NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Inverter-Based Resource Performance and Analysis

Technical Workshop

NERC IRPT Meeting
February 2019

RELIABILITY | ACCOUNTABILITY




NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Fundamentals of Inverter-Based Resource Power Plants

NERC IRPTF Meeting
February 2019

RELIABILITY | ACCOUNTABILITY




Inside a Solar PV Power Plant – Pt. 1

Venkat Reddy Konala, First Solar

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




PV Plant

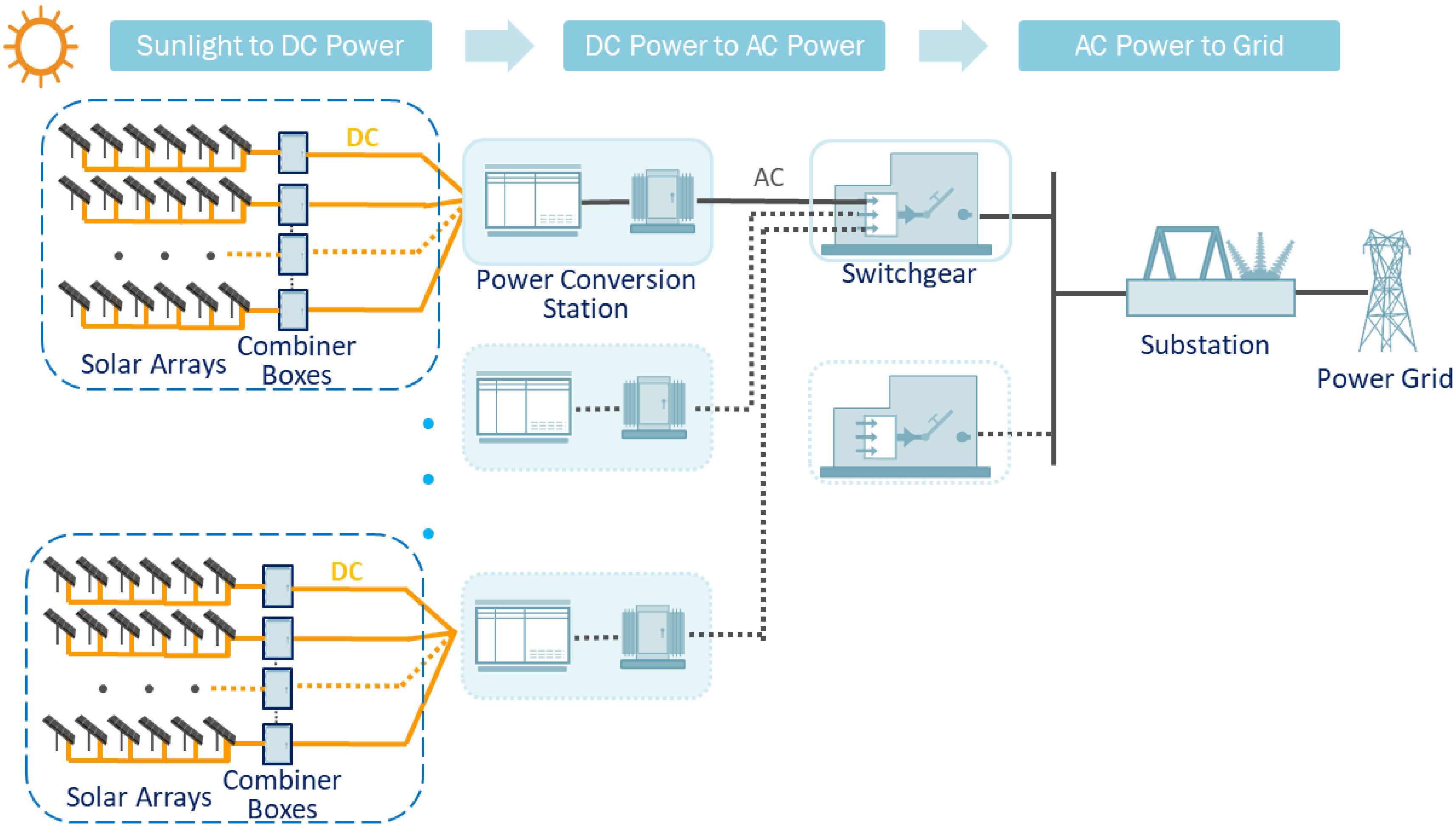
TOPAZ SOLAR FARM

Site: San Luis Obispo, USA

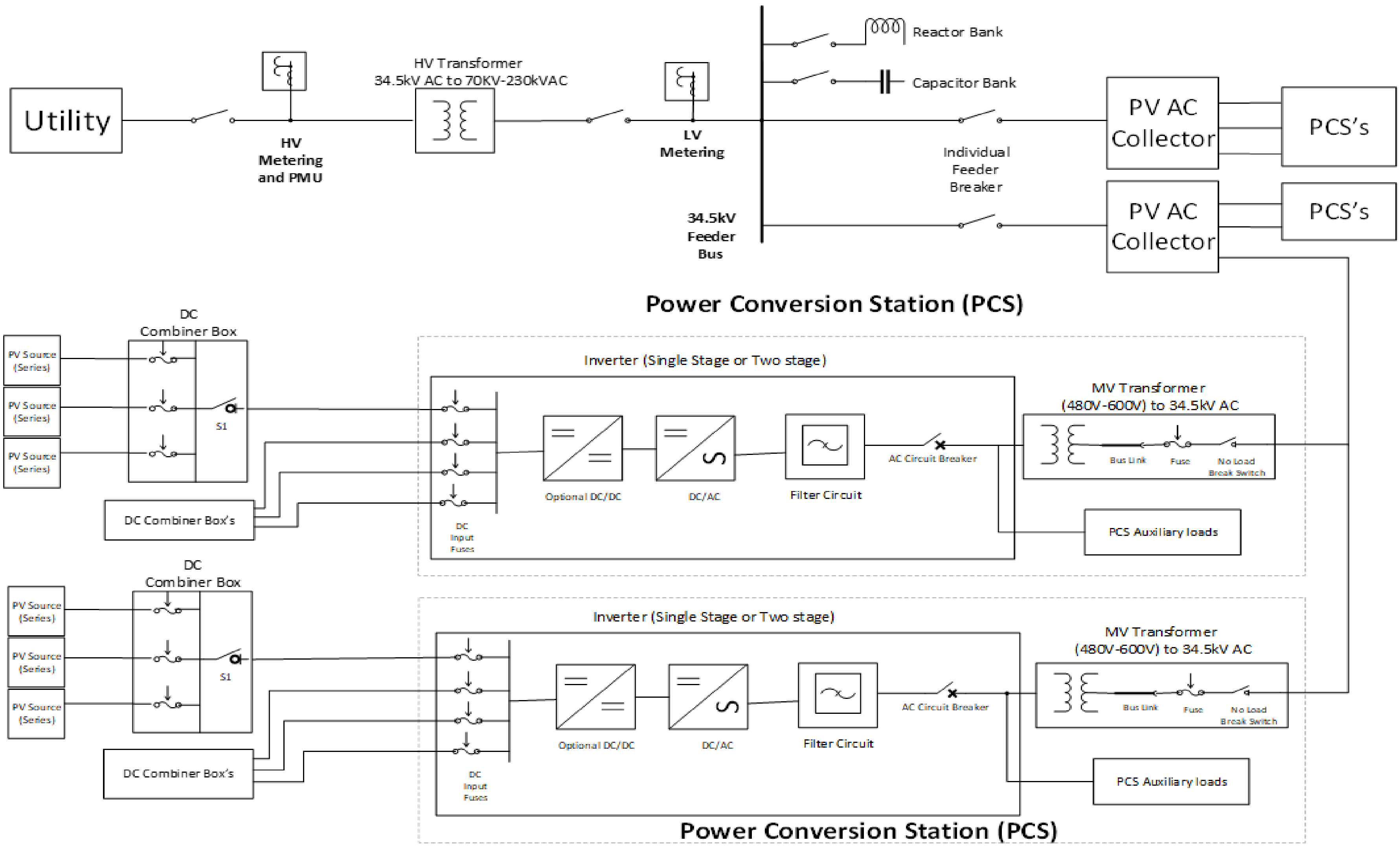
Size: 550MW

Owner: BHE Renewables

PV Plant – Overview



PV Plant – Electrical Overview

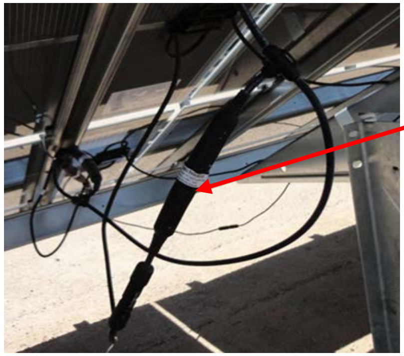


PV Plant – PV Source

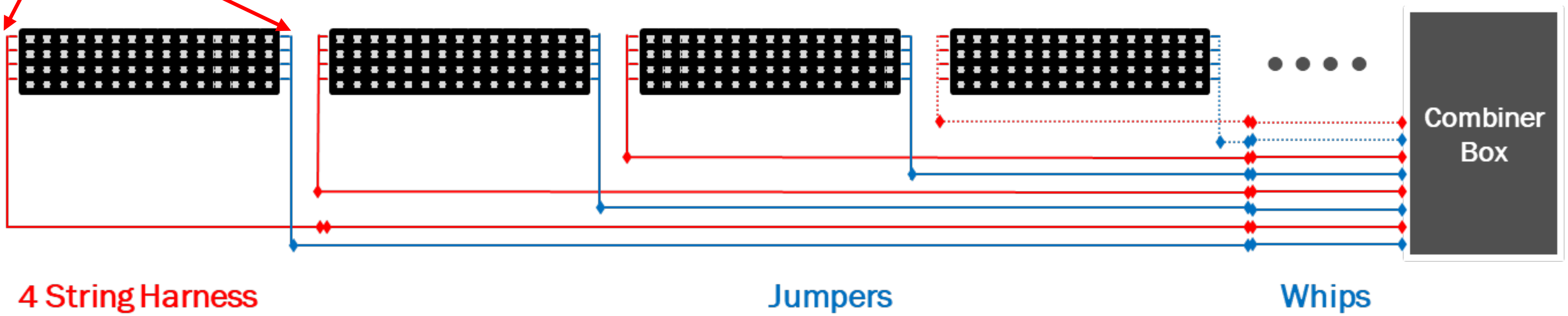
- PV Source
  - Series String : PV Modules connected in series to attain system voltage
  - Inline fuse protection at the end of each Series String
  - String DC Harness: Multiple Series Strings connected to attain system current

Series String

String DC Harness

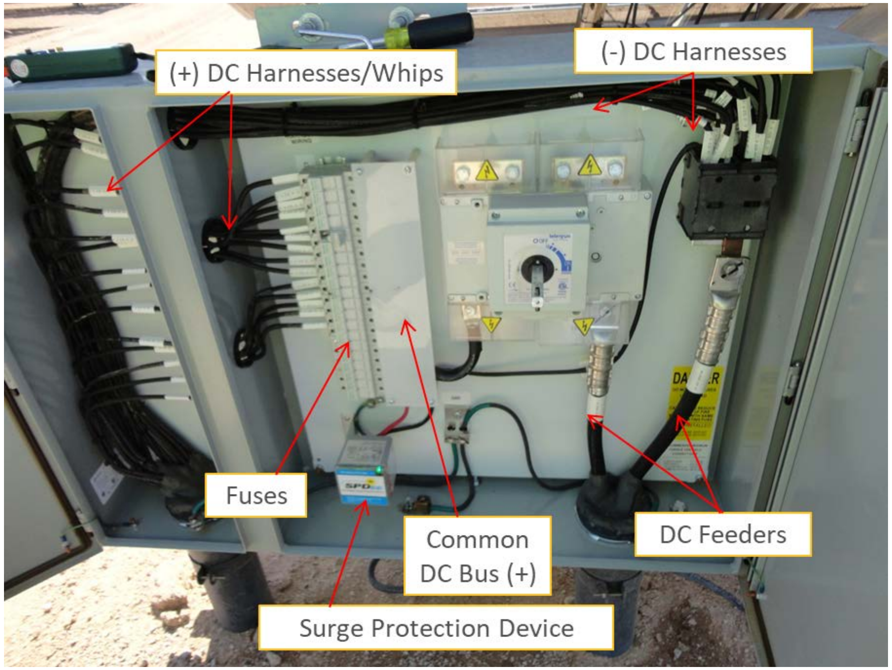


String Fuse



PV Plant – Combiner Box

- Combiner Box
  - Multiple String DC Harnesses connected to attain DC input power per box
  - Individual inputs are protected with a fuse
  - Output DC feeders can be disconnected via a switch accessible outside

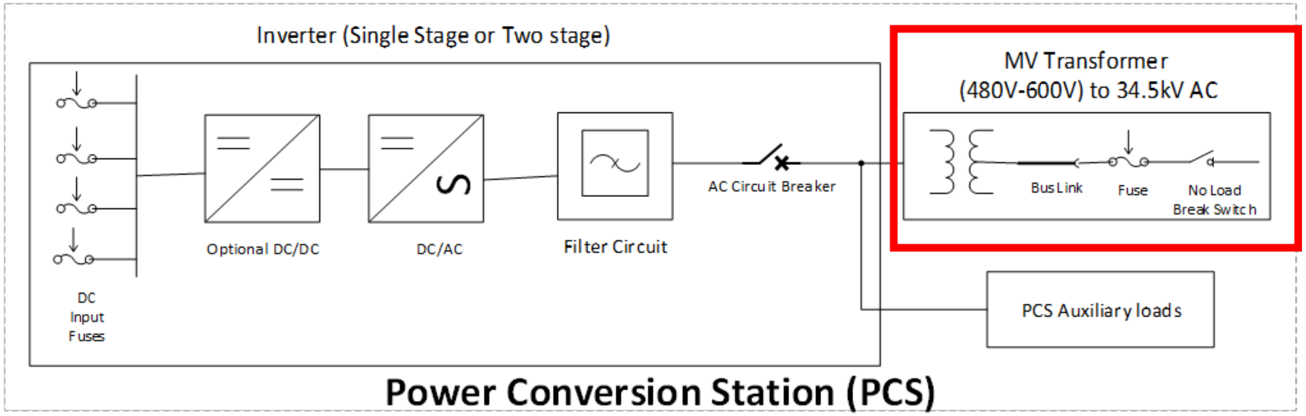


PV Plant – Power Conversion Station

- Power Conversion Station (PCS)
  - The PCS comprises of Inverter, Medium voltage step up transformer and any auxiliary loads

PV Plant – Power Conversion Station

- Medium Voltage Transformer (MVT)
  - The output of the inverter is stepped to 34.5kV voltage
  - The transformer can be oil filled or dry type transformer
  - The windings are galvanically isolated and protected on the high side via fuses, bus-link, and a disconnecting means is provided



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Inside a Solar PV Power Plant – Pt. 2

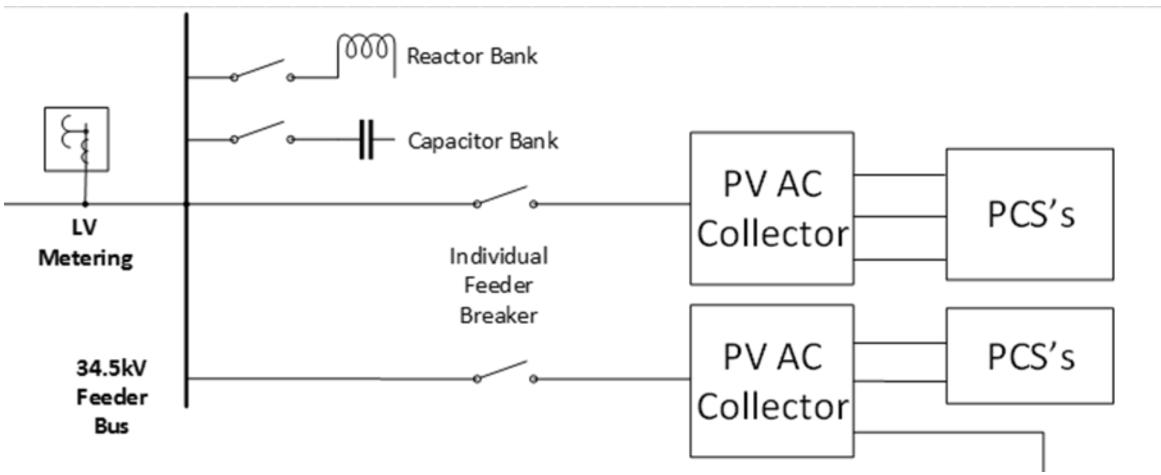
Chris Milan, First Solar

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY

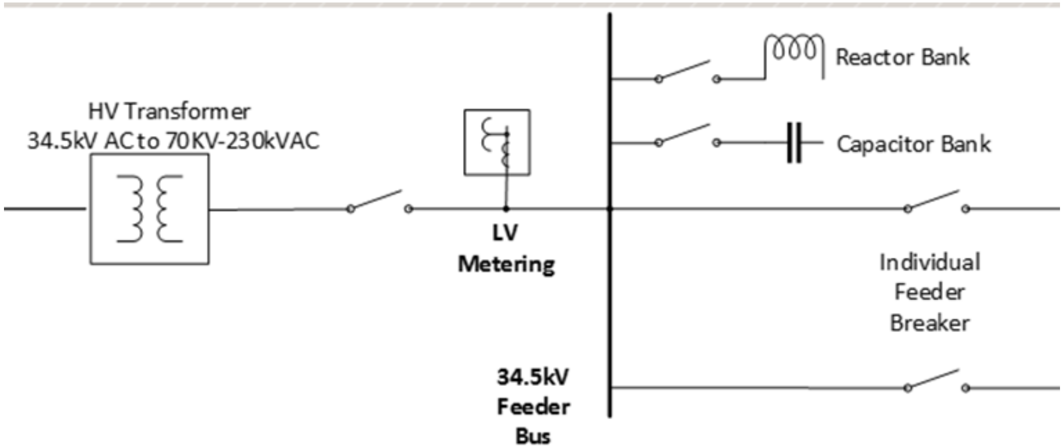



PV Plant – PV AC Collection System



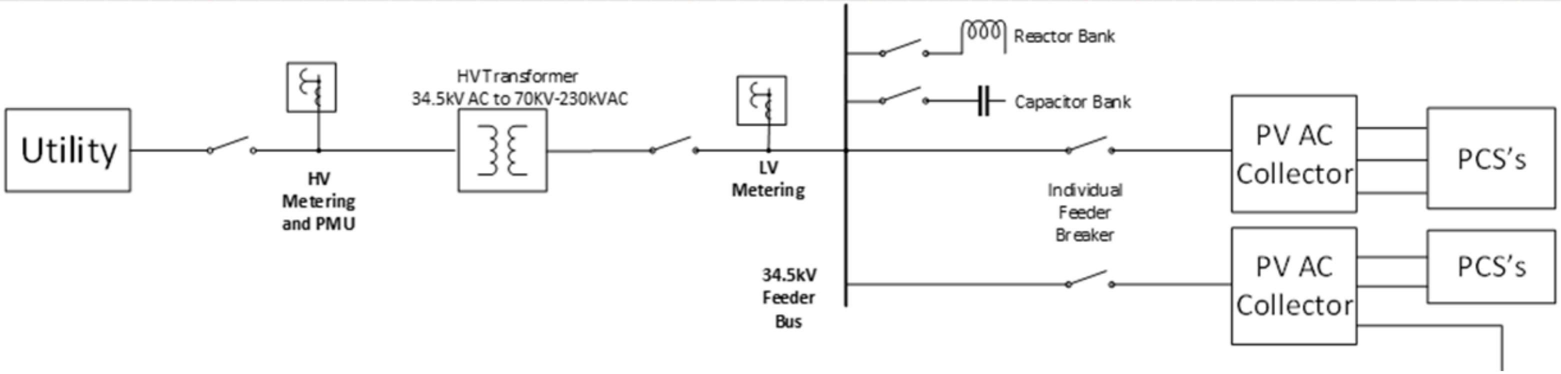
- Outputs of PCS daisy chained, connected to inputs of PV AC collector system
- Collection system is an aggregation of multiple daisy chained PCS inputs with a single feeder output
- Collection system can be combined by switchgear (with or without relay protection) or junction boxes.

PV Plant – Substation MV Feeder Bus



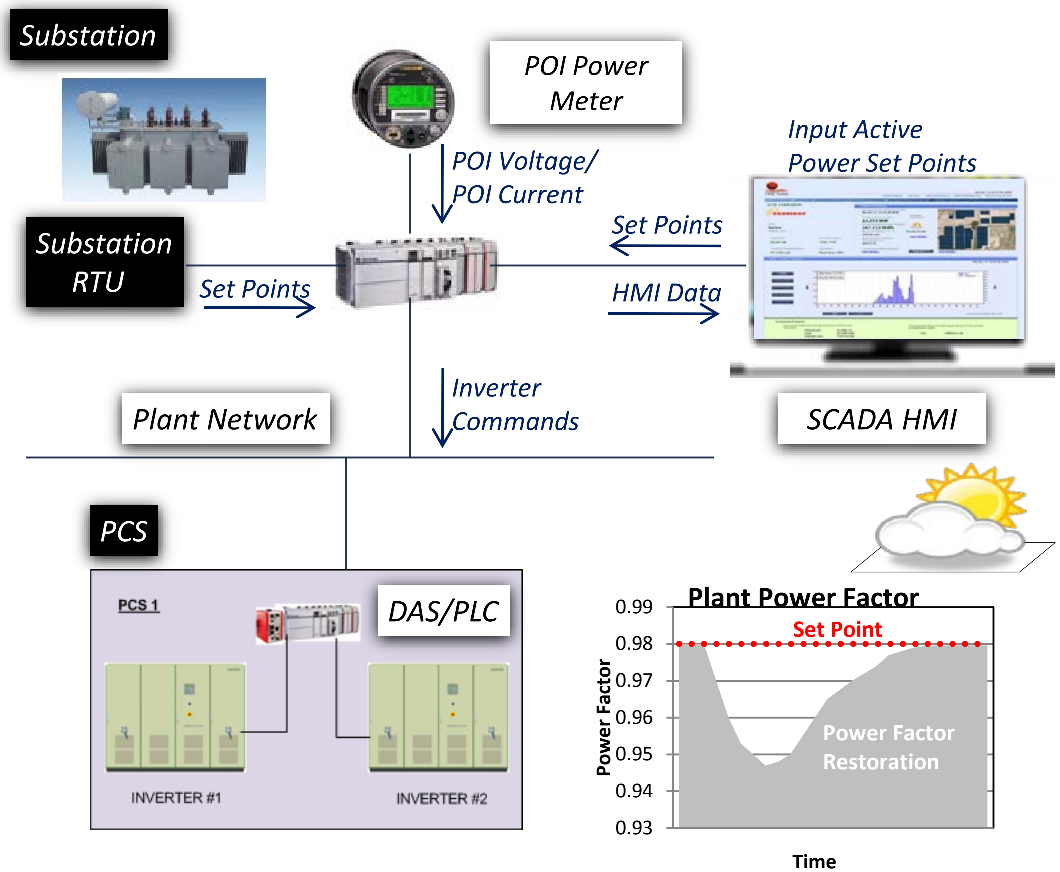
- Sections (Blocks) of PV AC Collection System are connected to MV feeder breakers in the substation up to 40 MW each.
- Reactor and Capacitor banks also connected to MV feeder bus, protected via individual feeder breakers to provide power factor support making up for design losses.
- Battery storage may be integrated on MV feeder breaker(s)
- Typical protection is UV, OV, OC, XFMR Diff
- Station Service Power

PV Plant – Substation HV Bus & GSU Transformer



- Typically low impedance transformer 7 to 9%
  - Low side onload tap changer (OLTC).
  - Stand alone or integrated with central controller
- MOD Disconnect Switch and Main Circuit Breaker
- HV Metering used for PPC and Revenue. Harmonic metering
- Line Protection or Breaker Protection Relay used to provide phasors for PMU
- Typical protection OV, UV, OF, UF, OC, XFMR Diff, Line Diff.

PV Plant – Central Controller

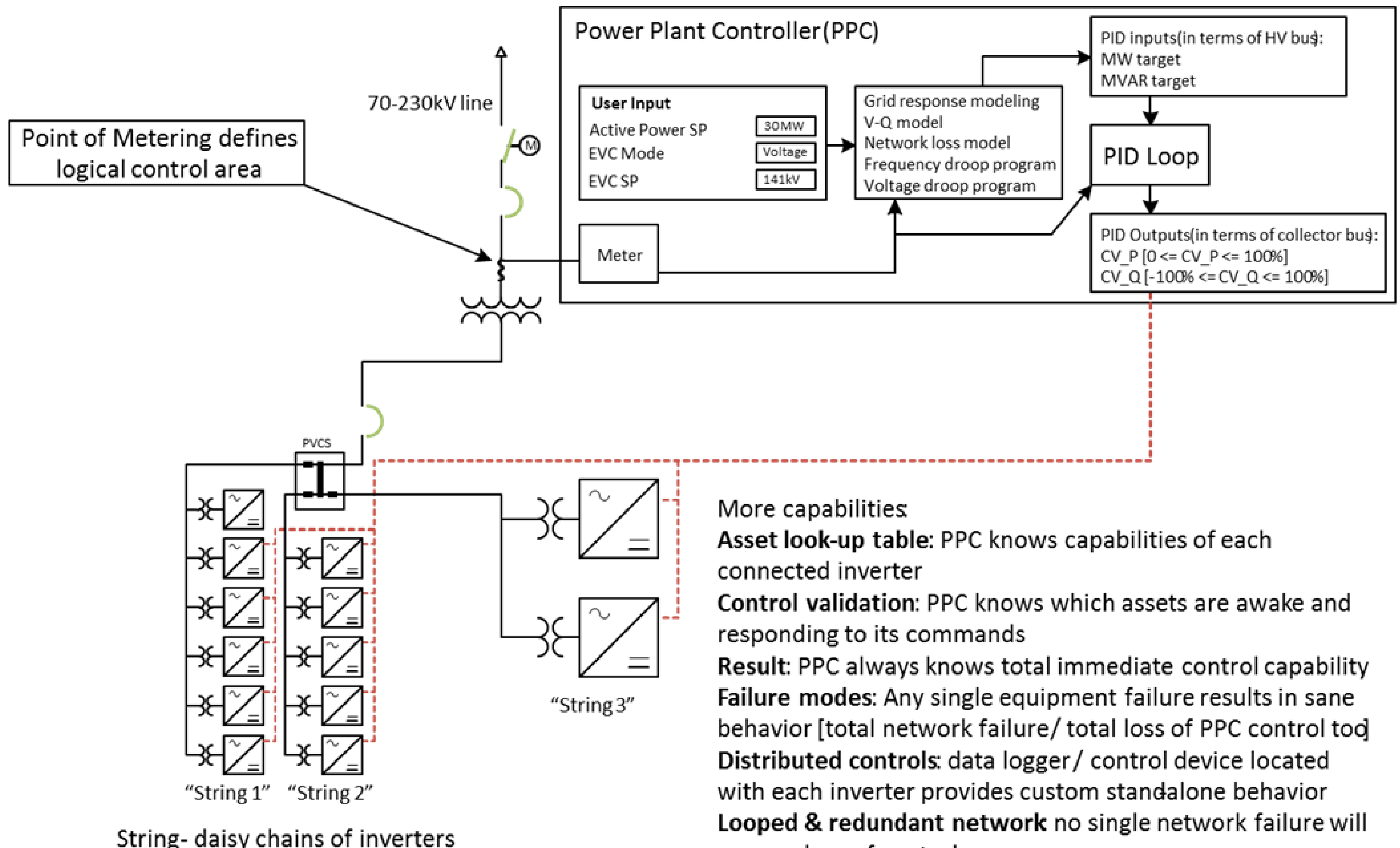


- Plant Control Functions
  - Active Power Control
    - Set Point
  - Voltage Regulation
    - Static
    - Dynamic
  - Power Factor Control
- Grid Integration Functions
  - Ride Through
    - Low Voltage
    - High Voltage
    - Frequency

Handled by Inverters

Real-Time, Reliable Plant Controller

PV Plant – Central Controller



More capabilities:

Asset look-up table: PPC knows capabilities of each connected inverter

Control validation: PPC knows which assets are awake and responding to its commands

Result: PPC always knows total immediate control capability

Failure modes: Any single equipment failure results in sane behavior [total network failure / total loss of PPC control too]

Distributed controls: data logger / control device located with each inverter provides custom standalone behavior

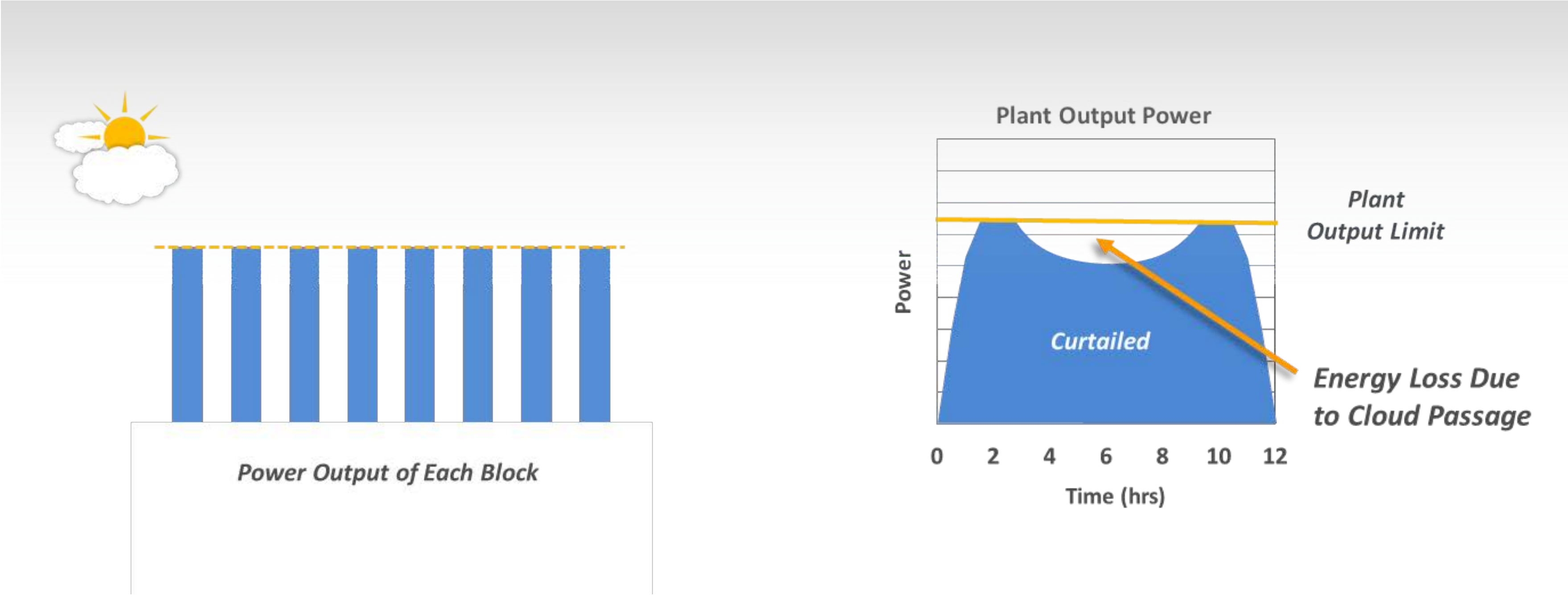
Looped & redundant network: no single network failure will cause a loss of control

PV Plant – Central Controller

- Power plant controller will read P,Q and V from POI meter and, based on the plant required reference, generates the P and Q commands to the inverter
- Line loss compensation to POI if required
- V Control Modes: Var, Power Factor, Voltage, Hybrid
  - Capacitor/Reactor control
- Frequency and Voltage droop control
- ADS & AGC integration
- Dynamic reserve operation for ancillary services support
- Battery storage control
- Typical AC to DC ratios are 1.2 to 1.4
  - Account for seasons, variable irradiance, losses, fixed tilt vs tracking
  - Potential leaves headroom for contingencies and reliability

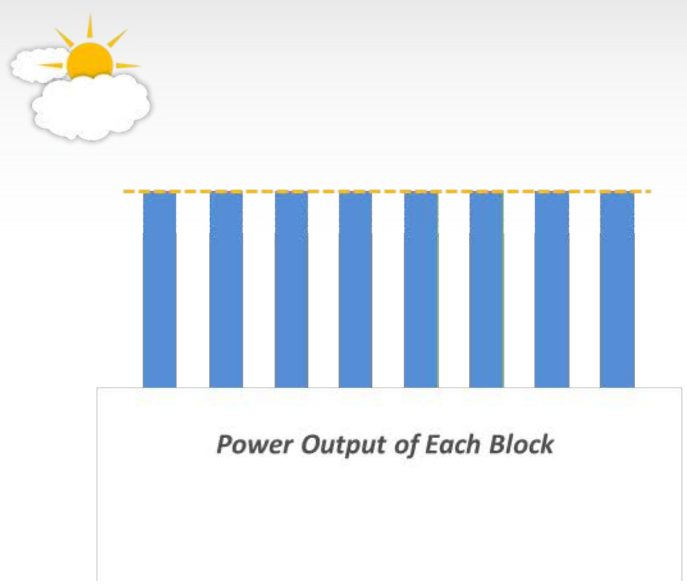
PV Plant – Central Controller

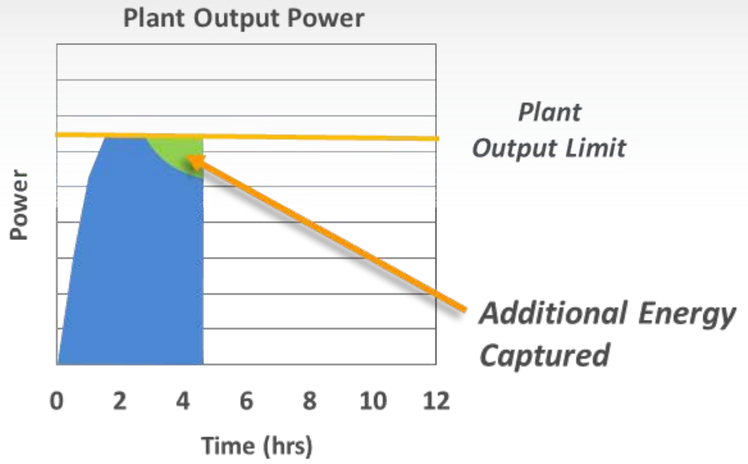
Variable irradiance without a Central Controller:



PV Plant – Central Controller

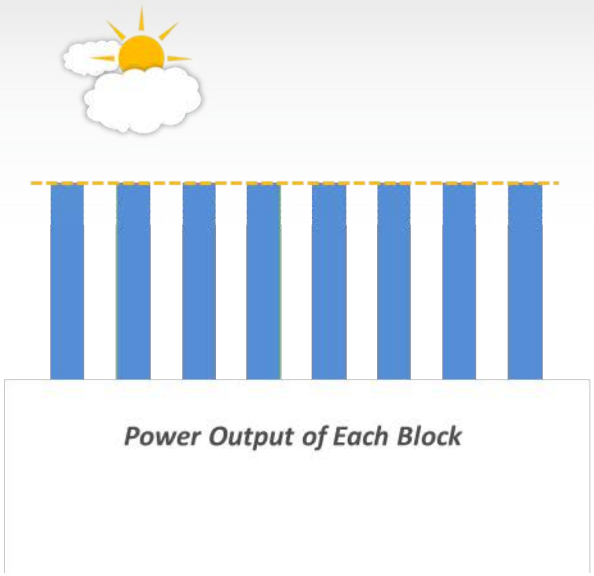
Variable irradiance with a Central Controller:

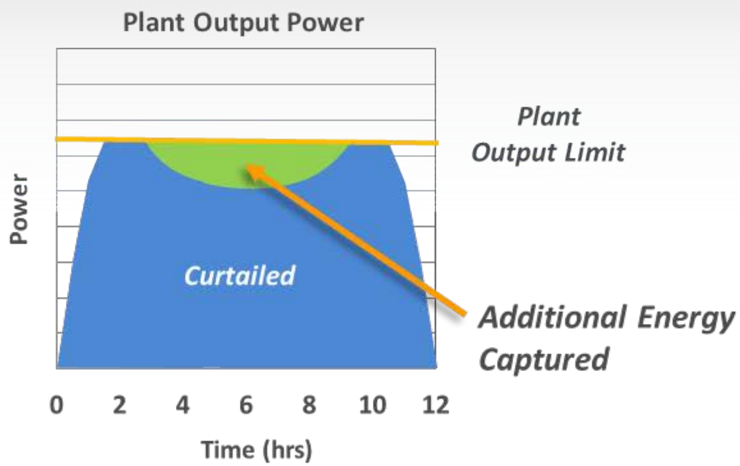




PV Plant – Central Controller

Variable irradiance with a Central Controller:





NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Utility Interface with an Inverter-Based Resource Facility

NERC IRPTF Meeting
Lou Fonte, California ISO

RELIABILITY | ACCOUNTABILITY




Interconnection Application

Generators wanting to interconnect to the CAISO controlled system must submit an application, which includes the following information (control and protection review):

- Single line diagram
- Three line diagram
- Circuit breaker trip and close control circuits
- Bill of material for all protective relays
- Relay settings for all protective relays

Additional Application Data for Inverter-Based Resources

- In addition to the previous data, inverter-based resources must also submit the following data:
  - Make, model, and number of inverter(s)
  - If momentary cessation is used:
    - High and low voltage settings
    - Time required for inverter to return following cessation
    - Inverter transient ramp rate (%/sec)
  - If reactive current injection is used:
    - High and low voltage settings
    - K factor
    - Time required for inverter to return following cessation
    - Inverter transient ramp rate (%/sec)
  - Inverter voltage and frequency trip settings, including time delays

Inverter Ramp Rates

Transient Ramp Rate:

Ramp rate used by the inverter during a return from momentary cessation or reactive current injection.

- NERC Alert 2 recommends total return time not to exceed 1 sec
- 100%/sec minimum required. Note: CAISO prefers 200%/sec

Operating Ramp Rate:

Ramp rate used when plant is initially started up (morning for solar plants) or brought off line (evening for solar plants).

- No NERC requirements or recommendations
- CAISO prefers 10%/minute

Dispatchable Generators

Dispatchable generators can be turned on or off, or can adjust their power output according to an order.

During periods of over generation, CAISO will require that IBRs follow their “Dots” (Dispatch Operating Targets).

Generator Interconnection Agreements (GIA)

- Generators wishing to participate in the CAISO controlled market are required to execute a Large Generator Interconnection Agreement (LGIA) or Small Generator Interconnection Agreement (SGIA)
- The CAISO is filing an application at FERC to modify its tariff to update the pro forma LGIA and SGIA
  - Updated agreements will seek to eliminate momentary cessation to the greatest extent possible
  - Updated agreements will preclude inverter tripping for momentary loss of synchronism (150 milliseconds)
  - The LGIA will introduce minimum data monitoring and recording requirements

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Fundamentals of Inverter Controls

Deepak Ramasubramanian, Electric Power Research Institute
Siddharth Pant, General Electric
Rajat Majumdar, Siemens Gamesa

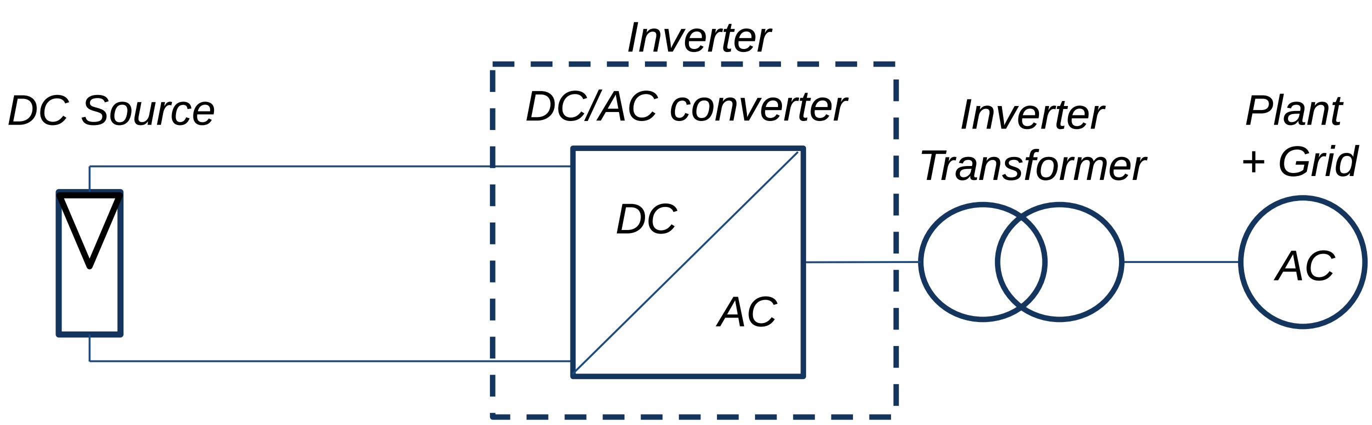
RELIABILITY | ACCOUNTABILITY




Inverter

60 Hz Power Source

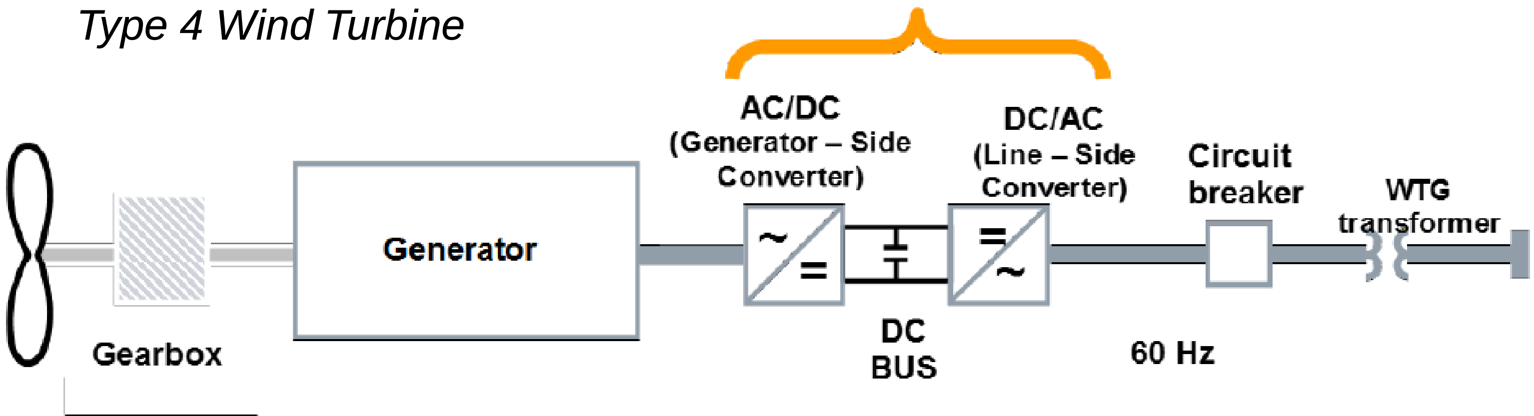
DC Power Source (Example – PV Solar, BESS, Fuel Cells)



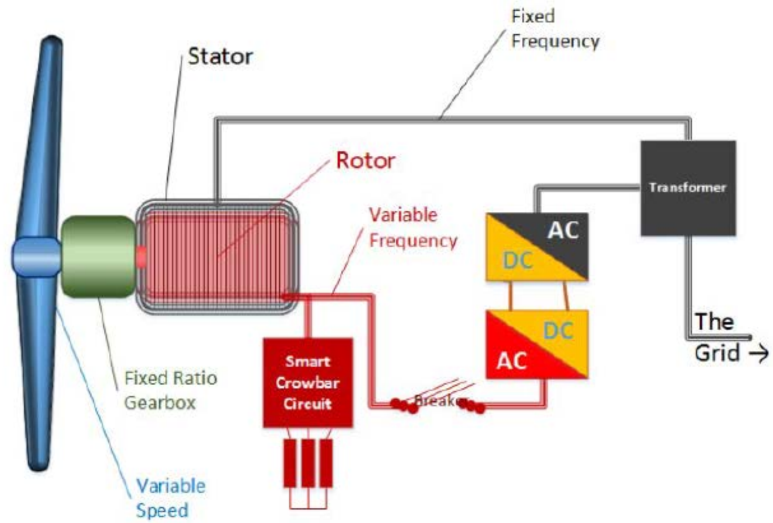
Inverter

- More broadly, inverters are used for interfacing resources that generate non-60Hz power to the grid (example, wind turbines, pumped storage hydro)

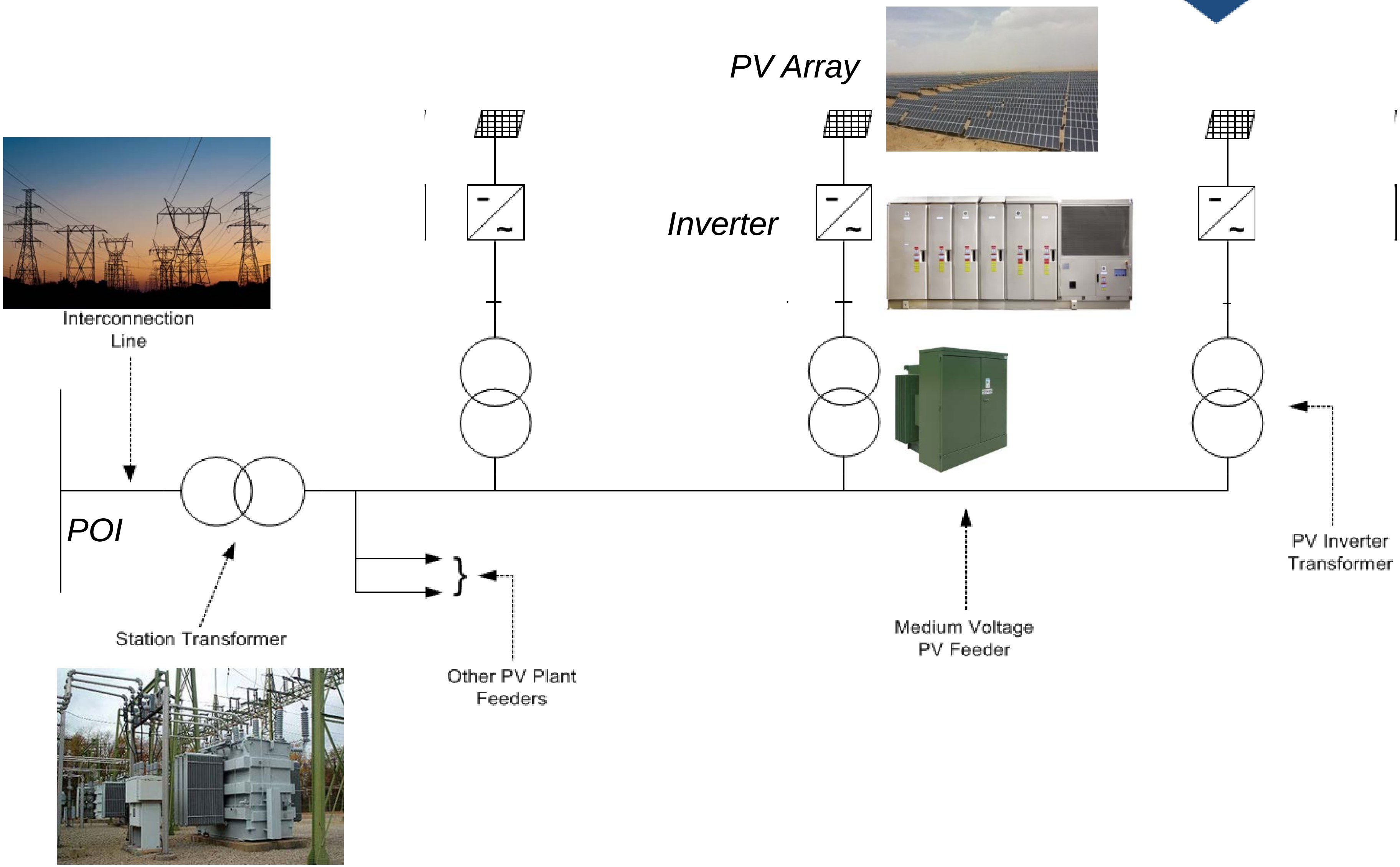
Type 4 Wind Turbine



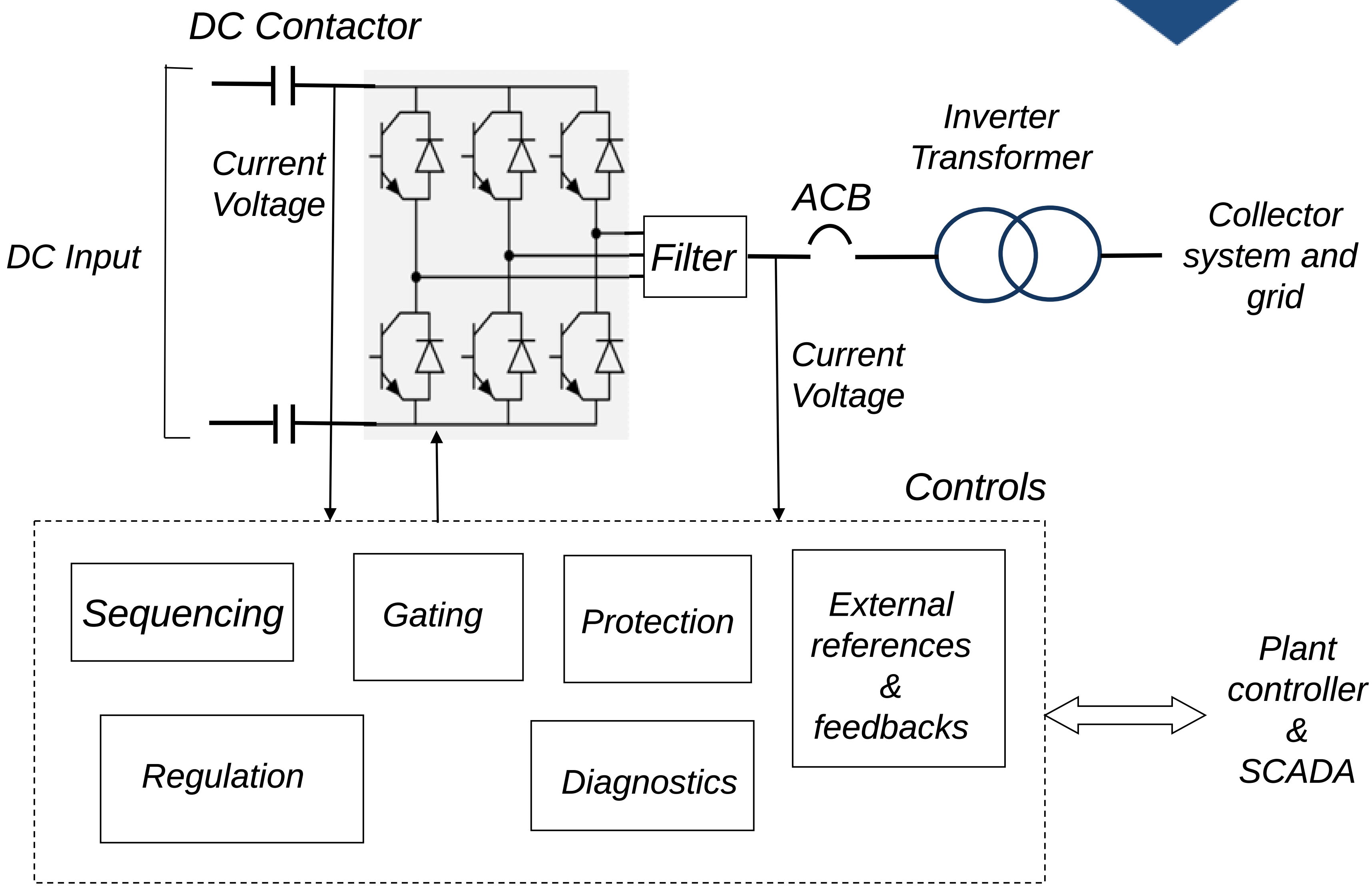
Type 3 Wind Turbine



Solar PV Power Plant



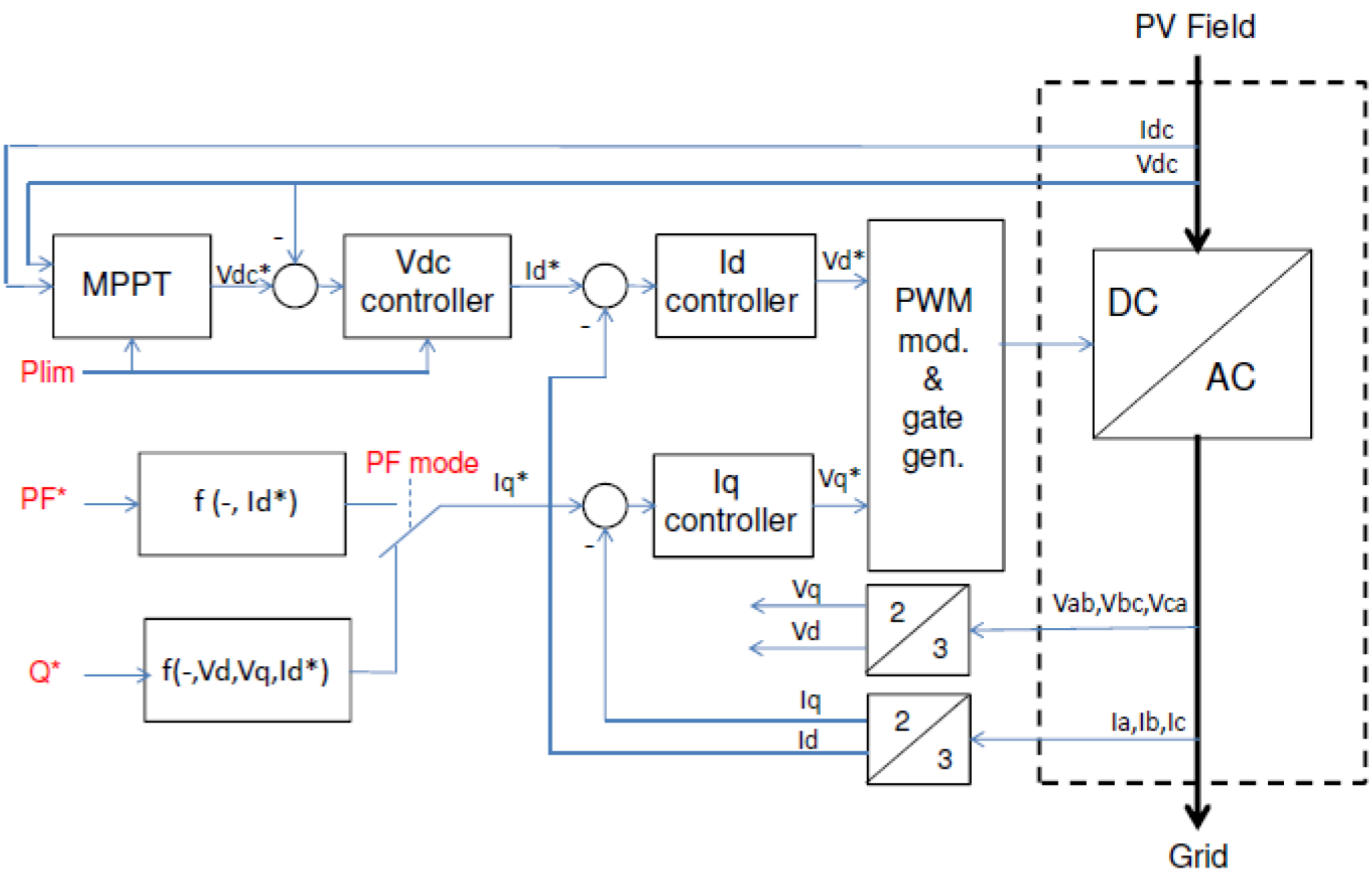
Power and Control Block Diagram



Control Functions in an Inverter

- Sequencing
- Power electronics device gating
- Protection
- External references and feedbacks
- Monitoring and diagnostics
- **Regulating functions**:
  - P, Q, current, voltage control loops
  - Maximum power point tracking (MPPT)
  - Active power – frequency and Reactive power – voltage control
- **Other control related functions**:
  - Synchronization to the grid (PLL)
  - Voltage ride-through, Frequency ride-through

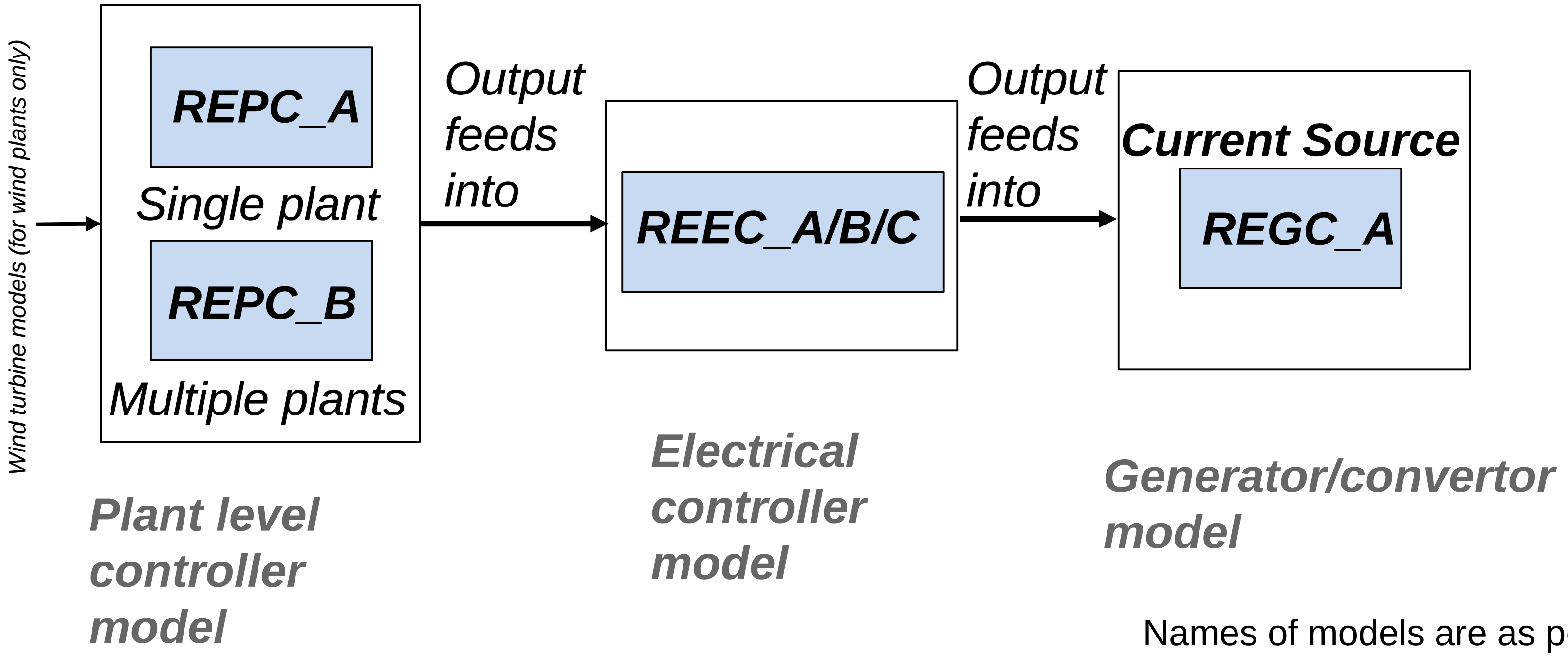
Solar Inverter Control Block Diagram



Basic Diagram of Solar Inverter Controls [Source: GE]

How is it Modeled in Positive Sequence Studies?

How many in the audience are familiar with this modeling setup?



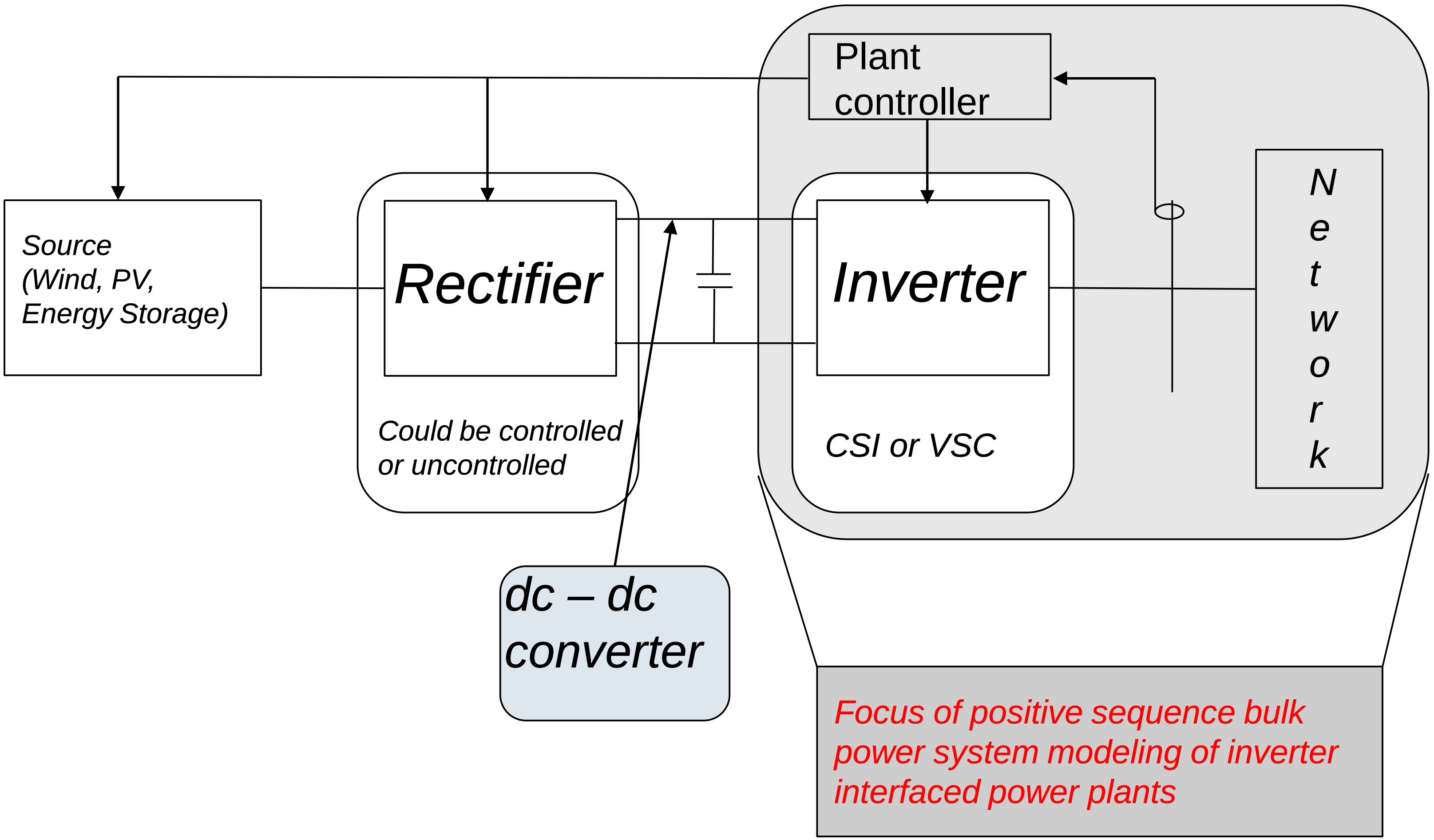
Names of models are as per WECC terminology

However, is it the same as set up shown in the previous slide?

How is Energy from Source Controlled?

- An example working of the controllers:
  - Extracting maximum power from source:
    - Each wind turbine has a controller to change the angle of attack of the turbine blades (pitch)
    - For a solar panel, the dc side voltage of the panel is controlled
  - An increase (decrease) in power extraction from the source will cause an increase (decrease) in the dc bus voltage of the rectifier (if present) – inverter combination.
  - The grid side inverter will control the dc bus voltage to a reference value, and thus increase (decrease) the active power command.
    - Simultaneously, if required, the grid side inverter is also controlling voltage/power factor
- But, in positive sequence modeling, an entire plant is represented as on generator. So, this level of detail is too much.

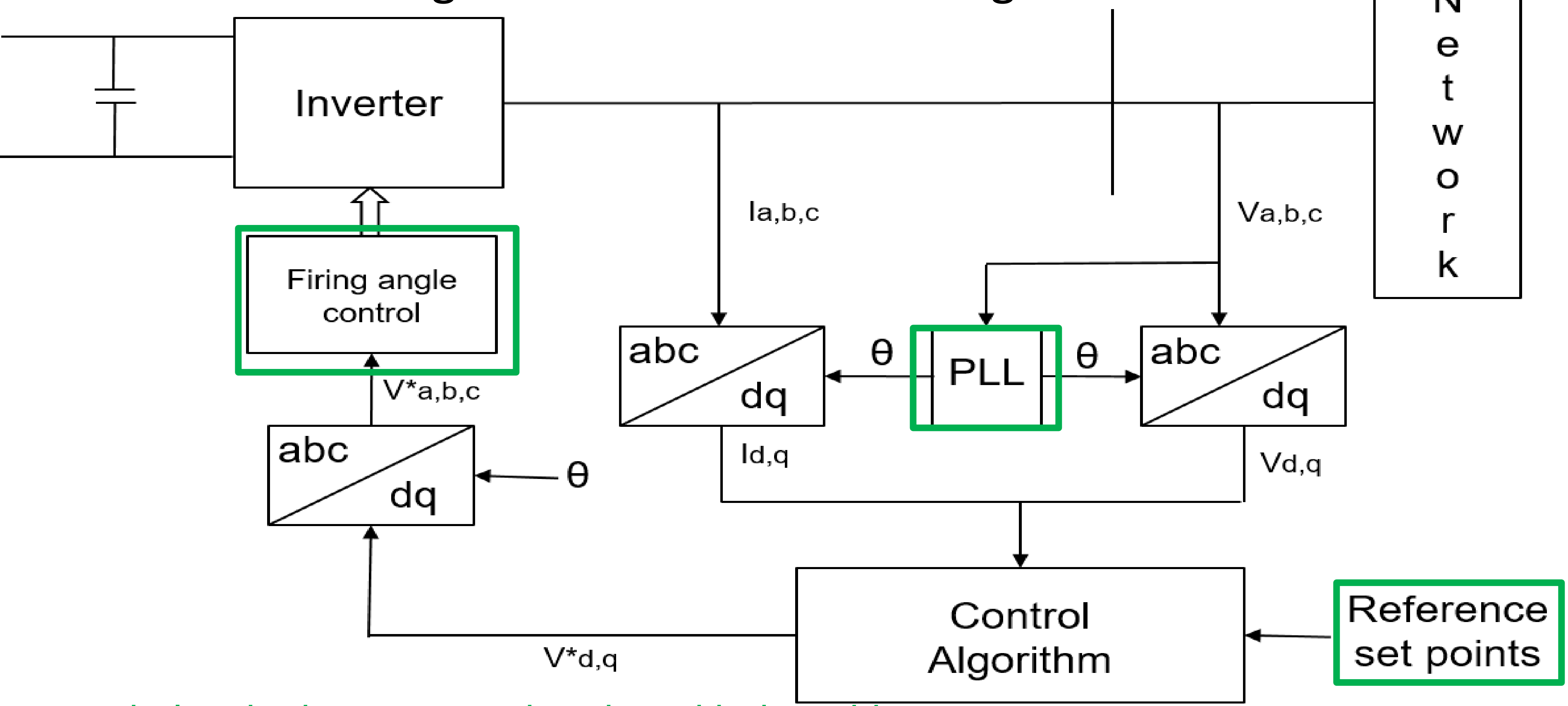
General Schematic from source to grid



Rectifier would be absent for solar/battery.

Electrical controller of each inverter

- Takes the power commands (or voltage command) from plant controller and generates sinusoidal voltage wave

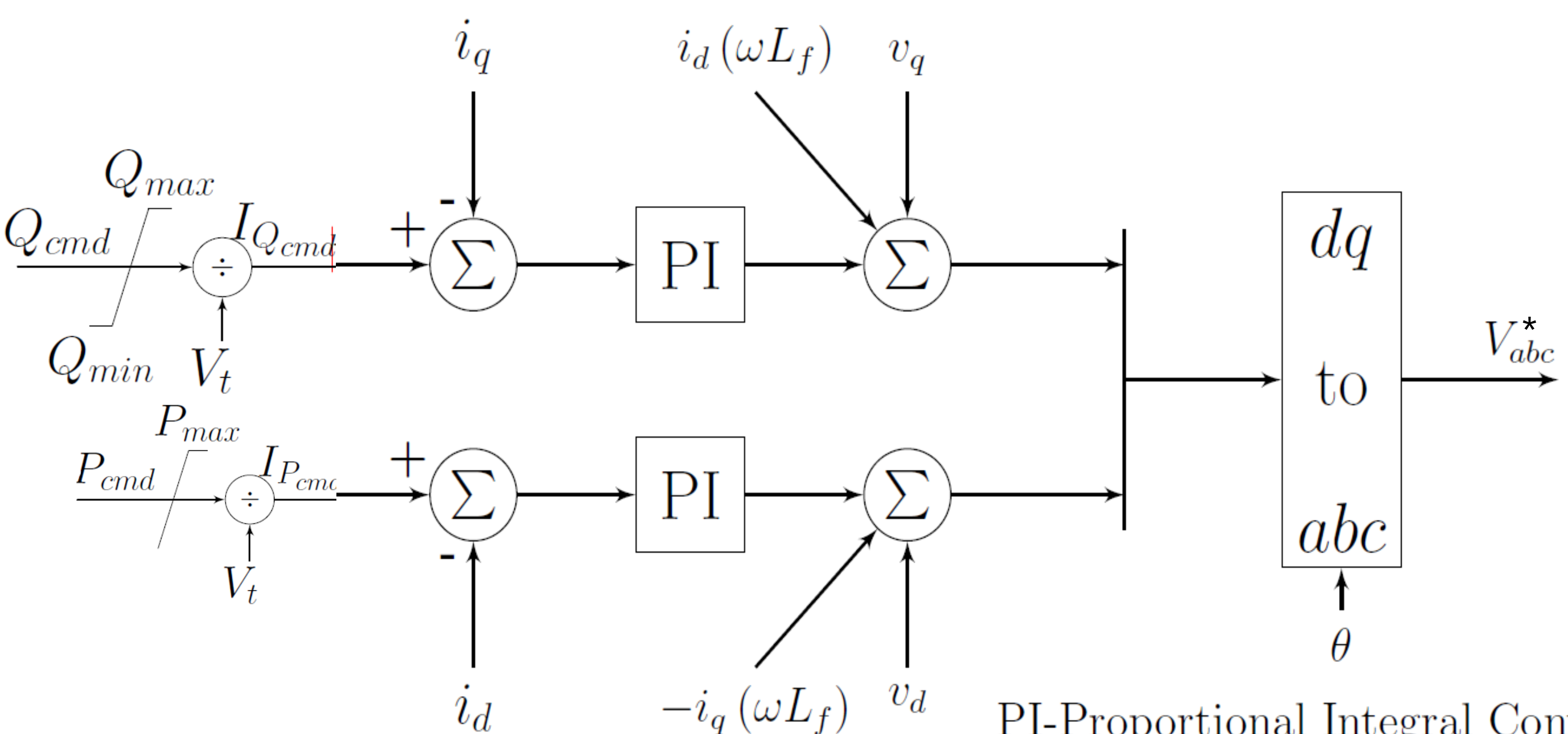


PLL – helps the inverter synchronize with the grid
Firing angle control – toggles the individual switches

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Generic electrical controller

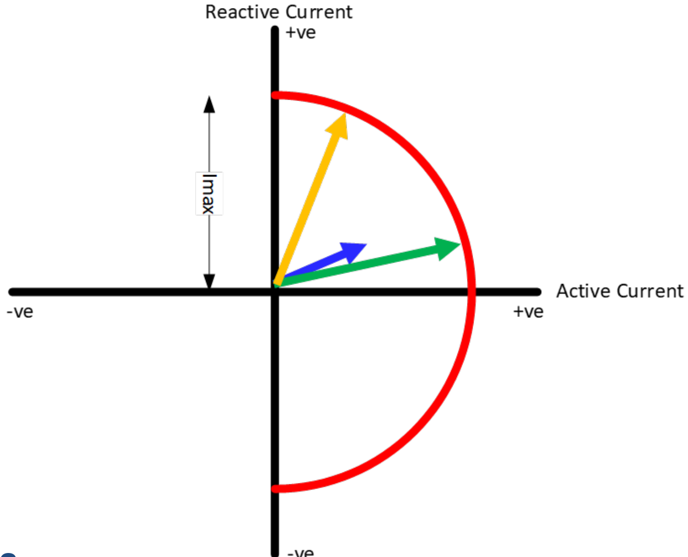
- Highly simplified generic control is shown here
  - Active and reactive power commands are converted to current commands
  - Current commands are converted to voltage reference values

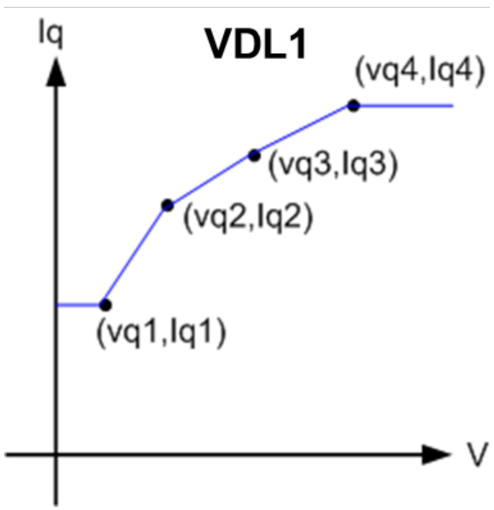


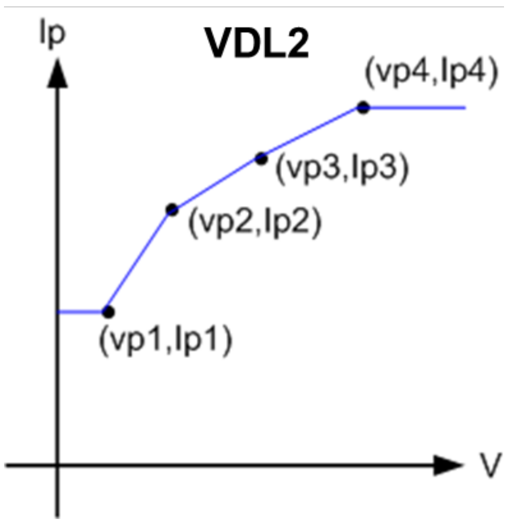
PI-Proportional Integral Controller

Prioritizing the type of current

- For safe and operable voltage levels, the grid needs adequate current to be injected by energy sources (and sinks).
- In a synchronous machine, magnetic flux is a limiting quantity, and thus available current can be large ☺
- However, an inverter is predominantly a current limited device, and thus, there can be concerns ☹
  - An inverter needs to be told what type of current to inject into the grid.

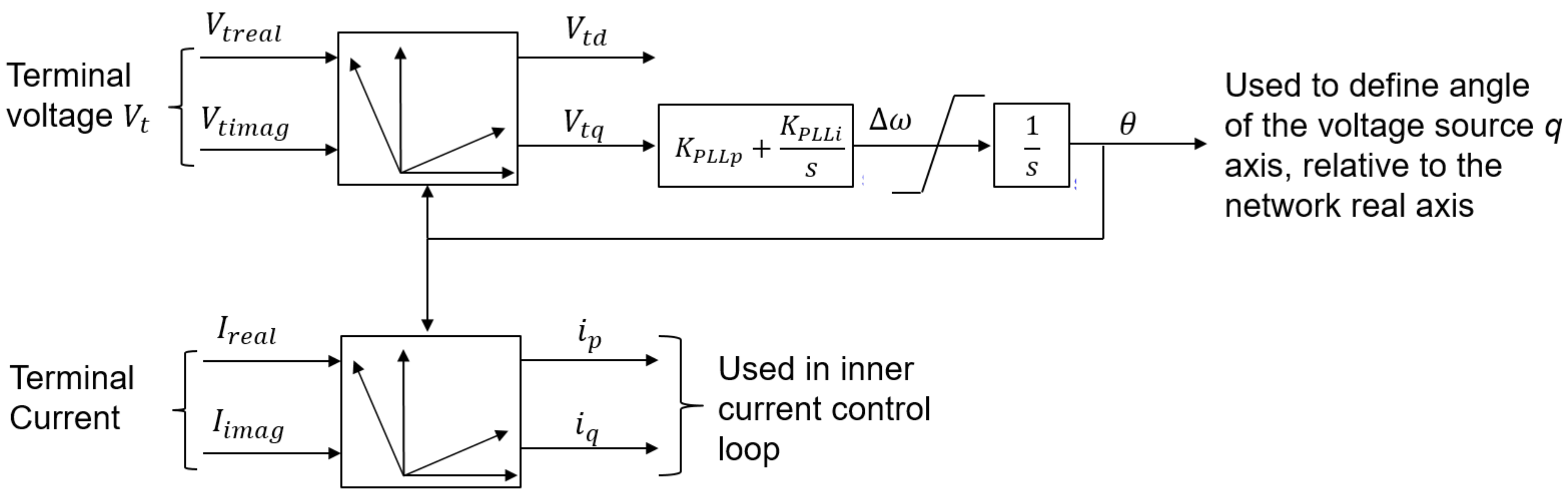






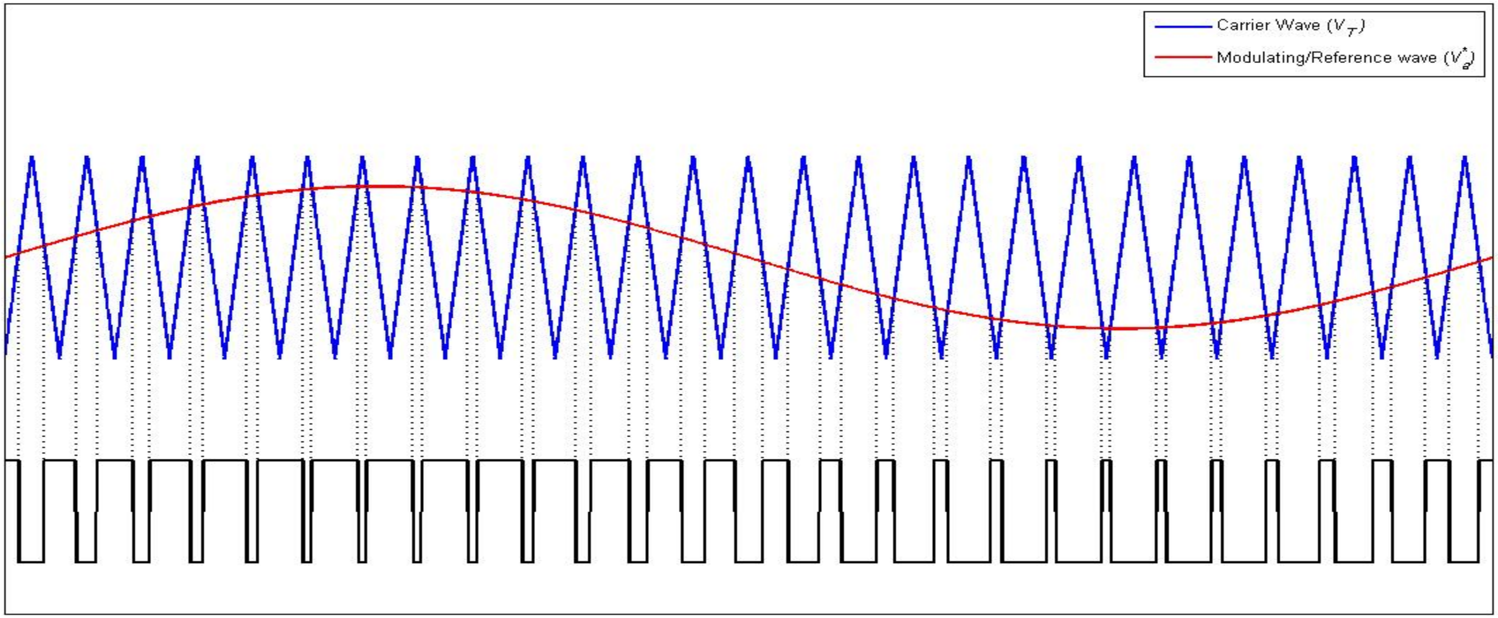
How does the synchronization happen?

- A synchronous machine needs a synchronmeter only during closing of the breaker switch.
  - Once this has been achieved, the magnetic flux inside the machine ensures synchronization under normal operating conditions.
- An inverter needs it always!
  - This is valid only for present state of the art technology



How is the final voltage waveform generated?

- The reference voltage wave (V*a,b,c) generated from the control algorithm is the modulation wave.
  - It is also the wave that needs to appear as the output of the inverter
- The triangular high frequency wave is the carrier wave.
  - It helps define the duration of switching the inverter transistors



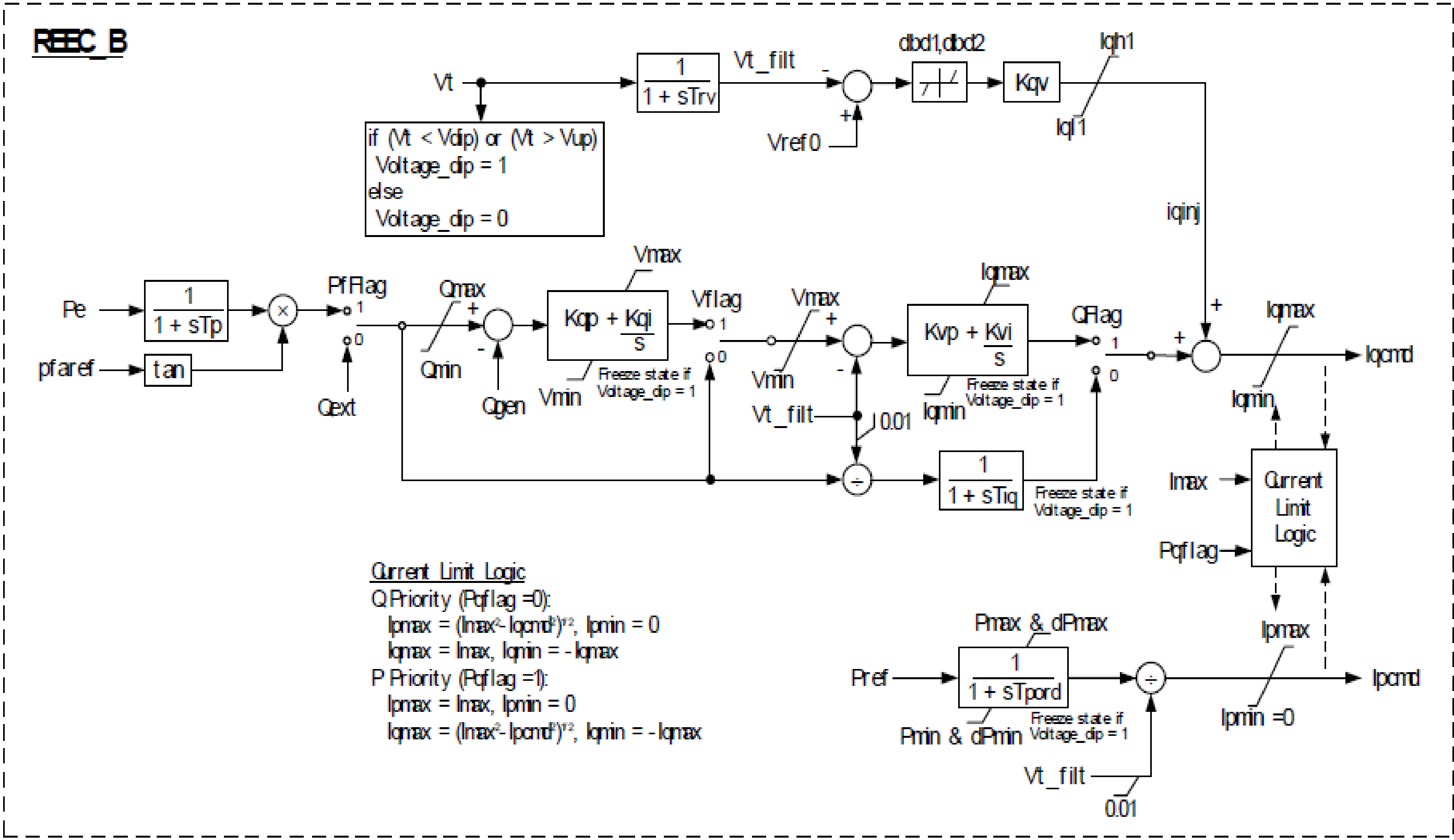
Manufacturer's perspective

- Inverter manufacturers were actively represented in the IRPTF and we welcome the guidelines
- Manufacturers are starting to see all or portions of the guidelines in customer specifications and also in draft Interconnection Agreements
- We prefer specifications to be functional rather than defining implementation,
  - e.g., We prefer - the inverter shall not trip for an overvoltage of 1.4 pu for 1 second, instead of - the overvoltage detection shall have a 1-second first order filter
- For designing and testing equipment, we prefer requirements to be definite rather than vague or physically open-ended
  - e.g., We prefer - the inverter may trip instantaneously for an overvoltage of 1.6 pu, instead of – the inverter shall not trip for an overvoltage greater than 1.5 pu 3 cycles (the latter statement does not define the maximum voltage withstand requirement)
- For designing and testing equipment, we prefer requirements to be at the inverter or inverter step-up transformer terminals

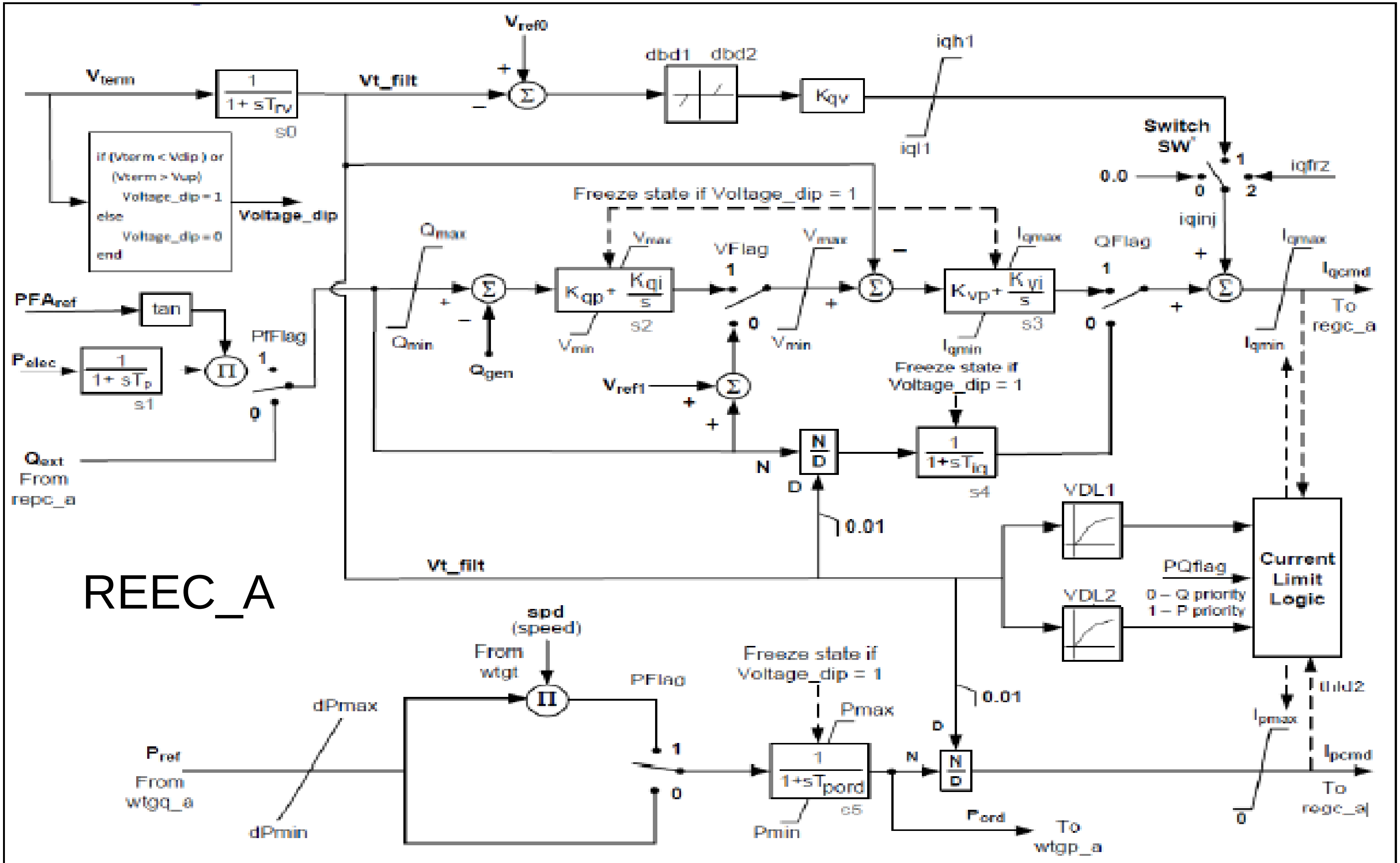
Manufacturer’s perspective

- Two classes of equipment
  - New designs
  - Existing equipment
- New Designs
  - Manufacturers are starting to incorporate the guideline into new designs
- Existing Equipment
  - In many cases, the control functionality recommended by the guideline is already built in the controls of existing equipment and needs to be enabled via parameters
  - In some cases, a firmware and/or hardware update may be required
  - There may be a cost and time element associated with the parameter changes and updates
  - Hardware and software limitations may not allow all equipment to be updated to meet the guideline. The guideline gives examples of such limitations for eliminating Momentary Cessation. Similar limitations may apply to other recommendations.

Design Choices

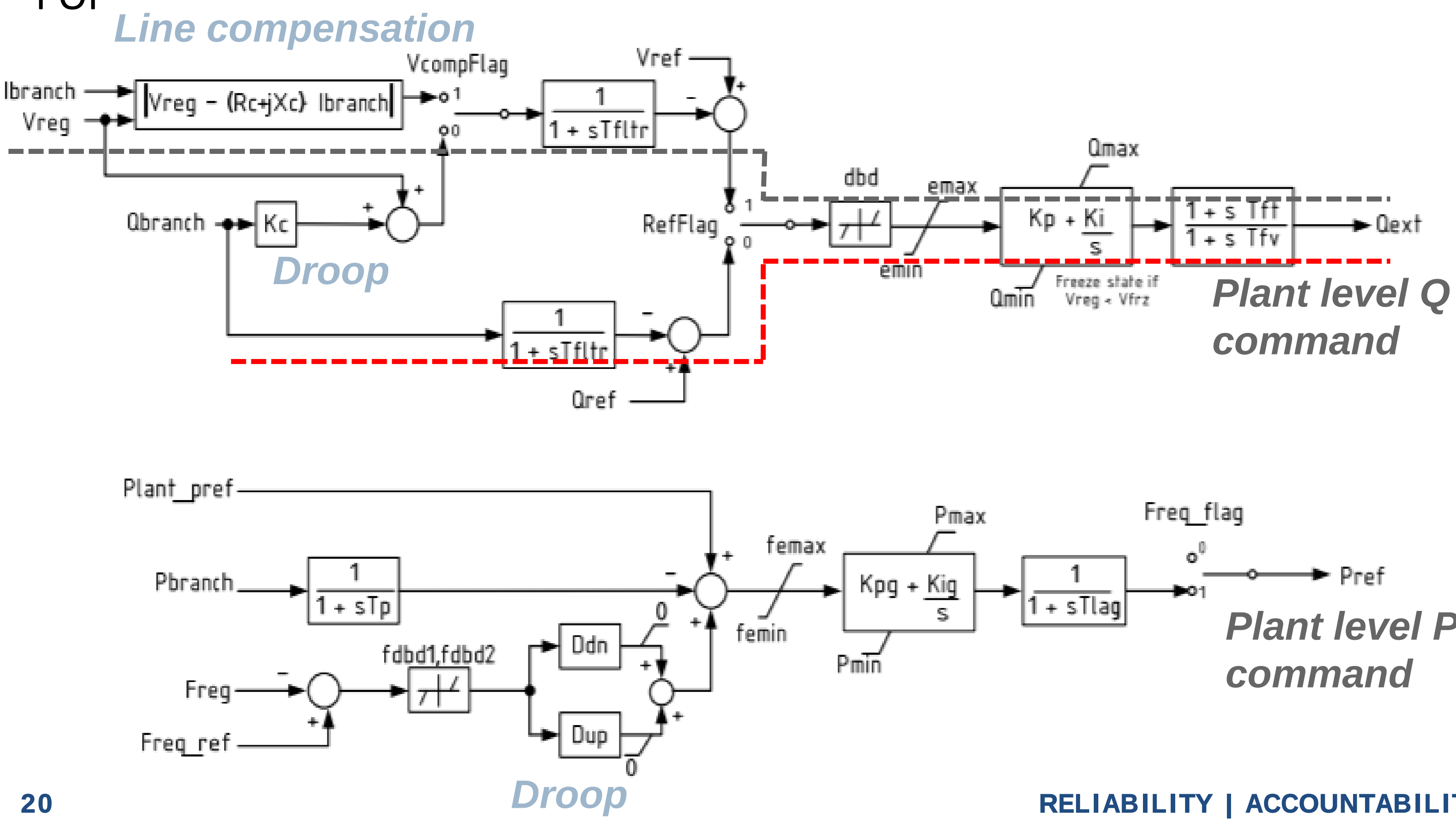


Design Choices



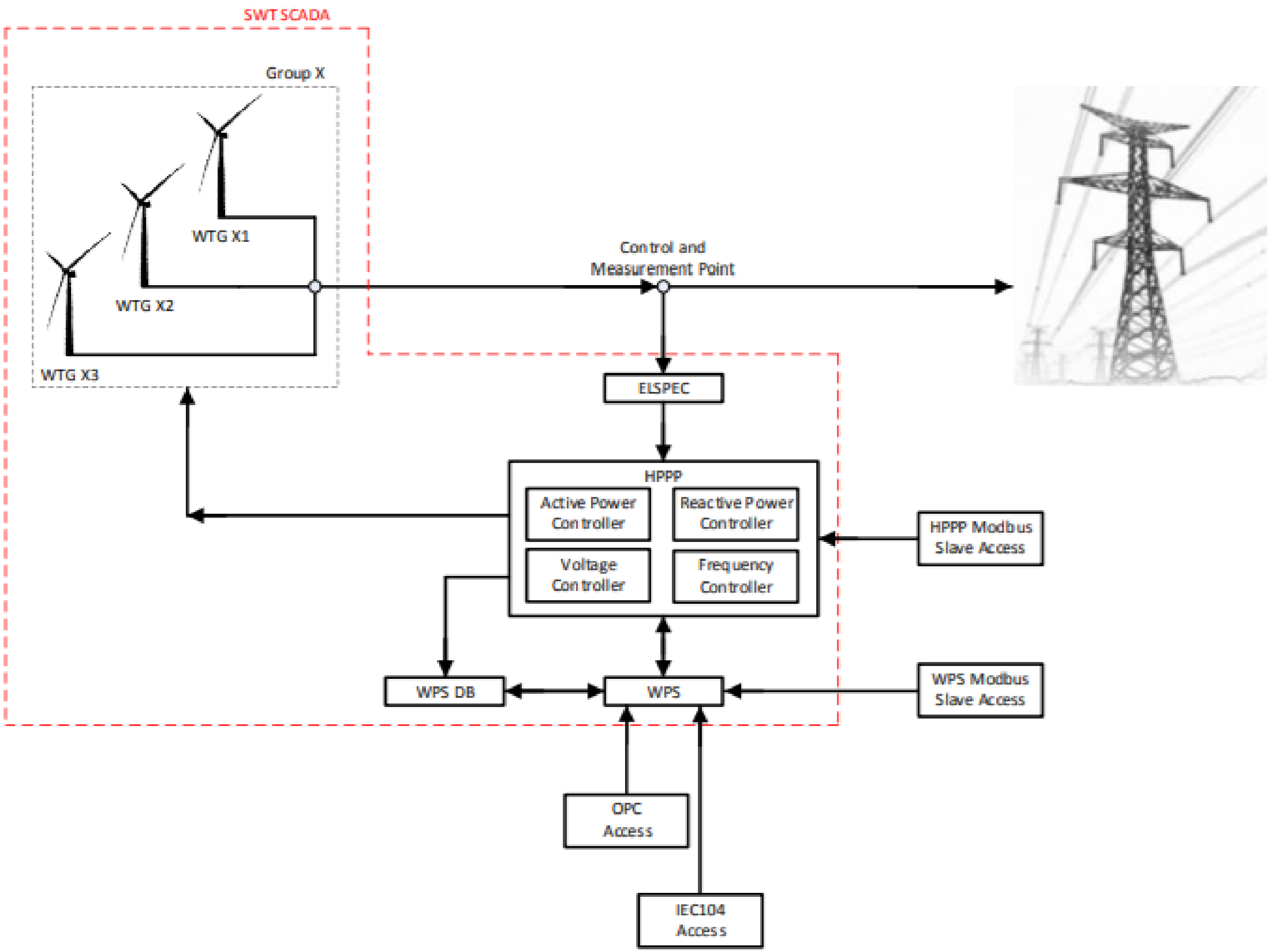
Plant Controller

- Takes measurements from POI and generates commands to individual inverters to maintain an active power level and either reactive power or voltage level at POI



Full Converter Wind Turbine Generator (Type 4)

High Performance Park Pilot (HPPP)



Various Controls within HPPP

- Active Power Control
  - **Ramp Control**
  - Fall Back Power Protection
  - **Power Boost**
  - Priority dispatch or curtailment
  - Variation limitations
  - High Wind Functions
  - Spinning Reserve
- Voltage Control
  - **Reference set point control**
  - V-mode

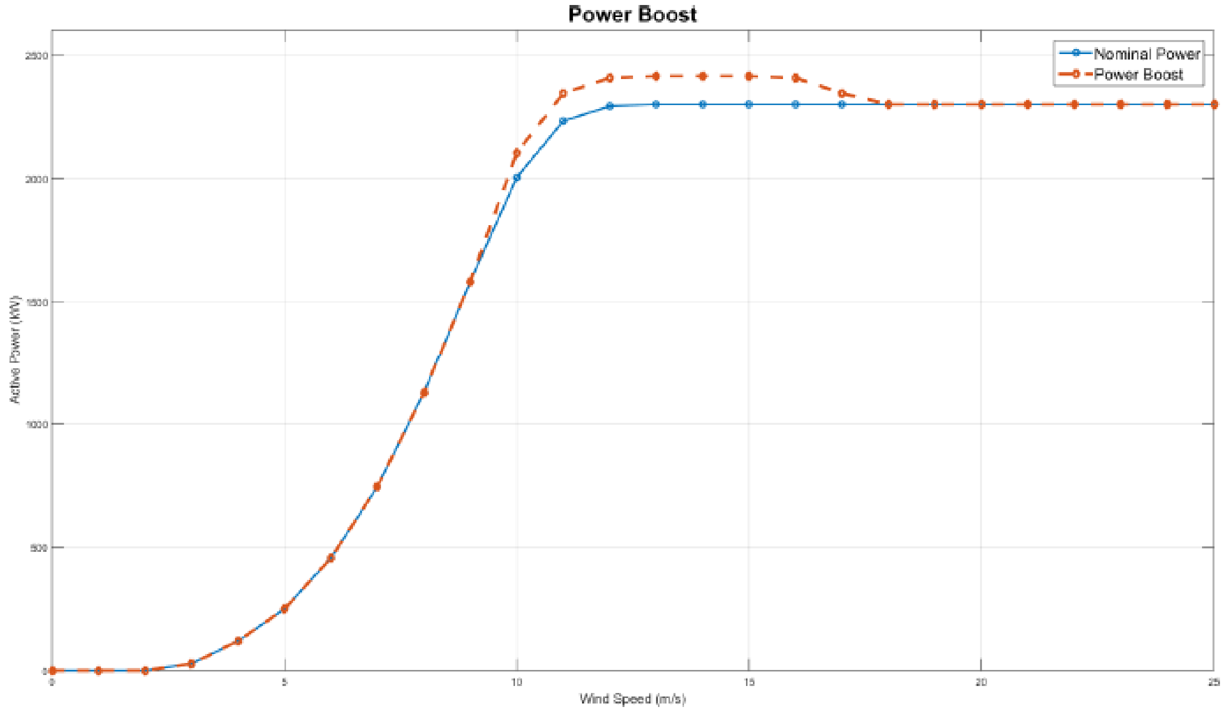
High Performance Park Pilot (HPPP)

- Reactive Power Control
  - Reactive power Control
  - Power Factor Control
- Frequency Control
  - Frequency Limitation Control
  - Frequency Stabilization Control
  - Generic Frequency Controller
  - Inertial Response
- Island Mode (commissioning only)
- Many other options but not very relevant to grid modeling aspect so not included here

Ramp Control

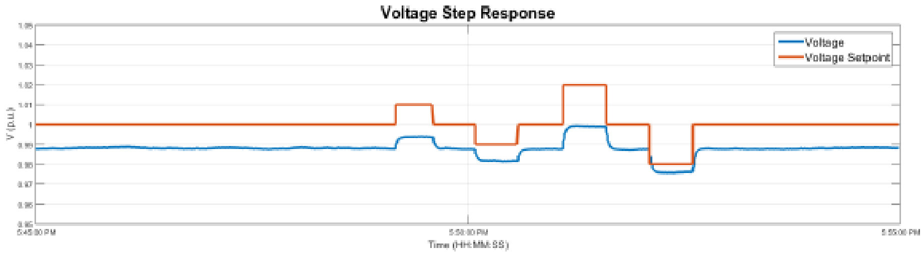
Active Power Control. The example is for a wind power plant producing about 70MW of active power. The plant production is curtailed to about 40MW and ramped down at a steady rate of 15 MW/min. After reaching and maintaining the new active power setpoint, a new setpoint of 65MW is dispatched allowing the wind power plant to ramp up at the same rate of 15 MW/min. Shortly after, the curtailment was released and the plant production ramped up at the same rate to track with the available active power based on wind conditions.

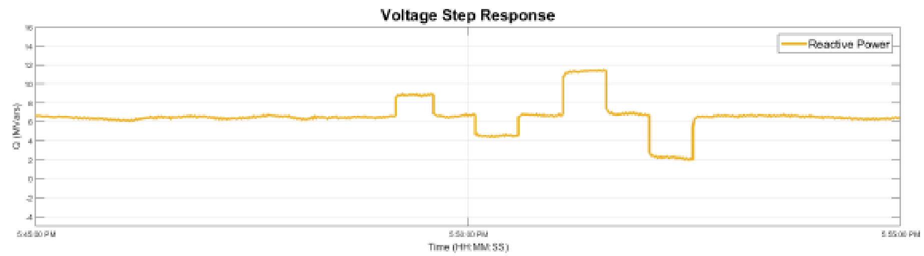
Power Boost



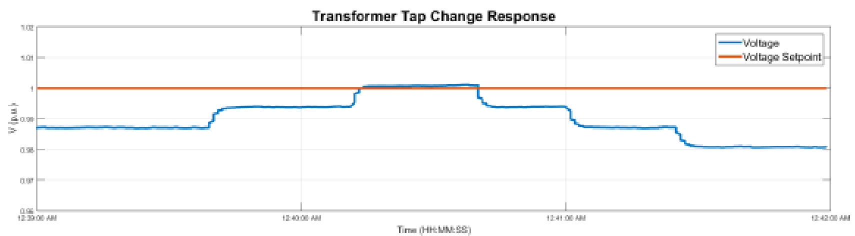
- If PB is a special function that allows WTG to produce 5% extra active power if certain conditions are met
  - Voltage is within +/-5% variation
  - Many other non electrical conditions
- Does not typically affect the total MW at POI

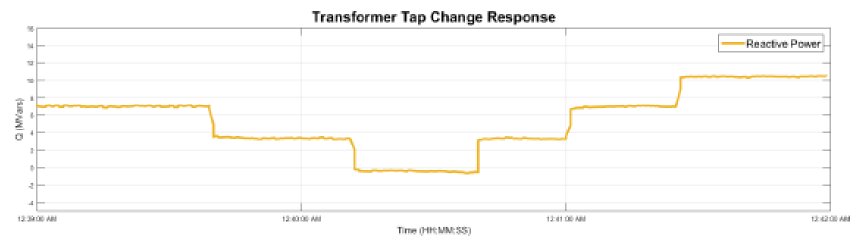
Voltage Control





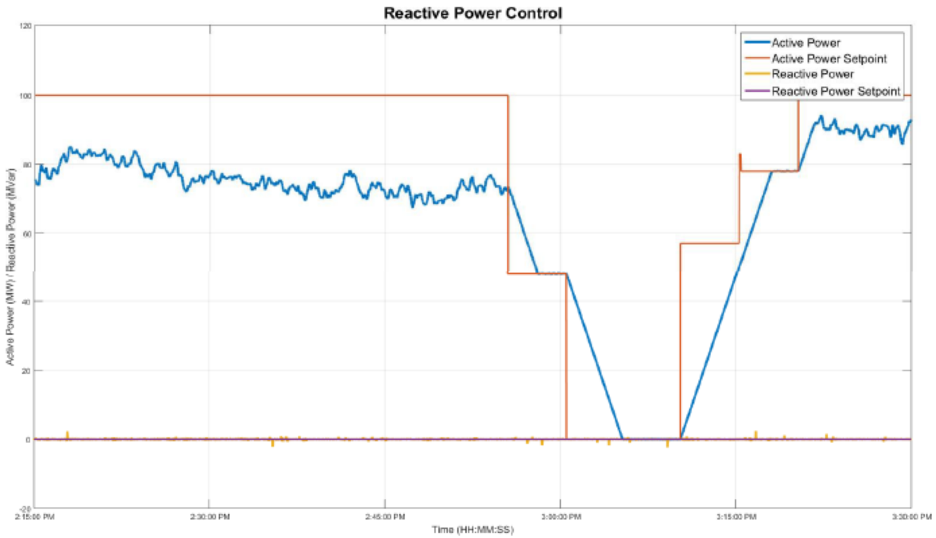
Voltage Reference Step Test. The example shows a wind power plant regulating voltage at 1 pu. When the voltage setpoint is increased by 1%, the turbines respond by increasing their reactive power production to support the new voltage set point. Similarly, when the voltage setpoint is decreased by 1%, the turbines absorb reactive power to support the new voltage setpoint. The same scenario is represented for 2% increase/decrease in the voltage setpoint.





Voltage Change Response. The example above shows how the voltage at the point of measurement control is changed by moving the taps on the main substation transformer (MST) and the HPPP directs the turbines to either absorb or produce reactive power in order to maintain the desired voltage setpoint.

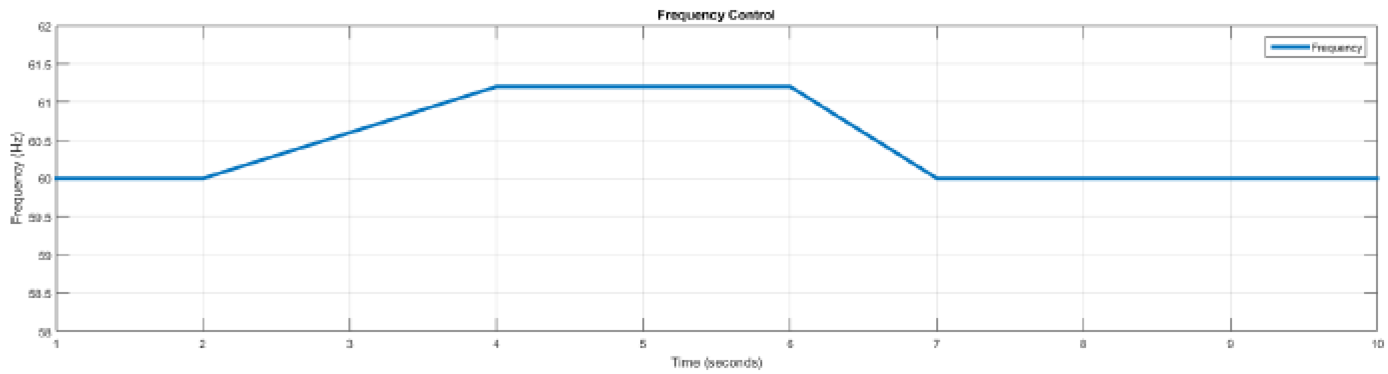
Reactive Power Control

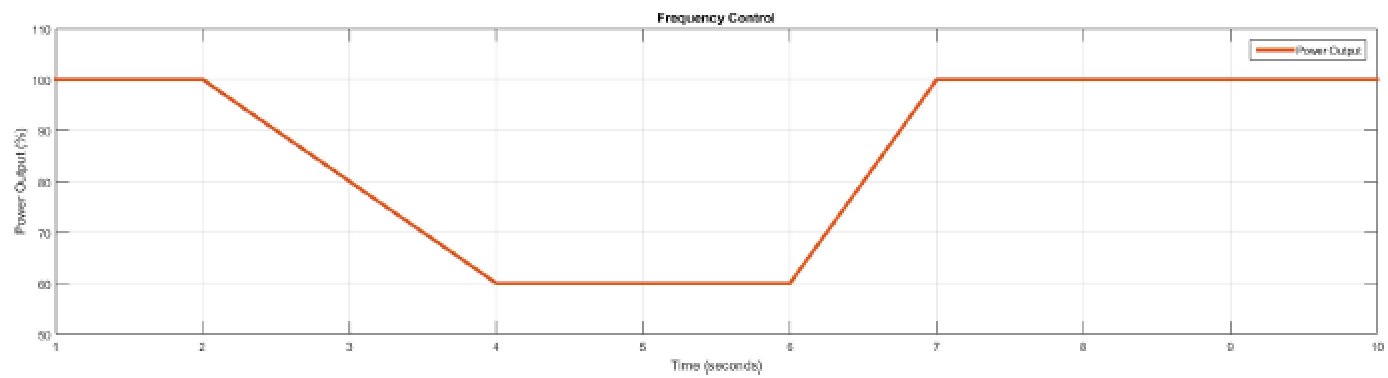


Reactive Power Control. Unless turbines are equipped with reactive power at no wind (V-Mode), reactive power control can be achieved only when there is active power production. In the example above, the turbines were curtailed to 0 MW. This permitted the reactive power controller to still regulate reactive power to 0 MVar as the setpoint dictated. Note the minimal variation in reactive power import/export. The HPPP is able to quickly and accurately regulate MVArs.

Power Factor Control. The example above shows both the active and the reactive power measurements at the control and measurement point as well as the power factor calculated. The site's power factor setpoint was 0.97 leading, represented by a negative number. The 3 hour period above shows that the HPPP controlled the power factor steadily with minor excursions outside of the setpoint.

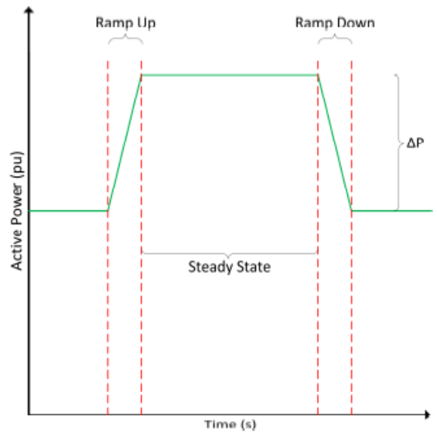
Generic Frequency Controller



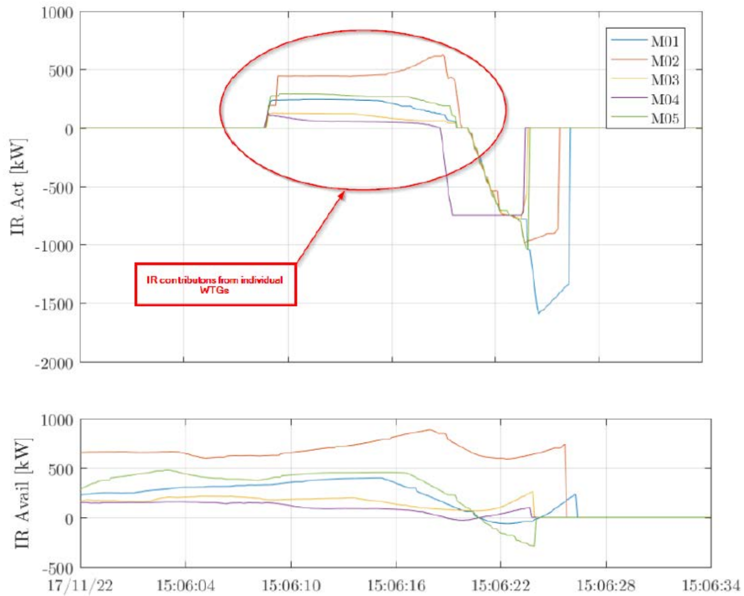


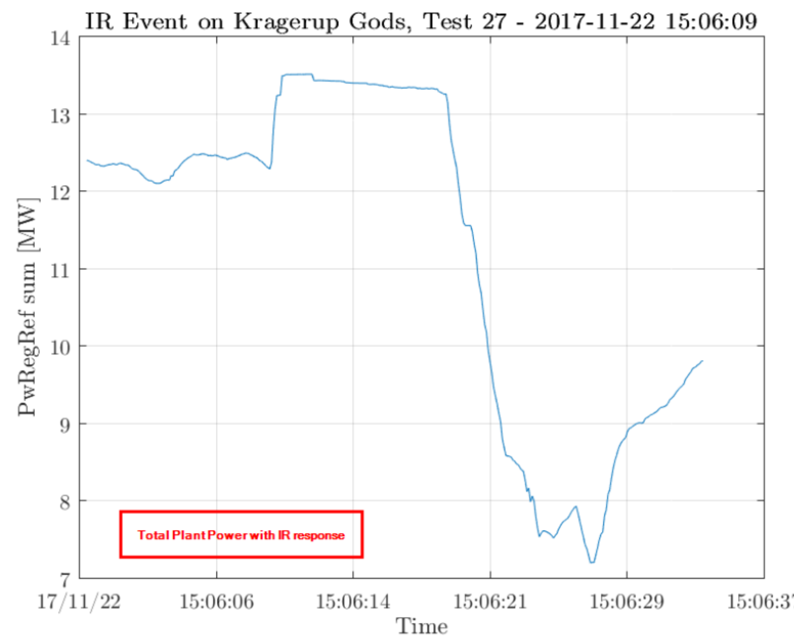
Generic Frequency Control. Over frequency event with a 5% droop and ignored dead-band. The above scenario depicts what may happen if an incident on the grid causes a fast frequency increase from 60 Hz to 61.2 Hz in a wind power plant using the generic frequency controller with a 5% frequency droop. After a short time delay for frequency measurement and communications, the HPPP sends commands to the turbines to reduce their output power from 100% to 60% of rated output, as measured at the control and measurement point.

Inertial Response



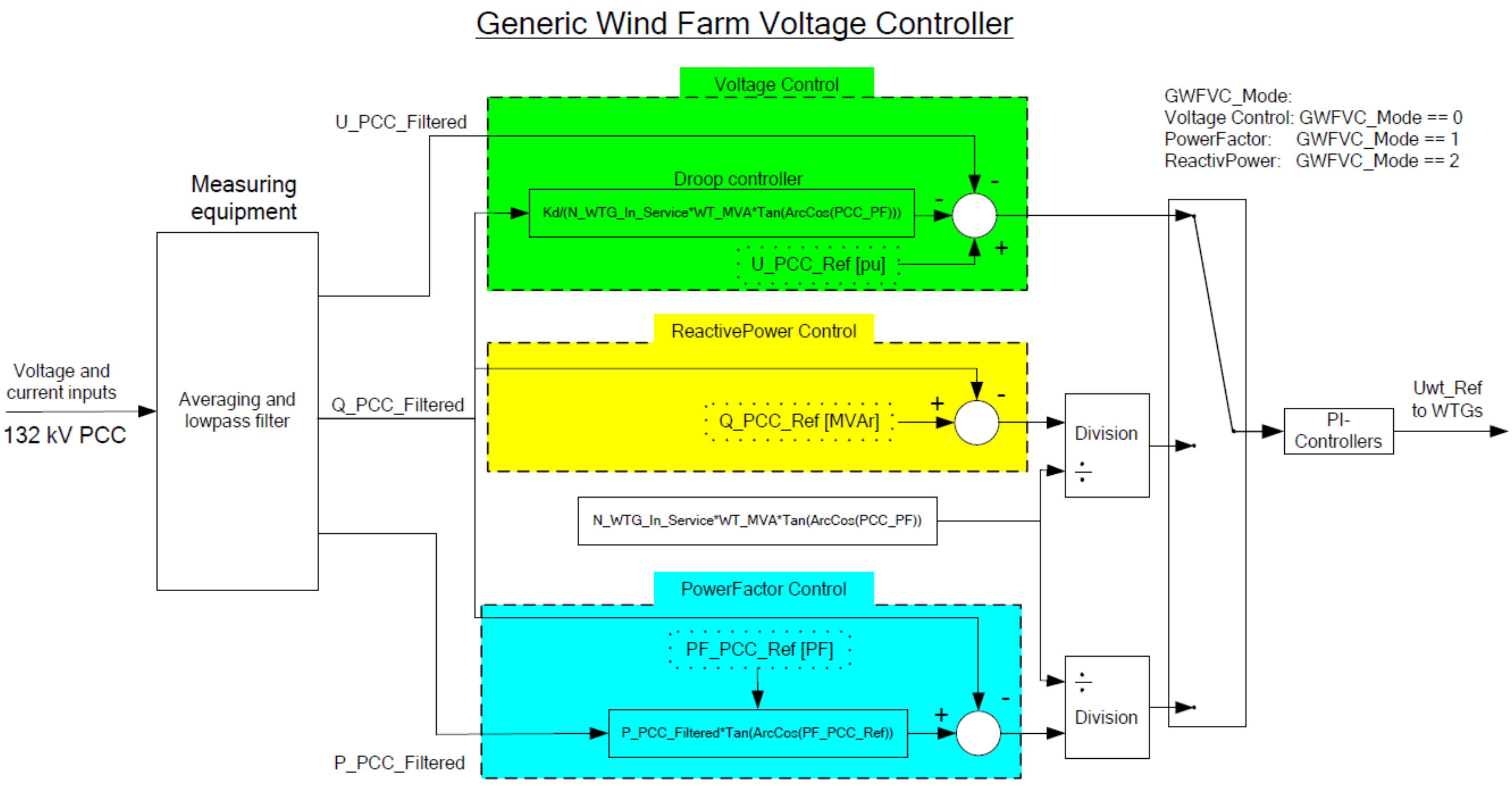
Inertial Response. The figure above presents how a turbine would respond in a control manner to respond to an under frequency situation when equipped with inertial response.



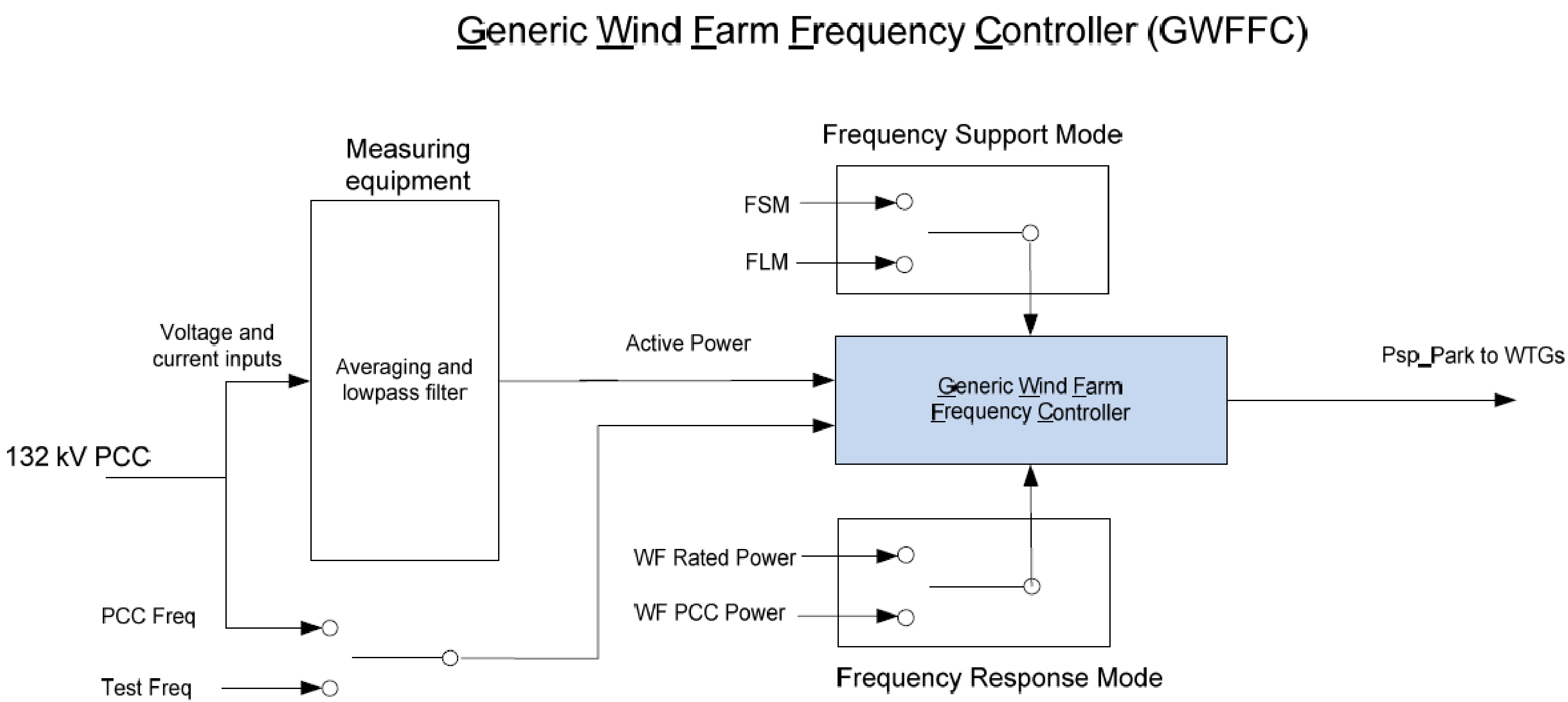


- HPPP calculates individual IR target based on available IR from WTGs
- Total IR at POI is in compliance

Voltage Controller Modeling Aspects



Frequency Controller Modeling Aspects



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Doubly Fed Induction Generator (Type 3)

High Performance Park Pilot (HPPP)

Siemens Gamesa Renewable Energy (SGRE)’s Wind Plant Controller with DFIG (Type 3) Wind Turbine Generators (WTG)

Fundamental Plant Control Functions

- Active Power Based Control
  - Active Power Control
  - Frequency Control
- Reactive Power Control
  - Reactive Power Control
  - Voltage Control
  - Power Factor Control

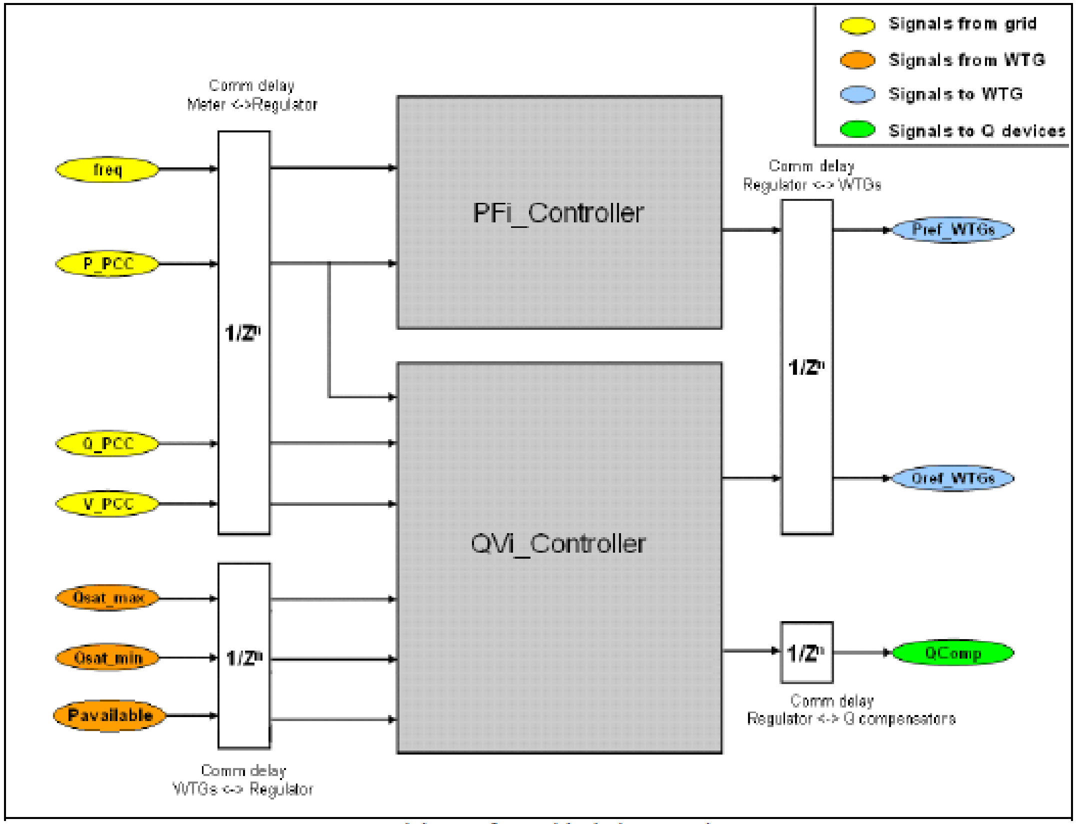
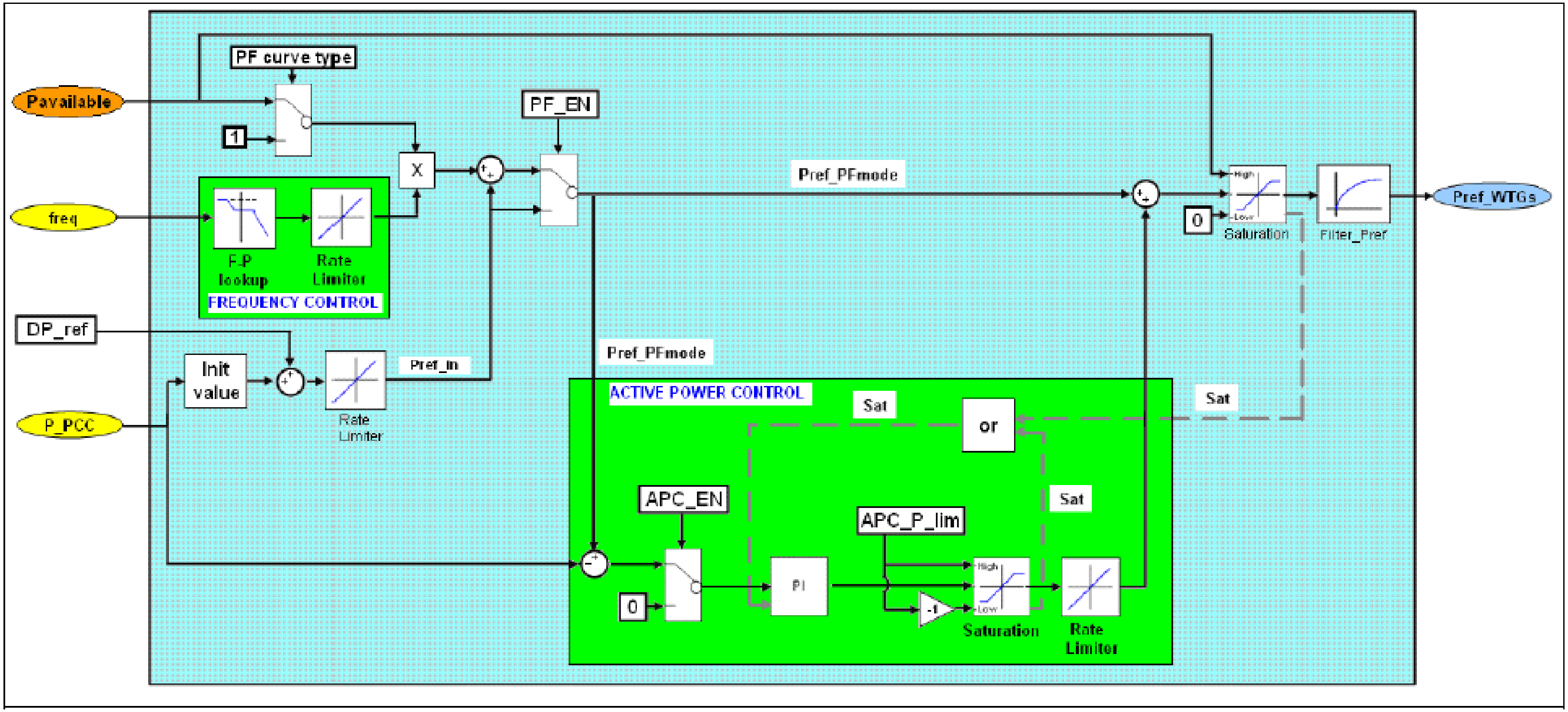
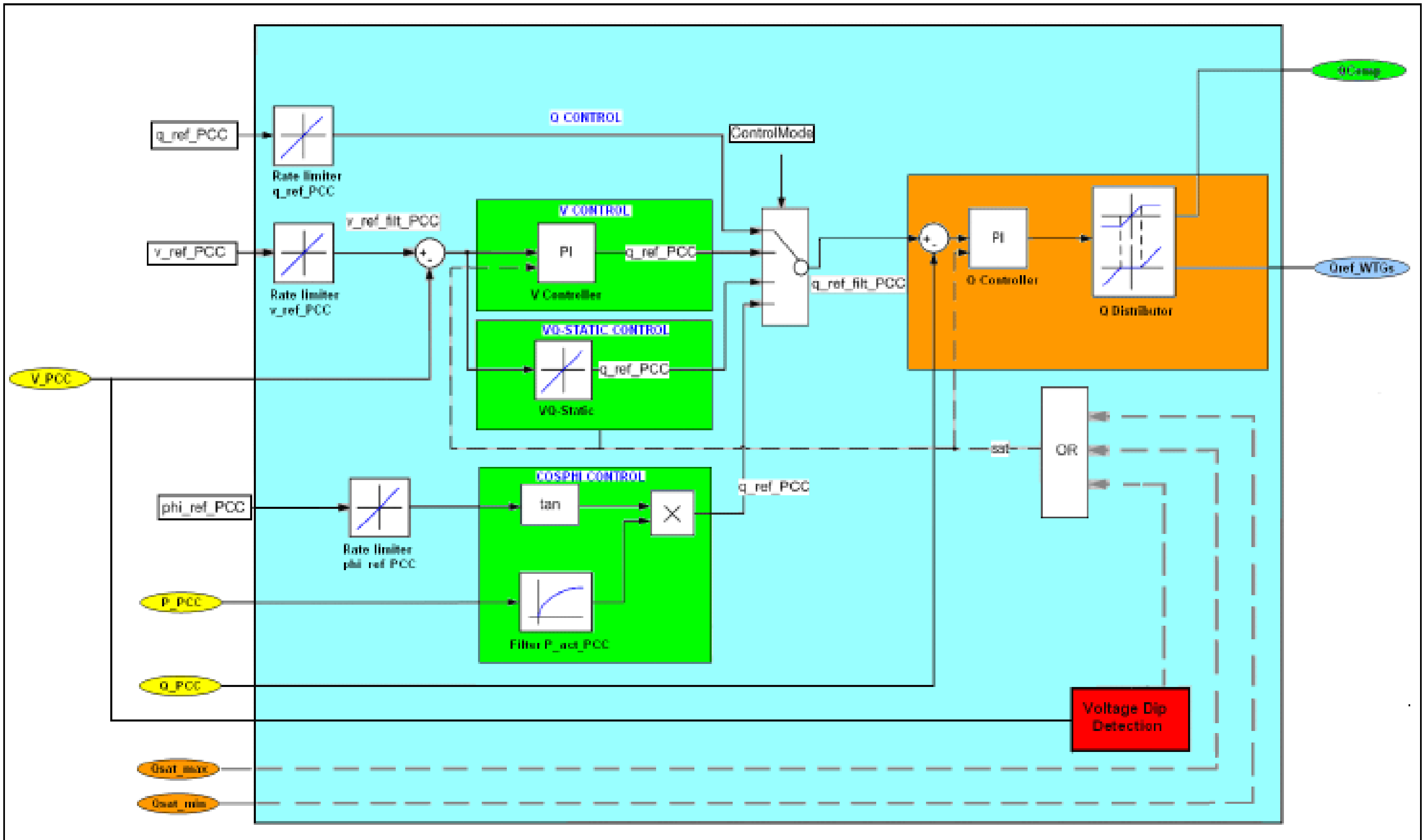


Figure 2: model main frame block diagram description

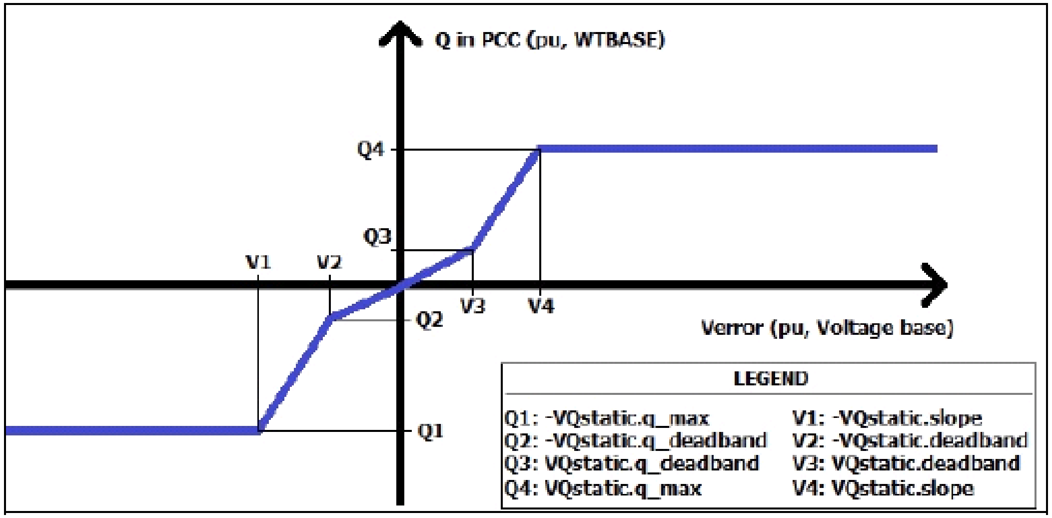
Active Power and Frequency Controller

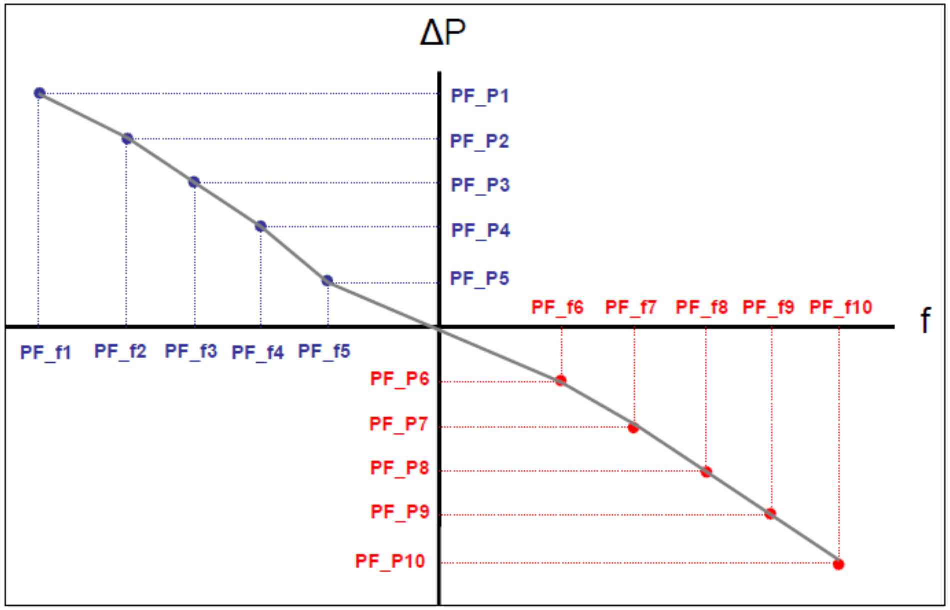


Reactive Power and Voltage Controller



Internal Look Up Tables





Questions and Answers

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Disturbance Analyses and NERC Alerts

NERC IRPTF Meeting
February 2019

RELIABILITY | ACCOUNTABILITY




NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Overview of the Blue Cut Fire And Utility Perspectives

David Piper, Southern California Edison

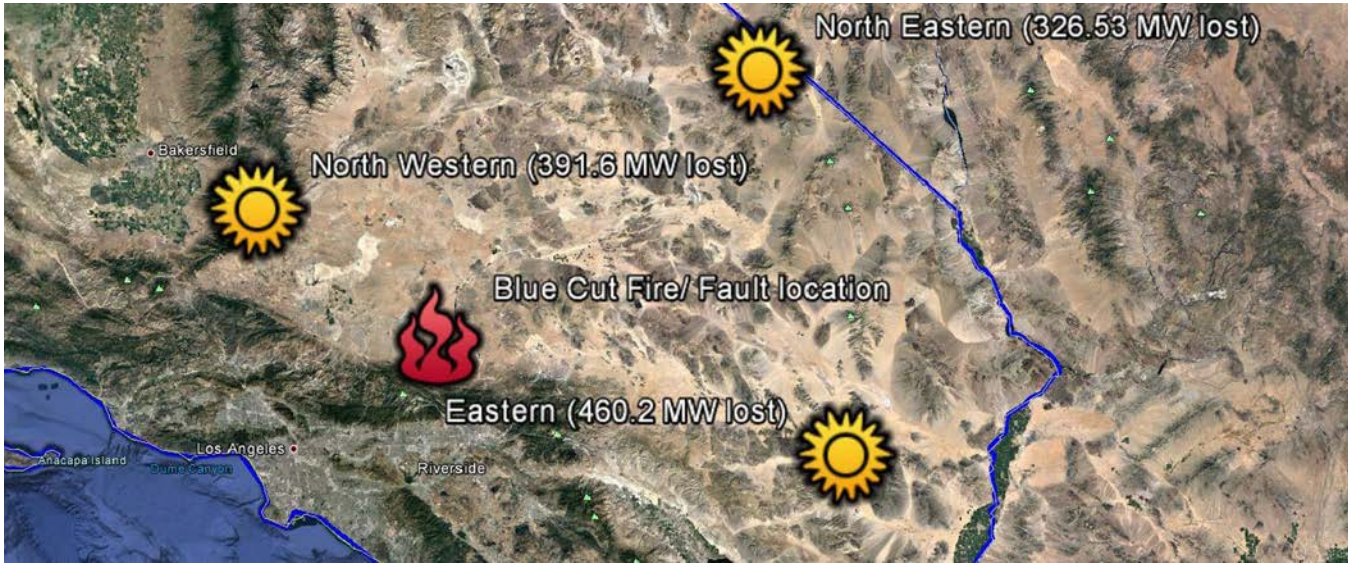
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Event Summary

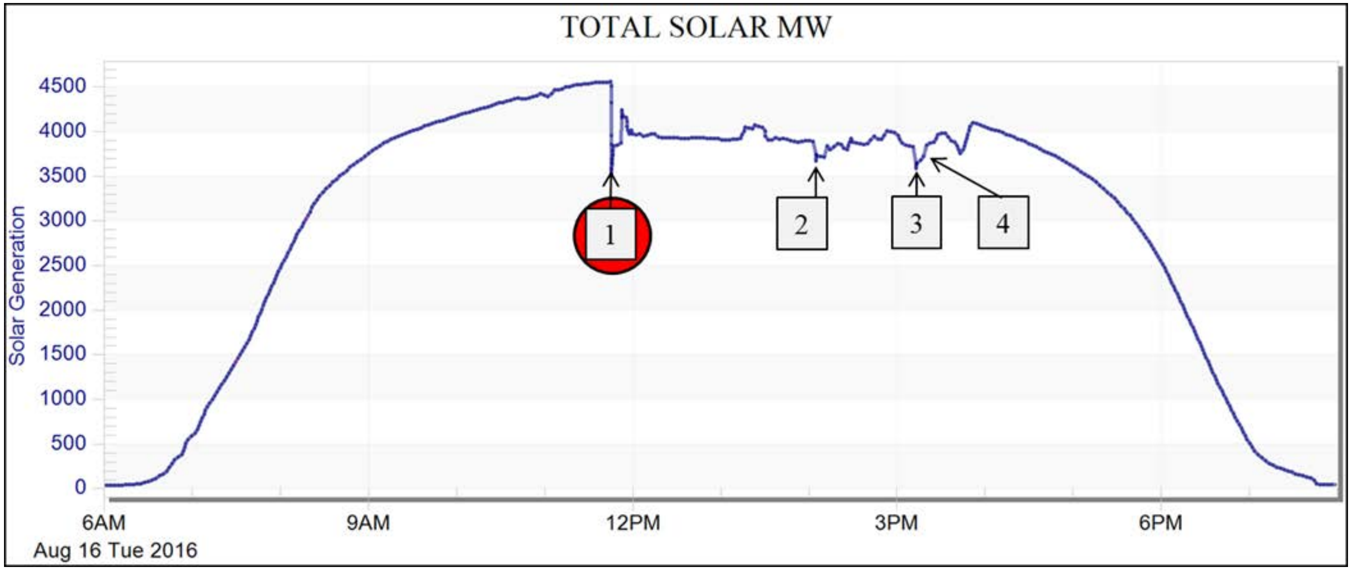
- The Blue Cut Fire began on August 16, 2016
  - Thirteen 500 kV faults
  - Two 287 kV faults
  - Four faults resulted in a loss of solar PV generation
  - Largest event resulted in the loss of ~1,200 MW of solar PV generation



Event Summary

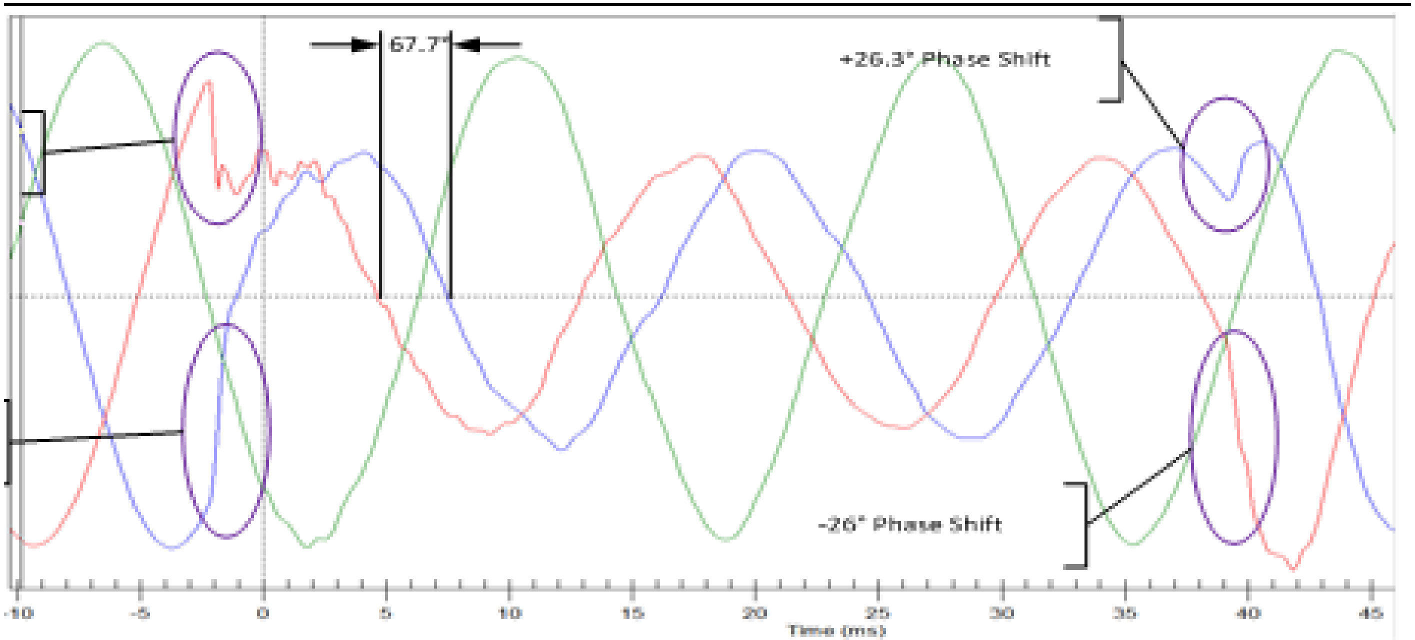
#	Date/Time	Fault Location	Fault Type	Clearing Time (cycles)	Lost Generation (MW)	Geographic Impact
1	8/16/2016 11:45	500 kV line	Line to Line (AB)	2.49	1,178	Widespread
2	8/16/2016 14:04	500 kV line	Line to Ground (AG)	2.93	234	Somewhat Localized
3	8/16/2016 15:13	500 kV line	Line to Ground (AG)	3.45	311	Widespread
4	8/16/2016 15:19	500 kV line	Line to Ground (AG)	3.05	30	Localized

Table 1: Solar Photovoltaic Generation Loss



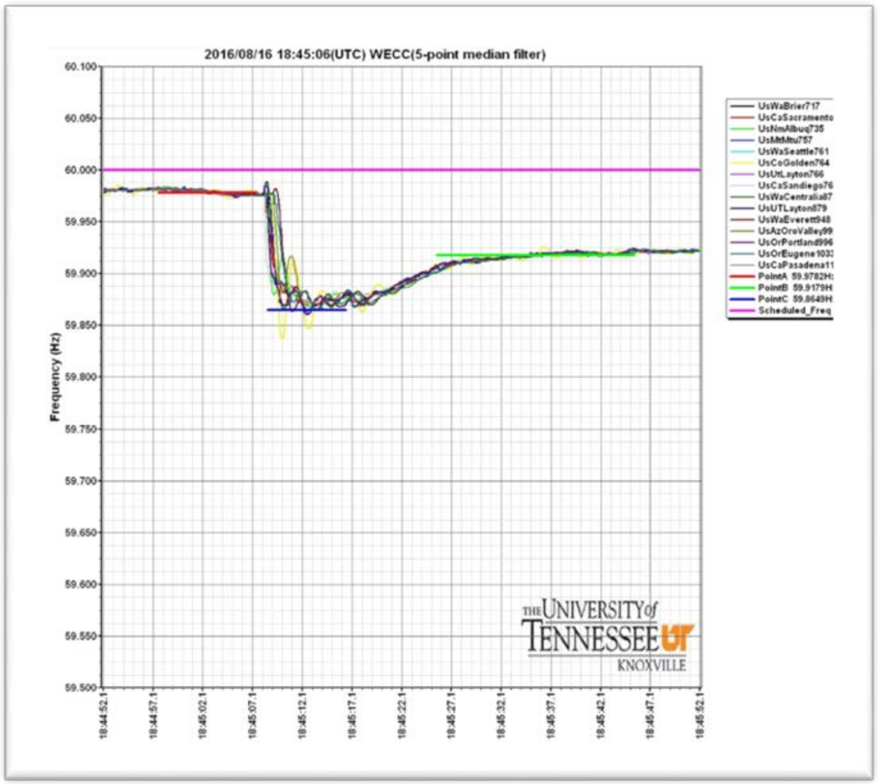
Initiating Fault

- Faults on the transmission system can cause waveforms to undergo instantaneous phase shifts, voltage sags, and harmonic distortion.
- Phase shifts can be interpreted as frequency deviation
- Line to Line faults cause significantly larger phase shifts



System Frequency During Event

- Frequency Measuring Network data showed that system frequency during the event did not fall below 59.86 Hz.

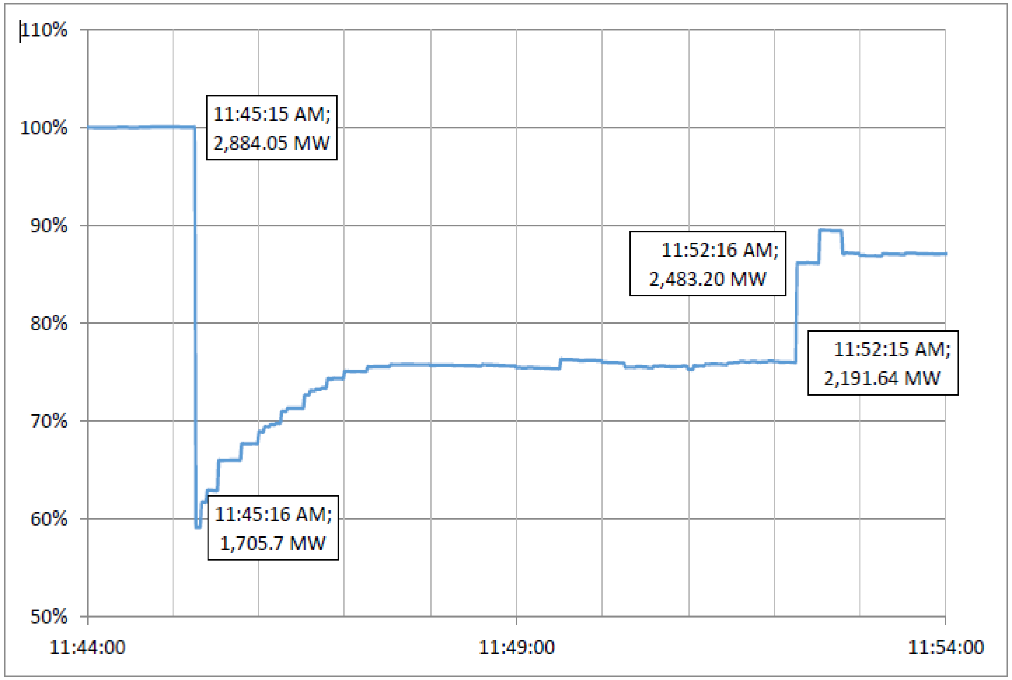


System Voltage During Event

- The initiating fault was a line-to-line fault, which resulted in a significant and widespread voltage sag below 0.9 pu voltage
  - Fault type (SLG, LL, 3PH) plays a large role in the magnitude and spread of fault voltage
  - Inverter controls cause inverters to cease to inject current into the grid while voltage is outside the continuous operating voltage range (typically 0.9 pu-1.1 pu) at the time of the event

1,200 MW Event Analysis

- ~700 MW of the total resource loss was attributed to a perceived low system frequency.
  - Many inverters were set to trip offline if frequency fell below 57 Hz.
- ~450 MW of the total resource loss was attributed to Momentary Cessation
- ~100 MW attributed to DC overcurrent protection



Key Findings

- Instantaneous trip settings combined with near instantaneous frequency measurements can cause inverters to be susceptible to erroneous tripping.
- The majority of inverters were configured to momentarily cease current injection when voltage was outside the range 0.9-1.1 pu
- The impact of Momentary Cessation needs to be considered in interconnection studies

Outcomes

- IRPTF group was formed
- NERC Alert was developed
- Inverters that were susceptible to erroneous tripping were reprogrammed to prevent them from tripping offline due to miscalculated frequency.
- IRPTF participants analyzed the WECC Resource Loss Protection Criteria
  - Determined that RLPC does not require modification

Utility Perspectives

- High speed recording devices (DFR/PMU) are necessary to observe Momentary Cessation and/or compare plant performance to dynamic models.
- Requests for event records must occur quickly because many devices are designed to overwrite old records as time passes.
- Inverter ride-through mode should be verified during plant design and commissioning.
- Inverter ride-through modes of existing plants must be understood and modeled in studies.
- The aggregate impact of **all** inverter based resources needs to be monitored as new resources connect to the interconnection.
    - Transmission, Subtransmission, and Distribution

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Canyon 2 Fire Disturbance and WECC Perspectives

Evan Paull, Western Electricity Coordinating Council

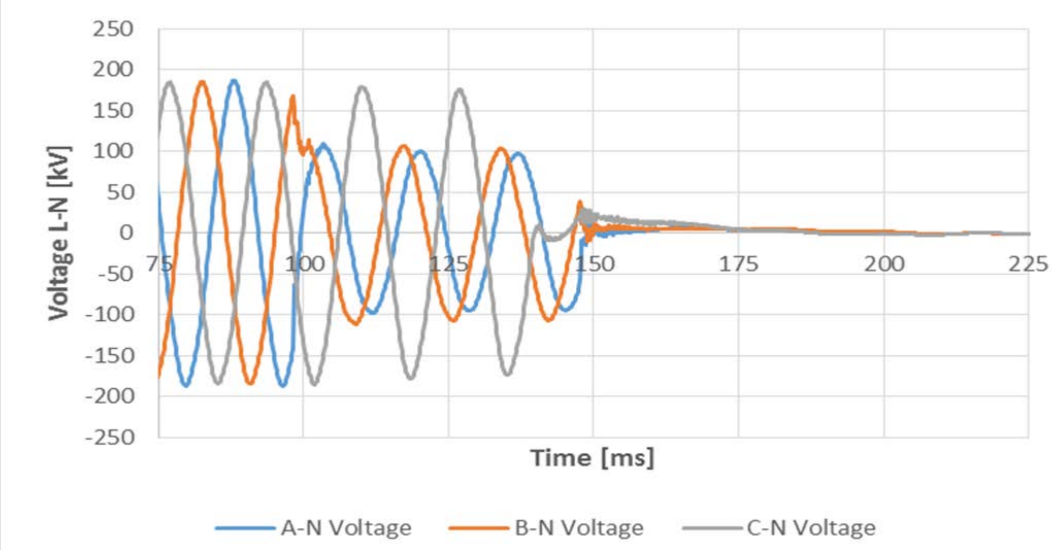
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Two Fault Events

Smoke from nearby fires caused 2 phase-to-phase faults just two minutes apart.

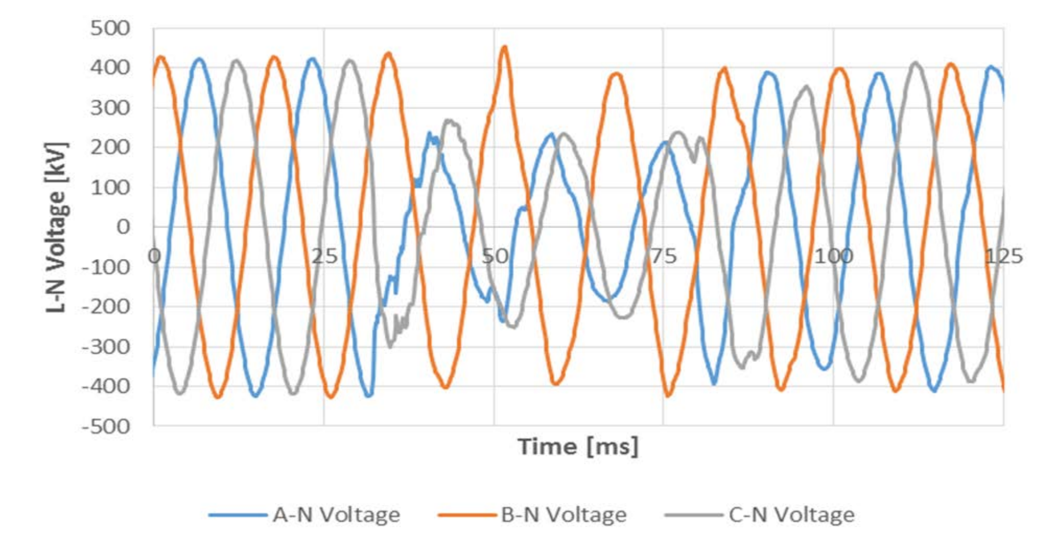


__Fault Event 1 at 12:12:__

220 kV

L-L Fault

< 3 cycle clearing



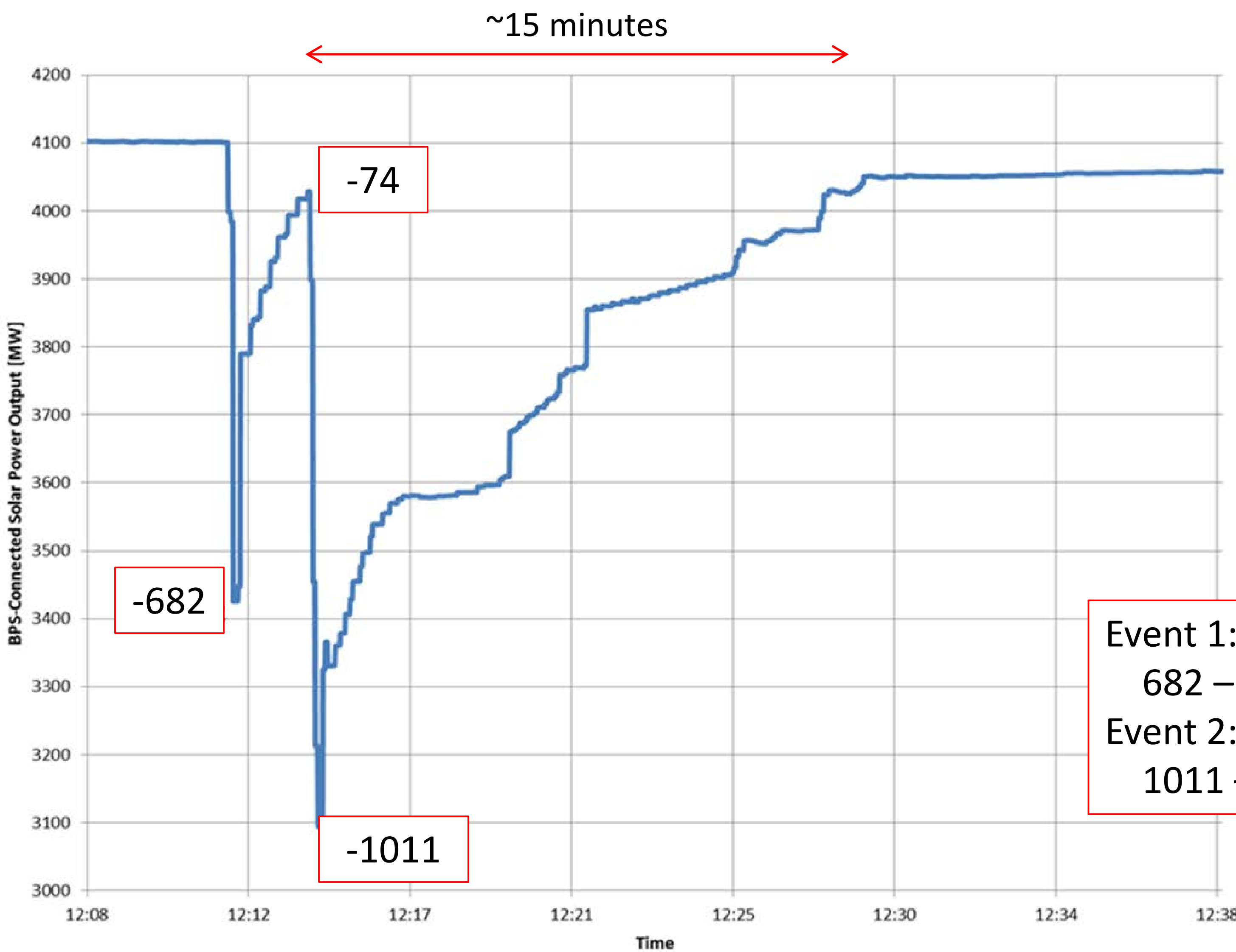
__Fault Event 2 at 12:14:__

500 kV

L-L Fault

< 3 cycle clearing

Aggregate SCE Solar PV Performance SCADA Data



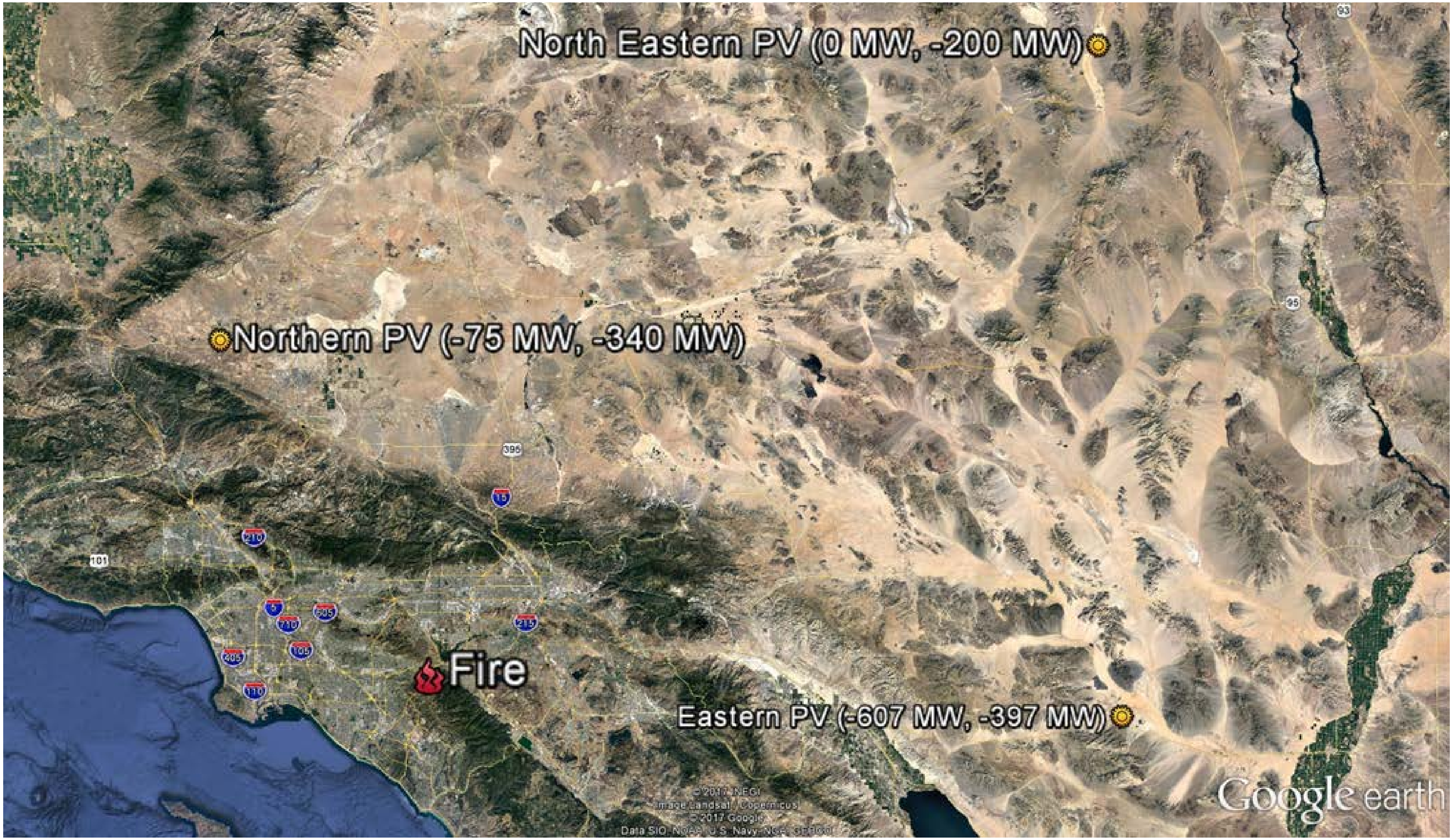
Event 1:

682 – 0 = 682 MW

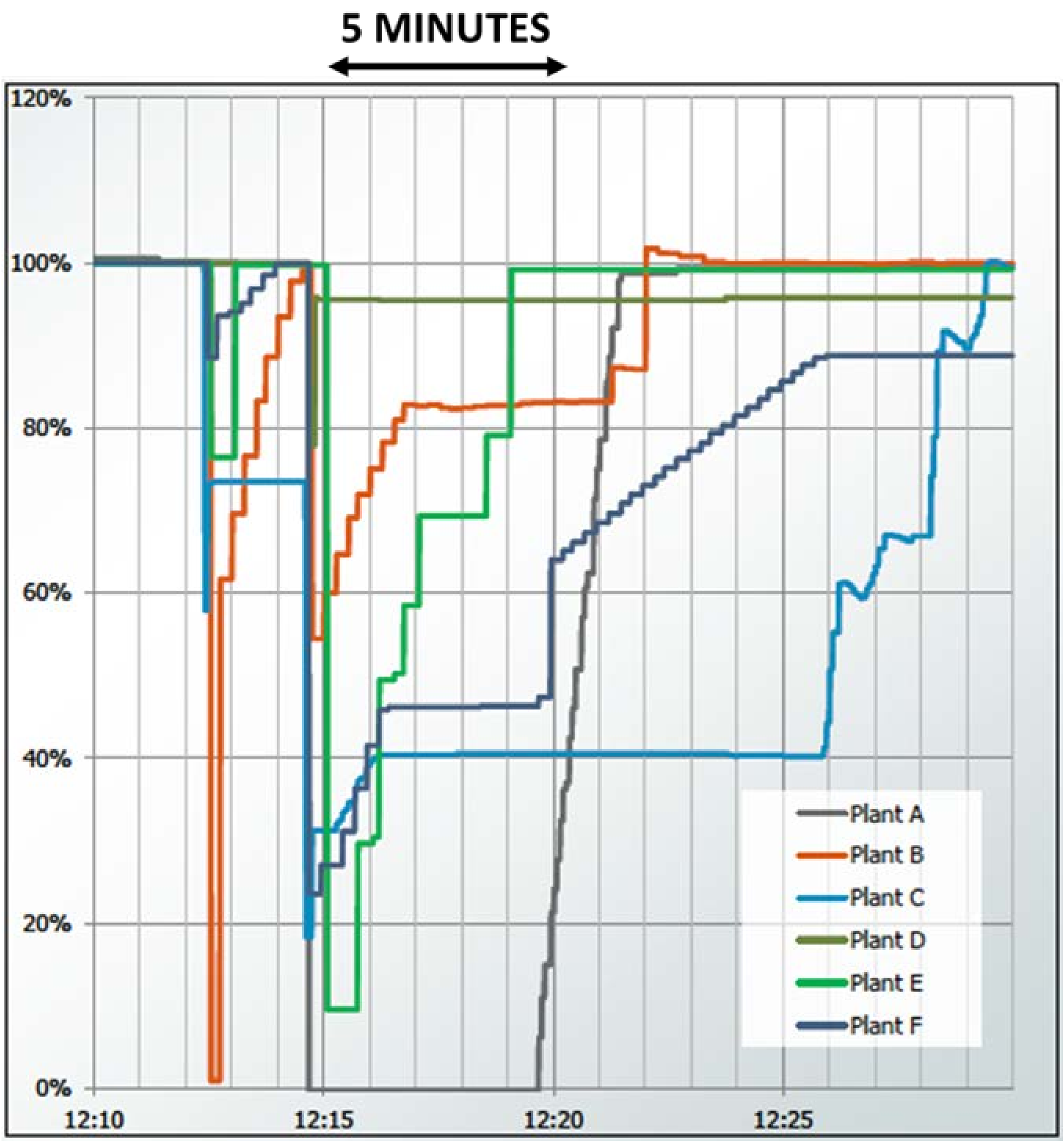
Event 2:

1011 – 74 = 937 MW

Map of Affected Area



Solar PV Outputs



Key Finding #1

No Erroneous Frequency Tripping

- Erroneous frequency tripping was one of the major issues in the August 16, 2016 “Blue Cut” event.
- Alert recommended GOPs and GOs ensure inverter controls do not erroneously trip on instantaneous frequency measurements
- By October 9, 2017 event, 97% of inverter manufacturer’s BPS-connected fleet had been updated
- Mitigating actions by inverter manufacturer and GOs appear to have worked

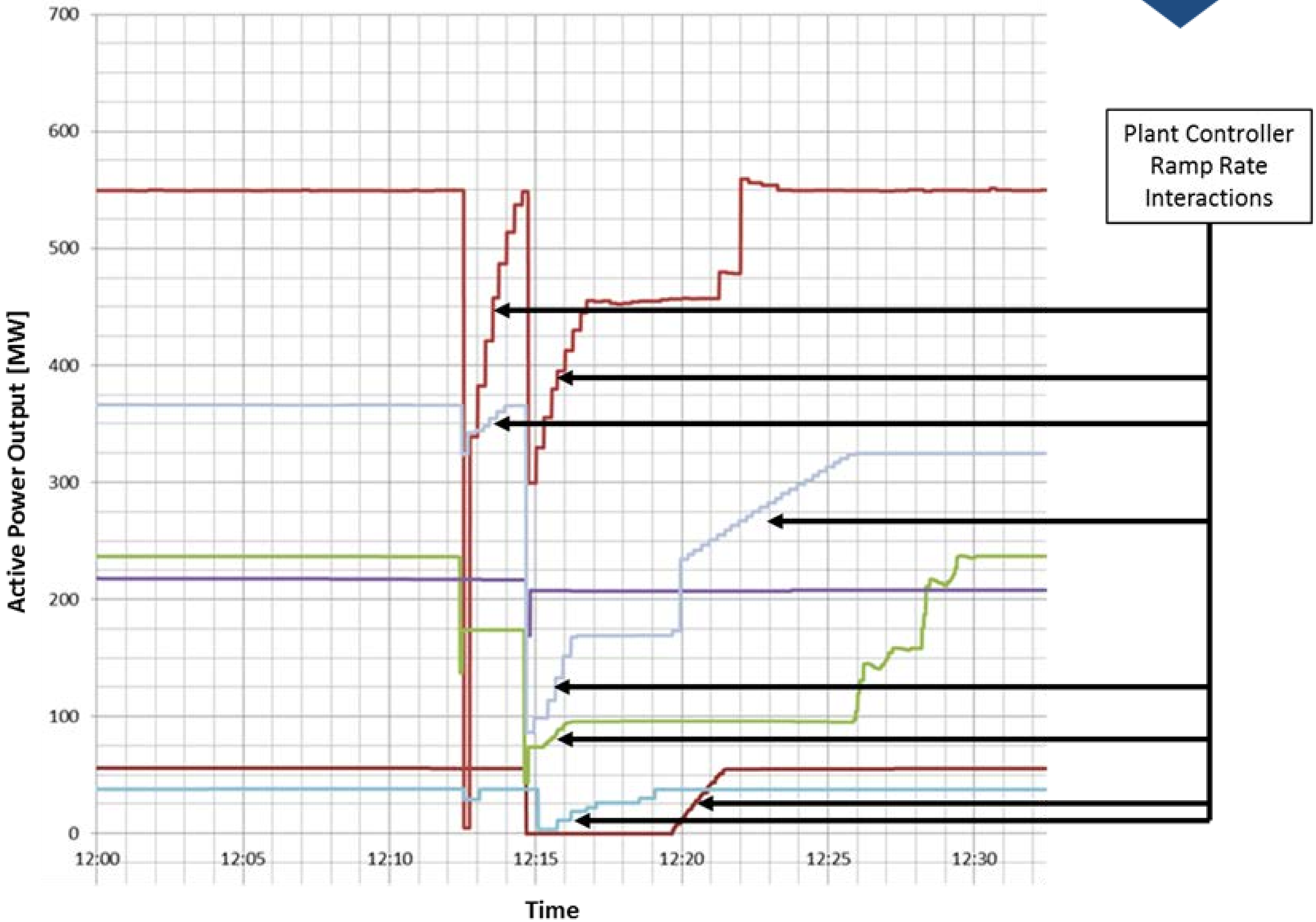
Continued Use of Momentary Cessation

- Solar resources continue to use momentary cessation, most commonly for voltage magnitudes outside 0.9–1.1 p.u.
- The NERC Alert II showed that few inverters cannot eliminate momentary cessation either directly or by opening the threshold sufficiently wide. Most are able to do this.
- The use of momentary cessation is not recommended, should not be used for new inverter-based resources, and should be eliminated or mitigated to the greatest extent possible. If it must be used then resources should return active current injection within 0.5 seconds of voltage recovery.

Ramp Rate Interactions with Momentary Cessation

- During ride-through conditions, the inverter controls its output and ignores signals sent by the plant-level controller. After voltage recovers and the inverter enters a normal operating range, it again responds to signals from the plant controller. The plant controller then applies its ramp rate limits to the remaining recovery of current injections, restraining the inverter from recovering quickly to its predisturbance current injection.

Key Finding #3



Ramp Rate Interactions with Momentary Cessation

- Active current injection should not be restricted by a plant-level controller or other slow ramp rate limits.
- Resources with this interaction should remediate the issue in close coordination with their Balancing Authority (BA) and inverter manufacturers to ensure that ramp rates are still enabled appropriately to control gen-load balance but not applied to restoring output following momentary cessation

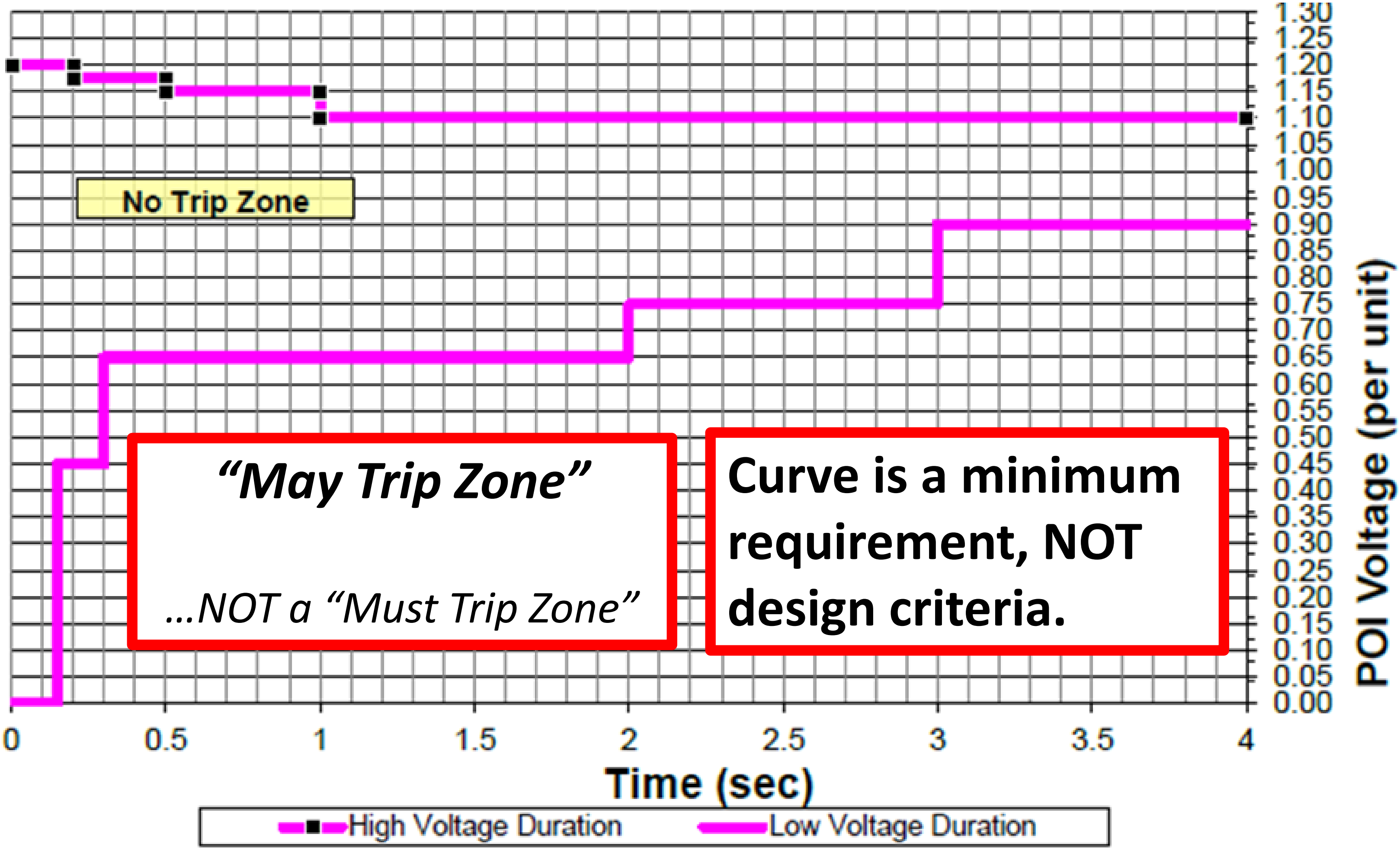
Key Finding #4

Interpretation of PRC-024-2 Voltage Ride-Through Curve

- Many inverters are set to trip when outside of the PRC-024-2 voltage ride-through curve. The curve is often used for inverter protective trip settings rather than setting the protection to the widest extent possible while still protecting the equipment.
- The region outside of the PRC-024-2 voltage ride-through curve is being **misinterpreted** as a "must trip" rather than "may trip".
- Voltage protection functions in the inverters should be set based on physical equipment limitations to protect the inverter itself and should not be set based solely on the PRC-024-2 voltage ride-through characteristic.

Key Finding #4

Interpretation of PRC-024-2 Voltage Ride-Through Curve

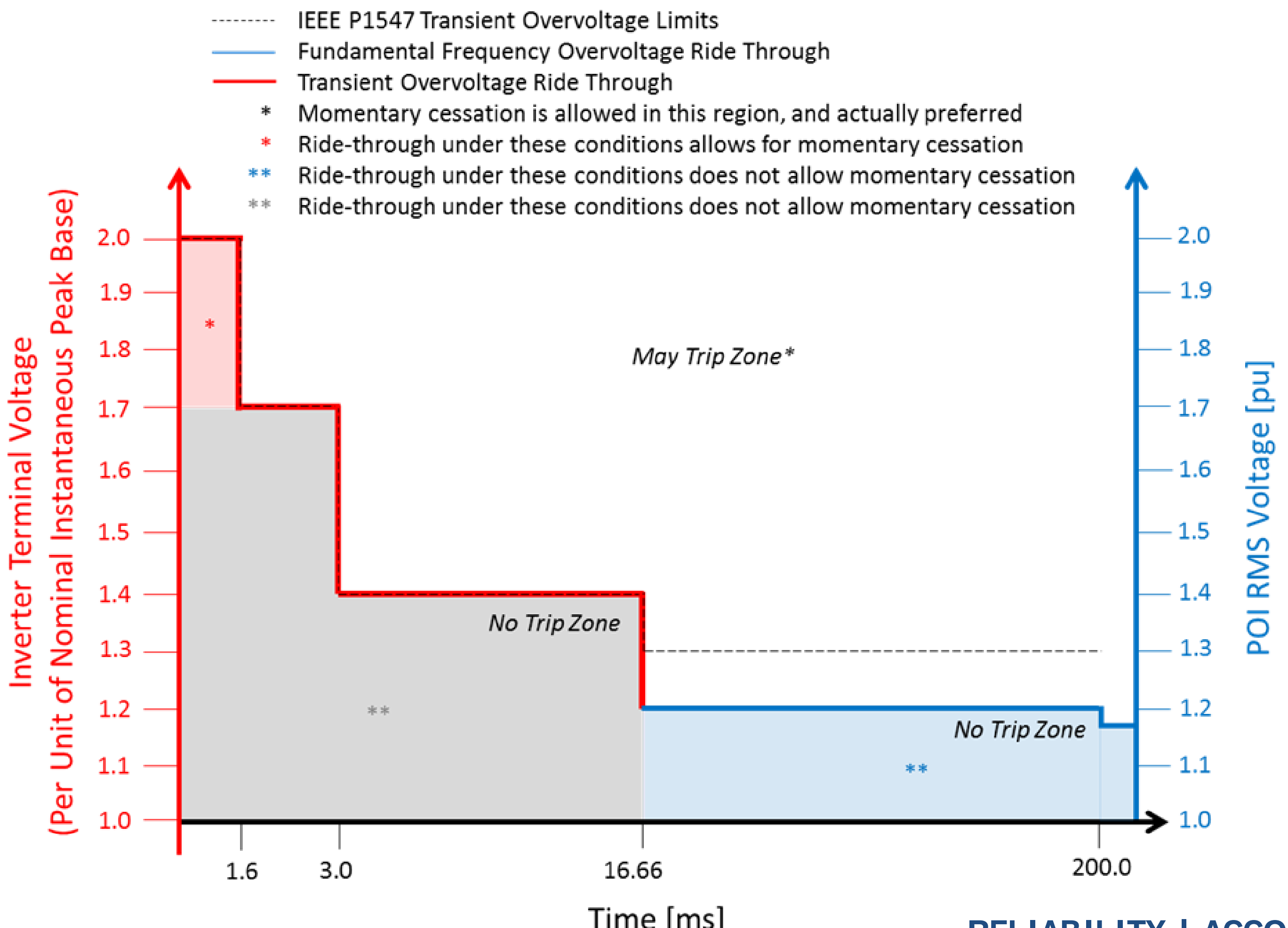


Instantaneous Voltage Tripping and Measurement Filtering

- A large percentage of existing inverters on the BPS are configured to trip using instantaneous overvoltage protection, based on the PRC-024-2 high voltage ride-through curve, and do not filter out voltage transients. Any instantaneous, sub-cycle transient overvoltage may trip the inverter off-line, making these resources susceptible to tripping on transients caused by faults and other switching actions.
- Inverter protective functions should use a filtered, fundamental frequency voltage input for overvoltage protection when compared with the PRC-024-2 ride-through curve.

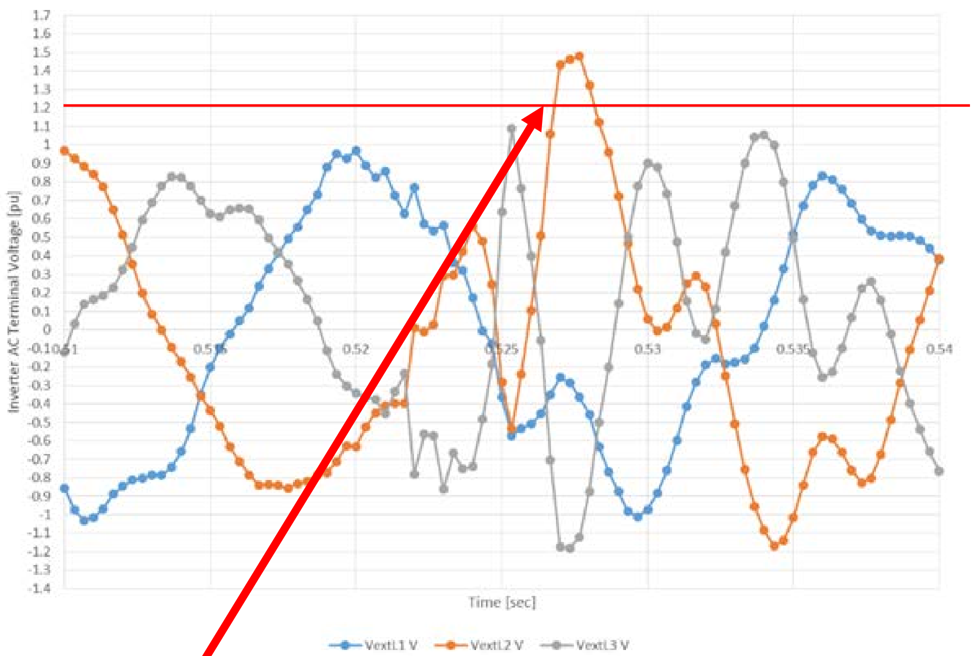
Key Findings #5
IRPTF Recommended HVRT

Instantaneous voltage tripping and measurement filtering



Key Finding #5

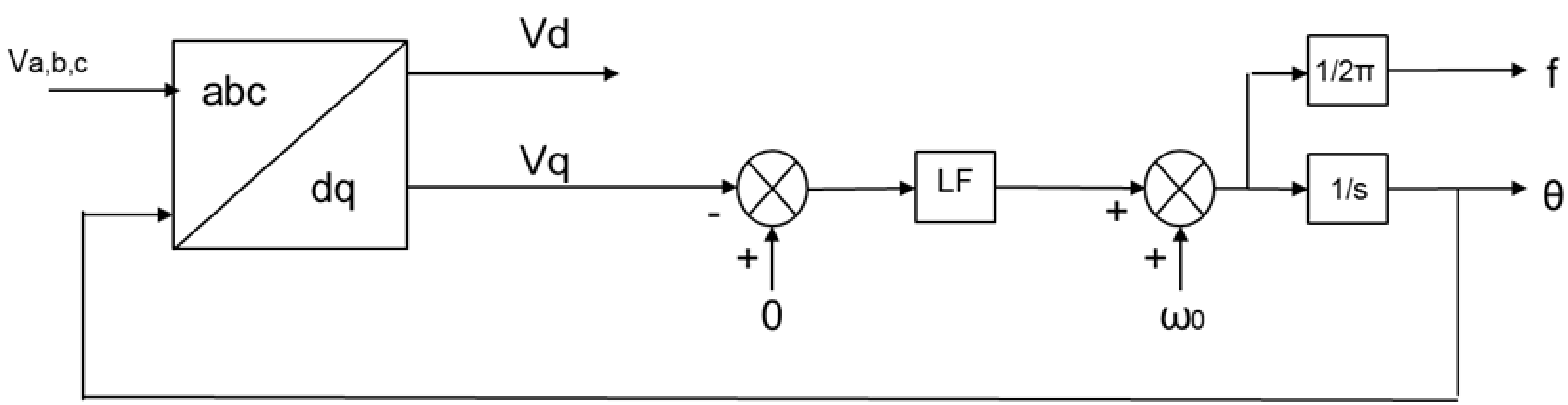
Instantaneous Voltage Tripping and Measurement Filtering



Inst. Voltage [pu nominal peak]	Samples	Time [sec]	Cycles
> 1.1	5	0.00167	0.1
> 1.2	4	0.00133	0.08
> 1.3	4	0.00133	0.08
> 1.4	3	0.00100	0.06

Phase Lock Loop Synchronization Issues

- Grid voltage phase jumps occur (during faults, breaker operations, etc.)
- Inverter PLLs should be robust to withstand BPS phase jumps
- Should not result in inverter tripping or momentary cessation
- Advanced controls should enable "PLL ride-through" rather than tripping



Key Finding #7

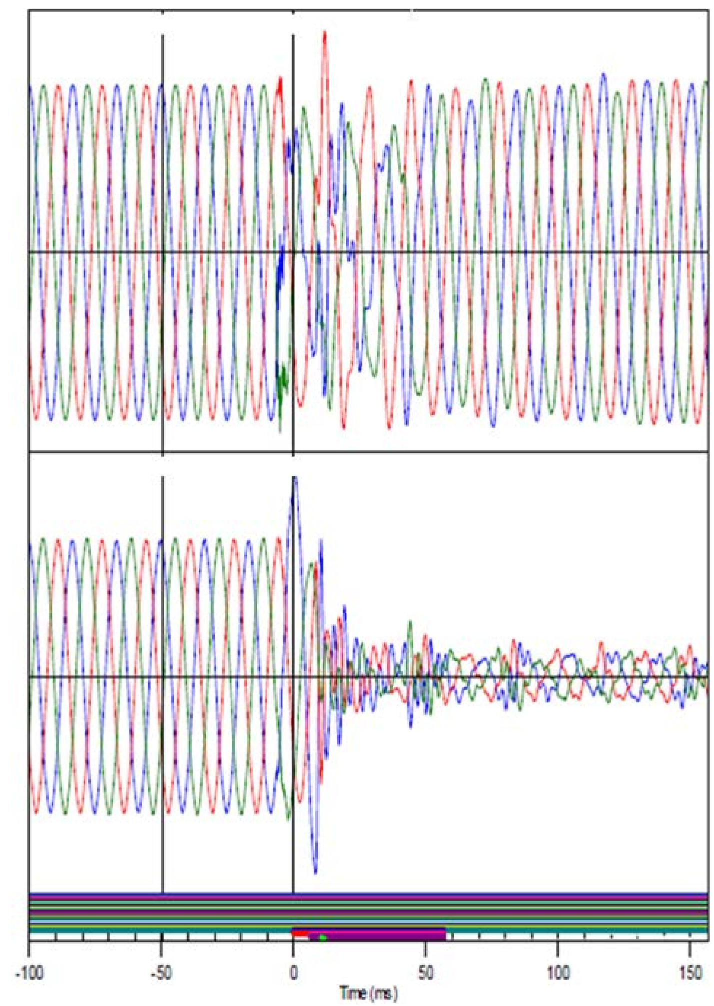
DC Reverse Current Tripping

- One inverter manufacturer reported fault codes for dc reverse current, which caused protective action to open the inverter primary circuit breaker.
  - Caused resources to remain off-line for average 81 minutes, manual reset
- GOs should coordinate with their inverter manufacturers to ensure that dc reverse current detection and protection are set to avoid tripping for dc reverse currents that could result during sub-cycle transient overvoltage conditions since these are not likely to damage any equipment in the plant. Mitigating steps may include:
  - increasing magnitude settings to align with the ratings of the equipment
  - implementing a short duration to the dc reverse current protection before sending the trip command.

Key Finding #8

Transient Interactions and Ride-Through Considerations

- There appears to be an interrelationship between in-plant shunt compensation, sub-cycle transient overvoltage, and momentary cessation that results in inverter tripping. The causes and effects are not well understood and require detailed Electromagnetic Transient (EMT) simulation studies
- EMT studies should be performed by affected GOPs, in coordination with their TO to better understand the cause of transient overvoltages resulting in inverter tripping. These studies should identify why observed inverter terminal voltages are higher than the voltage at the point of measurement and any protection coordination needed to ride through these voltage conditions.



NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Loss of Solar Resources during Transmission Disturbances due to Inverter Settings I and II

NERC Alert - Industry Recommendation

NERC IRPTF Meeting

Rich Bauer, NERC

RELIABILITY | ACCOUNTABILITY




NERC Alerts

- Alert I (Blue Cut Fire Disturbance Report)
  - June 20, 2017
- Alert II (Canyon 2 Fire Disturbance Report)
  - May 1, 2018

NERC Alert I

Industry Recommendation

Loss of Solar Resources during Transmission Disturbances due to Inverter Settings

Initial Distribution: June 20, 2017

NERC identified a potential characteristic exhibited by some inverter-based resources, particularly utility-scale solar photovoltaic (PV) generation, which reduces power output during fault conditions on the transmission system. An example of this behavior has been observed during recent BPS disturbances, highlighting potential risks to BPS reliability. With the recent and expected increases of utility-scale solar resources, the causes of this reduction in power output from utility-scale power inverters needs to be widely communicated and addressed by the industry. The industry should identify reliability preserving actions in the areas of power system planning and operations to reduce the system reliability impact in the event of widespread loss of solar-resources during faults on the power system.

For more information, see the [1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report]

[About NERC Alerts >>]

NERC Alert I

- **Generator Owners of solar photovoltaic (PV) resources should:**
- Recommendation Number 1: Frequency tripping
- Recommendation Number 2: Momentary Cessation (5 seconds)

NERC Alert I

Susceptible to Erroneous Frequency Calculations?			
	MW	Responses	Inverter units
Yes	6,244	74	7,148
No	10,527	76	7,230
Total	**16,771**	**150**	**14,378**

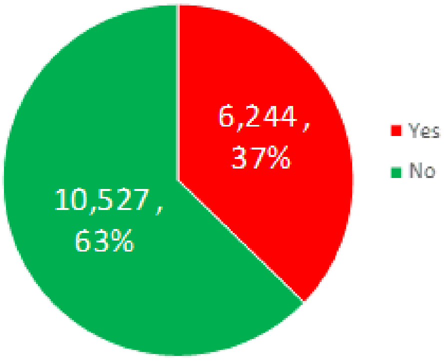


Figure 2: MW susceptible to Erroneous Frequency Calculations

Inverter cease output during abnormal voltages?			
	MW	Responses	Inverter units
Yes	14,113	119	11,821
No	2,657	31	2,557
Total	**16,771**	**150**	**14,378**

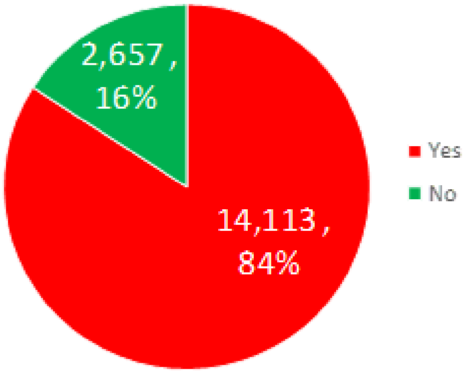


Figure 4: MW cease output during abnormal voltages

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Alert II
Level 2 – Industry Recommendation

- Level 2 NERC Alert – Industry Recommendation

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Industry Recommendation

Loss of Solar Resources during Transmission Disturbances due to Inverter Settings - II

Initial Distribution: May 1, 2018

NERC has identified adverse characteristics of inverter-based resource performance during grid faults that could present potential risks to reliability of the BPS. As the penetration of inverter-based resources (particularly solar PV resources) continues to increase in North America, these adverse characteristics need to be widely communicated. This Level 2 Industry Recommendation alerts industry to these adverse characteristics observed with BPS-connected solar PV resources, and provides recommended actions to address fault ride-through and timely restoration of current injection by all inverter-based resources connected to the BPS.
(See Background section for more information.)

Although this NERC Alert pertains specifically to BES solar PV resources, the same characteristics may exist for non-BES[1] solar PV resources connected to the BPS regardless of installed generating capacity or interconnection voltage. Owners and operators of those facilities are encouraged to consult their inverter manufacturers, review inverter settings, and implement the recommendations described herein. While this NERC alert focuses on solar PV, we encourage similar activities for other inverter-based resources such as, but not limited to, battery energy storage and wind resources.

For more information, see the October 9, 2017 Canyon 2 Fire Disturbance Report.

About NERC Alerts >>

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

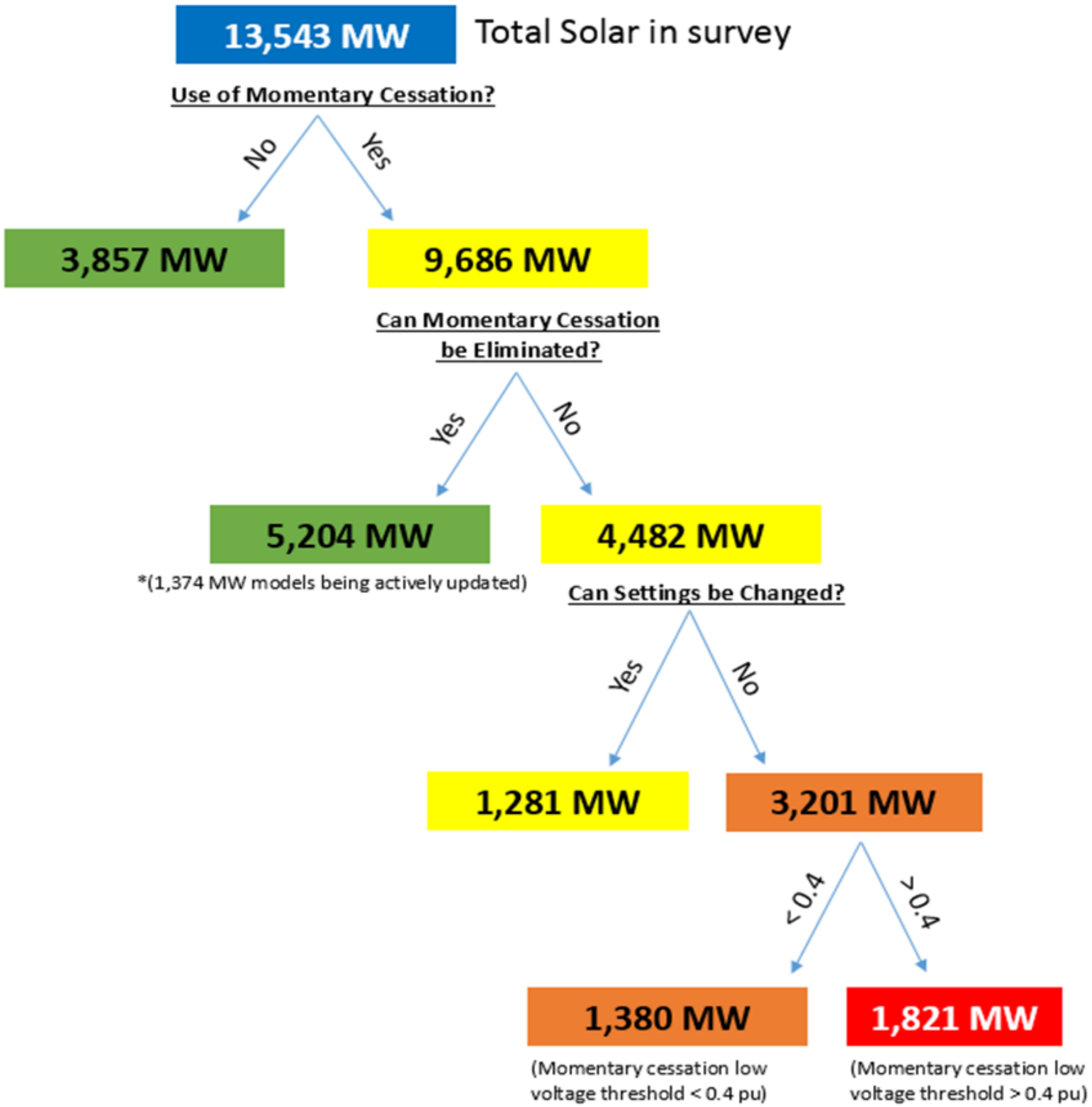
NERC Alert II

- **Generator Owners of solar photovoltaic (PV) resources should:**
- Recommendation 1(a&b) : Dynamic Models
  - Eliminate or improve Momentary Cessation (1 second)
- Recommendation 2: Plant Level Control interactions
- Recommendation 3: Voltage trip settings
- Recommendation 4: DC reverse current
- Recommendation 5: data transfer

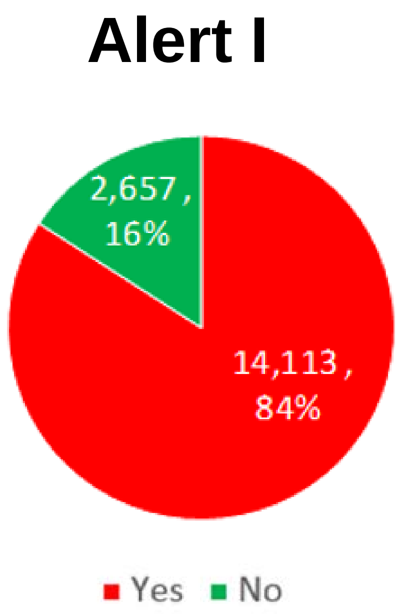
NERC Alert II

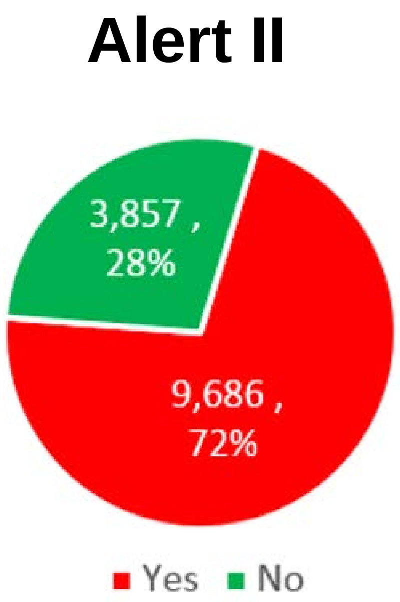
- **Transmission Planners, Planning Coordinators, Transmission Operators, and Reliability Coordinators should:**
- Recommendation 6 (a&b): Perform simulations

NERC Alert II



NERC Alert II





NERC Alert II

- Very few existing and proposed inverter models provided
- Some TPs/PCs created models from Alert data provided by GOs
- Limited Studies have not indicated a significant risk to the Interconnections
- More education/familiarization is needed on inverter modeling

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Inverter-Based Resource Protection and Fault Ride-Through

NERC IRPTF
February 2019

RELIABILITY | ACCOUNTABILITY




NERC

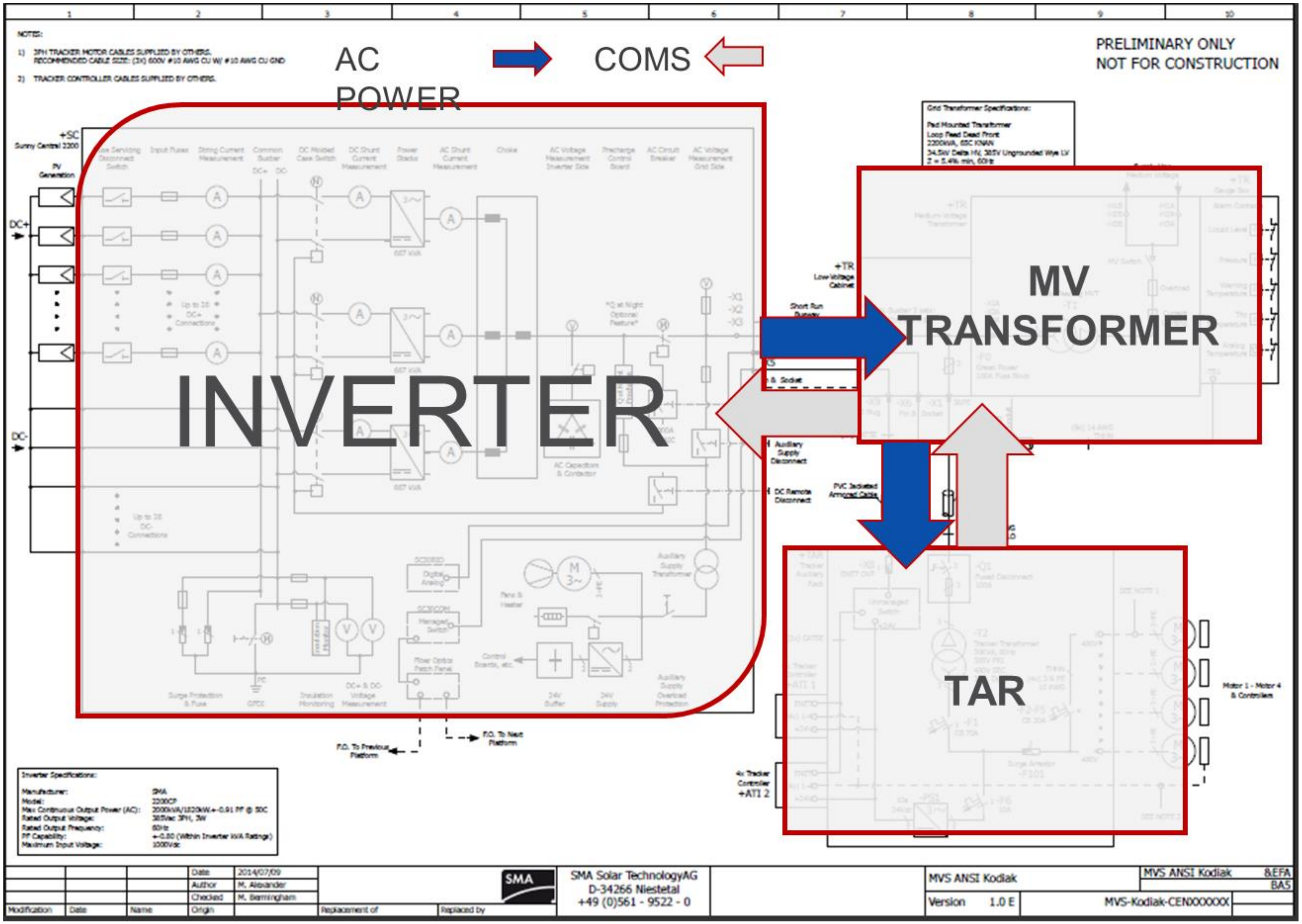
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Inverter Protection and Ride-Through

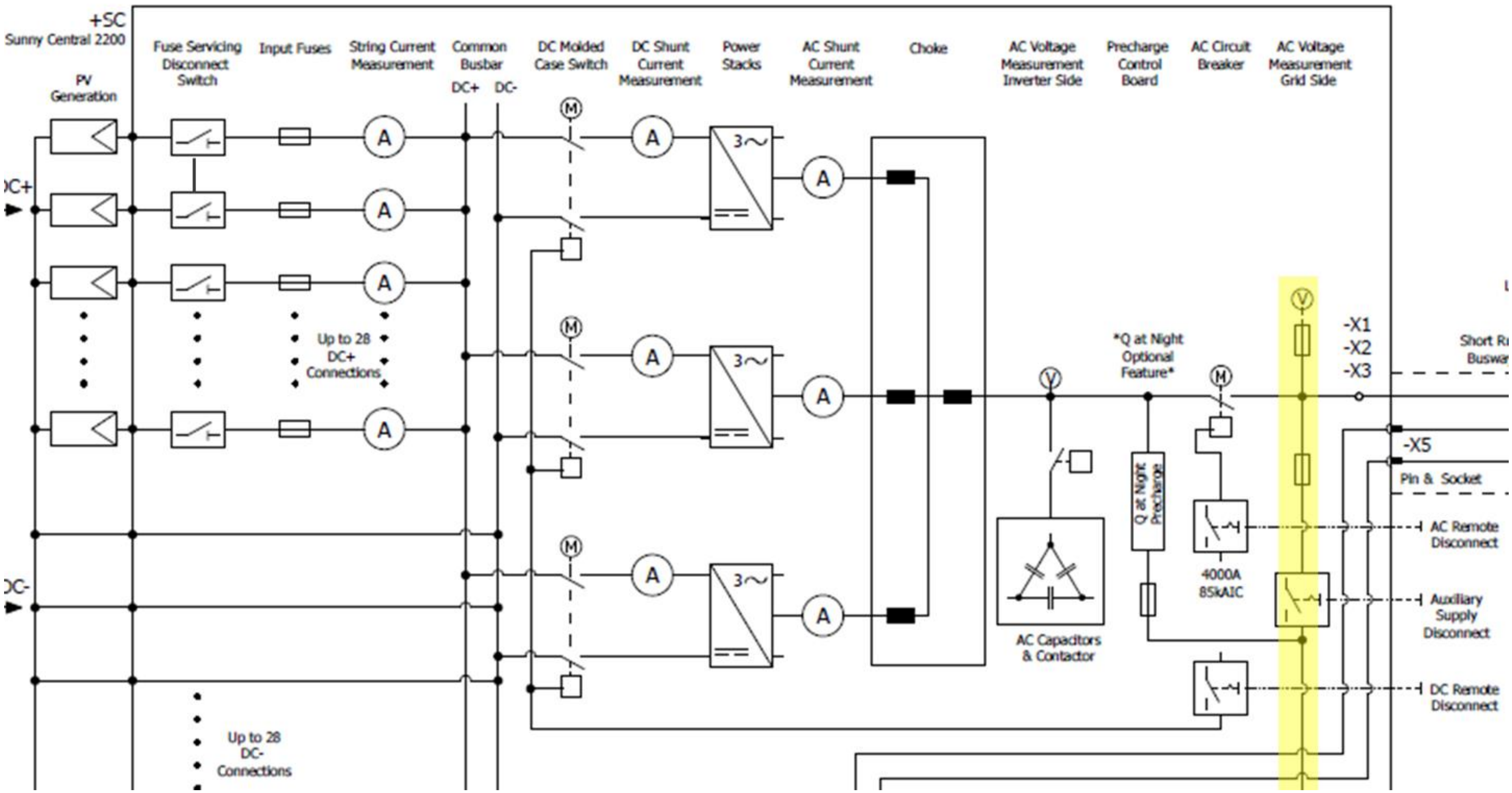
Gary Custer, SMA America

RELIABILITY | ACCOUNTABILITY

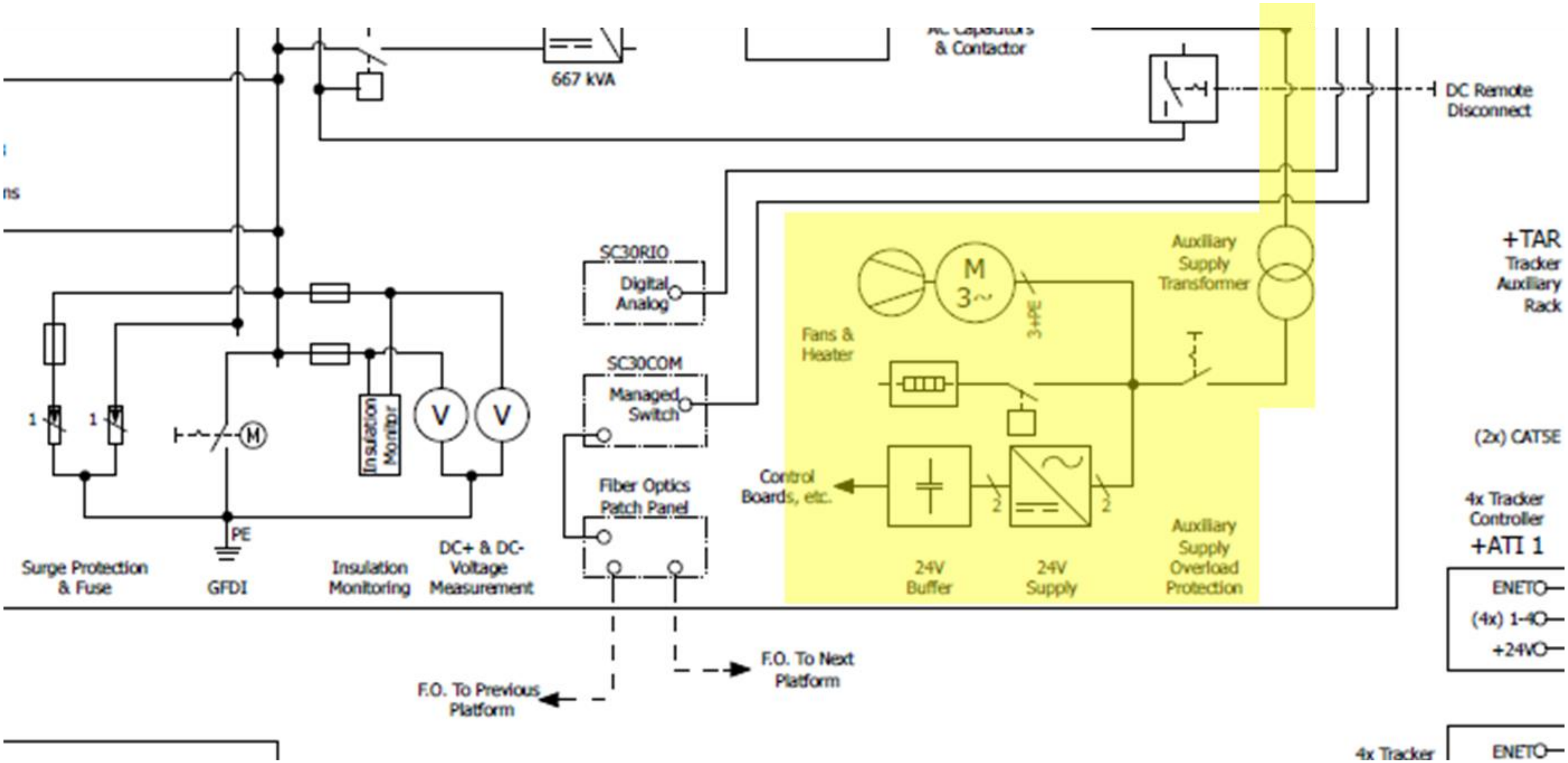
Line Diagram: Inverter + MV Block + TAR



Inverter


+SC
Sunny Central 2200
PV Generation
DC+
DC-
Fuse Servicing Disconnect Switch
Input Fuses
String Current Measurement
Common Busbar
DC+ DC-
DC Molded Case Switch
DC Shunt Current Measurement
Power Stacks
AC Shunt Current Measurement
Choke
AC Voltage Measurement Inverter Side
Precharge Control Board
AC Circuit Breaker
AC Voltage Measurement Grid Side
Up to 28 DC+ Connections
Up to 28 DC- Connections
Q at Night Optional Feature
Q at Night Precharge
AC Capacitors & Contactor
4000A 85kAIC
-X1
-X2
-X3
-X5
Pin & Socket
AC Remote Disconnect
Auxiliary Supply Disconnect
DC Remote Disconnect

Inverter: GFDI & Aux Power Supply



Inverter Faults

AC Grid Fault: Inverter responds to voltage and frequency faults observed on terminals or transfer trip signal.

- Inverter trips on frequency faults. Inverter has a wide operating frequency window (typical 57 to 63 Hz) . Same inverter hardware for 50Hz and 60Hz grids.
- Inverter can be set to the following modes for voltage faults:
  - Full Dynamic Support – Reactive current feed in.
  - Partial Dynamic Support – Active and reactive current feed in is blocked during the fault.
  - Disable (FRT off) – Inverter will likely trip on any disturbance.
- Trip settings are independent of the PLL.

Inverter Faults

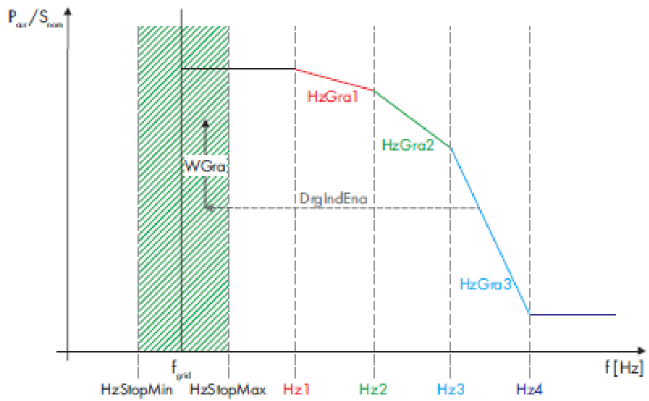
DC Fault

- DC Overvoltage - Some inverters trip on DC overvoltage.
  - SMA: Records high DC voltage but does not trip. If DC voltage is <AC voltage*sqrt2, PV field is disconnected from the inverter.
- DC Reverse Current – An AC surge can cause reverse current.
  - SMA: Inverter opens AC breaker and DC contactor.

PLL Fault

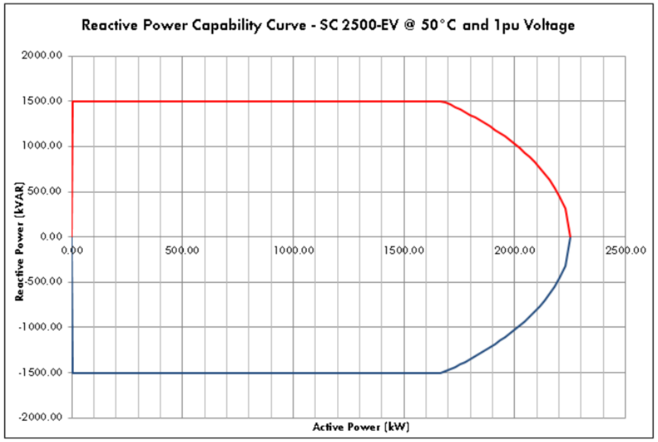
- Two typical methods of measuring frequency:
  - Zero crossing of voltage waveform.
  - SMA: PLL actively measures frequency (Requires ~100 ms).

Grid Support Features



Active Power Limitation on command

- Needs communication link to each inverter or PV plant
- Reduction of active power depending on grid frequency in case of grid failures, in case of power surplus, to avoid grid instabilities



Constant power factor or VAr set-point

- Configure inverter with fixed Var output.

Controlled power factor or VAr via comm's)

- Send Var setpoint commands to inverter via Modbus/TCP

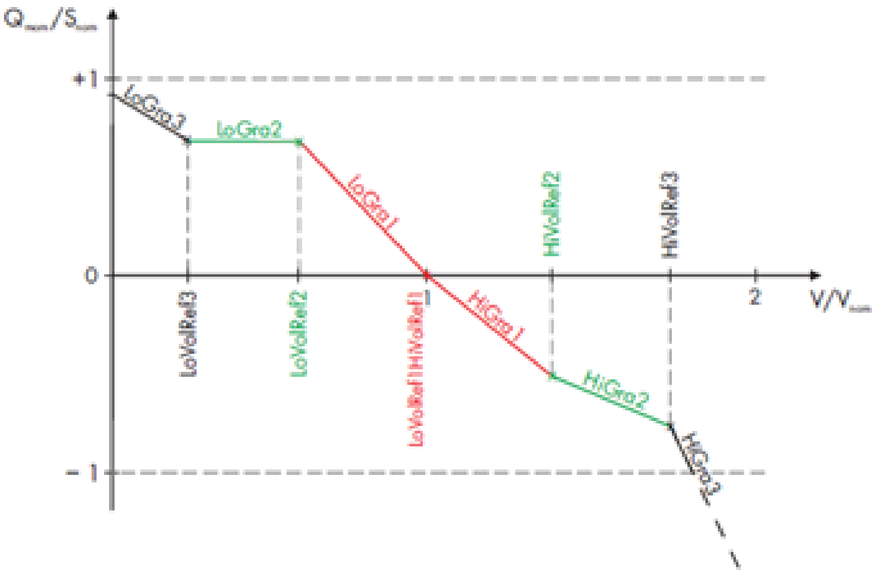
Autonomous VAr control (depending on V)

- VoltVAr control based on curve

Autonomous power factor control depending on real power output

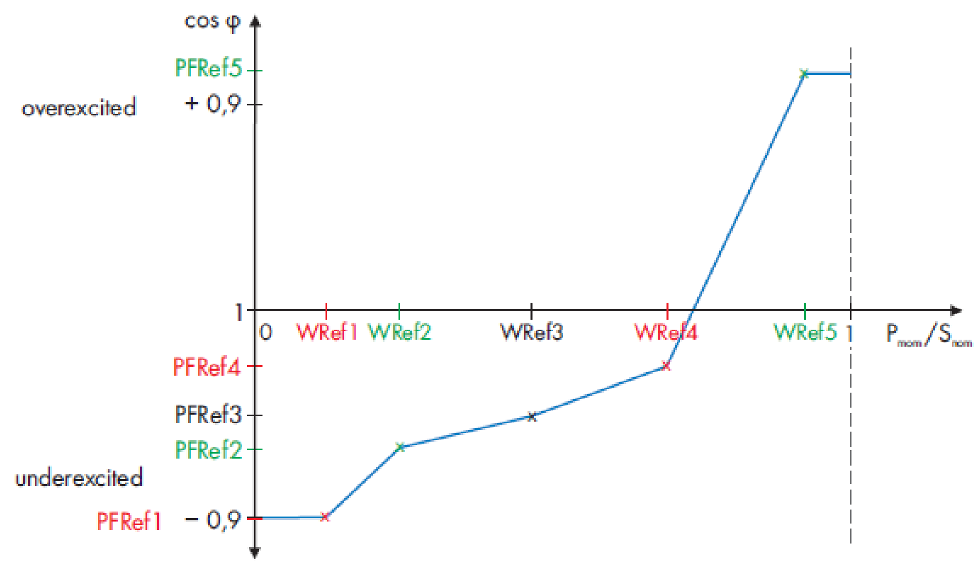
- VArs as a function of Watts

Grid Support Features



Voltage Control (VoltVAr)

- Uses reactive power to stabilize the voltage at the terminals of the inverter



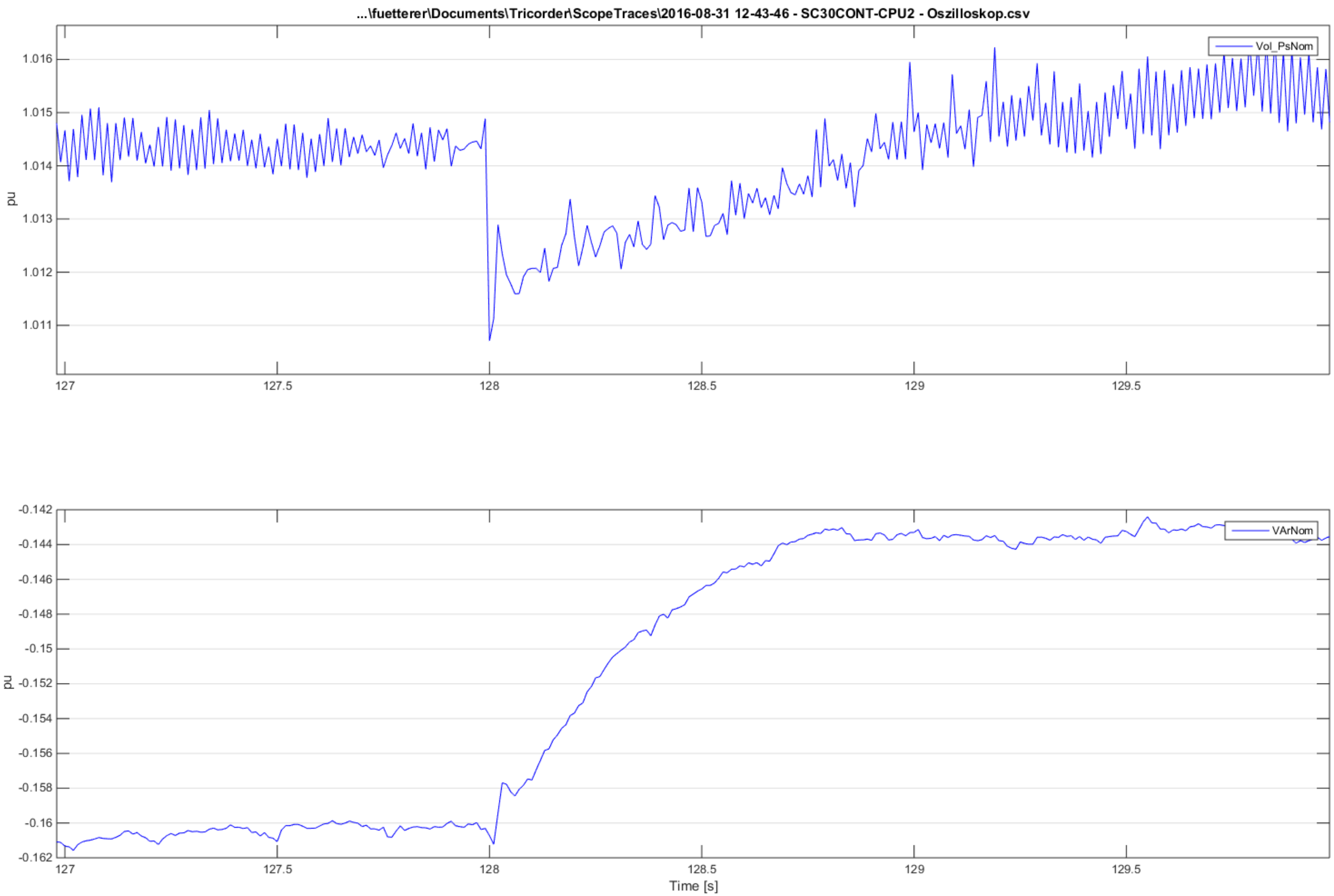
Reactive Power Control

- cos ϕ (P)

Inverter Voltage Control

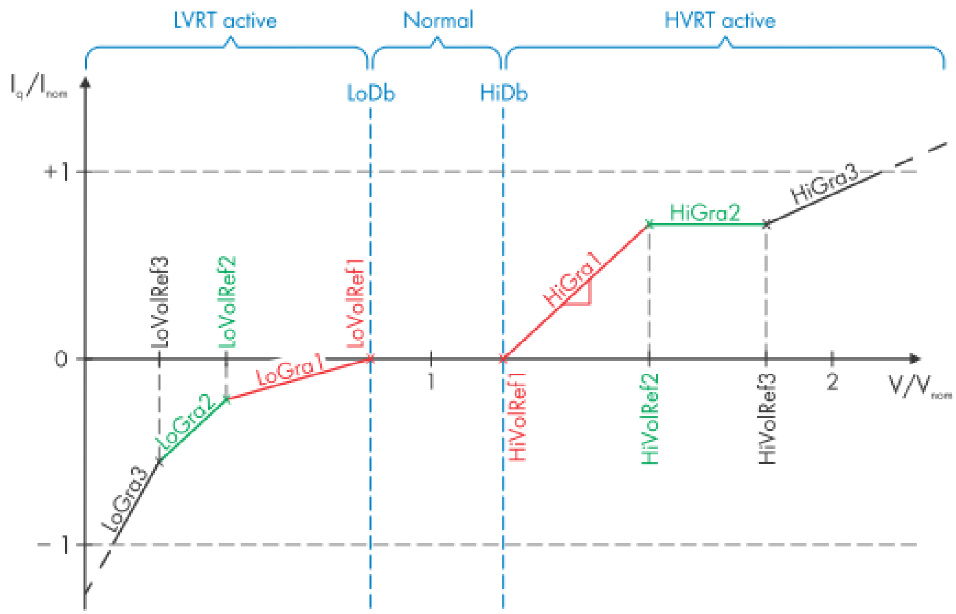
- Voltage Control (VoltVAr) uses reactive power to stabilize the voltage at the terminals of the inverter
  - Characteristic works like a proportional controller
  - VoltVAr uses positive sequence only, keeps V in limited range
- Inverters not "fighting" due to impedance between them
- No communication between inverters is required
- Coordinated voltage control at POI, PPC in combination with inverter control
  - Inverter gets V commands from PPC (slow… ~150 ms). PPC V controller sends V set points to all inverters. Inverter in VAr-Volt mode (fast…<20 ms)
- FRT-Full: Separate feature, tries to increase the positive sequence and to decrease the negative sequence.
  - German Grid Code (BDEW) requires a fast reaction with reactive current during a voltage sag (voltage < 0.9pu).

SMA Central Inverter – Voltage Control



Dynamic Grid Support (FRT)

- **Full Dynamic Grid Support**
  - Utility grid support during brief voltage dip by injecting reactive current.
  - Two ranges each with different gradients can be defined for UV and OV.

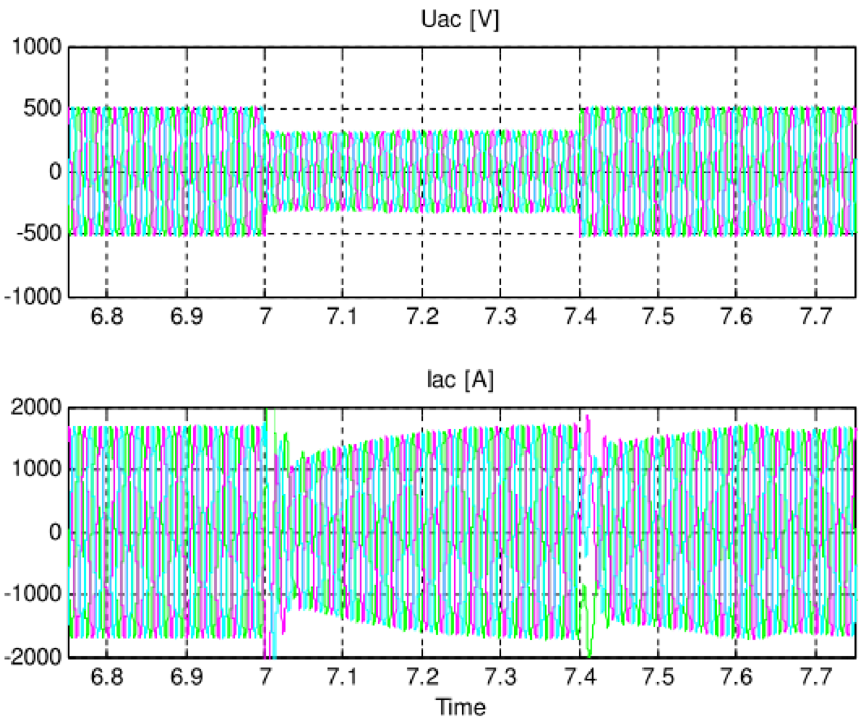


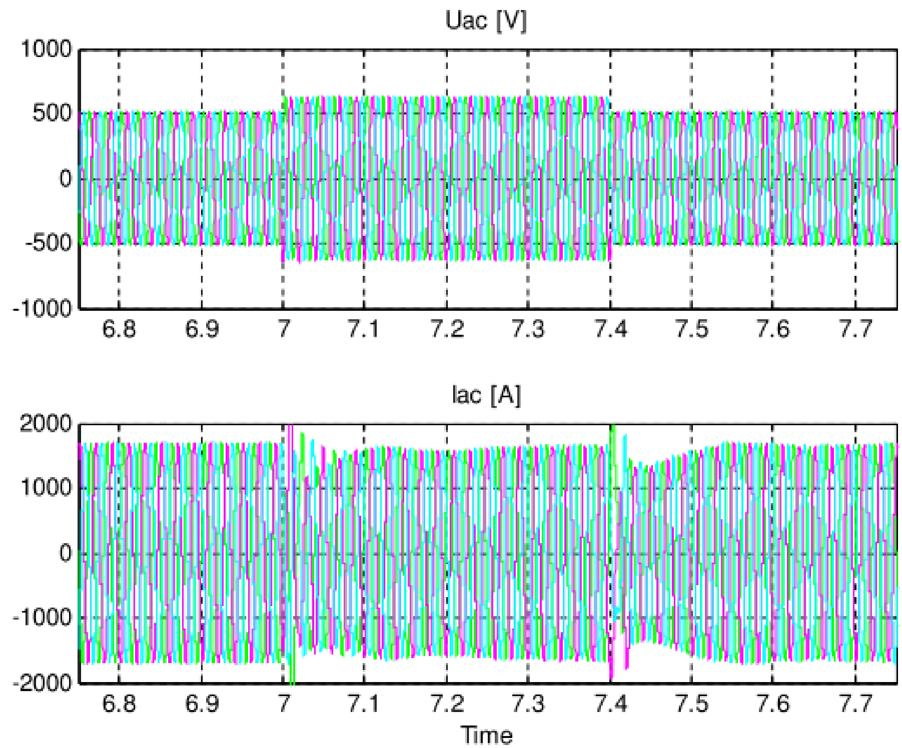
- **Limited Dynamic Grid Support**
  - Inverter interrupts grid feed-in during grid instability for a configurable time without disconnecting from the utility grid.

- The duration of the interruption is configurable via a parameter.
- All FRT modes can be set in PSS/e and PSCAD.

SMA HV & LV Ride-Through

- Fault Ride Through = Full (Reactive Current Injection)





Voltage Ride-Through (LVRT/HVRT)

Inverter Protection >140% for 1 ms = trip

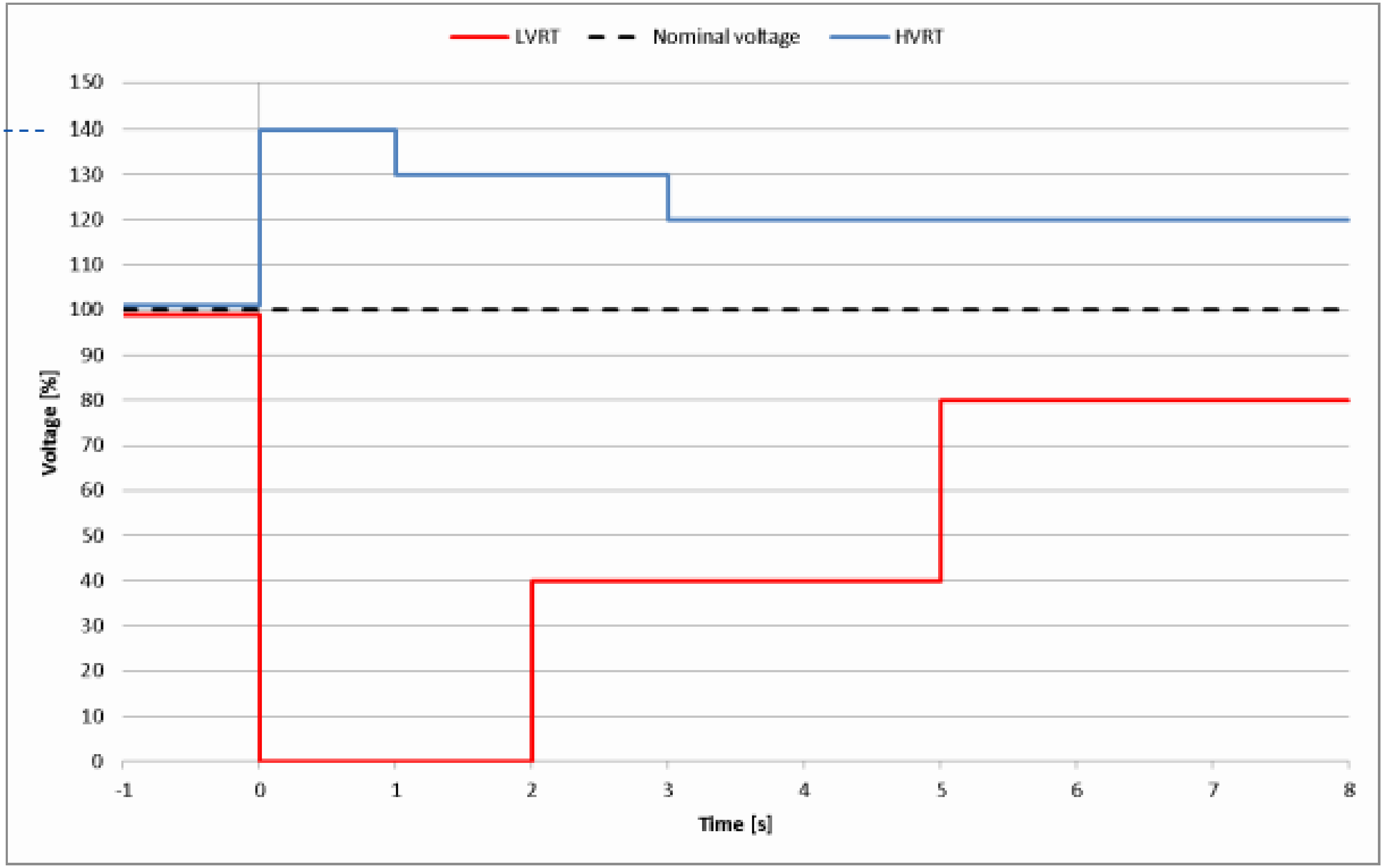
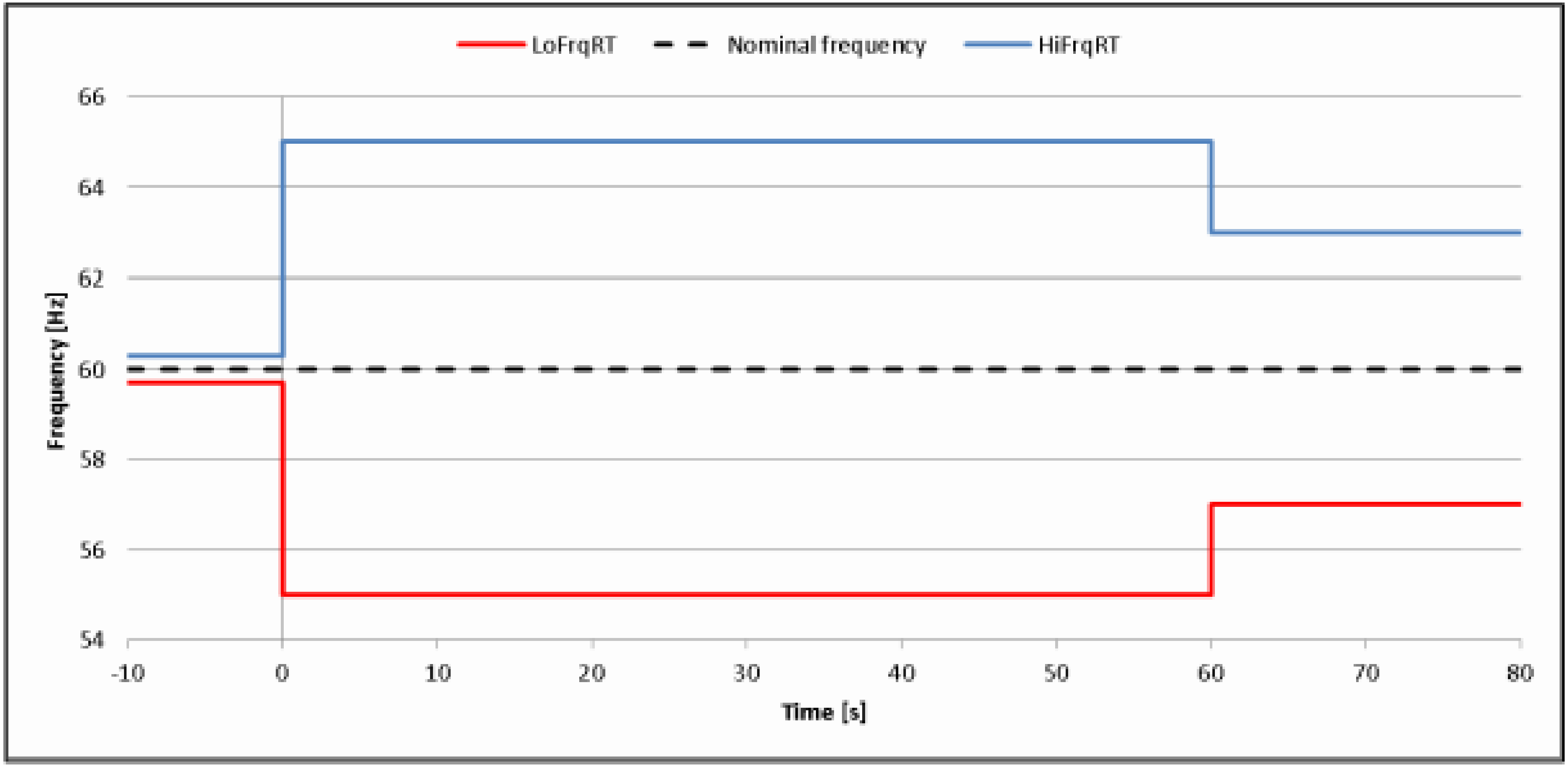


Figure 14: LVRT/HVRT capabilities

Frequency Ride-Through



NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Inverter-Based Resource Protection & Coordination

Matt Manley, POWER Engineers

RELIABILITY | ACCOUNTABILITY




Introduction

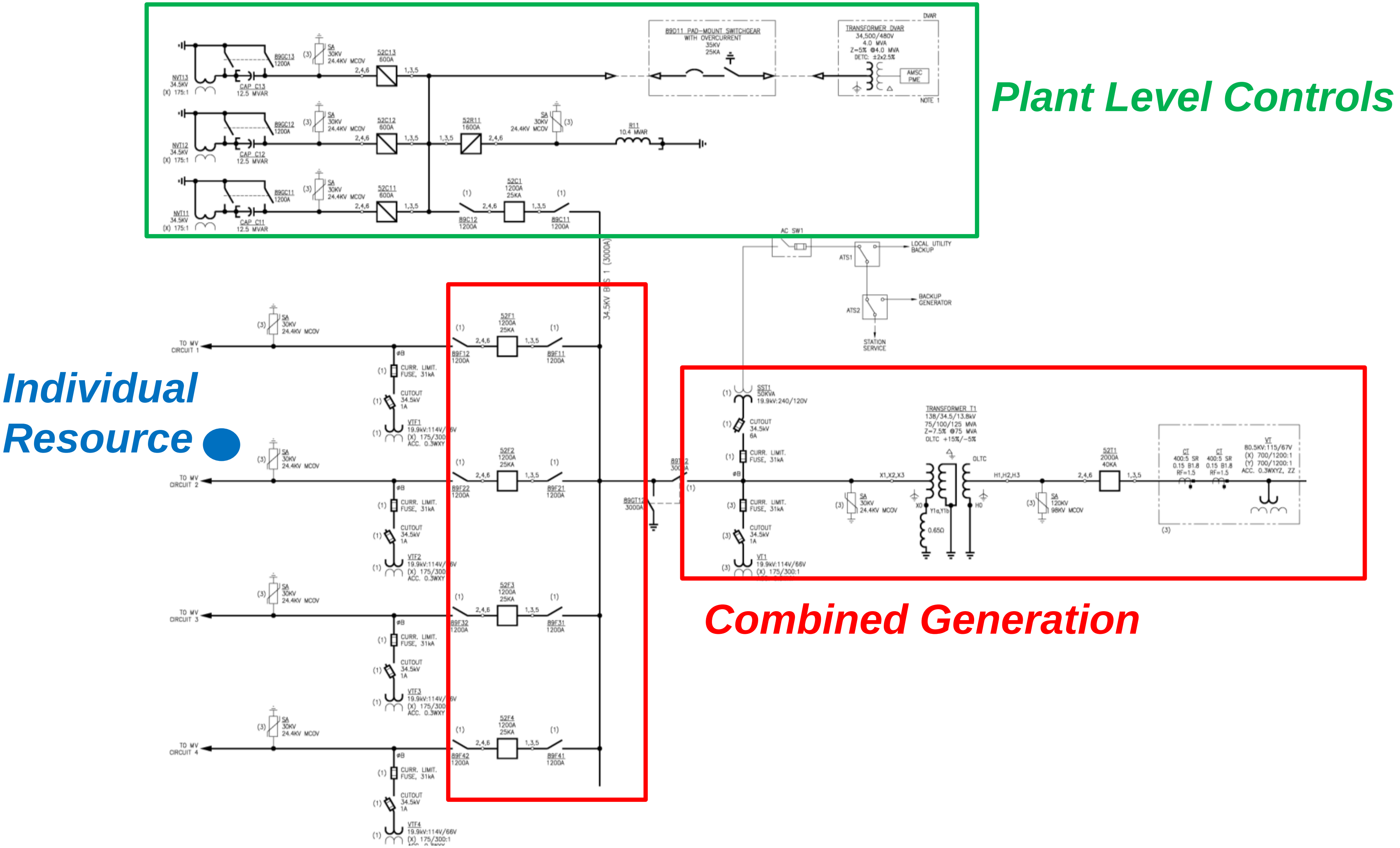
- Typical Standards and Elements
- Overcurrent Coordination
- Voltage Coordination
- PRC-019 Compliance Interpretation
- Overvoltage Event Example

Standards & Elements

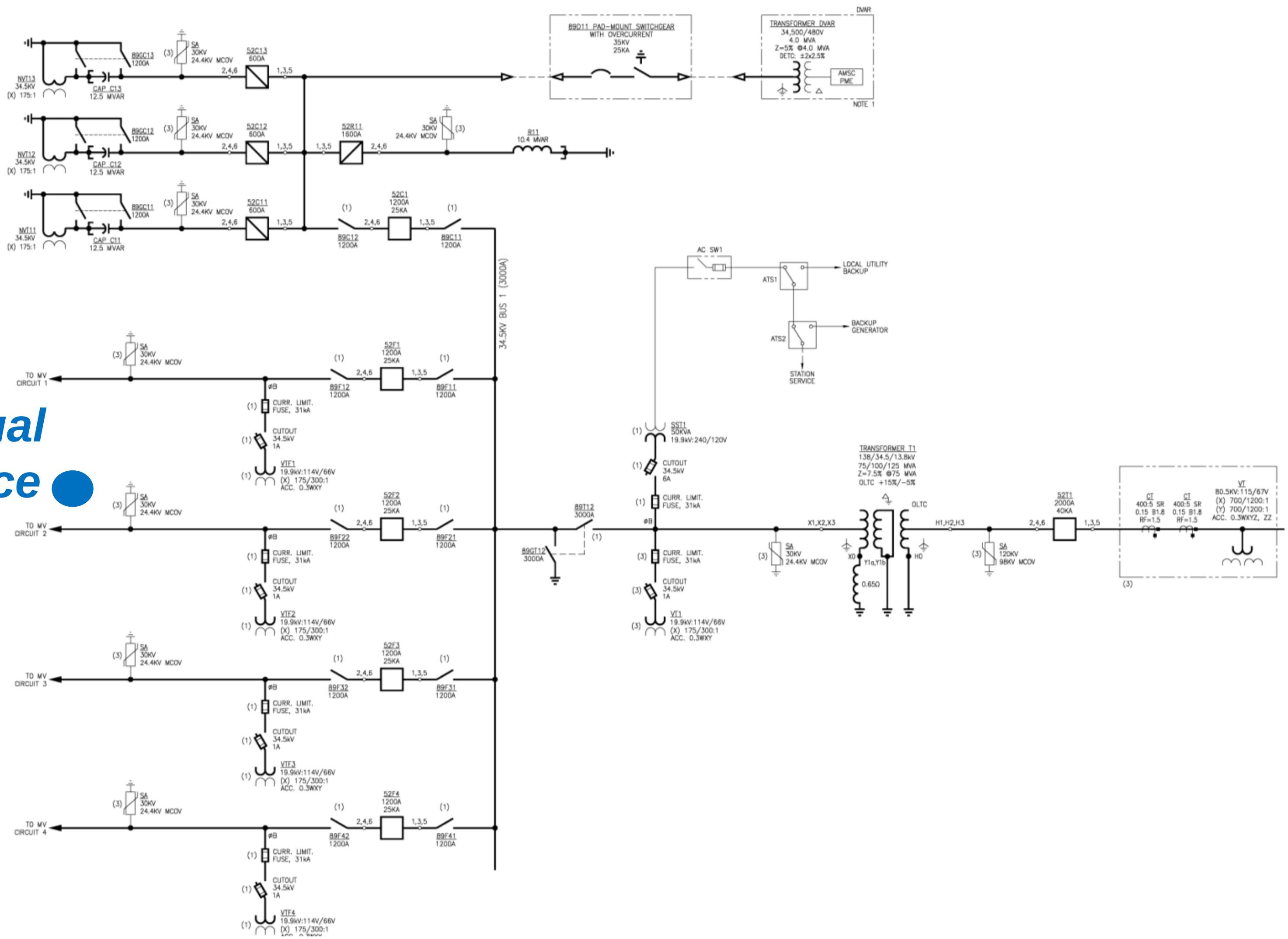
- Standards to Consider
  - PRC-019-2
  - PRC-023-4
  - PRC-024-2
  - PRC-025-2
  - PRC-026-1
  - PRC-027-1

- Applicable Elements
  - 21 – Distance
  - 27 – Undervoltage
  - 59 – Overvoltage
  - 81 – Frequency Over/Under
  - 50/51P – Phase time overcurrent
  - 50/51G – Residual ground overcurrent

Facility Overview

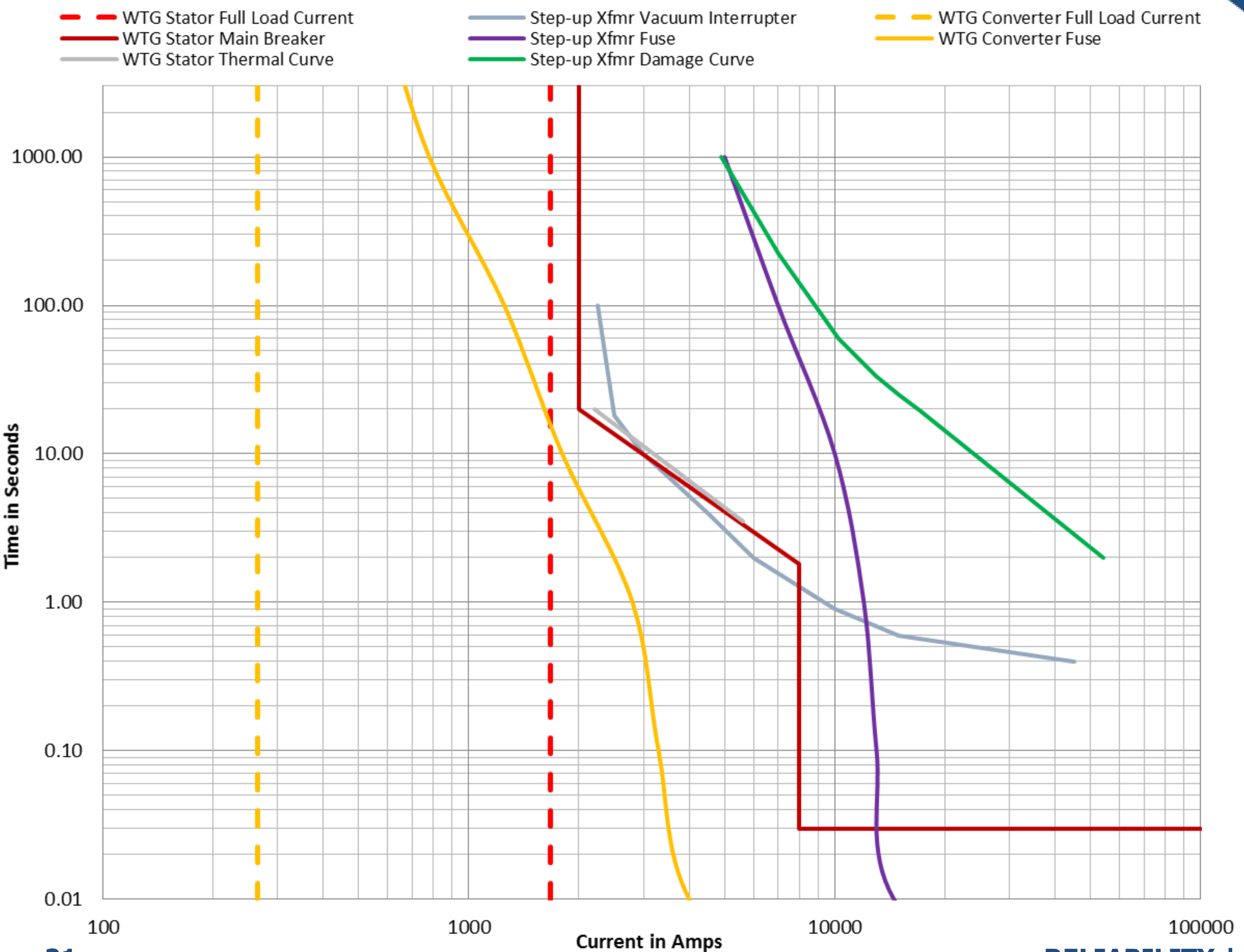


Facility Overview

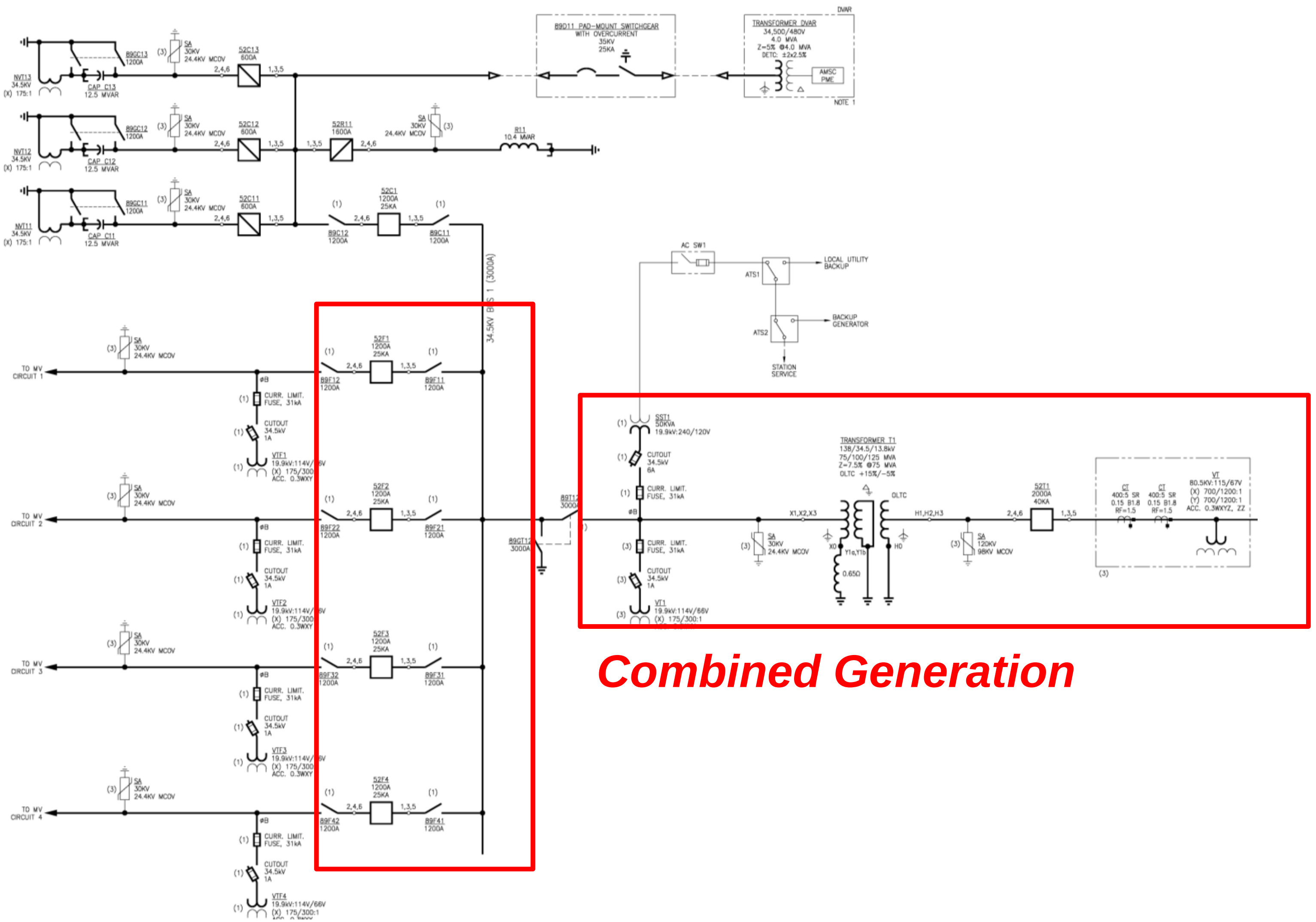


Individual Resource

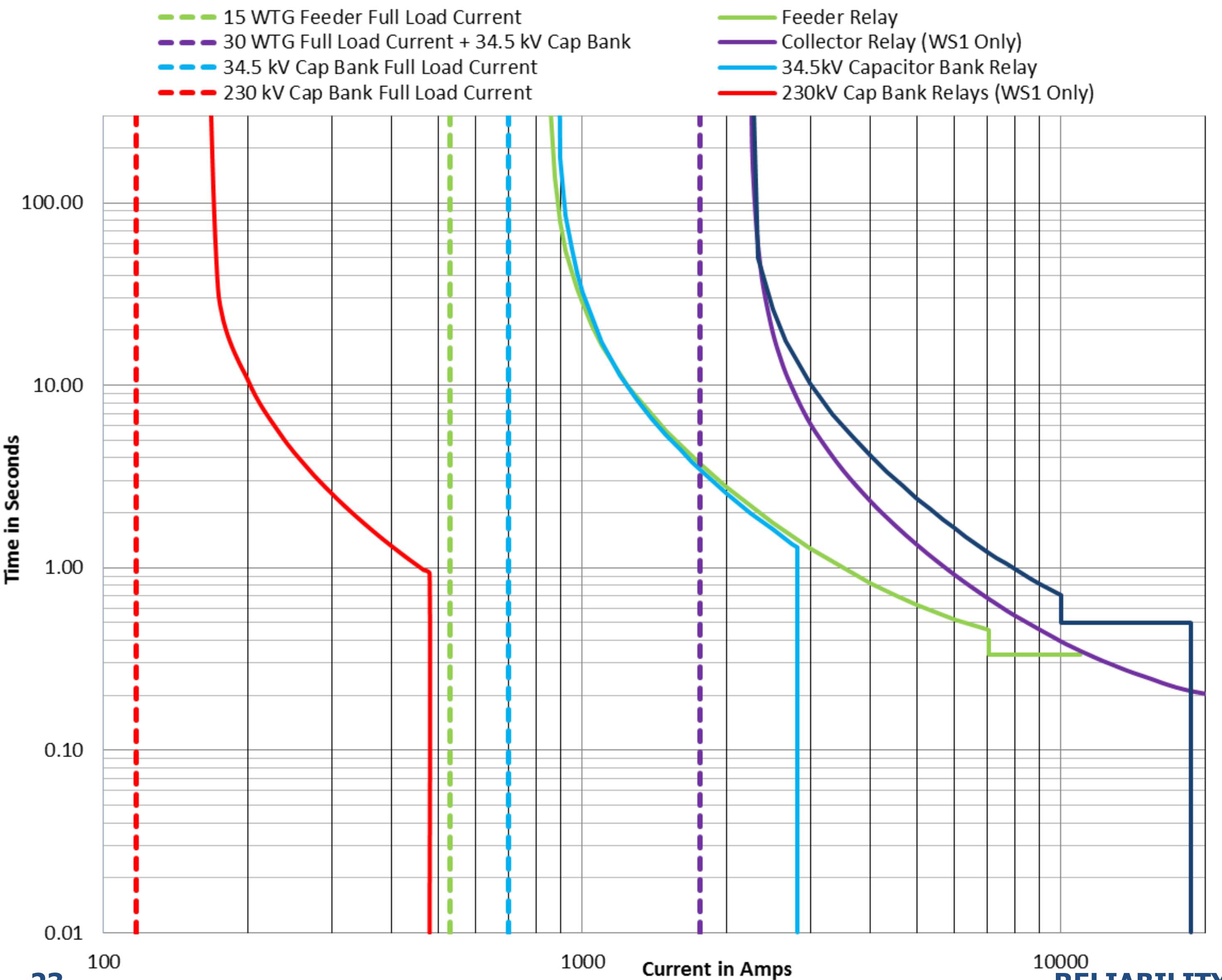
Individual Resources



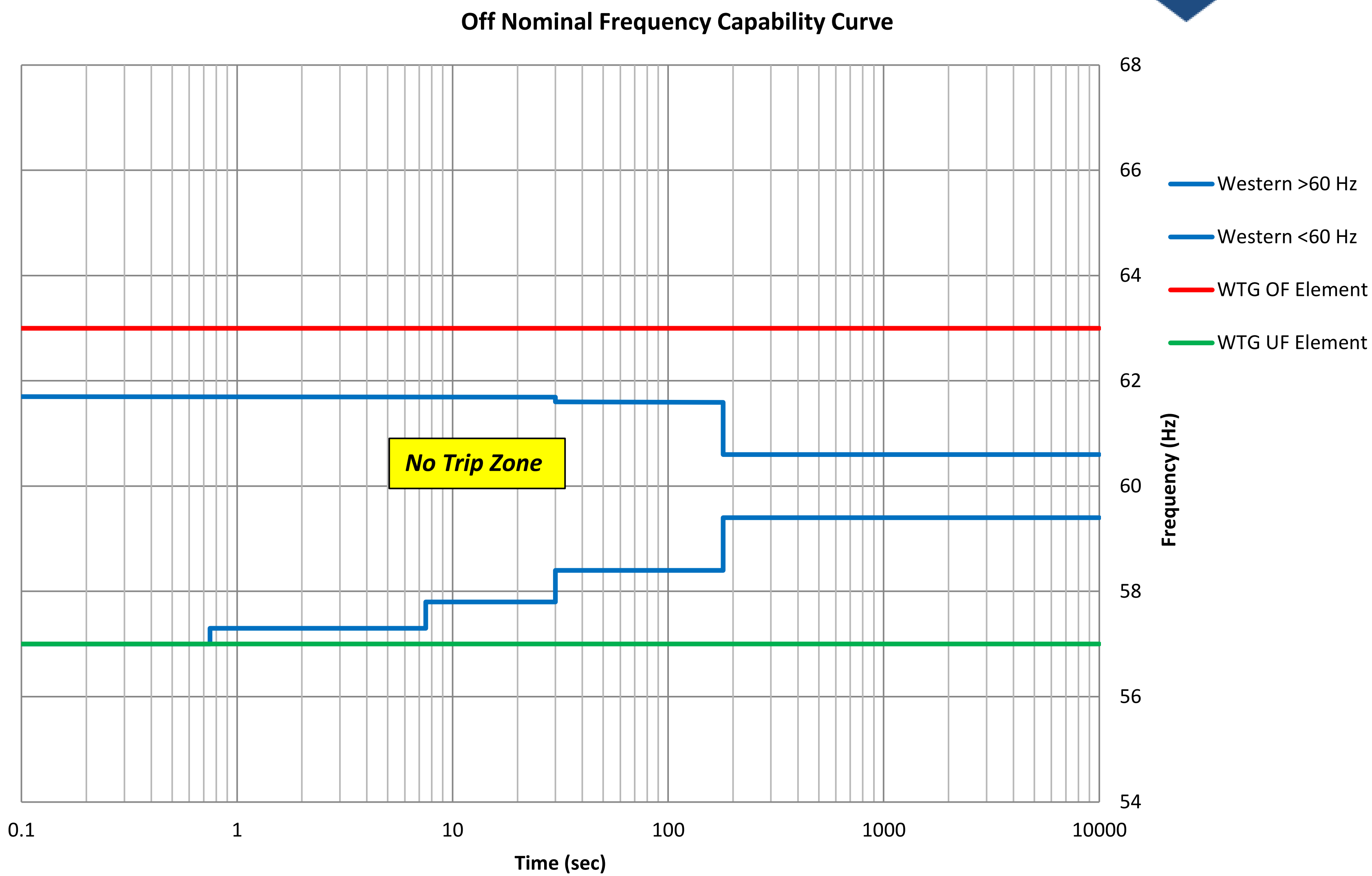
Combined Generation



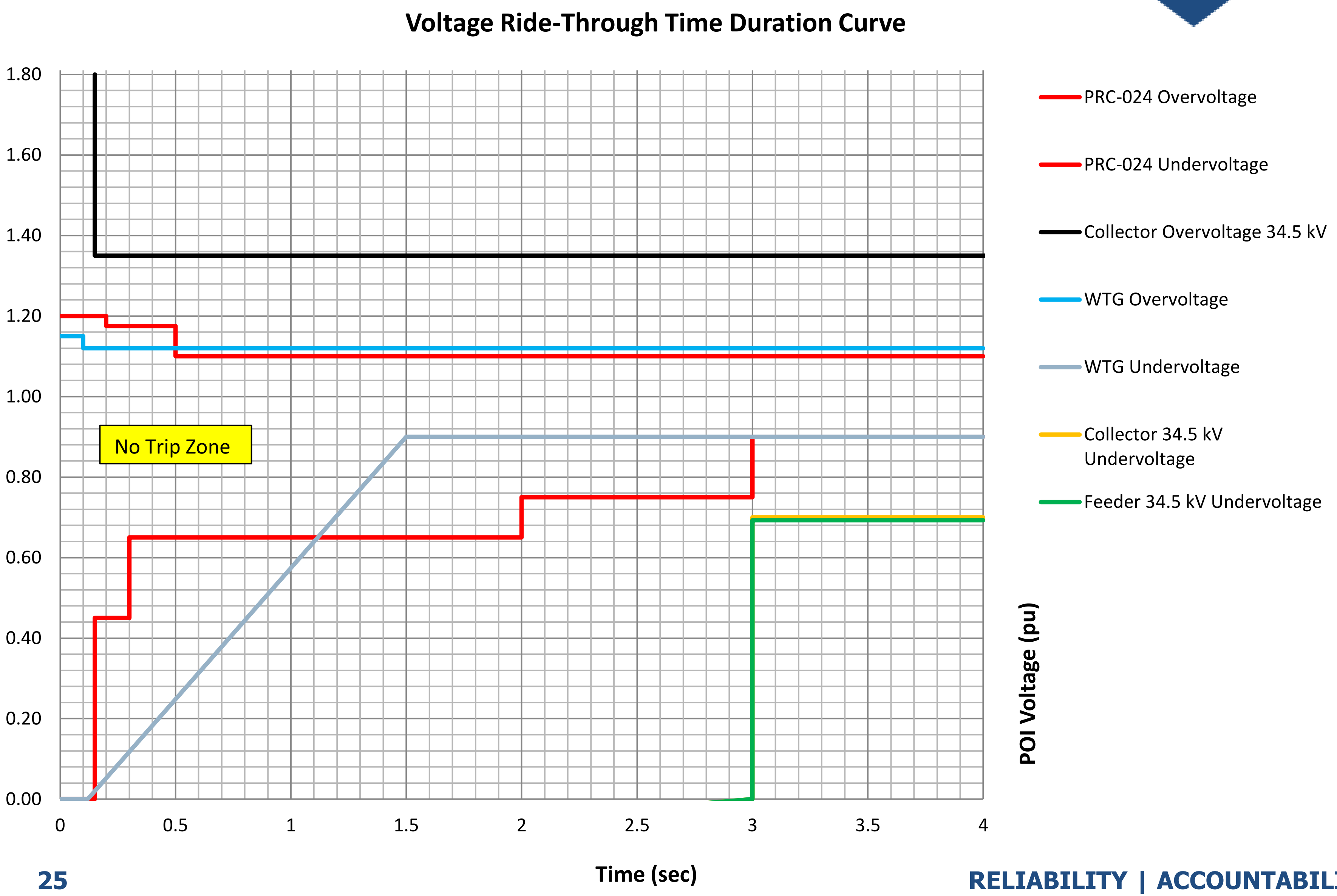
Combined Generation



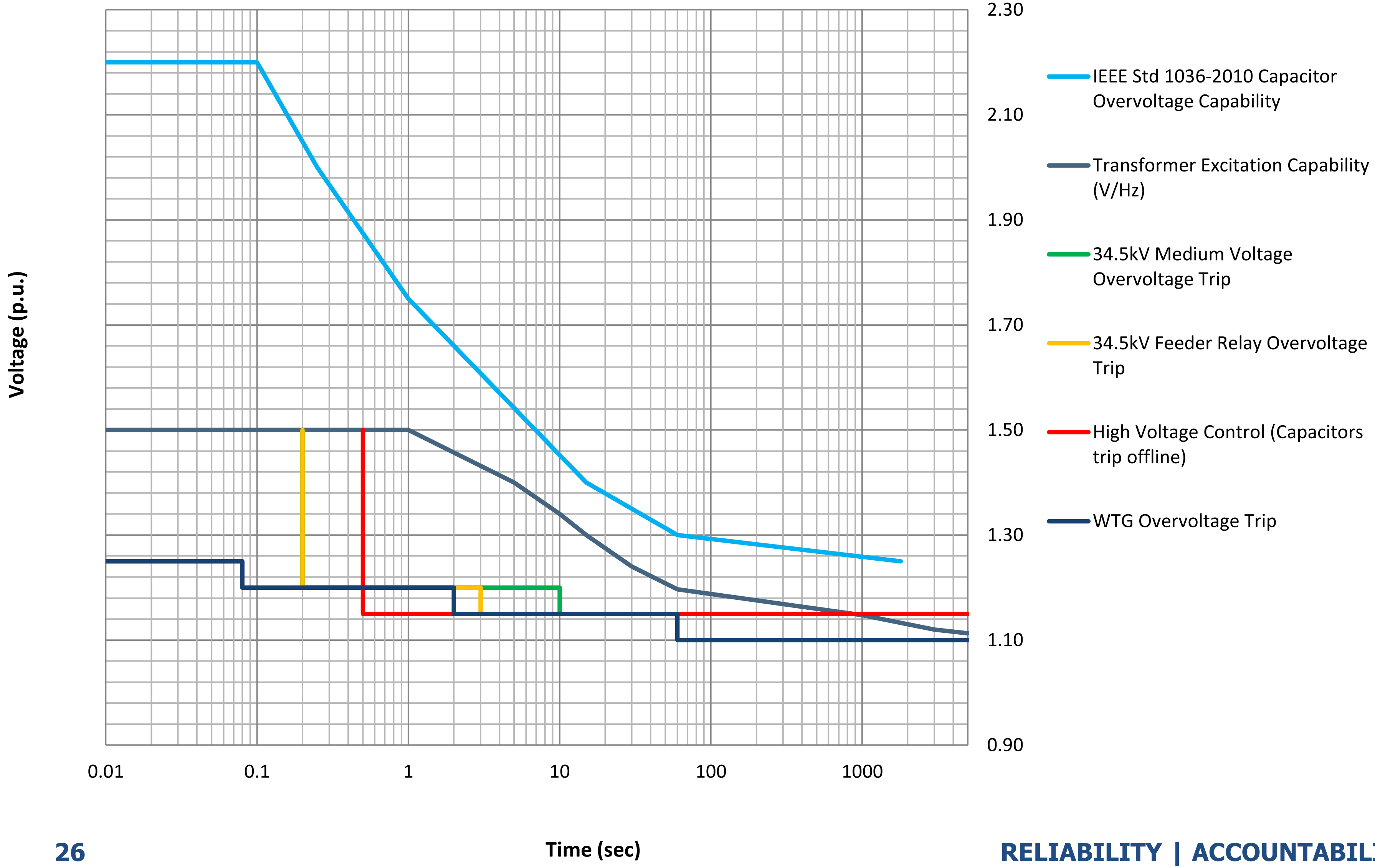
Frequency Protection



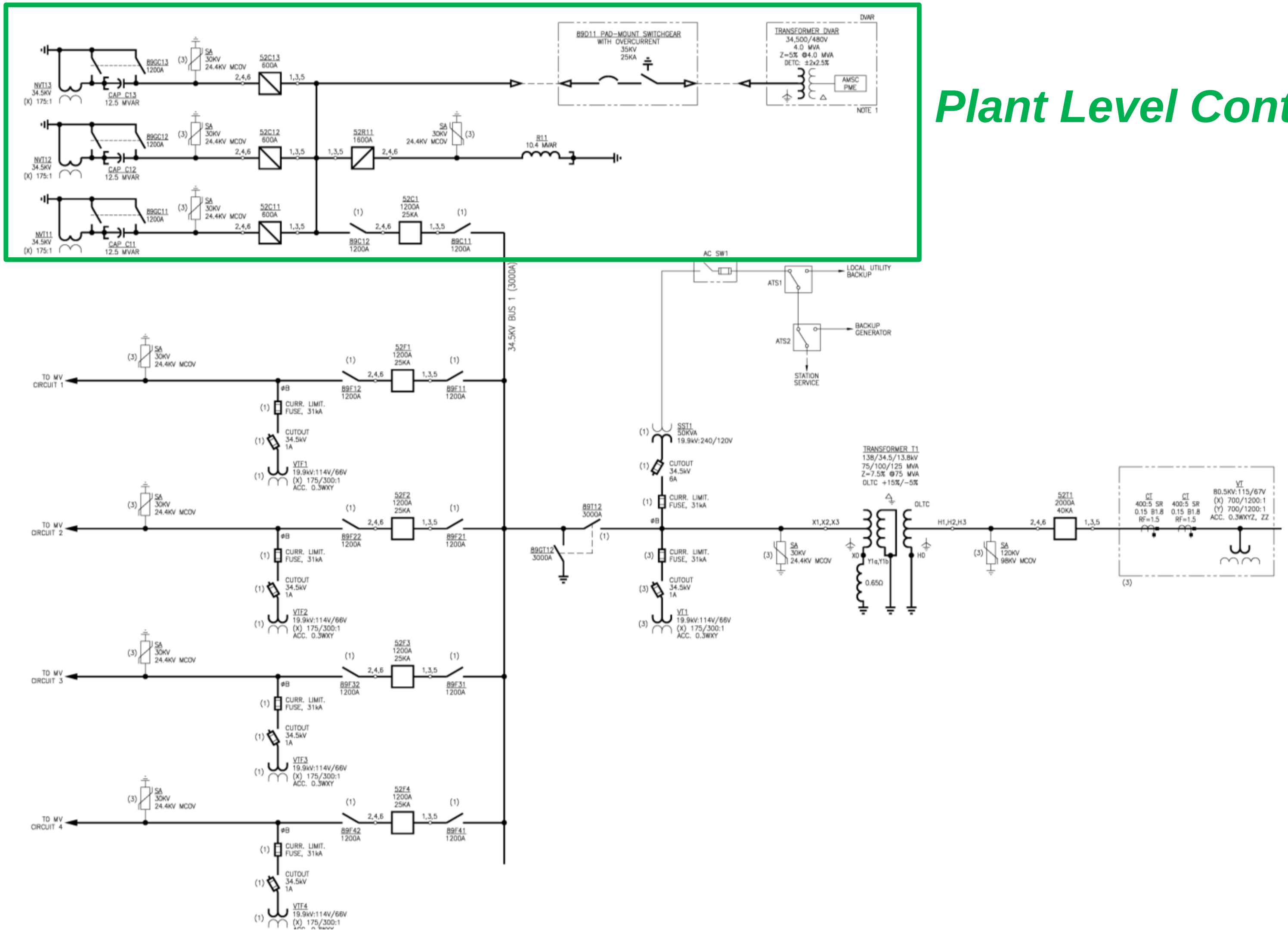
Voltage Protection



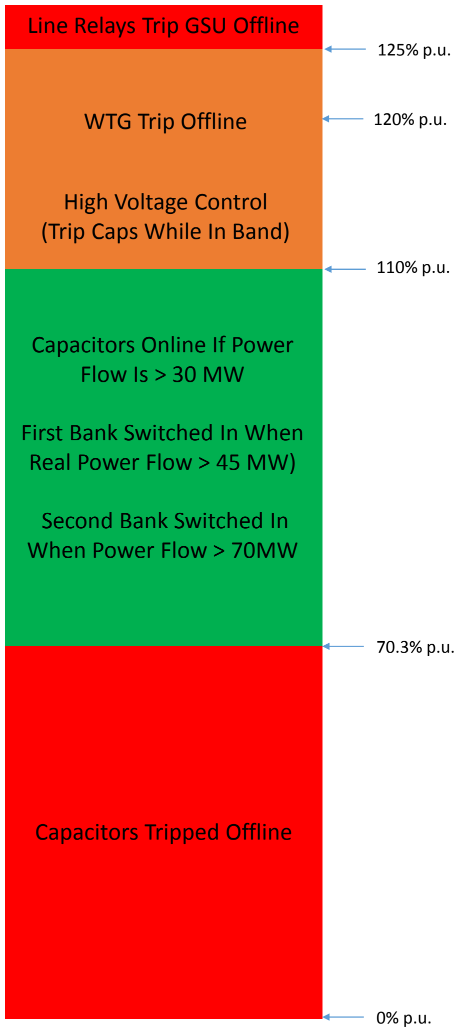
Voltage Protection



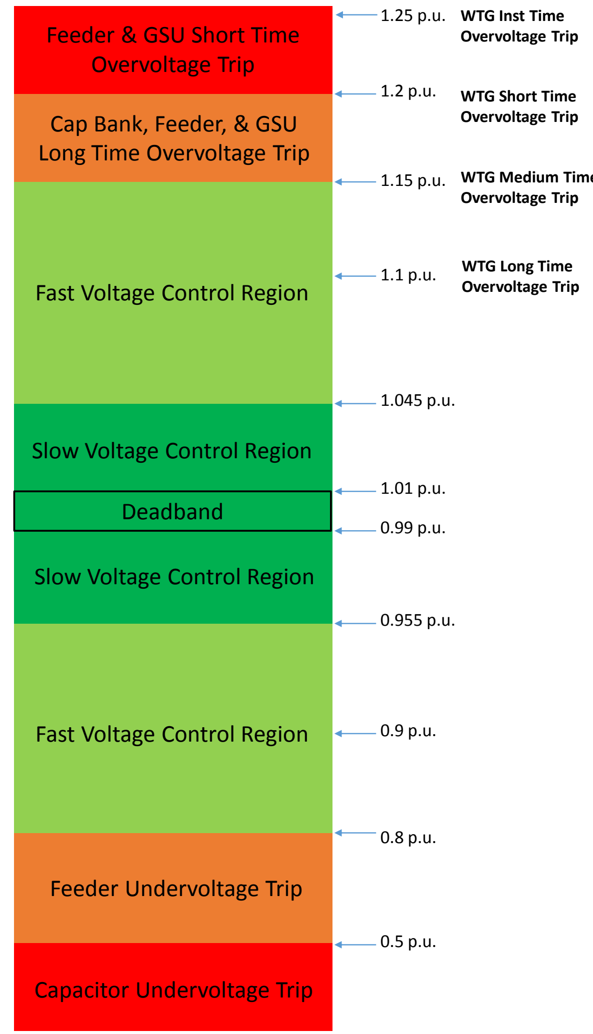
Plant Level Controls



PRC-019 Coordination

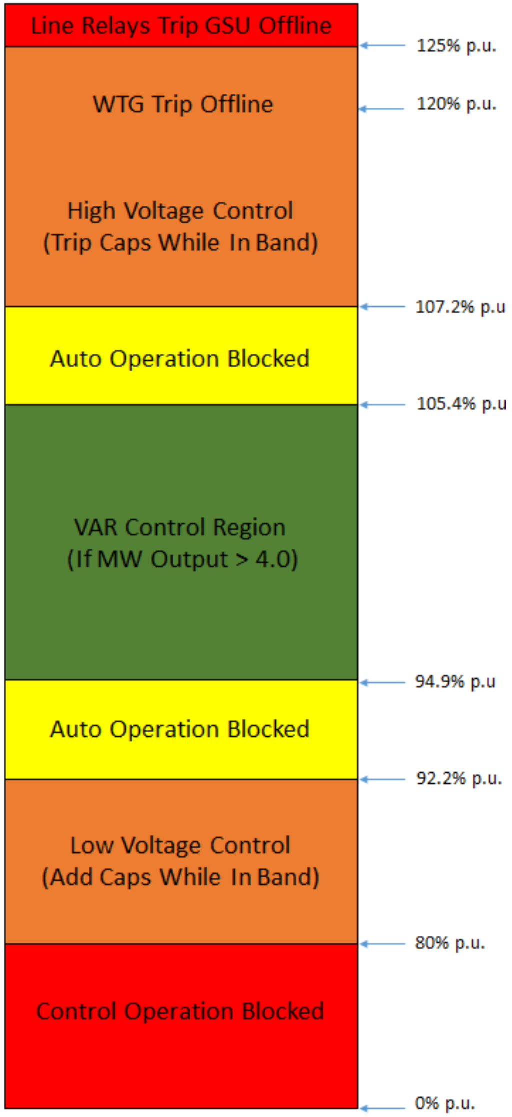


Power Flow Control



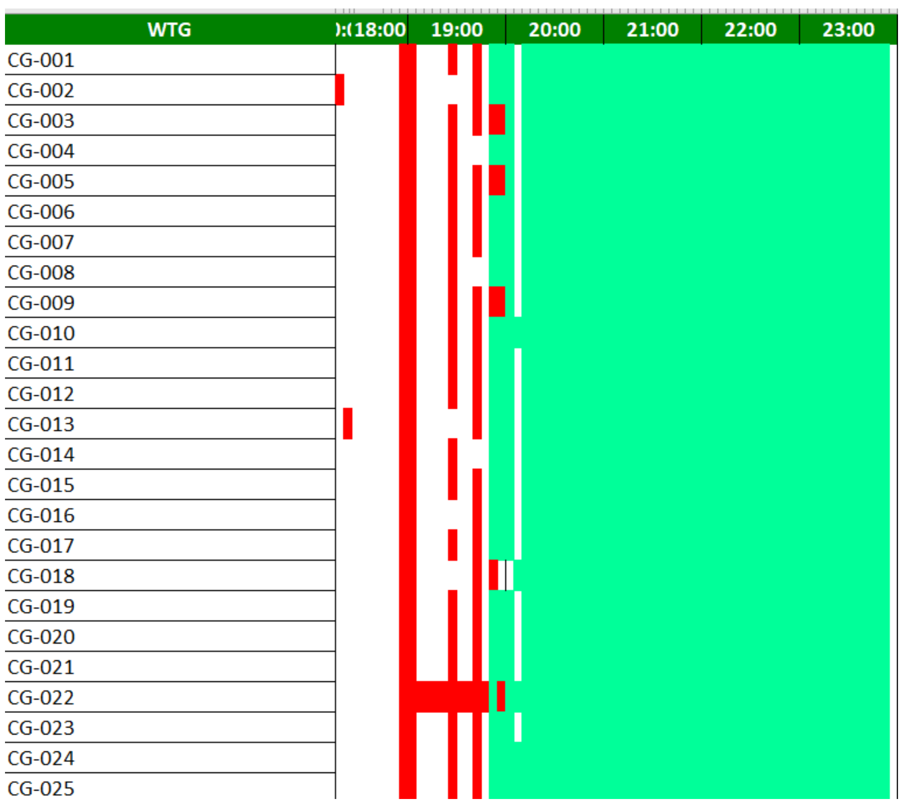
Voltage Control

PRC-019 Coordination Cont.



Example Event

- 230 kV Event
  - 4.29.2017 between 18:56 and 20:00, voltages in excess of 1.1 PU and numerous instances of 20 kV line-ground voltage imbalance.



Additional Information

"An Introduction to Completing a NERC PRC-019 Study"
(For Traditional and Distributed Generation Resources)
Western Protective Relaying Conference 2017
Texas A&M Protection Relaying Conference 2018
https://prorelay.tamu.edu/archive/2018-papers-and-presentations/

"An Introduction to Completing a NERC PRC-026 Study for Traditional Generation"
Western Protective Relaying Conference 2018
Texas A&M Protective Relaying Conference 2019
Georgia Tech Protective Relaying Conference 2019

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Practical Experience with Ride-Through Studies

Andrew Isaacs, Electranix Corporation

RELIABILITY | ACCOUNTABILITY




Background

- Transient stability tools are notoriously poor at predicting ride-through failure for IBR
- IBR Plants can and do trip because of:
  - Converter overcurrent
  - PLL failure to synchronize
  - DC side voltage protection
  - Transient or individual phase overvoltages
  - Unbalanced system operation
- None of these protections are possible to correctly represent in transient stability tools

Background

- Studies are predicting FRT failure (*but usually by accident!* i.e., FRT wasn't the main purpose of the study)
  - Benchmarking (EMT/Transient Stability)
  - Weak grid EMT studies
  - Sub-synchronous Control Interaction (SSCI) studies
  - EMT Control interaction studies
- EMT models require a lot of detail in both the plant model and the system model to correctly evaluate FRT

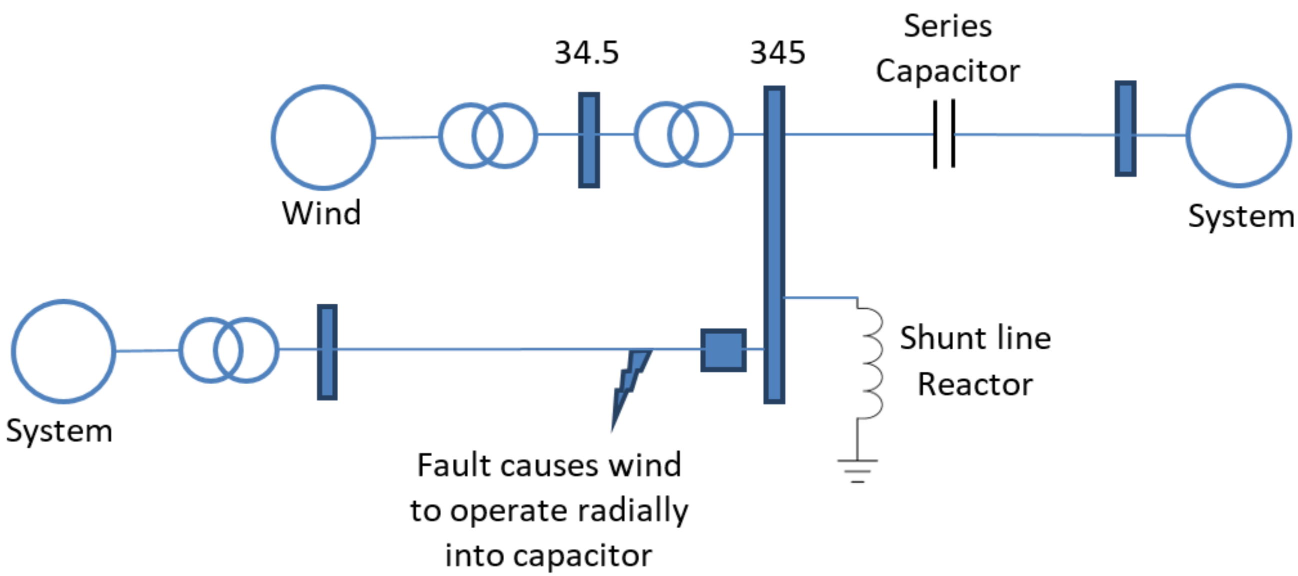
Issue: When is FRT required?

- There is no applicable ride-through standard
  - NERC, IEEE or other.
    - PRC-024-2, TPL-001-4 are not ride-through standards
  - Requirements are left to local entities
- Localized or interconnection specific ride-through requirements are sporadically and inconsistently applied, or insufficiently detailed in specification.
- IBR ride-through failure can be complex, and determination of the responsibility of new plants to overcome existing issues can be confusing.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

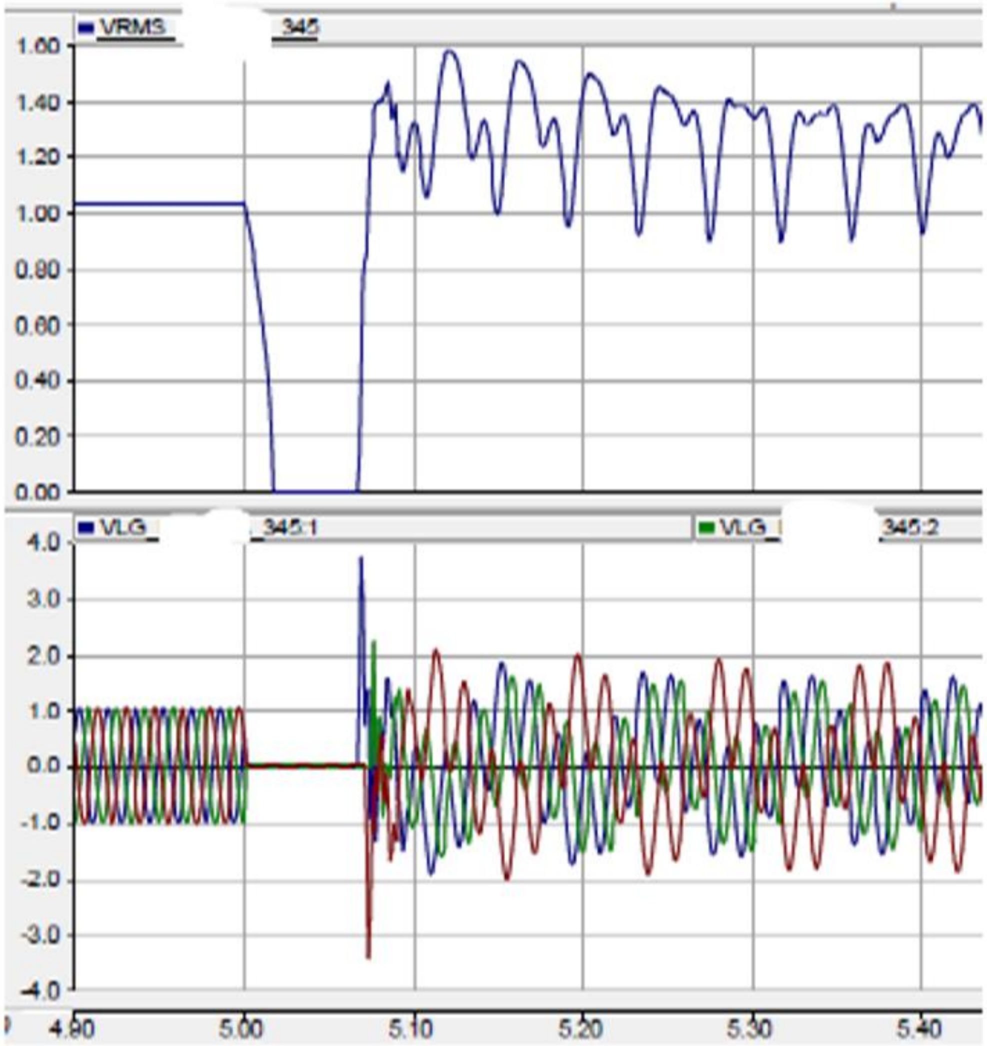
Case Study: FRT Failure!

- Wind connected radially into series capacitor
- 3LG fault leaves plant radially connected through capacitor (note series and parallel resonance)



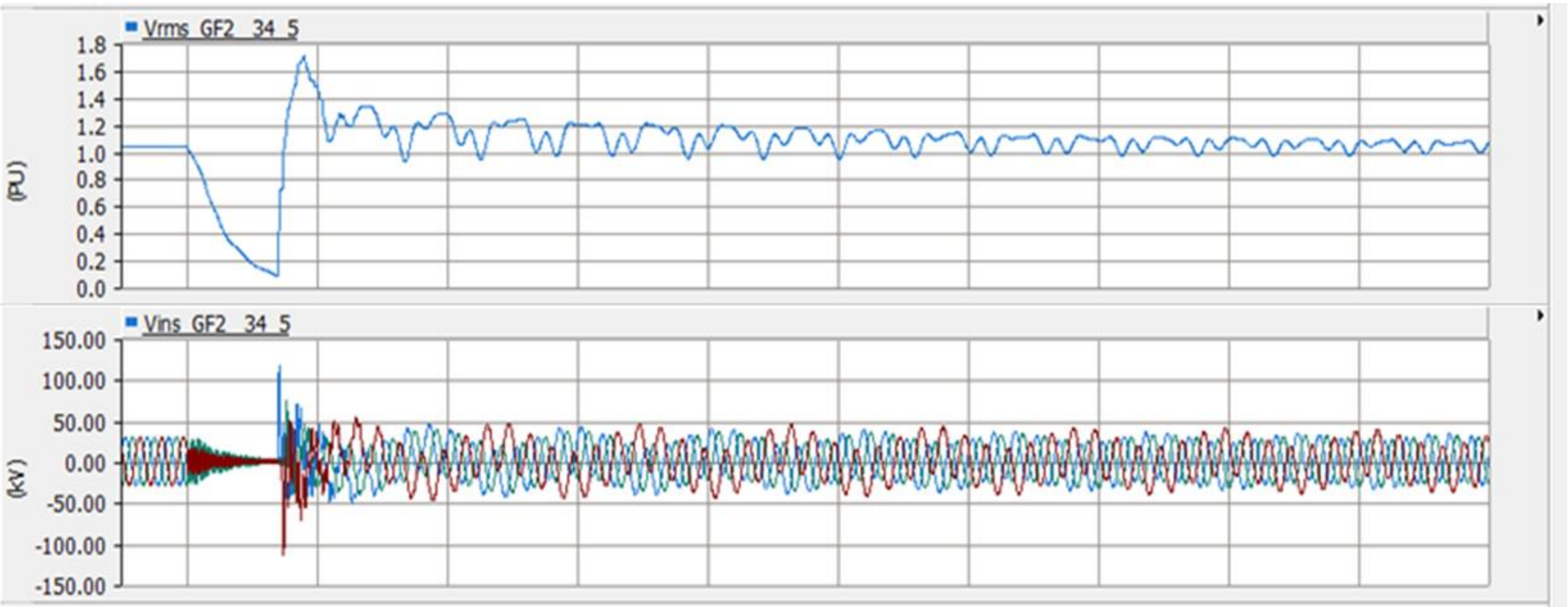
Existing System is Problematic

- Quantities ring at system resonant frequencies
- Mix of positive and negative sequence signals at resonant frequency (9Hz) result in characteristic waveshapes
- 60 Hz rms meter is trying to capture everything (not doing very well!) Note that 60 Hz quantities are not that high!



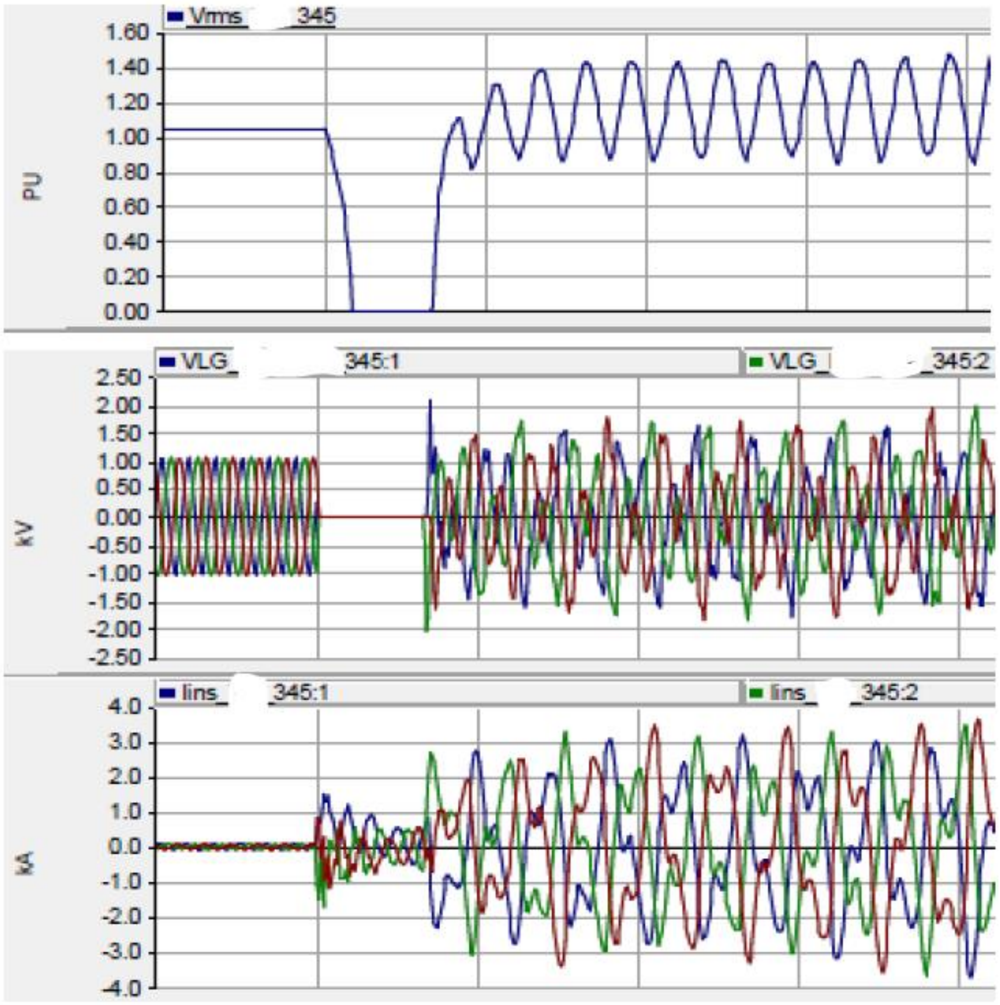
Different system, same behaviour

- Sharp and messy transient observable due to capacitor energy exchange with the system on fault clearing… high TOV, but short.
- Again, not captured well in 60 Hz RMS meter.



Adding wind makes things worse

- SSCI type behaviour causes sustained oscillations result in eventual or immediate tripping
- Very high currents in wind turbine
- Very high sustained phase voltages (note again 60 Hz component is not too high, and RMS signal is suspect)



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Is this FRT Failure?

- The plant is producing a significant amount of power, and is tripping on an N-1 fault.
- Generic RMS measurements (which are unreliable) on the existing system are *outside* PRC-24 (which is not a "ride-through" standard, but a protective relay standard).
- 60 Hz quantities are *within* PRC-24, transients are *outside* PRC-24.
- With the plant in service, some designs bring all quantities within PRC-24, and plant rides through.
- Many designs will see oscillations grow out of control, and the plants will trip on internal overcurrent, or other protections will operate due to oscillations.

What is required?

- Is it a reliability centered, qualitative, performance-based ride-through standard?
- This gets to the heart of why ride-through is important. It would look at:
  - When should ride-through be required as a non-negotiable, regardless of what the system behaviour looks like (eg. N-1 fault on an EHV system bus which causes drama through an extensive system)
  - When should FRT be discretionary based on probability or limited potential harm (eg. 3LG N-2 fault at the end of a radial line).
  - How and when should FRT be tested?
  - Is validation possible?
  - Who should pay?

What is required?

- Is it a quantitative requirement (like PRC-24, but better), so OEMs can build their equipment capability to a specification. Otherwise they are trying to hit an unknown target!
- Concern: if generic quantitative specifications are required, this is easier for OEMs, but making these metrics meet all system needs may require a high bar.
- It may leave out critical situations where FRT failure is allowed, or leave expensive capability on the table where it isn't required.

....Can we combine the two somehow?

Help us!!!

- IEEE P2800 just getting started
- PRC-024-2 revision underway
- NERC IRPTF guideline on interconnection requirements underway
  - Guideline on recommended performance from BPS-connected IBR already approved by industry.

Questions and Answers

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

IEEE Std. 1547-2018 and P2800 Updates

NERC IRPTF

February 2019

RELIABILITY | ACCOUNTABILITY

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

What You Need to Know About IEEE Std. 1547-2018

Deepak Ramasubramanian on behalf of Jens Boemer, EPRI

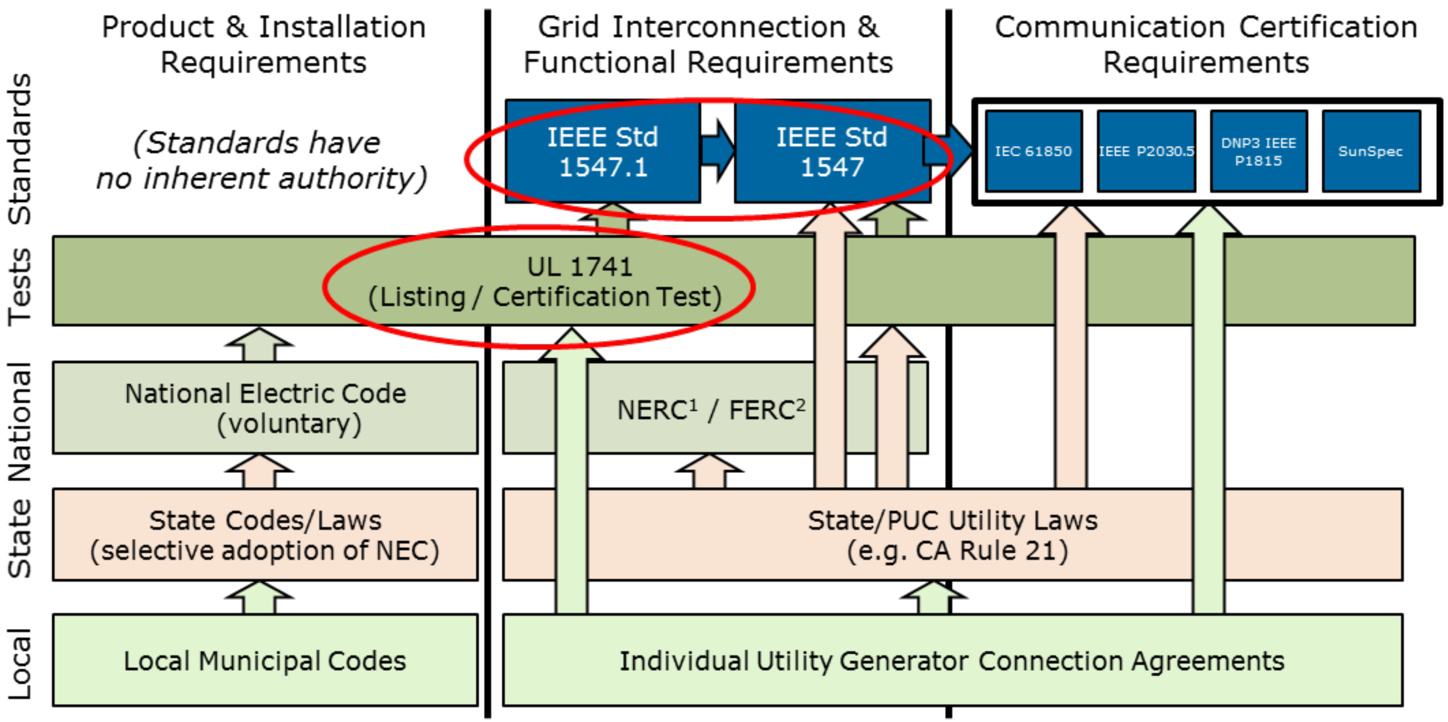
RELIABILITY | ACCOUNTABILITY




Disclaimer

- This presentation and discussion represents the authors' views and are not the formal position, explanation or position of the IEEE or the IEEE Standards Association.

Overview on North American Standards



[1] e.g., NERC PRC-024-02, [2] e.g., FERC Order No. 828

- Approval rate of >90% among 380 balloters
- IEEE 1547 is a voluntary industry standard – no inherent authority
- Requires adoption by an Authority Governing Interconnection Requirements
  - For example, a PUC, municipal or cooperative/ governing board

Example Adoption of IEEE Std 1547-2018

ISO New England

- Coordination between ISO-NE and the MA's utilities in the Massachusetts Technical Standards Review Group
- Reference to UL 1741 SA as a stopgap to verify DER ride-through capability in the interim
- Harmonization of voltage & frequency trip settings with IEEE Std 1547-2018 ranges of allowable settings

PJM Interconnection

- Two ad-hoc stakeholder workshops in 2018 for DER ride-through categories and trip settings (PJM website)
- Initiation of formal stakeholder proceedings in 2019
- Aiming at full adoption of IEEE Std 1547-2018 for jurisdictional DER by early 2020

Minnesota Public Utilities Commission

- Phase 1 (2017): Interconnection Process, Applications, Agreements
- Phase 2 (2018): Technical Requirements consistent with IEEE Std 1547-2018 (MN PUC website)
- Coordination with regional reliability coordinator, e.g., MISO

Evolution of grid support functions

IEEE Std 1547-2003

- **Shall NOT** actively regulate voltage
- **Shall** trip on abnormal voltage/frequency

IEEE Std 1547a-2014 (Amendment 1)

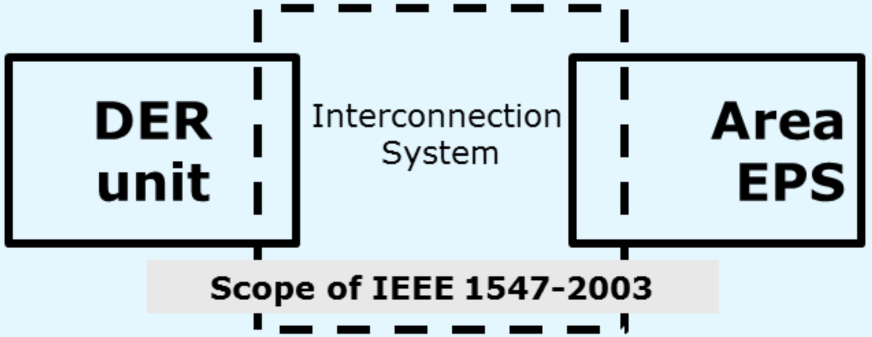
- **May** actively regulate voltage
- **May** ride through abnormal voltage or frequency
- **May** provide frequency response

IEEE Std 1547-2018

- **Shall be capable of** actively regulating voltage
- **Shall** ride through abnormal voltage/frequency
- **Shall be capable of** frequency response

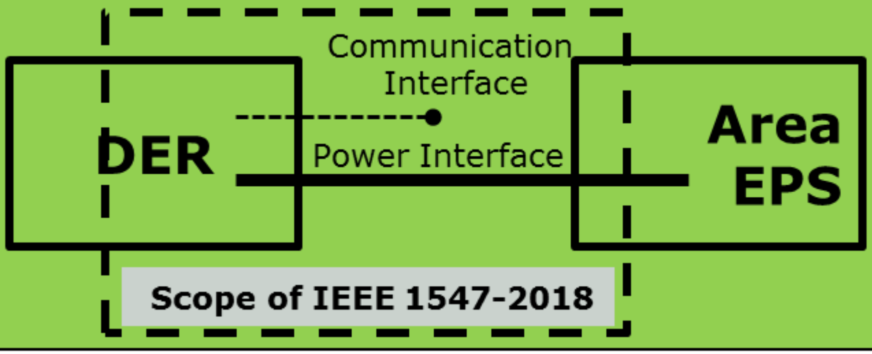
Source: NREL

Important changes in focus and coverage



IEEE Std 1547-2003

- Focused only on distribution system
- Specifications for the "interconnection system" sufficiently achieve the standard's objective.
- Meant as DER interconnection standard but mainly used for equipment listing.
- Limited to electrical requirements.



IEEE Std 1547-2018

- Focused on distribution and bulk system
- Specifications encompass the whole DER
- Equipment listing as well as plant-level verification.
- Includes both electrical as well as interoperability/communications requirements.

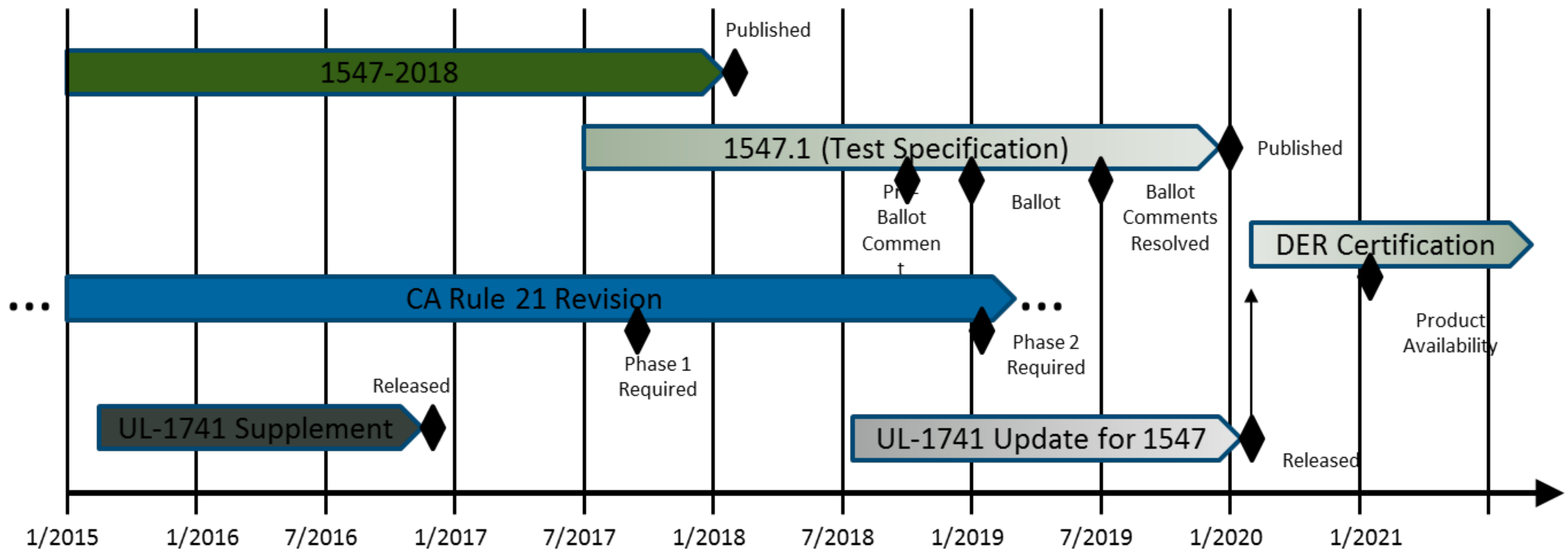
Source: EPRI

Abnormal Performance Capability

Category	Objective	Foundation
I	Essential bulk system needs and reasonably achievable by all current state-of-art DER technologies	German grid code for synchronous generator DER
II	Full coordination with bulk power system needs	Based on NERC PRC-024, adjusted for distribution voltage differences (delayed voltage recovery)
III	Ride-through designed for distribution support as well as bulk system	Based on California Rule 21 and Hawaii Rule 14H

Category II and III are sufficient for bulk system reliability.

Timeline of IEEE Std 1547-2018



Further Information

- http://sites.ieee.org/sagroups-scc21/standards/1547rev/
  - General
  - Scope
  - Purpose
  - Leadership Team
  - **Sources**
    - ✓ **discounted copies**
  - **SCC21-Reviewed Slide Decks Available for Interested Lecturers**
  - **Further Reading**
  - **Webinars**

- **Please submit further reading suggestions via the web form!**

IEEE P2800 Update

Bob Cummings, NERC

RELIABILITY | ACCOUNTABILITY




Filling the Gaps in North American Standards for IBR

		Performance	Test & Verification & Model Validation
BES[1]	BPS	• FERC Orders • NERC Reliability Standards & Guidelines IEEE P2800	• NERC compliance monitoring & enforcement IEEE P2800.1
	BPS	• Not available IEEE P2800	• Not available IEEE P2800.1
DER[2]		• IEEE Std 1547-2018 ✓	• IEEE P1547.1 • Ul 1741 (SA) • IEEE ICAP Work in Progress

[1] NERC definition of Bulk Electric System: ≥100 kV with gross individual / aggregate nameplate rating greater than 20 MVA / 75 MVA

[2] DER connected at typical (radial) primary and secondary voltage levels

IEEE standards are voluntary industry standards and must be adopted by the appropriate authority to become mandatory.

IEEE P2800 Standard

Scope:

This standard establishes the recommended **interconnection capability and performance criteria** for inverter-based resources interconnected with transmission and networked sub-transmission systems. Included in this standard are recommendations on performance for reliable integration of inverter-based resources into the bulk power system, including, but not limited to, **voltage and frequency ride-through**, active power control, reactive power control, dynamic active power support under abnormal frequency conditions, **dynamic voltage support under abnormal voltage conditions**, power quality, **negative sequence current injection**, and system protection.

Related activities:

IEC initiative to develop a single framework for connecting and controlling renewables. Contact: Charlie Smith, Charlie@esig.energy , U.S. TA for SC 8A.

Clarifications of the Scope

- Voluntary standard, requires reference by responsible parties', e.g., interconnection requirements / agreements
  - Candidate parties are transmission owners, state regulators, NERC, and FERC
- Technical minimum requirements, intention is that responsible parties can specify additional requirements
  - Some participants see a risk that it may be regarded as exhaustive requirements
  - Strive for balance between the common denominator and exhaustive requirements
  - May want to consider tiered requirements by use of "performance categories"
- Only "inverter-based" resources, e.g., wind power, solar photovoltaic, energy storage
  - Some participants suggested renaming to "inverter-coupled"
  - "Type 3" wind turbines (doubly-fed induction generators) are in scope
- Applicable to transmission and meshed sub-transmission grids (broad BPS definition)
  - May need different set of requirements for transmission and sub-transmission

More than 230+ Interested Parties Kickoff Meeting

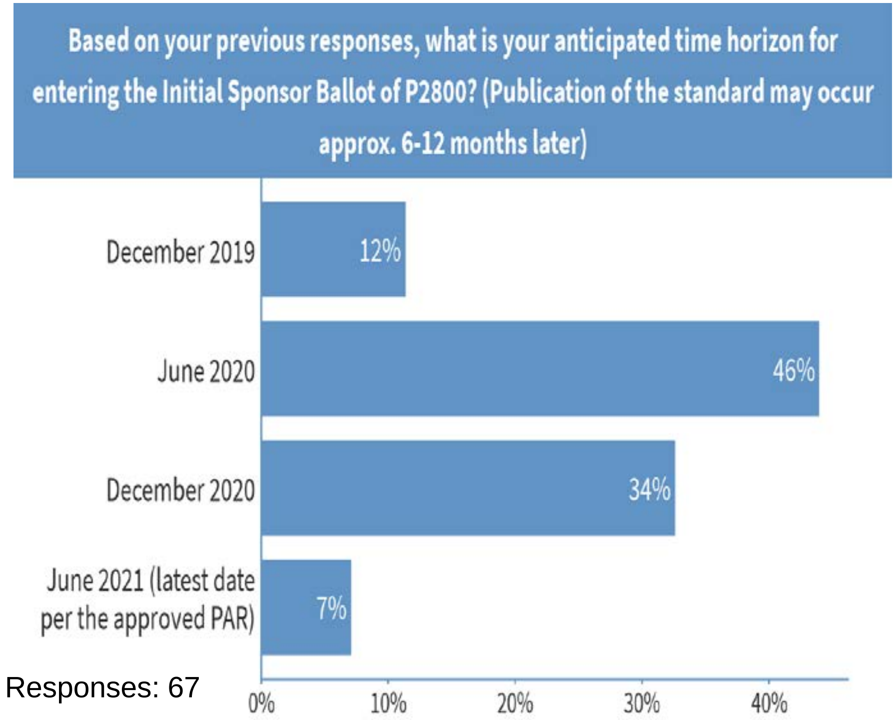
AEP	DNV GL	ESC Eng. Inc.	MEPPI	PEACE®	SouthernCo	Opal-RT	GridLab
AMSC	DOE	FERC	MISO	PJM	Tesla	LADWP	Entergy
AWEA	Dominion	First Solar	National Grid	Power Grid Eng. LLC	TVA	FuelCell Energy	Shell
Beckwith Electric	Duke Energy	GE	NERC	S&C Electric Co.	University of Auburn	Xanthus Consulting	…
Bernhard Ernst Energy Consulting	Electrotek Concepts	Hydro One	NextEra Energy	SANDIA	University of North Carolina	Seminole Electric Cooperative	
Brush Electric Machines, Ltd.	Enercon	Hydro Quebec	NREL	Sargent Lundy	WES Consulting, LLC	INL	
China State Grid	ESIG	Invenergy LLC	NV Energy	Seattle City Light	Western Energy Board	NYISO	
Cinch, Inc.	EnerNex	IREQ	Open Access Technology Intrntl.	Siemens	Wichita University	SCS Transmission Planning	
ComEd	EPRI	ISO New England Inc.	Outback Power	SMA	XcelEnergy	Avista	
ComRent	ERCOT	Leidos Engineering	Pacific Corp	Southern	XM Columbia	The University of Alabama	

IEEE P2800 Leadership Team

Role	Name	Affiliation	Stakeholder Group	Liaison
Chair	Jens C. Boemer	EPRI	Academic/Research	EDP&G, SCC21
Secretary	Wesley Baker	Power Grid Eng.	Service Provider/ Consulting	EMC, IRPTF
Vice-Chair	Bob Cummings	NERC	Regulatory and Governmental Bodies	NERC IRPTF
Vice-Chair	Kevin Collins	FirstSolar	Users, Industrial	NERC IRPTF
Vice-Chair	Babak Enayati	NationalGrid	Stakeholders represented in IEEE Power & Energy Society	T&D, SCC21, PES GovBrd
Vice-Chair	Ross Guttromson	SANDIA National Lab	Academic/Research	DOE
Vice-Chair	Chenhui Niu	State Grid Corporation of China	Stakeholders represented in IEEE P2800.1 Working Group	IEEE P2800.1, IEC SC8A
Vice-Chair	Manish Patel	Southern Company	Utility, Transmission	PSRC, IRPTF

Anticipated Timeline and Next Steps

- Stakeholders suggested to accelerate the proposed timeline by 6 months
  - ✓ Enter initial ballot in June 2020?
- Next step is for the P2800 Leadership Team to develop a strawman based on
  - ✓ IEEE Std 1547-2018 (structure, terminology)
  - ✓ NERC IRPTF Reliability Guideline (specifications)
- Kick off Sub-WGs once the strawman is available



Tentative Sub-Working Groups

I. Overall Document
II. General Requirements
III. Active Power – Frequency Control
IV. Reactive Power – Voltage Control
V. Low Short-Circuit Power VI. Power Quality
VI. Ride-Through Capability Requirements
VII. Ride-Through Performance Requirements
VIII. Inverter-Based Resource Protection
IX. Modeling & Validation
X. Measurement Data and Performance Monitoring*
XI. Interoperability, information exchange, information models, and protocols*
XII. Tests and verification requirements

- * May be merged with another Sub-WG

- Sub-WG scoping is currently underway
- If you are interested, please sign up at https://www.surveymonkey.com/r/MRW9SLQ
- Plan to kick off Sub-WG in the February/March 2019 timeframe (likely bi-weekly calls)

Next Meetings

- Coordinate with NERC IRPTF Meeting Schedule
- Allow for remote participation via WebEx
- Preferably no registration fee, as long as facilities and catering is provided in-kind

NERC IRPTF	IEEE P2800	Location	Comment
Tue/Wed, May 21-22, 2019	Wed/Thu, May 22-23, 2019	Atlanta, GA (NERC office)	Confirmed
Wed/Thu, September 4-5, 2019	Tue/Wed, September 3-4, 2019	Salt Lake City, UT (WECC)	*May be moved to PSRC Meeting Sep 16 – 19, 2019, in Denver, CO*
Tue/Wed, December 3-4, 2019	Wed/Thu, December 4-5, 2019	Phoenix, AZ (FirstSolar office)	Confirmed

Contacts

- IEEE P2800
  - Jens C Boemer
    j.c.boemer@ieee.org
  - Wes Baker
    wbaker@powergridmail.com

- IEEE P2800.1
  - Chenhui Niu
    niuchenhui@sgepri.sgcc.com.cn
  - Jens C Boemer
    j.c.boemer@ieee.org

Questions and Answers

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Inverter-Based Resource Performance Task Force Perspectives

Allen Schriver, NextEra Energy

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




IRPTF Scope

- Purpose:
  - **explore the performance characteristics** of utility-scale inverter-based resources (e.g., solar photovoltaic (PV) and wind power resources) directly connected to the bulk power system (BPS)…
- **Recommended performance characteristics** will be developed along with other recommendations related to inverter-based resource performance, analysis, and modeling.
- Technical materials intended to **support the utility industry, Generator Owners with inverter-based resources, and equipment manufacturers by clearly articulating recommended performance characteristics**, ensuring reliability through detailed system studies, and ensuring dynamic modeling capability and practices that support BPS reliability.

Deliverables

- Deliverables
  - Reliability guideline on inverter-based resource performance addressing, at a minimum, the topics listed above
  - Recommendations on inverter-based resource performance and any modifications to NERC Reliability Standards related to the control and dynamic performance of these resources during abnormal grid conditions
  - Detailed studies of any potential reliability risks under high penetration of inverter-based resource (particularly solar PV) given the findings from the Blue Cut Fire event and other related grid disturbances involving fault-induced solar PV tripping
  - Webinars and technical workshops to share findings, technical analysis, and lessons learned to support information sharing across North America
  - Other activities as directed by the NERC Planning Committee (PC) and Operating Committee (OC) in coordination with the Standards Committee

What We Have Accomplished

- System Simulation Analysis
- Reliability Guideline
- NERC Alerts
- PRC-024 SAR
- PRC-019 SAR and Implementation Guidance Document
- Potential Whitepaper on Disturbance Monitoring

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

What We Plan To Complete

- Reliability Guideline : Recommended Improvements to Interconnection Agreements for Inverter-Based Resources
- White Paper: Terminology for Fast Frequency Response and Low Inertia Systems – NERC IRPTF Perspectives
- Monitor and Support IEEE P2800: Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems
- Coordinated review of NERC Reliability Standards

Discussion

- Are we missing anything?

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

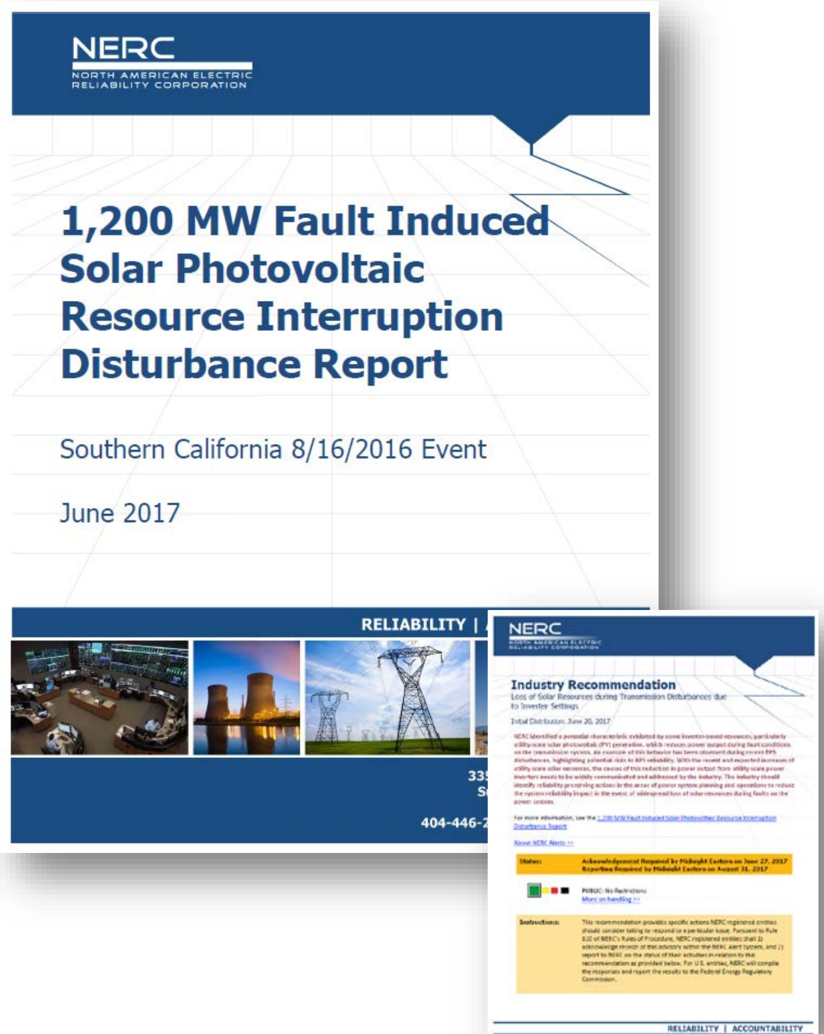
Recommended IBR Performance – Part 1

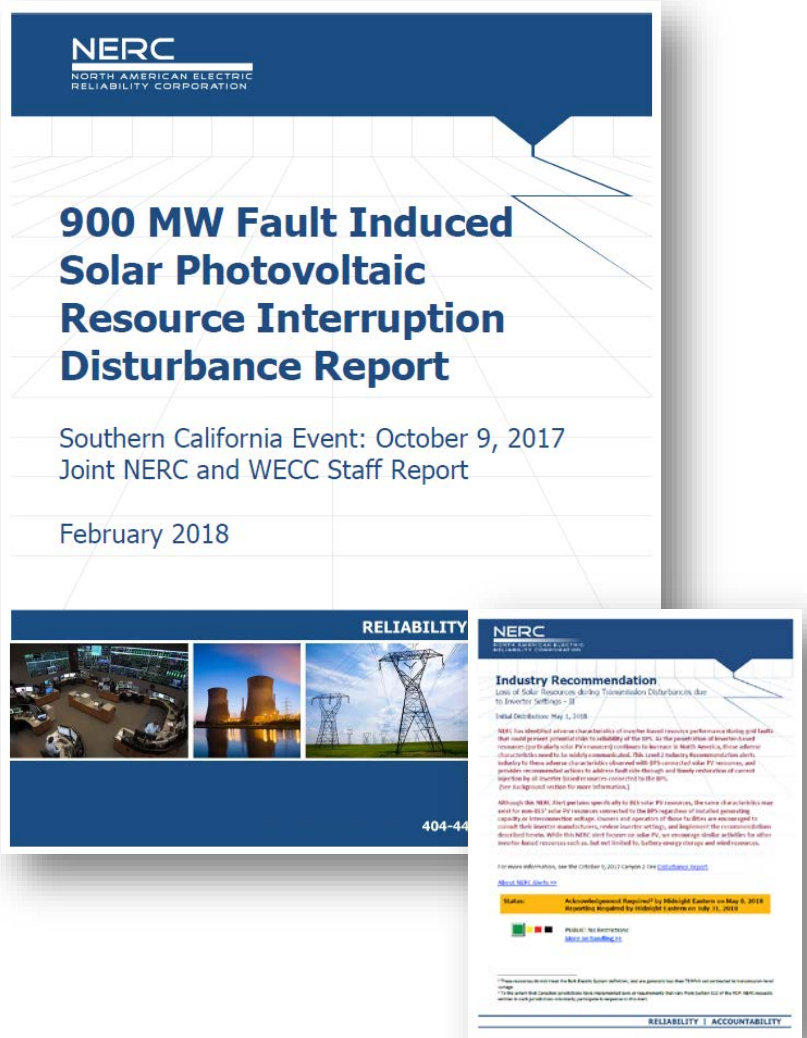
NERC IRPTF Meeting
February 2019

RELIABILITY | ACCOUNTABILITY

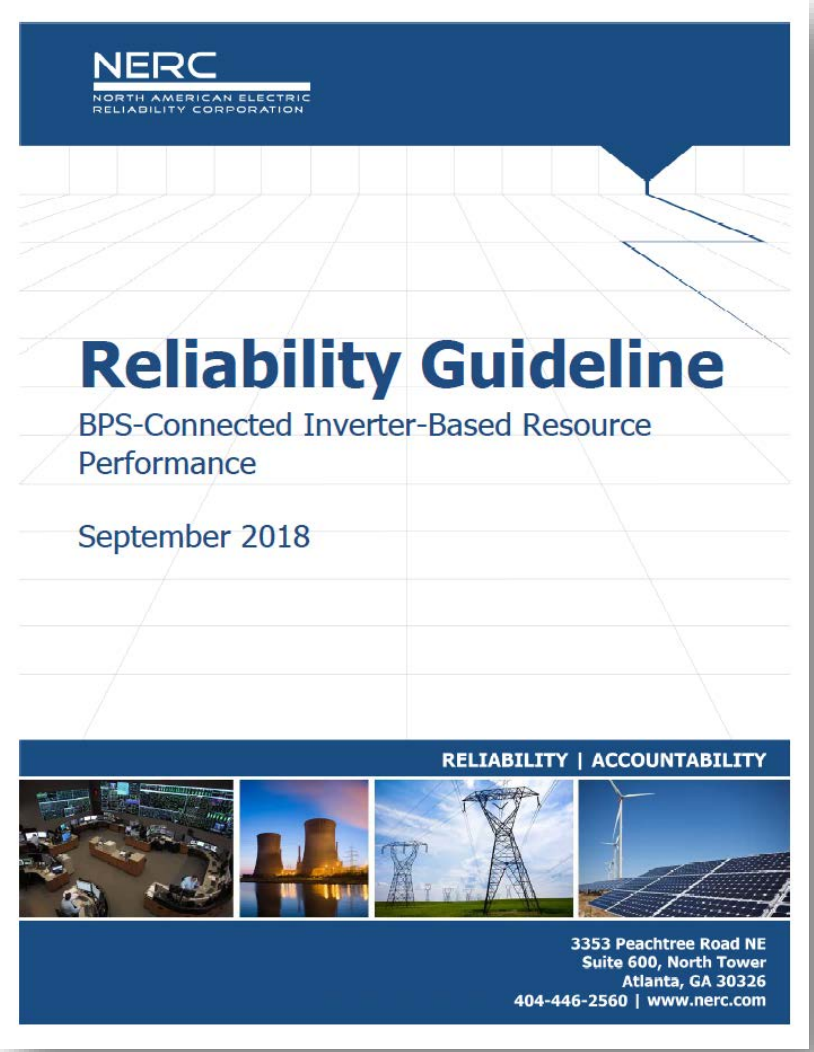



Background: Blue Cut Fire Disturbance Reports & Alerts





- Topics:
  - Momentary cessation
  - Active power-frequency control
  - Reactive power-voltage control
  - Protection aspects
  - Relation with IEEE 1547 and UL 1741
  - Measurement data and monitoring
  - Other related topics



https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

What is Momentary Cessation?

Lou Fonte, California ISO

NERC IRPTF Meeting

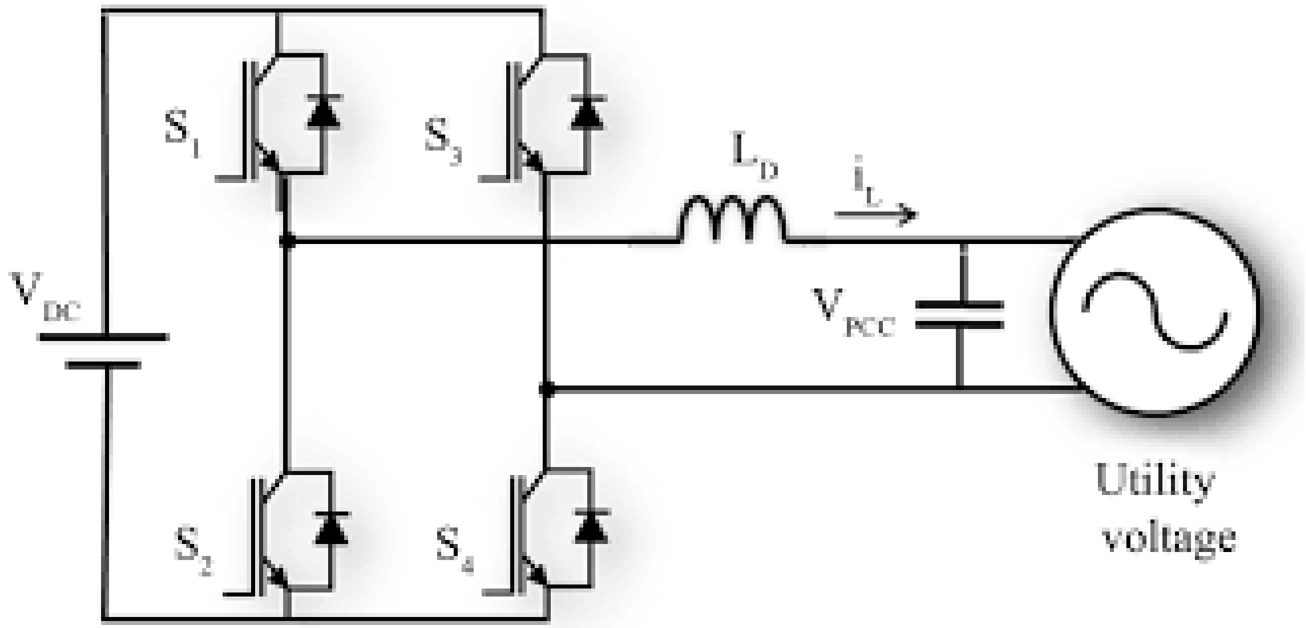
RELIABILITY | ACCOUNTABILITY




Single Phase Inverter Simplified Circuit Diagram

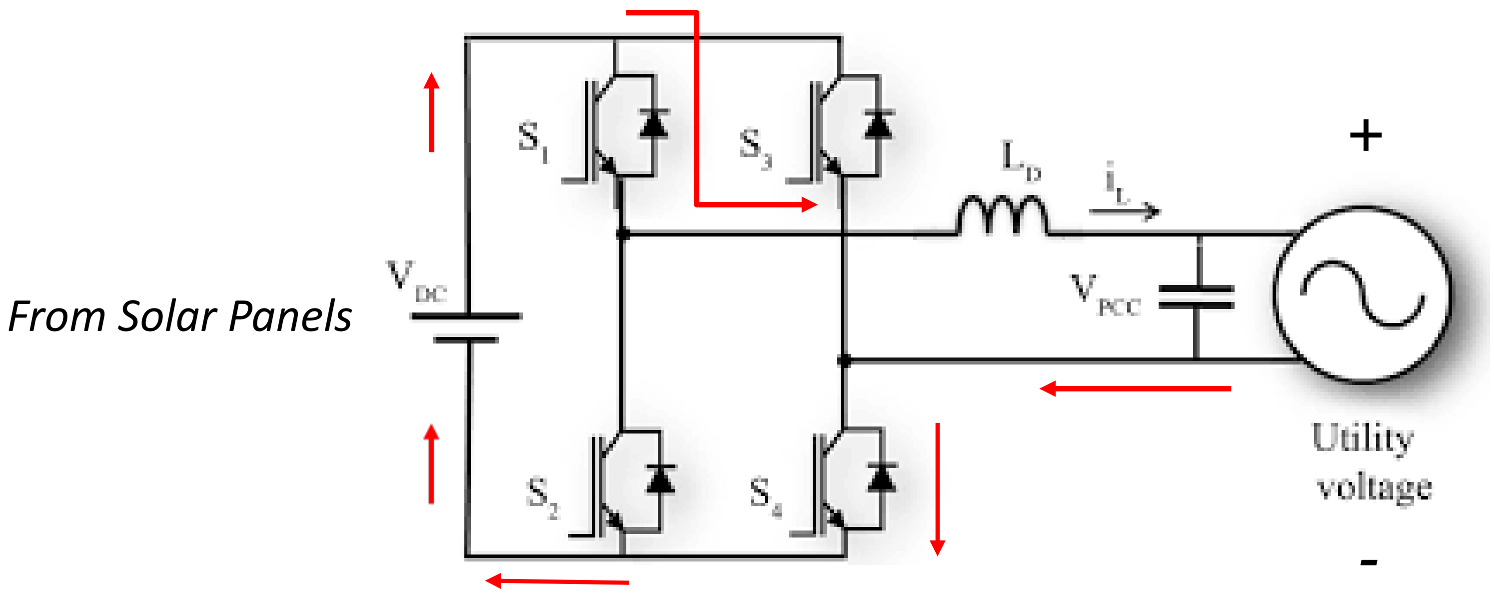
S1, S2, S3 and S4 are IGBTs (Insulated Gate Bipolar Transistors)

From Solar Panels



Single Phase Inverter Simplified Circuit Diagram

IGBTs S1 and S4 conducting

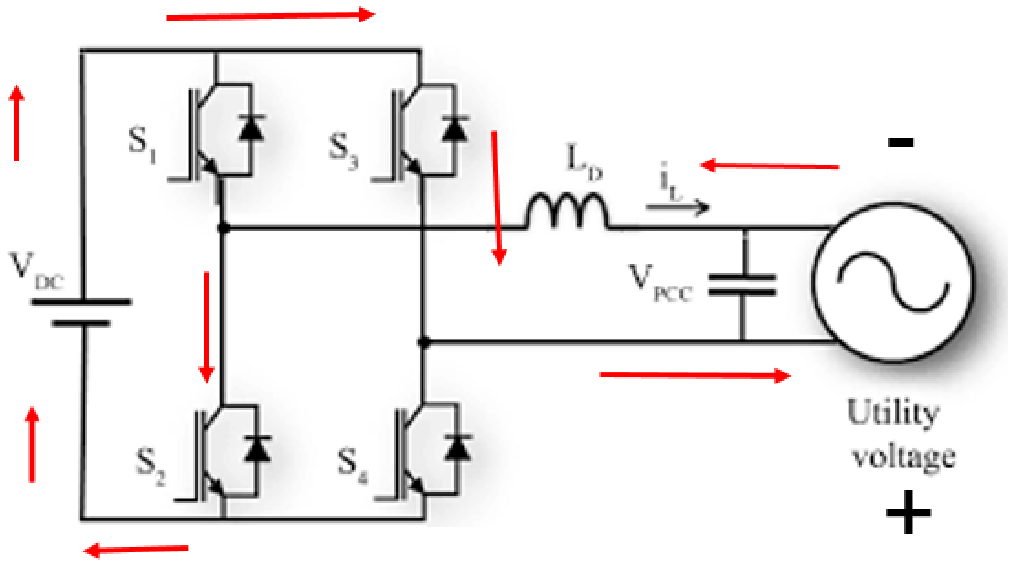


When the AC system voltage is ***POSITIVE*** *(i.e. V greater than zero)*

Single Phase Inverter Simplified Circuit Diagram

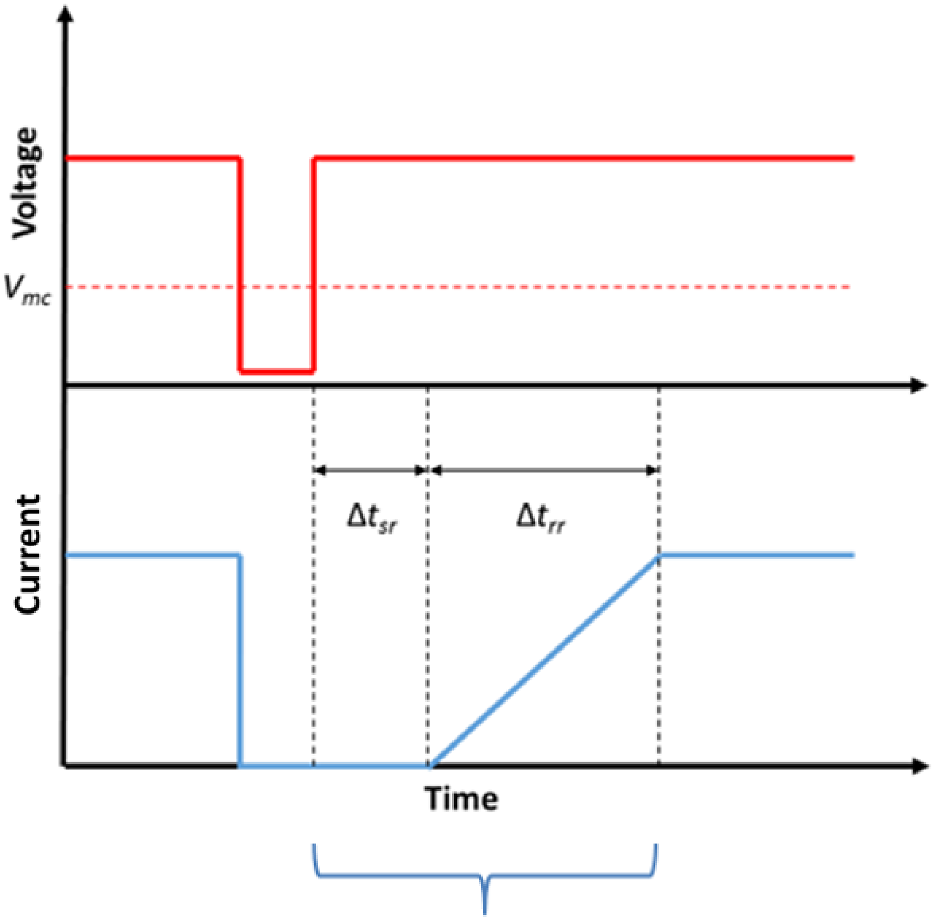
IGBTs S3 and S2 conducting

From Solar Panels



When the AC system voltage is **NEGATIVE** (i.e. V less than zero)

Momentary Cessation



Total inverter return time after voltage recovers.
NERC Alert 2 recommends this time not exceed 1 second.

V_{mc}: voltage threshold where momentary cessation occurs

Δt_{sr} : delay of current injection after voltage recovers

Δt_{rr} : ramp duration of recovery in current injection

Recommendations:

1. **Eliminate momentary cessation to the greatest extent possible**
2. **If momentary cessation cannot be eliminated, total time delay to return should not exceed 1 second**
3. **Decrease momentary cessation voltage threshold Vmc to lowest possible value**

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Active Power-Frequency Controls

Siddharth Pant, General Electric

NERC IRPTF Meeting

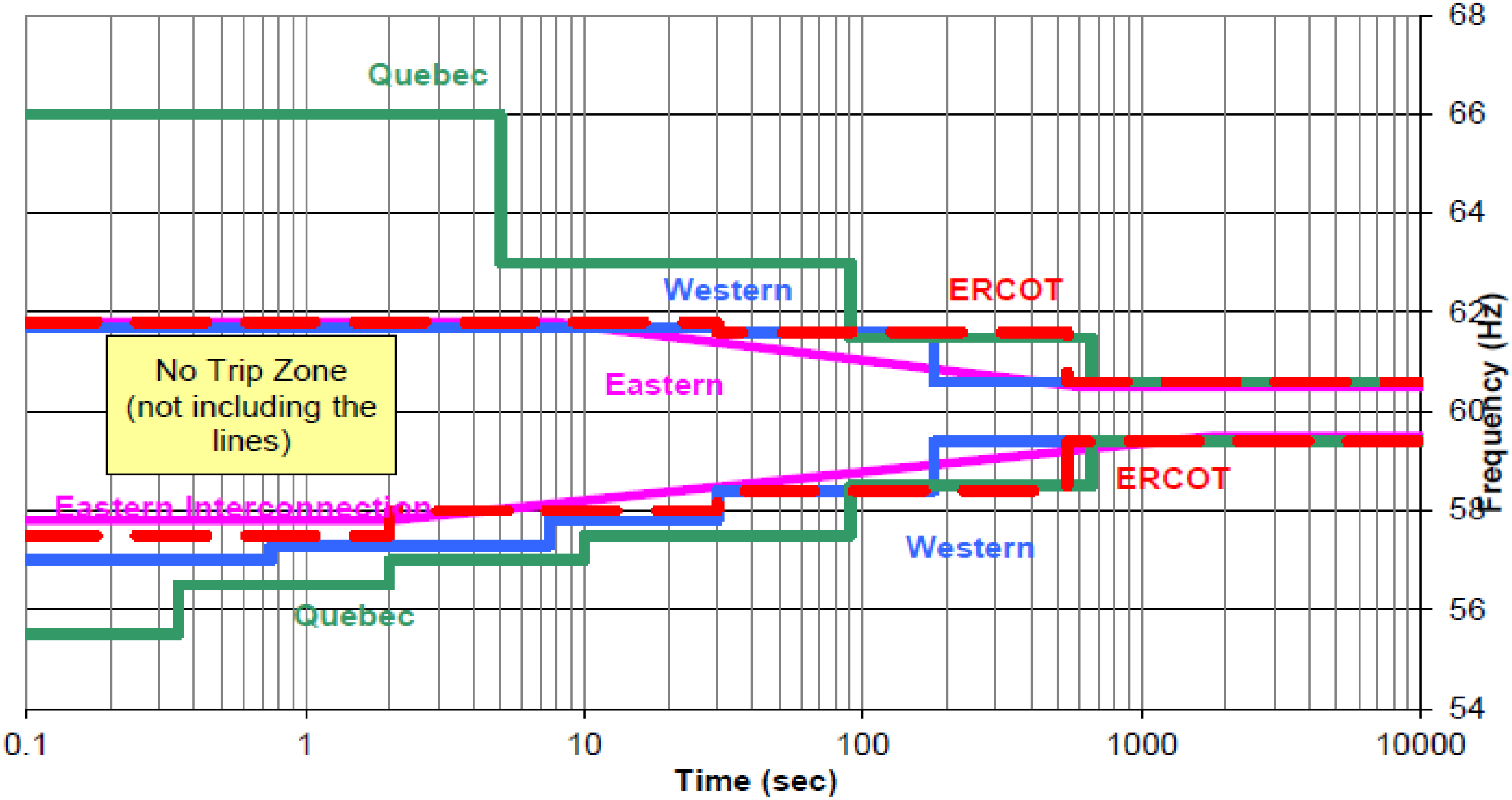
RELIABILITY | ACCOUNTABILITY




Applicability

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



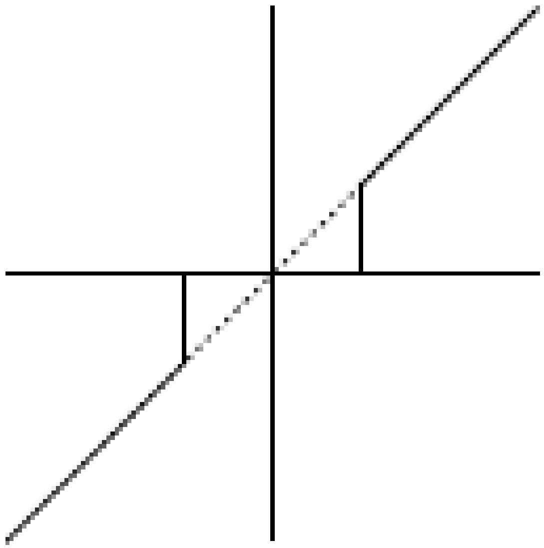
Active Power-Frequency Controls

- Inverter-based resources should have active power/frequency controls that adhere to FERC Order No. 842 and regional requirements, where applicable.
- All inverter-based resources should include a governor, or equivalent control that is responsive to changes in frequency. Reserving generation headroom to provide response to underfrequency events is not required.
- Frequency should be calculated over a period of time (e.g., 3-6 cycles).
- Adjustable proportional droop with a default value of 5%. The droop response should include capability to respond both in the underfrequency and overfrequency directions.
- Non-step adjustable deadband with a default value not to exceed +/- 0.036 Hz.
- May have a hysteresis where linear droop meets the deadband, not to exceed +/- 0.005 Hz.
- May be implemented at the inverter level or plant level.

Deadband Types

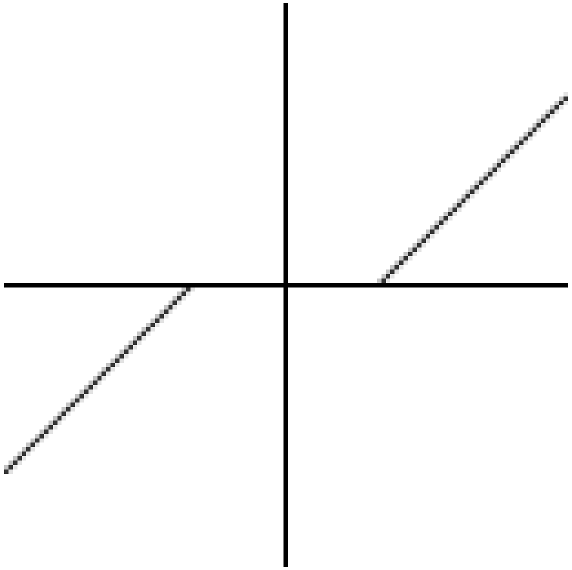
Step deadband

Type 1



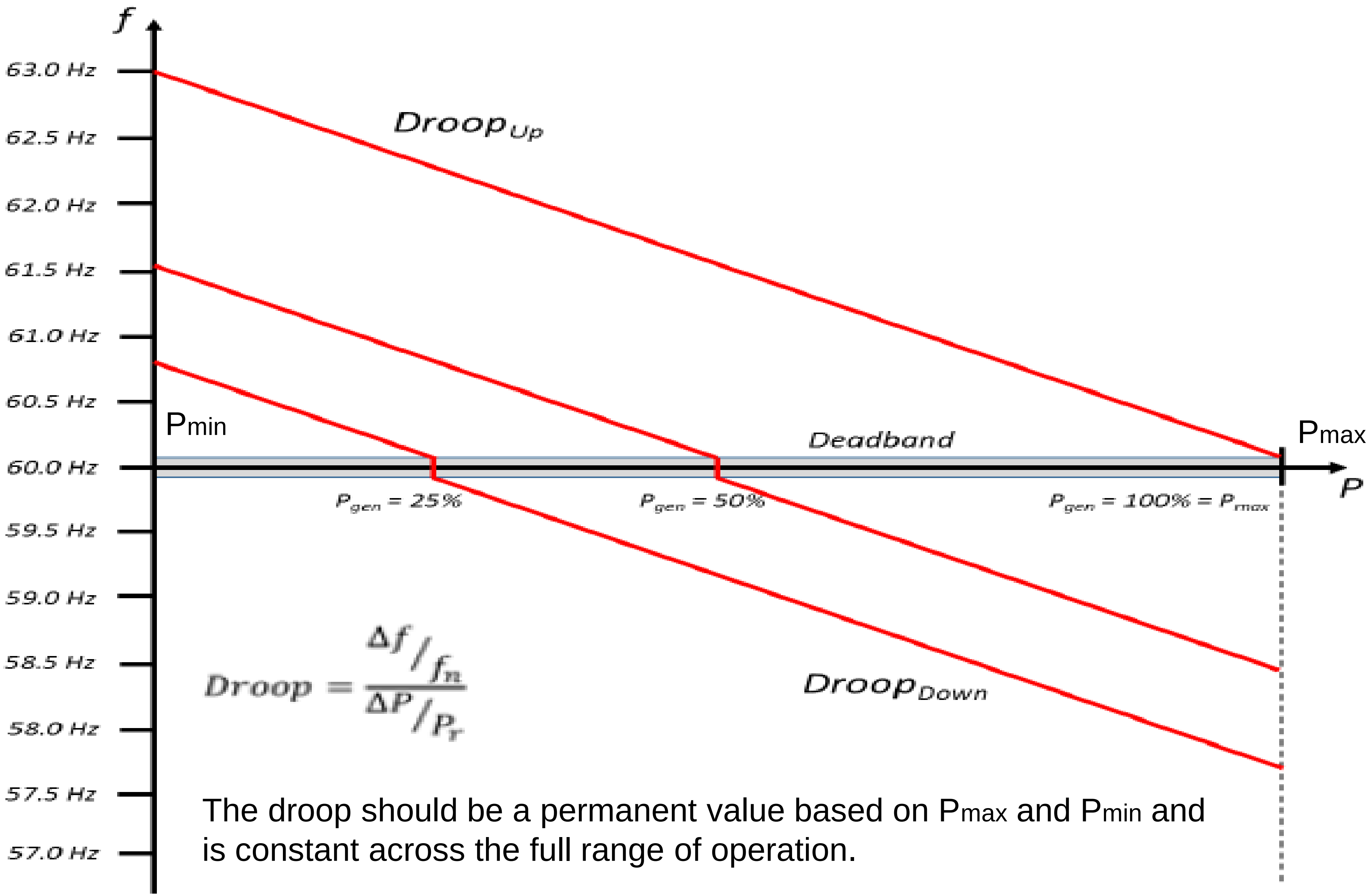
Non-step deadband

Type 2



Source: IEEE PES-TR1 Dynamic Models for Turbine-governors in Power System Studies

Steady-state Active Power-Frequency



The droop should be a permanent value based on Pmax and Pmin and is constant across the full range of operation.

Dynamic Active Power-Frequency

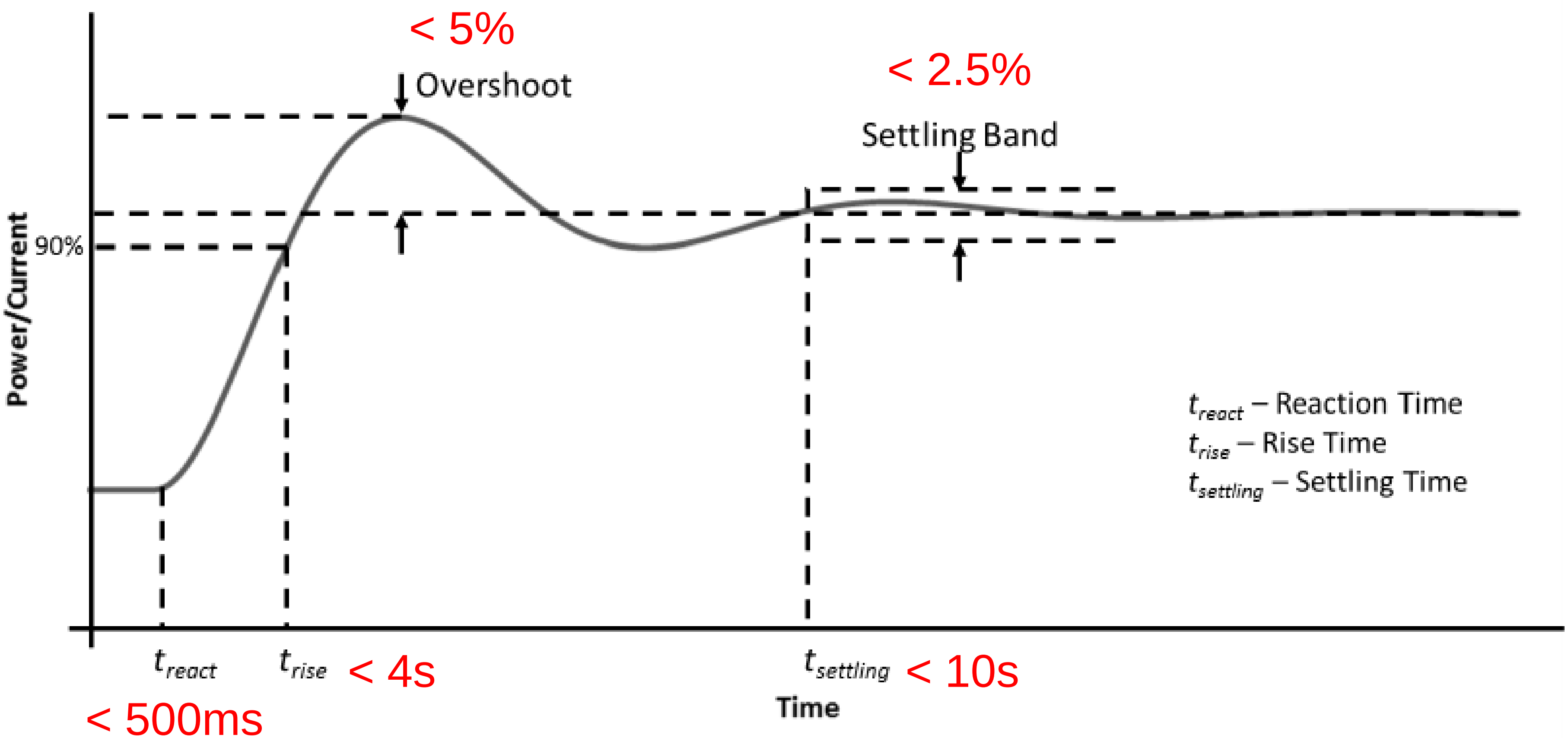


Figure F.1: Power/Current Response Characteristic

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Dynamic Active Power-Frequency

Table A.2: Dynamic Active Power-Frequency Performance		
Parameter	**Description**	**Performance Target**
For a step change in frequency at the POM of the inverter-based resource…		
Reaction Time	Time between the step change in frequency and the time when the resource active power output begins responding to the change[104]	< 500 ms
Rise Time	Time in which the resource has reached 90% of the new steady-state (target) active power output command	< 4 sec
Settling Time	Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power output command	< 10 seconds
Overshoot	Percentage of rated active power output that the resource can exceed while reaching the settling band	< 5%**
Settling Band	Percentage of rated active power output that the resource should settle to within the settling time	< 2.5%**

** Percentage based on final (expected) settling value

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reactive Power-Voltage Controls – Small Signal

Deepak Ramasubramanian, Electric Power Research Institute

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY

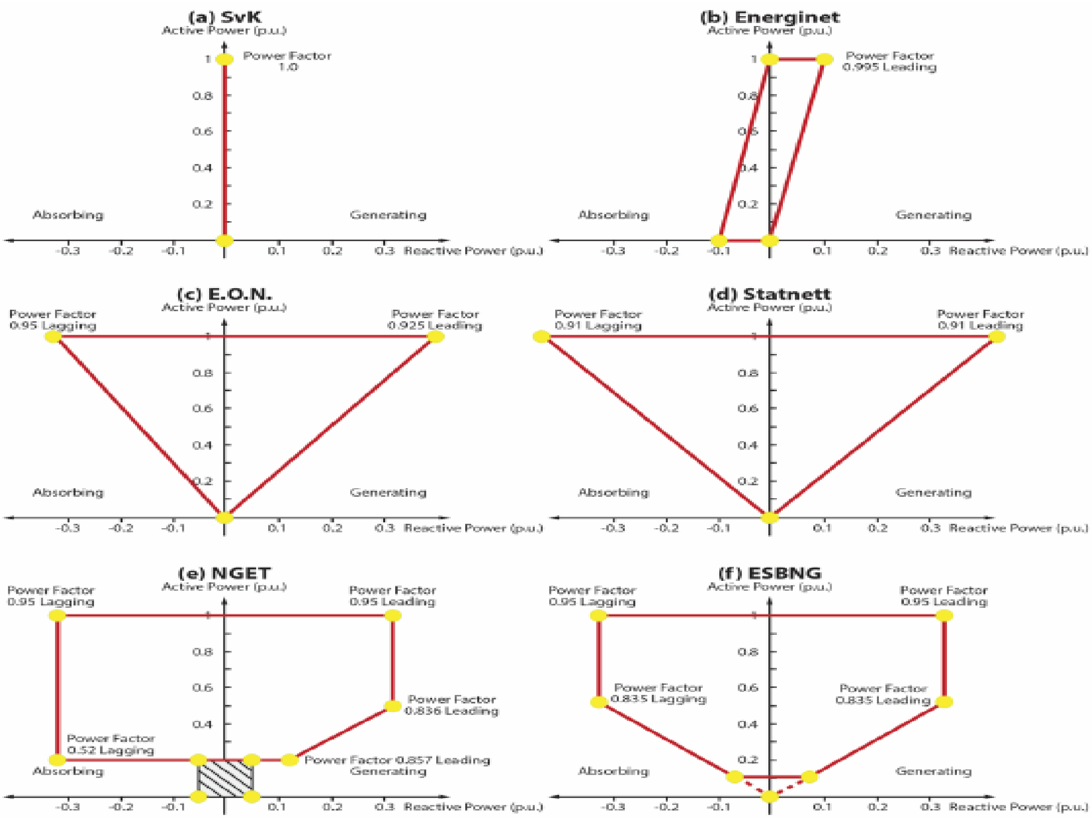


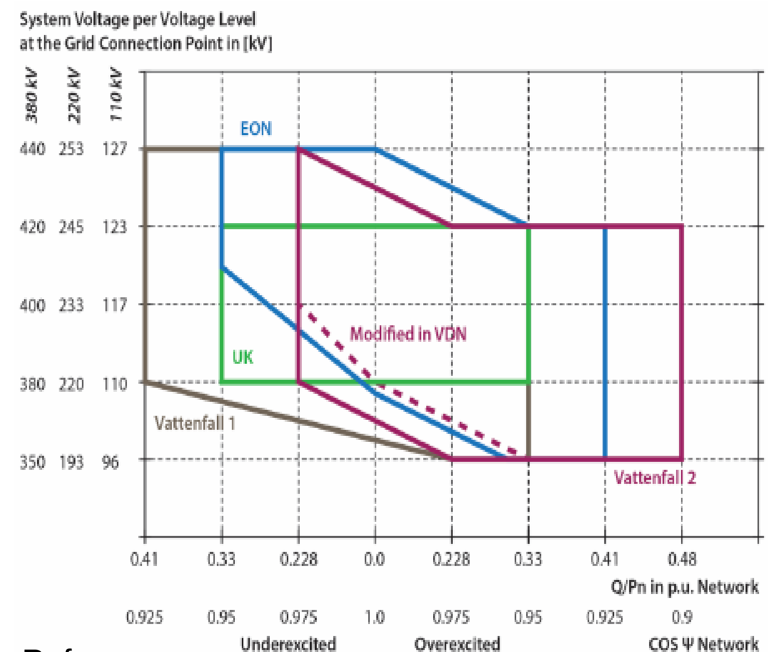

FERC Order 827

- Precedence has now been set by FERC Order 827 to mandate capability for reactive power – voltage controls:
  - Power Factor Range: Within a range of 0.95 leading to 0.95 lagging at the high-side generation bus, continuous reactive power must be provided.
  - Most of the reactive power must come from the inverters. However, recognizing that the inverter can be far away from the high side bus, static reactive devices (e.g. capacitors) can be used to make up for the losses
  - The power factor range must be met even when the source producing 0 MW.

Is this unusual?

- Reactive power – voltage control requirements have been present in Europe for quite some time now.

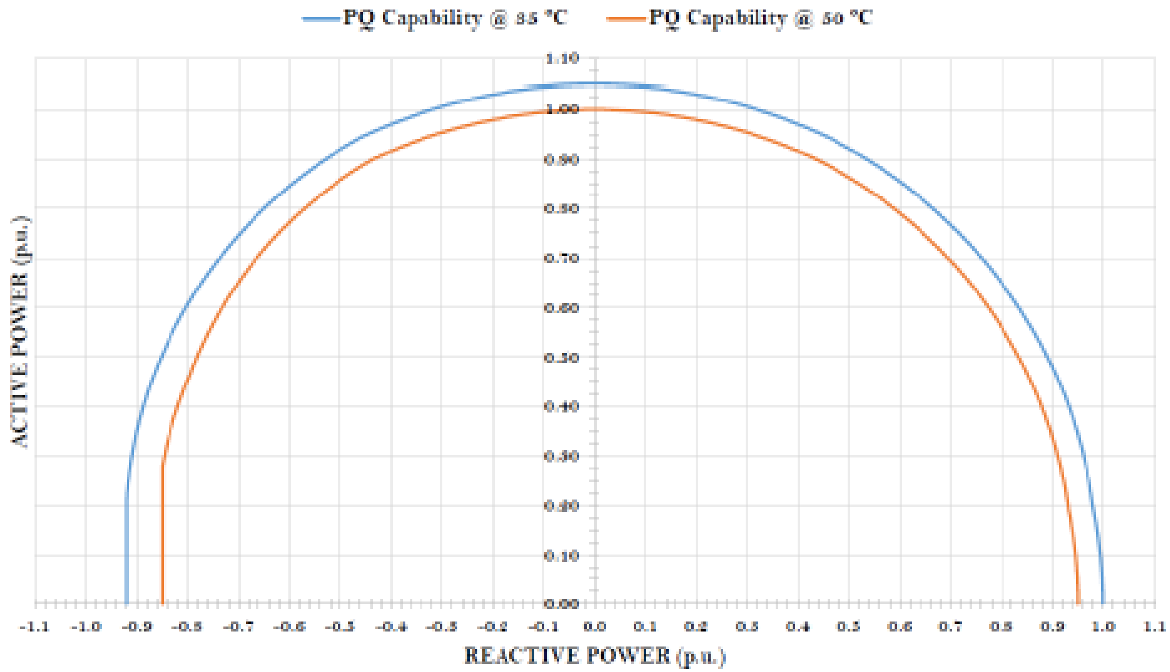




References:
1: The European Wind Energy Association, "Generic Grid Code Format for Wind Power Plants," Nov 2009.
2: *Global Interconnection Requirements for Variable and Distributed Generation: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002011528

Can an inverter resource provide this?

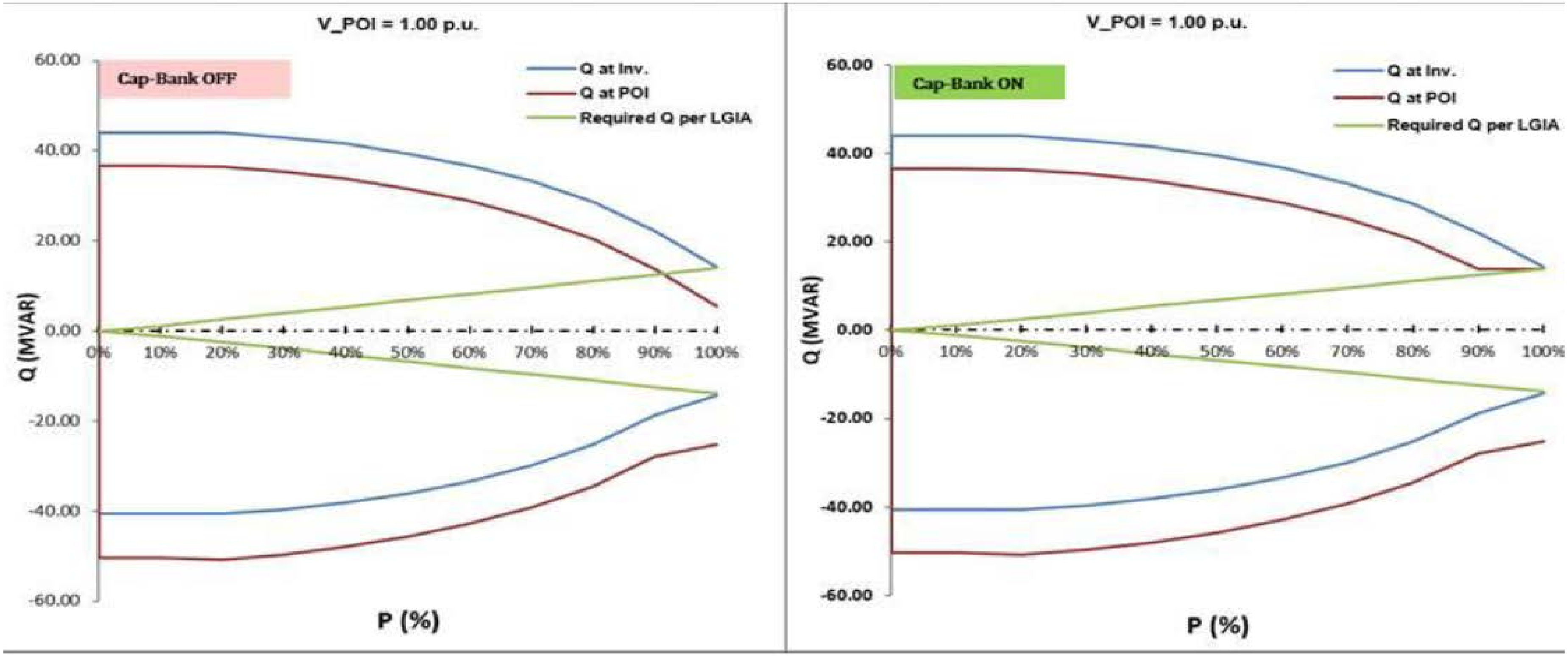
- Inverters have capability curves similar to synchronous machines.
- But, it must be kept in mind that an inverter is largely a current source, and the power output is a product of current * voltage



Inverter P-Q Capability—Vendor 1 [Source: First Solar]

How does this change by the time one reaches the high side bus?

- At close of maximum active power, losses will be more, and inverter reactive power headroom will be less
  - Static devices like capacitor banks are used.



Plant Capability Curve Example 2 [Source: First Solar]

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

What about the available additional capability at lower active power levels?

- As per the FERC Order 827, at lower active power levels, as long as the power factor is maintained, things are good.
- However, this added available capability should be made use of, if possible:
  - Unless there is a protection limitation in the plant
  - Unless there is a stability limitation

What is a Small Signal Event?

- Normal switching events, regular changes in generation and load (no trips)
- Voltage stays within the continuous operating range of the plant – say between 0.9pu and 1.1pu
- The plant controller, which is inherently slower than the inverter controller, is still in-charge.
  - If there is no plant controller, then the inverter will not enter a ride through mode when a small signal event occurs

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

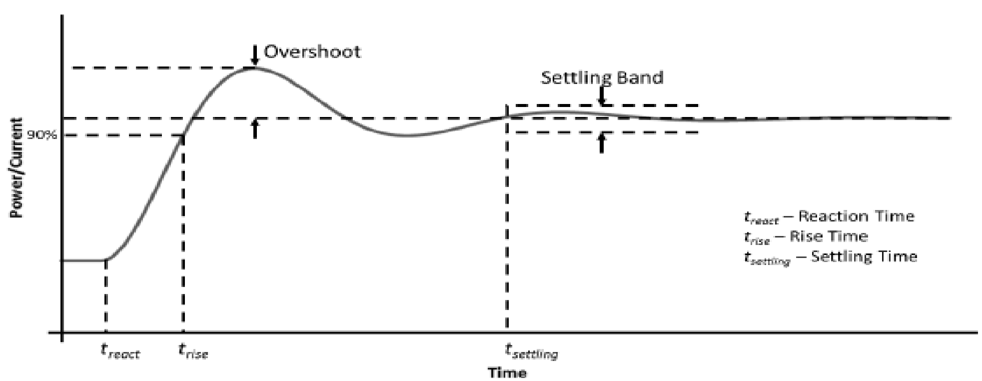
Voltage Control for Small Signal Events

- It is generally recommended that the inverter based plant have an automatic voltage regulator in service
  - A tariff amendment that has already been proposed by at least CAISO
- If there are no other voltage control devices regulating the same bus, then operate in automatic voltage control.
- If there are other plants/devices controlling the same point, then, use reactive power – voltage droop to ensure that the controllers of these devices do not fight with each other
  - Conceptually similar to the reason as to why active power – frequency droop is used in the system.
- Should be applicable during the recovery period after a large disturbance.

Recommended Performance

Table 3.1: Small Disturbance Reactive Power-Voltage Performance		
Parameter	**Description**	**Performance Target**
For a step change in voltage at the POM of the inverter-based resource…		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change[47]	< 500 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90 percent of its final value	< 1–30 sec**
Overshoot	Percentage of rated reactive power output that the resource can exceed while reaching the settling band	< 5 percent***

* Reactive power response to change in POM voltage should occur with no intentional time delay.
** Depends on whether local inverter terminal voltage control is enabled, any local requirements, and system strength (response should be stable for the lowest possible grid strength). Response time may be modified based on studied system characteristics.
*** Any overshoot in reactive power response should not cause BPS voltages to exceed acceptable voltage limits.



What if this is not possible..?

- Inverters responding to slow commands from plant controller would not support voltage stability in steady-state and contingency recovery.
- Inverters could be set on local voltage control with supervisory oversight from a much slower plant controller
- Even if this is not possible, then have fast non-AVR voltage control.

Takeaways

- Inverter resources should operate in closed loop automatic voltage control
  - This would help support voltage regulation and voltage stability
- Either the plant level controller can be fast, or the local inverter controller would have to be fast
- However, a fast controller should not cause transient voltage overshoot or any other forms of system instability.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Fault Response Behavior

Min Lwin, GE Energy Consulting
Matthew Richwine, Telos Energy

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY

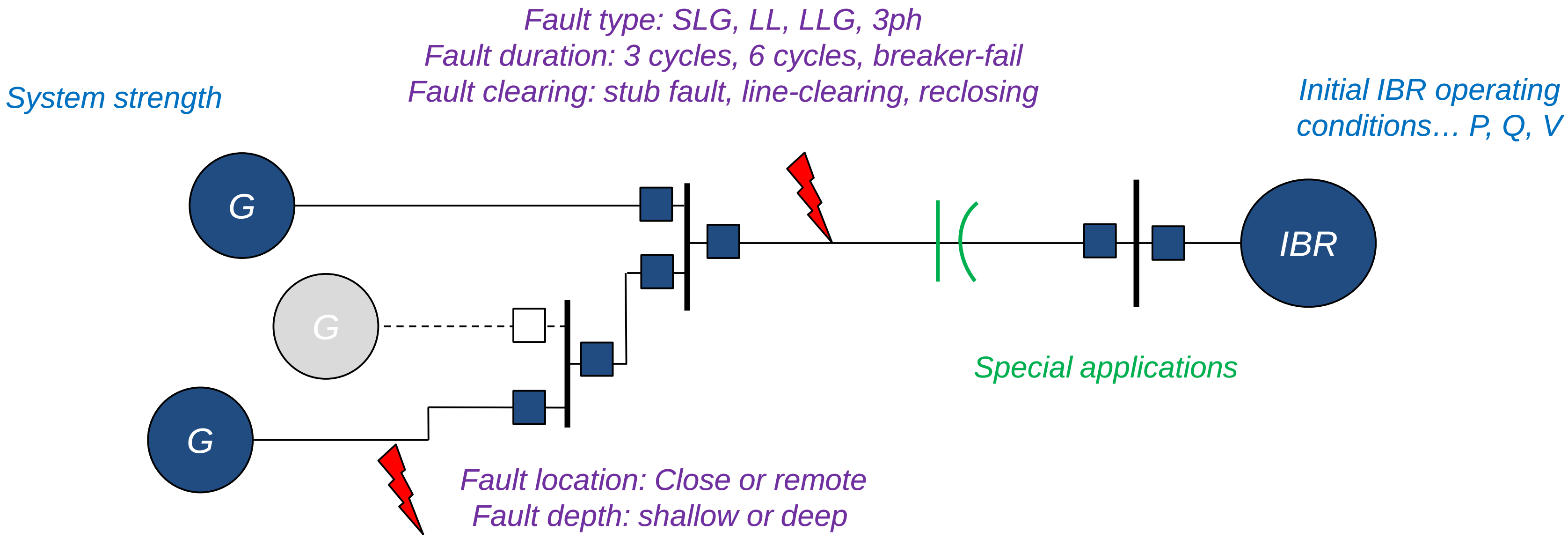



Fault Response Behavior

- What is a large signal event?
  - Typically fault events out on the grid
  - Voltage falls outside continuous operating range
    - For example, 0.9pu – 1.1pu at plant POM
  - Can be more complex than a simple voltage sag

Types of Faults

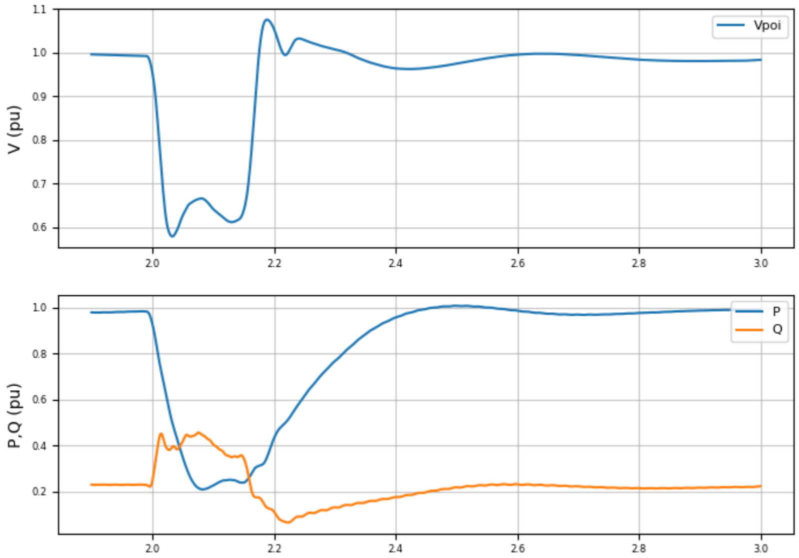
- Relevant factors for IBR response include:
  - Fault conditions – fault type, depth and location, line clearing, reclosing
  - Operating conditions – system strength, initial V, P, Q
  - Special applications – series compensation, islanding potential



All of these factors can affect the response of IBR to faults

During the Fault

- What happens during the fault?
  - Voltage magnitude may be reduced
  - Voltage angle deviation
  - Unbalance conditions
  - Power transfer may be limited
    - Angular stability concerns
      - Line loading changes could stress tie-lines
      - Partially-isolated synchronous machines may accelerate
    - Frequency stability concerns
      - Bulk system frequency may deviate if some generation is partially isolated from the system

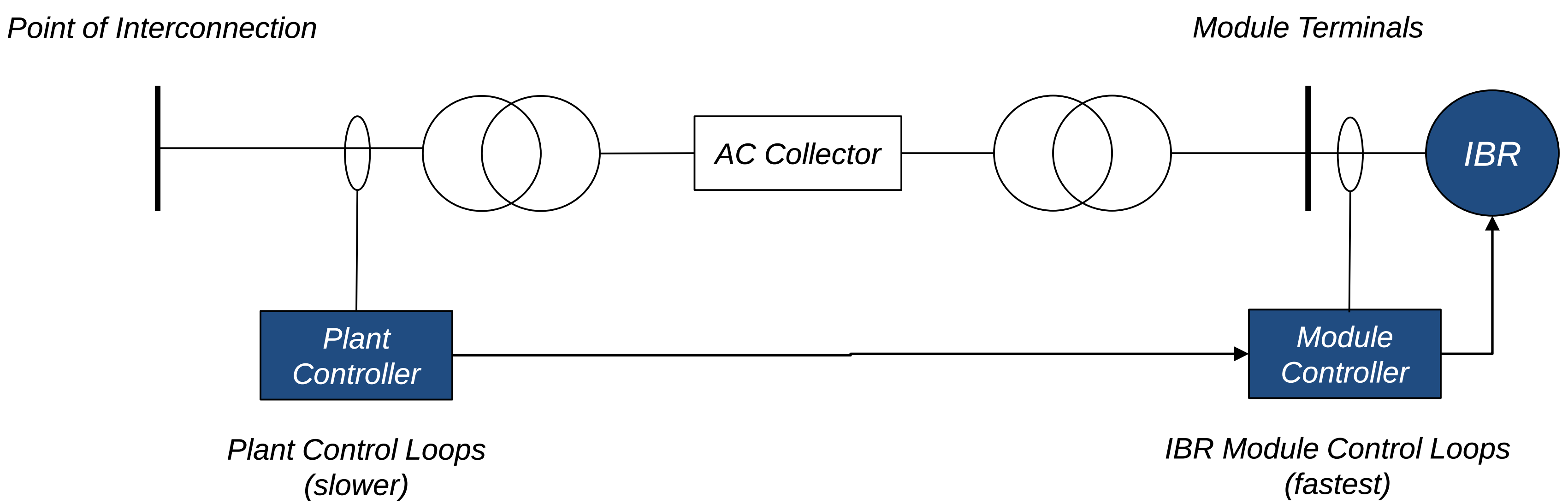


Successful Recovery

- Principles for stable recovery:
  - Recover voltage first and fast
    - Without voltage, active power transfer cannot occur
    - Prioritize fast current injection to support protective relays
  - Recover active power quickly after voltage has recovered
    - Prioritize control of active and reactive current based on terminal conditions
  - Manage voltage overshoot upon fault clearing to avoid trips or damage to equipment
    - Function of plant design + IBR controls
    - Particularly in weak grids, controls may need to be tuned to mitigate overvoltage

Inverter Behavior

- What can and should inverters do?
  - Can: be extremely fast… but this may compromise stability margins
  - Should: be stable (priority) and fast enough



IBRs should allow the flexibility to adjust controls response for various applications and system conditions

Large Disturbance Reactive Current-Voltage Performance

- Plant-level controller cedes control to individual inverters
  - Inverters then typically enter a "ride-through mode" - assume control of reactive current injection
    - "Ride-Through Mode" – depends on specific manufacturer design
      - Can be a discrete control mode or more continuous response
    - Dynamic response of overall IBR dominated by inverter response
  - After voltage recovery
    - Transition back to plant-level controls (if applicable) should not affect the performance for the overall response of the resource
    - If inverters enter momentary cessation during disturbance, slow plant-controller ramp rate limits should not be imposed on recovery
  - Other considerations
    - Negative sequence current injection – development of more detailed specifications needed

Large Disturbance Reactive Current-Voltage Performance

Table 3.2: Large Disturbance Reactive Current-Voltage Performance		
Parameter	**Description**	**Performance Target**
For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response should meet the following performance specifications…		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change[56]	< 16 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90 percent of its final value	< 100 ms**
Overshoot	Percentage of rated reactive current output that the resource can exceed while reaching the settling band	Determined by the TP/PC***

* For very low voltages (i.e., less than around 0.2 pu), the inverter PLL may lose its lock and be unable to track the voltage waveform. In this case, rather than trip or inject a large unknown amount of active and reactive current, the output current of the inverter(s) may be limited or reduced to avoid or mitigate any potentially unstable conditions.
** Varying grid conditions (i.e., grid strength) should be considered and behavior should be stable for the range of plausible driving point impedances. Stable behavior and response should be prioritized over speed of response.
*** Any overshoot in reactive power response should not cause BPS voltages to exceed acceptable voltage limits. The magnitude of the dynamic response may be requested to be reduced by the TP or PC based on stability studies.

Questions and Answers

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommended IBR Performance – Part 2

NERC IRPTF Meeting

February 2019

RELIABILITY | ACCOUNTABILITY

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Inverter-Based Resource Plant Measurement Data

Venkat Reddy Konala, First Solar

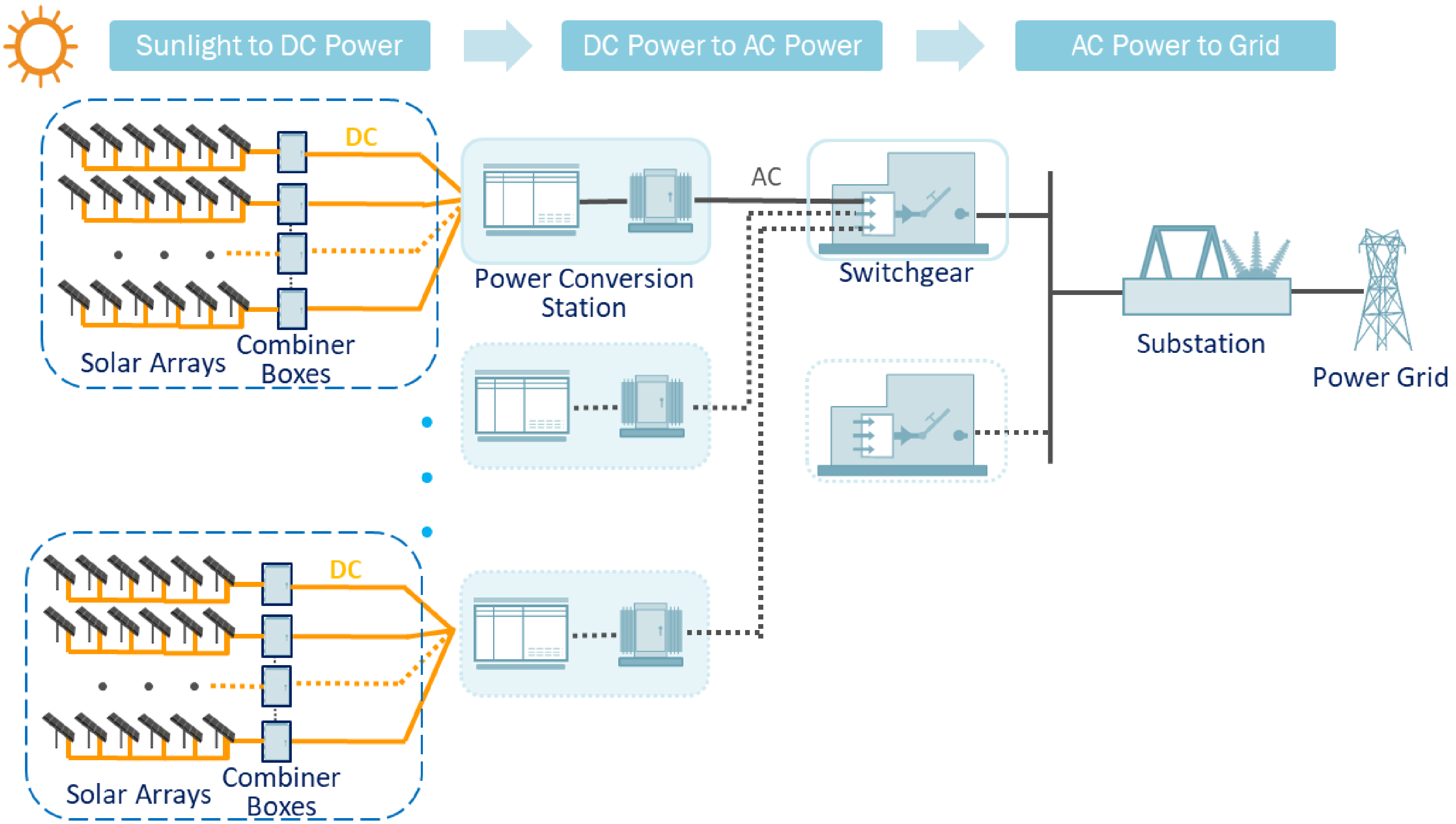
RELIABILITY | ACCOUNTABILITY



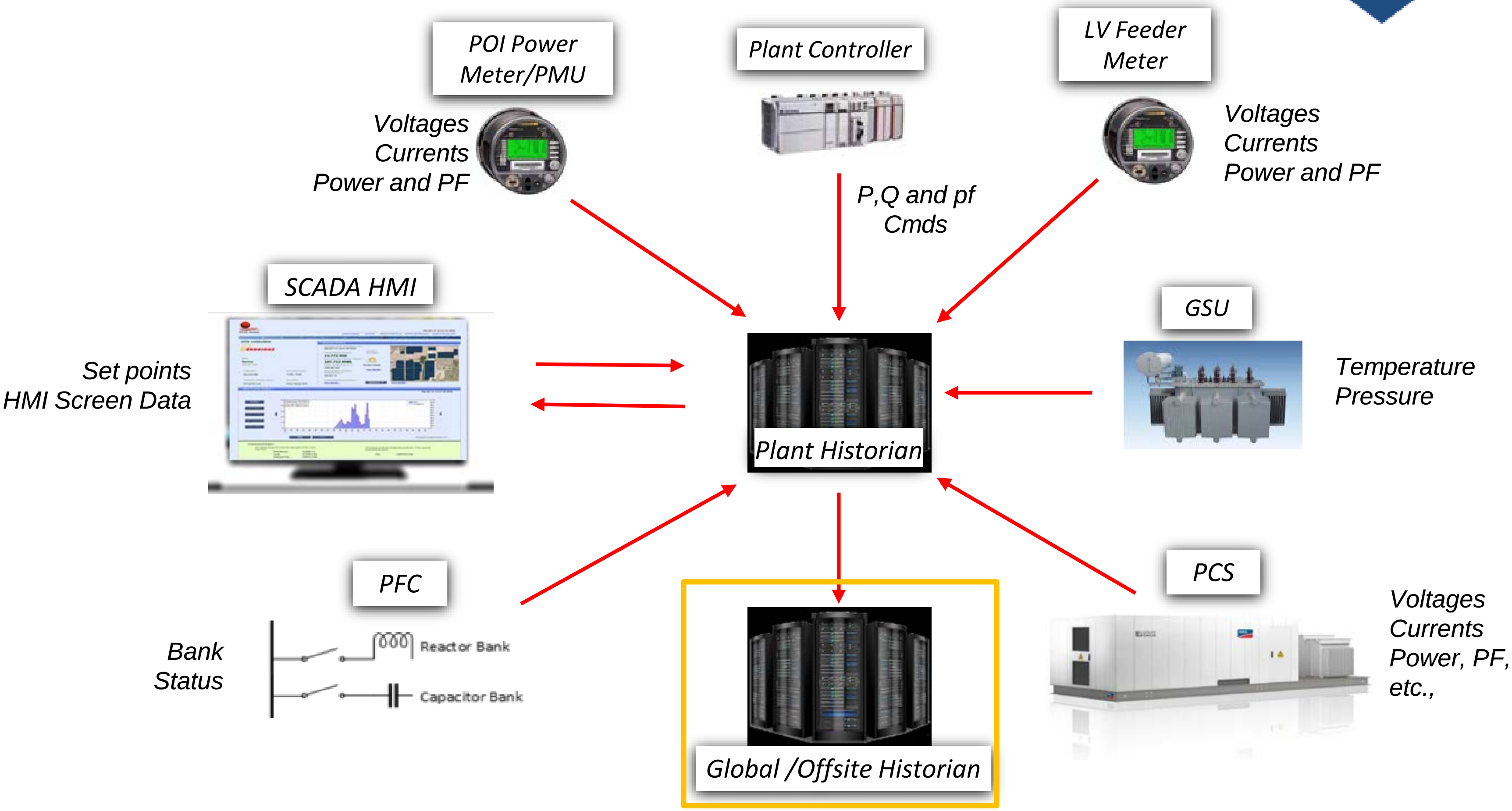

Why

- To accurately capture sufficient data to determine the response of IBR to grid disturbances
- Use for verification of compliance or,
- Root cause analyses to drive continuous reliability improvement of the BES

PV Plant Power – Overview



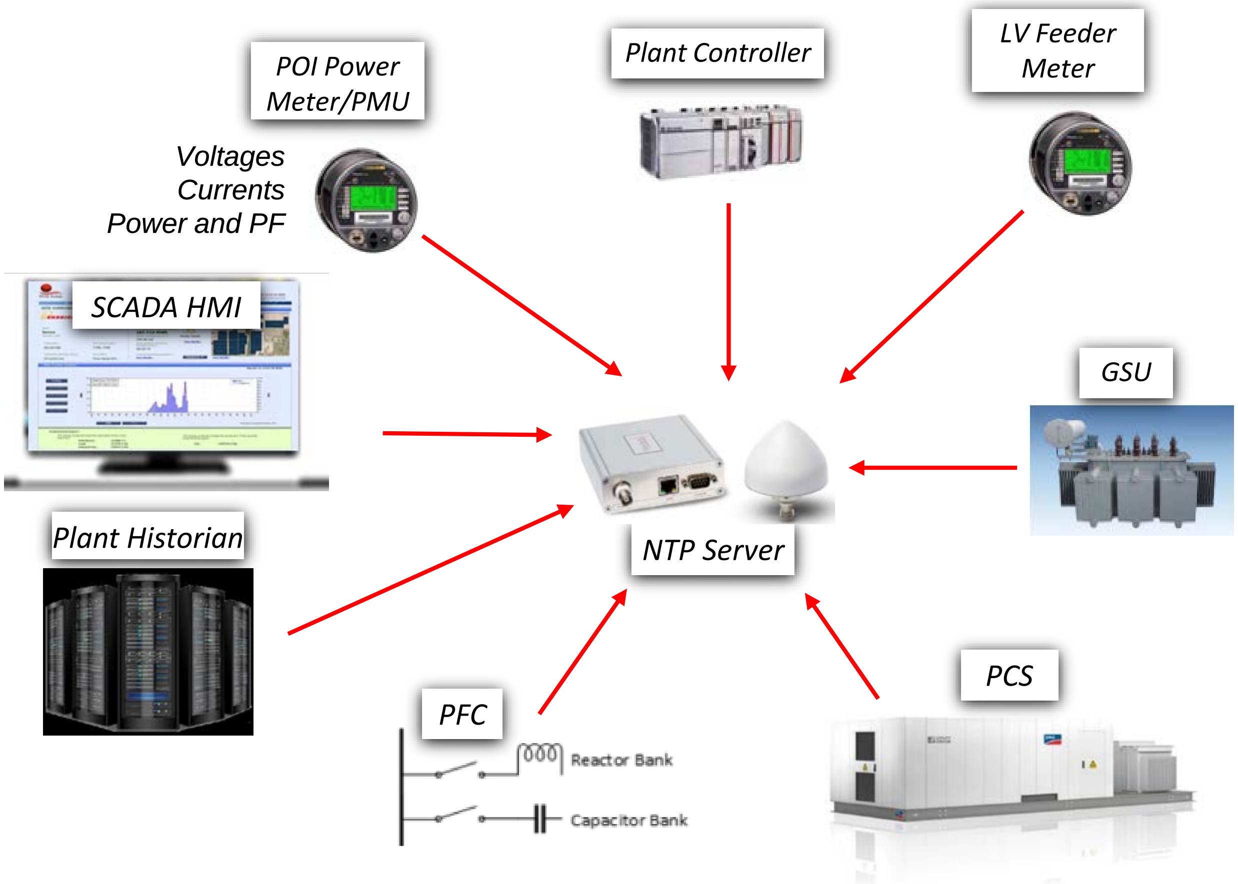
Plant Data Collection -Overview



- *PMU data stored in historian at higher sample rate*
- *Event log and data stored in inverter at higher sample rate*
- *Monitoring and control data stored in the data historian @ 1sec *resolution*

Time Synchronization

- IBR plant data needs to be synchronized



Inverter - Event log and Data

- Event Log and Data
  - Triggered on faults and grid events
  - Total event data duration up to 1-2 sec,
  - Includes high sample rate data before and after data trigger

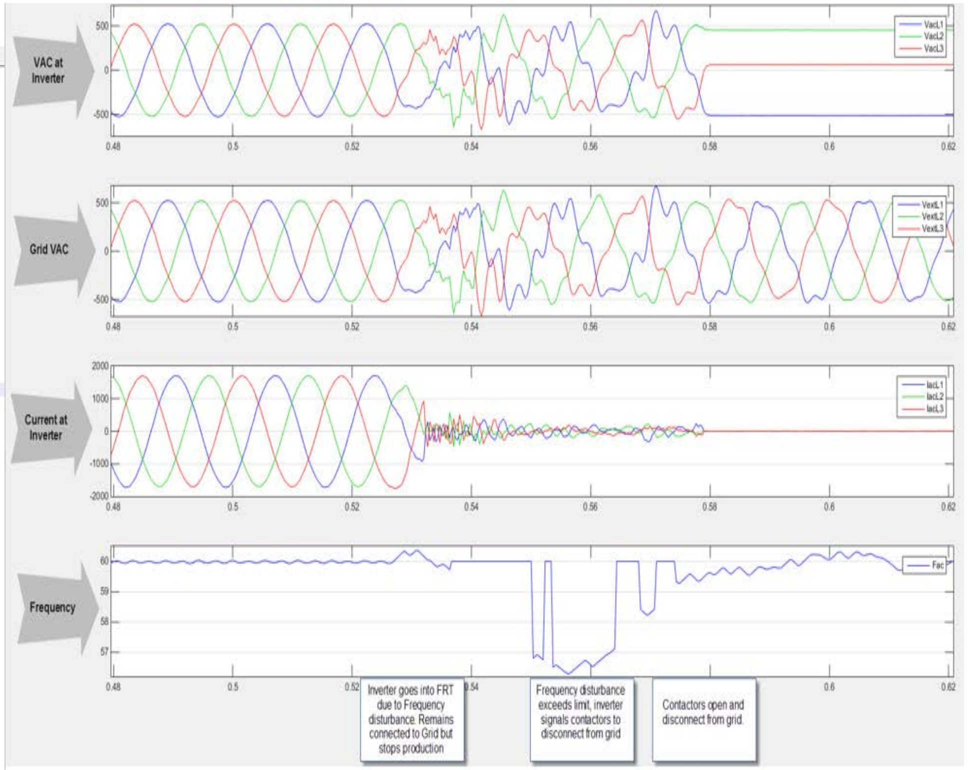
Event Logs show the operational status of the inverter and faults.

SC160816.EVT

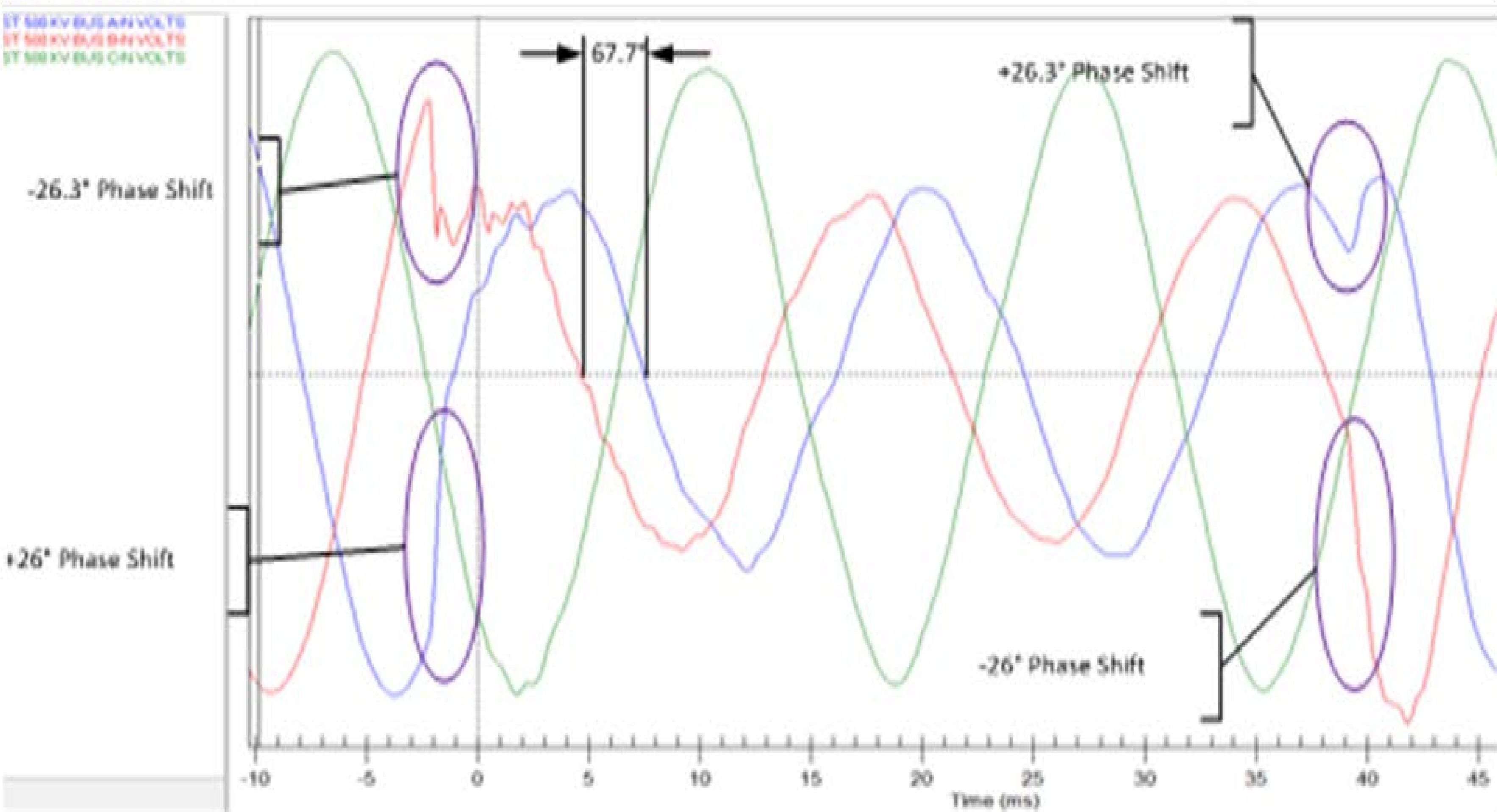
```
##############################
# SC - Event/Failure History
##############################
# SN:              105321257
# FW-Version:      V1.60.15.R
# FW-Version-2:    V1.60.25.R
# FW-Version-3:    V1.12.05.R
# FW-Version-4:    V1.00.00.R
# FW-Version-5:    V1.00.08.R
# FW-Version-6:    V1.00.08.R
# FW-Version-7:    V1.03.03.R
# FW-Version-8:    V8.01.00.N
# FW-Version-9:    V8.05.00.N
Date       ; Time     ; Type ; Number ; UserData
16.08.2016 ; 10:35:50 ; E    ; 10032  ; 2
16.08.2016 ; 10:35:50 ; F    ;   502  ; 8192
16.08.2016 ; 10:35:50 ; E    ; 10032  ; 502
16.08.2016 ; 10:35:51 ; E    ; 10058  ; 0
16.08.2016 ; 10:35:51 ; E    ; 10413  ; 33
16.08.2016 ; 10:35:52 ; E    ; 10007  ; 2
16.08.2016 ; 10:36:20 ; E    ; 10003  ; 1
16.08.2016 ; 10:37:45 ; E    ; 10412  ; 0
16.08.2016 ; 10:39:52 ; E    ; 10413  ; 34
16.08.2016 ; 10:41:46 ; E    ; 10412  ; 0
16.08.2016 ; 10:42:54 ; E    ; 10003  ; 2
16.08.2016 ; 12:55:29 ; E    ; 10058  ; 0
16.08.2016 ; 12:55:29 ; F    ;   502  ; 8192
16.08.2016 ; 12:55:29 ; E    ; 10032  ; 502
16.08.2016 ; 12:55:30 ; E    ; 10413  ; 35
16.08.2016 ; 12:55:31 ; E    ; 10007  ; 2
16.08.2016 ; 12:55:59 ; E    ; 10003  ; 1
16.08.2016 ; 12:57:24 ; E    ; 10412  ; 0
16.08.2016 ; 12:59:30 ; E    ; 10413  ; 36
16.08.2016 ; 13:01:25 ; E    ; 10412  ; 0
16.08.2016 ; 13:02:39 ; E    ; 10501  ; 0
16.08.2016 ; 14:03:32 ; E    ; 10032  ; 2
16.08.2016 ; 14:03:32 ; E    ; 10058  ; 0
16.08.2016 ; 14:03:32 ; F    ;   502  ; 8192
16.08.2016 ; 14:03:32 ; E    ; 10032  ; 502
16.08.2016 ; 14:03:32 ; E    ; 10413  ; 37
16.08.2016 ; 14:03:33 ; E    ; 10007  ; 2
16.08.2016 ; 14:04:02 ; E    ; 10003  ; 1
16.08.2016 ; 14:04:36 ; E    ; 10058  ; 0
16.08.2016 ; 14:05:27 ; E    ; 10412  ; 0
16.08.2016 ; 14:07:33 ; E    ; 10413  ; 38
16.08.2016 ; 14:09:27 ; E    ; 10412  ; 0
16.08.2016 ; 14:10:36 ; E    ; 10501  ; 0
16.08.2016 ; 14:10:36 ; E    ; 10003  ; 2
16.08.2016 ; 14:10:39 ; E    ; 10058  ; 0
```

Fault 502: Grid Frequency disturbance
Event 10413: 700ms Flight Recorder file created due to grid event. About 2100 data points total

A 4th event was detected around 14:10 but fault was within limits and inverter Rode Through.

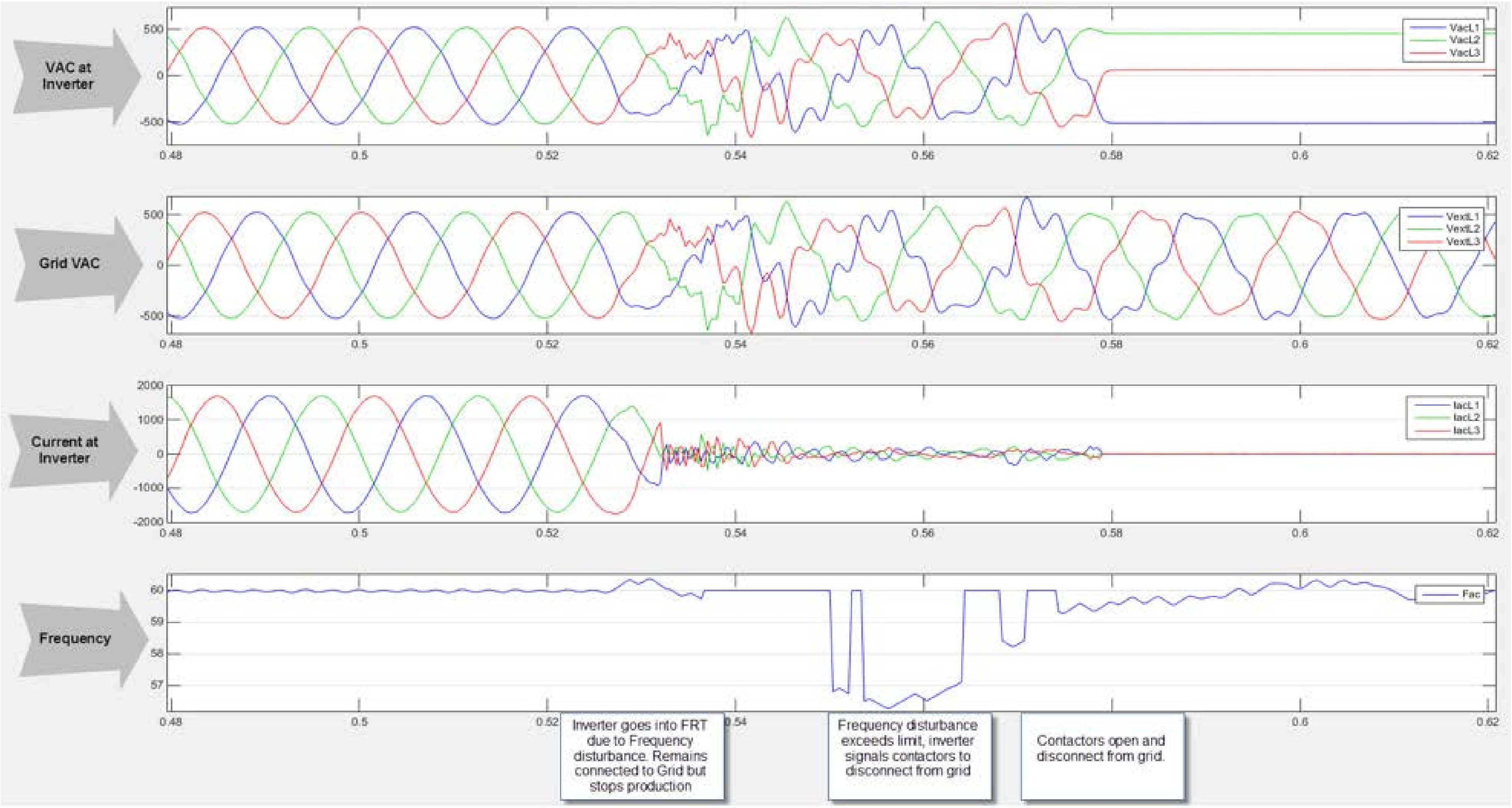


Blue Cut Fire - DFR



DFR Data - Phase Jump at Fault Location

Blue Cut Fire - Inverter



Inverter Event Capture Data

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Measurements and Dispatchability

Lou Fonte, California ISO

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Measurement Data & Monitoring

Problem Statement: Analyzing inverter behavior and performance during the clearing of high voltage transmission system faults required data such as inverter current, voltage, measured frequency and fault codes. This data was often not available.

Action Item: The CAISO is filing with FERC to amend its tariff to require Inverter Based Resources larger than 20 MW to monitor and record critical data during certain events. The data will be available to the CAISO upon request.

Measurement Data and Monitoring

Plant Level Data

- Three Phase voltage, current and phase angle
- Status of ancillary reactive devices
- Status of circuit breakers
- Status of plant controller
- Plant control set points
- Position of main plant transformer no load taps
- Position of main plant tap changer (if used)
- Protective relay trips or relay target data

Measurement Data and Monitoring

Inverter Data

- Frequency, current and voltage
- Voltage and current during momentary cessation (if used for transient high voltage)
- Voltage and current during reactive current injection
- Alarm and fault codes
- DC current
- DC voltage

Measurement Data and Monitoring

- Data must be time synchronized to one millisecond

- Recording must include, as a minimum, 150 milliseconds of data prior to the event, and 1000 milliseconds of data after the event trigger

- Data must be stored for a minimum of 30 calendar days

Measurement Data and Monitoring

Event Triggers

1. A voltage or frequency ride through event
2. Momentary cessation for transient high voltage
3. An inverter trip

Measurement Data and Monitoring

Phase angle Measuring Unit (PMU)

- The CAISO will require the installation of a PMU or functional equivalent at the entrance to the facility or the main substation transformer

- Minimum resolution of 30 samples per second

- Real time telemetry is NOT required

Common Data Monitoring Systems

1. Digital Fault Recorder (DFR)
2. Sequence of Events Recorder (SER)

Both devices offer high resolution.

SER will need to be synchronized to a time reference (GPS clock)

Dispatchability

- **Dispatchability** – the ability for a Generator to adjust its power output according to an order
- **FERC Order 842** – requires new Generators to have functioning primary frequency response capability. Note, no headroom requirements at this time
- During periods of over generation, CAISO will require Generators to follow their DOTs (Dispatch Operating Targets). CAISO may also ask for “dec” (decrement) bids and if necessary, order pro rata reduction

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Integrating IBR into Low Short Circuit Strength Systems

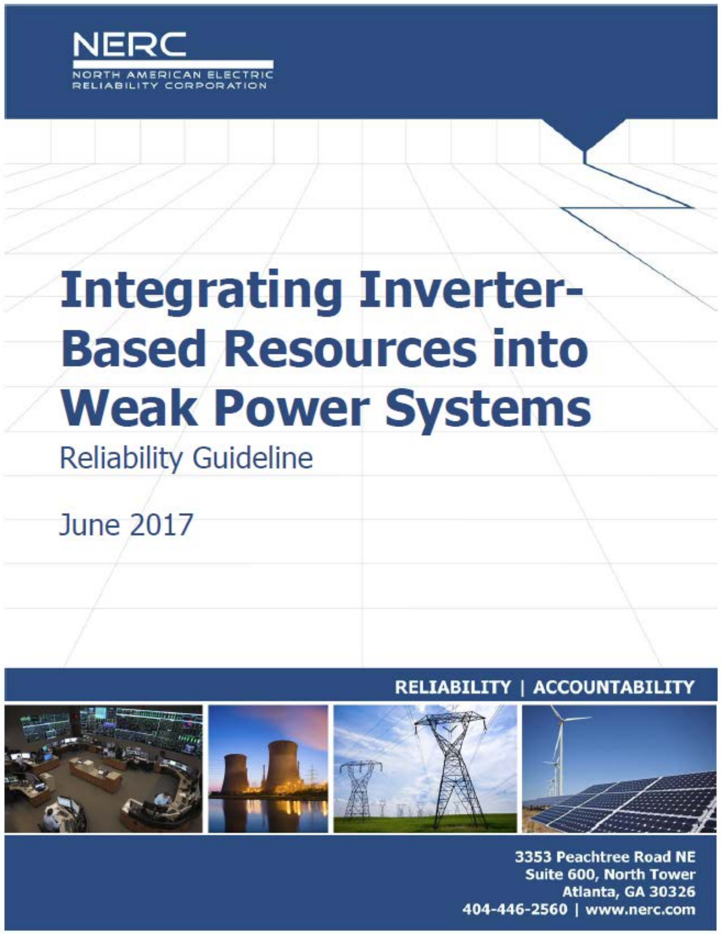
Andrew Isaacs, Electranix Corporation

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Credit and References



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Integrating Inverter-Based Resources into Weak Power Systems

Reliability Guideline

June 2017

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[1] WG B4.62, "Connection of Wind Farms to Weak AC Networks," Cigré Technical Brochure 671, December 2016.

[2] WG C4.601, "Modelling and dynamic behavior of wind generation as it relates to power system control and dynamic performance," Cigré Technical Brochure 328, August 2007.

[3] WG C6.08, "Grid Integration of wind generation," Cigré Technical Brochure 450, February 2011.

[4] WG C1/C2/C6.18, "Coping with Limits for Very High Penetrations of Renewable Energy," Cigré, 2013.

[5] WECC MVWG, "WECC Solar Plant Dynamic Modeling Guidelines," Western Electricity Coordinating Council, Salt Lake City, UT, April 2014. [Online]. Available: HERE.

[6] WECC MVWG, "WECC Second Generation Wind Turbine Models," Western Electricity Coordinating Council, Salt Lake City, UT, January 2014. [Online]. Available: HERE.

[7] WECC MVWG, "WECC Wind Plant Dynamic Modeling Guidelines," Western Electricity Coordinating Council, Salt Lake City, UT, April 2014. [Online]. Available: HERE.

[8] WECC MVWG, "Value and Limitations of the Positive Sequence Generic Models of Renewable Energy Systems," Western Electricity Coordinating Council, Salt Lake City, UT, December 2015. [Online]. Available: HERE.

[9] Y. Zhang, S. H. F. Huang, J. Schmall, J. Conto, J. Billo and E. Rehman, "Evaluating system strength for large-scale wind plant integration," 2014 IEEE PES General Meeting, National Harbor, MD, 2014, pp. 1-5.

SCR metric

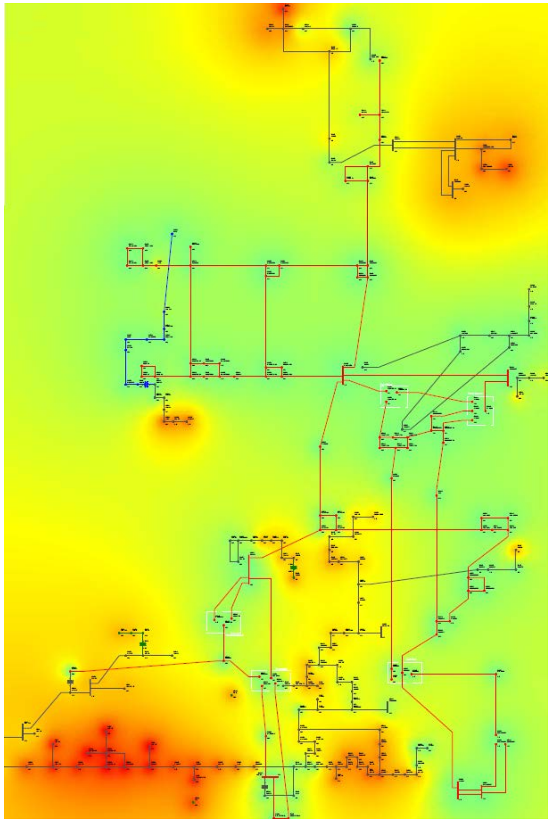
- SCR is the most basic and easily applied metric to determine relative system strength.
  - Calculations should be applied after worst realistic contingency
  - Assume no contribution from nearby IBR

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{VER}}$$

  - Doesn't account for load
  - If there are multiple IBR plants, SCR doesn't work well

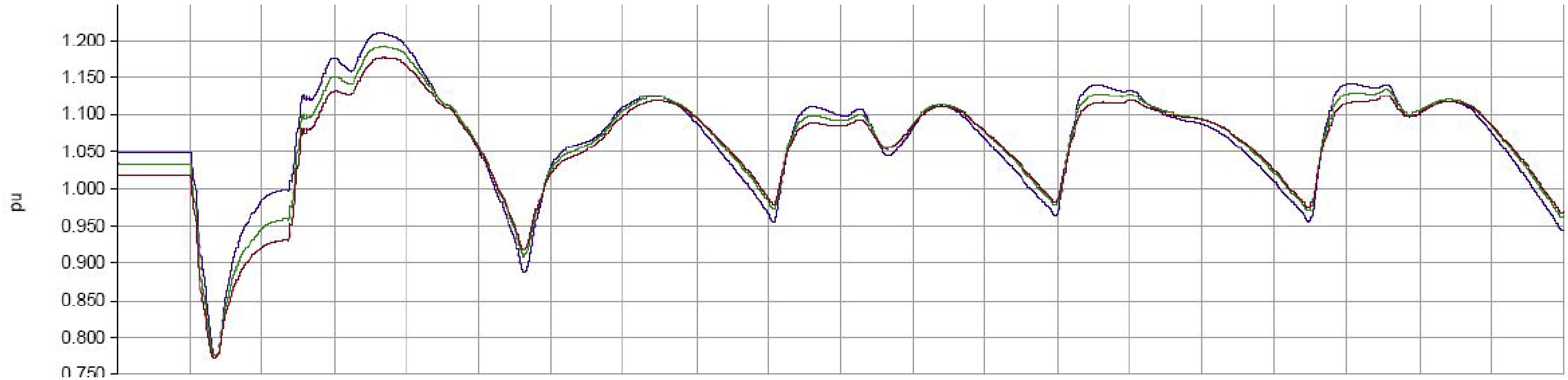
Other metrics

- WSCR and CSCR can be used for multiple IBR plants
  - Requires well-delineated renewable regions with low load
  - Acceptable threshold is system dependent
- IPSCR can be used for screening wider areas
  - New metric, good for very wide area screening
  - Requires more experience and validation
- **Weak grid issues are system and equipment specific and it is difficult to define a "minimum system strength" criteria that can be applied uniformly.**



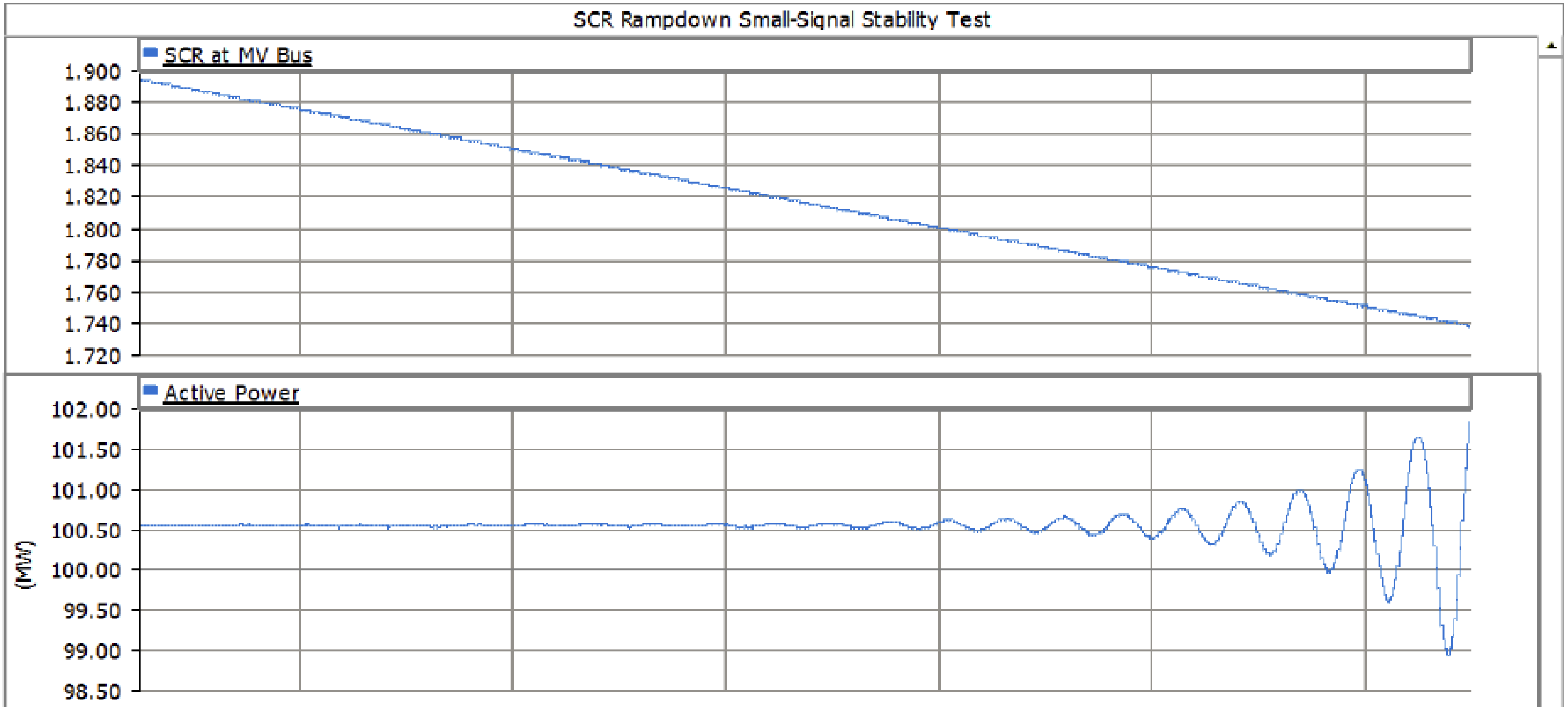
Issues associated with weak systems

- MOST COMMON ISSUE: Ride-through failure…
  - May trip on OV, UV, OF, UF
  - May trip on transient OV, inverter overcurrent, PLL sync errors, DC bus voltage, or other protections
- Interactions between different controls, or between a control system and the grid *(Plot is system voltage, 6 cycles per division)*



Issues associated with Weak Systems

- Classic stability limits: there are physical limits to how much power you can push through an impedance
- Control instability (small signal)



Planning Study Considerations

- Transient stability models have inherent limitations (detailed in NERC report)
  - Usually catch classical voltage instability
  - May miss FRT failure
  - May miss control system instability
  - May miss control interactions
  - May miss momentary cessation
  - May not include plant protections
  - Are often not validated for large signal response

Planning Study Considerations

- For planning modern systems, various levels of dynamic models are required:
  - Generic Positive Sequence Stability Model
    - Interconnection-wide use
  - Detailed Positive Sequence Stability Model
    - Interconnection study should use detailed models for close-in plants
  - Electromagnetic Transient (EMT) Model
    - Highest level of detail model for weak grids, risk of control interactions, series capacitor proximity, model validation, or other special needs. (http://www.electranix.com/publication/technical-memo-pscad-model-requirements/)

Mitigation of weak grid issues

- Depending on the situation, the following may be helpful:
  - Change the rules that are being broken (carefully…)
  - Changes in plant controls
  - Synchronous condensers
  - Transmission reinforcement
  - Increased local load (in some cases)
  - Series Compensation (be very careful!!)
  - Smaller generator or curtailed output
  - FACTS, BESS (Situational)
  - Novel control alternatives (eg. constant voltage control characteristics or synthetic inertia)

$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{VER}}$$

- If the system is weak, involve the OEM!

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

What Are Grid Forming Inverters?

Deepak Ramasubramanian, EPRI

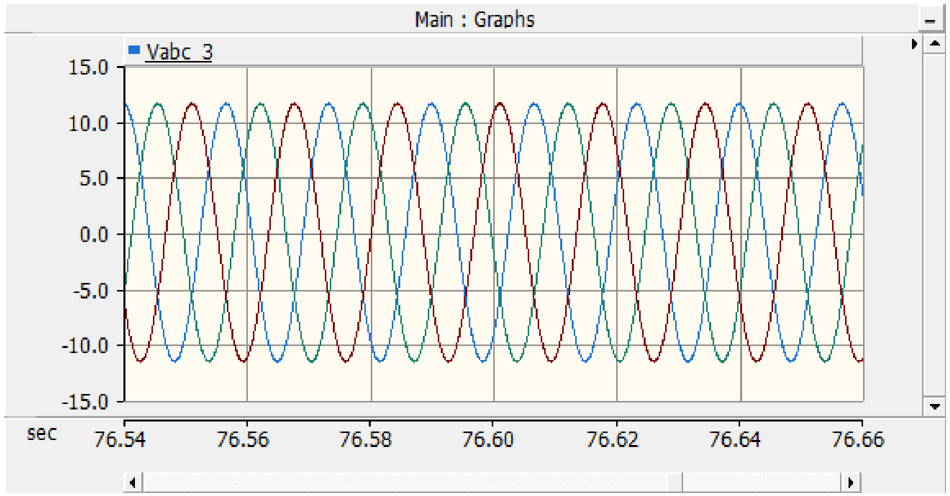
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Basic Quantities of Power Systems

- Sinusoidal voltage/current wave has three quantities:
  - Magnitude (V/I)
  - Phase angle displacement (δ/θ)
  - Frequency (ω)



- Sinusoidal output from a synchronous machine,
  - Voltage magnitude is mainly controlled by level of excitation
  - Phase angle is mainly controlled by governor position
    - Which controls the angular displacement of the rotor shaft
  - Frequency is mainly controlled by speed of rotation of rotor
    - But, it is also affected by rate of change of phase angle

Basic Operation of Converter

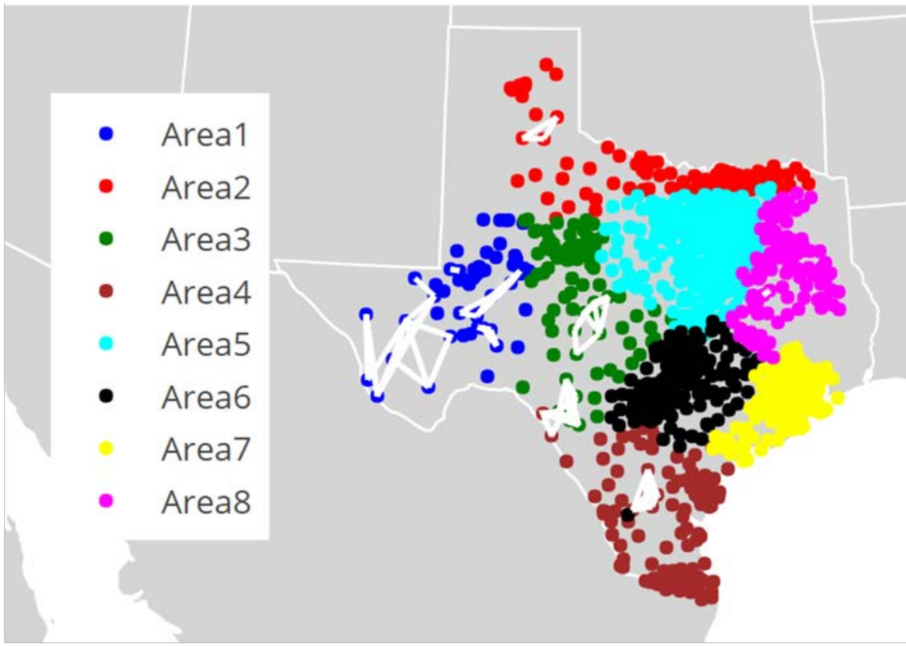
- Sinusoidal output from a converter:
  - Voltage magnitude is controlled by reactive power – voltage control loop
  - But how about phase angle and frequency??
    - There is no rotating rotor whose speed or twist can be controlled.
  - So how is the ‘position’ of the sine wave w.r.t. time decided and controlled?
- In comes the phased locked loop:
  - Uses measured three phase quantities as input
    - Usually voltage on the grid side of the inverter
  - Derives a value of angle as an output
    - As a by-product, drives a value of frequency
- This derived value of angle is used by the converter to generate a sinusoidal wave.
  - So, the angle of sinusoidal wave of the converter follows the angle of sinusoidal wave of the grid.

The All Important Phase Angle

- If the angle of the grid is not known (or cannot be evaluated), present-day wide spread converter controls would have difficulty producing a viable sinusoidal wave.
- Factors upon which angle evaluation depends:
  - ‘Strong and smooth’ voltage measurement
  - A strong voltage wave is one which will not change by a large amount for a small change in current injection
  - A smooth voltage wave is one which has a low total harmonic distortion
- Both these characteristics are present in a current independent (to a large extent) voltage source:
  - Example: synchronous machine
- So, if present-day converters are electrically near to a voltage source, they can function very well.

When Can the Voltage Waveform Be 'Bad'?

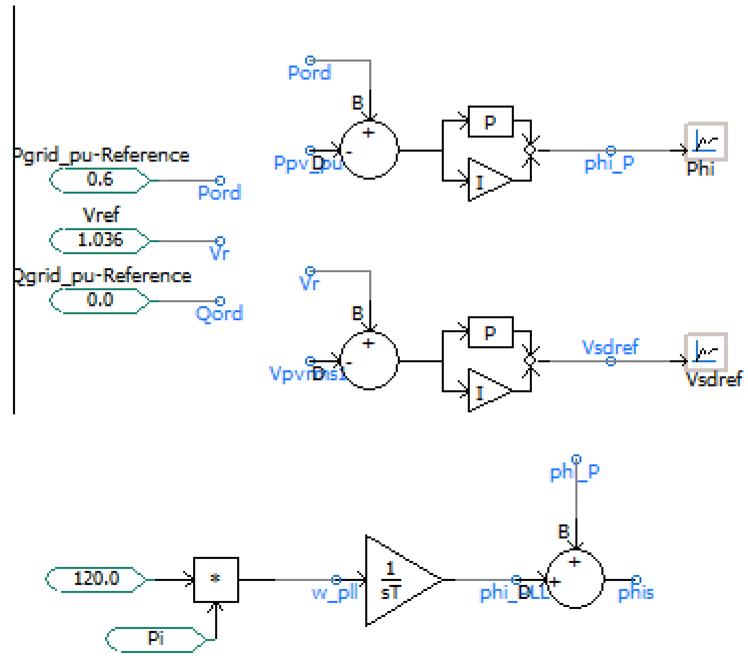
- A bunch of current controlled converters (present – day converter control) located electrically close to each other, but electrically far away from the rest of the system.
  - Example: Texas panhandle.
- The number of synchronous machines in the system is much lower than the number of converters
  - Very low (or zero) inertia and thus the system is more brittle and 'moves' around fast.



This is from an artificial system which is statistically equivalent to ERCOT's network (https://electricgrids.engr.tamu.edu/electric-grid-test-cases/activsg2000/)

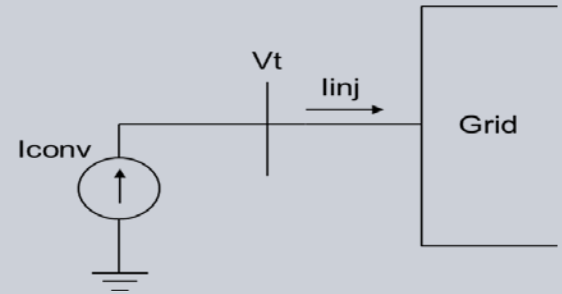
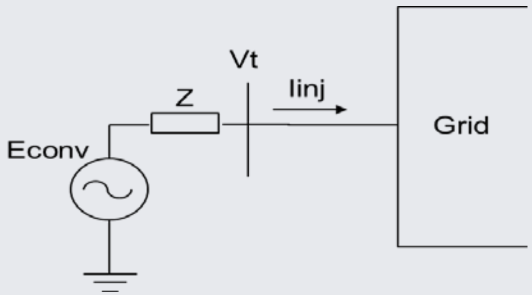
Grid Forming Converter

- The converter controls do not rely on a phase locked loop to provide an angle based on voltage measurements
  - Some form of grid tracking has to be present in order to be a ‘good citizen’ of the power system
- Converter controls make the converter a current independent (to a large extent) voltage source.
- One way of accomplishing this:
  - The angle is derived by an active power controller
  - The voltage magnitude is derived by a voltage controller
  - The derived angle is added to synchronous speed



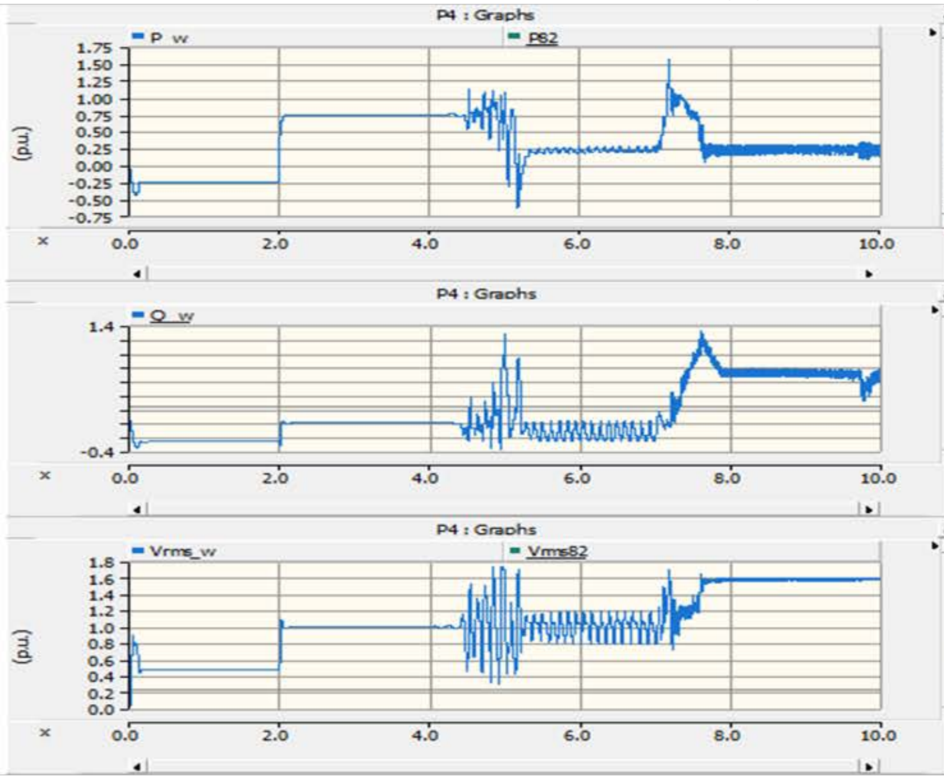
This is just one of the ways in which a grid forming converter can be constructed

Comparison of Control Modes

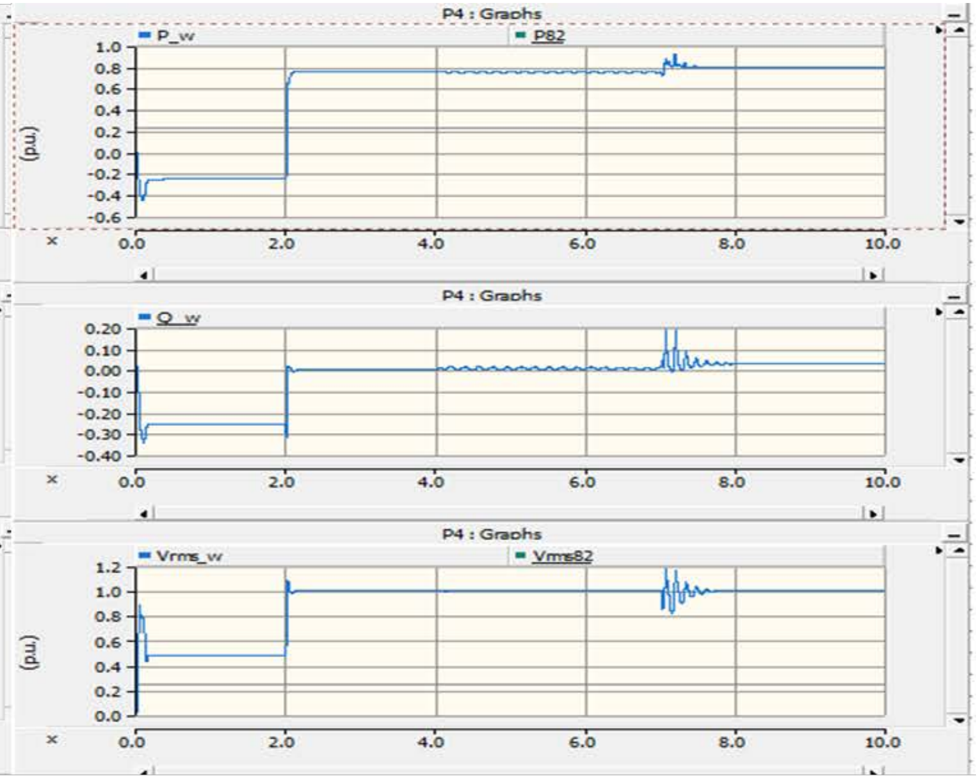
	Viewed by grid as	Requires strong grid?	Current control	One line representation
Grid following	Current source	Yes	Strict	
Grid forming	Voltage source	No	Loose	

Example Application

- Nine converters in the system. One equivalent voltage source
- At t = 2s, all converter are synchronized
- At t = 4s, the grid (equivalent voltage source) is lost
- At t = 7s, a converter is tripped.



Without grid forming



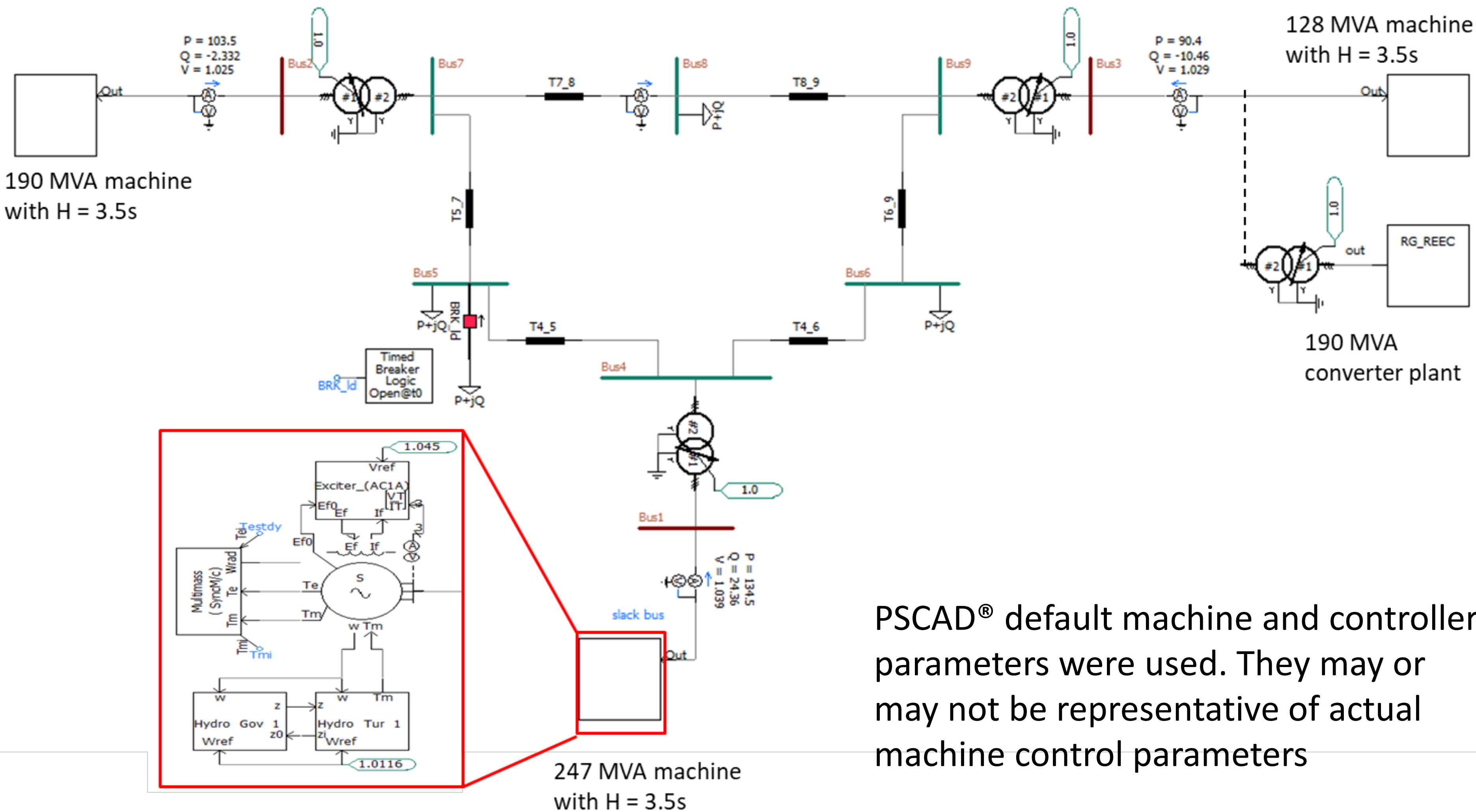
With grid forming

What about Sharing of Power?

- Having a grid forming converter is good as converters can operate in a stable manner and inject current.
- However, it is now another converter on the system in addition to the many already present.
- So, how should the frequency of its sinusoidal way change with respect to a load/generation disturbance?
    - In a synchronous machine, this change occurs naturally due to deceleration or acceleration of the rotor.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

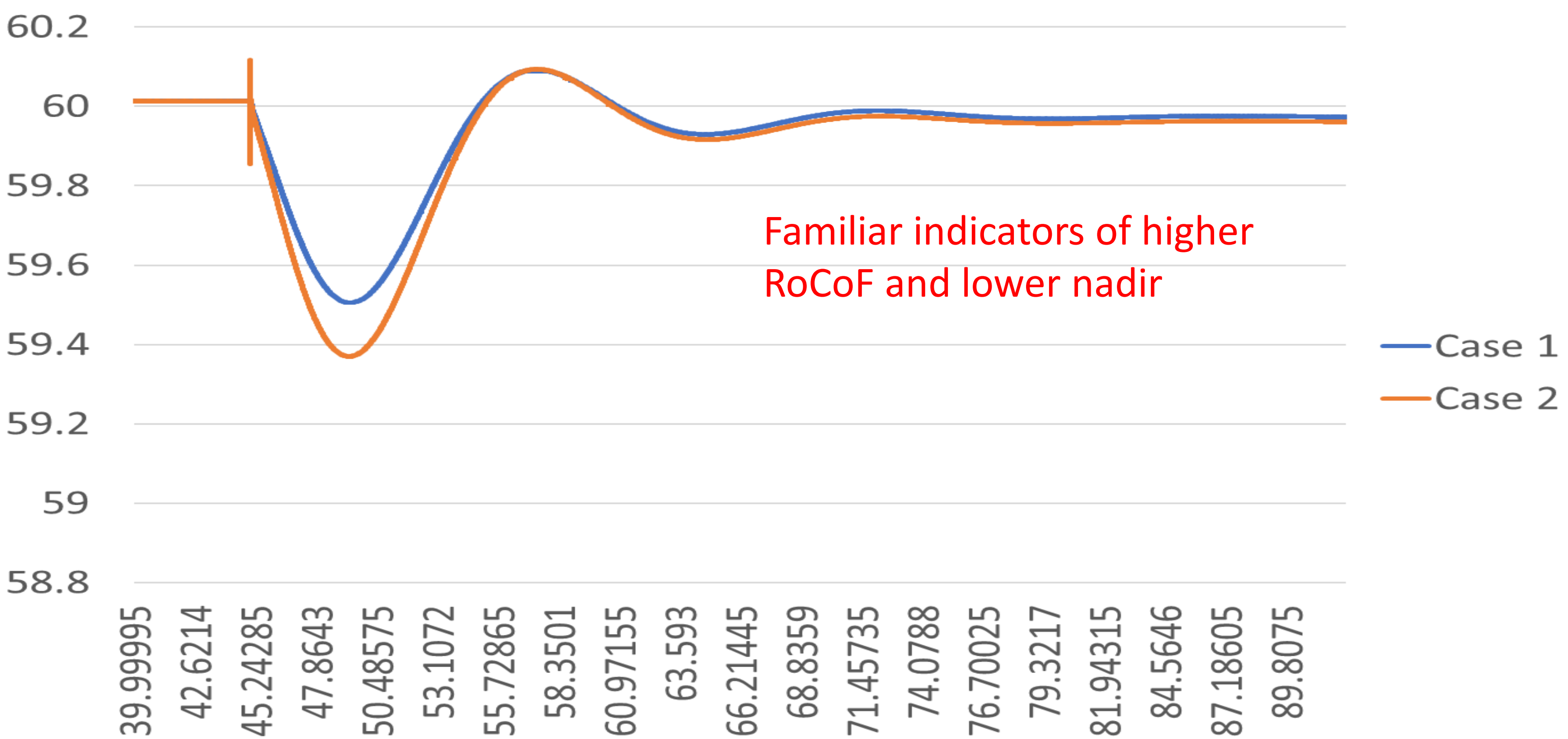
Another Example



PSCAD® default machine and controller parameters were used. They may or may not be representative of actual machine control parameters

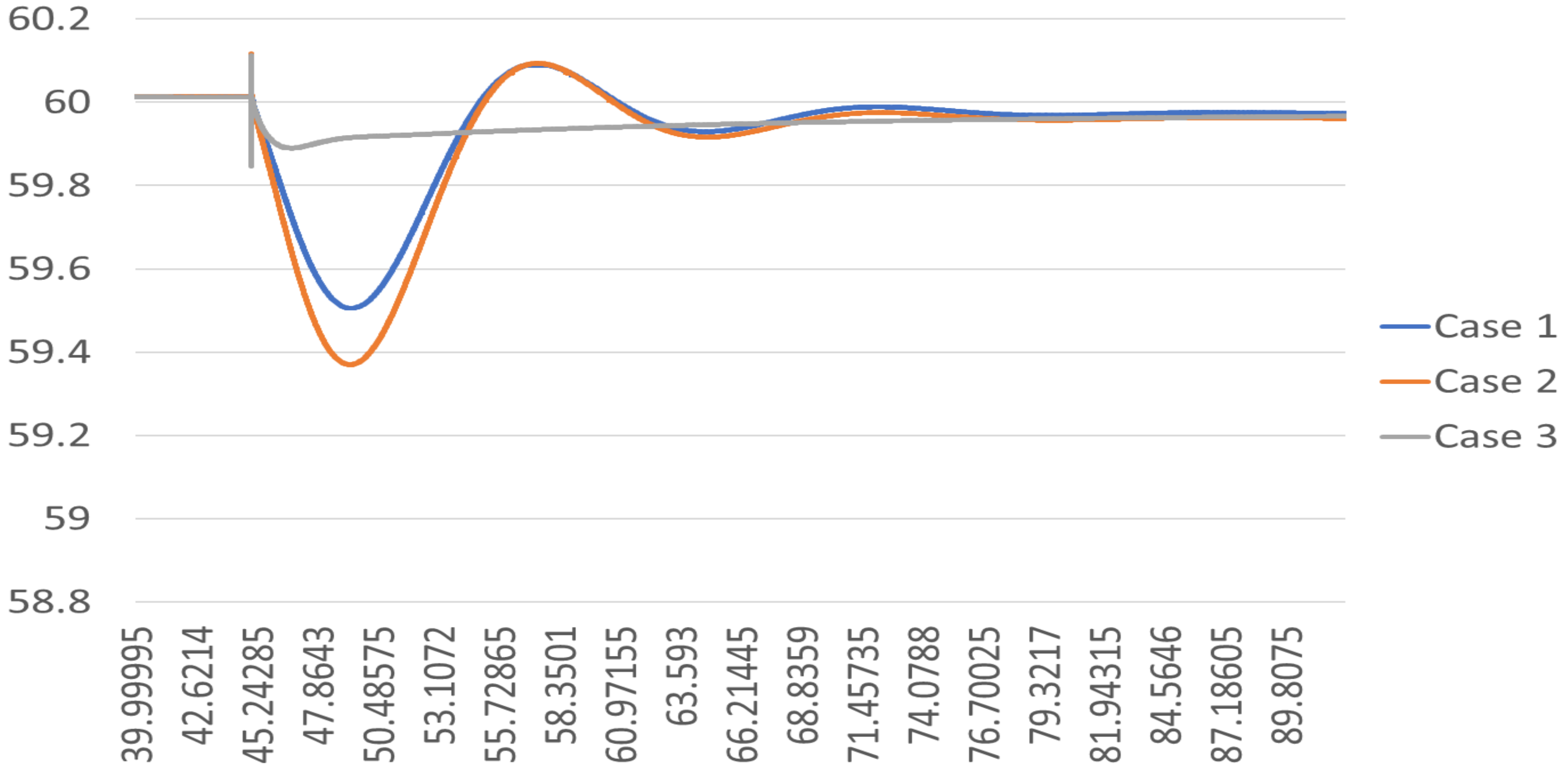
Comparison of Frequency for Load Increase Event

- Case 1 – all three machines in service, converter out of service
- Case 2 – converter replaces machine at bus 3



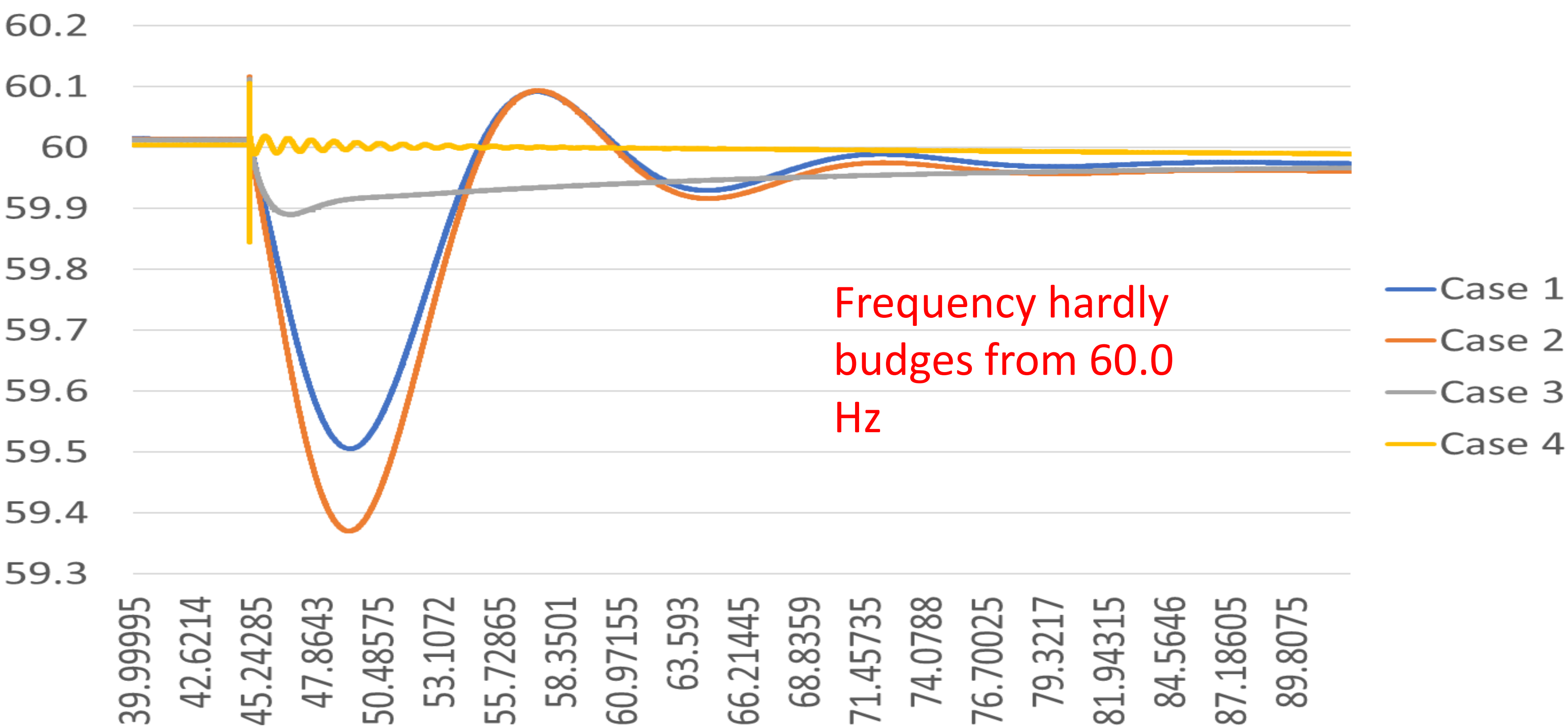
Comparison of Frequency for Load Increase Event

- Case 3 – Converter has frequency droop enabled as per FERC Order 842
  - But also has quite a bit of headroom available



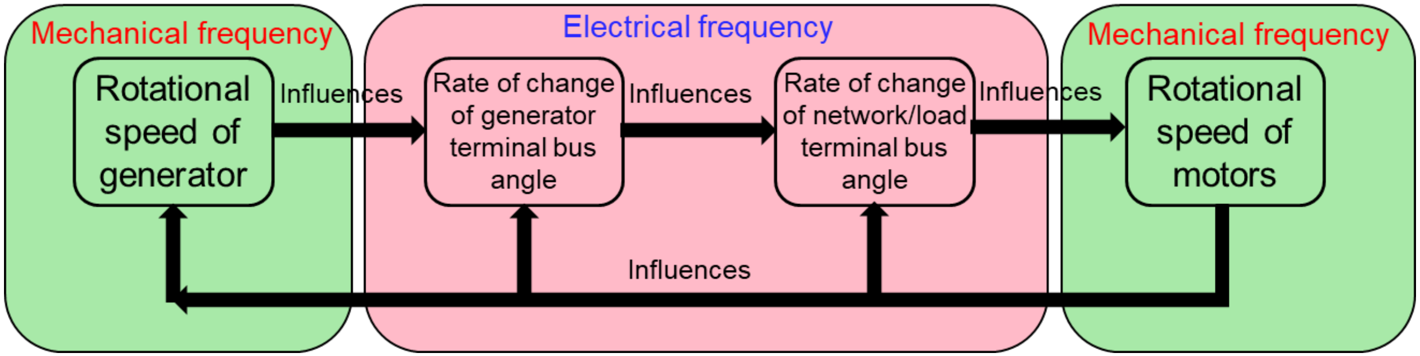
What if There is a Large Machine?

- Case 4 – Suppose there is a pseudo infinite bus (say at bus 2 in the network) – like a very large machine?
    - Would this be acceptable from a system operation perspective? With the converter at Bus 3

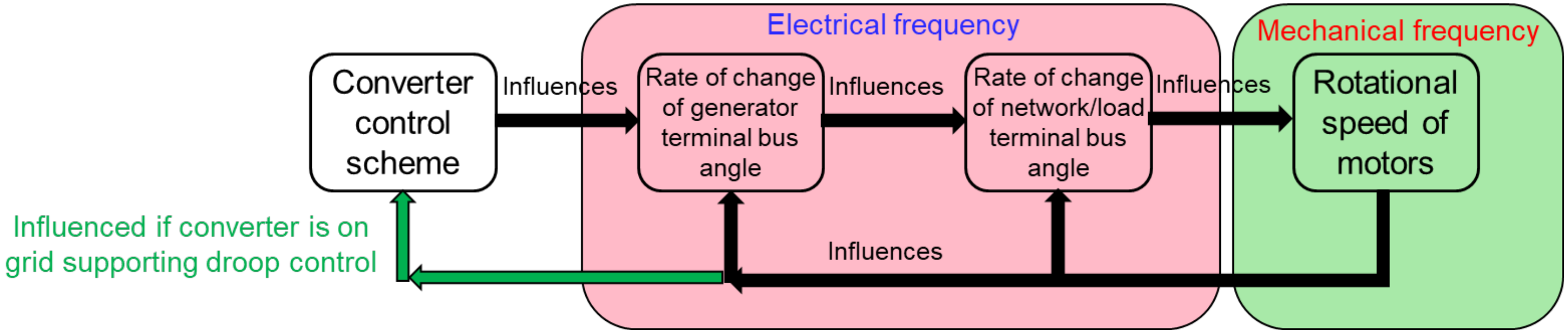


What is System Frequency as More Converters are Present?

- Conventional system:
  - System frequency governed by speed of rotating machines.

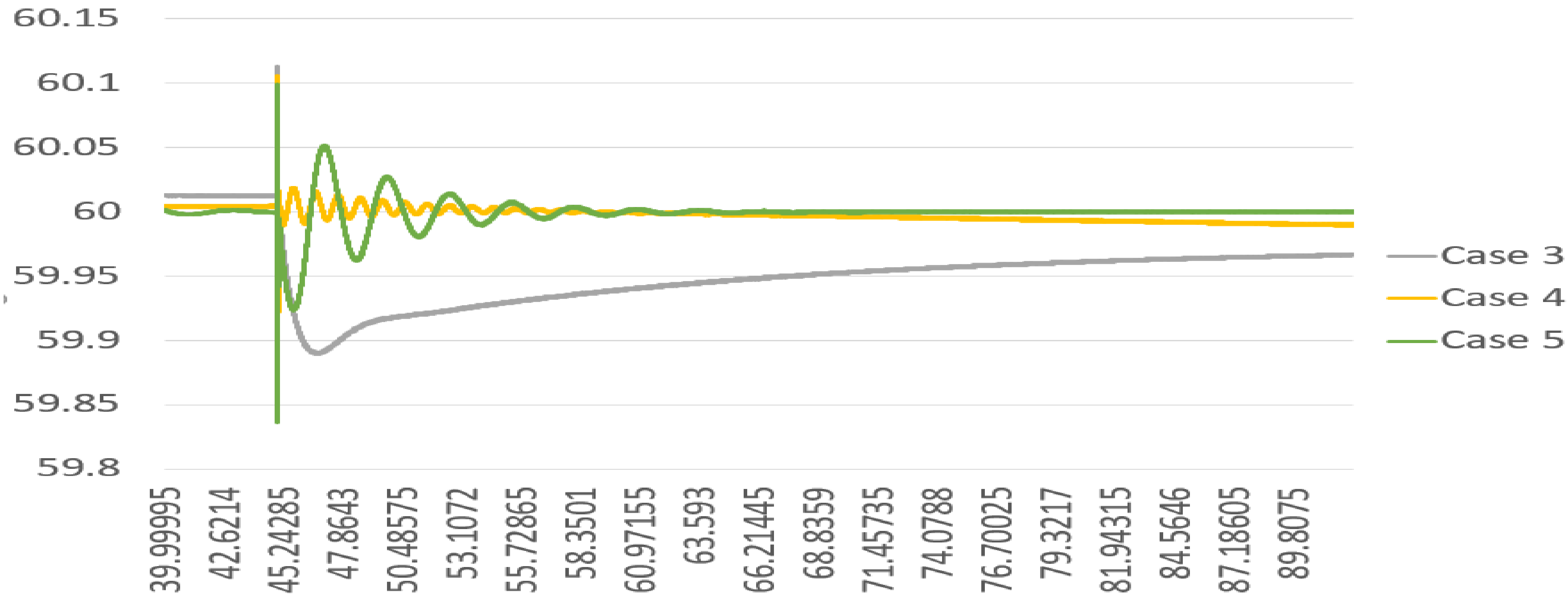


- All converter system:
  - No physical link between generation/load balance and frequency
  - Converters can operate at any frequency.



Almost Ideal Grid Forming Converter

- Case 5 – Almost ideal grid forming converter behaves almost as a pure voltage source (Case 5):
  - Steady voltage output, and Steady frequency output



[1] D. Ramasubramanian, E. Farantatos, S. Ziaeinejad and A. Mehrizi-Sani, “Operation Paradigm of an All Converter Interfaced Generation Bulk Power System,” *IET Generation, Transmission & Distribution*, vol. 12, no. 19, pp. 4240-4248, Oct 2018.
[2] Mohammad Mousavi, Ali Mehrizi-Sani, Deepak Ramasubramanian and Evangelos Farantatos, “Performance Evaluation of an Angle Droop–Based Power Sharing Algorithm for Inverter-Based Power Systems,” *2019 IEEE Power & Energy Society General Meeting (PES)*, Atlanta, GA, 2019 *[accepted for publication]*

Questions and Answers

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BPS IBR Modeling Fundamentals

Songzhe Zhu, California ISO
David Piper, Southern California Edison
Deepak Ramasubramanian, Electric Power Research Institute
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommended BPS-Connected IBR Modeling Techniques

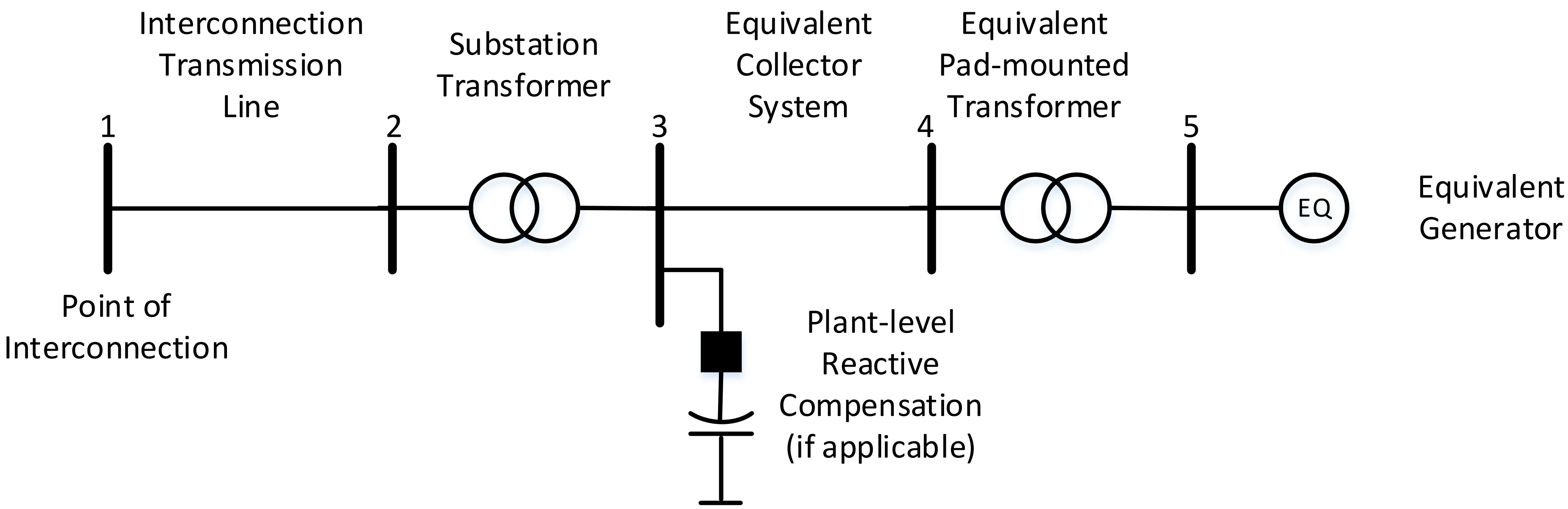
Songzhe Zhu, California ISO
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Power Flow Representation

- BPS-connected IBR powerflow representation

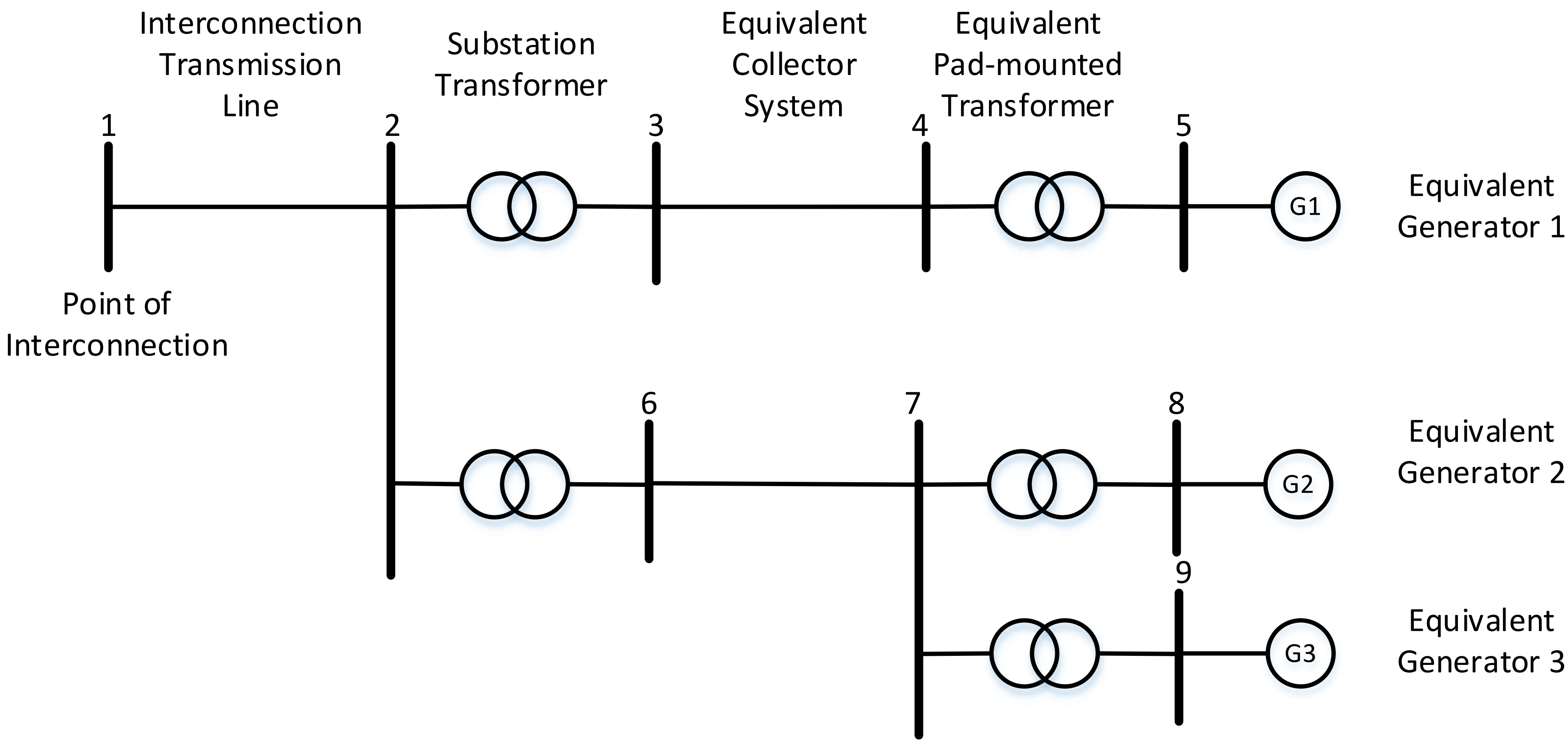


Typical Single-Generator Equivalent Power Flow Representation

Collector System & IBR Equivalencing

- Equivalent impedance of the collector system shall be represented
  - Inverters respond to the terminal voltage
  - Voltage at POI and terminals are quite different
- Multi-generator representation may be needed
  - Multiple main GSUs, with separate collectors behind them
  - Significantly diverse impedances behind different feeders
  - Inverters by different manufacturers are installed behind the feeders and these inverters have different control and protection settings

Multi-Generator Representation



Illustrative Multi-Generator Equivalent Power Flow Representation

* Although not illustrated by this example, all var devices should be modeled explicitly.

Dynamic Models

- Generic models
  - Approved by the regional entity for the interconnection, such as WECC
  - Models are supported and benchmarked among different software platforms
  - Easy access to model documents and user guides
  - Positive-sequence dynamic models
  - Generally applicable for systems with a short circuit ratio of 3 and higher at the point of interconnection
- User-written models
  - Specifically developed for the equipment and the level of transients modeled customized to fit the particular study purpose
  - Used in the SSR/SSCI studies, weak grid studies, etc.
  - Lack of documentation and “black box” to the transmission planners

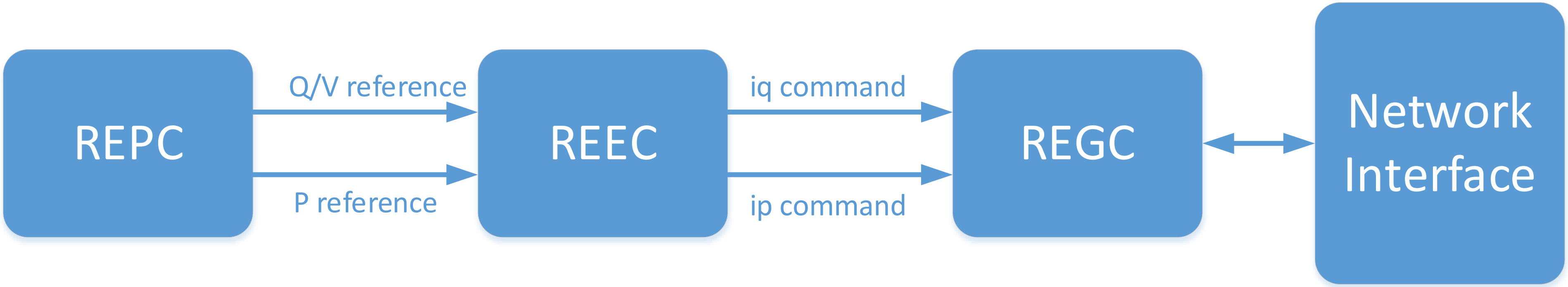
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Generic Dynamic Models

Description	Model Name	Applicability Notes
Converter	REGC_A	All IBR
Electrical control	REEC_A REEC_B REEC_C	Type 3 and 4 WTG, solar PV using momentary cessation Solar PV not using momentary cessation Battery energy storage
Plant controller	REPC_A REPC_B	 For controlling multiple devices
Ride-through protection	LHVRT LHFRT	Voltage ride-through Frequency ride-through
Drive-train	WTGT_A	Type 3 and 4 WTG
Turbine aero-dynamics	WTGAR_A	Type 3 WTG
Pitch control	WTGPT_A	Type 3 WTG
Torque controller	WTGTRQ_A	Type 3 WTG

The model library will expand with more modeling enhancement

Generic Model Structure



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Scaling for the Equivalent Generator Size

- Pmax and MVA base in the power flow model and dynamic models are aggregated values
- Power flow model –
  - MVA base is the sum of the individual MVA base of the inverters
  - Pmax is the maximum active power output from the equivalent generator in accordance with the generation interconnection study and interconnection agreement
    - often lower than the sum of the individual rated MW of the inverters due to the practice of oversizing inverters
- Dynamic models –
  - Model parameters are expressed in per unit of the MVA base for the model
  - Typically MVA base matches the MVA base in the power flow model

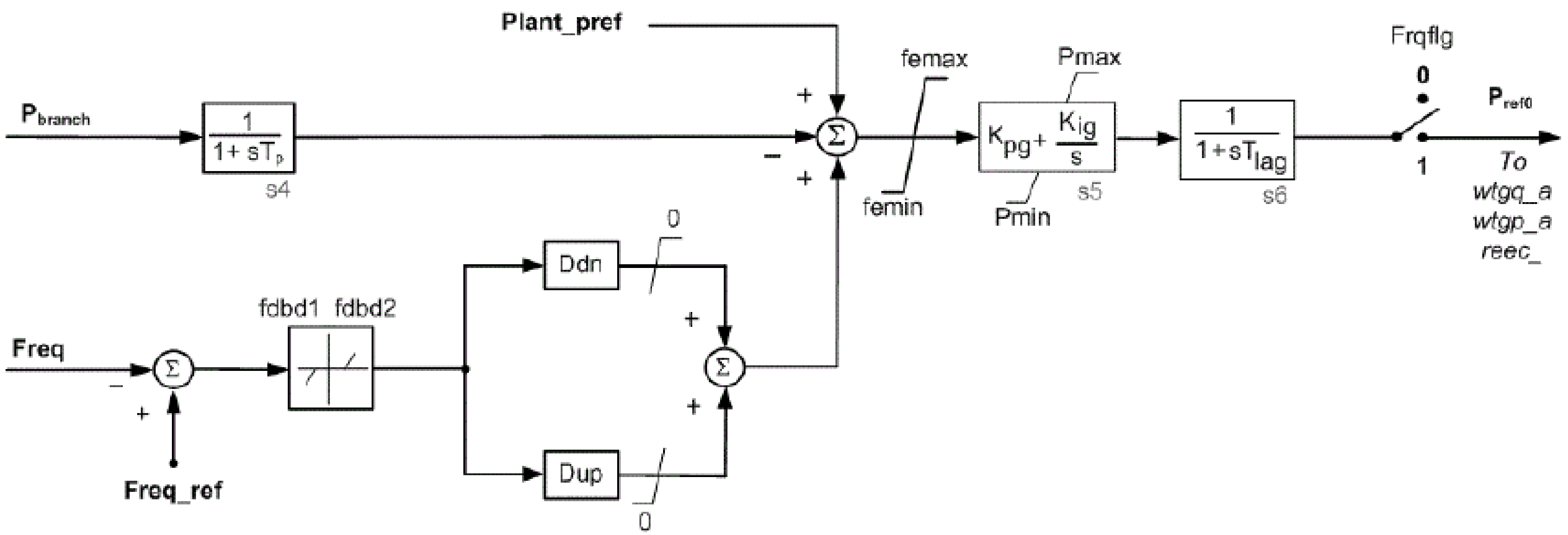
Active Power – Frequency Control Options

- Power flow model: base load flag (BL)
  - BL = 0: Pgen can be dispatched downward and upward
  - BL = 1: Pgen can be dispatched downward only
  - BL = 2: Pgen is fixed
- Dynamic model: REPC
  - frqflag= 0/1: governor response no/yes
  - ddn & dup: downward & upward regulation control gain (pu power/pu freq on MVA base)
  - fdbd1 (+) & fdbd2 (-): over- and under-frequency deadband for frequency response (pu)

Functionality	BL	frqflag	ddn	dup
No response	2	0	N/A	N/A
Down regulation only	1	1	>0	0
Up and down regulation	0	1	>0	>0

Active Power – Frequency Control Key Parameters

- Other control parameters in REPC for frequency response
  - Kpg: proportional gain
  - Kpi: integral gain
  - Tlag: lag time constant



Source: PSLF Manual

Reactive Capacity Requirement

- Interconnection requirement for IBR reactive capacity has evolved
  - No requirement
  - 0.95 lead/lag power factor at point of interconnection for wind resources
  - FERC Order No. 827 – 0.95 lead/lag power factor at high-side of the generator substation (point of measurement) and shall be dynamic
- The modeling recommendation in this presentation focuses on IBR complying with FERC Order No. 827

Model IBR Reactive Capability

- Inverter P-Q capability
  - Manufacturer provides P-Q capability curves under different ambient temperatures and DC voltages
  - The transmission planners use the P-Q capability curves to verify if there is sufficient capability to meet the interconnection requirement
- Generator reactive capability in the power flow model
  - The reactive capability is modeled per requirement
  - Qmax and Qmin of the equivalent generator are reactive capability at Pmax, limited by the minimum amount to meet the interconnection requirement
- Generator reactive capability in the dynamic models
  - The physical capability is modeled, not limited by the PF requirement

Reactive Power – Voltage Control in Power Flow

Assuming the only dynamic var sources are inverters –

- If inverters regulating voltage at point of measuring (POM)
  - Voltage regulation bus is the high-side bus of the GSU
  - The Generator is set to cont_mode = 2 with pf = 0.95, i.e. the power flow solution will try to hold voltage at the regulated bus constant within Q limits specified by pf
- If inverters regulating terminal voltage
  - The Generator is set to cont_mode = -2 with pf ≤ 0.95, i.e. the power flow solution will try to hold terminal voltage constant within Q limits specified by pf
- Voltage regulation of LTC transformers
  - Type 2 transformers; load tap changer on the "from" winding
- Controlled shunts – SVD

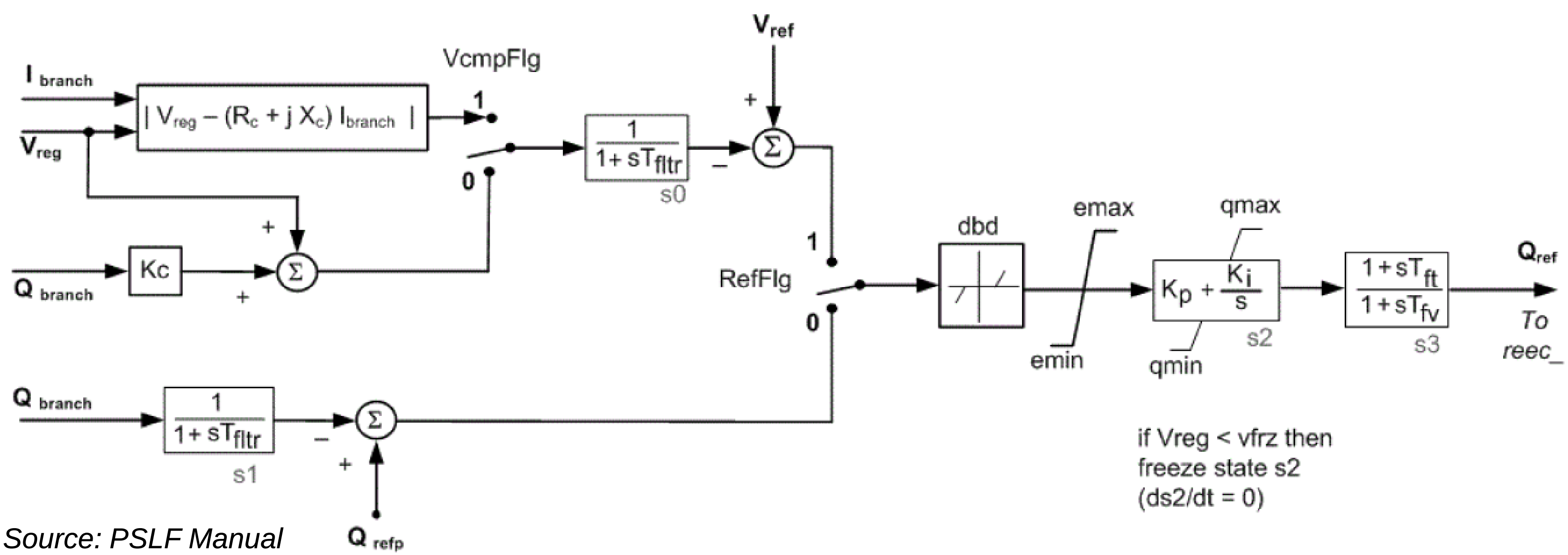
Reactive Power – Voltage Control in Dynamic Models

- Different voltage control options are modeled by the combination of pfflag, vflag and qflag in reec model and refflag in repc model

Functionality	PfFlag	Vflag	Qflag	RefFlag
Constant local PF control	1	N/A	0	N/A
Constant local Q control	0	N/A	0	N/A
Local V control	0	0	1	N/A
Local coordinated V/Q control	0	1	1	N/A
Plant level Q control	0	N/A	0	0
Plant level V control	0	N/A	0	1
Plant level Q control + local coordinated V/Q control	0	1	1	0
Plant level V control + local coordinated V/Q control	0	1	1	1

Plant Level Reactive Power – Voltage Control Options

- Voltage Control: reflag=1
  - Select the regulating bus (Vreg)
  - Set VcmpFlg=1 if using line drop compensation (Rc and Xc)
  - Set VcmpFlg=0 if using reactive droop (Kc)
- Constant Q Control: reflag=0
  - Select the monitored branch



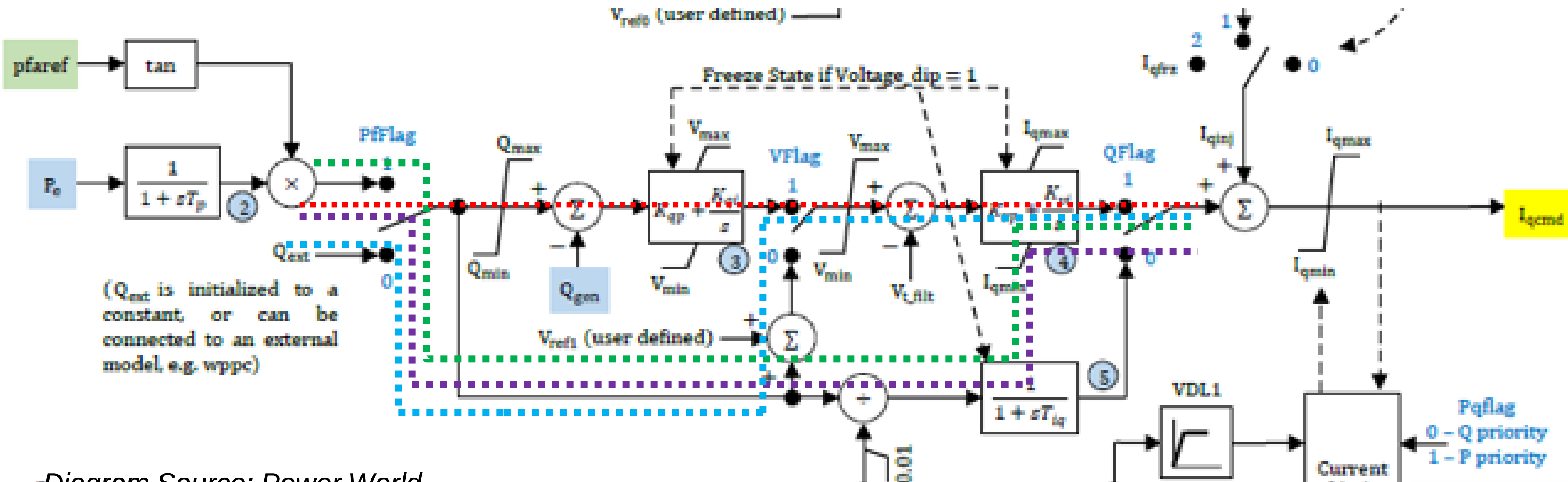
Source: PSLF Manual

Plant Level Reactive Power – Voltage Control Key Parameters

- Key parameters
  - Control deadband (dbd)
  - Input (emax/emin) and output (qmax/qmin) limits
  - Control gains (kp/ki)
  - Intentional phase lead (Tft)
  - Communication lag (Tfv)
  - Voltage threshold to freeze plant voltage integral control (vfrz)

Inverter Level Reactive Power – Voltage Control Options

If no plant controller…



-Diagram Source: Power World

- PF Control
- Constant Q Control
- Local V Control
- Local Coordinated Q/V Control

Inverter Level Reactive Power – Voltage Control Options (Cont.)

If coordinated with plant controller…

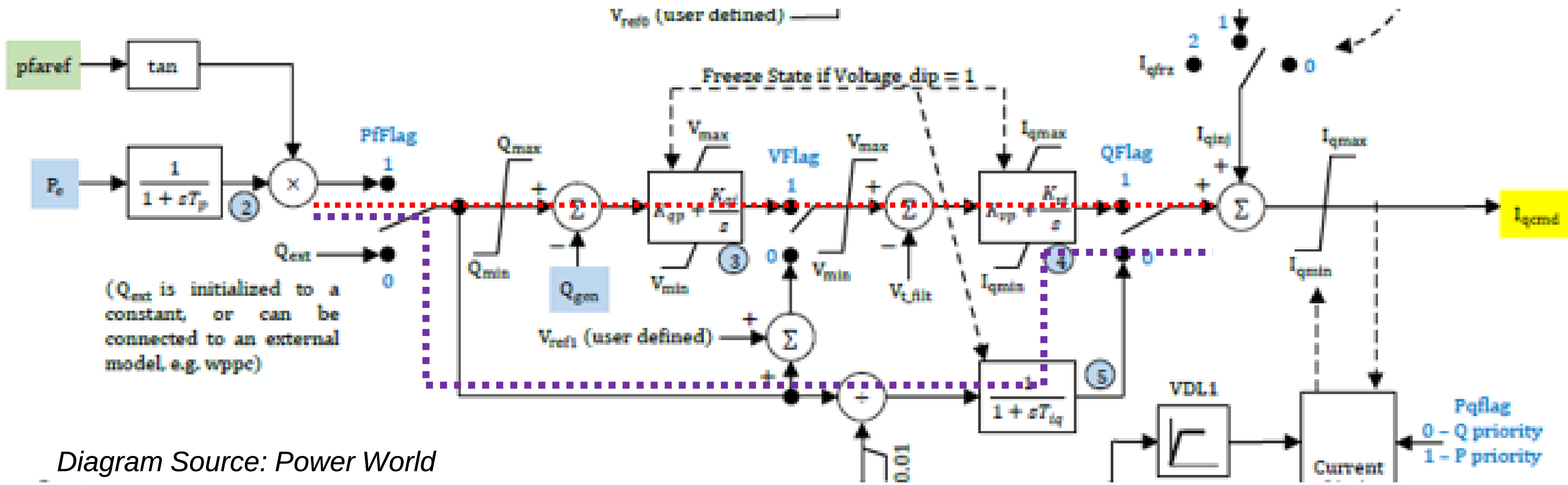


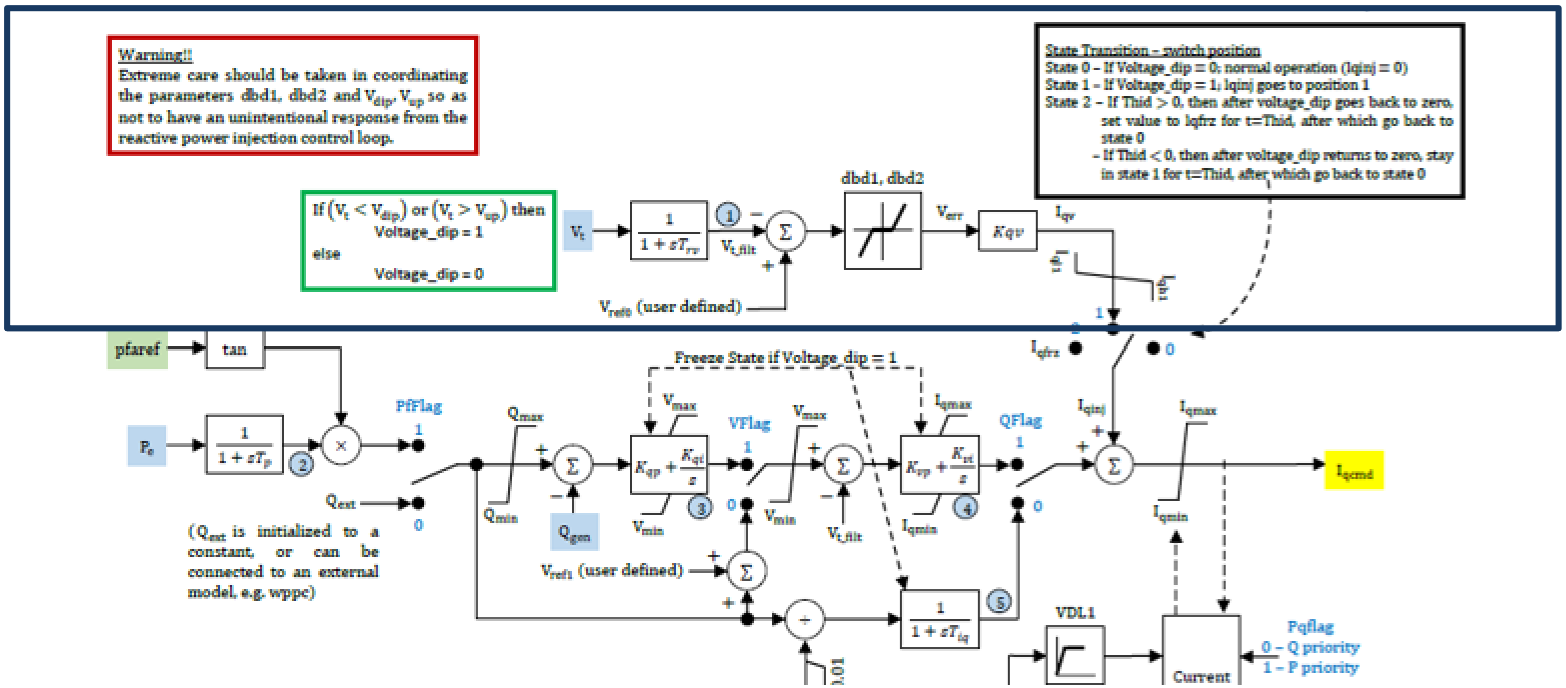
Diagram Source: Power World

Plant level Q or V Control

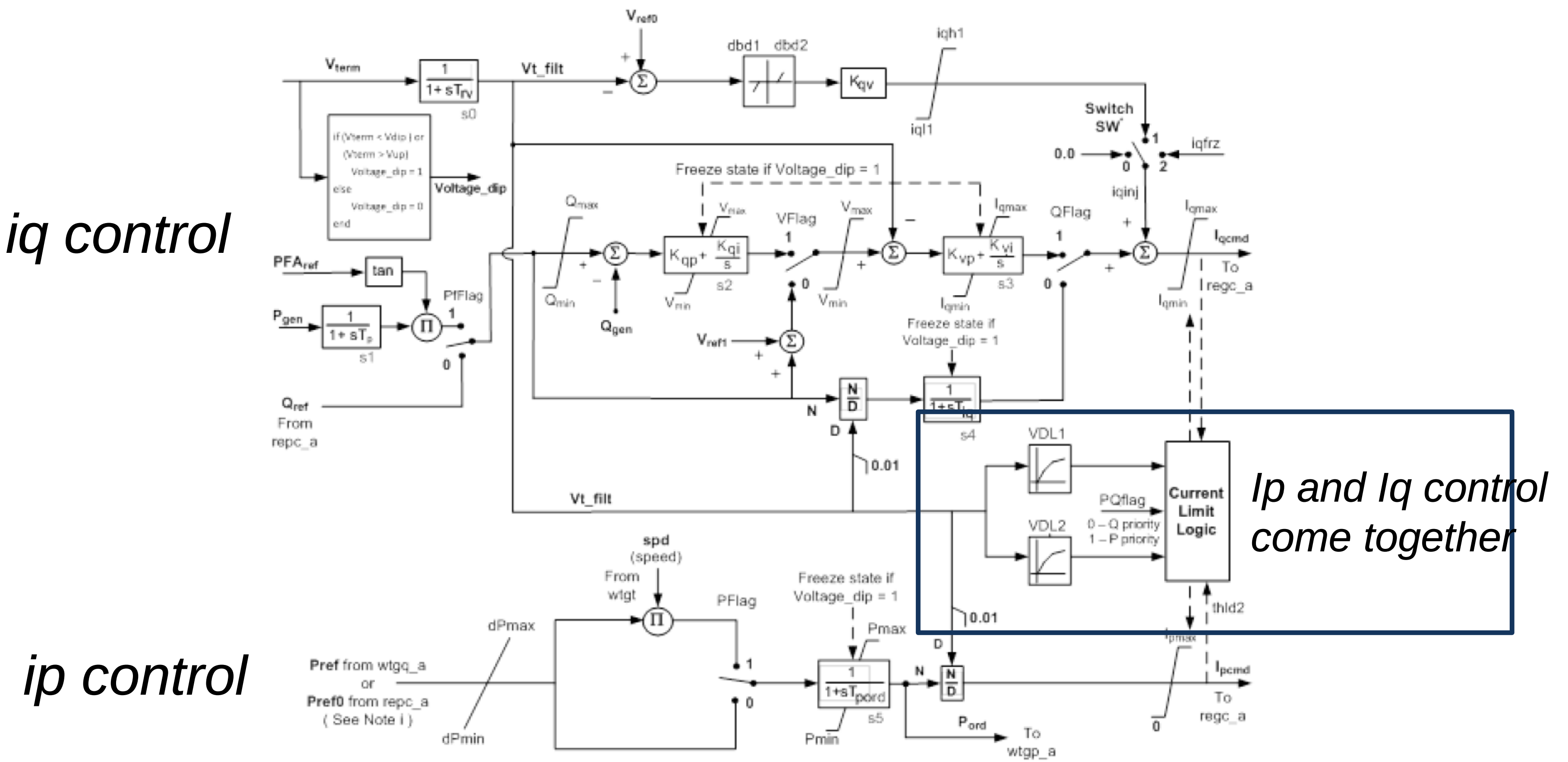
Plant level Q or V Control and Local Coordinated Q/V Control

Inverter Level Reactive Power – Voltage Control during Voltage Dip

- Voltage dip: Vt < Vdip or Vt > Vup
- During voltage dip, local Q control and local V control freeze
- K-factor control: proportional gain Kqv



Inverter Current Limit



Invert Current Limit (Cont.)

- Define the maximum inverter current imax
- REEC_A: voltage-dependent current limits for ip and iq separately (VDL1 and VDL2)
- Total current $\sqrt{i_p^2 + i_q^2}$ is limited by imax
- During low voltage, ipcmd or iqcmd may be reduced until the voltage recovers depending on P/Q priority

If (pqflag = 0) {Q priority}

Iqmax = Imax

Iqmin = - Iqmax

Ipmax = $\sqrt{Imax^2 - Iqcmd^2}$

Ipmin = 0.0

else {P priority}

Iqmax = $\sqrt{Imax^2 - Ipcmd^2}$

Iqmin = - Iqmax

Ipmax = Imax

Ipmin = 0.0

End

Coordinate Plant Level and Inverter Level Controls

- Key factors to achieve desired control performance –
  - Choose control option: plant level control or plant level control and local coordinated control
  - At what voltage levels, freeze plant level Q/V control (vfrz) and local Q/V control (vdip) taking into account plant controller regulates POM bus voltage while the inverter controller regulates terminal bus voltage
  - At what voltage levels, k-factor control shall be activated
  - Control gains and time constant associated with each control mode
  - P/Q priority

Frequency Ride-through

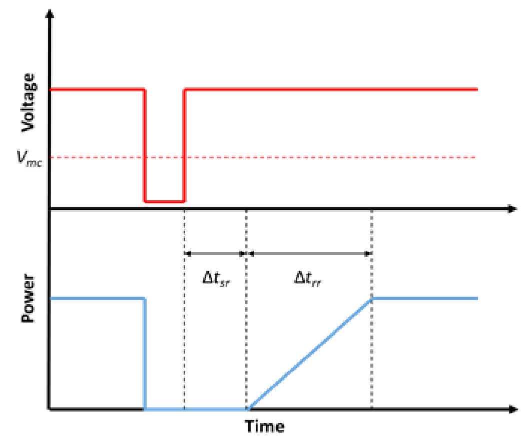
- Lhfrt model parameters should match the actual frequency protective relay settings and are verified with EMT simulations
- The settings should be PRC-024 compliant
- Frequency calculation in positive sequence stability programs are not accurate during and immediately following the fault
- Work-around of false frequency tripping for a close-by simulated fault –
  - Use lhfrt in “alarm only” mode and analyze each individual alarms
  - Disable frequency tripping under low voltage condition
  - Do not set instantaneous tripping and always include some delay for frequency tripping

Voltage Ride-through

- Lhvrt model parameters should match the actual voltage protective relay settings and are verified with EMP simulations
- The settings should be PRC-024 compliant
  - PRC-024 requirement is set with voltage at the point of interconnection (POI)
  - The actual protection is set with terminal voltage
  - The voltage set points should take into account the difference between inverter terminals and POI

Model Solar PV Momentary Cessation

- Model structure: REGC, REEC_**A**, REPC
- Modeling elements
  - Current reduction during cessation [REEC_A].VDL1 and VDL2
    - set current limits to 0 for both ip and iq when the voltage is below $V_{mc\text{-}lv}$ or above $V_{mc\text{-}hv}$
  - Disable low voltage power logic [REGC].lvplsw = 0
  - Ramp control [REGC].rrpwr, iqrmax and iqrmin
  - P/Q priority during recovery [REEC_A].pqflag
  - Voltage dip logic [REEC_A].vdip = $V_{mc\text{-}lv}$, vup = $V_{mc\text{-}hv}$
  - Active current recovery delay [REEC_A].thld2



Modeling enhancements under development:
- *VDL1 and VDL2 are being expanded*
- *Reactive current recovery delay will be added*

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Practical Experience Working with IBR Models

David Piper, Southern California Edison

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




History of Renewable Models

- User-written models
  - Not necessarily tested/benchmarked.
  - Software limits
  - Troubleshooting challenges
  - Model version issues
- 1st generation renewable models
  - Solar PV plants could be modeled with wind models
  - Did not include full range of possible control implementations
- 2nd generation renewable models
  - Expanded control architecture and added parameters
  - Included additional fault ride-through logic
- Future improvements…

https://www.esig.energy/wiki-main-page/generic-models-individual-turbines/#Generic_Type_IV_Model_.28Phase_II.29

A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik and J. J. Sanchez-Gasca, "Description and technical specifications for generic WTG models — A status report," *2011 IEEE/PES Power Systems Conference and Exposition*, Phoenix, AZ, 2011, pp. 1-8.

Models in 2019 WECC Base Cases

Model Type	Solar PV MW	Total MW in case
REEC_A	0	5,717
REEC_B	11,216	12,805
wt1g	N/A	1,235
wt2g	N/A	1,635
wt3g	N/A	5,386
wt4g	1,184	4,617
gewtg	23	3,165
Total	**12,423**	**34,560**

Note: Table is based on turbine type flag in case, which is not always correct

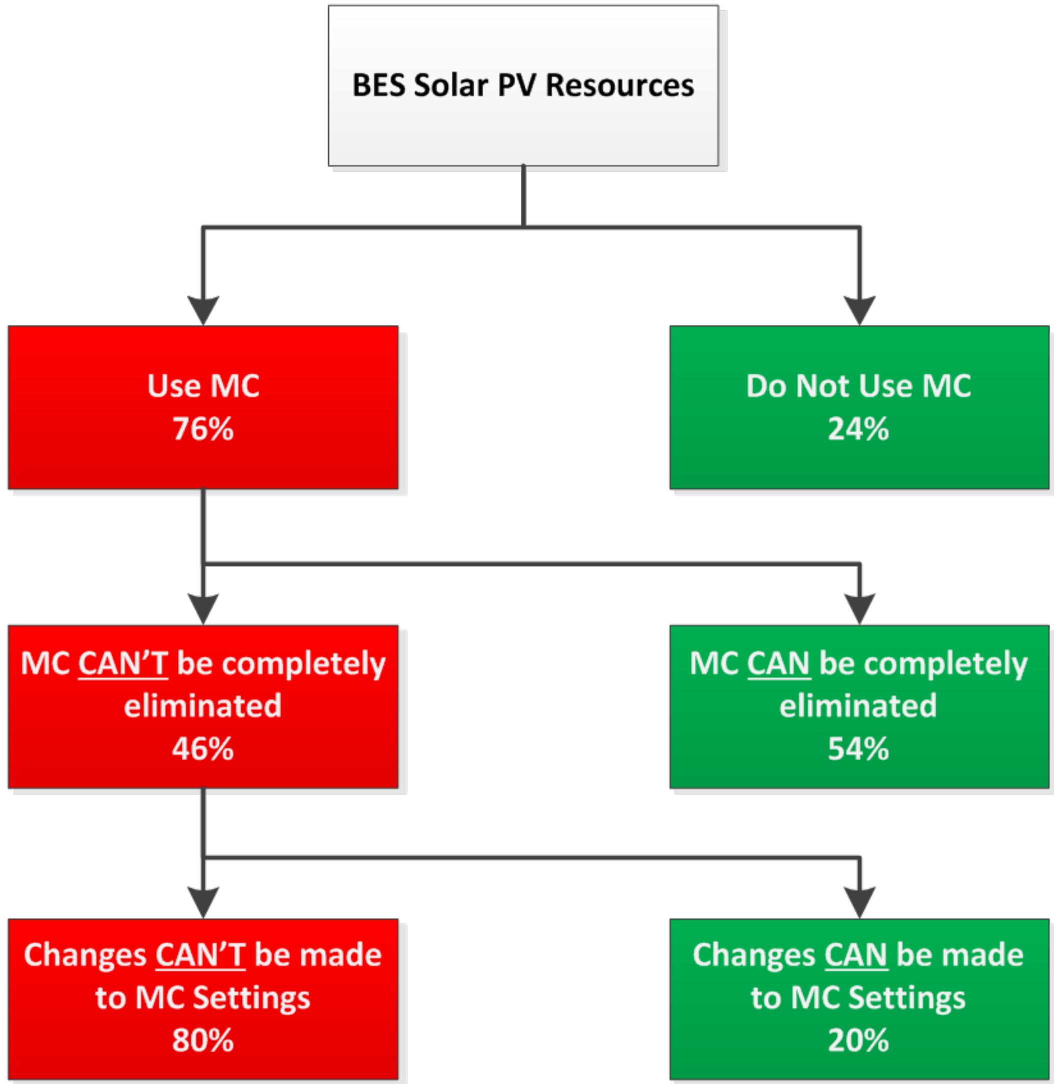
Key takeaways:

- No PV modeled as REEC_A
  - MC delay is not captured
- Some PV is still modeled as WT4G and GEWTG

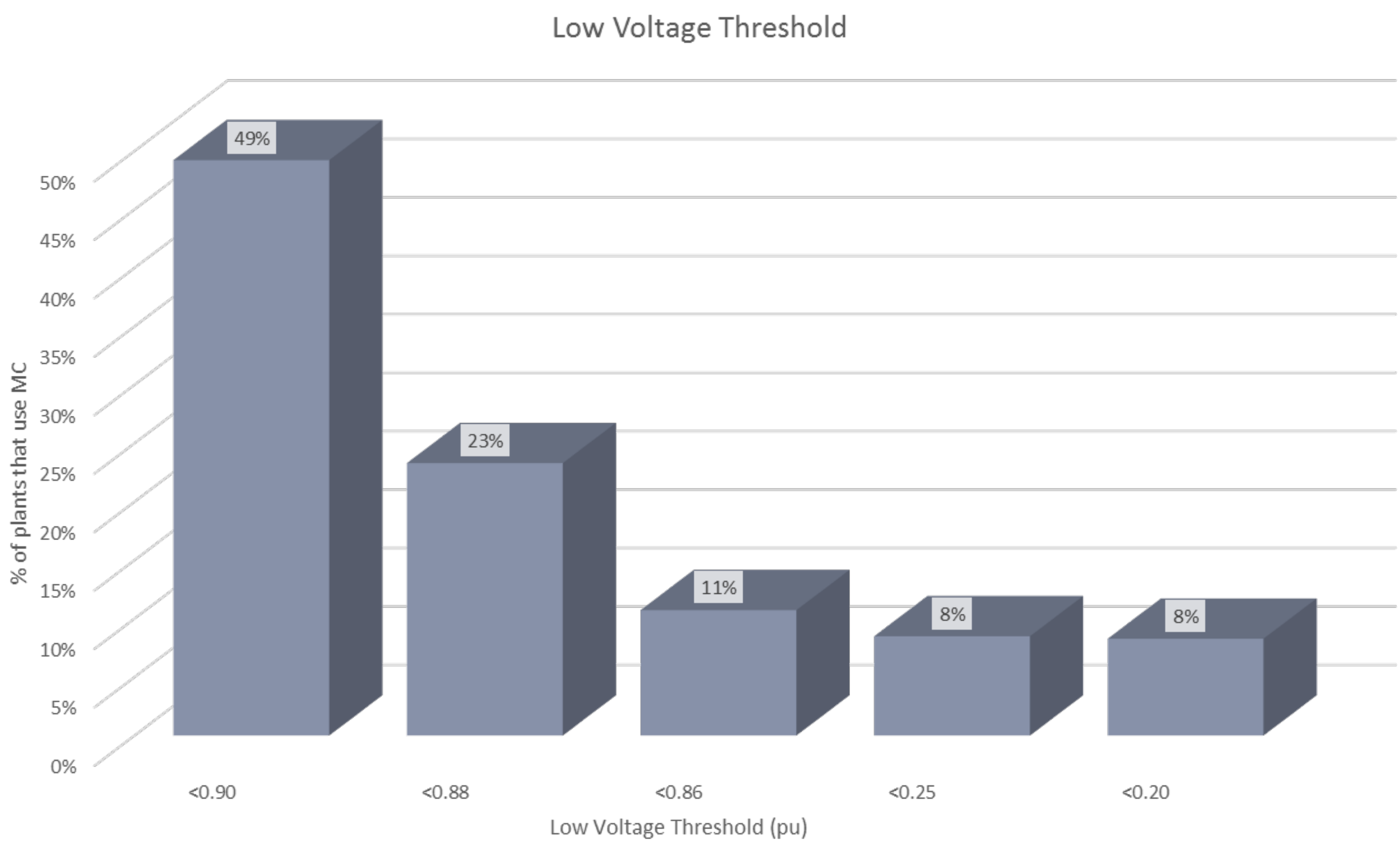
Updating Existing Models

- Renewable models were implemented into base cases using the best information and dynamic models that were available at the time.
- Newest models should be used to accurately capture plant dynamic performance, namely:
  - Momentary Cessation
  - Frequency/Voltage ride-through limitations
- In 2018, SCE and CAISO sent data requests to selected generators. Requested data includes:
  - Momentary Cessation settings
  - Ride through settings
- SCE and CAISO will eventually capture all generators that participate the CASO market

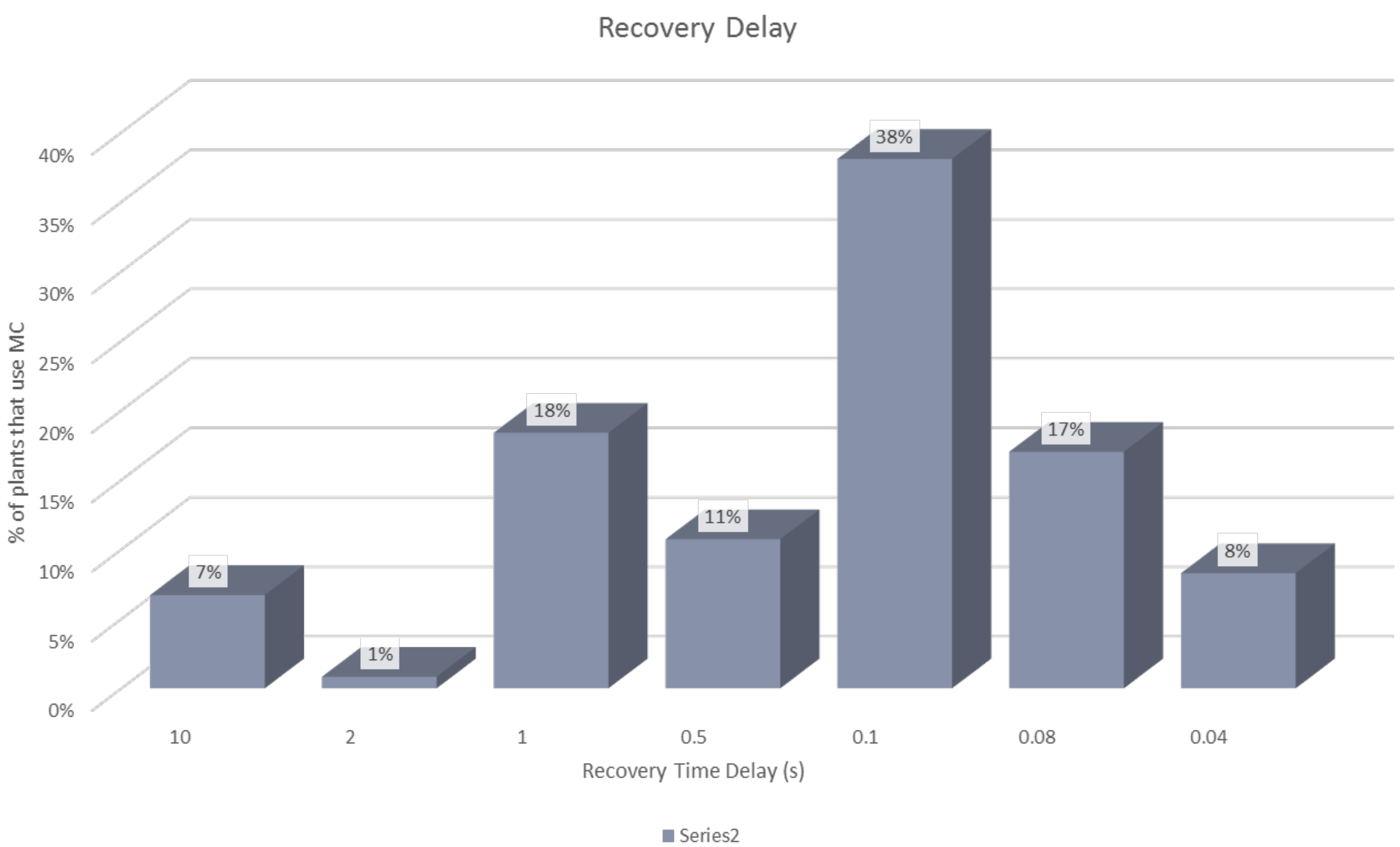
Momentary Cessation Usage (2018)



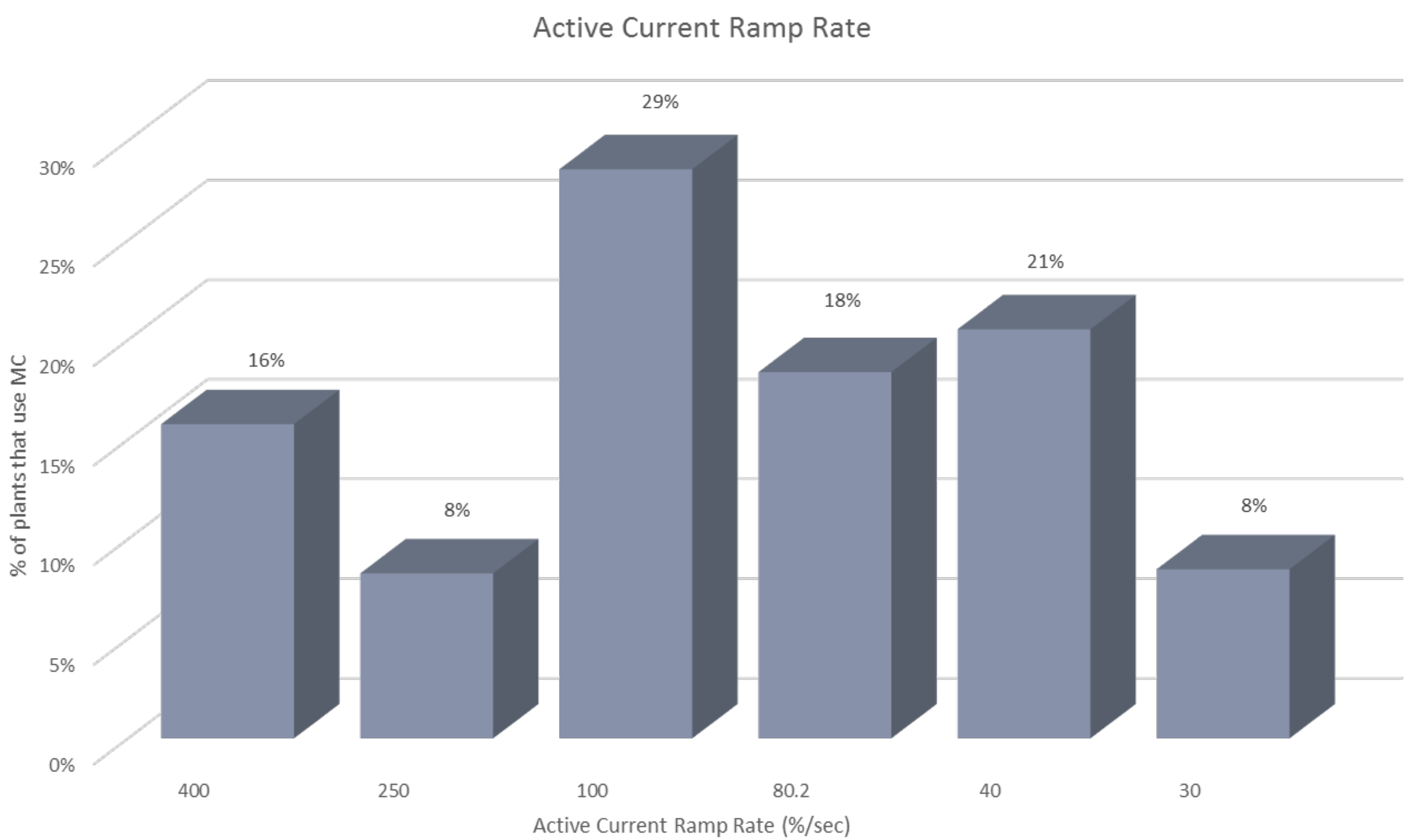
Momentary Cessation Settings (2018)



Momentary Cessation Settings (2018)



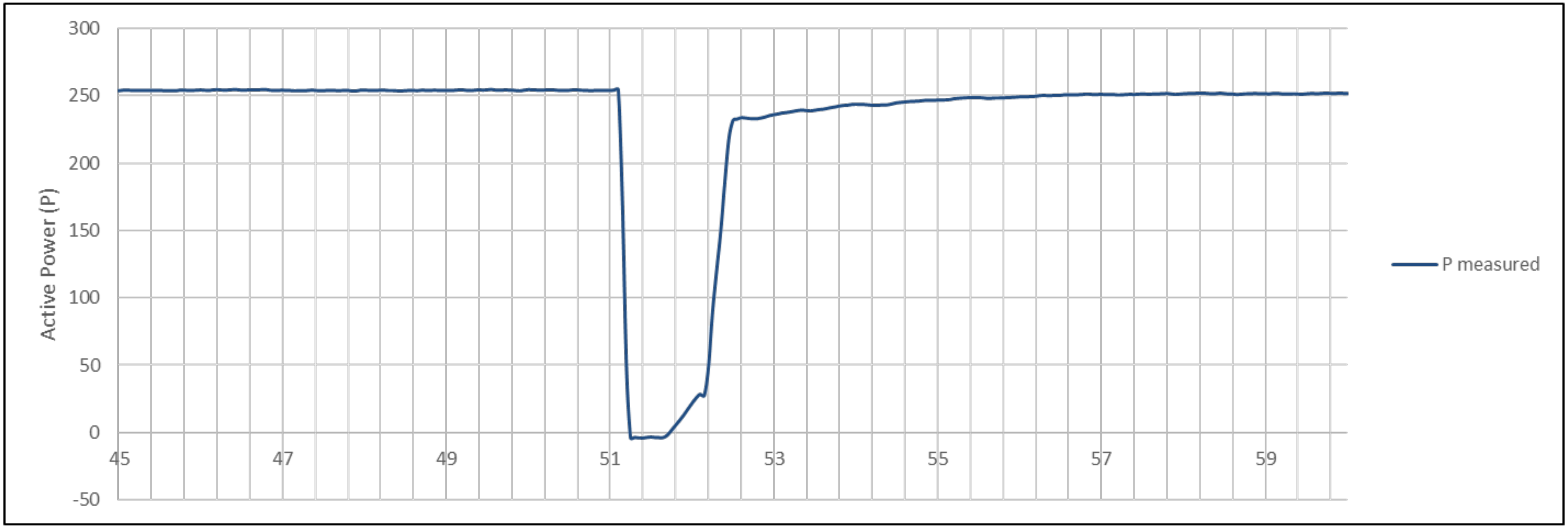
Momentary Cessation Settings (2018)



Commissioning and Testing

- Most commissioning and/or model verification tests perform:
  - Verification of gross and net real (P) and reactive (Q) power capability
    - MOD-025-2
  - Verification of Models and Data for Generation Excitation Control System
    - Voltage reference step test (staged)
    - MOD-026-1
  - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
    - Speed governor reference change (staged)
    - Partial load rejection test (staged)
    - MOD-027-1
- Event analysis can identify errors in dynamic model performance.
  - Momentary Cessation
  - Tripping due to voltage/frequency excursion

Example: Comparison of Event to Plant Model



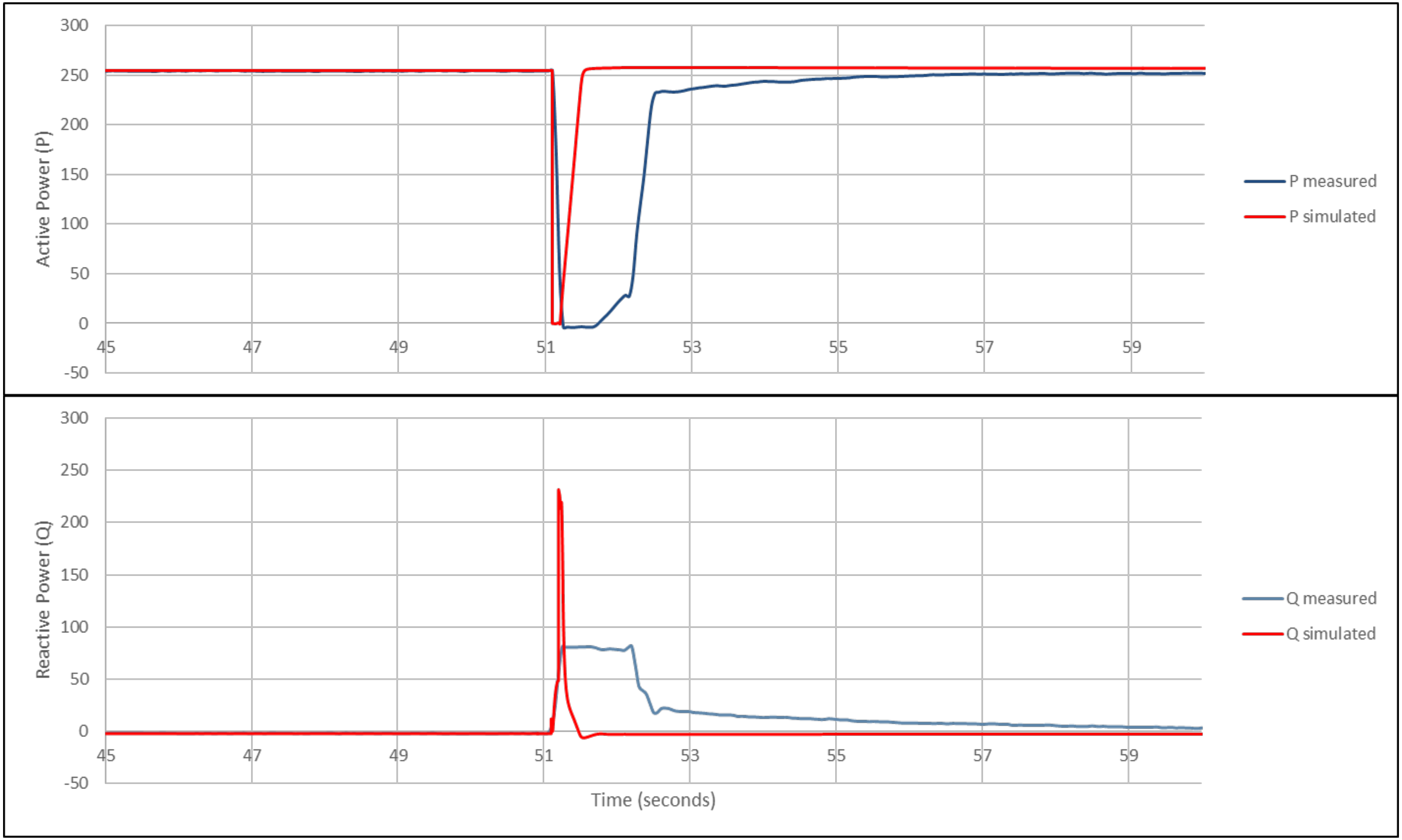
- Several observations can be made from high speed event records:
  - This plant clearly uses momentary cessation
  - Possibly two inverter types or settings (groupings), evidenced by piecewise recovery response
  - Active current recovery delay in this case is about 1 sec for largest grouping
  - Ramp rate ~1.3-1.4 pu/s for largest grouping

Example: Analysis of Plant Model (Momentary Cessation Parameters)

- In this example, reec_b was used to model the plant
  - reec_a not used
    - No ability to control active power recovery delay
    - VDL1 and VDL2 blocks can't be used to define MC breakpoints
- regc_a defines MC breakpoints and Active Power ramp rate

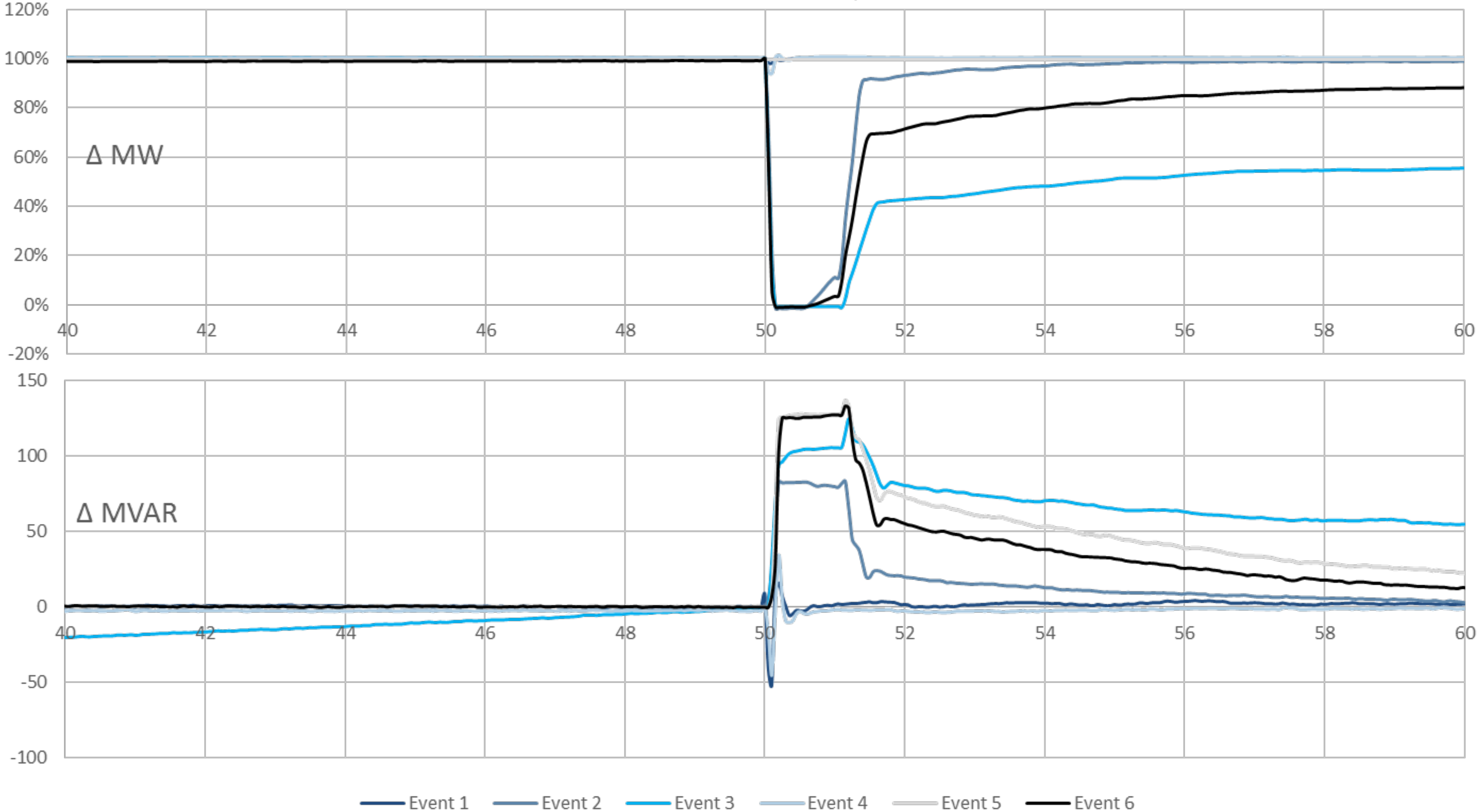
Model	Parameter	Value
regc_a	LVPLSW	1
	RRPWR	1.4
	BRKPT	0.9
	ZEROX	0.5
	LVPL1	1.1

Ex: Measured vs Simulated Performance Room for Improvement



Multiple Event Records May be Needed When Analyzing Models

- More than one event should be compared to model



Benchmarking model with EMT model

- Detailed, vendor-specific 3-phase models can (and probably should) be used to benchmark generic Renewable Energy System models that are provided to Transmission Planners when staged tests are not possible.
  - PSCAD
  - Matlab
  - EMTP-RV
  - Etc
- Large signal disturbance performance accuracy should be emphasized
  - Such as response to system faults

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Key Takeaways

- Accurate modeling critical for reliable operation and planning of the bulk power system
- Power plant controls and technologies are evolving and the models need to reflect these changes accordingly
- Plant-level controls can and should be modeled, as appropriate, if they affect the unit in the dynamics timeframe
- Generator testing programs have benefits beyond standards compliance
- Planners should require sufficient, clear, and comprehensive reports of the development of a baseline model and/or reverification – “trust but verify”
- Disturbance-Based PPMV

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Modeling Issues: Now and Into the Future

Deepak Ramasubramanian, EPRI
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY

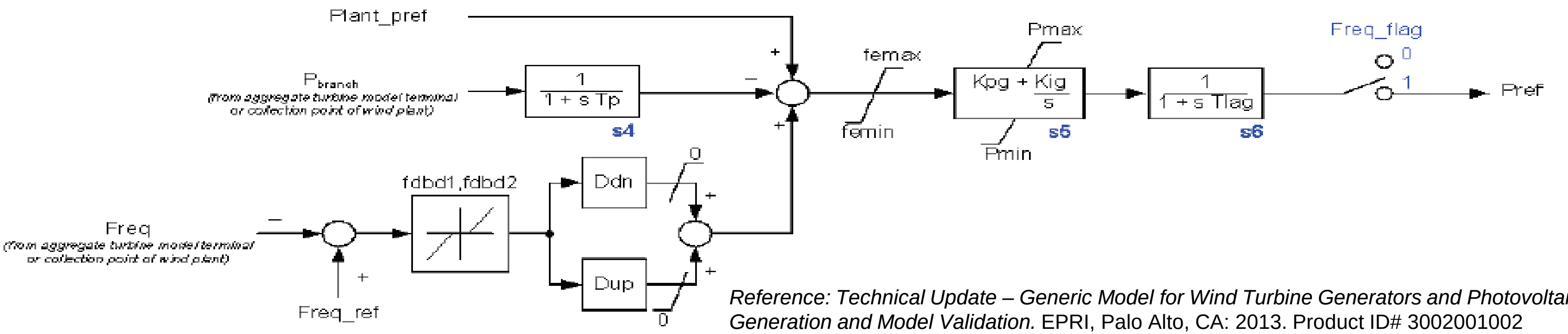



Present Day Modelling Obstacles

Frequency response…

- How many are familiar with the MWcap or TRATE parameter in GE-PSLF™ or Siemens PTI PSS®E, respectively?
- What does this parameter signify?
  - It sets the rating of the turbine behind the generator.
  - The rating of the turbine is generally lower than the rating of the machine
- What does this parameter do?
  - Serves as a base for the per unit quantities in the turbine-governor model (e.g. TGOV1, GGOV1)
- Why is it important?
  - It defines the maximum, and amount of frequency dependent power that can come from the turbine, and thus generator

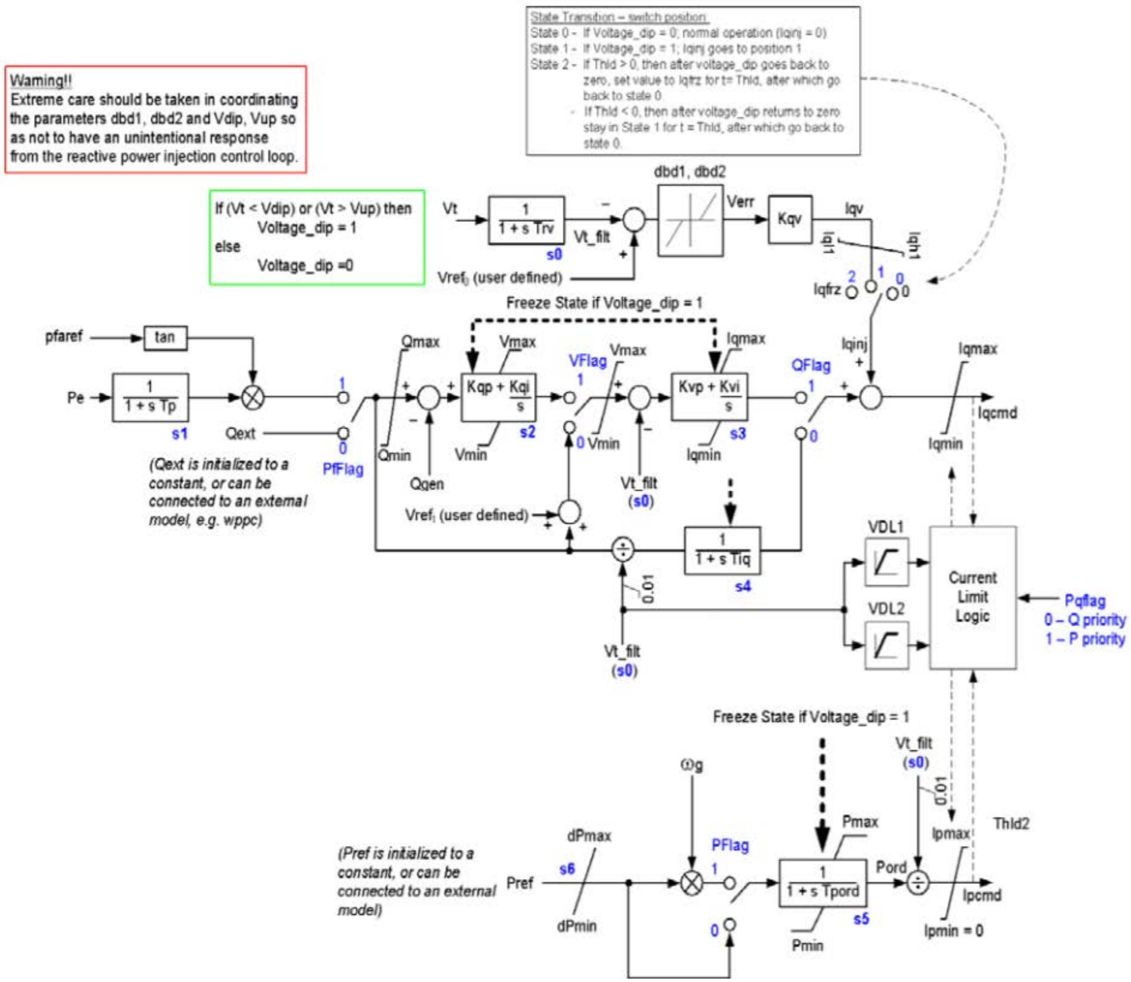
But, in REPC_*...



Reference: Technical Update – Generic Model for Wind Turbine Generators and Photovoltaic Generation and Model Validation. EPRI, Palo Alto, CA: 2013. Product ID# 3002001002

- There is no corresponding MWcap or TRATE parameter
  - Why? Because the maximum amount of power that is available is highly dependent on the amount of available solar/wind energy
- This has to be considered while enabling the frequency control loop, especially for under frequency response. There is a difference between:
  - Being dispatched to say a power level of 0.8pu (Here Pref = 0.8pu, while Pmax = 1.0pu)
  - There being only 0.8pu of power available (Here, Pref = Pmax = 0.8pu)

Local voltage control...



- If voltage control is enabled either through Qflag = 1, and/or Vflag = 1
  - Then, either Kqp/Kqi, or Kvp/Kvi should be non – zero.

Reference: Technical Update – Generic Model for Wind Turbine Generators and Photovoltaic Generation and Model Validation. EPRI, Palo Alto, CA: 2013. Product ID# 3002001002

Future Modeling Challenges

Robust model for low short circuit

- Present REGC_A model can suffer from numerical instability
- Can show a stable post fault recovery

- This is being tackled with the development of two new models
  - REGC_B – this model is expected to be numerically robust
  - REGC_C – this model is expected to be numerically robust and be able to show some of instabilities that occur in low short circuit conditions
    - NOTE: It is not intended to replace detailed EMTP studies, but instead help bridge the gap

Inertial response...

- Although explicitly disavowed by FERC Order 842, inertial response capability is presently used in many existing wind plants
- If viable, this kind of response could also be used to supplement droop response
- Representation of this response is being tackled by the development of a new model

References

Reliability Guideline – PPMV Inverter-Based Resources

https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/PPMV_for_Inverter-Based_Resources.pdf

Reliability Guideline – Inverter Based Resource Performance Guideline

https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

Reliability Guideline – Modeling Distributed Energy Resources in Dynamic Load Models

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

Reliability Guideline – Integrating Inverter-Based Resources into Low Short Circuit Strength Systems

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

Reliability Guideline – Power Plant Model Verification Using PMUs

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Power%20Plant%20Model%20Verification%20using%20PMUs%20-%20Resp.pdf

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Recommended Study Approaches for IBR

NERC IRPTF Meeting
February 2019

RELIABILITY | ACCOUNTABILITY




NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

CAISO Reliability and Interconnection Studies

Songzhe Zhu, California ISO

RELIABILITY | ACCOUNTABILITY

Growth of IBR within CAISO Controlled Grid

- As of January 2019, grid connected IBR

	Solar	Wind	Battery
MW Capacity	11,868	6,505	136
% of All Resources	17%	9%	0.2%

- Forecast in 2024

	Solar	Wind
MW Capacity	15,500	7,200

- Behind-the-meter PV capacity forecast

	2019	2022	2025	2028
MW Capacity	8,065	10,877	13,508	15,834

Reliability Challenge of the High IBR Penetrated Grid

- Observed and potential impacts on system stability due to
  - Lack of frequency response capability or headroom
  - Momentary cessation used by the existing IBR
  - Limited reactive capability during disturbance
  - Fast control with high control gains causing oscillation
  - Tripping of distributed IBR during large transmission disturbances
- System short circuit strength
- Sub-synchronous resonance and sub-synchronous control interactions

Scenario Development for Reliability Assessment

- Assess system reliability under scenarios representing stressed dispatch conditions
  - Load: high load condition is not necessarily more stressed than light load
  - High dispatch of IBR
  - Low unloaded online capacity margin for synchronous generators
  - High power transfers across critical transmission paths
- Reality check of the stressed dispatch conditions
  - Forecasts of load and resources from regulatory agencies
  - Verify dispatch conditions against historical data and hourly production cost simulation for future years
- Develop sensitivities to address uncertainties

Stability Analysis Approach

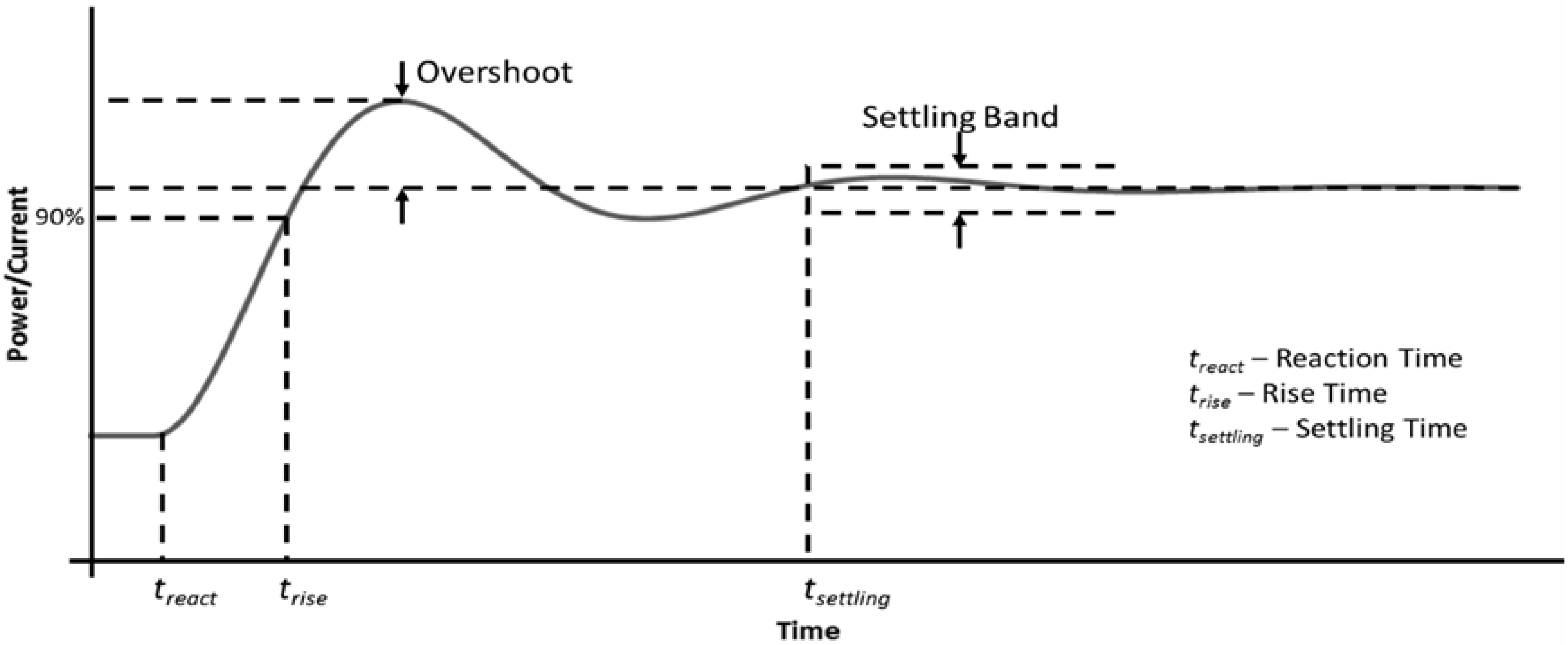
- First and most importantly, the study needs accurate dynamic models
- For bulk system assessment, select contingencies that produces the more severe system impact in accordance with TPL-001-4
  - Selection varies depending on the objectives of the assessment
  - Generally 3-phase-to-ground fault followed by loss of single element and single-phase-to-ground fault followed by loss of multiple elements
  - Extreme events

System Performance Requirement

- System performance is evaluated per TPL-001-4 and TPL-001-WECC-CRT-3.1
  - Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load.
  - Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.
  - For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
  - All oscillations that do not show positive damping within 30-seconds after the start of the studied event shall be deemed unstable.
  - The system remains stable and cascading and islanding shall not occur

NERC Reliability Guideline for IBR Performance

- The performance is defined by how fast and how much the IBR controlled currents respond to a disturbance



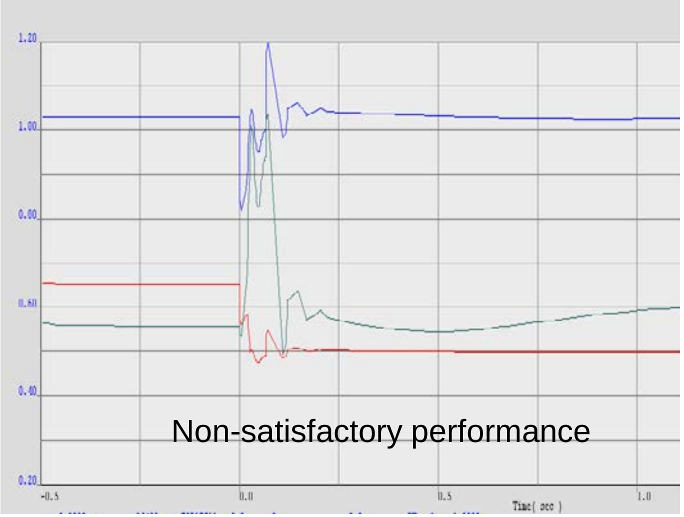
NERC Reliability Guideline for IBR Performance line

Table 2.1: Dynamic Active Power-Frequency Performance		
Parameter	**Description**	**Performance Target**
For a step change in frequency at the POM of the inverter-based resource…		
Reaction Time	Time between the step change in frequency and the time when the resource active power output begins responding to the change	< 500 ms
Rise Time	Time in which the resource has reached 90% of the new steady-state (target) active power output command	< 4 sec
Settling Time	Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power output command	< 10 seconds
Overshoot	Percentage of rated active power output that the resource can exceed while reaching the settling band	< 5%**
Settling Band	Percentage of rated active power output that the resource should settle to within the settling time	< 2.5%**

Table 3.2: Large Disturbance Reactive Current-Voltage Performance		
Parameter	**Description**	**Performance Target**
For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response should meet the following performance specifications…		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change	< 16 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90% of its final value	< 100 ms**
Overshoot	Percentage of rated reactive current output that the resource can exceed while reaching the settling band	Determined by the TP/PC***

Evaluate IBR Performance

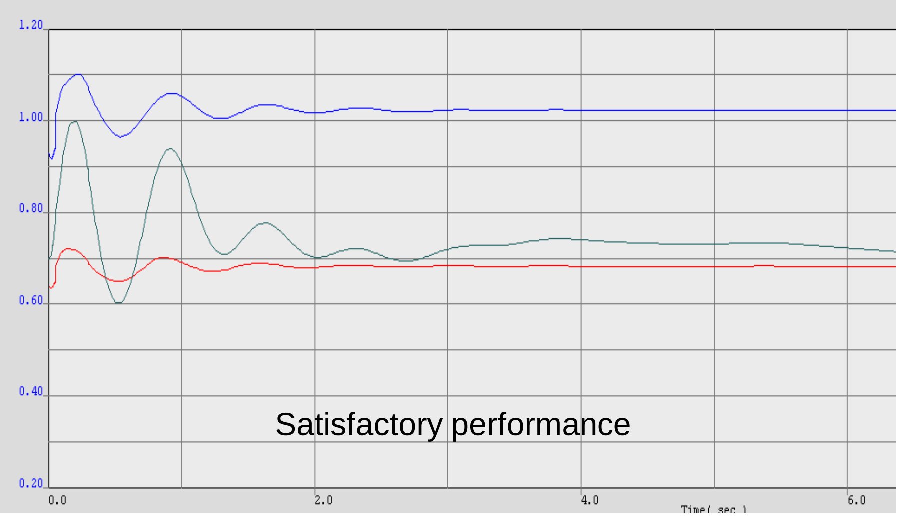
- Evaluation of IBR performance in simulation
  - Positively damped oscillation
  - Qg changes in the right direction to control voltage
  - Controlled voltage does not stay at the high voltage limit for more than a few cycles post-fault
  - Active power returns to pre-fault value
  - Ramping of active power is more than 1pu/sec



Vt

Qg

Pg



NERC Alert II on Loss of Solar Resources

- NERC alert on loss of solar resources during transmission disturbances due to inverter setting – II
  - Recommendations for generator owners to provide current inverters setting together with accurate dynamic models
  - Recommendations for generator owners to eliminate momentary cessation to the greatest extend possible and provide proposed settings together with proposed dynamic models
  - Recommendations for TP, PC, TO and RC to track, retain and use the updated models to identify any potential reliability risks related to instability, cascading, or uncontrolled separation
  - Recommendations for TP, PC, TO and RC to track, retain and analyze the proposed dynamic models, and to approve or disapprove the proposed dynamic models

Summary of Inverter Settings and Dynamic Models

- Most of the solar inverters use momentary cessation while more than half of them will eliminate momentary cessation

Total Submittal (MW)	No MC (MW)	Currently Using MC (MW)	MC Can Be Eliminated (MW)	MC Remaining (MW)
6601	843	5758	3250	2507

- Most common momentary cessation settings are
  - Low voltage threshold between 0.86 and 0.9 p.u.
  - Recovery delay less or equal to 0.5 sec
  - Active power recovery ramp rate greater or equal to 1 p.u./sec
- A few updated dynamic models are provided
- No proposed dynamic models are provided

Assessment of Loss of Solar Resources

- CAISO and its PTOs with solar resources within CAISO controlled grid performed the joint assessment in response to NERC Alert II
- Two scenarios were studied
  - 2019 heavy summer: 1-in-5 load condition for 2019 summer, solar output level 95%, wind output level 55%, COI, PDCI, EOR path flows based on highest imports in 2017 summer
  - 2019 light spring: 40% of summer peak load, solar output level 97% and wind output level 33%, COI, PDCI, EOR path flows based on highest imports in 2017 spring

Updating Dynamic Models

- Start from the WECC master dynamic file (MDF)
- Dynamic models, if provided by the GOs for current inverter settings, were used to replace the MDF models. Modifications were made to fix obvious discrepancy.
- The CAISO and the TPs modified the MDF models by incorporating the momentary cessation settings submitted, if models not provided by the GO.
- All model updates for MOD-032 compliance were incorporated.
- Corrections were made to achieve flat-run.

Creating Proposed Dynamic Models

- Start from the updated dynamic models for current settings
- If the MC can be eliminated, restore original MDF models.
- If MC can’t be eliminated but settings can be changed, modified the current setting models with the proposed settings.

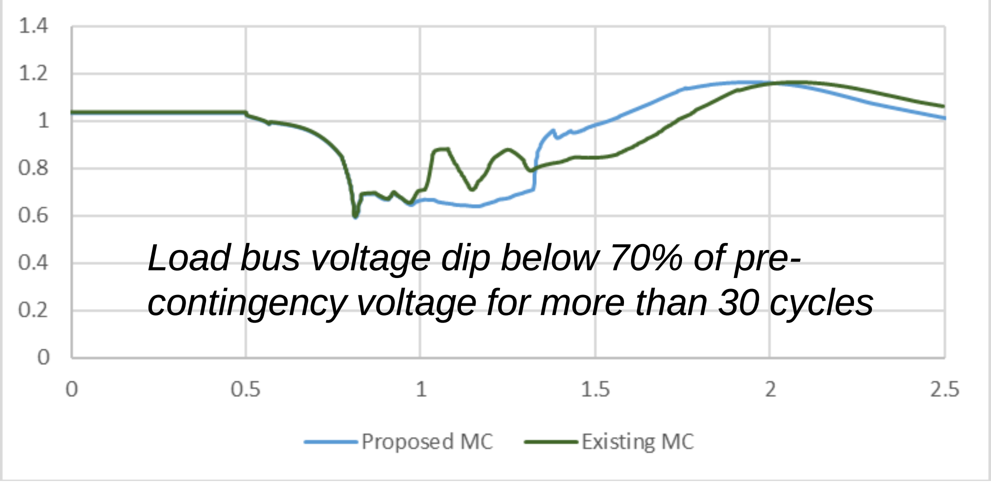
Contingencies

- Selected P1 contingencies
  - 3-phase-to-ground fault on 500kV or 230kV lines near critical 500kV or 230kV substations, normal fault clearing and the faulted line open from both ends
- Selected P6 contingencies
  - Loss of one 500kV line followed by system adjustment in the base case, 3-phase-to-ground fault on 500kV or 230kV lines near critical 500kV or 230kV substations, normal fault clearing and the faulted line open from both ends
- Selected P7 contingencies
  - Simulated extreme event of 3-phase-to-ground fault on 500kV buses followed by normal clearing of fault with two 500kV lines open from both ends
  - Single-phase-to-ground fault, normal fault clearing and Bipolar DC outage

Study Results

- Simulations are performed for

  (2 scenarios) x (18 contingencies) x (updated models or proposed models)
- In all the simulations, the system is stable and there is no cascading or uncontrolled separation
- One voltage performance issue is identified at a load bus under one contingency with the proposed models



Modeling Issue

- This voltage performance issue is caused by representing elimination of MC with original models from MDF
- No violation if making a few parameters more consistent with the NERC alert submission
  - Inconsistency has been identified between the MDF models and inverter settings provided in many plants

Conclusions from the Alert Study

- The information supplied by the generator owners was mostly incomplete or deficient.
- The study does not serve the purpose of assessing individual models given the deficiency.
- However, the proposed setting changes align with the NERC recommendation to improve reliability. The CAISO and TPs approved the proposed changes to the equipment.
- The CAISO and TPs will continue working with GOs to get accurate dynamic models.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Practical Experience Studying IBR

David Piper, Southern California Edison
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Outline

- Study Tools – Lessons Learned
- What to do when models don't match reality
- Impact of transmission faults on system voltage
- Transient Overvoltage
- Successive Events
- Impact of inverter based resource on:
  - Frequency Stability
  - Voltage Stability
  - Dynamic Voltage Stability
  - System Separation

Study Tools – Lessons Learned

Monitoring aggregate IBR in dynamic simulations can be difficult:

- PSLF:
  - No dynamic ‘meter’ model (i.e. vmeta/ameta) to record and report the aggregate P/Q output of inverter based resources
  - Generators can be aggregated in post processing (time consuming)
  - A user-written model can be used (we went this route)
- PowerWorld:
  - Can use injection groups to record P/Q of IBR
    - Must be manually defined in advance of simulation.
- PSSE:
  - Unknown

What to do When Models Don't Match Reality

<u>Long term planning studies:</u>

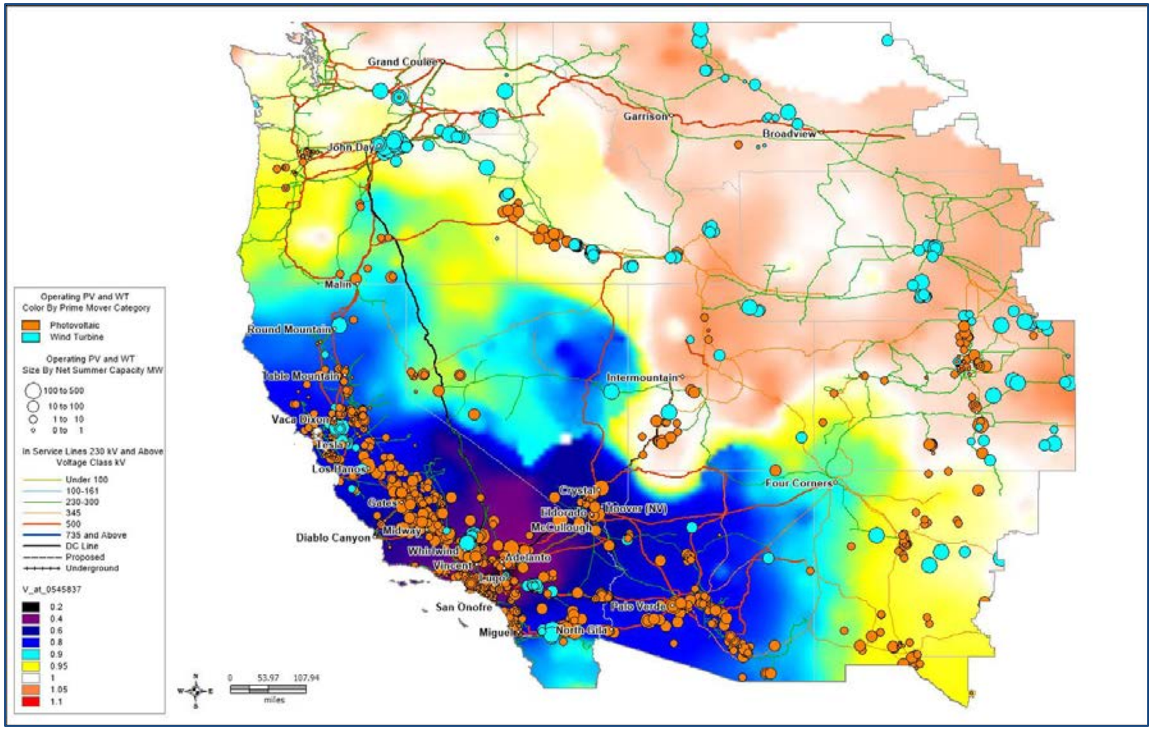
- Use NERC MOD-032-1 standards to request updated models

<u>Real-time/Seasonal Studies:</u>

- If event records are available:
  - Compare event records to model performance
  - If performance does not match, coordinate with GO and consider revising model to match event records
- If no event records are available
  - Use NERC Alert Data and compare to models

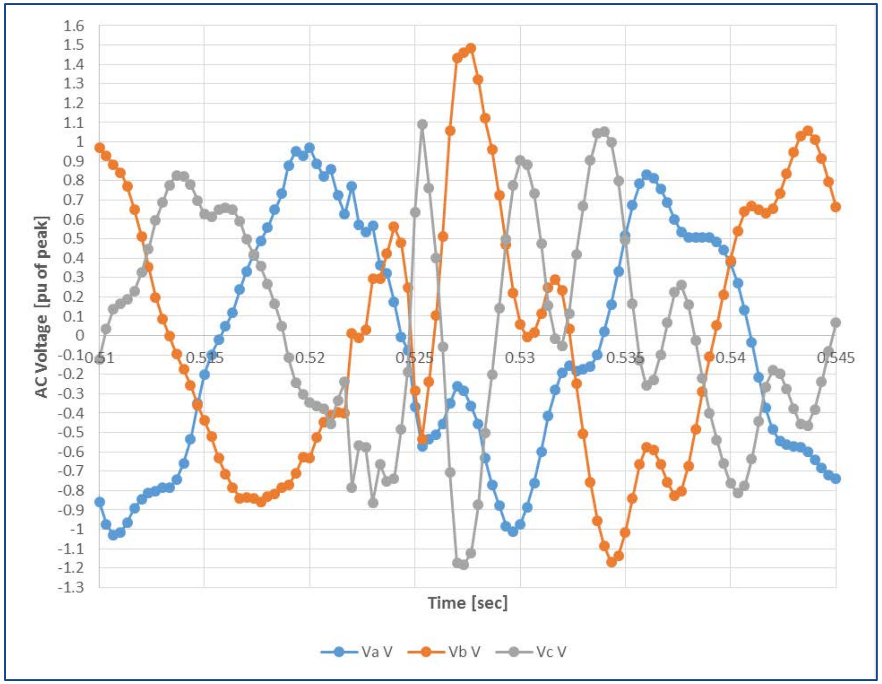
Fault Voltage impact on inverters

- Most legacy inverters momentarily cease current injection when voltage is outside 0.9-1.1 pu.
- 3-ph fault can cause widespread voltage depression below 0.9 pu.
- > 9,000 MW of impacted inverter based resources for most impactful faults



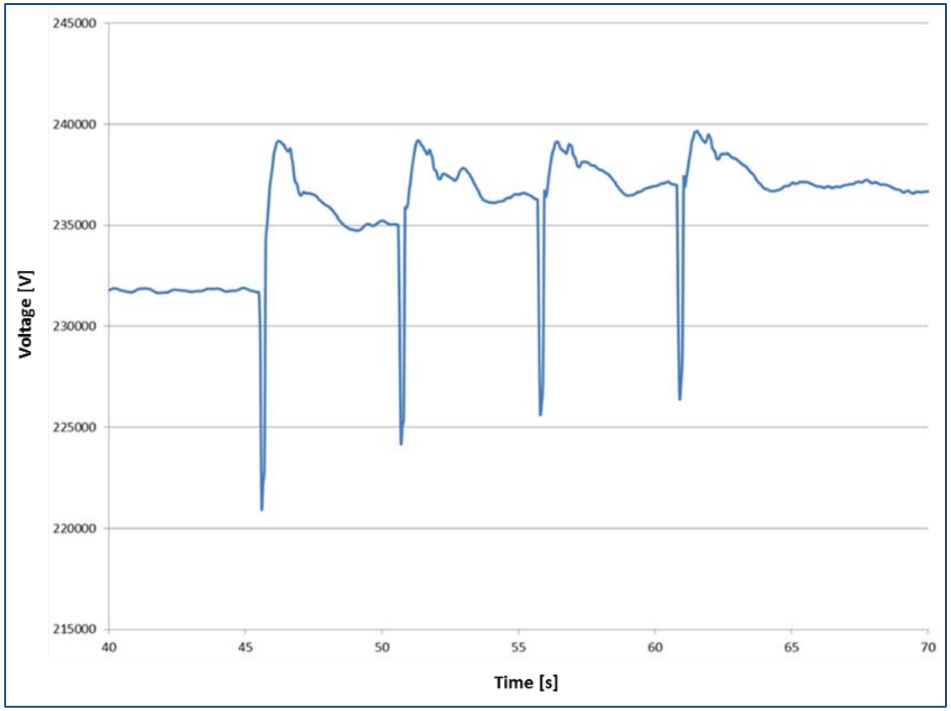
Transient Overvoltage

- Transient overvoltage can cause inverters to shut down
  - Inductive/capacitive circuit interruption
  - Switching
  - Capacitive Restrike
  - SLG fault (unfaulted phases)
  - Etc…
- This isn't captured in positive sequence software



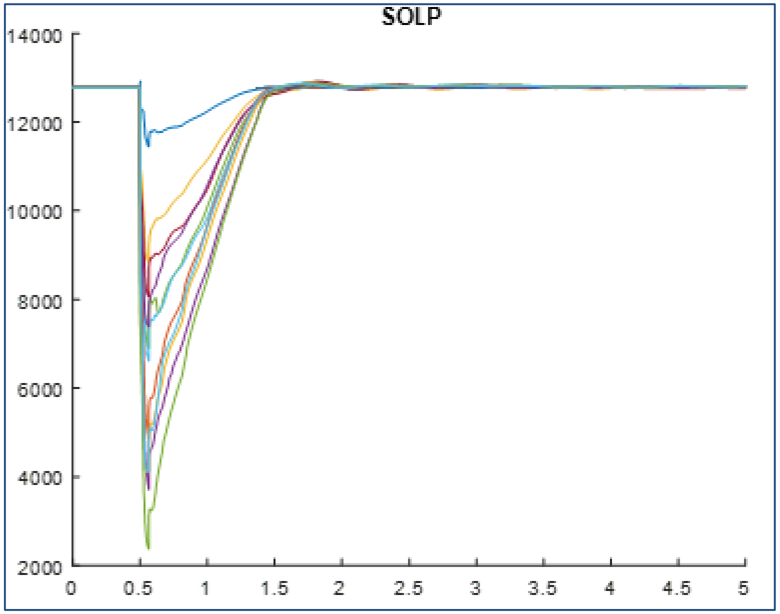
Successive Events

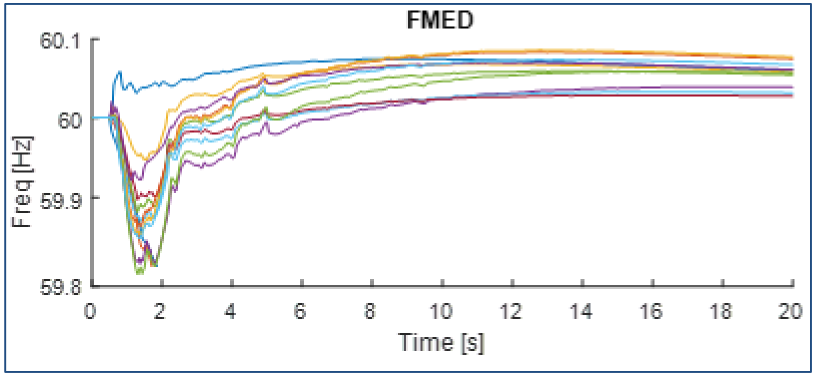
- Inverter based resources may be set to "lock-out" after successive events.
  - This may cause a permanent trip of the unit
- Successive events can be caused by:
  - Failed reclose attempts
  - Successive faults (such as during a fire)
- This usually isn't captured in simulations



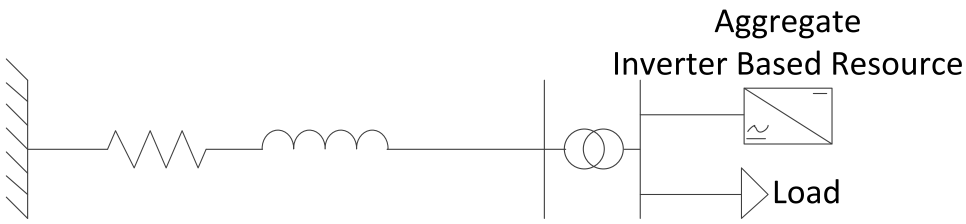
Momentary Cessation = Energy Loss

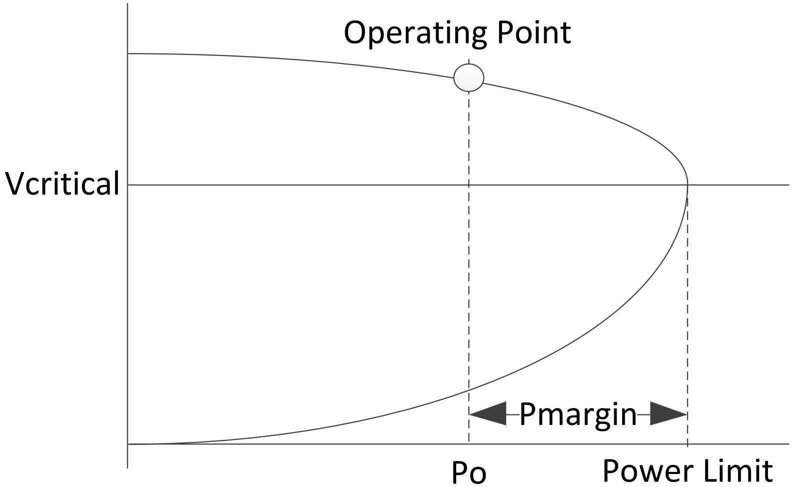
- Frequency Stability
  - The total energy loss (MW·seconds) due to Momentary Cessation is proportional to the change in system frequency
    - Magnitude and duration of gen loss matters!
  - Frequency nadir occurs faster in high PV penetration cases





Voltage Stability



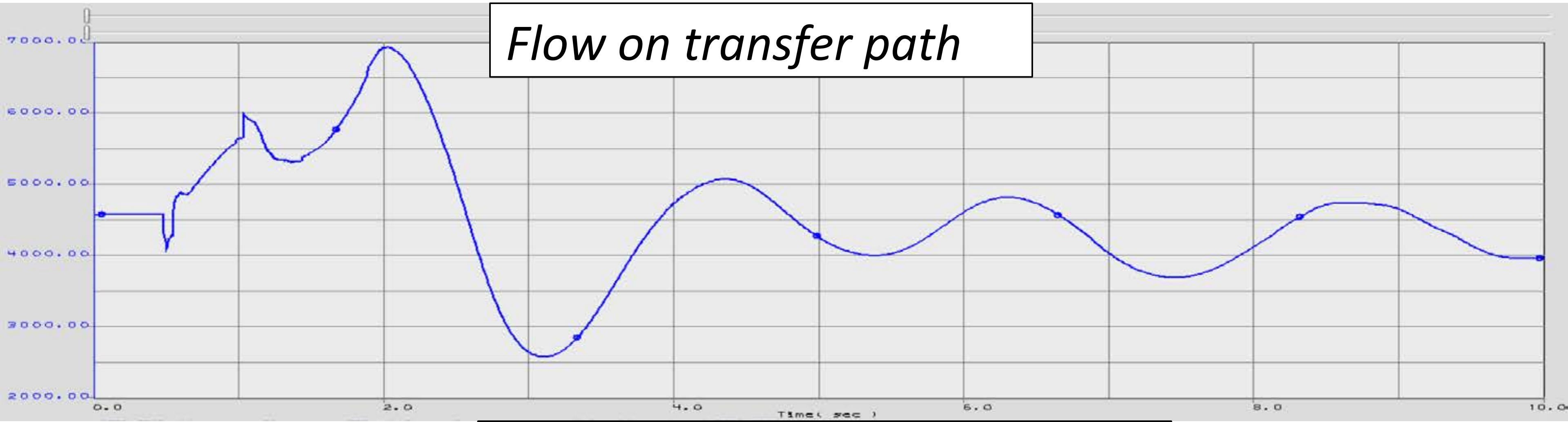


- If Pmargin<Ploss (due to fault) then voltage stability limit will be exceeded
- May be a situational awareness problem

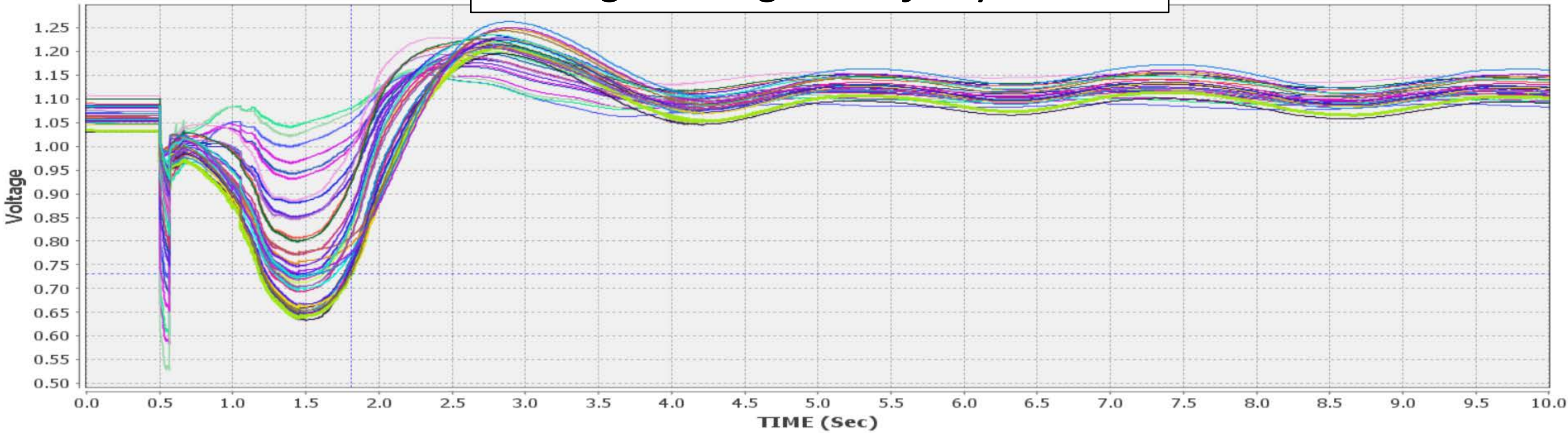
Dynamic Voltage Stability

- Excessive power swings can cause voltage collapse

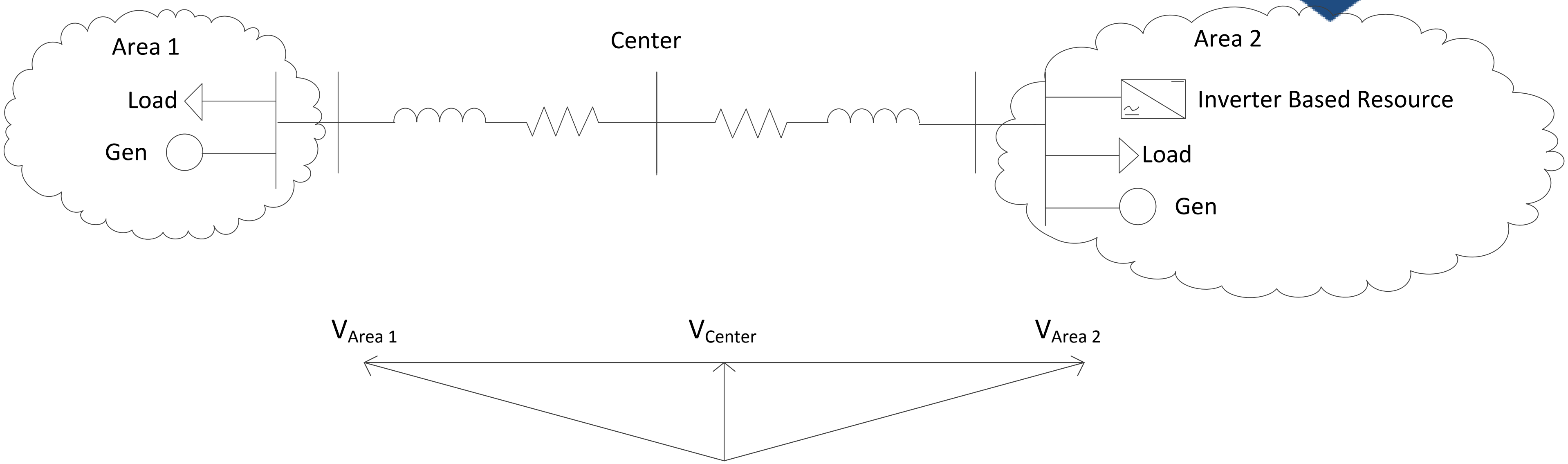
Flow on transfer path



Voltage along transfer path



System Separation



- Loss of inverter based resource can cause systems to separate.
- Distance relays may isolate the two systems.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

IBR Modeling, Performance, and Verification Testing

Farhad Yahyaie, Powertech Labs

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Case Study 1: Using Small-Signal Analysis in Model Validation Studies

1. Identify dominant modes in time domain
2. Find corresponding modes in frequency domain
3. Identify parameters with most impact on the modes
4. Adjust parameters to tune the modes
5. Check results in time domain simulations

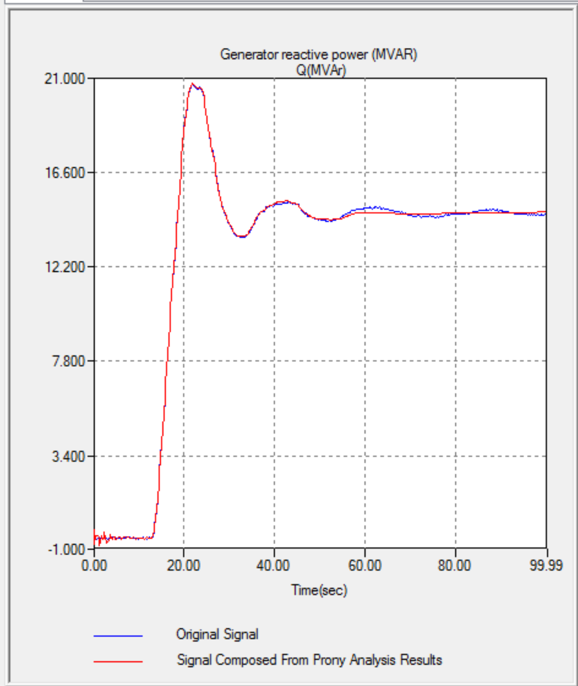
Case Study 1: Using Small-Signal Analysis in Model Validation Studies

Step 1: Identifying Dominant Modes from Field Measurements

- Performing Prony analysis on measured data, frequency and damping of modes can be identified

Prony Analysis

Q(MVAr)



No.	Mag	Phs(deg)	Frq(Hz)	Dmp(%)	Real(1/s)	Imag(rad...
1	61.7665	158.585	0.017	79.310	-0.1416	0.109
2	40.8367	-67.318	0.051	29.406	-0.0989	0.322
3	23.6100	-33.867	0.421	84.674	-4.2071	2.643
4	17.1466	-146.809	0.291	37.032	-0.7289	1.828
5	15.6589	20.915	0.084	25.589	-0.1398	0.528
6	14.5523	0.000	0.000	-100.000	0.0002	0.000
7	3.4995	-42.613	0.464	9.347	-0.2738	2.916
8	1.5657	-32.636	0.302	8.166	-0.1556	1.899
9	1.2607	-15.134	0.553	10.967	-0.3834	3.475
10	1.2581	10.483	0.333	5.500	-0.1154	2.095
11	0.9071	26.179	0.242	7.214	-0.1099	1.519
12	0.7969	-66.429	0.201	7.009	-0.0886	1.261
13	0.7309	-103.036	0.425	3.807	-0.1016	2.668
14	0.5238	87.227	1.446	2.581	-0.2346	9.089
15	0.5093	78.589	0.151	10.209	-0.0972	0.947
16	0.4648	-87.198	0.142	5.207	-0.0464	0.890
17	0.4338	-132.002	1.465	2.174	-0.2003	9.207
18	0.3854	-41.030	0.380	3.785	-0.0903	2.385
19	0.3491	93.839	0.484	2.639	-0.0803	3.042
20	0.2379	167.666	0.971	4.642	-0.2834	6.098

Use Only Selected Modes In List For Composed Signal

Ignore Modes With Frequencies Less Than 0.10 Hz

Time Window: From 0.00 Sec To 100.00 Sec

Recalculate Export

- *Frequency = 0.05 Hz*
- *Damping = 29.4 %*

Case Study 1: Using Small-Signal Analysis in Model Validation Studies

Step 2: Finding Dominant Modes in Frequency Domain

- Using Small-Signal Analysis Tool (SSAT), frequency and damping of modes of the existing (pre-tuned) system can be determined.

12 Modes Are Available; 12 Modes Are Shown After Applying Filters

N...	Real	Imaginary	Frequency(...	Damping(%)	Dominant State
1	-50.0000	0.0000	0.0000	100.00	10000 : EQGEN0.50.55 : 0 : :1 : regc_a : VFILTER : 1
2	0.0000	0.0000	0.0000	-100.00	10000 : EQGEN0.50.55 : 0 : :1 : regc_a : CONV : 1
3	-77.2520	0.0000	0.0000	100.00	10000 : EQGEN0.50.55 : 0 : :1 : reec_b : VFILTER : 1
4	0.0014	0.0000	0.0000	-100.00	99999 : INFBUS23230. : 0 : :1 : gencls : : Speed
5	-0.0014	0.0000	0.0000	100.00	99999 : INFBUS23230. : 0 : :1 : gencls : : Angle
6	-9.9569	22.9956	3.6599	39.73	10000 : EQGEN0.50.55 : 0 : :1 : reec_b : IND_QI : 1
7	-52.0567	0.0000	0.0000	100.00	10000 : EQGEN0.50.55 : 0 : :1 : repc_a : QF_Q_PL : 1
8	-47.8557	0.0000	0.0000	100.00	10000 : EQGEN0.50.55 : 0 : :1 : repc_a : QF_Q_PL : 1

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Case Study 1: Using Small-Signal Analysis in Model Validation Studies

Step 3: Identifying Parameters with Most Impact on the Dominant Mode

- Using sensitivity analysis, identify effect of model parameters on the identified mode

Mode Shape | Mode Shape Scatter | Participation Factor | Mode Data | Sensitivity Data | Sensitivity Plot

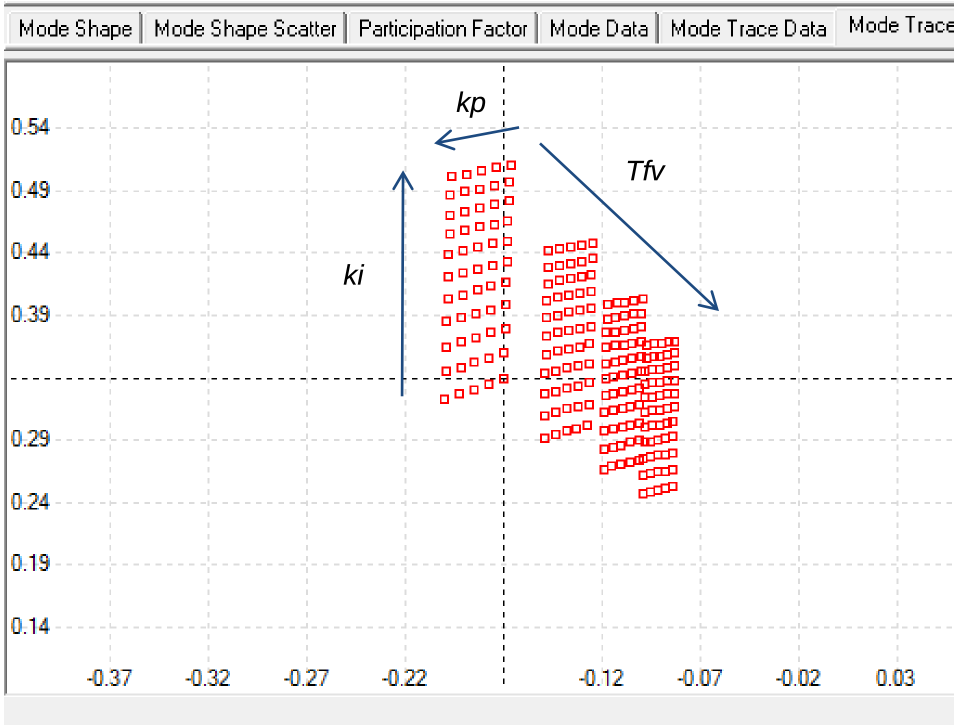
No.	Device Type	Device ID	Parameter...	Base Value	Real Sens.	Imag. Sens.	Freq. Sens.	Damp. Se...
1	Dynamic ...	10000 [EQGEN0.50.55] '...	Kqi	1.000000	-0.0015	-0.0008	-0.0001	0.0001
2	Dynamic ...	10000 [EQGEN0.50.55] '...	Kqp	0.100000	-0.0343	-0.0076	-0.0012	0.0013
3	Dynamic ...	10000 [EQGEN0.50.55] '...	Kvi	100.000000	0.0565	0.1631	0.0260	-0.0043
4	Dynamic ...	10000 [EQGEN0.50.55] '...	Kp	0.100000	21.0704	-9.0599	-1.4419	-0.5763
5	Dynamic ...	10000 [EQGEN0.50.55] '...	Ki	1.000000	-0.6712	-0.6294	-0.1002	0.0317
6	Dynamic ...	10000 [EQGEN0.50.55] '...	Tfv	0.150000	-12.8275	7.9065	1.2584	0.3160

plant controller parameters (Kp, Ki, and Tfv) are more effective

Case Study 1: Using Small-Signal Analysis in Model Validation Studies

Step 4: Adjusting Parameters to Tune the Mode

- Using mode trace analysis, find the set of parameters that provide the best frequency/damping match



Case Study 1: Using Small-Signal Analysis in Model Validation Studies

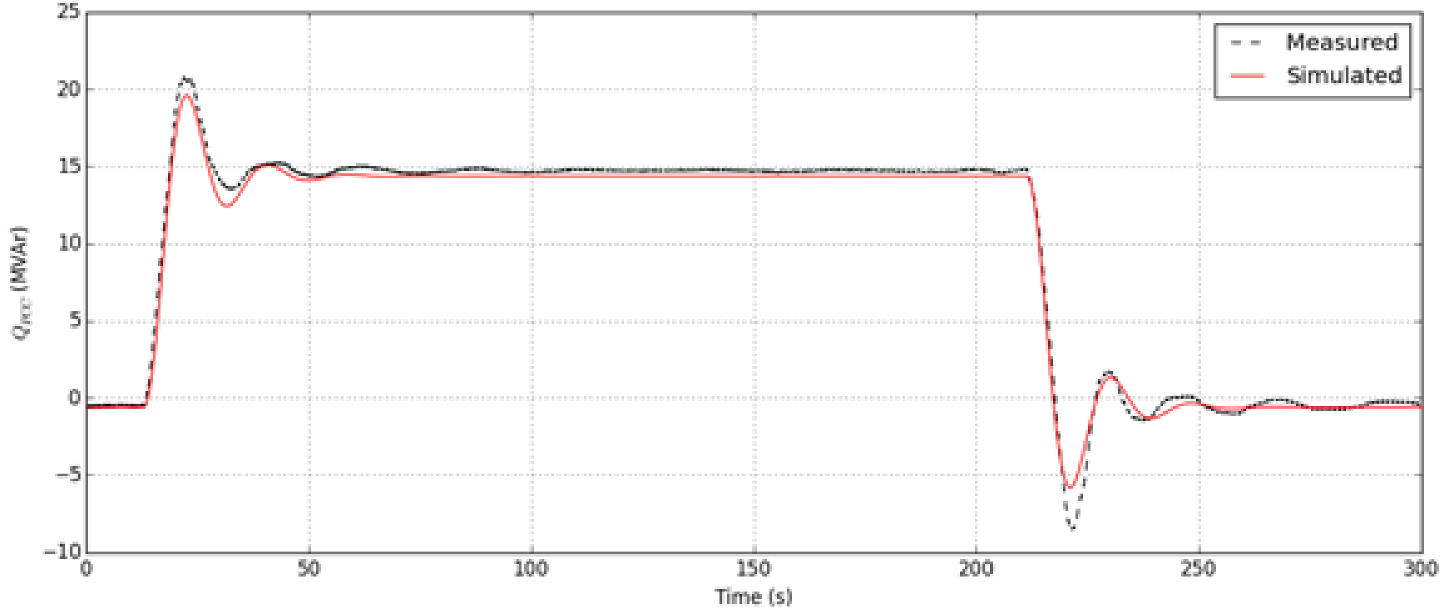
Step 4: Adjusting Parameters to Tune Modes

10000, 'REPC_A ', '1 ', 'Ki '	10000, 'REPC_A ', '1 ', 'Tfv '	10000, 'REPC_A ', '1 ', 'Kp '	Real	Imag..	Freq.	Damp.
0.17000	6.00000	0.03000	-0.0916	0.3414	0.0543	25.9194
0.17000	6.00000	0.02000	-0.0879	0.3423	0.0545	24.8755
0.17000	6.00000	0.01000	-0.0842	0.3432	0.0546	23.8321
0.10000	3.00000	0.01000	-0.1708	0.3432	0.0546	44.5552
0.15000	5.00000	0.05000	-0.1193	0.3438	0.0547	32.7773
0.15000	5.00000	0.04000	-0.1148	0.3453	0.0550	31.5580
0.15000	5.00000	0.03000	-0.1104	0.3466	0.0552	30.3390
0.15000	5.00000	0.02000	-0.1059	0.3480	0.0554	29.1206
0.13000	4.00000	0.05000	-0.1497	0.3481	0.0554	39.5052
0.11000	3.00000	0.05000	-0.2004	0.3492	0.0556	49.7758
0.15000	5.00000	0.01000	-0.1015	0.3492	0.0556	27.9027
0.18000	6.00000	0.05000	-0.0989	0.3502	0.0557	27.1734
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

$K_p = 0.03, K_i = 0.15, T_{fv} = 5.0$

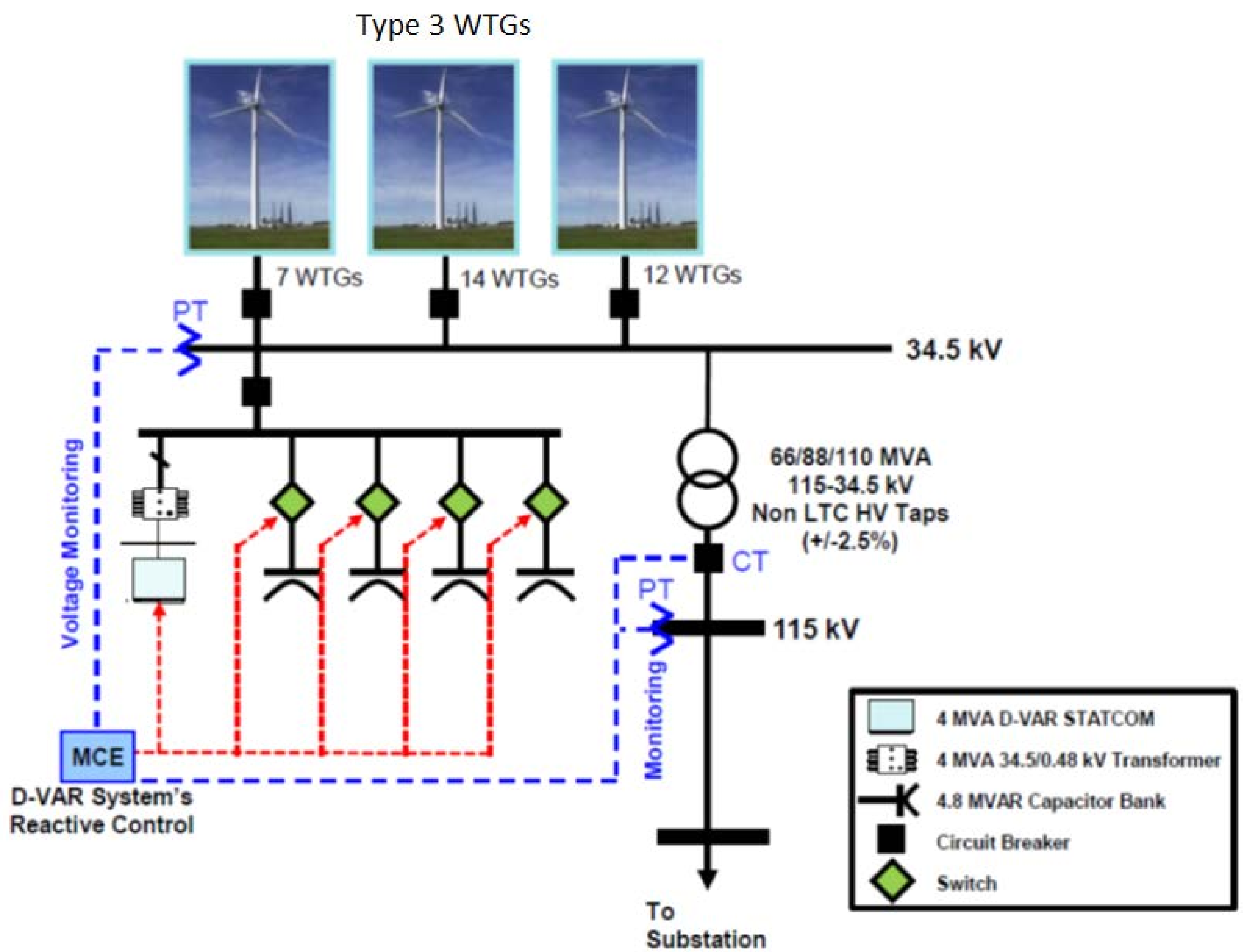
Case Study 1: Using Small-Signal Analysis in Model Validation Studies

Step 5: Checking Results in Time Domain Simulations

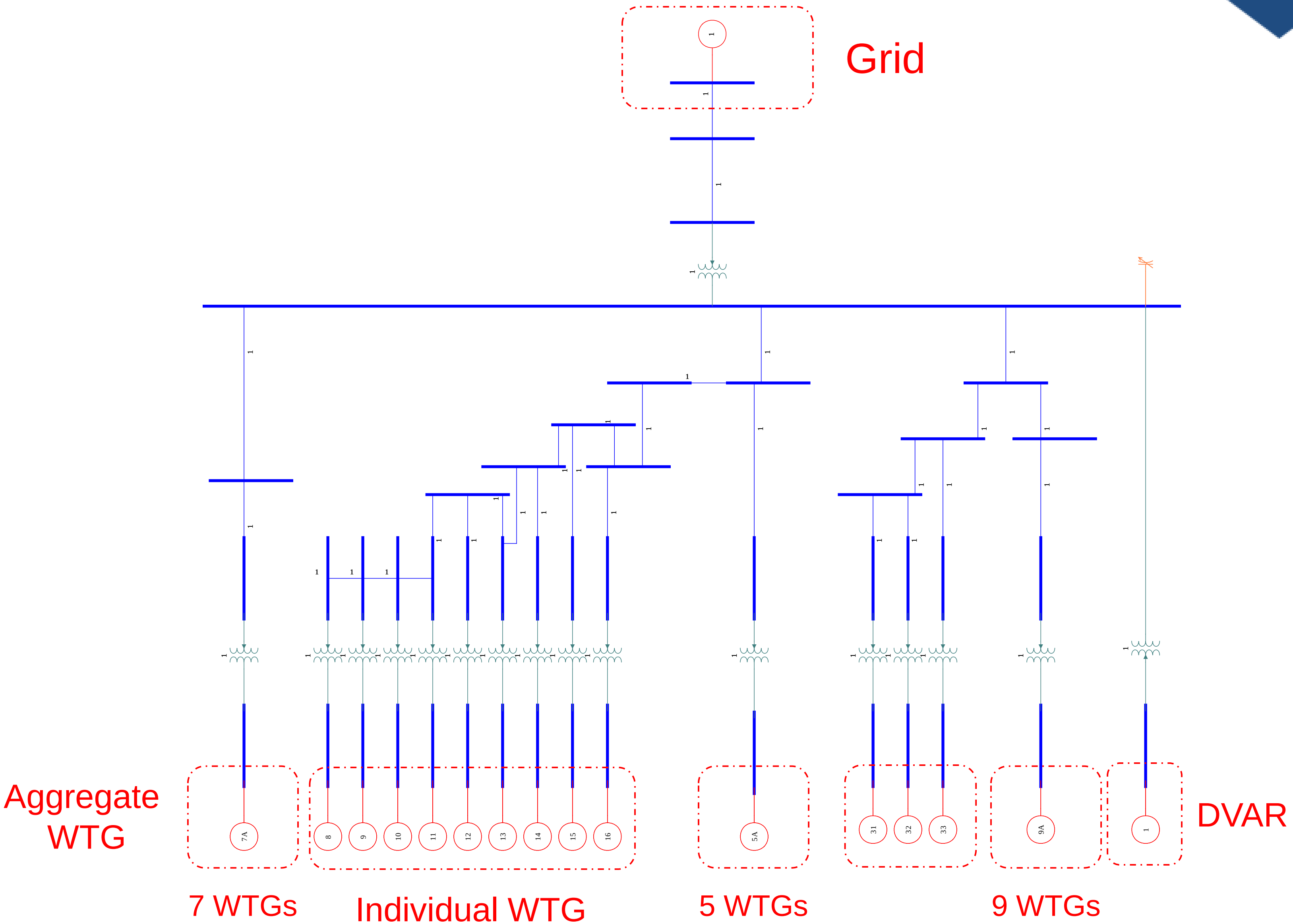


Tuned simulation results

Case Study 2: Model Verification Study for an Unusual Wind Farm



Case Study 2: Model Verification Study for an Unusual Wind Farm



Case Study 2: Model Verification Study for an Unusual Wind Farm

Modeling Requirements and Approach

Requirements:

- Do not change powerflow representation
- Models must be compatible in both PSS/E V33 and V34

Approach:

- Use second-generation renewable-energy models

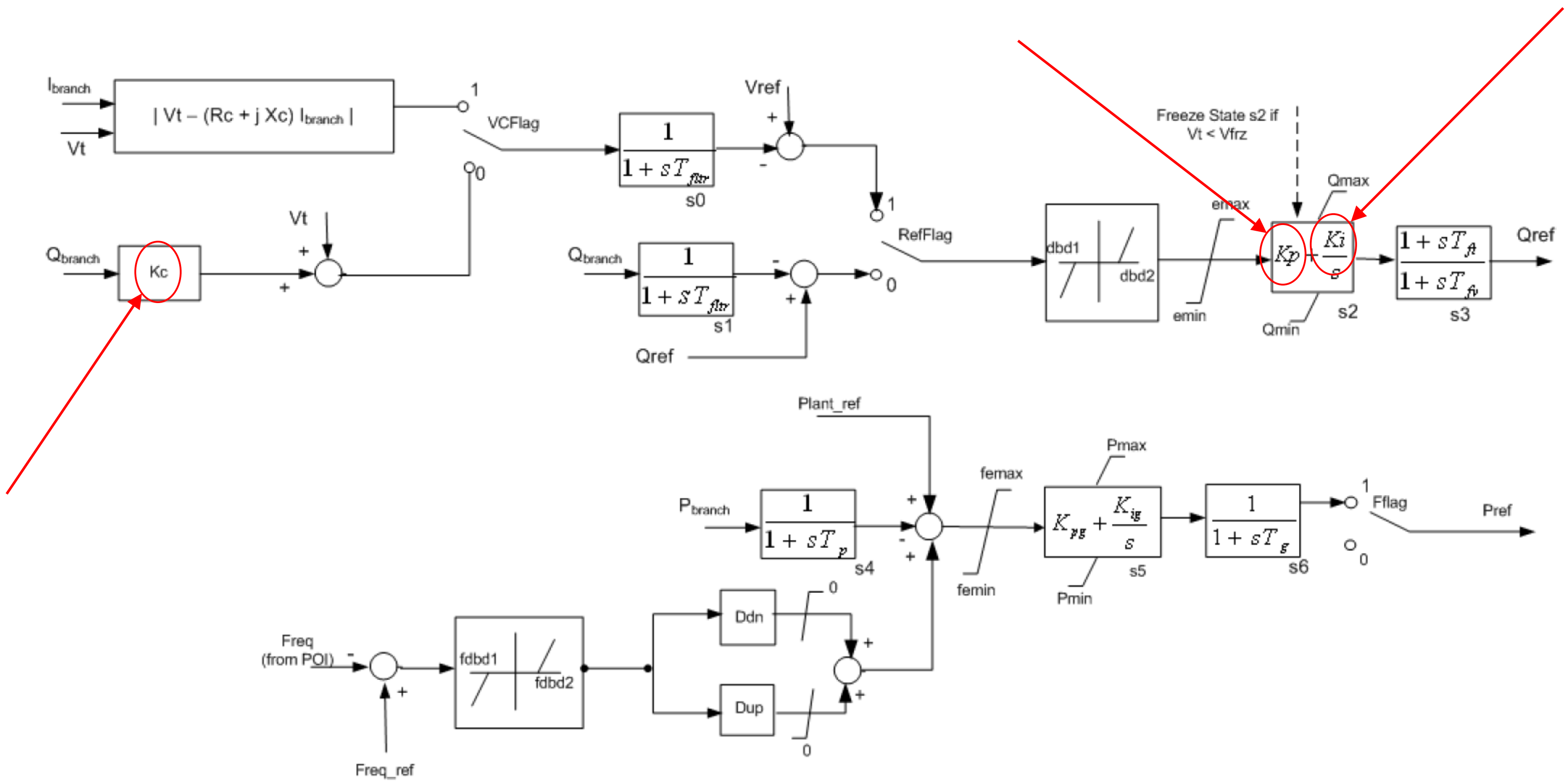
Case Study 2: Model Verification Study for an Unusual Wind Farm

- Use the following models for each individual/aggregated WTG (i.e., 15 sets of models):

PSS/E Model	Description
REGCA1	Renewable Energy Generator/Converter Model
REECA1	Renewable Energy Electrical Control Model
WTDTA1	Generic Drive Train Model for Type 3 Wind Machines
WTPTA1	Generic Pitch Control Model for Type 3 Wind Generator
WTARA1	Wind Turbine Aerodynamic model
WTTQA1	Wind turbine Torque Control model
REPCTA1	Generic Renewable Plant Control Model
VTGTPAT	Low/High Voltage Protection
FRQTPAT	Low/High Frequency Protection

Case Study 2: Model Verification Study for an Unusual Wind Farm

- All 15 sets of models used in this wind farm have exactly the same parameters values, except REPC models that have different values for Kp, Ki, and Kc in each set.



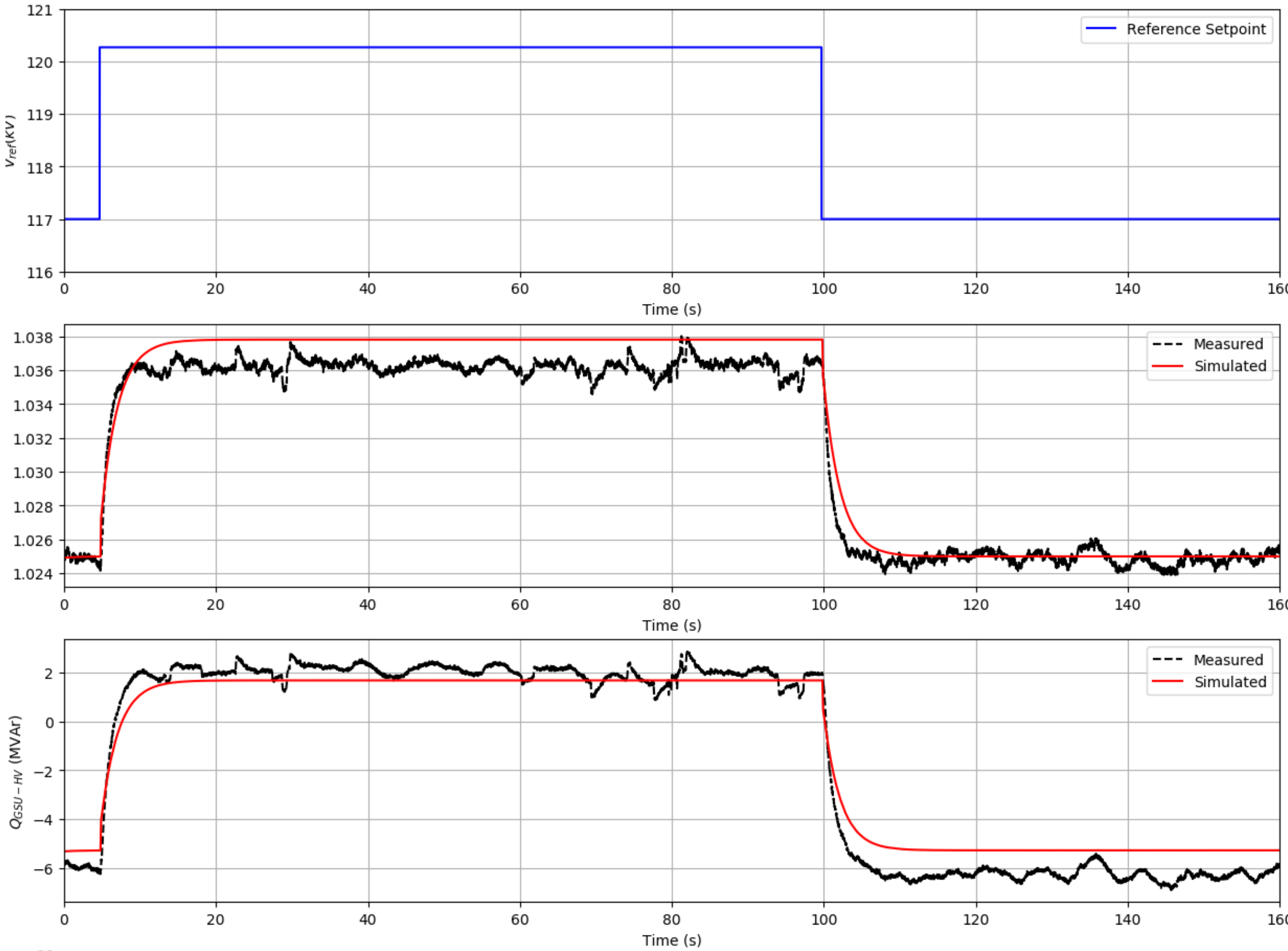
Case Study 2: Model Verification Study for an Unusual Wind Farm

Voltage Step Response

Vref (kV)

Vact (pu)

Q (MVAr)



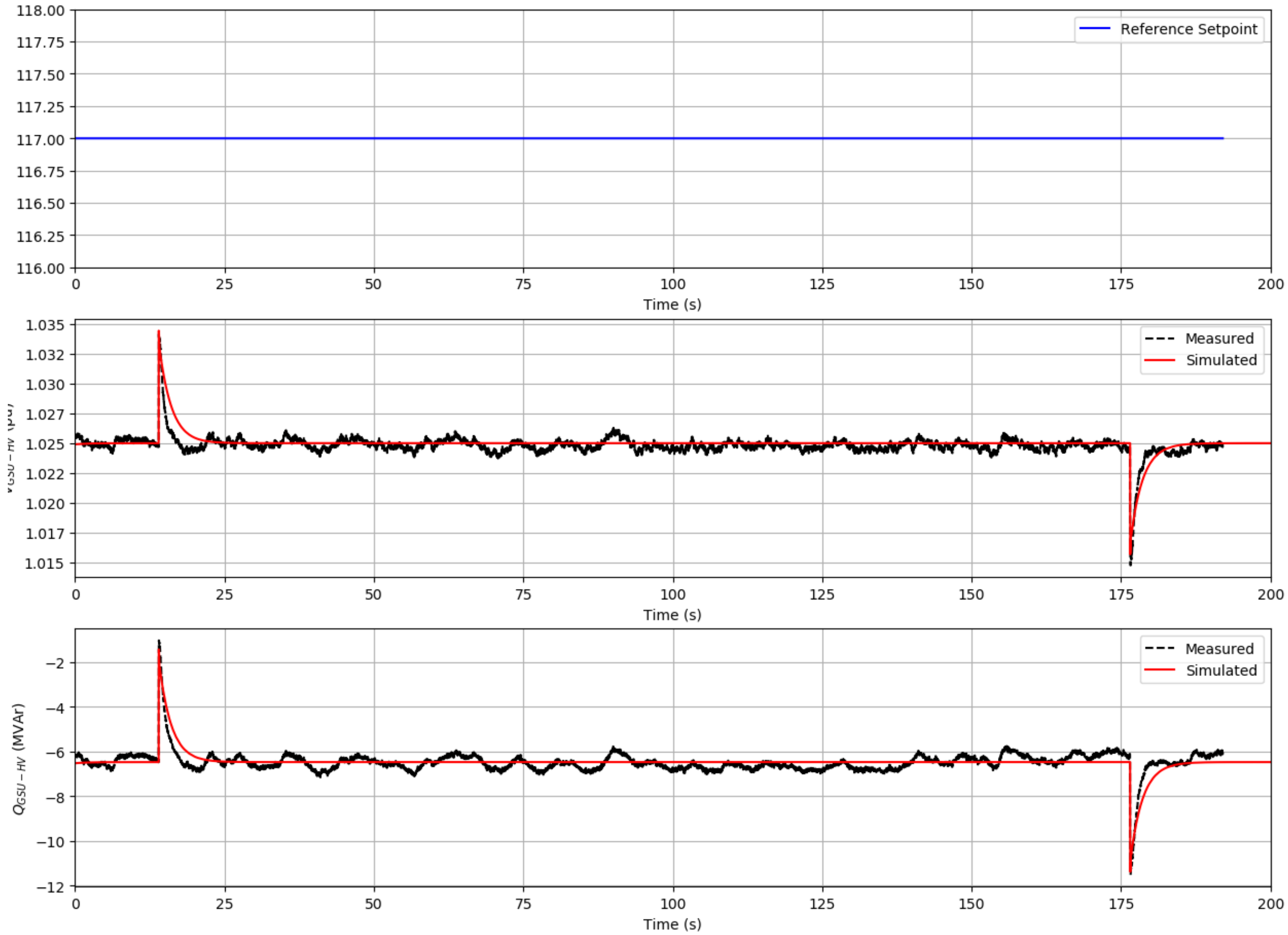
Case Study 2: Model Verification Study for an Unusual Wind Farm

Capacitor Switching Test

Vref (kV)

Vact (pu)

Q (MVAr)



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Case Study 3: Evaluating Protective Relay Settings Based on PRC-024

- Voltage protective relay setting requirement based on PRC-024

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

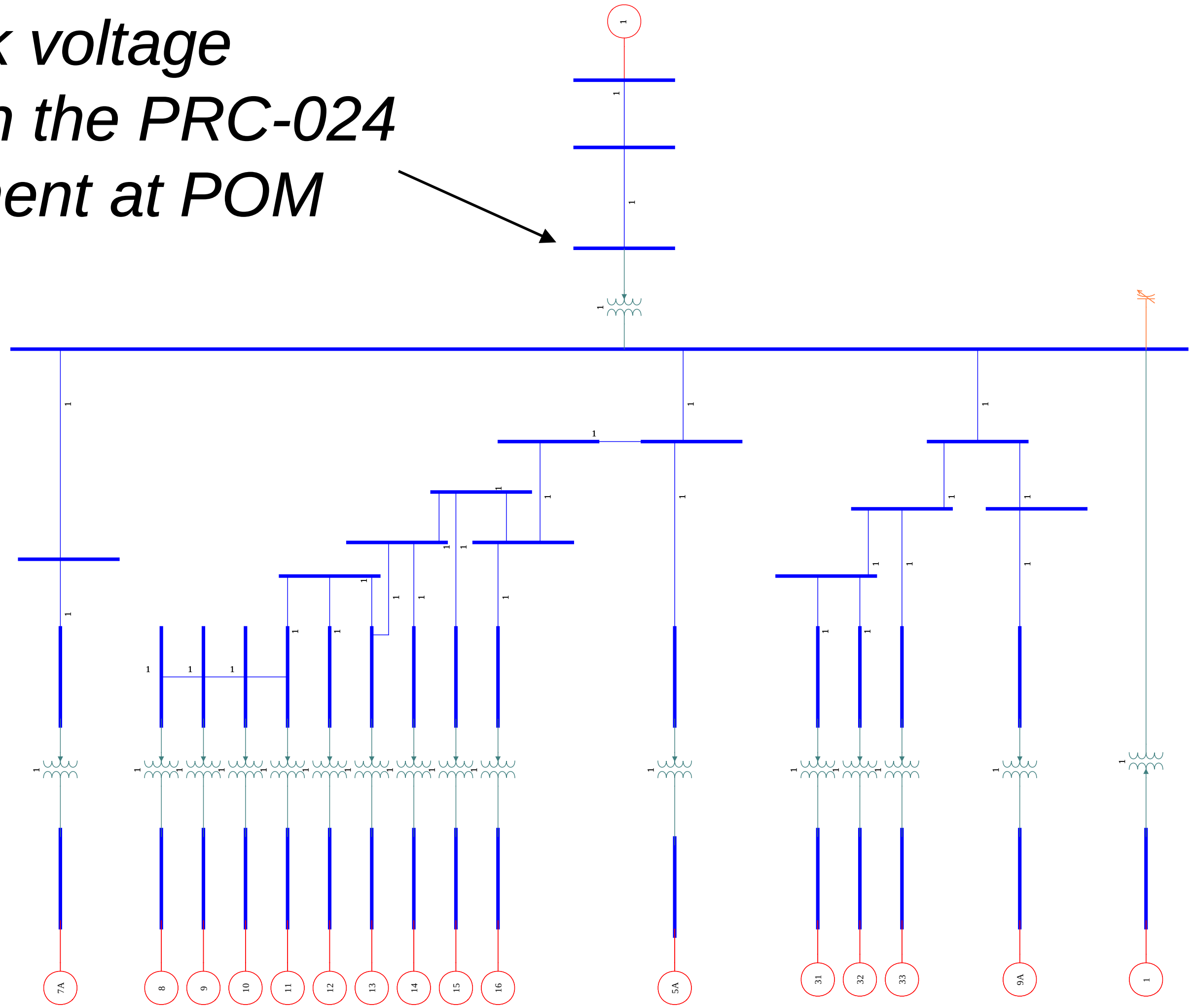
Case Study 3: Evaluating Protective Relay Settings Based on PRC-024

- Worst case scenario study based on PRC-024 requirement

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
1.19	0.20	0.00	0.15
1.174	0.50	0.46	0.30
1.14	1.00	0.66	2.00
1.09	No Trip	0.76	3.00
		0.91	No Trip

Case Study 3: Evaluating Protective Relay Settings Based on PRC-024

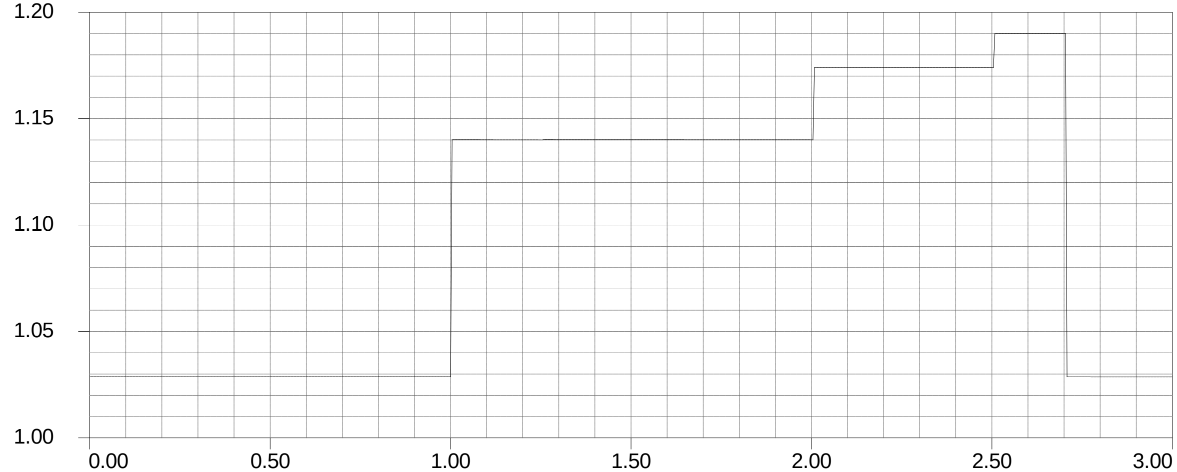
Playback voltage based on the PRC-024 requirement at POM



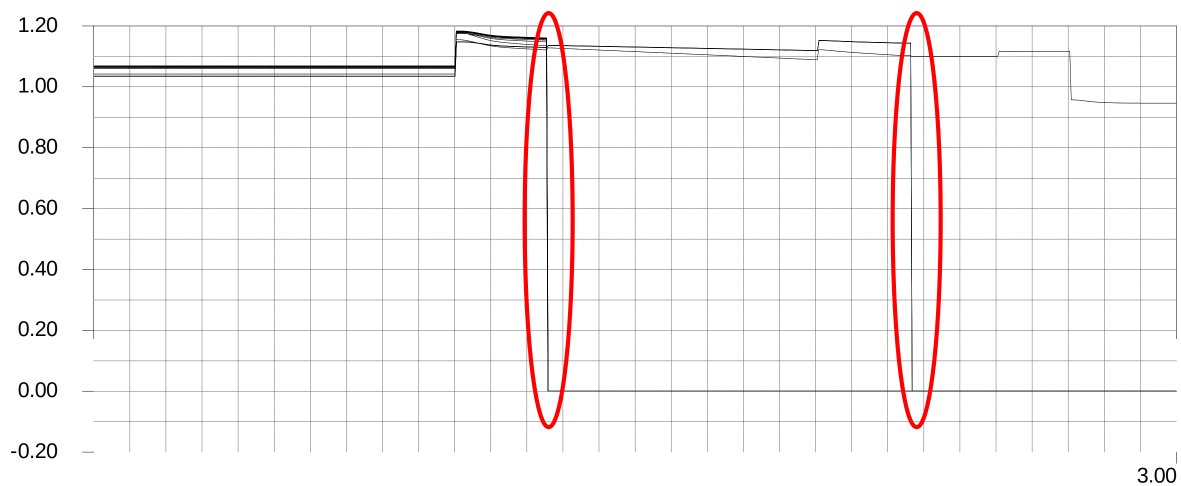
Case Study 3: Evaluating Protective Relay Settings Based on PRC-024

High Voltage Ride-Through

POI Voltage (pu)



Gens. Terminal Voltage (pu)



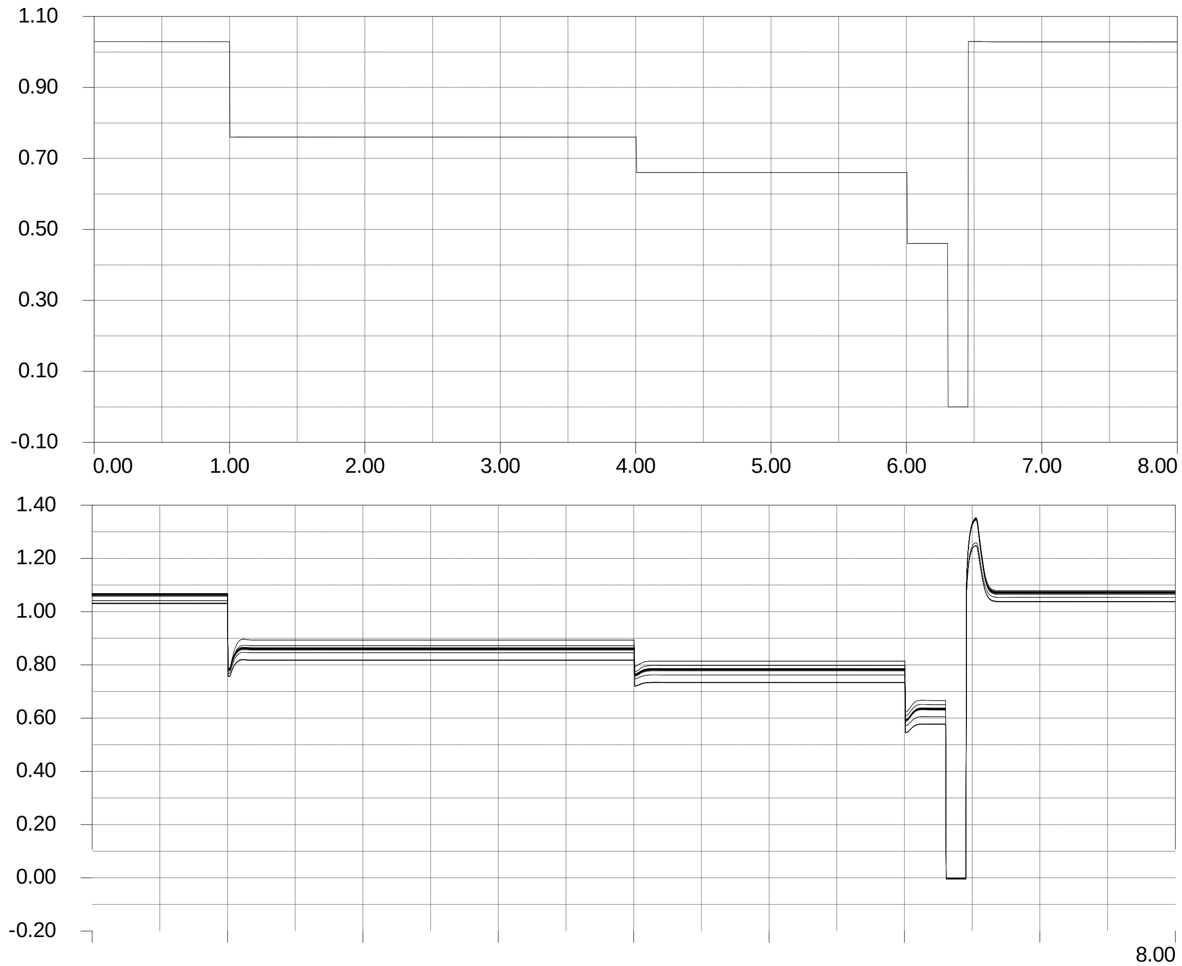
Some Units Tripped

Case Study 3: Evaluating Protective Relay Settings Based on PRC-024

Low Voltage Ride-Through

POI Voltage (pu)

Gens. Terminal Voltage (pu)



No Trip

How to Perform PRC-019 Study

(i.e., coordination of generating unit or plant capabilities, voltage regulating controls, and protection)

in this Case?

Turbine level / Feeder level / Collector Bus Level / Plant level

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

The Realities of Interconnection Studies

Wes Baker, Power Grid Engineering
NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Challenges

Interconnection Queue

- Extensive interconnection queues
- Limited study timelines

Dynamics Models

- Data uncertainty: How do I know models are correct?
- Unfamiliarity with the technology

Prior Queued Requests

- How should these be included?
- May have their own unresolved modeling issues

What to study?

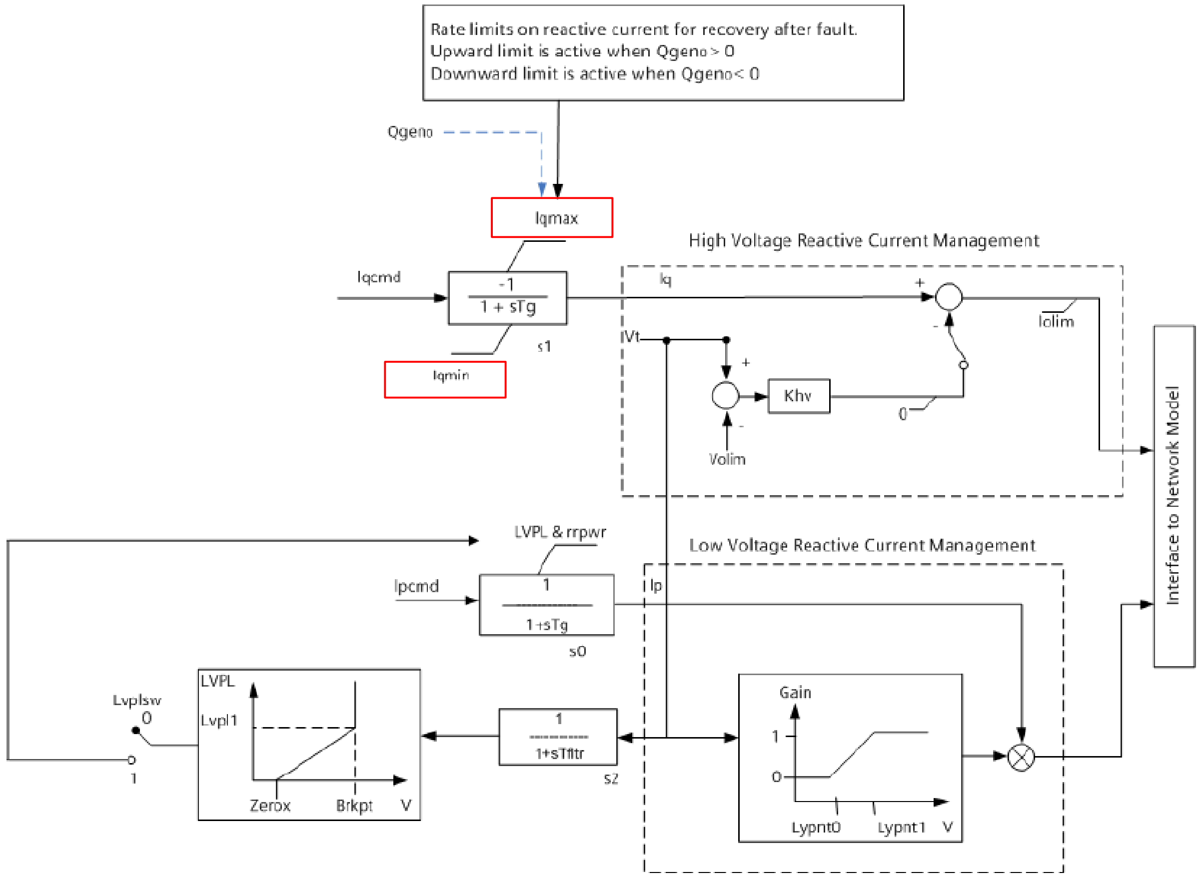
Modeling Data

- The timeline of the study makes it difficult to resolve modeling issues.
- Screening the dynamics models' data upon submission is helpful. 2nd generation generic dynamic models can be screened using [1].
  - Check control flags align with the requirements for active power and reactive power control.
  - Ensure the plant does not use momentary cessation (REEC_A).
  - Compare the parameterization with typical value ranges.
- More difficult with vendor-specific models.
- Ideally the RMS-type models would be validated with the vendor-specific EMT-type models

[1] WECC, "Central Station Photovoltaic Power Plant Model Validation Guideline," 2015.

Iqrmax and Iqrmin

REGC_A

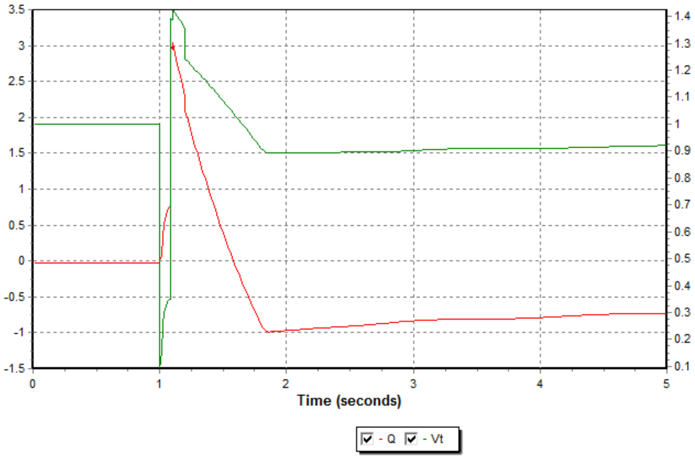


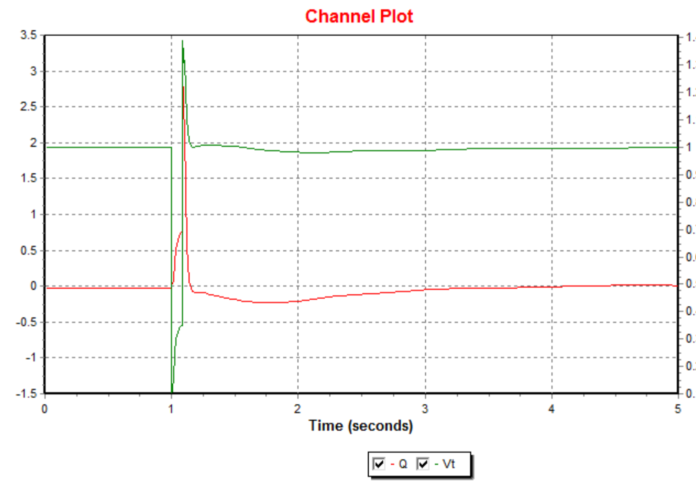
Source: Siemens PTI, "PSS®E 33.10 Model Library," 2017.

Iqrmax and Iqrmin

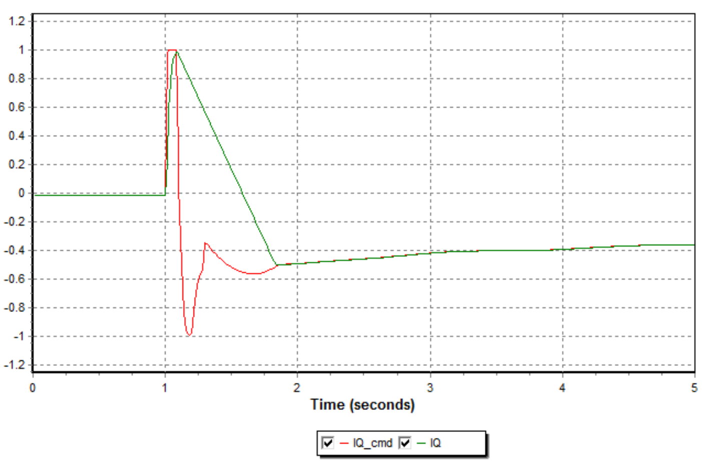
Iqrmin = -2.0

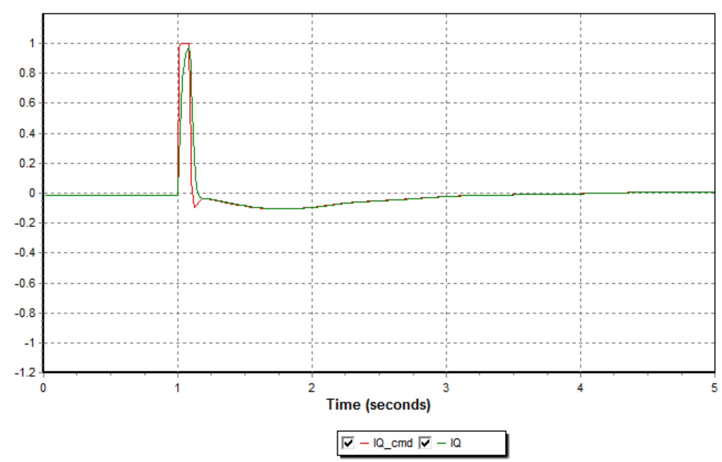
Iqrmin = -99





terminal voltage
reactive power





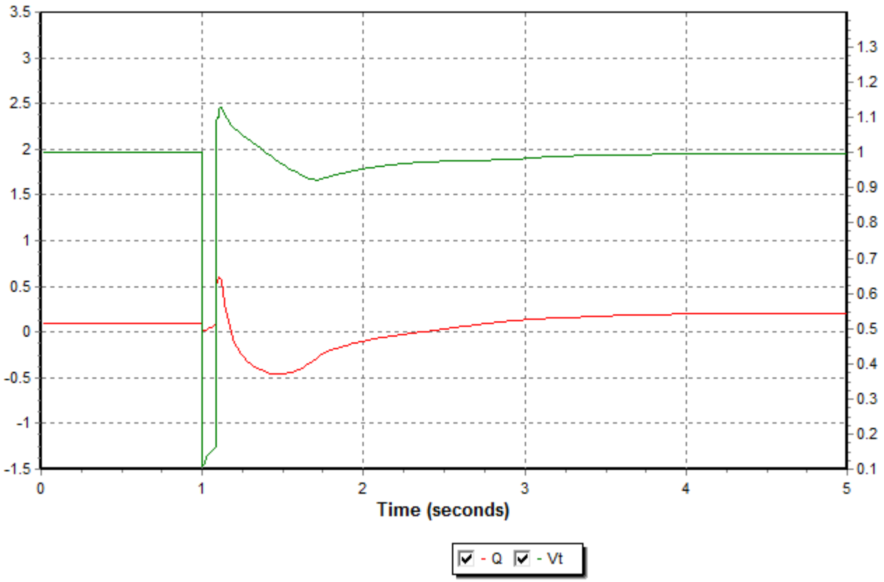
Iq injected
Iq command

Irqmax and Irqmin

terminal voltage

reactive power

Iqrmax = +2.0



Iqrmax = +99

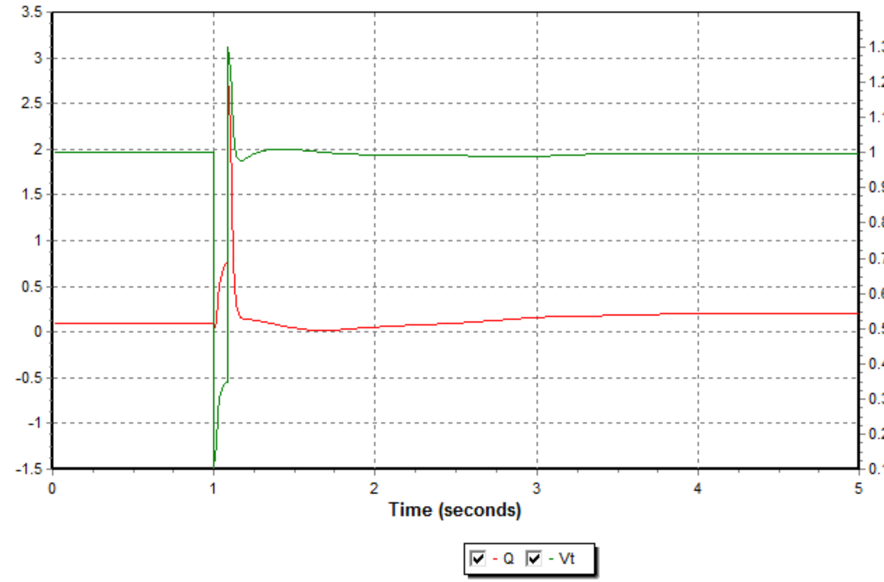


Table 3.2: Large Disturbance Reactive Current-Voltage Performance		
Parameter	**Description**	**Performance Target**
For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response should meet the following performance specifications…		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change[56]	< 16 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90 percent of its final value	< 100 ms**
Overshoot	Percentage of rated reactive current output that the resource can exceed while reaching the settling band	Determined by the TP/PC***

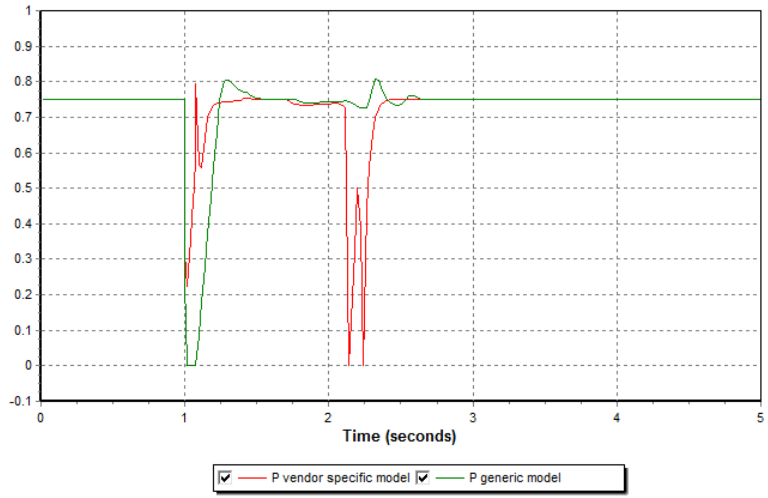
Vendor-Specific RMS-Type Models

- Better reflect the inverter's controls
- Preferred for interconnection studies and for connections to weak grids*
  - *Vendor-specific EMT-type models may be more appropriate for weak grid
- Issues
  - Conflicting model and/or function names
  - Implementation issues
    - Ex. Storing terminal voltage angle in the machine rotor angle array
  - Difficult to troubleshoot
    - Detailed block diagrams and detailed documentation are not always provided
  - Shareability
- Still may need a generic model
  - Wide-area studies, post-queued request studies, regional case development, etc.

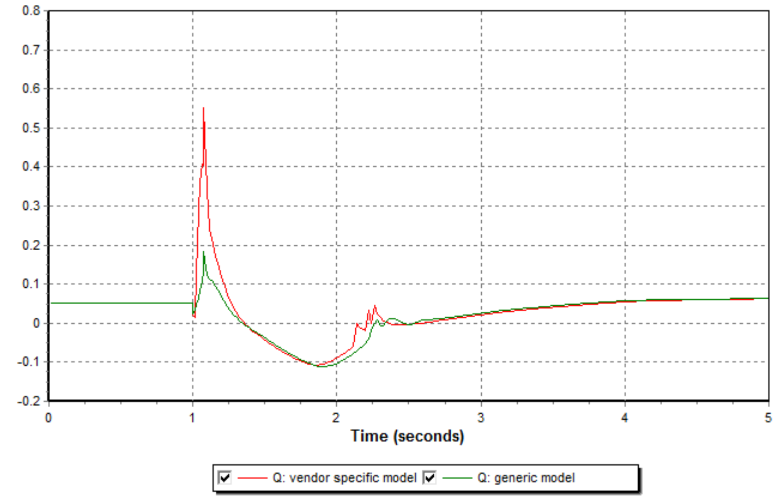
References:
[1] NERC, "1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report," 2017.
[2] CIGRE, "TB 671 Connection of Wind Farms to Weak AC Networks," 2016.

Vendor-Specific Models

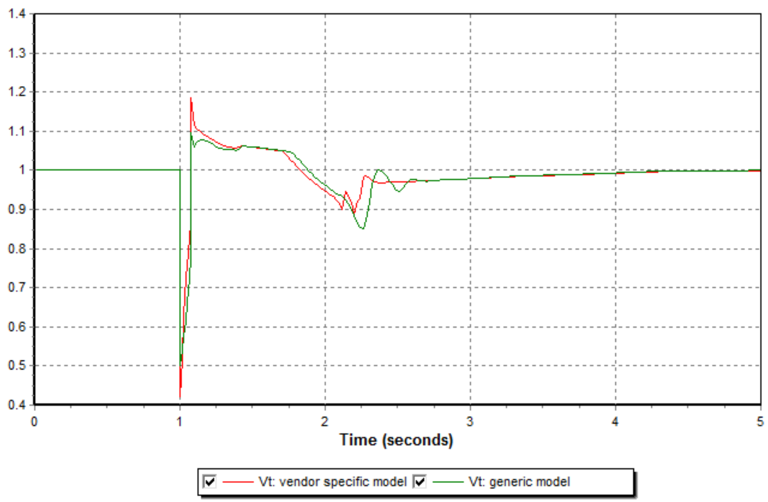
Power



Reactive Power



Terminal Voltage



generic model

vendor-specific model

Positive Sequence Stability Tools

Stability Program Limitations

- Positive Sequence RMS
- Fundamental Frequency
- Network Modeled in Phasor Domain
- OK For Oscillations Up To ~5hz

Converter Model Simplifications

- No DC Dynamics
- Simplified Inner Control Loop
- No Synchronization Controls (PLL)
- No Gate Control Or Switching Behavior

Convergence For Close-in Faults

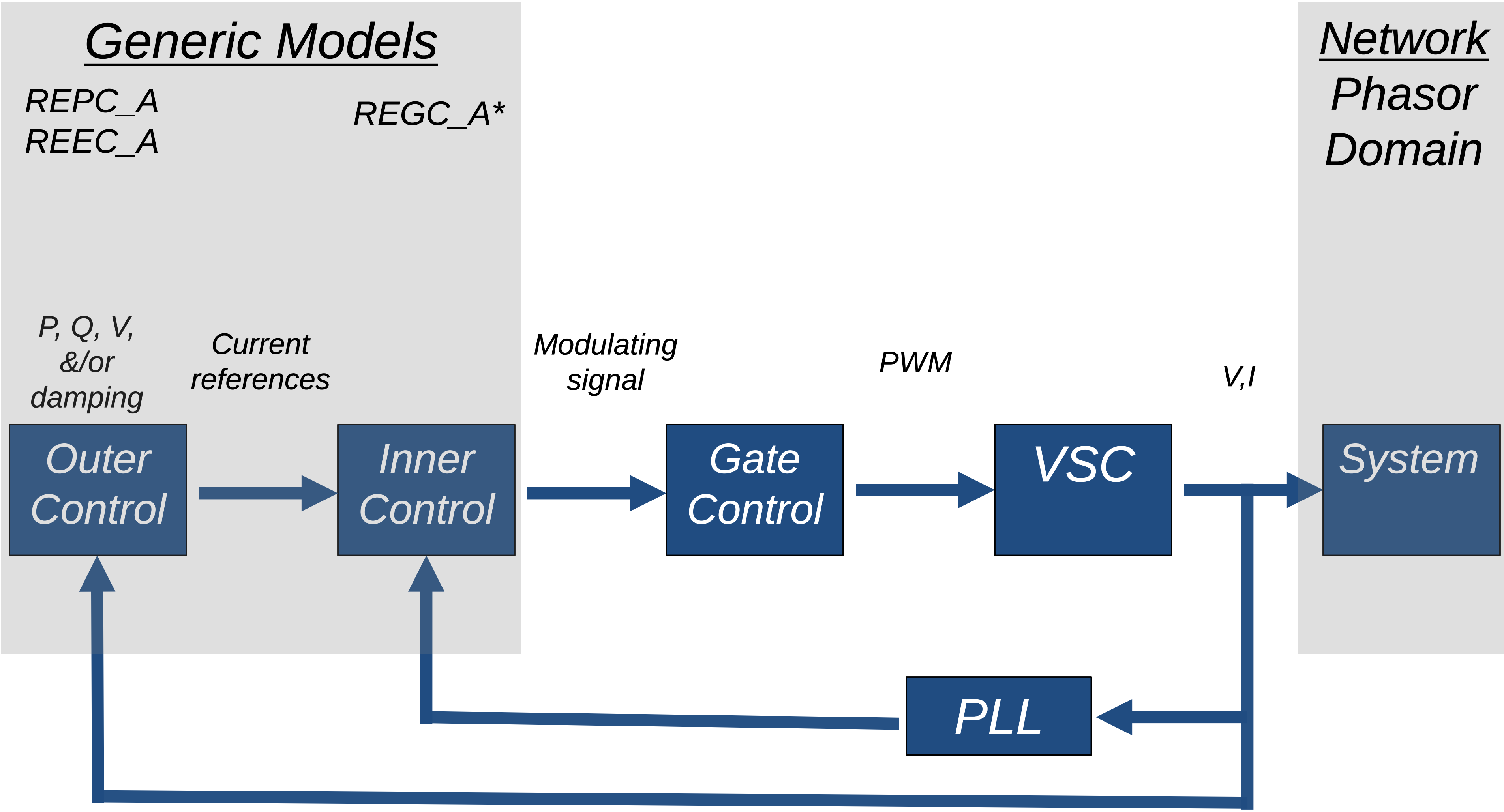
Dynamic Frequency Calculation

IBR Ride-Through: Limited to + Seq. Voltage & Frequency Relays

Computationally Efficient for large systems

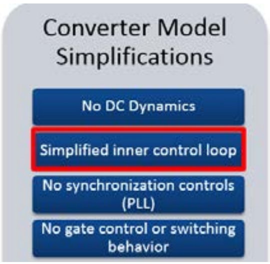
References:
NERC, "Integrating Inverter-Based Resources into Weak Power Systems," June, 2017.
CIGRE, "Modelling Of Inverter- Based Generation For Power System Dynamic Studies," May, 2018.

Simplified Converter Control Structure



*Simplified representation

Converter Model Simplification

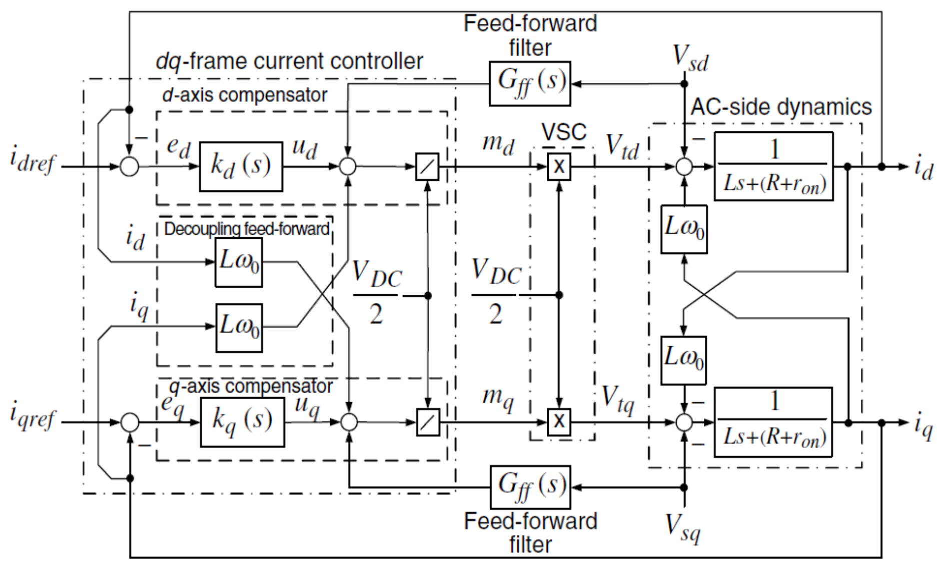


Generic Model

$$i_{ref} \longrightarrow \boxed{\frac{1}{0.02s+1}} \longrightarrow i$$

versus

Ex. Control Block Diagram



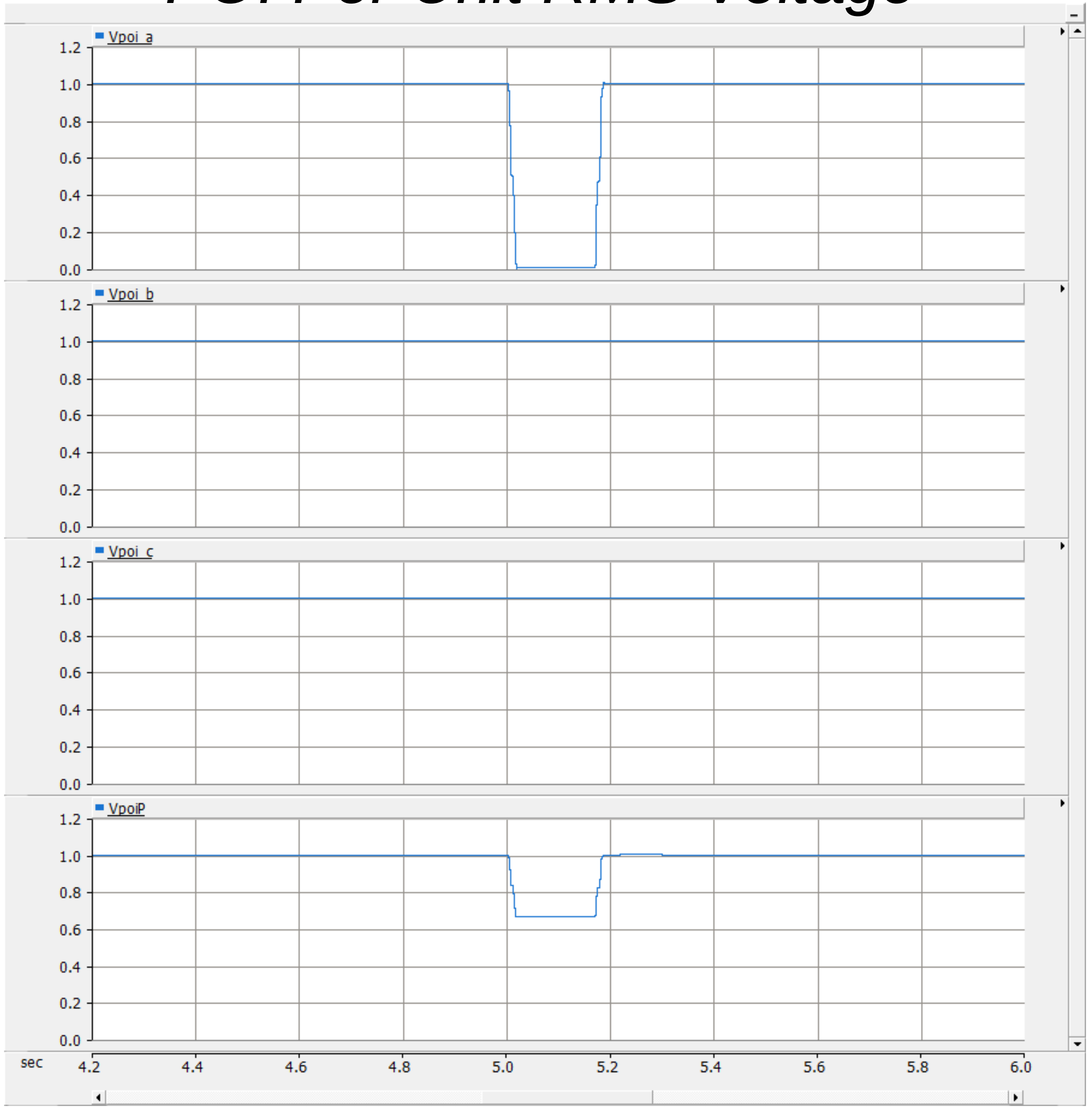
Source: R. Yazdani, Armirnaser Iravani, Voltage-Sourced Converters in Power Systems. IEEE Press, 2010. Figure 8.10

Positive Sequence Stability Tools

- Conclusions about the following should not be made:
  - Unbalanced disturbances
    - Many of the NERC TPL-001-4 planning events are SLG faults
  - Weak grid /Control interactions
  - DC side dynamics
  - Ride-through
  - Other dynamics faster than typical electromechanical oscillation frequencies
- For these type of studies/phenomena, a vendor-specific EMT-type model would be more appropriate.

Example: A-G Fault

POI Per Unit RMS Voltage



Ph. A

Ph. B

Ph. C

Positive Seq.

PRC-024-2 Low Voltage Ride-Through Duration

Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)
<0.45	0.15
<0.65	0.30
<0.75	2.00
<0.90	3.00

Closing Thoughts

- Recommendations:
  - Include the recommended performance specifications from the guideline in the LGIA.
  - Verify in the impact study stage that the IBR model is meeting the recommended performance specifications.
  - Require a vendor-specific EMT-type model and/or have the RMS-type models benchmarked to the vendor-specific EMT-type model.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Innovative Approaches to IBR Studies

Andrew Isaacs, Electranix Corporation

NERC IRPTF Meeting

RELIABILITY | ACCOUNTABILITY




Disclaimer

- Electranix is an Independent Consultancy. I am not speaking on behalf of anyone other than myself, and these are perspectives from the outside! ISO-NE, ERCOT, and AEMO have not endorsed this presentation (or seen it… yikes!).

- One thing we can agree on…

Go Jets!

EMT studies are becoming common

- Interconnected/harmonized system models (cross-platform, cross-genre models)
- Real code models are here
- Very large parallelized EMT models for dynamic performance evaluation
- Regional library development for EMT system models
- Increasing adoption of EMT as part of routine planning

ISO New England Experience

- ISO New England – Integrating EMT into interconnection process:
    - **EVERY** Interconnection application requires PSCAD model submission, along with benchmarking report
    - > 5 year accumulation of EMT models for IBR
    - Quality check and review of both PSS/E and PSCAD models is performed for every interconnection
    - Limited “critical case” PSCAD dynamic performance analysis for each IBR or HVDC interconnection
- Renewable cluster studies
- Validation of OEM design studies (HVDC and FACTS)

ISO New England Experience

- Successes over this period:
  - Many model issues have been identified
  - Many potential reliability or cost risks have been mitigated in the study phases which would not have been with conventional tools
  - Several very useful studies have been possible because models were readily available
  - Comprehensive library of EMT models available for future needs
- Issues:
  - Extra cost for generators
  - Reliance on consultants
  - Additional study burden slowing interconnections

ERCOT Experience

- Required EMT model submission for many interconnections, each added to EMT model library
- Routine SSCI studies required anywhere near series caps
- Semi-regular large scale EMT studies for validating operations metrics and PSS/E models. (eg. every 2 years)
- Validation EMT studies to confirm controversial or constraint generating transient stability studies.
- Effort ongoing to make internal staff capable of studies

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERCOT Experience

- Successes:
  - Degree of confidence in key operating constraints
  - Ability to do high quality post-event analysis, particularly SSCI
  - New capability in engineering staff
  - Developing a high quality EMT model library for the future
- Issues:
  - Getting engineers up to capability is slow and difficult (not the engineer's fault!), studies are time-consuming.
  - Very transparent process for stakeholders, but data sharing is difficult!

AEMO (Australian) Experience

Lots going on there…. Too much to summarize!

- EMT model submission required, along with very extensive model testing and PSS/E benchmarking analysis.
- Complex screening methodology for EMT study requirements
- Highly detailed guidelines which flex and change quickly
- Very wide-area EMT studies being performed, including entire states.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

AEMO (Australian) Experience

- Successes:
  - Very rapid acceleration in simulation and modelling capability nationwide
  - New understanding gained in high penetration systems
  - Sophisticated model databases and validation processes
- Issues:
  - Heavy requirements and rapidly changing rules create a lot of uncertainty and cost
  - Screening effectiveness is uncertain, study requirements may not be consistent as they are in a continual state of development
  - In the short term, insufficient people with specialist knowledge.
  - Significant delay for Generator interconnections.

Other Americans integrating EMT

- PacifiCorp: Cluster analysis, weak grid spot checks
- ATC: Developing new screening metrics, regional spot checks
- AEP: Checking TS constraints, SSCI screening
- Tri-State: Regional spot checks, known problem areas
- Xcel: Regional spot checks for weak grids, known problem areas
- National Grid: Large DG integration studies (>800 MW)
- HECO: Islanding studies, cluster studies, routine interconnection studies
- There are others (California?)

Final notes

- Where utilities do not require EMT study, generators are doing studies privately
  - Disadvantage: These studies are secret!
- Transient stability studies are not dead… it is still much easier to define operating limits, do bulk/routine studies, evaluate inter-area issues with TS
- New initiative into transient stability "Real Code" models. IEEE Task Force Under AMPS Committee (Analytical Methods for Power Systems) and TASS Working Group (Transient Analysis and Simulation)
- Computer and software capability is rocketing upwards. $6000 CAD for 32 core/64 thread monster, and PSCAD tools are using the hardware capability as fast as it comes.

Questions and Answers