# Western Electricity Coordinating Council
# Modeling and Validation Work Group

# Cross-Current Compensation Model

November 3, 2014

## I. OBJECTIVE

The paper describes a model to represent Cross-Current Compensation at generators that share a common bus. Cross-Current Compensation is used at a number of hydro-power plants in the Pacific Northwest.

## II. BACKGROUND

The majority of synchronous generators control their terminal voltage. Automatic voltage regulators (AVRs) in generator excitation systems use the measured generator terminal voltage as feedback for control. Line Drop Compensation is a function used to get better high voltage system voltage control, particularly when the impedance of the generator step-up transformer is large. Line Drop Compensation is implemented by increasing high voltage sensitivity by a adding a term proportional to generator reactive power / current. Line Drop Compensation is usually set to ¼ to ½ of the generator step-up transformer. Line Drop Compensation is traditionally only used for a single generator with dedicated step up transformer (e.g. Palo Verde, Grand Coulee, Centralia, etc). In GE PSLF, Line Drop Compensation is modeled as a positive "xcomp" number in generator model data.

In cases of two or more generators connected to the same bus, Reactive Current Compensation is required to enable stable reactive power sharing of two units. Reactive Current Compensation effectively inserts a calculated impedance between the two machines, and reduces voltage sensitivity by a term proportional to generator reactive power / current. Reactive Current Compensation is typically set to –5% on the generator base. In GE PSLF, Reactive Current Compensation is modeled as a negative "xcomp" value in the generator model data. A non-negative setting of "xcomp" will result in instability of the common bus generators with AVRs.

While required for stable reactive power sharing among paralleled generators, Reactive Current Compensation reduces system voltage support provided by the generators. Generators on the Lower Columbia River provide important voltage support to the California-Oregon Intertie and Pacific HVDC Intertie, but the generators are paired together, sharing a step up transformer and require Reactive Current Compensation. In 1998, BPA and US Army Corps of Engineers developed and implemented at John Day a design that combines Reactive Current and Line Drop Compensation to improve system voltage support while maintaining stability of the paralleled units [1]. When rotating DC exciters were replaced with static excitation systems in early through mid-2000s, the new design included Line Drop Compensation at each of the generators for system voltage support plus Cross-Current Compensation between the units to enable stable reactive power sharing. Such designs are in operation at John Day, The Dalles, Willamette Valley plants, and will be installed at Chief Joseph power plant. Until now, only Line Drop Compensation was modeled for these plants by setting "xcomp" parameter to a positive number in the generator models. This function only works in simulations as long as paralleled units have the same active and reactive power loading, and have identical dynamic models. However, this modeling practice has become a limitation in (a) operational state-estimator based studies, where loading on paralleled units is almost certainly different, and (b) planning studies when one of the units is generating while a paralleled unit is condensing and therefore have different power output and control settings. The models become unstable in simulation runs, as the generators without Cross-Current Compensation become unstable, as they would in reality. Therefore, there is a need to develop and implement a Cross-Current Compensation model to enable stable reactive power sharing among paralleled units with Line Crop Compensation.

| Control Type | | PSLF Model | Typical Value |
|---|---|---|---|
| Terminal Voltage Control | Single Unit | "xcomp" is zero | 0 |
| Line Drop Compensation | Single Unit | "xcomp" is positive | ¼ to ½ of generator step-up transformer |
| Reactive Current Compensation | Paralleled Units, most cases | "xcomp" is negative | –5%, or –0.05 per unit |
| Line Drop Compensation with Cross-Current Compensation | Paralleled Units, a few cases | "xcomp" is positive, **"ccomp" model is required** | LDC is ¼ to ½ of generator step-up transformer,<br>CCOMP is –12% to -15%, or –0.12 to –0.15 per unit |

## III. MODEL DESCRIPTION

A Cross-Compensation model **CCOMP** is implemented in GE PSLF. The model parameters are:

- "rc" – cross-compensation resistance, typically 0.0
- "xc" – cross-compensation reactance, must be negative, typically –0.12 to –0.15 pu
- "rt" - joint compensation resistance, typically 0.0
- "xt" – joint compensation reactance, set to 0.0 for US ACE design
- "tf" – filtering time constant, set to 0.0
- "flag" – flag setting regulation type, set to 1.0 for US ACE design

This model implements cross current compensation for the voltage regulators of a pair of generators that are bussed together at their terminals. The model can represent two different implementations of cross compensation as described depending on the "flag" setting:

"flag" = 0, differential and collective current compensation. The current-compensated AVR voltages are calculated as:

$$Vcompa = Vt - (rc + jxc)(Ia-Ib) - (rt + jxt)(Ia+Ib)$$
$$Vcompb = Vt + (rc + jxc)(Ia-Ib) - (rt + jxt)(Ia+Ib)$$

where:
Vt terminal voltage for units “a” and “b”
Vcompa is compensated voltage for unit “a”
Vcompb is compensated voltage for unit “b”
Ia is unit “a” current
Ib is unit “b” current
Generator “rcomp” and “xcomp” values are ignored with “flag”= 0

“flag” = 1, differential and individual generator compensation mode. The current-compensated generator terminal voltages are calculated as:

$$Vcompa = Vt - (Rc + jXc)(Ia-Ib) - (Rcompa + jXcompa)Ia$$
$$Vcompb = Vt + (Rc + jXc)(Ia-Ib) - (Rcompb + jXcompb)Ib$$

Vt terminal voltage for units “a” and “b”
Vcompa is compensated voltage for unit “a”
Vcompb is compensated voltage for unit “b”
Ia is unit “a” current
Ib is unit “b” current
Rcompa, Xcompa are the series compensation impedance of generator “a”, part of generator data
Rcompb, Xcompb are the series compensation impedance of generator “b”, part of generator data

MVA base for units “a” and “b” must be the same.

More details can be found in GE PSLF manual.

An example of dynamic data in GE PSLF program:

```
gentpj  44001 “HYDRO 1” 13.8 “01” : #9 “mva”=163 … “xcomp” 0.05 …
gentpj  44001 “HYDRO 1” 13.8 “02” : #9 “mva”=163 … “xcomp” 0.05 …
ccomp   44001 “HYDRO 1” 13.8 “01” : #9 … “xc” -0.13 … “xt” 0.0  … “flag” 1
exst1  44001 “HYDRO 1” 13.8 “01” : #9
exst1  44001 “HYDRO 1” 13.8 “02” : #9
```

## IV. MODEL TESTING AND VALIDATION

The following eight configurations are considered, as described in Figure 5:

1. Both units are on-line at same loading
2. Both units are on-line at different MW loadings, same MVAR loading
3. Both units are on-line, unit one is generating and unit two is condensing
4. Both units are on-line, unit one is condensing and unit two is generating
5. Both units are on-line at same MW loadings, different MVAR loading
6. Both units are on-line at different MW and MVAR loadings
7. Unit one is on-line, with second unit off-line
8. Unit one is off-line, second unit is on-line

| Unit | MW | V0 (PU) | VPOST (PU) | Q0 (MVAR) | QPOST (MVAR) | DV (PU) | DQ (PU) | Estimated Droop |
|---|---|---|---|---|---|---|---|---|
| U1 | 125 | 0.9801 | 0.9965 | -6.27 | 49.66 | 0.0164 | 0.3422 | 0.0479 |
| U2 | 125 | 0.9801 | 0.9965 | -6.27 | 49.66 | 0.0164 | 0.3422 | 0.0479 |
| U3 | 130 | 0.9801 | 0.9964 | -6.18 | 49.43 | 0.0163 | 0.3403 | 0.0479 |
| U4 | 120 | 0.9801 | 0.9964 | -6.18 | 49.43 | 0.0163 | 0.3403 | 0.0479 |
| U5 | 125 | 0.9801 | 0.9963 | -13.1 | 43.78 | 0.0162 | 0.3481 | 0.0465 |
| U6 | 0 | 0.9801 | 0.9963 | -13.1 | 41.31 | 0.0162 | 0.3329 | 0.0487 |
| U7 | 0 | 0.9801 | 0.9962 | -12.96 | 40.962 | 0.0161 | 0.3300 | 0.0488 |
| U8 | 125 | 0.9801 | 0.9962 | -12.96 | 43.43 | 0.0161 | 0.3451 | 0.0467 |
| U9 | 125 | 0.9753 | 0.9916 | -4.7 | 49.84 | 0.0163 | 0.3337 | 0.0488 |
| U10 | 125 | 0.9753 | 0.9916 | -14.7 | 39.74 | 0.0163 | 0.3331 | 0.0489 |
| U11 | 130 | 0.9801 | 0.9961 | -19.8 | 34.92 | 0.016 | 0.3348 | 0.0478 |
| U12 | 110 | 0.9801 | 0.9961 | 5.2 | 59.29 | 0.016 | 0.3310 | 0.0483 |
| U13 | 125 | 0.9803 | 1.0286 | -25.91 | 144.36 | 0.0483 | 1.0419 | 0.0464 |
| U14 | OFF | | | | | | | |
| U15 | OFF | | | | | | | |
| U16 | 125 | 0.9803 | 1.0286 | -25.91 | 144.36 | 0.0483 | 1.0419 | 0.0464 |

The models are stable, and the results are satisfactory.

Voltage reference steps of 5% and 6.5% were simulated and compared with test done on actual generators with cross-current compensation. Figure 6 shows simulated steps and Figures 7A and 7B show actual test results. There is very close correspondence between the actual and simulated voltage change, as well as actual and simulated changes in reactive power.

Further validation was performed using a large collection of data from a different, two-generator hydro plant utilizing cross current compensation. The results shown in figures 9A through 9D compare a single unit with varying settings of line drop compensation to demonstrate the correct implementation of single unit behavior. Figures 10A and 10B compare the measured step responses of one of the paired units while both units were online with line drop compensation enabled on each unit. The operating points of the models were set different for each unit, with the regulator gain slightly altered on the responding unit to boot, just to ensure all stability concerns were explored. Figures 11A and 11B compare the responses of one of the units while steps were inserted into Vref points in both units simultaneously. Again, each model was set at a different loading point.

The results show that the cross current compensation model, **CCOMP**, can adequately capture the behavior of the excitation systems of this plant, so that finally plants incorporating this control feature can be properly represented.

## V. INTERIM CONVERSION BETWEEN GE PSLF AND PTI PSS®E

There are no equivalent **CCOMP** models in PTI PSS®E or TSAT programs at this time.

All of the known generators with Cross Current Compensation are in the Pacific Northwest, and have primary impact on the California – Oregon Intertie (COI) and the Pacific HVDC Intertie (PDCI). While it is very desirable to develop a similar model in PSS®E, COI and PDCI operators do not use PSS®E for either planning or operating studies, and therefore, we do not want model conversion issues to impede state estimator based stability studies.

A small value of Reactive Current Compensation can be used for generators to ensure model stability until a corresponding **CCOMP** model is developed in PSS®E.

## VI. REFERENCES

[1] Dmitry Kosterev, "Design, Installation, and Initial Operating Experience with Line Drop Compensation at John Day Powerhouse," IEEE Transactions on Power Systems, vol.16, no.2, May 2001, pp. 261-265.

CONTRIBUTORS:

- John Undrill
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- Eric Bakie, Idaho Power Company

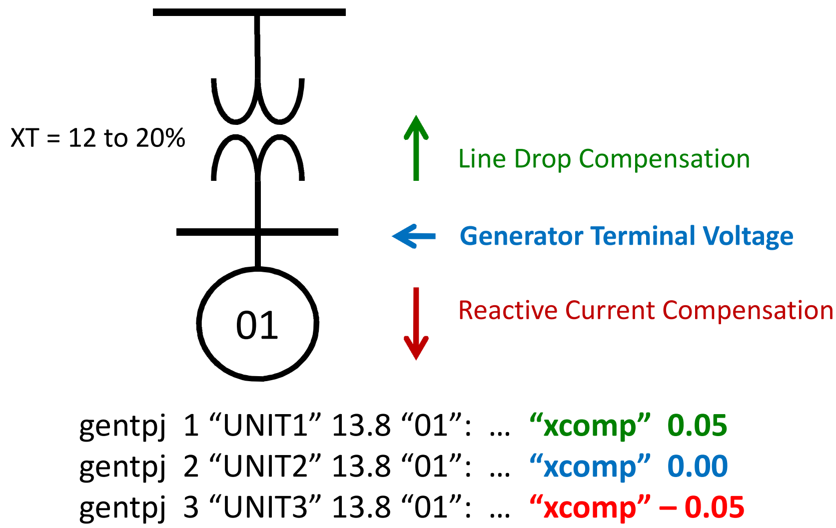



Figure 1: single unit voltage control settings

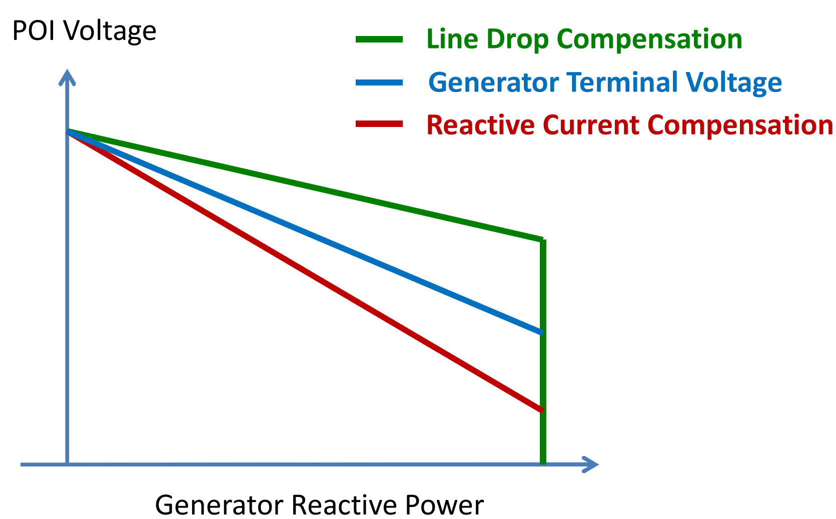
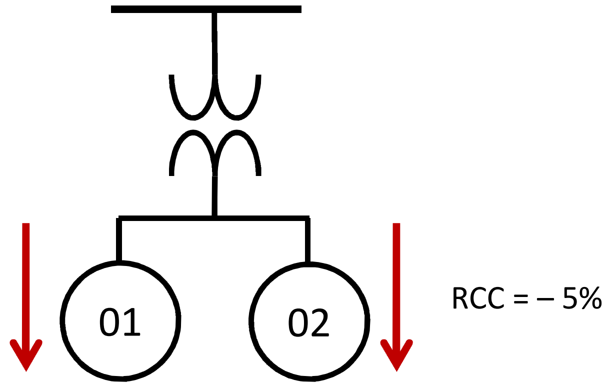



Figure 2: effect of voltage control settings on voltage - reactive power control

Approximately (neglecting transformer impedance, and assuming generator voltages stay close to unity) on per unit basis:

- VPOI = VGEN – XT*Q - terminal voltage control
- VPOI = (VGEN + XCOMP*Q) – XT*Q = VGEN – (XT – XCOMP)*Q – Line Crop Compensation
- VPOI = (VGEN – XCOMP*Q) – XT*Q = VGEN – (XT + XCOMP)*Q – Reactive Current Compensation




Model:
gentpj 1 “UNIT1” 13.8 “01”: … **“xcomp” – 0.05**
gentpj 1 “UNIT1” 13.8 “02”: … **“xcomp” – 0.05**

Figure 3: general rule for two paralleled units

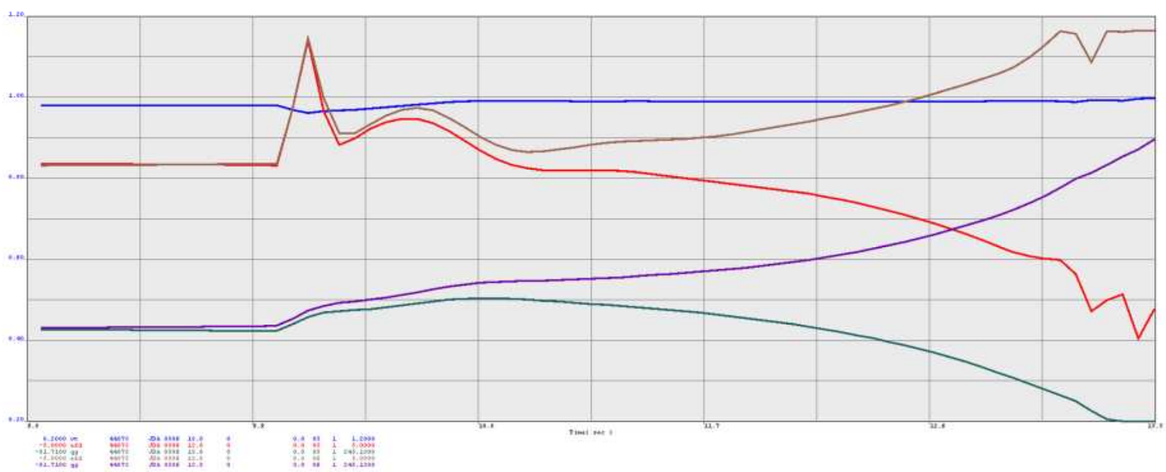
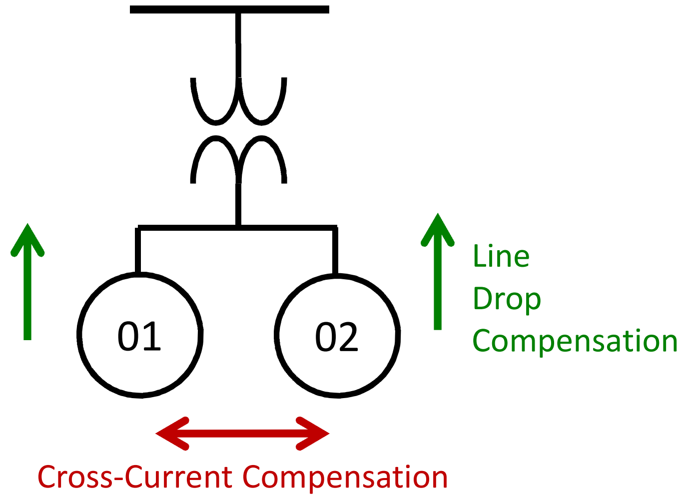


Figure 4: parallel units become unstable when “xcomp” is positive and they are loaded at different active power levels or have different parameters

**Voltage, Field Voltage Unit 1, Field Voltage Unit 2, Reactive Power Unit 1, Reactive Power Unit 2**




gentpj 1 “UNIT1” 13.8 “01”: … **“xcomp” 0.05**
gentpj 1 “UNIT1” 13.8 “02”: … **“xcomp” 0.05**
ccomp 1 “UNIT1” 13.8 “01”: … **“xc” – 0.13 … “xt” 0.0 “flag” 1**

Figure 5: two paralleled units with Line Drop Compensation and Cross-Current Compensation

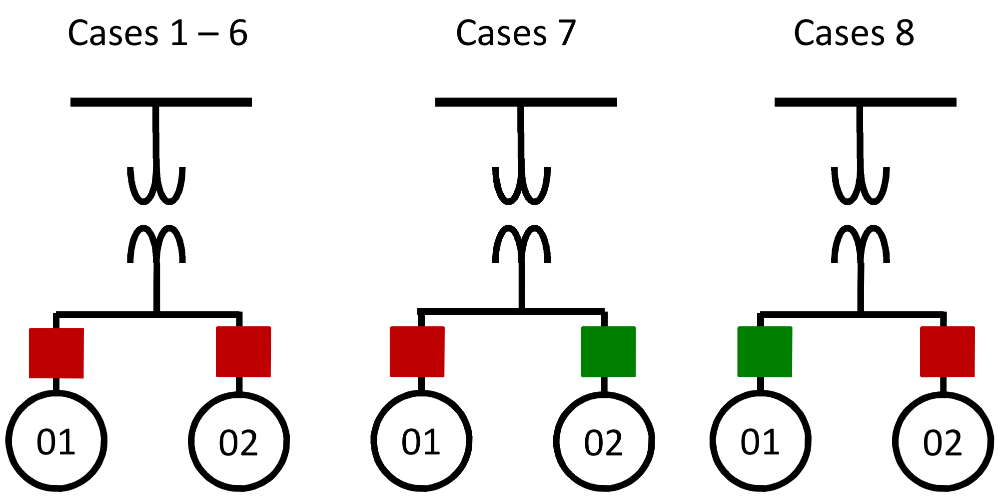



Figure 6: test scenarios

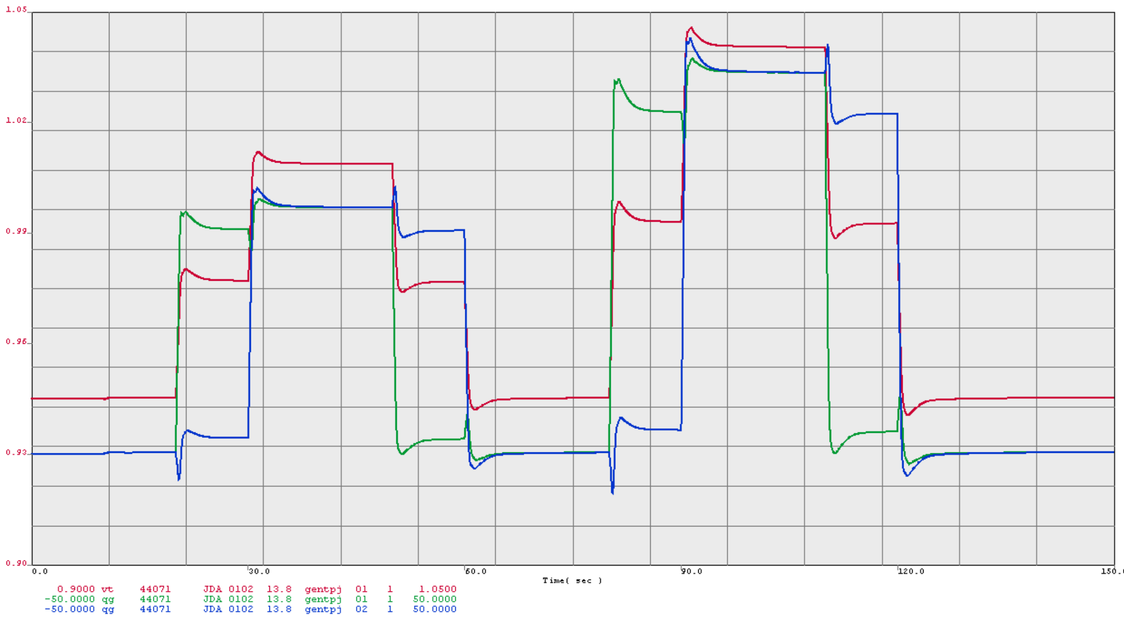



Figure 7: simulated sequential voltage reference steps of 5% and 7.5%

- Red = bus voltage
- Green = Unit1 reactive power
- Blue = Unit 2 reactive power

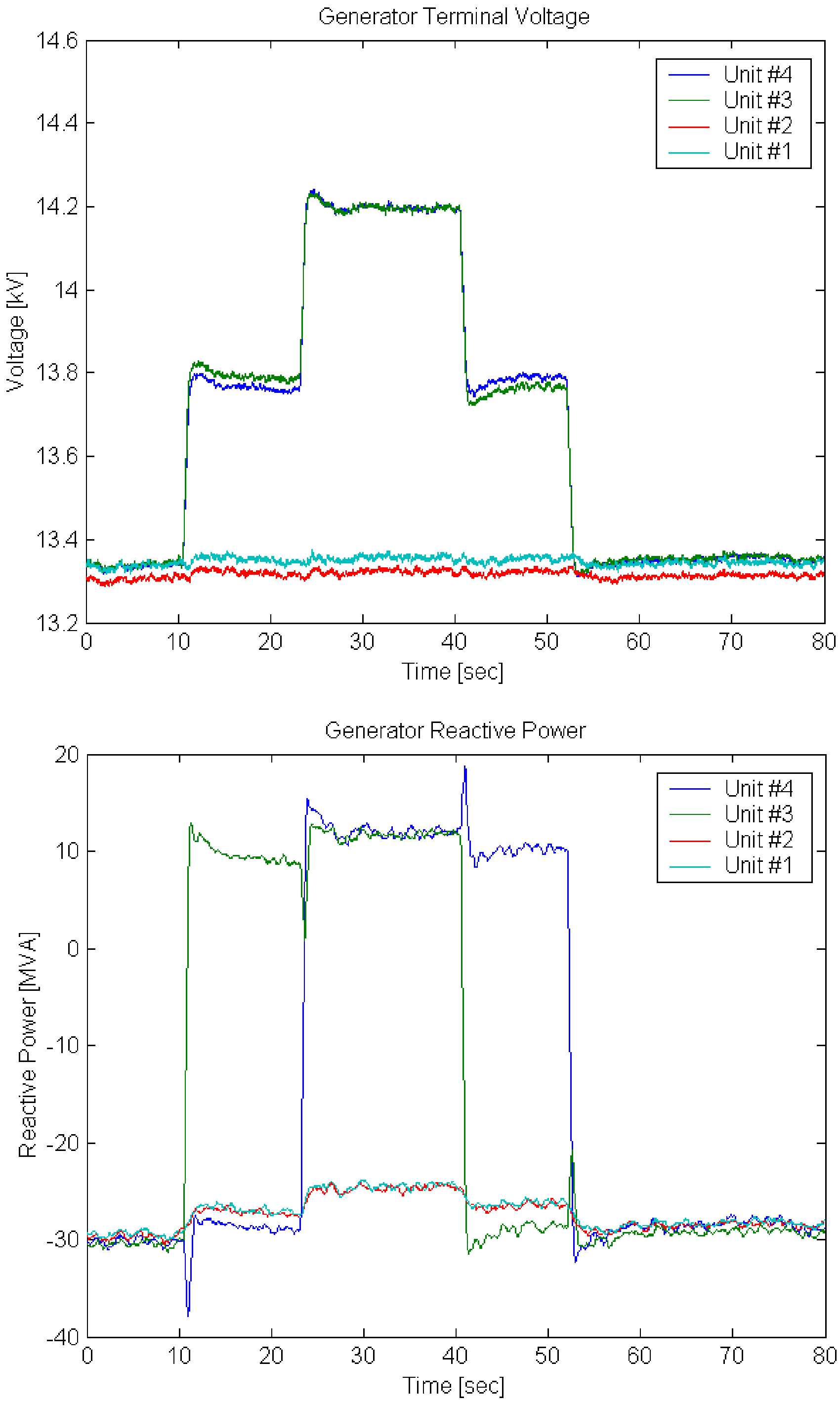



Figure 8A: John Day generator 5% voltage reference steps

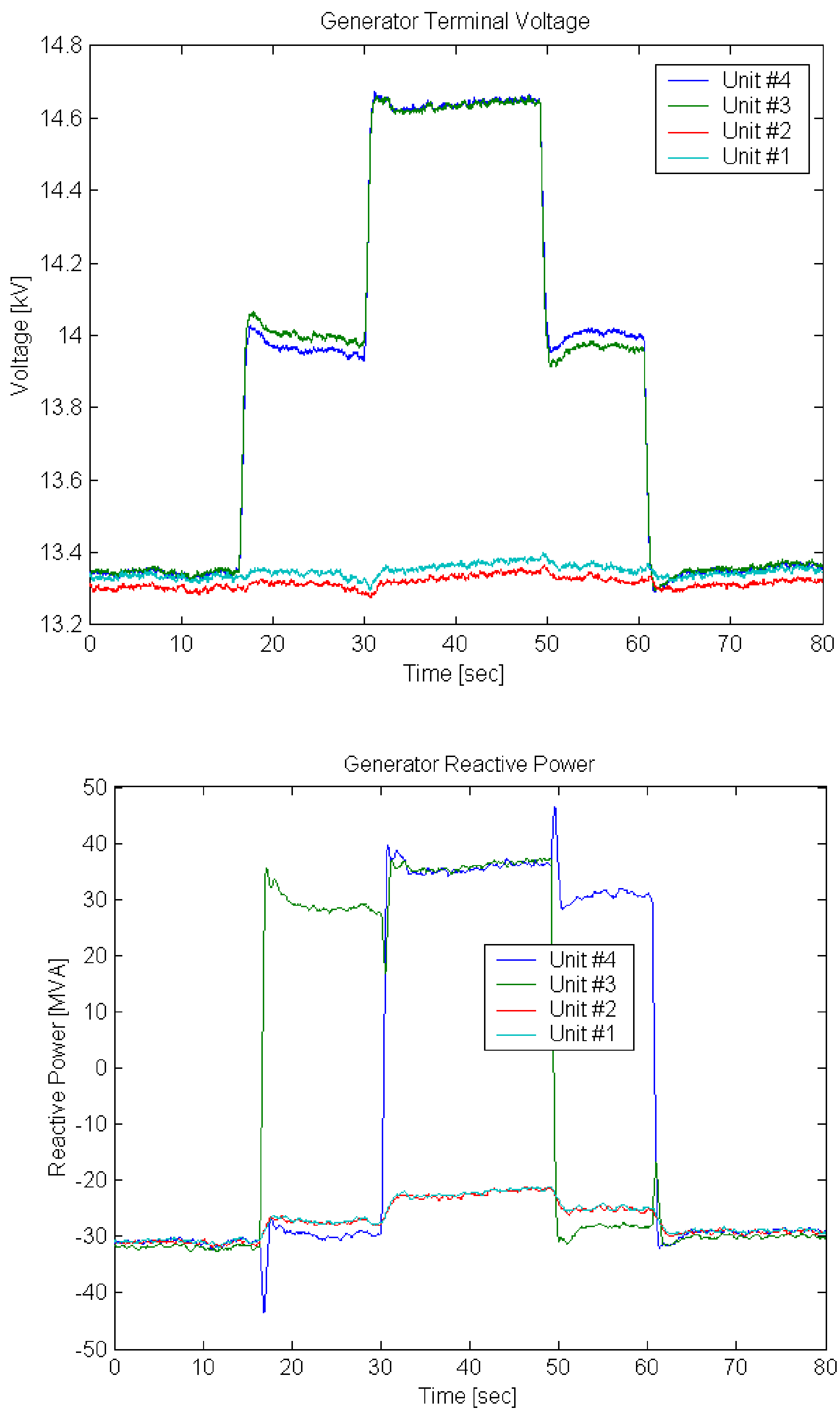



Figure 8B: John Day generator 7.5% voltage reference steps

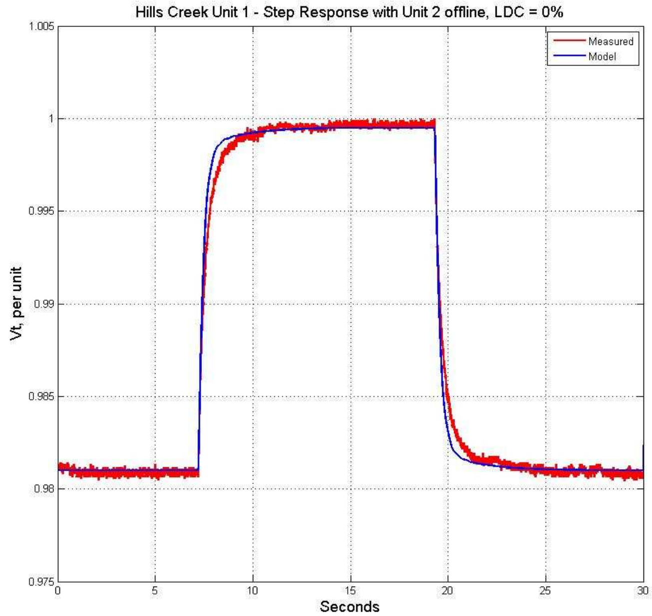



Figure 9A – Step Response of Isolated Unit with LDC = 0% - Terminal Voltage

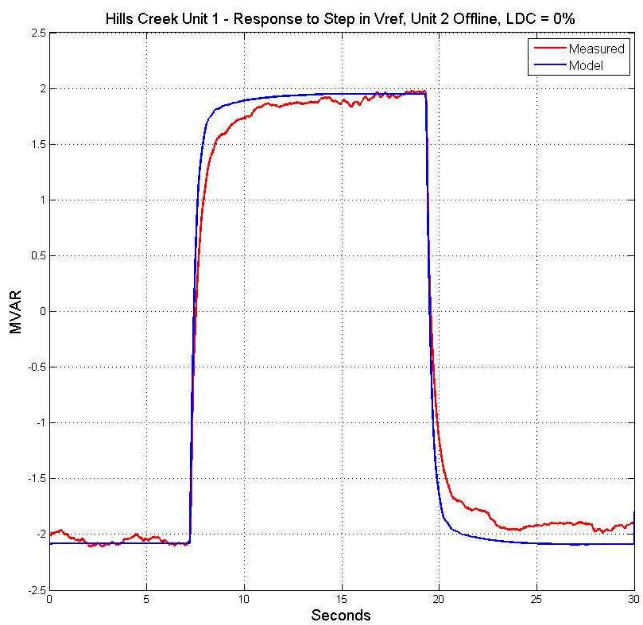



Figure 9B – Step Response of Isolated Unit with LDC = 0% - Reactive Power

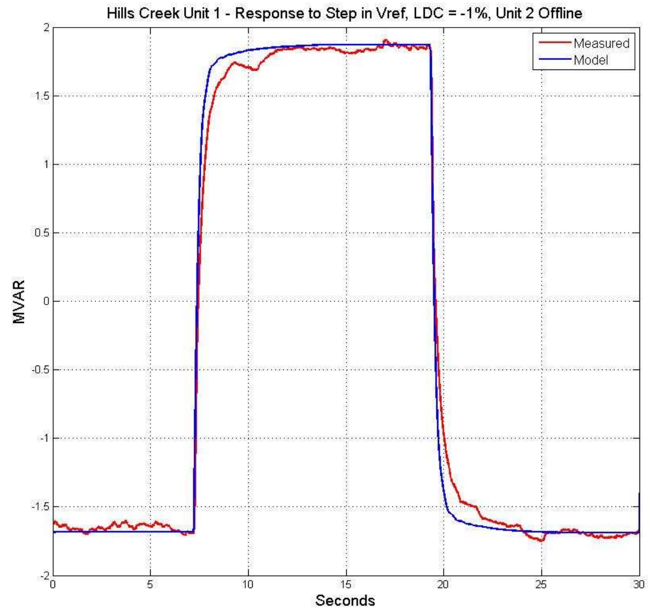



Figure 9C – Step Response of Isolated Unit with LDC = -1% - Reactive Power

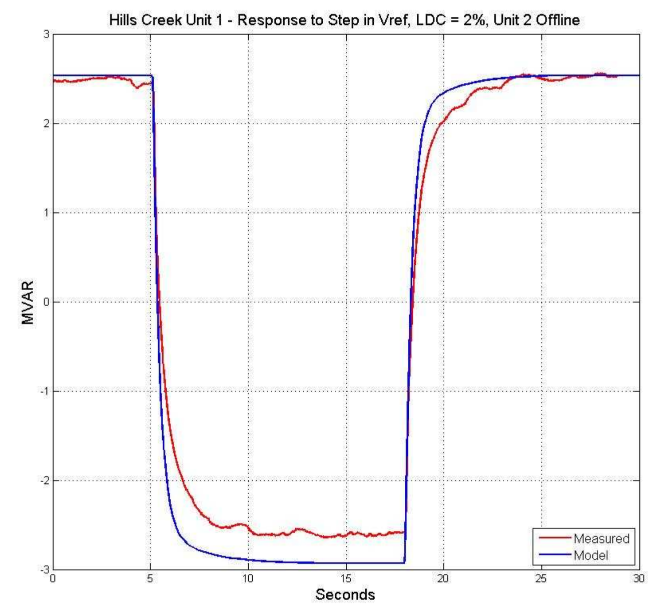



Figure 9D – Step Response of Isolated Unit with LDC = +2% - Reactive Power

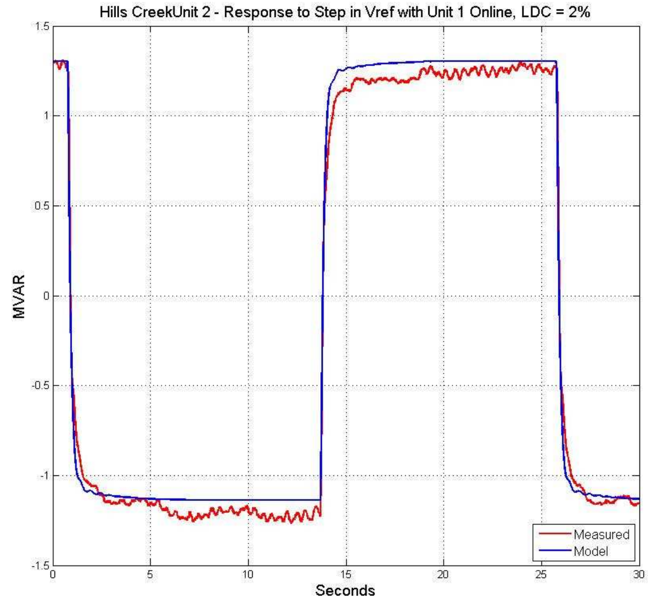



Figure 10A – Step Response of One Parallel Unit with LDC = +2% - Reactive Power

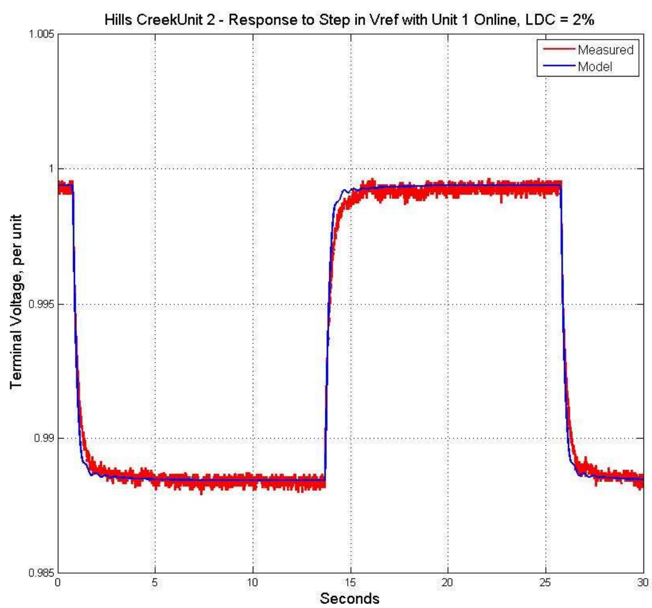



Figure 10B – Step Response of One Parallel Unit with LDC = +2% - Terminal Voltage

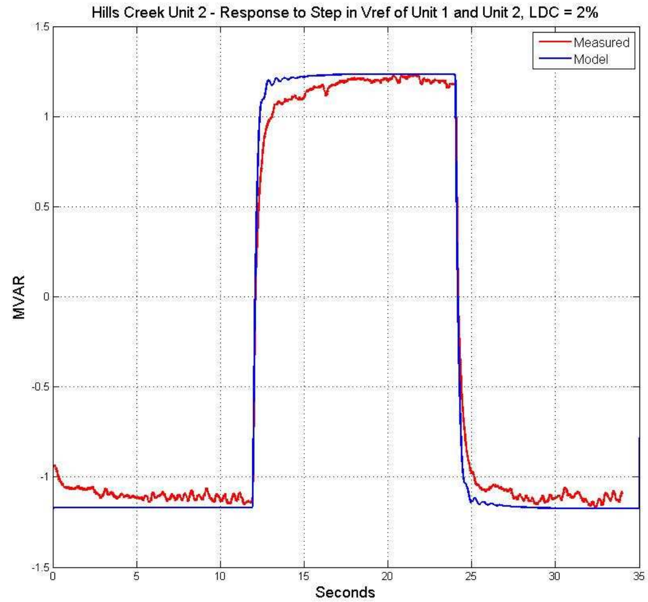



Figure 11A – Response of Single Parallel Unit to Step in Both Units with LDC = +2% - Reactive Power

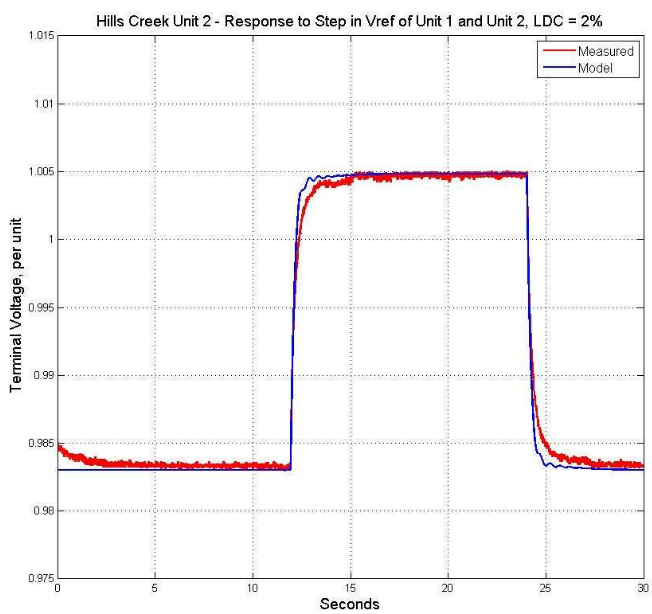



Figure 11B – Response of Single Parallel Unit to Step in Both Units with LDC = +2% - Terminal Voltage