low limits
Battery storage status (if storage is included in inverter-based DER system)	
Capacity rating	The useable capacity of the battery, maximum charge minus minimum charge from a technology capability perspective (Watt-hours)
State of charge	Currently available energy, as a percent of the capacity rating (percentage)
Available energy	State of charge times capacity rating minus storage reserve (Watt-hours) See storage settings section for definition of "storage reserve"
Maximum battery charge rate	Set using DS91. The maximum rate of energy transfer into the storage device. (Watts) This establishes the reference for the charge percentage settings in function INV4.
Maximum battery discharge rate	Set using DS91. The maximum rate of energy transfer out of the storage device (Watts).This establishes the reference for the discharge percentage settings in function INV4.

Status Point	Description
Internal battery voltage	Internal battery voltage
DC inverter power input	Used for determining efficiency of inverter
Nameplate and Settings Information	
Manufacturer name	Text string
Model	Text string
Serial number	Text string
Inverter power rating	The continuous power output capability of the inverter (Watts)
Inverter VA rating	The continuous Volt-Amp capability of the inverter (VA)
Inverter VAR rating	Maximum continuous Var capability of the inverter (Var)
Maximum battery charge rate	The maximum rate of energy transfer into the storage device. (Watts) This establishes the reference for the charge percentage settings in function INV4.
Maximum battery discharge rate	The maximum rate of energy transfer out of the storage device. (Watts) This establishes the reference for the discharge percentage settings in function INV4.
Storage present indicator	Indication of whether or not battery storage is part of this system.
PV present indicator	Indication of whether or not PV is part of this system.
Time resolution	Time resolution and precision
Source of time synchronization	Text string

The retrieval of status items may be undertaken using one or all of the following methods:

- Single status values:
 - On-demand, request a single status value. That status value will then be returned to the requester.
 - Upon a status value change or upon exceeding a deadband or upon exceeding a limit (depending upon the type of status point), that status value will be transmitted
- Sets of status values:
 - During initialization of the inverter-based DER system, sets of status values can be assigned to one or more “data sets”. These data sets can then be used in the following ways:
 - * On-demand, request one of these data sets. All of the status values in the requested data set will be returned to the requester
 - * Periodically, all of the status values in each data set will be transmitted
 - * Upon change or upon exceeding a deadband or upon exceeding a limit of a status point in the data set, all of the status values in the affected data set will be transmitted
 - After initialization, using the communications network, data sets can be created, modified, and/or deleted, and the reporting triggers can be established (e.g. upon demand, periodically, upon change).

The “on-demand” retrieval method for a single status values and at least one data set are mandatory. The other retrieval methods may be optional or may be deemed mandatory for different implementations.

3.9.4 Time synchronization DS94: time synchronization requirements

The inverter-based DER device will use the time synchronization services specified in IEC 61850-8-1.

4. Terms, definitions and abbreviations

For the purposes of this document, the following terms, definitions and abbreviations apply.

4.1 Terms and definitions

common data class **CDC**

classes of commonly used data structures which are defined in IEC 61850-7-3

device

material element or assembly of such elements intended to perform a required function

[IEV 151-11-20]

NOTE A device may form part of a larger device.

electrical connection point **ECP**

point of electrical connection between the DER source of energy (generation or storage) and any electric power system (EPS)

Each DER (generation or storage) unit has an ECP connecting it to its local power system; groups of DER units have an ECP where they interconnect to the power system at a specific site or plant; a group of DER units plus local loads have an ECP where they are interconnected to the utility power system.

NOTE For those ECPs between a utility EPS and a plant or site EPS, this point is identical to the point of common coupling (PCC) in the IEEE 1547 "*Standard for Interconnecting Distributed Resources with Electric Power Systems*".

electric power system **EPS**

facilities that deliver electric power to a load

[IEEE 1547]

event **event information**

a) something that happens in time [IEV 111-16-04]

b) monitored information on the change of state of operational equipment

[IEV 371-02-04]

NOTE In power system operations, an event is typically state information and/or state transition (status, alarm, or command) reflecting power system conditions.

function

a computer subroutine; specifically: one that performs a calculation with variables provided by a program and supplies the program with a single result

[Merriam-Webster dictionary]

NOTE This term is very general and can often be used to mean different ideas in different contexts. However, in the context of computer-based technologies, it is used to imply software or computer hardware tasks.

generator

a) energy transducer that transforms non-electric energy into electric energy [IEV 151-13-35];

b) device that converts kinetic energy to electrical energy, generally using electromagnetic induction

The reverse conversion of electrical energy into mechanical energy is done by an electric motor, and motors and generators have many similarities. The prime mover source of mechanical energy may be a reciprocating or turbine steam engine, water falling through a hydropower turbine or waterwheel, an internal combustion engine, a wind turbine, a hand crank, or any other source of mechanical energy. [WIKI 2007-12]

information

a) intelligence or knowledge capable of being represented in forms suitable for communication, storage or processing [IEV 701-01-01];

b) knowledge concerning objects, such as facts, events, things, processes, or ideas, including concepts, that within a certain context has a particular meaning [ISO/IEC 2382-1, definition 01.01.01]

NOTE Information may be represented for example by signs, symbols, pictures, or sounds.

information exchange

communication process between two or more computer-based systems in order to transmit and receive information

NOTE The exchange of information between systems requires interoperable communication services.

inverter

a) static power converter (SPC);

b) device that converts DC electricity into AC electricity, equipment that converts direct current from the array field to alternating current, the electric equipment used to convert electrical power into a form or forms of electrical power suitable for subsequent use by the electric utility

[IEC 61727:2004, definition 3.8]

NOTE Any static power converter with control, protection, and filtering functions used to interface an electric energy source with an electric utility system. Sometimes referred to as power conditioning subsystems, power conversion systems, solid-state converters, or power conditioning units.

measured value

physical or electrical quantity, property or condition that is to be measured

[IEC 61850-7-4]

NOTE 1 Measured values are usually monitored, but may be calculated from other values. They are also usually considered to be analogue values.

NOTE 2 The result of a sampling of an analogue magnitude of a particular quantity.

monitor

to check at regular intervals selected values regarding their compliance to specified values, ranges of values or switching conditions

[IEV 351-22-03]

photovoltaic system

a) a complete set of components for converting sunlight into electricity by the photovoltaic process, including the array and balance of system components [US DOE];

b) a system comprises all inverters (one or multiple) and associated BOS (balance-of-system components) and arrays with one point of common coupling, described in IEC 61836 as PV power plant [IEC 61727:2004, definition 3.7]

NOTE The component list and system configuration of a photovoltaic system varies according to the application, and can also include the following sub-systems: power conditioning, energy storage, system monitoring and control and utility grid interface.

photovoltaics**PV**

of, relating to, or utilizing the generation of a voltage when radiant energy falls on the boundary between dissimilar substances (as two different semiconductors)

[Merriam-Webster dictionary]

point of common coupling**PCC**

point of a power supply network, electrically nearest to a particular load, at which other loads are, or may be, connected [IEV 161-07-15]

NOTE 1 These loads can be either devices, equipment or systems, or distinct customer's installations.

NOTE 2 In some applications, the term "point of common coupling" is restricted to public networks.

NOTE 3 The point where a local EPS is connected to an area EPS [IEEE 1547]. The local EPS may include distributed energy resources as well as load (see IEV definition which only includes load).

power conversion

power conversion is the process of converting power from one form into another

This could include electromechanical or electrochemical processes.

In electrical engineering, power conversion has a more specific meaning, namely converting electric power from one form to another. This could be as simple as a transformer to change the voltage of AC power, but also includes far more complex systems. The term can also refer to a class of electrical machinery that is used to convert one frequency of electrical power into another frequency.

One way of classifying power conversion systems is according to whether the input and output are alternating current (AC) or direct current (DC), thus:

DC to DC

- DC to DC converter
- Voltage stabiliser
- Linear regulator

AC to DC

- Rectifier
- Mains power supply unit (PSU)
- Switched-mode power supply

DC to AC

- Inverter

AC to AC

- Transformer/autotransformer
- Voltage regulator

[WIKI 2007-12]

prime mover

equipment acting as the energy source for the generation of electricity

NOTE Examples include diesel engine, solar panels, gas turbines, wind turbines, hydro turbines, battery storage, water storage, air storage, etc.

set point

the level or point at which a variable physiological state (as body temperature or weight) tends to stabilize

[Merriam-Webster Dictionary]

set point command

command in which the value for the required state of operational equipment is transmitted to a controlled station where it is stored

[IEV 371-03-11]

NOTE A setpoint is usually an analogue value which sets the controllable target for a process or sets limits or other parameters used for managing the process.

4.2 Acronyms

SEP: Smart Energy Profile

DNP3: Distributed Network Protocol

GPRS: General Packet Radio Service