Advanced inverter functions: communication bandwidth and latency considerations

SAND2016-9506C

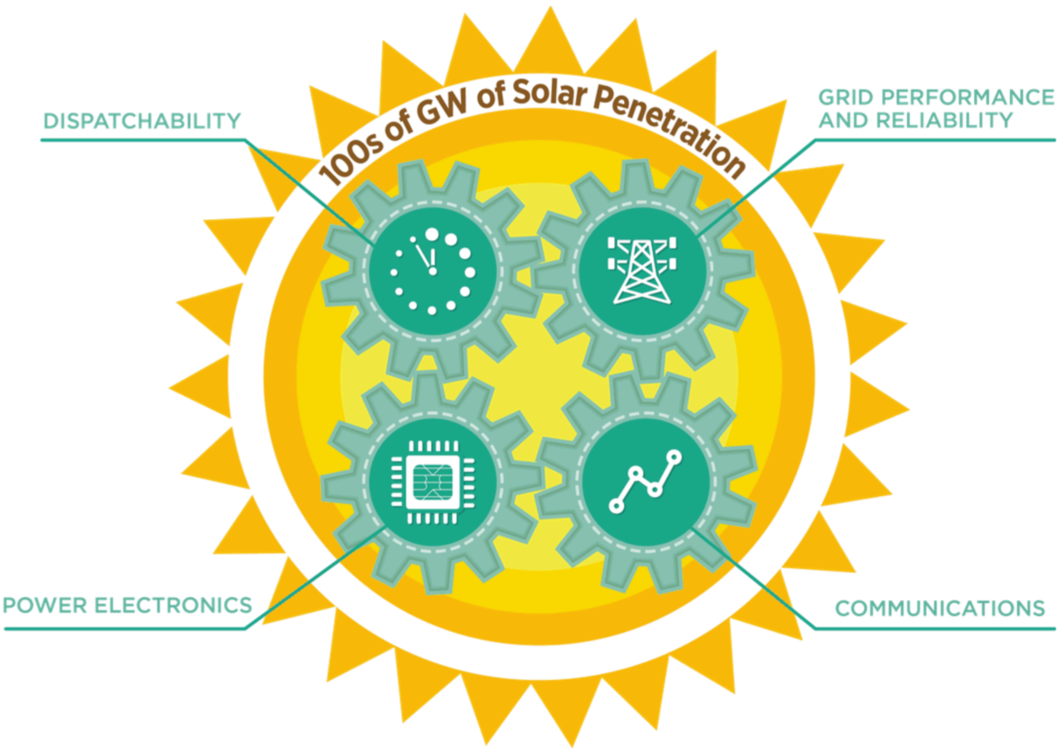
Sandia National Laboratories

SunShot
U.S. Department of Energy

D1

Where do we fit in:

SYSTEMS INTEGRATION VISION



- Grid Performance and Reliability
- Dispatchability
- Power Electronics
- Communications

Slide 2

D1 NEED NEW GRAPHICS

DOEUSER, 8/29/2014

Sunshot'15 Communications metrics

Communications Target Metrics	
Attribute	**Target Metric[25]**
Scalability: Defined as the ability to scale the communication network in the number of connected nodes, bandwidth, latency, and coverage distance in order to meet the needs of various applications.	Up to 5,000,000 nodes
Availability: Defined as the probability that the communication network will perform without a failure for a stated period of time. This not only includes the performance of the physical network but also the accuracy of the messages being sent and received.	> 99.999%
Response Time: Defined as the delay between the moment a message/command is sent from the source node and the moment at which that information is received and acted upon at the destination node.	< 1s
Cost[26]: Defined as the life-cycle cost of building, operating, and maintaining the communication network and end devices. This includes the initial capital costs for equipment and infrastructure build-up and the recurring costs for operation and maintenance.	LCOE < 6¢/kWh by 2020
Interoperability[27]: Defined as the capability of two or more networks, systems, devices, applications, or components to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user.	Compliance with Open Standards which include SunSpec Modbus, Smart Energy Profile (SEP 2), IEC 61850, MultiSpeak, and DNP3

(Few) Communication standards

Function	SunSpec	IEC 61850	IEEE 2030.5	DNP3
Nameplate Ratings	✔	✔	✔	✔
Basic Settings	✔	✔	✔	✔
Measurements and Status	✔	✔	✔	✔
Immediate Controls (Power, PF, and VAr)	✔	✔	✔	✔
Dynamic Reactive Current Control curves	✔	✔	✔	✔
Volt-VAr	✔	✔	✔	✔
Watt-Power Factor	✔	✔	✔	✔
Frequency-Watt	✔	✔	✔	✔
Voltage Ride-through	✔	✔	✔	✔
Frequency Ride-through	✔	✔	✔	✔
Pricing Signals	✔	✔	✔	✔
Basic Scheduling	✔	✔	✔	✔

IEC 61850

- IEC 61850 provides a comprehensive model for power system devices to organize data, configure objects and map them on to protocols, so that they are consistent and interoperable.
- The IEC 61850 standard consists of many parts. Part 3, 4 and 5 describes the general and specific functional requirements for communication in substation. The part 7-2 and 7-4 describe the abstract services and the abstraction of data objects. The data objects consists of building blocks Common Data Classes (CDC) elements which are defined in part 7-3. The mapping of these abstract services and data objects on to manufacturing Messaging Specification (MMS) protocols is defined in part 8-1. The mapping of sample values on to Ethernet data frames is separately defined in part 9-2. The part 10 of the standard defines a testing methodology to determine the conformance of equipment to be used.
- Message structure: The IEC 61850 has proposed two different types of communication stacks, and there are seven types of messages based on time requirements.

IEC 61850

- Fig. below shows the IEC 61850 based communication stack. IEC 61850 specifies the communication of time critical GOOSE and sampled value messages directly on data link layer to avoid any overhead delays. The type 2, 3, 5, 6 and 7 messages are mapped over complete OSI-7 layer stack as a client /server application. According to IEEE 802.1Q, priority tagging and Virtual Local Area Network (VLAN) tagging are defined in the link layer of the stack. This ensures the segregation of the IEDs according to their functions and also provides higher priority for the most time critical data.

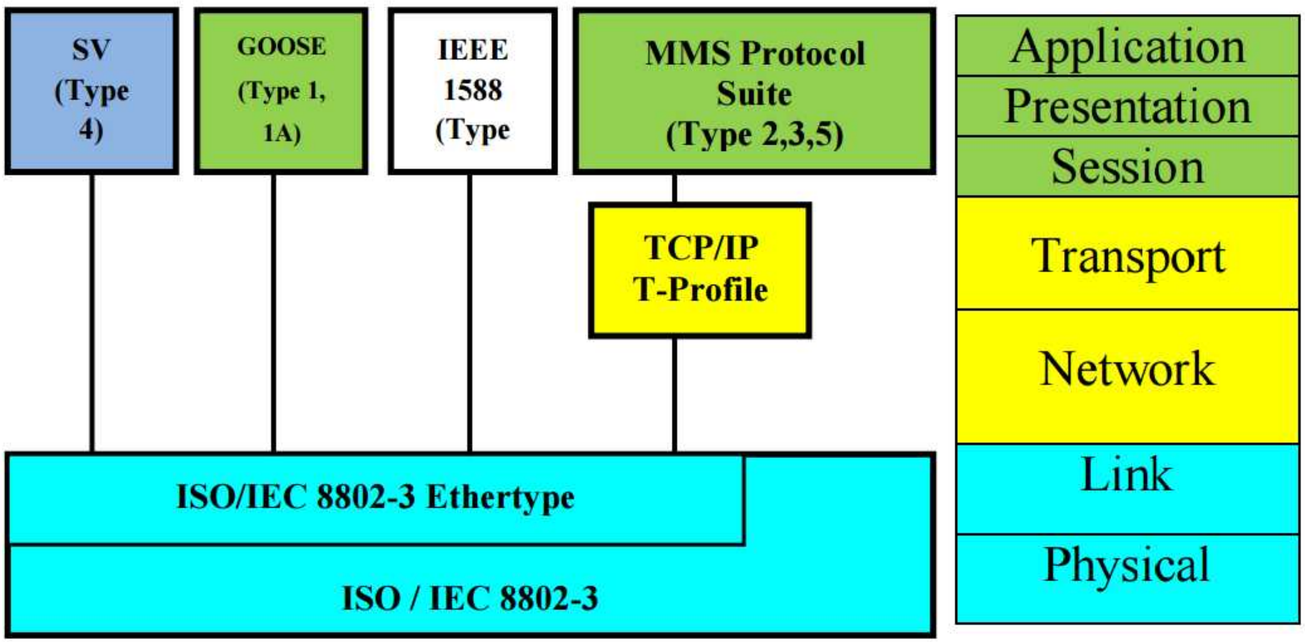


Fig. 1. OSI 7-layer stack of IEC 61850

What are the timing requirement?

- Time requirements for different messages IEC 61850 differentiates the different messages according to their transfer time requirements. The transfer time counts from movement the transmitting node puts data content on top of the transmission stack up to the moment the receiving node extracts the data from the transmission stack. The IEC 61850 standard specifies the time requirements of different messages for substations, but the time requirements for DERs connected to distribution system are not specified. IEEE 1646 standard gives the time requirements to different types of information messages for external or remote or DER IEDs to the substation. Table below gives the time requirements of different messages of distribution substation and DERs

TABLE I
MAXIMUM MESSAGE DELIVARY TIME

Information Type	**Internal in substation (msec)**	**External (DER) to substation (msec)**
Protection information	0-4	8-12
Monitoring and control information	16	1 s

- IEC 61850 was initially proposed for substation automation systems later it was extended to utility automation. The new extensions of the standard such as part 7-420 defines the logical nodes for DERs, part 90-1 describes the communication between two substations, part 90-5 describes the Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118, part 90-7 describes the Object Models for DER inverters, etc.

What about size of messages?

TABLE II
SIZE OF DIFFERENT MESSAGES EXCHANGED BY DER IEDS

Type of message	Source IED	Destination IED	Size (bytes)
Trip commands	DER Control IED	DER Breaker IED	98
	P&C IEDs (substation)		
	Station PC		
Sample Values	MU IED	DER Control IED	102
Status Update	DER control IED	Server	200
	DER Breaker IED	DER Control IED	150
		Server	

- As illustrated conceptually in Figure 4.6, the transformation of the electric grid from a centralized and hierarchical network architecture to a more distributed one – with ever-increasing numbers of small and/or variable generators scattered throughout the grid – adds significant system complexity and technical challenges.
- Communications needs vary greatly depending on the type of applications, locations, and topologies of the power systems. Besides, as both communication technologies and solar grid integration applications are evolving rapidly, the capabilities developed today must be able to adapt and meet the future challenges.
- Network latency, availability, scalability, and cost are the key issues to be addressed in order to adequately and cost-effectively monitor the behavior and manage the impact of solar generation. Cyber security, while not a primary focus for SunShot, should be taken into consideration when designing communication solutions. Cyber security has become a top priority for electric power systems because the evolving electric grid is increasingly interconnected and dependent on information technology and telecommunications infrastructures to ensure its reliability.

What does DNP say?

Distributed
Network
Protocol

DNP Application Note AN2013-001

DNP3 Profile
for Advanced Photovoltaic
Generation and Storage

1 Introduction

This document describes a standard data point configuration, set of protocol services and settings – also known as a *profile* – for communicating with photovoltaic (PV) generation and storage systems using DNP3. The purpose of defining this profile is to make it easier to interconnect the DNP3 masters and outstations that are used to control such systems.

This document is an application note, meaning it does not specify any changes to the DNP3 standard at all; it merely describes how to use DNP3 for a particular purpose. It is, however, intended to be an interoperability standard for those wishing to build and specify PV generation and storage systems.

Although this document describes a DNP3 profile, it is designed based on the structured *data models* of the International Electrotechnical Commission (IEC) 61850 protocol standards family. In particular, it is based on those data models that are specific to distributed generation and photovoltaic systems. The intent is that a system implementing this DNP3 application note can be easily integrated with an IEC 61850 network by means of a gateway, while remaining conformant with DNP3 best practices.

This application note supersedes application note *AN2011-001 DNP3 Profile for Basic Photovoltaic Generation and Storage* and is intended to be backward-compatible with it. The point numbers and

DNP approach

- The mandatory data objects and data attributes associated with these logical nodes are defined in the IEC 61850-7-4, IEC 61850-7-420 and IEC 61850-90-7 standards. They were used to determine the DNP3 points list

  - Frequency-Watt (FW)
  - Dynamic Reactive Current (TV)
  - Must Disconnect (MD) and Must Remain Connected (MRC)
  - Watt-Power Factor (WP)
  - Voltage-Watt (VW)
  - Temperature Curves (TMP)
  - Pricing Signal Curves (PS)
  - Real Power Smoothing (RPS)
  - Dynamic Volt-Watt (DVW)
  - Peak Power Limiting (PPL)
  - Load and Generation Following (LGF)

Function or Communication Verification
Anti-Islanding Protection
L/HVRT
L/HFRT
Volt-Var Mode
Ramp Rates
Fixed Power Factor
Soft Start
Monitor Alarms
Monitor DER Status and Output
Limit Maximum Real Power
Connect/Disconnect
Frequency-Watt Mode
Voltage-Watt Mode
Dynamic Reactive Current Support

But what about dynamic control?

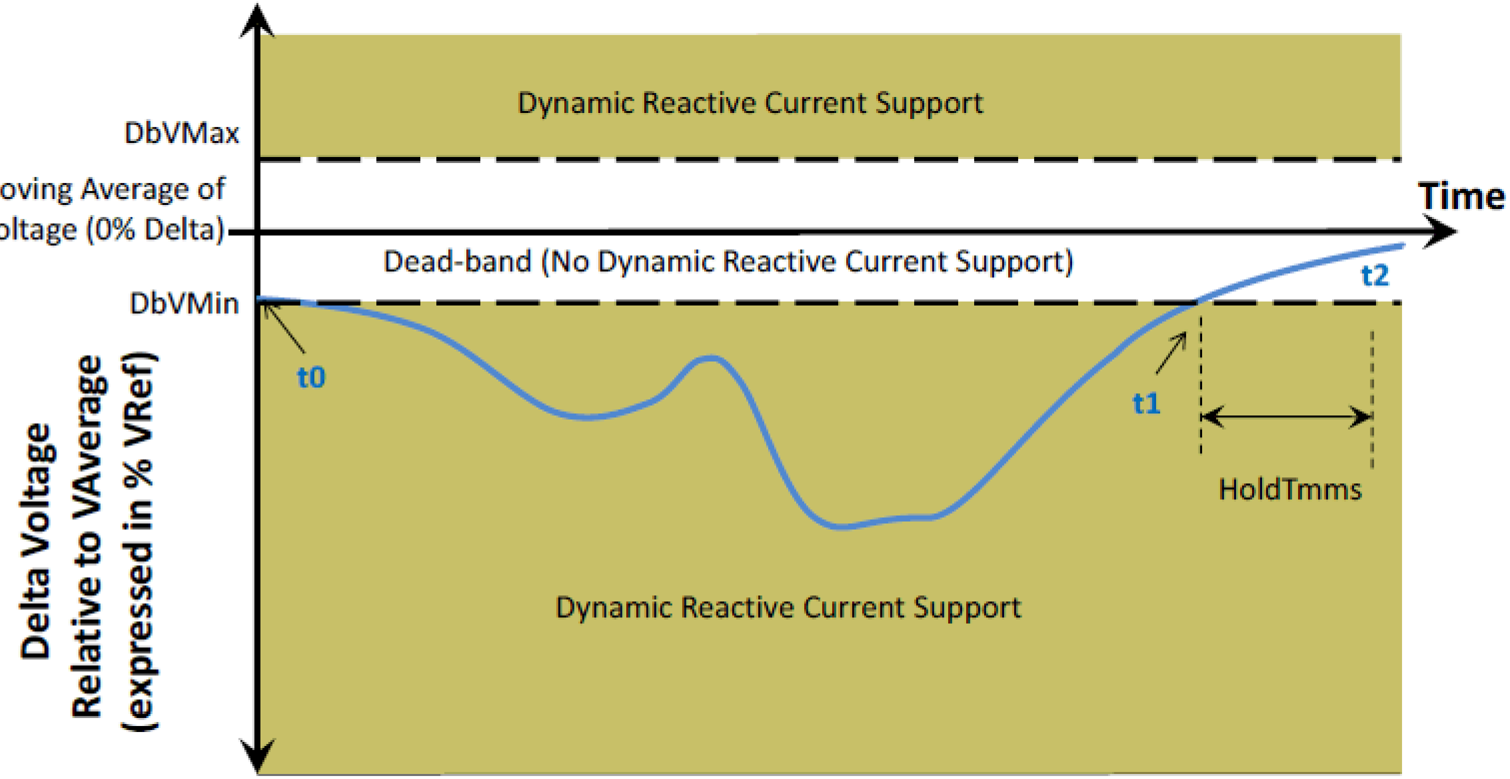


Figure 15 – Event-Based Dynamic Current Support

- What are the communication bandwidth/delay/latency requirements?

Table 1 – IEC 61850 Logical Nodes in this Profile

Class	Instance	Description	Source	Inverter Function
CSWI	1	DER Connect/Disconnect Switch	Basic	INV1
DGSM	1	Volt/VAR Curve 1 Commands	Basic	VV
DGSM	2	Volt/VAR Curve 2 Commands	Basic	VV
DGSM	3	Volt/VAR Curve 3 Commands	Basic	VV
DGSM	4	Volt/VAR Curve 4 Commands	Basic	VV
DGSM	5	Volt/VAR Curve 5 Commands	Basic	VV
DGSM	6	Volt/VAR Curve 6 Commands	Basic	VV
DGSM	7	Volt/VAR Curve 7 Commands	Basic	VV
DGSM	8	Volt/VAR Curve 8 Commands	Basic	VV
DGSM	9	Volt/VAR Curve 9 Commands	Basic	VV
DGSM	10	Volt/VAR Curve 10 Commands	Basic	VV
DGSM	n	Generic Curve Commands	IEC	All Curves
DOPM	1	Connect/Disconnect Operational Mode	Basic	INV1
DOPM	2	Limited Watts Operational Mode	Basic	INV2
DOPM	3	Fixed Power Factor Mode	Basic	INV3
DOPM	4	Charge/Discharge Storage Operational Mode	Basic	INV4
DOPM	5	Pricing Signal Operational Mode	Basic	INV5
DOPM	6	Constant Var Operational Mode	IEC	VV
DOPM	7	Real Power Smoothing Operational Mode	EPRI	RPS
DOPM	8	Dynamic Volt-Watt Operational Mode	EPRI	DVW
DOPM	9	Peak Power Limiting Operational Mode	EPRI	PPL
DOPM	10	Load/Generation Following Operational Mode	EPRI	LGF

Point Index	Name / Description	Def Evt Cls	Transmitted Value		Scaling		Units	Reso-lution	IEC 61850				Inv Func
			Minimum	Maximum	Multi-plier	Off-set			LN Class	LN Inst	Data Object	CDC	
8	Inverter active power output - Present real power output level (negative = charging)	3	-2147483648	2147483647	1	0	Watts	1	MMXU	1	TotW	MV	DS93
9	Inverter reactive output - Present reactive power output level (negative = absorbing)	3	-2147483648	+2147483647	1	0	VARs	(1%)	MMXU	1	TotVAr	MV	DS93
10	Frequency at the connection point	3	0	7000	0.01	0	Hz	0.01	MMXU	2	Hz	MV	DS93
11	Active power at the connection point	3	-2147483648	2147483647	1	0	Watts	(1%)	MMXU	2	TotW	MV	DS93
12	Reactive power at connection point	3	-2147483648	+2147483647			VARs	(1%)	MMXU	2	TotVAr	MV	DS93
13	Power factor at the connection point	3	-100	+100	0.01	0	n/a	0.01	MMXU	2	TotPF	MV	DS93
14	Phase A Volts at connection point	3	0	2147483647	1	0	Volts	(1%)	MMXU	2	PhV.PhsA.mag	WYE	DS93
15	Phase A Volts angle	3	0	3600	0.1	0	Degrees	0.1	MMXU	2	PhV.PhsA.ang	WYE	DS93
16	Phase B Volts at connection point	3	0	2147483647	1	0	Volts	(1%)	MMXU	2	PhV.PhsB.mag	WYE	DS93
17	Phase B Volts angle	3	0	3600	0.1	0	Degrees	0.1	MMXU	2	PhV.PhsB.ang	WYE	DS93
18	Phase C Volts at connection point	3	0	2147483647	1	0	Volts	(1%)	MMXU	2	PhV.PhsC.mag	WYE	DS93
19	Phase C Volts angle	3	0	3600	0.1	0	Degrees	0.1	MMXU	2	PhV.PhsC.ang	WYE	DS93
20	DC Inverter input power	3	0	2147483647	1	0	Volts	(1%)	MMDC	1	Watt	MV	DS93
21	DC current level available to inverter	3	0	2147483647	1	0	Amp	(1%)	MMDC	1	Amp	MV	DS93
22	DC voltage between PV system and inverter	3	0	2147483647	1	0	Volts	(1%)	MMDC	1	Vol	MV	DS93
23	External battery voltage (between battery charger and battery)	3	0	2147483647	1	0	Volts	(1%)	ZBAT	1	Vol	MV	DS93
24	Internal battery voltage	3	0	2147483647	1	0	Volts	(1%)	ZBAT	1	InBatV	MV	DS93
25	State of Charge – currently available energy in the battery, as a percentage of capacity rating	3	0	1000	0.1	0	Percent	0.1	ZBAT	1	AhrPct	ASG	DS93
26	VArs Available that can be produced without impacting active power (Watts) output	2	- 2147483648	2147483647	1	0	VARs	(1%)	ZINV	1	VArAval	MV	VV

Table 16 – Analog Output Point List

Point Index	Name	Supported Control Operations			Transmitted Value		Scaling		Units	Reso-lution	Default Event Class		IEC 61850				Inv Func
		Select/Operate	Direct Operate	Direct Operate – No Ack	Minimum	Maximum	Multi-plier	Off-set			Chg	Cmd	LN Class	LN Inst	Data Object	CDC	
0	Time window for Connect/Disconnect	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	1	WinTms	ING	INV1
1	Timeout period for Connect/Disconnect	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	1	RevtTms	ING	INV1
2	Time window for limited Watts mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	2	WinTms	ING	INV2
3	Timeout period for limited Watts mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	2	RevtTms	ING	INV2
4	Ramp time for limited Watts mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	2	RmpTms	ING	INV2
5	Time window for fixed power factor mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	3	WinTms	ING	INV3
6	Timeout period for fixed power factor mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	3	RevtTms	ING	INV3
7	Ramp time for fixed power factor mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	3	RmpTms	ING	INV3
8	Time window for charge or discharge rate mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	4	WinTms	ING	INV4
9	Timeout period for charge or discharge rate mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	4	RevtTms	ING	INV4
10	Ramp time for charge or discharge rate mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	4	RmpTms	ING	INV4
11	Time window for price mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	5	WinTms	ING	INV5
12	Timeout period for price mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	5	RevtTms	ING	INV5
13	Ramp time for price mode	X	X	X	0	2147483647	1	0	Seconds	1	2	2	DOPM	5	RmpTms	ING	INV5

Comparable protocols:

TABLE III
PERFORMANCE EVALUATION OF 100 AND 1000 MBPS WIRED LAN

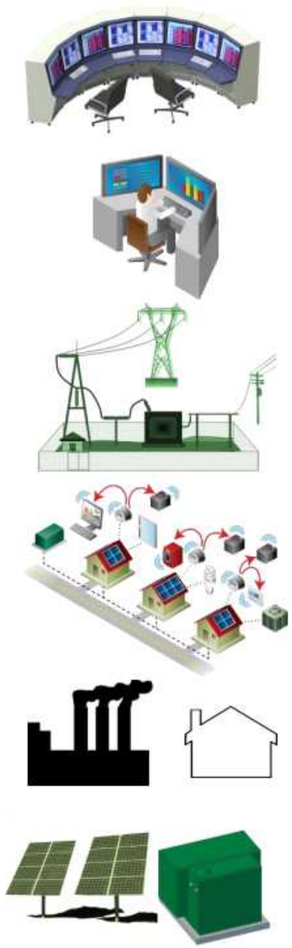
Type of Message	100 Mbps		1000 Mbps	
	Delay (ms)	Throughput (kbps)	Delay (ms)	Throughput (kbps)
GOOSE	0.11	80	0.08	80
Sampled Values	0.14	3500	0.106	3500
Other MMS type traffic	0.22	1000	0.203	1000

TABLE IV
PERFORMANCE EVALUATION OF 100 AND 1000 MBPS WIRED LAN

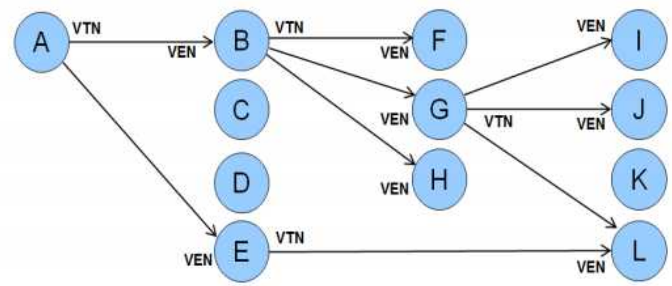
Type of Message	54Mbps		24 Mbps	
	Delay (ms)	Throughput (kbps)	Delay (ms)	Throughput (kbps)
GOOSE	0.84	80	0.88	80
Sampled Values	1.02	3500	1.03	3500
Other MMS type traffic	0.92	1000	0.92	1000

But will it scale?

Multi-tiered Integration of DER Groups



DER "Group" management protocols must support architectures of multiple tiers of aggregation



Example: OpenADR (a demand response protocol) was designed to operate at any number of nested levels.

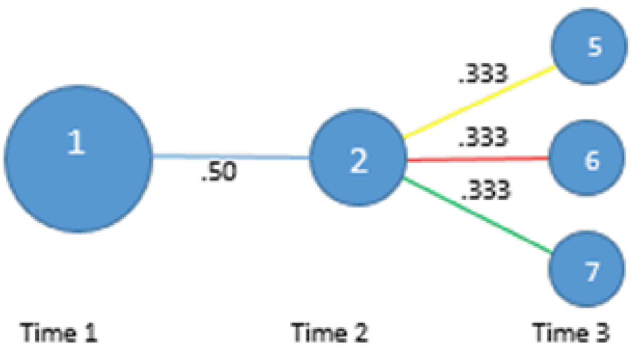
VTN = Virtual Top Node

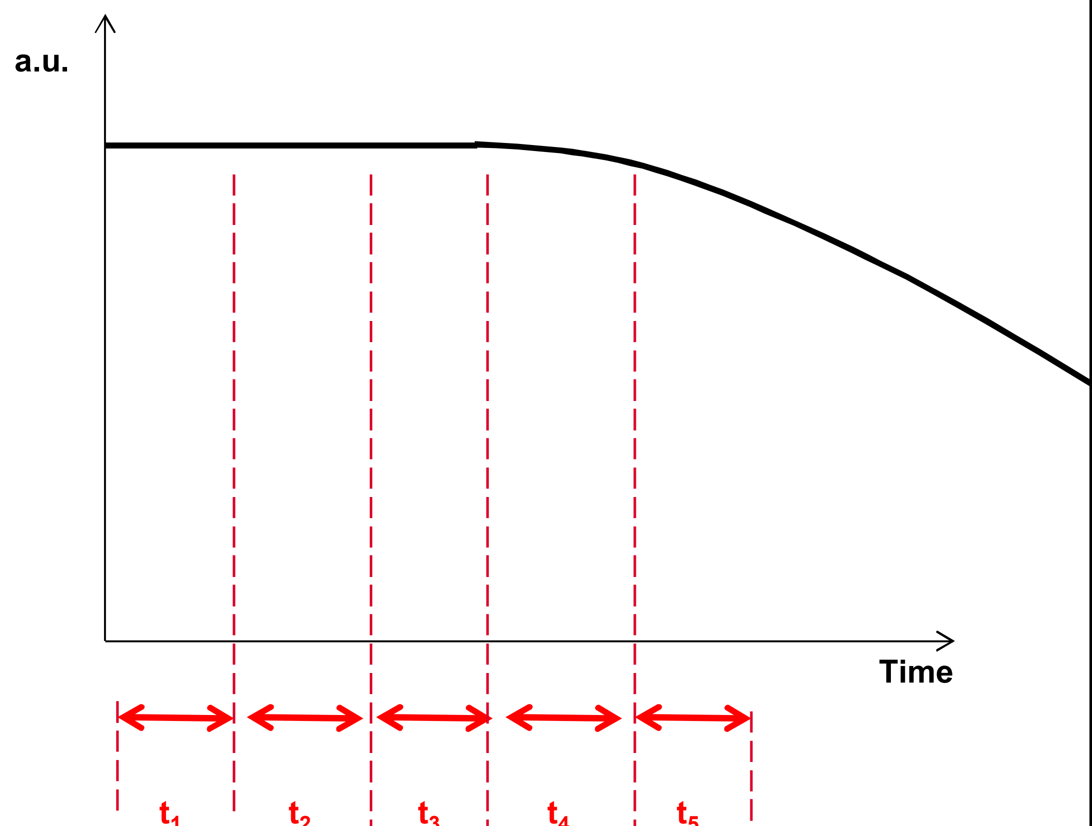
VEN = Virtual End Node

Ref: "Enterprise Integration of Distributed Energy Resources", Brian Seal, EPRI IntelliGrid Smart Grid Information Sharing Webcast, January 22rd, 2014

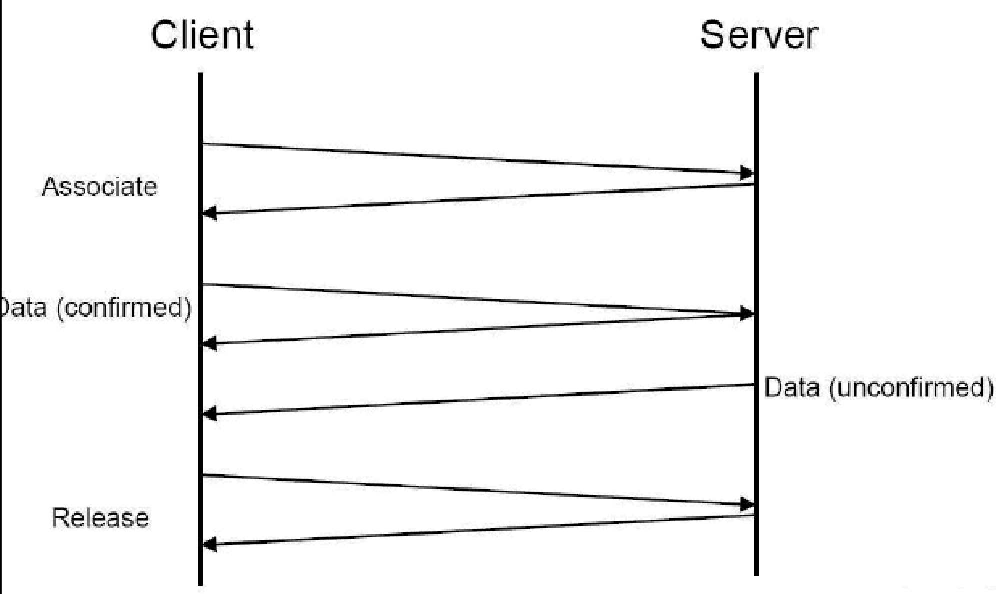
Latency considerations

Timing diagram approach:

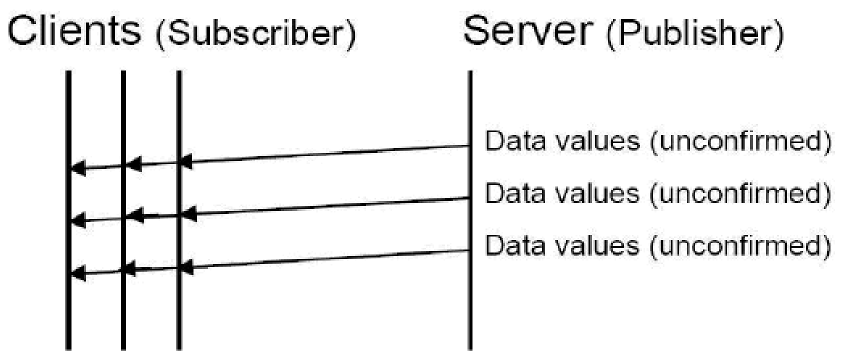




Other notations to represent timing diagrams

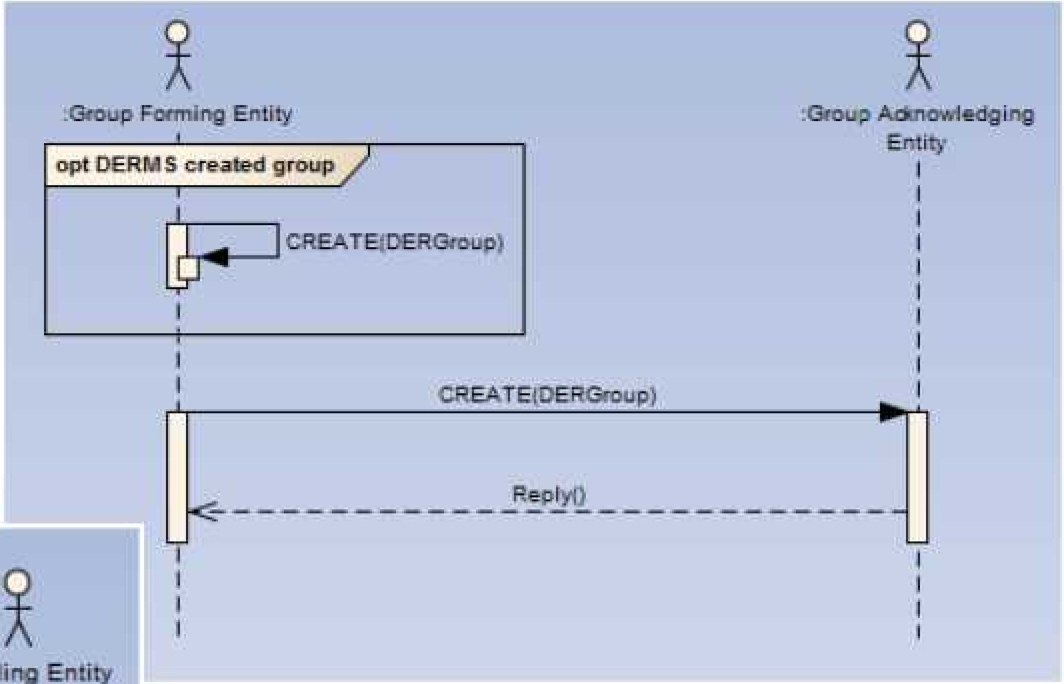


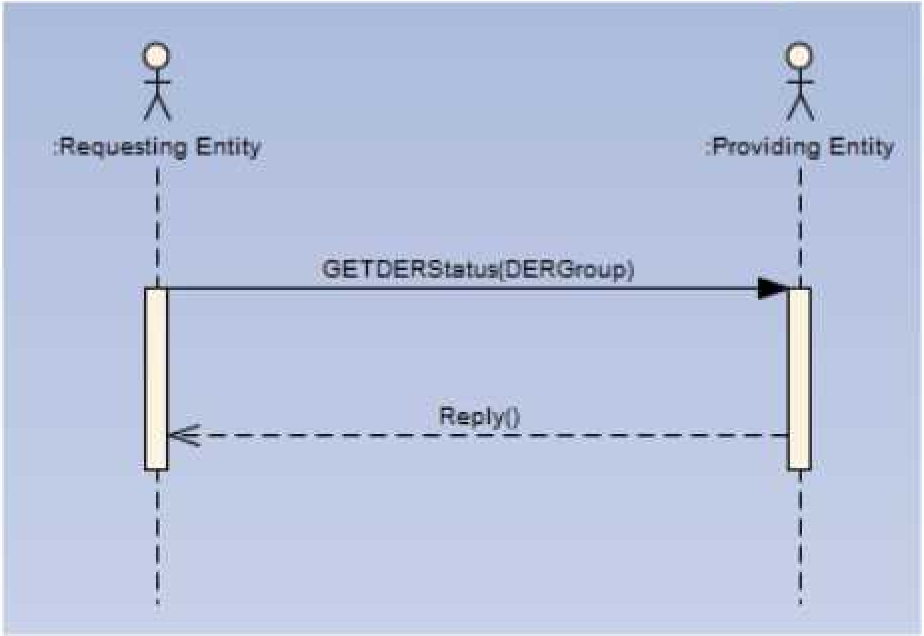
Two-Party-Application-Association



MultiCast-Application-Association

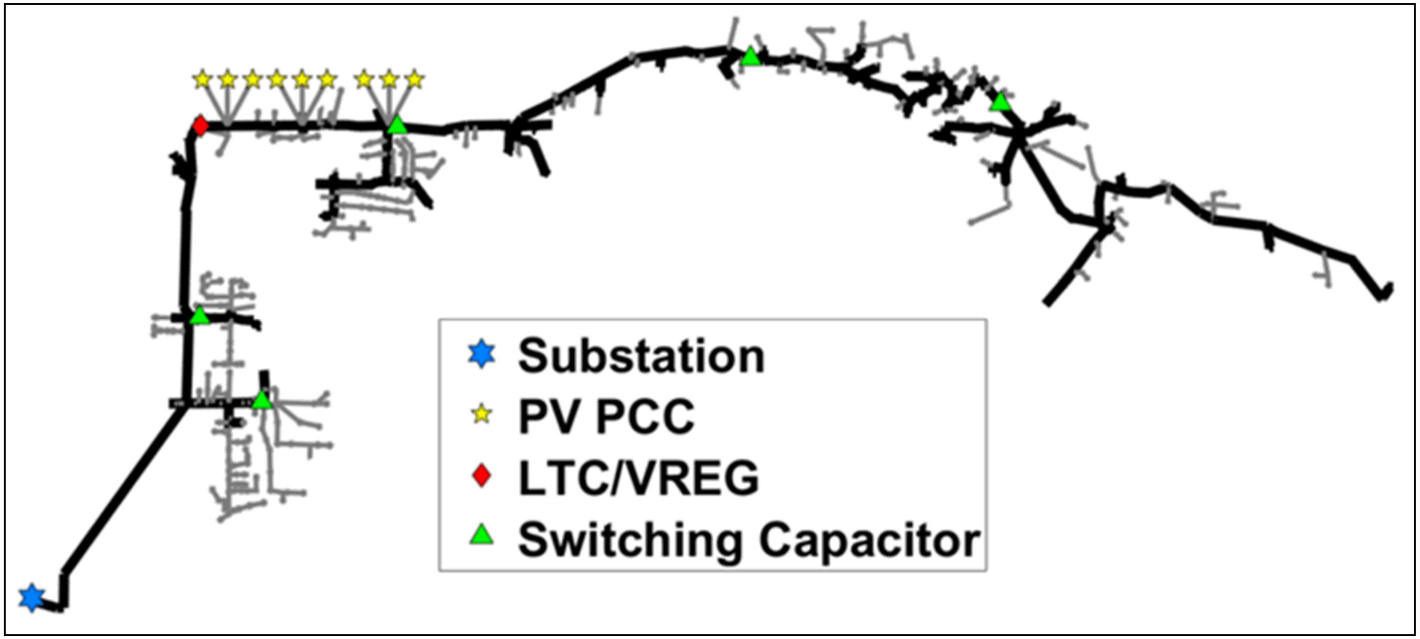
Sequence diagrams



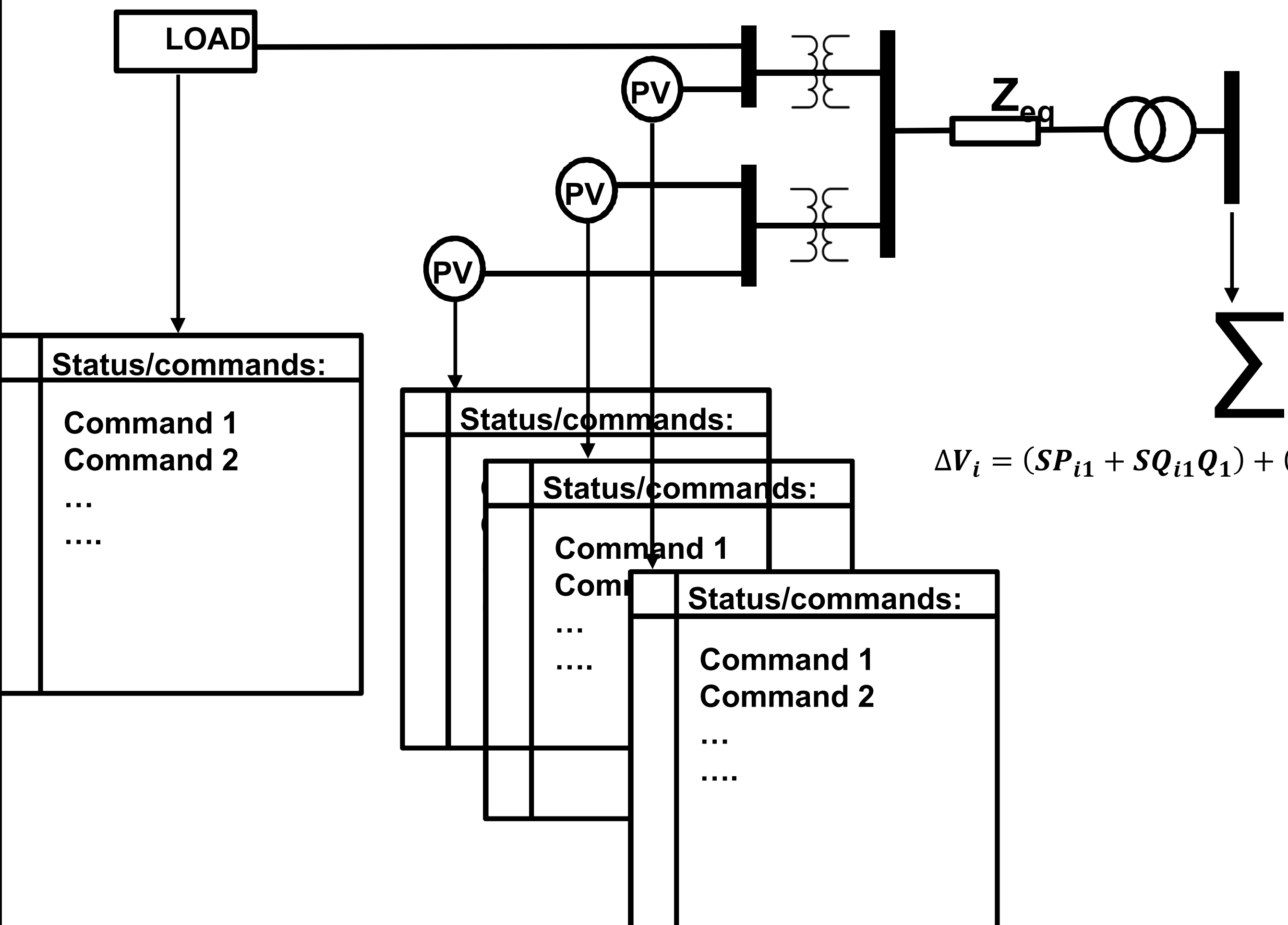


Distribution communications example

- Distribution Example
  - A rural 12kV distribution feeder in southern California was chosen as the test feeder.
  - Consists of 2970 medium- and low-voltage buses and 2569 lines servicing 1447 customers through 401 service transformers



Distribution communications example



Aggregate Voltage change:

$$\Delta V_i = (SP_{i1} + SQ_{i1}Q_1) + (SP_{i2} + SQ_{i2}Q_2) + \ \ldots + (SP_{iN} + SQ_{iN}Q_N)$$

Stability metrics:

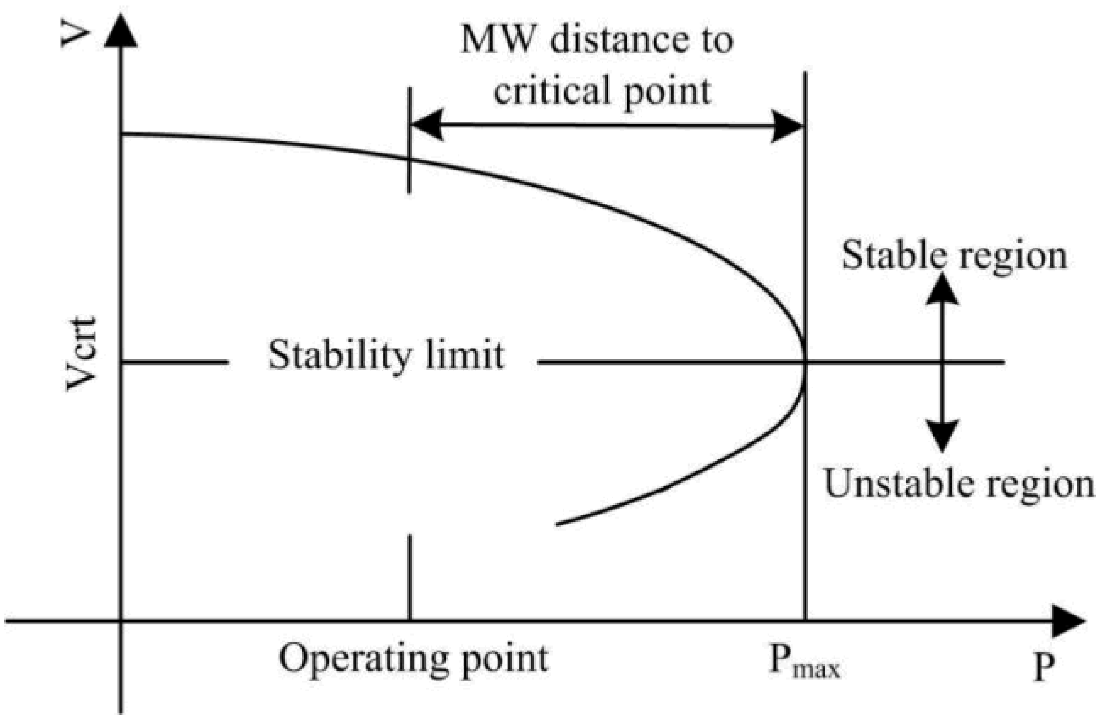
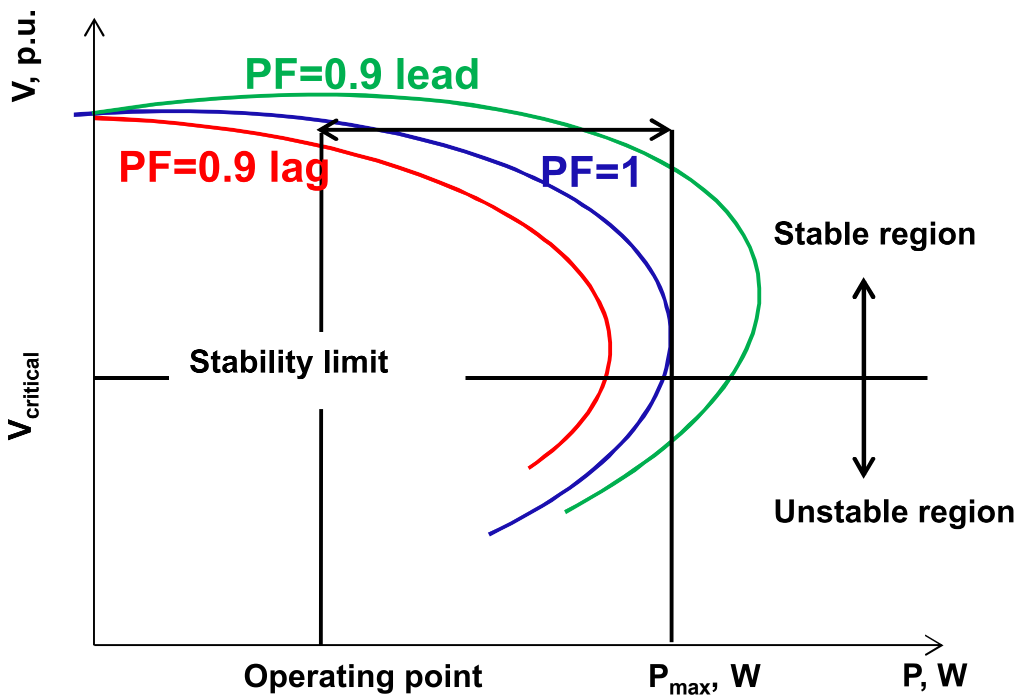


Figure 1. Sketch Map for P-V Curve

Stability metrics - contd



Stability metrics (contd)

- In load flow analysis can be written in general form as:

$$V_2^4 + 2V_2^2(PR + QX) - V_1^2V_2^2 + (P^2 + Q^2)|Z|^2 = 0$$

- From this equation and line receiving end active and reactive power equations, after some calculations we have:

$$2V_1^2V_2^2 - V_2^4 - 2V_2^2(PR + QX) - |Z|^2(P^2 + Q^2) \geq 0$$

- From the last equation, it is clearly seen that the value of the (16) is decrease with the increase of the transferred power and impedance of the line, and it can be used as a bus stability index for a distribution networks as:

$$SI_1 = 2V_1^2V_2^2 - V_2^4 - 2V_2^2(PR + QX) - [Z]^2(P^2 + Q^2)$$

Stability metrics (contd)

- ***Line Stability Indices VCPI:*** The VCPI indices proposed by M.Moghavvemi and Faruque. [Faruque] investigates the stability of each line of the system and they are based on the concept of maximum power transferred through a line.

$$VCPI(1) = \frac{P_R}{P_{R(max)}}$$

$$VCPI(2) = \frac{Q_R}{Q_{R(max)}}$$

- where the values of *PR* e *QR* are obtained from conventional power flows calculations, and *PR*(*max*) and *QR*(*max*) are the maximum active and reactive power that can be transferred through a line. The VCPI indices varies from 0 (no load condition) to 1 (voltage collapse).

Stability metrics (contd)

- **Voltage Sensitivity Factor**s relative to real power or reactive power injection can be expressed as, respectively:

$$S_{Vp} = \frac{\Delta V_i}{\Delta P_i} \quad \text{or} \quad S_{Vq} = \frac{\Delta V_i}{\Delta Q_i}$$

- Since majority of voltage control in a power systems is based on reactive power injection, it is clear that a voltage stability criterion is: $S_V > 0$.

Stability metrics (contd)

- **Real Power sensitivity**
- There is usually uncertainty in the metering or forecast of loads. By computing the sensitivity to the load, one can estimate the effects of inaccuracy in the nominal values used. Secondly, it might be possible to shed load at a bus, and it would be useful to know how much margin can be gained for each MW of load shed. Finally, the sensitivity computation identifies buses that are good candidates for planned improvements. For example, load margin sensitivity can specify good locations for VAR support or areas where interruptible contracts would contribute the most to system security.
- The real power loss in a system is given by the popularly referred to as "exact loss" formula [Elgerd]:

$$P_L = \sum_{i=1}^{N} \sum_{j=1}^{N} \left[\alpha_{ij}(P_i P_j + Q_i Q_j) + \beta_{ij}(Q_i P_j - P_i Q_j)\right]$$

Where

$$\alpha_{ij} = \frac{r_{ij}}{V_i V_j}\cos(\delta_i - \delta_j) \qquad \text{and} \qquad \beta_{ij} = \frac{r_{ij}}{V_i V_j}\sin(\delta_i - \delta_j)$$

- The sensitivity factor of real power loss with respect to real power injection from Distributed Generation (DG) is then given by:

$$S_{Pp} = \frac{\partial P_L}{\partial P_i} = 2\sum_{i=1}^{N}(\alpha_{ij} P_j - \beta_{ij} Q_j)$$

Perform simulations and analysis

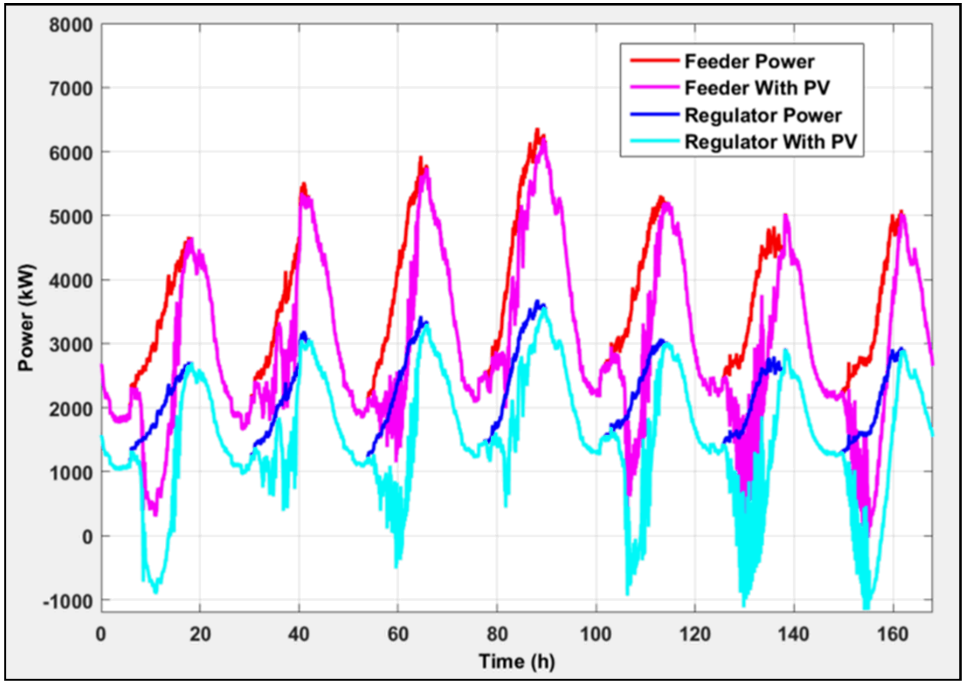
- Distribution Example

$$SQ_{ij} = \frac{\Delta V_i}{\Delta Q_j}$$

$$[SQ] = \begin{bmatrix} 7.17E-05 & 1.37E-06 & -2.01E-05 \\ -2.07E-05 & 7.35E-05 & 1.41E-06 \\ 1.10E-06 & -2.00E-05 & 7.24E-05 \end{bmatrix}$$

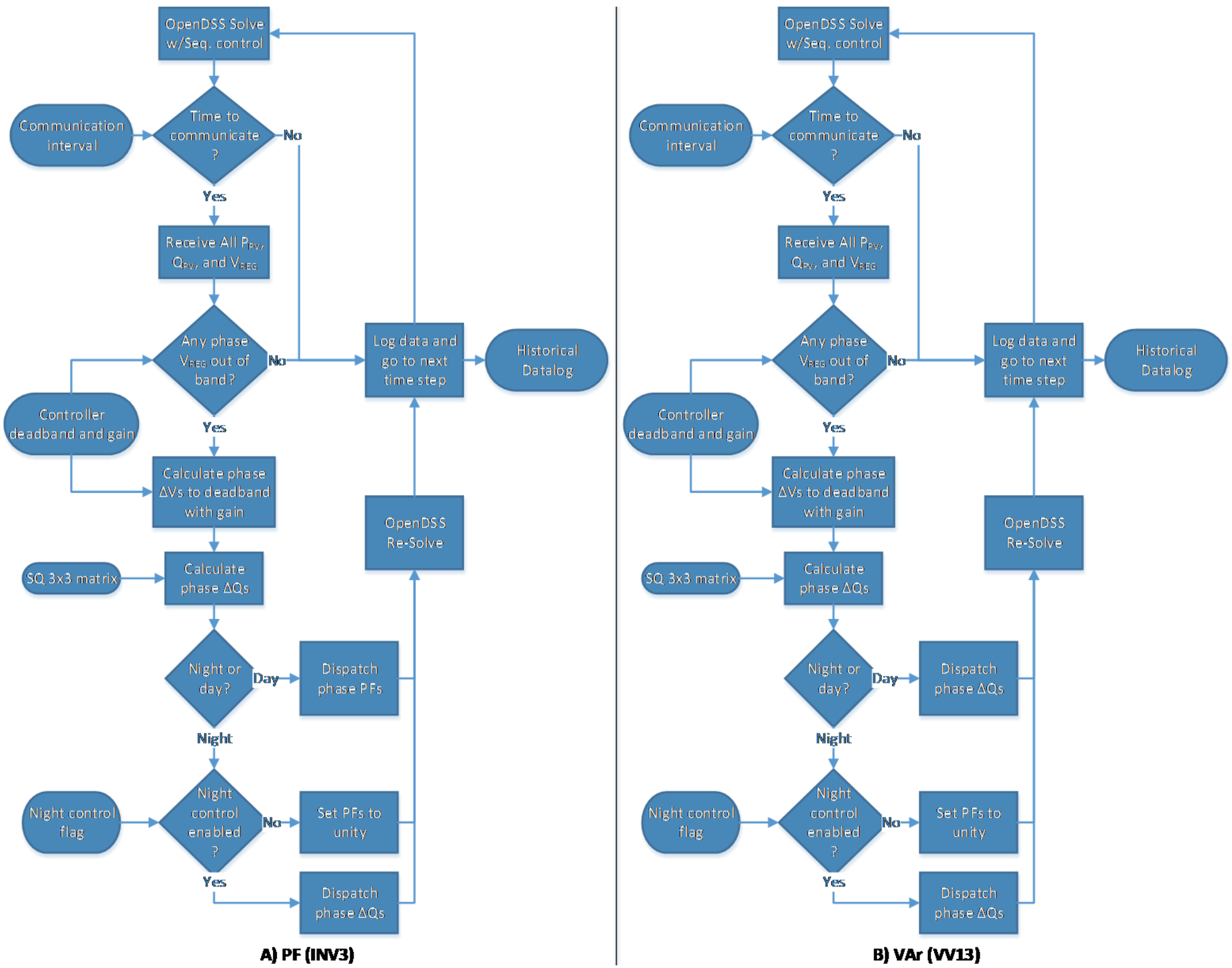
$$[\Delta Q] = [SQ]^{-1} * [\Delta V \quad]$$

$$PF = \frac{\sum P_A}{\sqrt{((\sum P_A)^2 + ((\sum Q_A) + \Delta Q_A)^2)}}$$



Basecase and unity PF PV feeder and VREG real powers, peak week

Simulation flow charts

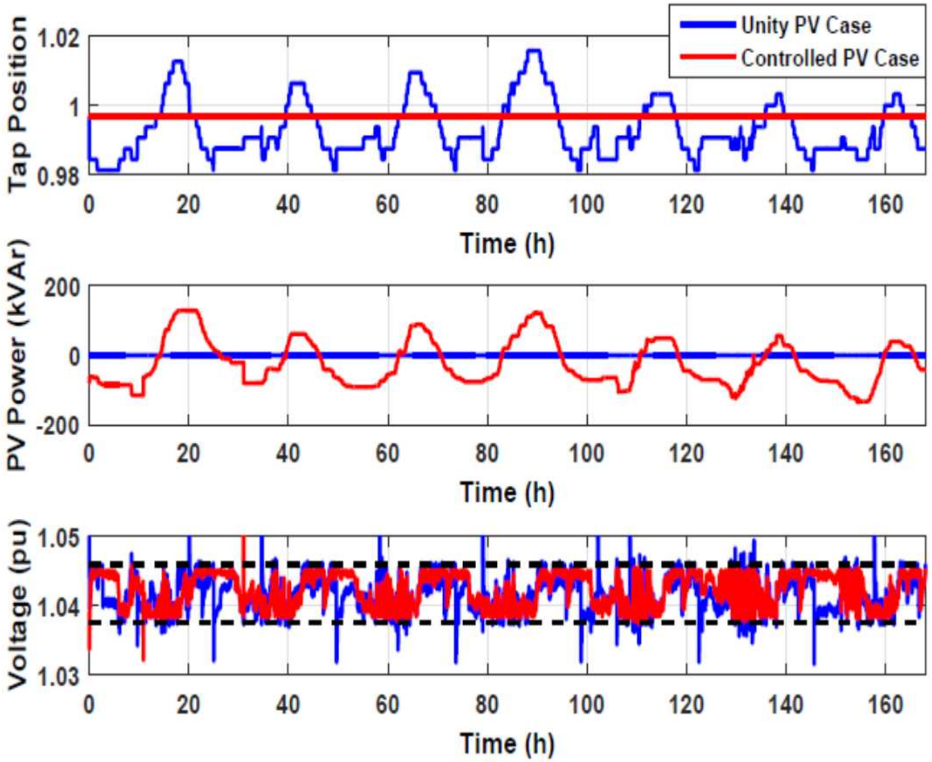


Controller diagram for a) PF (INV3) and b) VAr (VV13).

Olga Lavrova, SPI 2016

Results :

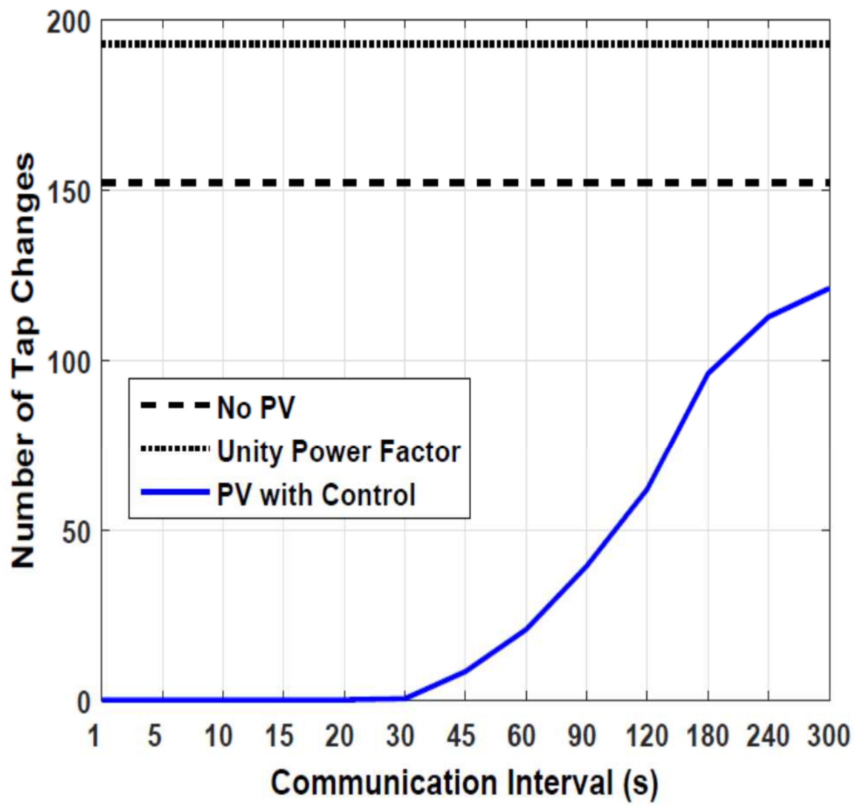
- Distribution Example



Var based controller results for the simulation week with 1 sec communication intervals

Results :

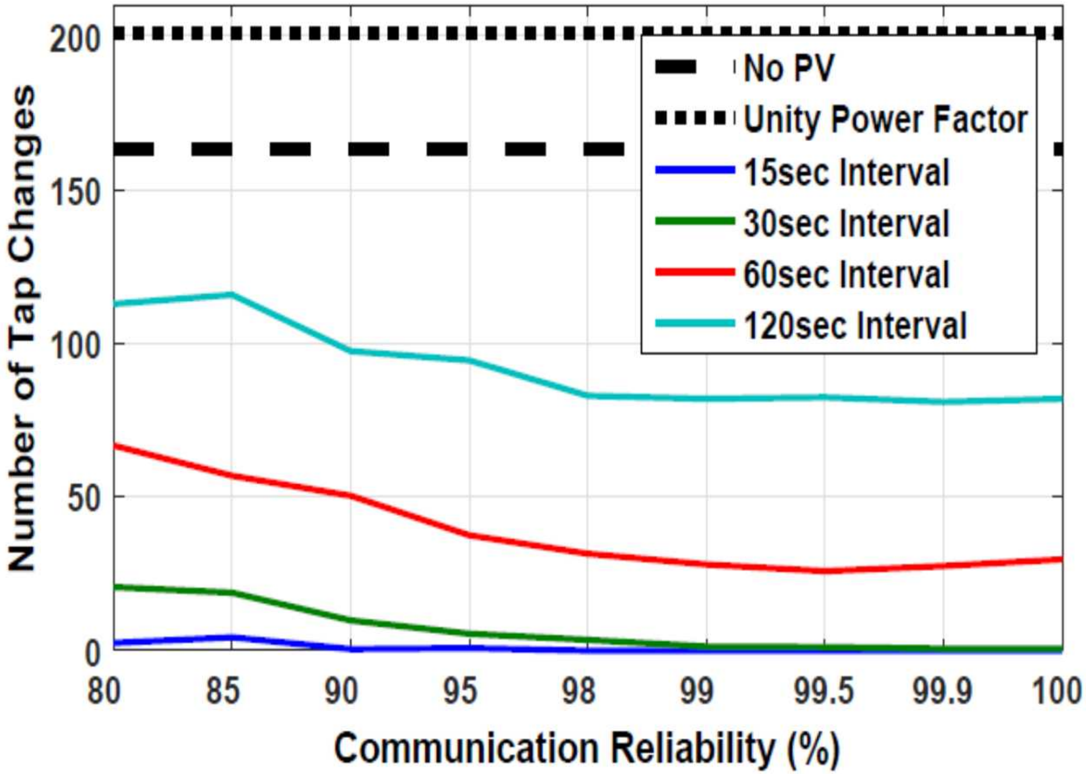
- Distribution Example



VAr-based controller results for peak week with basecase and unity PF operation thresholds

Results :

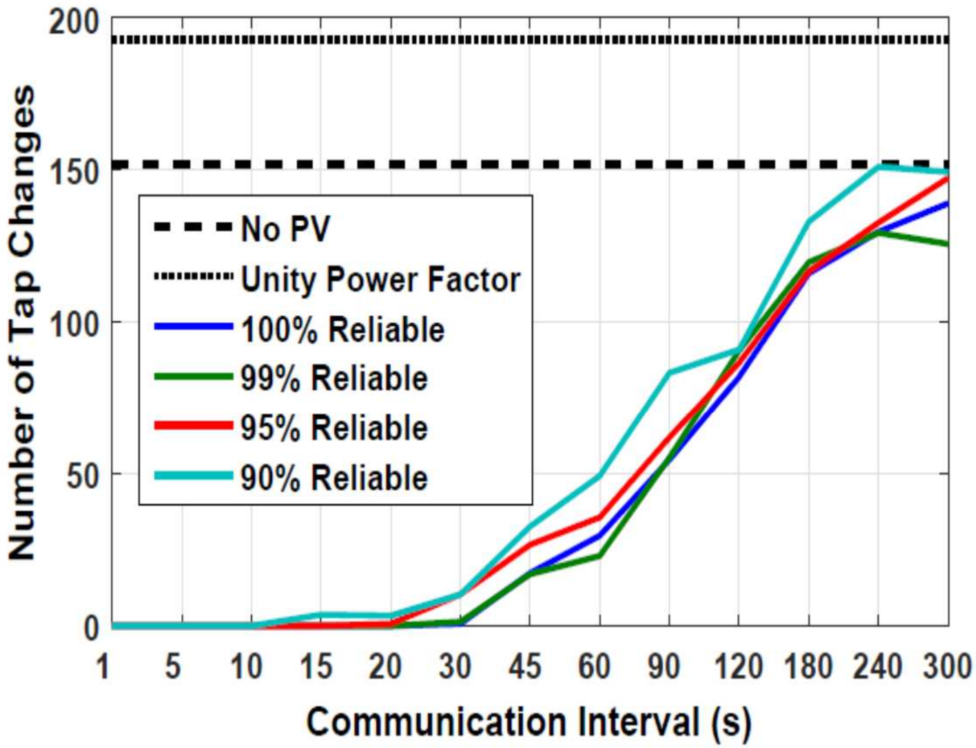
- Distribution Example



Controller results for different communication intervals and network reliability

Results :

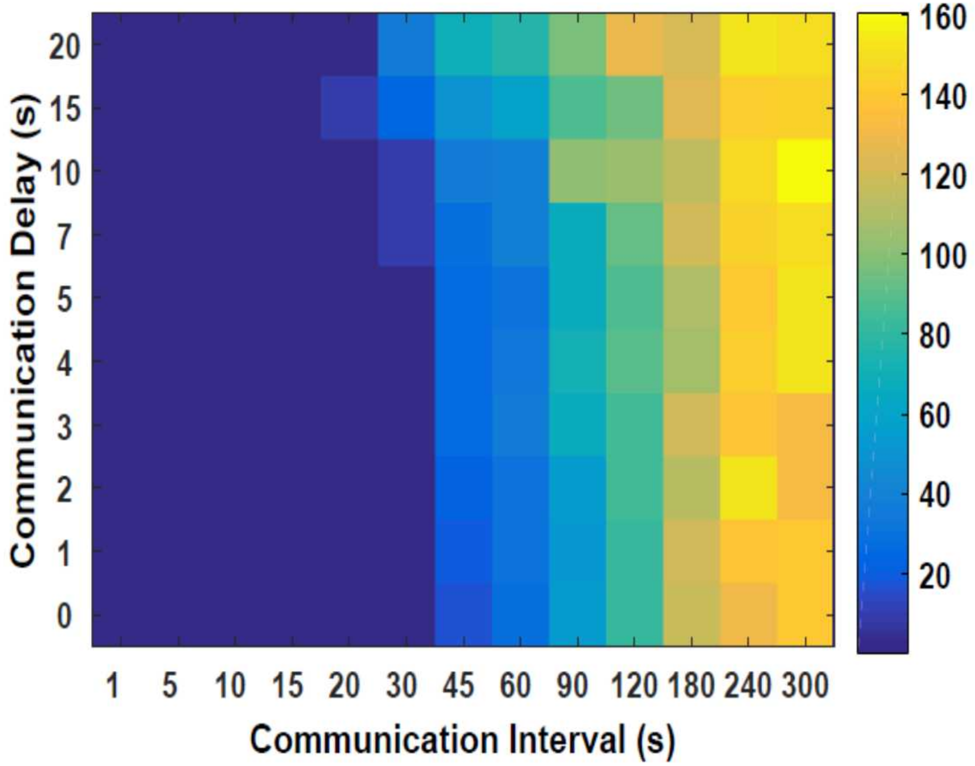
- Distribution Example



Controller results for different network reliability and communication intervals

Results :

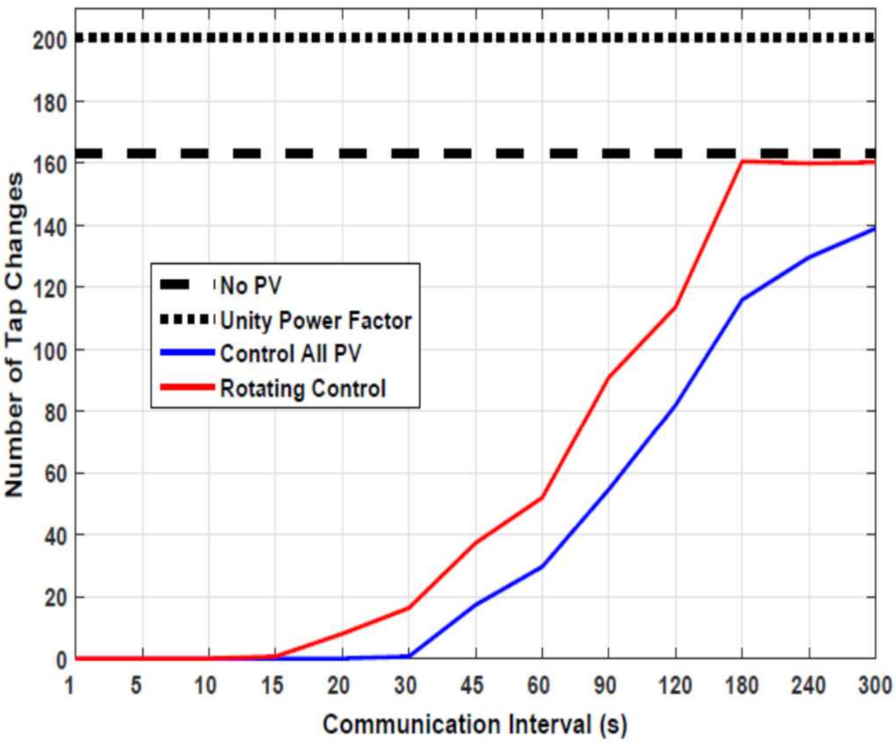
- Distribution Example



Number of tap changes during the simulation week with different communication intervals and network delays d

Results :

- Distribution Example



Bandwidth-limited control that could only rotate through communicating with a third of the PV systems at a time

Thank you for your attention