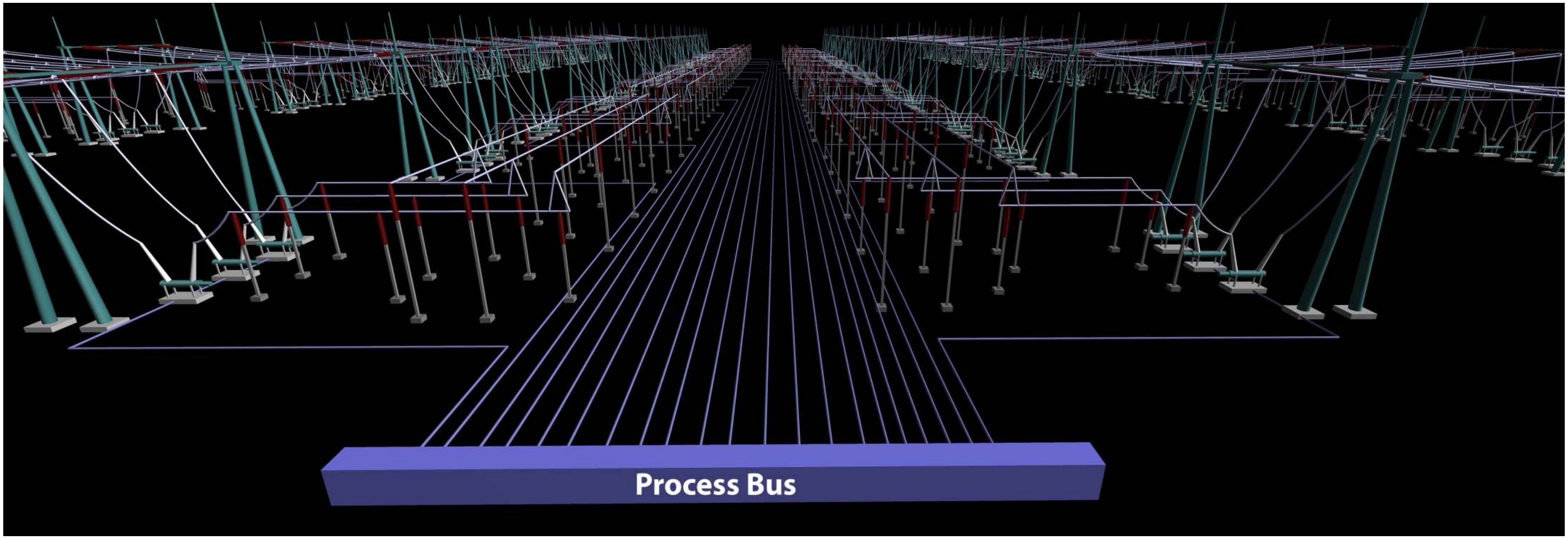

Protection and Control of Systems with Converter Interfaced Generation

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Challenges Generated by Renewables

Variability, Impact on Reliability

Creation of High Ramp Rates

CIG: Protection, Stability and Control

- Low Voltage Ride Through
- Protection
- Stability – traditional stability is meaningless

Protection Challenges

Protection of CIG (Converter Interfaced Generation) and associated circuits and components is challenging due to:

(a) Insufficient separation between fault and load currents caused by converter interfaced sources,

(b) Large fault contributions from utility side – small fault contributions from inverter based sources and

(c) Requirement to operate in utility connected mode as well as islanded mode.

(d) Lack of inertia

These issues are common for wind systems, PV systems and µGrids.

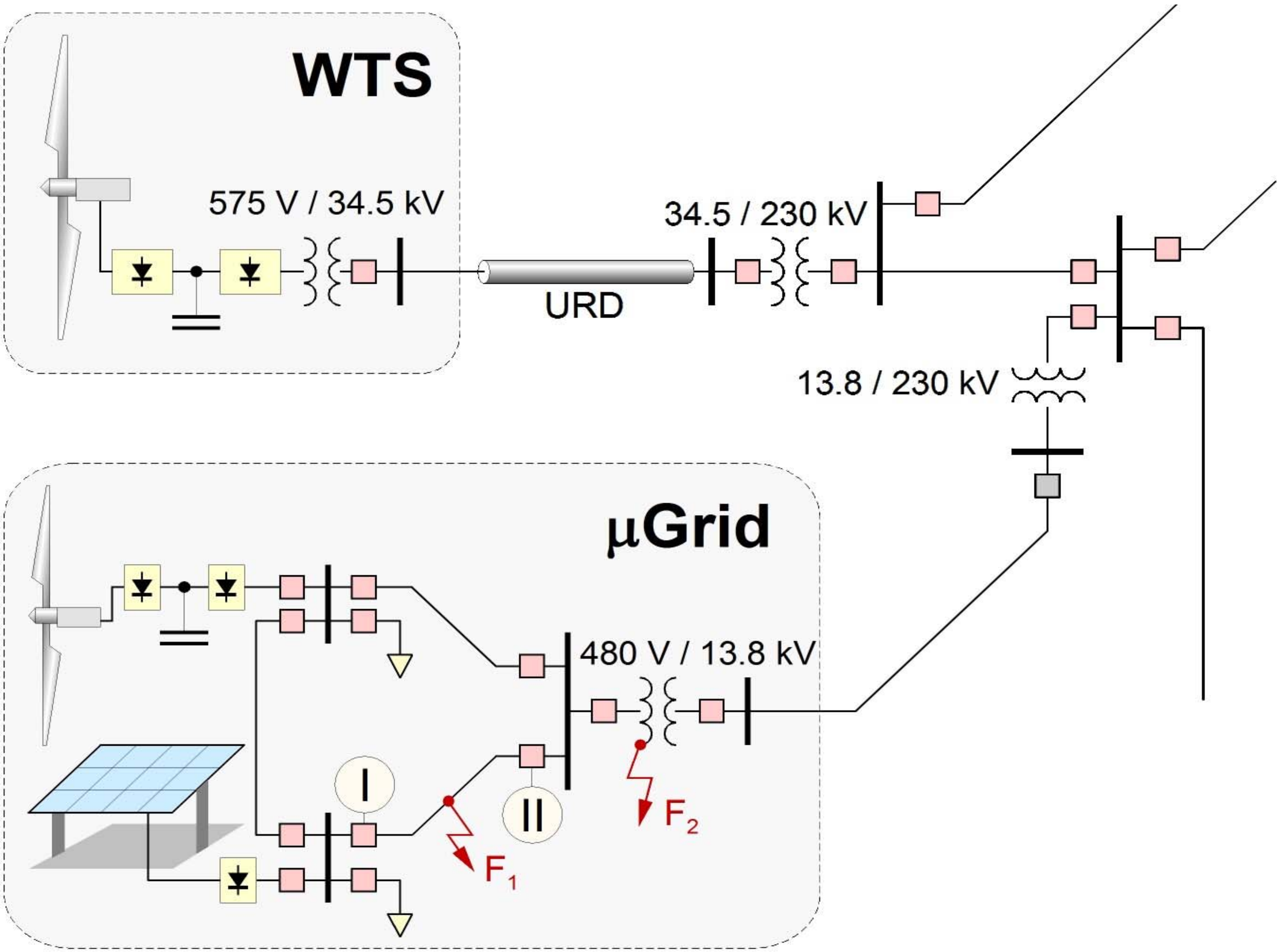
Another Operational Issue:

Deployment of Converter Interfaced Generation (CIG) is ever increasing (wind, PV, etc.) with many systems reaching more than 50% presently. Stabilization and riding through disturbances is a problem of increasing significance.

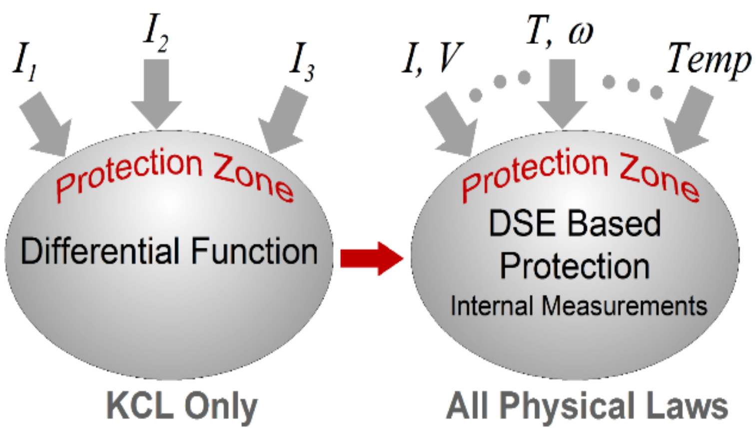
Need for CIG to smoothly follow the oscillations of the system and avoid excessive transients and activation of transient ride through controls, i.e. provides stabilization control to the CIG.

Enabling Technology: Dynamic State Estimation based protection which provides reliable protection and estimation of frequency and rate of frequency change locally at the inverter as well as at the system using only local measurements. This information enables supplementary inverter control for smooth inverter/system synchronization and disturbance ride through.

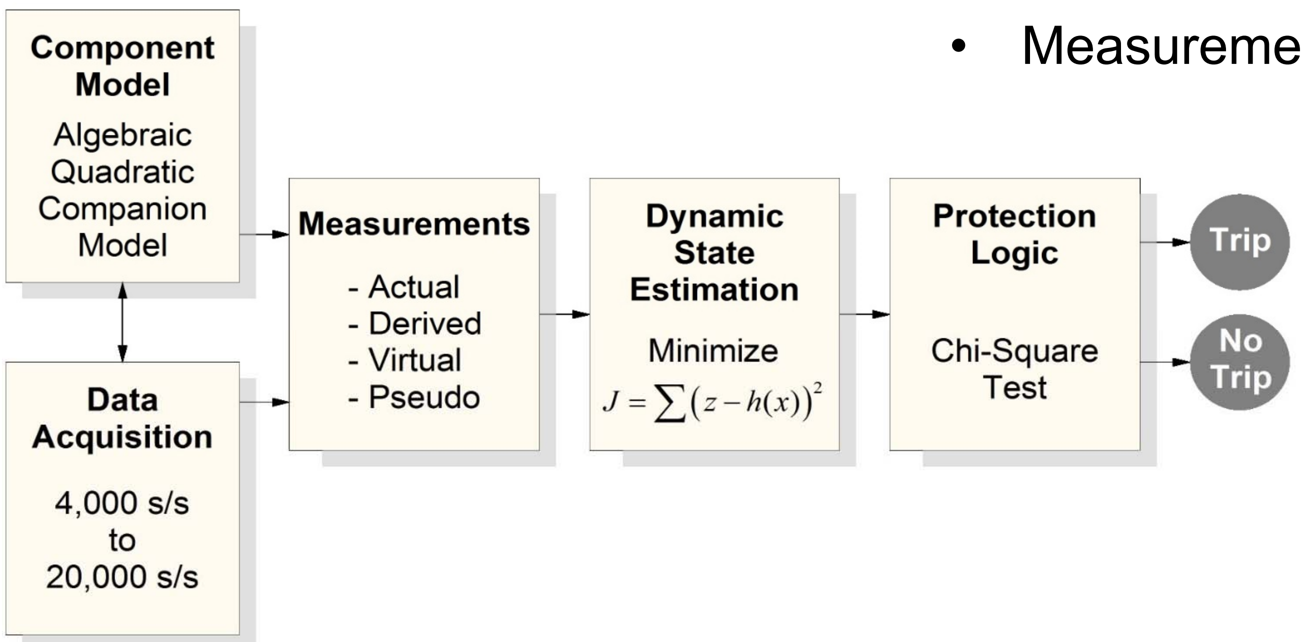
Example Systems



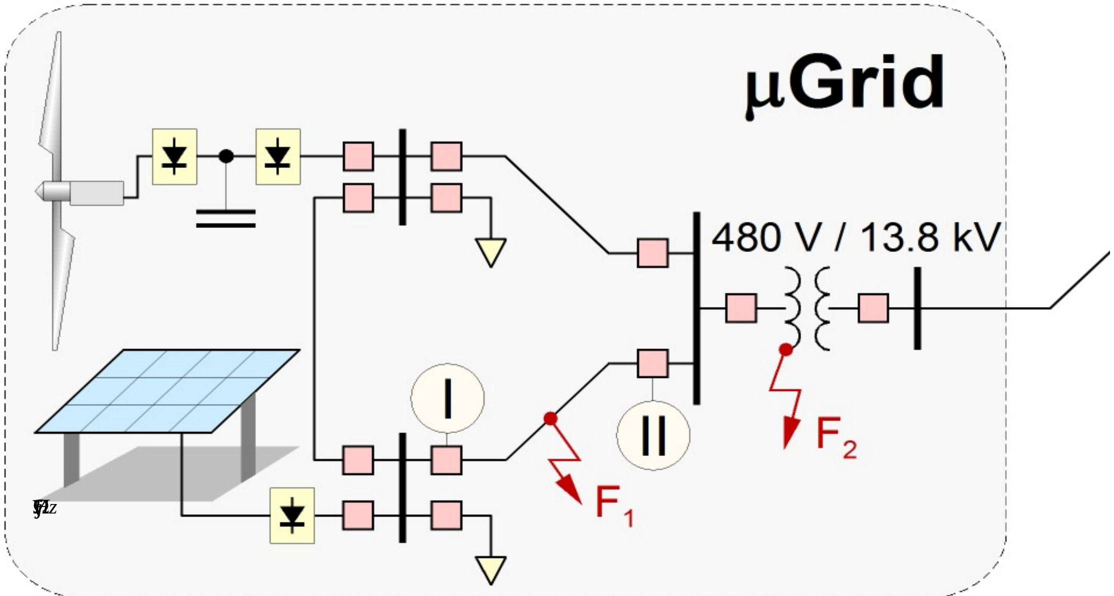
Dynamic State Estimation Based Protection



- Setting-less protective relay
- Sampled Value based dynamic state estimation
- Fast fault detection (sub ms)
- Measurement of frequency
- Measurement of ROCOF



Example of Fault Detection: Comparison of Legacy Protection and DSE Based Protection



Protection of circuit I-II

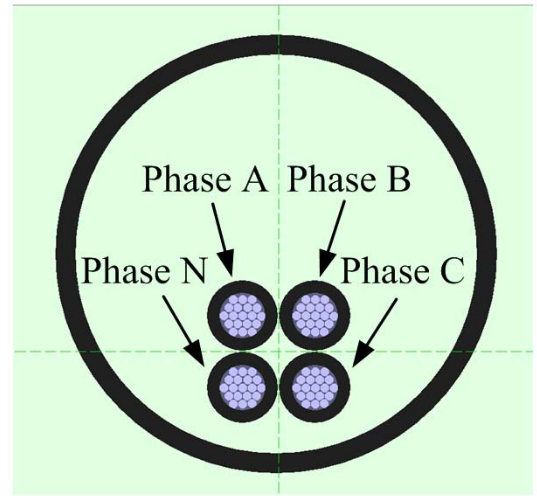
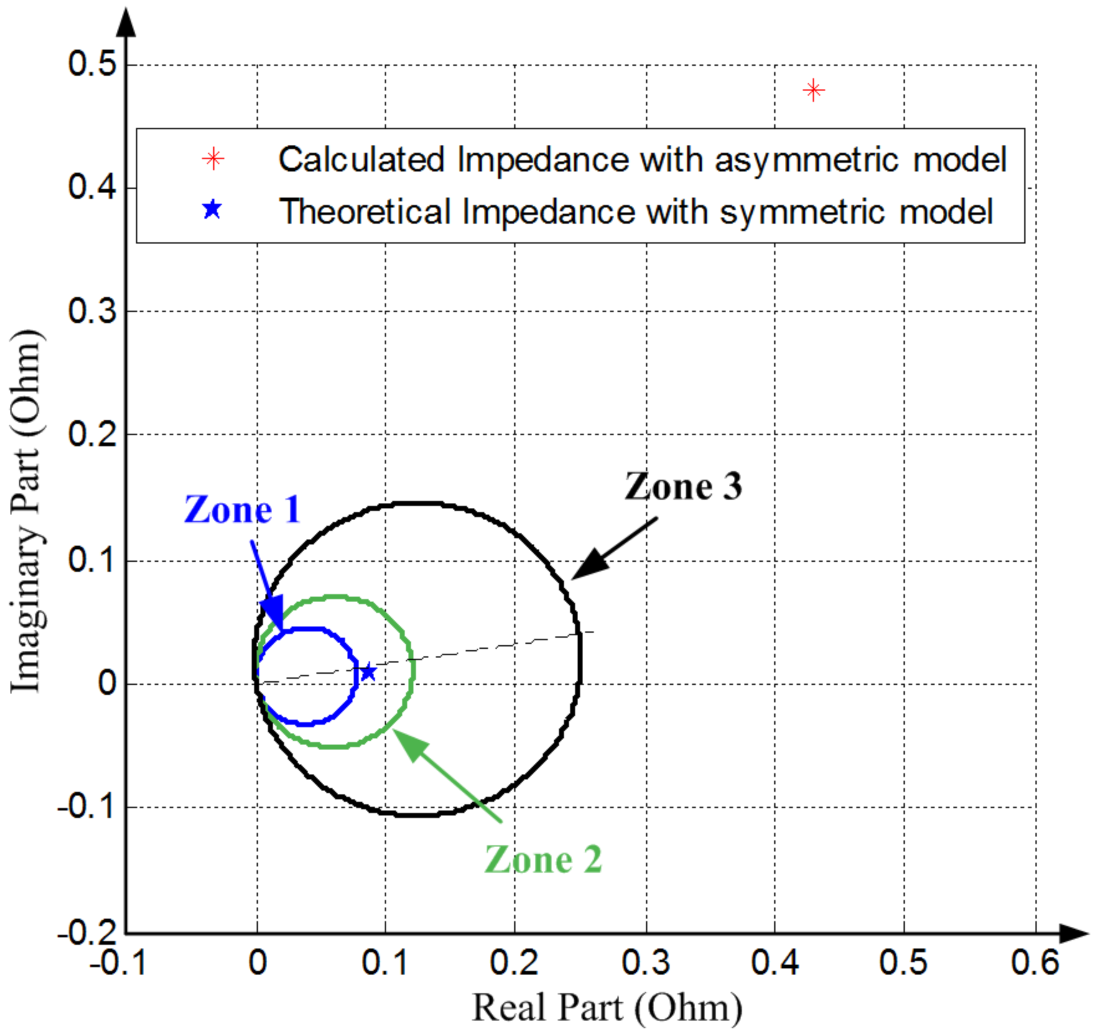


Table 1: Example µGrid circuit parameters

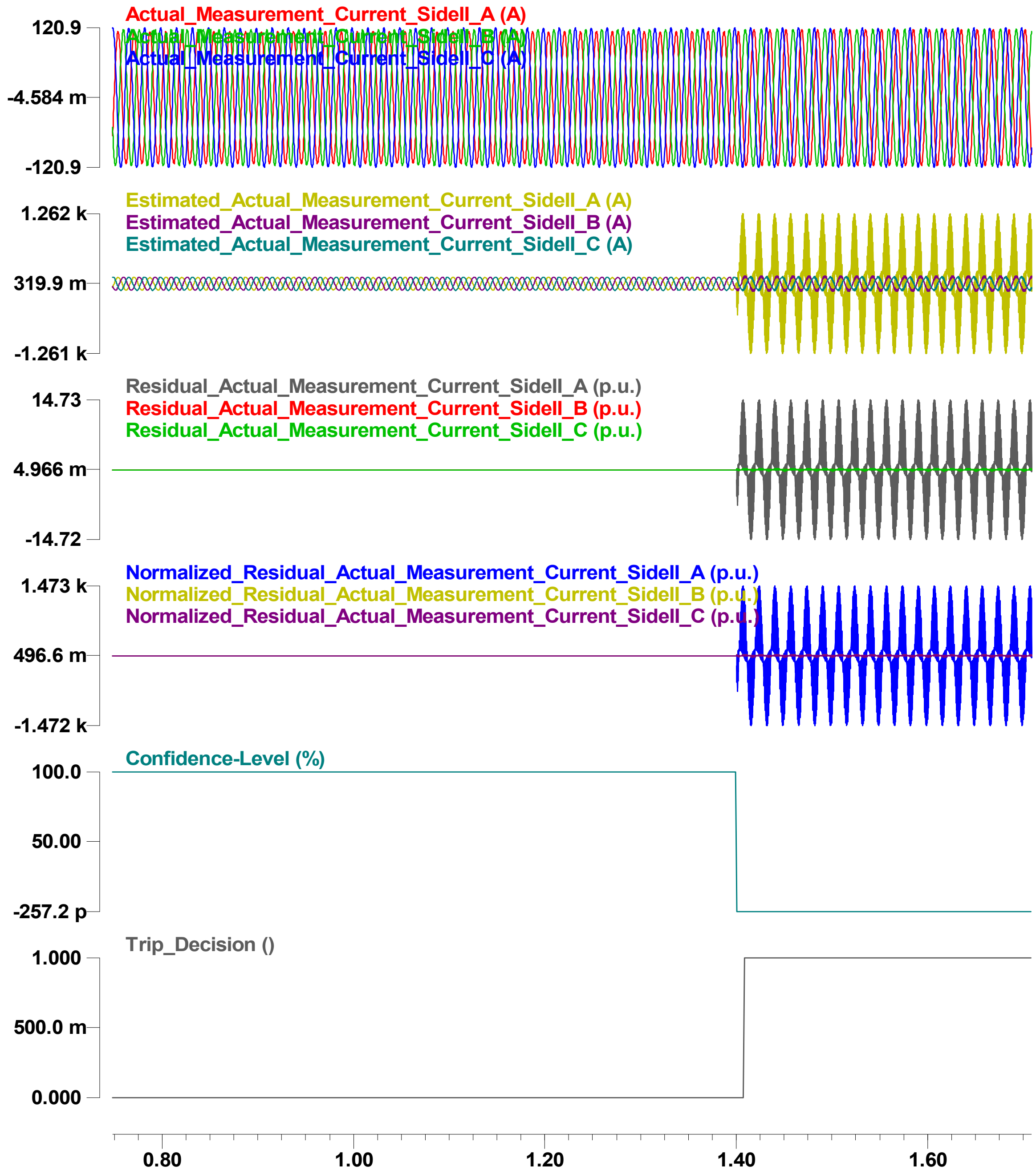
Object	*Parameter*	*Value*
System	Line to line voltage	480 V
	Fundamental frequency	60 Hz
	Length of the monitored circuit	375 feet
Monitored Circuit	Positive (Negative) sequence	$0.0957+\ j\ 0.0153\ \Omega$
	Zero sequence	$0.2186+\ j\ 0.1555\ \Omega$

Legacy Protection: Distance Relay



Performance of Legacy Protection Function

- Incorrect non-operation (mis-operation)
- Inherent time delays due to phasor based detection circuit



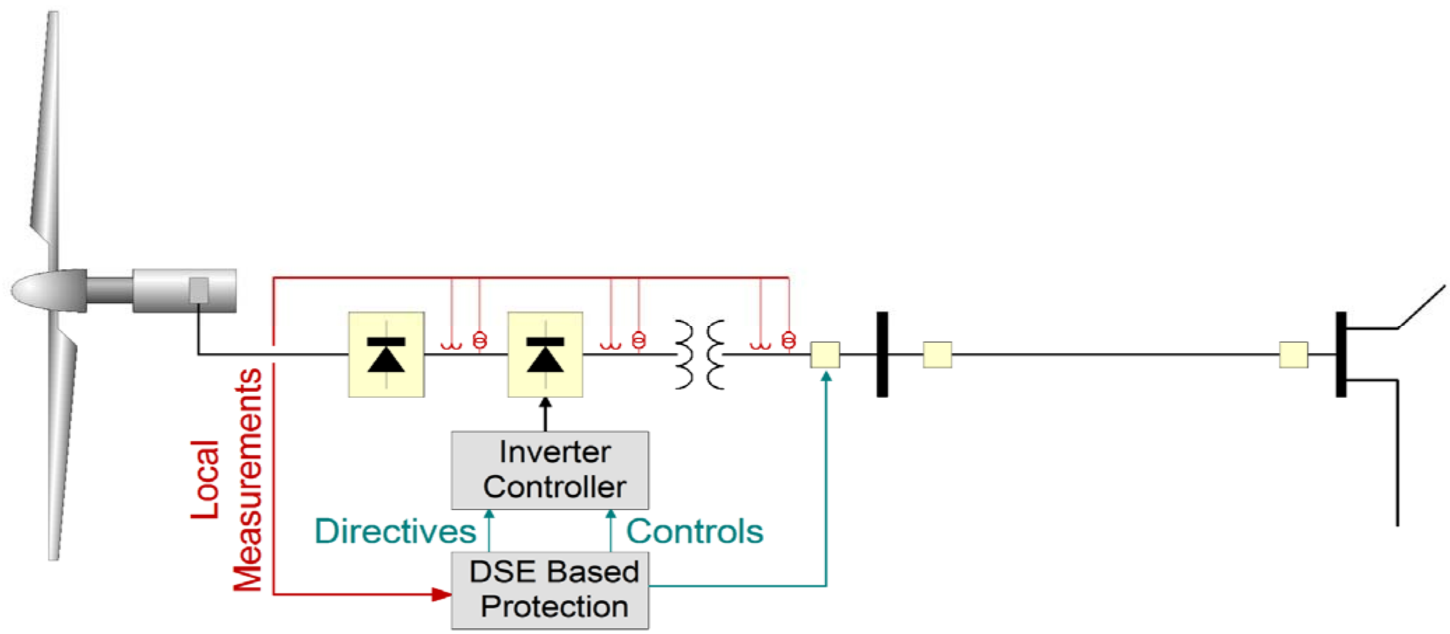
Performance of Setting-Less Protective Relay

- Correctly detects the fault.
- Detection is achieved in less than 0.2 ms

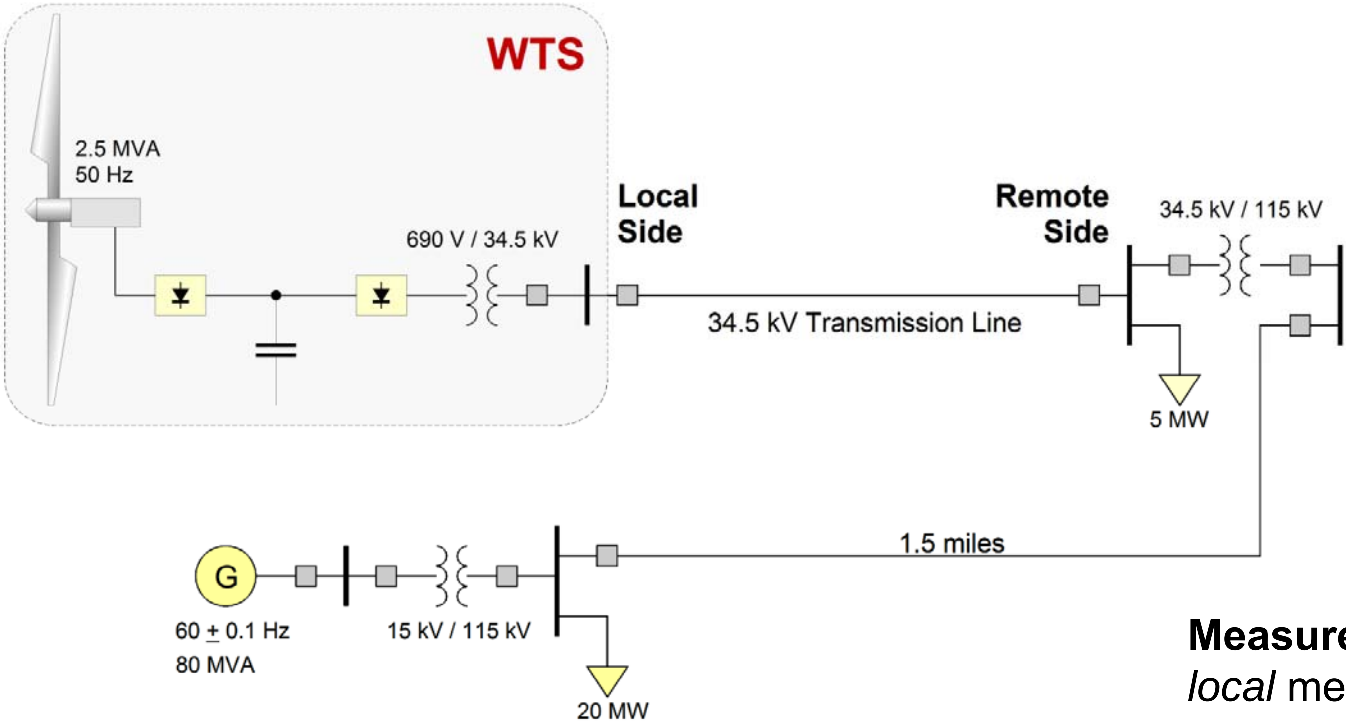
Operational Stability:

Need for CIG to smoothly follow the oscillations of the system and avoid excessive transients and activation of transient ride through controls, i.e. provides stabilization control to the CIG.

Enabling Technology: The setting-less relay provides estimated frequency and rate of frequency change locally at the inverter as well as at the system using only local measurements. This information enables supplementary inverter control for smooth inverter/system synchronization and disturbance ride through.



Example Test System



- Wind Turbine System (WTS), with 50 Hz voltage input
- Oscillating source with frequency 60 ± 0.1 Hz
- 34.5kV Transmission line,
- Measurements at the Local side only
- Results have been obtained for different lengths of line

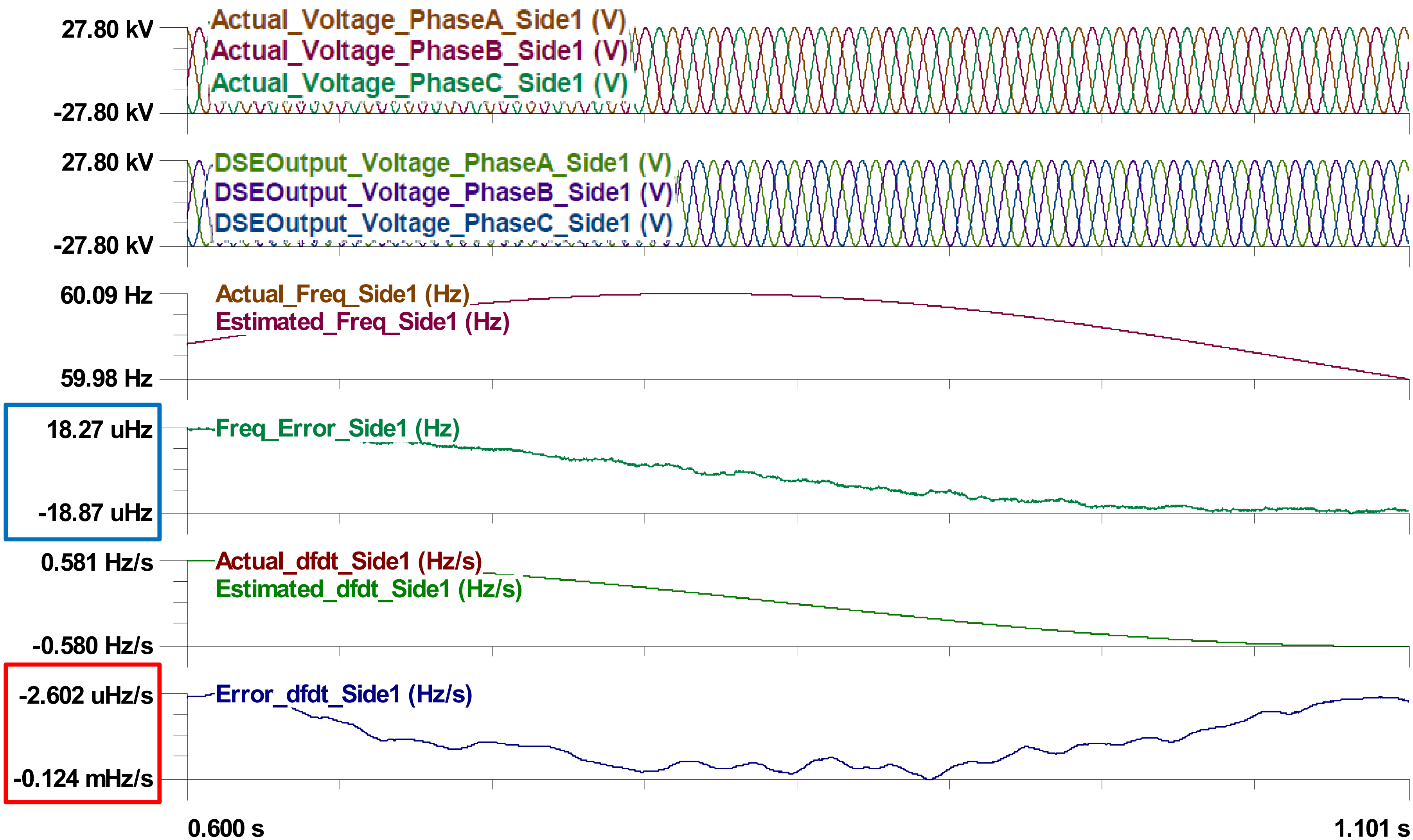
Measurements: Three-phase *local* measurements

Target: Estimate three-phase *local & remote* measurements, f and df/dt

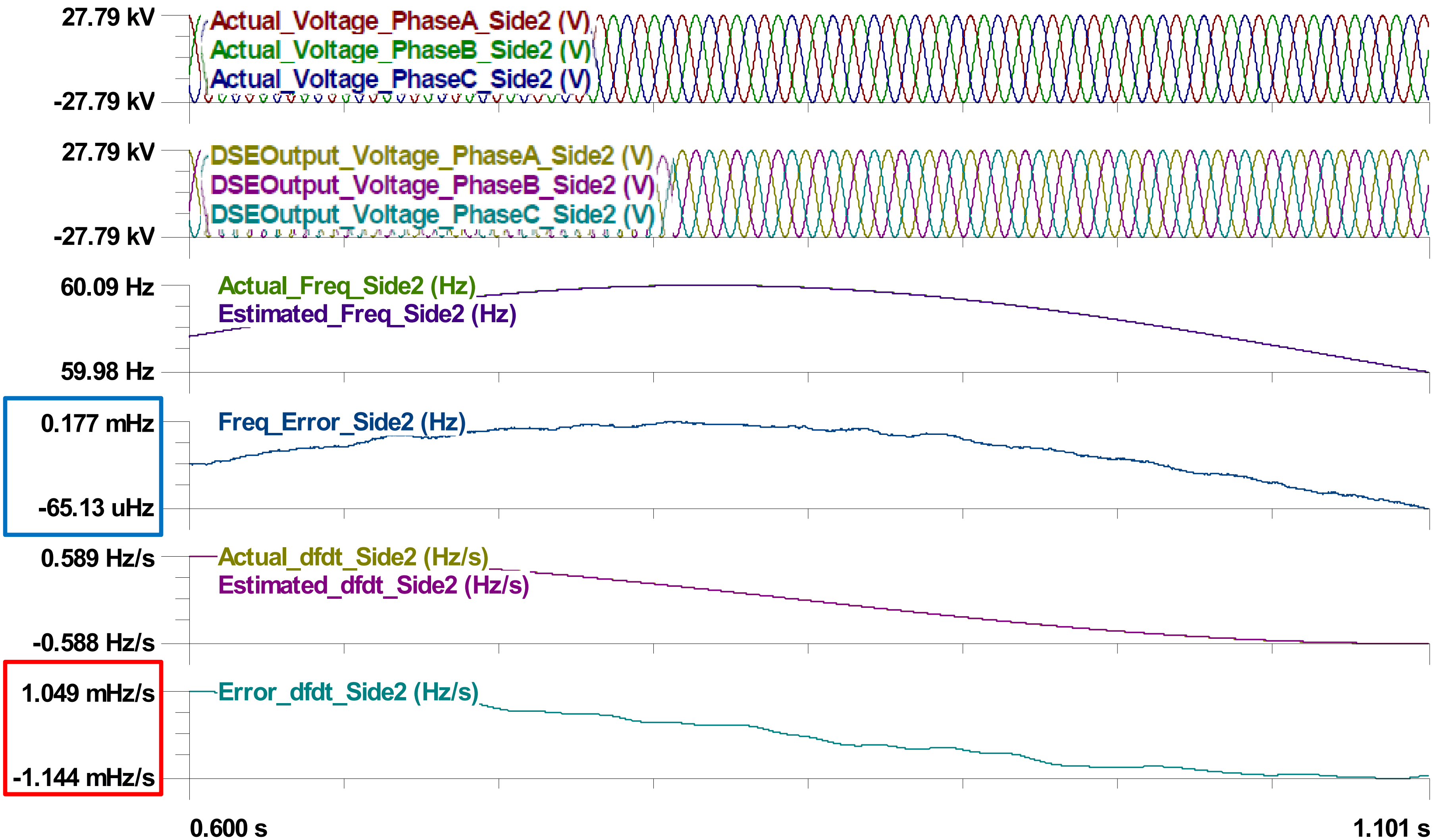
Method: Dynamic State Estimation

Performance: how accurate f and df/dt

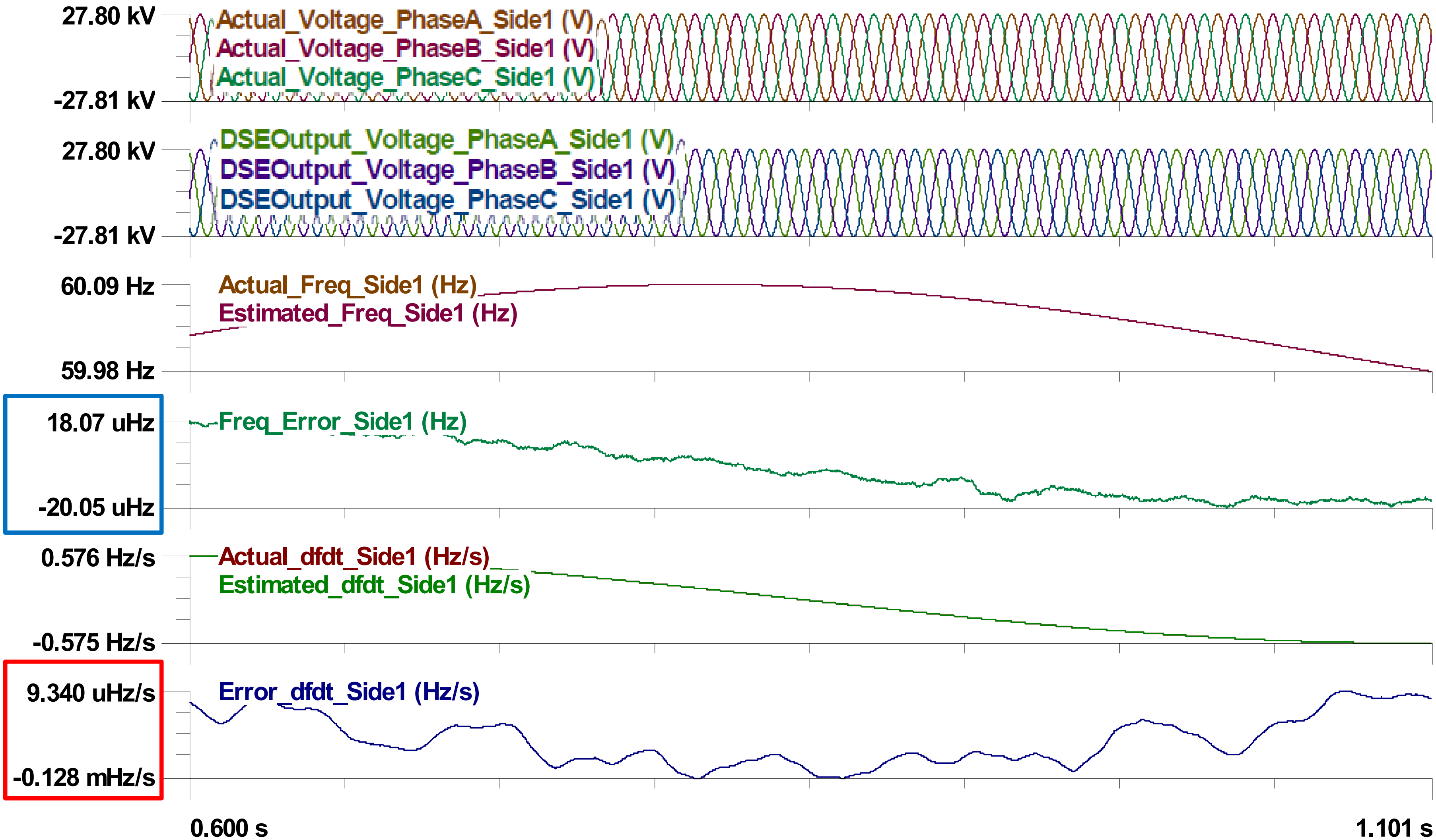
Case 1: 1.5 miles – Side 1



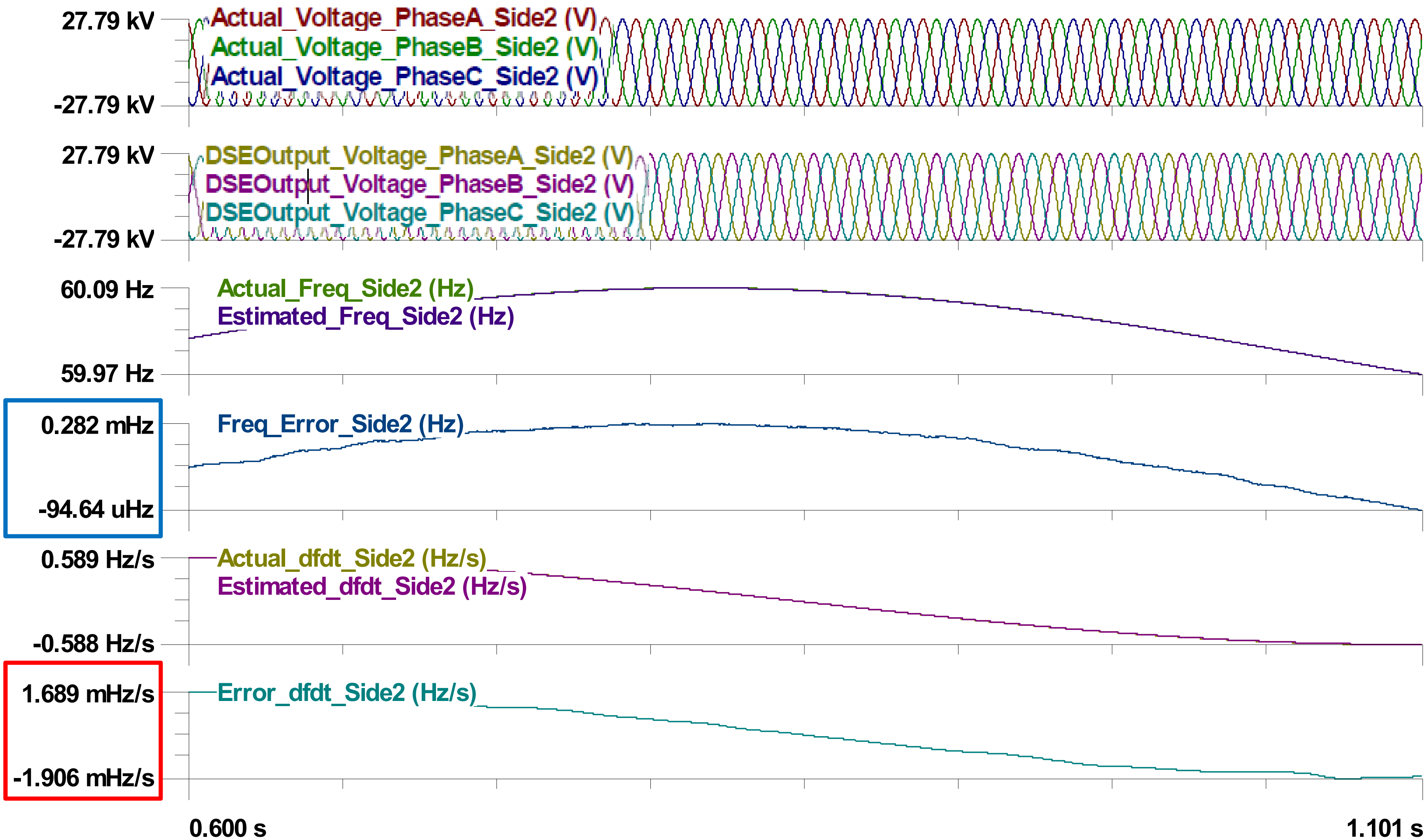
Case 1: 1.5 miles – Side2



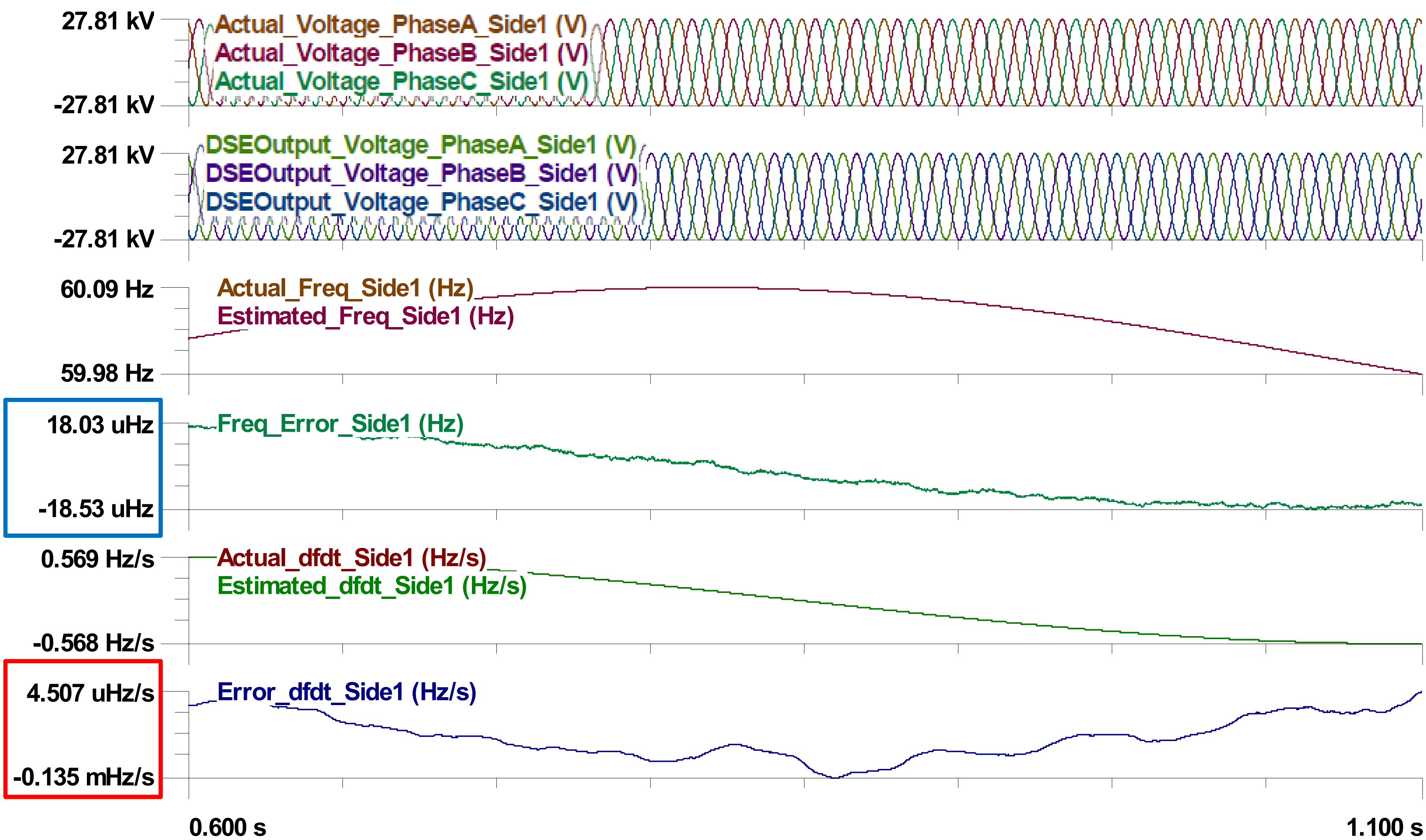
Case 2: 2.5 miles – Side 1



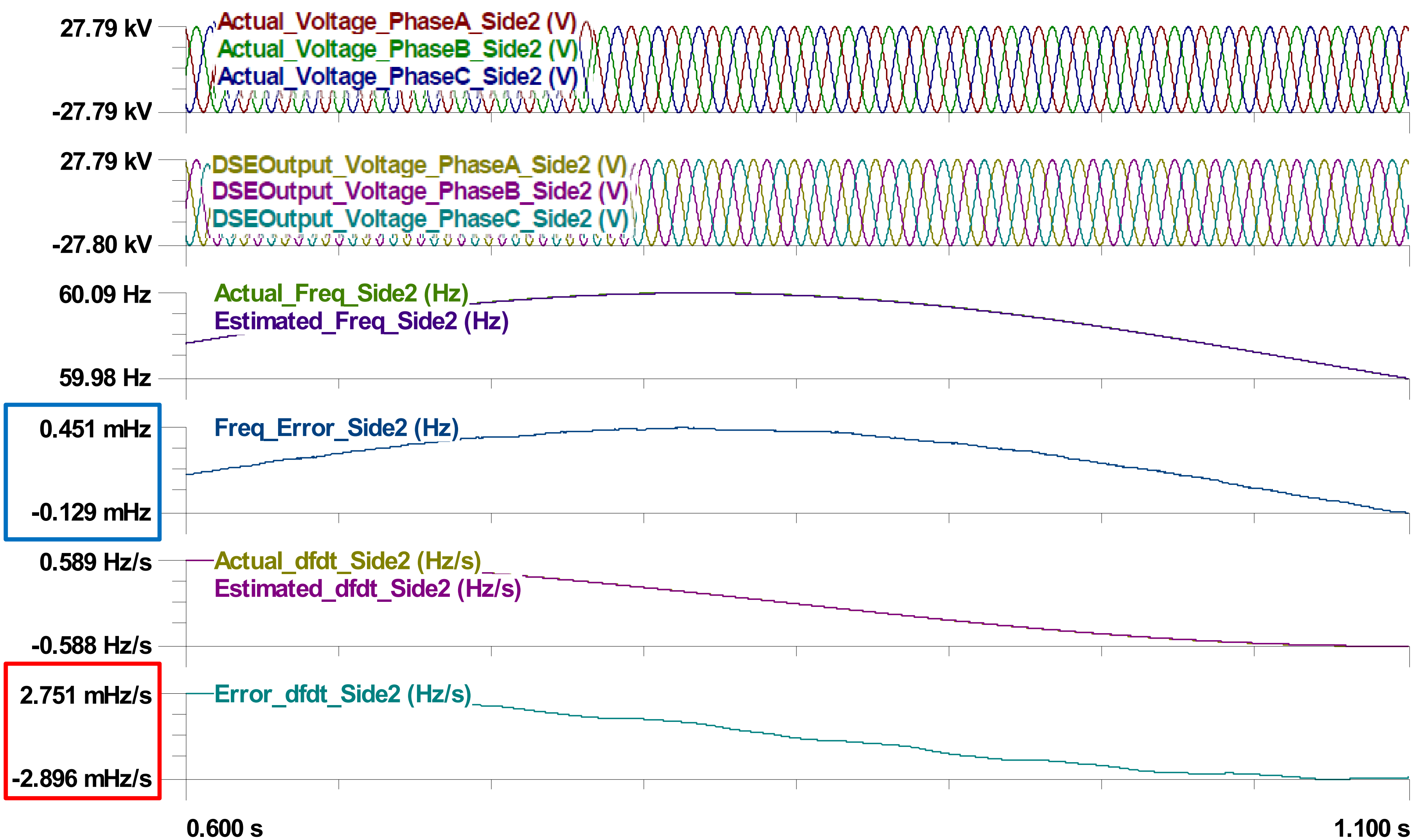
Case 2: 2.5 miles – Side2



Case 3: 4 miles – Side 1



Case 3: 4 miles – Side2



Summary of Results – f and df/dt

Frequency : 59.98Hz ~ 60.09Hz, Rate of Change: -0.6 ~ 0.6Hz/s

Side 1 Results

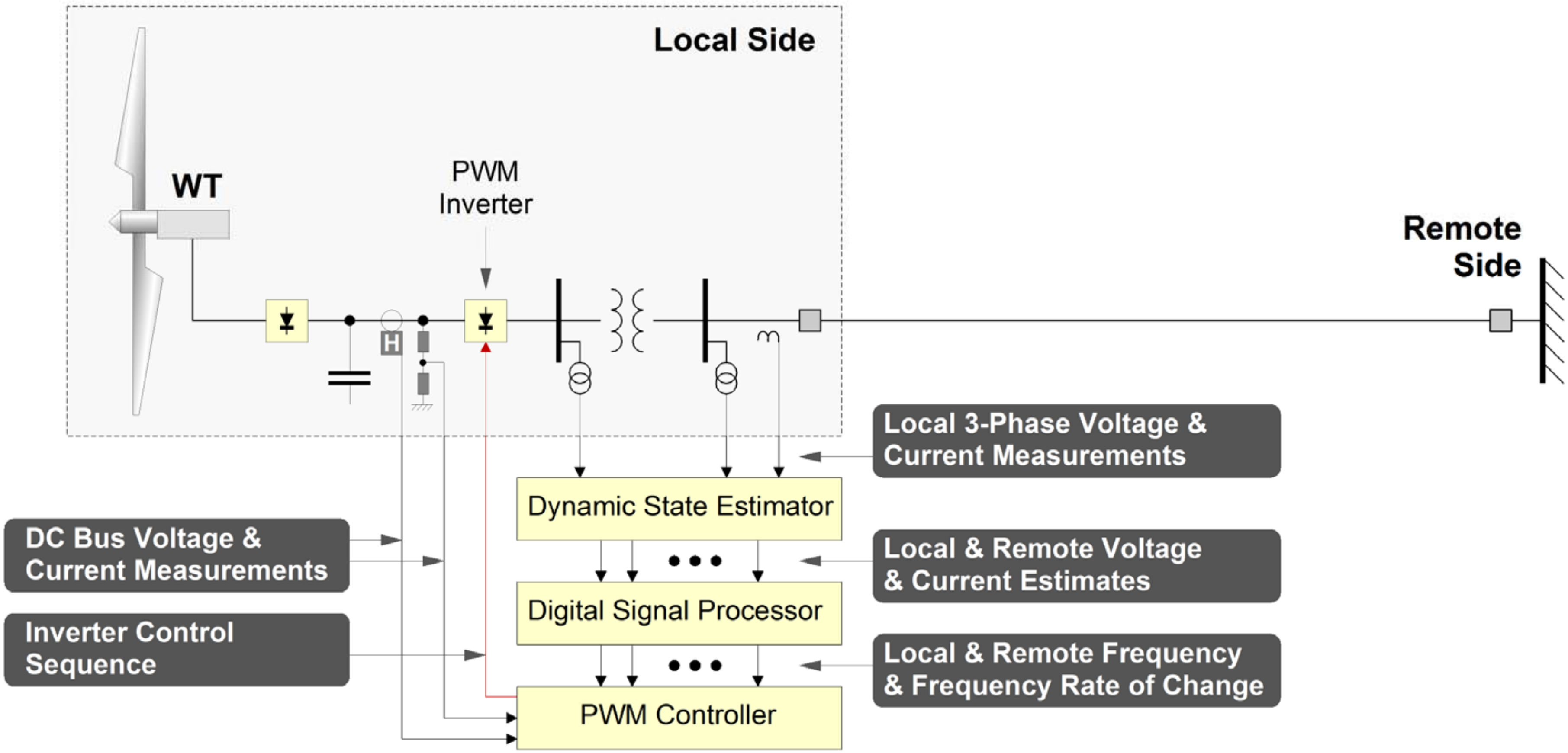
Case number	Line length	Frequency error	dFreq/dt error
1	1.5 *miles*	$-1.887\times10^{-5} \sim 1.827\times10^{-5}\,Hz$	$-1.24\times10^{-4} \sim -2.602\times10^{-6}\,Hz/s$
2	2.5 *miles*	$-2.005\times10^{-5} \sim 1.807\times10^{-5}\,Hz$	$-1.28\times10^{-4} \sim 9.340\times10^{-6}\,Hz/s$
3	4 *miles*	$-1.853\times10^{-5} \sim 1.803\times10^{-5}\,Hz$	$-1.35\times10^{-4} \sim 4.507\times10^{-6}\,Hz/s$

Side 2 Results

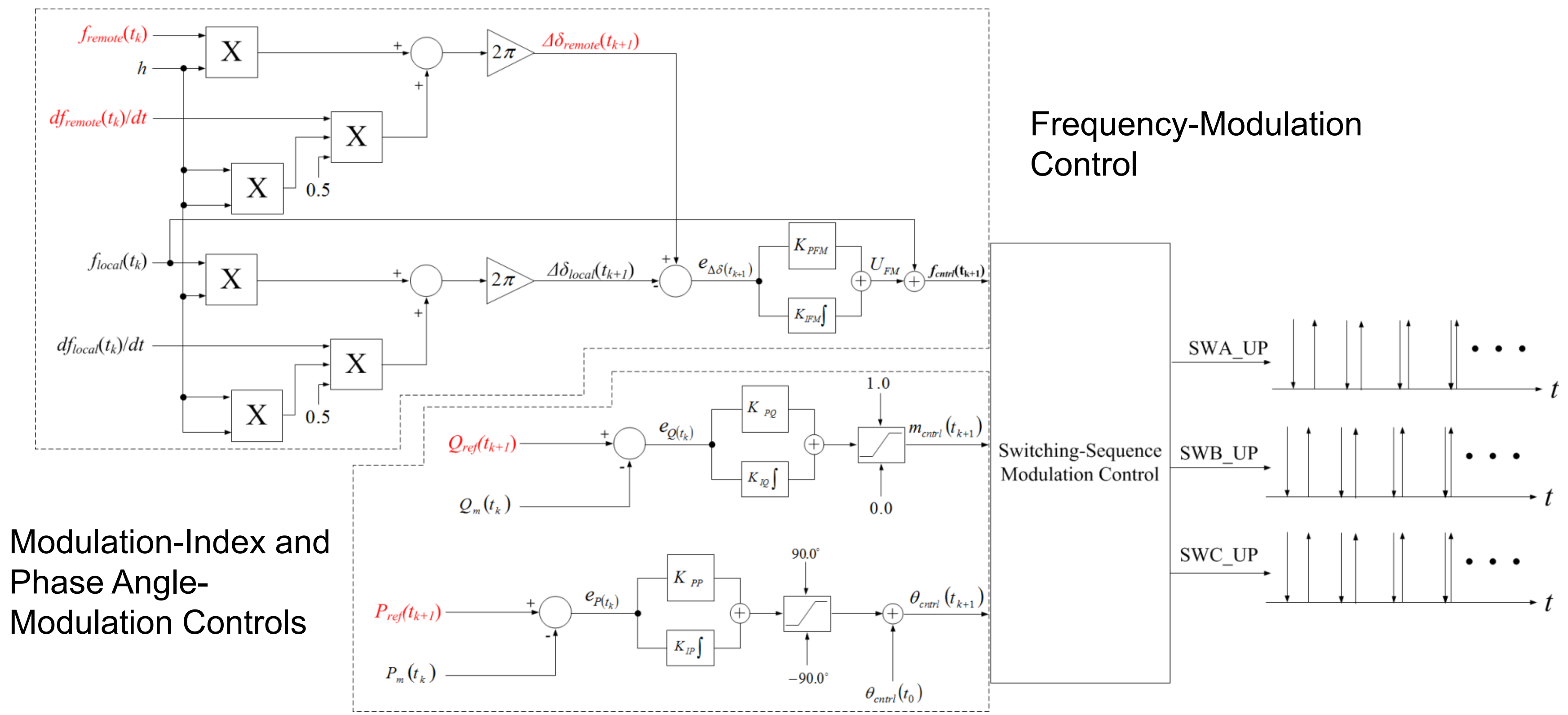
Case number	Line length	Frequency error	dFreq/dt error
1	1.5 *miles*	$-6.513\times10^{-5} \sim 1.77\times10^{-4}\,Hz$	$-1.144\times10^{-3} \sim 1.049\times10^{-3}\,Hz/s$
2	2.5 *miles*	$-9.464\times10^{-5} \sim 2.82\times10^{-4}\,Hz$	$-1.906\times10^{-3} \sim 1.689\times10^{-3}\,Hz/s$
3	4 *miles*	$-1.29\times10^{-4} \sim 4.51\times10^{-4}\,Hz$	$-2.896\times10^{-3} \sim 2.751\times10^{-3}\,Hz/s$

CIG Performance with Supplementary Controls

Predictive Inverter Control Enabled by Dynamic State Estimator



Frequency-Modulation, Modulation-Index, Phase Angle-Modulation Controls (P-Q Mode) PWM Controller



The frequency-modulation control ***gradually*** modulates the frequency of converter switching sequences to slowly synchronize with remote-end transmission and prevent large current transient.
The modulation-index and phase-angle modulation controls modulate the amplitude and phase angle of the AC output voltage by controlling the duty ratio and start time of switching sequences.

Frequency- and Phase Angle-Modulation Controls (P-Q Mode)

Switching-Sequence Definition

Negative Edge:

$$ct_{(2i)a} = \frac{\theta_{cntrl}}{2\pi \cdot f_{cntrl}} + \frac{i}{f_S} + f_N\left(f_S, \frac{i}{f_S} + \frac{\theta_{cntrl}}{2\pi \cdot f_{cntrl}}, m_{cntrl}\right), \quad i = 0, 1, 2, \ldots, 10$$

$$f_N(a, b, c) = solve\left(c \cdot \cos(2\pi \cdot f_{cntrl} \cdot t) = 2 \cdot a \cdot (t - b), t\right), \quad i = 0, 1, 2, \ldots, 10$$

Positive Edge:

$$ct_{(2i+1)a} = \frac{\theta_{cntrl}}{2\pi \cdot f_{cntrl}} + \frac{i}{f_S} + f_P\left(f_S, \frac{i}{f_S} + \frac{\theta_{cntrl}}{2\pi \cdot f_{cntrl}}, m_{cntrl}\right), \quad i = 0, 1, 2, \ldots, 9$$

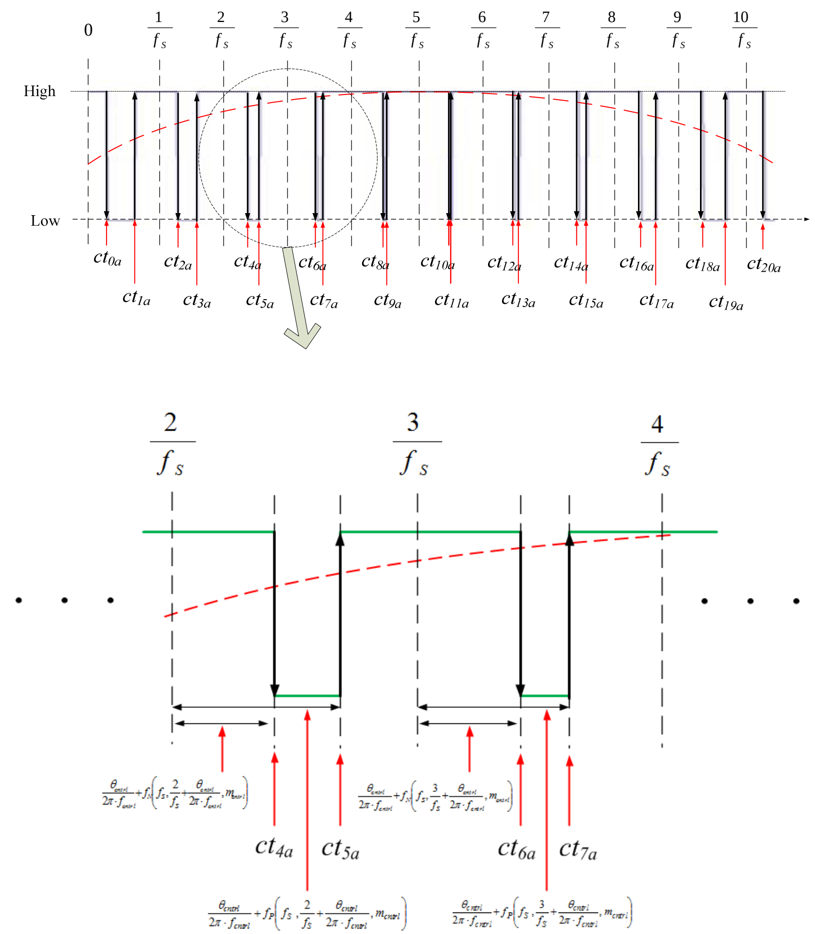
$$f_P(a, b, c) = solve\left(c \cdot \cos(2\pi \cdot f_{cntrl} \cdot t) = -2 \cdot a \cdot \left(t - b - \frac{1}{a}\right), t\right), \quad i = 0, 1, 2, \ldots, 9$$

where:

fs: Switching frequency (Hz).

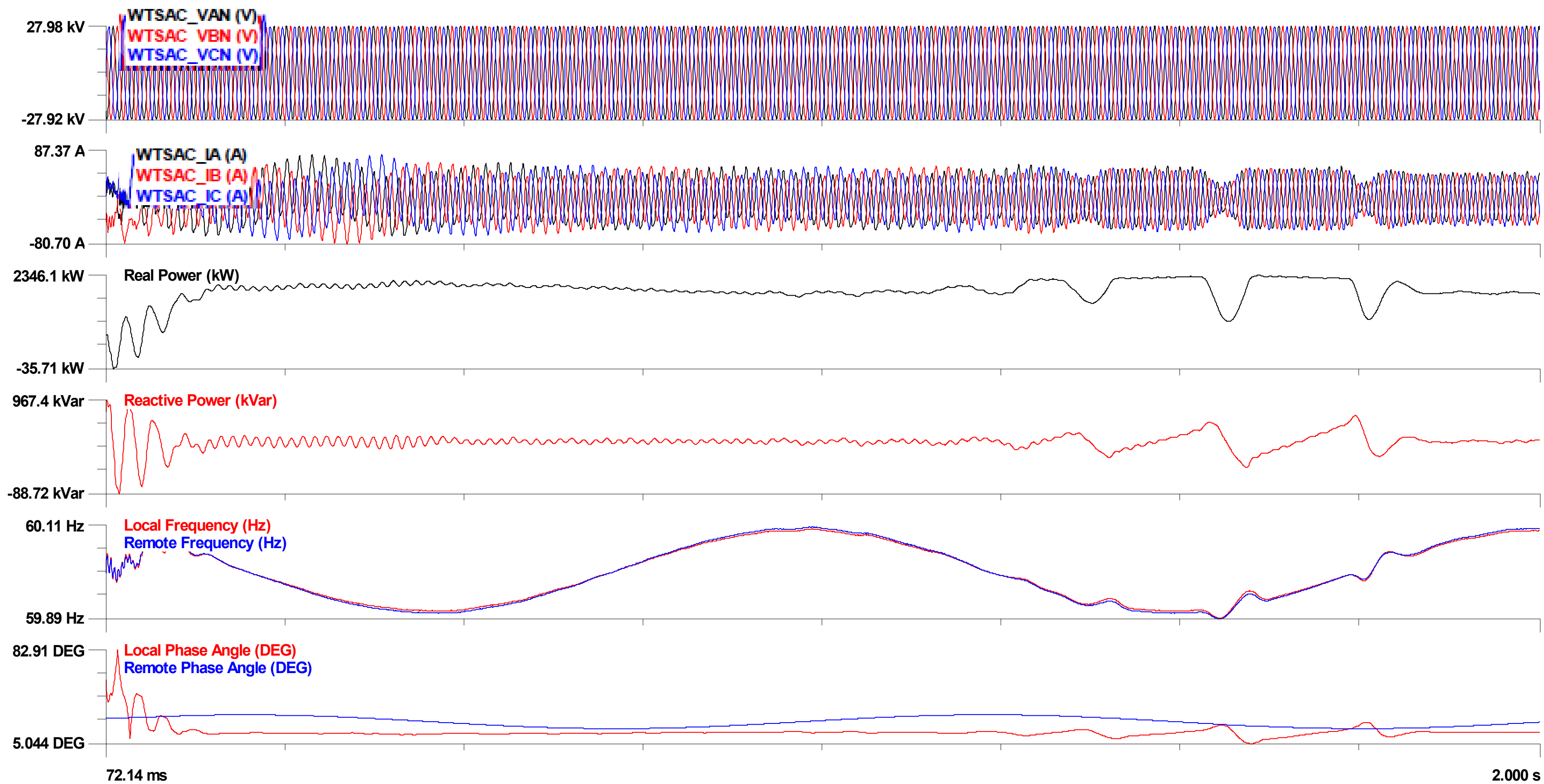
f_N(*a*, *b*, *c*): A function for calculating the negative-edge time per each sampling period (sec).

f_P(*a*, *b*, *c*): A function for calculating the positive-edge time per each sampling period (sec).



Simulation Results:

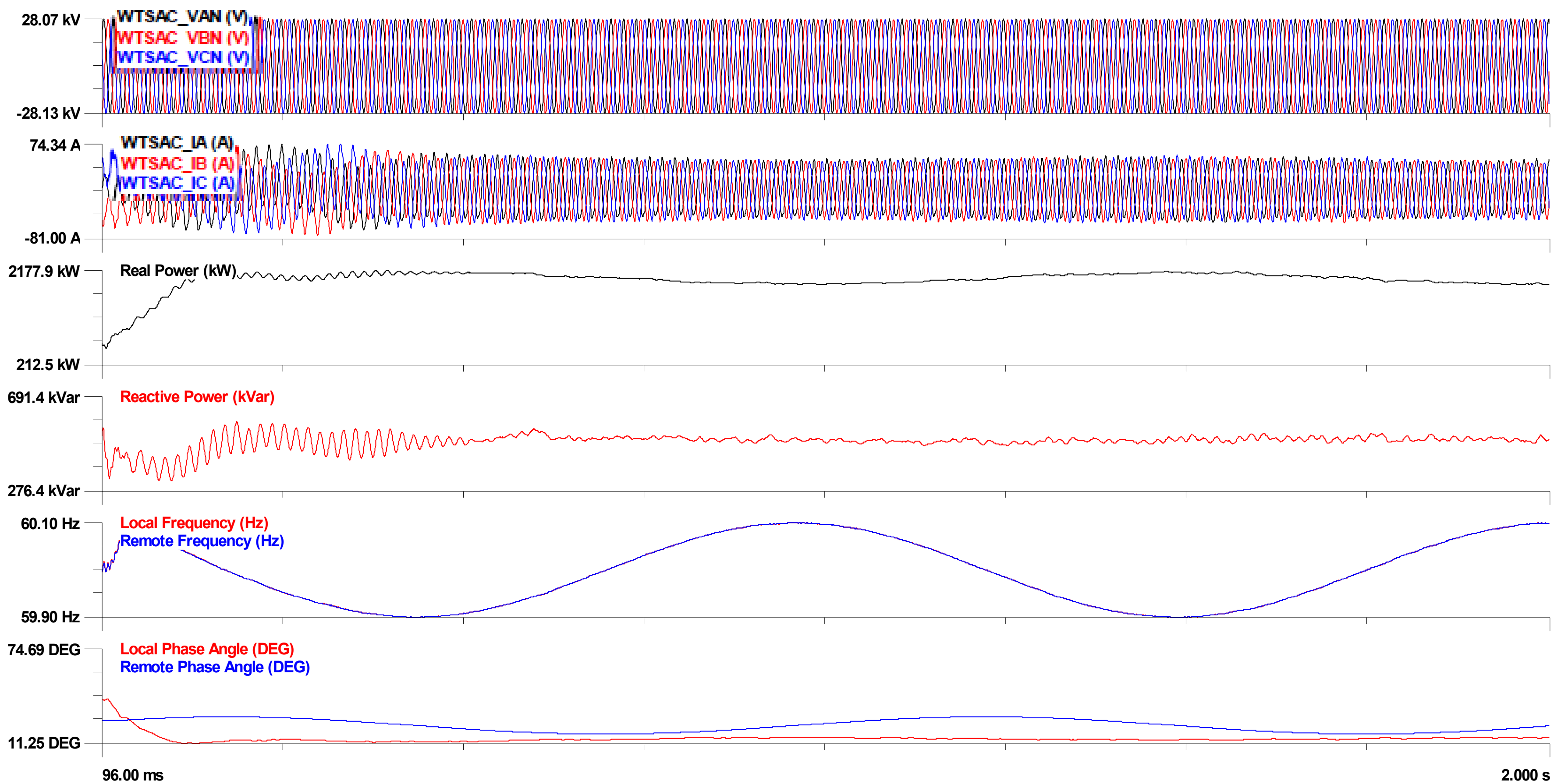
CIG System without Predictive Inverter Control



We perform this simulation test for a case that a remote converter-interfaced generation (CIG) is under frequency oscillation when a local CIG does not have the Predictive Inverter Controller. The frequencies of two CIGs cannot synchronize with each other, consequently power-factor angle difference oscillates. Thus the CIG systems exceed their desirable operation constraints. Therefore, CIG system requires the Predictive Inverter Control to minimize the transient.

Simulation Results:

CIG System with Predictive Inverter Control



We perform this simulation test for a case that a remote converter-interfaced generation (CIG) is under $60 + 0.1\sin(2\pi \cdot t)\,Hz$ frequency oscillation when a local CIG has the Predictive Inverter Controller (P-Q mode: Controlled at 2 MW and 0.5 Mvar). The frequencies of two CIGs can synchronize with each other and power-factor angle difference is kept within their desirable operation constraints. Therefore, CIG system with the Predictive Inverter Controller can successively minimize the transient.

Conclusions

- As the penetration level of CIG increases, one observes a number of issues in the normal operation of the system, oscillations among inverters, reduced fault currents and legacy protection systems failures.
- The setting-less protective relay provides reliable protection for system with converter interfaced generation.
- The setting-less relay (dynamic state estimation) also provides the enabling technology for supplementary sluggish control to limit the oscillations among inverters and synchronize inverters with the power system and minimize activation of LVRT logic.
- The accuracy of the proposed methods to provide the necessary signals has been demonstrated.

Acknowledgements

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