ESIG Interconnection Studies Short Course

Alex Shattuck and Andrew Isaacs

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

November 17-19, 2025

ESIG Background

ESIG

1989

UWIG Established

ESIG started as the Utility Wind Interest Group (UWIG) in 1989, a group of six utilities interested in learning more about wind energy

Early 2000's

Understanding Improves

Wind integration understanding rapidly improved, and was helped by consolidation of balancing areas and growth of larger market operators (ISO/RTOs) in early 2000's

2011

UWIG becomes UVIG

Solar energy emerged at scale and with similar integration issues, and UWIG became the Utility Variable Generation Integration Group (UVIG) in 2011

2018

UVIG becomes ESIG

With renewables, storage and decarbonization as mainstream pathways to the future, UVIG merged with the International Institute for Energy Systems Integration (iiESI) and became the Energy Systems Integration Group (ESIG) in March 2018

ESIG Differentiators and Mission

ESIG

DIFFERENTIATORS

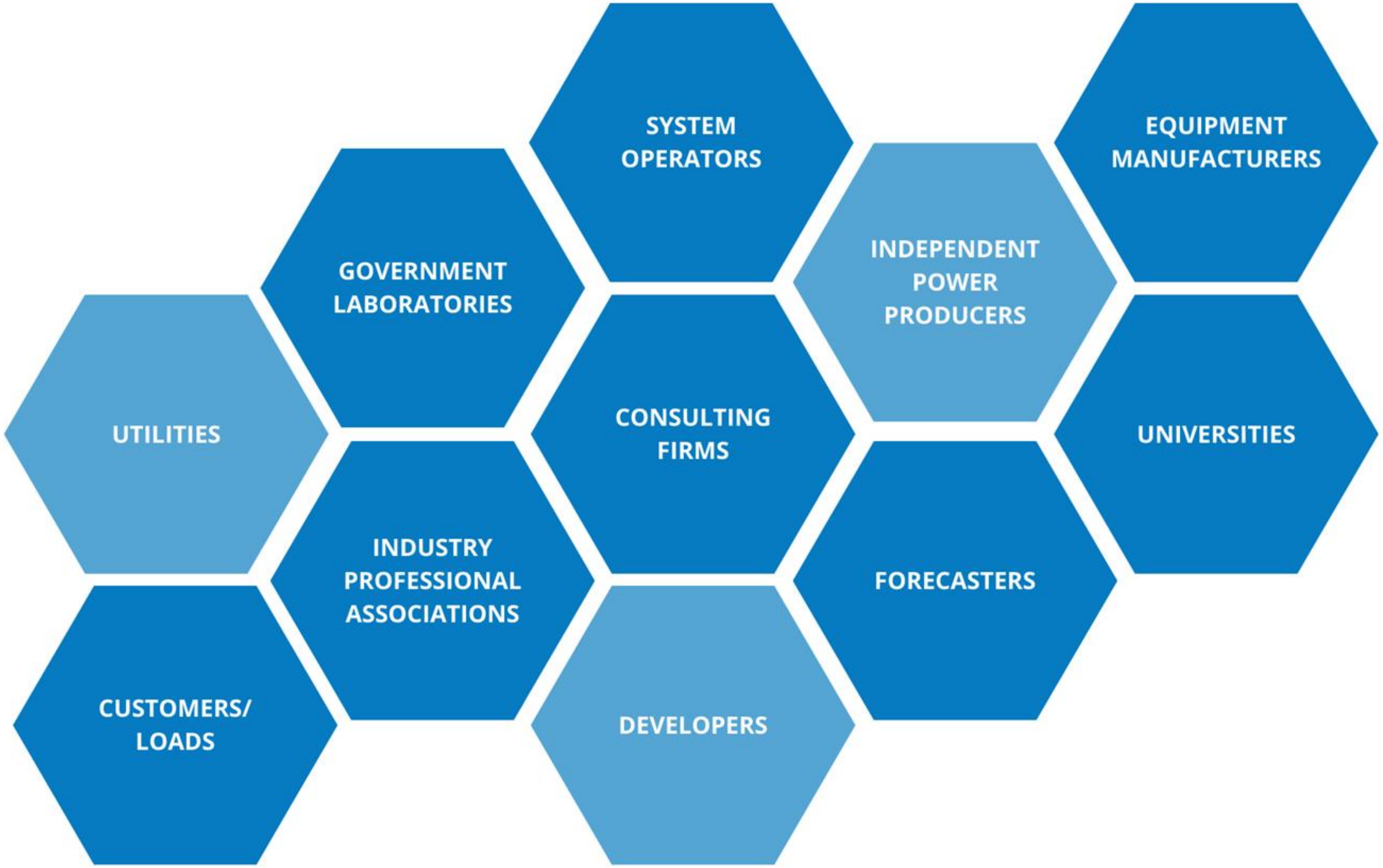
Stellar Technical Reputation | Best in Class, Global Reach | Independent and Trusted

MISSION

- Address the technical challenges for transforming energy systems through collaboration, education and knowledge sharing
- Work with all industries, energy vectors and applications globally
- Forward leaning, but not advocating, keeping everyone at the table
- Working at the cutting edge of the technical pathways toward 100%
- Pragmatically progressive—reliable, economic and sustainable transformation

ESIG Membership

250+ Members Globally



Welcome!

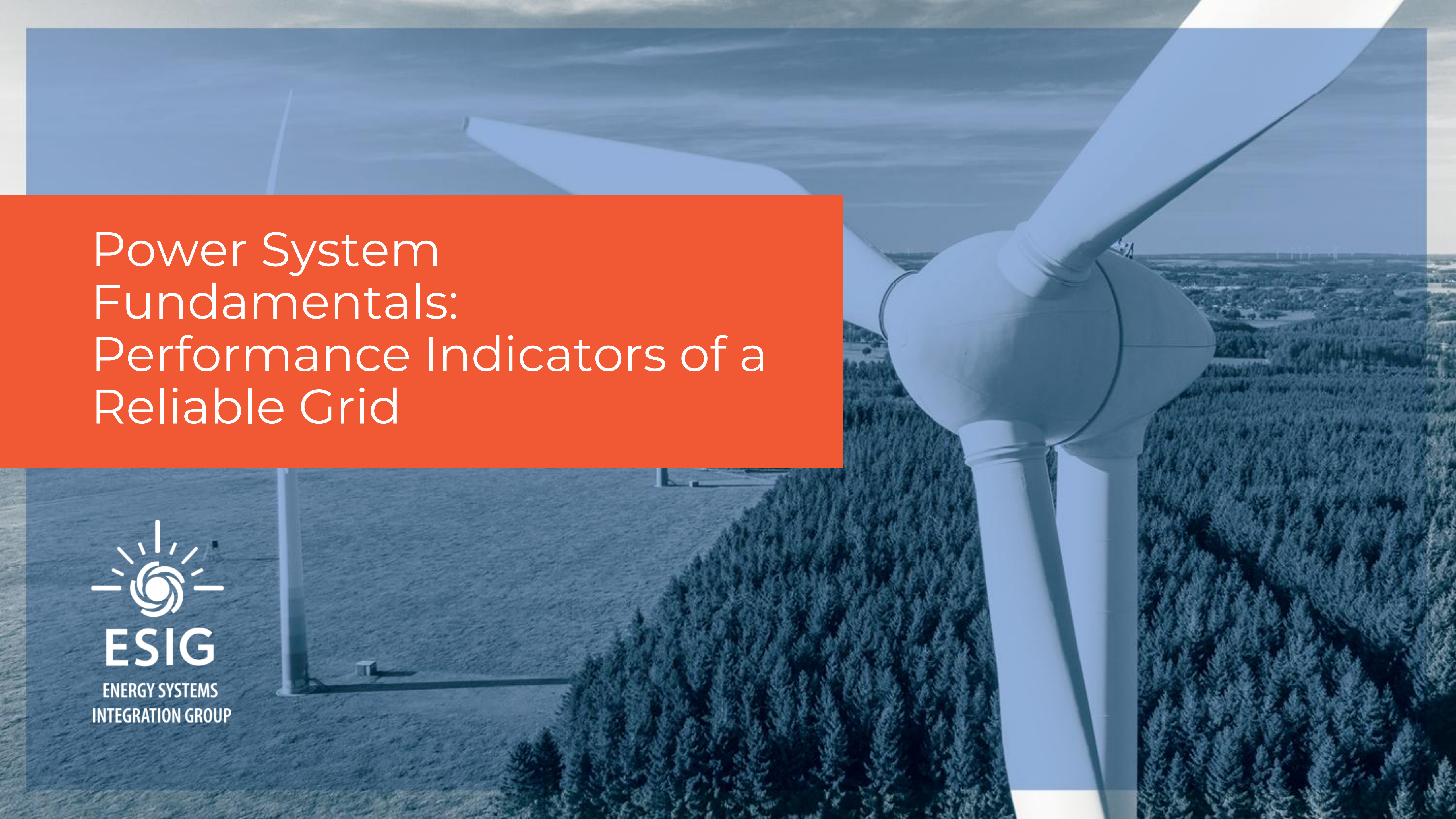
- **Welcome to the first presentation of ESIG's Interconnection Studies Short Course!**
  - **Instructors for the week:**
    - Andrew Isaacs – Vice President – Electranix
    - Alex Shattuck – Director of Grid Transformation – ESIG
- **Logistics for the week:**
  - Training will run 9a—p
  - Happy Hour is Tuesday 5:30p-6:30p

Welcome!

- **Some questions to kick us off:**

1. **Poll of industry sector**

2. **What topics are you hoping we cover this week?**



Power System Fundamentals: Performance Indicators of a Reliable Grid

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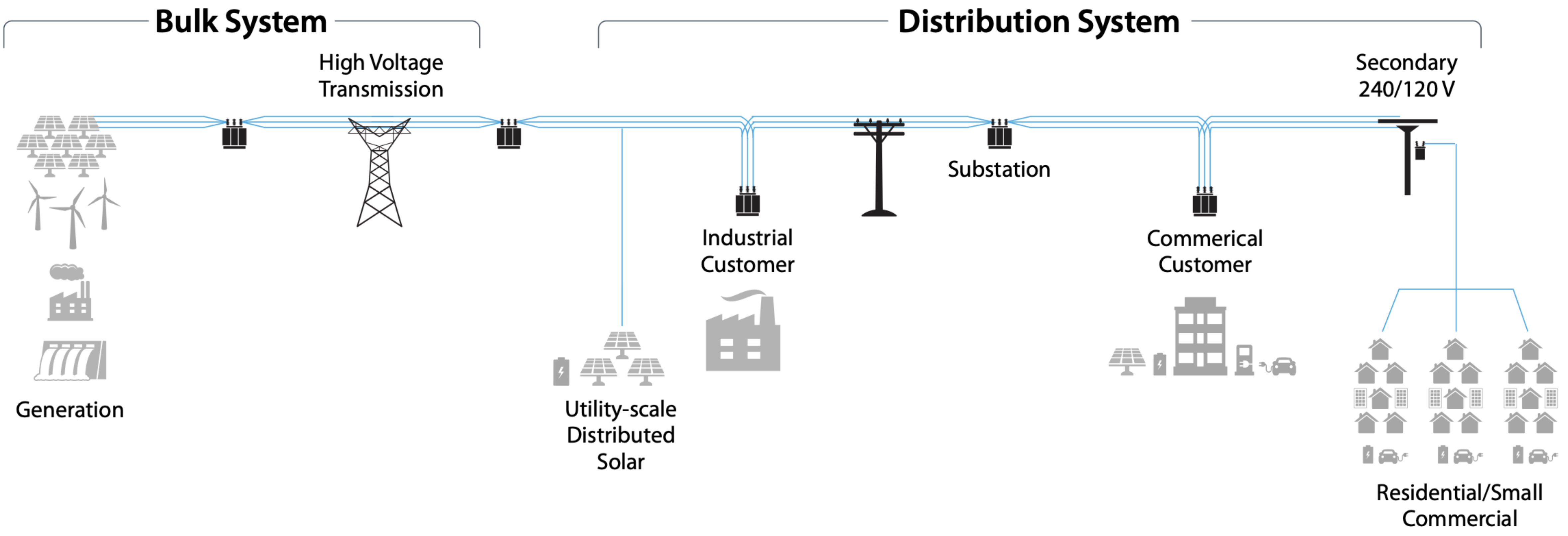
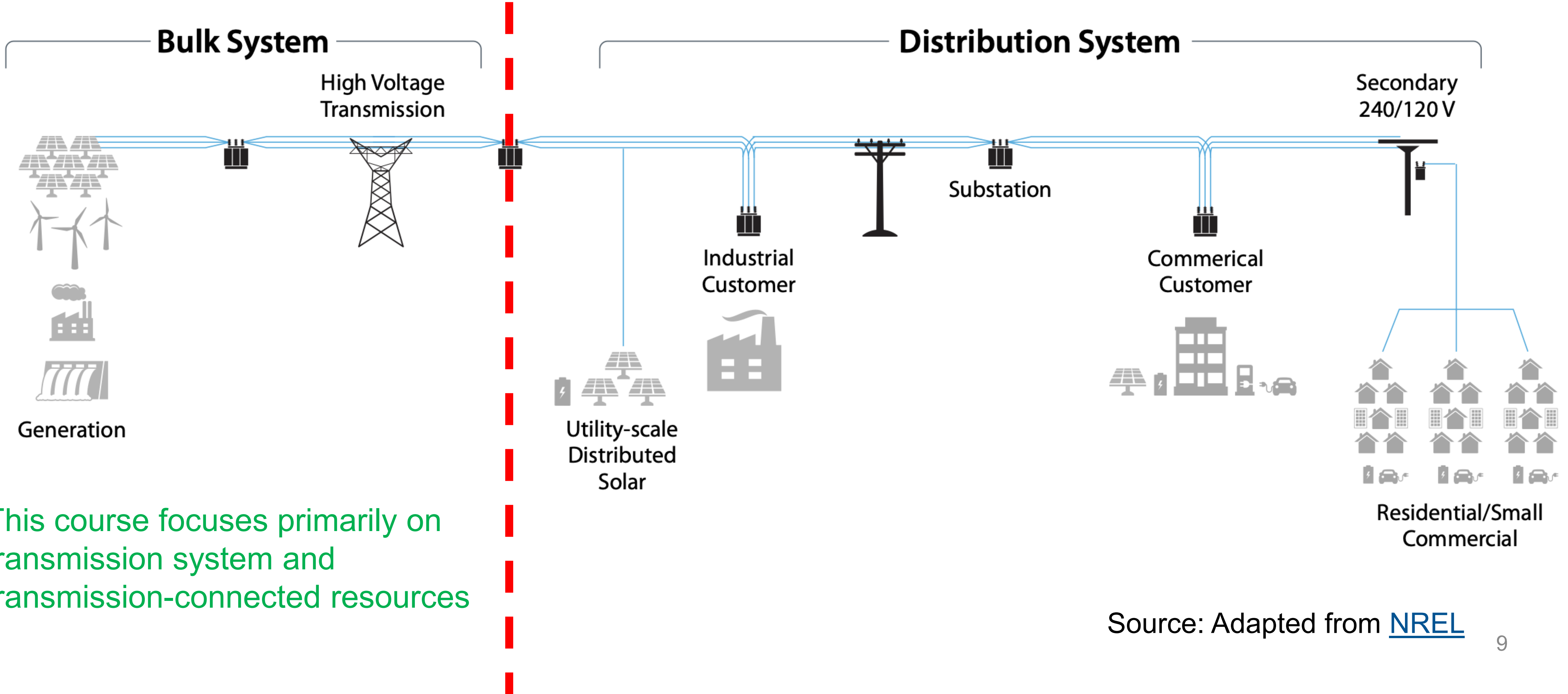
Major Components of the Power System



Source: NREL

Major Components of the Power System

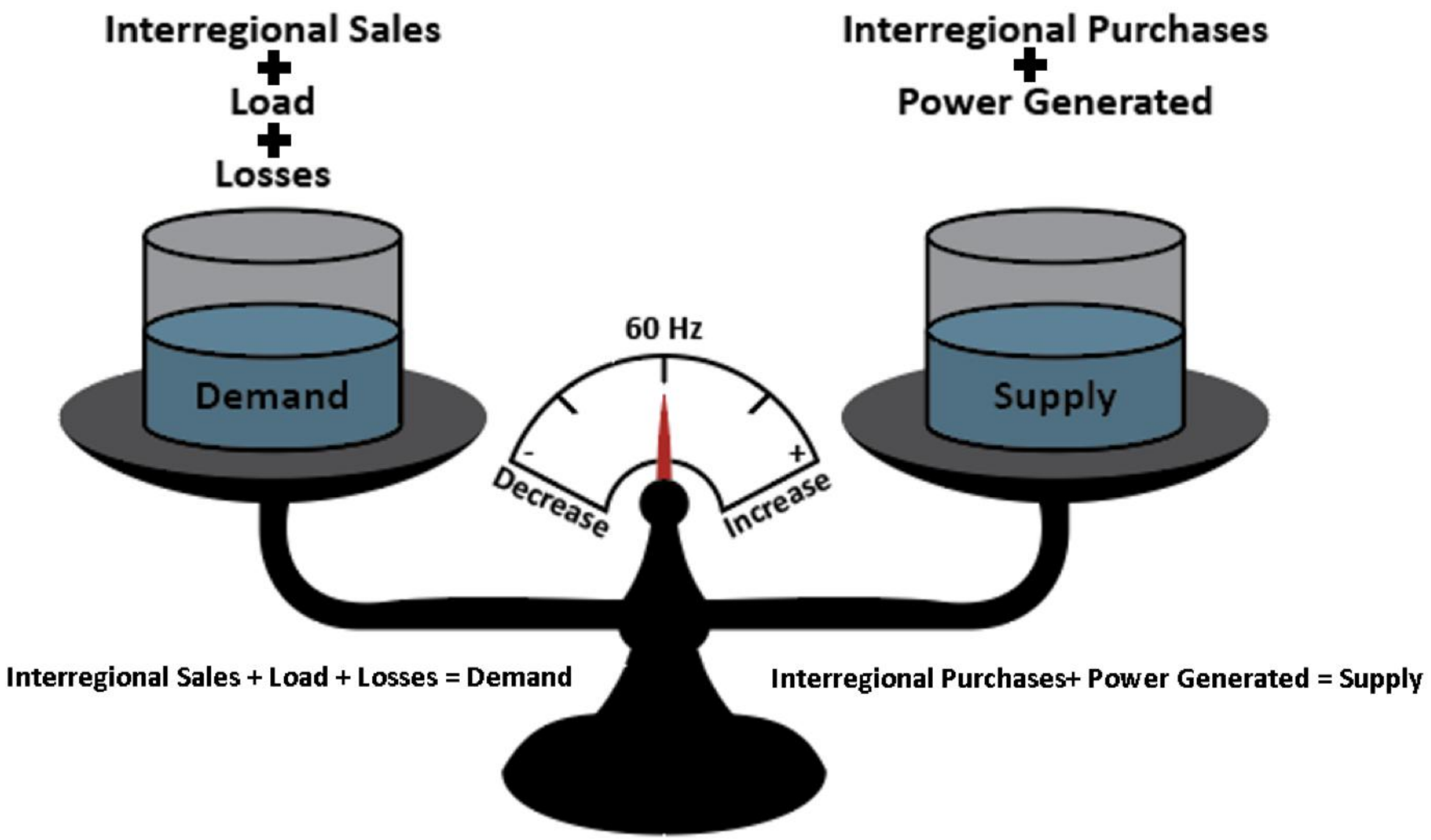
Transmission – Distribution Interface (T-D Interface)



This course focuses primarily on transmission system and transmission-connected resources

Source: Adapted from [NREL]

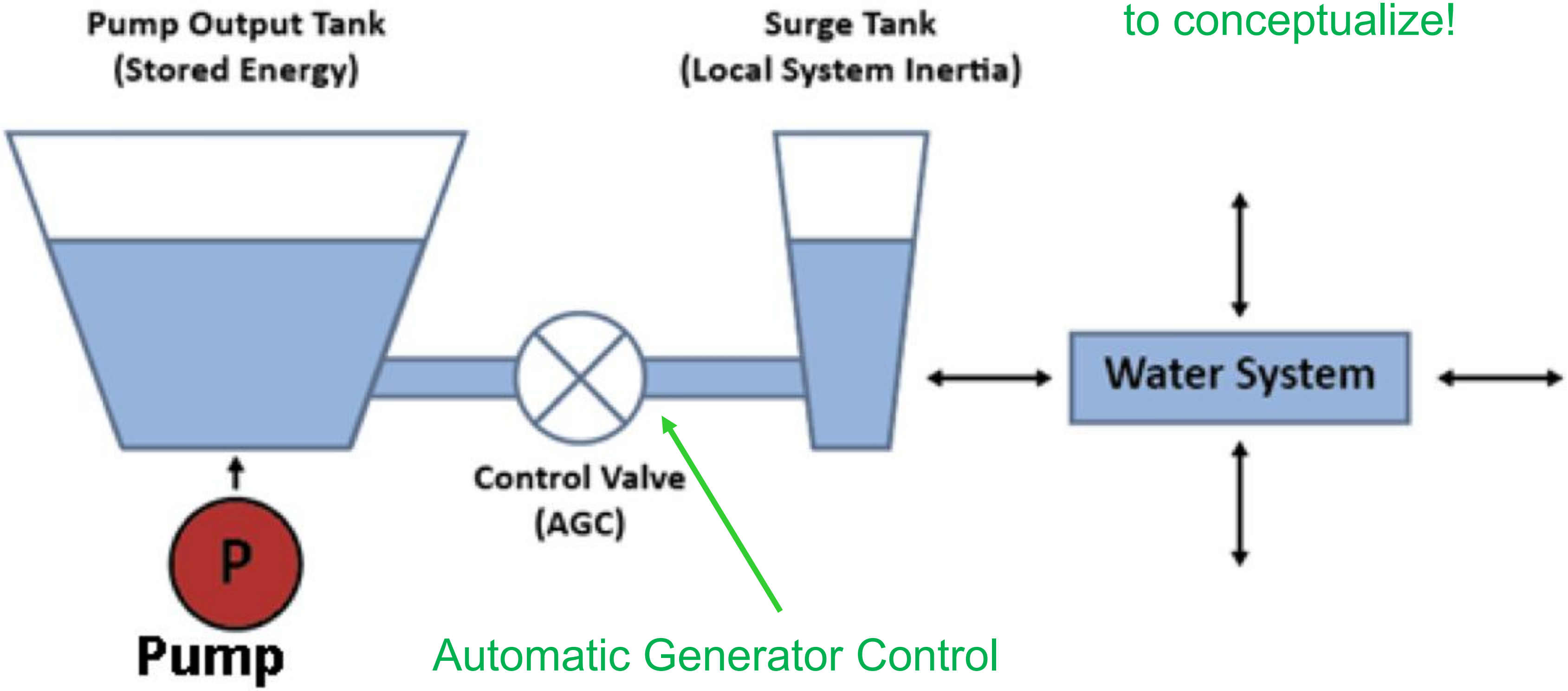
Energy Supply and Demand Must be Balanced



Source: NERC

Energy Supply and Demand Must be Balanced

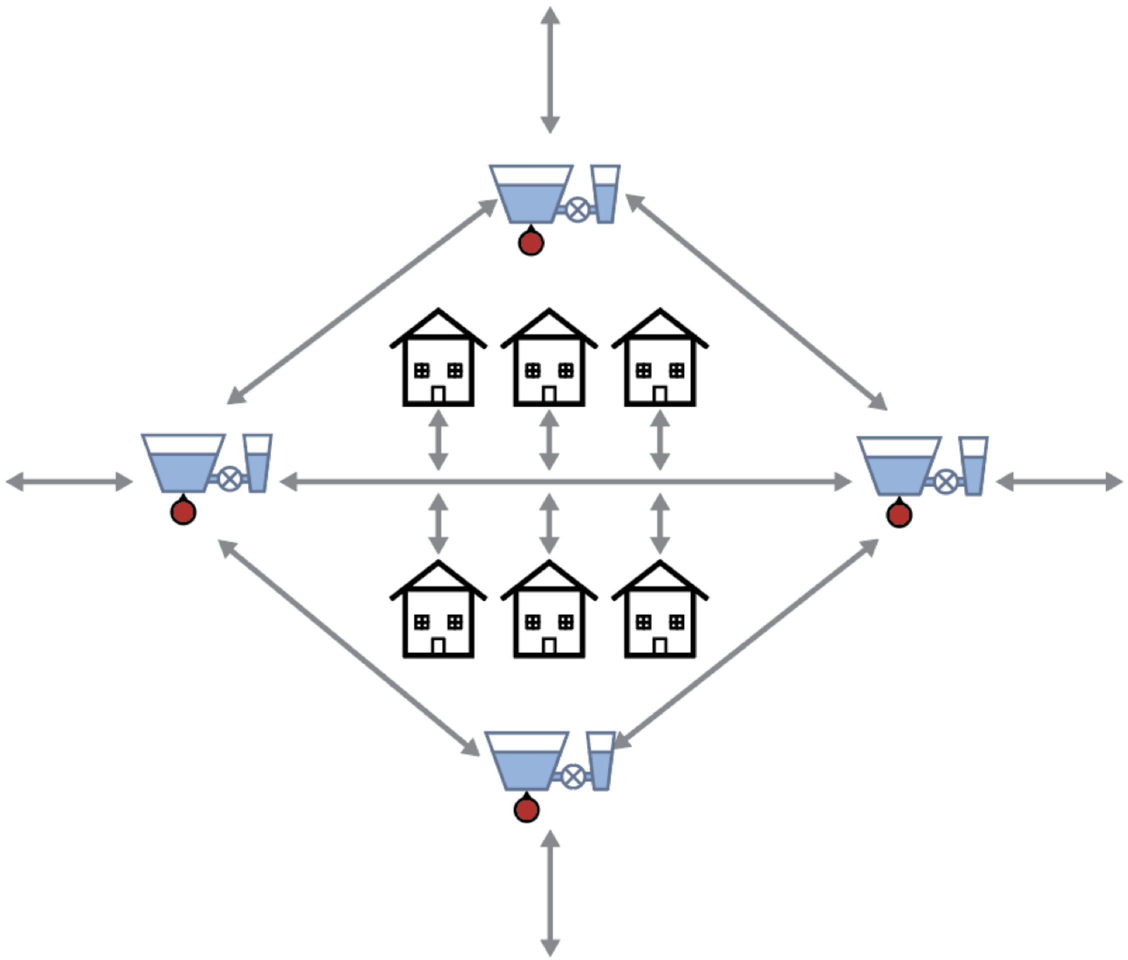
Pumps and water are a good way to conceptualize!



Automatic Generator Control

Source: NERC

Energy Supply and Demand Must be Balanced



- **Balancing Authorities do the heavy lifting**
  - Balancing their own system while managing inter-area flows
- Must manage:
  - **Interchange Error:** Net flows into our out of the balancing area
  - **Frequency Error:** Difference between actual and nominal frequency

Source: NERC

Energy of Sufficient "Quality" Must Be Provided

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- **What is power quality?**
  - How closely the delivered power matches the ideal standard of electricity
- **What is "ideal" in this context?**
  - Ideal sine wave
  - At the correct voltage
    - Within specified bounds
  - At the correct frequency.
- **Why is power quality important?**
  - Failure to meet PQ standards
  - Safety hazards and malfunction
  - Reduced efficiency

Parameter	Definition	Impact on System
Voltage Sag (Dip)	Momentary voltage reduction below nominal level	Causes resets, dimming, motor stalling
Voltage Swell (Overvoltage)	Temporary voltage increase	Leads to overheating, component stress
Transients/Surges	Sudden spikes in voltage or current	Damages semiconductors and power supplies
Harmonic Distortion (THD)	Deviation from the fundamental sine wave	Causes overheating, inefficiency
Frequency Deviation	Change in system frequency from nominal (50/60 Hz)	Affects timing, motor speed, and stability
Voltage Unbalance	Unequal voltage across phases in three-phase systems	Leads to vibration and excessive current in motors
Power Factor (PF)	Ratio of real power to apparent power	Indicates efficiency of power usage
Crest Factor (CF)	Ratio of peak to RMS voltage	Identifies waveform distortion risks

Source: Vitrek

Who's in Charge of Reliability in North America?

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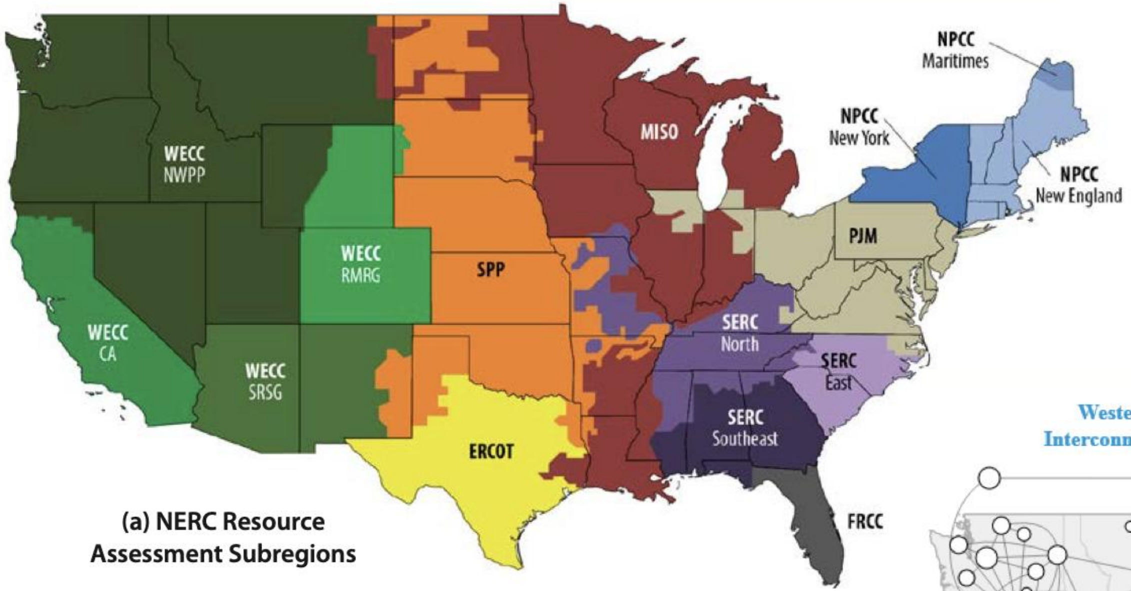
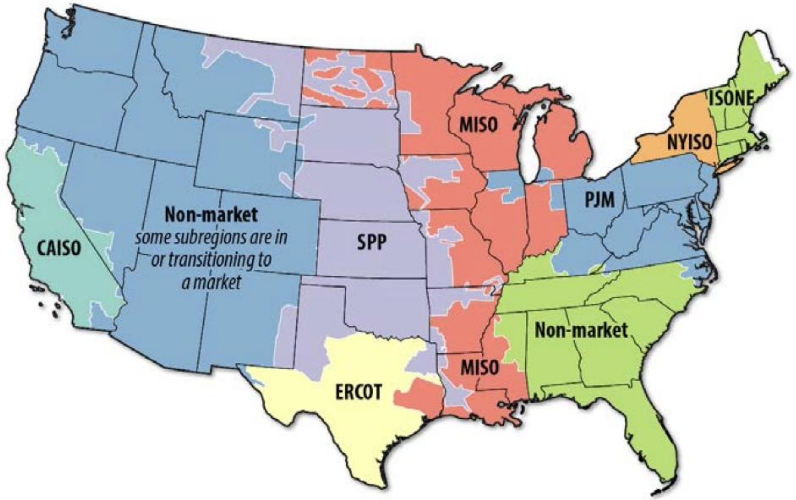
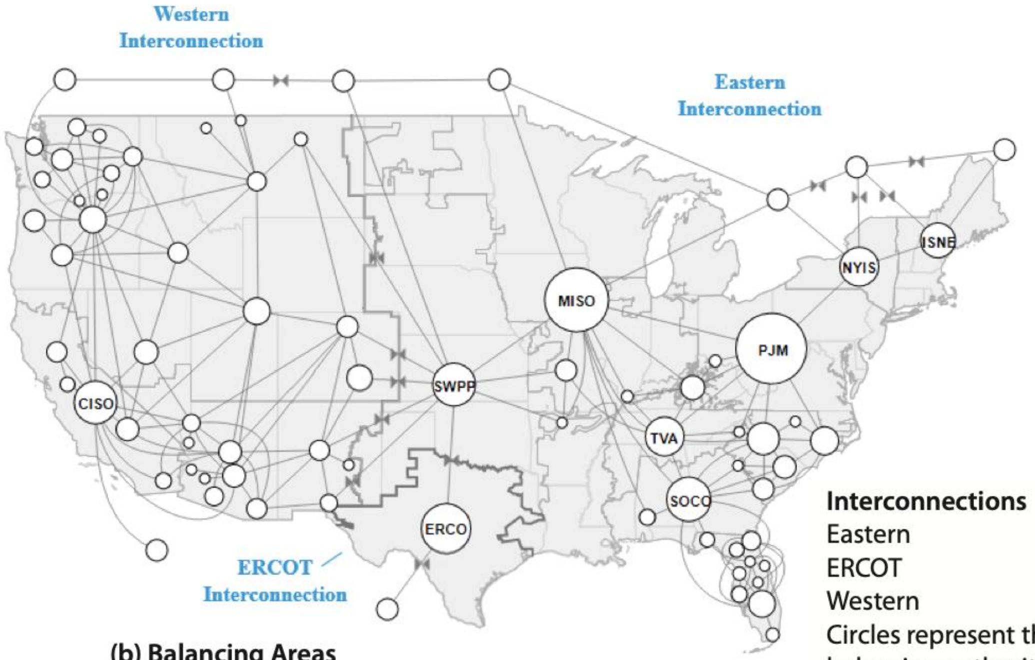


(a) NERC Resource Assessment Subregions



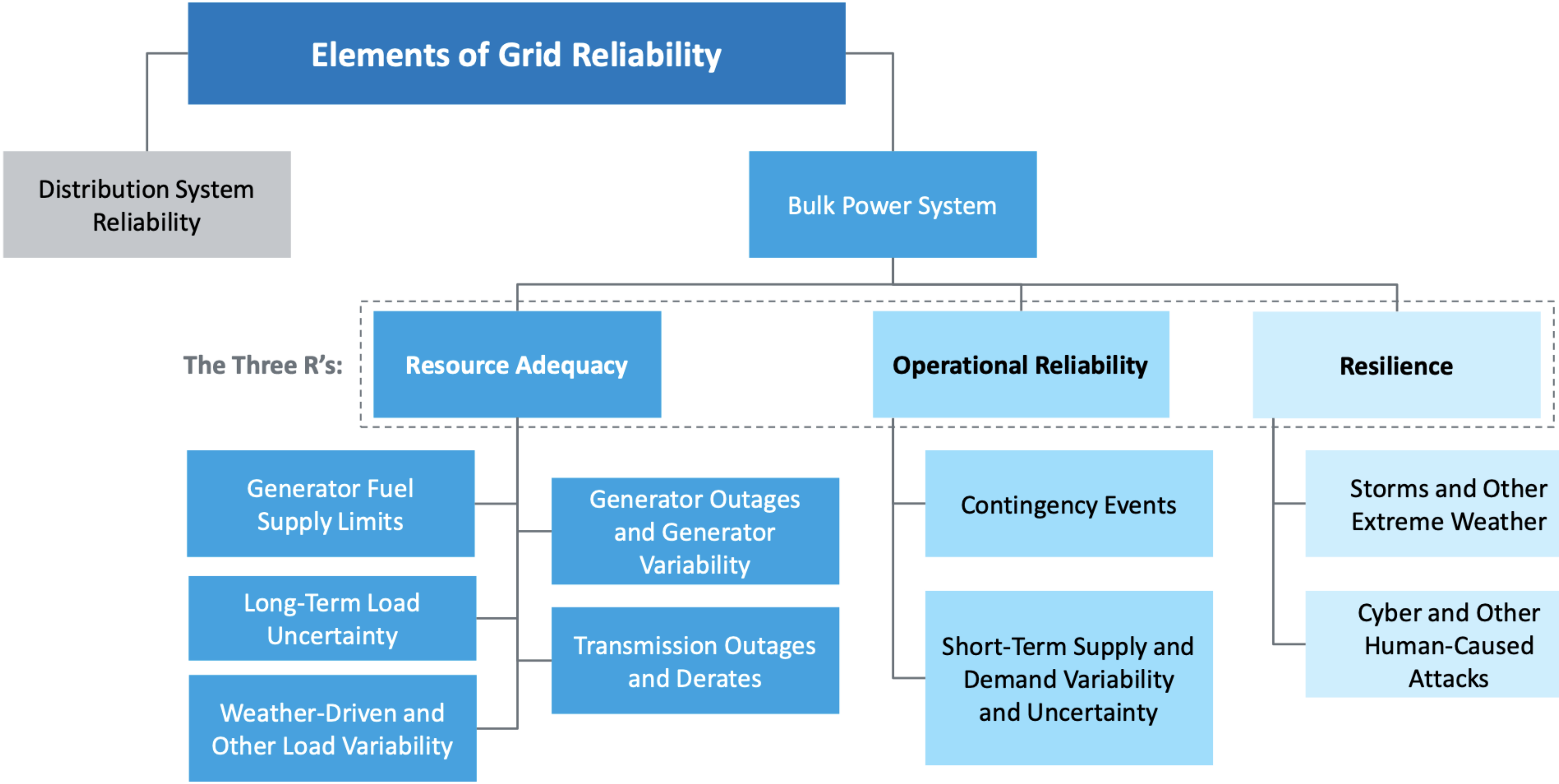


(b) Balancing Areas (EIA 2016)

Interconnections
Eastern
ERCOT
Western
Circles represent the balancing authorities

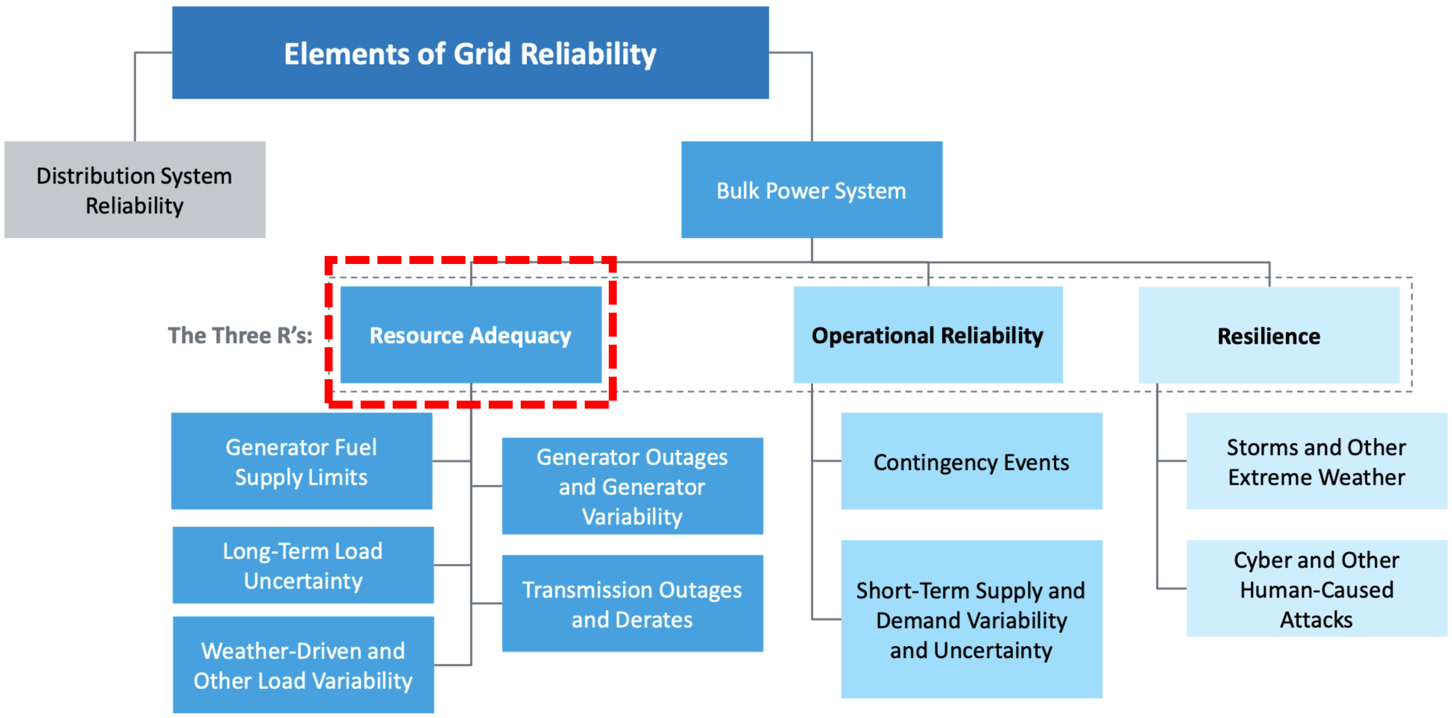
Source: NREL

Elements of Grid Reliability



Source: NREL

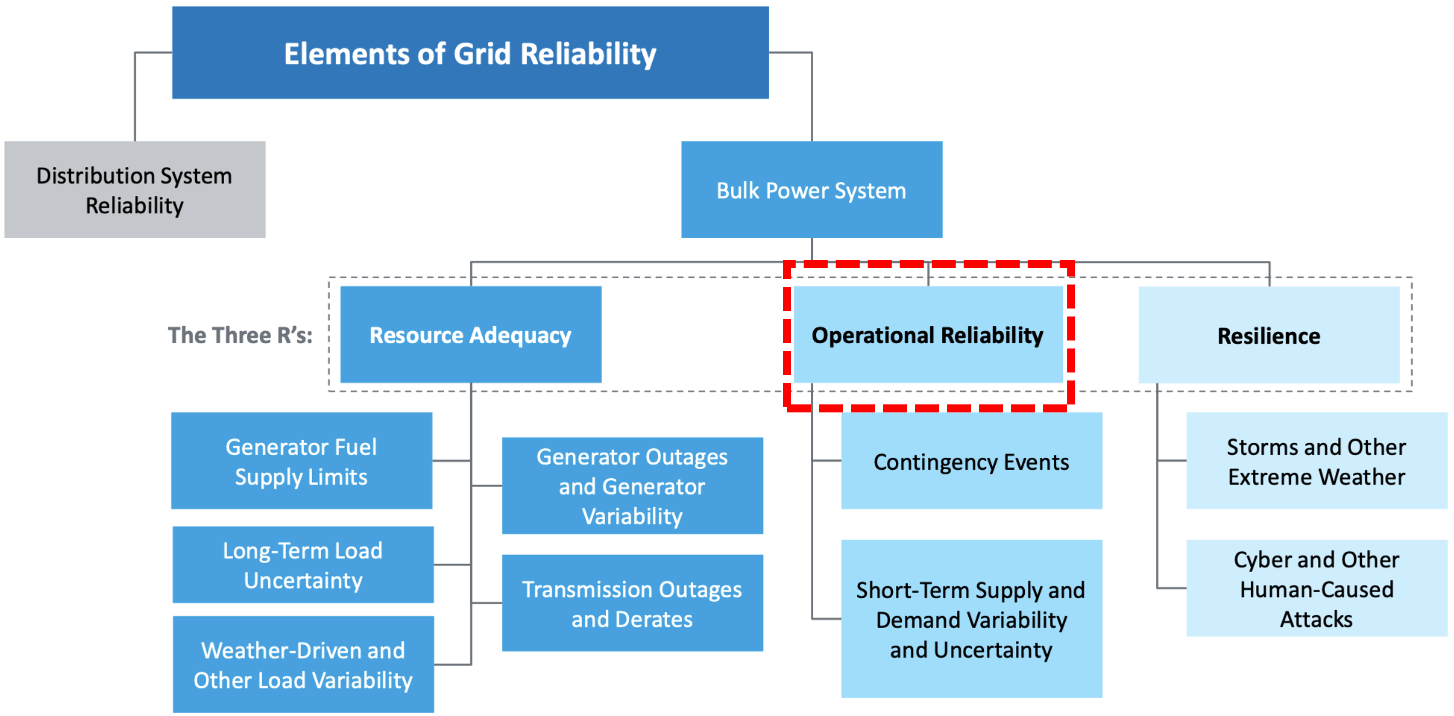
Elements of Grid Reliability: Resource Adequacy



Source: NREL

- **Resource Adequacy:**
  - *The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account reasonably expected unscheduled outages of system elements* – NERC
- Requires detailed probabilistic analysis to ensure energy can be supplied to specific metrics over numerous conditions

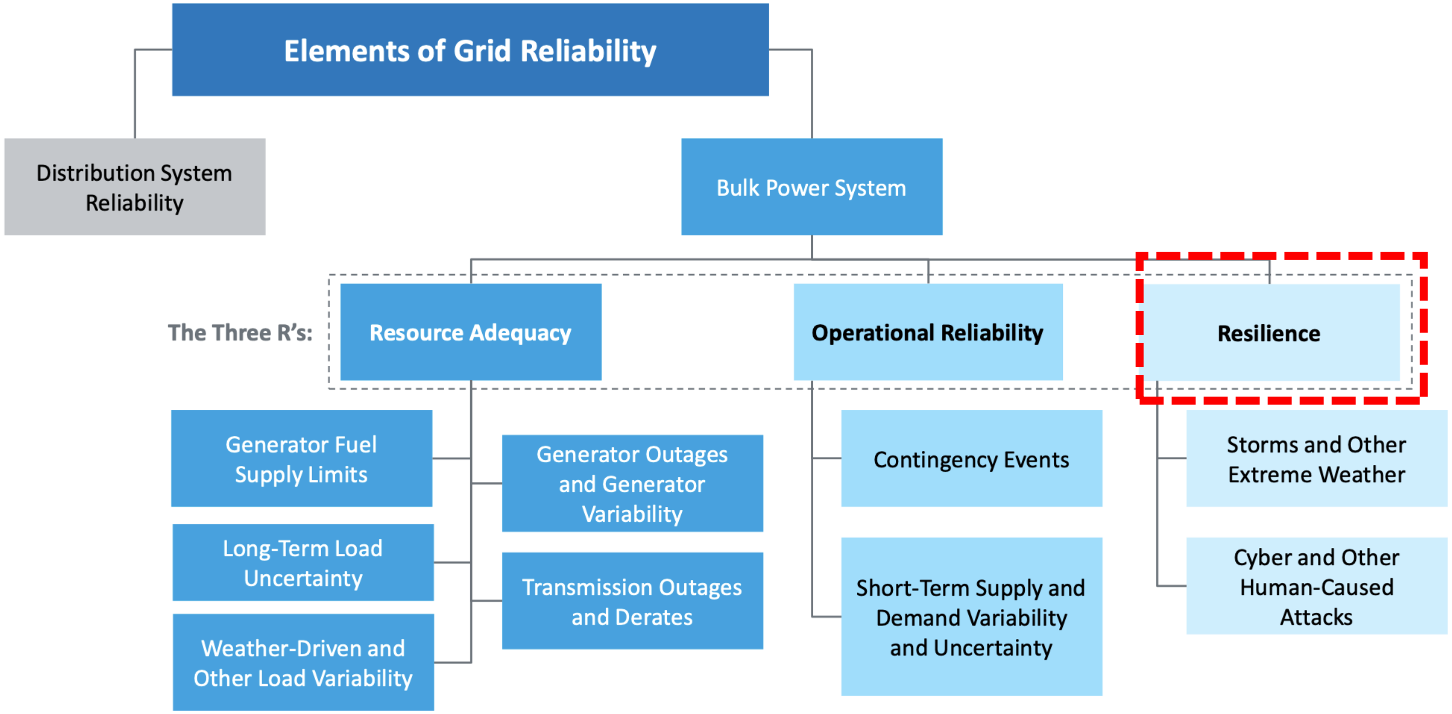
Elements of Grid Reliability: Operational Reliability



- **Operational Reliability:**
  - *The ability of the BPS to withstand sudden disturbances, (…), while avoiding uncontrolled cascading blackouts or damage to equipment* – NERC
- Transmission planning, interconnection planning, and related studies inform inputs and outcomes of operational reliability

Source: NREL

Elements of Grid Reliability: Operational Reliability



- **Resilience:**
  - *The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event* – FERC
- Much less well-defined
- Overlaps with both resource adequacy and operational reliability

Source: NREL

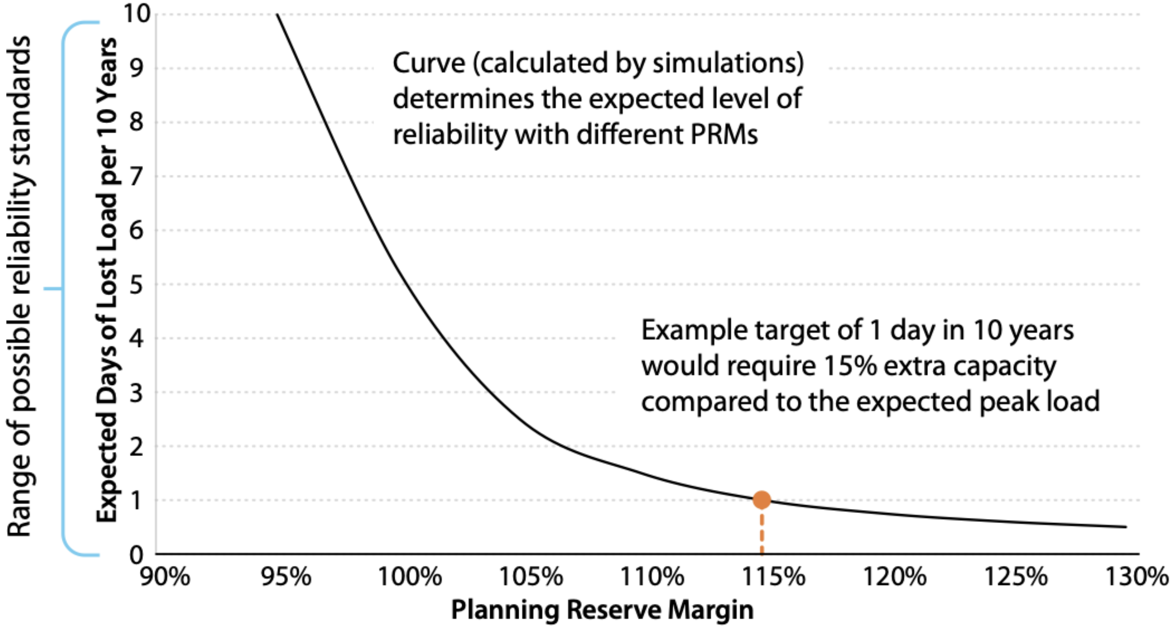
How is Power System Reliability Measured?

Resource Adequacy Metrics:

Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
MISO	18.3%	Planning Reserve Margin	Yes: established annually	0.1 day/year LOLE	MISO[a]
NPCC-New England	13.4%–13.6%	Installed Capacity Requirement	Yes: three-year requirement established annually	0.1 day/year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	20.0%[b]	Installed Reserve Margin	Yes: one-year requirement, established annually	0.1 day/year LOLE	NYSRC, NPCC Criteria
PJM	14.4%–14.8%	Installed Reserve Margin	Yes: established annually for each of three future years	0.1 day/year LOLE	PJM Board of Managers, ReliabilityFirst
SERC-Central/East/Southeast	15.0%[c]	Reference Margin Level (RML)	No: NERC-applied 15%	0.1 day/year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula[d]	15.0%	Reliability Criterion	No: Guideline	0.1 day/year LOLP	Florida Public Service Commission
SPP	16.0%	Resource Adequacy Requirement	Yes: studied on biennial basis	0.1 day/year LOLE	SPP RTO Staff and Stakeholders
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-CA /MX[e]	17.4%–19.0%	RML	No: Guideline	0.02% LOLP	WECC
WECC-WPP	13.5%–15.2%	RML	No: Guideline	0.02% LOLP	WECC[f]
WECC-SRSG	10.7%–12.4%	RML	No: Guideline	0.02% LOLP	WECC

[a] In MISO, the states can override the MISO planning reserve margin.
[b] For the capacity year beginning May 1, 2023 (New York ISO 2023).
[c] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[d] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[e] California is the only state in the Western Interconnection that has a wide-area planning reserve margin (CPUC no date).
[f] WECC's Reference Margin Level in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.

- No system can be 100% reliable so metrics are needed
- **Loss of Load Expectation (LOLE)** – expected number of time periods that could face supply shortfall



Source: NREL

How is Power System Reliability Measured?

- **Performance Metrics (EIA 2022):**
  - System Average Interruption Index (SAIDI)
    - Minutes on non-momentary interruptions
  - System Average Interruption Frequency Index (SAIFI)
    - Number of non-momentary interruptions
  - Customer Average Interruption Duration Index (CAIDI)
    - Average number of minutes to restore

- **Performance Metrics (NERC):**
  - Three levels of Energy Emergency Alert
    - Level 1-2 are levels of growing potential for shortfall of generation
    - Level 3 indicates a possible need to shed load and/or actual load shedding events

Source: NREL

How is Power System Reliability Measured?

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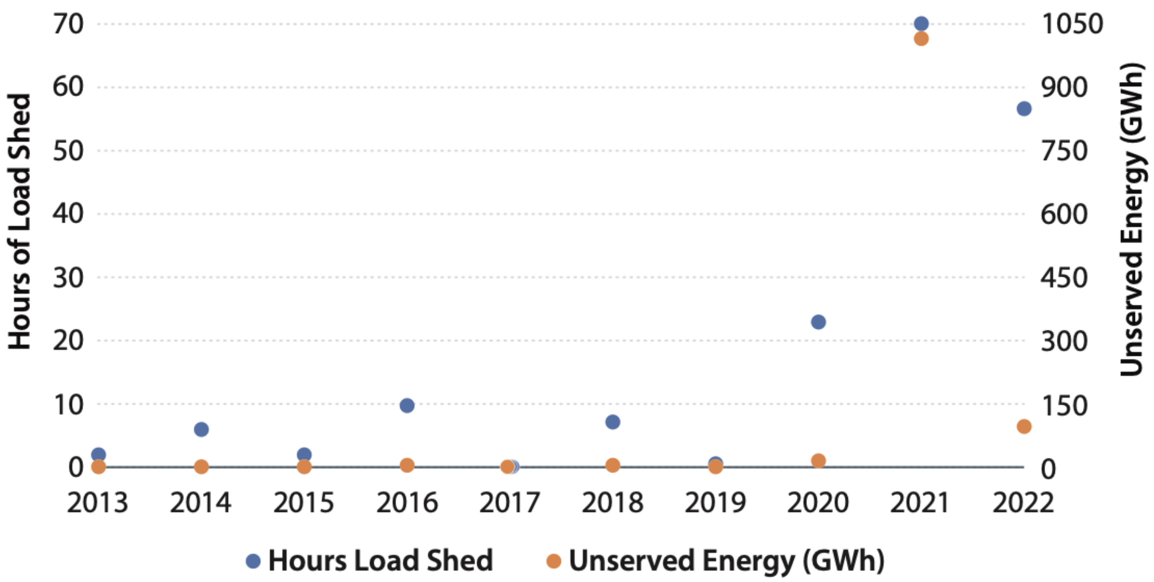
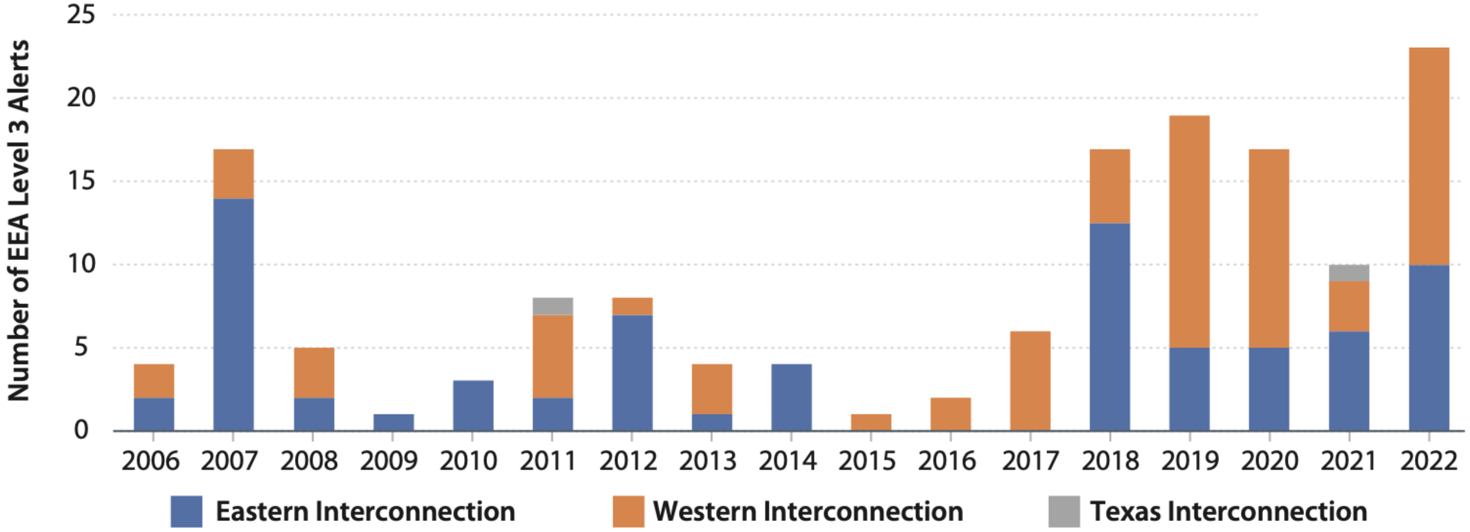
United States-wide Level 3 Energy Emergency Alerts and Unserved Energy





Source: NREL

High Priority Performance Indicator: ACE

- **What is ACE?**
  - **Area Control Error** measures the imbalance between supply and demand over a defined area
- Maintained with careful balance of generation and supply:
  - Day ahead and other scheduling
  - Generator dispatch
  - Demand response
  - Inertial, Primary, secondary, tertiary, and time controls

ACE calculation for compliance reporting:

- Reporting ACE = $(NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$
- Reporting ACE (WI) = $(NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$

where:

- NI_A is Actual Net Interchange,
- NI_S is Scheduled Net Interchange,
- B is BA Bias Setting
- F_A is Actual Frequency,
- F_S is Scheduled Frequency,
- I_{ME} is Interchange (tie line) Metering Error
- I_{ATEC} is ATEC (WI only)

Source: NERC

High Priority Performance Indicator: Maintaining System Voltage and Frequency

- **Maintaining system voltage and frequency is critical for power system reliability:**
  - Power quality
    - Ensuring quality is sufficient to minimize adverse effects
  - Ridethrough
    - Keeping system frequency and voltage within specified bounds is essential for “normal operations”
    - Remaining near nominal quantities provides extra “margin” during system disturbances
- In **system steady state** (normal operation) slow controls take precedence
  - Automatic voltage regulation or primary frequency response, for example
- In **system dynamic state** (abnormal operation) fault ridethrough and fast controls take precedence

Key Takeaways

- Maintaining grid reliability is done cumulatively through:
  - Resource adequacy
    - Maintaining balance within and between areas
  - Establishing reliability metrics and ensuring compliance with them
  - Maintaining power quality
    - Through performance metrics and conformity with them
    - Depends on grid-friendly performance during both ”normal operating” and “abnormal” conditions

Grid Reliability During Normal Operations

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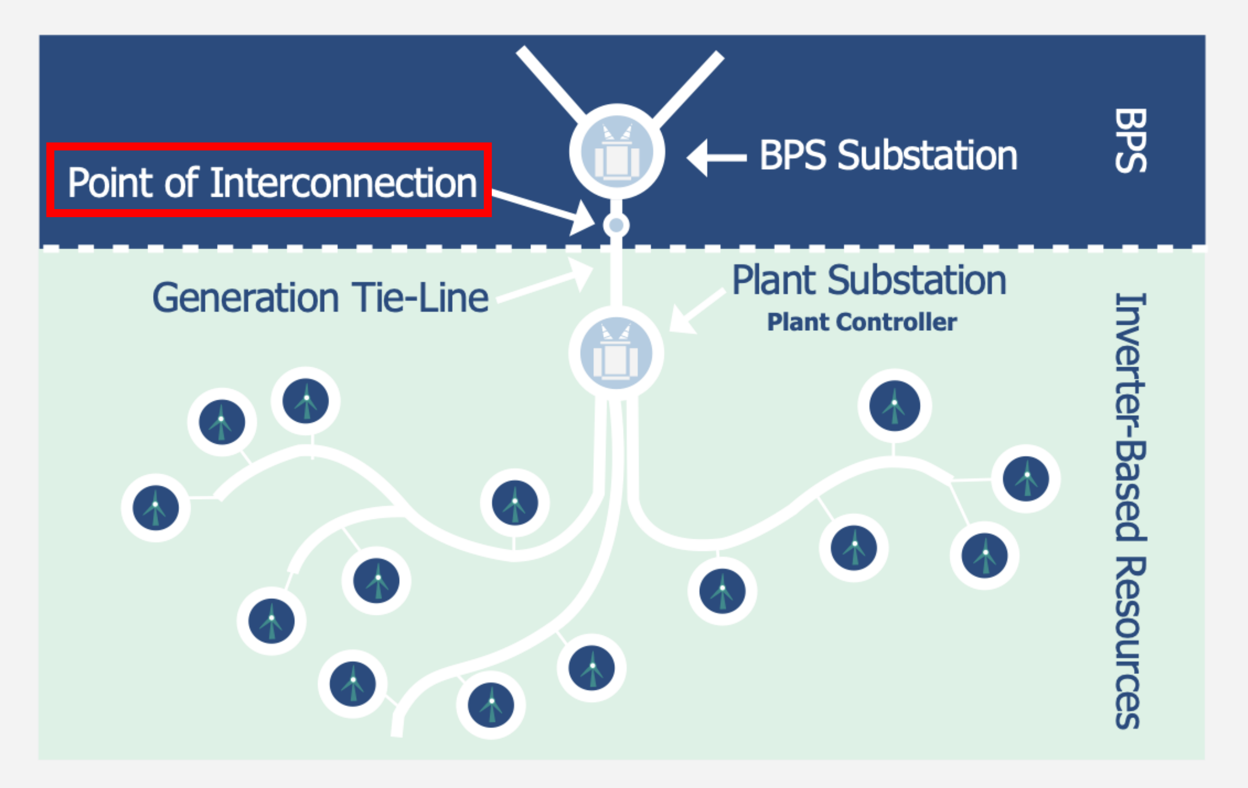
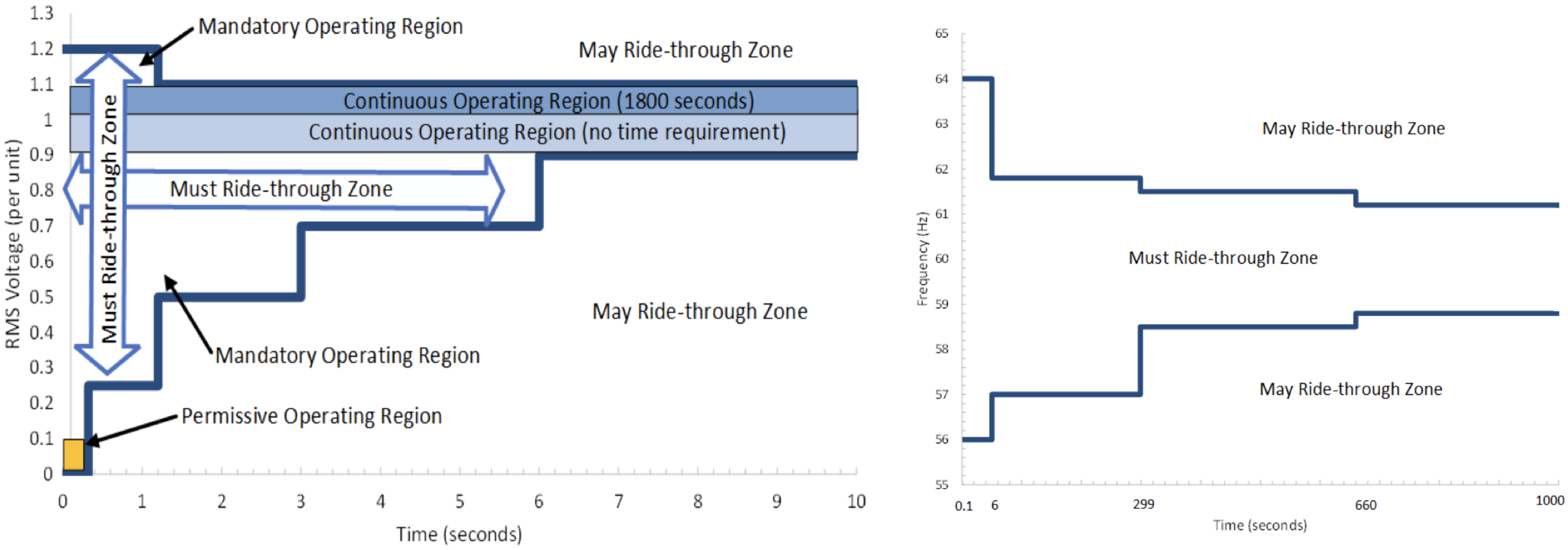
What is Normal Operation for Resources

- **Oversimplified:** any operating point that is not ridethrough
  - Regions of mandatory operation for a resource
    - Measured at the POI
    - Must remain online except when damage to equipment could occur
- **Less simple:** the controls and operation of a resource when its POI measurements are within appropriate bounds
  - Reactive power control, voltage control, primary frequency response, etc.
- **Normal operating regions are specified by each transmission service provider**



Source: NERC

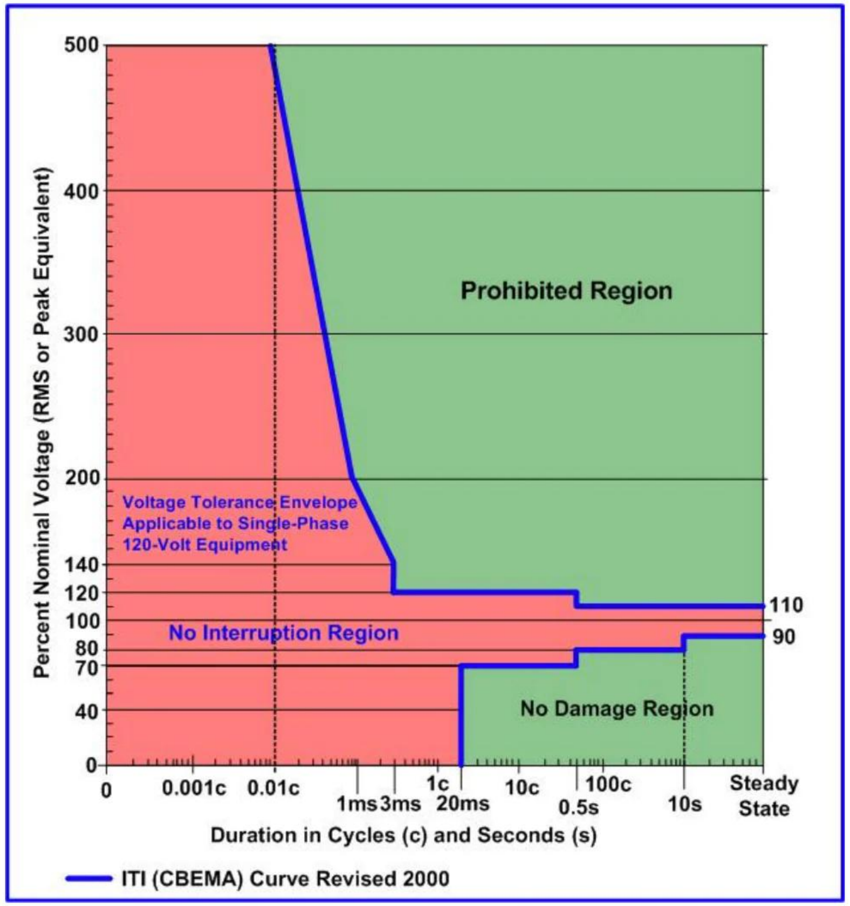
What is Normal Operation for Resources



Source: NERC

What is Normal Operation for Equipment?

- **Generating and demand facilities may be limited by auxiliary equipment**
  - Cooling
  - Wind turbine mechanical controls
  - Transformers
  - Power supplies
  - Communication
  - IT
- Some auxiliary equipment is mandatory for operation of a facility
  - Normal operations include ensuring this equipment is supplied power within proper ranges



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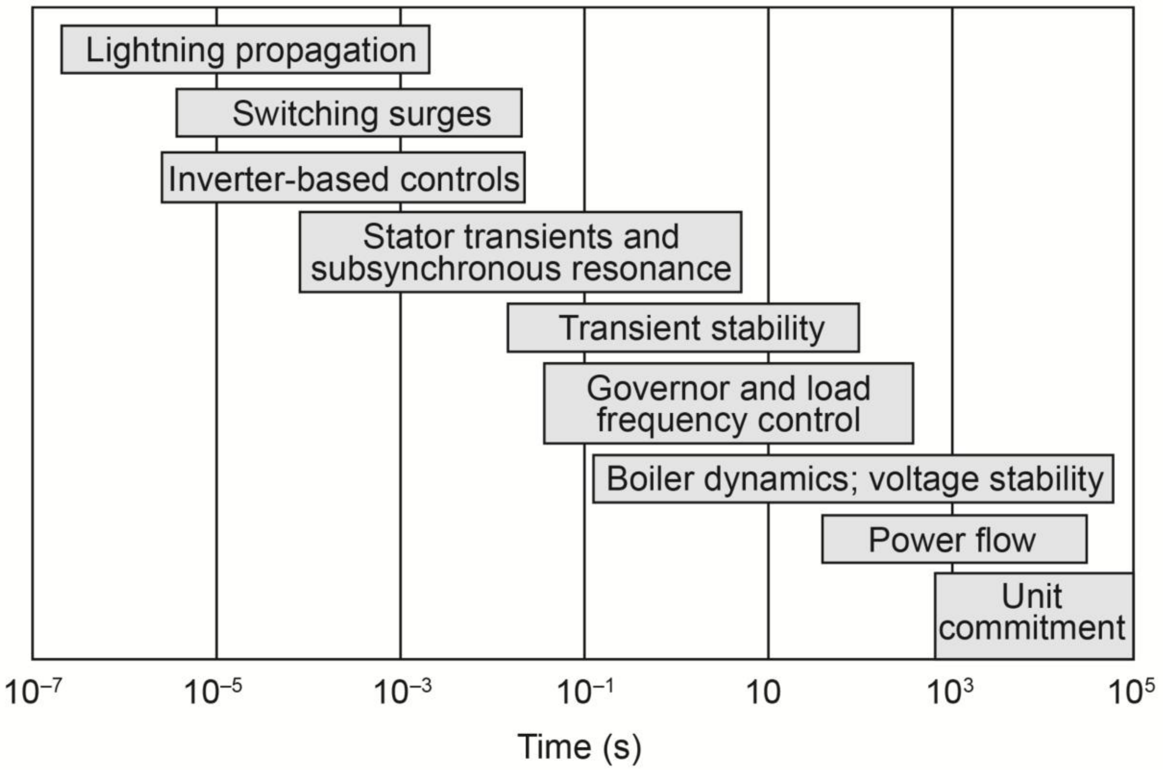
What is Normal Operation for the Power System?

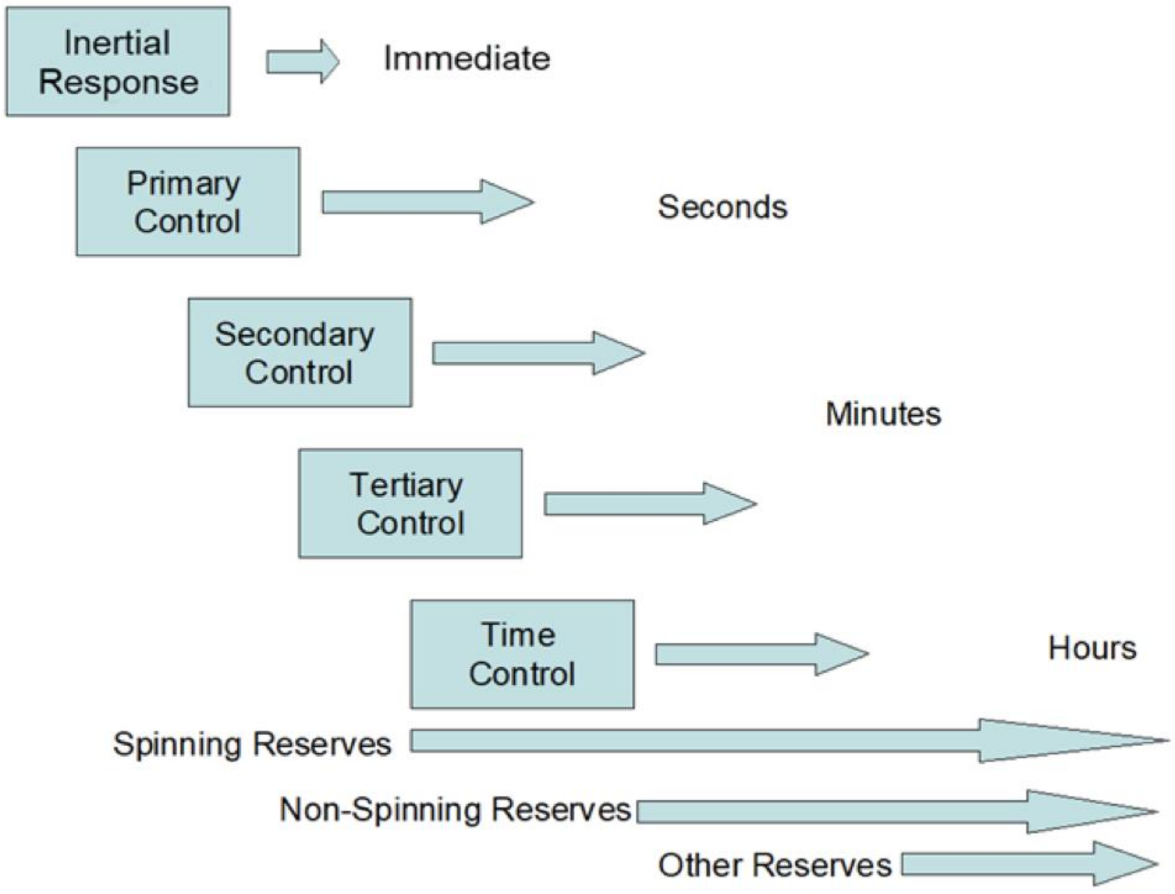
- **Ensuring quality power to demand customers**
  - Sufficient power quality
  - Minimizing disruptions in delivery
- **Maintaining system quantities within specified bounds**
  - Frequency near nominal (Frequency stability)
  - Voltage within specified operation band (Voltage stability)
- **Managing outages and ensuring reserve margins are met**
- **Posturing the system for potential disturbances**



Source: Smart Grid Wide-Area Transmission System Visualization

Normal Operation Timeframes

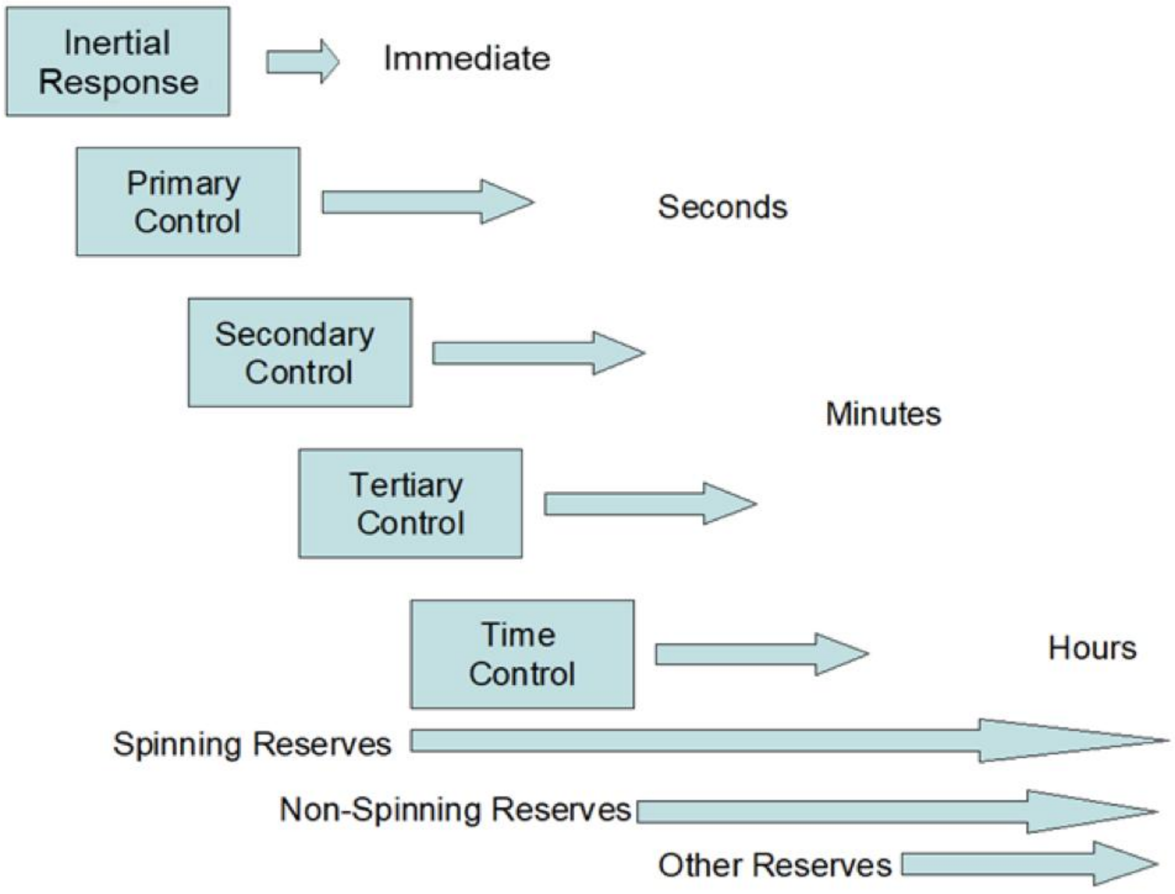
- **Primary Controls**
  - Operating on seconds timeframe
    - Autonomous controls that respond based on power system stimuli
    - Operates when measured quantities hit thresholds or trigger values
- **Examples:**
  - Primary frequency response
  - Fast frequency response*
  - Automatic voltage regulation
  - Transmission-connected power electronics devices



Source: NERC

Normal Operation Timeframes

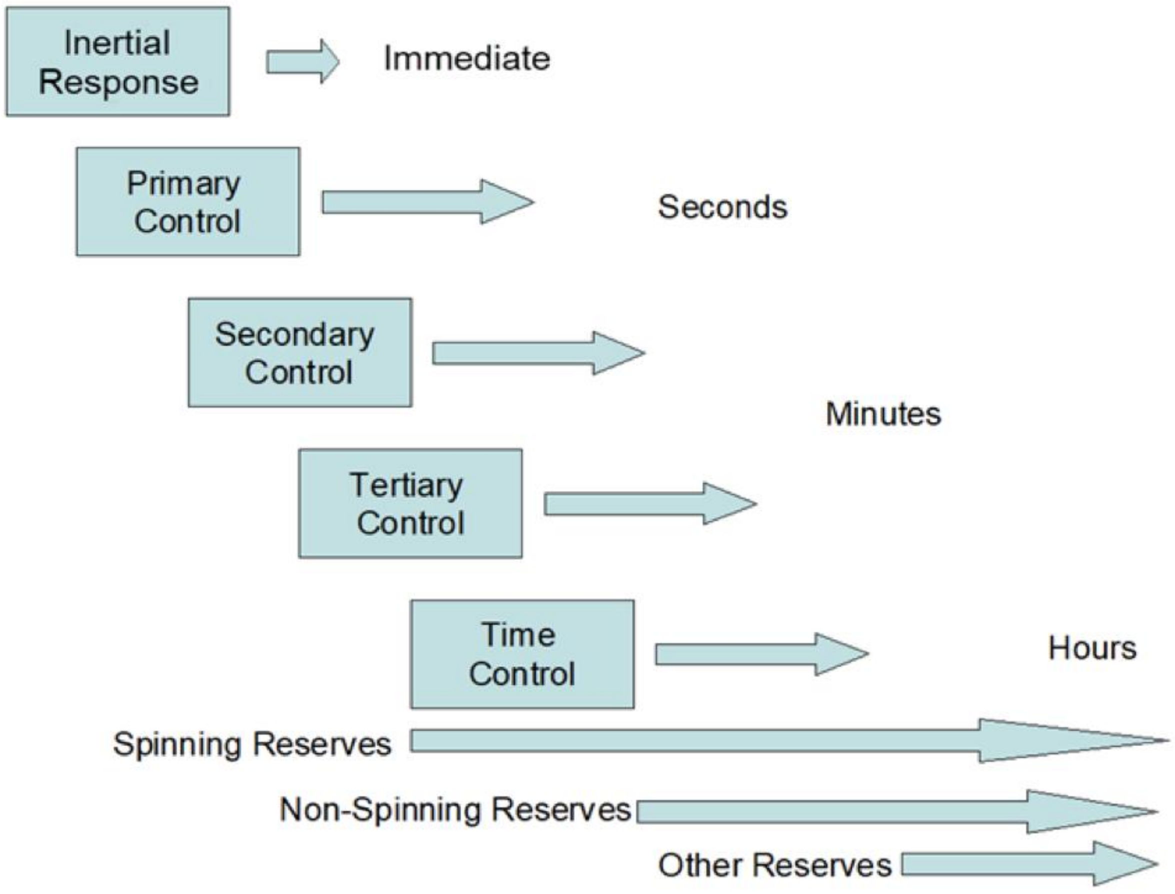
- **Secondary and tertiary controls**
  - On the minutes timeframe
  - Often involve operator inputs and manual actions
  - Used for balancing the system and recovery from disturbances
- **Examples:**
  - Active power setpoint changes
  - Reactive power setpoint changes
  - Voltage setpoint changes
  - Transmission equipment status changes



Source: NERC

Normal Operation Timeframes

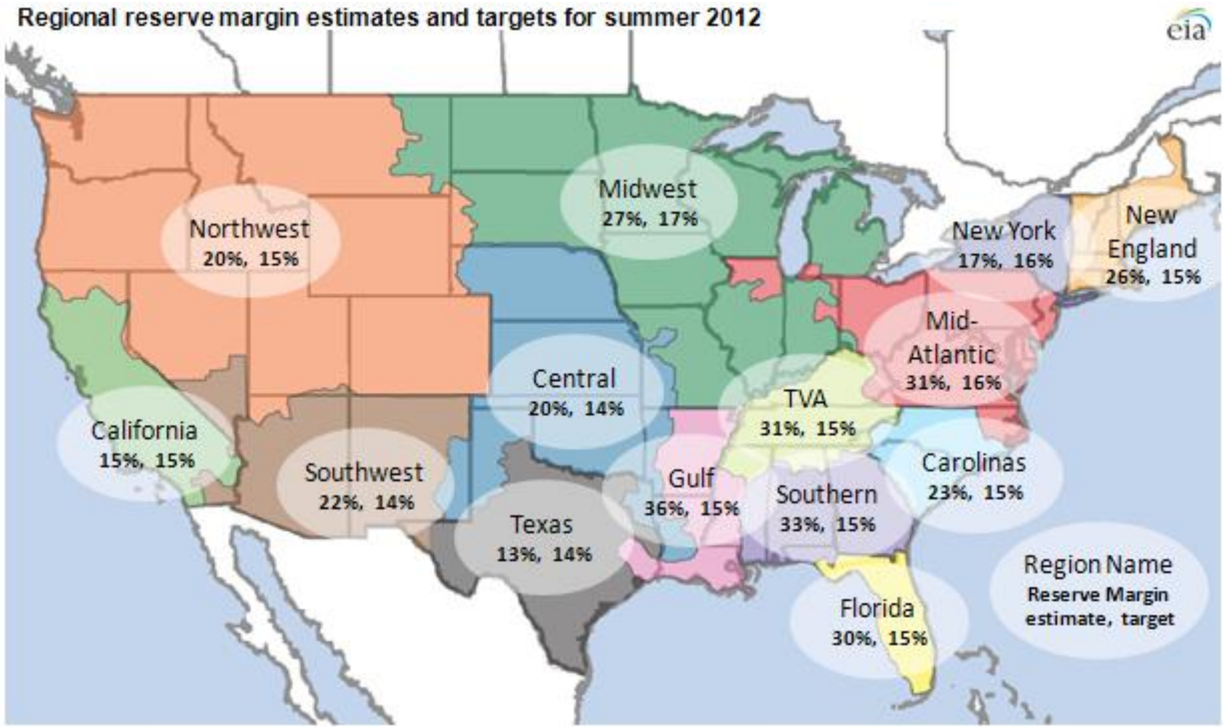
- **Time controls+**
  - On the hours timeframe
  - Involve operator inputs and manual actions
- **Examples:**
  - Ensuring reserve margins are met
  - Planning/scheduling outages
  - Balancing inter-area exchanges



Source: [NERC]

Reserve Margins

- **Important for ensuring sufficient energy is available during normal operations to prepare for abnormal conditions**
  - Reserve margins are based on the expected largest loss of source that a balancing area may observe
  - These are maintained through procuring generation in addition to the expected demand to help system balance in the event of a loss of source (generator or area tie)



Source: EIA

Active Power Controls: Why?

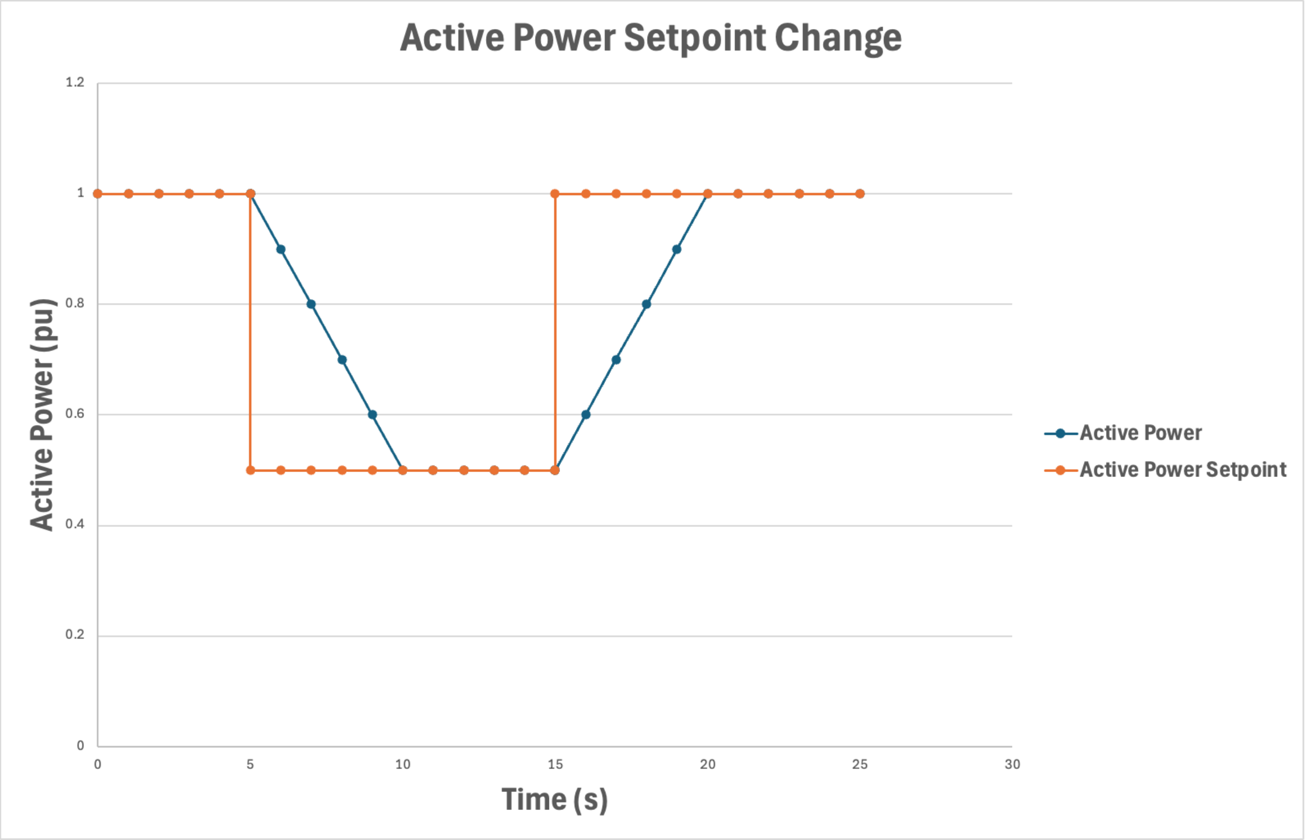
- **Balancing load and generation**
  - Automatic and grid operator initiated active power changes from generating resources are used to manage system frequency and load/gen balance
  - Balancing Authorities use these controls to maintain their ACE and interchanges
    - Also utilized to ensure reserve generation is available
  - Redispatching based on system conditions and possible next contingencies
- **Maintaining nominal system frequency (remember power quality?)**
  - Frequency is a wide-area metric and is affected by changes to generation or demand
  - Automatic frequency controls (primary frequency response) help maintain system frequency by altering active power injection based on measured system frequency

Active Power Controls: Overview

- **Active Power Setpoint Change (secondary/tertiary/time)**
  - Active power reference signal is input into the controller, and the controller moves to the new setpoint
- **Response to grid frequency disturbance (primary)**
  - **Primary Frequency Response**
    - Immediate and proportional change in active power injection in response to frequency disturbances – should move in grid-stabilizing direction
  - **Fast Frequency Response***
    - Similar to PFR in that active power injection will change in response to frequency disturbances
      - Acts on significantly faster timeframes to PFR. Capable of providing full response in ~30 cycles

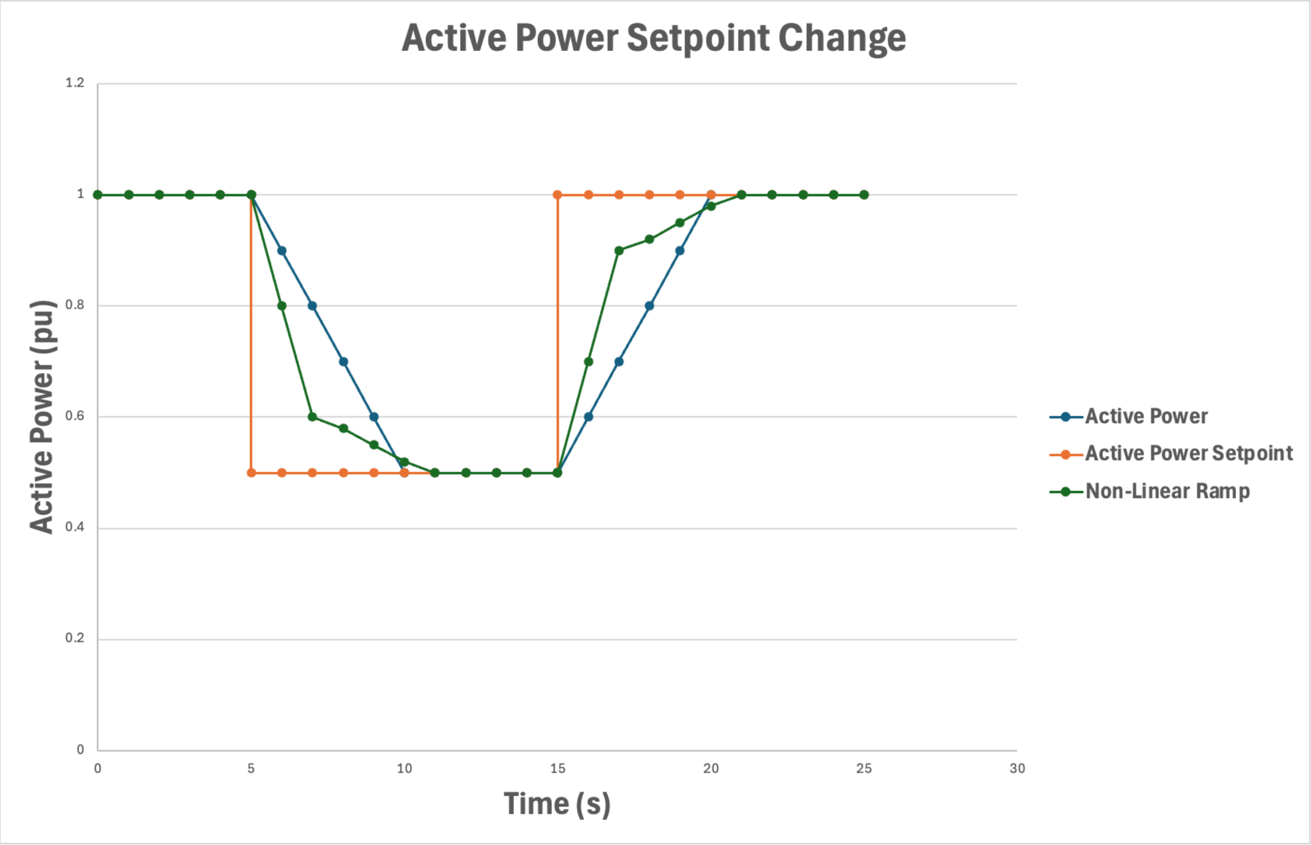
Active Power Controls: Active Power Setpoint

- **Secondary or tertiary control (or longer)**
- **Example: Active Power Setpoint Change to Power Plant Controller**
  - TSO needs to curtail the resource
  - TSO sends signal to reduce power to 0.5pu at 5 seconds
  - Active power injection **ramps** down
  - TSO sends signal to increase active power at 15 seconds
  - Active power injection ramps up



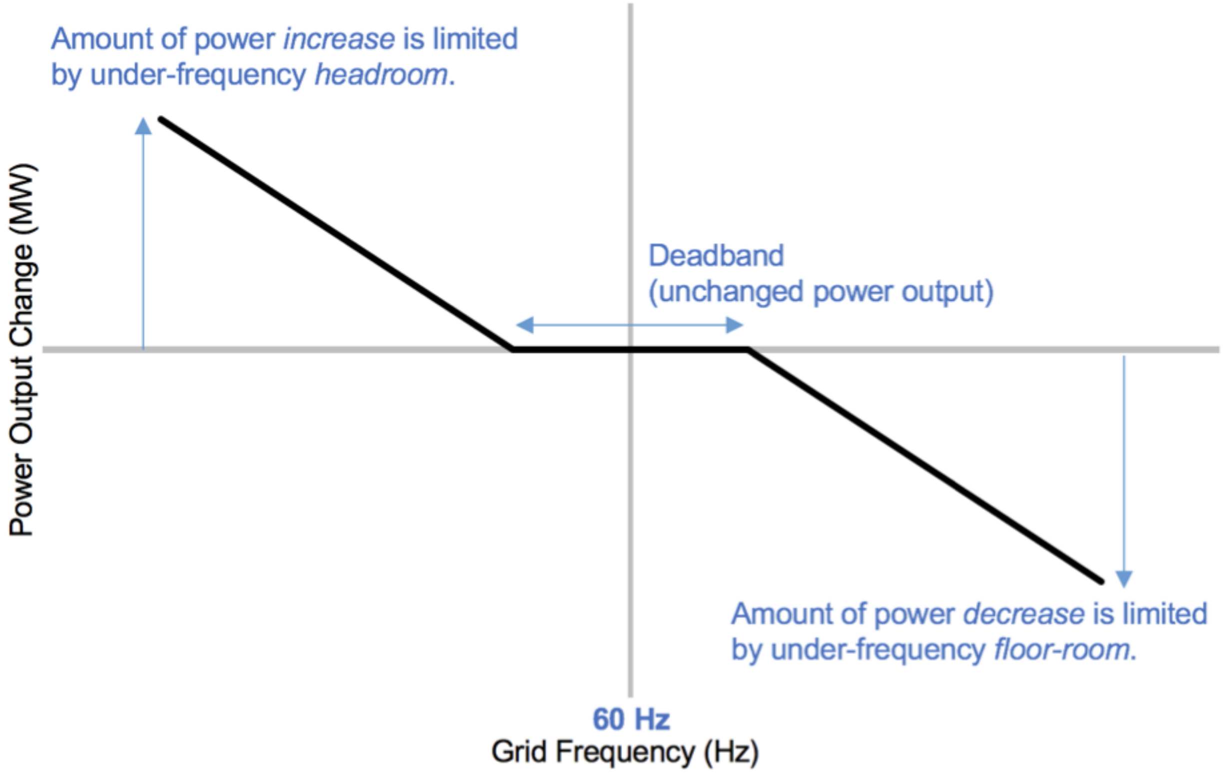
Active Power Controls: Active Power Ramp Rates

- Each resource should have parameters that control the rate of change of active power injection in response to a setpoint
  - **This is different than ramp rates for PFR or fault ride through**
- Ramp rate minimum and maximum should be specified by the TSO and may change based on:
  - System strength
  - Resource type
  - System needs
- Some resources may have non-linear ramp rates



Active Power Controls: Primary Frequency Response

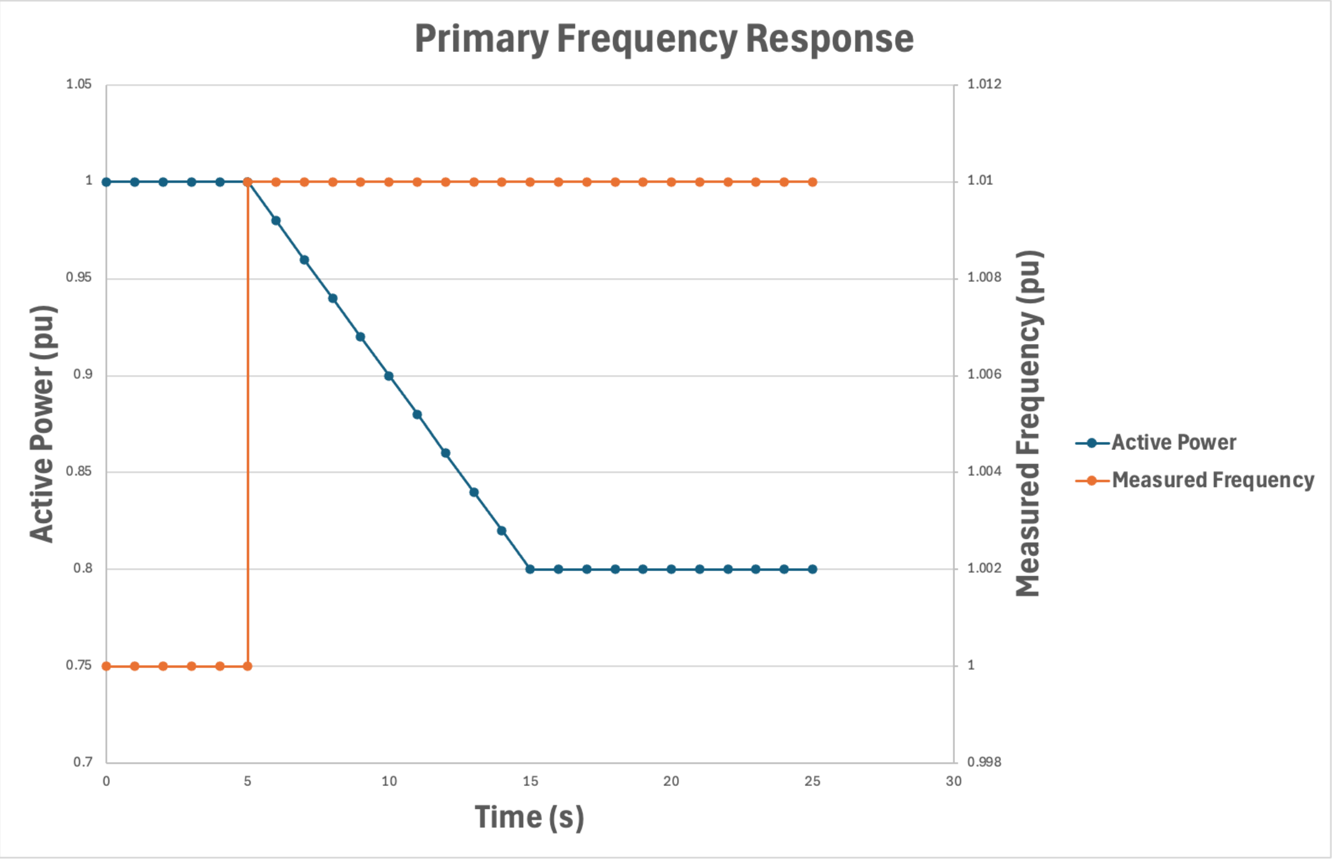
- **Primary Control**
  - Changes active power injection to support the system frequency
  - Operates with a **deadband** to avoid constant fluctuation
    - Typically either 17 or 36 mHz
    - Once measured frequency is outside deadband, control begins
      - Does the delta calculation use nominal or deadband value?
  - Operates with a **droop** to specify response magnitude
    - Typically 5%



Source: UPENN

Active Power Controls: Primary Frequency Response

- **Primary Frequency Response Example**
  - Frequency excursion occurs at 5 seconds
    - 1% frequency change (60.6 Hz)
  - IBR plant operates on 5% droop
    - With 5% droop, every 1% of frequency mismatch solicits 20% active power response
  - IBR plant reduces active power injection by 20% while system frequency remains high

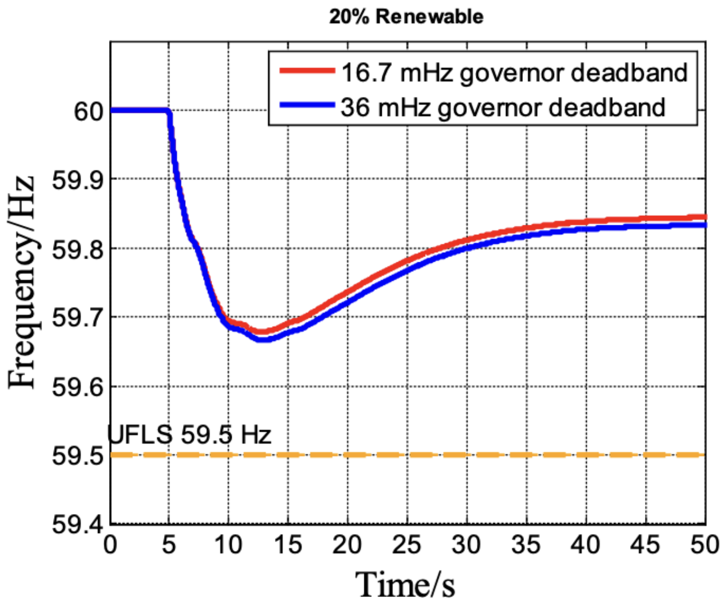


Active Power Controls: Primary Frequency Response

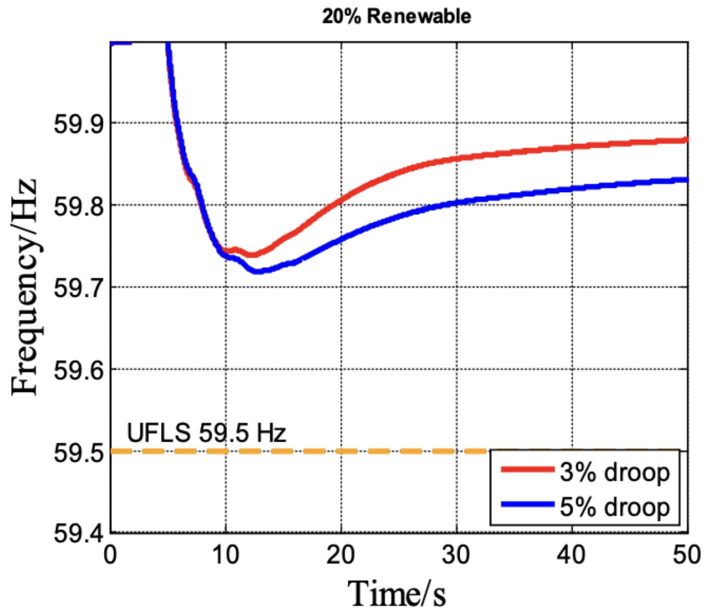
Effects of deadband and droop settings

Source: IEEE PESGM

- Dead-band



- Droop setting



- A narrow governor dead-band makes the governor kick in earlier.
- Improvement is not obvious.

A 3% governor droop can significantly improve the frequency nadir and settling frequency of WECC.

Reactive Power Controls: Why

- **Maintaining nominal voltage levels at point of interconnections (remember power quality?)**
  - Voltage is much more location dependent than frequency
  - Maintaining voltage levels at numerous local control points helps keep voltages near nominal
- **Maintaining specific voltages at TSO discretion**
  - Some portions of the system may need “help”
  - For example: plants may be run ”high” (i.e 1.03pu) to support voltage levels if the local area is prone to low voltages
- **Maximizing reactive power capability for use on the grid**
  - Operating at fixed reactive power levels may not allow for additional capabilities to be utilized during disturbances
  - Choosing appropriate reactive power control modes is critical
    - Appropriate modes and settings for an individual plant or the region

Reactive Power Controls: Overview

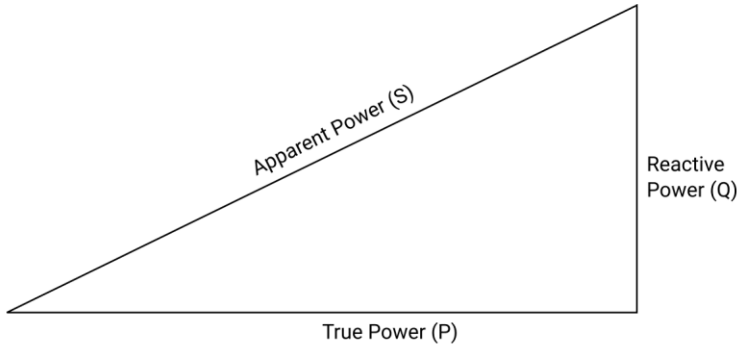
- **Reactive Power Setpoint (secondary/tertiary/time)**
  - Reactive power setpoint is given to the controller, and the reactive power injection moves to that setpoint
- **Power Factor Setpoint (secondary/tertiary/time)**
  - The plant operates at one specified power factor at all times. Reactive power varies with active power
- **Automatic Voltage Regulation (primary)**
  - Changes reactive power injection as a function of voltage.
  - Can be **open** or **closed loop** controllers
    - **Open loop** controllers do not incorporate any feedback
      - May be unstable in most grid conditions
    - **Closed loop** controllers incorporate feedback to minimize large swings in output and controller interactions

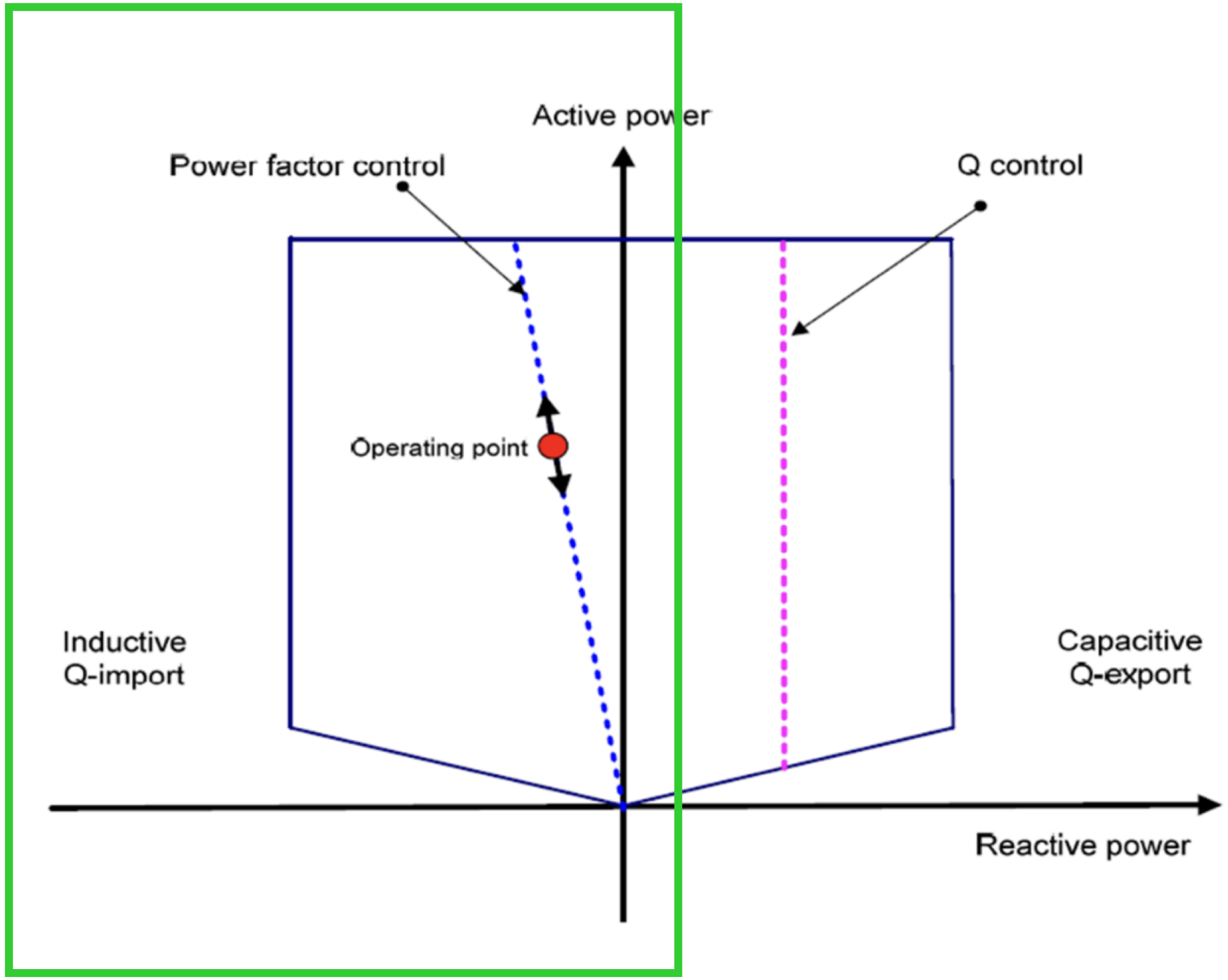
Reactive Power Controls: Overview

- **Reactive Power Setpoint (secondary/tertiary/time)**
  - Reactive power setpoint is given to the controller, and the reactive power injection moves to that setpoint
- **Power Factor Setpoint (secondary/tertiary/time)**
  - The plant operates at one specified power factor at all times. Reactive power varies with active power
- **Automatic Voltage Regulation (primary)**
  - Changes reactive power injection as a function of voltage.
  - Can be **open** or **closed loop** controllers
    - **Open loop** controllers do not incorporate any feedback
      - May be unstable in most grid conditions
    - **Closed loop** controllers incorporate feedback to minimize large swings in output and controller interactions

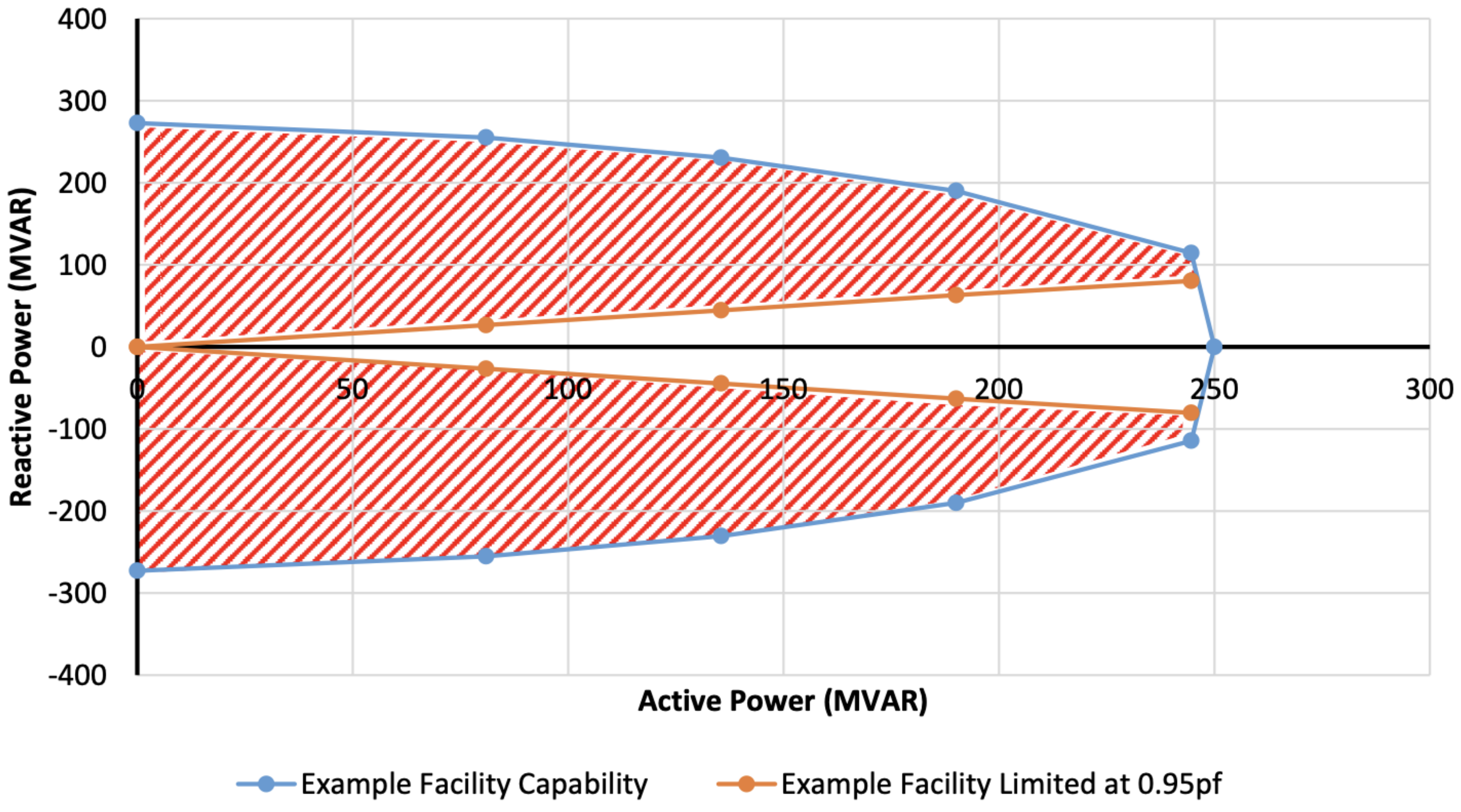
Reactive Power Controls: Power Factor Control

- **Secondary or Tertiary**
  - IBR plant operates at a fixed power factor
  - Reactive power changes based on changes to active power to maintain power factor
  - Can also be implemented along with AVR (power factor limiters)





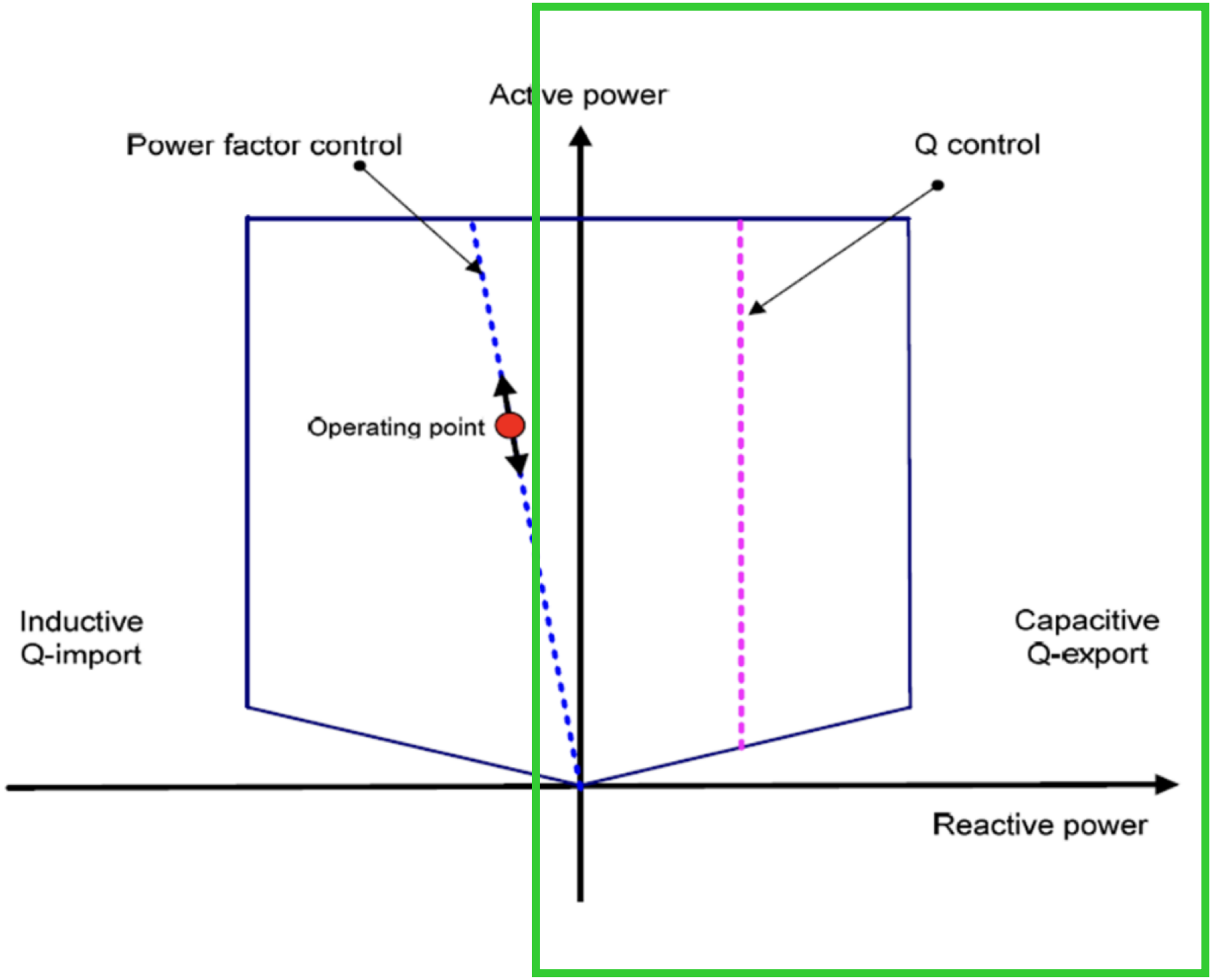
Risks of Fixed Power Factor Control and Limiters



NERC Level 2 Alert data shows 35% of the currently installed IBRs are operating in this limited mode

Reactive Power Controls: Reactive Power Setpoint

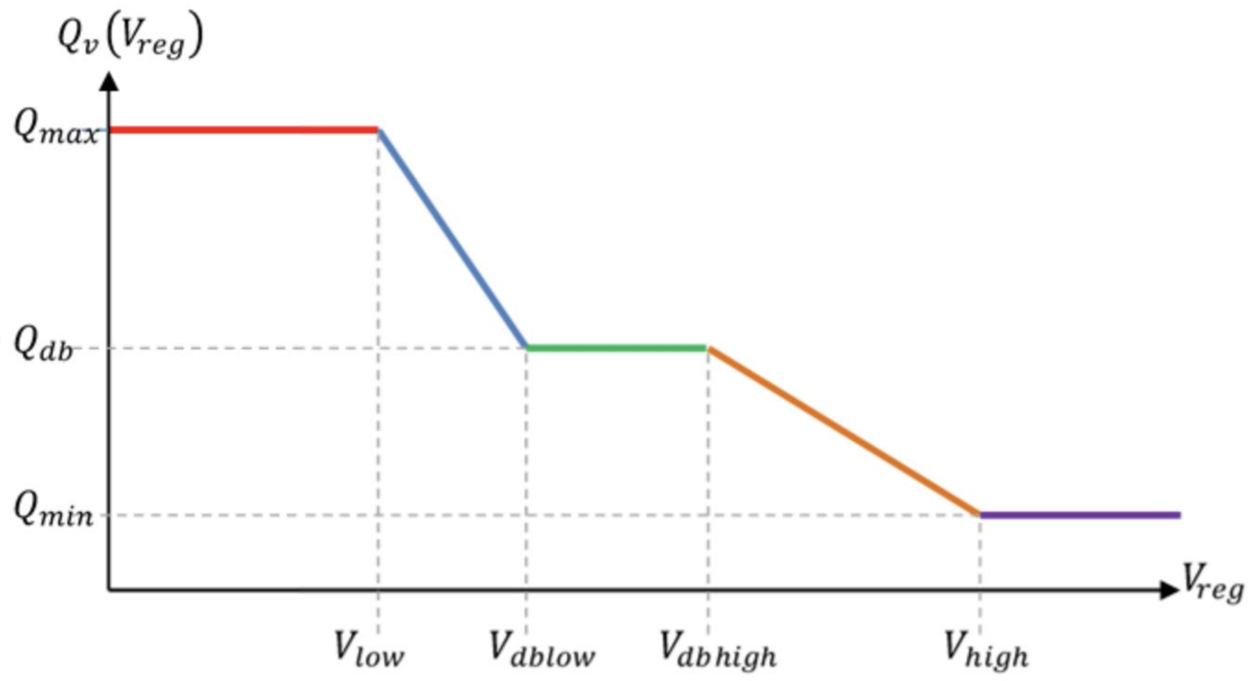
- **Secondary or Tertiary**
  - IBR plant operates at a specific reactive power setpoint
  - Reactive power remains at this level regardless of active power output
    - Also will not regulate voltage
  - Still limited by reactive power capability limits
  - Not often used in ”live operations”
    - Typically used during commissioning, maintenance, testing, or other TSO interventions



Reactive Power Controls: Voltage Droop/Slope

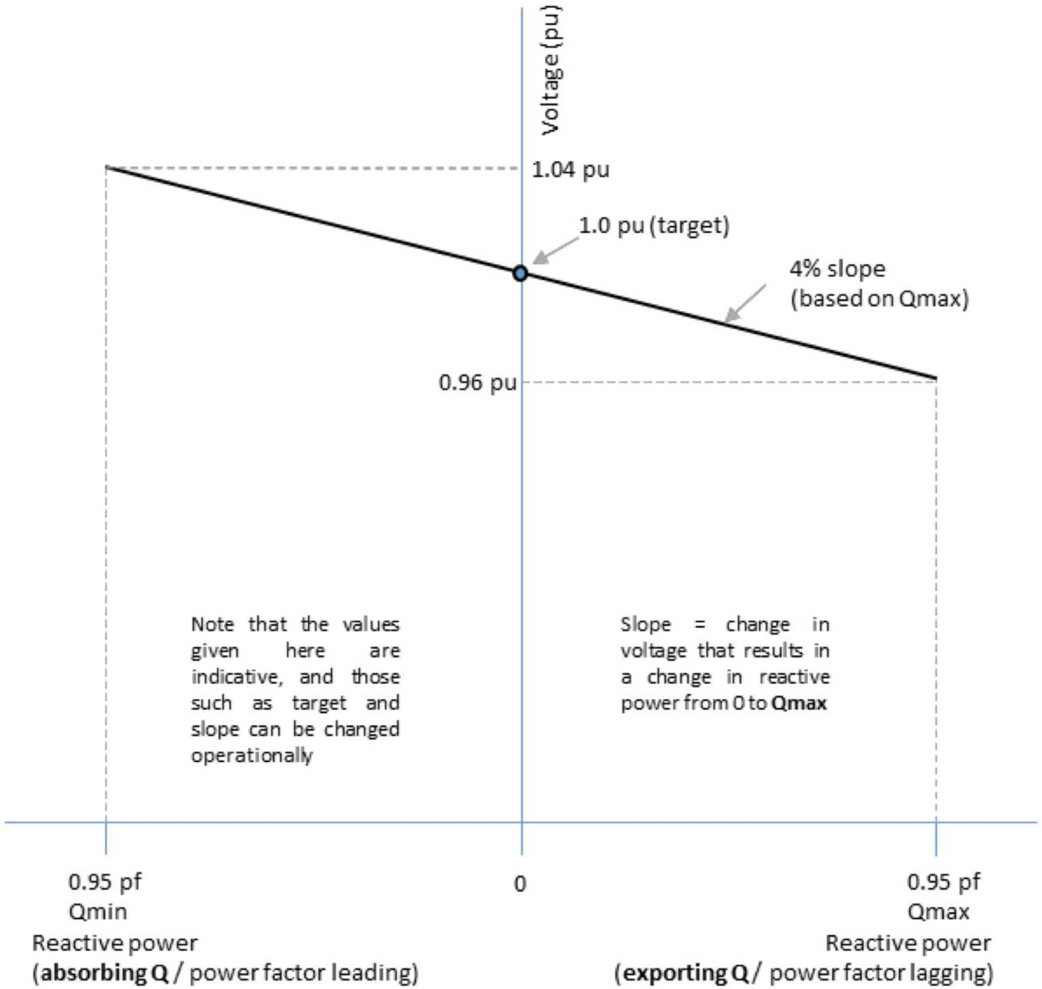
- **Primary**
  - Voltage regulation is primary goal
  - Reactive power injection changes based on difference between measured voltage and a target
  - Deadbands are utilized to avoid controller interactions and "hunting"
  - Droop or slope determine the magnitude of the total reactive power response
  - Control gains determine rise time and other response speed

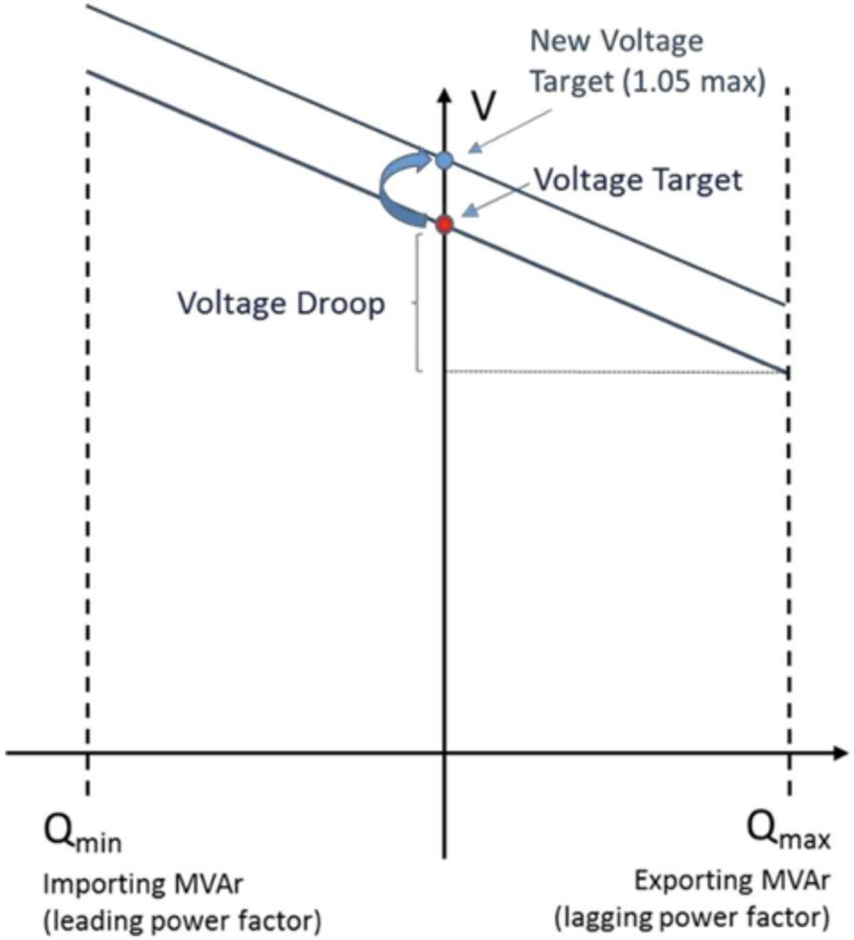
Source: [Powerworld]()



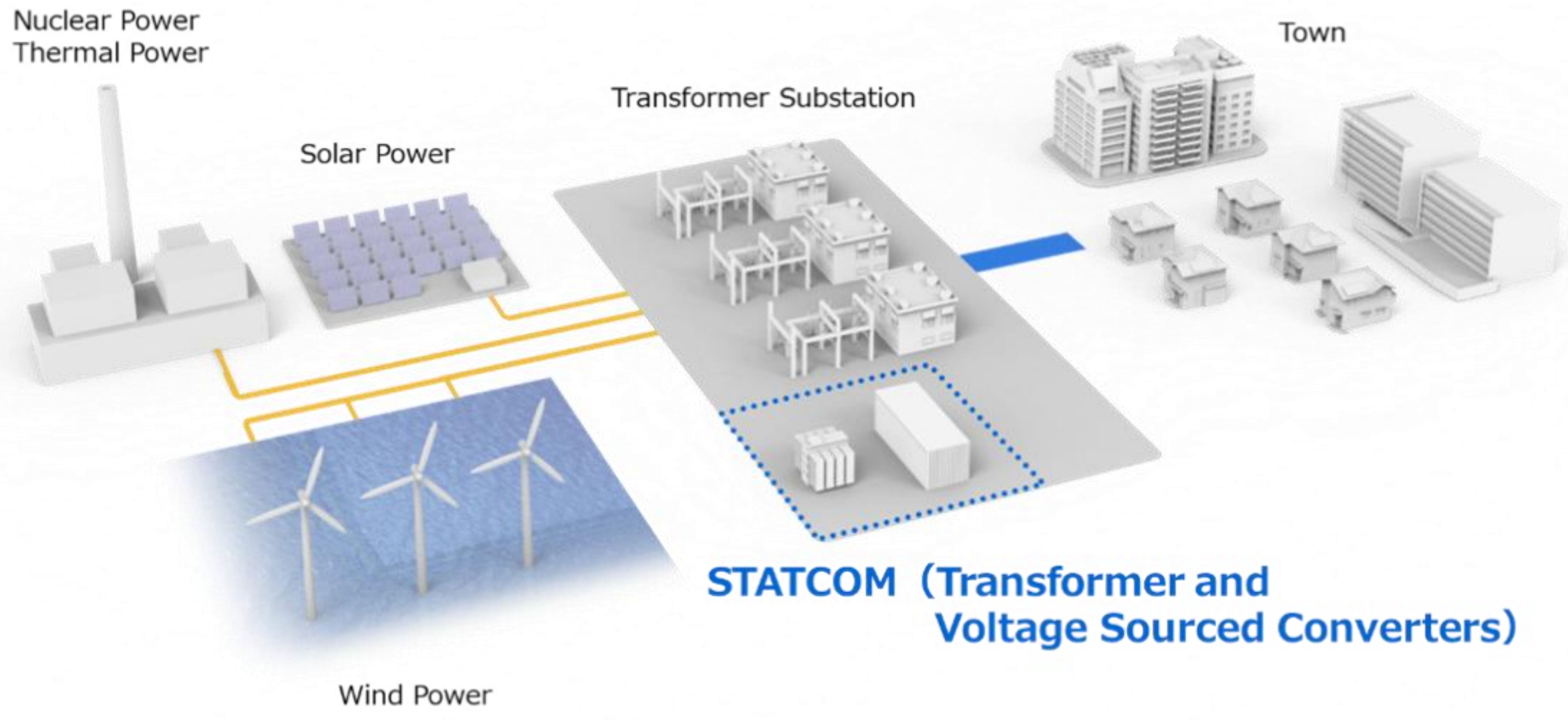
Reactive Power Controls: Voltage Droop/Slope

Source: [NESO]





Brief Detour for Andrew to Talk STATCOM



Source: [Toshiba]

Inertial and Primary Controls in Practice

- **As discussed, these controls react to disturbances faster than operators can**
  - **Inertial controls**
    - Need to be studied and validated
    - Devices capable of response on this timeframe need to be in-service and in the right locations
    - Dependent on **quality modeling and study work**
  - **Primary Controls**
    - Need to be studied and validated
    - Control parameters should be based on real system needs confirmed by TSO
    - May need to be studied/assessed together with multiple resources to minimize controller interactions
    - Dependent on **quality modeling and study work**

Key Takeaways

- **There are many tools available to maintain normal operation reliability**
  - Utilizing these tools requires detailed study work and accurate representations of the system and its components
    - Need to be sure of performance before connecting to the system
- **Interconnection studies and processes are the cornerstone of reliability**
  - Feeds new representations into the system models
  - Changes to equipment to ensure reliability are significantly easier before commercial operation
  - Studying how a resource will perform on the system **before** interconnection is critical
- Part of normal operation reliability is **posturing the system to be prepared for operation in abnormal conditions** and recovery from those conditions

Grid Reliability During Abnormal Operations

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Power Systems are Rarely “Fully Intact”

- **There will always be planned and unplanned outages:**
  - Routine transmission maintenance
  - Emergency transmission maintenance
  - Area interchange fluctuations
  - Carbon-based outages
  - Market-based outages
- **What is “abnormal” in the context of this training?**
  - Focusing on typical “sudden” disturbances
    - What causes typical disturbances
    - What happens to the power system when disturbances happen
    - How to ensure reliability throughout and following the disturbances
    - Importance of ridethrough criteria in ensuring reliability

What Disturbs the Grid?

- **Natural Disturbances**
  - Acts of Nature: storms, lightning, flooding, wind, fire, geomagnetic disturbances
  - Wildlife
- **Technological Disturbances**
  - Failures of physical or digital infrastructure
- **Human-driven Disturbances**
  - Accidents
  - Physical attacks
  - Cyber attacks
  - Other intentional acts meant to disrupt the power system

What Disturbs the Grid?

Threats	Technologies/Sectors	Potential Impacts
Temperature Change	**Generation**	
	Biopower	Crop damage and increased irrigation demand
	Hydropower	Reduced generation capacity and operational changes
	Solar PV	Reduced generation capacity (e.g., higher heat can impact panel efficiency)
	Thermal technologies (coal, geothermal, natural gas, nuclear, concentrated solar power)	Reduced generation efficiency and capacity
	Transmission and distribution	Reduced transmission efficiency and capacity
	Demand	Increased demand for cooling
Water Availability and Temperature	**Generation**	
	Biopower	Decreased crop production
	Hydropower	Reduced generation capacity and operational changes
	Thermal technologies	Reduced generation capacity
Wind Speed Changes	**Generation**	
	Wind	Variations in generation capacity, making investments harder to pay back or generation harder to predict long-term
Sea Level Rise	**Generation** Bioenergy Hydropower Solar PV Thermal technologies Wind	Physical damage to infrastructure and power disruption/loss—all generation technologies

Extreme Events (e.g., storms, short-term extreme heat events, floods, fires, and other natural disasters)	**Generation** Bioenergy Hydropower Solar PV Thermal technologies Wind	Physical damage to infrastructure and fuel sources, and power disruption/loss—all generation technologies
	Transmission and distribution	Reduced transmission efficiency and capacity Reduced transmission efficiency and capacity
	Demand	Unpredictable changes to peak electricity demand
Technological	**Generation** Bioenergy Hydropower Solar PV Thermal technologies Wind	Physical damage and power disruption/loss—all generation technologies
	Transmission and distribution	Physical damage and reduced transmission capacity
	Demand	Unpredictable demand
Human-caused (e.g., cyberattacks, accidents, and physical attacks/ malicious events)	**Generation** Bioenergy Hydropower Solar PV Thermal technologies Wind	Physical damage and power disruption/loss—all generation technologies
	Transmission and distribution	Physical damage and reduced transmission capacity
	Demand	Unpredictable demand

Source: NREL

Transposing Real Life to Reliability Planning

- **Events that disturb the power system come in many shapes, sizes, and timeframes**
  - Planning for "every" possible eventuality must be balanced with cost to do so
  - NERC standards (i.e. TPL series) and local reliability councils specify what **must** be planned for
- **Many complex occurrences can be transposed to simple planning contingencies**
  - Fuel loss – reduced nameplate or trips
  - Car crash into substation – equipment trip
  - Cyber attacks – generator or element trips

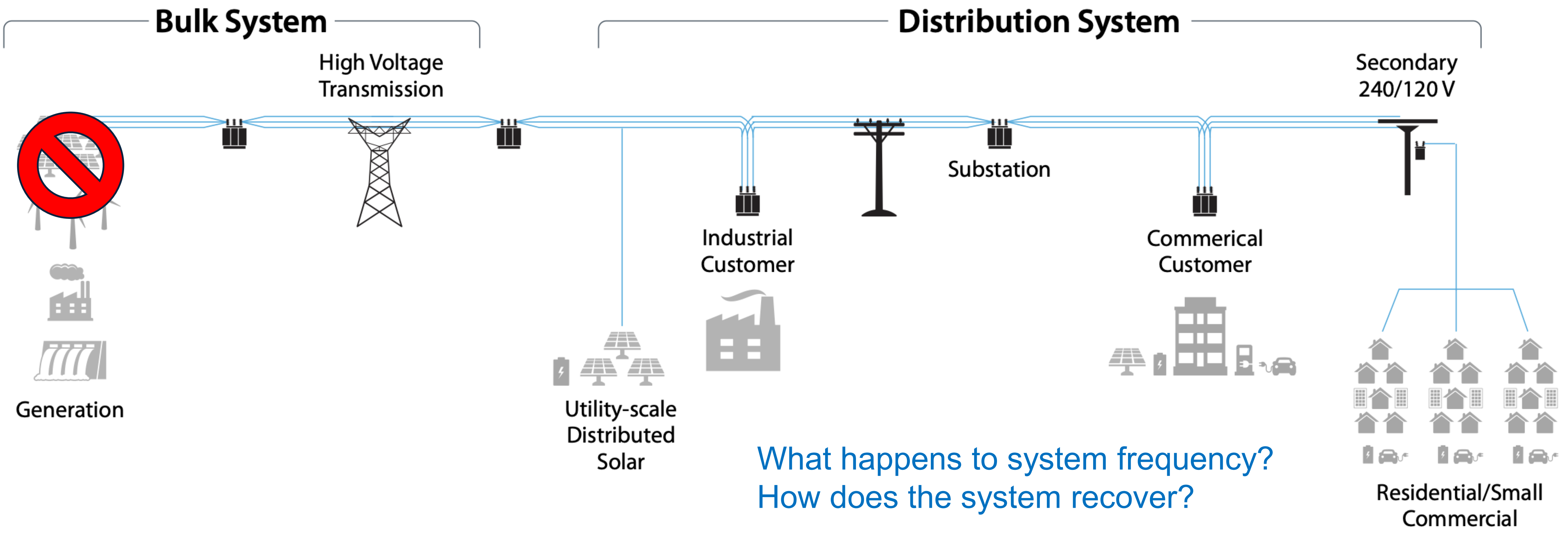
Threat Likelihood Scores		Threshold Descriptions
Categorical	**Numerical**	
High	9	Accidents
Medium-High	7	More likely to occur than not.
Medium	5	May occur.
Low-Medium	3	Slightly elevated level of occurrence. Possible, but more likely not to occur.
Low	1	Very low probability of occurrence. An event has the potential to occur but is still very rare.

Source: NREL

Categorizing Disturbances

- **Most real-world grid disturbances fall into just a few categories**
  - Generator trip
  - Load trip
  - Transmission element trip or enter service
  - (Reduced nameplate-type disturbances should be handled in the long-term timeframe through resource adequacy)
- **Even these simple categories have nuance**
  - Contingency events are messy
    - Some contingencies have automatic actions included in the events
  - Contingencies as used in the interconnection and planning processes often exclude return to service behaviors
  - Contingencies may cascade and are difficult to model

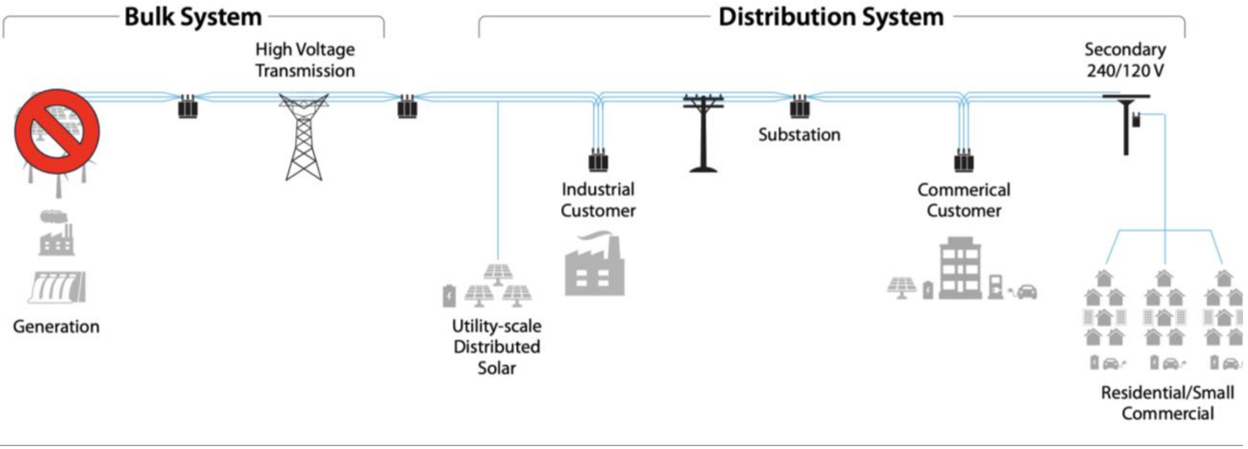
Disturbance Examples: Generator Trip

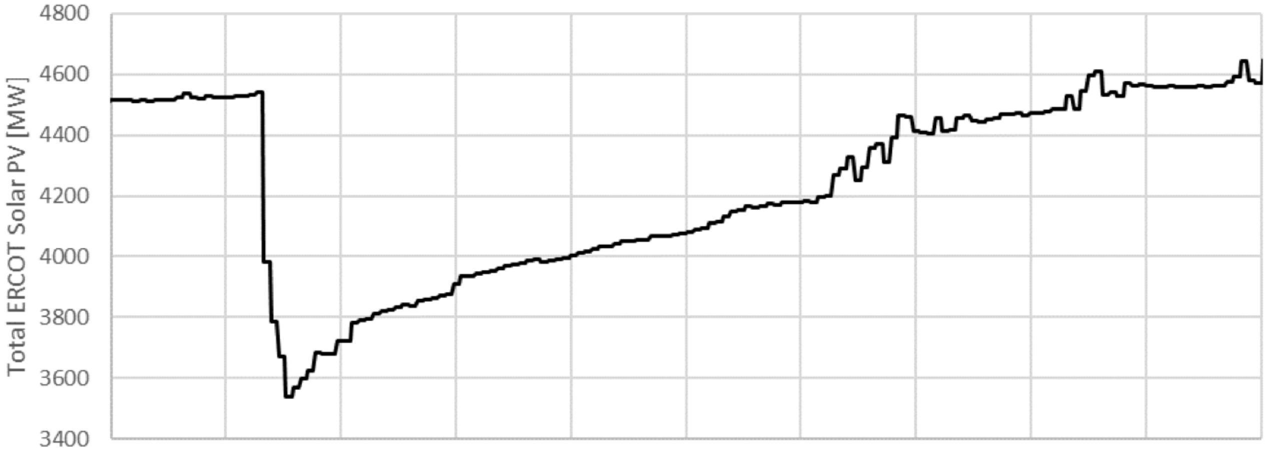


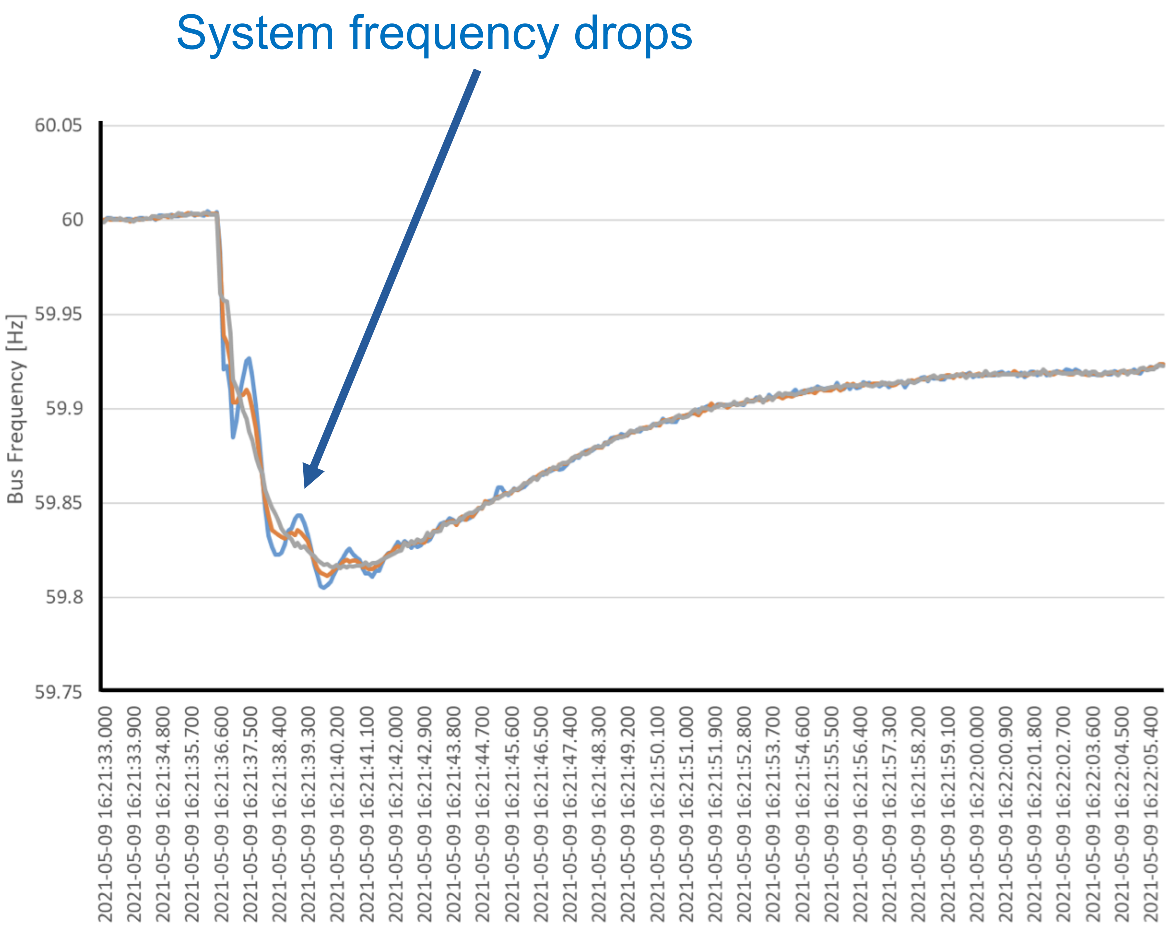
What happens to system frequency?
How does the system recover?

Source: NREL

Disturbance Examples: Generator Trip



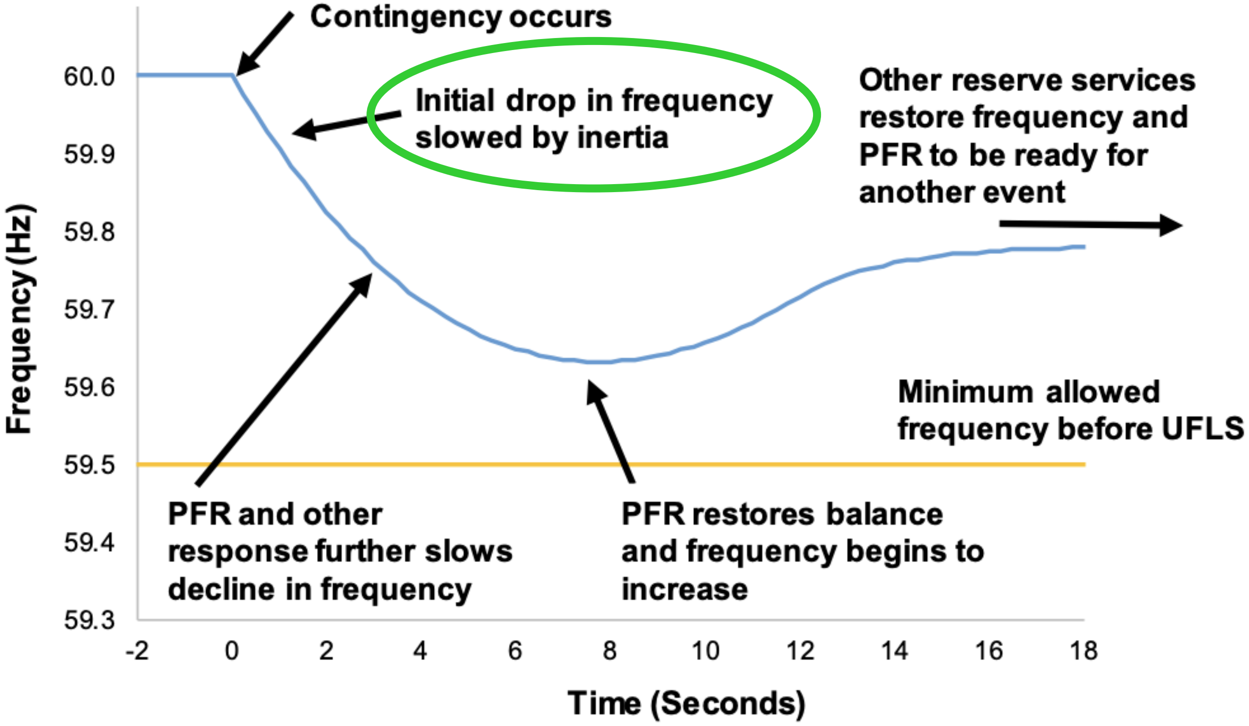




Source: [NERC]

Successful Recovery From Low Frequency

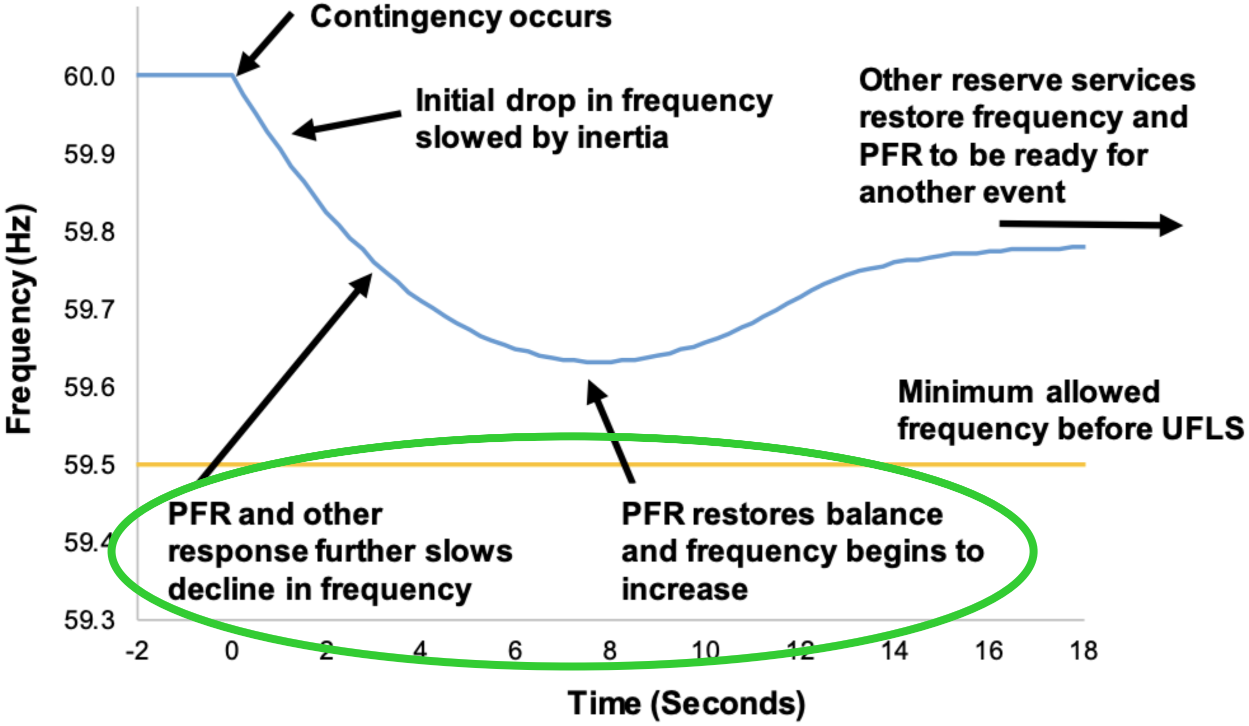
- **Inertia provides “first” response in the current paradigm**
  - Spinning mass-driven synchronous machines resist changes to system frequency based on physics
- **Current power system planning and resource mix depends on inertia**
  - Current underfrequency load shedding programs depend on slowed ROCOF and arrested nadirs



Source: NREL

Successful Recovery From Low Frequency

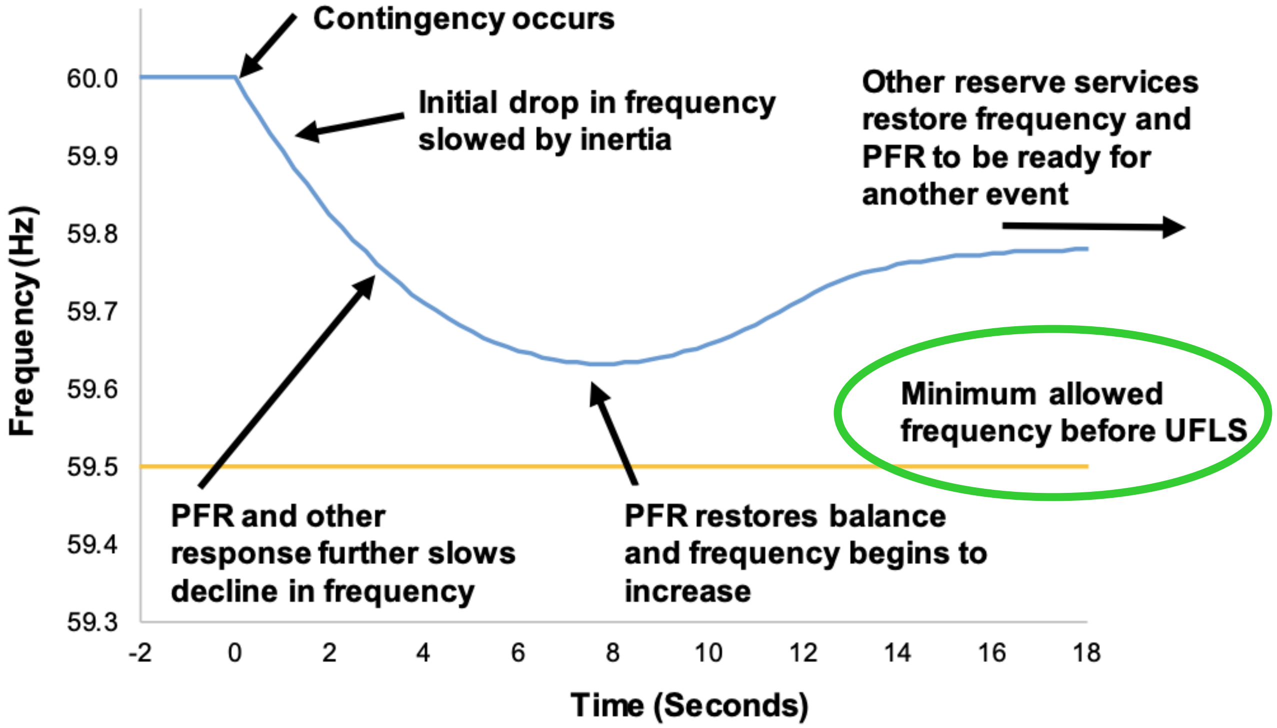
- **Primary frequency response and other response comes next**
  - These controls need to be paramterized prior to disturbance
  - Adjust active power injection to slow frequency dip and help return to nominal
- **Control needs may need adjusting as the system changes**
  - Sufficient PFR droops, deadbands, ramp rates, etc. are dependent on current system needs
  - How to ensure sufficient "extra" energy?



Source: NREL

Successful Recovery From Low Frequency

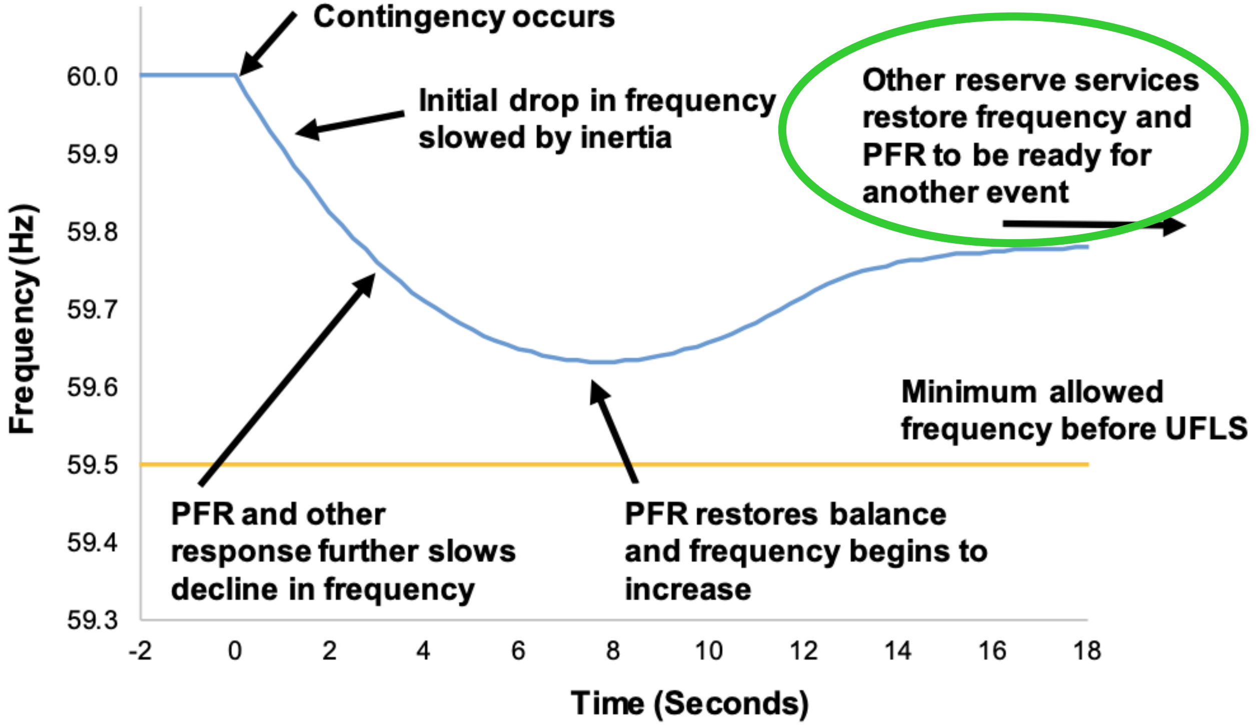
- **Post-event response needs to consider “extremes” like UFLS thresholds**
  - UFLS thresholds trigger plans to remove firm loads to keep the system intact
  - Frequency ridethrough capability of all critical equipment must be considered
- **As power system changes, capabilities and thresholds must be analyzed**



Source: NREL

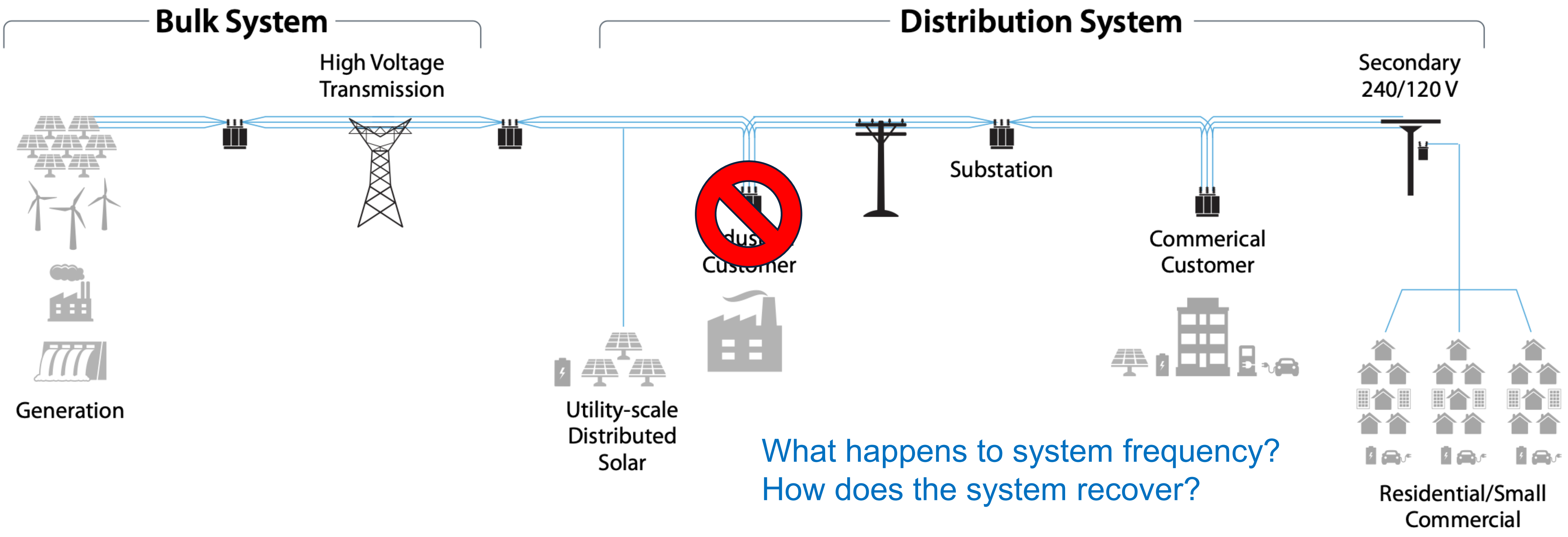
Successful Recovery From Low Frequency

- **Operators react to balance the system**
  - Once the physics-based and automated actions occur operators can rebalance the system and move frequency back to nominal
  - This allows units who provided PFR response to return to their normal operating point
    - This is critical to ensure sufficient capabilities are available for future events
- **Current paradigm is heavily dependent on spinning reserves and quick-ramping machines**



Source: NREL

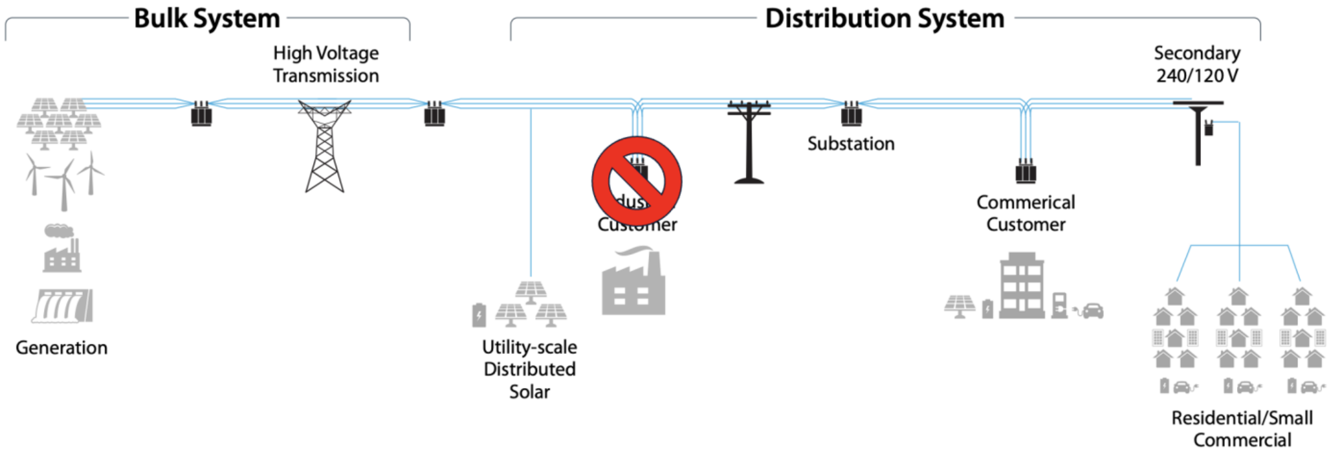
Disturbance Examples: Major Load Trip

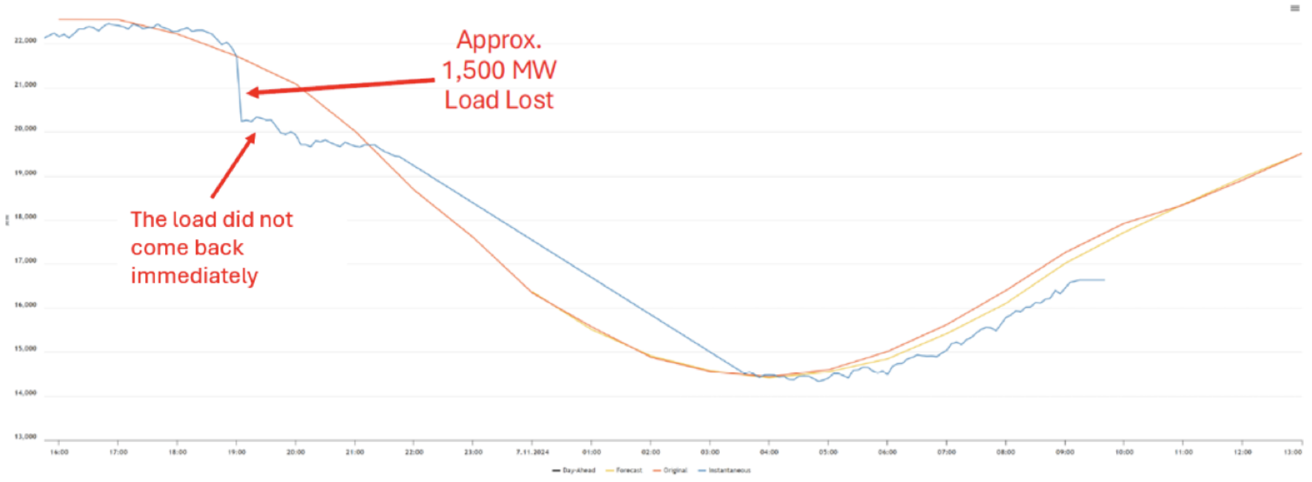


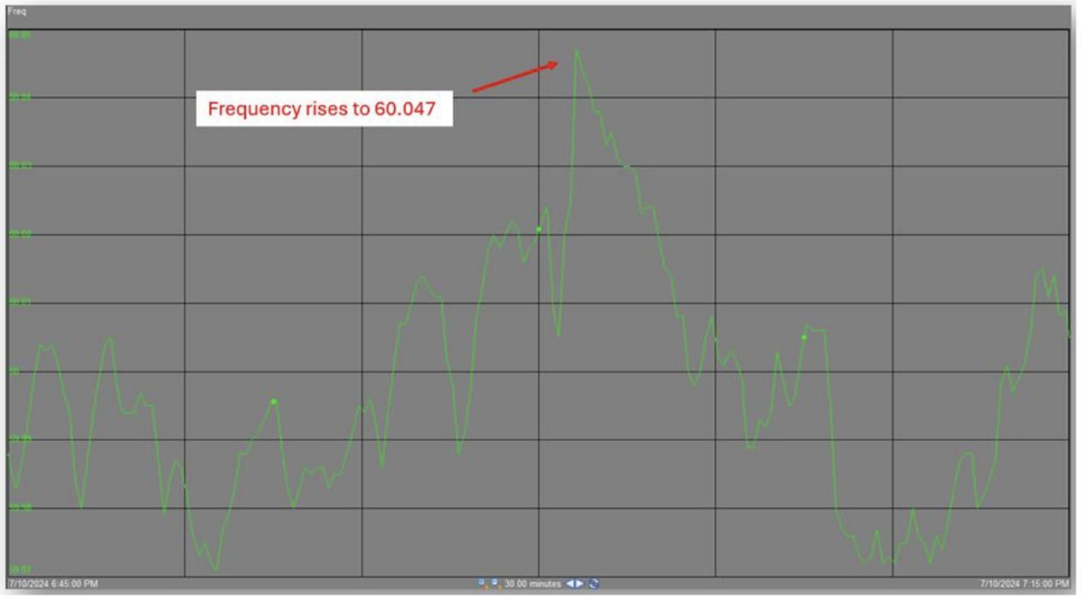
What happens to system frequency?
How does the system recover?

Source: [NREL]

Disturbance Examples: Major Load Trip



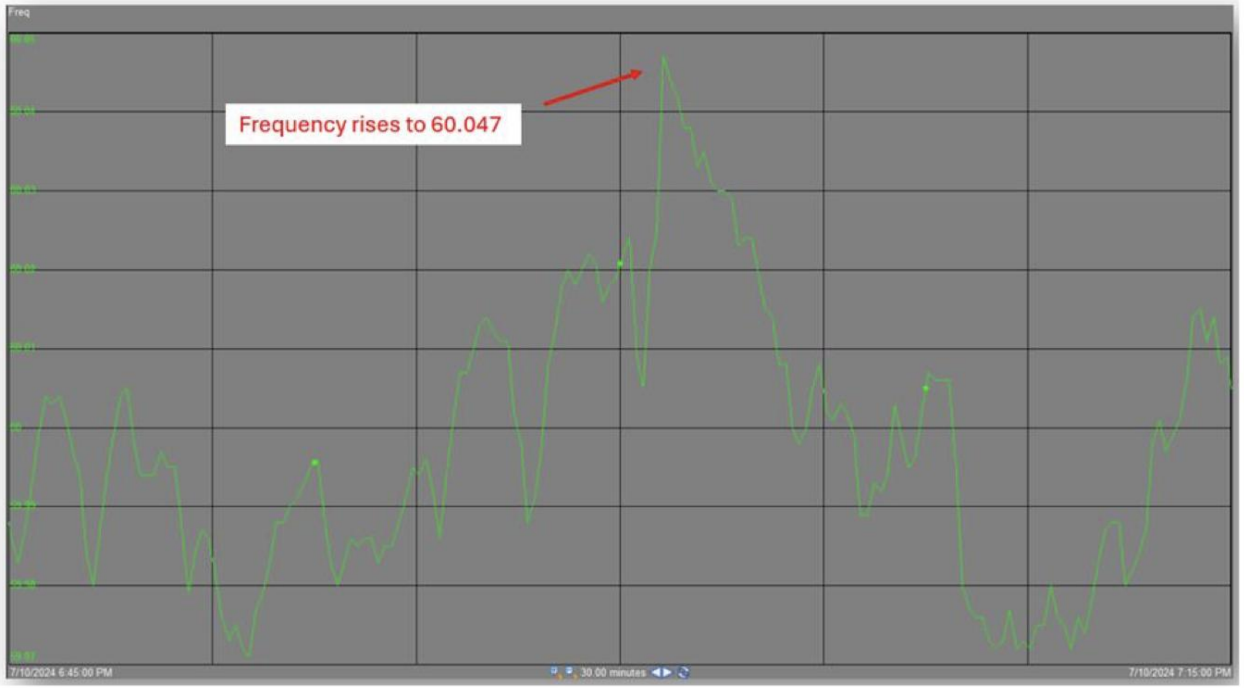




Source: [NERC]

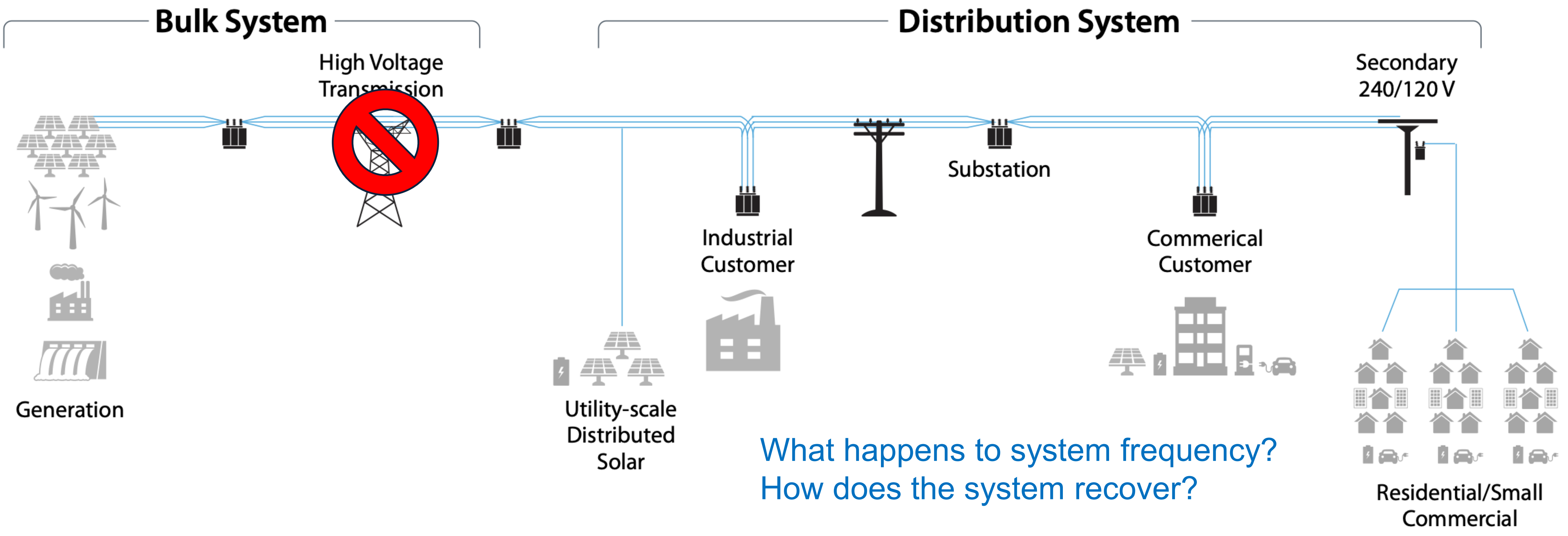
Successful Recovery From High Frequency

- **Similar to recovery from low frequency**
  - "Easier" due to no need for extra energy
    - PFR curtails online generation
  - Same fundamentals apply
- **Industry typically does not focus on high frequency as a major event**
  - How will this change with higher large load penetration?



Source: NERC

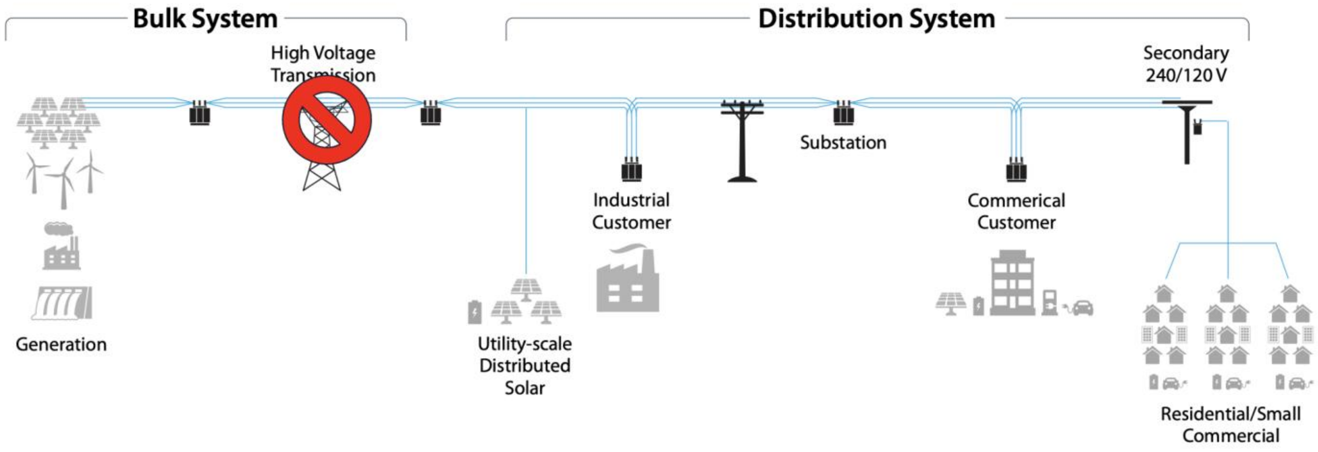
Disturbance Examples: Major Transmission Trip



What happens to system frequency?
How does the system recover?

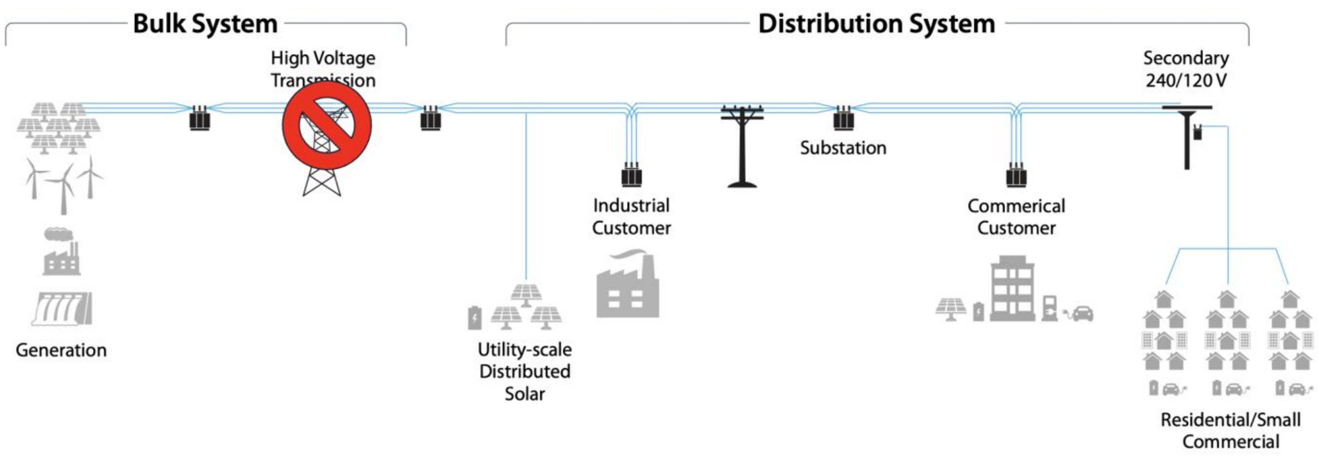
Source: [NREL]

Disturbance Examples: Major Transmission Trip



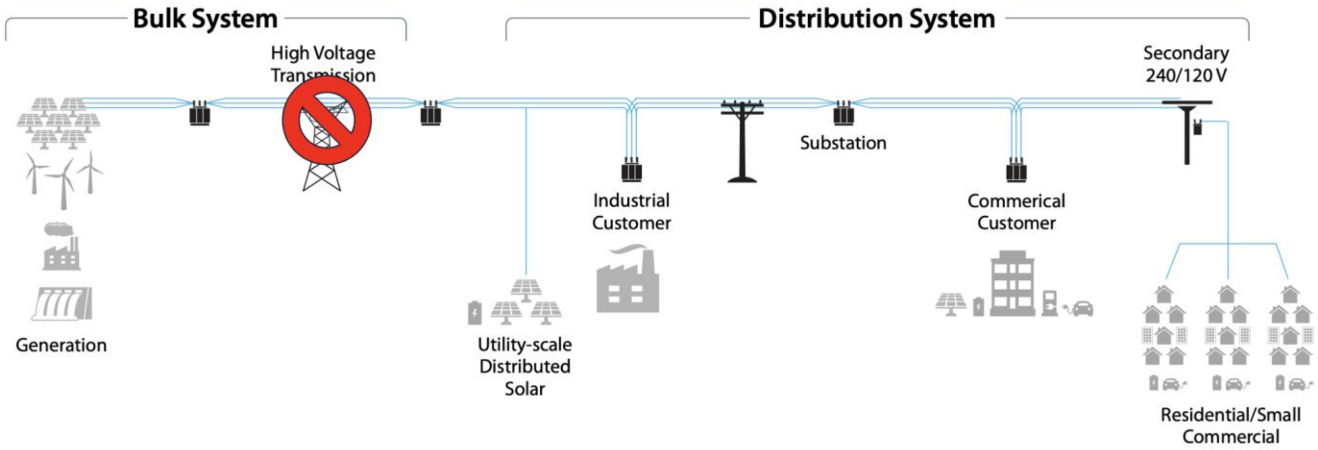
- **Transmission trip at this location may "look" very similar to generator trip**
- **Considerations in addition to frequency dip**
  - Are there any radial connections?
  - Are there now overloads caused by changing flows?
    - Will these cascade?

Disturbance Examples: Major Transmission Trip



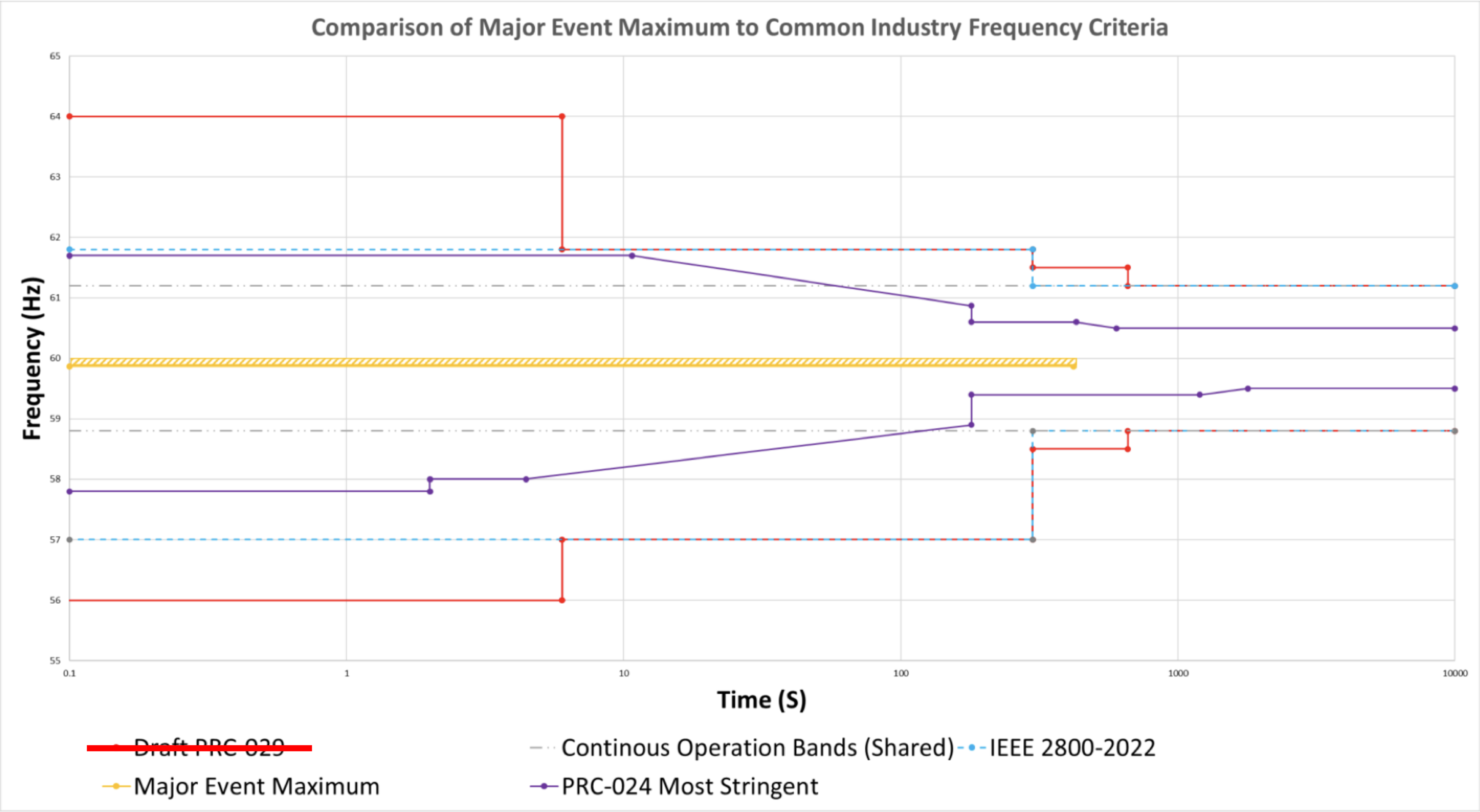
- **Depending on the location, transmission trips can raise or lower system frequency**
  - This would trigger similar inertial and PFR responses
  - This would necessitate similar rebalancing actions from operators
  - Fundamentals of frequency excursion recovery apply

Disturbance Examples: Major Transmission Trip



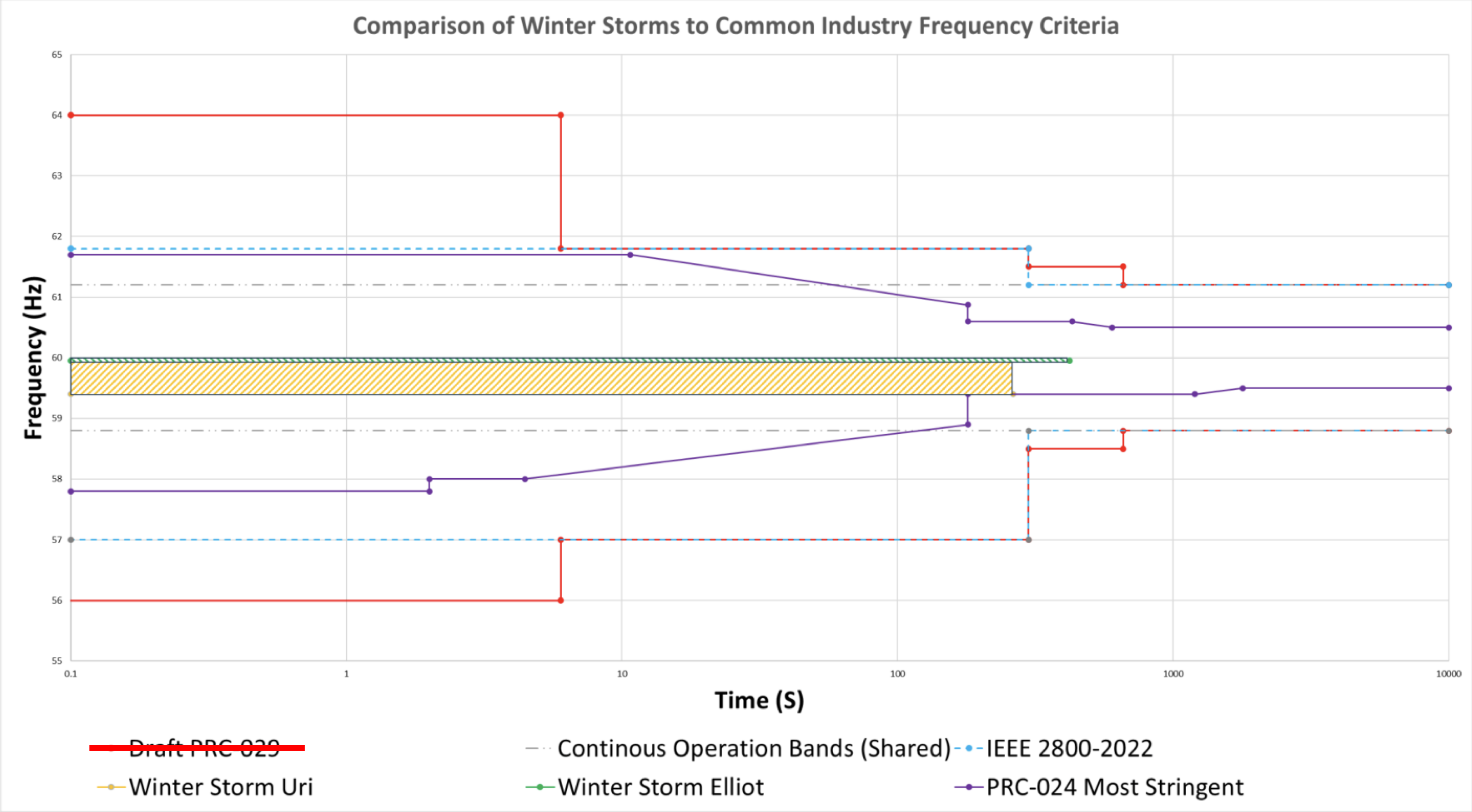
- **Considerations based on new transmission topology**
  - Overloaded elements
    - Hard to ”control” around
    - Require posturing of the system for the “next” event due to timeframe
  - Opportunities for voltage collapse
    - Can “control” around with detailed special studies
    - Also require posturing of the system or remedial action schemes or other special operations

Why Haven't We Discussed Frequency Ridethrough?



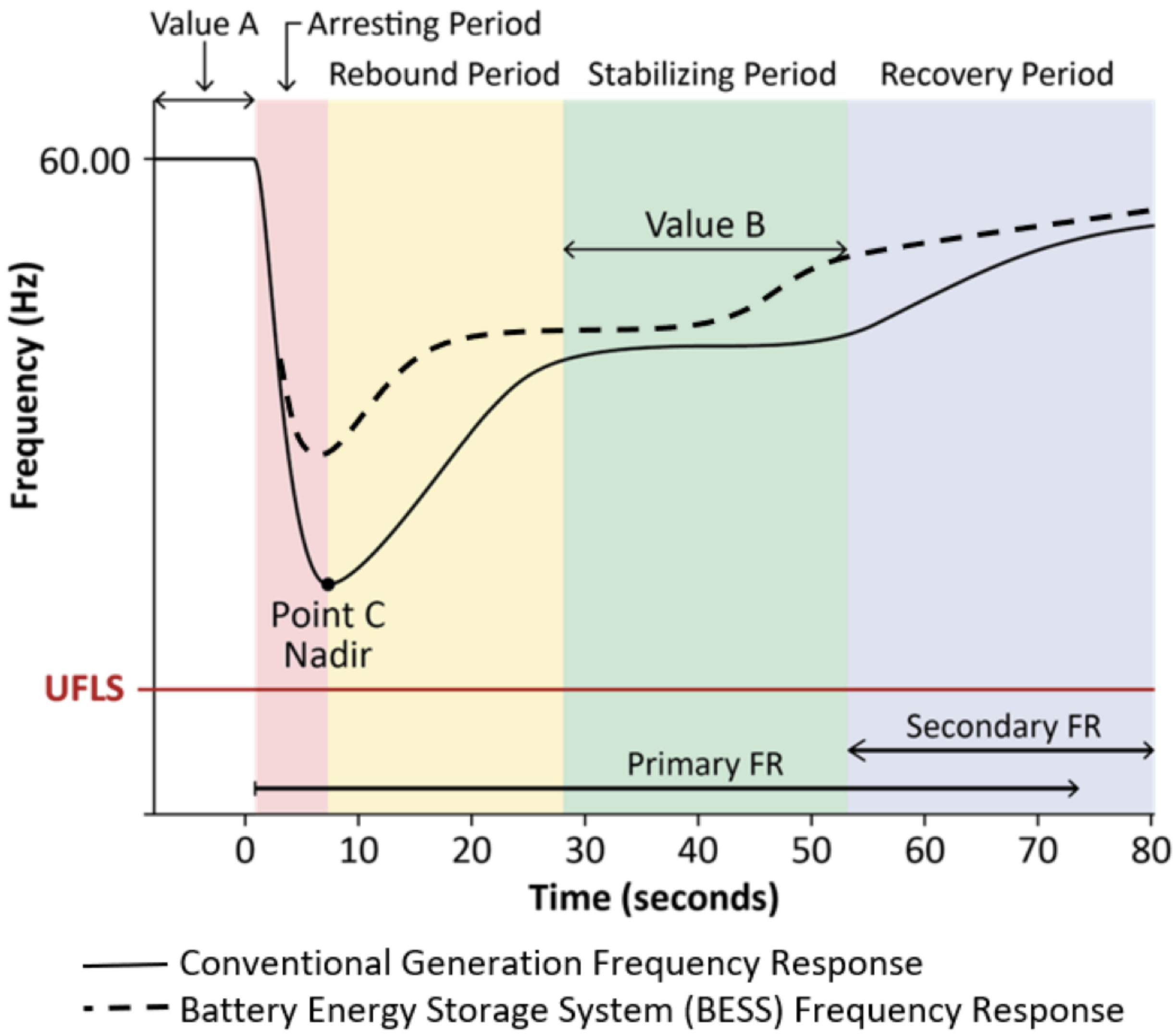
Source: NERC

Why Haven't We Discussed Frequency Ridethrough?



Source: NERC

Brief Detour for Andrew to Talk UFLS

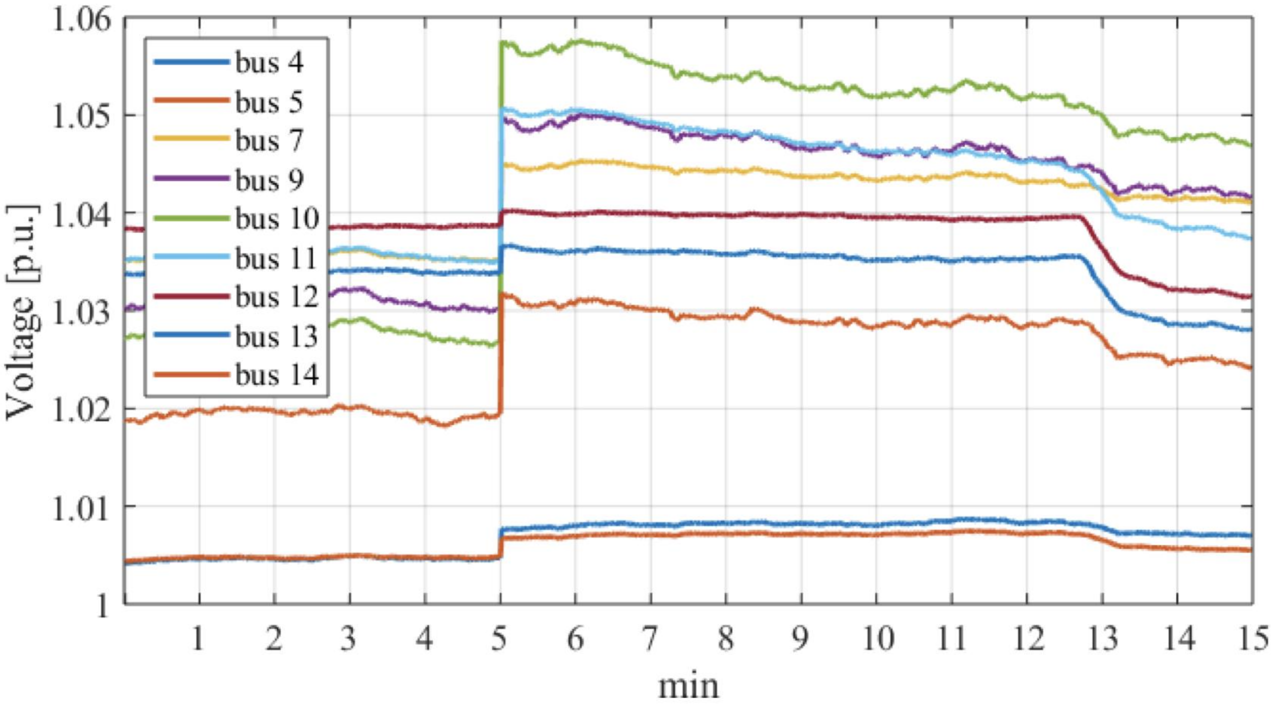


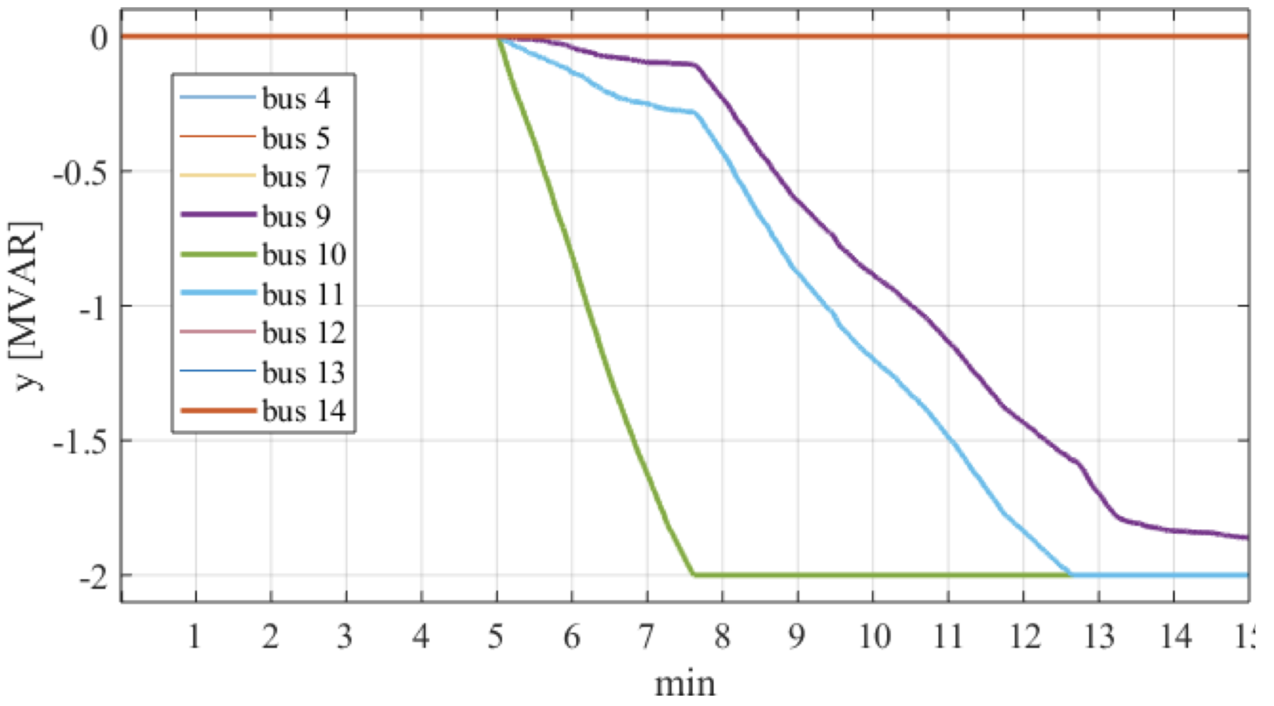
Source: [NERC]

Voltage Disturbances

- **While frequency disturbances are wide-spread, voltage deviations are not**
  - Voltage disturbances are localized phenomenon
  - Generators or other capable facilities use controls to recover and maintain their own voltages
  - Each resource performs their voltage ridethrough independently based on their individual measured voltages
    - Different from frequency response with system-wide coordination
      - Voltage response is often not coordinated during abnormal conditions
- **Voltage disturbances often exceed normal operation thresholds**
  - Voltage disturbances are more “severe” from a percent change perspective
  - Resources enter ridethrough modes
    - These modes’ primary function is to keep the resource online while ensuring no damage occurs to the equipment
      - Most ridethrough requirements allow tripping when damage may occur
  - Coordination of ridethrough controls is critical

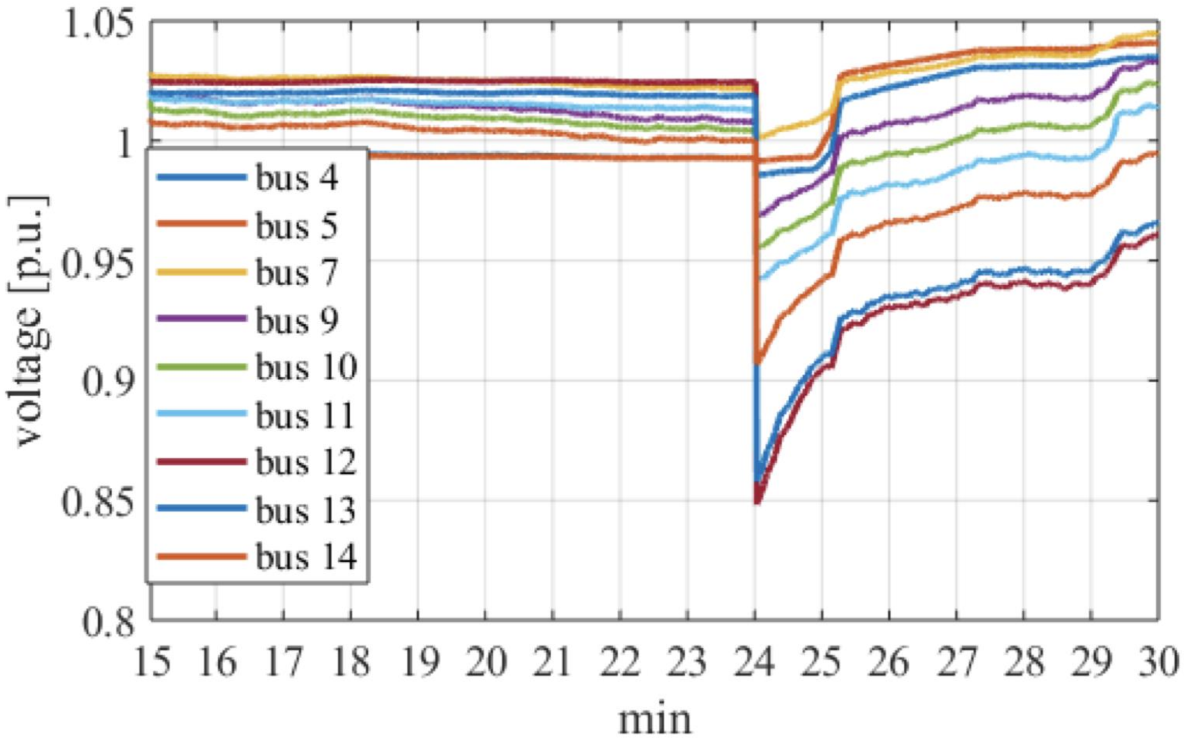
Voltage Disturbances

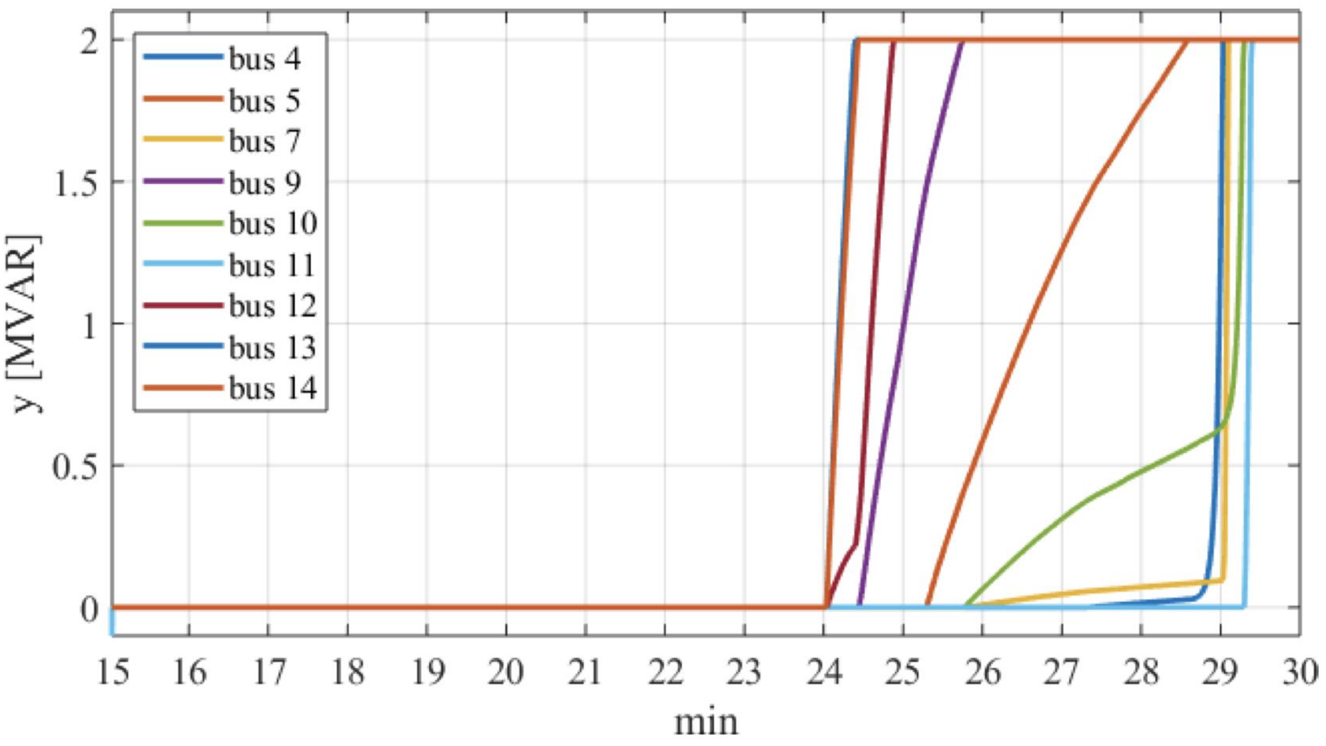




Source: NREL

Voltage Disturbances





Source: [NREL]

Voltage Disturbance Mitigations and Recovery

- **Sufficient ridethrough criteria are necessary to ensure resources stay online**
  - This is particularly critical for IBR
  - Reduced ridethrough capability can cause cascading issues
  - Ridethrough criteria are a balance between system needs and equipment capabilities
    - These must be confirmed throughout the interconnection process and with interconnection studies
- **Ridethrough controls must be properly parameterized**
  - Resources can ”drive themselves to failure”
  - There is no one size fits all for ridethrough controls
  - Important to consider “hand-off” between normal operations > ridethrough > and back to normal
  - How will these fast, independent controls react to eachother?

Additional Considerations for Abnormal Operation

- **Voltage and frequency excursions are only a subset of abnormal conditions**
  - Oscillations
    - Forced and natural
  - Harmonic resonance
  - Unbalanced faults
  - Controller interactions
  - Severely weak systems
  - Geomagnetic disturbances
  - Relay misoperation
  - Many others…
- **Some of these will be discussed in more detail throughout this week and at the EMT Training in December**

Where Do Interconnection Studies Help

- **Stability in both normal and abnormal conditions depends on thorough interconnection processes and studies**
  - The tools used to posture the system, mitigate severity of disturbances, and recover from those disturbances depend on accurate representations of all components of the power system
- **Inaccurate data, models, and improper study practices undermine stakeholder's ability to plan the system**
  - Closing these gaps in the interconnection studies timeframe is critical in the emerging paradigm (more to come later)
  - **Bad inputs = Useless results**

Changes to Power System Fundamentals with High IBR Penetration

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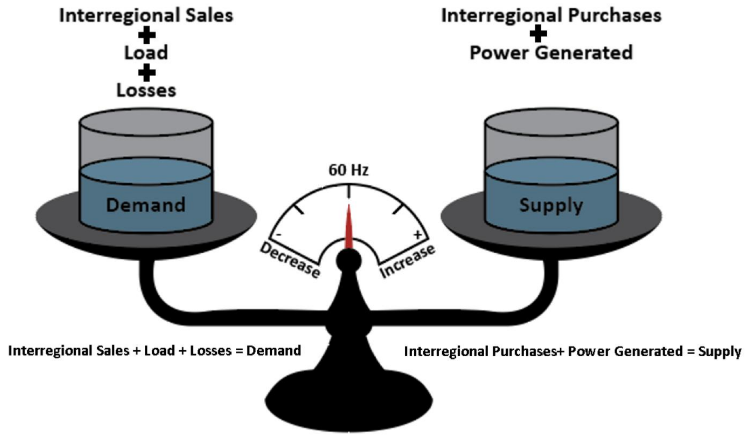
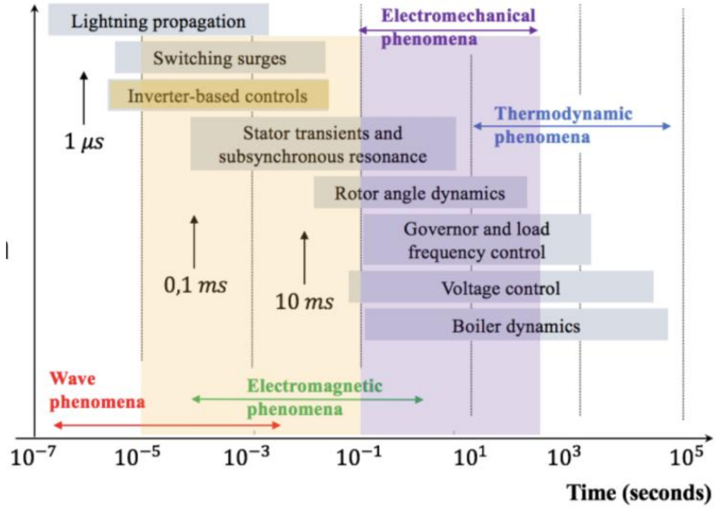
Recap: Fundamentals in the Current Paradigm

- **System balancing**
  - Generation and demand need to be balanced
- **System control timeframe**
  - Power system control timeframes have been largely constant
- **Inertia and "system strength"**
  - Fundamental to system performance
- **Frequency and voltage stability**
  - Frequency and voltage stability assumptions have remained largely constant
- **Largest system disturbances are losses of generation**
  - Large loads are changing this paradigm

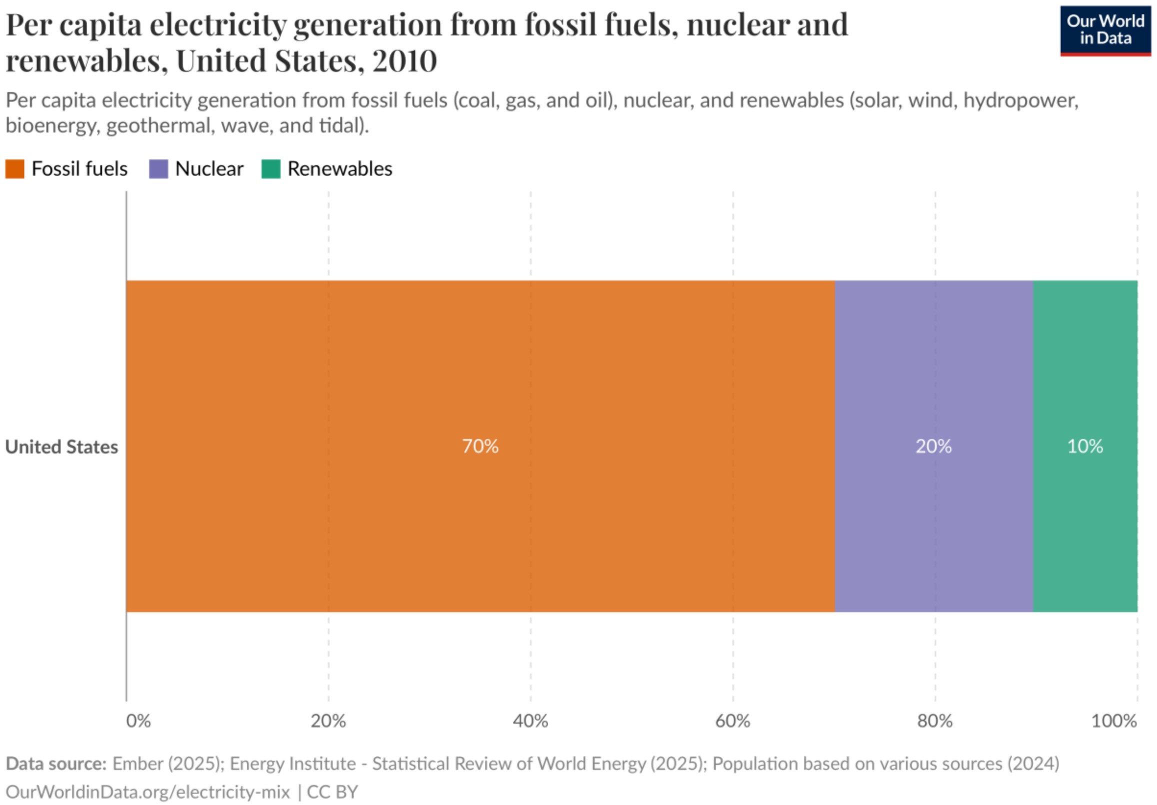


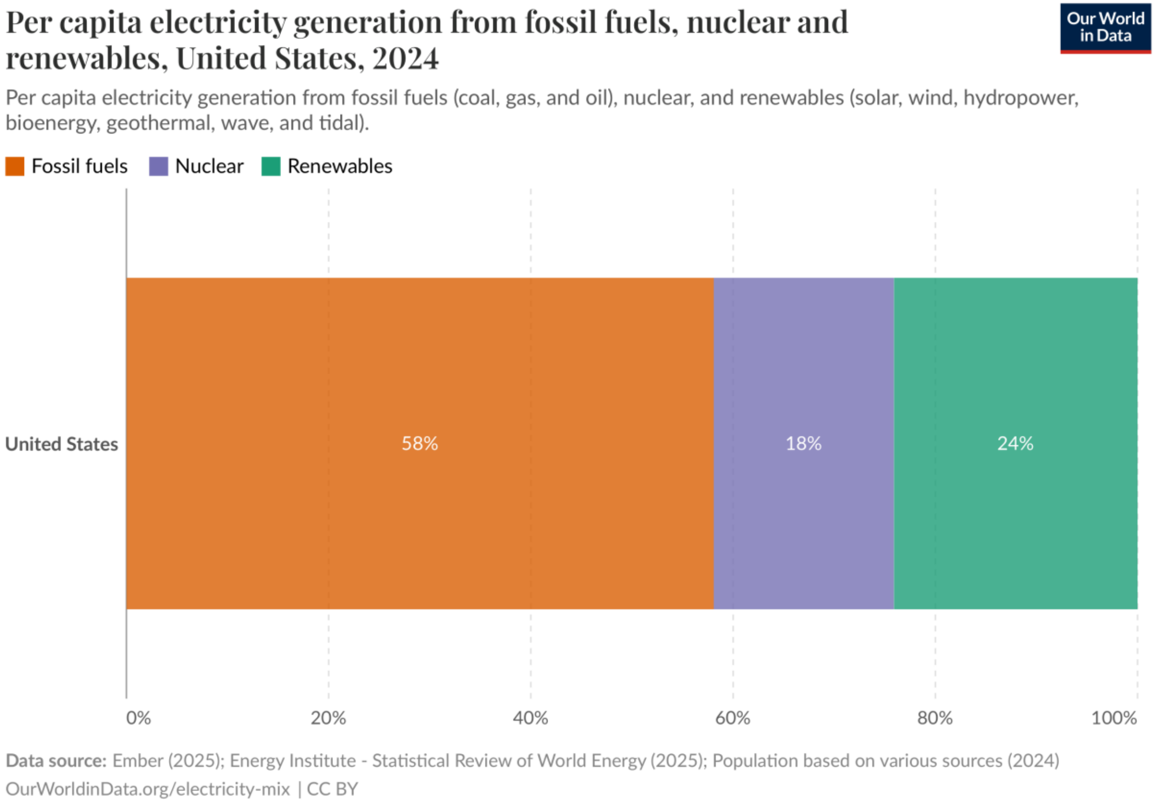


Source: GPST

The Resource Mix is Changing

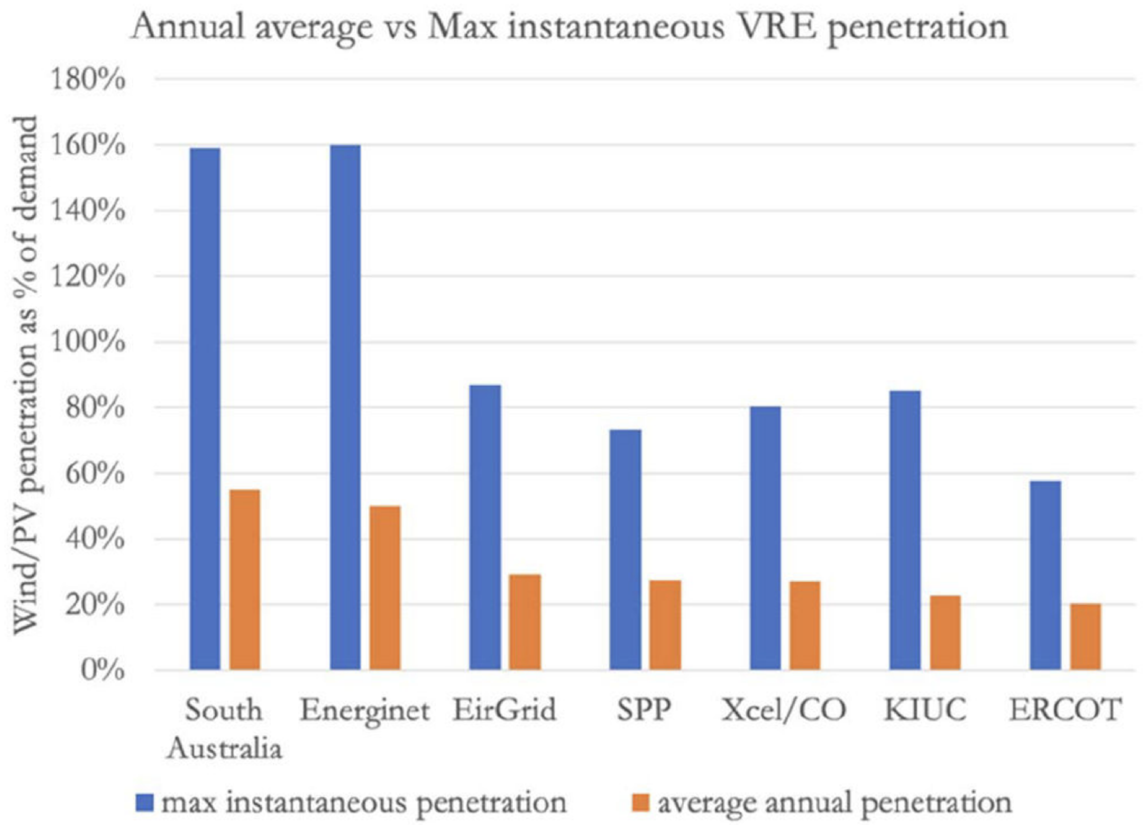
- **Resource mix is changing**
  - Increased penetrations of renewables overall





The Resource Mix is Changing

- **Resource mix is changing**
  - Some regions have significant penetrations of renewables



Source: [IET Journals]

Inverter-based Resources Are Very Different

- **Power electronic-connected resources are different than synchronous resources**

Differences between Inverter-Based Resources and Synchronous Generation	
Inverter-Based Resources	**Synchronous Generation**
• Driven by power electronics and software	• Driven by physical machine properties
• No (or little) inertia	• Large rotating inertia
• Very low fault current	• High fault current
• Sensitive power electronic switches	• Rugged equipment tolerant to extremes
• Very fast and flexible ramping	• Slower ramping
• Very fast frequency control	• Inherent inertial response
• Minimal plant auxiliary equipment prone to tripping	• Sensitive auxiliary plant equipment
• Dispatchable based on available power	• Fully dispatchable
• Can provide essential reliability services	• Can provide essential reliability services

Needs updating

Adapted from: NERC's An Introduction to Inverter-Based Resources on the Bulk Power System

System Balancing

- **Generation and load must be balanced**
- **Power generation only happens when there is ”fuel” available**
  - IBR are not “fully dispatchable”
  - Only generate power when there is sufficient wind/sun
    - Battery energy storage can be fully dispatchable when charged
- **Adds significant variability in supply**
  - Forecasting becomes even more important
    - Adding generation forecasting to demand forecasting
  - Previous assumptions for dispatching need to change

Differences between Inverter-Based Resources and Synchronous Generation

Inverter-Based Resources	Synchronous Generation
• Driven by power electronics and software	• Driven by physical machine properties
• No (or little) inertia	• Large rotating inertia
• Very low fault current	• High fault current
• Sensitive power electronic switches	• Rugged equipment tolerant to extremes
• Very fast and flexible ramping	• Slower ramping
• Very fast frequency control	• Inherent inertial response
• Minimal plant auxiliary equipment prone to tripping	• Sensitive auxiliary plant equipment
• Dispatchable based on available power	• Fully dispatchable
• Can provide essential reliability services	• Can provide essential reliability services

System Balancing

- **Managing variability**
  - Carrying more reserves
  - Mandating operating headroom
  - Detailed weather (wind/solar) forecasting
  - Utilizing storage
- **Managing dispatch assumptions**
  - "Nameplate" means much less
  - There may not be capacity even if there is capability
  - How do dispatch commands coordinate with primary controls at the IBR plant?

Differences between Inverter-Based Resources and Synchronous Generation

Inverter-Based Resources	Synchronous Generation
• Driven by power electronics and software	• Driven by physical machine properties
• No (or little) inertia	• Large rotating inertia
• Very low fault current	• High fault current
• Sensitive power electronic switches	• Rugged equipment tolerant to extremes
• Very fast and flexible ramping	• Slower ramping
• Very fast frequency control	• Inherent inertial response
• Minimal plant auxiliary equipment prone to tripping	• Sensitive auxiliary plant equipment
• Dispatchable based on available power	• Fully dispatchable
• Can provide essential reliability services	• Can provide essential reliability services

Power System Timeframe

- **IBR bring extremely fast controls driven by power electronics and software**
  - Performance is significantly more decoupled from physical behaviors when compared to synchronous machines
  - Software-based controls and power electronics significantly increase the speeds and magnitudes of response
- **IBR controls will get even faster**
  - With increased penetrations of grid forming inverters, overall timeframe will become faster

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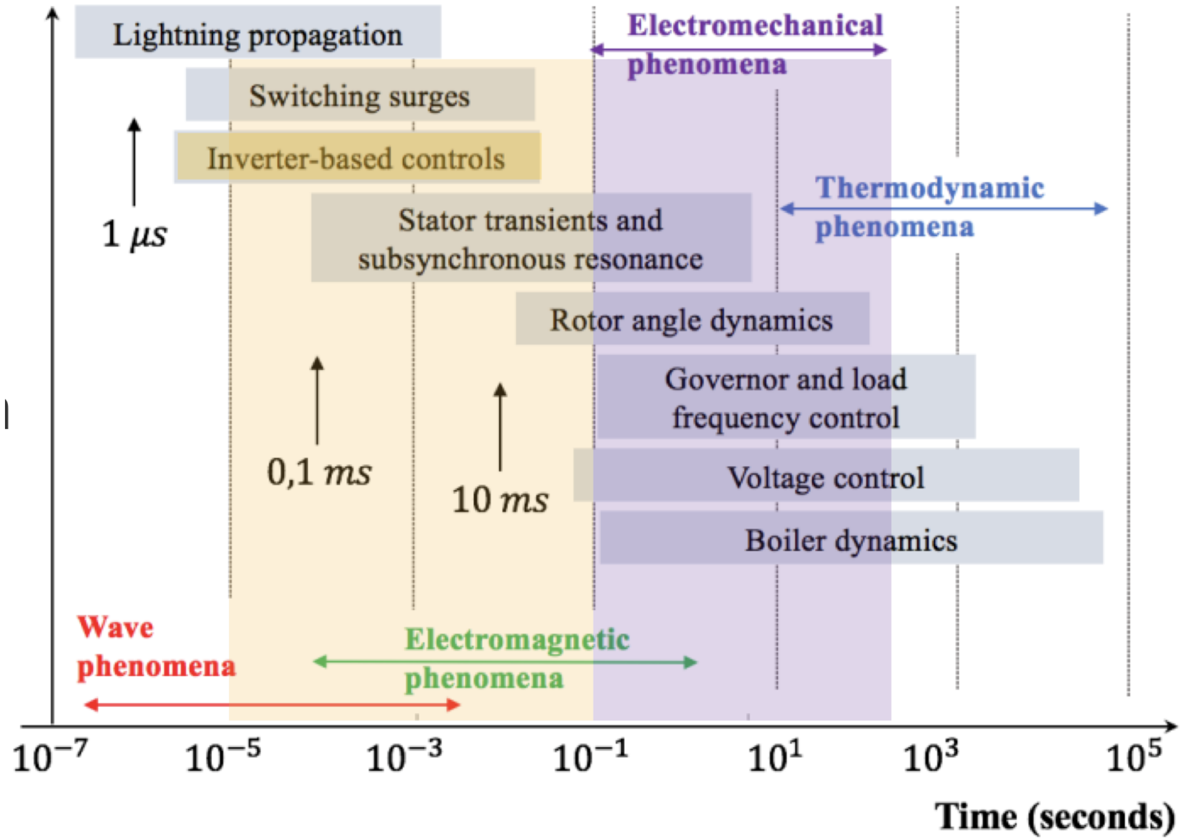
Power System Timeframe

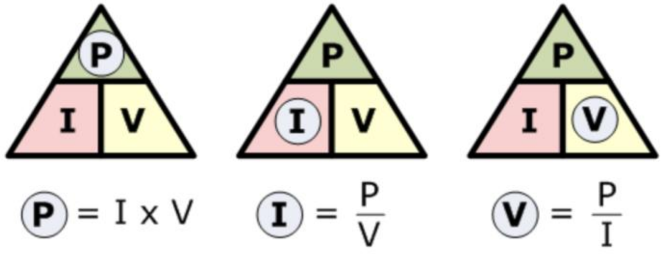
- Relevant control and time constants in a synchronous generator-dominated system fall within the electromechanical window
- Relevant controls and time constants for IBR are significantly faster and encompass the electromagnetic window
- **As more IBR integrate with the system:**
  - System stability becomes more dependent on faster controls
  - Fast transients and responses to those transients play larger roles in reliability
  - The system response overall becomes faster



Source: GPST

Inertia and System Strength: Introduction

- **Synchronous machines provide inertia to the power system**
  - Large spinning masses have momentum and resist changes
  - Power-electronics resources decouple the mechanics from power injection (type 1-3 wind need consideration)
- **Fault current is provided by this momentum**
  - During system disturbances voltage drops
  - Synchronous generator inertia continues to provide power



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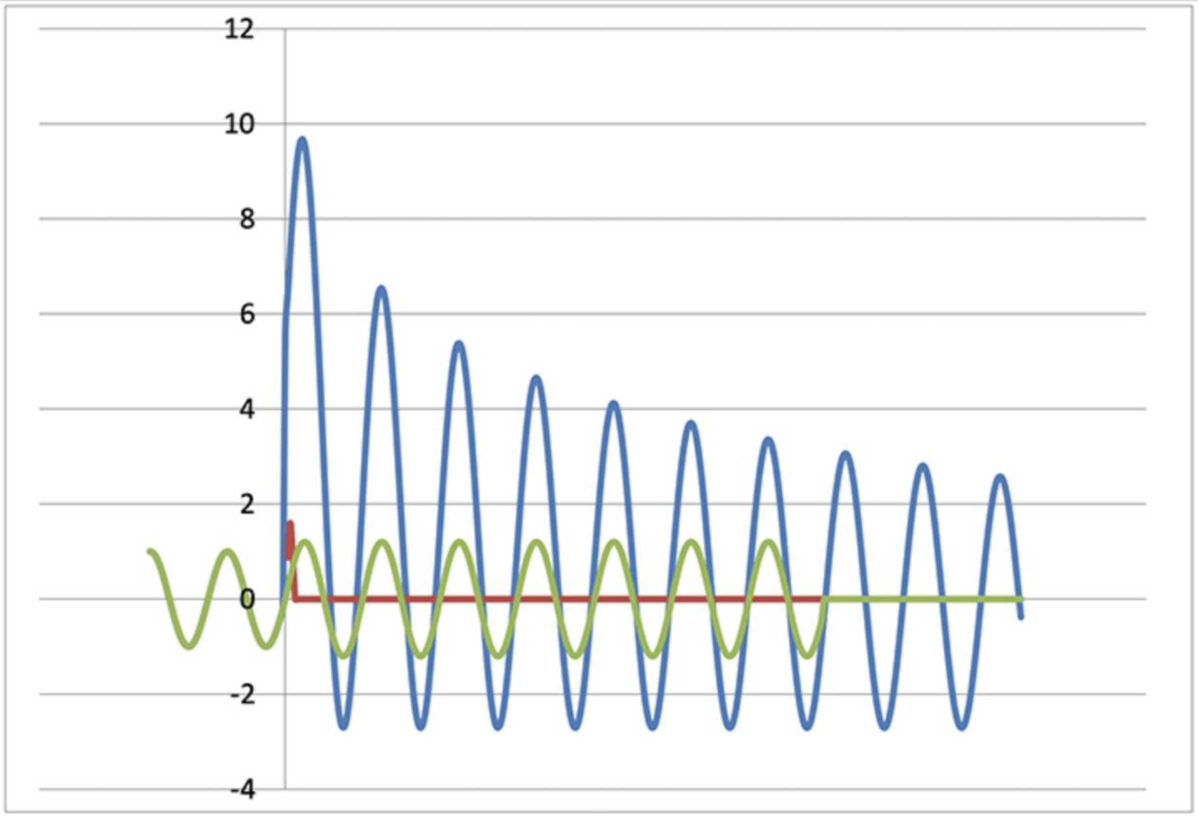
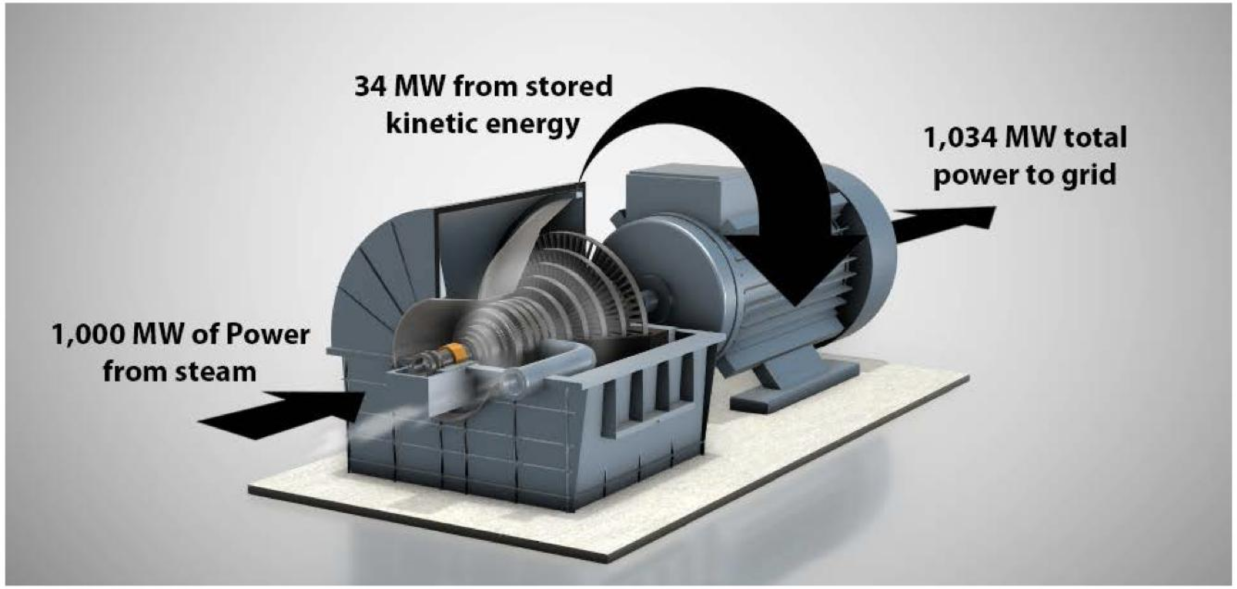
Source: ElectronicsTutorials

Short Detour to System Protection



Fault currents for a synchronous generator (blue), an inverter with rapid disconnect (red), and an inverter with ride-through capability (green).

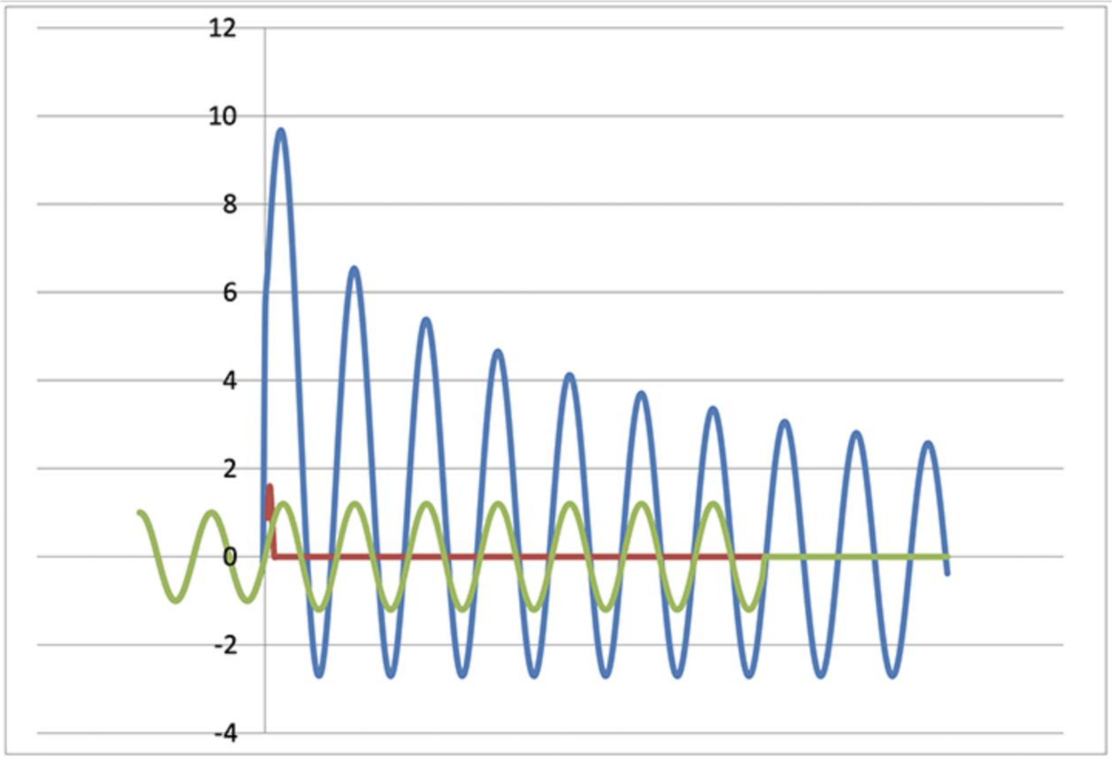
Source: NREL



Source: NREL

Short Detour to System Protection

- **~6x fault current injection from synchronous machine**
- **System protections currently use fault current as a primary trigger**
  - What happens when protection expects 6x fault current?
- **Challenges quantifying IBR fault current**
  - IBR ***do*** provide some fault current
  - Fault current injection changes with control changes
  - There is no "one size fits all" for fault current
  - Cannot fit a IBR-sized peg into a synchronous machine-sized hole



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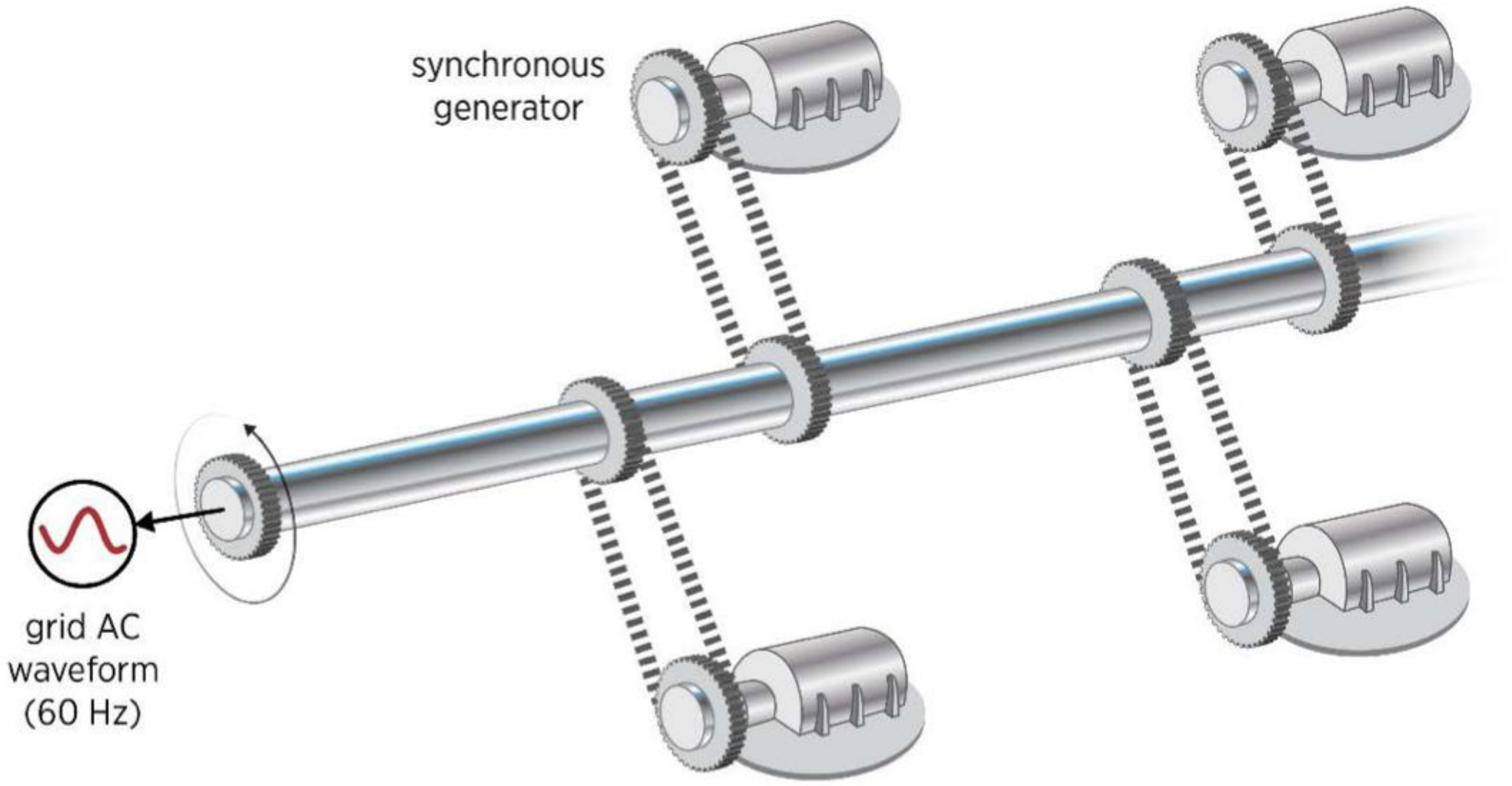
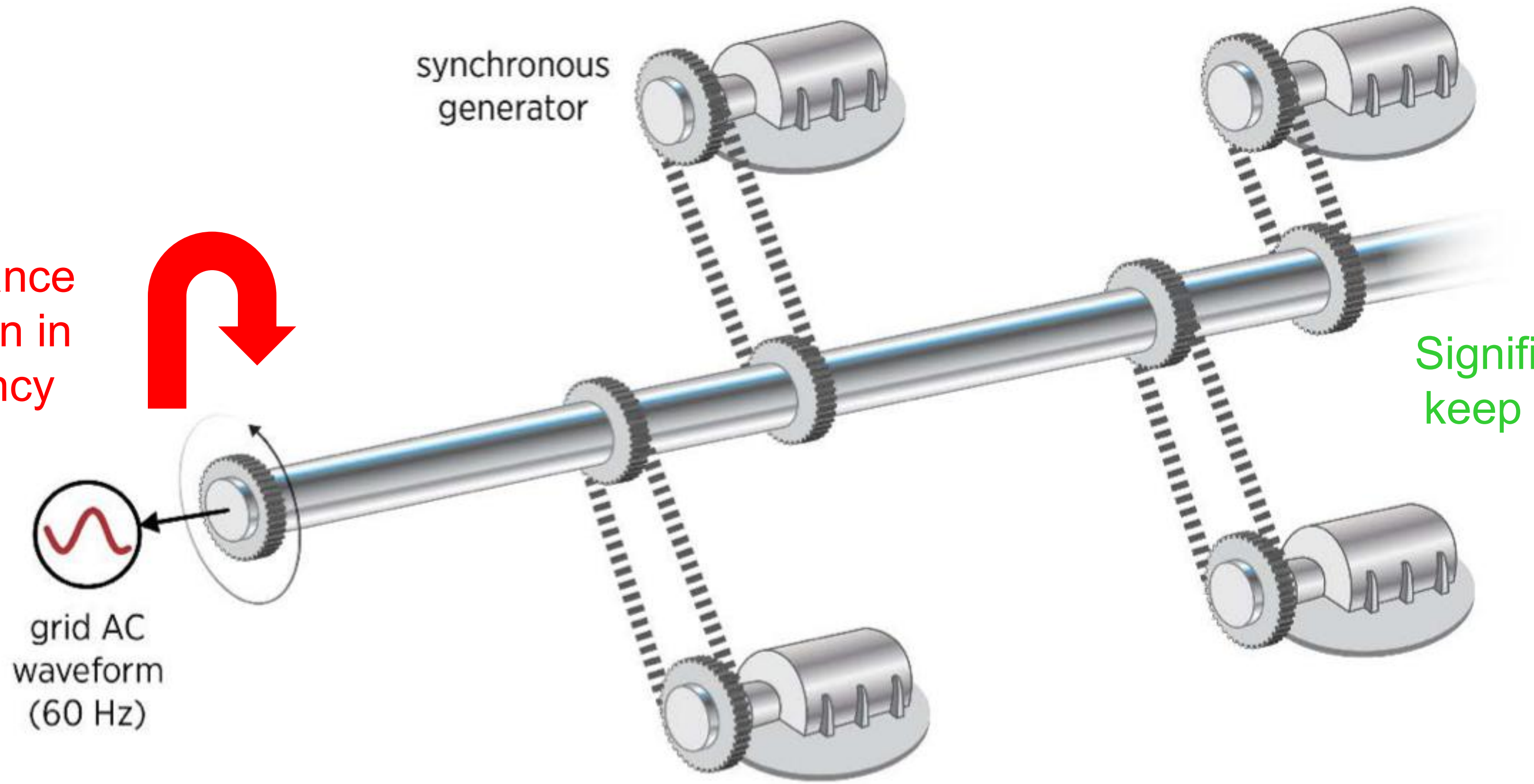
Inertia and System Strength: Introduction



Source: NREL

Inertia and System Strength: Introduction

System disturbance causes reduction in system frequency



Significant “torque” to keep frequency near nominal

Source: NREL

Inertia and System Strength: Introduction

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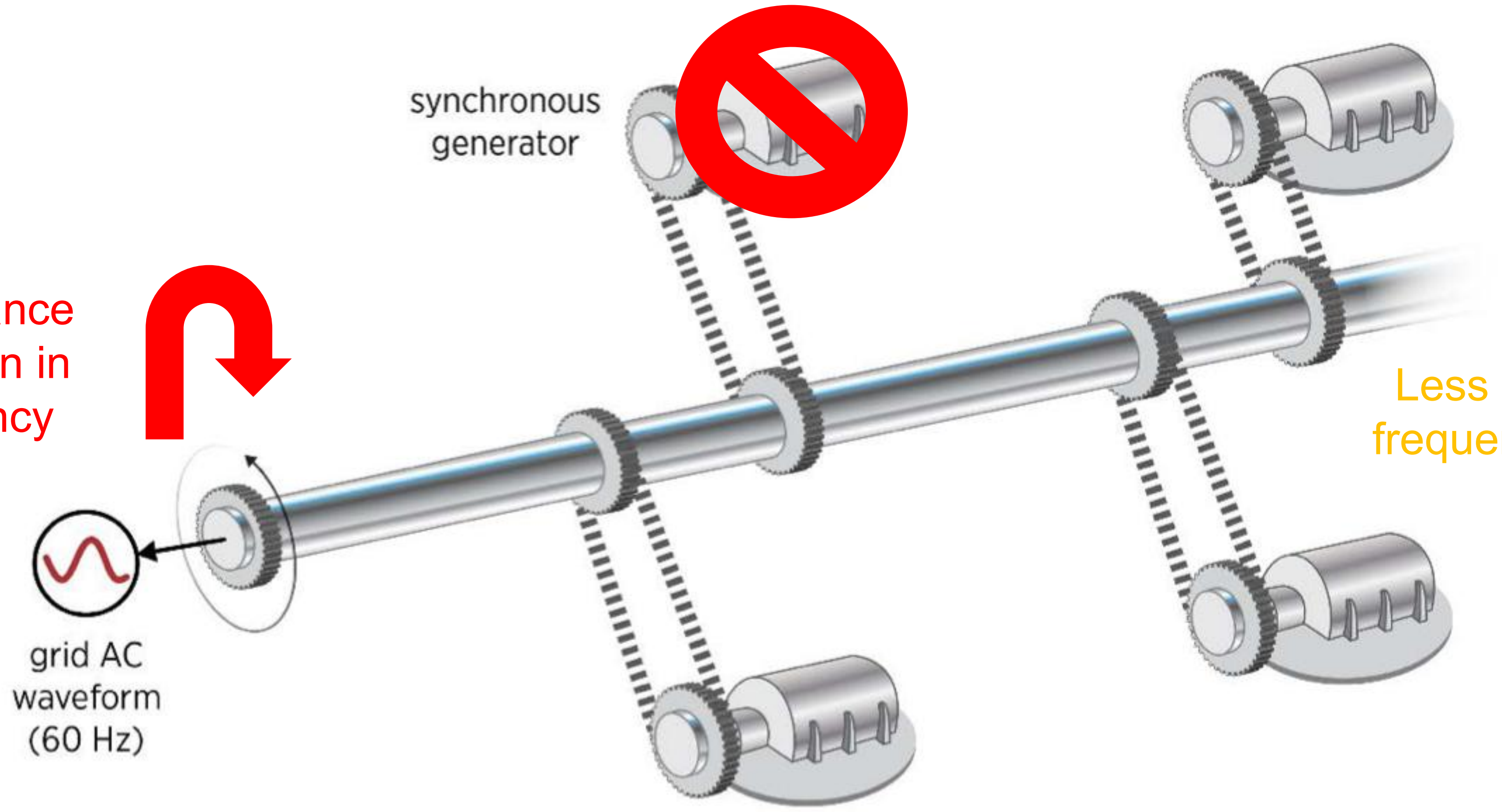
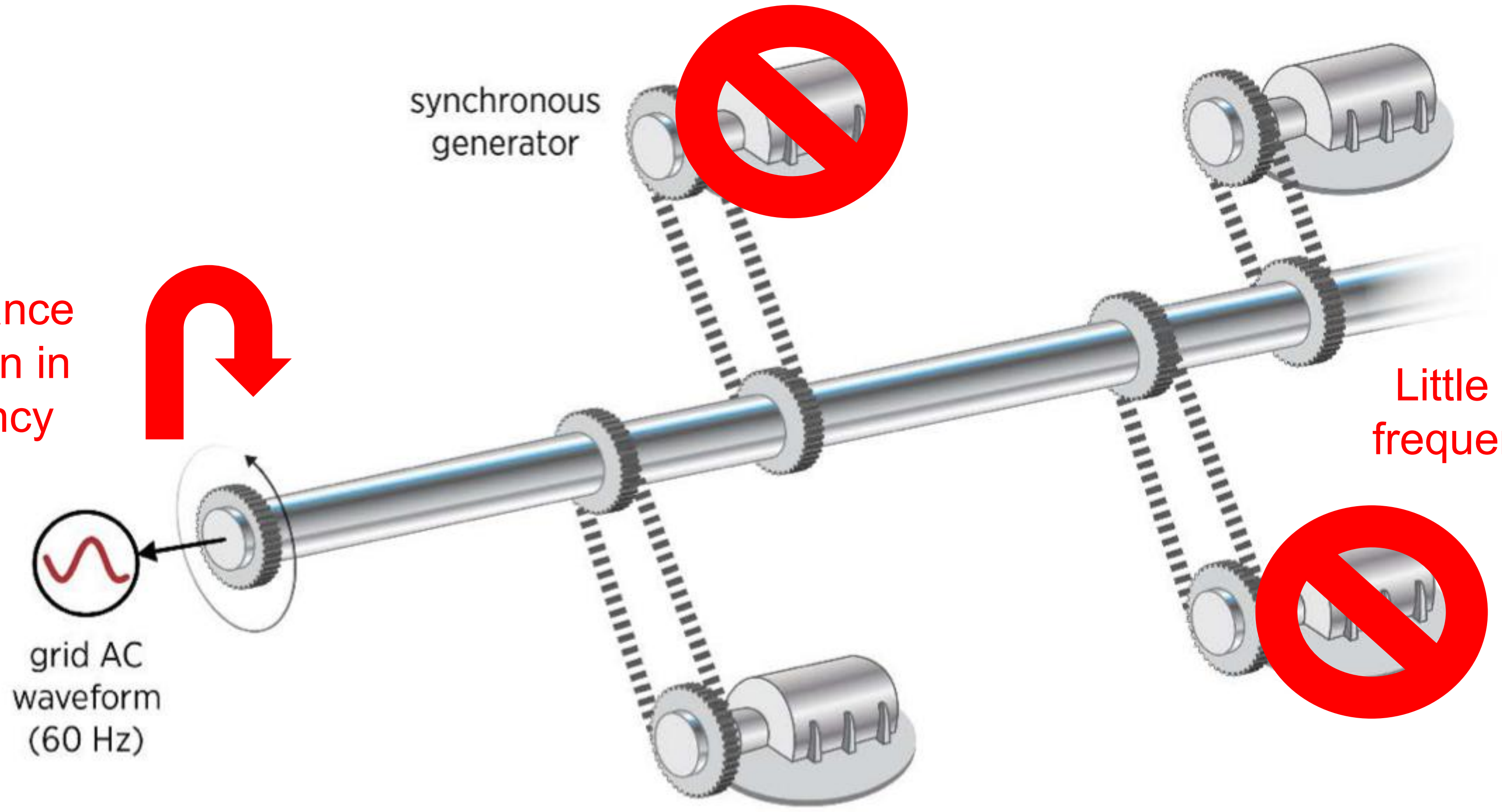


Less “torque” to keep frequency near nominal

Source: NREL

Inertia and System Strength: Introduction

System disturbance causes reduction in system frequency



Little “torque” to keep frequency near nominal

Source: [NREL]

How Does This Effect the Power System?

- **What happens when system inertia or "system strength" reduce?**
  - Simply put: ***all assumptions change***
- Frequency perturbations will be larger and happen faster (Rate of change of Frequency (ROCOF) increase)
  - Higher ROCOF means its harder to establish and remain within limits
  - Reduces time for operators to make adjustments
  - UFLS thresholds become critical and more difficult
- System voltages will be "less firm"
  - With lower system strength, each change in reactive power will cause a larger change in voltage
- Higher likelihood of protection system misoperation
  - Increased likelihood of cascading failures
- Increased wear on equipment and potentially shorter lifespans

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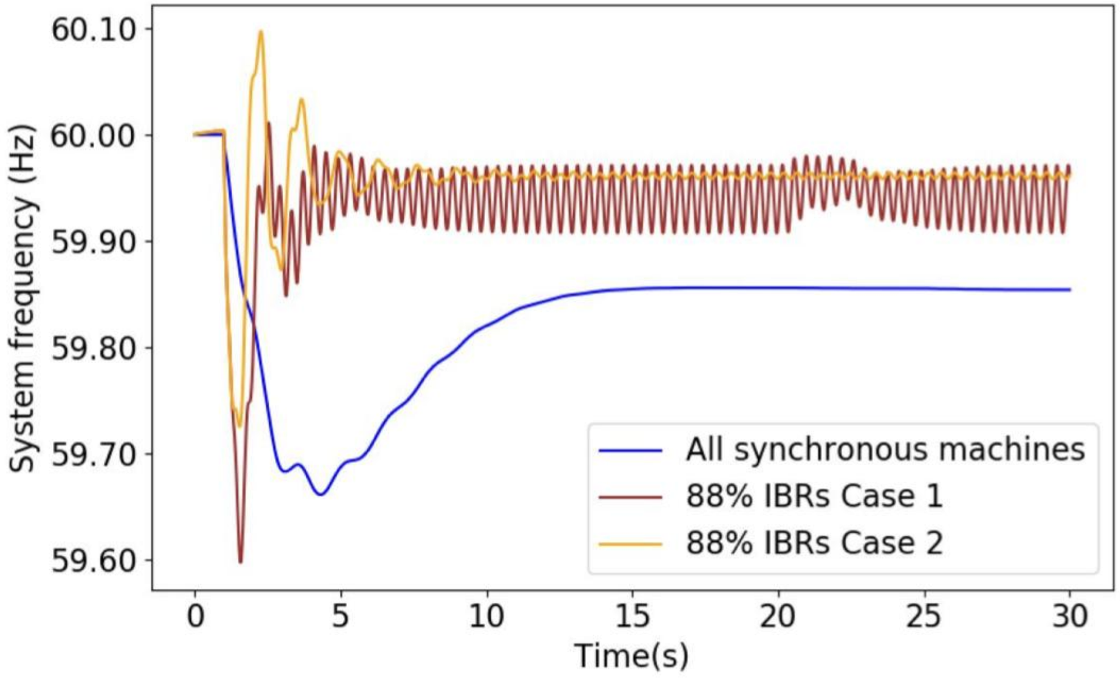
Major implications to frequency and voltage stability

- Higher likelihood of protection system misoperation
  - Increased likelihood of cascading failures
- Increased wear on equipment and potentially shorter lifespans

Frequency Stability: Different System Responses

- **Frequency stability is the ability to maintain frequency near nominal**
- **Many considerations for stability**
  - Frequency dynamics need to become faster
    - To arrest faster and deeper ROCOF and avoid UFLS
    - Primarily through fast-acting and well-tuned PFR/FFR
  - Sampling, control, and reaction times are critical
  - IBR do not provide frequency response "naturally"
- **Frequency response can help arrest the nadir, but is not a direct replacement for inertia**



Source: GPST

Frequency Stability: Changes to "Tools"

Technology	Synchronous Inertia	FCR			FFR		
		Type	Time to full response	Sustained response#	Type	Time to full response	Sustained response#
Synchronous Generator (incl. pumped hydro storage and CAES)	Yes	Droop respone (for pumped hydro only in gen mode)	10-20s	Yes	Droop Response*	2s	Yes
Load	Yes (if directly connected)	Droop response	few seconds	Yes	Step	0.25-0.5s	Yes
Smart Load	No	Droop response	few seconds	Yes	Proportional to Δf or RoCoF	0.5-1s	Yes
Synchronous Conden-ser	Yes	-	-	-	-	-	-
Wind Turbine	No	Droop response	few seconds	Yes (depending on wind)	Step or proportional to Δf or RoCoF	0.5-1s	Few seconds with recovery. Ineffective at low wind speed.
Solar PV	No	Droop response	few seconds	Yes (depending on sun)	Step or proportional to Δf or RoCoF	0.5-1s	Yes (depending on sun)
Battery Storage	No	Droop response	few seconds	Yes (depending on SoC)	Step or proportional to Δf or RoCoF	0.2-1s	Yes (depending on SoC)
Supercapacitor	No	-	-	-	Step or proportional to Δf or RoCoF	<0.2s	Only a few seconds (depends on size)
Flywheel	Yes (if directly connected)	Droop response	few seconds	Yes	Step or proportional to Δf or RoCoF	<0.01s	<15 min
Pumped Storage w. variable speed	No	Droop response	10-20s	Yes	-	-	-
HVDC VSC	No	Droop response	few seconds	Yes	Step or proportional to Δf or RoCoF	0.2 – 1s	No, depends on available energy

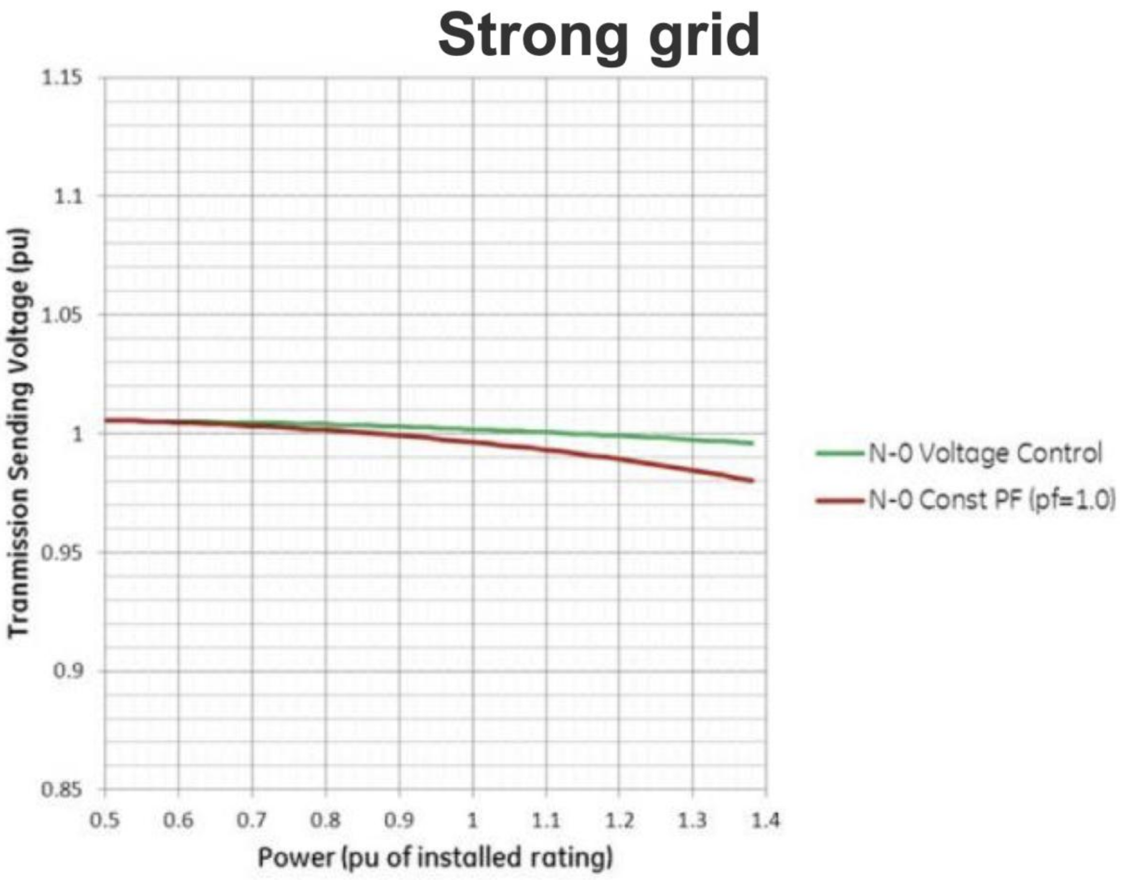
* EirGrid and SONI procure FFR with a response time of two seconds from synchronous machines, full response of FCR from these machines is expected at 5 seconds (faster than most utilites require), thus availability of FFR from synchronous machines will depend upon existing capabilities and FFR definition
# Note, curtailment of renewable resource will allow sustatined response depending on primary energy source variations(e.g. sun, wind).

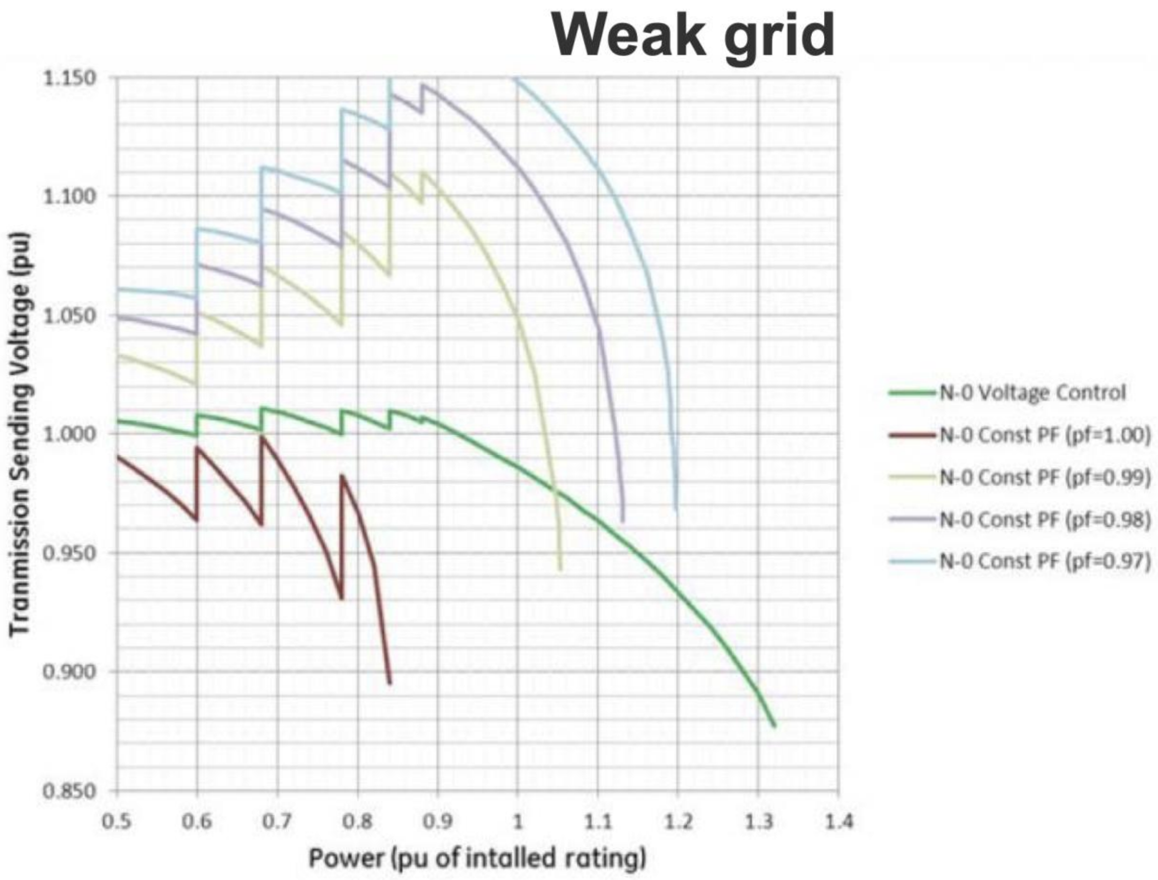
Source: CIGRE JWG C2/C4.41 Technical Brochure: Impact of High Penetration of Inverter-based Generation on System Inertia of Networks

Voltage: Different System Responses

- **Voltage stability is the ability to maintain system voltages near nominal**
- **Many considerations for stability**
  - In “weak systems” small changes are magnified
    - Voltage control under these conditions is challenging
  - Current-limited IBR may reduce capability for control (highly dependent on control tuning)
  - Different control modes have different concerns
    - More parameters and control means more opportunities for adverse performance
  - Ridethrough is critical
    - Cannot support the system if you aren’t connected
- **Control tuning and detailed modeling are mandatory**

Voltage: Different System Responses





Source: [GPST]

Emerging Large Loads

- **Will be discussed later in the week**
  - Large loads change the paradigm once again
- **Large loads are susceptible to many of the same reliability issues as IBR (and then some more)**
  - Power electronic-based ridethrough difficulties
  - Software-based controls
  - Non-technical stakeholders

  Old

  - Massive power demand density
  - Uncertainty on what will actually be installed ***after interconnection agreements are signed***
  - Potential for large and extremely fast fluctuations in demand
  - Power quality is high priority

  New

Need for Enhanced and IBR-specific Essential Reliability Services

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Intro to Essential Reliability Services

- **Introduction to ERS**
  - What are they and what are they currently
  - How are these linked to synch gen and conventional paradigm
- How are these problematic for IBR?
  - Are they directly applicable
  - Can IBR even do them?
  - How can IBR perform?
- How to adapt ERS paradigm to enable and maximize IBR capabilities for the system

Intro to Essential Reliability Services

- **Who specifies Essential Reliability Services?**
  - NERC developed essential reliability services through their ERSTF
  - Done as part of their duties as the Electric Reliability Organization
  - Created a framework document in **2015**
    - Lots of “smoke” but not much ”fire”
- **What is an Essential Reliability Service?**
  - **Simply put:** minimum characteristics without which the power system cannot be operated reliably
  - **Slightly deeper:** capabilities, controls, performance requirements, etc. that are used to help ensure system reliability
- **Policy makers need to be informed**
  - If these are “essential” they need to be mandatory

Intro to Essential Reliability Services

- **Essential Reliability Services in NERC footprint fall intro three categories:**
- **Frequency**
  - Managing system frequency
  - Planning for frequency excursions
  - Arresting and recovering
- **Ramping**
  - Resource adequacy
  - System balancing
- **Voltage**
  - Maintaining voltages
  - Reactive power capabilities

NERC ERSTF Recommendations

Source: NERC

Table 1: Summary of Measures and Industry Practices Recommendations					
Reference Number	**Title**	**Brief Description**	**BA or Interconnection Level**	**ERSTF Recommendation**	**Ongoing Responsibility**
1	Synchronous Inertial Response(SIR) at an Interconnection Level	Measure of kinetic energy at the interconnection level. It provides both a historical and future (3-years-out) view.	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
2	Initial Frequency Deviation Following Largest Contingency	At minimum SIR conditions from Measure 1, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the Resource Contingency Criteria (RCC) in BAL-003-1 for each interconnection).	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
3	Synchronous Inertial Response at a BA Level	Measure 3 is exactly the same as Measure 1 but performed at the BA level. It provides both a historical and future (3 years out) view and will help a BA identify SIR-related issues as its generation mix changes.	BA	Measure	Resource Subcommittee and Frequency Working Group

NERC ERSTF Recommendations

Source: NERC

Reference Number	Title	Brief Description	BA or Interconnection Level	ERSTF Recommendation	Ongoing Responsibility
4	Frequency Response at Interconnection Level	Measure 4 is a comprehensive set of frequency response measures at all relevant time frames: Point A to C frequency response in MW/0.1 Hz, Point A to B frequency response in MW/0.1 Hz (similar to ALR1-12), C:B Ratio, C:C' Ratio as well as three time-based measures (t_0 to t_C, t_C to $t_{C'}$, t_0 to $t_{C'}$), capturing speed of frequency response and response withdrawal.	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
5	Real Time Inertial Model	Develop a real-time model of inertia including voltage stability limits and transmission overloads as criteria. This is an operator tool for situational awareness and alerts them if the system is nearing a limit and any corrective action is required.	BA	Industry Practice	BA

NERC ERSTF Recommendations

Reference Number	Title	Brief Description	BA or Interconnection Level	ERSTF Recommendation	Ongoing Responsibility
6	Net Demand Ramping Variability	Measure of net demand ramping variability at the BA level. It provides both a historical and future view.	BA	Measure	Reliability Assessment Subcommittee
7	Reactive Capability on the System	At critical load levels, measure static & dynamic reactive capability per total MW on the transmission system and track load power factor for distribution at low side of transmission buses.	TOP	Measure	Performance Analysis Subcommittee and the System Analysis and Modeling Subcommittee
8	Voltage Performance of the System	Measure to track the number of voltage exceedances that were incurred in real-time operations. This should include both pre-contingency exceedances and post-contingency exceedances. Planners should consider ways to identify critical fault-induced delayed voltage recovery (FIDVR) buses and buses with low short-circuit levels.	No Further Action	No Further Action	No Further Action

Source: NERC

NERC ERSTF Recommendations

Reference Number	Title	Brief Description	BA or Interconnection Level	ERSTF Recommendation	Ongoing Responsibility
9	Overall System Reactive Performance	When an event occurs on the system related to reactive capability and voltage performance, measure to determine if the overall system strength poses a reliability risk. Adequate reactive margin and voltage performance should be evaluated across all horizons (planning, seasonal, real time). This type of post-mortem analysis comports with various requirements in existing and proposed NERC standards.	BA	Industry Practice	Event Analysis Subcommittee
10	System Strength	Based on short circuit contribution considerations, determine if low system strength poses a potential reliability risk. When necessary, calculate short circuit ratios to identify areas that may require monitoring or additional study.	Planning Coordinator	Industry Practice	Planning Coordinator

Source: NERC

Key Takeaways from NERC Framework

- **The bulk of this work was performed in 2015**
  - Assumptions, trends, and realities have all changed substantially
  - There has been little to no work done and easily available to enhance ERS for the new paradigm
    - This topic is discussed in only 4 paragraphs in the 2024 LTRA
- **Numerous ERS are synchronous machine focused**
  - Multiple are actual 1-1 synchronous machine metrics
    - This isn’t bad, but enhancement is needed as the grid transitions
  - Those that can also apply to IBR are framed with synchronous concepts
- **How do you ensure power system reliability when ”essential” capabilities are based on a power system that no longer exists?**

IBR Need to be Involved: Technically

- **Inverter-based resources have extreme flexibility in controls and performance**
  - Many of these are currently underutilized
  - Unlocking these needs policy changes and information sharing
  - Industry needs more knowledge on what IBR can do and how they can do it
- As synchronous machines get **replaced** services need to come from **the resources replacing them**
- Inverter-based resources software-based nature is a strength
  - While synchronous resources are strongly bound to physics, IBR can create be flexible and create new solutions “quickly”
  - This has happened already in markets like ERCOT
  - Allows easier and faster linking between system needs and resource performance
- **Many major OEM already have solutions that are market ready and in use in Europe**
  - They aren’t utilized in North America because there is no requirement or incentive

What ERS can IBR Provide?

Grid Following	Grid Forming	Battery Energy Storage
Voltage Support	Grid following+	Grid Following+
Frequency Support	Providing System References	System Reserves and Balancing
Fast Frequency Response	Stable Operation in Weak Grid	"Cheap" GFM Capability
Advanced Controls	Microgrid or Islands	Headroom for "full" GFM Controls
"Custom" Solutions***	Blackstart***	Headroom in Hybrid Configurations

How to Procure Essential Services From IBR?

- **Two ways to make change on the power system:**
  - **Incentivize it**
    - Provide cost recovery to IBR resources who prove capability and provide essential services
    - How to manage this discussion in the context of resources provide these services "naturally"
  - **Require it**
    - Changes to FERC *pro forma* LGIA/LGIP
    - Changes to NERC Standards
    - How to ensure requirements sufficiently move the technical minimum forward
    - How to do this while staying **"technology agnostic"**

Studying the New Power System Paradigm

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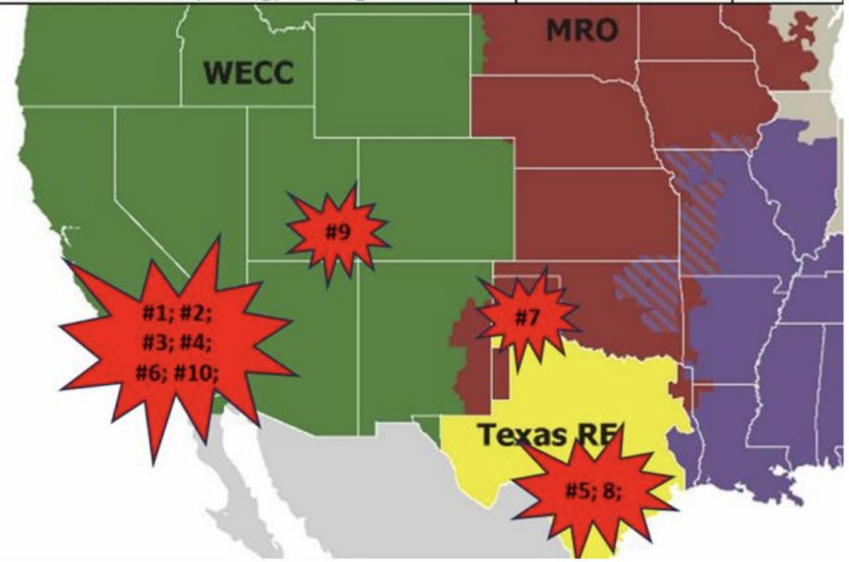
The Current Paradigm Isn't Working

Reliability improvements begin with understanding the results of the current paradigm:

- **10 major disturbances published by NERC since 2016**
  - Totaling ~15,000 MW
  - These are not ALL events, just those classified in NERC procedure for mandatory release
- None of the affected facilities in any of these published reports had models which accurately reflected actual performance
- Motivations for IBR interconnection are not aligned with grid reliability
- Current regulatory structure promotes disparate, misaligned, and sometimes confusing requirements
- Stakeholder-driven processes fail to produce sufficient technical minimum requirements

Reference Number	Disturbance	IBR Reduced (MW)	Year
#1	Blue Cut Fire	1,753	2016
#2	Canyon 2 Fire	1,619	2017
#3	Angeles Forest & Palmdale Roost	1,588	2018
#4	San Fernando	1,205	2020
#5	2021 Odessa	1,112	2021
#6	Victorville & Tumbleweed & Windhub & Lytle Creek Fire	2,464	2021
#7	Panhandle Wind	1,222	2022
#8	2022 Odessa	1,711	2022
#9	Southwest Utah	921	2022
#10	California Battery Energy Storage	906	2023



[Adapted from NERC Ridethrough Technical Conference, Sep. 4 2024]

The Current Paradigm Isn't Working

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"This report shows that the voluntary recommendations set forth in NERC Guidelines and other publications are not being implemented."

-Inverter-Based Resource Performance Issues Report, NERC, November 2023

- **Planning a reliable power system depends on accurate modeling of the system and resources connected to it. This includes accurate modeling of IBR performance, as well as protections or**

Table 3.1: Solar PV Tripping and Modeling Capabilities and Practices

Cause of Reduction	Can Be Accurately Modeled in Positive Sequence Simulations?	Can Be Accurately Modeled in EMT Simulations?
Inverter Instantaneous AC Overcurrent	No	Yes
Passive Anti-Islanding (Phase Jump)	Yes[a]	Yes
Inverter Instantaneous AC Overvoltage	No	Yes
Inverter DC Bus Voltage Unbalance	No	Yes
Feeder Underfrequency	No[b]	No[c]
Incorrect Ride-Through Configuration	Yes	Yes

Table 3.1: Solar PV Tripping and Modeling Capabilities and Practices

Cause of Reduction	Can Be Accurately Modeled in Positive Sequence Simulations?	Can Be Accurately Modeled in EMT Simulations?
Plant Controller Interactions	Yes[d]	Yes[e]
Momentary Cessation	Yes	Yes
Inverter Overfrequency	No[b]	Yes
PLL Loss of Synchronism	No	Yes
Feeder AC Overvoltage	Yes[f]	Yes
Inverter Underfrequency	No[b]	Yes

Adapted from: NERC 2022 Odessa Disturbance Report

What's so Different - Technology

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Adapted from: NERC's An Introduction to Inverter-Based Resources on the Bulk Power System

What's so Different - Technology

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- **Software-based IBR add significantly more complexity and uncertainty in both performance and modeling**
  - Need to view IBR performance and modeling with a software-development lens
  - IBR have significant performance flexibility dictated by software parameters
  - Renewable technology is relatively immature and has not been standardized
    - Efforts are being made to standardize IBR performance but intellectual property and patents are large roadblocks
  - Continuity of data and change management is critical throughout the lifecycle of the IBR plant

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Adapted from: NERC's An Introduction to Inverter-Based Resources on the Bulk Power System

What's so Different - Technology

- **Little or no "inertia" and low fault current contribute to the "weakening" of the power system**
  - Advanced grid services can help IBR operate at these weaker, or islanded operating points
- **Much of the current power system has been designed, planned, and operated with the assumption of significant inertia and fault current**
- **Changes in inertia and fault current have ripple effects for:**
  - Protection design and operation
  - Automatic voltage and frequency control
  - Emergency power system operations (i.e UFLS)
  - Standardization of performance and requirements

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Adapted from: NERC's An Introduction to Inverter-Based Resources on the Bulk Power System

What's so Different – Process and Stakeholders

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Synchronous Paradigm	IBR Paradigm
Often developed by engineering firms with engineering staff	Often developed by non-engineering firms without engineering staff
Reliability standards are the minimum	Reliability standards are the maximum
Detailed plant information easier to obtain	Detailed plant information more difficult
Detailed information available sooner in the process	Detailed information may not even be available during the interconnection process
Differences between studied and real performance typically smaller	Higher likelihood of large discrepancies in studied and actual performance
As-built information for modeling is easier to obtain	Sometimes difficult to obtain as-built information
Significantly more "operational awareness"	Less "operational awareness"

Why is Modeling IBR So Hard (in general)

Synchronous Machine	Modeling Consideration	Inverter-Based Resource
• More mature • Parameters and controls are standardized • Relatively simple plant construction (generator and main power transformer)	**Technology Maturity and Construction**	• Significantly less mature • Parameters and controls cannot be standardized (*performance can*) • Relatively more complex plant construction (collector cables, collector transformers, multiple manufacturer plants and hybrid resources
• Largely dictated by the physical behavior of a large spinning mass • Relatively small variations in performance from control parameters	**Technology Performance**	• Rarely dictated by the physical behavior of a spinning mass (i.e., Type 1-3 wind) • Relatively extremely high variation in performance from control parameters
• Majority of parameters are standardized and map 1-1 with the equipment • Relatively few model parameters • 1-1 mapping with measurable quantities reduces the number of tunable parameters and makes site-specific modeling easier	**Model Parameters**	• Few models have 1-1 mapping with the equipment • Thousands of parameters • Lack of mapping reduces quality of study inputs and reduces the ability to implement "tuned" site-specific controls

Why is Modeling IBR So Hard (in North America)

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Interconnection and planning requirements in North America do not allow or disincentivize the use of the representative models

- **Vendor equipment-specific models are not allowed to be submitted or are disincentivized with extra scrutiny and costs in most interconnections**
  - This is out of alignment with the NERC Dynamic Modeling Recommendations and FERC Order 2023
- **Manufacturers of IBR equipment do not recommend the use of generic or standard model library models to do site-specific or reliability studies**
  - Standard library and generic models are fine for long term, research, or representing machines far from
- **Developers are not often willing to do perceived "extra" work that could jeopardize interconnection date**

	Generic	Standard Library	Equipment Specific Models
Publicly Available	✓		
Short Time to Market (incl. validated models)			✓
Easy Maintenance			✓
Accuracy			✓
Minimal Tool Implications			✓
Usability	✓	✓	✓
Readiness for hybrid PPs, new technology, etc.			✓
"As-built" configuration for entire modeling portfolio			✓

Source: Vestas

The Modeling Paradigm has Changed (Rapidly)

ESIG

- **Modeling IBR is extremely different than modeling synchronous machines**
  - Modeling synchronous machines is “easy”
    - Grounded in physics of spinning masses
    - Relatively simple and highly standardized controls
    - Extremely mature technology
  - Modeling IBR brings significant challenges
    - Performance is almost entirely software-based
    - Complex, not standardized, and often patented control schemes make generic modeling vastly insufficient

The Modeling Paradigm has Changed (Rapidly)

- **Manufacturer-specific User-defined models deserve their reputation**
  - In the mid 2010's UDM were plagued with:
    - Poor documentation
    - Poor performance (in simulation software i.e. memory leaks)
    - Inaccuracy (in representing their products)
  - This was almost every TSO's first experience with UDM
    - These same people are likely in leadership roles now
- **Industry developed standard library models (i.e. WECC Generic) were a reaction**
  - Industry needed some way to represent IBR and OEM models were insufficient
  - Generic models were developed with OEM input but this input was misconstrued
  - Generic models are being misused as part of common and tariff-directed practice
- **The manufacturer-specific standard library experiment has failed**

The Modeling Paradigm has Changed (Rapidly)

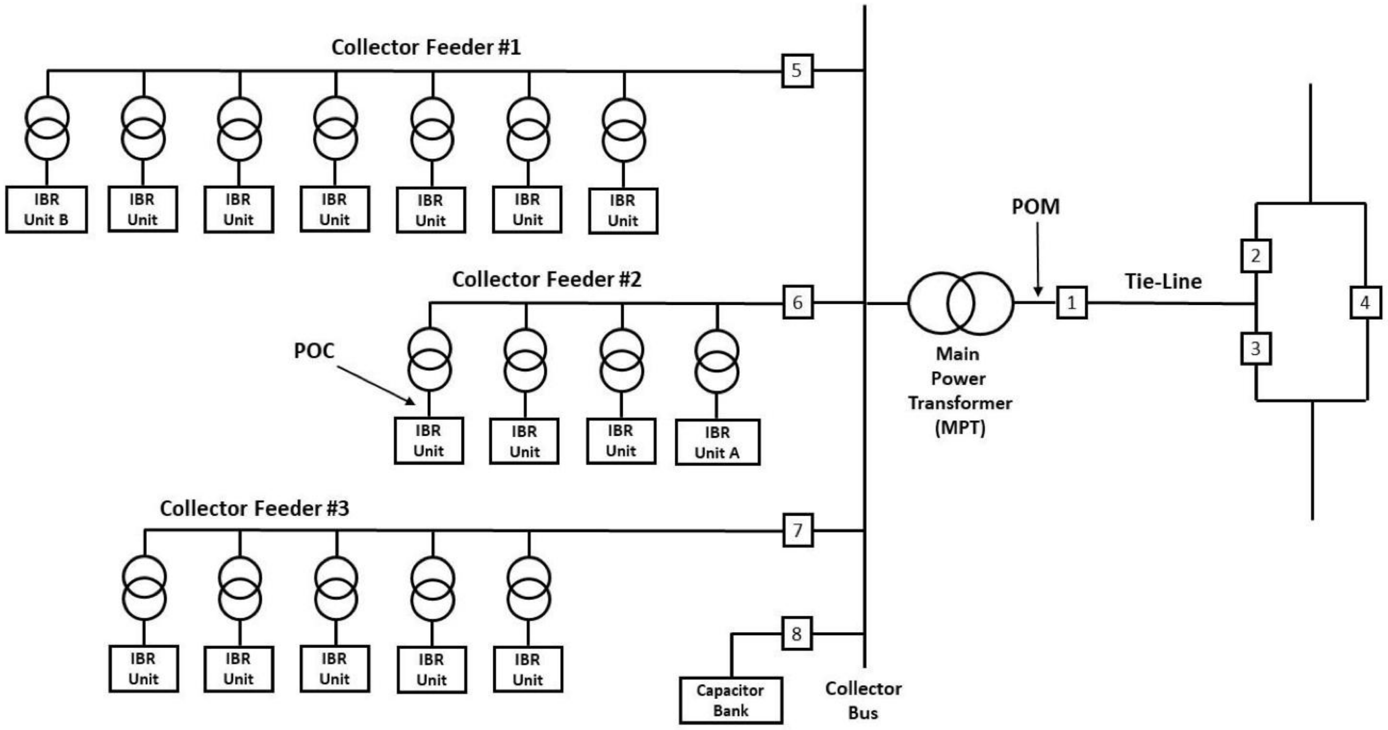
ESIG

- **Major improvements in the model space driven by international grid codes**
  - The rest of the world has recognized this problem and have come up with different solutions
    - Open-sourced model code
    - High-quality generic models with “hooks”
    - Standardized interfaces (wrappers) for real-code models
    - Model accuracy and validation requirements with high bar for accuracy and model quality
- **Most all of the roadblocks for proper modeling in North America have technical solutions in practice internationally**
- **In order to unlock full capabilities for IBR and ensure reliability, accurate modeling is paramount**

Small Detour Into Steady State Modeling: Aggregation

- **Aggregation is incredibly important…. and incredibly contentious!**
  - Disaggregated models aren't used in large planning cases
    - Can be essential for reliability (and economically prudent) for design evaluation studies
  - Some IBR technology types and layouts benefit much more than others

Source: NERC



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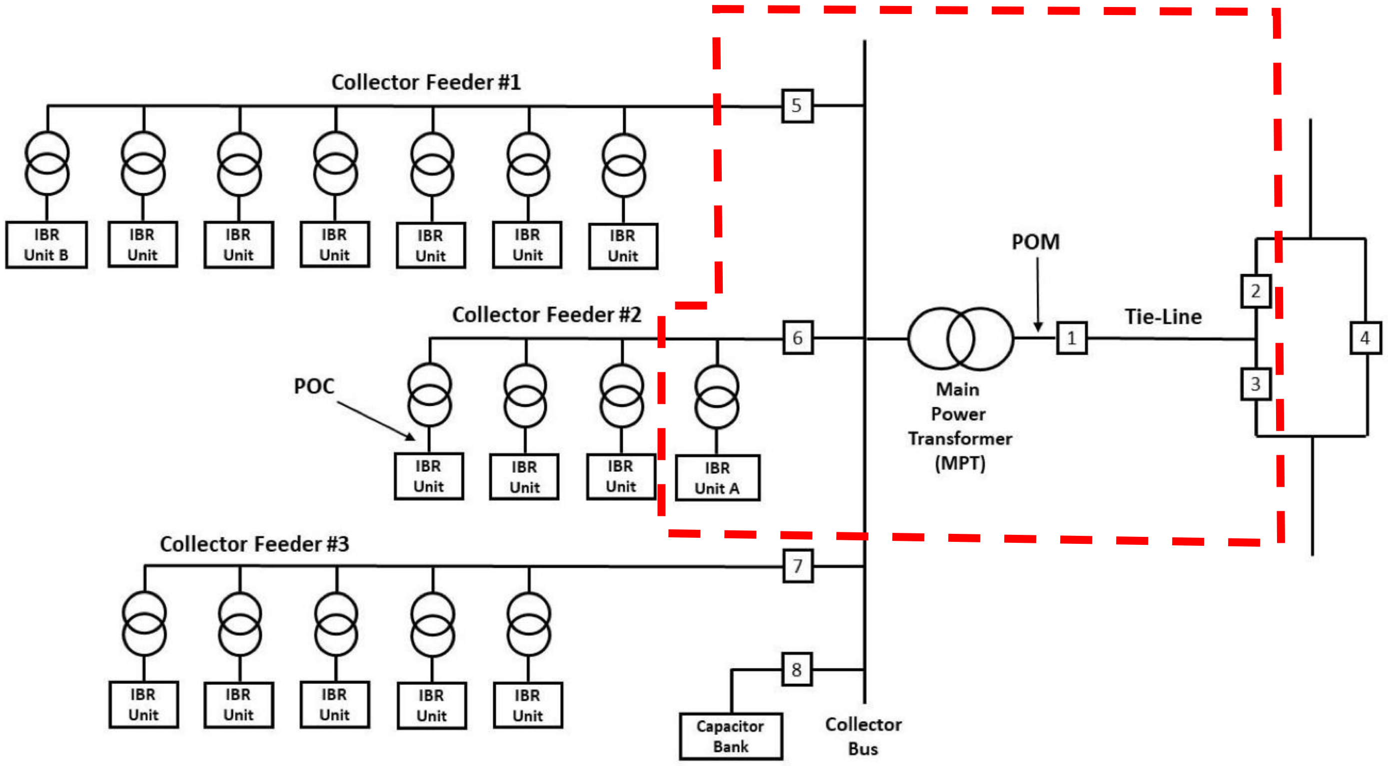
Source: [NERC]

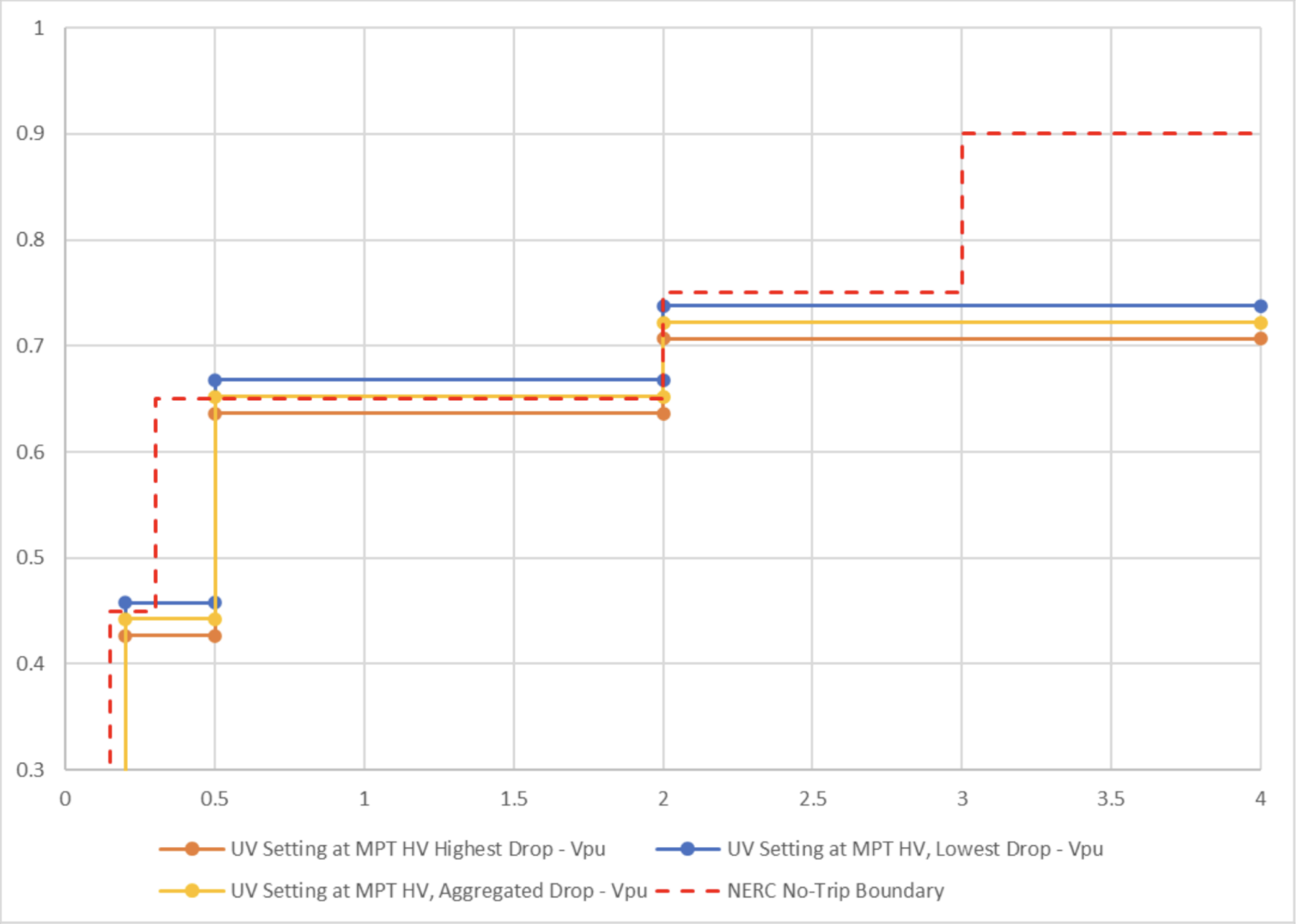


Considerations For Aggregation

- **Not every IBR facility or technology type gain substantial benefits from disaggregated studies**
  - IBR technologies with small (short) collector systems see limited benefits
- **Making both an aggregated and disaggregated steady state model is easier than it sounds**
  - Many common practices involve building some sort of disaggregated representation as part of the aggregate model build
- **Simulation domain and study purpose matters**
  - Massive considerations for compute time when considering EMT
  - Not all assessments benefit from being performed in the disaggregate
- **Potential benefits of disaggregated study work (keeping in mind the above)**
  - Demonstrate partial tripping and actual ridethrough capability (major observation from NERC event reports)
  - Site reactive power compensation sizing and capability
  - Working with voltage-dependent IBR technologies

Aggregation Examples

(...) it can be observed that the difference in voltage drop between the two extreme IBR units can be significant. - NERC



Source: NERC

Aggregation Examples

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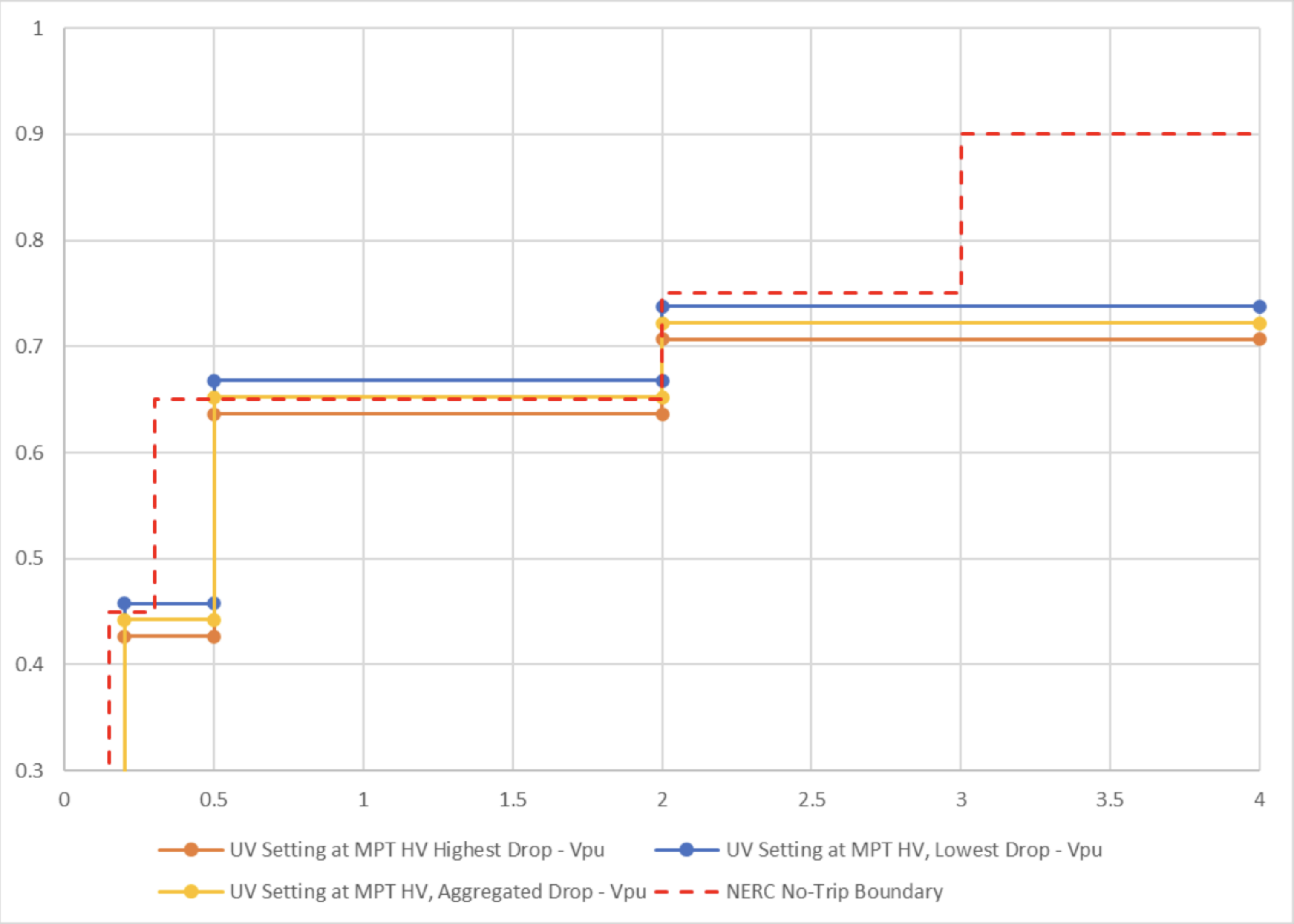
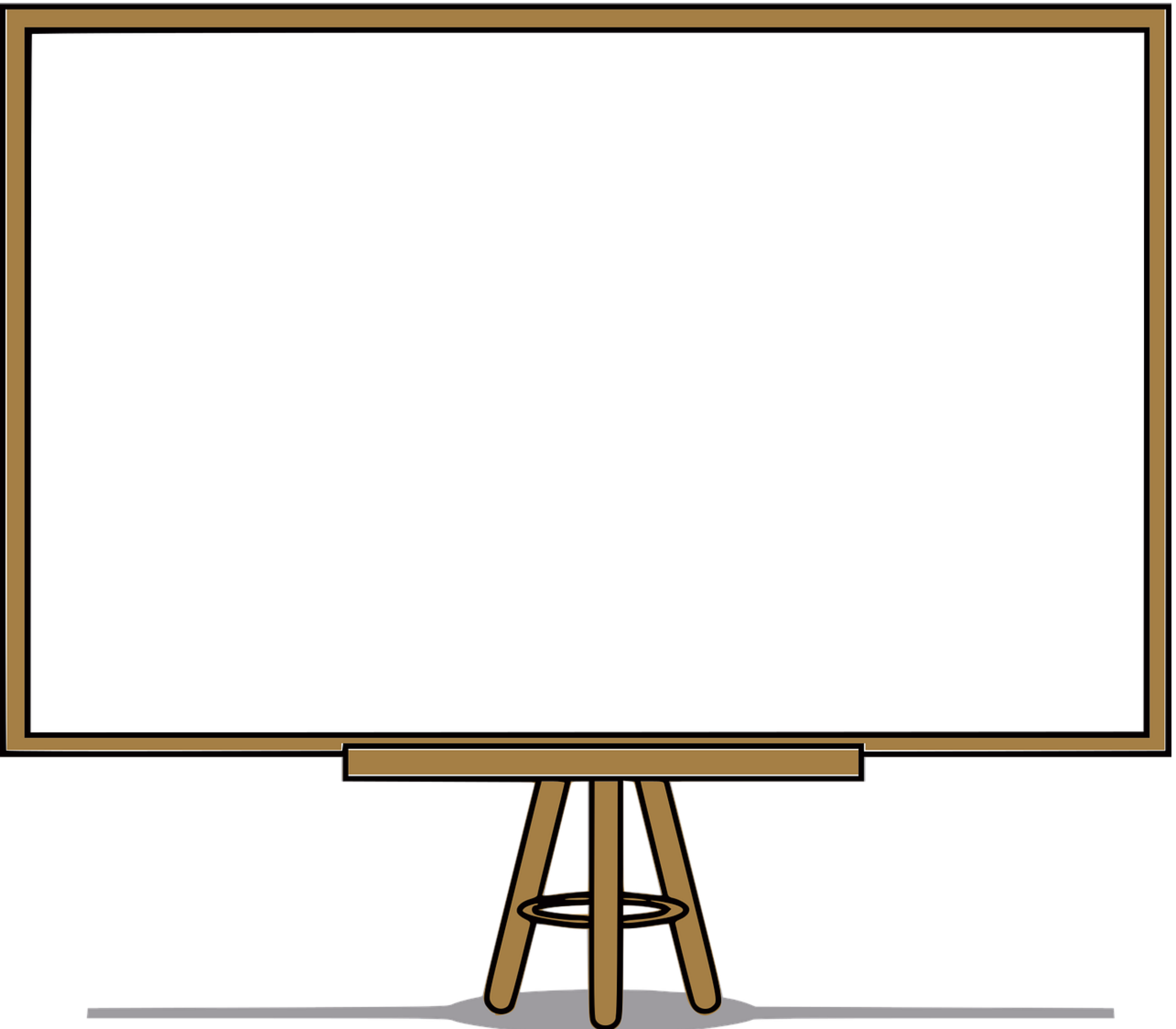


Source: NERC

Generic Standard Library and Equipment-Specific Modeling – Thought Examples



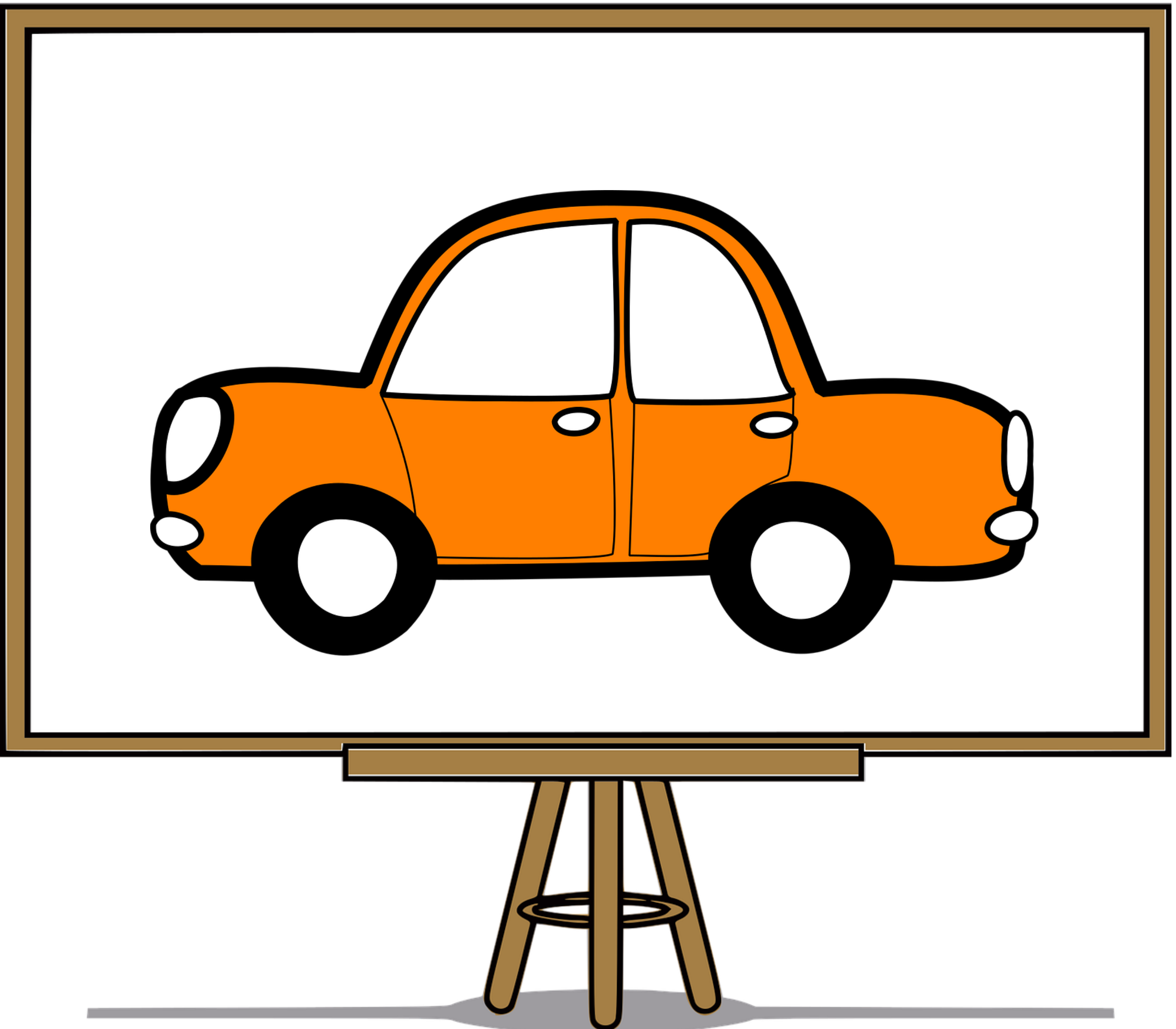
Task: Paint a picture of a vehicle

(represent an IBR plant in general)

Generic or Standard Library Model

Equipment Specific Model

Generic Standard Library and Equipment-Specific Modeling – Thought Examples



Task: Paint a picture of a vehicle

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Generic or Standard Library Model

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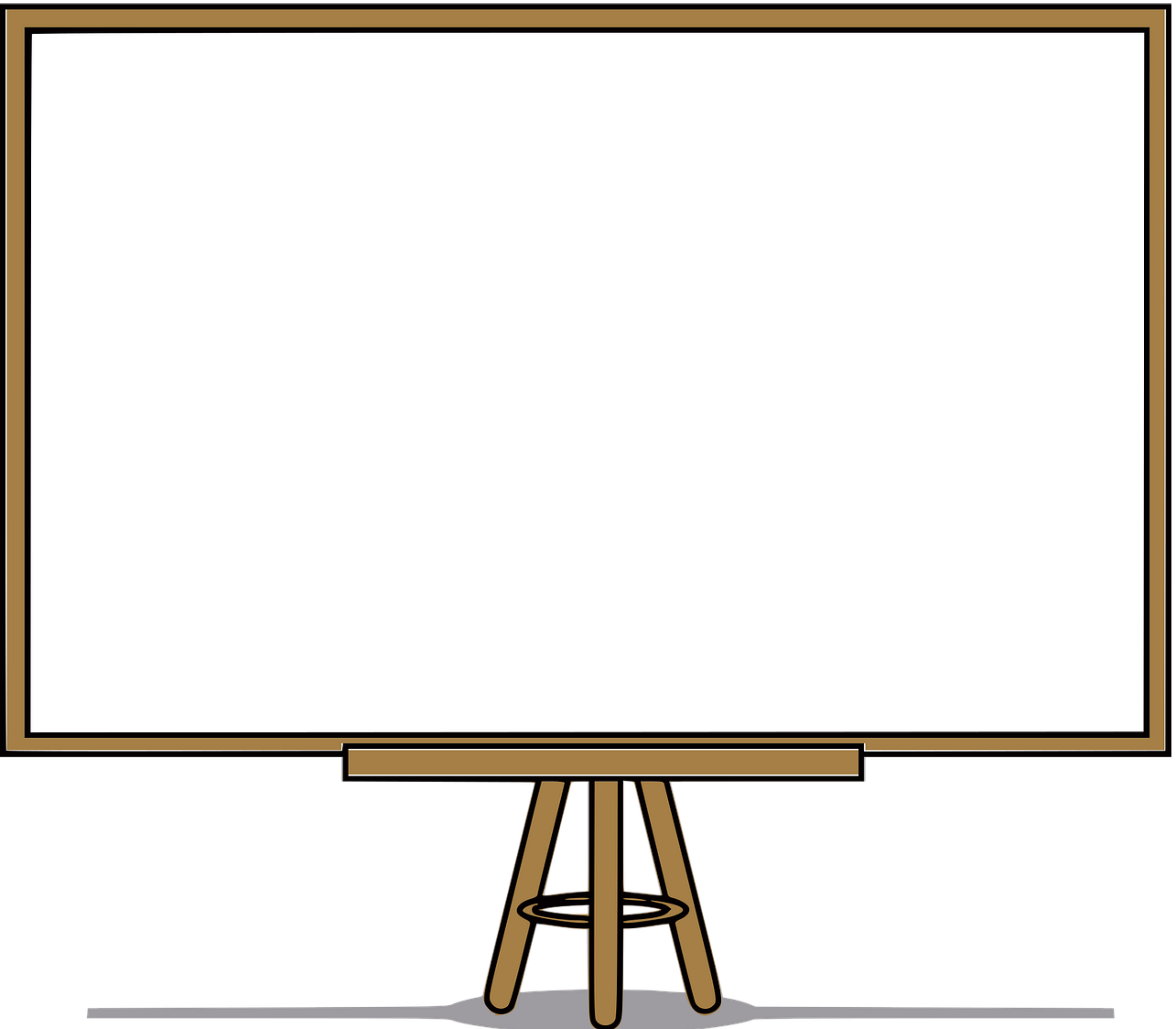
Generic Standard Library and Equipment-Specific Modeling – Thought Examples

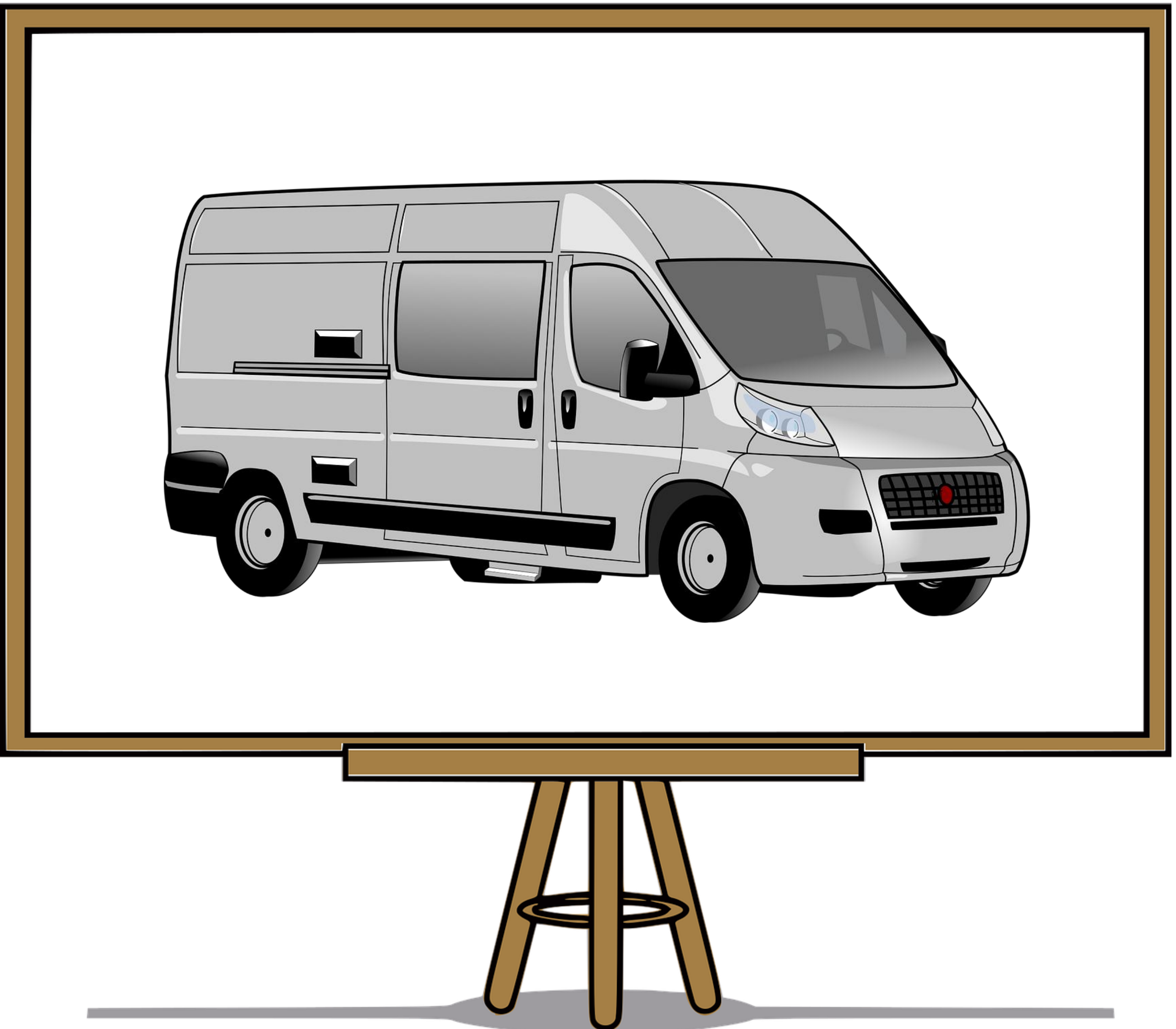


Task: Paint a picture of a van

(represent an IBR plant of a specific type)

Generic or Standard Library Model	Equipment Specific Model
	

Generic Standard Library and Equipment-Specific Modeling – Thought Examples



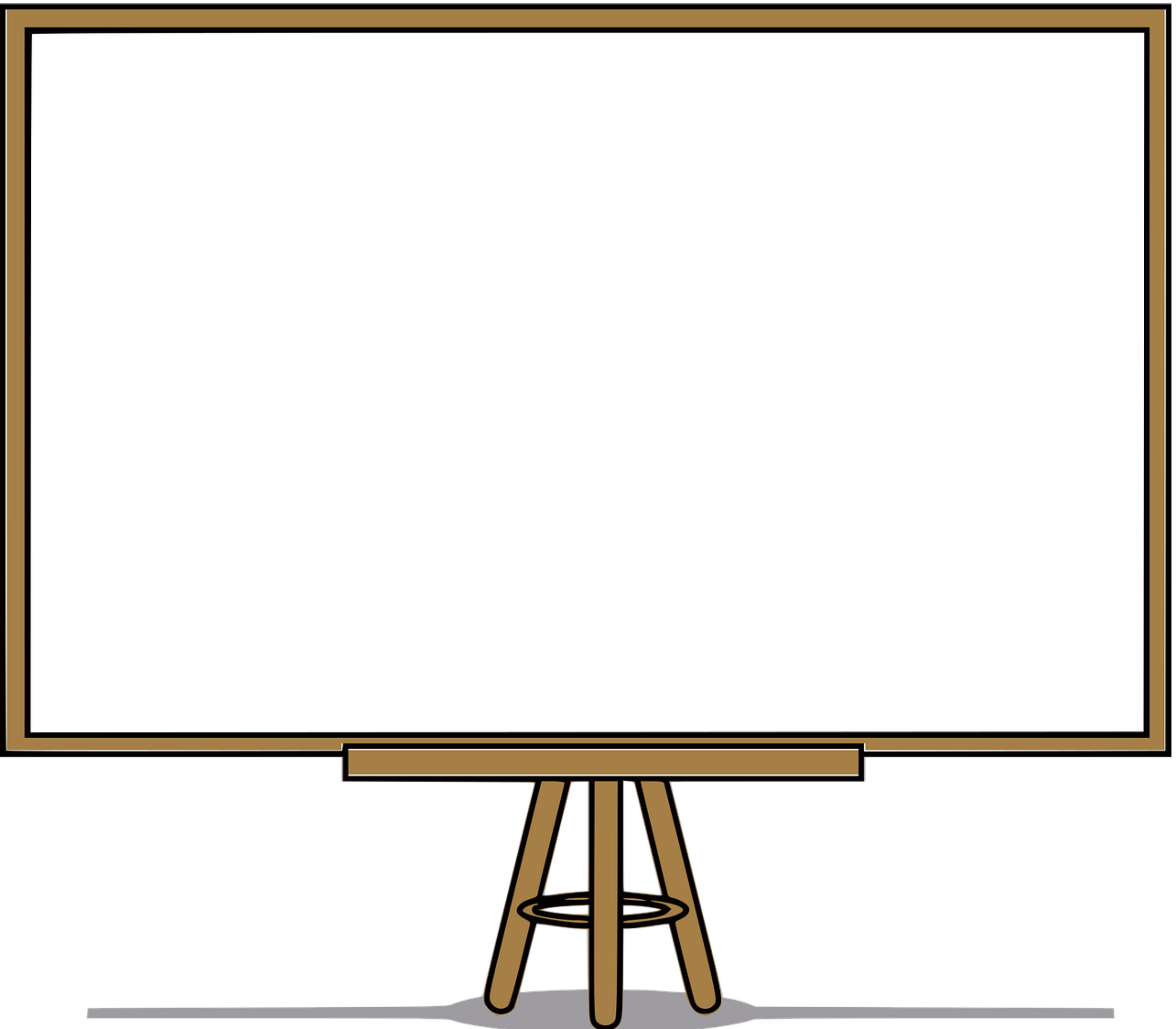
Task: Paint a picture of a van

(represent an IBR plant of a specific type)

Generic or Standard Library Model

Equipment Specific Model

Generic Standard Library and Equipment-Specific Modeling – Thought Examples



Task: Paint a picture of a Mercedes sedan

(represent an IBR plant of a specific type by a specific manufacturer)

Generic or Standard Library Model

Equipment Specific Model

Generic Standard Library and Equipment-Specific Modeling – Thought Examples

Task: Paint a picture of a Mercedes sedan

(represent an IBR plant of a specific type by a specific manufacturer)

Generic or Standard Library Model

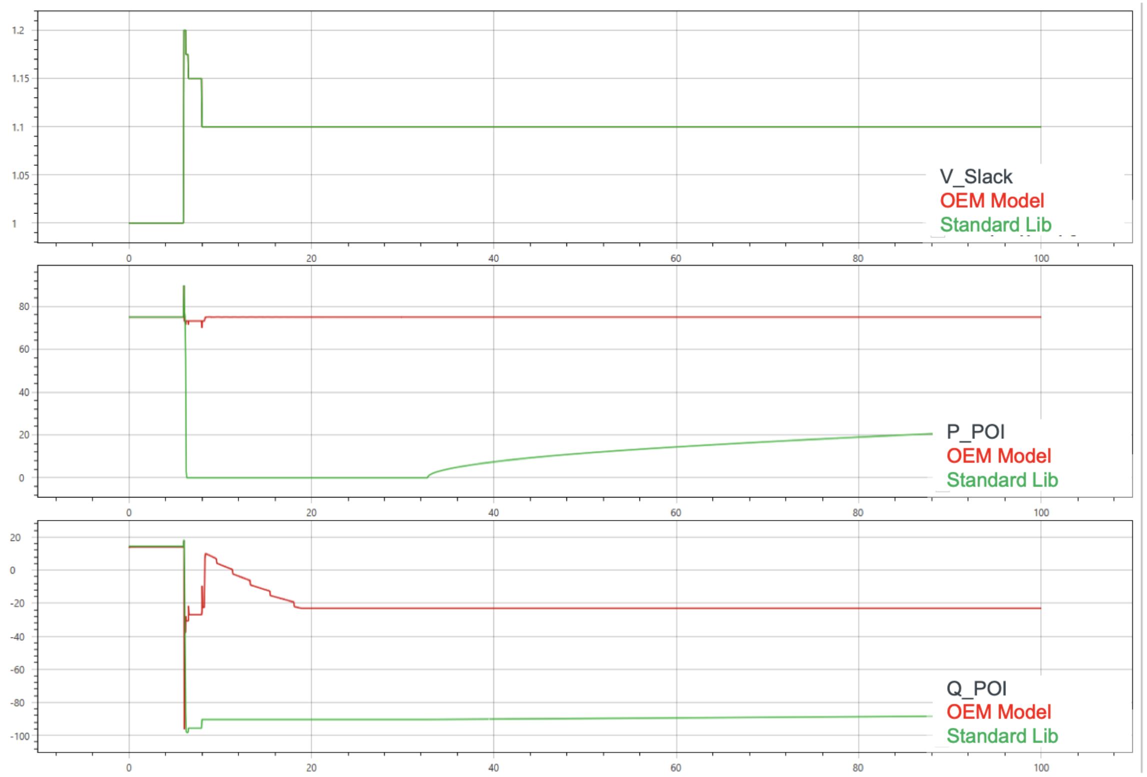
Equipment Specific Model

Generic vs. Equipment Specific – Real World

Vestas Case Study – Comparing Models Used in the Planning and Interconnection Process to Site-Specific Equipment-Specific Models

Classification: Public

Vestas



The "Standard Lib" represents NERC MOD validated models used in current reliability processes

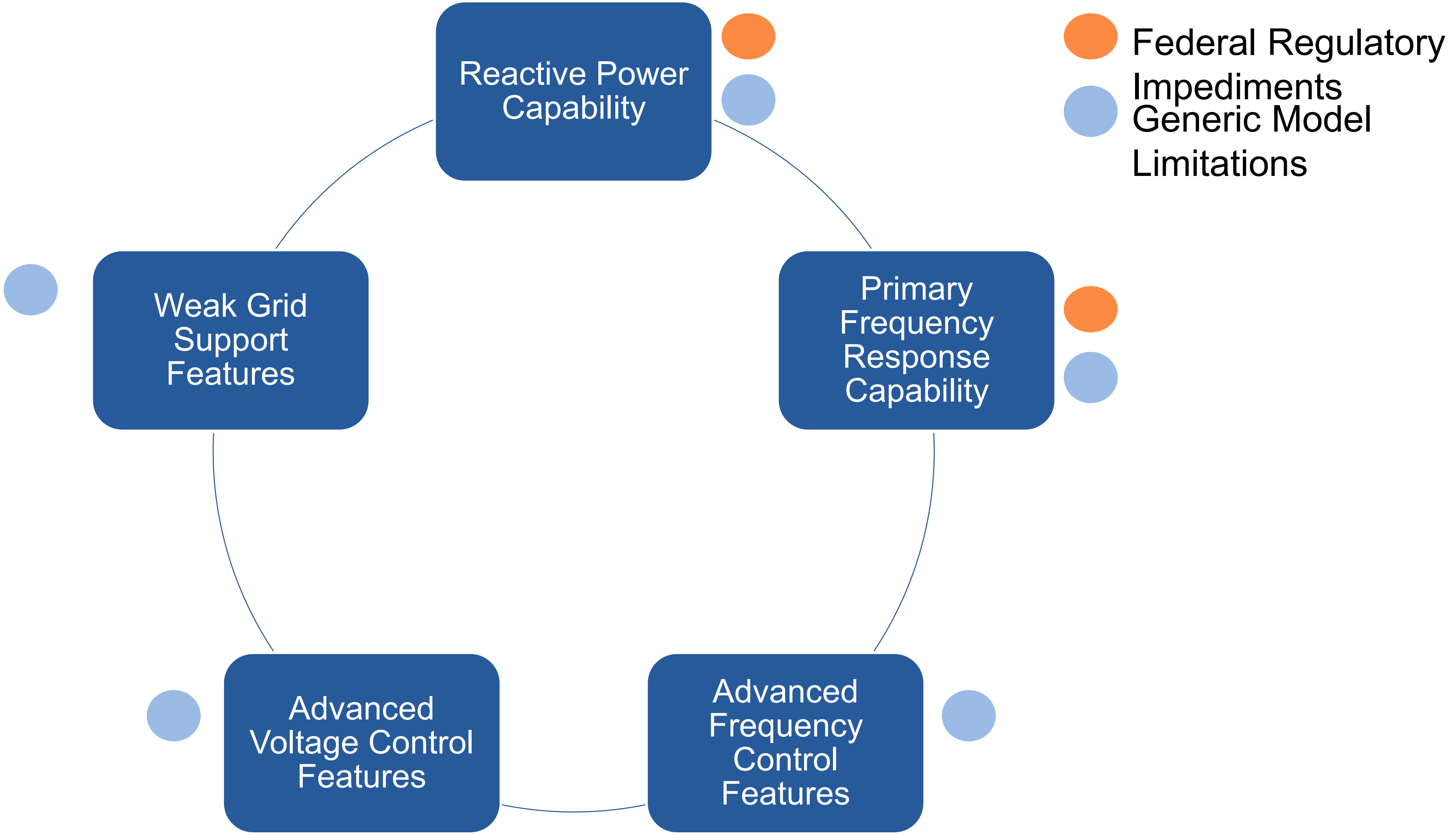
Source: [Vestas]

Why is IBR Modeling Detail So Important?

ESIG

- **The power system is evolving rapidly, and the current stability margin is being reduced by current IBR interconnection and planning processes**
- **Transmission enhancements are on a significantly slower time scale than IBR interconnections**
- **IBR have significantly underutilized capabilities**
  - Enabling these capabilities (which are only available in equipment-specific models) is essential to the efficient use of the current power system and to inform efficient future grid enhancements
- **Utilizing "advanced" IBR capabilities will be essential to maintaining grid reliability and avoiding erroneous transmission upgrades**
- **Reliance on generic and standard library models ensures that interconnection and planning studies will always be wrong when compared to actual performance**
  - "Wrong" in this case is neither conservative nor optimistic
  - Generic and standard library models give both false positives and negatives

What is Being Underutilized?

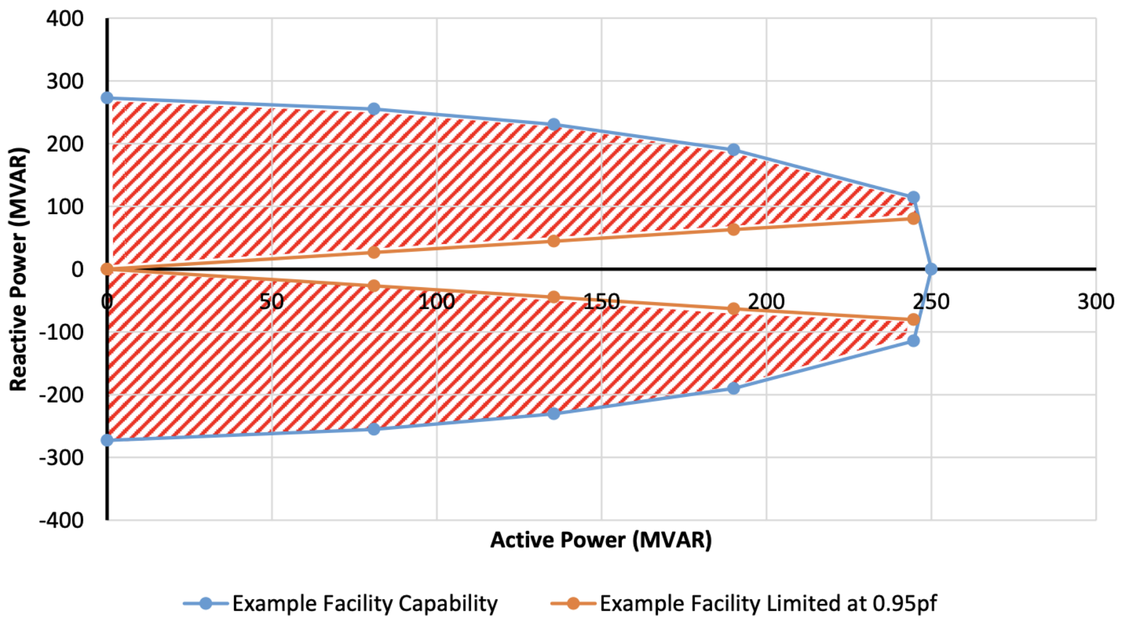


Federal Regulatory Impediments – An Example

ESIG

Language with unexpected interpretations in FERC Order 827 limits reactive power capability

- FERC Order 827 states to "(…) maintain a composite powe delivery at continuous rated power output at the high-side c the generator substation within the range of 0.95 leading and 0.95 lagging, unless the Transmission Provider has established a different power factor range (…)"
- This is similar, but not identical, to the IBR operating points that contributed to the Iberian blackout
    - IBR were operated at a fixed power factor
        - No matter the grid condition, the plant will deliver a fixed reactive power for a given active power
    - FERC Order 827 dictates a power factor limited operation
        - The direction of reactive power (leading or lagging) may change, but is still limited to +/- 0.95



NERC Level 2 Alert data shows 35% of the currently installed IBR are operating in this limited mode

Grid Forming Inverters – Added Complexity to an Unprepared Paradigm

ESIG

- Grid forming inverters are extremely similar to grid following inverters
- Grid forming controls add complexity on top of the complexity of studying and planning grid following resources
  - Industry shows evidence of reliability issues tied to grid following, these may exacerbate with grid forming
- Integration of grid forming technology in North America is disjointed
  - Little to no Federal guidance on whether to require, incentivize, or even integrate GFM
- Every battery energy storage resource that is connected without grid forming capabilities increases the opportunity cost of adding it later
  - Many BESS can implement GFM with simple software changes
  - Not every IBR needs to be GFM

Reliability Consideration	Grid Following	Grid Forming
Technology Maturity	Immature compared to synchronous	Immature compared to GFL
Software-based	Susceptible to IBR performance and ridethrough issues	
Power Electronic-Connected		
Model Parameters	Similar complexity and difficulties	
Grid Impact	”Passive” grid participant	“Active” grid participant
Modeling and Study Risks	Insufficient accuracy can lead to self tripping of an IBR and cause local reliability issues	In addition to GFL, insufficient accuracy can create improper references and control interactions

Grid Forming vs. Grid Following – In Depth

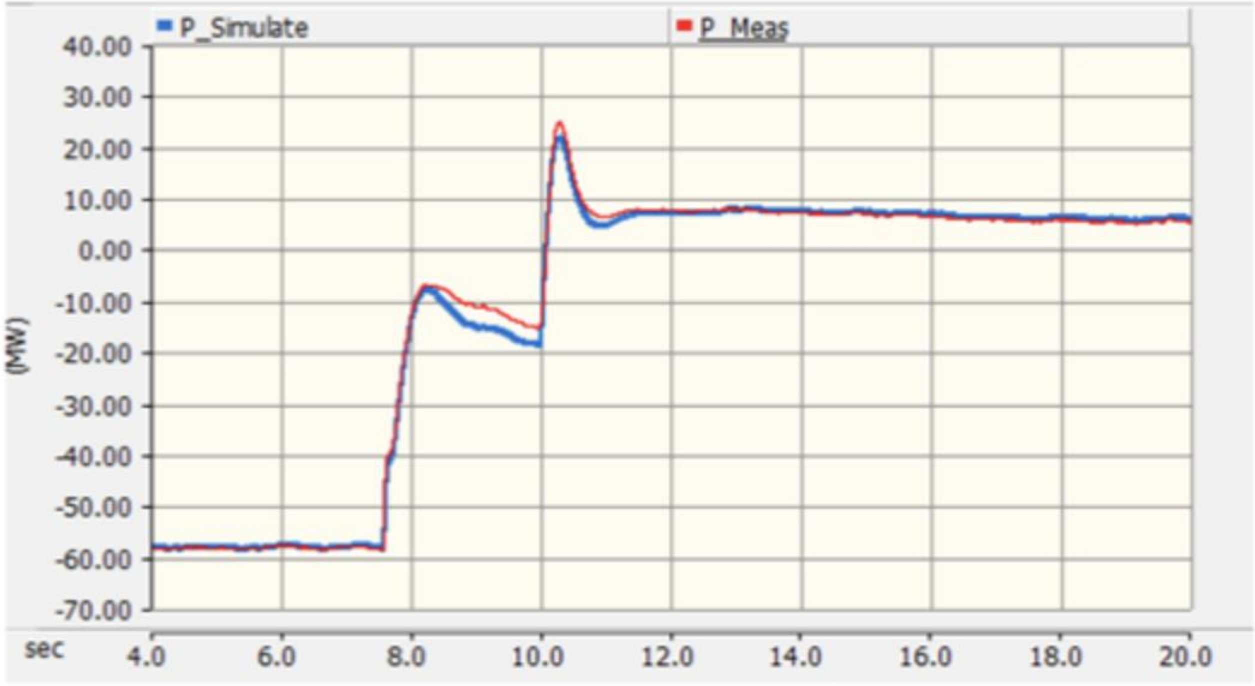
Inverter Attribute	Grid-Following Control	Grid-Forming Control
Reliance on grid voltage	Relies on well-defined grid voltage, which the control assumes to be tightly regulated by other generators (including GFM inverters and synchronous machines)	Actively maintains internal voltage magnitude and phase angle
Dynamic behavior	Controls current injected into the grid (appears to the grid as a constant current source in the transient time frame)	Sets voltage magnitude and frequency/phase (appears to the grid as a constant voltage source in the transient time frame)
Reliance on PLL for synchronization	Needs phase-locked loop (PLL) or equivalent fast control for synchronization	Does not need PLL for tight synchronization of current controls, but may use a PLL or other mechanism to synchronize overall plant response with the grid.*
Ability to provide black start	Not usually possible	Can self-start in the absence of network voltage. When designed with sufficient energy buffer and over-current capability, it can also restart the power system under blackout conditions. (Only a limited number of generators on a system need to be black start–capable.)
Ability to operate in low grid strength conditions	Stable operation range can be enhanced with advanced controls, but is still limited to a minimum level of system strength	Stable operation range can be achieved without a minimum system strength requirement, including operation in an electrical island. (GFM IBRs will not, however, help to resolve steady-state voltage stability for long-distance high-power transfer.)
Field deployment and standards	Has been widely used commercially. Existing standards and standards under development define its behavior and required functional-ities well.	Has been deployed in combination with battery storage primarily for isolated applications. Very limited experience exists in inter-connected power systems. Existing standards do not yet define its behavior and required functionalities well.

* A GFM inverter also needs a synchronization mechanism when it has reached its current or energy buffer limits. If it reaches these limits, it will temporarily fall back to grid-following operation and will need to track the grid voltage phasor.

- Grid forming is a spectrum
- Different methods for implementing GFM
  - Virtual synch machine
  - Droop control

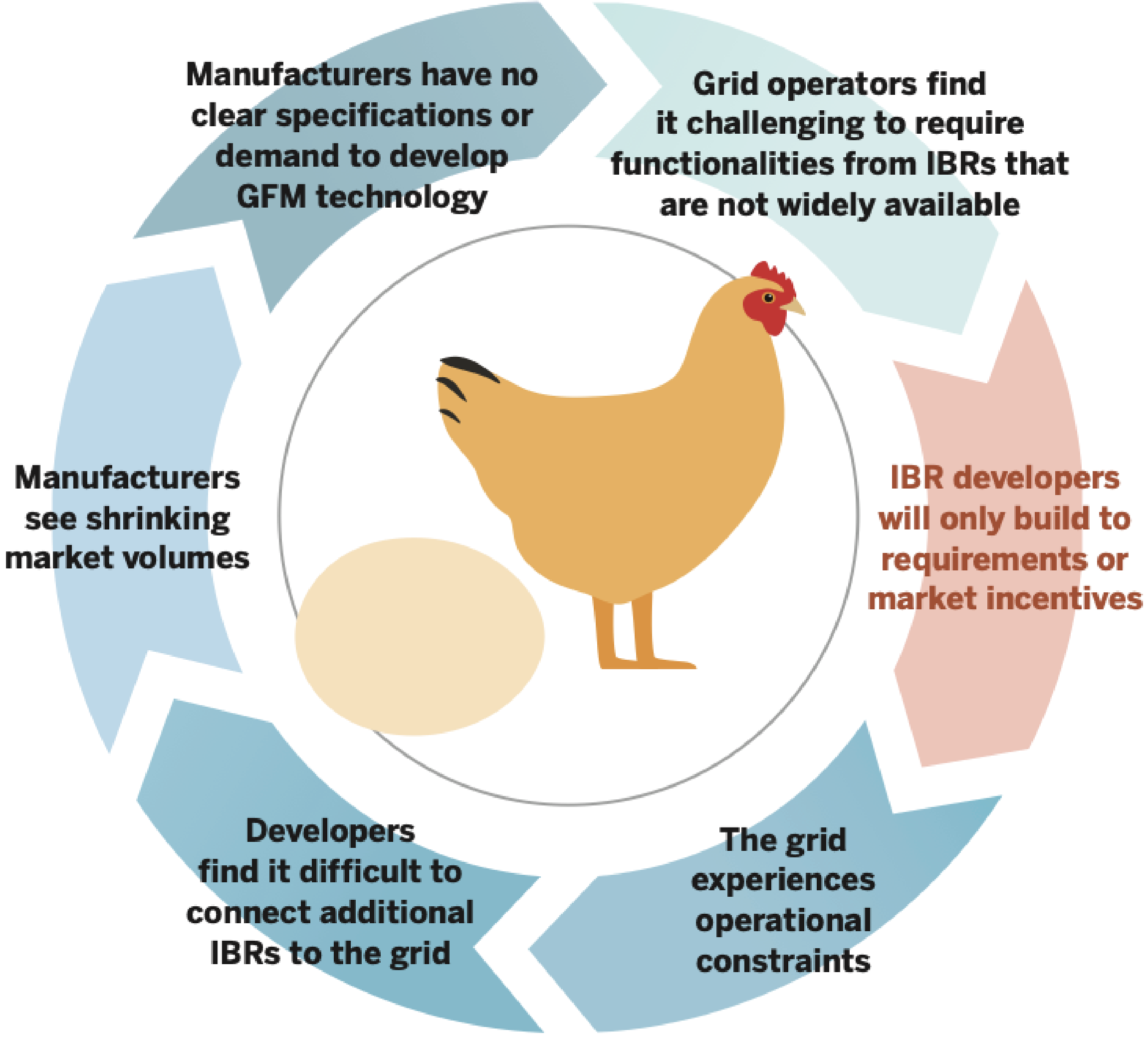
How does GFM Help – Operating Example

- Grid forming controls provide extremely fast response times
  - These are controlled responses, even in extreme grid conditions
  - Can stabilize weak grids or provide voltage and frequency references in the absence of synchronous machines
- If there is sufficient additional energy (like in BESS) these stabilizing responses can sustain for long periods of time
- Kapolei Energy Storage:
  - Response to extreme underfrequency disturbance
  - Plant responded within 250ms to arrest the frequency drop
  - Sustained this grid forming response for 30 minutes while the system recovered



Source: Hawaiian Electric Company.

How to unlock GFM – Need to Break the Cycle



How to unlock GFM

In the proposed process for deploying new GFM capabilities to serve system needs, the outer circle follows steps 1 through 9 as discussed in the text, while the three inner elements show how the nine steps relate to IBR equipment manufacturers and project developers and owners. Steps 1 through 9 are not set in stone and will likely need to be an iterative loop as systems and technologies continue to evolve.

- Need to move with urgency
- System operators need to clearly define what they *want and need* from GFM resources
  - Studies defining quantitative needs are not currently widespread
  - System operators have difficulty mandating the interconnection of GFM
- Specification and details for how system operators will test for and confirm performance are necessary ASAP
  - Few system operators currently have GFM testing specifications
- Manufacturers take these grid needs, and develop equipment that can meet the grid needs and system operator requirements
  - Little to no international guidance on GFM performance specifications
  - Adds extreme difficulty when procuring resources to develop new technologies

Conclusions

ESIG

Regulatory enhancements are needed to close gaps and enhance North American system reliability

- Major events comprised of unexpected IBR tripping show that the current modeling paradigm is insufficient
- Many of the modeling challenges have solutions internationally
- There is strong best practice available for IBR modeling in North America
  - This best practice is often at odds with current regulatory processes
- Regulatory processes need enhancements to allow stakeholders to perform best practice
- Process enhancements must have strong industry consensus technical foundation (i.e. IEEE 2800-2022, P2800.2, etc.)
- Stakeholder driven processes need enhancement to prevent gaming, lobbying, and misinformed comments and ballots

ERO Members -- Transmission Owners

NERC

FERC

Conclusions

Modeling IBR is hard, data and evidence shows the current paradigm is insufficient, and logic continues that added complexities of GFM will exacerbate these insufficiencies

- Grid forming inverters have many of the same reliability issues as discussed for GFL in numerous NERC disturbance reports
- There is insufficient understanding of how much GFM is needed, where it is needed, and what types of GFM resources can be connected
- There are not many incentives for installing GFM resources
- Grid forming resources are very important to high renewable penetration goals
- There are significant lessons that can be learned from GFL mistakes
- Standardization efforts are underway (much sooner than for GFL)

ERO Members -- Transmission Owners

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Introduction to IBR Plant Model Construction

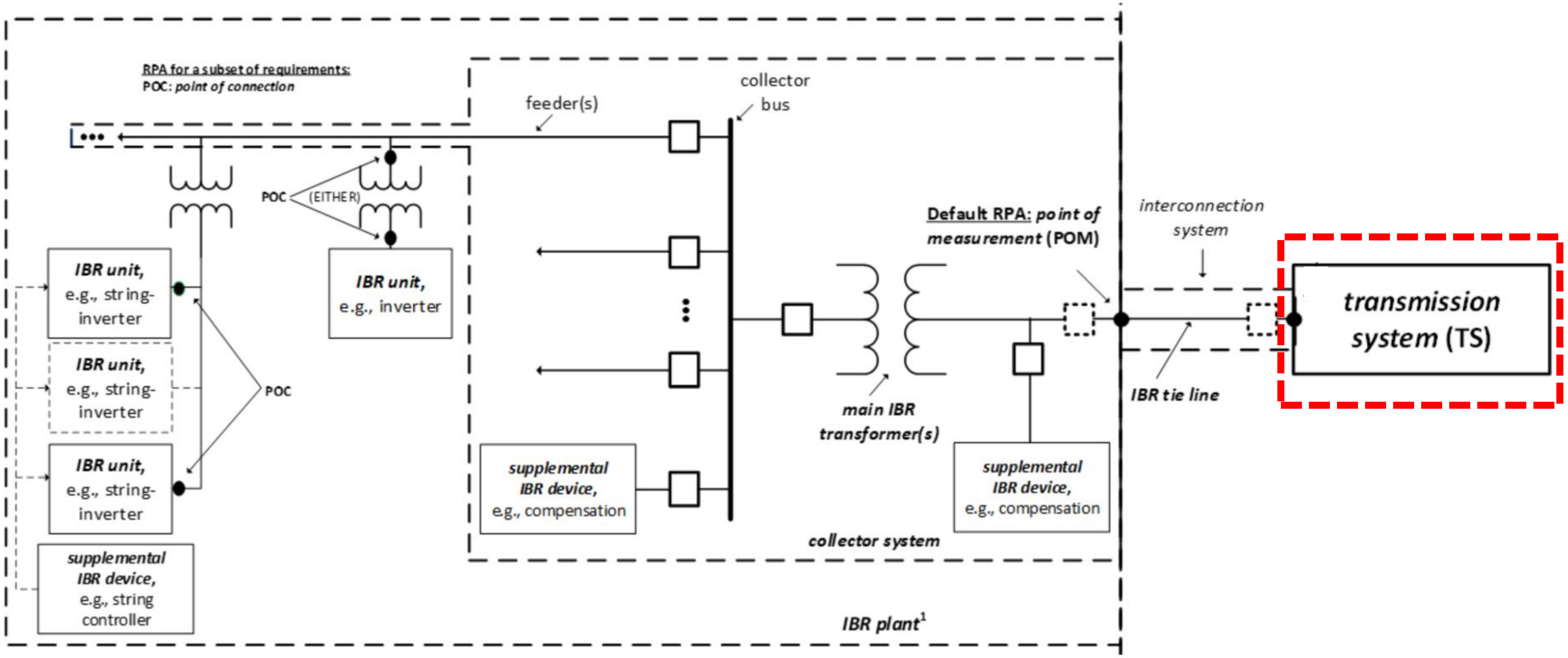
ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

Fundamentals of IBR Plant Model Construction

- **What is the purpose of creating IBR plant models?**
  - **At a high level:** To represent the behavior of the IBR plant during normal and abnormal conditions
    - We need to know how an IBR plant will behave under certain conditions and stimuli
  - **Digging in:** There are numerous ways to represent an IBR plant including:
    - Aggregate
    - Disaggregate
    - Generic/standard
    - Vendor-specific
  - **Key consideration:** How you represent the IBR plant in the model space should be considered based on the goals and purpose for the study work being conducted
    - **Choose two of the following:** (1) Quick study (time and computation); (2) Accuracy; (3) Cost

Components of an IBR Plant – Transmission System

IBR Plant model creators (developers, consultants, OEM) do not often have access to transmission system models

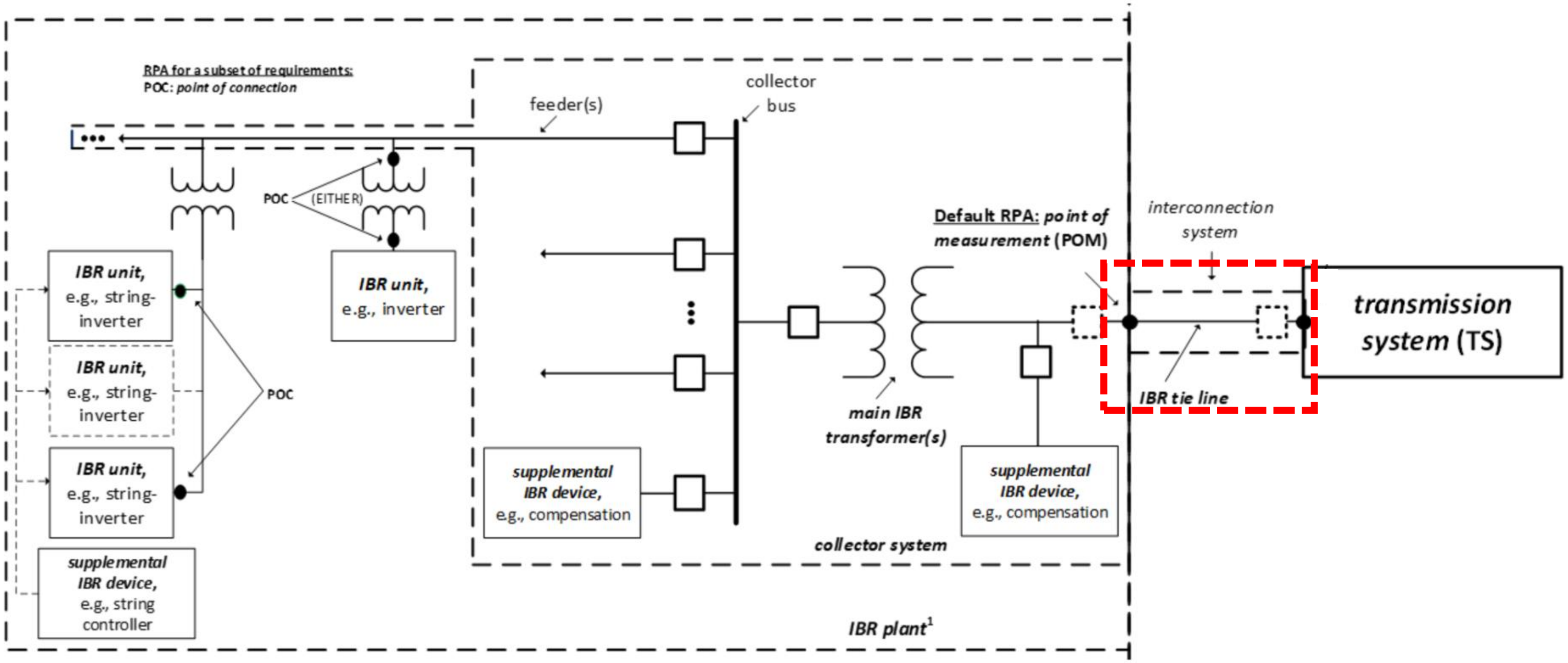


Source: Adapted from IEEE 2800-2022

- Equivalent networks are used in place of the transmission system
- Single machine infinite bus (SMIB) are often used
  - Can be adapted to approximate some TS conditions:
    - SCR
    - X/R ratio
    - System impedance
- Data comes from utility, TO, TP, PC
  - Point of contact at the interconnecting utility should be able to provide sufficient information

Components of an IBR Plant – IBR Tie Line

IBR tie lines are often "ignored" due to typically very short lengths

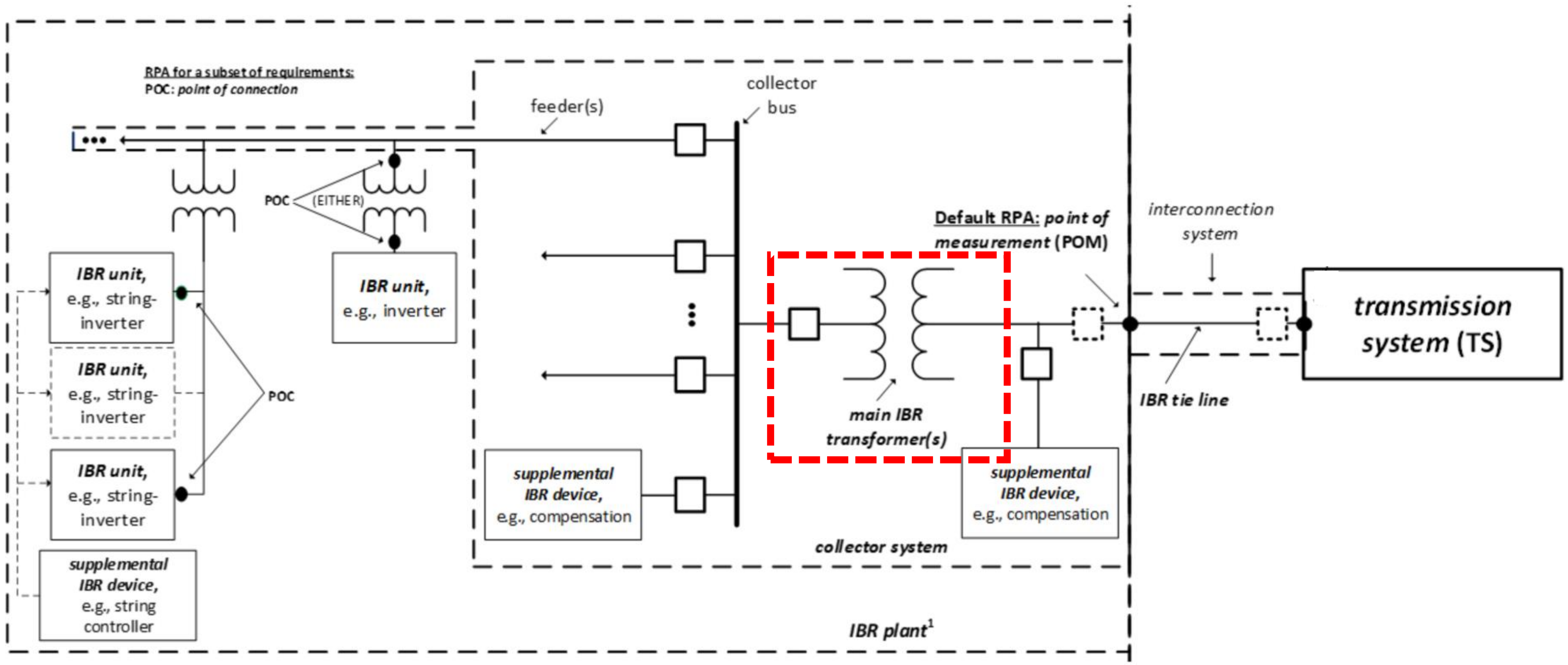


Source: Adapted from IEEE 2800-2022

- Many IBR tie lines are extremely short (hundreds of feet) and their impedance is often not included
- Tie lines are important outside of just their impedance
  - Different regional requirements apply at sending or receiving end of tie line
  - Tie lines are often used for controller feedback in the model space
- Data comes from IBR plant developer or their consultant:
  - Construction drawings
  - Cable schedules
  - Cable cutsheets

Components of an IBR Plant – Main Power Transformer

Main IBR transformers: also known as main power transformers (MPT) are frequent causes of incorrect representation

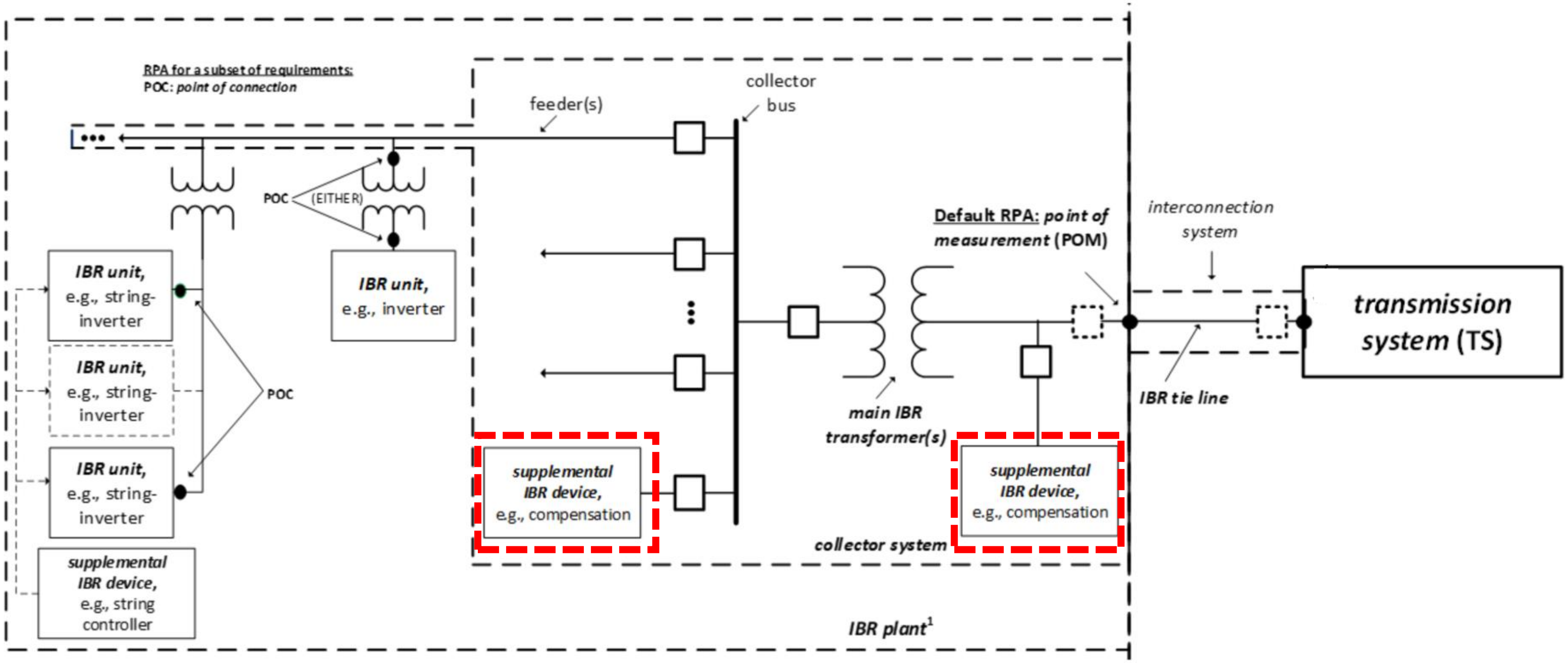


Source: Adapted from IEEE 2800-2022

- MPT are important control devices at the IBR Plant
  - Offload tap changers
  - Onload tap changers
    - Deadbands, step size, step number
- Transformer characteristics are crucial
  - Impedance base in the software may be default or specified
  - Transformer documentation can be confusing
  - Prone to data errors when moving between software tools
- Simulations often are not run long enough to incorporate MPT dynamics
- Data comes from IBR plant developer or their consultant
  - Factory Acceptance Tests
  - Saturation characteristics

Components of an IBR Plant – Supplemental Devices

Supplemental devices are often critical when representing IBR performance and capability

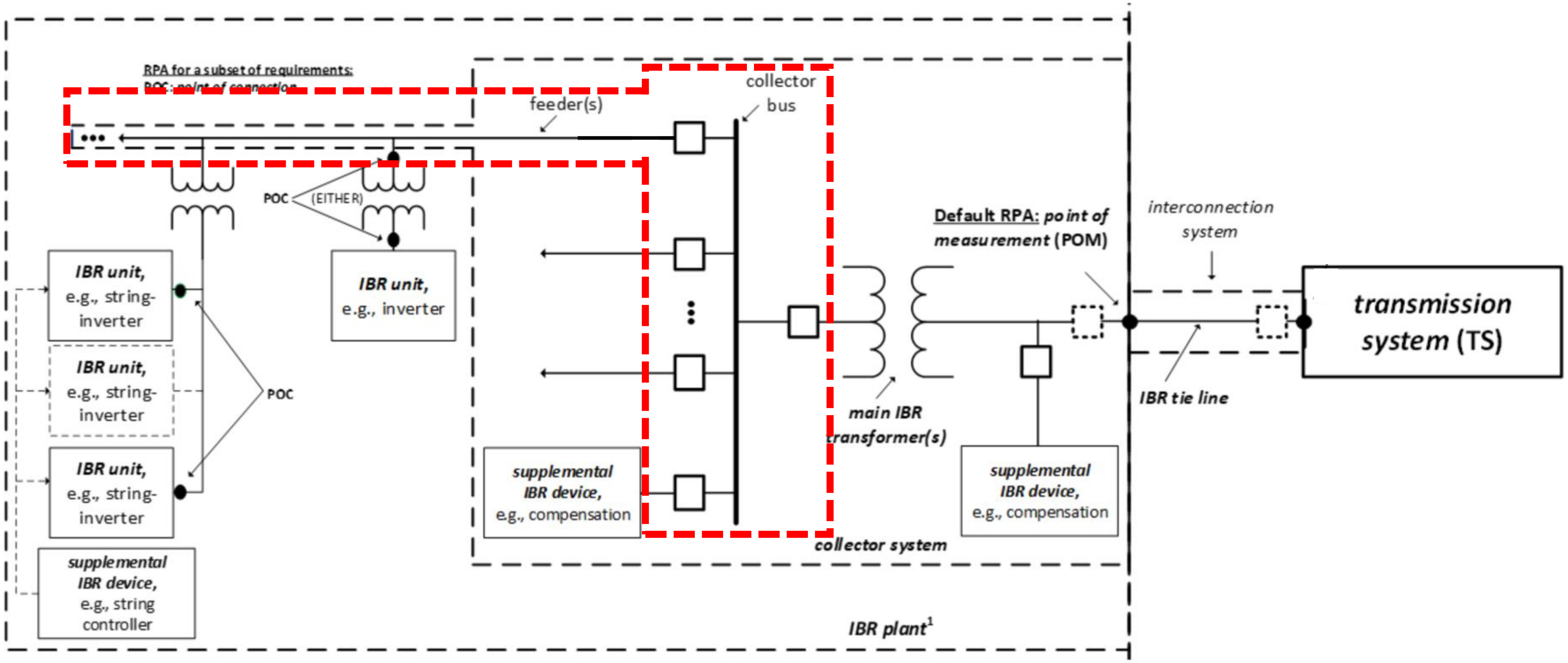


Source: Adapted from IEEE 2800-2022

- Supplemental devices add additional capabilities to the IBR Plant design
  - Fixed shunts (capacitors or reactors)
  - Switched shunts
  - Communication devices
    - Time delays and sample times
- In steady state:
  - Represent size and type of device to be used for capabilities
- In dynamics:
  - Need to consider communication, stepping logic, triggers, and other controls
- Data comes from developer or their consultant
  - Control drawings
  - Construction drawings
  - Third party control vendors

Components of an IBR Plant – Collector System

Collector systems vary widely among different types of IBR plants, but general layout is the same

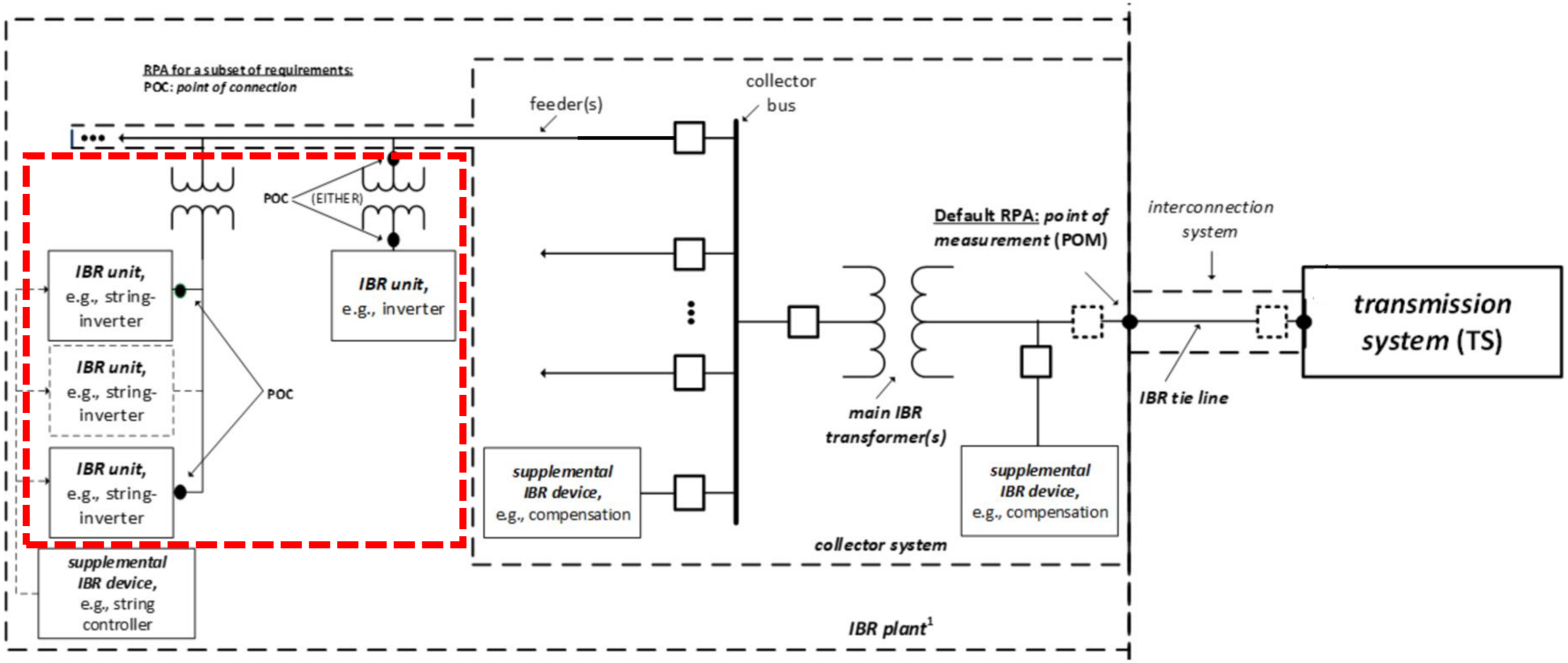


Source: Adapted from IEEE 2800-2022

- Composed of numerous components
  - Substation collector buses
  - Cable sections and junctions
  - Protective relays
- With so many components, errors are easy to make
  - Incorrect cable types
  - Incorrect distance data
  - Problems with in-house automation and aggregation
- Data comes from developer or their consultant
  - Construction drawings
  - Cable cutsheets
  - Protection documentation

Components of an IBR Plant – Inverters

Easy in the steady state, much more difficult in dynamic simulation

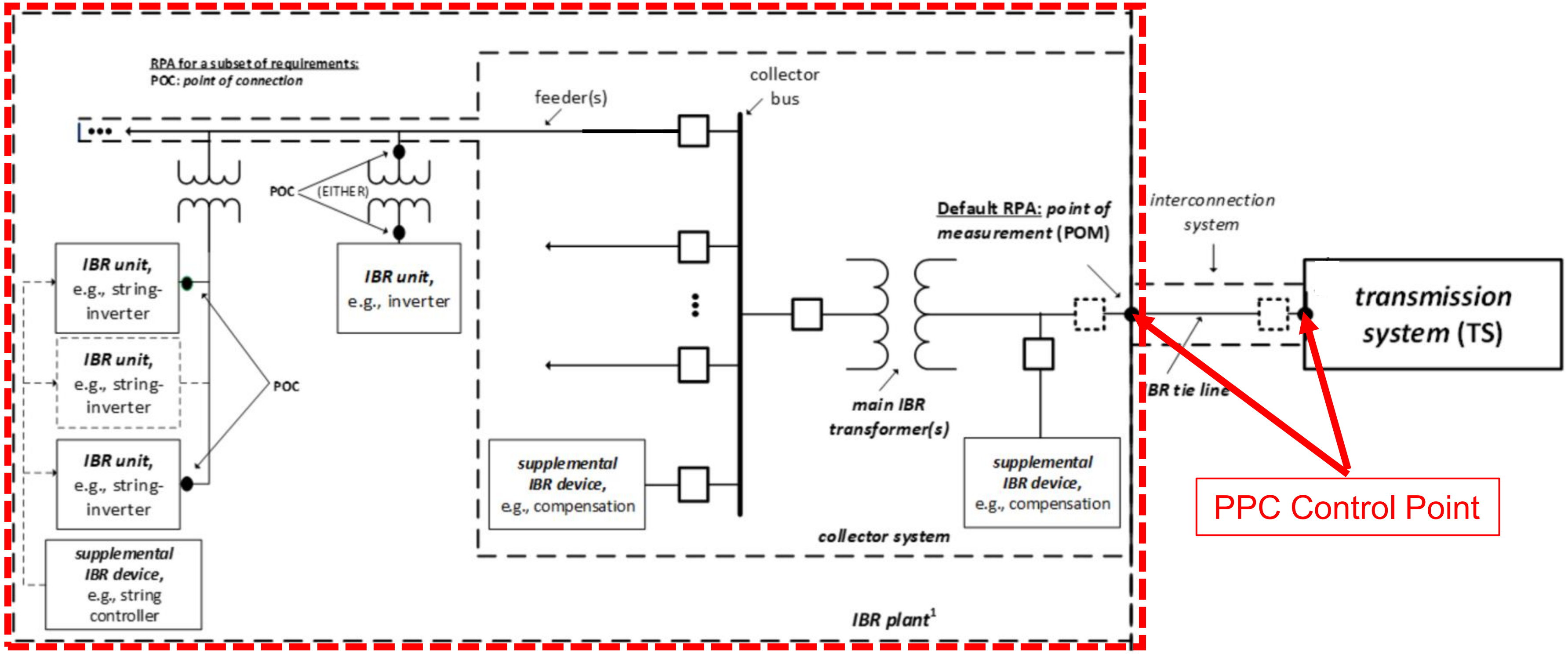


Source: Adapted from IEEE 2800-2022

- "Inverter" means OEM provided equipment
  - Could include in inverter model and generator step-up transformer (GSU)
  - Could have this information included in one component and connect directly to collector voltage
- In steady state: inverter models are relatively simple and are comprised of easy to transpose data from the OEM
  - Represent capabilities of the inverter
  - Contain the correct data to link to dynamic models
- In dynamics:
  - Actual performance must be represented based on level of detail and type of study
- Data comes from developer or their OEM
  - Inverter active power capabilities
  - Inverter reactive power capabilities
  - GSU impedance and tap settings

Components of an IBR Plant – Plant Controller(s)

Power plant controller(s) work to operate the IBR plant during normal operations and coordinate plant-wide performance



- Not included in steady state models
- May be standalone controller or part of multiple PPC control scheme
  - Needs to also coordinate with supplemental devices and MPT controls
  - Difficult to manage multiple OEM and control vendors
- Data comes from developer, Inverter OEM, or their PPC OEM
  - OEM plant controller documentation
  - Third party documentation
  - Communication protocols

Source: Adapted from IEEE 2800-2022

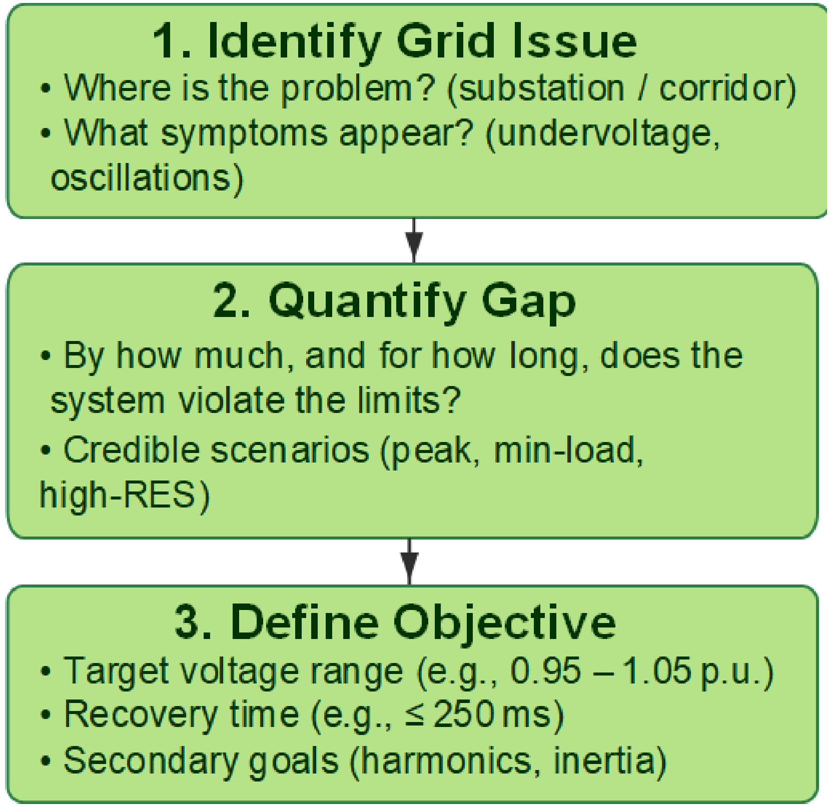
STATCOM Sidebar!

Topic Change

STATCOM and voltage control…

- Process for STATCOM procurement:

(source: Functional Performance requirements for GFM STATCOM – 2025 IEEE PES GM)



Extra Functional STATCOM Requirements:

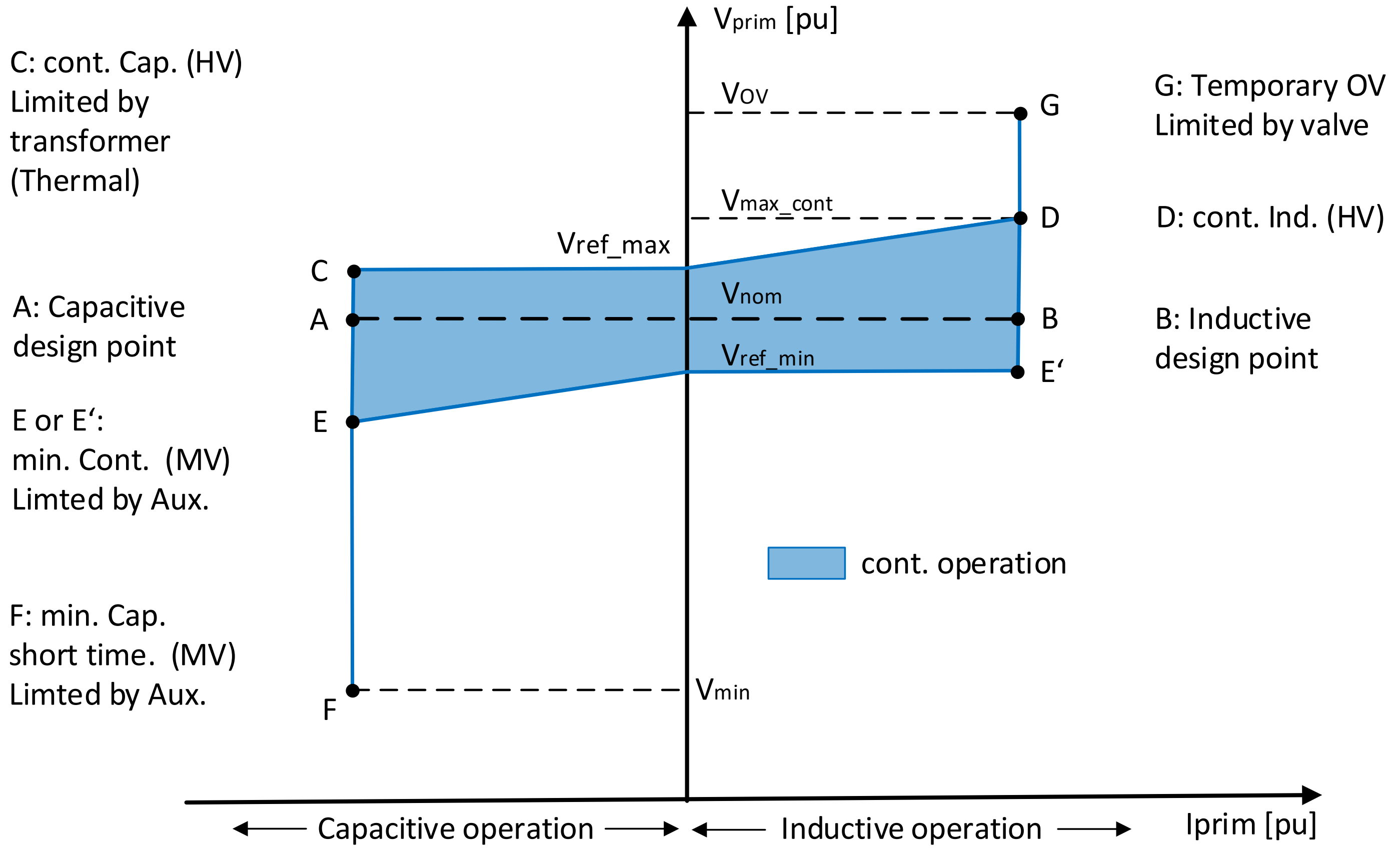
You decide… do you need:

1. Active harmonic cancellation
2. Redundancy/Automatic failover
3. Power Oscillation damping
4. Degraded Modes
5. Negative Sequence Cancellation
6. Slow reactive power control (dynamic reserve)
7. Stability supervision and gain adjustment
8. Automatic gain setting based on fault level
9. Coordination between multiple STATCOMs
10. Manual VAR control
11. Flicker control
12. Black start / energization support (special ride-through)
13. Grid-forming control

(source: Functional Performance requirements for GFM STATCOM – 2025 IEEE PES GM)

Operational points for STATCOM rating

Hello!

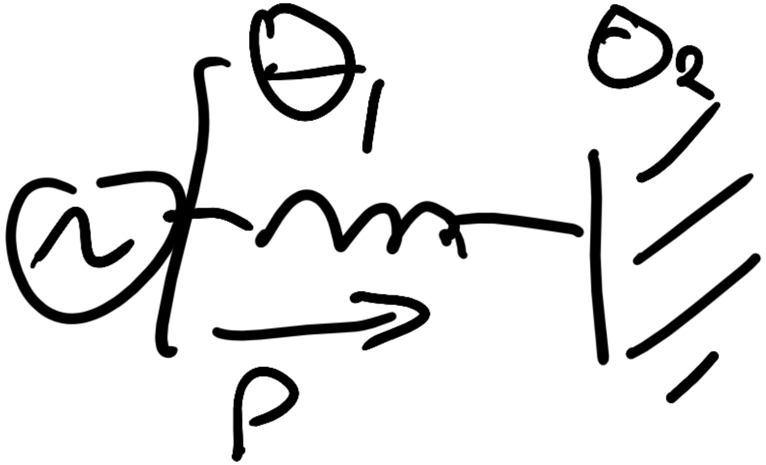


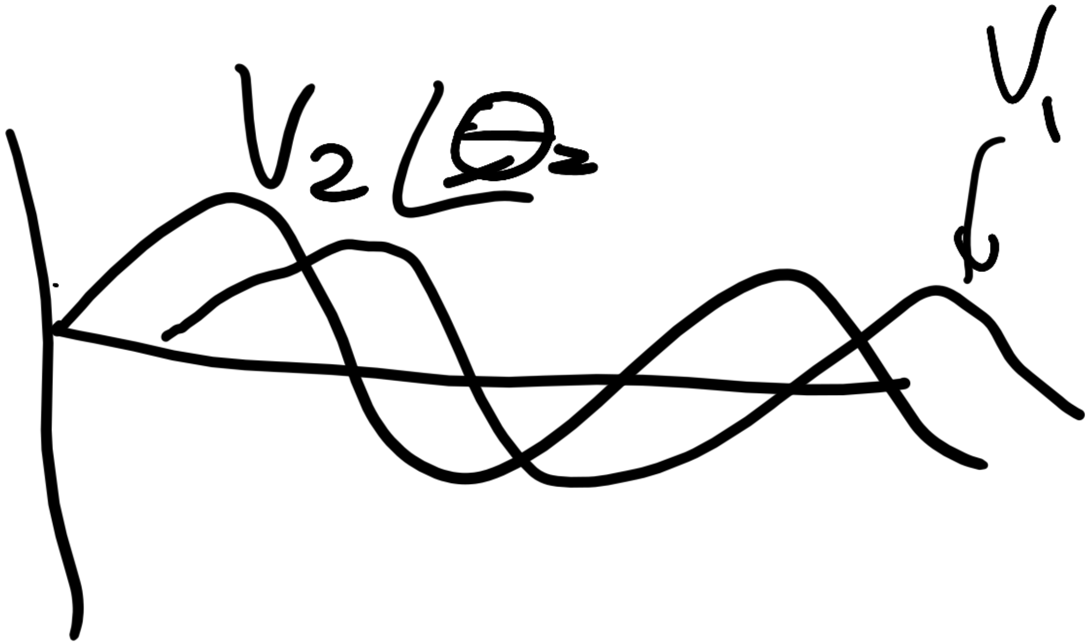
(source: Functional Performance requirements for GFM STATCOM – 2025 IEEE PES GM)

Introduction to IBR controls

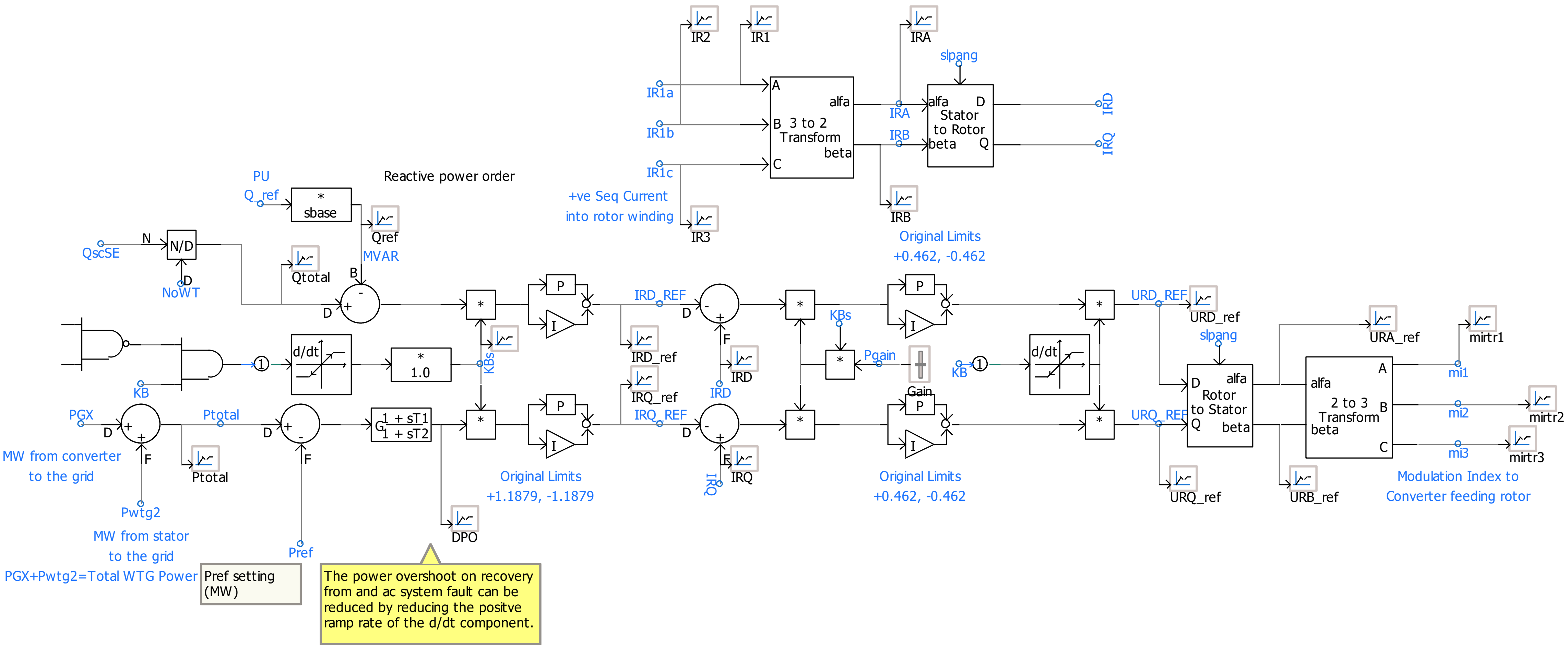
Topic Change

Reminder of high level VSC concept and control objective…

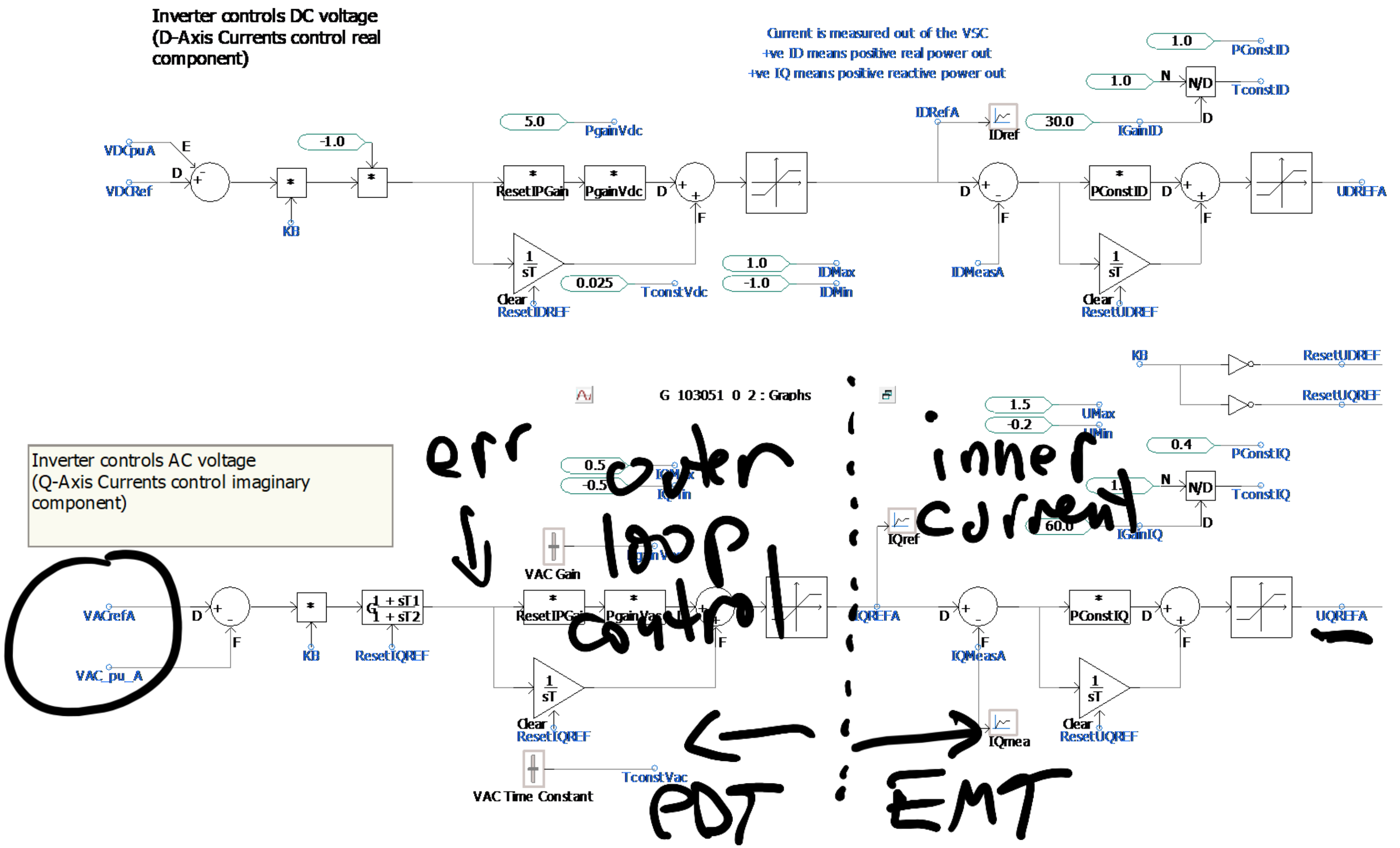




Outer and Inner Controls

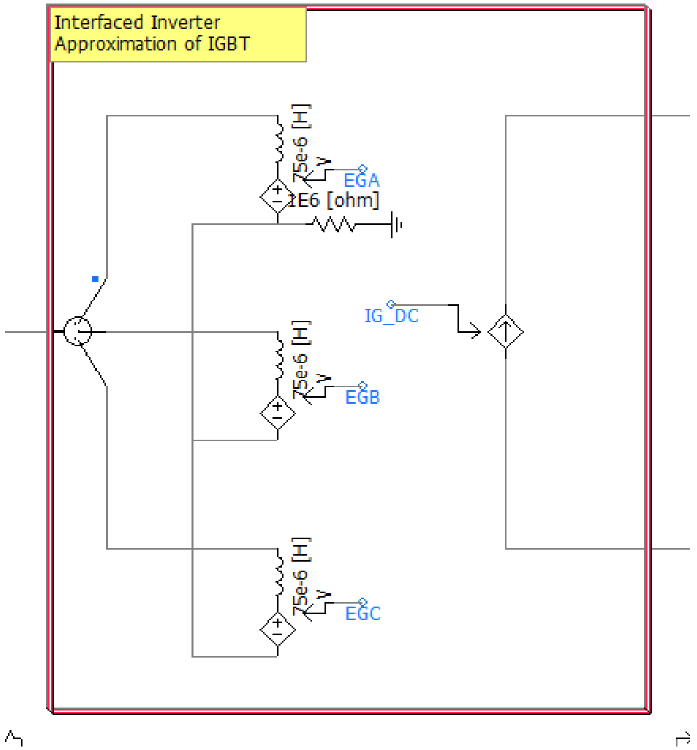


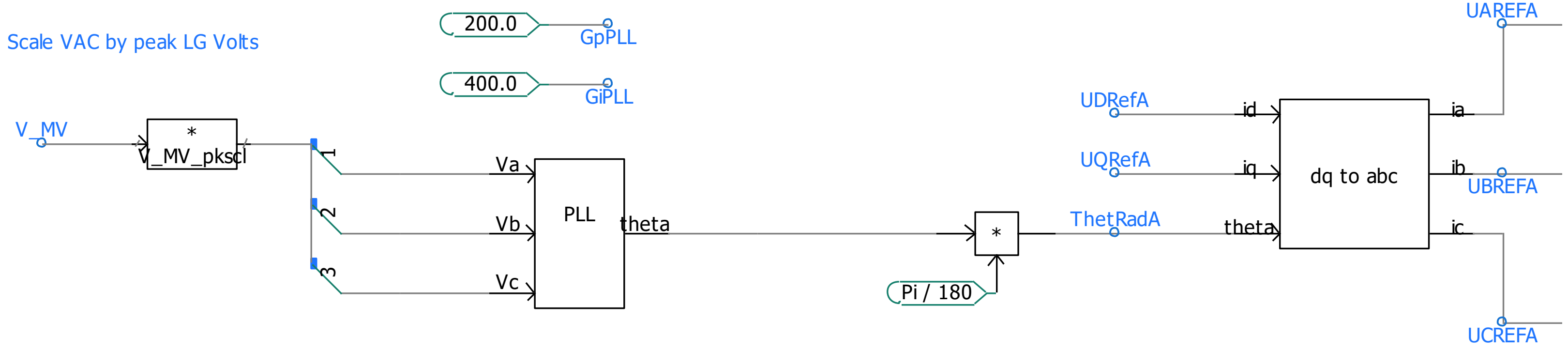
Outer and Inner Controls



PLL and firing controls

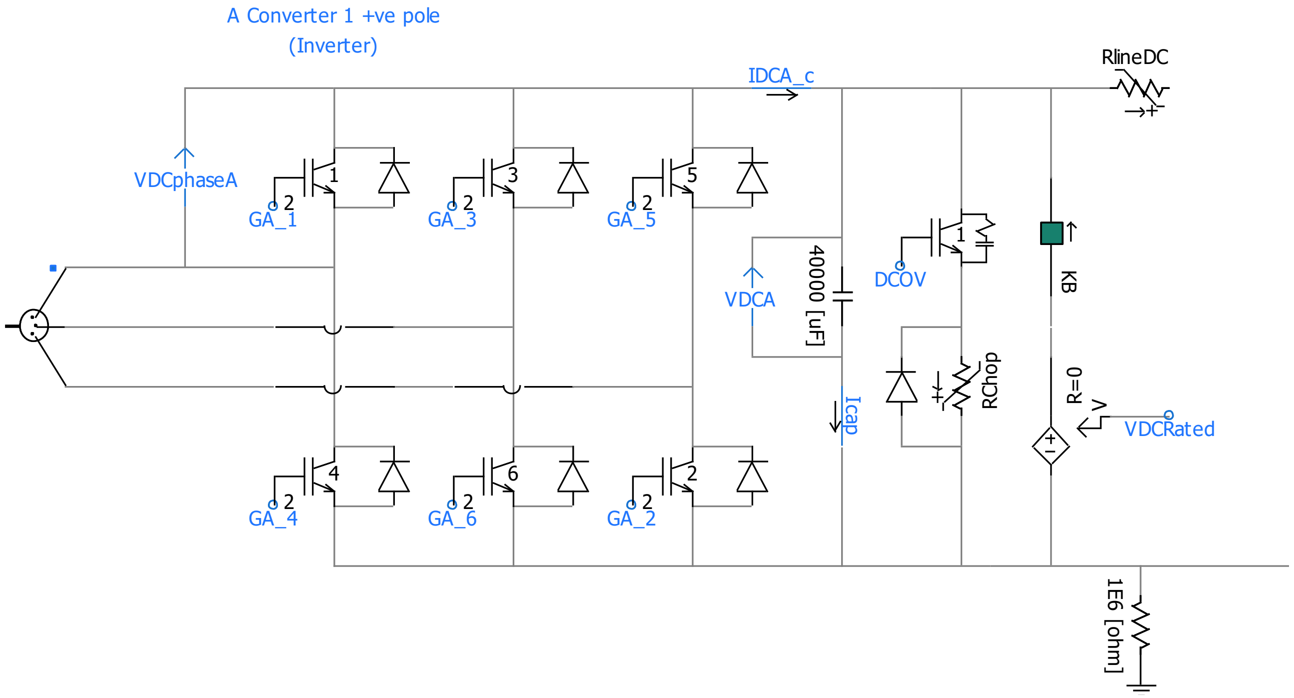
- Simplified voltage source approximation of IGBT bridge (average source model):





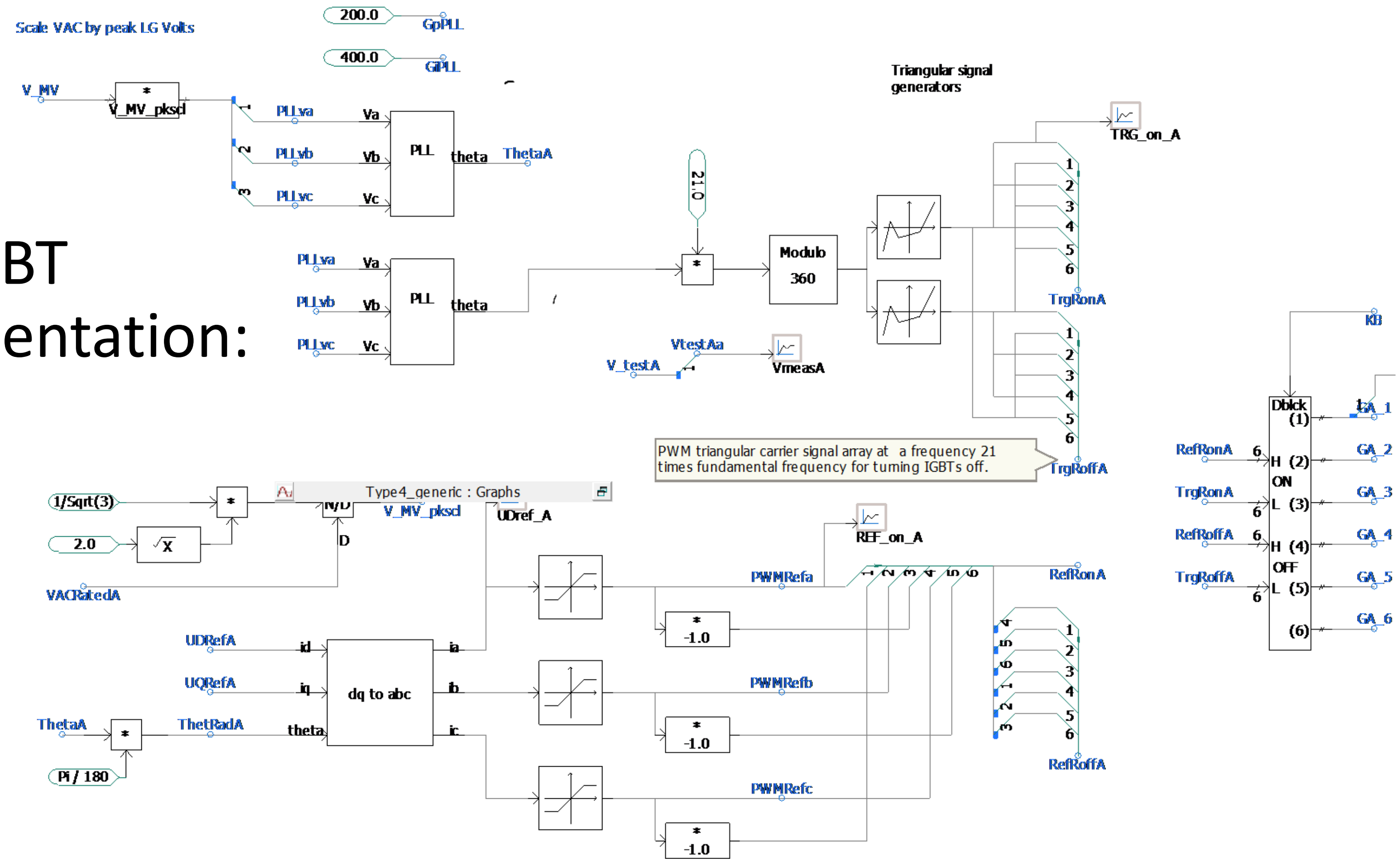
PLL and firing controls

- Full IGBT representation:



PLL and firing controls

Full IGBT representation:



Discussion on Validation

Topic Change

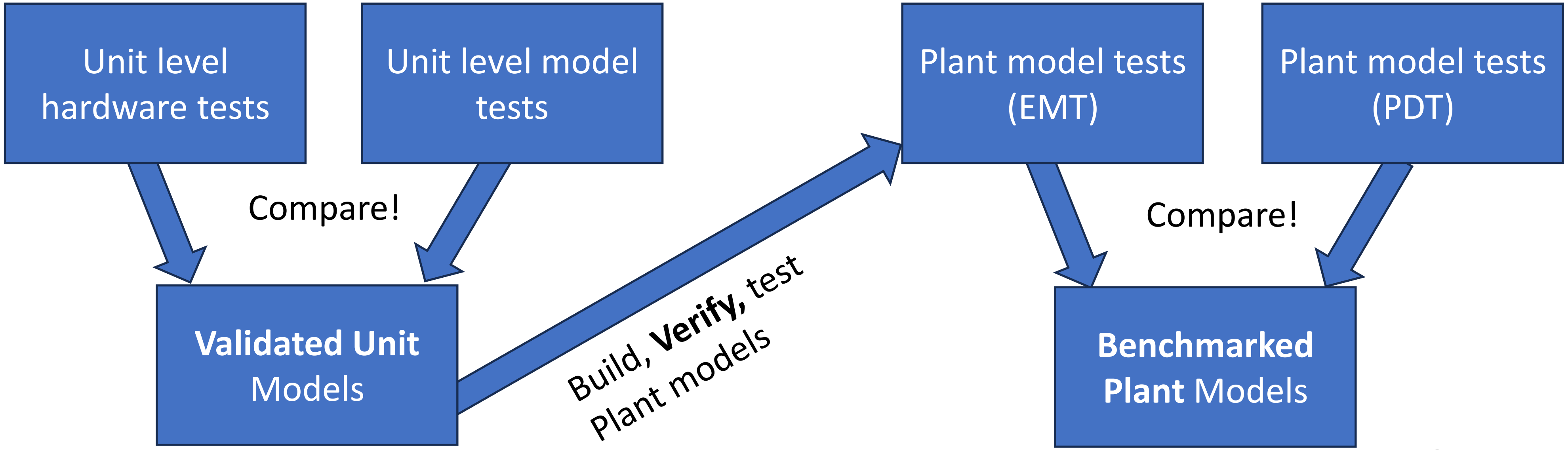
Disclaimer!!

- I have experiences and opinions which may differ from others (especially in the 2800 drafting groups)!!
- **Where the following slides are good, then I am representing the SG3 leadership team. Where the following slides are wrong or bad, I am representing myself!! ☺**

Acknowledgement: Much hard work and discussion from members of 2800.2 drafting team. In particular, manufacturer teams helped us a lot!

Definitions:

- **model validation:** The process of comparing measurements with simulation results for the assessment of whether a model response sufficiently mimics the measured response.
- **model benchmarking:** the process of comparing simulation results from two models for the assessment whether a response from one model sufficiently mimics the response from the other model for the same disturbance and external power system conditions
- **model verification:** The process of checking documents and files or equipment and respective settings (e.g., controls & protection), and comparing them to model parameters or model structure.



Source: IEEE ©2024

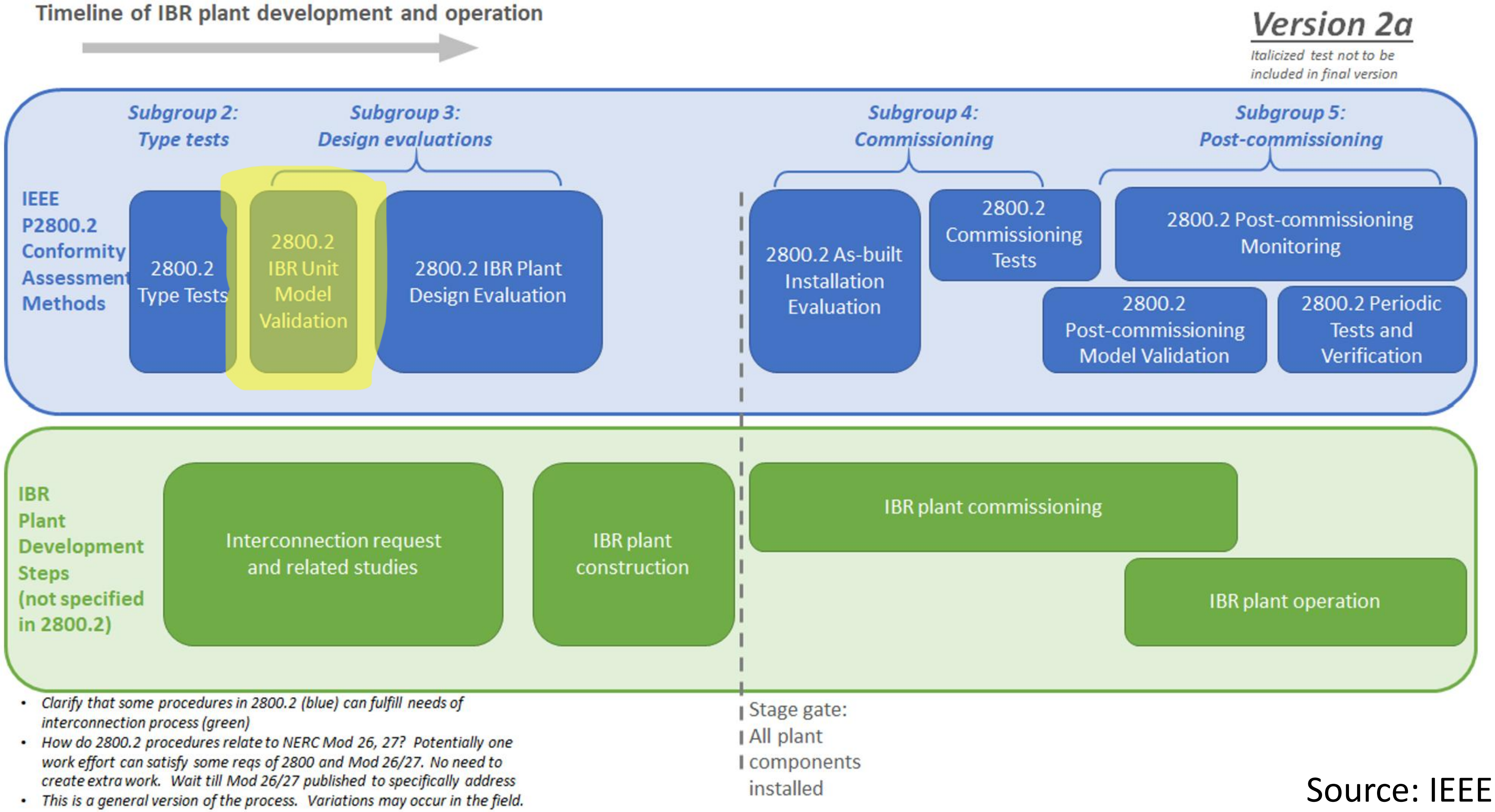
Why do we care?

- Reliability!
  - Studies accurately predict system performance
    - (verified) Plant models accurately represent what is constructed and how it is configured
      - (validated) Unit equipment models accurately represent the controls and protection functions…

IEEE 2800-2022 requires validation!!

Per IEEE 2800 Clause 12 (Test and verification requirements), *the original equipment manufacturer (OEM) shall perform IBR unit level testing and testing of the supplemental IBR device equipment*. The details of these equipment-level type tests to be performed are listed in clause 5.

Where does validation sit in the process?



- *Clarify that some procedures in 2800.2 (blue) can fulfill needs of interconnection process (green)*
- *How do 2800.2 procedures relate to NERC Mod 26, 27? Potentially one work effort can satisfy some reqs of 2800 and Mod 26/27. No need to create extra work. Wait till Mod 26/27 published to specifically address*
- *This is a general version of the process. Variations may occur in the field.*

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What validation test sets are being proposed?

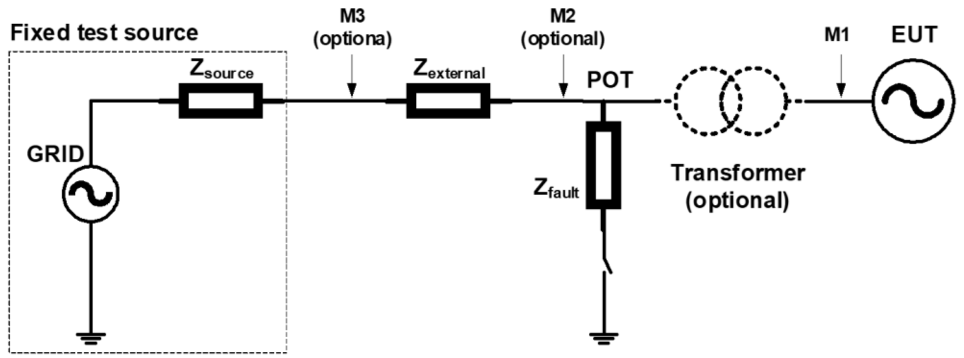


Figure 16—Test circuit for method 1

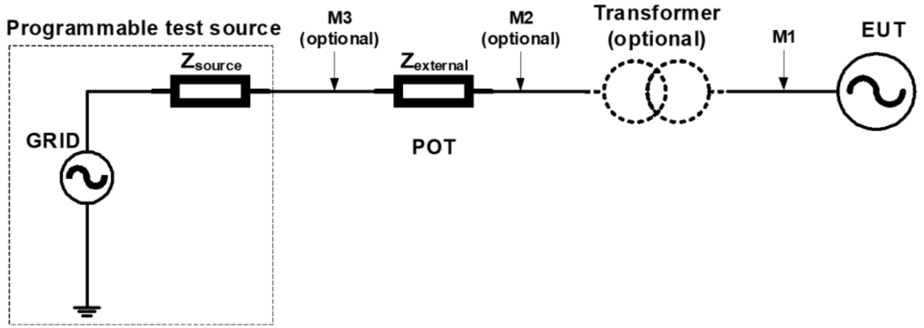


Figure 17—Test circuit for method 2

- Method 3: Control Hardware In the Loop (CHIL)
  - Connect control hardware to real-time EMT simulator test benches

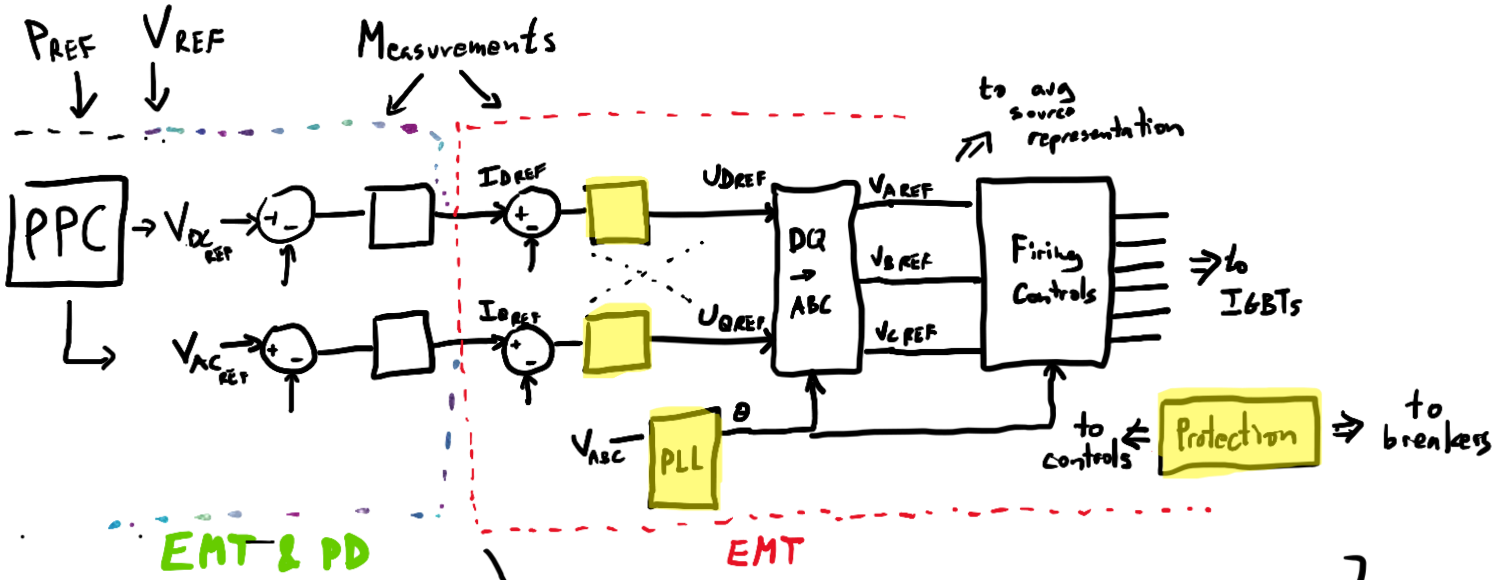
Source: IEEE ©2024

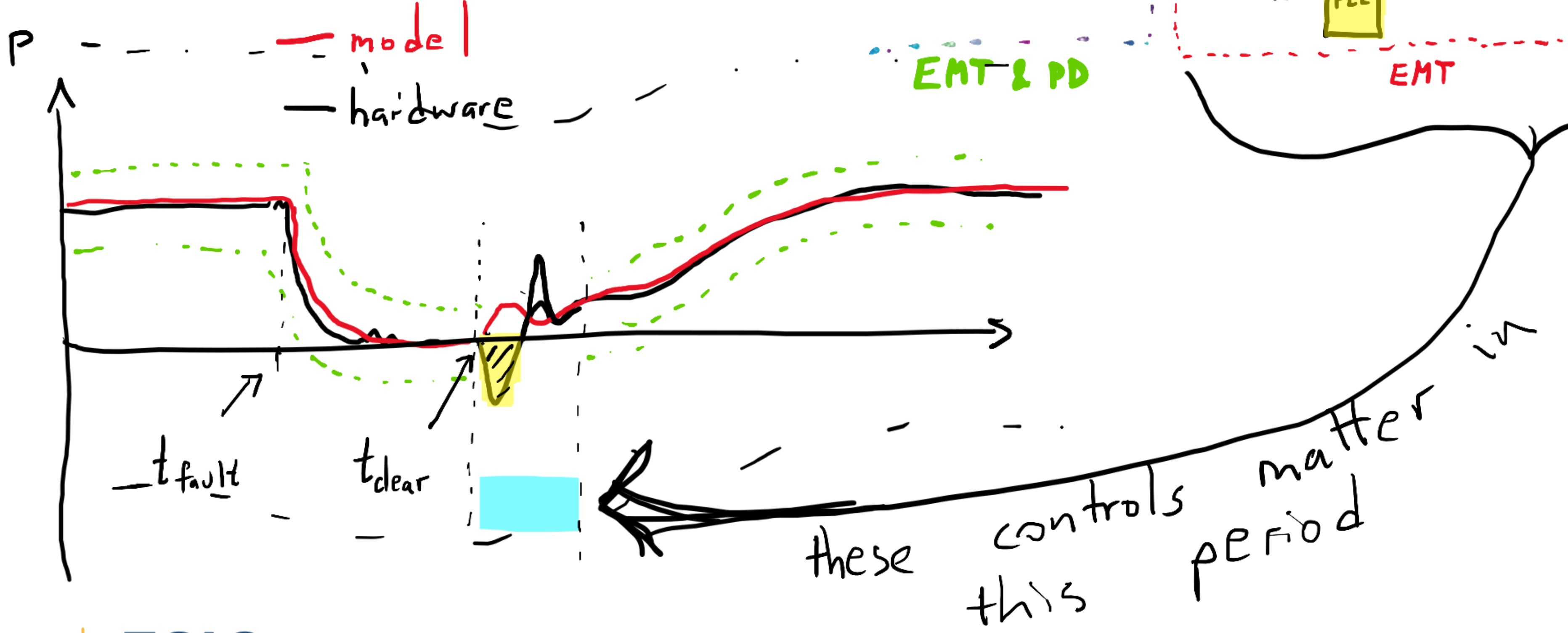
What will be validated?
(models compared against type tests)

1. Voltage and reactive power control modes – Clause 5.7.4
2. Primary Frequency response – Clause 5.9.4
3. Fast Frequency response – Clause 5.9.4
4. Voltage disturbance ride through – Clause 5.11.4 to 5.11.8
5. Frequency disturbance ride through – Clause 5.13
6. Limitation of overvoltage over one fundamental frequency period – Clause 5.14.4
7. PPC Testing – Clause 5.17
8. Frequency Scanning
9. Protections – Clause 5.15
   a. Frequency protection
   b. ROCOF protection
   c. Voltage protection
   d. AC overcurrent protection
   e. Unintentional islanding protection

Source: IEEE ©2024

Unit Validation challenge!





Note that hardware and model may both “ride-through” in Validation testing, but accuracy and correctness is needed in each aspect to ensure confidence in ride-through behaviour in plant and system contexts.

What gets in the way of close comparisons?

- Insufficient care in modeling practice.
  - Developing good EMT modeling practice takes time and a strong investment in modeling by OEMs.
  - “real code” techniques and appropriate processes are needed

- Uncertainties in test system conditions (for example)
  - Nonlinearities (eg. Transformers)
  - Point-on-wave impacts
  - Measurement error
  - Simulation artifacts

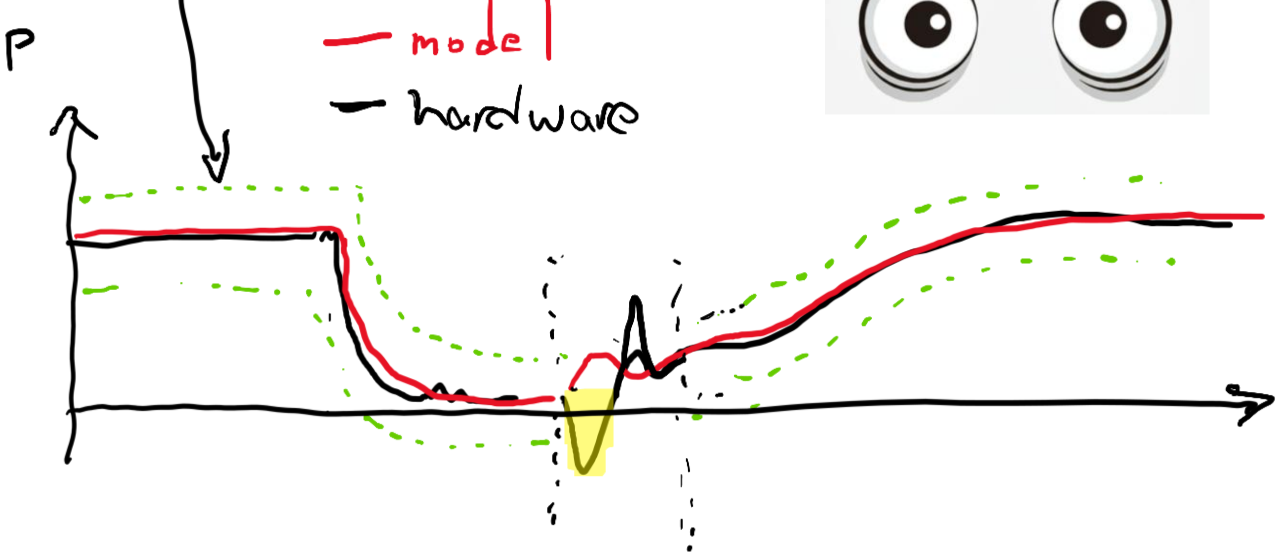
Quantitative and Qualitative

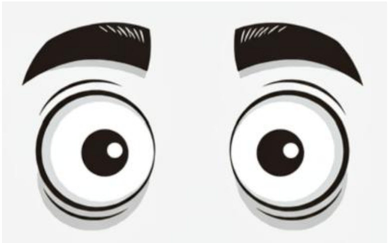
- Huge point of discussion in 2800.2… possibly the most contentious part of the entire standard. A few discussions were *lengthy.*
  - Where should the quantitative bands be drawn?
  - “Should we even use quantitative metrics at all?”

Which is best? ☺

Quantitative

Qualitative

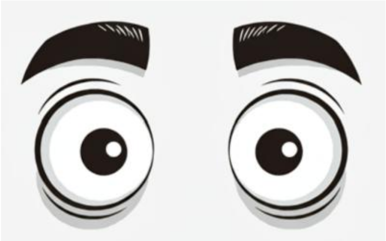




Quantitative: Pros and Cons

- Pros:
  - Can standardize model quality to a degree. Repeatable, transparent outcomes are desirable.
  - Can automate the evaluation
  - Can theoretically be performed with little experience
- Cons:
  - **False "pass":** If bands are too wide, serious errors in modeling can be sent through as validated models.
  - **False "fail":** If bands are too narrow, legitimate differences may be flagged as errors and delay and headache is introduced.
  - Can theoretically be performed with little experience

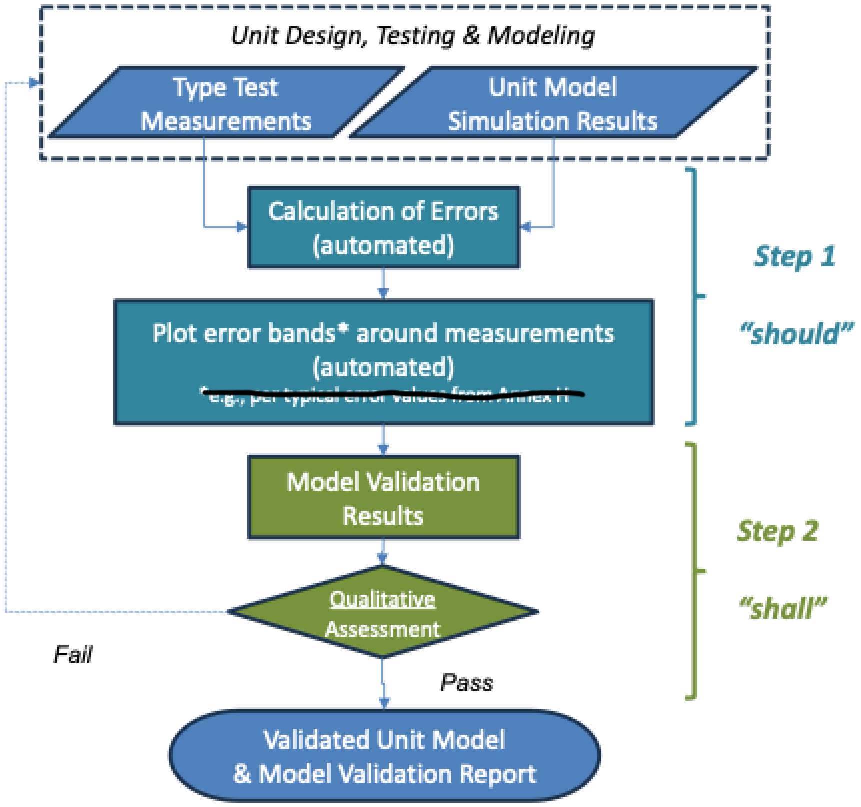
Qualitative: Pros and Cons



- Pros:
  - Experienced engineers can sufficiently evaluate whether the model is suited for purpose, and ask questions appropriately
  - When done well, effectively identifies important errors in models
- Cons:
  - There may not be enough “experienced engineers” to do this correctly at scale.
  - You can’t get help from automation tools. Large amounts of data can make any engineer’s eyes glaze over, regardless of experience.
  - Without standardization, opinions will differ on what is “acceptable”

(My) recommended approach:

- OEM (could be other parties) writes a "validation report" that includes:
  - Use quantitative comparison as guidance to identify regions that lie outside appropriate error bands
  - Engineering review and discussion of comparisons which lie outside error bands
  - Qualitative comparison using expert engineers
- Recipient or users of unit level models should review the validation report and accept, reject, or ask questions as appropriate.



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Example quantitative bands (removed from current draft)

[Table X] – Permissible maximum errors when EUT is type tested by P-HIL testing method

Case description	**Time window**	**Positive- and negative-sequence values**							
		Active power		**Reactive power**		**Active current**		**Reactive current**	
		Transient	Quasi steady state	Transient	Quasi steady state	Transient	Quasi steady state	Transient	Quasi steady state
Case dependent information such as pre-fault voltage, test equipment settings such as short circuit impedance if used, etc.	Pre-fault	n/a	0.05	n/a	0.05	n/a	0.05	n/a	0.05
	Fault	0.2	0.15	0.2	0.15	0.2	0.15	0.2	0.15
	Post-fault	0.2	0.15	0.2	0.15	0.2	0.15	0.2	0.15

[Table Y] – Permissible maximum error when EUT is type tested in field

Case description	**Time window**	**Positive- and negative-sequence values**							
		Active power		**Reactive power**		**Active current**		**Reactive current**	
		Transient	Quasi steady state	Transient	Quasi steady state	Transient	Quasi steady state	Transient	Quasi steady state
Case dependent information such as pre-fault voltage, estimated grid Impedance, grid operating condition, etc.	Pre-fault	n/a	0.05	n/a	0.05	n/a	0.05	n/a	0.05
	Fault	0.2	0.15	0.2	0.15	0.2	0.15	0.2	0.15
	Post-fault	0.2	0.15	0.2	0.15	0.2	0.15	0.2	0.15

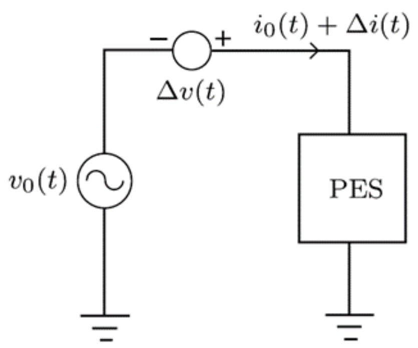
[Table Z] – Permissible maximum error when EUT is type tested by C-HIL testing method

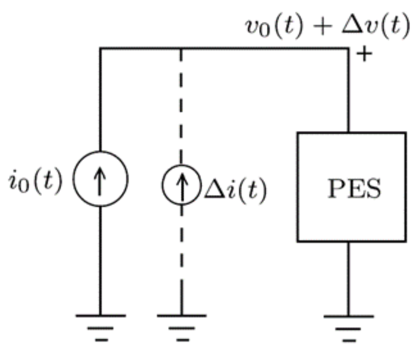
Case description	**Time window**	**Positive- and negative-sequence values**							
		Active power		**Reactive power**		**Active current**		**Reactive current**	
		Transient	Quasi steady state	Transient	Quasi steady state	Transient	Quasi steady state	Transient	Quasi steady state
Case dependent information such as pre-fault voltage, test equipment settings such as short circuit impedance if used, etc.	Pre-fault	n/a	0.05	n/a	0.05	n/a	0.05	n/a	0.05
	Fault	0.1	0.05	0.1	0.05	0.1	0.05	0.1	0.05
	Post-fault	0.1	0.05	0.1	0.05	0.1	0.05	0.1	0.05

Source: IEEE ©2024

Frequency Scans!!

- Variation of converter impedance characteristics with frequency is widely used in real studies, and happens to provide a good representation of the small signal control characteristics!
- We can use this for model validation!





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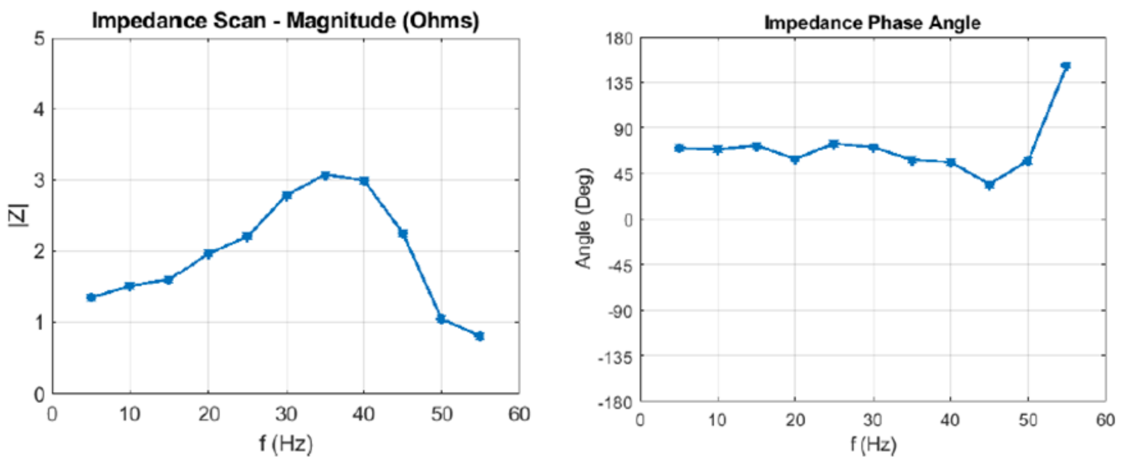
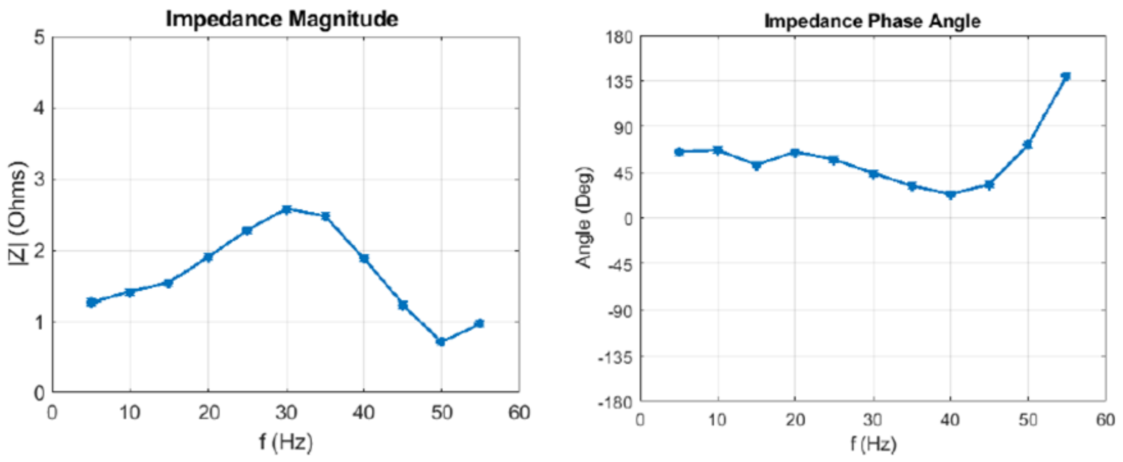
PSCAD Results



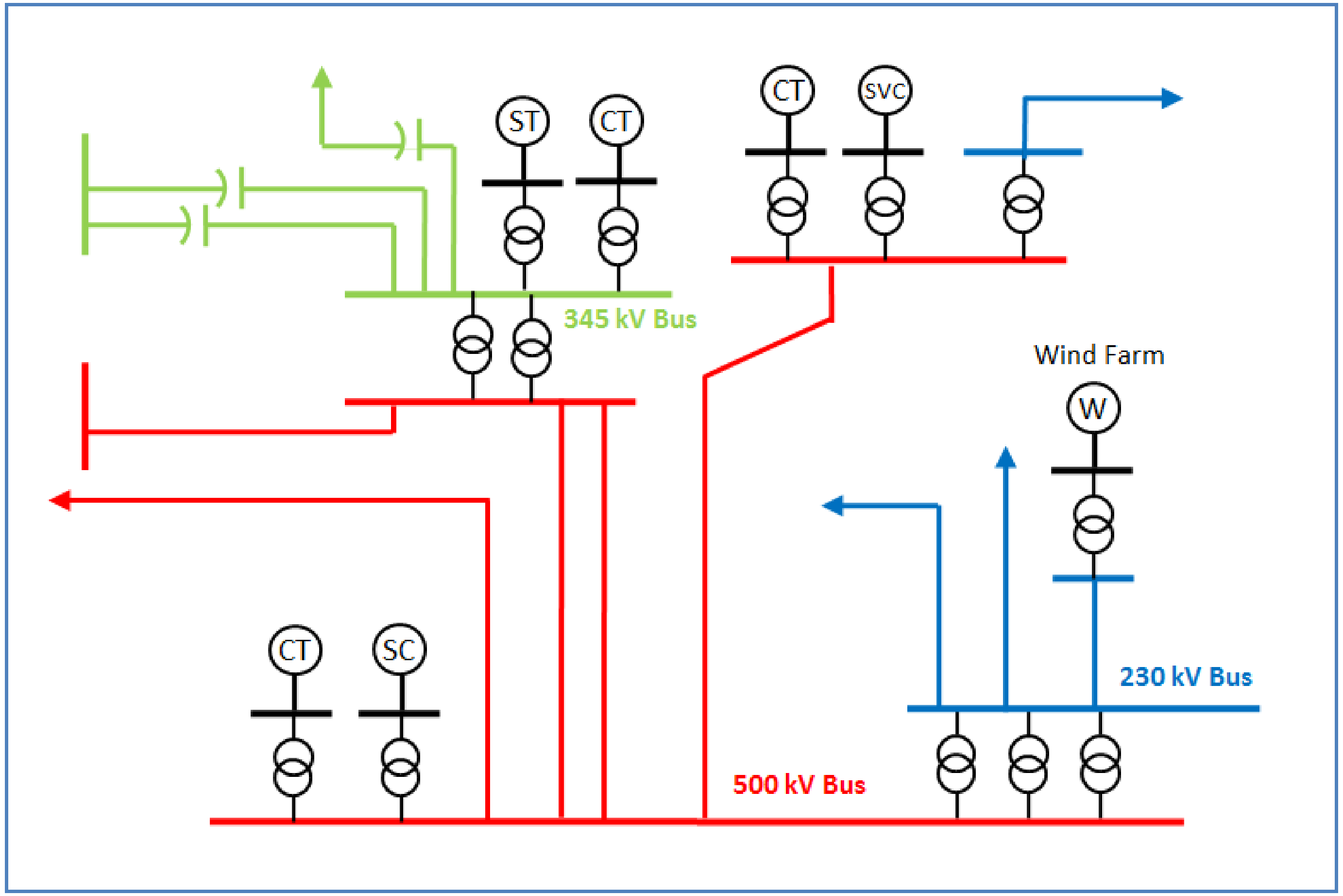
HiL-RTS Results



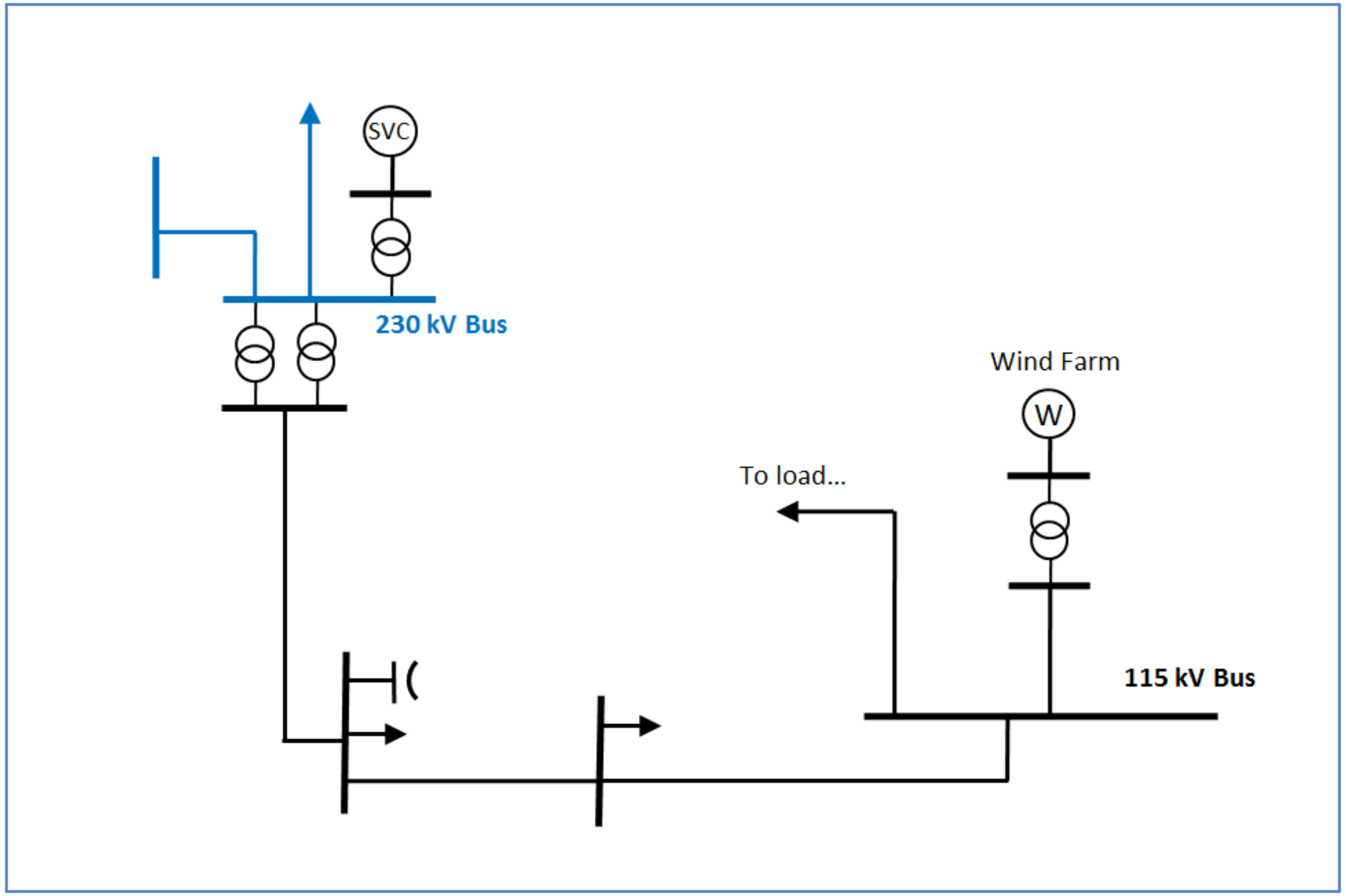
Weak Grid Concepts and System Strength Metrics

Topic Change

What is a *strong* system?

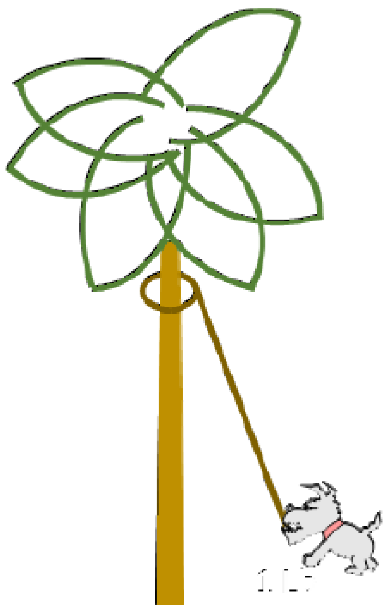


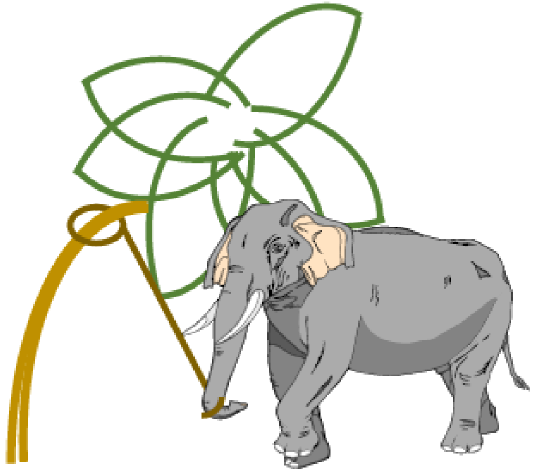
What is a *weak* system?



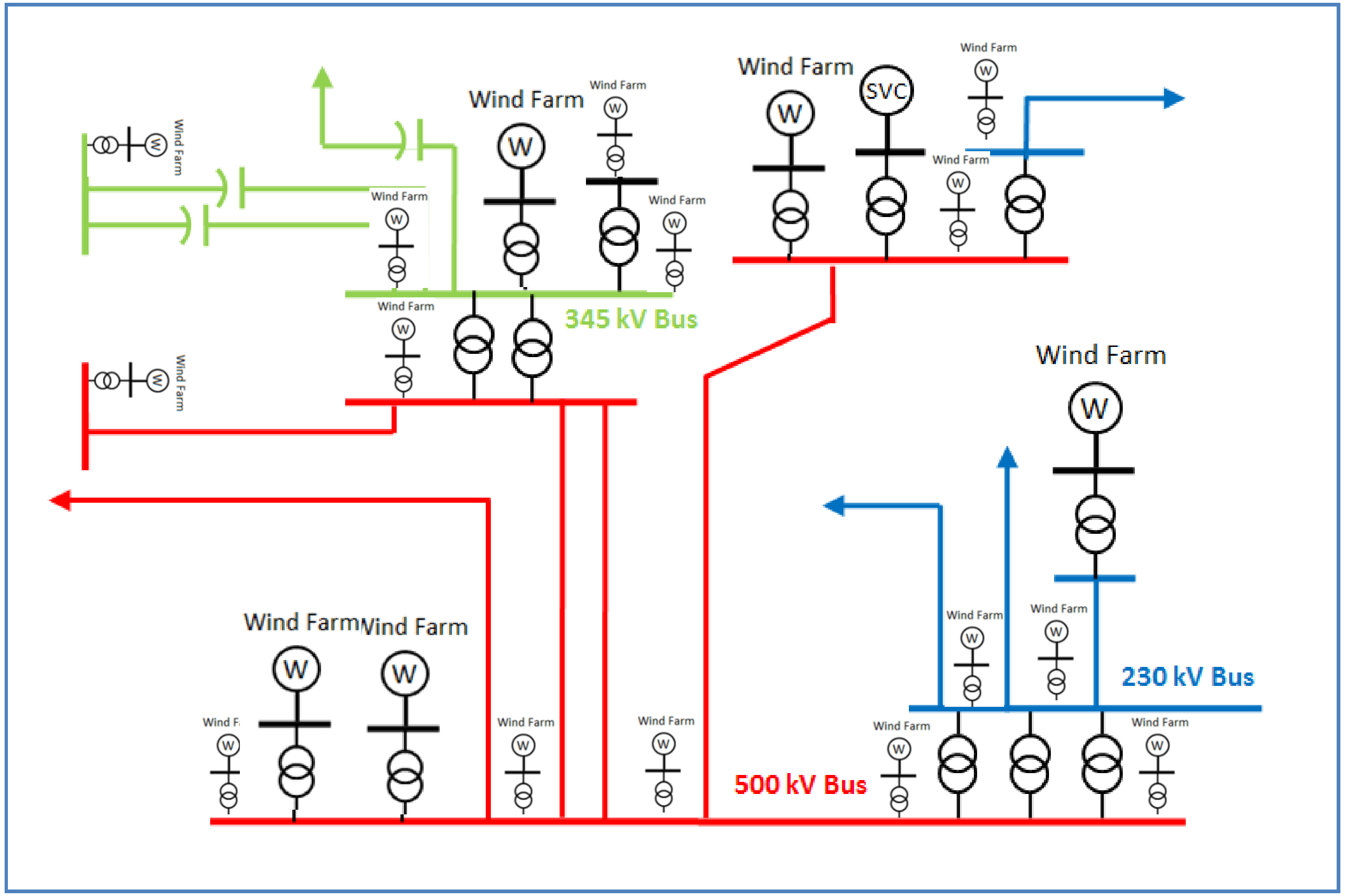
Is the network *relatively* weak or strong?

- The size of the wind farm ***relative*** to the strength of the system is a useful metric… *(Figure courtesy NREL/GE)*





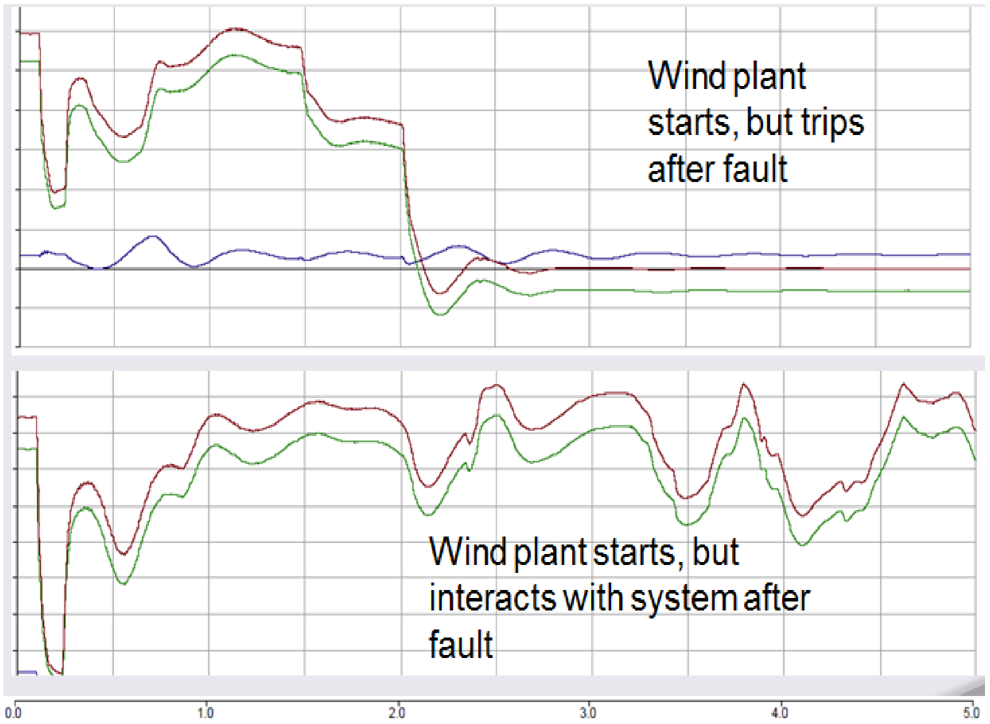
What is a *weak* system in Texas?



Technical Issues in Weak Grids

- Failure to ride through disturbances
  - Plant may trip following a network disturbance, leading to wider system issues, such as under-frequency or loss of voltage support.
  - Weak systems make ride-through more difficult

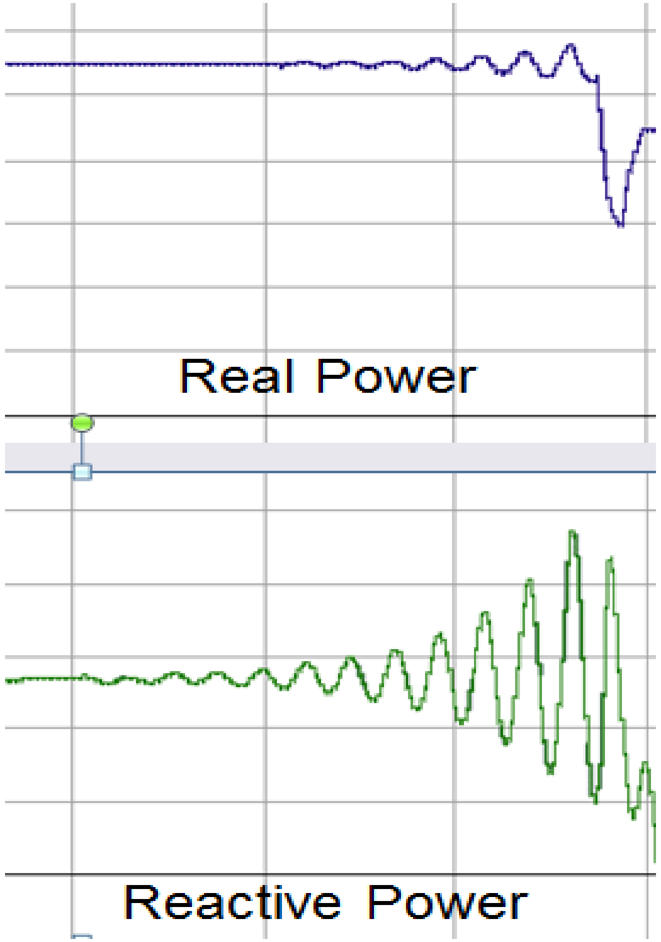
- Control interactions
  - The weaker the interconnection, the more likely controls will be to influence each other and interact negatively with each other or with the system.



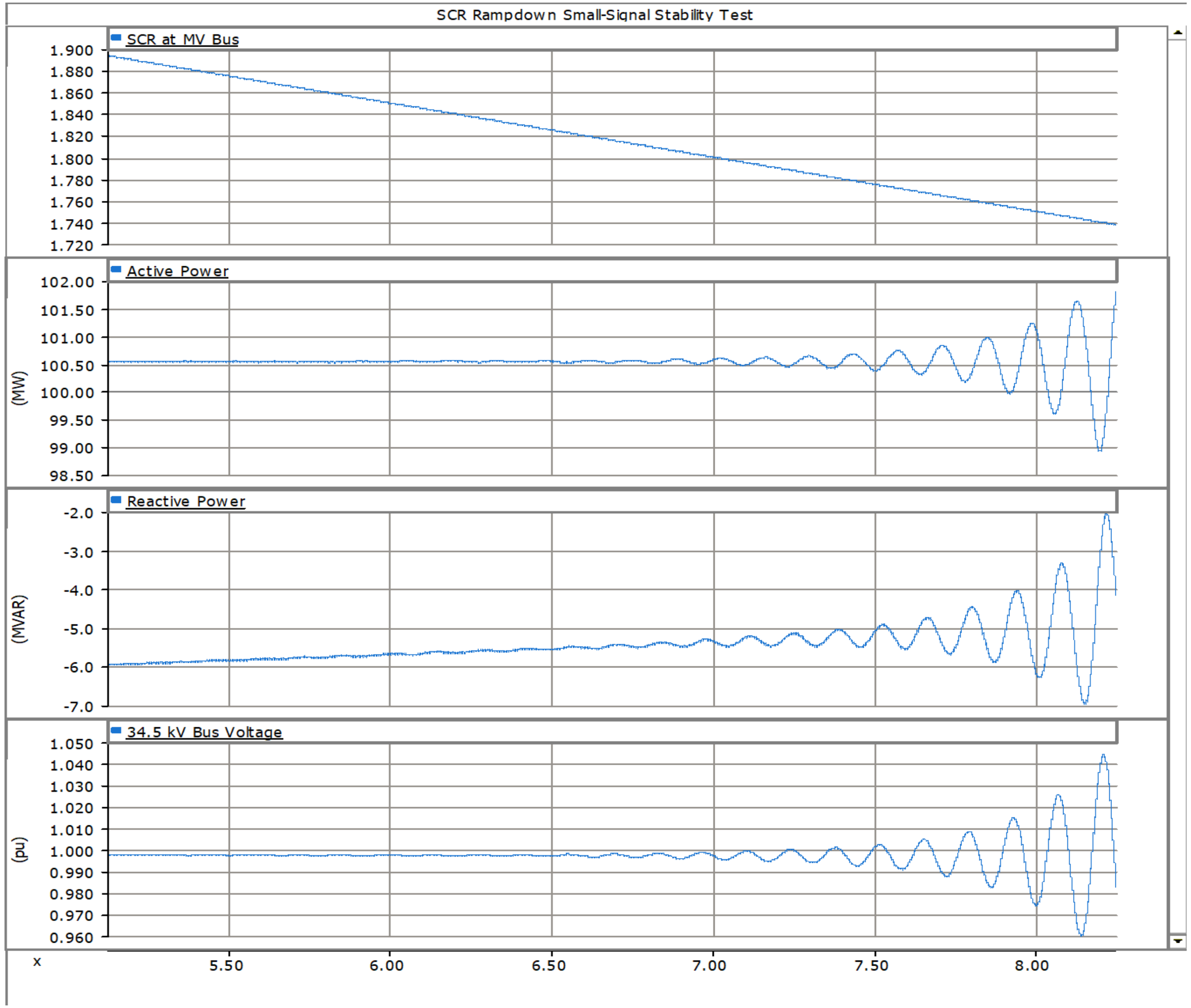
Technical Issues in Weak Grids

- Control instability
  - If the network is weak enough, controls may enter unstable region with no external influence needed (small signal instability)

- Example
  - Wind farm located in Western Canada on a long radial connection, SCR approx. 1.2

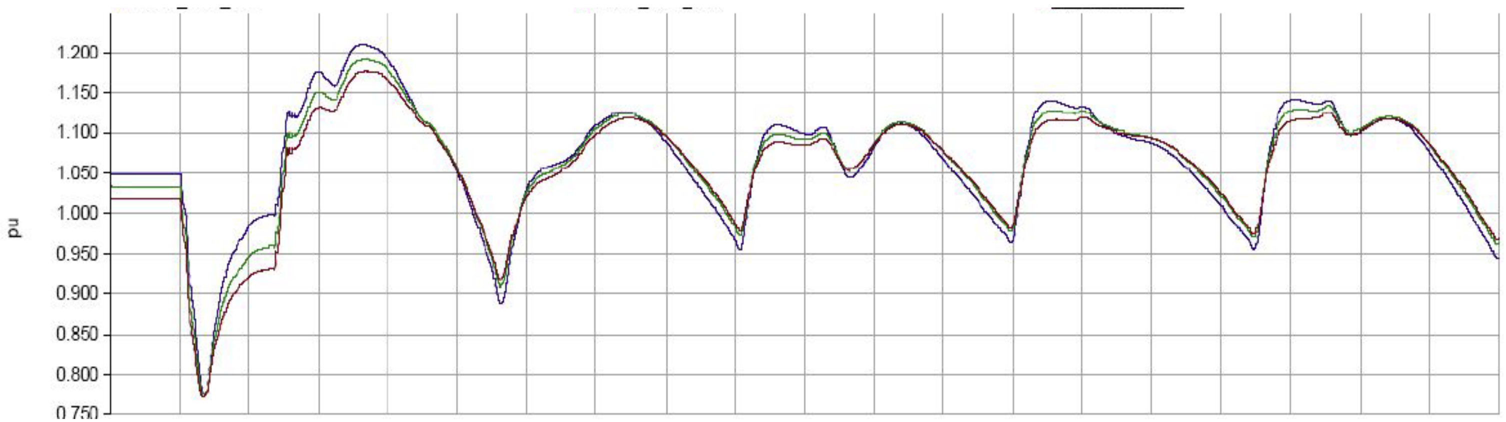


Small Signal Control Instability

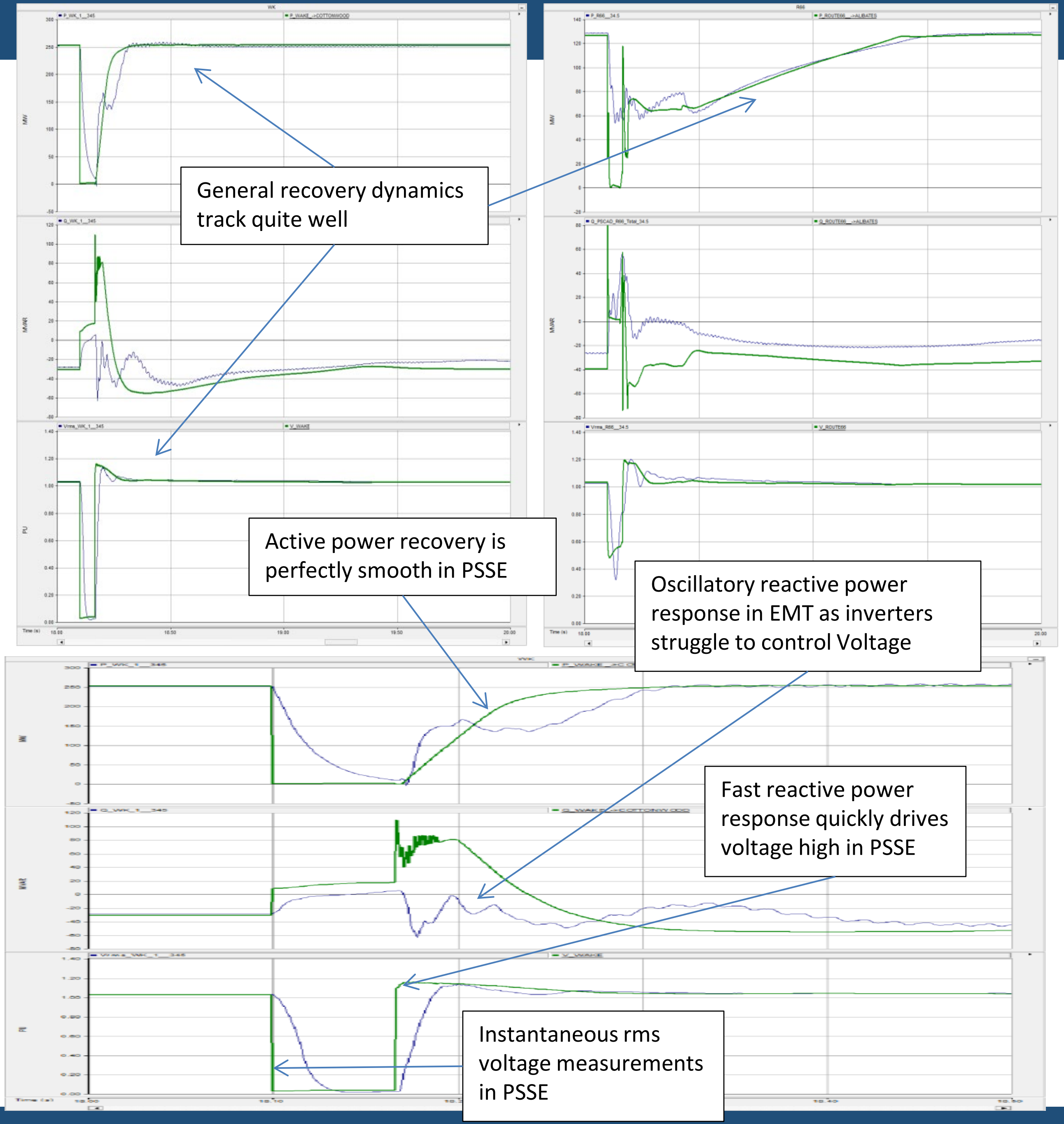


Technical Issues in Weak Grids

- Cycling between turbine control modes
  - Turbine controls may have special control modes to handle fault ride through (eg. reduce active power, tightly control terminal voltage, gently ramp active power back up to rated values)
  - If system is weak, control modes may be invoked multiple times as turbine attempts recovery, introducing severe transients into the system.



Transient Stability Limitations: Texas example:



SCR Definition

- The relative strength of the ac system, the IBR/FACT/HVDC is connecting to, is often parameterized by an index called the short circuit ratio or SCR.

$$\boldsymbol{Short\ Circuit\ Ratio\ (SCR) = \frac{Short\ Circuit\ MVA\ (SCMVA)}{Rated\ Power\ (Prated)}}$$

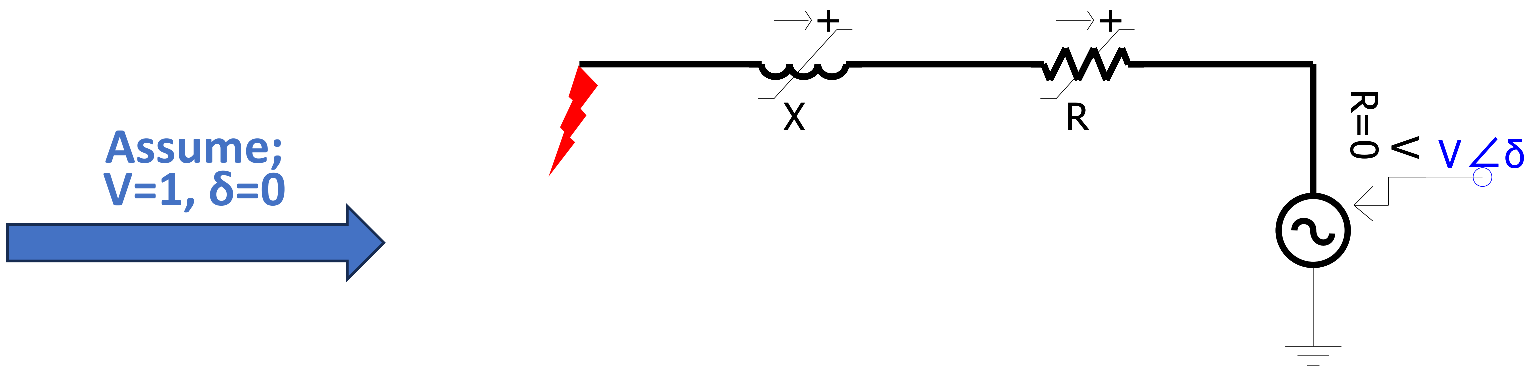
Representation of an AC Grid for testing

To represent an AC grid in a simulation tool, following parameters are required;

1. **R** (Resistance of the grid)
2. **X** (Reactance of the grid)
3. **V** (Voltage magnitude behind the impedance)
4. **δ** (Voltage angle behind the impedance)

The objective is to calculate above parameters backwards from available SCR information (i.e. SCR and X/R)

SCR & X/R



Calculation of Impedance

- $SCMVA = SCR \cdot Prated$
- $Isc = \frac{SCMVA}{V_{pre\_fault}}$
- $Z = \frac{V}{Isc}$
- $R = \frac{Z}{\sqrt{1+k^2}}$
- $X = k \cdot R$

Per unitize on Sbase = Prated

- $SCMVA = SCR \cdot 1$
- $Isc = \frac{SCR}{1}$
- $Z = \frac{1}{SCR}$
- $R = \frac{1}{SCR} \cdot \frac{1}{\sqrt{1+k^2}}$
- $X = \frac{1}{SCR} \cdot \frac{k}{\sqrt{1+k^2}}$

Note: $k = X/R$

Power Transfer Limit

The power transfer across an impedance can be written as;

$$P(\delta) := \frac{V1^2}{|Z|} \cdot \cos(\arg(Z)) - \frac{V1 \cdot V2}{|Z|} \cdot \cos(\arg(Z) + \delta)$$

Assume;
X/R=∞ (i.e. R = 0) **Fully Inductive**

$$P(\delta) := \frac{V1 \cdot V2}{X} \cdot \sin(\delta)$$

$When\ R = 0 \ \rightarrow\ X = \frac{1}{SCR}$

$$P(\delta) := SCR \cdot \sin(\delta)$$

$$MAX(P) := SCR$$

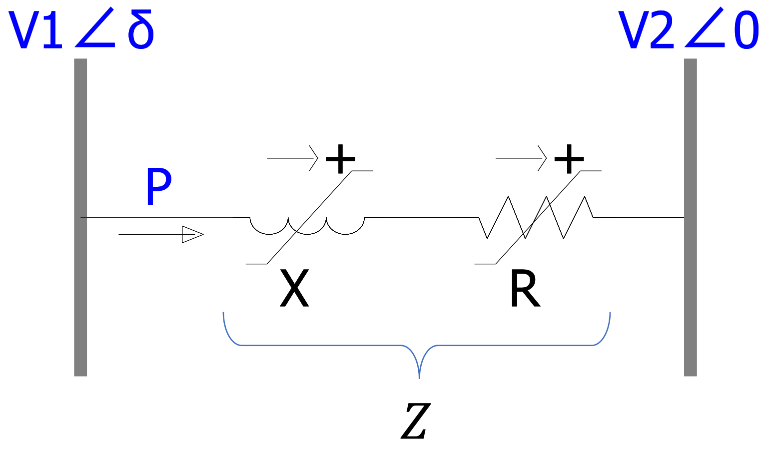
Assume;
X/R=0 (i.e. X = 0) **Fully Resistive**

$$P(\delta) := \frac{V1^2}{R} - \frac{V1 \cdot V2}{R} \cdot \cos(\delta)$$

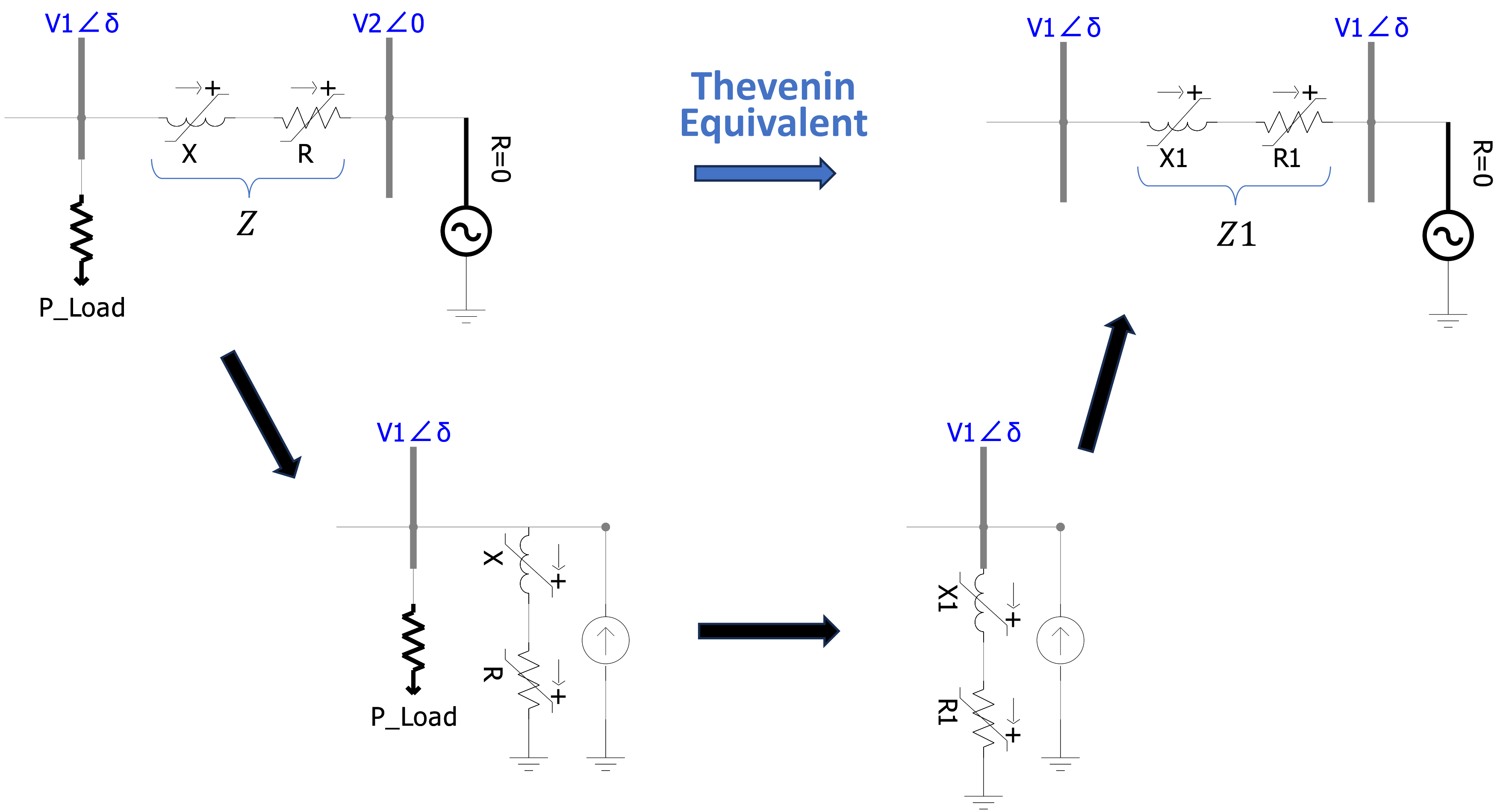
$When\ X = 0 \ \rightarrow R = \frac{1}{SCR}$

$$P(\delta) := SCR \cdot (1 - \cos(\delta))$$

$$MAX(P) := SCR \cdot 2$$



Representation of AC Grids of SCR < 1

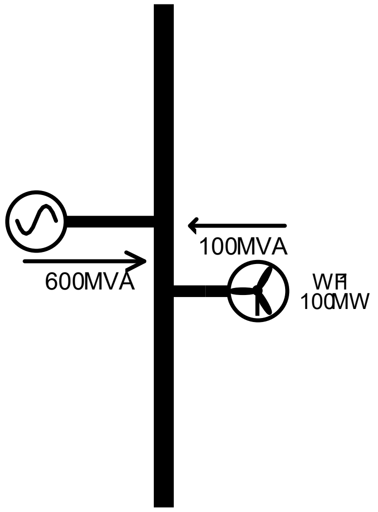


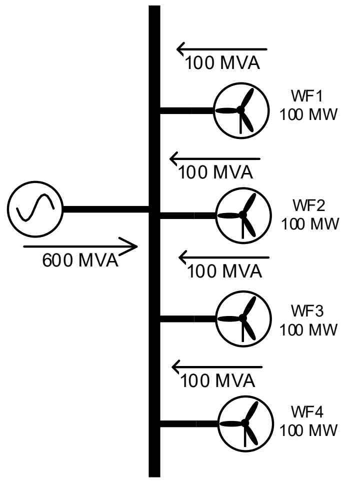
Sample SCRs…

SCR Value	Concerns?
Less than 1.5	- Power electronics can't maintain control… wind plant will not run at full power. - Conventional study tools (Transient stability) may not run.
Less than 2.5	- Potential for control problems… Wind plant may trip inappropriately, or interact badly with the external network - Conventional study tools may not be accurate
Higher than 2.5	- Wind plant will likely perform predictably

SCR Metric - Limitations

- Can be misleading if there are multiple wind plants sharing system strength (Credit Cigre/AEMO)





$$\frac{600}{100} = \text{SCR} = 6$$

$$\text{WF1 SCR} = \frac{600+100+100+100}{100} = 9\ ???$$

Metrics – Effective SCR (ESCR)

- ESCR accounts for the impedance increasing effect of capacitive filters (usually used in HVDC)

$$ESCR_{POI} = \frac{SCMVA_{POI} - MVAR_{Filter}}{MW_{VER}}$$

- First parallel resonance shifts the fundamental frequency impedance, so shunt capacitance can weaken the system.

Effect of shunt capacitance on Z60

Metrics – Weighted SCR (WSCR)

- Allows consideration of nearby resources which share SCMVA
- Neglects electrical separation
- May misrepresent group strength if there are outliers

$$WSCR = \frac{\text{Weighted} \quad S_{SCMVA}}{\sum_{i}^{N} P_{RMWi}}$$

$$= \frac{(\sum_{i}^{N} S_{SCMVAi} * P_{RMWi})/\sum_{i}^{N} P_{RMWi}}{\sum_{i}^{N} P_{RMWi}}$$

$$= \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{(\sum_{i}^{N} P_{RMWi})^2}$$

Where does WSCR work?

Workshop: Calculate SCR and WSCR for each group

Small problem plant

A	B	A*B	
MW	SCMVA		SCR
25	25	625	1
100	1000	100000	10
200	3000	600000	15
400	4000	1600000	10
200	3000	600000	15
400	2000	800000	5
200	1000	200000	5
1525	14025	3900625	
WSCR 1.677237			

Larger problem plant

A	B	A*B	
MW	SCMVA		SCR
100	100	10000	1
100	1000	100000	10
200	3000	600000	15
400	4000	1600000	10
200	3000	600000	15
400	2000	800000	5
200	1000	200000	5
1600	14100	3910000	
WSCR 1.527344	0.910631		

Reduction in problem plant MW

A	B	A*B	
MW	SCMVA		SCR
5	25	125	5
100	1000	100000	10
200	3000	600000	15
400	4000	1600000	10
200	3000	600000	15
400	2000	800000	5
200	1000	200000	5
1505	14025	3900125	
WSCR 1.72189	1.026623		

Increase in problem plant SCMVA

A	B	A*B	
MW	SCMVA		SCR
25	125	3125	5
100	1000	100000	10
200	3000	600000	15
400	4000	1600000	10
200	3000	600000	15
400	2000	800000	5
200	1000	200000	5
1525	14125	3903125	
WSCR 1.678312	1.000641		

increase in power at strong bus

A	B	A*B	
MW	SCMVA		SCR
25	25	625	1
100	1000	100000	10
200	3000	600000	15
450	4000	1800000	8.888889
200	3000	600000	15
400	2000	800000	5
200	1000	200000	5
1575	14025	4100625	
WSCR 1.653061	0.985586		

increase in power at weak bus

A	B	A*B	
MW	SCMVA		SCR
25	25	625	1
100	1000	100000	10
200	3000	600000	15
400	4000	1600000	10
200	3000	600000	15
400	2000	800000	5
250	1000	250000	4
1575	14025	3950625	
WSCR 1.592593	0.949533		

WSCR Pros and Cons

Goals of metric:

- represent sharing of conventional system strength
- represent electrical coupling between devices

Problems with WSCR:

- doesn't necessarily show local plant concerns
- more sensitive to active power changes than to increases in SCMVA, unless strongly coupled electrically.
- doesn't account for non-active power electronic devices like STATCOMs
- Doesn't account for capacity, only dispatched power
- Requires relatively close grouping of resources to have any meaning.

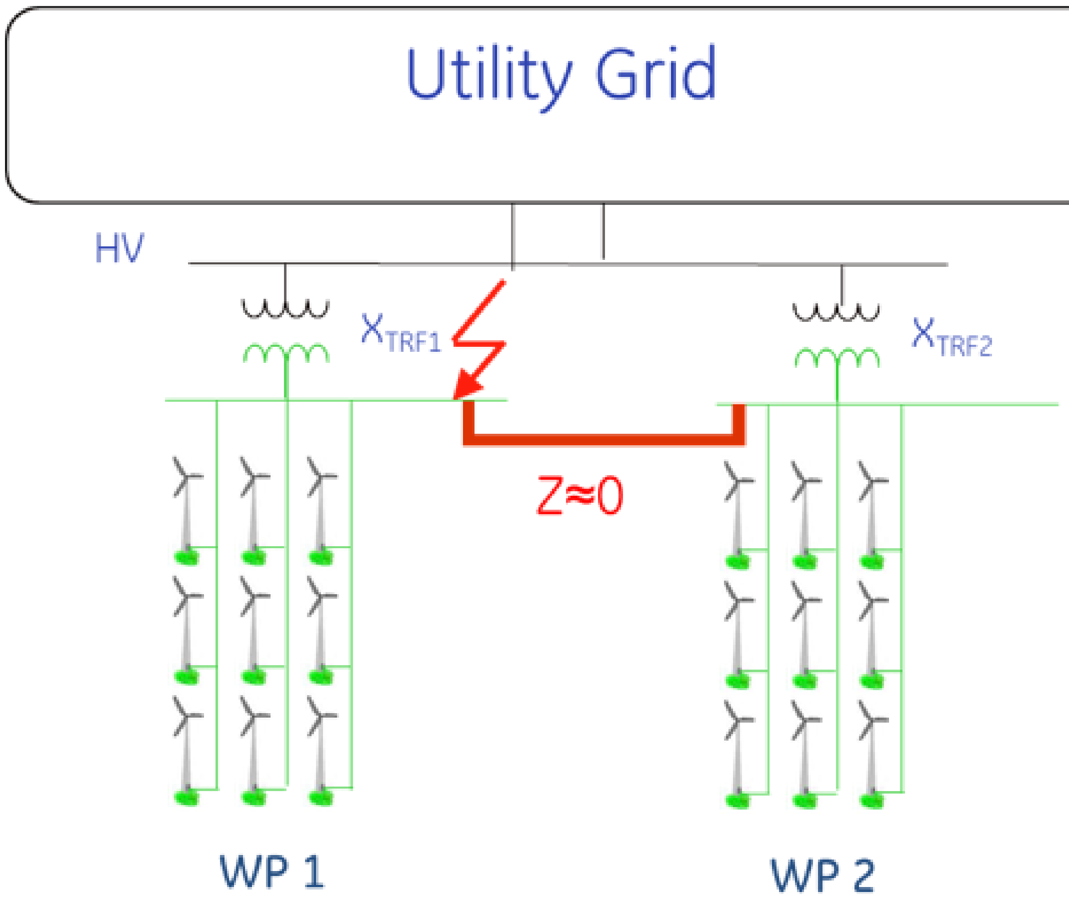
Good things about WSCR:

- Weights improvements to weak buses over strong buses.

Metrics – Composite SCR

- MV buses of wind farms in the cluster are shorted together and fault level is calculated in the simulation tool at the shorted bus.
- Similar limitations to WSCR

$$\mathrm{CSCR} = \frac{S_{MV}}{(WP1_{RAT} + WP2_{RAT} + WP3_{RAT})}$$



Metrics – SCR with Interaction Factors (SCRIF), or Equiv. SCR

- Similar to “Multi-Infeed ESCR” (MIESCR)
- Allows consideration of other plants for evaluation of system strength for a single interconnection
- Allows consideration of FACTS (like STATCOM)
- Does not provide a common metric for a group of resources
- Requires more substantial calculation

$$SCRIF_i = \frac{S_i}{P_i + \sum_j \left(IF_{ji} * P_j\right)} \qquad IF_{ij} = \frac{\Delta V_i}{\Delta V_j}$$

Metrics – MVA vs. MW (eg. WSCR-MVA)

- Care should be taken with all simple metrics with de-rated wind capacity.
- You can use MVA rating of equipment, rather than Power
- Allows consideration of partial power generation
- Allows consideration of FACTS (like STATCOM)
- Similar limitations to WSCR
- *The reality is usually somewhere in between MW and MVA*

Comparison of SCR based metrics:

Table 2.1: Comparison of SCR Methods

Metric		Simple calculation using short circuit program	Accounts for nearby inverter based equipment	Provides common metric across a larger group of VER	Accounts for weak electrical coupling between plants within larger group	Considers non-active power inverter capacity*	Able to consider individual sub-plants within larger group
SCR	Short Circuit Ratio	★★	X	X	X	X	X
CSCR	Composite SCR	★	★★	★★	X	X	X
WSCR-MW	Weighted SCR using MW	★	★★	★★	★	X	X
WSCR-MVA	Weighted SCR using MVA	★	★★	★★	★	★★	X
SCRIF	Multi-Infeed SCR	X	★★	X	★★	★★	★★

IPSCR

- Inverter Penetration SCR (IPSCR) [1]

$$IPSCR = \frac{SCMVA_{Case\ B}}{SCMVA_{Case\ C}}$$

IBR penetration ↑ **IPSCR** ↓

- Evaluates how much system strength comes from IBRs
  - Case B = case with all IBRs turned off
  - Case C = case with all conventional generation turned off and IBR Xsource tuned until it contributes 1 p.u. SCMVA

SCR — Effective for one IBR interconnection

WSCR — Accounts for nearby IBRs but neglects electrical separation

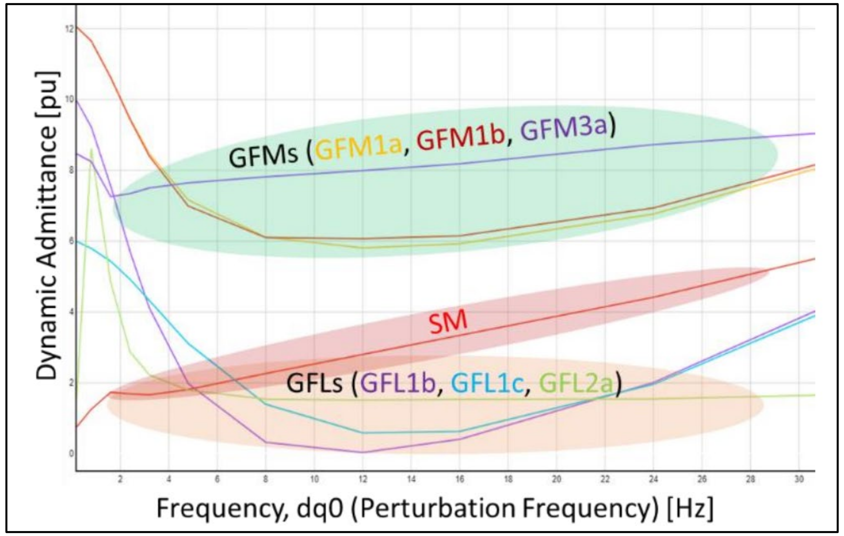
IPSCR — Accounts for nearby IBRs and does not require a defined boundary

Can IPSCR be refined further?

[1] L. Unruh and A. Isaacs (2021), 'Description of Inverter Penetration (IPSCR) Metric for Quantifying System Strength in Large Networks'

Generation Resource Characterization

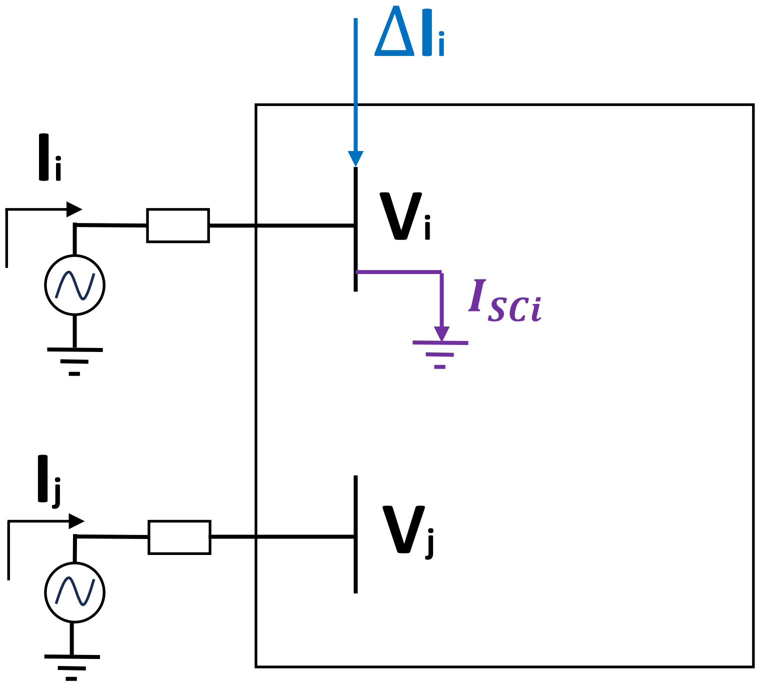
- Industry has been exploring how to characterize GFM technology using impedance scans
- Entities are suggesting or requiring impedance scans for GFM technology
- Provides perspective on how technology will behave
- GFM technology routinely shows superior behaviour when compared to GFL and SM
- How do we tie resource characterization into our metric? We make it impedance based



Source: M. Richwine et al., Power System Stability Analysis & Planning Using Impedance-Based Methods, 2023

Modifying SCRIF

$$\begin{bmatrix}\Delta V_i\\ \Delta V_j\end{bmatrix} = \begin{bmatrix}Z_{ii} & Z_{ij}\\ Z_{ji} & Z_{jj}\end{bmatrix}\begin{bmatrix}\Delta I_i\\ \Delta I_j\end{bmatrix}$$



Calculate interaction factor:

$$\begin{bmatrix}\Delta V_i\\ \Delta V_j\end{bmatrix} = \begin{bmatrix}Z_{ii} & Z_{ij}\\ Z_{ji} & Z_{jj}\end{bmatrix}\begin{bmatrix}\Delta I_i\\ 0\end{bmatrix}$$

$$\Delta V_i = Z_{ii}\Delta I_i$$

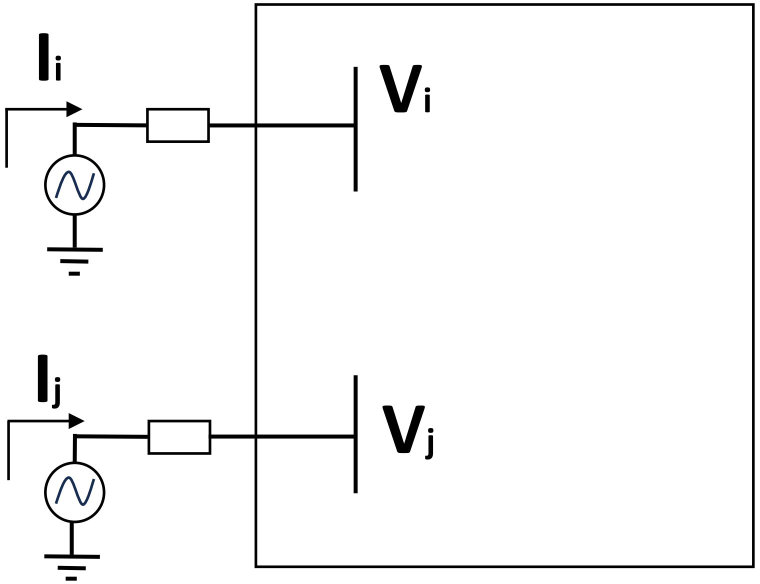
$$\Delta V_j = Z_{ji}\Delta I_i \longrightarrow \boxed{\frac{\Delta V_j}{\Delta V_i} = \frac{Z_{ji}}{Z_{ii}}}$$

Calculate SCMVA:

$$\begin{bmatrix}\Delta V_i\\ \Delta V_j\end{bmatrix} = \begin{bmatrix}Z_{ii} & Z_{ij}\\ Z_{ji} & Z_{jj}\end{bmatrix}\begin{bmatrix}I_{SCi}\\ 0\end{bmatrix}$$

$$\Delta V_i = Z_{ii} I_{SCi} \longrightarrow I_{SCi} = \frac{\Delta V_i}{Z_{ii}} \longrightarrow \boxed{SCMVA_i = \frac{\Delta V_i{}^2}{Z_{ii}}}$$

Modifying SCRIF



Developing Impedance-Based SCR Metric:

$$SCRIF = \frac{SCMVA_i}{P_i + \sum_{j=1, j \neq i}^{n} (P_j * IF_{ji})}$$

$$\boxed{IF_{ji} = \frac{\Delta V_j}{\Delta V_i} = \frac{Z_{ji}}{Z_{ii}}}$$

$$\boxed{SCMVA_i = \frac{\Delta V_i^{\,2}}{Z_{ii}}}$$

$$SCRIF = \frac{\frac{\Delta V_i^{\,2}}{Z_{ii}}}{\sum_{j=1}^{n} \left(P_j * \frac{Z_{ji}}{Z_{ii}} \right)}$$

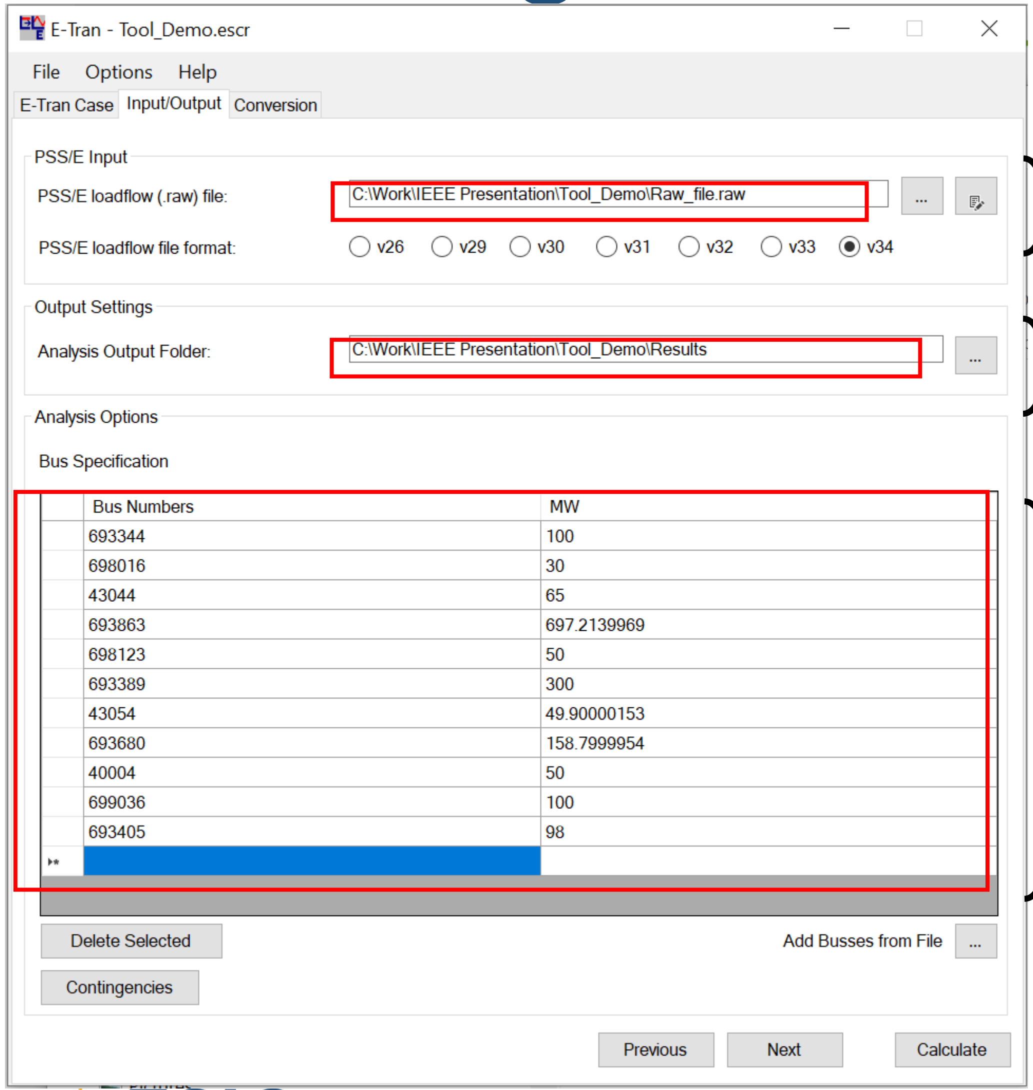
$$\boxed{NSCR = \frac{\Delta V_i^{\,2}}{\sum_{j=1}^{n} (P_j * Z_{ji})}}$$

Expanding to entire system

- The NSCR calculation can readily be expanded to large systems

Construct full system admittance matrix → Modify to develop contingency specific matrices → Reduce matrices based on POIs of interest → Invert admittance matrix to get impedance matrix → Calculate interaction factors → Compute NSCR values

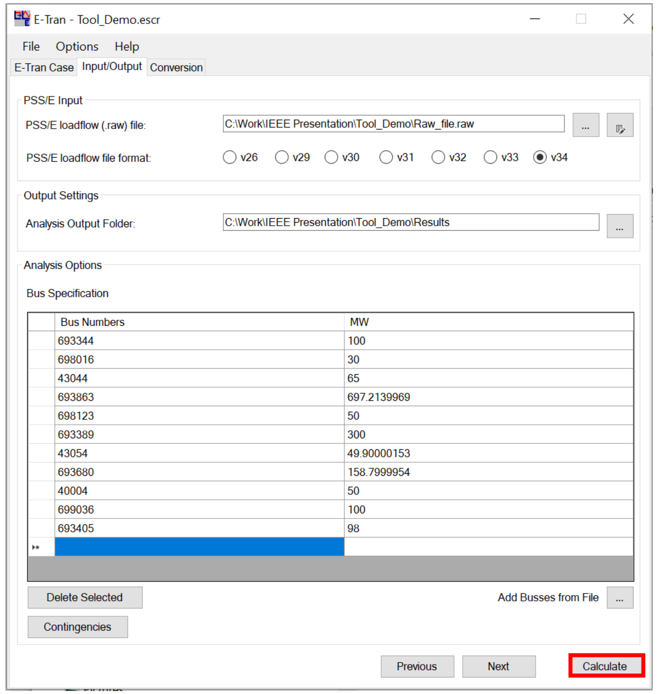
Building a tool…

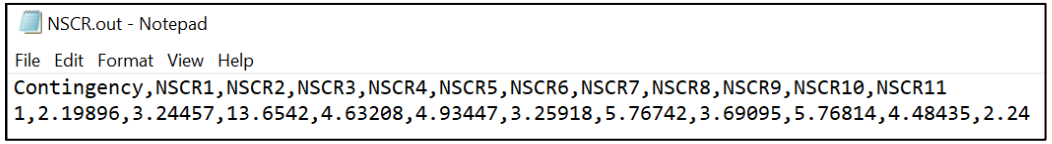


Folder to output results to

POI buses of interest and corresponding MW injections

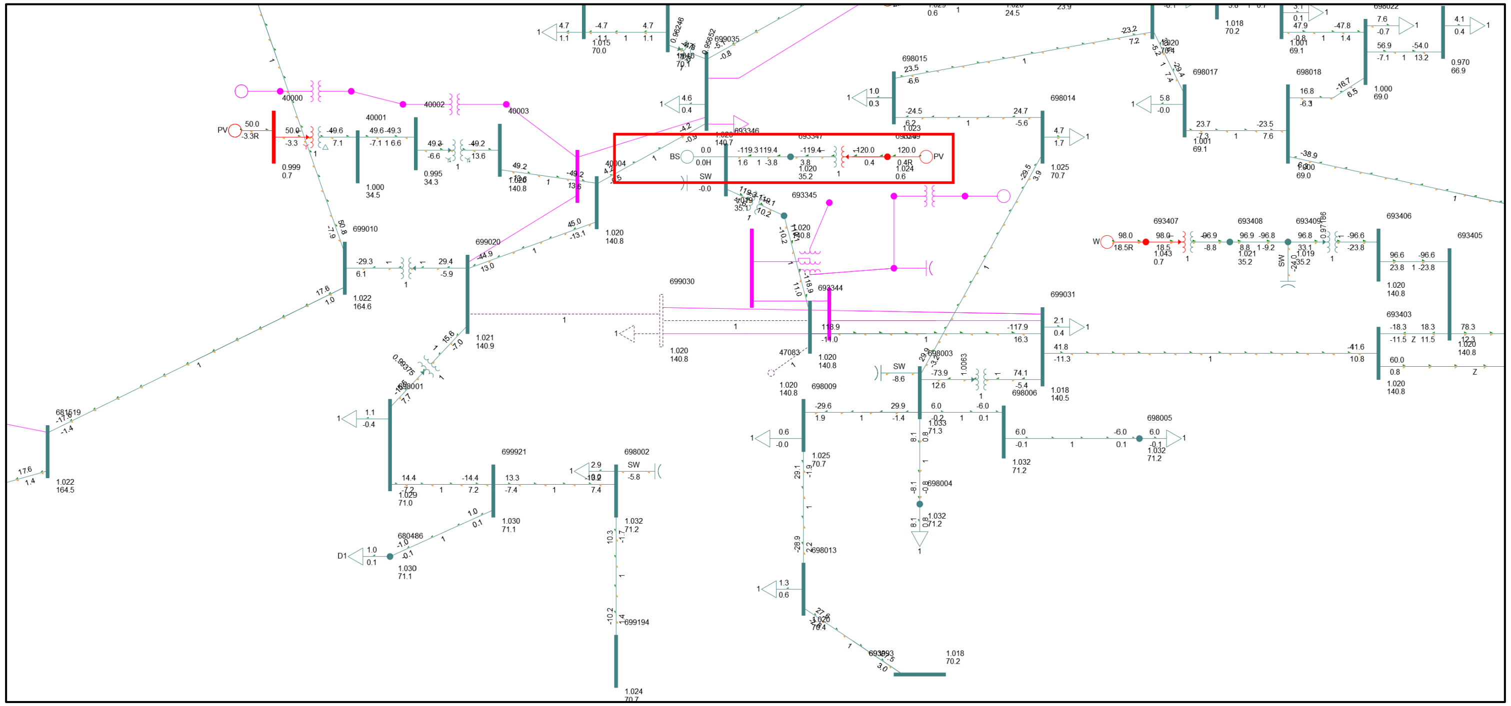
Raw file with correct Zsource





Calibrating the tool

- We can use known system instabilities to set "bad" NSCR numbers
- PV plant was found to have:
  - Stability @ 100 MW
  - Marginal stability @ 120 MW
  - Instability @ 140 MW



Setting unstable NSCR values

```
Contingency,NSCR1,NSCR2,NSCR3,NSCR4,NSCR5,NSCR6,NSCR7,NSCR8,NSCR9,NSCR10,NSCR11
1,2.19896,3.24457,13.6542,4.63208,4.93447,3.25918,5.76742,3.69095,5.76814,4.48435,2.24
```

100 MW

```
Contingency,NSCR1,NSCR2,NSCR3,NSCR4,NSCR5,NSCR6,NSCR7,NSCR8,NSCR9,NSCR10,NSCR11
1,2.02501,3.17621,13.5431,4.60871,4.90736,3.23487,5.71591,3.66555,5.73015,4.44036,2.10722
```

120 MW

```
Contingency,NSCR1,NSCR2,NSCR3,NSCR4,NSCR5,NSCR6,NSCR7,NSCR8,NSCR9,NSCR10,NSCR11
1,1.87673,3.11084,13.4345,4.58567,4.88065,3.21101,5.66569,3.64057,5.69279,4.39756,1.9895
```

140 MW

Plant Dispatch	EMT Result	NSCR
100 MW	stable	2.1989
120 MW	marginally stable	2.0250
140 MW	unstable	1.8767

SCR-based metrics

- Key Takeaways
  - While lower SCR typically increases the likelihood of potential issues with inverter-based resources, these methods should be used as a screening tool for simple "radial" systems only.
  - Weak grid issues are system- and equipment-specific and it is difficult to define a "minimum system strength" criteria that can be applied uniformly.
  - What is "weak" for one manufacturer may not be a problem for another. What was "weak" for one manufacturer two years ago may no longer be difficult to achieve. The addition of a new piece of equipment may (through poor controls, for example) suddenly destabilize otherwise very well controlled existing equipment.

Appropriate use of SCR-based metrics

- Use metrics to gain a high-level understanding of relative impact of the interconnecting plant
- If there is any concern, involve planners, developers, and manufacturers to identify potential risks
- Use that understanding, *combined with specific knowledge of the equipment and transmission system*, decide whether further study is required.

- Note: it is very difficult to use SCR to set planning guidelines and thresholds

Mitigation Alternatives

- If a small SCR suggests there may be problems, mitigation is directly suggested by the formula…
- How do we fix a weak system problem?

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

Mitigation alternatives

- *SMALLER GENERATORS!*
- Selective curtailment or RAS
- More transmission
- Larger transformers
- Series capacitors (careful)
- Control tuning
- Synchronous Condensers
- FACTS (SVC or STATCOM?)
- **GFM Batteries!!**

When to do an EMT Study?

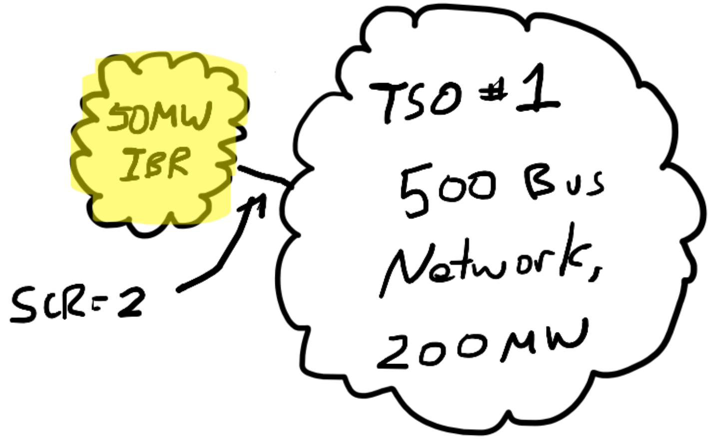
Topic Change

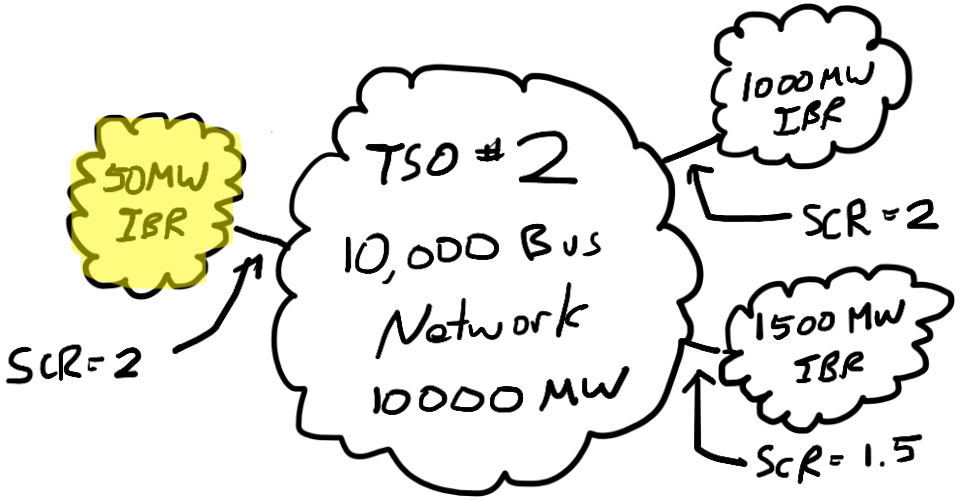
When to do EMT, and how complex of a model?

- Two related questions…
    - We will try to answer the question: **When to do an EMT study?**
    - Spoiler: you may leave the presentation dissatisfied! ☹

Will most studies benefit from EMT? Yes.

- Should we therefore do EMT study all the time?
  - Hypothetical!





1 engineer available,
2 months to perform study

1 engineer available,
2 months to perform study

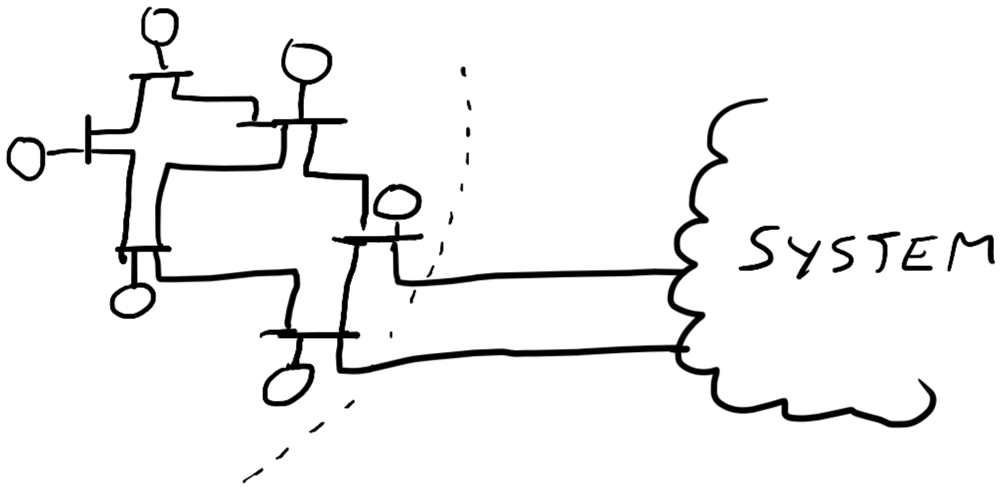
Your specific criteria for when to do EMT will differ from others…

- Each utility has unique challenges!
  - Variables include:
    - Availability of human resources and training/expertise
    - Strength of your system now and into the future?
    - Available time
    - Availability of appropriate component models
    - Proximity of series compensation
    - Others!!
  - What are the possible consequences of missing something?

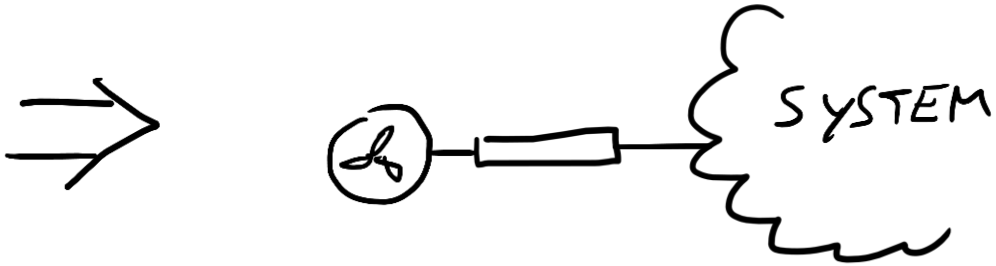
System strength screening metrics:

- We have tools to help us decide!
    - SCR, ESCR, WSCR, IPSCR, SCRIF, CSCR, etc.
        - BE CAREFUL!! These don't always work…

Can you make this…

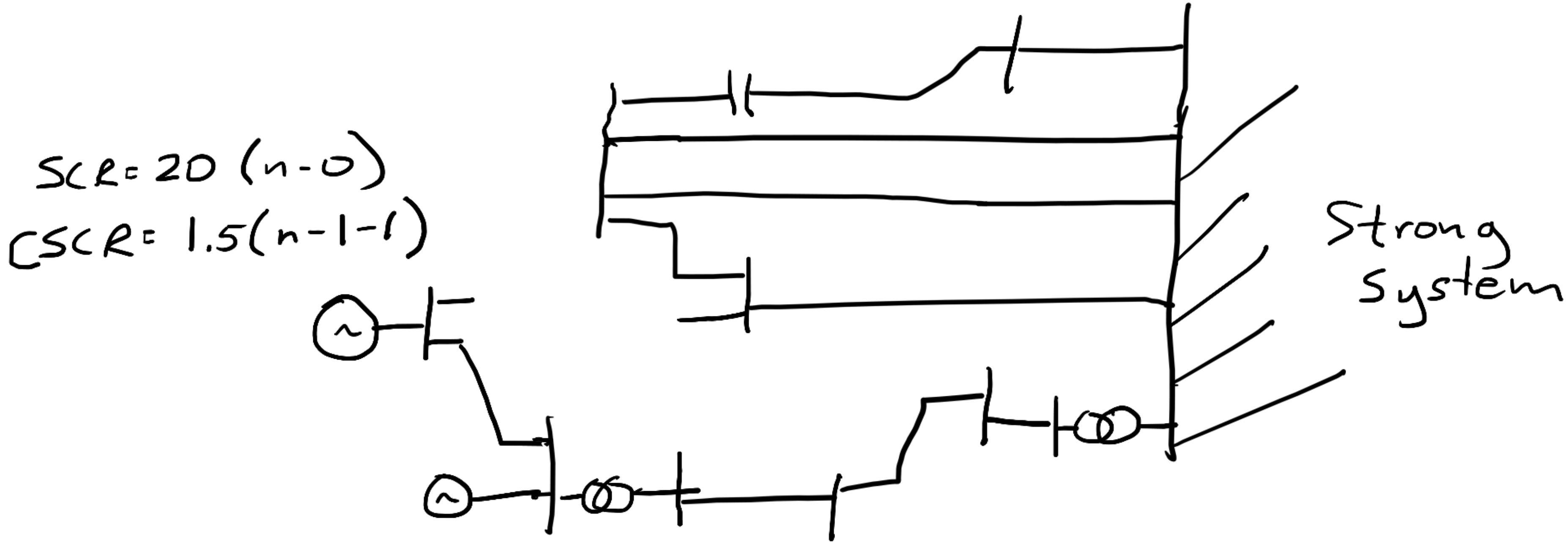


…look like this? If not, SCR based metrics may not be appropriate!



Engineering judgement or manual review!

- Using a **map** and your most **experienced planners' brains**, you can identify priority areas for EMT study.
  - xSCR screening metrics can be used to help focus, but should be supplemented by judgement



What causes “red flags” that indicate EMT study is recommended?

- Situational Triggers for EMT study:
  - New or untested technology
  - Close proximity to series capacitors, especially when radial operation is possible (n-x)
  - Weak grid (n-x), with serious consequences for ride-through failure
  - Weak grid (n-x), with close proximity of multiple IBR plants
  - Grid strength undefinable, very high IBR penetration
  - Issues with instability, ride-through or operability near installed IBR plants
  - Planners or operators “get the heebie-jeebies!”, aka “you’ll know it when you see it!”, aka “trust your intuition!”
  - Phasor Domain studies indicate strange or unbelievable results
  - Classical concerns: lightning, TRV, TOV, switching, MAD, control design, etc…
  - Design evaluation is a type of EMT study which should become routine!

Study processes, Analysis, Mitigation

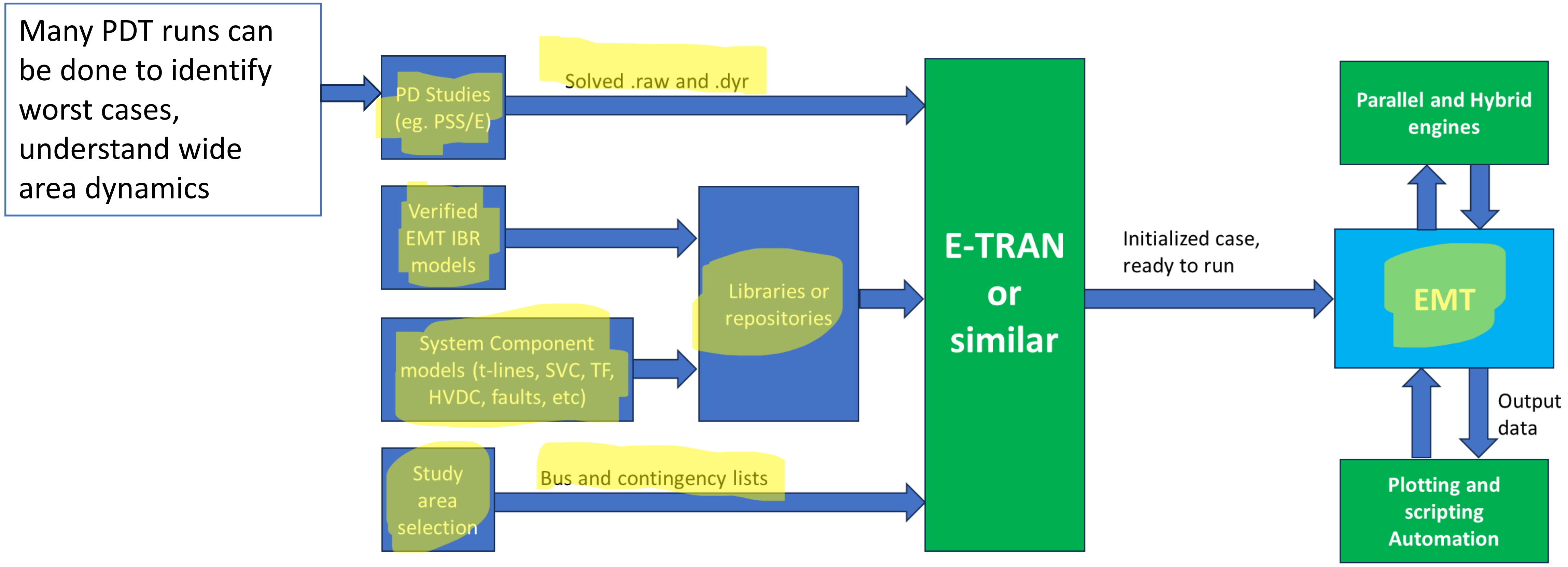
Topic Change

Design of Weak System Studies (EMT)

General steps:

1. Develop and publish detailed criteria for model quality
2. Begin model intake and quality assurance as soon as possible (includes adequacy check and benchmarking).
3. Ensure input design cases are as good as possible (ie. the powerflow and transient stability work is finished)
4. Develop study parameters in conjunction with ISO, TO, and consultant if necessary and document carefully.
   1. Agree on the overall motivation for the study
   2. Negotiate size of study area
   3. Negotiate outage list
   4. Agree on monitored quantities
   5. Agree on criteria for pass/fail
5. Organize data into substitution libraries
6. Organize case into optimal parallel processing structure (load balancing, port mapping, etc)
7. Develop automation and control for composite models, including:
   1. Faults and outages
   2. Monitoring of critical quantities
   3. Pass/fail analysis should be automated if there are too many output traces
   4. Plotting
8. Mitigate and iterate as needed

PDT/EMT Study Interface (Electranix Approach)

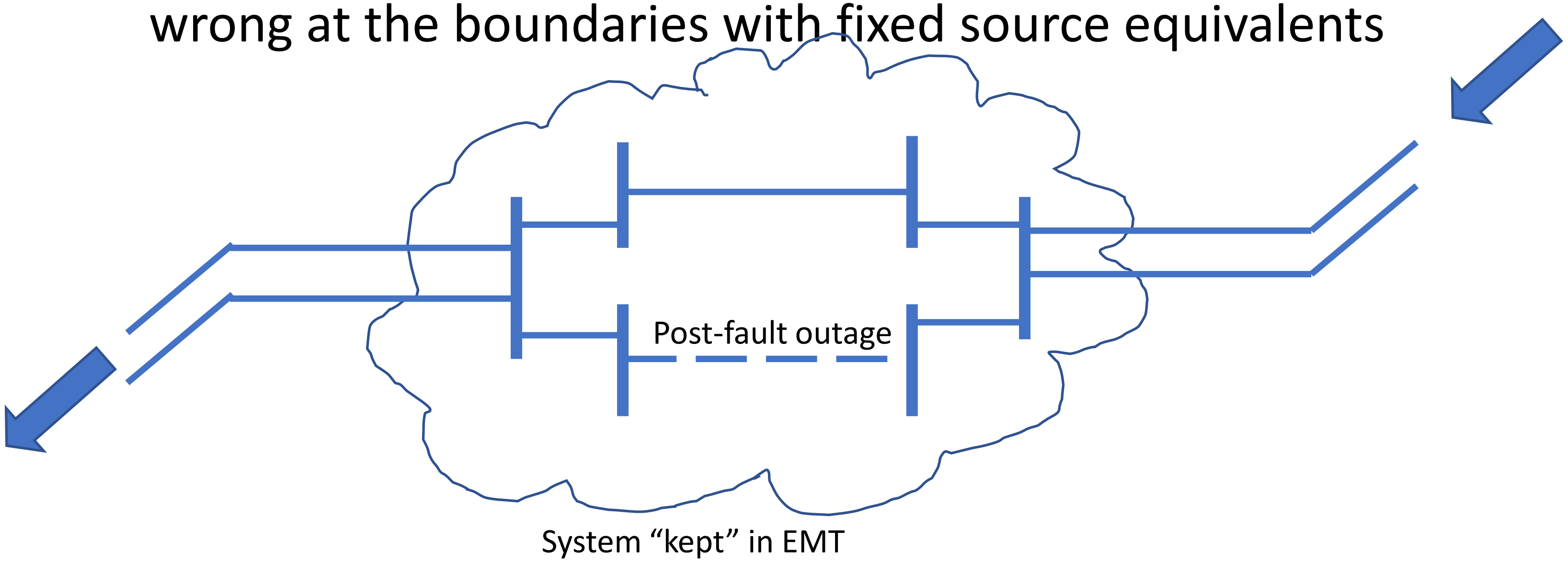


When should you use Co-Simulation?

Topic Change

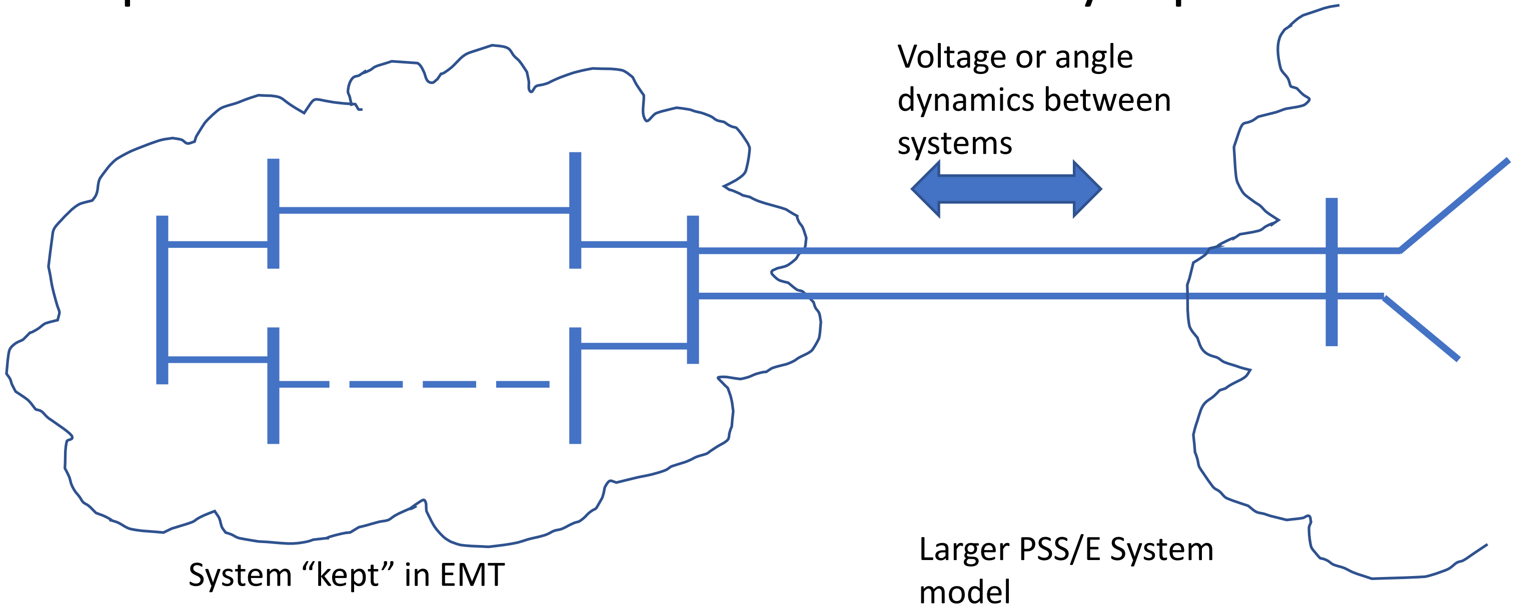
Use case #1

- High path flows through your study area
  - Post contingency angles (and therefore powerflow) will be wrong at the boundaries with fixed source equivalents



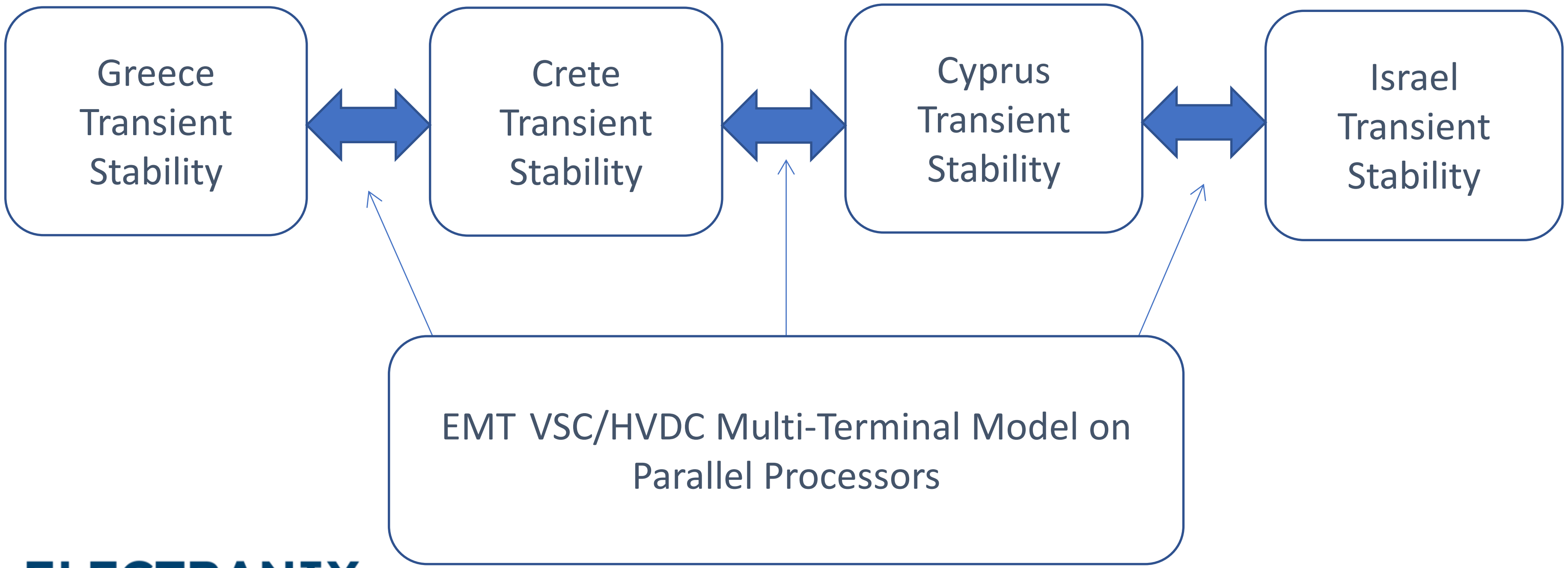
Use case #2

- Inter-area machine dynamics
  - Areas swinging against each other will not be represented with fixed source boundary equivalents



Use case #3

- ‘Glue’ between incompatible transient stability tools
  - Different PSS/E versions, PowerFactory, PSLF



Use case #4

- Uncertainty
  - What don't I know? How do I get the very best warm fuzzy feeling about my study accuracy?

Alternatives to Co-simulation

- Larger EMT study area, or multiple study areas modeled in EMT using parallel simulation. (There are going to be limits, however!)
- Be aware of your model limitations. Are they really important for what you're studying?

GFM Applications

Topic Change

Functional Definitions

Grid-Following: *Most inverter based resources currently in service rely on fast synchronization with the external grid (termed Grid-Following) in order to tightly control their active and reactive current outputs. If these inverters are unable to remain synchronized effectively during grid events or under challenging network conditions, they are unable to maintain controlled, stable output.*

What technology uses Grid-Following?

- *Current generation wind turbines*
- *Current generation transmission connected PV*
- *DER*
- *Most BESS applications*
- *LCC HVDC*
- *Most VSC HVDC*
- *last generation STATCOMs and SVCs*

Functional Definitions

Grid-Forming: *Grid-Forming resources do not require very fast synchronism with the external grid to produce a predictable output. Instead of output currents being their primary control objective, they maintain control of an internal voltage phasor.*

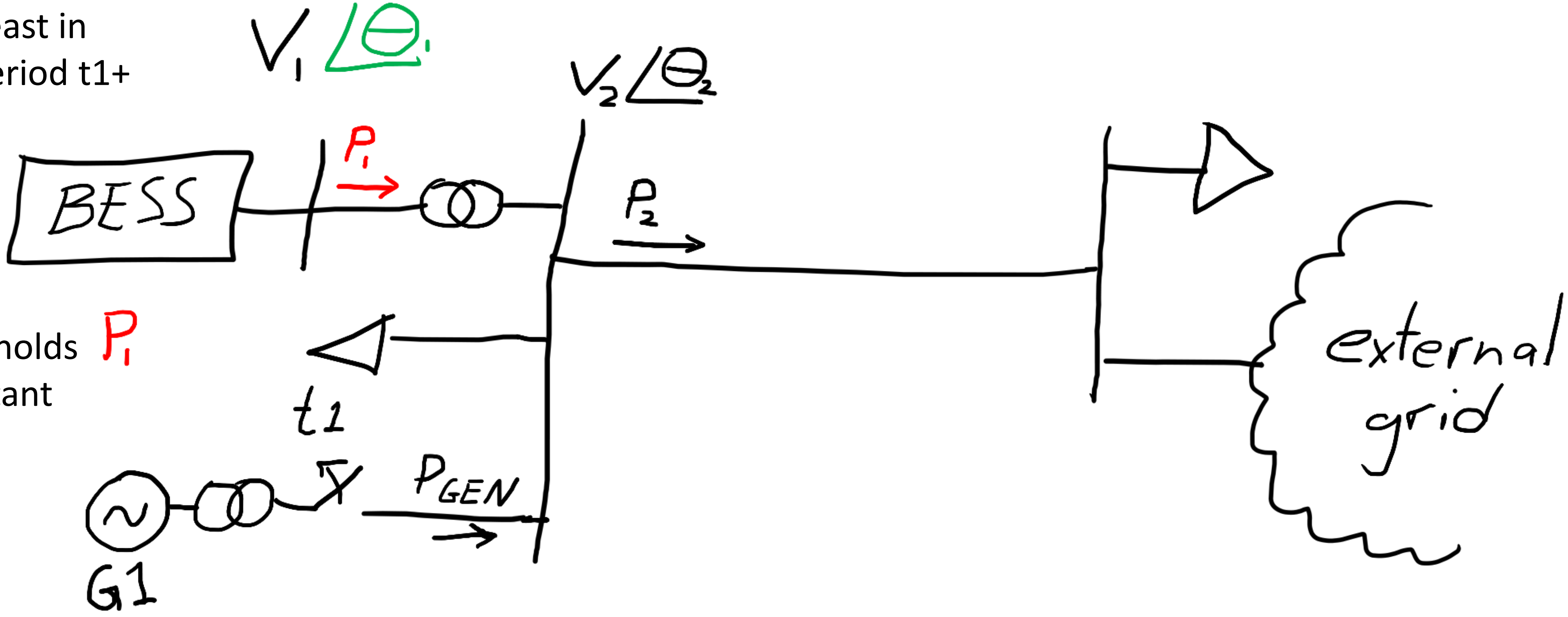
In some applications (eg. Black start or microgrid applications), this voltage phasor is held relatively constant, allowing the plant to operate in an island as the sole frequency determining element. In other applications (eg. bulk grid connected applications), the voltage phasor may be controlled to maintain synchronism with other elements and also control active and reactive currents. There are many ways to implement this type of control, but common to all of them is a constant voltage phasor in the sub-transient to transient time frame, which provides a degree of stability in the controls during challenging network conditions.

Potentially good for weak grids and high IBR penetration !!

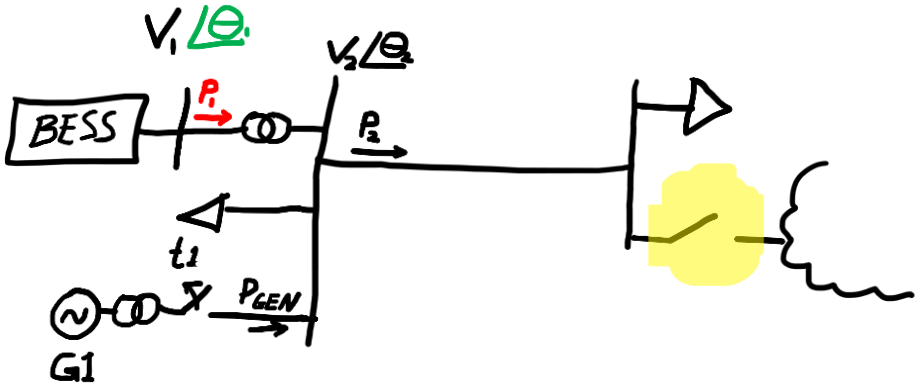
What does that actually mean?

Grid-Forming holds Θ_1 constant… at least in the transient period t1+

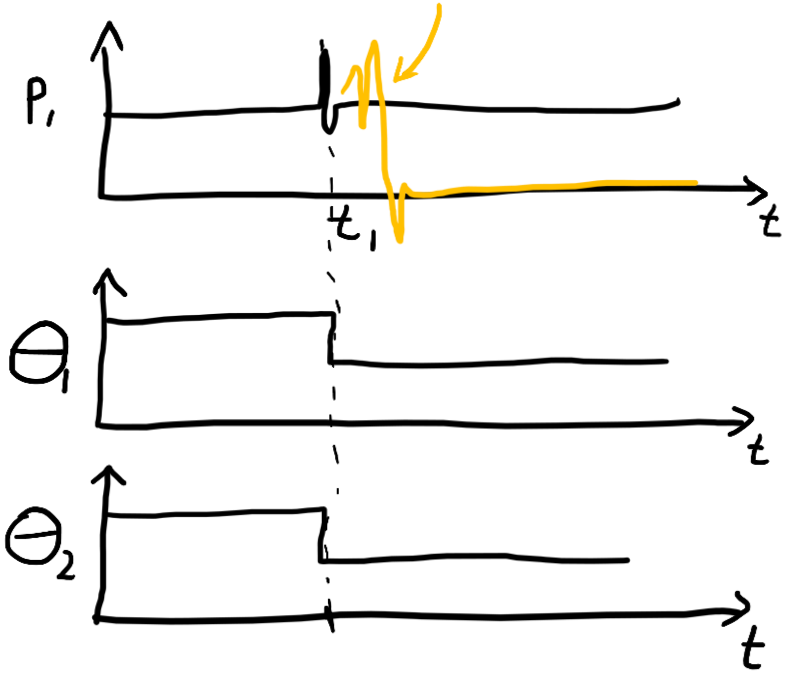
Grid-Following holds P_1 (currents) constant during t1+



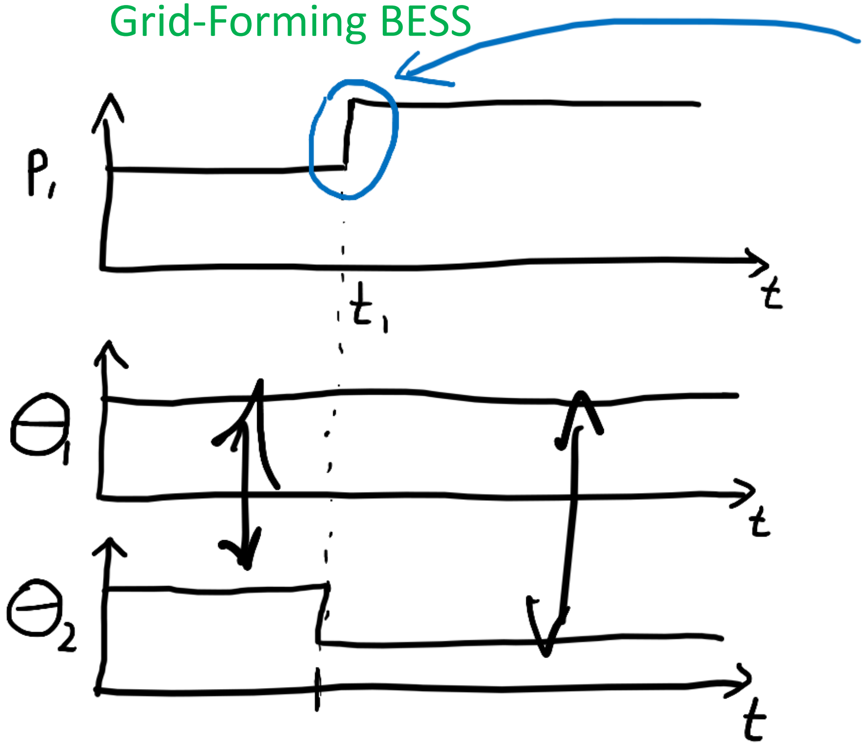
What does it look like when you disconnect the generator G1? (Island system)



Grid-Following BESS
(neglecting weak grid instability and tripping)



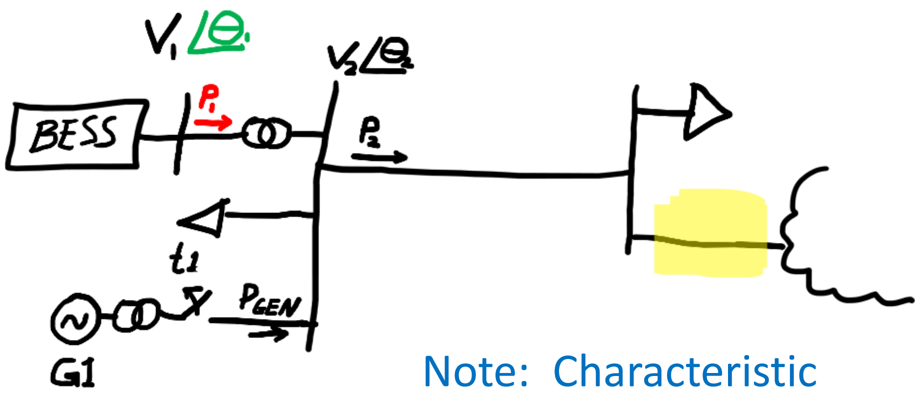
Grid-Forming BESS



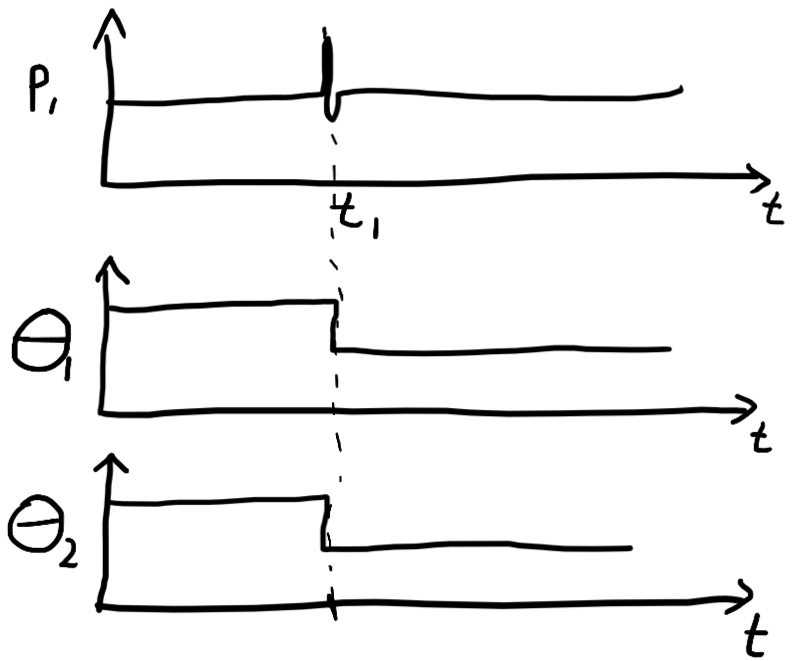
Note: Characteristic "Inertial Response"

Note: Grid-Forming BESS performance is contingent on having sufficient current and energy headroom when the angle changes!!

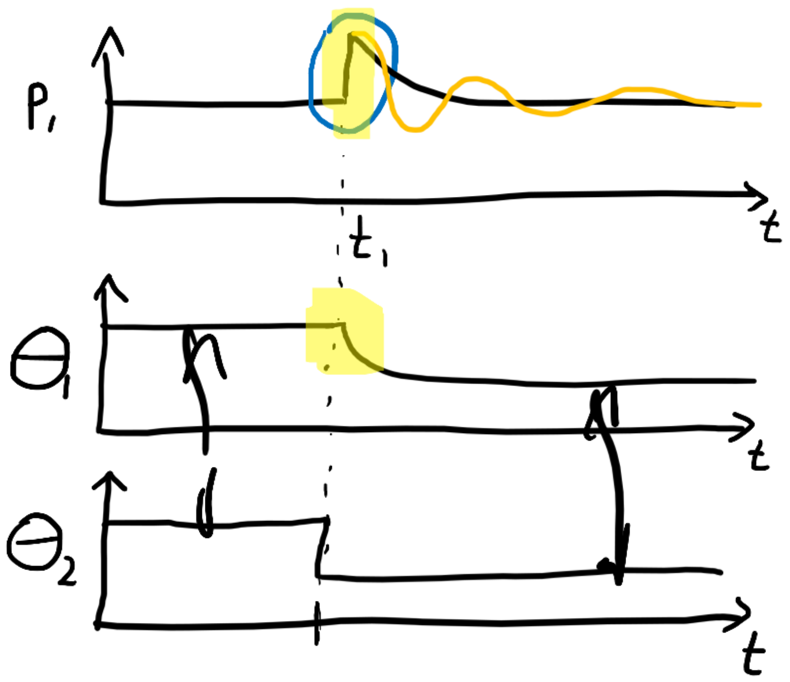
If we re-connect the island, and…
add power control/grid synchronization



Grid-Following BESS



Grid-Forming BESS

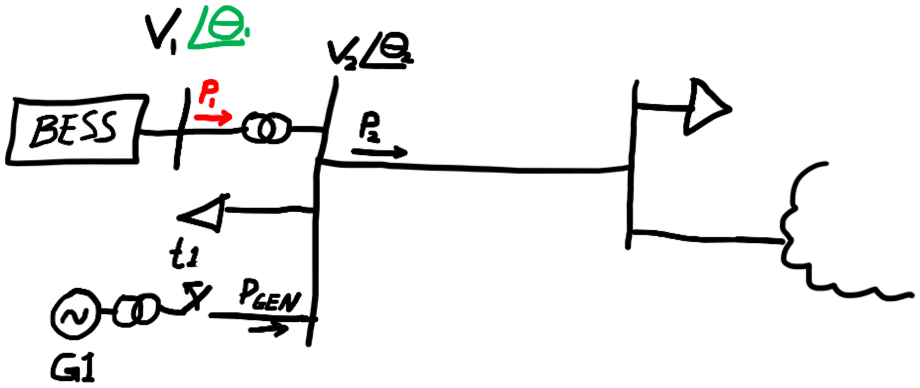


Note: Characteristic "Inertial Response"

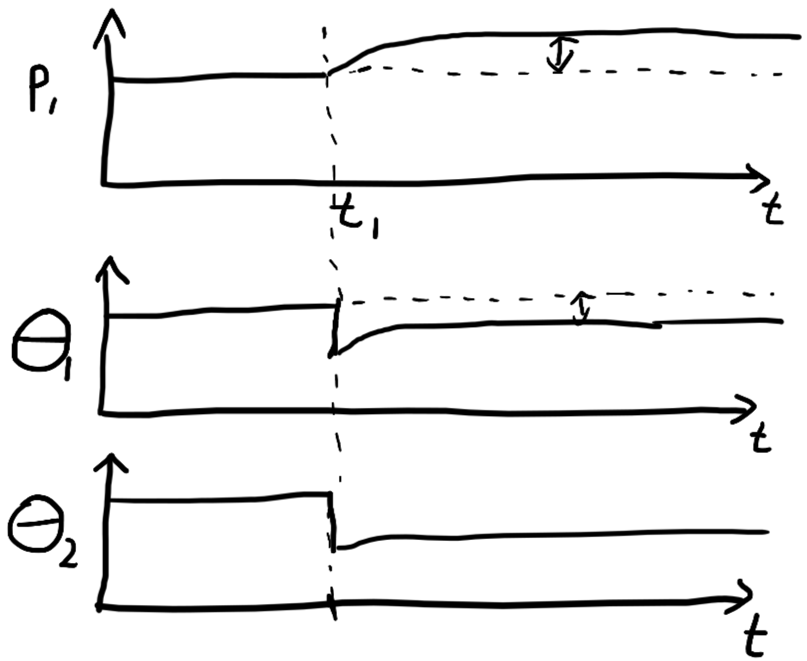
Note: Synchronous machine-type response if desired

Note: Grid-Forming BESS performance is contingent on having sufficient current and energy headroom when the angle changes!!

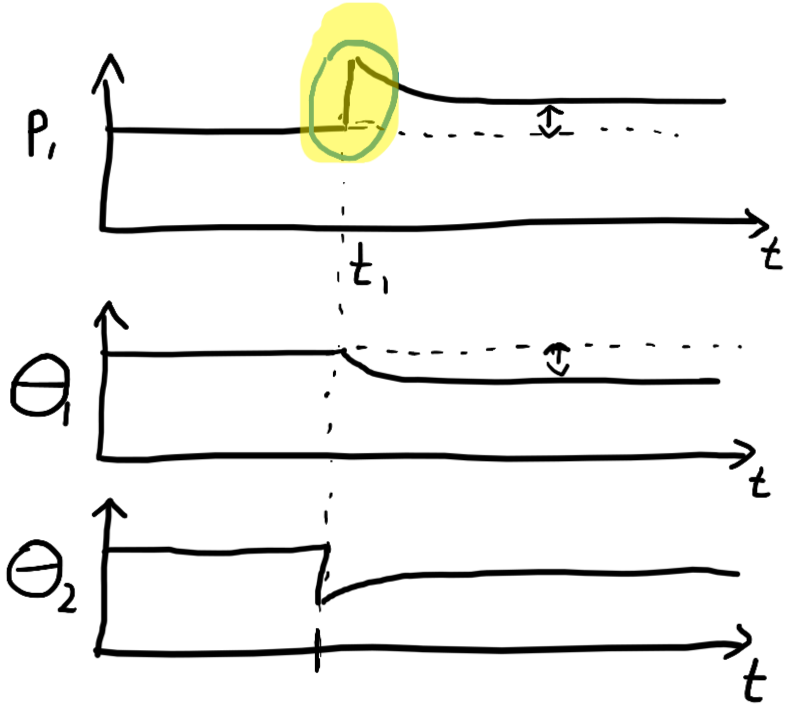
If we re-connect the island, and…
add power control/grid synchronization, and…
add frequency-droop control



Grid-Following BESS



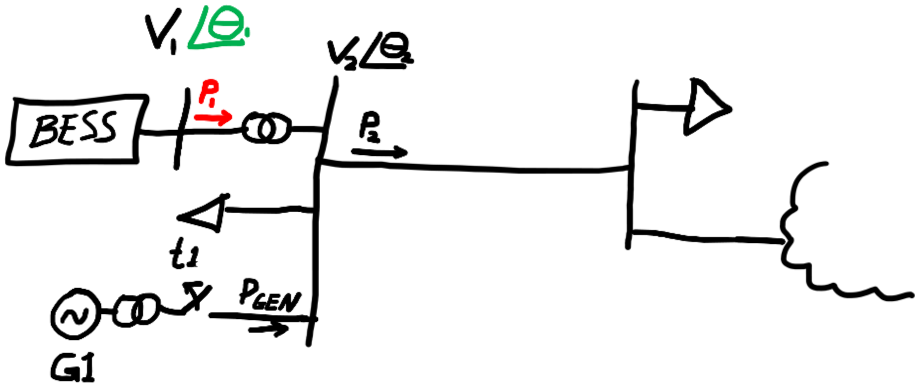
Grid-Forming BESS



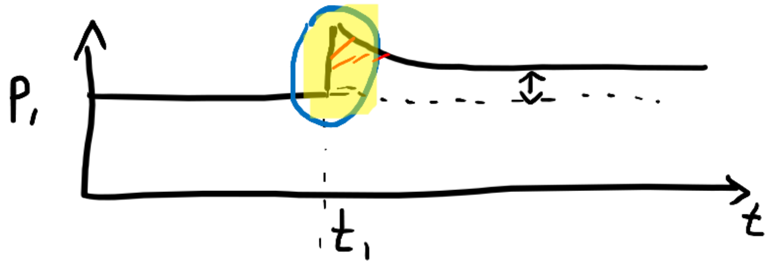
Note: Characteristic "Inertial Response"

Note: Grid-Forming BESS performance is contingent on having sufficient current and energy headroom when the angle changes!!

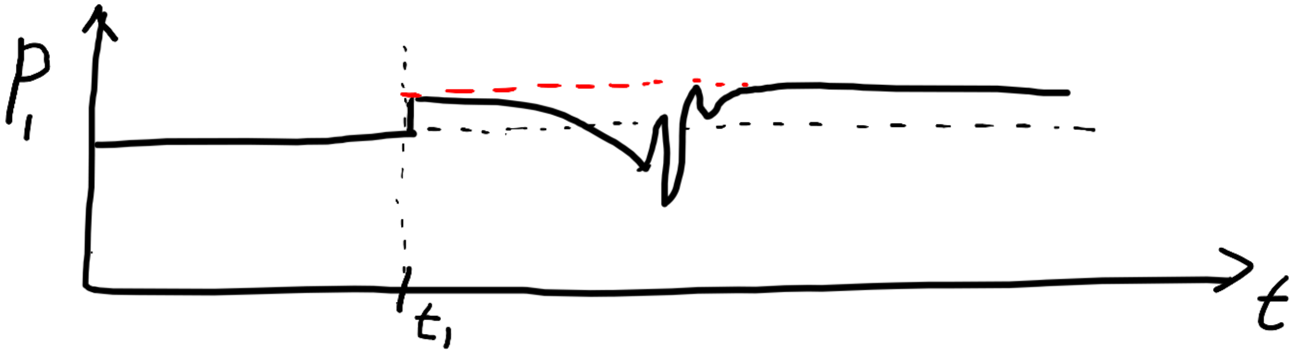
If we re-connect the island, and…
add power control/grid synchronization, and…
add frequency-droop control and…
run out of current margin in the BESS?



Grid-Forming BESS (headroom available)

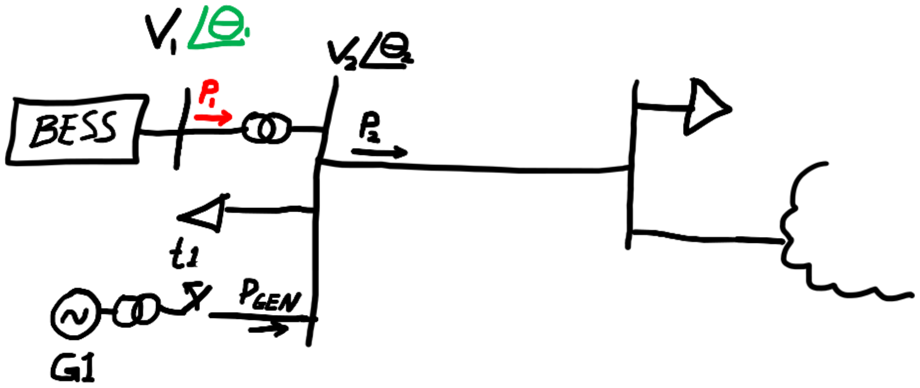


Grid-Forming BESS (out of current headroom!)
(example only… response will vary!!)

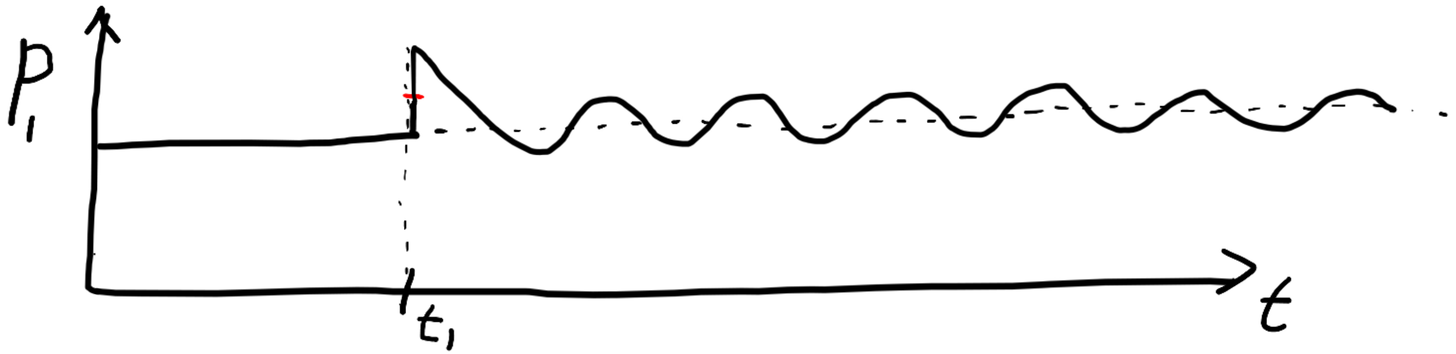


Note: If BESS runs out of headroom, many things can happen… it is down to how the controls are implemented!!

What else could possibly go wrong with GFM? A few things seen in recent studies…



Undamped oscillation or inter-machine modes

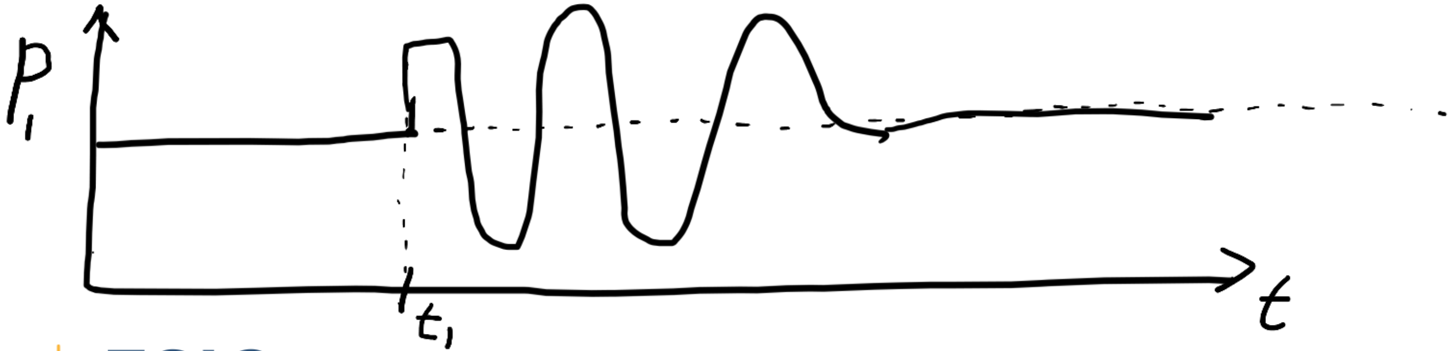


Voltage control and droop, frequency control and droop settings all need to be correct and coordinated…

…and other things!!

Everything depends on the controls!!!

Interaction between entry and exit of FRT modes with nearby devices (GFL *and* GFM!)



Additional Reminders about GFM Resources:

1. GFM effect requires energy and current headroom
2. There are multiple ways to implement controls (VSM, Droop, Other). A lot can be done to shape the response for specific needs
3. For resources with energy and current headroom (like batteries), the hardware is generally similar between GFM and GFL.
4. Generally all the things that GFL can do should be expected from GFM as well!

Pressing need for GFM is simple… the “Killer App”

going down!

$$SCR = \frac{SCMVA}{MW_{IBR}}$$

Synchronous Machines

GFM IBRs

GFM HVDC/FACTS

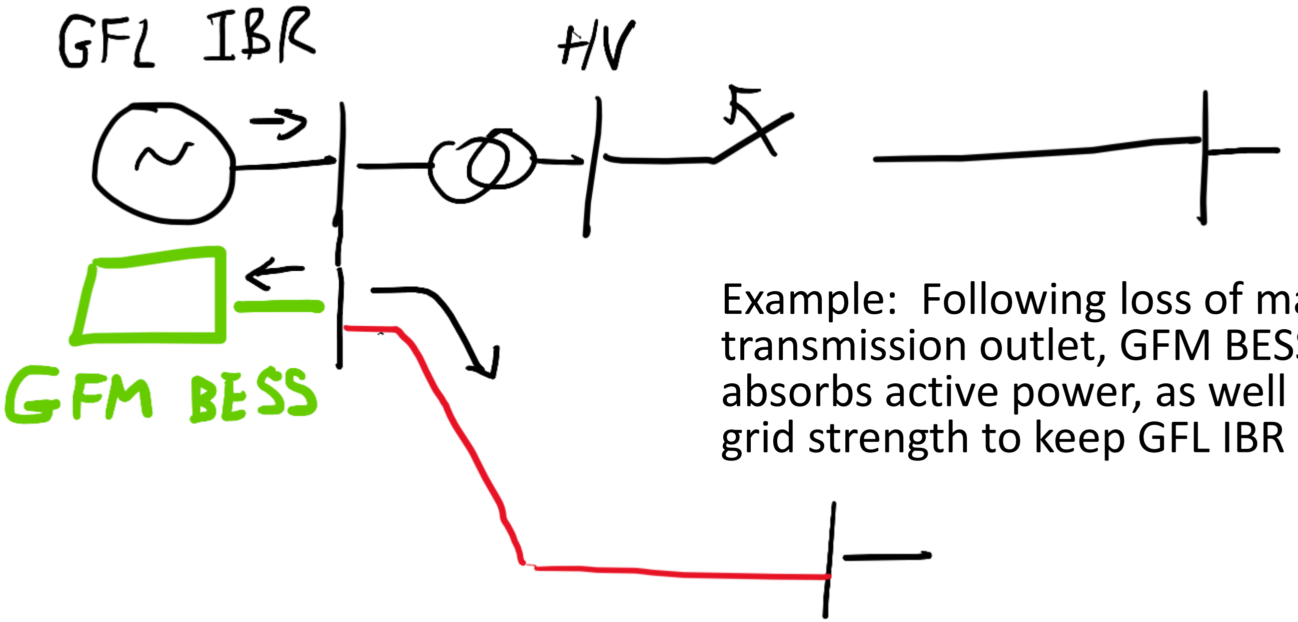
GFL IBRs

GFL HVDC/FACTS

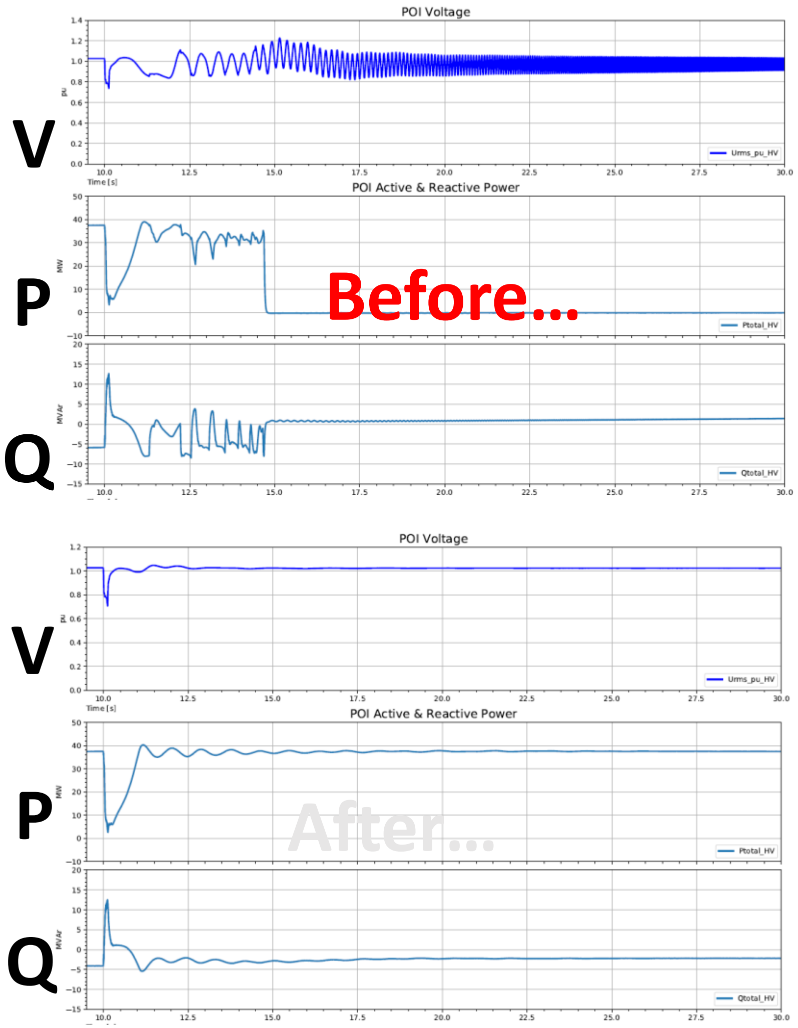
- ***Note: SCR based metrics are becoming less valuable in general. Use with care or don't use at all!!***

Increasing transmission capacity and local SCR

- For load or generation regions constrained by short term transmission overloads, GFM BESS can "catch" the system

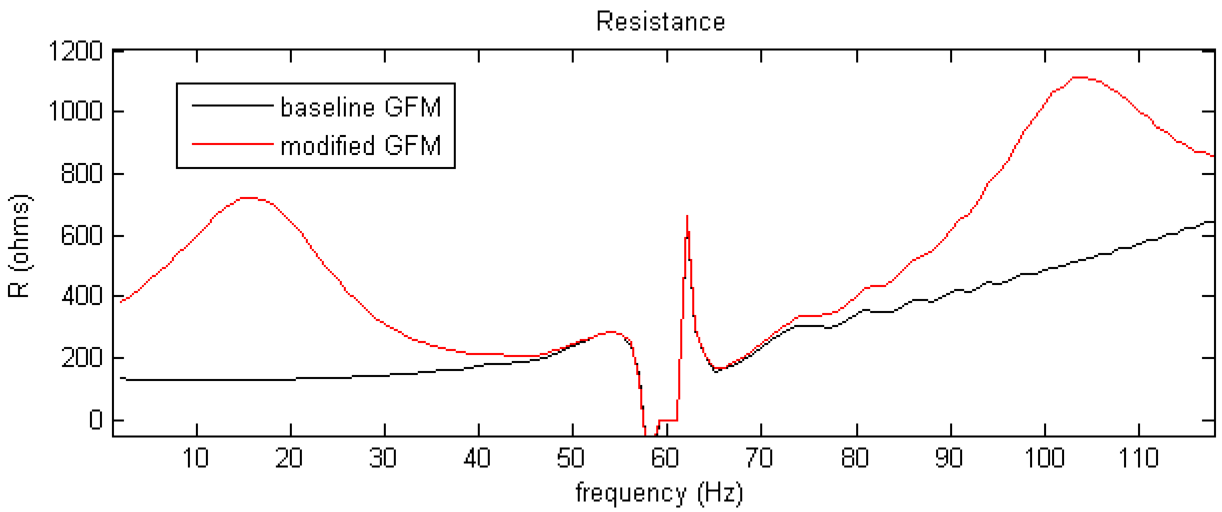


Example: Following loss of main transmission outlet, GFM BESS quickly absorbs active power, as well as providing grid strength to keep GFL IBR online.



Power system damping, including SSCI

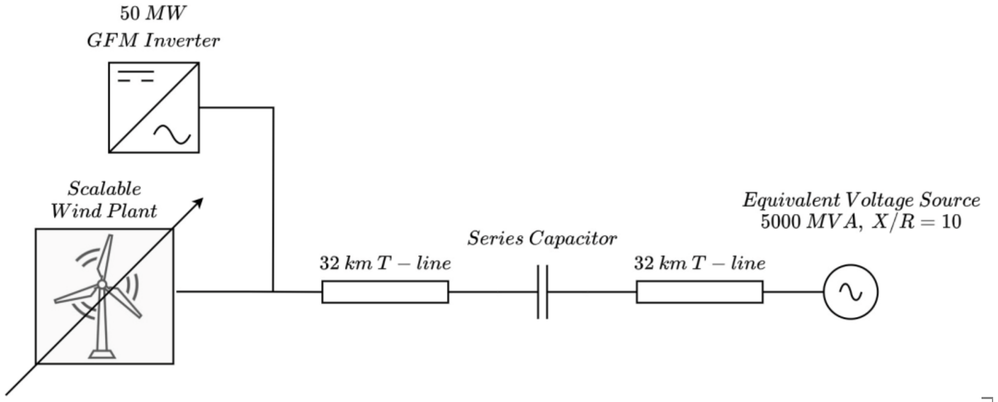
- GFM generally providing positive system damping in sub-synchronous frequency range
- Minor control changes (e.g. virtual impedance) can increase damping impact

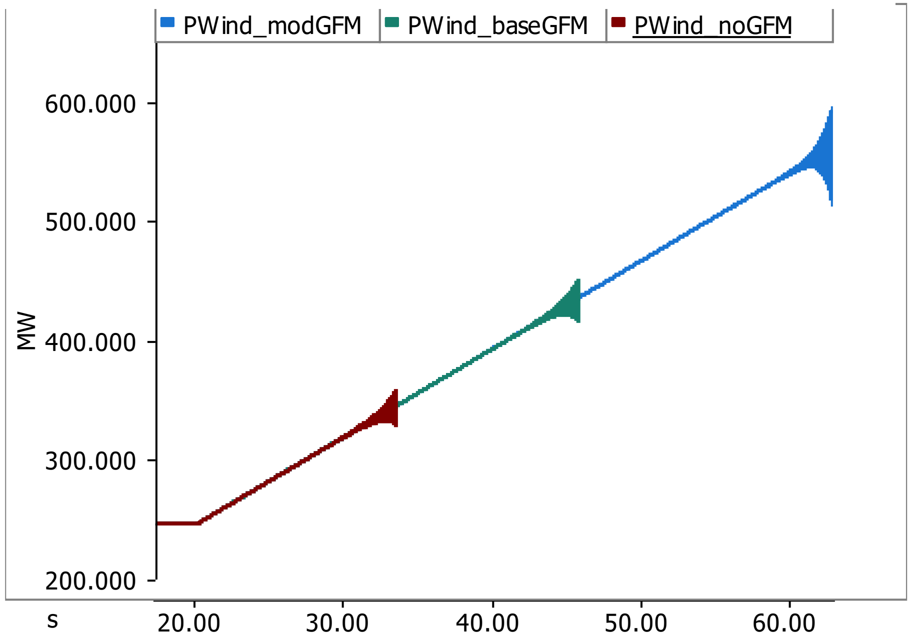


Credit: Research effort by Lukas Unruh – standby for paper or contact lu@electranix.com

Power system damping, including SSCI

- Research example shows GFM stability benefits in series compensated system with Type 3 Wind Plant
- Stable limit of Wind Plant MW output increased by 200 MW with addition of 50 MW GFM
- Relatively small amount of GFM may provide substantial stability benefits

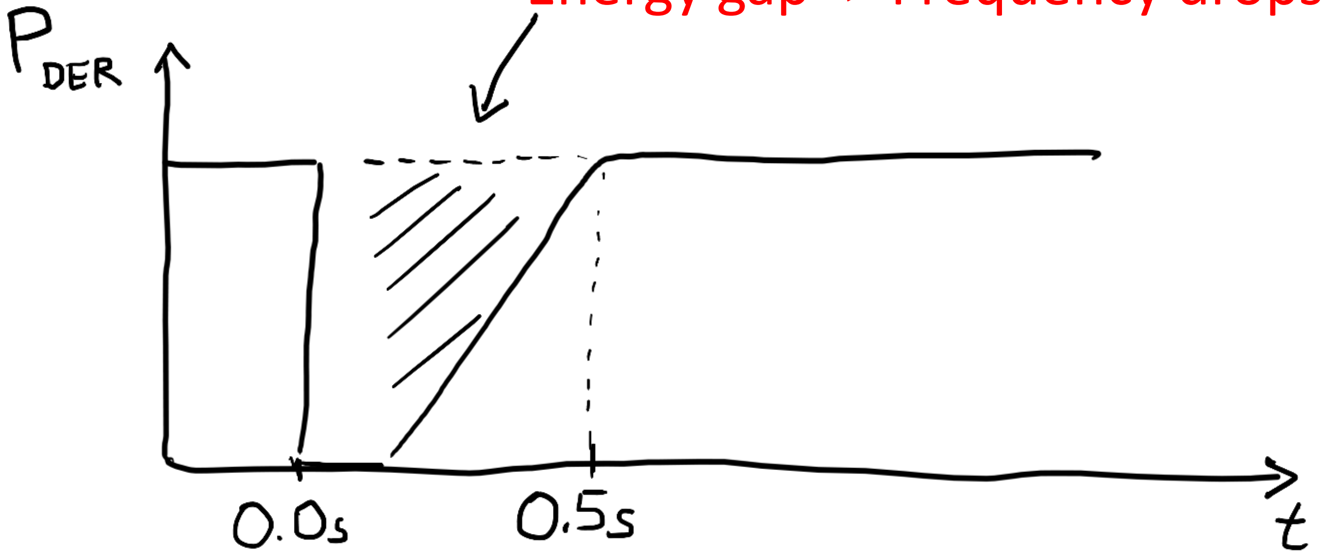


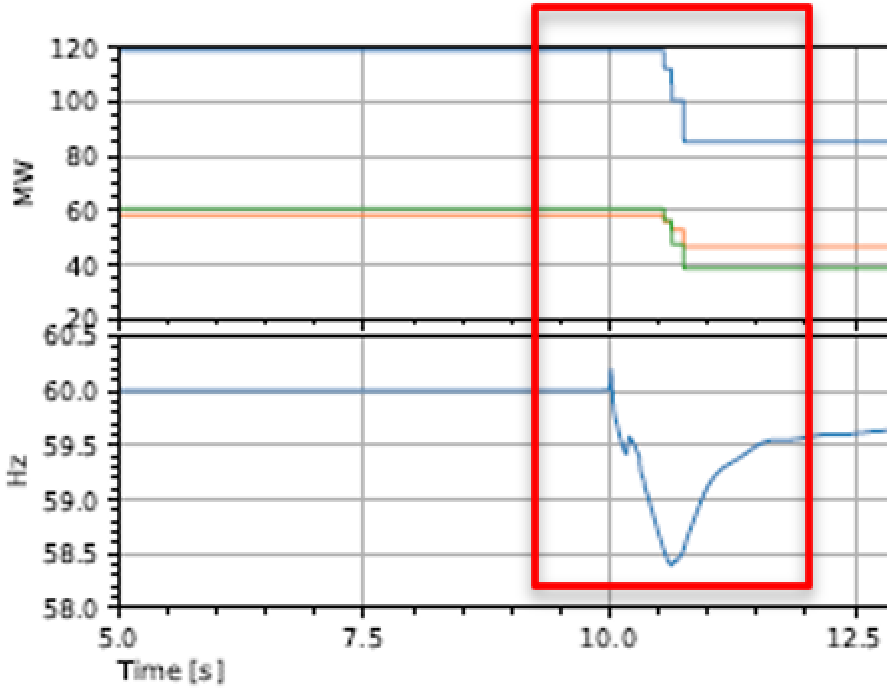


Very Fast Frequency Response Needed!

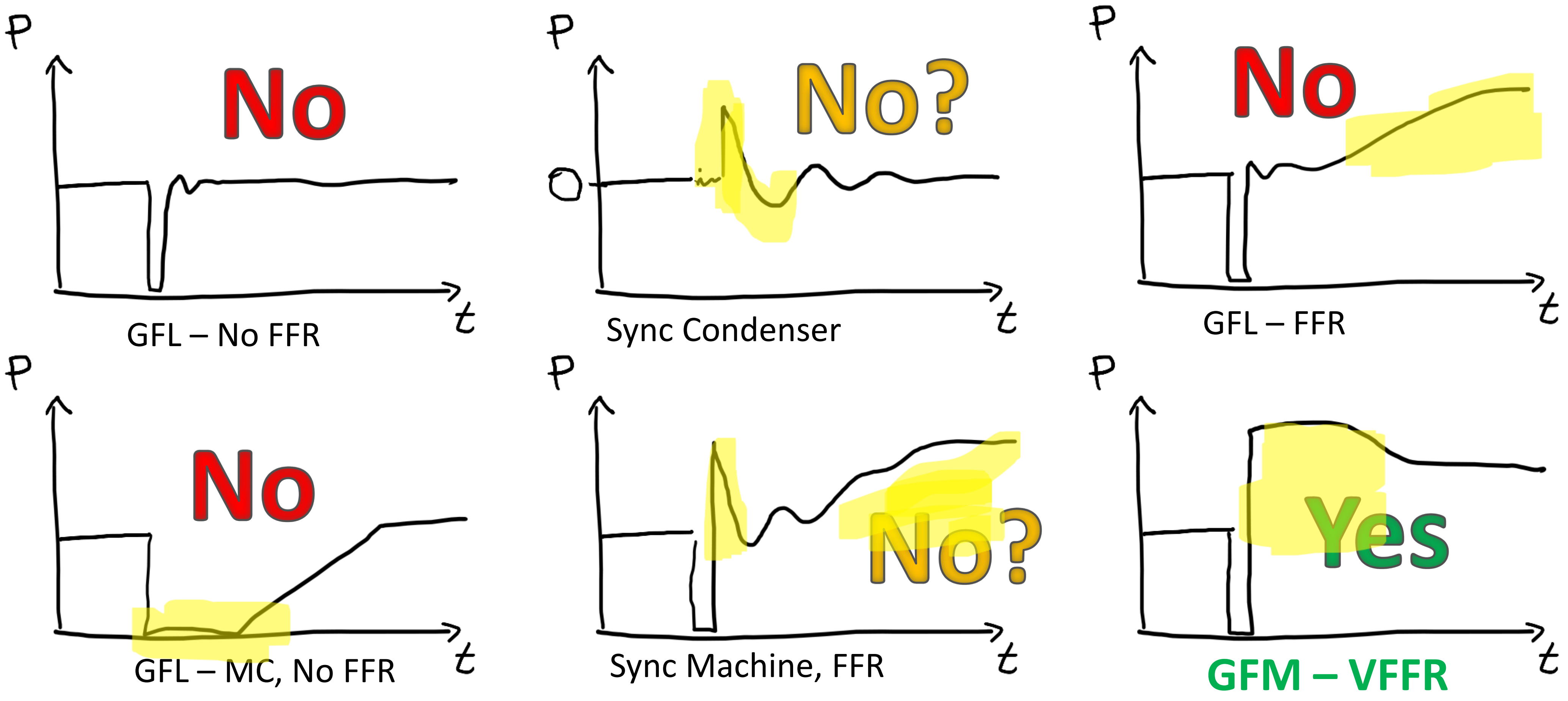
HECO: 50-70% DER penetration, with approximately 0.5 pu UV block threshold, short MC, and recovery ramp rate of 2.2 pu/s.

Energy gap -> Frequency drops!!





Very Fast Frequency Response Provided!



The following apply to *all* resources, GFM and GFL
(Ref: New NERC guide!)

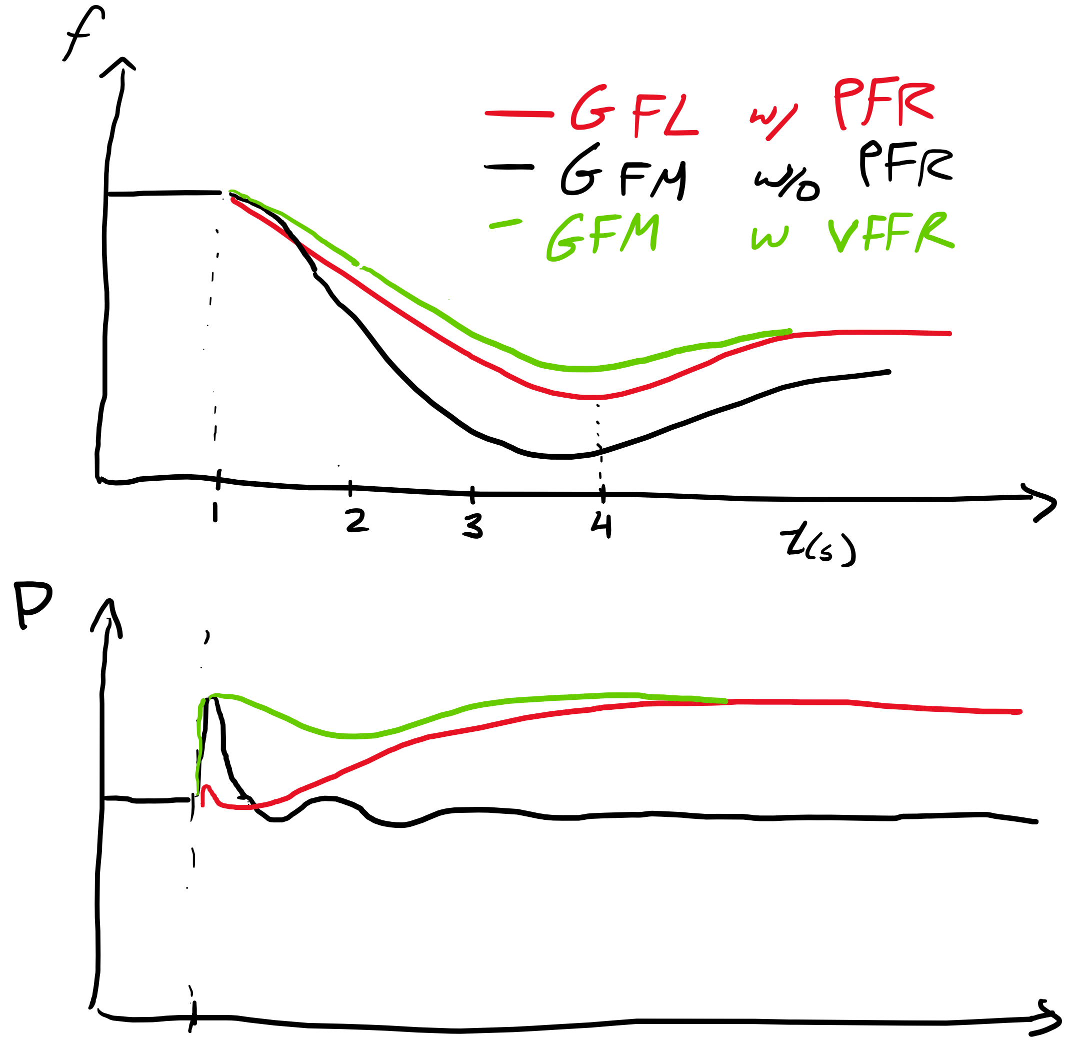
- **Dispatchability:** Capability of the facility to be dispatched (or curtailed) to a specific active power set point
- **Steady-State Voltage Control:** Capability of the facility to control steady-state voltage at the point of interconnection to a specific voltage schedule (set point and operating band)
- **Dynamic Reactive Power Support:** Capability of the facility to provide dynamic reactive support in response to normal and emergency grid conditions within the expected ride-through performance range
- **Active-Power Frequency Control:** Capability of the facility to respond to changes in system frequency by changing active power output when the resource has available headroom/tailroom
- **Disturbance Ride-Through Performance:** Capability of the facility to ride through normal grid disturbances within a defined set of parameters or expectations including faults, small and large disturbances, and phase jumps
- **Fault Current and Negative Sequence Current Contribution:** Capability of the facility to provide fault current, including negative sequence current to mitigate unbalanced voltage conditions
- **Security:** Capability of the facility to ensure cyber and physical controls are in place to ensure resilience to potential threats.

Additional Functional Specs for GFM BESS

1. **GFM-Specific Voltage and Frequency Support:** GFM shall provide autonomous, near-instantaneous frequency and voltage support by maintaining a nearly-constant internal voltage phasor in the sub-transient time frame.
2. **Seamless Transition between Islanded and Grid-Connected Operation:** GFM shall be able to seamlessly respond (based only on its local measurements) to changes from a larger synchronous grid condition to an islanded grid condition with no synchronous machines (and back again), and continue to help maintain nominal voltage and frequency up to its equipment capabilities. Beyond the sub-transient time frame, GFM shall adjust its power output to maintain synchronism with other resources.
3. **Ability to Stably Operate with Loss of Last Synchronous Machine:** GFM shall be able to stably operate through and following the disconnection of the last synchronous machine in its portion of the power grid.
4. **Phase Jump Performance:** GFM shall resist near-instantaneous voltage phase angle changes by providing appropriate levels of active and reactive power output in the sub-transient time frame.
5. **System Strength:** GFM shall reduce the change in voltage for a given change in current in the sub-transient time scale (i.e., improve the strength of the local network of connection).

System vs. Local Inertial response

- Depending on the size or the inertia of the overall system, the key elements of needed frequency response change.
- GFM doesn't inherently provide optimal response, it needs to be tuned.
- GFL may be able to provide what you need!



Additional key technical points:

- GFM is currently commercially available in BESS technology.
- Cost for GFM is expected to be marginally higher than GFL in BESS in the short term, and eventually there may be no cost difference. Some OEMs are already saying there is no cost difference.
- Existing GFL BESS may or may not be upgraded to GFM at a future date, depending on vendor.
- GFM is currently being advertised as available by 2 STATCOM vendors
- GFM is *not* currently widely available in PV or wind technology, due to potentially large cost increment stemming from increased energy and current headroom requirements.

Large Loads - Overview

Topic Change

Types of Large Loads: Hyperscale Cloud

- Purpose: IT resources for shared use across the internet.
- Owned by: Cloud service providers (CSPs)
- Size: 10's to 100's of MW
- Examples:
  - Amazon Web Service (AWS), Google Cloud Platform, Microsoft Azure
  - Netflix, Amazon shopping, Office 365, Google search, etc.
- Interface Hardware:
  - Cooling by Variable Speed Drive, sometimes with active filter
  - IT infrastructure behind distributed power distribution, behind UPS
  - Office lighting and admin computing
  - Diesel generator backup

Types of Large Loads: Crypto Mining

- Purpose: Calculation of Bitcoin, Ethereum, and other Cryptocurrency tokens.
- Owned by: Private developers
- Interface Hardware:
  - Cooling by natural wind or forced air
  - IT infrastructure behind small power supplies (no UPS)
  - No generator backup

Types of Large Loads: AI Inference

- Purpose: Distributed user requests to access trained models.
- Owned by: Private developers or Hyperscale AI
- Size: 100's to >1GW
- Examples:
  - Google gemini search, GPT user requests, etc.
- Interface Hardware:
  - Similar to hyperscale cloud computing, but potentially lower reliability requirement (eg. may use UPS)

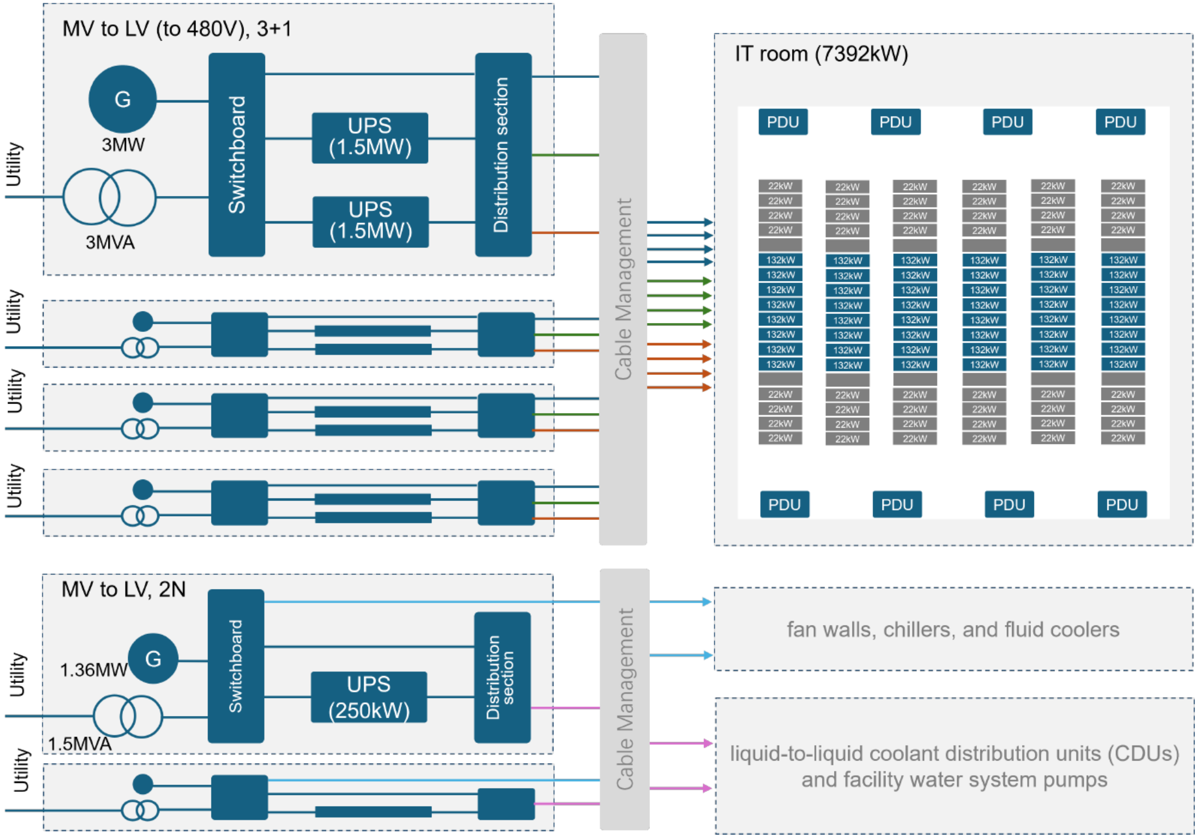
Types of Large Loads: AI Training

- Purpose: Training major AI models for use in inference.
- Owned by: Private Developers or Hyperscale AI
- Size: 100's to >1 GW (in aggregate up to 5 GW)
- Examples:
  - Microsoft, Oracle, xAI, Amazon, Meta
- Key Feature: Variable active power output.
- Interface Hardware:
  - Same as AI Inference

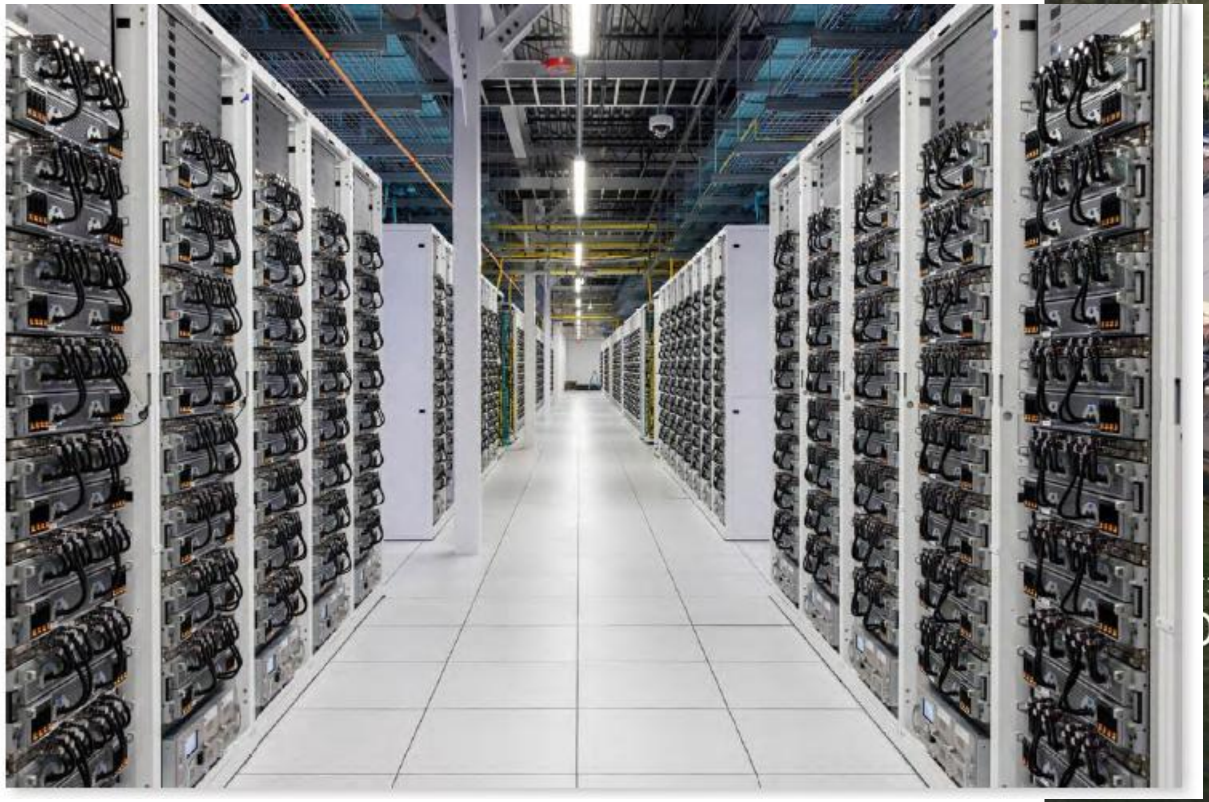
What does an AI load look like?

- 250 MW "Colossus"
- 200K GPUs
- Built in 122 days
- 2M gallons of water per day (est.)
- $10bn (est.)

10 MW piece

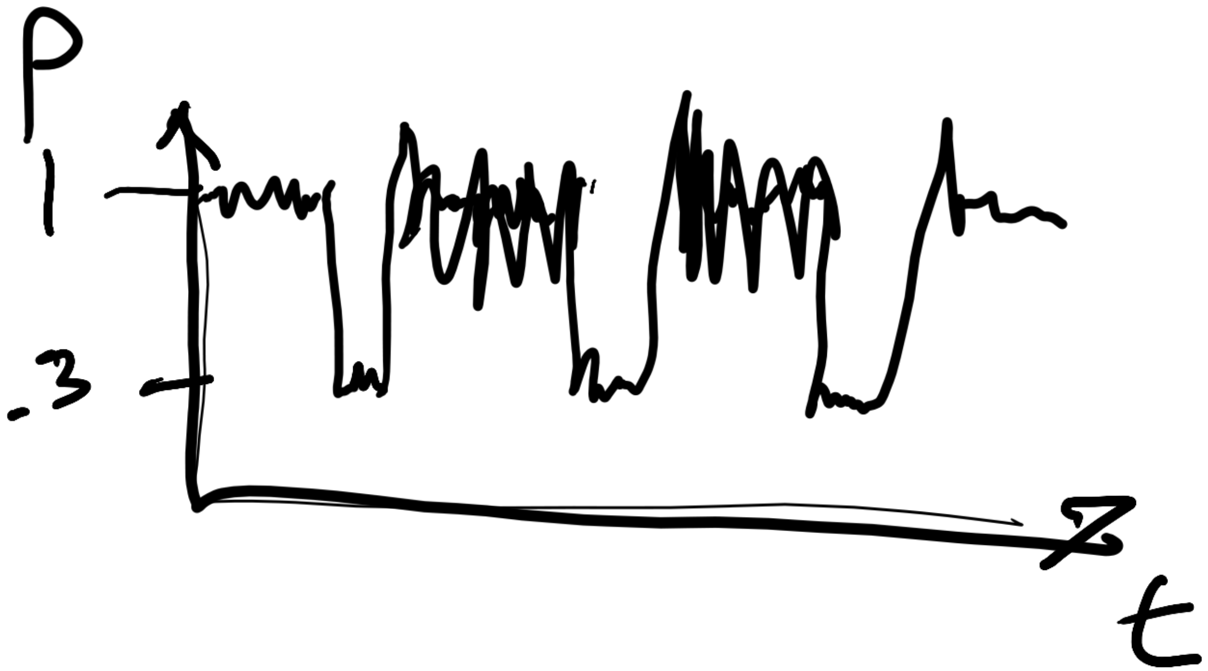


“Colossus” xAI data center (250 MW)



Summary of reliability risk categories

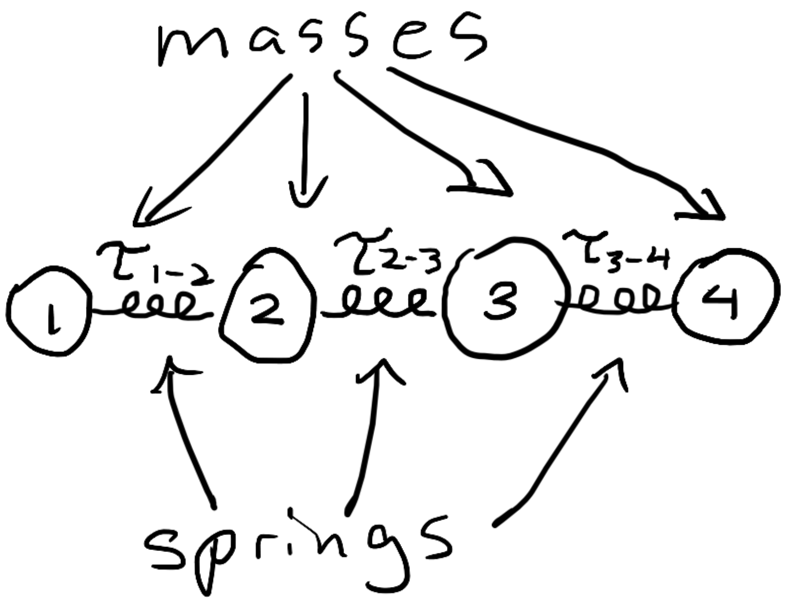
- The following are categories of risk that may drive requirements and/or studies:
  - **Basic powerflow considerations**
  - **Active power variation**
    - Synchronous generator damage
    - Flicker
    - Machine mode oscillations
    - Interarea oscillations
  - **Ride-through failure**
    - Load rejection overvoltage
    - VAR adequacy
    - Resource adequacy
  - **Passive damping**
    - SSCI instability

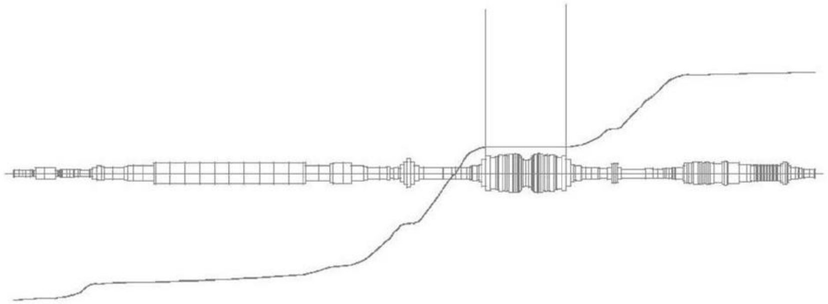


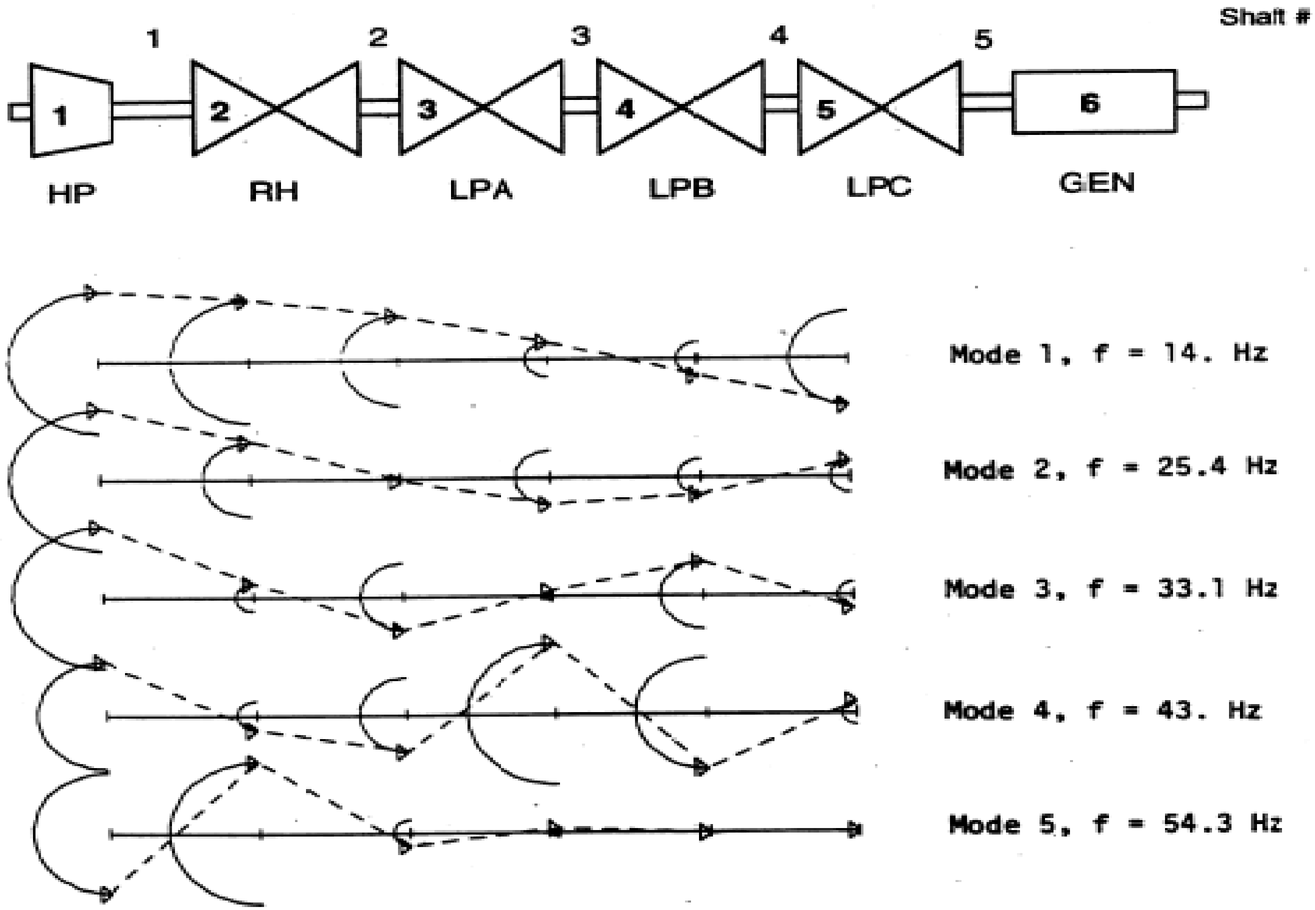
Basic Powerflow Studies:

- **Ensure the following:**
  - Sufficient generation exists (careful with “imports will handle it”)
  - Can serve the full load under outage conditions
  - VARs available to control the voltage for various transfer scenarios
  - VARs available for fast changes in load

Reminder… Synchronous Generator Shaft



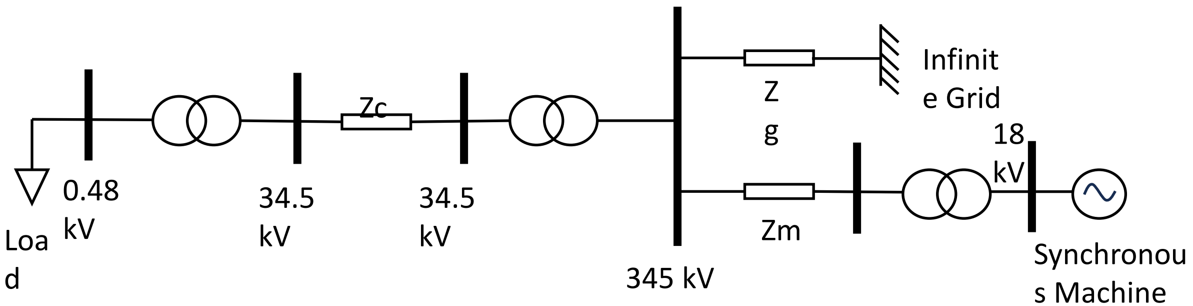




Active Power Variation Studies:

- **Synchronous generator damage risk evaluation:**
  - EMT simulation is required
  - Model detail of synchronous machine shaft system
  - Use various load profiles to force oscillations into the grid, including components of torsional frequencies
  - Measure generator shaft torques and terminal active power variation
  - Compare the torque and active power against machine long term capabilities
  - Alternative: compare load output power against variation criteria.
- **Data Required:**
  - Synchronous machine shaft models
  - Range of potential load profiles
  - Detailed grid model
  - Mechanical and electrical limit data for machines, or requirement criteria

Example (ERCOT study)



Key Parameters:

- Machine Rating = 100 MW
- **Synchronous machine key torsional mode: 12 Hz**
- Load profiles:
  - Profile 1 (S1 – S8): Fixed frequency square wave varying between 25 MW and 100 MW with a ramp rate of 10 MW/1ms
  - Profile 2 (S9 – S16): Proxy waveform mimicking measured AI training load profile

Scenario No.	Load Variation	Max Pk-Pk Active Power Variation* (Generator electrically close: Zm = 0)			Alternating Torque	
		At the Load	At the Machine	At the Grid	Tau12 (pu)	Tau23 (pu)
	Hz	MW	MW	MW		
S1	Load profile 1 at 2 Hz	76.81	32.98	77.81	0.233	0.234
S5	Load profile 1 at 12 Hz	77.61	11.89	82.55	5.124	5.028
S9	Load profile 2	85.55	6.21	87.44	0.042	0.042
S13	Load profile 2 with 12 Hz oscillations	88.86	8.09	92.22	0.993	0.974

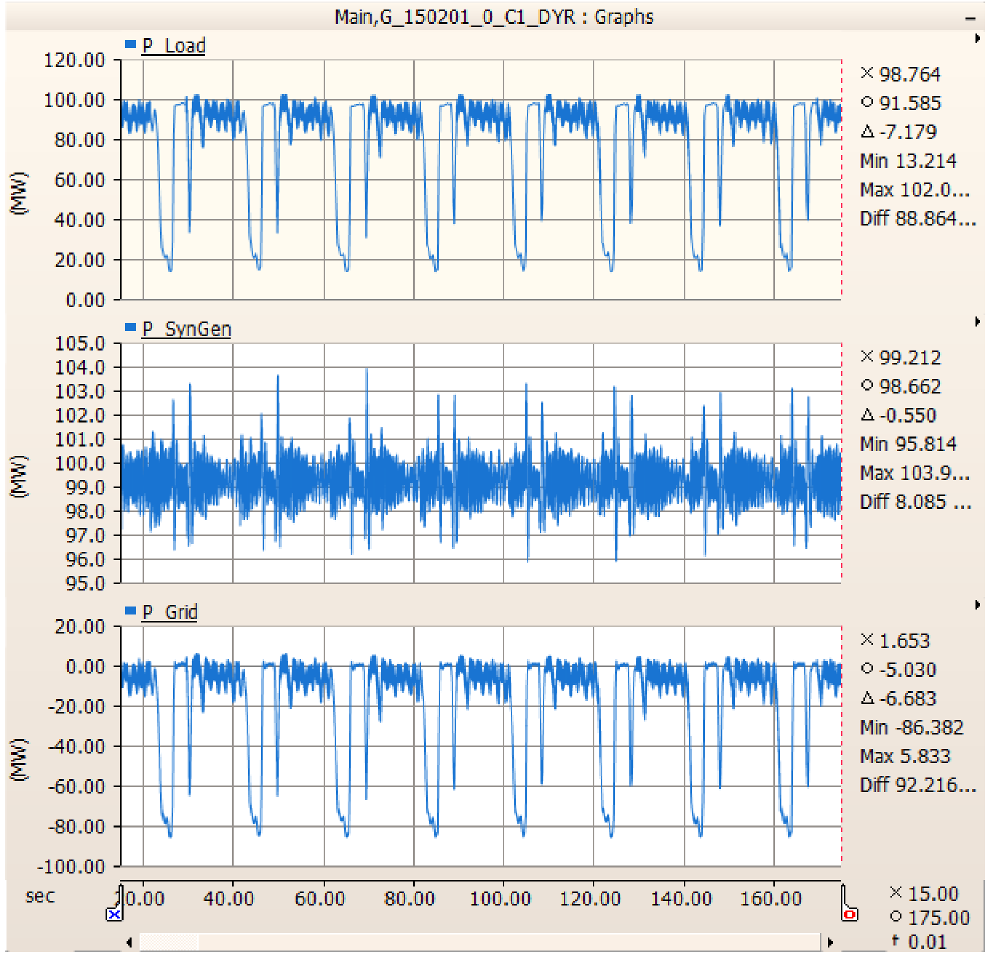
**Note: Split of active power between machine and grid is initially determined by impedance split, and the final variation will depend on the frequency of the variation and other machine characteristics over time. Ref. ERCOT LLWG October 24 meeting:*

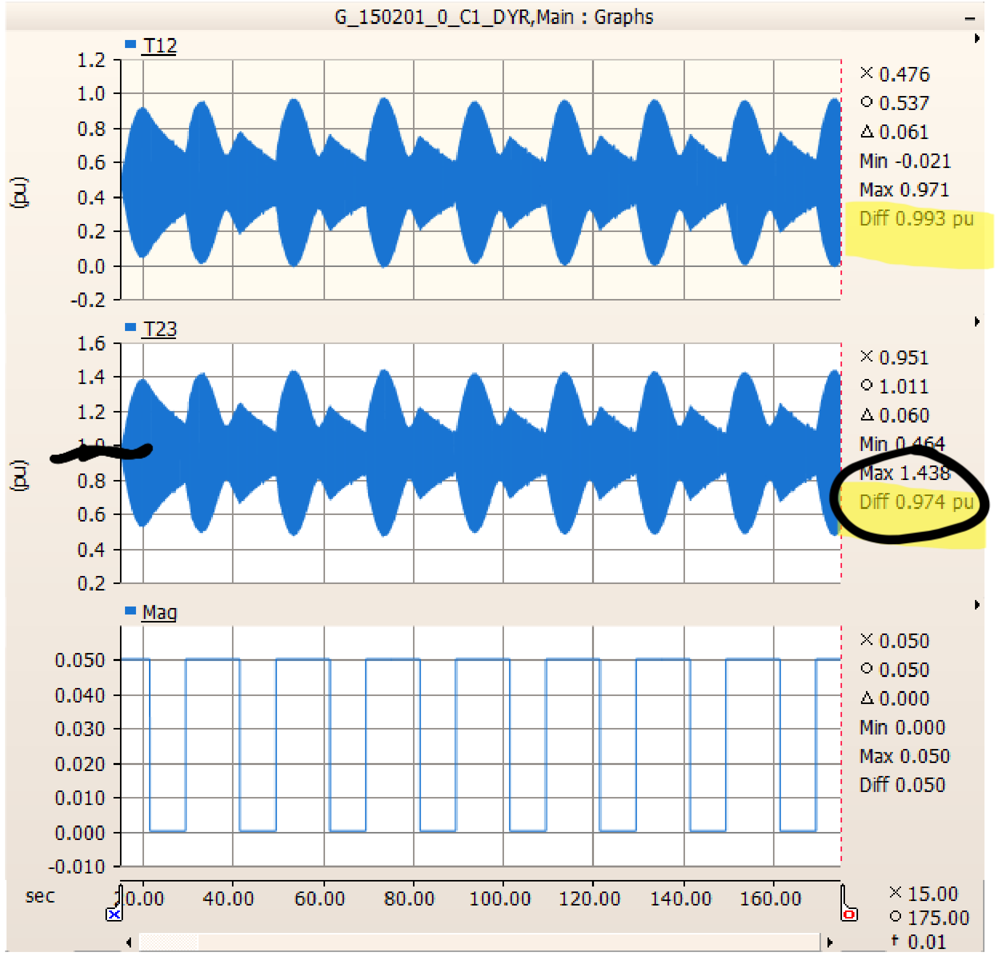
Load profile 2 with 12 Hz – Scenario S13 (similar to paper on slide 6) **1pu Torque… strong Torque Amplification!**

P Load

P Gen

P Grid





Torque 12

Torque 23

Per unit 12 Hz Component

Some additional study challenges

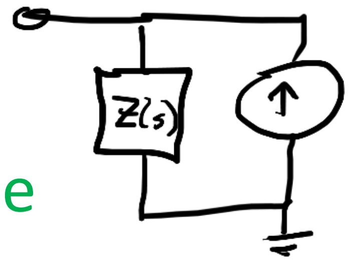
- Data is **very hard** to get for load
  - Limits on load variation
  - Harmonic profiles
  - Sufficiently detailed models to quantify damping
  - Ride-through capability
- Data is **very hard or impossible** to get for synchronous machines
  - Multi-mass data
  - Physical design limits
- Studies require specialist skills (EMT experts with special training)

Active Power Variation Studies:

- **Flicker:**
  - EMT simulation may be required
  - Flicker can be evaluated simply using powerflow tools (worst case)
  - Flicker can be more precisely quantified using simulated flicker meters
- **Data Required:**
  - Range on load profiles, particularly ramp rates, magnitudes, and frequency content limits
  - Measurements are useful

What about harmonics?

- Some events were recorded of large harmonics associated with data centers…
- What is needed is a frequency dependent Norton equivalent source
- Perturbation techniques can be used to derive impedances, and currents can be measured in strong testbeds (EMT and/or site measurement)



Study!

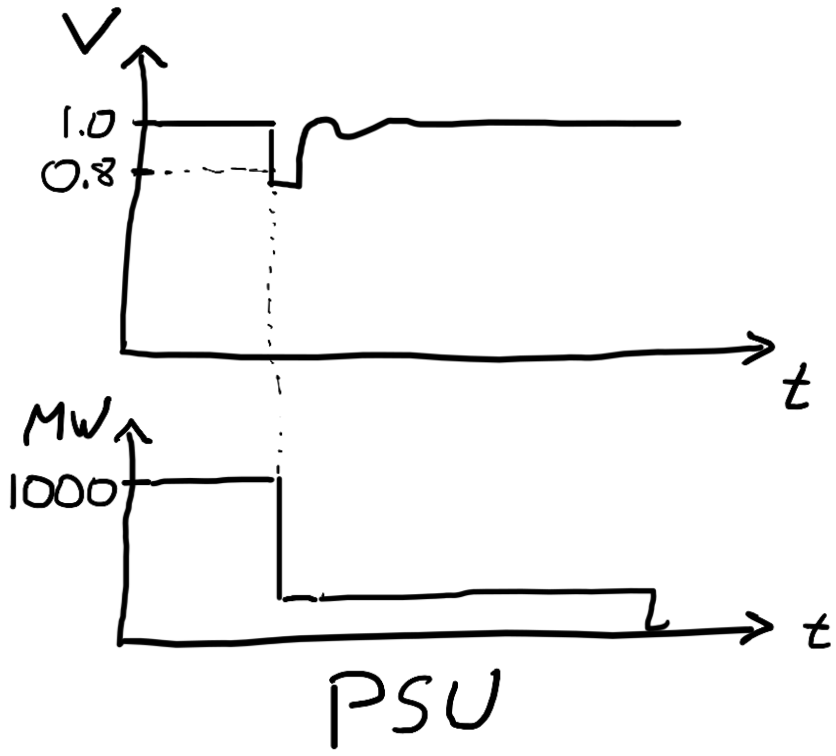
- Frequency-dependent impedance characterization is done for the external system under many operating conditions
- Harmonic sources are added
- *Multi-port* harmonic "powerflow" is calculated to create a family of possible voltage amplifications, add existing measured background harmonic voltage distortion, and check harmonic voltage distortion, and harmonic current ratings of equipment

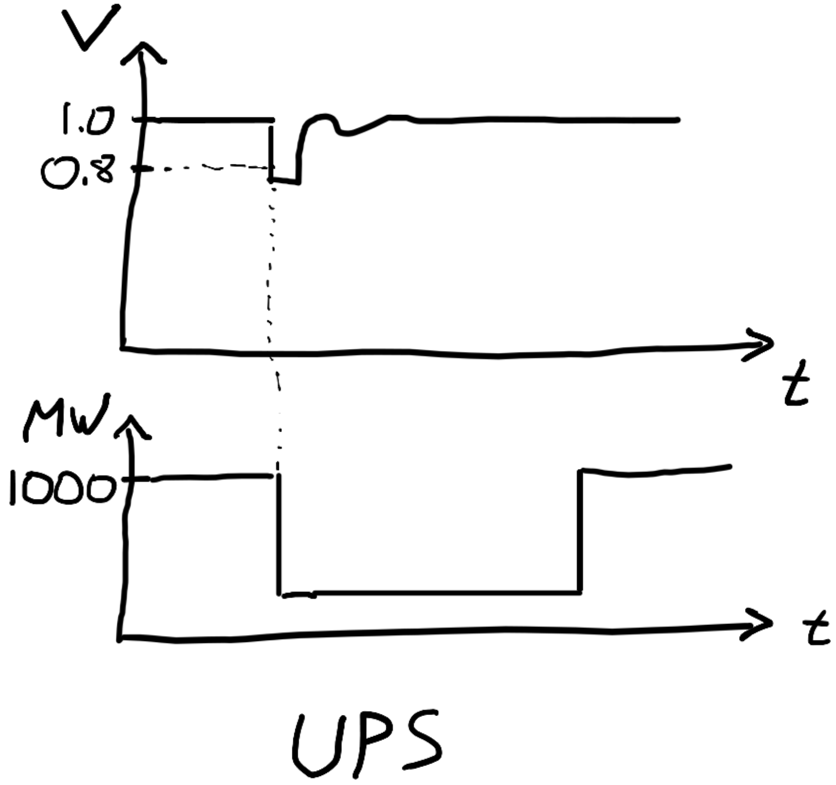
Active Power Variation Studies:

- **Machine mode oscillations and interarea oscillations :**
  - Phasor domain (transient stability) tools are used to force the load at key machine or system modes
- **Special data required:**
  - Transient stability models for load with flexible variation profiles
  - Range on load profiles
  - Detailed grid model
  - Data on machine mode frequencies
  - Data on interarea mode frequencies and drivers for oscillations (if interarea oscillations are being studied)

Ride-through background…

- Small voltage depressions may lead to load disconnections…



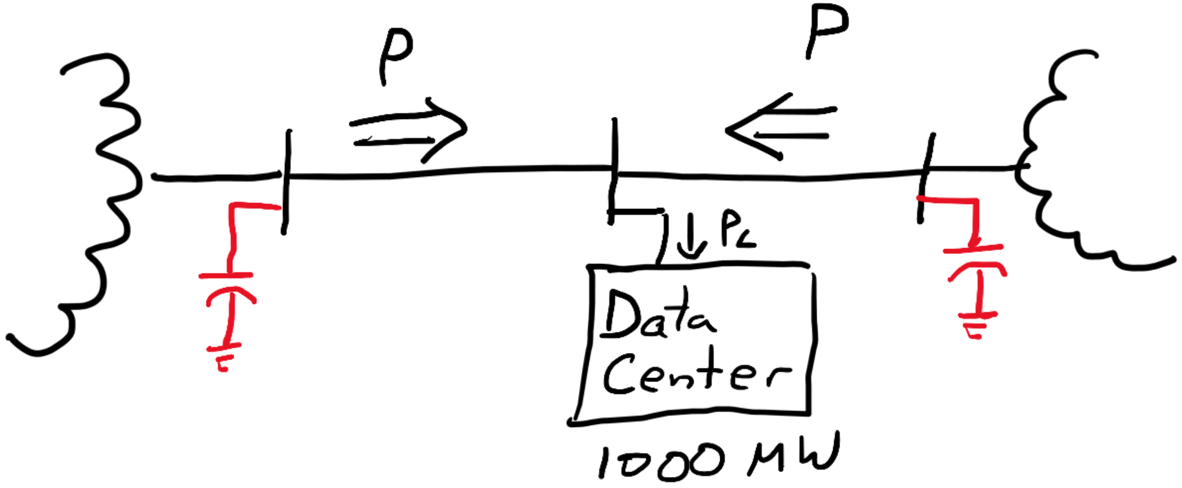


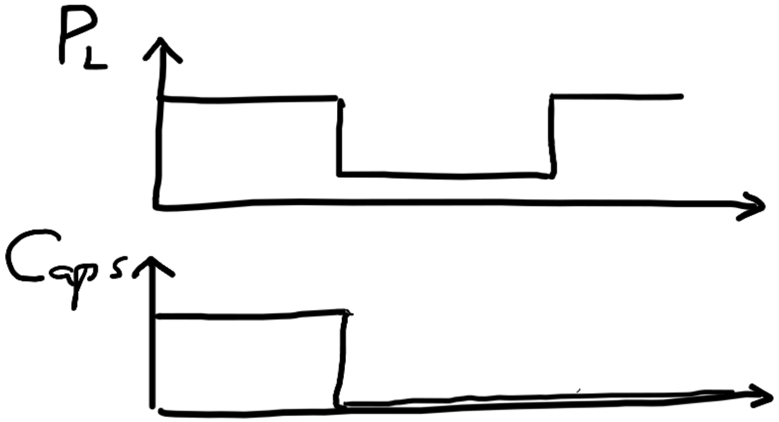
Ride-Through Impact Studies

- Need to ensure that bulk regional disconnection and reconnection (or not) of load will not:
  - Cause load-rejection temporary overvoltage
    - Results in IBR or STATCOM tripping
  - Cause problems with VAR adequacy or dynamic voltage problems (for example if the capacitors don't reconnect)
  - Adversely impact frequency of the grid
  - Impact generator resource commitment or create dispatching problems.
  - Study tools may be a mix of Phasor Domain and EMT
- **Special data required:**
  - Ride-through characteristics of the load
  - Ride-through characteristics of nearby devices in the system

Thinking about dynamic VARs!

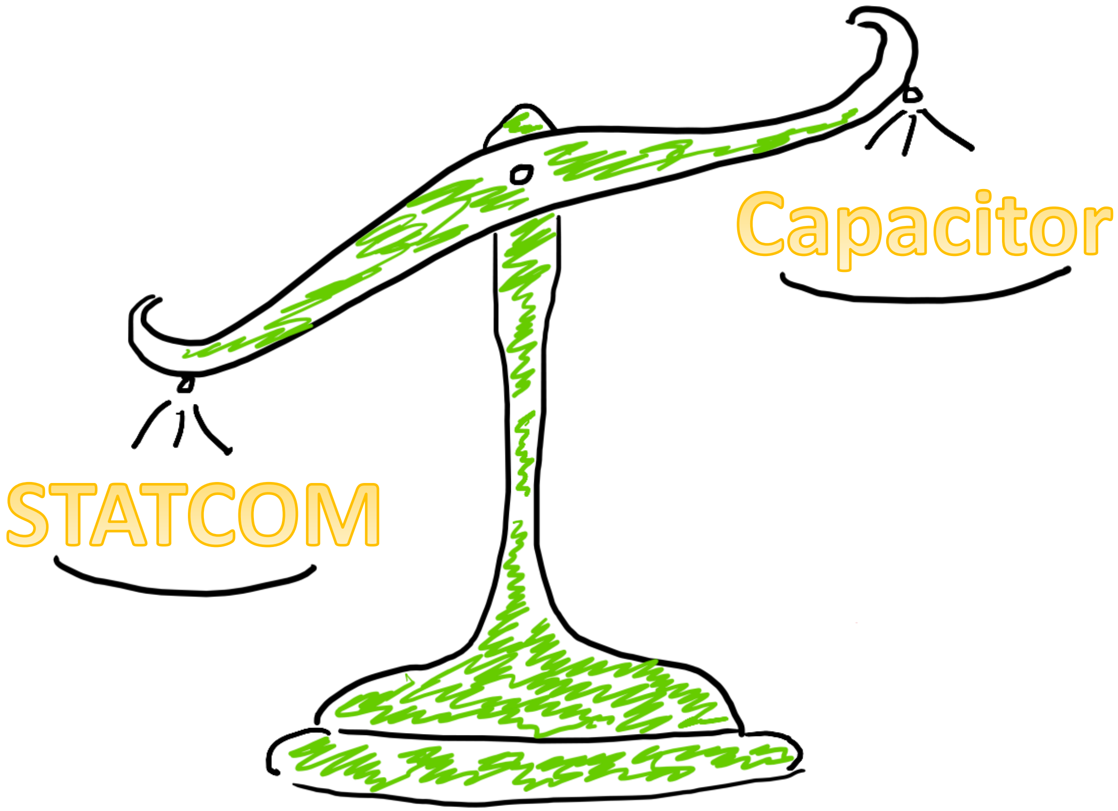
- Steady state voltage studies (powerflow) are usually used to determine VAR requirements. Shunt caps are the preferred option to regulate load transfers because they are cheap, and traditionally load doesn't move too fast. Dynamic VARs are often used for load when voltage recovery is problematic (eg. induction motor loads). But…





What is the problem with switched Caps?

1. Caps can be switched off, but not immediately switched on (without special designs). Large, fast load changes will drive large, fast voltage changes!
2. Switching caps causes transients on the system, and wear and tear on breakers.
3. Caps weaken the power system by increasing effective 60 Hz impedance.
4. Caps increase the likelihood of problematic harmonic resonances in the system.
5. **STATCOM solves all of the above, but requires money and time!**

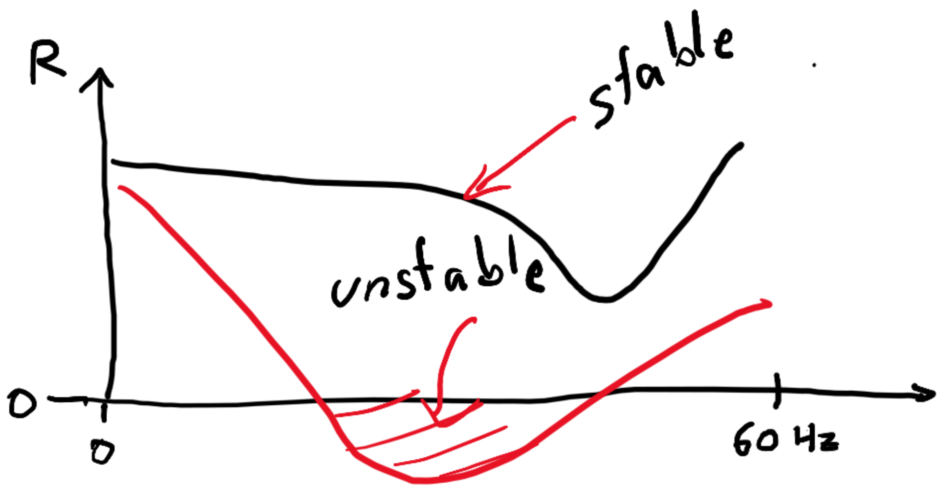


Passive Damping Studies

- SSCI and SSTI are well known phenomena whereby power electronic controls add to or remove damping from the grid.
- If damping becomes negative at an electrical resonance point (eg. Series caps) or at a mechanical resonance point (eg. Machine torsional), instability can occur.
- Study is performed in EMT using very detailed models

Special data required:

- Dynamic impedance characteristics of the load
- Dynamic model of the rest of the grid



What kind of models do you need?

- As always, it depends on what kind of study you're doing…
- You need to collect the appropriate models for the type of concern you are evaluating!

EMT model ≠ EMT model

PDT model ≠ PDT model

Study/model matrix…

Concern	EMT Model with protection (OEM specific)	EMT Model including switching circuitry (OEM specific)	EMT Model including grid-facing control representation (OEM specific)	EMT Model with software cycling (OEM agnostic)	OEM Specific Harmonic Model (Norton Source)	Powerflow Model	PDT Model with software cycling	PDT Model without software cycling
SSTI screening (eg. UIF)	No	No	No	No	No	Yes	No	No
SSTI due to software cycling	No	No	No	Yes	No	No	No	No
Torque impact due to fast changes in load	No	No	No	Maybe	No	Maybe	Maybe	No
SSTI due to control damping	No	No	Yes	No	No	No	No	No
SSCI due to control damping	No	No	Yes	No	No	No	No	No
Harmonic model creation	No	Yes*	Yes*	No	No	No	No	No
Harmonic evaluation	Maybe	Maybe	Maybe	Maybe	Yes	No	No	No
Flicker evaluation	No	No	No	Maybe	No	Yes	No	No
Ride-through sensitivity	Yes*	No	Yes*	No	No	No	No	No
Ride-through impact	Maybe	No	Maybe	No	No	No	No	Maybe
Frequency impact	Maybe	No	No	No	No	No	No	Maybe
IBR/FACTS interaction impact	Maybe	No	Maybe	Maybe	No	Maybe	Maybe	Maybe
Machine mode oscillations due to software cycling	No	No	No	Maybe	No	No	Yes	No
Interarea oscillations	No	No	No	No	No	No	Yes	No
Resource balancing due to ramping	No	No	No	No	No	Yes	No	No
Steady state constraints	No	No	No	No	No	Yes	No	No
Dynamic VAR margin	No	No	No	No	No	Yes	No	Yes

**Alternative to EMT modeling could be detailed laboratory testing on OEM specific equipment*

Large Loads – Requirement Philosophy

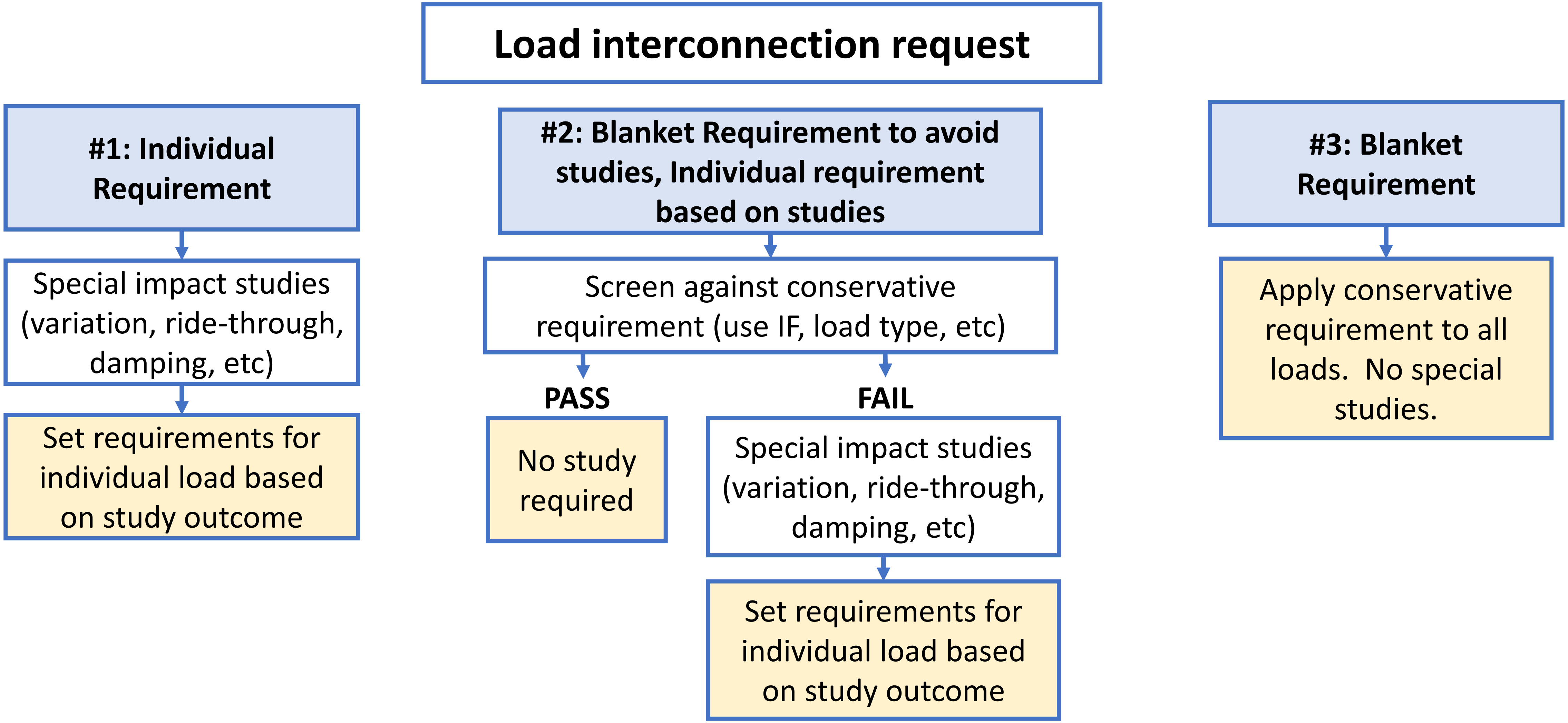
Topic Change

Summary of reliability risk categories

- The following are categories of risk that may drive requirements:
  - **Active power variation**
    - Synchronous generator damage
    - Flicker
    - Machine mode oscillations
    - Interarea oscillations
  - **Ride-through failure**
    - Load rejection overvoltage
    - VAR adequacy
    - Resource adequacy
  - **Passive damping**
    - SSCI instability

Also consider…
- Power factor requirements
- Modeling requirements
- Test and verification requirements
- (future) Voltage control? Frequency control? Damping?

Competing Philosophies for Requirements:



Requirement Philosophy Pros and Cons:

#1: Individual Requirement

Pros:
- Maximum load flexibility

Cons:
- Very heavy study burden
- Re-study may be needed if grid or load changes
- You may find yourself with zero margin

#2: Blanket Requirement to avoid studies, Individual requirement based on studies

Pros:
- Expedited time frames for remote projects over alternative #1

Cons:
- Study burden still heavy
- Re-evaluation may be needed if grid or load changes
- Possibility to miss issues depending on screening approach
- You may find yourself with zero margin again

#3: Blanket Requirement

Pros:
- No study required.
- Accommodates future changes to the grid

Cons:
- Possibility to over-constrain loads, which costs money and may make theoretically good projects unfeasible.
- Possibility to miss issues if requirements are set incorrectly

Some additional study challenges

- Data is **very hard** to get for load
  - Limits on load variation
  - Harmonic profiles
  - Sufficiently detailed models to quantify damping
  - Ride-through capability
- Data is **very hard or impossible** to get for synchronous machines
  - Multi-mass data
  - Physical design limits
- Studies require specialist skills (EMT experts with special training)

Framework alternatives – Active Power Variation

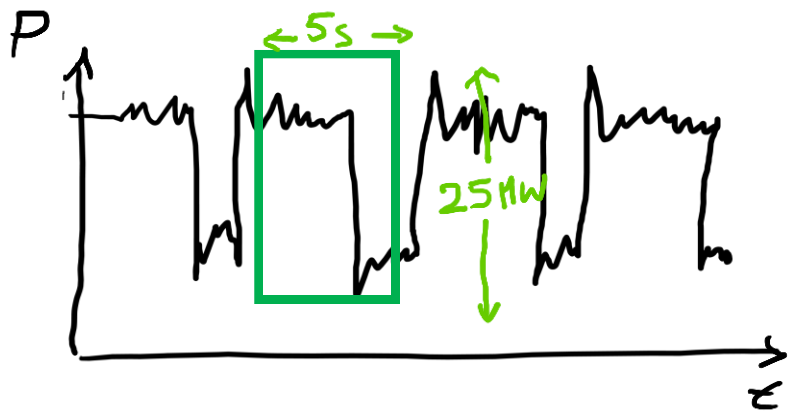
1. Limit harmonic/sub-harmonic content in load active power.

   Pros:
   - Can target frequency ranges and limit magnitudes according to equipment limits
   - Allows varied load profiles provided key frequencies aren't introduced

   Cons:
   - Requires very careful specification of frequency content measurement
   - Requires understanding of how frequencies interplay with each other
   - Requires understanding of how duration of perturbations interacts with magnitude of perturbations.
   - May be more difficult to monitor and enforce, and more difficult to conceptualize.
   - Data center loads may not be able to avoid certain frequencies.

Framework alternatives – Active Power Variation

2. Limit absolute variation magnitude.



Pros:

- Conceptually simple to understand
- Addresses multiple concerns
- Allows any type of load variation within the magnitude limit.

Cons:

- Hard to choose a single value that protects equipment adequately and doesn't over-constrain load shapes.

Framework considerations – Ride through

- You can use a ride-through profile (similar to IBR FRT curves) but…
  - Does that mean no-trip or no-temporary-reduction (eg. UPS pickup)?
  - If temporary reduction is allowed, how fast should they return? 1s?
    - Note: Consider frequency, load-rejection overvoltage, dynamic voltage control, and how many loads may trip together for a common event.
  - Load rejection of multiple collocated loads could cause significant temporary overvoltage. **How can we fix this?**
- Consider that many or maybe most loads will not be able to initially meet this criteria, particularly if you don't allow temporary reduction.

Example requirement: ATC

- Load Interconnection Guide, rev 15 – published August 22, 2025 (pages 32-35)
- ATC Planning Criteria, V25 – published August 28, 2025 (pages 34-37)
- Uses a blanket requirement, but allows studies to prove exceptions.

#2: Blanket Requirement to avoid studies, Individual requirement based on studies

- Uses absolute variation magnitude limit:

  <25 MW over any 5 second period

ATC	Criteria	Department:	System Planning
		Document No:	PLG-CR-0001-V25
Title: Transmission System Planning Criteria		Issue Date:	August 28, 2025
		Previous Date:	February 4, 2025

ATC

Load Interconnection Guide

Revision 15.0
August 22, 2025

Example Criteria: ATC (Loads >200 MW)

ATC	Criteria	Department:	System Planning
		Document No:	PLG-CR-0001-V25
Title: Transmission System Planning Criteria		Issue Date:	August 28, 2025
		Previous Date:	February 4, 2025

ATC

Load Interconnection Guide

Revision 15.0
August 22, 2025

9.2 Voltage Ride Through

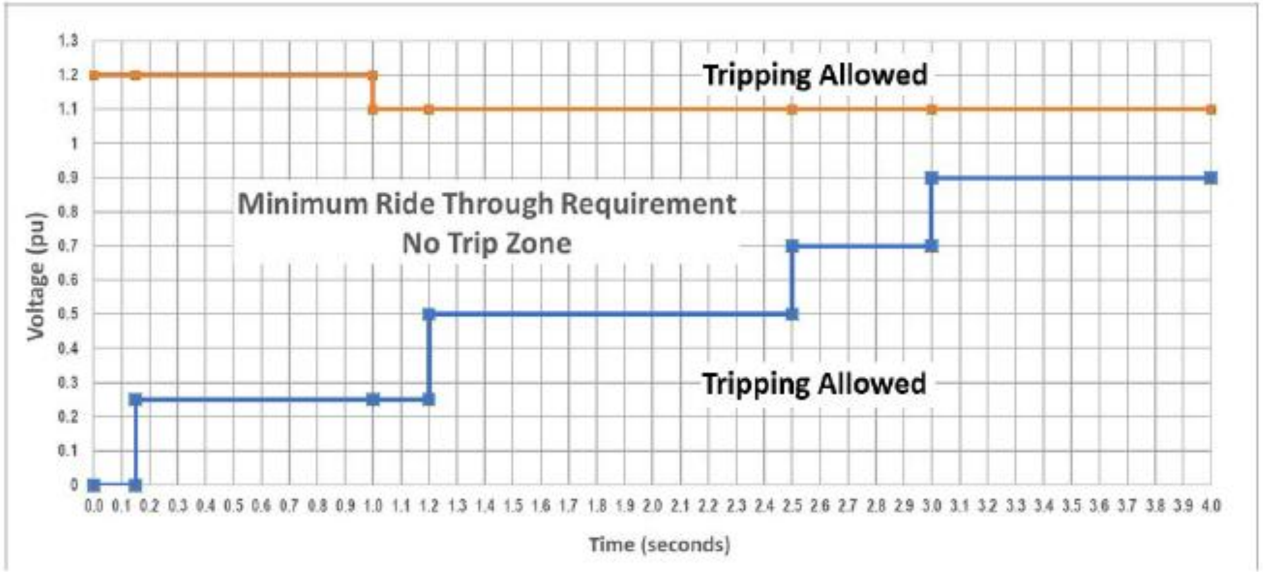


Figure 9.2-1: Voltage Ride Through Curve for Large Loads

POI Voltage (pu)	Minimum ride-through time (s)
V > 1.20	May ride-through or trip
V > 1.10	1
V > 1.05	Continuous
V < 0.90	3
V < 0.70	2.5
V < 0.5	1.2
V < 0.25	0.15

Note 1: Load must ride through 3 voltage deviation events within 10 seconds

Note 2: POI Voltage is at the connection point to the ATC transmission system. For ride-through, the relevant voltage is the lowest (in the case of undervoltage) or highest (in the case of overvoltage) magnitude fundamental frequency phasor component of the applicable voltages at the POI relative to the nominal voltage. Instantaneous phase voltages may exceed these levels.

Note 3: Load should not trip for instantaneous transients due to normal system events such as faults, energization or switching.

Example Criteria: ATC (Loads > 200 MW)

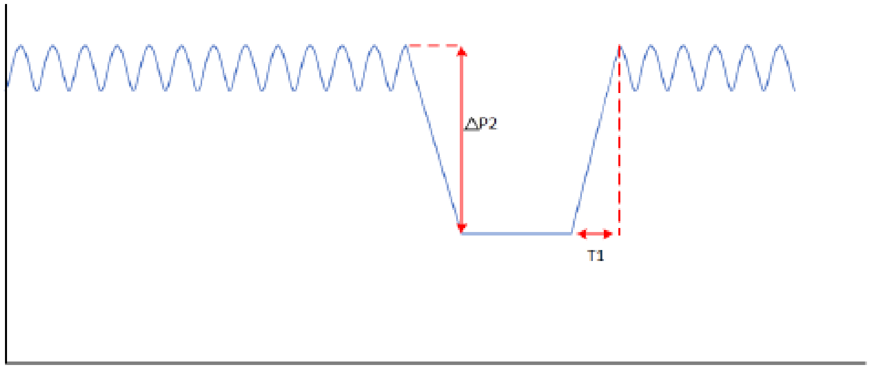
Table 9.1-1: Active Power Oscillation Criteria Limits

Constant	Limit	Unit
ΔP2	25	MW
T1	5	seconds
P3	50	MW
R2	0.5	MW/second (MW/s)

9.1 Load Active Power Oscillations & Ramp Rate Limits

Customer's equipment/facility shall be designed and operated within the maximum allowable variation limit of steady state (continuous load operation) active power oscillations as follows and as measured at the point of connection to the ATC transmission system. Note that these values are the total aggregate values for all sites at a given point of interconnection, or at multiple sites if oscillations are driven by common processes across multiple sites.

Criterion 1: Repetitive changes in load active power must be <ΔP2 for any period of time <T1 seconds calculated using a sliding time window.



Criterion 2: Any change (increase or decrease) in active power >P3 MW should be limited to <R2 MW/s.

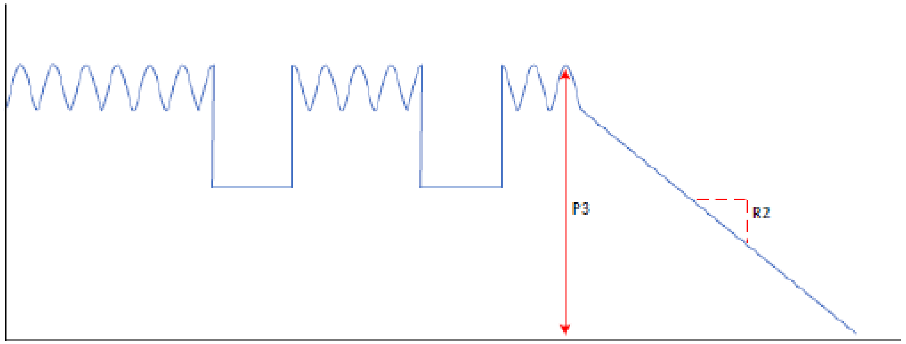


Figure 9.1-4: Active Power Criterion for P3 and R2 Example

Mitigation of large active power variations

Topic Change

Variability Mitigation

- "Load floor"
- HV/MV energy storage
  - E-STATCOM with or without GFM BESS
- DC level (power supply) storage (eg Nvidia GB300 or DC storage)
- Low voltage GFM BESS or GFM BESS behind series reactor
- Full conversion UPS with large energy storage or supercapacitors
- Thyristor switched resistor
- Software mitigation?

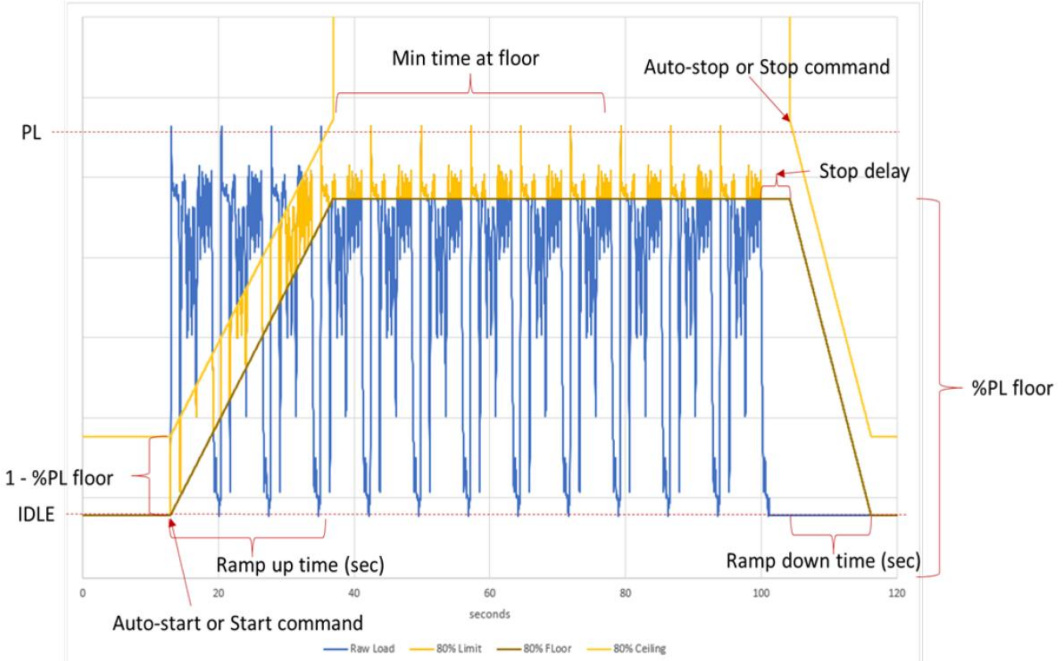
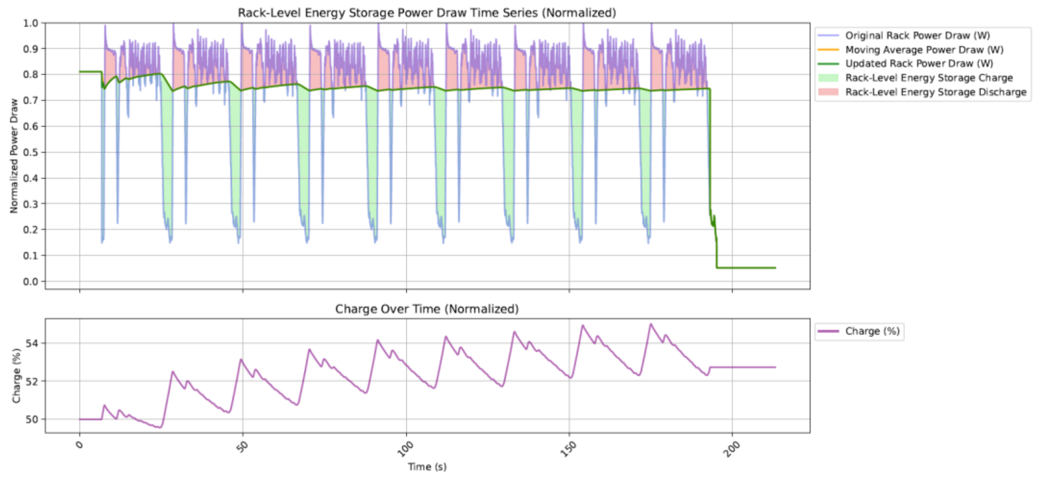


Fig. 7. Energy-storage solution simulated on the power waveform from Figure 1

Solution	Reliability	Performance	Energy	Cost	Ability to meet tightest spec	Dependency on the developer	Lifetime
Software-only mitigation	Medium	Medium	High	Medium	High	High	High
GPU power smoothing	High	Medium	High	Low	Medium	Medium	Medium
Rack-level energy storage	High	High	Low	High	High	Low	High

TABLE I

SUMMARY OF VARIOUS PROPOSED SOLUTIONS. FOR ENERGY, COST, AND DEPENDENCY ON THE DEVELOPER, LOWER IS BETTER.



Power Stabilization for AI Training Datacenters

Fig. 7. Energy-storage solution simulated on the power waveform from Figure 1