IEEE std. 2800 – 2022
Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission System

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Scope

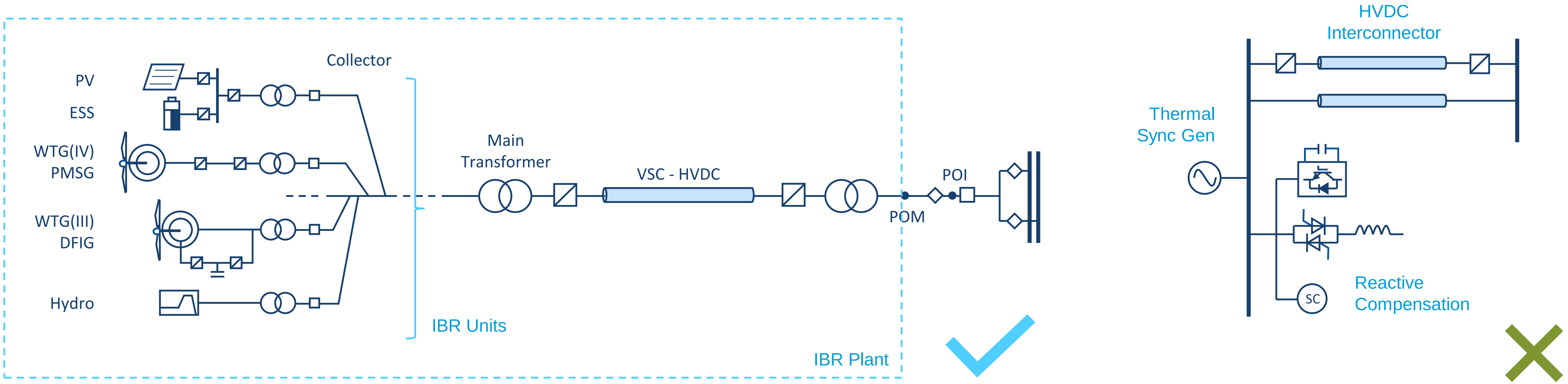
Provide minimum performance requirements on reliable integration of inverter-based resources (IBR) into transmission systems, such as:

- Voltage and Frequency Ride-through
- Active Power Control and Reactive Power Control
- Dynamic Active Power (Reactive Power) Support under Abnormal Frequency (Voltage) Condition
- Power Quality (Flicker, Harmonics)
- Negative Sequence Current Injection
- System Protection

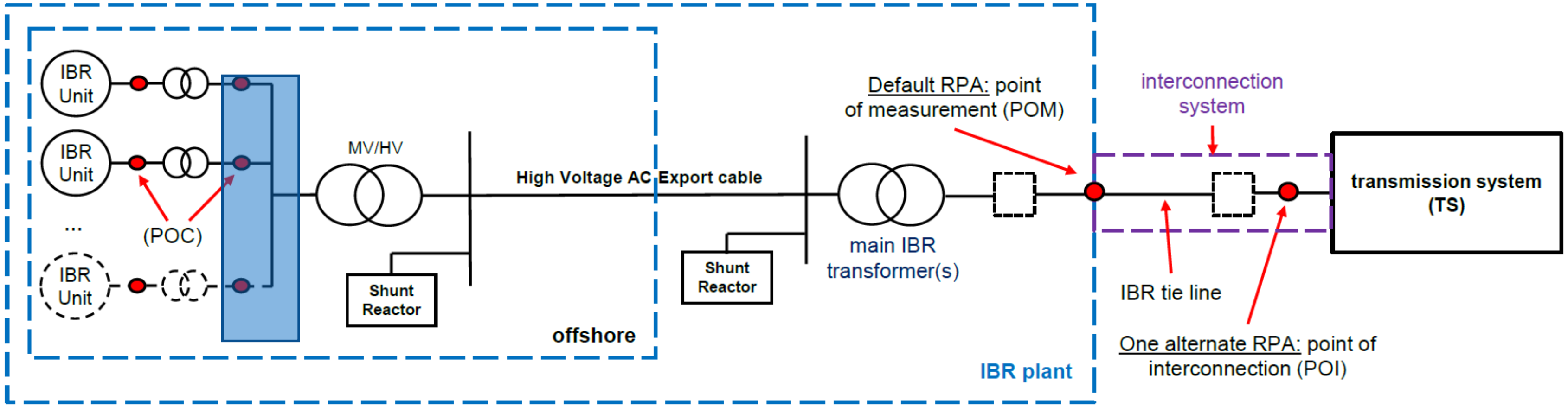
The criteria and requirements are applicable to all **IBR plants** interconnected to transmission system.

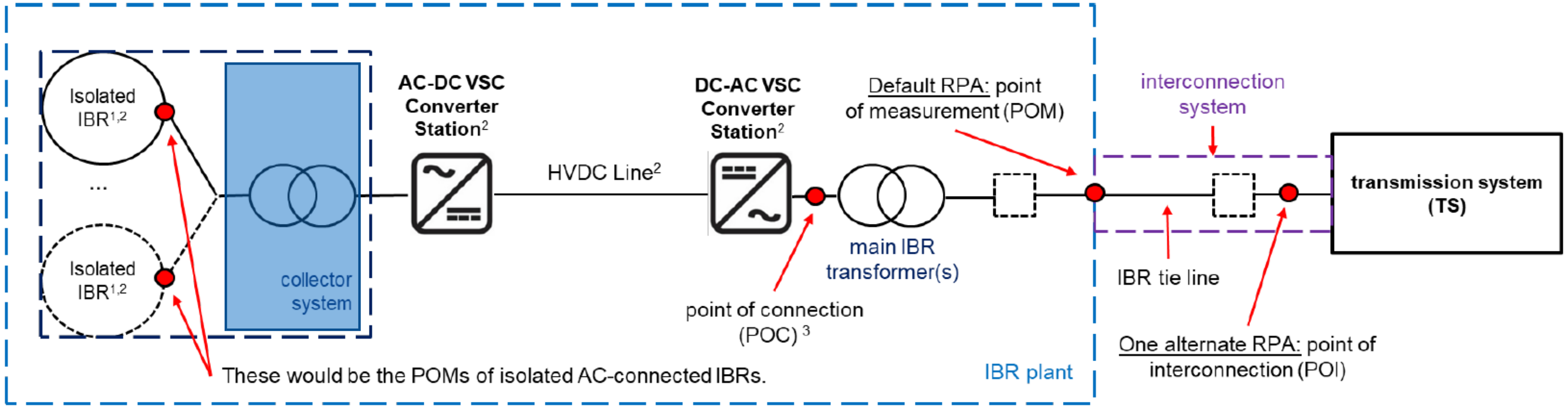
Definition – IBR Plant

- IBR Plant is required to fulfill the performance requirement measured at the Point of Measurement (POM).
- Note that IBR unit itself may not fulfill the requirements, but it can with any other **supplemental IBR device** such as controller, voltage support equipment (cap bank, STATCOM, Synchronous condenser), protection system, harmonic filter



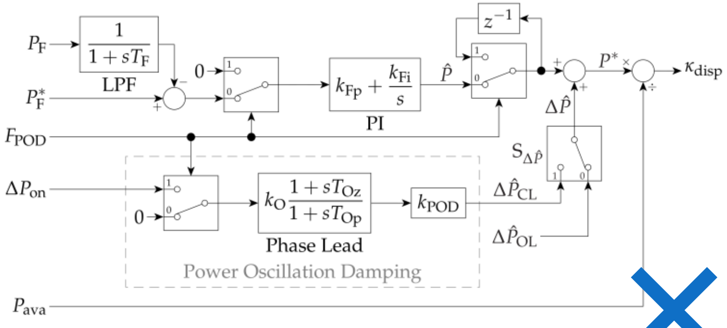
AC Connected Grid Vs DC Connected Grid



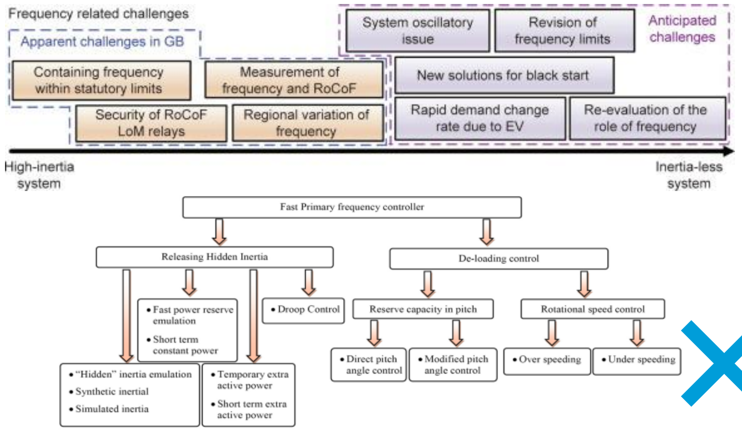


Scope

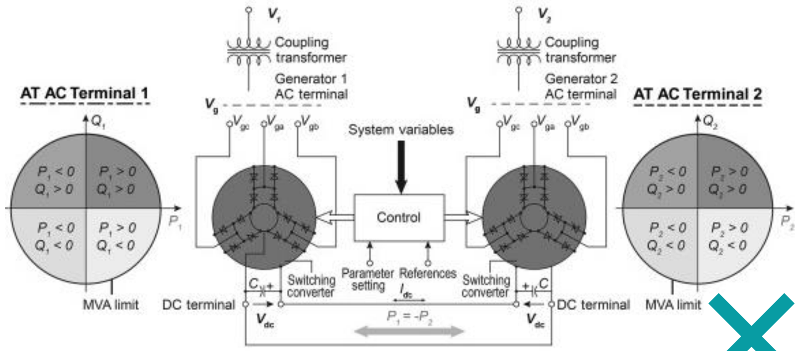
Latest Technology
e.g. Power Oscillation Damping



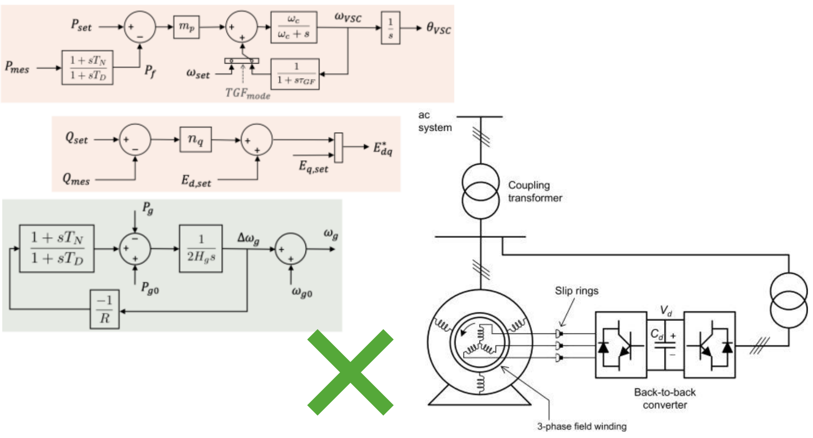
Issues of Increasing IBR Penetration
Loss of Inertia, Fault Duty



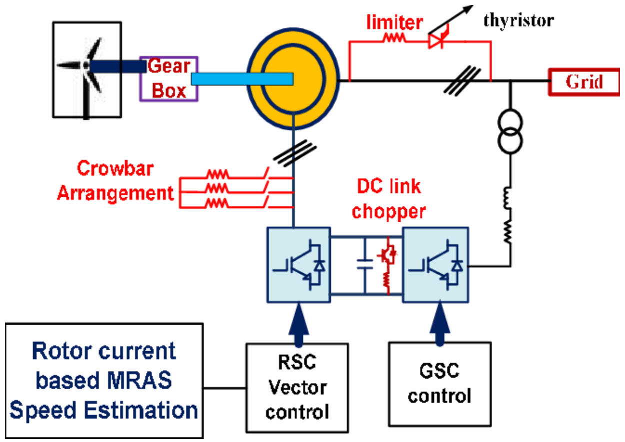
Requirement and Scope of Interconnection
Studies / Load Relieifing Action



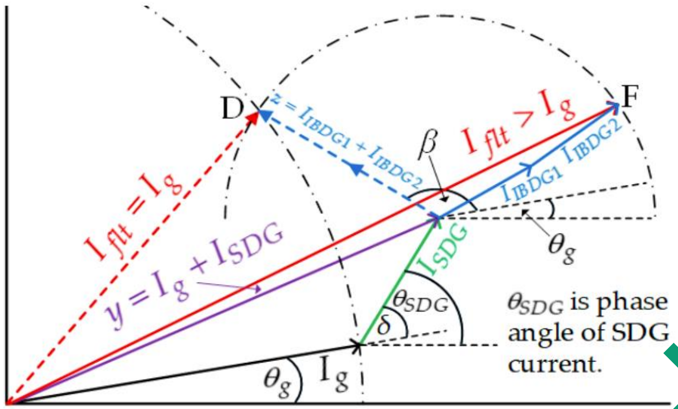
Emerging Use of Synchronous Machine
e.g. Synchronous Condenser



IBR Self-Protection Requirement/
IBR Unit Operating Requirement

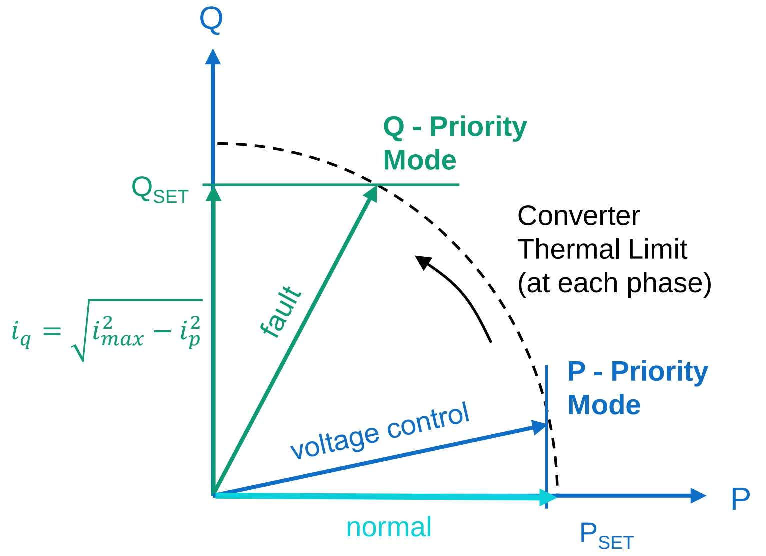


Single Pole Open / SPT-Reclosing
Effects

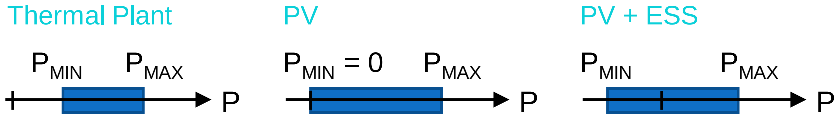


Capacity Limit

Converter should limit IBR output P below its available P, i.e. $P < P_{AVL}$

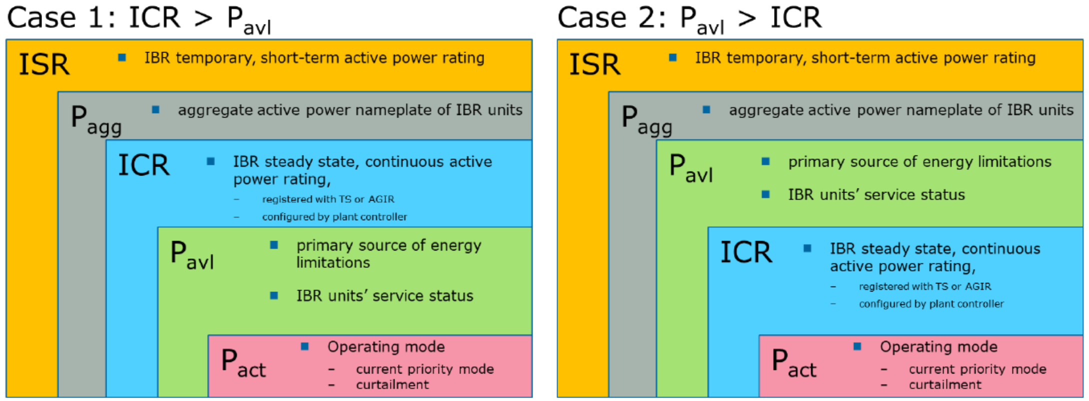


I_{MAX} depends on **operating mode**



Note: be aware of the components –

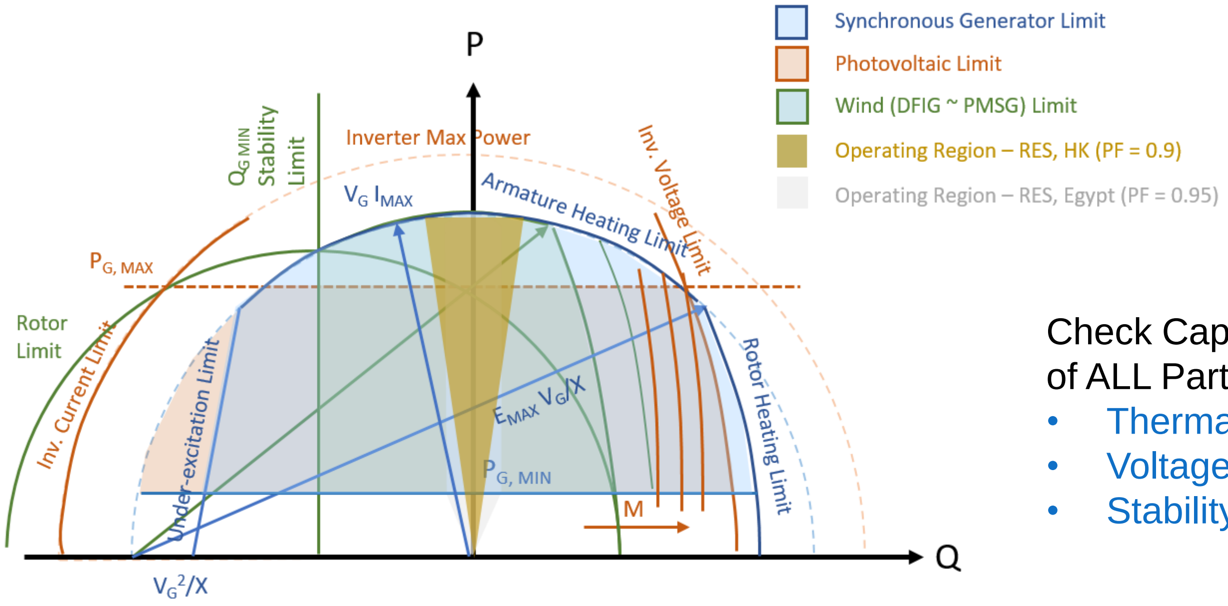
- Harmonic Current
- Negative Sequence Reactive Current



ICR < ISR
NOT necessary

IBR Continuous Rating (ICR) – Active Power Rating as specified in TS's Registry
IBR Short-Term Rating (ISR) – Short-time Active Power Rating in an IBR Plant

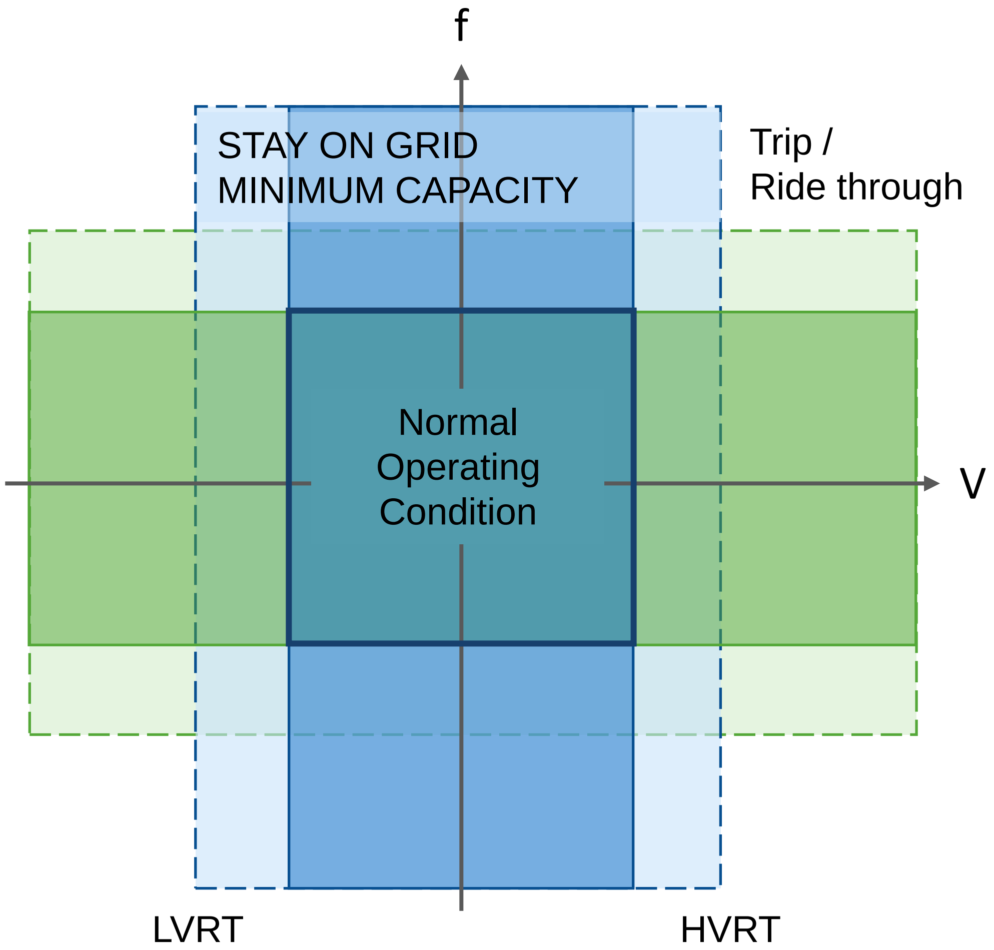
- When ISR > ICR, the IBR can be used to accommodate services such as PFR or FFR.



Check Capacity Limit of ALL Parts

- Thermal
- Voltage
- Stability

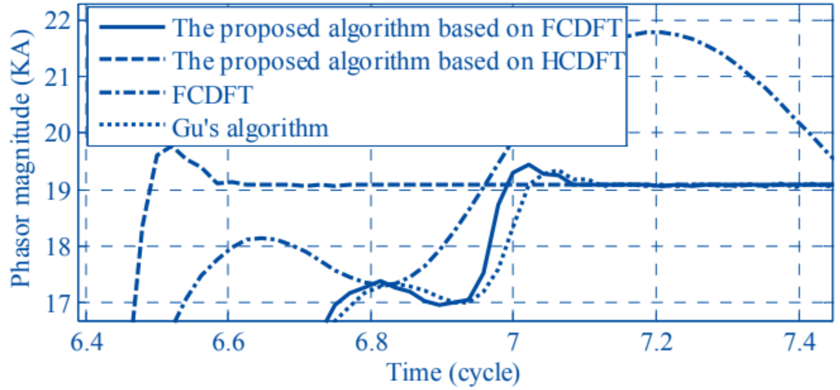
Applicable Voltage and Frequency



Transforming Instantaneous Value to Phasor (1 cycle delay):

$$\hat{X}(r) = \frac{\sqrt{2}}{N} \sum_{n=0}^{N-1} x(r+n)\, e^{-j\frac{2\pi}{N}n}$$

DFT / Cosine Filter

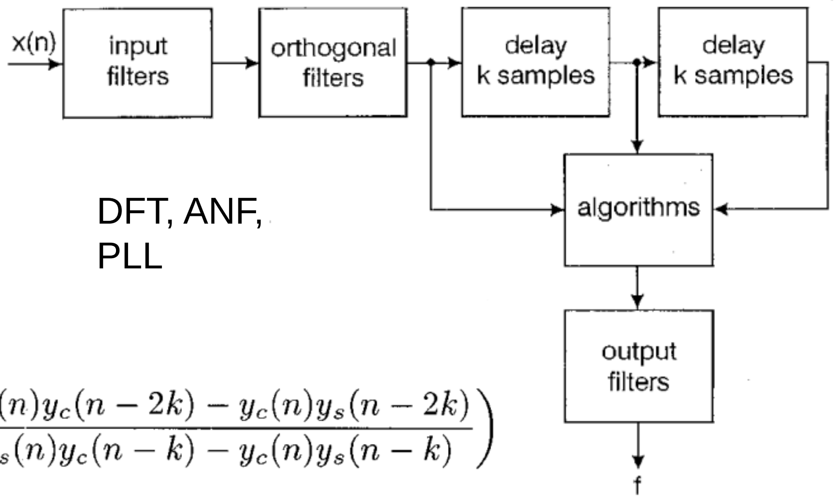


Avoid using instantaneous value for tripping.
Use filtered value or time-delay measurement to avoid spurious tripping.

Filtered Values are prone of:

- Harmonics
- Measurement Noise
- Reaction to Power Electronics Device against Fault

DFT, ANF, PLL



$$f = \frac{1}{2\pi kT} \times \arccos\left(0.5\frac{y_s(n)y_c(n-2k) - y_c(n)y_s(n-2k)}{y_s(n)y_c(n-k) - y_c(n)y_s(n-k)}\right)$$

Note: LVRT and HVRT are based on lowest/ greatest magnitude fundamental phasor component

Note: Both $V_{L\text{-}L}$ and $V_{L\text{-}G}$ are limited.

Measurement Accuracy

- Limiting largest possible deviation and rate-of-rise (e.g. Δf and df/dt)

Parameter	Minimum accuracy [a]	Range
Voltage[c,d]	± 2.5%	0.5 p.u. to 1.2 p.u.
Current [c,d]	± 2.5%	0.2 p.u. to 1.2 p.u.
Frequency[b]	± 0.010 Hz	0.80 p.u. to 1.1 p.u. [g]
Active Power [e]	± 5%	0.2 p.u. $< P <$ 1.0 p.u.
Reactive Power [e]	± 5%	0.2 p.u. $< Q <$ 1.0 p.u.

Note:
IEEE Std 519 – 2014:
Harmonics Measurement Requirement
Voltage THD < 2.5%
Individual Voltage Harmonics < 1.5%

Steady State Time Frame

Parameter	Minimum accuracy [a]	Maximum length of Sliding window	Maximum resolution [b]	Range
Voltage [c]	± 10% [d,e]	1 cycle [f]	1/32 cycle	0.1 p.u. to 2.0 p.u.
Current [c,g]	± 10% [d,e]	1 cycle [f]	1/32 cycle	0.1 p.u. to 1.4 p.u.
Frequency [h,i]	± 0.010 Hz	6 cycles	1/4 cycle	0.80 p.u. to 1.1 p.u. [j]

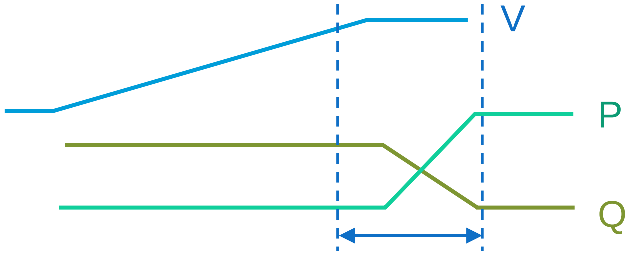
Transient Time Frame

[b, i] Applicable for fundamental frequency ONLY and when $U_1 > 10\%\ U_N$

Control Capability and Prioritization of IBR Response

- The IBR shall be capable of responding to external control input (from TS / IBR operator) such as cease operation ($P = 0$ vs Open CB), limit active power below ICR ($P = P_{SET}$) as specified by TS operator, mode change (normal **to** voltage support mode) or setpoint change transitioned smoothly over a specified time.
- The following items should take precedence over Active/ Reactive Power Control & TS Abnormal Response requirement.
  - Disabling Setting
  - IBR Tripping to clear a fault either within IBR plant or in the interconnection system
  - IBR Tripping due to Self Protection
  - Ride-through Requirement
  - P/f Response Requirement
  - Power Limiting ($P_{MAX} = P_{SET}$)
  - V/Q Response Requirement

Enter Service

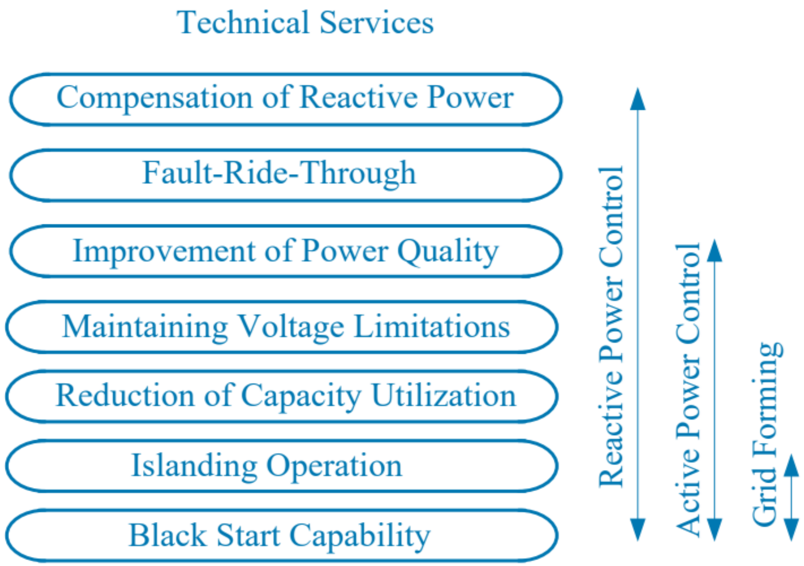


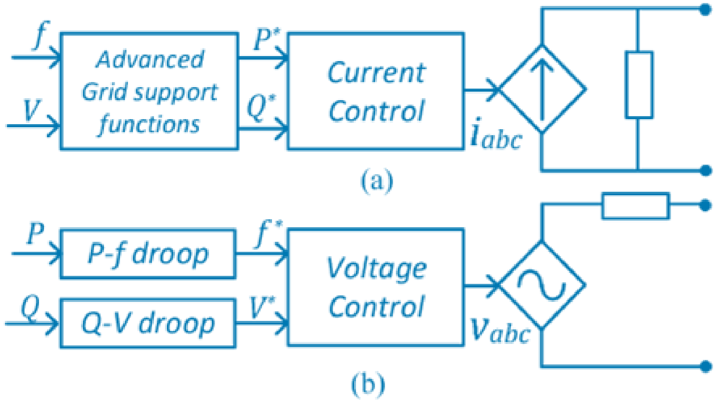
Enter Service (1s – 1000s)

- IBR plant shall NOT energize transmission system (TS) when the TS is de-energized. Exception may be given for black start.
- Enter Service
  - Enter after an IBR plant was **out-of-service** when primary energy source is not available OR Return to service after an IBR plant trip due to self-protection or following an unsuccessful ride-through
  - Enter or Return to service after the TS with applicable voltage and frequency within range.

Enter service criteria		Default settings [c]	Ranges of available settings
Permit service	When Enabled	Disabled	Enabled/Disabled
Applicable voltage within range	Minimum value	Specified by *TS Operator*	0.90 p.u. to 0.95 p.u. [a]
	Maximum value	Specified by *TS Operator*	1.05 p.u. to 1.10 p.u. [b]
Applicable frequency within range	Minimum value	Specified by *TS Operator*	0.98 p.u. to 0.99 p.u. (58.8 Hz to 59.4 Hz @60 Hz) (49.0 Hz to 49.5 Hz @50 Hz)
	Maximum value	Specified by *TS Operator*	1.002 p.u. to 1.02 p.u. (60.12 Hz to 61.2 Hz @60 Hz) (50.1 Hz to 51 Hz @50 Hz)

- Note: Average dP/dt, i.e. ramp rate, should be limited in duration of enter service.



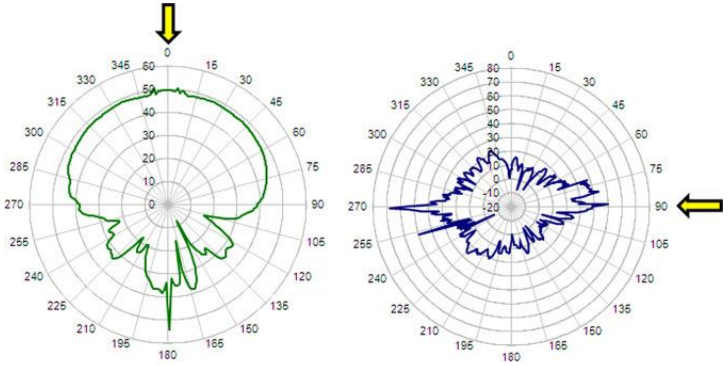


(a) Grid Following (f for synchronization and V for voltage control and active power curtailment)
(b) Grid Forming (droop control to determine output power – P & Q)

Interconnection Integrity

Protection from EMI Requirement:

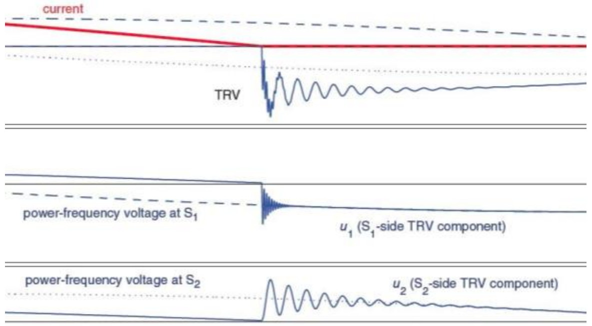
No change in state or mis-operation of IBR unit under minimum electric field strength of 30V/m.



(1) (2)

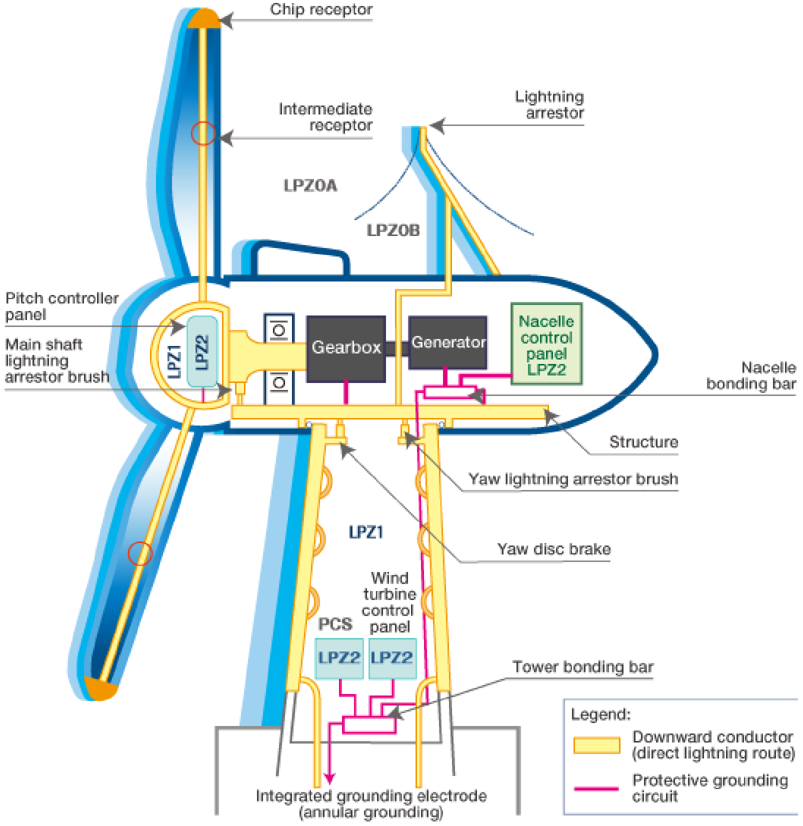
Switchgear Requirement:

Isolating Switchgear shall be capable of withstanding 220% of IBR plant volage for out-of-phase switching.



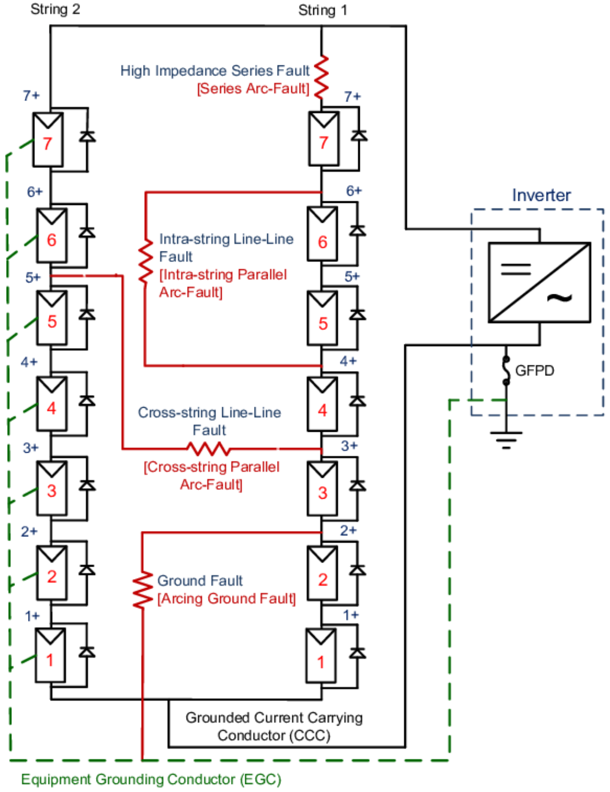
Lightning and Surge Withstand Performance:

Interconnection System, inc. Protection, Control and Communication device should have capability withstand voltage and current surge as required by TS owner.



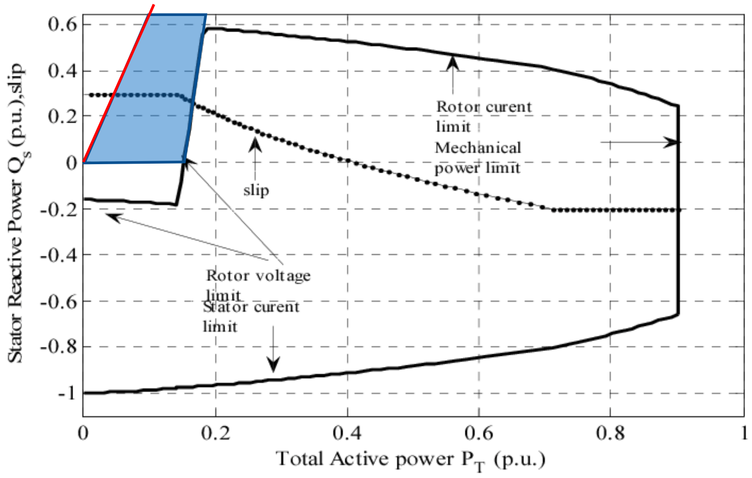
Integration with TS Grounding:

No specific requirement. TS Owner shall specify requirement as appropriate.

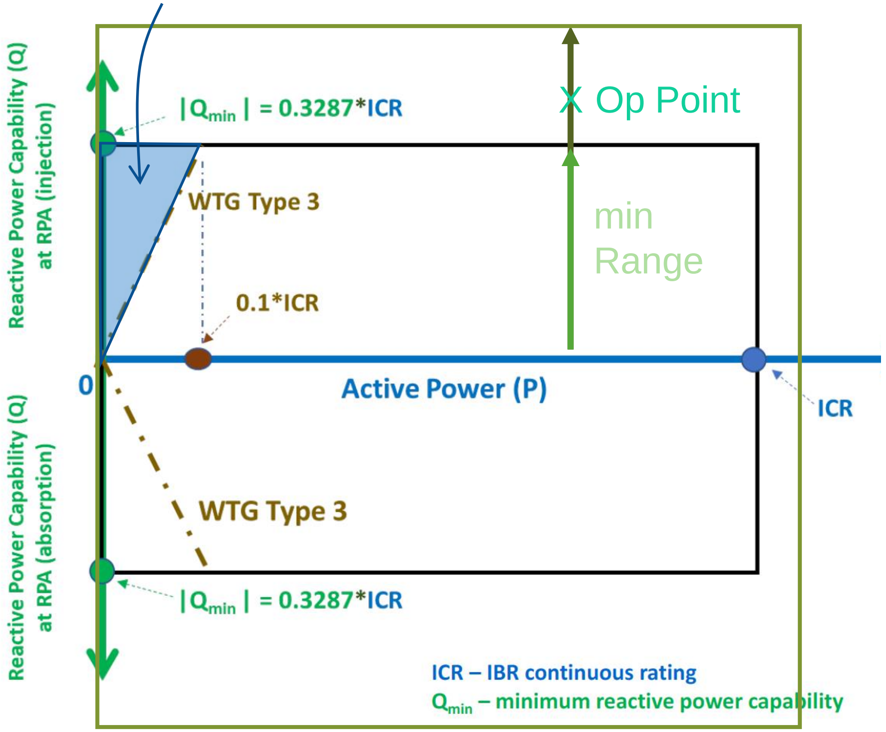


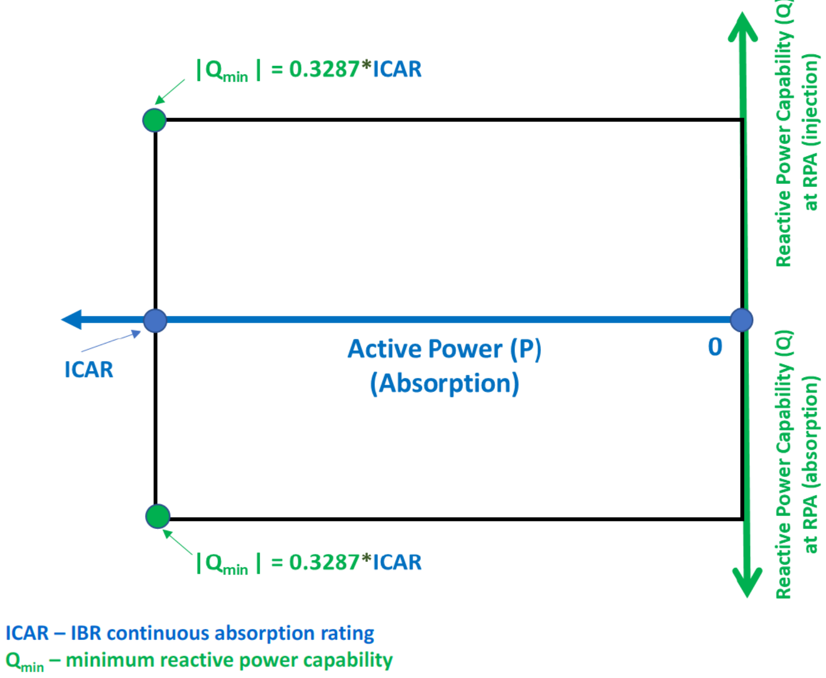
Reactive Power – Voltage Control Requirement

DFIG Capacity Curve



Direct-on-line DFIG limitation

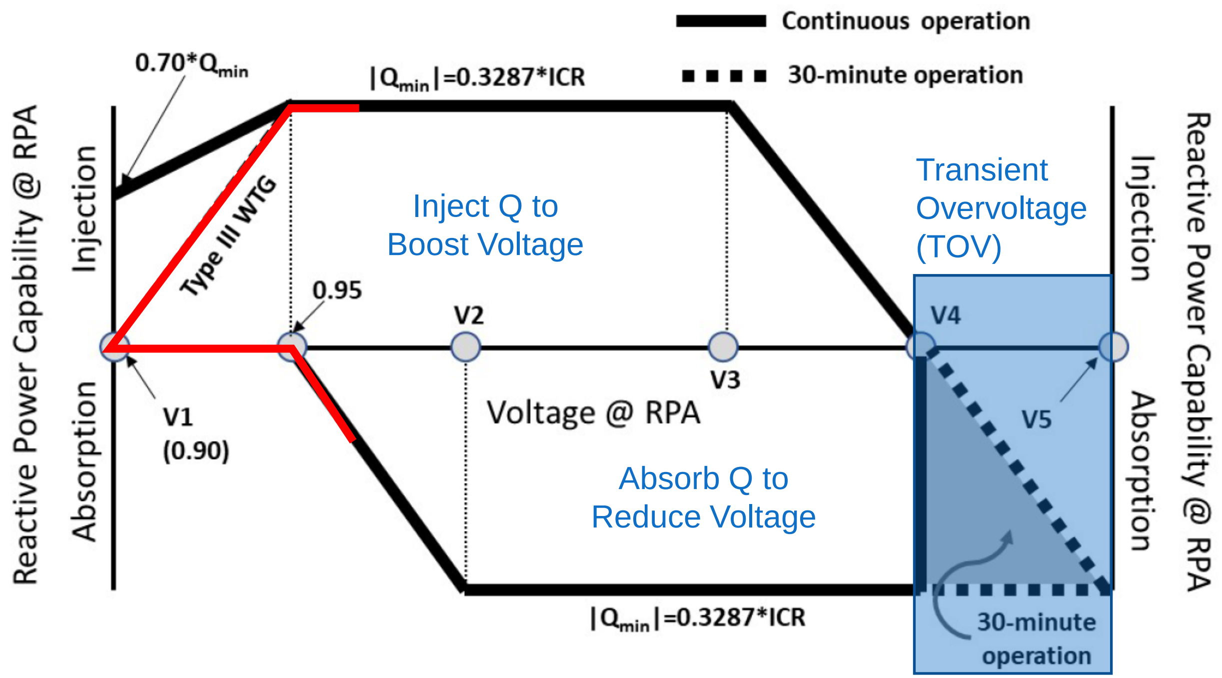




Note:

- IBR unit shall be able to provide reactive power support even when the primary energy source is NOT available, and during the transition stage.
- IBR has the capability to remain in service while NOT exporting or importing P, except cover for losses.

Reactive Power – Voltage Control Requirement



Note:

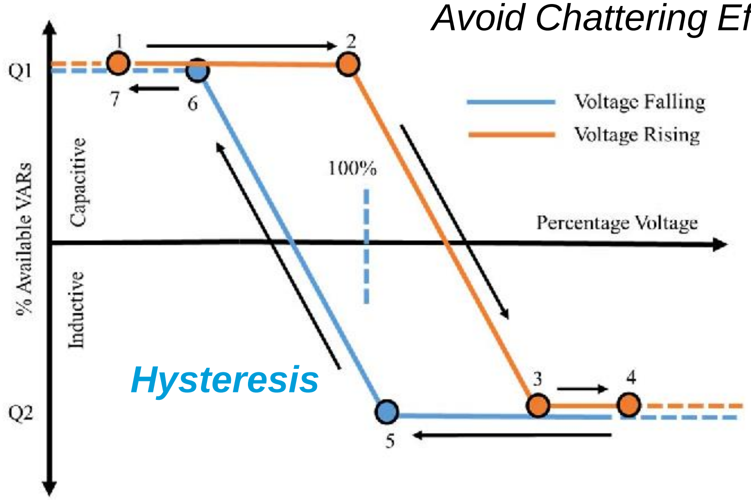
- *IBR Plant* shall be capable to maintain the voltage schedule, i.e. Reactive Reserve Dispatch (within the reactive power capability) provided by TS Operator.
- OLTC tap changing is allowed to retain IBR unit voltage within range for which their reactive power capability is required.
- Dynamic Voltage Support from Power Electronics based system (inc. the *IBR unit*, SVR, STATCOM) or rotating machines with excitation control (inc. Sync Machine or type III WTG) or Static Voltage Support (inc. shunt cap or shunt reactor) can be used to fulfill this requirement without significant step changes or discontinuity.

TS Nominal Voltage at RPA	V1 (p.u.)	V2 (p.u.)	V3 (p.u.)	V4 (p.u.)	V5 (p.u.)
< 200 kV	0.90	0.99	1.03	1.05	1.10
>= 200 kV except 500 kV and 735 kV as below	0.90	1.00	1.04	1.05	1.10
500 kV	0.90	1.02	1.06	1.10	1.10
735 kV [b]	0.90	1.02	1.06	1.088	1.10

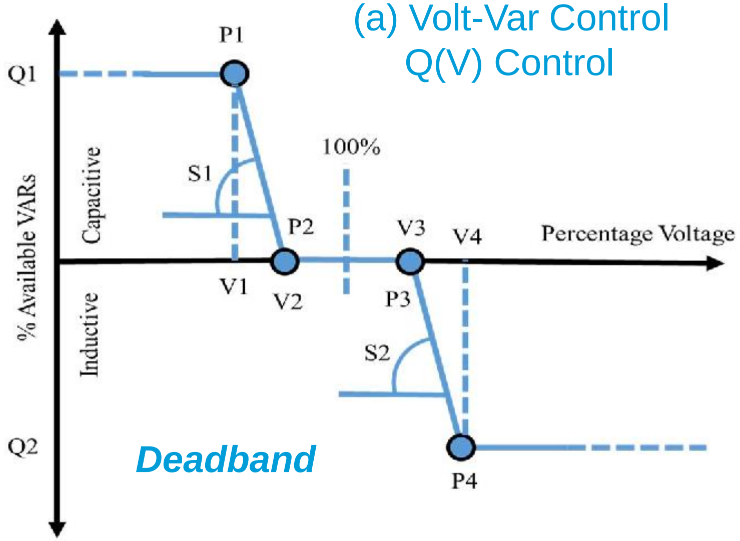
Enough Voltage for reactive power absorption

Reactive Power – Voltage Control Requirement

Avoid Chattering Effect

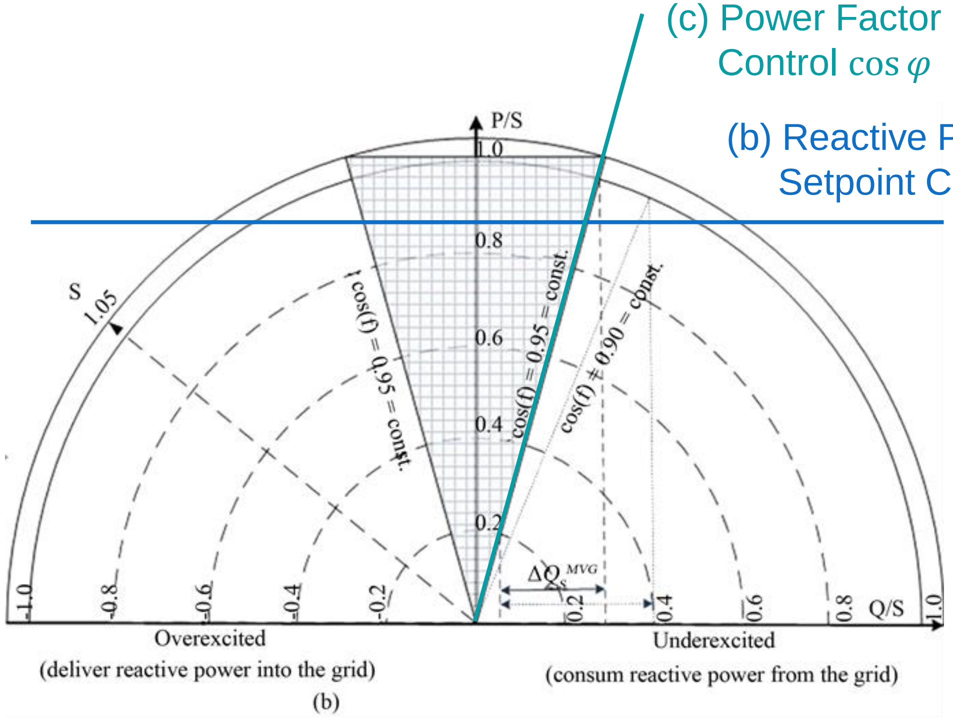


(a) Volt-Var Control
Q(V) Control

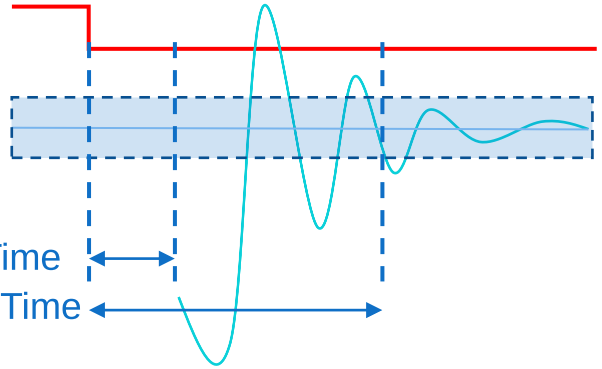


(c) Power Factor Control $\cos\varphi$

(b) Reactive Power Setpoint Control



$\xi > 0.3$ (damping ratio)



Requirement:

Reaction Time < 200ms

Reaction Time (1s – 30s)

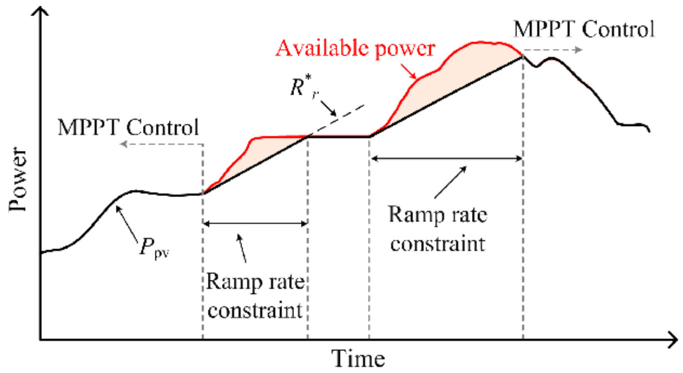
depending on

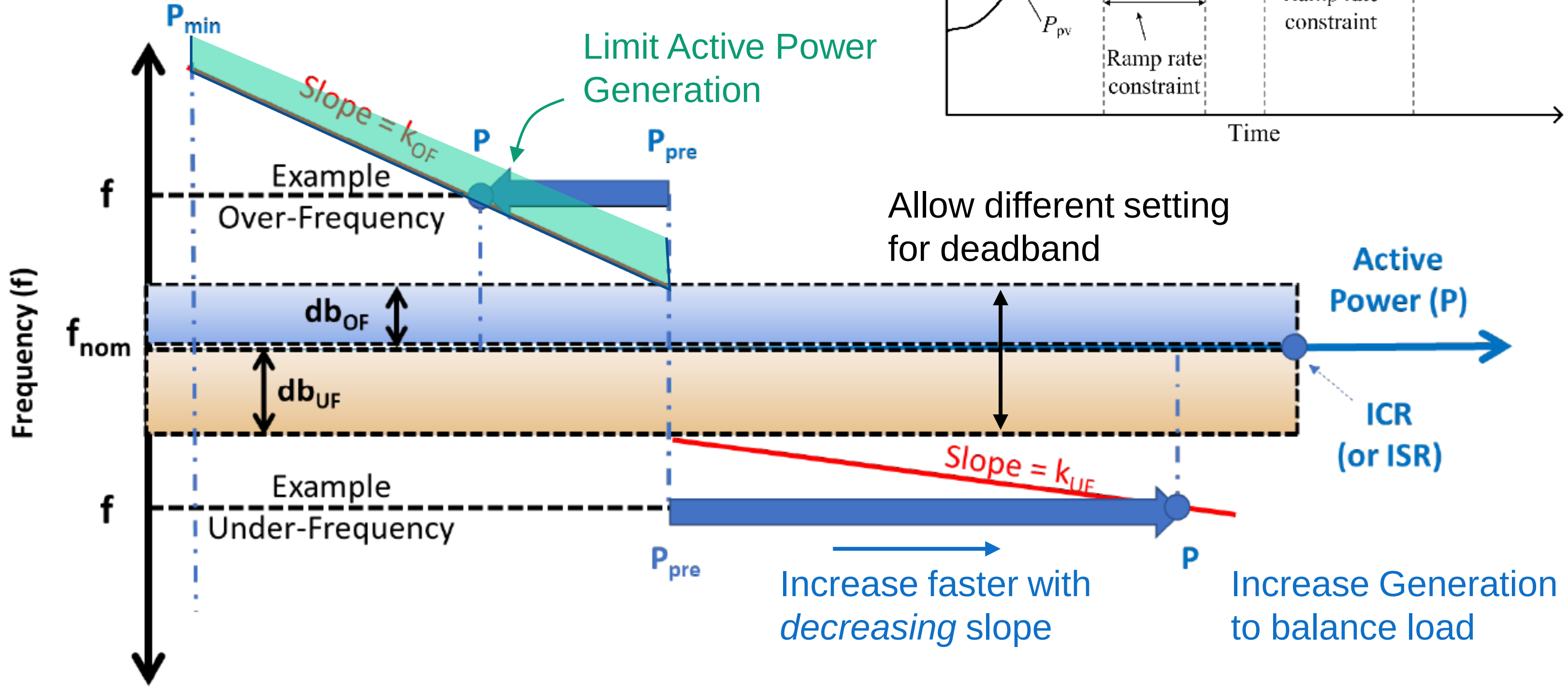
- Grid strength
- Local Voltage Control device
- Overshoot Requirement

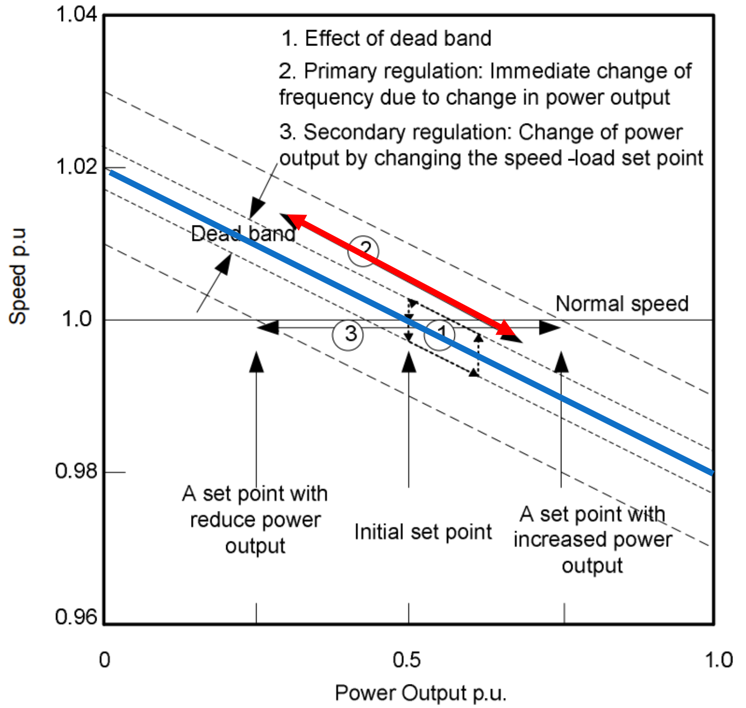
Active Power – Frequency Response Requirement

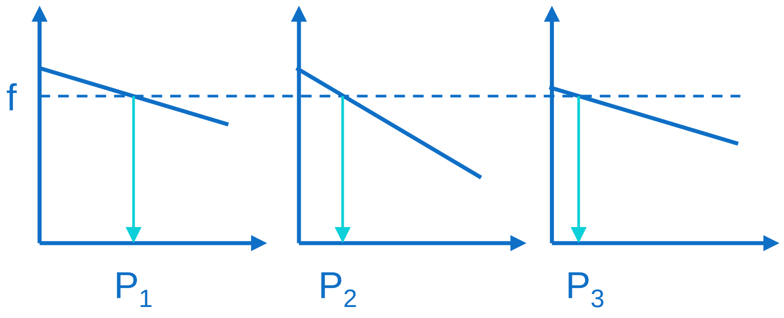
Note:

1. Avoid Oscillatory behavior
2. Power Ramp Limit is applied









IBR plant shall be capable of sustaining PFR as long as the *primary energy source* is available. [different spinning reserve provided for upward / downward direction]

Active Power – Frequency Response Requirement

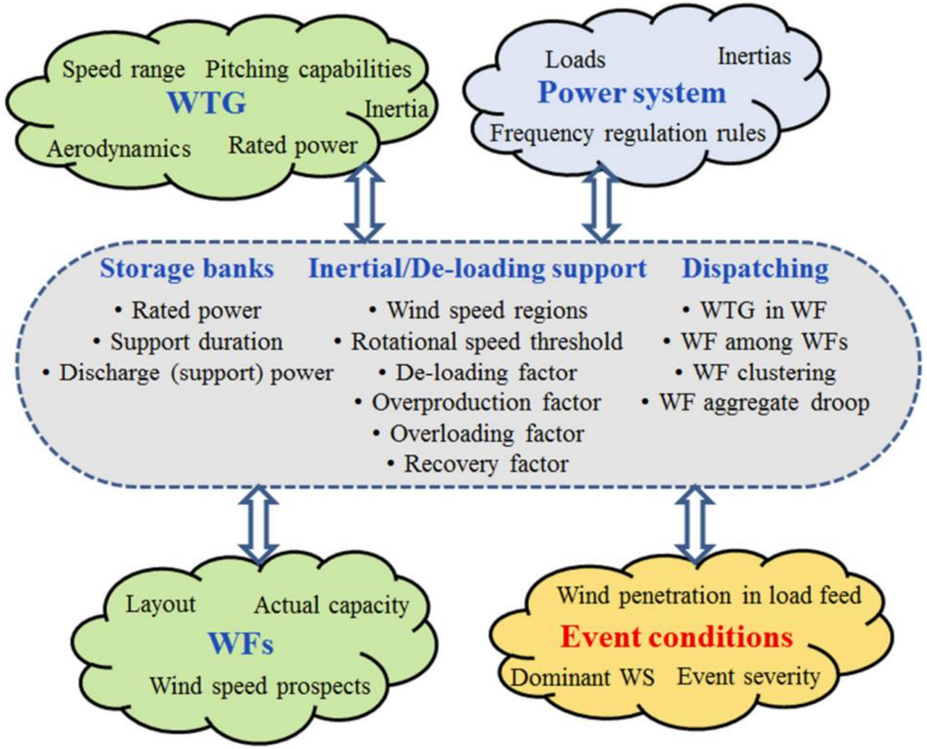
- **Parameter** for Active Power Frequency Response Dynamic Performance for IBR Plant

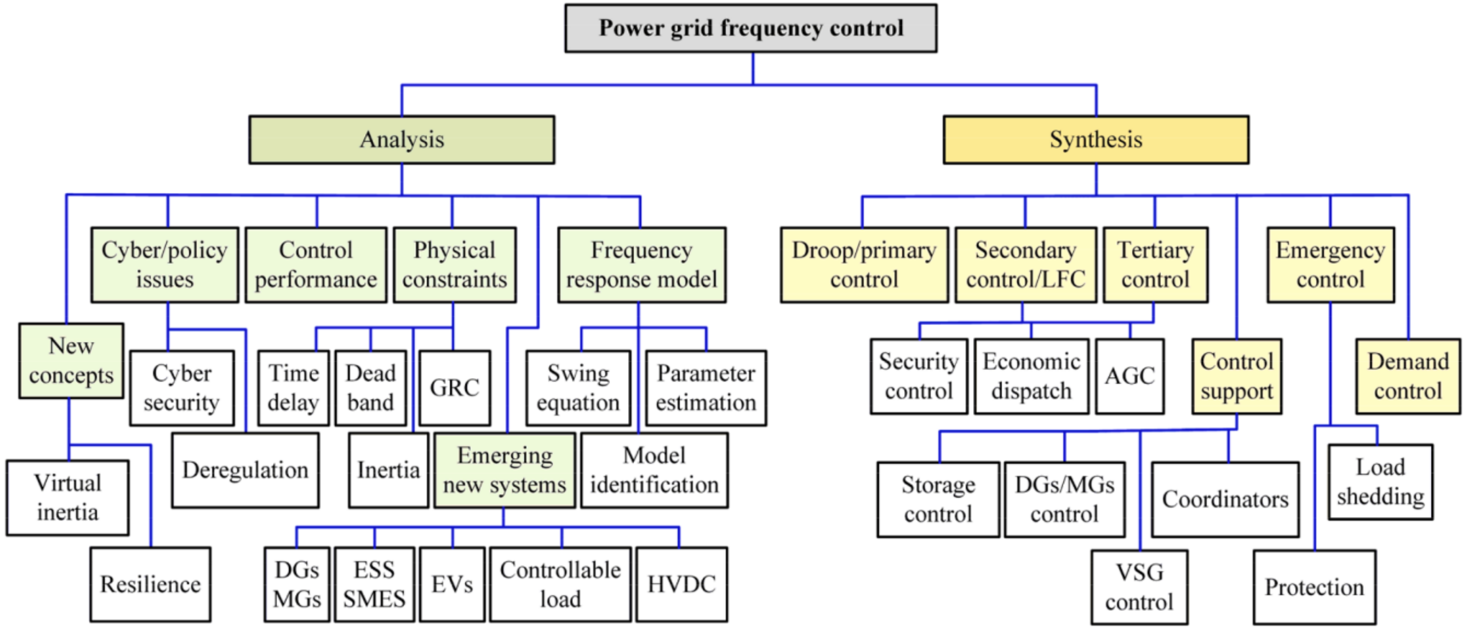
Parameter	Units	Default Value	*Ranges of available settings*	
			Minimum	Maximum
Reaction time	seconds	0.50	0.20 (0.5 for WTG)	1
Rise time	seconds	4.0	2.0 (4.0 for WTG)	20
Settling time	seconds	10.0	10	30
Damping Ratio	unitless	0.3	0.2	1.0
Settling band	% of Change	Max (2.5% of change or 0.5% of ICR)	1	5

Time need to wait before PFR comes in

- **PFR Utilization** in Operation:
  - During Temporary Frequency Disturbance within continuous operating region outside Deadband, the IBR plant shall adjust its P output from the pre-disturbance levels.
  - Response to under-frequency disturbance shall NOT be required for IBR plant operating at available active power, i.e. MPPT. With Delta Power Control, i.e. curtailed operation, under under-frequency condition, IBR plant shall have the capability to dynamically maintain its headroom as prime energy source varies.
  - Hybrid IBR with storage capable of absorbing power when PFR may limit PFR provision to P $\geq$ 0 if agreed to by the TS operator. [Check current SOC and SOC limit during the operation]
  - Total Active Power output may be capable of and allowed to exceed ICR to ISR within IBR plant.

Active Power – Frequency Response Requirement





$$p_{\mathrm{VSG}} = \underbrace{\frac{f-f^*}{R}}_{\text{droop}} \underbrace{-k_D\left(f-f^*\right)}_{\text{damping}} \underbrace{-k_{J_v}\frac{\mathrm{d}f}{\mathrm{d}t}}_{\text{inertia}}$$

$$\begin{cases} H\dfrac{d\omega}{dt} = P_{ref} - P_o - k(\omega-\omega_{ref}), & \text{VSG control} \\ T_f\dfrac{1}{m_p}\dfrac{d\omega}{dt} = P_{ref} - P_o - \dfrac{1}{m_p}(\omega-\omega_{ref}), & \text{droop control (filter)} \end{cases}$$

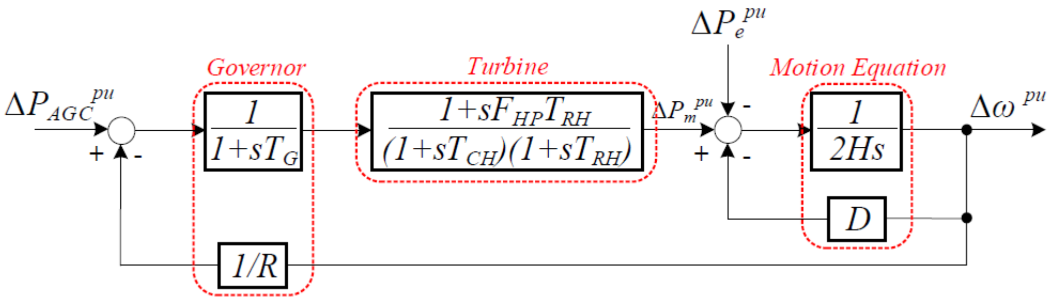
It changes the setpoint (pitch or I-V op point) to decide reserve ($P_{AVL} - P$).

Extra energy source are from energy storage (**SOC**), rotational energy from turbine ($1/2\ J\omega^2$), capacitor energy.

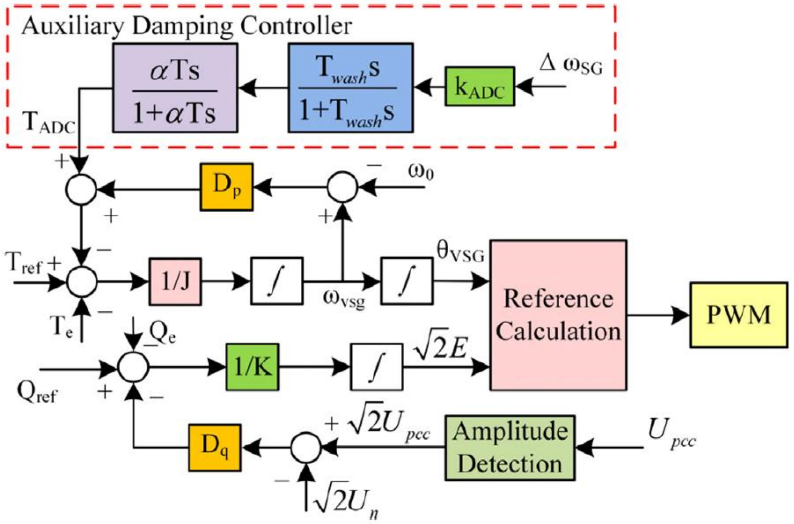
Active Power – Frequency Response Requirement

Names of Frequency Controller

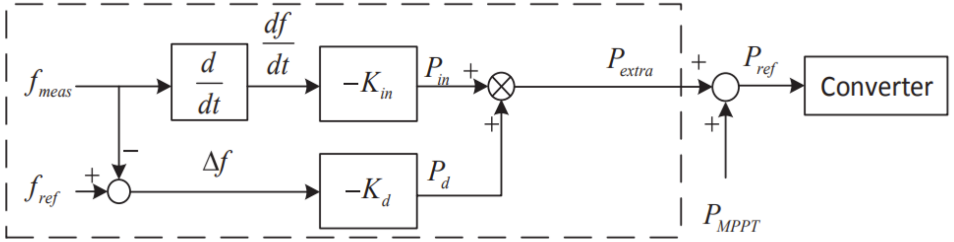
Frequency Controller of Synchronous Generator



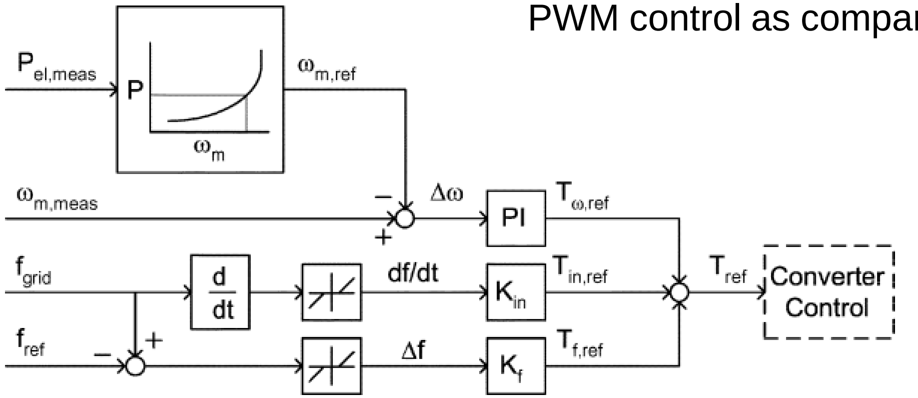
Virtual Synchronous Generator (VSG)



Virtual Inertia / Synthetic Inertia



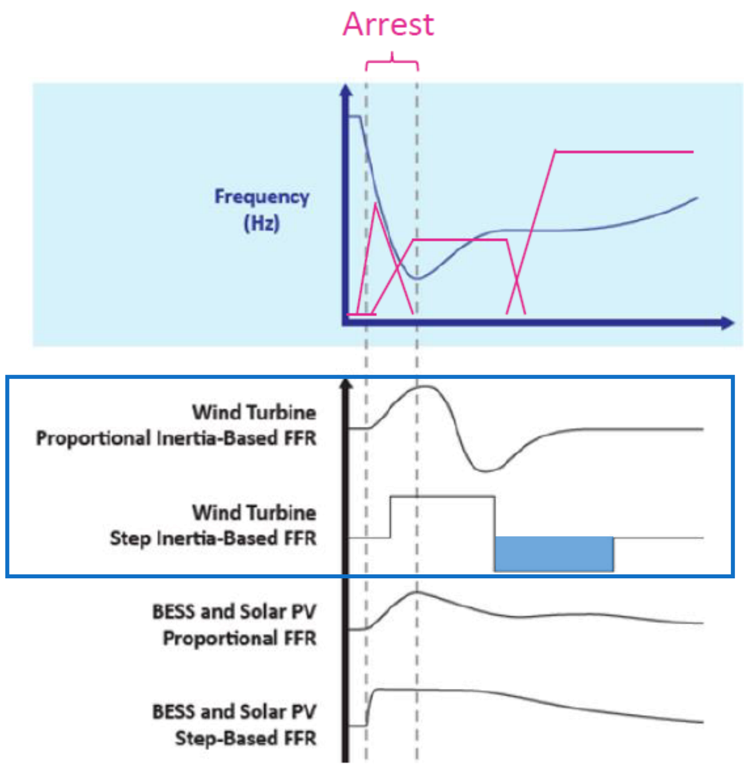
Inertia Emulation



Faster to extract rotational energy from WTG with PWM control as compared to traditional sync gen.

Active Power – Frequency Response Requirement

Fast Frequency Control = “Active Power injected to the grid in response to frequency changes during arresting period”



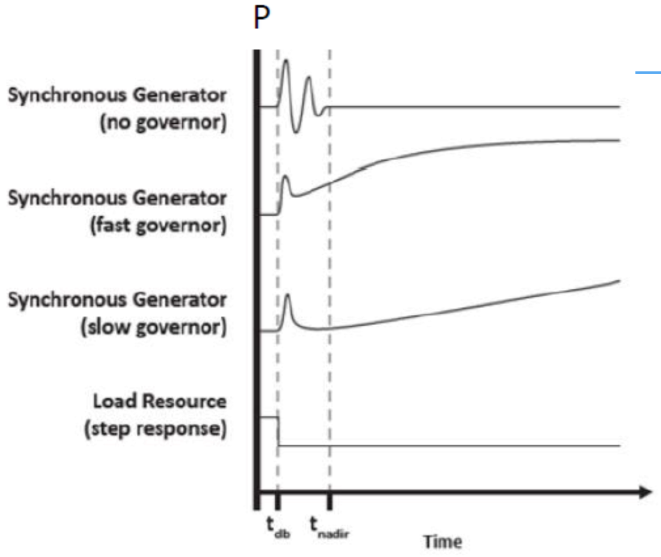
Check 1) Response Speed
2) Response Shape
3) Response Duration

for →

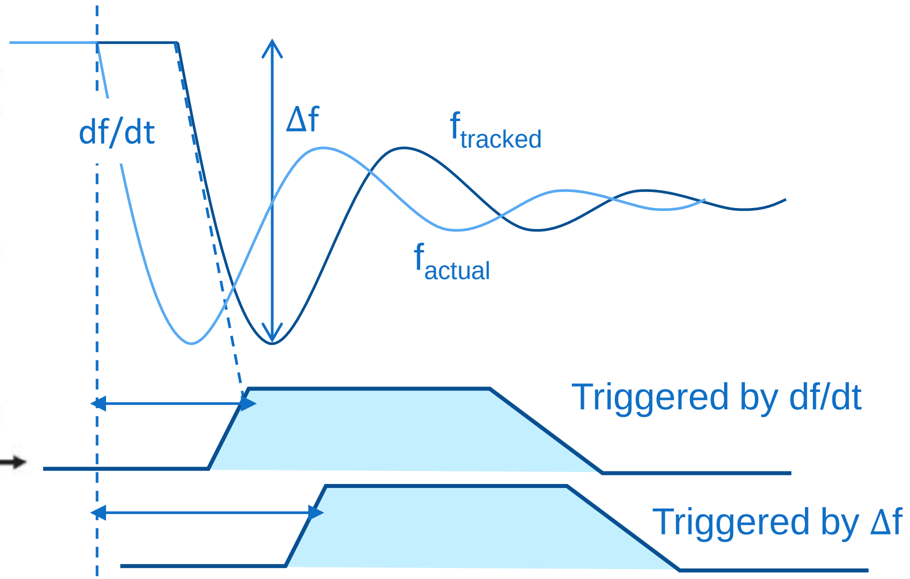
a) Inertia
b) PFR
c) FFR

Question:

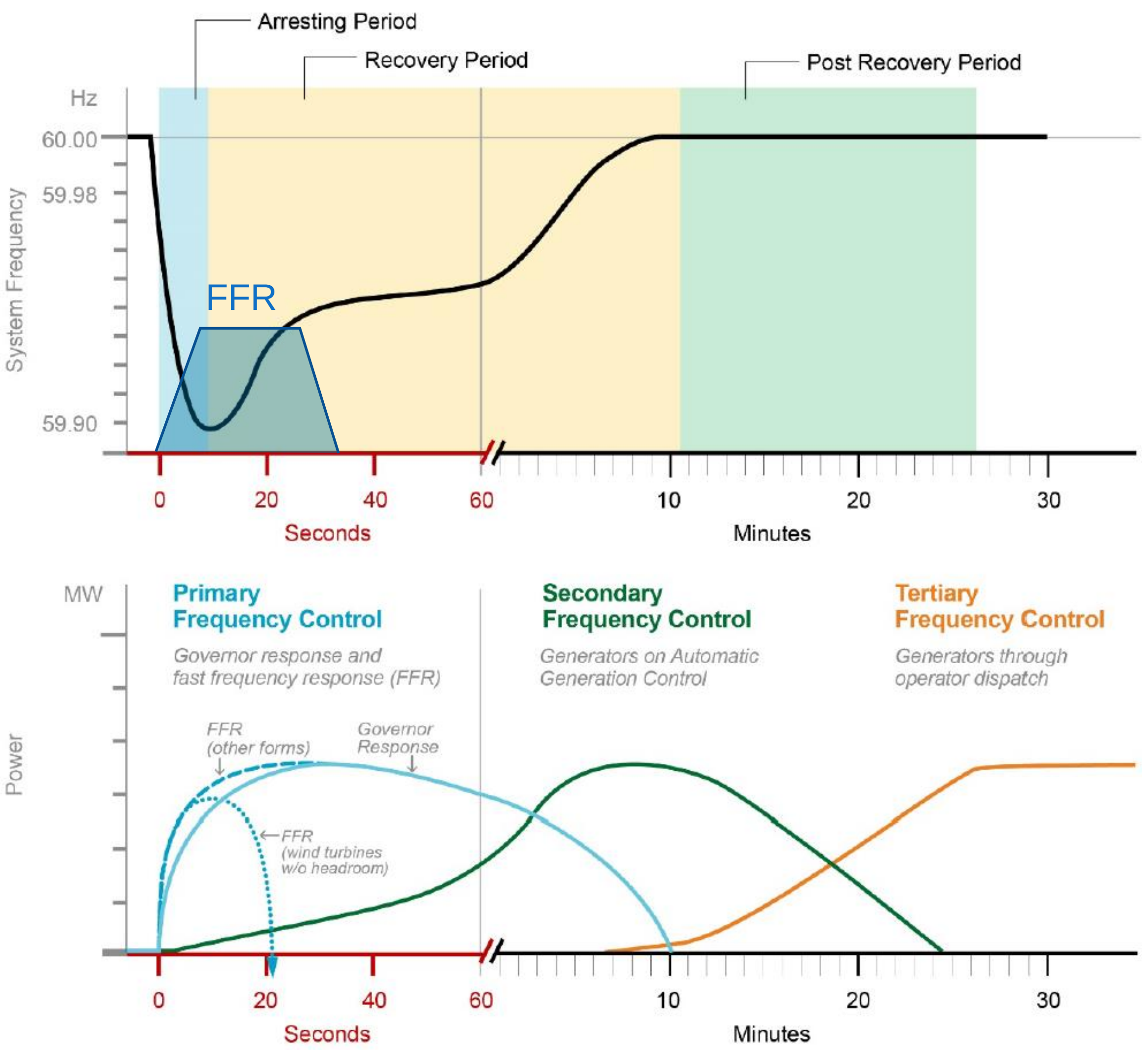
1. What trigger (df/dt vs Δf)?
2. Trigger how much?
3. Does it trigger too much with an overshoot?
4. Trigger for how long?



Droop or Step to arrest df/dt or Δf ?

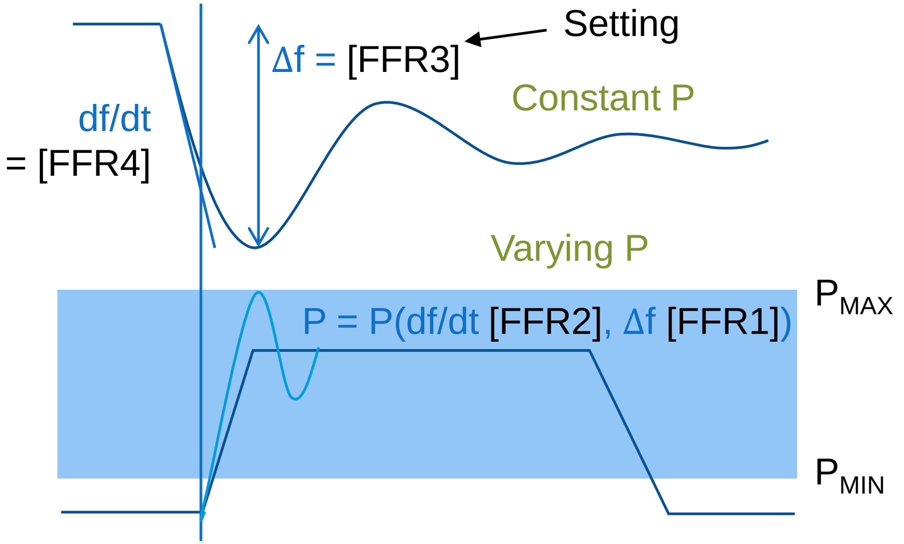


Active Power – Frequency Response Requirement



FFR Requirement:

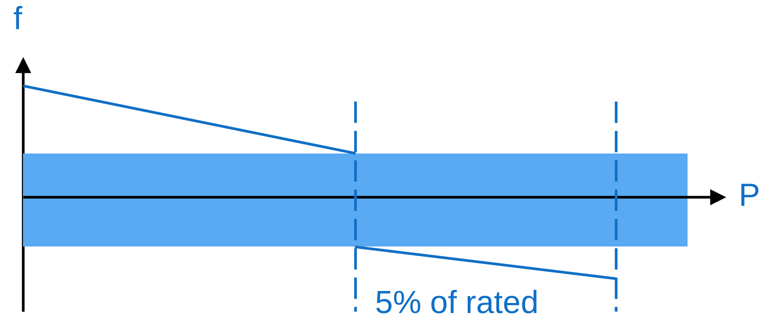
- FFR capability shall be an autonomous function that is automatically self-deployed by the IBR plant responded to frequency deviation.
- Triggers for FFR may be specified based on frequency deviation
- Actuation of FFR can be temporarily exceeding ICR but limited by ISR.
- Overshoot limited by **10%** of the changes, and any oscillations may be positively damped.
- FFR and PFR shall actuate independently and limited by P_{AVL}.

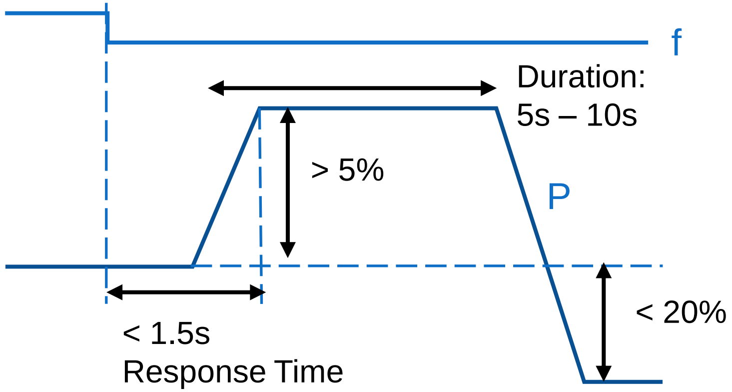


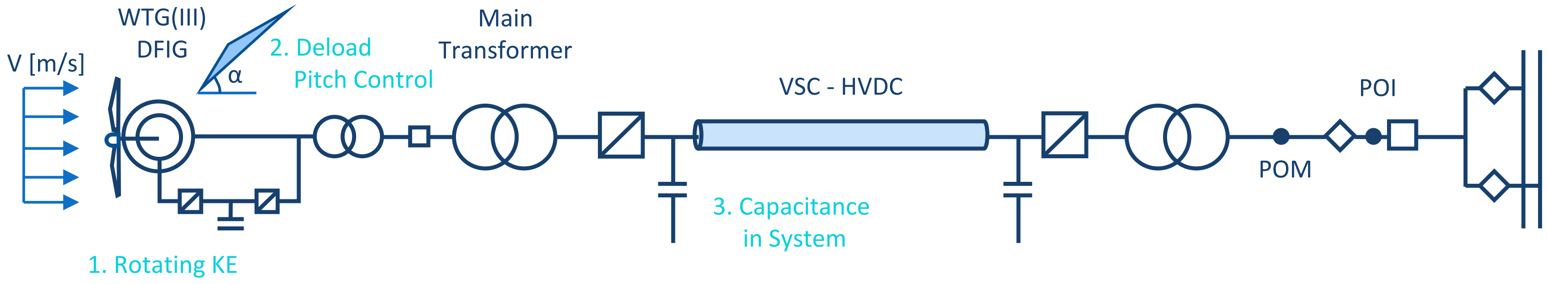
Active Power – Frequency Response Requirement

Fast Frequency Response from WTG Based IBR Plant

- Temporary increase of P output shall be equal to at least 5% of total rated power in service and operating at or above 25% of rated power.
(e.g. 30WTGs in plant, each rated 4MW and 25 are producing 1MW or more, then temporary increase in P = at least 5% x 4MW x 25 = 5MW)
- WTG based IBR Plant shall provide a temporary increase of P for the hold time from 5s – 10s (from start of ramp up to start of ramp down). [due to inertia based response of WTG system] The response time to maximum P shall be within 1.5s.
- WTG based IBR plant shall limit decrease in P output during energy recovery to 20% or less.
- When recovering from providing FR, WTG may be permitted to reduce P below the pre-event P if needed to return rotor speed to normal operation.







Response to TS Abnormal Condition

Voltage Ride-through Requirement

- Voltage Ride-through Requirement is ONLY applicable when applicable frequency is inside the continuous operating region (i.e. frequency normal).
- Any tripping of IBR plant, or failure to provide the specified ride-through capability, due to IBR self-protection as a direct or indirect result of voltage disturbance will be considered as a non-compliance (NC) with this standard.
- Exception:
  - For a voltage disturbance reduces the applicable voltage at the RPA to less than **50%** of nominal, the IBR shall be considered compliant with this standard if the post-disturbance apparent current is NOT less than **90%** of the pre-disturbance current. (NOT every single IBR has to ride-through all possible disturbance)
  - The IBR plant shall satisfy requirement unless tripping of IBR plant is required to clear faults either internal to the plant or on the interconnection system (IBR tie line) which may provide sole connectivity between IBR plant and the TS.

With Auxiliary Equipment
causes ride-through limitation
(e.g. Motor Load without LVRT)

Applicable voltage (p.u.) at RPA	Operating mode/response	Minimum ride-through time (s) (design criteria)
V > 1.20	May Ride-Through or May Trip	NA
V > 1.10	Mandatory Operation	1.0
V > 1.05	Continuous Operation[82]	1800
V < 0.90	Mandatory Operation	3.00
V < 0.70	Mandatory Operation	2.50
V < 0.50	Mandatory Operation	1.20
V < 0.25	Mandatory Operation	0.16
V < 0.10	Permissive Operation[83]	0.16

Out-Zone Fault

Without Auxiliary Equipment
e.g. HVDC – WTG

Applicable voltage (p.u.) at RPA	Operating mode/response	Minimum ride-through time (s) (design criteria)
V > 1.20	May Ride-Through or May Trip	NA
V > 1.10	Mandatory Operation	1.0
V > 1.05	Continuous Operation[82]	1800
V < 0.90	Mandatory Operation	6.00
V < 0.70	Mandatory Operation	3.00
V < 0.50	Mandatory Operation	1.20
V < 0.25	Mandatory Operation	0.32
V < 0.10	Permissive Operation[83]	0.32

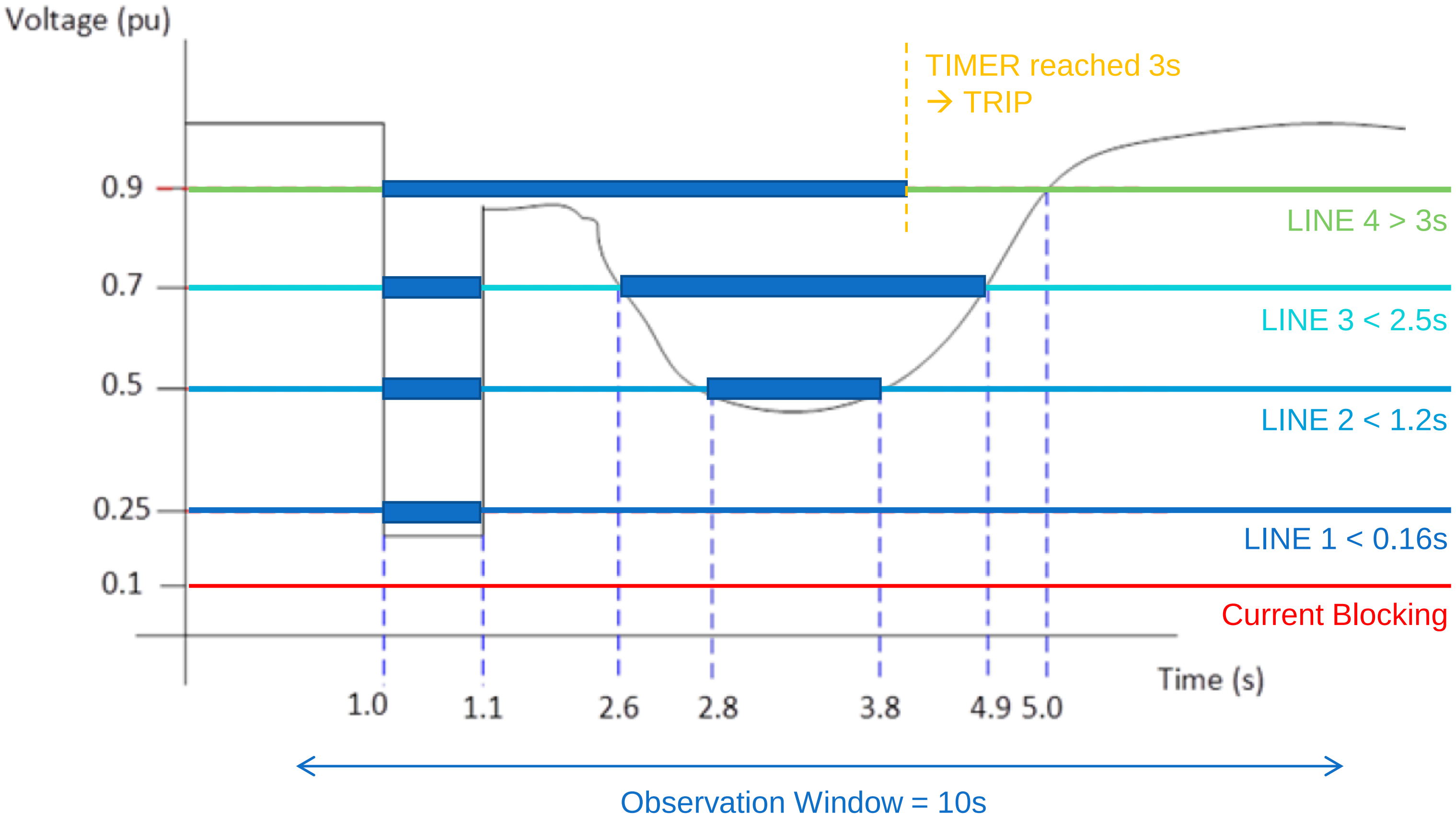
Response to TS Abnormal Condition

Voltage Ride-through Requirement

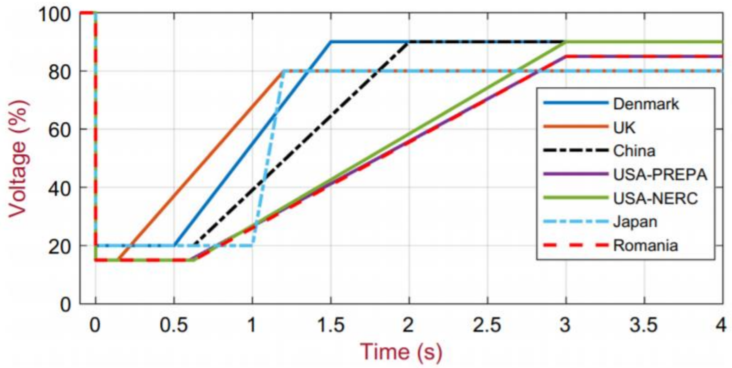
- If the IBR Plant cannot deliver both P and Q due to its current limit (or S limit), when the applicable voltage is below 95%, then preference shall be given to P-priority or Q-priority as specified by the TS owner. By default, IBR unit shall operate in Q-priority mode during high and low voltage ride-through events.
- Exception:
  - If required for self-protection – IBR plant may trip with U_2 > 3% U_N + 10s hold, provided that the voltage unbalance is neither caused nor aggravated by unbalanced currents of the IBR plant. When the duration of U_2 > 3% U_N greater than the specified time limit, the IBR shall remain in grid for as long as possible, and tripping shall be the last resort.
- During LVRT, including faults on TS, where applicable voltage is still within *permissive operation region*, the IBR Plant
  - Shall NOT tripped
  - May continue exchange current with TS, or operate in Current Blocking Mode (NOT to absorb Q to worsen voltage instability). Active and reactive current oscillation shall be positively damped during the disturbance and post-disturbance.
  - If operates in Current Blocking Mode, the IBR units shall restart current exchange **< 5 cycles** when applicable voltage returns to continuous operating region.
- Note:
  - P-priority mode can avoid IBR plant instability with close-in fault active power injection.
  - If there is NO or little P delivered by WTG during fault, rotor loses counter torque and blades may shear off. (ONLY acceptable with Q-priority mode, short-time disturbance period and large inertia)

Response to TS Abnormal Condition

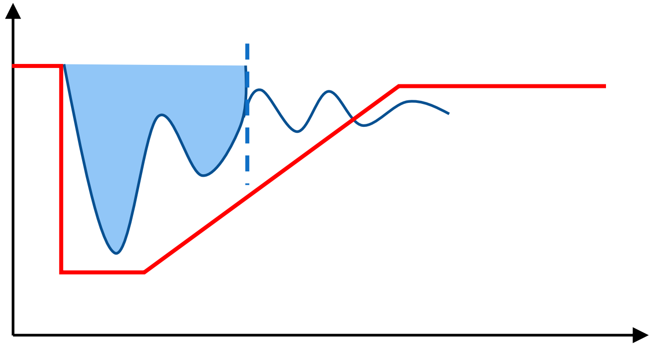
Voltage Ride-through



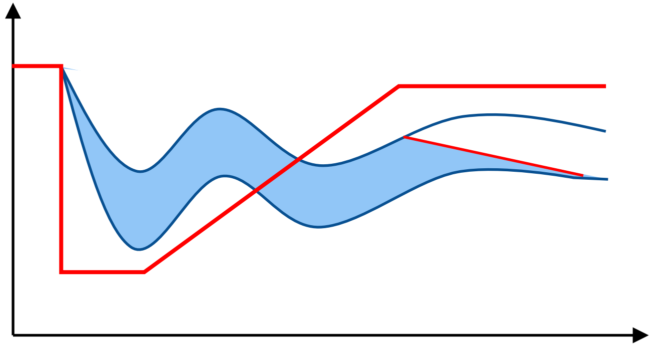
Voltage Vs Time Curve:



Area Under Curve:



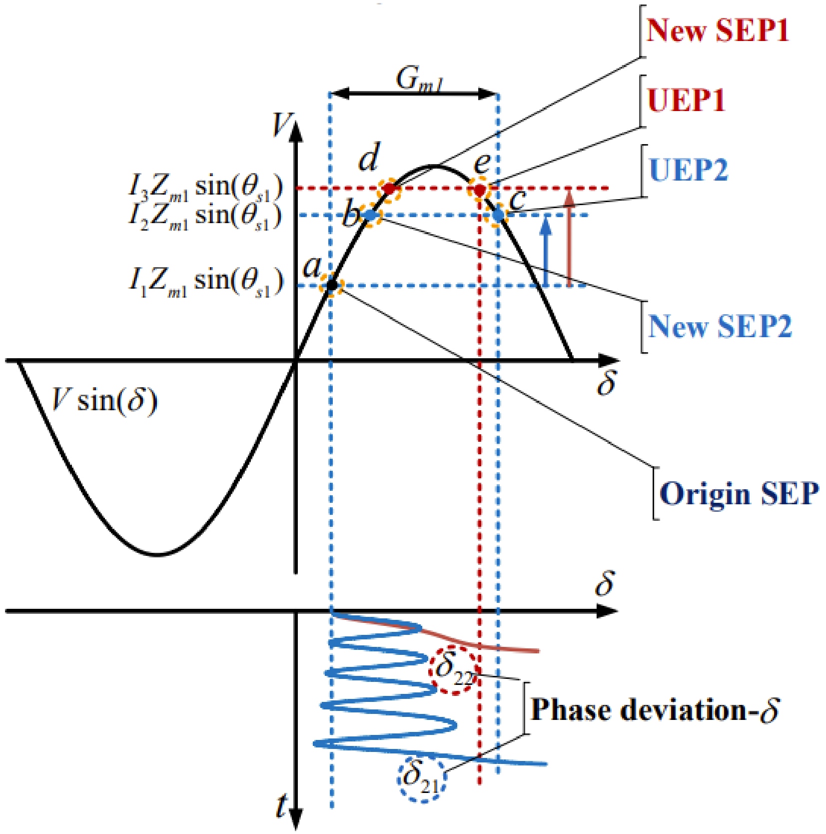
Voltage Vs Time Evelope



Response to TS Abnormal Condition

Current Injection during Ride-through Mode

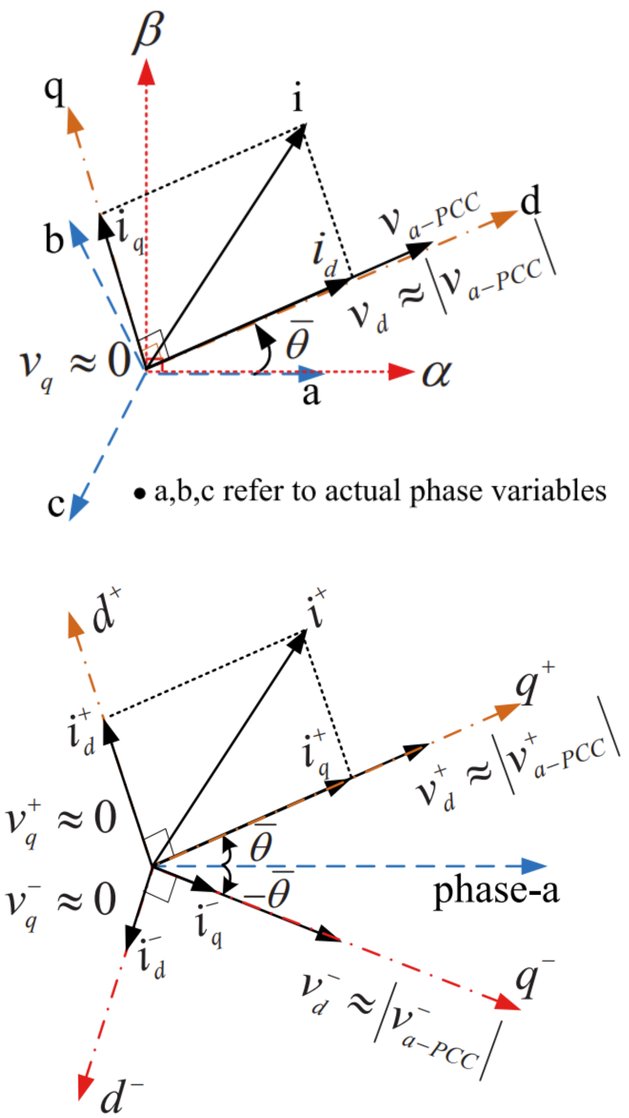
- During RT mode including fault condition, injection of current from IBR unit shall have a fundamental frequency component (track system frequency during fault condition) in voltage with exception on:
  - During a fault and a period immediately following a fault clearing, off-nominal frequency components including abnormal harmonics components, shall be permitted due to transients, transformer in-rush, etc. [Note: inability of frequency tracking algorithm]
  - DFIG, when the rotor is crowbarred or for close-in faults where controllability of rotor current is lost.
  - Severe or close-in fault causes PLL to NOT track IBR unit terminal voltage frequency.
- In case of ESS, when operating in P-priority mode, IBR unit shall prioritize active current to maintain pre-disturbance charging or discharging rate.



Negative Damping due to Multi-swing angle instability

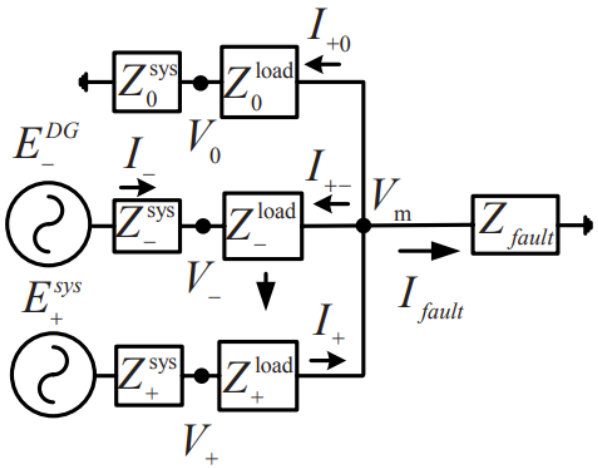
Response to TS Abnormal Condition

abc – dq transformation & sequence network:

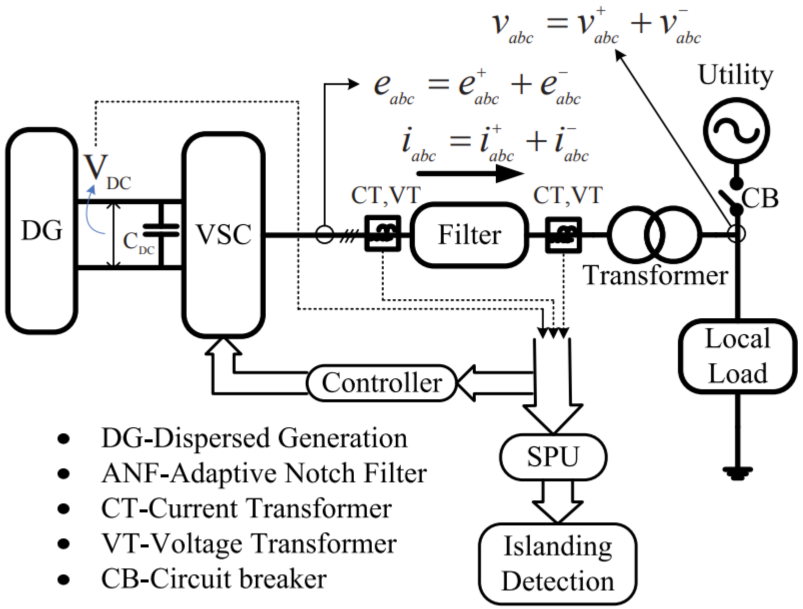


Negative Sequence Injection and Related Requirement

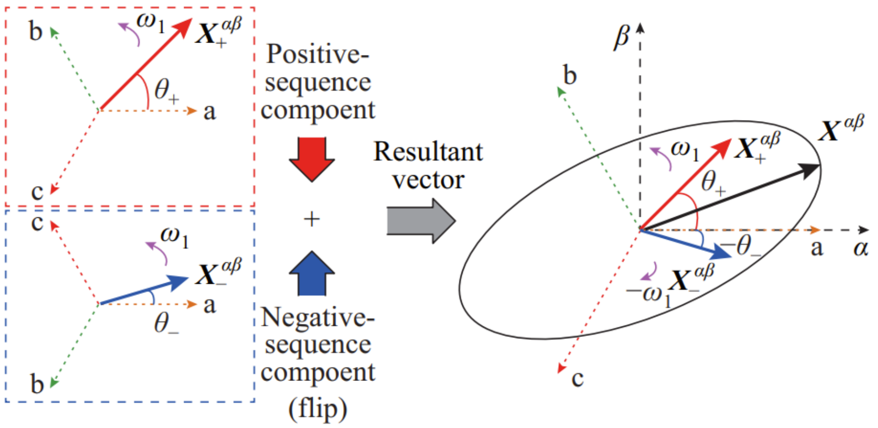
System Sequence Network during Fault:



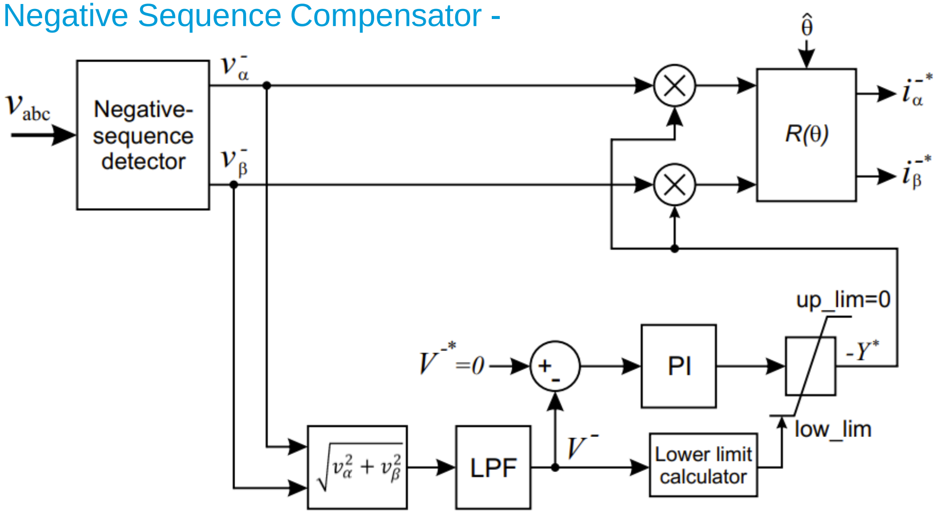
Network Interface between TS and DG:

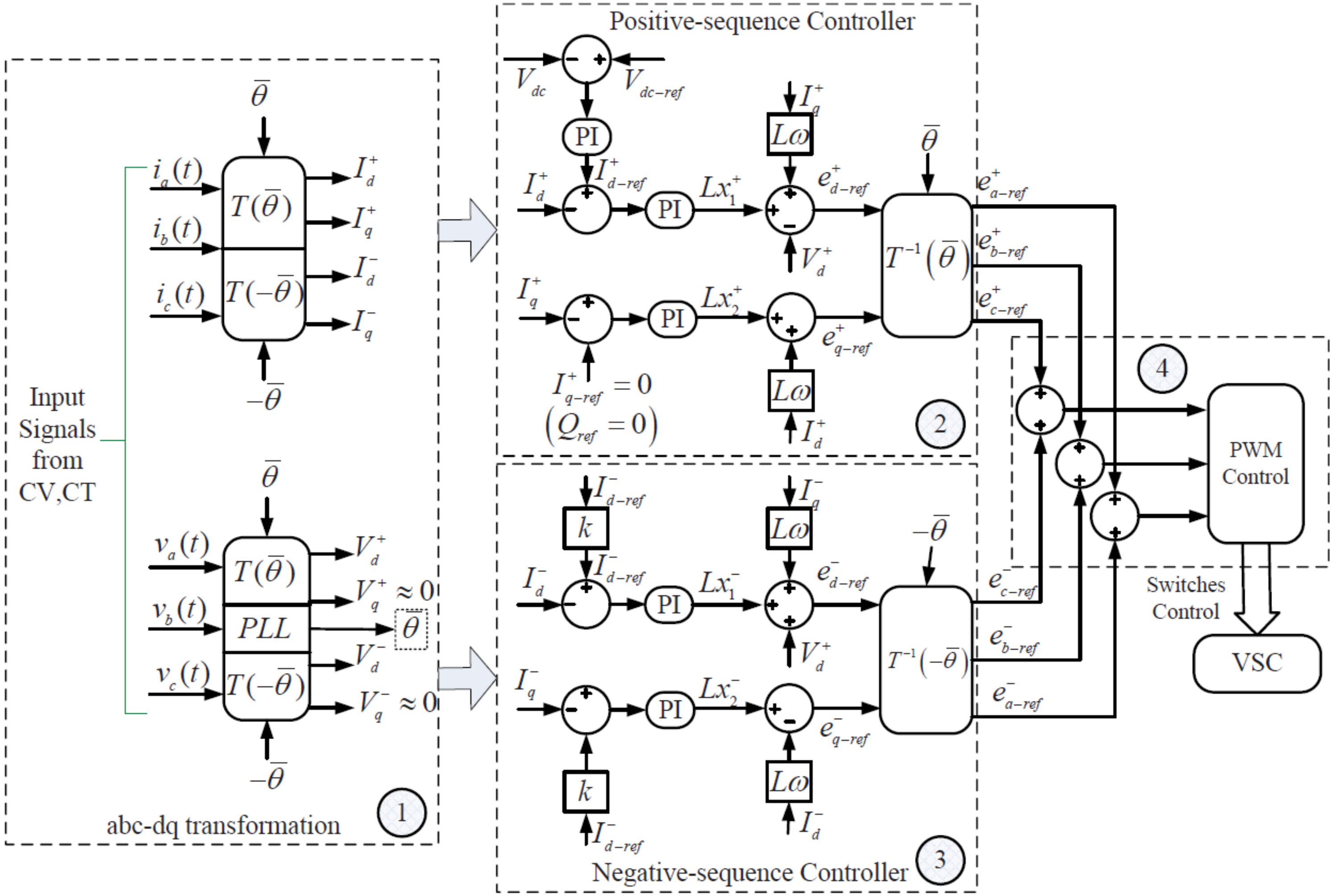


Response to TS Abnormal Condition



Negative Sequence Compensator -



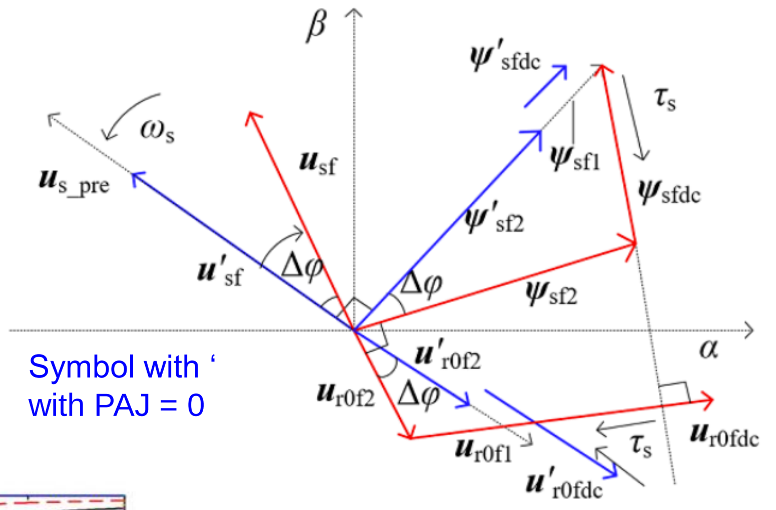


Response to TS Abnormal Condition

Negative Sequence Injection and Related Requirement

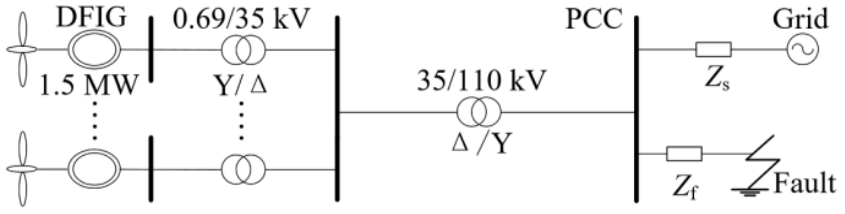
- For balanced fault, IBR unit shall inject reactive current dependent on IBR unit terminal voltage (i.e. Q = Q(V)). The incremental positive sequence reactive current (ΔIR-1) shall NOT be negative, i.e. OV – Q absorption, UV – Q injection.
- For unbalanced fault, in addition to increase IR-1, the IBR unit shall inject negative sequence current depending on IBR unit terminal U_2. I_2 leads U_2 by an allowable range as specified -
  - 90 – 100^o for full converter based IBR units
  - 90 – 150^o for type III WTGs
- Assume pre-fault I_2 is zero or negligible, the I_2 injection during a fault is an incremental negative sequence reactive current (ΔIR-1). If the IBR units' total current limit is reached, either ΔIR-1 or ΔIR-2, or both may be reduced.
- Note:
  - In case of DFIG, ΔIR-1 or ΔIR-2 injection during fault is driven by machine parameters and control dynamics and may not be controllable as described.
  - Angle between I_2 and U_2 may not be precisely controllable. With slip for negative sequence component as (2 – s), the overvoltages caused by unbalance do NOT decay until the unbalance condition is cleared. U_2 under high fault condition can induce voltage large enough to exceed the rotor side converter voltage rating $U_r = U_S\ (2 – s)n$. It can lead to overmodulation of rotor side converter (e.g.. Partial loss of control) or rectification of rotor side converter.

Response to TS Abnormal Condition

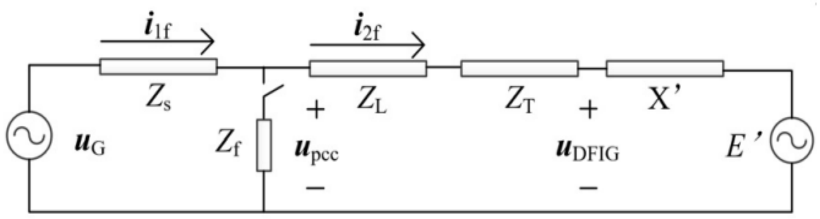


Symbol with ‘
with PAJ = 0

Negative Sequence Phase Angle Jump (PAJ) Under LVRT Condition

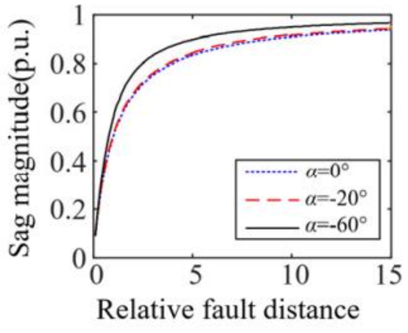


(a)Integrated diagram

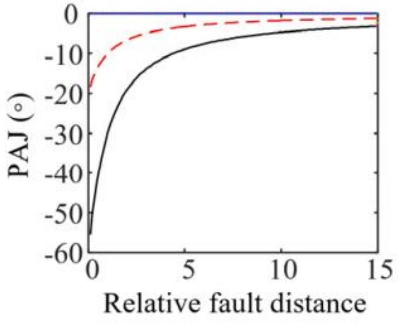


(b) Equivalent circuit

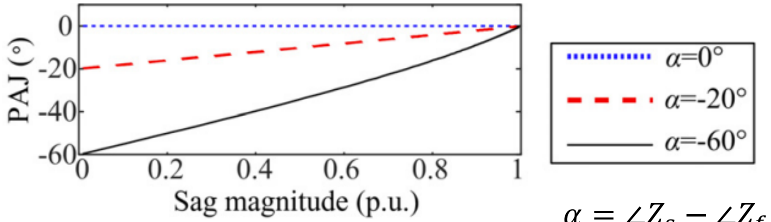
$$u_{pcc}\left(t \geq t_f\right) = Z_f \frac{u_G + \frac{Z_1}{Z_2}E'}{Z_1 + Z_f + \frac{Z_1 Z_f}{Z_2}} \approx \frac{Z_f}{Z_f + Z_s} u_G$$



(a)Relation of U_{pcc} and λ



(b)Relation of $\Delta\varphi$ and λ



$\alpha = \angle Z_s - \angle Z_f$

Note:

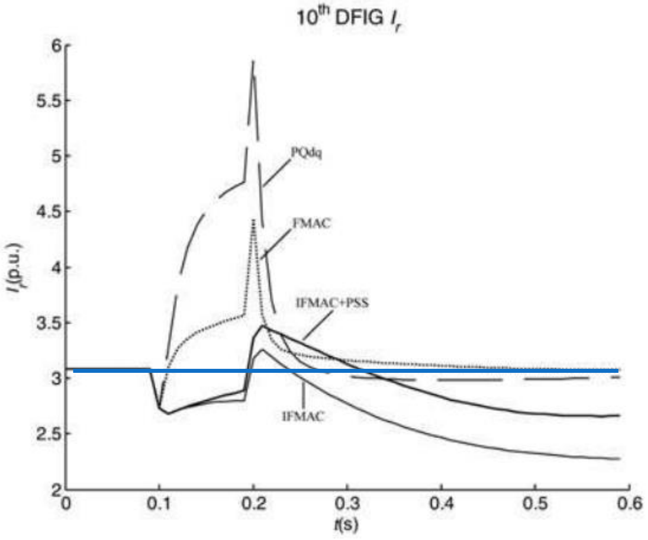
1. PAJ intensifies rotor overcurrent by including transient components in stator flux.
2. PAJ causes angle rotation of transient components, and rotor OC occurs with a delay (not at beginning of the fault)
3. Increased rotor OC imposes challenges for DFIG to comply with grid code (e.g. crowbar protection connected longer time, delayed response time for Q injection)
4. Inadequate research is on phase-to-phase fault LVRT requirement. Sag magnitude, PAJ, transformer type and point on wave may affect the response of WTG in asymmetrical sag.

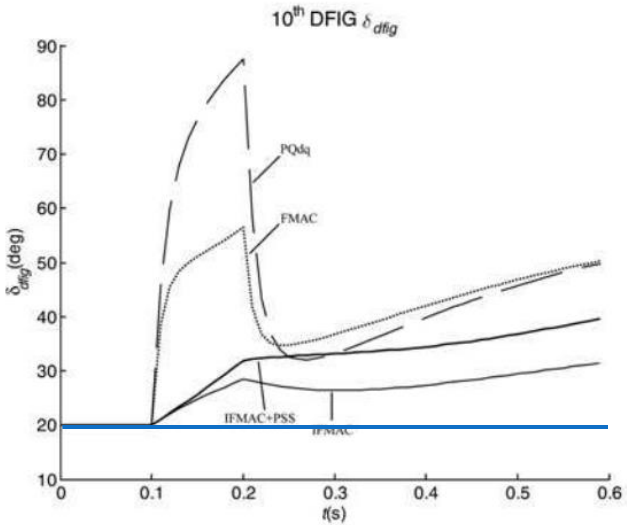
Response to TS Abnormal Condition

Fault Ride-through Performance of DFIG

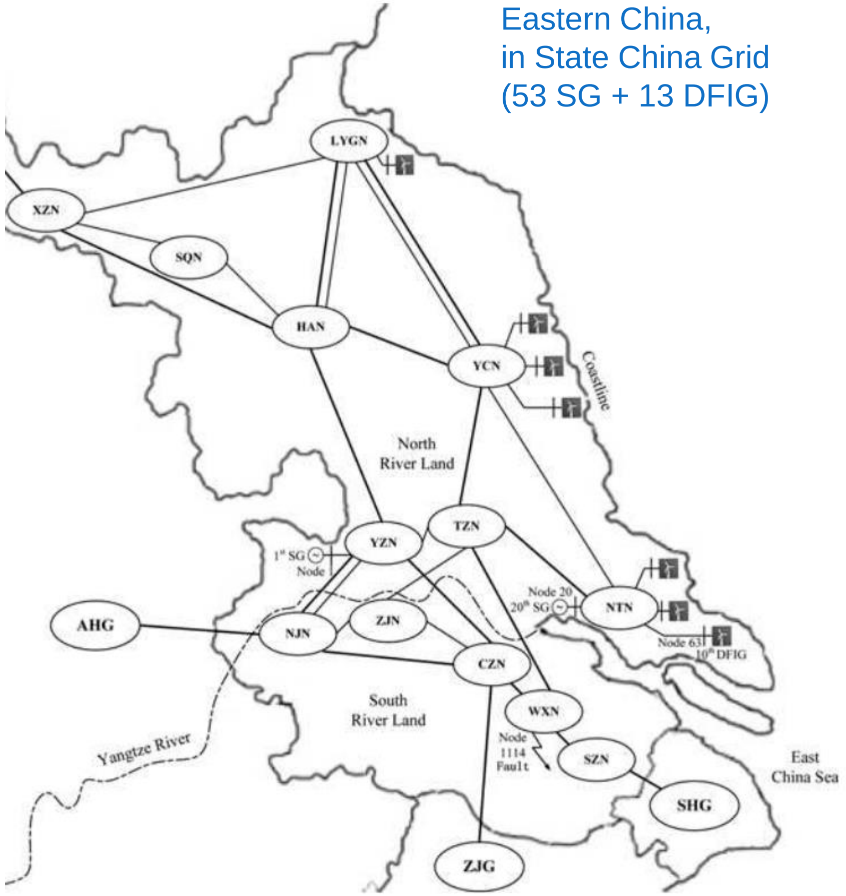
- Using an active crowbar circuit
- Using an ESS connected to an intermediate DC bus or rotor KE storage system
- Using an improved rotor current control for stator flux regulation
- Using an external voltage or reactive power compensation
- Using an additional series grid-side converter.

Improved Flux Magnitude and Angle Control (FMAC) with Power Angle Control from PSS can help stabilize DFIG power angle, hence reduce rotor current surge and terminal voltage dip. PSS + FMAC can help contribute positive damping and suppress network oscillation.





Eastern China,
in State China Grid
(53 SG + 13 DFIG)



Response to TS Abnormal Condition

Consecutive Voltage Deviation Ride-through Capability

- TS Operator should specify ride-through requirements for dynamic voltage oscillation stimulated by a TS fault, line opening or generator tripping. These may cause the applicable voltage to deviate outside the continuous operation region multiple times. The oscillation is specified with
  - Upper and Lower Limits of Oscillating Applicable Voltage
  - Frequency of Oscillation in Synchronous Reference Frame
  - Damping Ratio of the Oscillation

- The consecutive voltage deviation RT capability via an VSC-HVDC may be limited by the energy absorption capability, thermal design of DC chopper and fast control of active power production by the isolated IBR.
  - Note: Without direct communication between onshore WTG units and offshore AC/DC converter station, maintaining DC voltage by stopping or reducing injection of active power from offshore AC network is not feasible. Hence, a DC chopper is added to avoid rise in DC voltage and lead to equipment damage by absorbing excess energy.
- IBR owner shall inform TS operator on the limitation regarding the capability of IBR facilities to meet the consecutive voltage deviation requirement and any remedy measures taken, such as
  - DC chopper may be designed to absorb ICR for at least 2 seconds (consider burning of parallel IGBT)
  - New control methods of offshore AC/DC converter station enable fast reduction of active power by changing offshore AC network voltage.

Response to TS Abnormal Condition

Restoration after Voltage Ride-through

- Upon the applicable voltage returning the continuous operation region, the IBR shall have the capability to restore active power output to 100% of pre-disturbance level within the active power recovery time (default = 1.0s, in range of 1.0s – 10s), except:
  - Limited by available active power from primary energy source, or by transmission capacity.
  - WTG-based plant with pitch angle changed to reduce overspeed due to severity and duration of voltage disturbance. (Active Power output to maximum output with pitch angle control within 1.0s, and shall be capable to restore active power output to 100% of pre-disturbance level as soon as practical.)
- Note:
  - In order to limit oscillatory behavior of IBR plant (possible occur at specific unit, collector system or converter transformer) of a weak grid upon fault recovery and maintain system stability, it may be desirable to limit the average rate of active power recovery.
  - IBR units shall have the capability to cease the injection of ΔIR-1 or ΔIR-2 when applicable voltage returns to normal operation region.

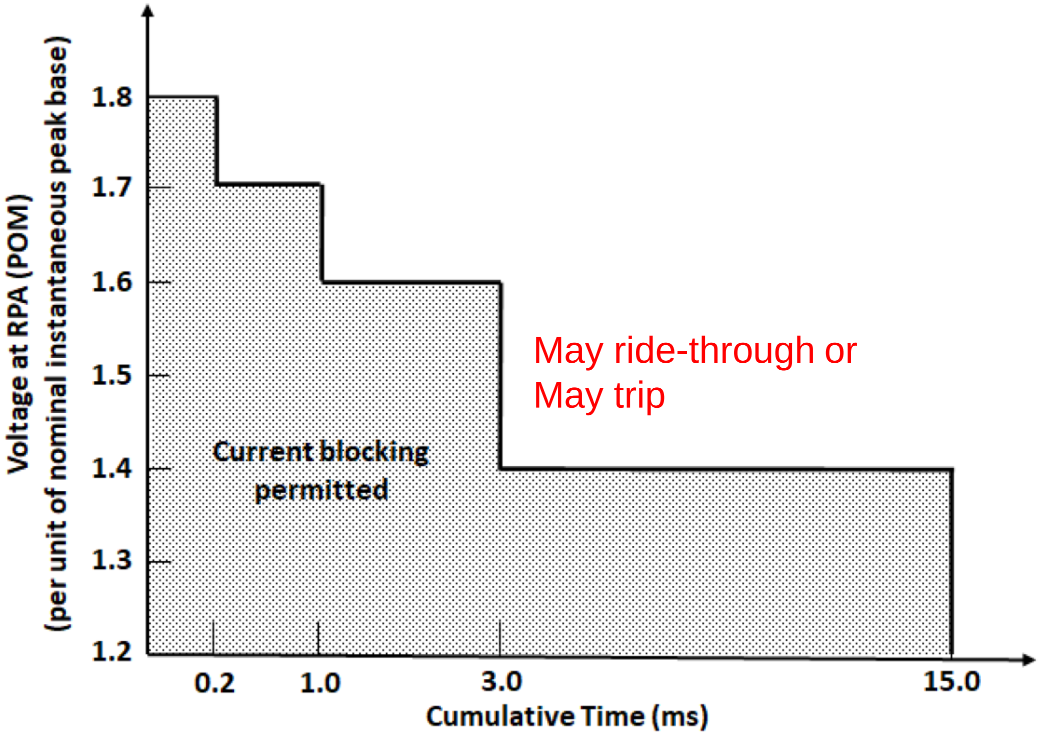
Response to TS Abnormal Condition

Transient Voltage Ride-through Requirement

- The IBR plant shall ride-through TOV that do NOT exceed the fundamental frequency overvoltage with individual phase-to-phase or phase-to-ground instantaneous voltage magnitudes do NOT exceed the cumulative duration over 1 min time window.

Voltage [c] (p.u.) at RPA	Minimum ride-through time (ms) [d] (design criteria) [b]
V > 1.80	See Note [a]
V > 1.70	0.2
V> 1.60	1.0
V > 1.40	3.0
V > 1.20	15.0

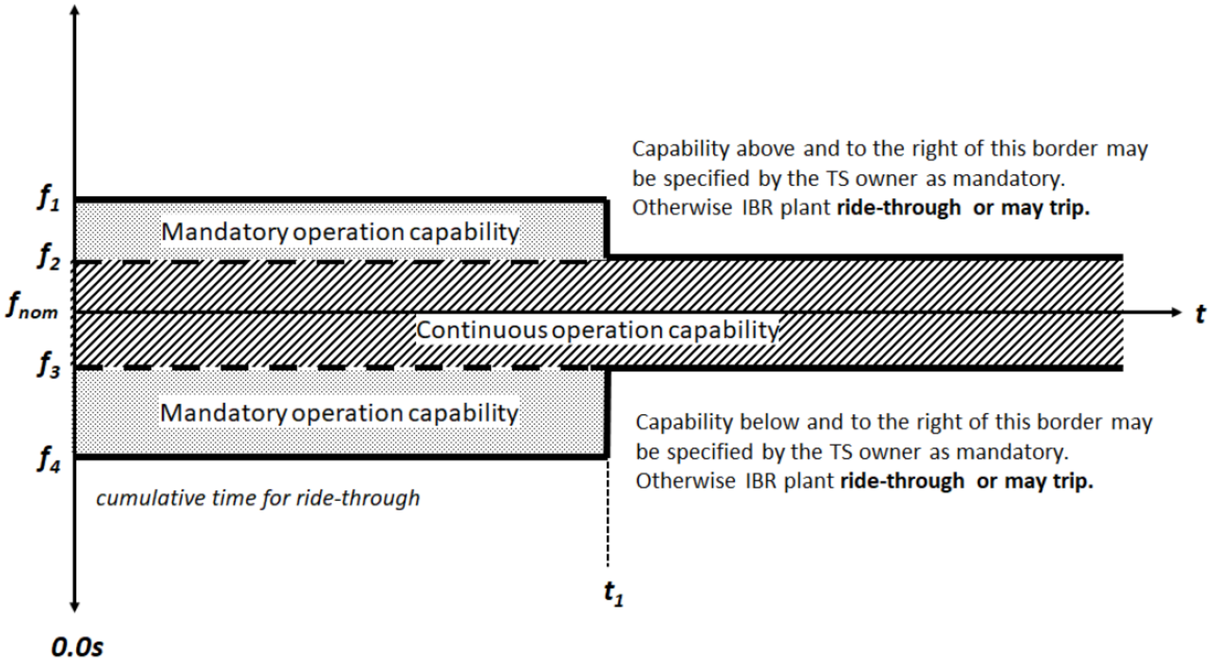
- The following should be coordinated:
  - Surge Protection (Arrester, Voltage Clamp)
  - TOV Ride-through Requirement (from Converter)
  - TOV Trip Requirement (from Protection)



Response to TS Abnormal Condition

Frequency Disturbance Ride-Through Requirement

- Only applicable when voltage is within continuous operating region.
- Under applicable frequency within continuous operating region, the IBR shall exchange P and Q with TS within ICR and within volt-per-hertz (V/f) capability limits of IBR units, supplemental IBR device and transformers (to avoid overflux) as specified in other standard.
- During temporary frequency disturbance with $f_4 < f < f_3$, the IBR plant shall
  - Maintain Synchronism with TS
  - Meet the requirement on PFR and FFR or maintain pre-disturbance P output or as required by TS operator.
  - Continuous to exchange current with TS and shall NOT initiate a protective function (oscillation with positive damping are acceptable)
  - Modulate active power to mitigate the UF conditions specified.



Frequency range (Hz)	% from f_{nom}	Minimum time (s) (design criteria)	Operation
f_1, f_4	+3, -5	299.0 (t_1)	Mandatory Operation
f_2, f_3	+2, -2	∞	Continuous Operation

Response to TS Abnormal Condition

ROCOF Ride-through

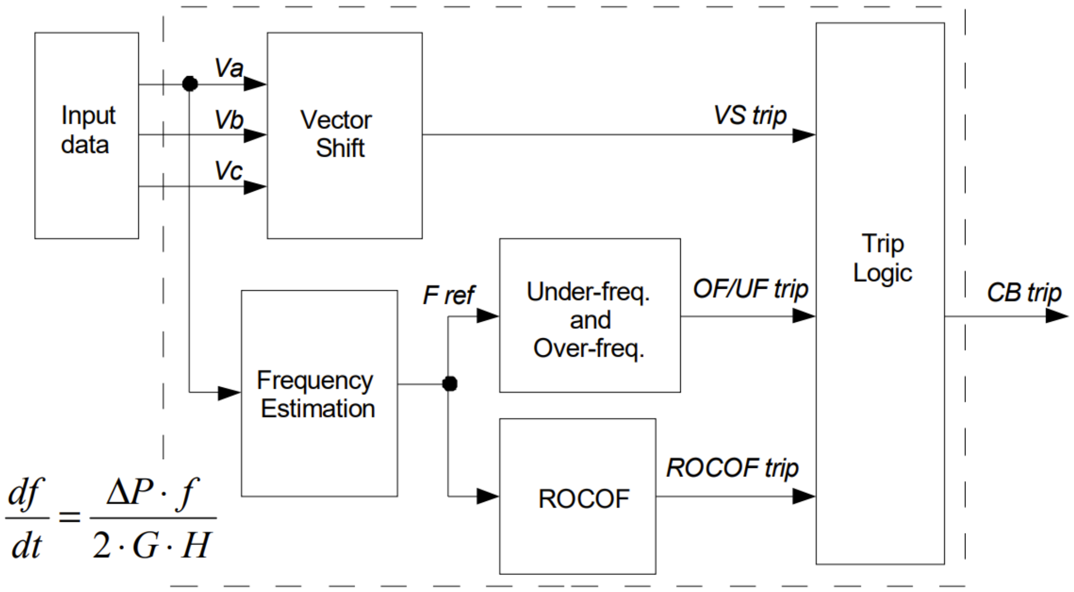
- IBR plant shall ride-through and shall not trip for frequency excursions having an absolute rate of change of frequency (ROCOF) magnitude that is less than or equal to 5.0Hz/s.

$$\frac{df}{dt} < 5.0 \text{ Hz/s}$$

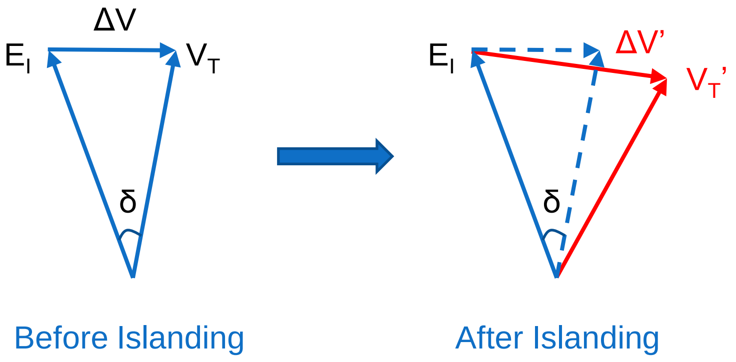
Voltage Phase Angle Changes Ride-through

- IBR plant shall ride-through positive-sequence phase angle changes within a sub-cycle-to-cycle time frame of the applicable voltage of less than or equal to 25 electrical degree. (Typically caused by line switching or load rejection, depending on pre-network flow)
- IBR plant shall remain in operation for any change in phase angle of individual phases caused by unbalanced faults.
- Current blocking in post-disturbance period shall NOT be permitted.

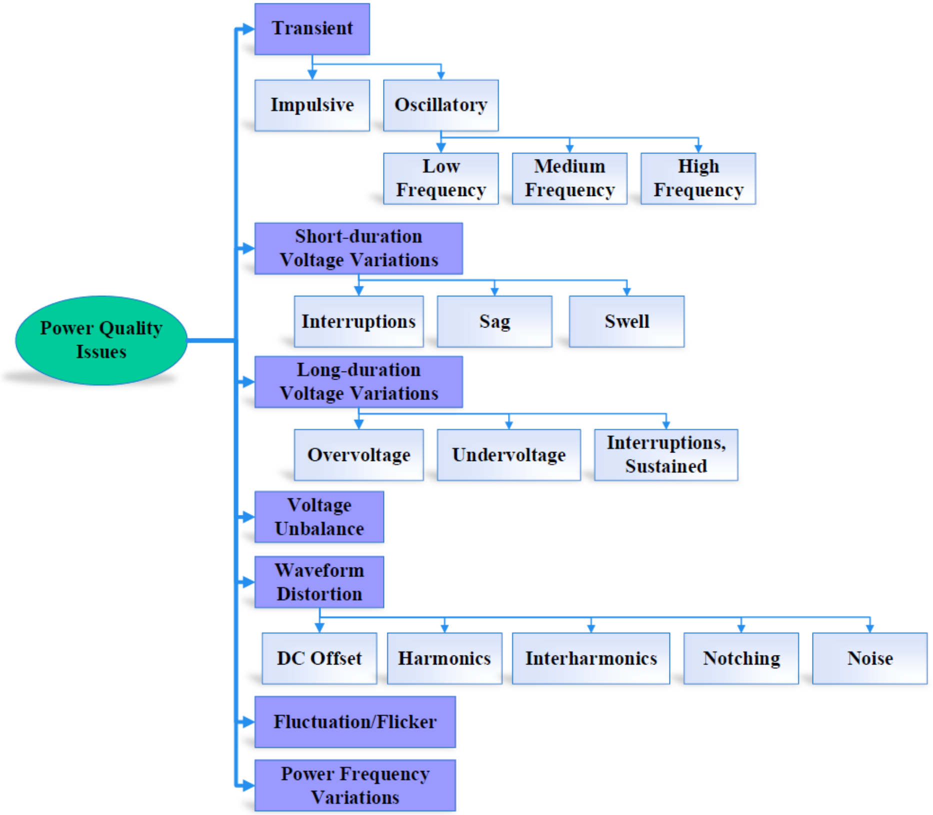
$$\Delta\angle U_1 < 25^o$$



$$\frac{df}{dt} = \frac{\Delta P \cdot f}{2 \cdot G \cdot H}$$



Power Quality Requirement



Problem	Definition	Causes	Effects
Voltage sag/dip	A decrease in Root-Mean-Square (RMS) voltage	Faults, starting of large loads, grid loading, supply voltage variations, inrush current, inaccurate connection	Overloading or stalling of motors, lock-up, unreliable data
Voltage swell/rise	An increase in RMS voltage	Start/stop of heavy loads, supply voltage variation, inrush current, inaccurate connection	Data loss, damage to equipment, lock-up, unreliable data
Transient	An abrupt change in voltage, current or both	Snubber circuits, lightning, start/stop of heavy loads, inaccurate transformers connection	Disturbance in electrical equipment, data loss, the flickering of lights, damage of sensitive equipment
Harmonic	Integral multiples of the fundamental frequency, resulting in a distorted voltage or current waveform	Non-linear loads	Losses in electrical equipment, transformers and motors overheating, lock-up, unreliable data
Voltage fluctuation/flicker	Variations or random alteration in the voltage magnitude	Load switching, fluctuation of supply voltage	Over and under voltages, the flickering of lights, damage the equipment at the load-side
Power frequency variation	Deviations of the system frequency	Heavy load	Inefficiency in motors and sensitive devices, heating up, gradual breakdown
Voltage interruption	A decrease to less than 0.1 pu in supply voltage or load current	Failure of protecting devices, insulation failure, control malfunction	Malfunction in data processing equipment

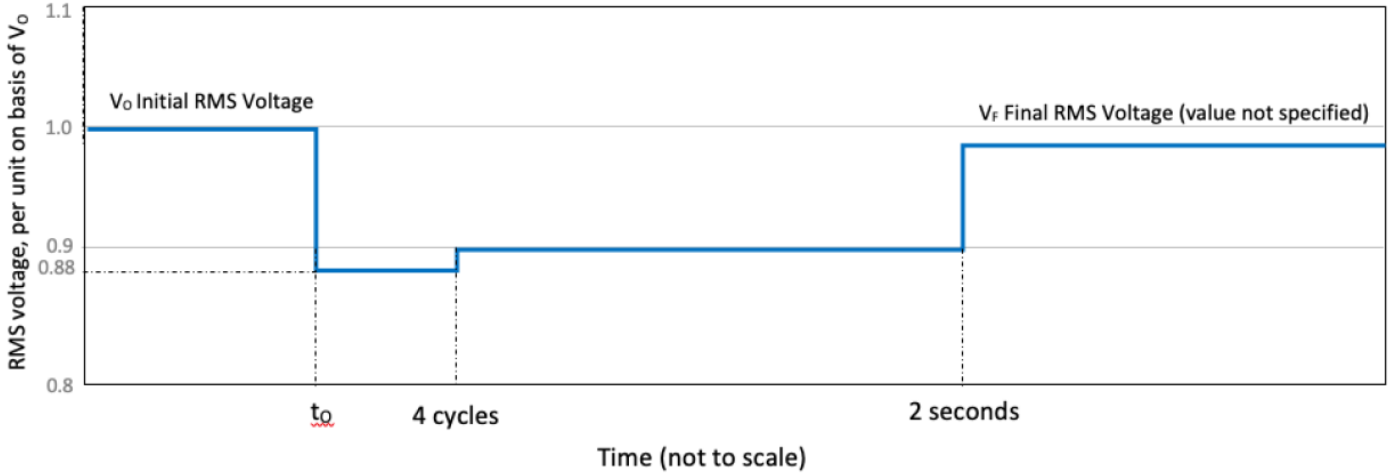
Power Quality Requirement

Limitation of Voltage Fluctuation Induced by IBR Plant

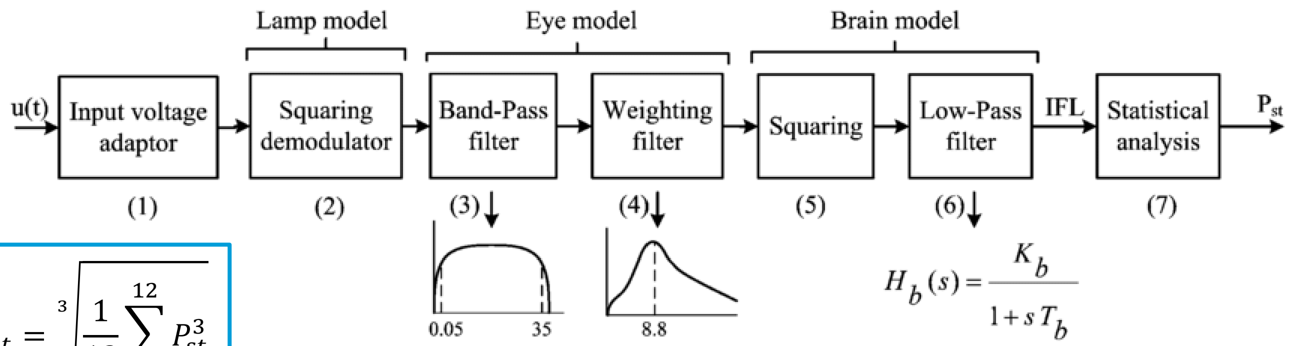
- Rapid Voltage Change (RVC)
  - NOT intended to address issues associated with slow voltage variation, such as cloud shadow passage, wind speed change.
  - Frequent RVC
    - – NOT to exceed **2.5%** of nominal voltage.
    - – Shall apply to sudden changes due to Tx energization and cap bank switching. NOT apply to switching, unplanned tripping.
  - Infrequent RVC
    - – Initial RMS Voltage V_0 and final RMS Voltage V_F shall be equal to or above the per unit values between t_0 and t_0 + 2s.
- Flicker Value
  - Shall NOT be greater than the limits

E_{Pst}	E_{Plt}
0.35	0.25

Min Acceptable Voltage due to **Infrequent Events**



IEC Flicker Model



$$H_b(s) = \frac{K_b}{1 + sT_b}$$

$$P_{lt} = \sqrt[3]{\frac{1}{12}\sum_{i=1}^{12} P_{st}^3}$$

Power Quality Requirement

$$\%TRD = \frac{\sqrt{I_{rms}^2 - I_1^2}}{I_{rated}}$$

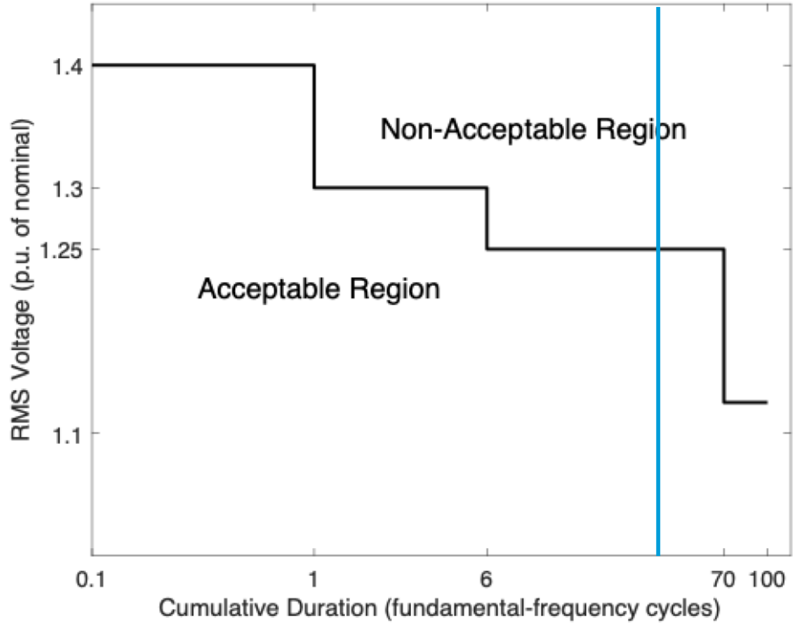
Limitation on Harmonic Distortion

RPA LL Voltage (kV)	Individual harmonic order h			Total rated current distortion (TRD) Percent (%)
	h <11 Percent (%)	$11 \leq h < 17$ Percent (%)	$17 \leq h \leq 50$ Percent (%)	
≤ 69	4.0	2.0	1.5	5.0
69.001-161	2.0	1.0	1.0	2.50
>161	1.5	1.0	1.0	2.0

Note:

1. Current harmonics requirement only applicable if the TS voltage harmonics prior to IBR plant connection is blow the limits as specified in IEEE std. 519. (prior to = need to measure before connection)
2. Current limits are applicable only if **U_2 < 2% U_N**.
3. Future revision may differentiate specified individual harmonics not only based on voltage class, but also TS characteristics such as short-circuit ratio of RPA.

Limitation on Cumulative Instantaneous OV



Note:

1. IBR plant shall not cause the instantaneous magnitude of applicable voltage at RPA to exceed the max magnitude and cumulative duration as specified over 1 min time window.

Voltage Harmonics of Inverter-Based Resources

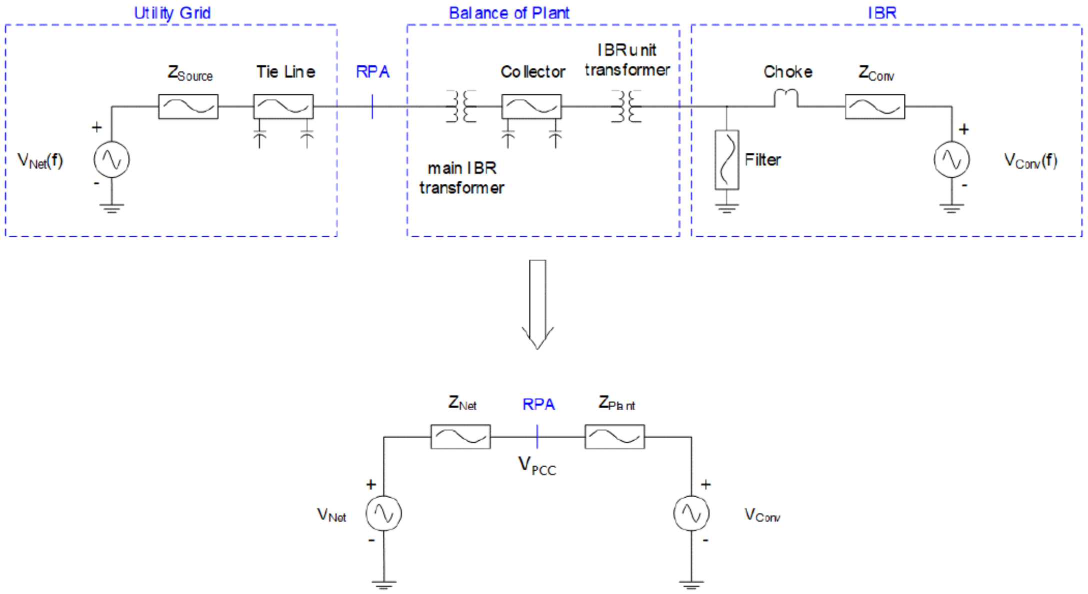
To determine the total harmonic content after IBR plant connection, which depends on impedance and admittance of balance of plant, harmonic driving point impedance of the grid at POI and background or ambient voltage distortion present in the grid without the IBR plant.

The individual aggregated harmonics levels is the result of 1) harmonic emission, and 2) amplification or damping of the pre-existing background voltage harmonics.

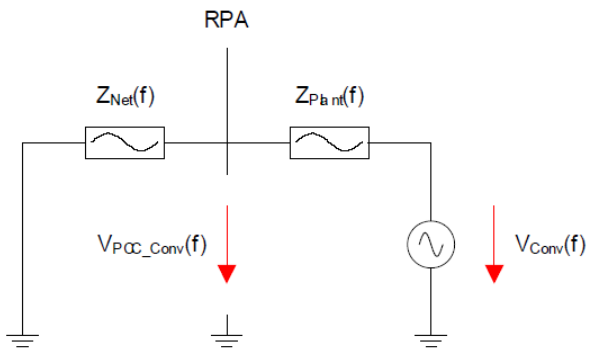
Consider

- Different network configuration
- System Load and Generation Scenario
- Voltage Transfer Function & Voltage Synthetization with Modulation Techniques under different plant topology (inc. filters and cables connected)

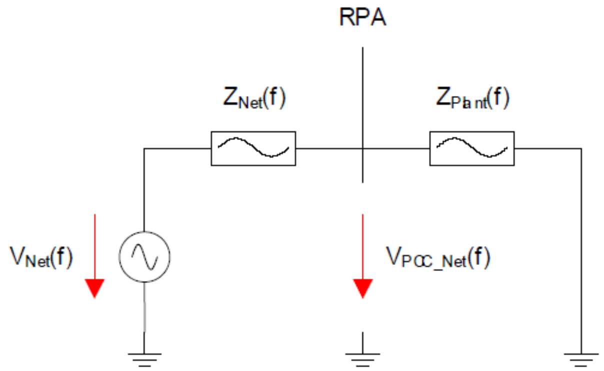
If the inverter's Thevenin reactance is inductive (+ve) and the grid reactance is capacitive (-ve) at a frequency (grid reactance swing between inductive and capacitive at frequency above > 100Hz), the harmonic current will be increased.



Harmonic Emission Determination



Harmonic Amplification or Damping Determination



Voltage Harmonics of Inverter-Based Resources

Harmonic Limit:

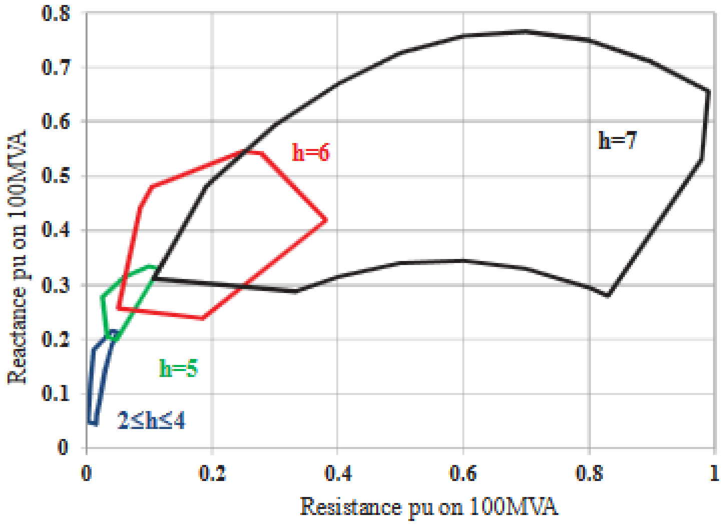
1. Limit on the amplification factor (AF) caused by the interaction between IBR plant and the network.
2. Limit on harmonics emission level of the IBR plant at the RPA (calculated without voltage harmonics background)

$$AF_{\lim}(f) \geq \left| \frac{Z_{plant}(f)}{Z_{plant}(f) + Z_{net}(f)} \right|$$

Verification:

Initial harmonics performance evaluations can be performed by a study, with steps

1. Determine the range, in R – X plane of the transmission system harmonic impedances. It considers possible topology (e.g. line outage), generator online/ offline, capacitor bank status.
2. Determine pre-existing harmonics voltage at RPA.
3. Manufacturer to determine the Thevenin model for IBR units for each harmonics in different operating points, including the controls unit particular at the lower-order harmonics.
4. Model also the balance of plant (inc. inverter, Tx, CB, cap bank, filter and supporting auxiliaries)
5. Perform analysis of harmonic performance for the range of operating conditions and status of inverter units and balance of plant (BoP) components.



Protection Requirement

1. **Stable** within requirement (V, f) except self-protection and tie-line isolation during fault.
2. **Avoid** instantaneous value, use filtered value or delayed relaying instead.
3. **Check** equipment damage curve (e.g. frequency capacity, overexcitation V/f limit)
4. **Consider** additional current from reactive support equipment during voltage excursion.
5. **Disable** active island detection algorithm. Use direct transfer trip (DTT) instead.
6. **Provide** dependability with backup (step-distance, zero-sequence OC, UV) and OC guard for main.
7. **Expect** delayed response from directional element, distance element and fault-type identification.

Modelling Requirement

Upon the request from TS operator, the IBR owner shall provide

1. Verified IBR plant level models, including
   a) steady-state power flow model
   b) positive sequence (fundamental-frequency) stability dynamic model
   c) EMT model
   d) short circuit and harmonics model

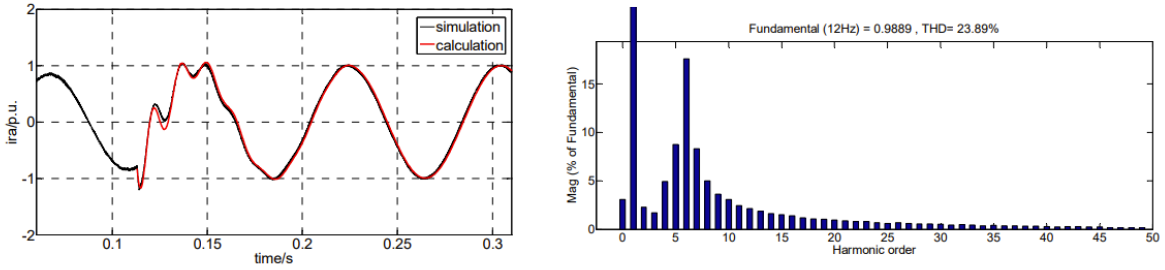
   to perform IBR plant design evaluation and system studies.

2. Documentations detailing development and verification and brief explanation of control strategy.

In addition, TS operator can also request for

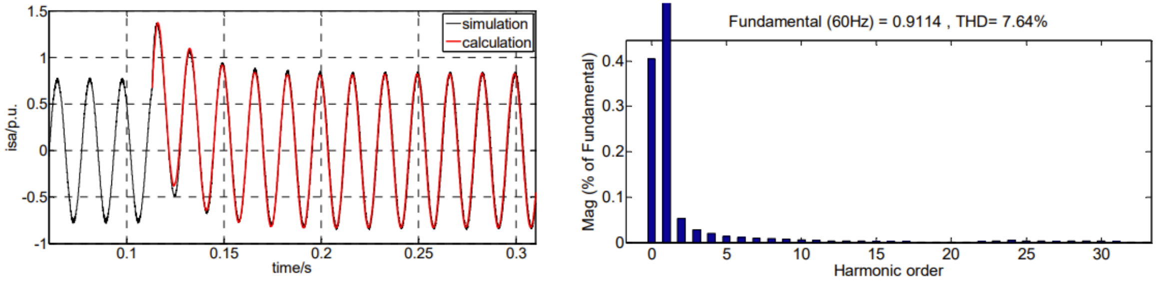
   a) Non-aggregated IBR unit EMT model with type / HIL test result (for converter interaction & stability at collector and converter transformer)
   b) Supplemental Equipment EMT model
   c) Aggregate Plant Level EMT Model
   d) IBR unit stability model inc. converter and respective electrical control model.

Rotor Short Circuit Current - DFIG



(a) (b)

Stator Short Circuit Current - DFIG

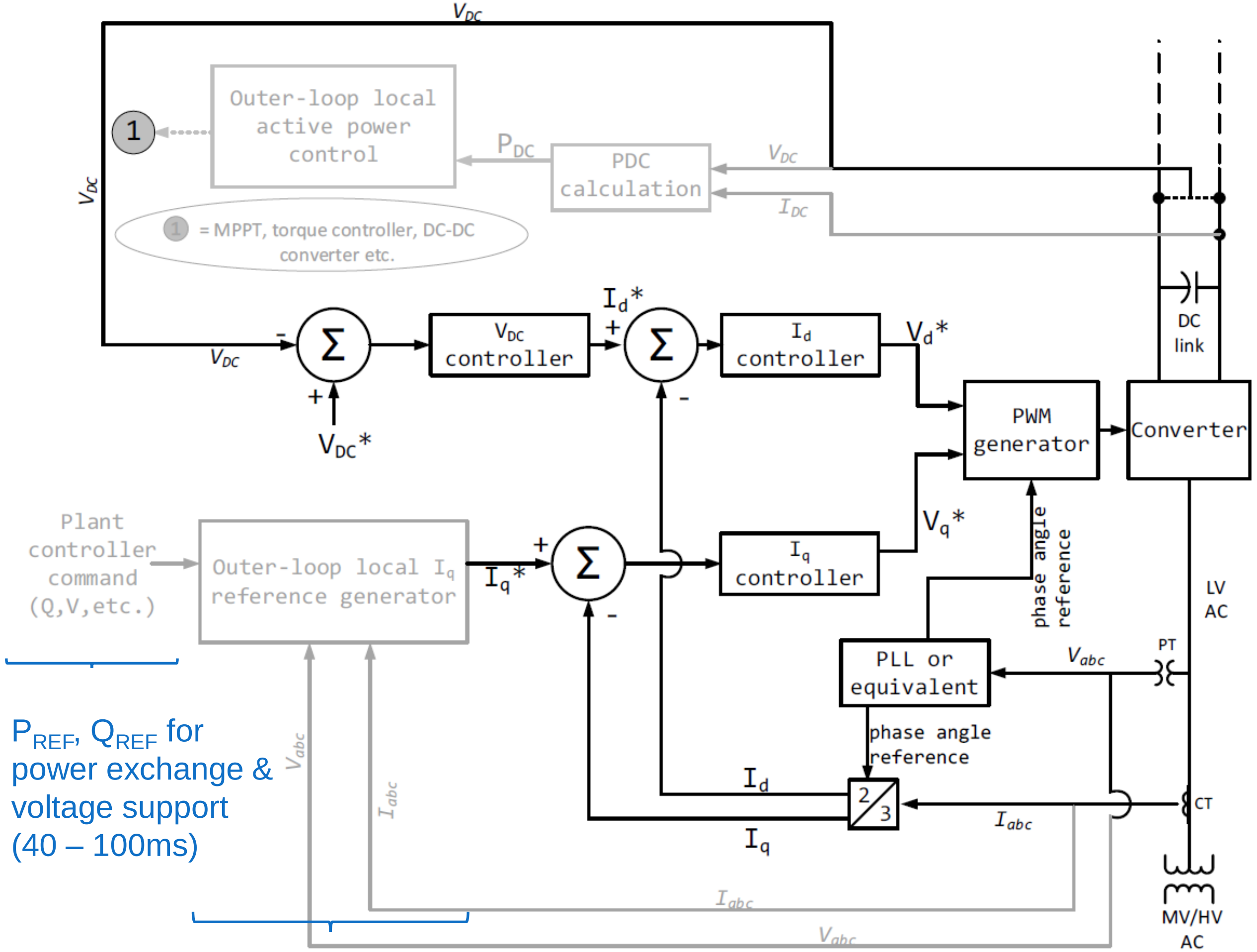


(a) (b)

Note:
IBR Plant ground grid design data may be needed for lightning, insulation, short circuit and protection coordination studies.

Inverter Controller

V_{DC} regulation – control I_{AC} (1 - 6 cycle)
PLL for frequency tracking & synchronization
Control I_d and I_q with dq0 ref and PLL θ-ref

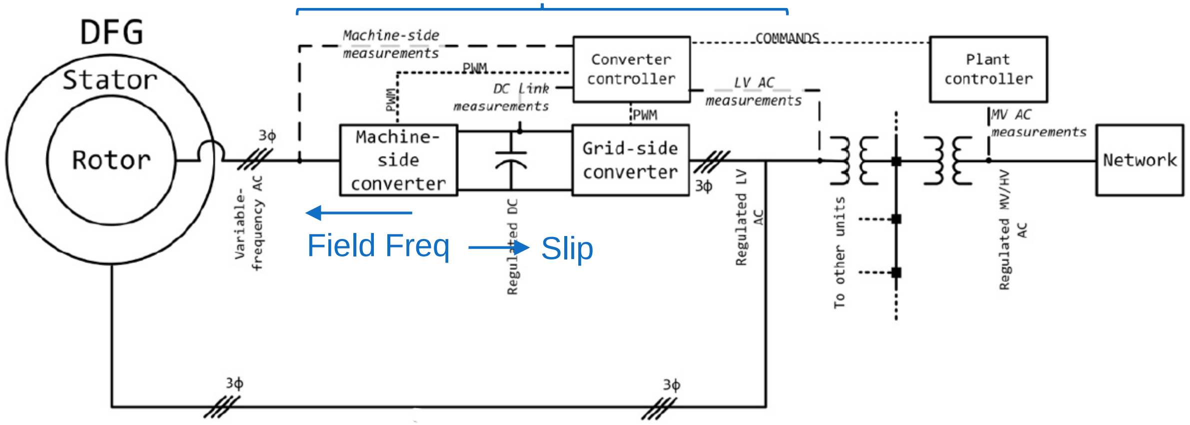


P_{REF}, Q_{REF} for power exchange & voltage support (40 – 100ms)

P: Including MPPT for PV & torque controller for WTG (0.5s – 5s), Q: regulate Q output (0.25 – 1s), measurement filter + calculation delay

Note:
- Control has impact on inverter stability and should be modelled in detail under various system condition.

Modulate stator terminal voltage to deliver or absorb reactive power



Note:
- DFIG has a rotor back-to-back converter sized to 30% - 35% rated power of the machine. It is to impose a voltage and current at a controlled frequency to establish a precise slip between stator and rotor. It also modulate stator terminal voltage magnitude to absorb or deliver reactive power to the grid.
- If mechanical rotor speed is super-synchronous (s > 1), grid side converter (GSC) delivers active power to grid.
- Type III WTG exhibits some inverter-like behavior and some machine-like behavior.

System Strength

Note: SCR is NOT preferrable as

- Only fundamental frequency impedance (not full spectrum)
- Assume single IBR unit (without interaction or individual response)
- NOT include other IBR or Power Electronics equipment (e.g. wind heterogeneity, responsive loads and FACTs)
- Only system strength at POI (no information on collector and converter transformer)
- Assume well-regulated voltage source with simple series impedance (NO information on loads in between, i.e. NOT all current travels all along the tie-line)

The term “system strength” or “system stiffness” typically means

- System inertia, or df/dP, which classically refers to ability of system resist change in frequency
- Source Impedance Strength, which refers to how high the impedance is to the grid voltage sources as seen from some point on the system relative to the size of generator connector at that point. Weak grid = higher Z_S.

$$SCR = \frac{S_{3\phi F}}{S_{rated}}$$

Assumed Strong Coupling IBR – IBR **(no interaction)**

$$WSCR = \frac{\sum_i^N \left(S_{3\phi F,i} \times P_{rated,i}\right)}{\left(\sum_i^N P_{rated,i}\right)^2}$$

$$CSCR = \frac{S_{3\phi F\ (No\ IBR)}}{\sum_i^N P_{IBR,i}}$$

$$SCRIF_i = \frac{S_{3\phi F,i}}{P_i + \sum_j \left(IF_{ji} \times P_j\right)}$$

$$IF_{ij} = \frac{\Delta V_i}{\Delta V_j}$$

Metric		Simple calculation using short circuit program	Accounts for nearby inverter-based equipment	Provides common metric across a larger group of IBR	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	Yes	No	No	No	No	No
CSCR	Composite SCR	Partial	Yes	Yes	No	No	No
WSCR	Weighted SCR	Partial	Yes	Yes	Partial	No	No
SCRIF	Multi-Infeed SCR	No	Yes	N/A	Yes	Yes	Yes

Interaction Factor reflects the coupling in voltage, grid strength and short circuit level (also include external factor – sync cond, low Z Tx)

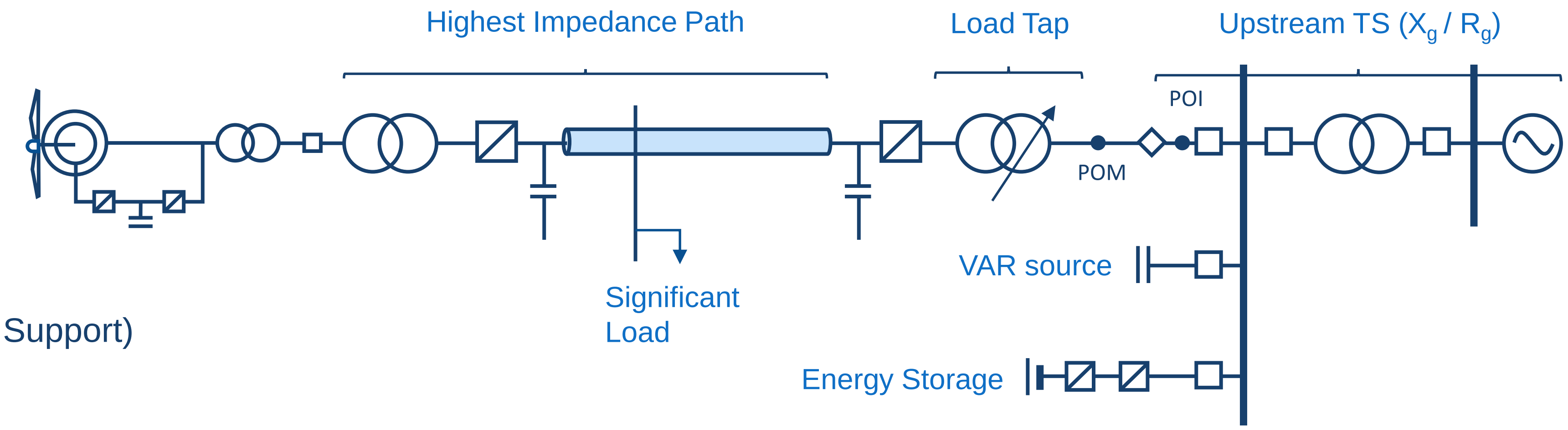
Assume all IBRs are connected to a virtual POI with equivalent system impedance

Only indicate further stability analysis is needed with low system strength.

Stability Modelling Information Requirement

Information should be included

1. Converter
   - Full switching model
   - Average Model
2. Control Loop
   - PLL (Sync, Phase Track)
   - Inner Loop
   - Outer Loop
     (Energy Exchange, Voltage Support)
3. Latency
   - Sampling
   - Code Execution
4. Filters
   - Measurement

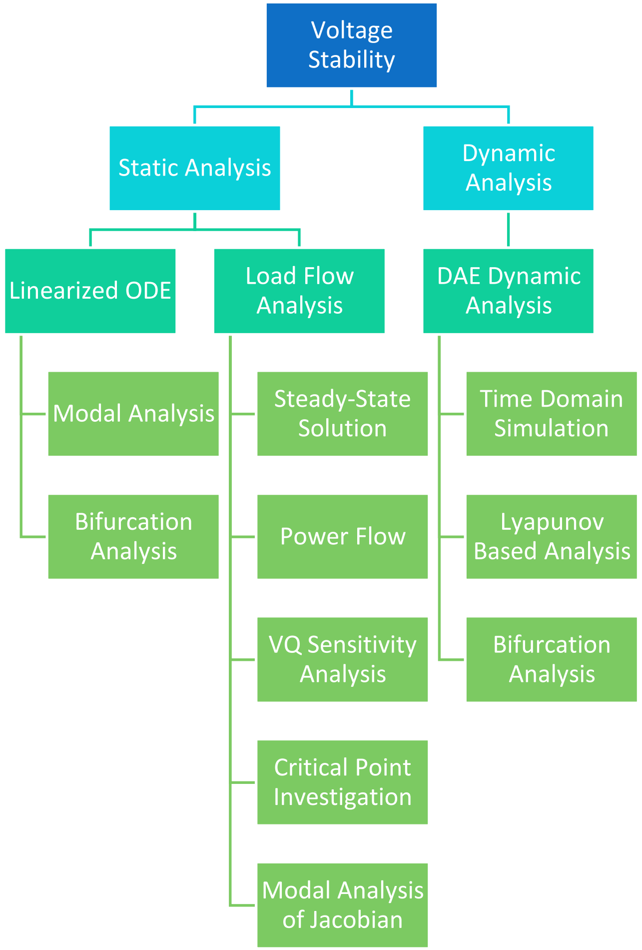


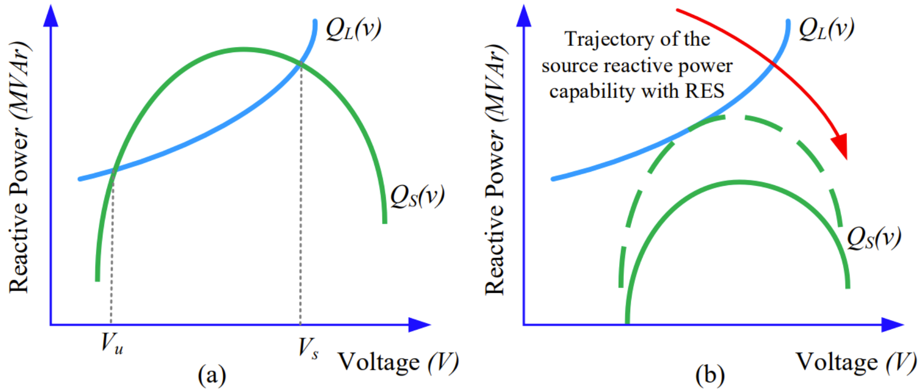
For Low SCR Grid,
Inverter Instability and Interaction may occur depending on

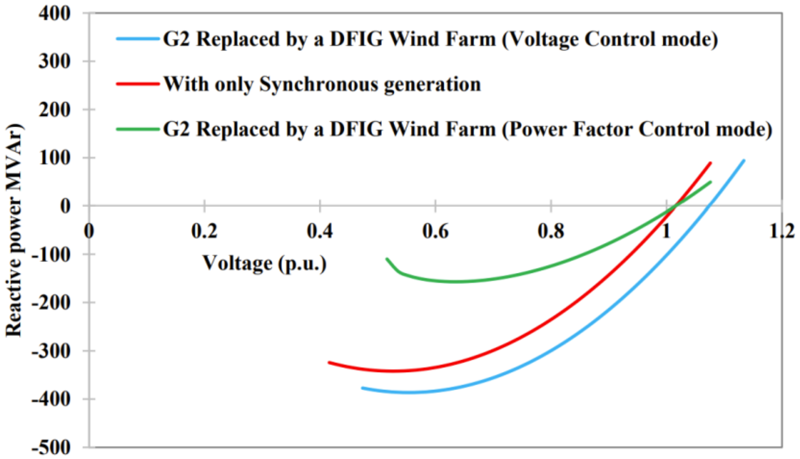
- System Condition
- Improper Control Setting
- Resonance with other Generation & Transmission Facilities
- Input Power from Primary Energy Source

Inverter Instability – Voltage Stability

- Large Z_S (Low system strength) → Smaller I_F → Larger dV/dP, dV/dQ (voltage sensitivity)
- The system conditions that can lead to low system strength includes:
  - High IBR output
  - Low thermal generation (sync gen connected to large rotational mass)
  - Large Tie flow
  - Planned or Forced Outage
- Mitigation Measures:
  - Voltage Control and Support Capability of IBR
    [Note: constant pf mode / constant Q mode should operate in closed loop to improve voltage stability and power transfer capability]







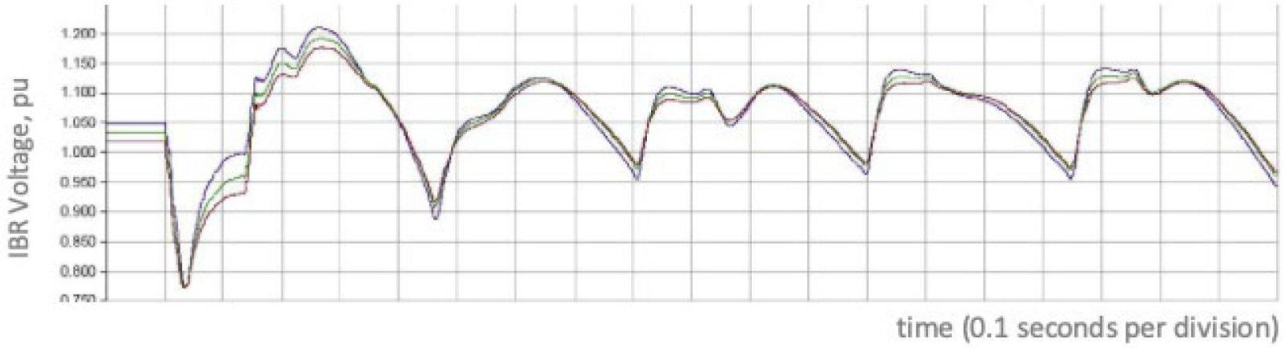
Inverter Instability – Control Instability

Control Instability

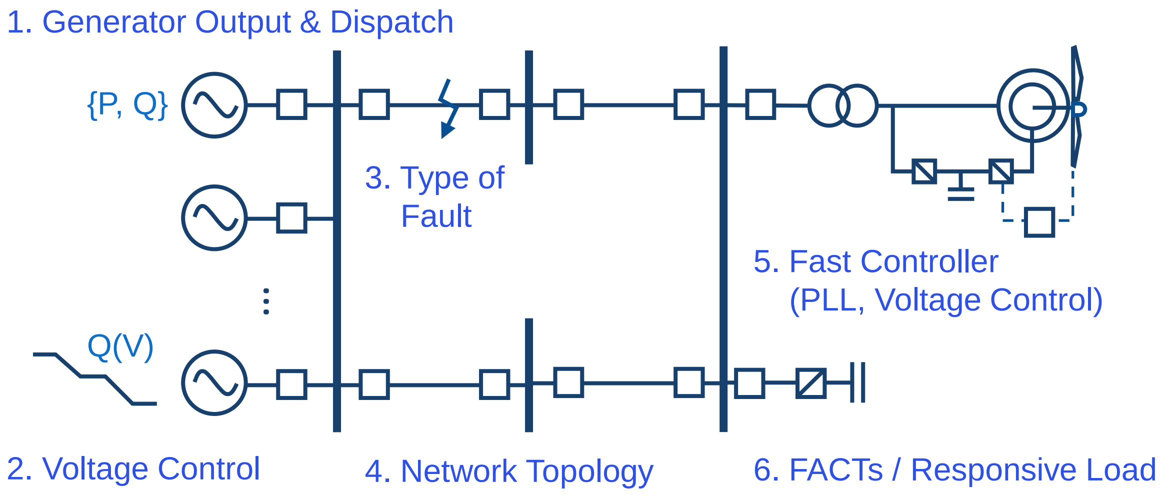
- Relates to interactions between fast but delayed and high gain controllers with power electronics resources, e.g. IBR units and FACTs with high impedances connecting the resources to the grid.
- It leads to control instability such as oscillations, unit tripping or power quality concern.
- Solution: return the IBR controller.

Chattering

- Due to non-linear control, change in control modes and protection operation.
- Wind farm enters LVRT mode resulting reduced active power, allowing the voltage to recover and the WTG returns to normal operating mode and resume outputting active power.

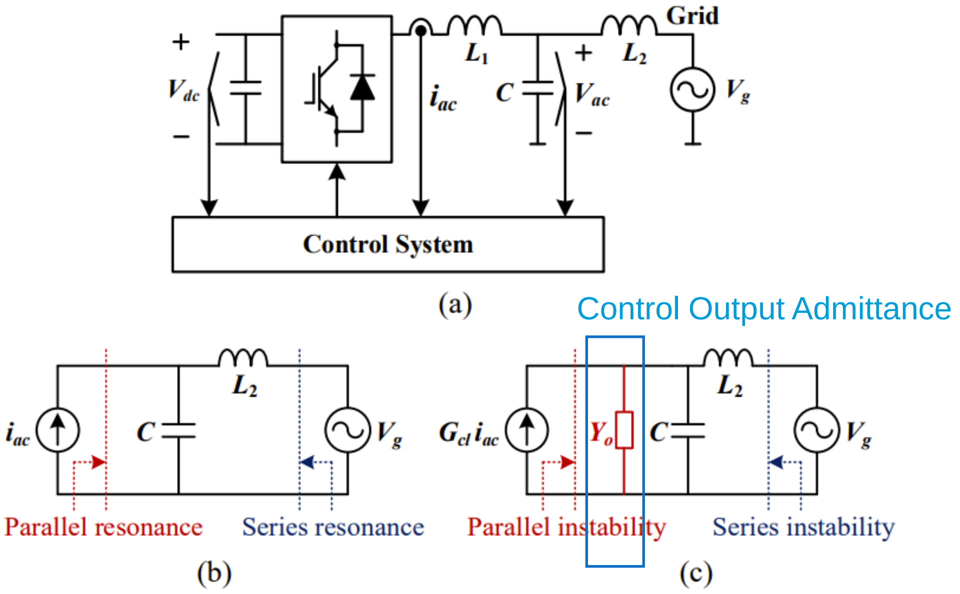


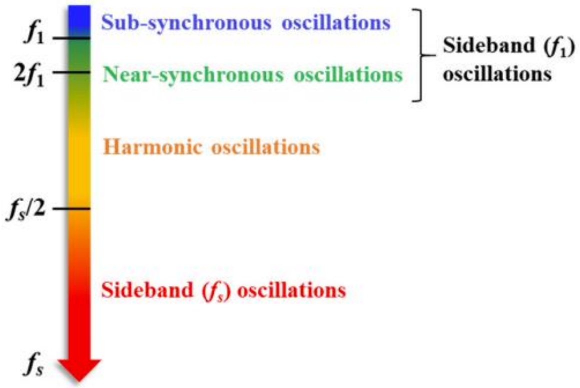
Consideration:



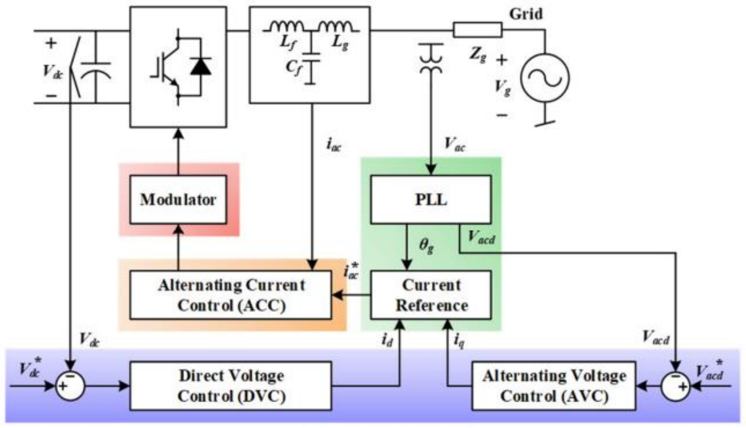
Inverter Instability – Harmonic Instability

- Harmonics instability can appear in strong network with high SCR.
- It can occur due to the active nature of IBR impedance, which results in negative resistance. It is often from the current control interaction of parallel VSCs.
- It often refers to oscillation at a frequency above the fundamental frequency, but many of the mechanisms that result in oscillation at frequency below the fundamental can also trace back to negative resistance.
- These types of control interactions and instability are often not detectable using existing positive-sequence simulation tools since these models does not include plant level voltage control and fast controllers such as PLL and inner current controllers.





f_1: Grid fundamental frequency; f_s: Switching frequency



Cascaded control system for VSCs

Inverter Instability – Control Instability Mitigation Measures

1. System Reinforcement: Series Capacitors are employed to reduce line impedance and improve transmission capacity. Yet, subsynchronous instability should be considered for the interaction on DFIG and series cap. Synchronous condenser are often employed to supply fault current, inertia, and voltage support capability. Yet, it is prone to synchronous machines instability.
2. Controller Changes: PLL, inner current loop and plant level voltage control are key controllers in IBRs that can cause control instability in low system strength grid. Re-tune IBR controllers can alleviate the issues related to low system strength. Voltage Controller are typically adjusted to slower response with voltage droop (inc. deadband). Yet, changes to PLL and inner current loop may require complex engineering effort.
   [Note: Controller changes are often system specific.]
3. FACTS Device: SVC and STATCOMs can help provide dynamic voltage support to control voltage fluctuation and provide transient ride-through capability. Yet, the fast control loops may also be subject to low system strength control instability.
4. Reduction of Plant Capacity or Output: System strength can be improved by either reducing plant capacity or limiting plant output.

Inverter Instability – Sub-synchronous Instability

Subsynchronous Torsional Interaction (SSTI)

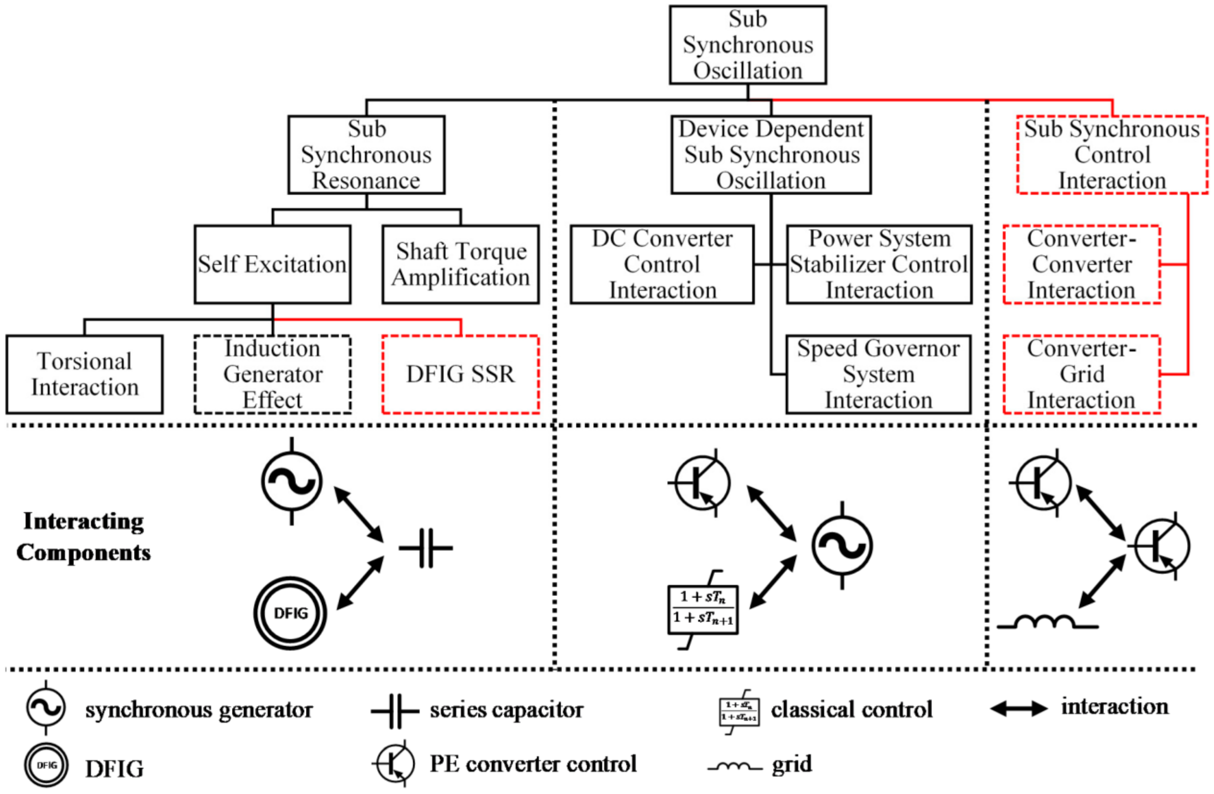
- Inverter control + torsional oscillation of nearby turbine generator

Subsynchronous Resonance (SSR)

- Series Compensation (Series Cap) + Turbine Generator

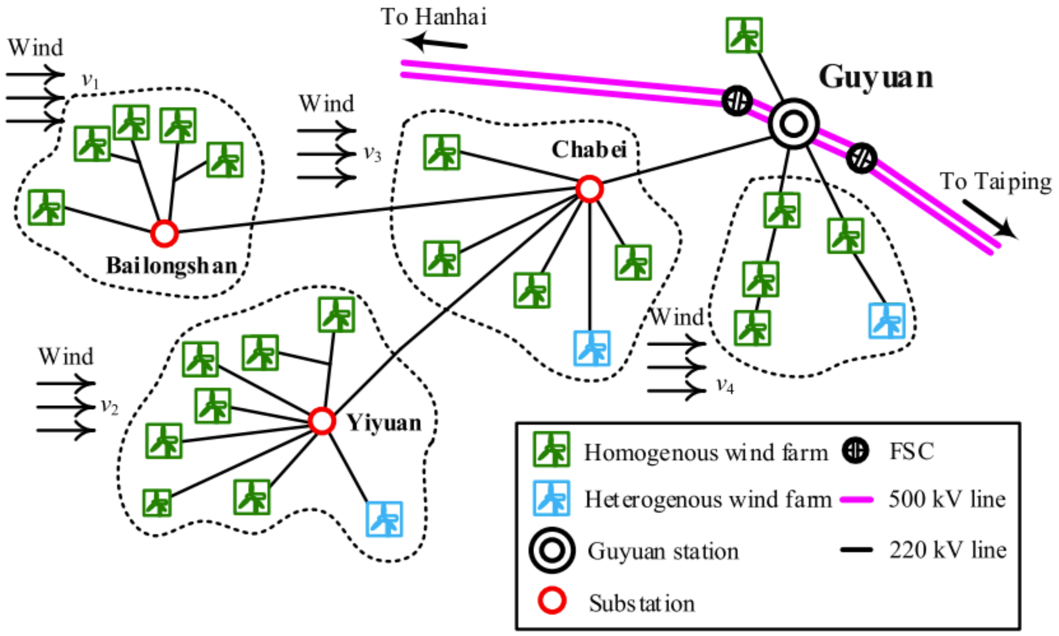
Sub-synchronous Control interaction (SSCI)

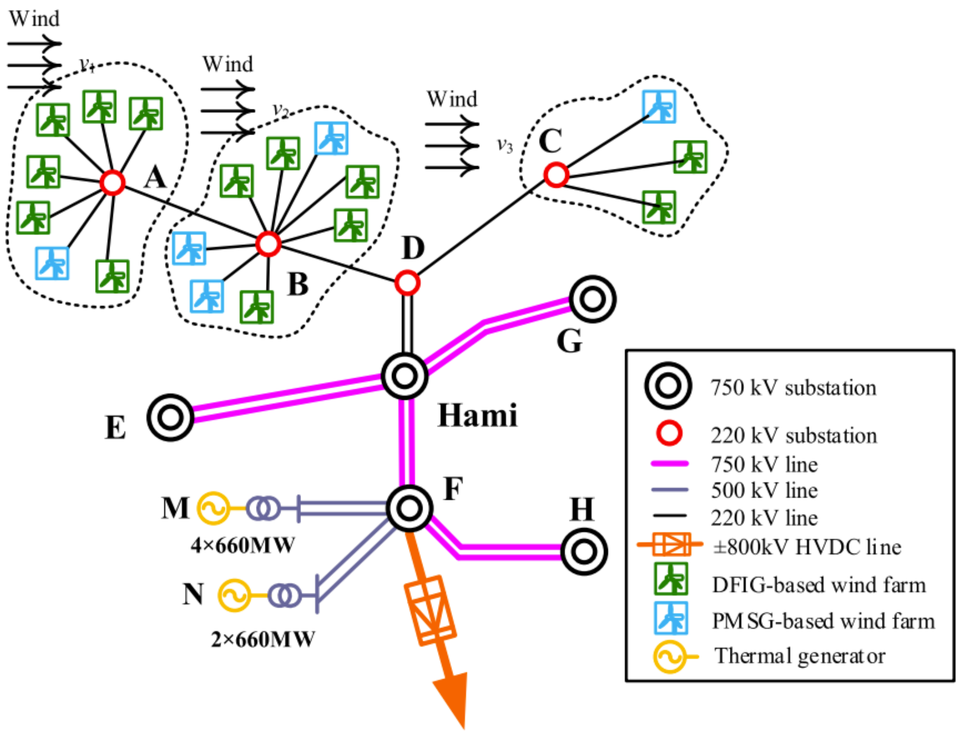
- Induction Generator (with self-excitation)
  - DFIG effective inductance and series capacitor forms a resonant circuit at sub-synchronous frequency.
  - Rotor back-to-back converter in DFIG tends to effectively increase rotor circuit resistance, which increases effective negative resistance as seen from stator side (due to slip effect of induction generator) [Note: Converter Control are source of negative damping]



Inverter Instability – SSCI Example

DFIG + Series Cap
PMSG + Weak Grid
under low wind condition





At sub-synchronous frequency, converter controls greatly enlarged rotor resistance as viewed from the stator-side. DFIG's converter controls saturated and magnitude of the oscillation got amplified.

DFIG's converter control structure and parameters, wind speed, number of online WTGs and degree of series-compensation significantly impacts on the SSCI features, i.e., the frequency and magnitude of the oscillation.

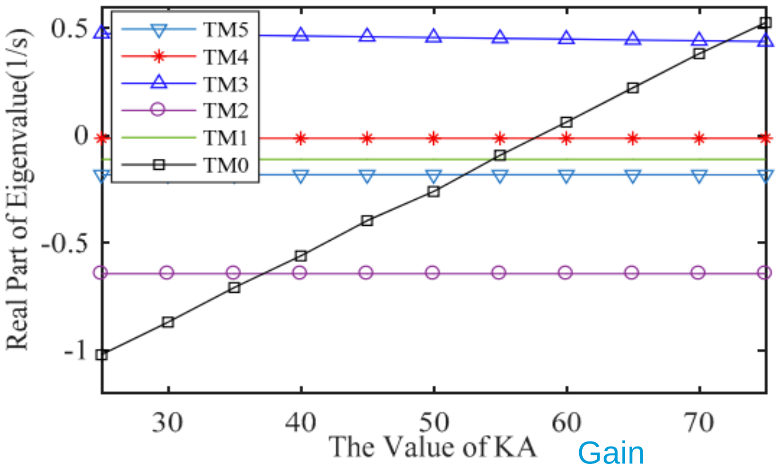
The oscillation was triggered when the total output wind power dropped down to a certain level. At certain operating conditions, the oscillation frequency matched with one of the torsional frequencies of the STGs.

The oscillation was initiated due to the interaction between virtual capacitance/inductance offered by the PMSG's converter controls and the weak AC grid.

Inverter Instability – Subsynchronous Instability Identification

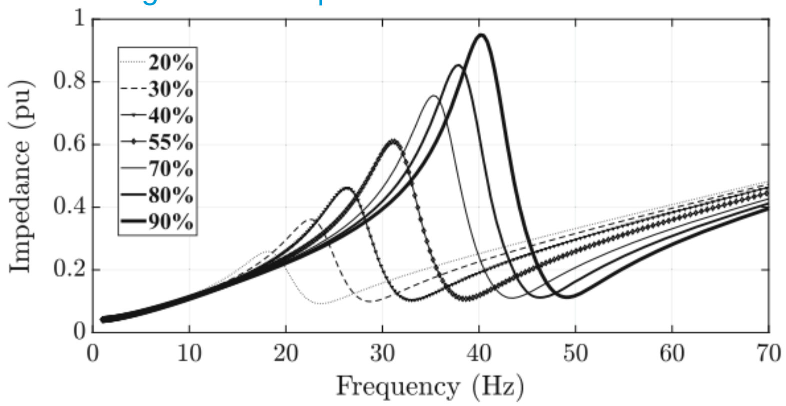
SSR Analysis Methods	Features	Advantages	Disadvantages
Eigenvalue analysis	It is also called state-space analysis method, which is a quantitative analysis method based on the small disturbance linearization model and obtains SSR-related information by solving eigenvalues.	• Provides frequency and damping information for entire system in one calculation. • Analyzes the influence of parameters on SSR system.	Higher order model parameters are required for the entire system, which is difficult to analyze.
Electromagnetic transient analysis	Using a step-by-step numerical integration method, a set of differential equations of the system are solved. The mathematical model can be linear or nonlinear.	• The dynamical characteristics of all power system components can be represented. • Has a unified simulation software tools such as EMTP, PSCAD, EMTDC.	Only time domain response results can be given. It is difficult to directly give SSR reasons and the mechanism of instability.
Complex torque coefficient analysis	Frequency scanning of the mechanical and electrical complex torque coefficients of the shaft system in the subsynchronous frequency range to determine whether the system will undergo subsynchronous oscillation.	• Damping frequency curve can be obtained. • The influence of various parameters on the electrical damping characteristics can be analyzed.	• Large time-frequency analysis error. • Only applicable to single machine infinite bus system.
Frequency scanning	It is an approximate linear method to calculate the equivalent impedance for a specific frequency and filter out the system conditions with potential SSR.	• Simple theory and less calculation. • Can quickly determine if there is a SSR risk.	• Only electrical resonance points can be obtained. • Can only be judged qualitatively and with poor accuracy.

Torsional Mode of turbogenerator shaft system



Gain

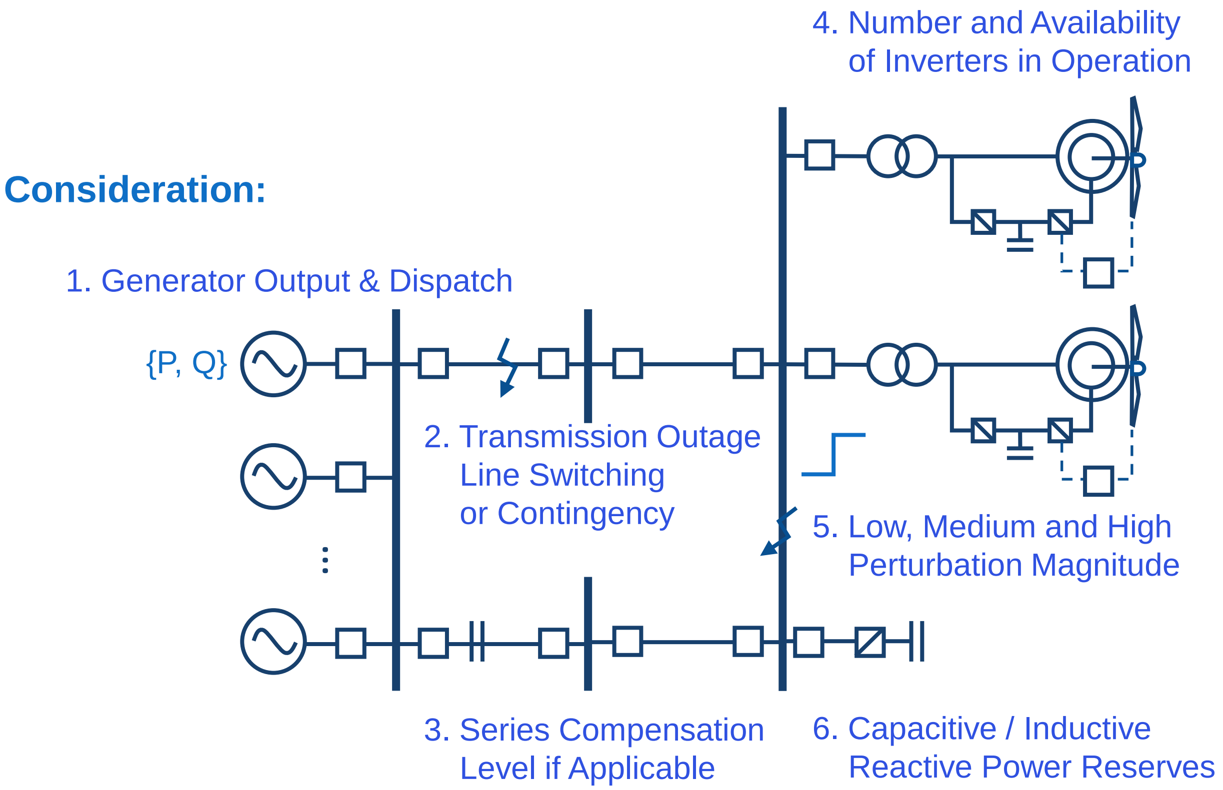
Degree of Compensation



Inverter Instability – Subsynchronous Instability Identification

Frequency Scan

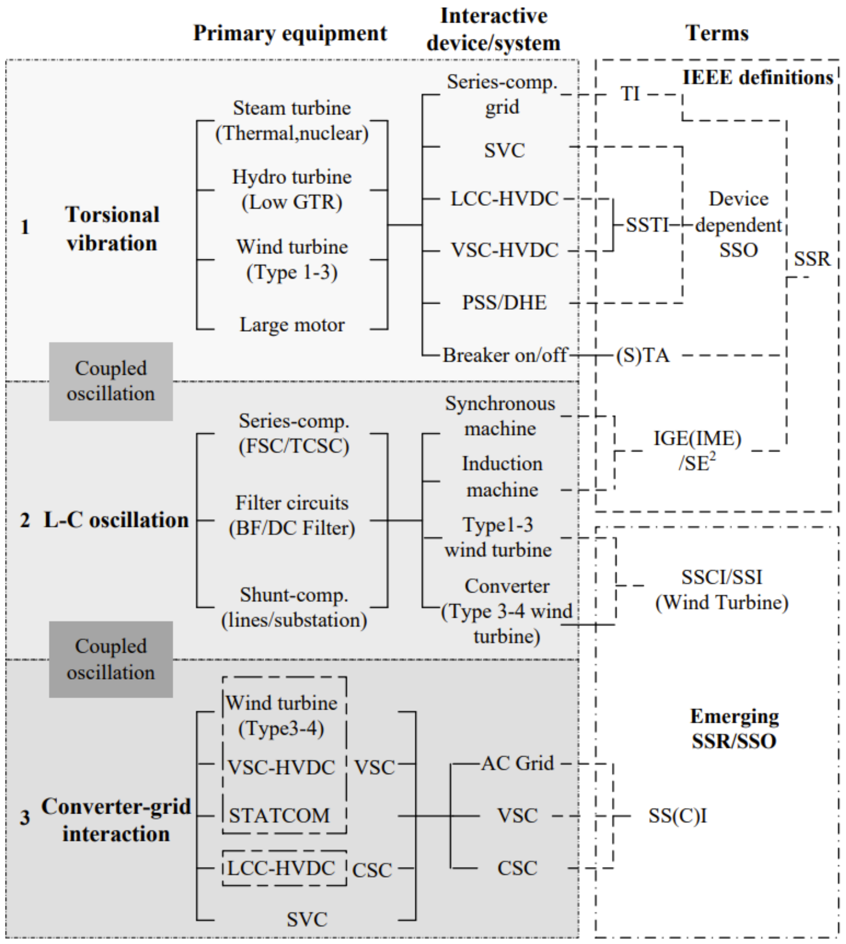
- It looks for total impedance of IBR and the connected electric grid.
- In order for the IBR to have unstable interaction with the grid, the reactive components of the IBR and grid impedance need to have equal magnitude and opposite sign to create a natural frequency which is generally in a sub-synchronous frequency ranged from 5 to 55Hz.
- In the frequency region where typical IBR have a negative resistance characteristics, sub-synchronous instability can occur under various system conditions.



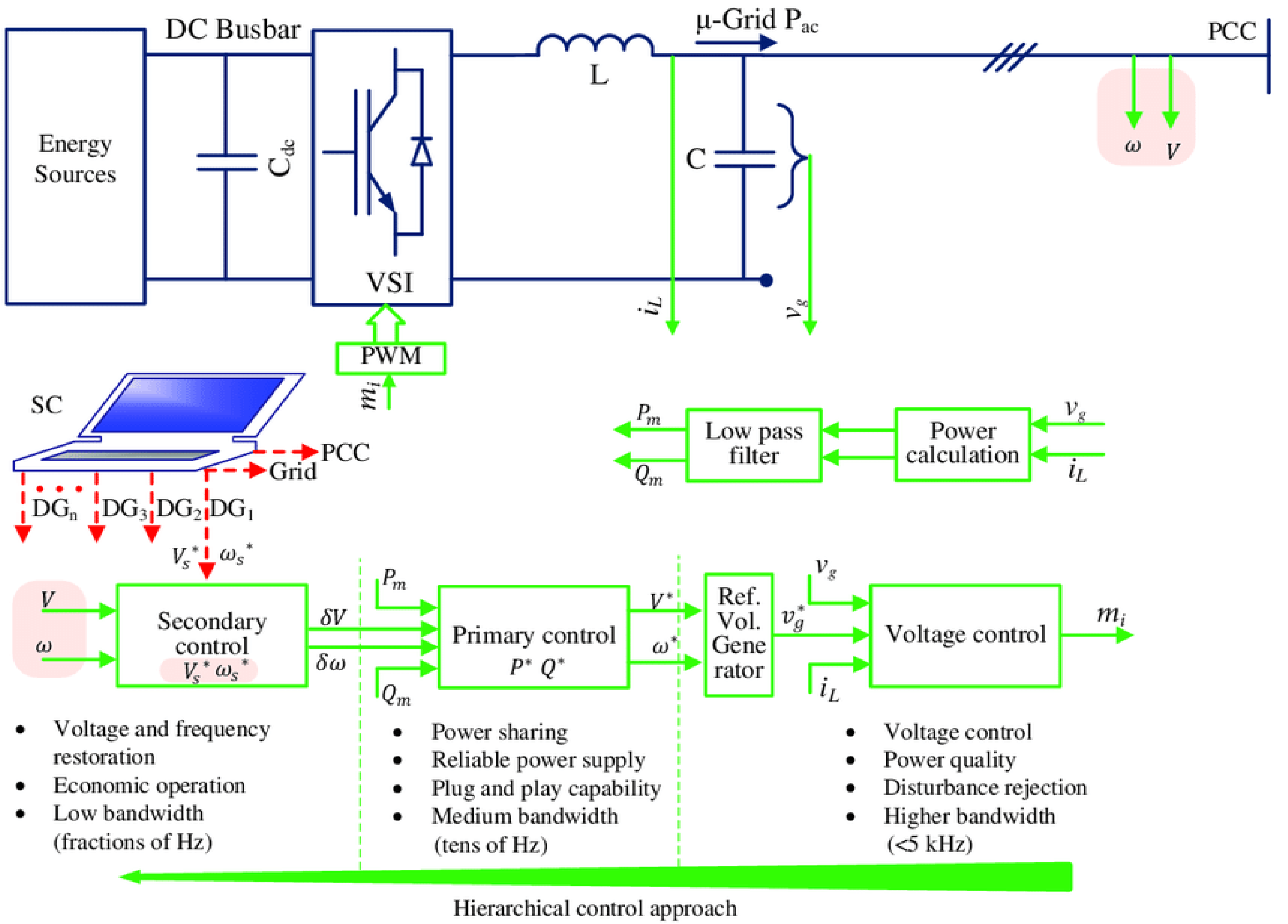
Inverter Instability – Subsynchronous Instability

Sub-Synchronous Instability Mitigation

- Bypass Series Capacitor →
  impact on transmission capacity and stability concern such as angular and voltage instability
- Controller Changes by Manufacturer →
  Dynamic frequency scan provides system impedance information to evaluate if this is due to their control damping, and potentially re-tune their controls. (but it may lead to delay in response)
- Subsynchronous Instability Protection →
  IBR has its protection capability to disconnect itself when detecting subsynchronous instability, but tripping itself can cause further frequency and voltage issues with the loss of support.
- FACTS Device and Transmission Reinforcement →
  Reconductoring, addition of new circuit or FACTs device can provide damping and effectively eliminate sub-synchronous instability, but limited industrial experience and expensive cost may prove challenging.



Grid Forming Converter



Note:

Grid following control in relative weak grid often leads to an instability in phase-locked loop and associated controls of IBR which requires voltage phasor tracking.

Grid forming control, which has its own capability to regulate voltage and frequency, are expected to contribute to system strength, reducing grid impedance and increasing voltage stiffness.

It is expected that the inverter protects itself from **overcurrent**. Reaching the current limit, inverter cannot operate as grid forming and switch to different mode (e.g. restricted mode). Such OC can occur during sudden large voltage change (e.g. short circuit fault). → Chattering Effect

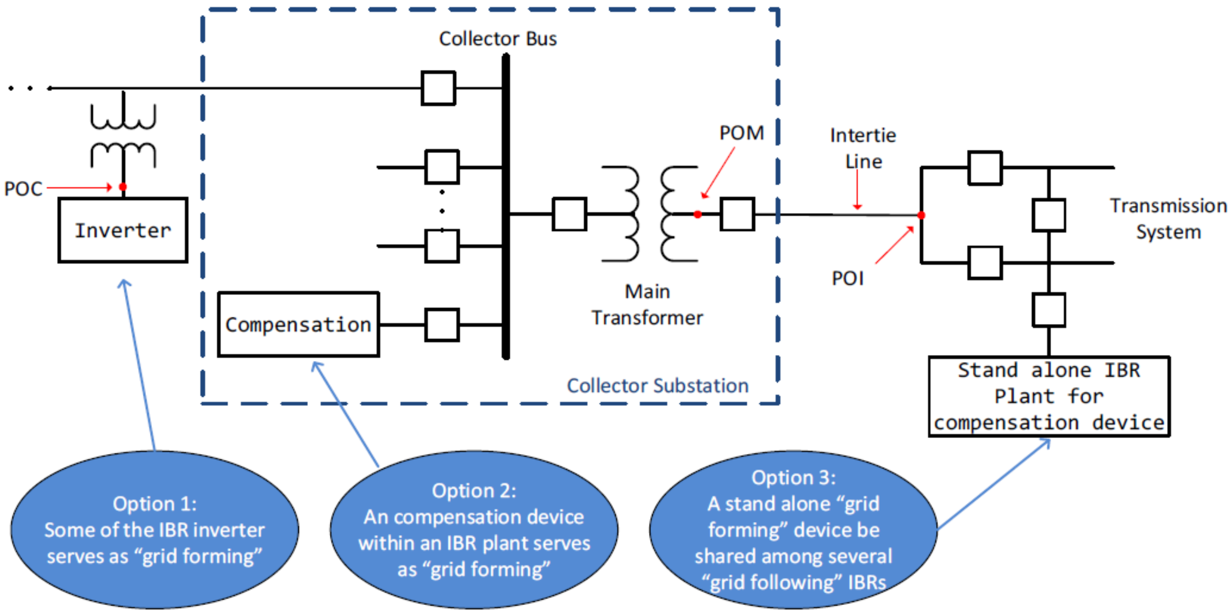
Sufficient **energy headroom** should be present for inverter to respond to sudden phase angle jumps in the grid.

Grid Forming Converter

Considerations

- Power Electronics Hardware and Rating:
  - How much energy storage is needed (for frequency support and stabilization)?
  - How much should the inverter and energy storage be oversized for fast current injection (for voltage recovery and tight voltage control)?
- Control Software Development (to be revised):
  - Harmonics
  - Frequency Responsive Ride-through
  - Stability (oscillation damping)
- Wind Turbine
  - Energy Yield, blades, mechanical drivetrain, tower structure, foundation design for machine instability analysis
- Reliability Impact
  - Increased reactive power / current requirement (phase) may change thermal management needs in inverter.

Grid Forming Options



- Grid Performance
  - Loss of System Inertia
  - Reduction of Short Circuit Current & Protection Coordination
  - Increase in Network Impedance & Instability of IBR Control Structure
  - Frequency Control and corresponding Reserves (as an Ancillary Service, FFR Vs PFR)
  - Reduction in Damping Torque and Voltage/ Current Rating for Sizing Component
  - Black Start and Cold Load pick up (and in-rush current of transformer and induction motor)

Conclusion

This standard

- provides the basic requirements on when the IBR plant shall stay on grid without tripping or ride-through.
- acknowledges the requirements measured in POM, without constraining them on IBR units or supplemental IBR units (controllers, reactive support devices, sync condensers).
- stresses the limits in plant design, such as frequency and overexcitation capacity
- suggests the voltage ride-through requirements as a cumulative time-voltage constraint.
- specifies the protection requirement – NOT to use instantaneous value (but delayed or filtered quantity)
- indicates the requirements on providing simulation models.
- highlights the metrics to quantify system strength and concerns in low system strength grid on stability.
- points out the topics for future studies or reviews (e.g. damping oscillation control, DFIG performance under phase-to-phase fault).