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National Renewable Energy Laboratory
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Modeling and Testing of Unbalanced Loading and Voltage Regulation

Final Report

Subcontract Report
NREL/SR-581-41805
July 2007

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List of Acronyms

ANSI	American National Standards Institute
BL	beginning location
CAP	capacitor
CC	constant current
CP	constant power
CT	current transformer
DG	distributed generation/distributed generator
DR	distributed resource(s)
EL	end location
GMD	geometric mean distance
HL	heavy load
HV	high voltage
LL	light load
LTC	load tap changer/load tap-changing
LV	low voltage
ML	midlocation
PF	power factor
VDC	voltage-dependent current
VR	voltage regulator
VRR	voltage regulating relay
VT	voltage transformer

Executive Summary

Introduction

A distributed generation (DG) penetration limit study (Davis 2003) indicated a range of DG sizes can be interconnected with a distribution circuit. The DG size limit is dependent on system voltage, the location of the DG on the circuit, and system protection, voltage regulation, and other issues related to DG and circuit characteristics. The study showed that the DG could be larger if it was allowed to actively regulate voltage, rather than operate at a fixed unity power factor.

Fixed power factor operation of the DG has a minimum effect on the existing traditional voltage regulation controls of the circuit because, as the system voltage changes, the field current of the DG synchronous generator is adjusted to bring the kilovar output typically back to zero and maintain the desired kilowatt setpoint. Therefore, the only effect on the system voltage is the kilowatt injection at that point on the distribution circuit. However, if the DG synchronous machine is allowed to absorb or export volt-amperes reactive, the voltage can be decreased or increased at that point on the circuit, and much larger kilowatt injections—and thus, larger DG—can be installed on the circuit.

A number of problems are associated with interconnecting DG with a distribution circuit. Some are related to circuit design and operation, and others are related to the analytical tools used to evaluate DG operation. Distribution circuits are primarily designed for radial, one-way power flow, and distribution line voltage regulators are typically designed to regulate voltage based on a unidirectional flow of power. When DG is interconnected with the circuit, two-way flows can result. In addition, most of the load served on a distribution circuit is single-phase, yet most of the analytical tools used to evaluate circuit performance are based on balanced three-phase loads and balanced three-phase line circuit impedances. When balanced three-phase power flow programs are used to calculate the voltage profile on a distribution circuit and determine if voltage limits are being violated by DG, the accuracy of the service voltages at the individual single-phase loads on the single-phase laterals is a concern because only the three-phase portion of the circuit is modeled. American National Standards Institute Standard C84.1 voltage limits may be satisfied based on three-phase balanced load/impedance analysis, but the voltages at single-phase loads may be violated when the DG operates or shuts down.

This is a significant concern for utilities because liability issues arise when customer equipment is damaged because of HV or LV on a circuit. Therefore, it is critical to evaluate the effects of DG on the distribution circuit voltage profile to ensure customers do not receive service voltages (at the customer billing meter) outside Range A or Range B of American National Standards Institute C84.1. This can be accomplished by using modeling and simulation tools that recognize single-phase loads, unsymmetrical distribution transformer connections, and unbalanced line impedances.

Purpose

The purpose of the project is to:

- Explain how voltage regulation reduces voltage spread
- Define the effects of unbalanced loading and voltage on system protection and DG output ratings
- Develop models for an actual distribution circuit, its voltage regulation equipment, and all the DG generator types, recognizing unbalanced loading and unbalanced circuit impedances
- Validate these models by comparing power flow simulations and voltage profiles with actual measured circuit data
- Determine the optimum generator operating conditions (i.e., P and Q) to provide the greatest improvement in released capacity, reduced energy losses, and voltage regulation
- Determine the maximum DG penetration limits with synchronous generator real and reactive power injections.

Project Objectives

The project objectives are five-fold:

- To develop a load model for an actual 13.2-kV distribution circuit that represents how the real and reactive load on the circuit changes when the voltage is raised or lowered with capacitor switching, distribution line voltage regulator step changes, and load tap changer and DG voltage regulation
- To develop models for distribution overhead and underground circuit line elements, transformers, shunt capacitors, step voltage regulators, and synchronous, induction, and inverter DG generators
- To verify the models by comparing the power flow simulated data with actual circuit measured data
- To determine the maximum DG size that can be interconnected with the circuit
- To determine the optimum generator operating conditions for maximum released capacity savings, reduced energy losses, and voltage regulation improvement.

Project Results

- The circuit load was modeled using constant current, constant power, and a voltage-dependent current. The voltage-dependent current model best represented the load characteristics of the circuit, with a variance of only 2%. The constant current model had a variance of 3.9%, and the constant power model, which is typically used, had a variance of 12.5%.

The voltage-dependent current model that best represents how the load changes with changes in source voltage is:

$$\frac{\%\Delta P}{\%\Delta V} = 1.26$$

$$\frac{\%\Delta Q}{\%\Delta V} = 4.66.$$

- During heavy load conditions when all voltage regulation equipment was turned on, the circuit tag end voltage improvement was 14.87 V over only the load-tap changing transformer voltage. When the first step regulator was turned on, the tag end voltage improved 4.11 V. With the second, the voltage increased another 11.34 V. With the first capacitor turned on, the voltage increased only 0.97 V. When the second was turned on, the total voltage gain was 1.75 V. When the third was turned on, another 1.66-V rise occurred at the tag end. It may be necessary to operate DG to absorb volt-amperes reactive to prevent high voltage during light-load conditions.
- The highest unbalanced voltage of 1.52% occurred during heavy load conditions with load tap changer regulation and one step regulator turned on. Because most synchronous generators trip when the unbalanced voltage is more than 3%, unbalanced three-phase power flow studies should always be conducted on the circuit to ensure unbalance does not exceed 3% at the point of interconnection (not the point of common coupling). Adding load tap changer regulation during heavy load conditions lowered the maximum unbalanced voltage to 1.44%; adding step regulators worsened the unbalanced voltage. This was to be expected because an increase in voltage causes an increase in load and unbalance. When all three capacitors were turned on, the maximum unbalanced voltage was reduced to 1.31%. Turning all regulation on lowered the maximum unbalanced voltage to 1.31%. The 13-utility unbalanced voltage survey showed a maximum measured voltage unbalance of 5.94%. The high imbalances occurred on open delta transformer connections.
- The highest voltage unbalance during light-load conditions was 1.26%.
- At many locations on the circuit, the current imbalance exceeded 20%. Most synchronous machines trip at 10%–20% current imbalance; therefore, studies must determine the current imbalance at the location where the DG is to be sited. Otherwise, it may never operate without tripping. The load imbalance at the substation reached 4% at heavy load and 6% at light load.
- The causes of unbalanced voltage and current and how unbalanced conditions affect protective relaying are described. The neutral relay is set to trip for ground faults, and the trip value may have to be increased to account for increased neutral current because of unbalance.
- Significant unbalanced loading can occur even though voltages are balanced at the source. Reclosers and the substation breaker with ground fault-sensing circuits are affected by load imbalance. Unequal single-phase load connected line-to-line does not produce neutral current in the ground relay.

- Fuse preload because of unbalanced loading can cause fuses to become unselective with other protective devices such as reclosers and lead to misoperation.
- Reducing unbalanced loading reduces the losses created by the neutral current in the neutral conductor.
- Unbalanced three-phase voltages have a significant effect on the heating of induction and synchronous generators. For example, a 5.5% voltage unbalance can cause an approximate 25% increase in temperature. The phase currents with unbalanced voltages are greatly unbalanced, on the order of four to five times the voltage unbalance. If overload relay protection settings are raised because of unbalance, the generator may not be protected against overload and open phases.
- Heating of induction generators because of voltage unbalance is affected by phase rotation because it affects which phase has the highest line currents. This means that negative sequence current protection must be used to protect the induction generator from failure because of voltage unbalance. The negative sequence losses are proportional to the square of the negative sequence voltage. The generator may have to reduce output below nameplate rating to avoid overheating with voltage unbalance. An equation was developed to determine machine rating under unbalanced voltages if one knows the unbalanced voltage and the ratio of the positive-to-negative sequence impedances of the induction generator. A 5% voltage unbalance causes a 3.2%–10.7% power output derate, depending on the positive-to-negative sequence impedance ratio.
- Models were developed for:
    - Line impedance
    - Line voltage drop
    - Line loss (which was validated using unbalanced and balanced line configurations and unbalanced and balanced load conditions)
    - Transformers for three-phase and single-phase and different loading combinations
    - Secondary and service impedances
    - Shunt capacitors and step regulators
    - Synchronous, induction, and inverter generation.

The models were validated by measuring power quantities throughout the circuit on the peak day and comparing these data with simulation data. The percent variance between field-measured data and simulation data for phase currents at eight nodes throughout the circuit were within 6%. The highest phase voltage variance was only 1.5%.

- The voltage spread, measured as the difference between the highest three-phase voltage and the lowest single-phase voltage for the heavy-load condition, was 25.2 V with no regulation at the substation and on the distribution circuit. When all regulation was implemented, the voltage spread was reduced to only 10.4 V, and there were no voltage criteria violations. For the light-load condition, the voltage spread was 16.65 V for no regulation. With all regulation operating, the spread was only 2.91 V.
- The load imbalance at the substation was 4% for heavy load and 5.45% for light load. Adding step regulators always worsened the voltage unbalance because of the effect of the voltage-dependent current model.
- Three voltage control strategies were tested for the 400-kW induction generator at low and high substation primary voltage, for a total of six simulations. Three voltage control strategies were tested for the 400-kW inverter-based generation at low and high substation primary voltage, for a total of six simulations. Thirteen voltage control strategies were tested for high voltage, and 13 were tested for low voltage, for the synchronous generator at the beginning, mid-, and end locations of the circuit, for a total of 78 simulations. The maximum released capacity of 10.44% was achieved with the 1,000-kW synchronous generator with P = 100% and Q = 100%. The voltage improvement was 0.82%, and the loss reduction was 0.56% out of a 5.4% base.
- The optimum location for the DG with the highest released capacity of 10.44% is at the source of the circuit because it directly offsets the load current and load losses of the circuit. The optimum DG location for loss reduction is at the end of the circuit. Adding generation here reduces, on a prorata basis, the load and the length of the circuit. To improve voltage regulation, there is little difference between locating the DG at the midpoint or end of the circuit. However, there is a slightly better improvement at the midpoint for circuits on which the conductor size of the entire three-phase backbone is the same.
- The DG penetration study showed synchronous DG had a real power limit of 13,980 kW at the tag end of the circuit. The optimum location was at the midpoint, with the lowest single-phase voltage improvement of 1.7% and a real power loss savings of 2.04%. The base case real power losses were 5.4%. The DG penetration study found that the maximum real and reactive power output limit was 14,490 kW and 2,007 kVAr, which allows a larger DG to be installed than when only real power is injected. Again, the optimum location was at the midpoint of the circuit. However, in this case, the lowest single-phase voltage was improved 4.55% versus only 1.7% in the real power limit case. The real power loss savings were marginally better, with a 2.3% savings versus 2.04%.

Conclusions

- The voltage-dependent current model best represents how the real and reactive components of the load change with changes in voltage. This model, which had an error of only 2%, should always be used in lieu of the constant power model, which had an error of 12.5%.

- Heavy-load conditions produce the highest voltage unbalance, and adding a load tap changer and one step voltage regulator caused the maximum percent voltage unbalance to be 1.52%. The typical limit for voltage unbalance is 3%. It is recommended that a three-phase unbalanced power flow study be conducted on a circuit before a synchronous generator is installed because the unit may be installed at a location where the voltage unbalance causes the unit to trip. In this case, it will never operate at that location. Furthermore, the current imbalance cannot exceed 10%–20%, or the synchronous DG will trip. There were many locations on the distribution circuit at which the current imbalance exceeded 20%. Inverter-based generation was not sensitive to voltage or current unbalance and operated up to 100% current imbalance.
- The models developed for the line elements, distribution equipment, and generation and the simulations conducted during peak load conditions compared favorably with the actual phase currents, phase voltages, and power factors measured at eight locations throughout the circuit. However, it is essential to know the phasing of the loads on the circuit to obtain this high degree of accuracy. The variance between simulated and measured data was less than 6% for phase currents and did not exceed 1.5% for phase voltages. These low variances indicate the models are accurate enough to represent actual circuit operation under unbalanced load conditions. The only measured circuit data needed to perform accurate simulations are the phase voltages and currents at the source of the circuit and the regulator, capacitor, and DG locations.
- Unbalanced load can cause neutral relaying trip settings to be increased and preloading on fuses, which results in inselectivity with other protective devices.
- Unbalanced voltage can derate the output of synchronous and induction generators up to 10.7%.
- The optimum location of DG on a circuit for the highest released capacity of 10.44% is at the source of the circuit. The greatest loss reduction of 0.56% occurs when the DG is located at the tag end of the circuit. There is little difference between locating the DG at the midpoint or the tag end for the greatest improvement in voltage regulation.
- The maximum DG real and reactive output was 14,490 kW and 2,007 kVAr, and the optimum location was at the midpoint of the circuit. The real power loss savings were 2.3% versus the base case of 5.4%. The lowest single-phase voltage was improved 4.55%.

Recommendations

- Always model distribution circuit loads with a voltage-dependent current, and use a validated unbalanced three-phase power flow to determine the percent unbalanced load and voltage during the peak load and at the locations where DG is planned. Using a balanced three-phase power flow or simplified single-phase power flow will not indicate the unbalanced load and voltage at locations where DG is planned. A location may be selected where a synchronous or induction generator may never operate because of circuit unbalance conditions.

Successful modeling of a distribution circuit using an unbalanced three-phase power flow requires knowledge of which phases the loads are connected to. Otherwise, incorrect unbalanced load and voltage data will result. The use of three-phase metering is not warranted because the highest load imbalance occurs during light load and the highest unbalanced voltage occurs during heavy load. It is not practical to install metering at various locations throughout the circuit to capture light and heavy load unbalanced power quantities over a long period of time (such as a year) when simulations can produce similar information with nearly the same accuracy in considerably less time.

- The optimum voltage regulation method for the least voltage spread used the substation transformer load tap changer, step regulators, capacitors, and DG. The maximum released capacity is achieved when the DG is located at the beginning of the circuit, the maximum loss reduction is achieved at the end, and the best voltage regulation occurs at the middle. It is recommended that the DG be located at the midpoint of the circuit to produce the best overall improvements in voltage regulation, loss reduction, and released capacity.
- The circuit selected had voltage unbalance conditions that closely agreed with the average voltage unbalance measurements taken at 13 major utilities. Therefore, the results should be representative of the average distribution circuit.

  It was shown that single-phase DG connected to the appropriate phases can improve the phase unbalanced conditions. Simulation studies can be used to determine to which phases to connect single-phase DG.
- Voltage regulation and system protection issues are the most difficult for interconnecting DG with a distribution circuit. It is recommended that inverter-based generation be considered as the preferred DG type where the level of unbalanced voltage and current may prevent synchronous and induction generators from operating on the circuit.
- It is recommended that future research develop an optimal control algorithm to control the substation transformer load tap changer, the bidirectional step regulators, the switched capacitors, and the DG. This could be accomplished for less than $500,000 because the equipment is already installed on the Milford Circuit 8103.

Benefits to California

Test data indicate the models developed for this project accurately represent the operation of a distribution circuit. Applying these models results in DG siting that ensures the DG will perform its intended function and produce the highest released capacity savings, lowest energy losses, and improved voltage regulation.

Table of Contents

List of Figures

List of Tables

1 Introduction

An earlier study (Davis 2003) reported that the maximum-sized distributed generation (DG) that can be installed on a distribution circuit depends on:

- Circuit system voltage
- The location of DG on the circuit
- Circuit configuration and characteristics
- System protection issues
- Voltage regulation issues
- DG characteristics.

The study also found that larger DG units can be installed on higher-system-voltage circuits and at the substation with fewer effects on system protection and voltage regulation. If the DG actively regulates voltage, larger units can be interconnected because high-voltage (HV) conditions during light-load (LL) conditions can be curtailed if the DG absorbs volt-amperes reactive.

These findings were the results of tests that used (3Φ) balanced power flows on distribution circuits with balanced loads. However, most distribution circuits have unbalanced loading conditions, unbalanced line impedances, and unbalanced voltage conditions. Therefore, there is no assurance that these results represent what happens on the single-phase (SΦ) laterals of a three-phase circuit.

The single-phase portion of the circuit may serve more than 90% of the load. Just because the voltage limits are satisfied on the three-phase portion of the circuit does not mean there are no voltage limit violations on the single-phase loads. Installing DG on the circuit adds another level of complexity to the analysis of the distribution system, but it can also contribute added benefits of released capacity, lower energy losses, and improved voltage regulation.

The objectives of this project are to:

1. Select a distribution circuit and install DG to reduce an overload and improve voltage regulation
2. Develop models and run simulations to calculate voltage profiles on the distribution circuit with the load tap changer (LTC), step regulators, capacitors, and DG regulating the voltage
3. Install metering on the circuit and DG installations and compare actual measured data with simulations to verify the models
4. Determine the maximum-sized DG and the optimum DG operating conditions that will provide the greatest released capacity, lowest energy losses, and most improved voltage regulation.

2 Project Approach

The approach of the project is to:

1. Develop a load model of a distribution circuit to represent how circuit load changes with changes in voltage
2. Develop circuit line elements and circuit equipment models
3. Develop DG models for synchronous, induction, and inverter generation
4. Model an entire 13.2-kV distribution circuit with all three-phase and single-phase loads connected to the correct phases of the distribution circuit
5. Install a 1,000-kW synchronous generator on the circuit and install the appropriate metering equipment to measure the power quantities of the circuit, including single-phase loads
6. Validate the models by conducting a multitude of power flow simulations and comparing the simulations with circuit-measured data on the circuit peak day (with DG on and off)
7. Report the variance between simulated and measured power quantities
8. Determine the largest DG that can be installed on the circuit without violating voltage, thermal, and reverse power criteria
9. Determine the optimum DG operating conditions to give maximum released capacity, reduced energy losses, and improved voltage regulation.

3 Project Results: Traditional Voltage Regulation Methods

3.1 Introduction

A number of methods can improve voltage regulation. Some use voltage regulation equipment to raise or lower voltage at the substation or on the distribution circuit to reduce the voltage difference between LL and heavy-load conditions. Others reduce the impedance of the circuit to reduce the voltage difference or spread, and still others reduce the load current (i.e., improve the power factor) to reduce the voltage drop and, thus, the voltage spread.

Methods that can be applied at the substation include:

- Use DG voltage regulators (VRs).
- Apply capacitors at the distribution substation.
- Apply voltage-regulating equipment, such as LTC transformers and bus or circuit voltage-regulating equipment, at the substation.
- Balance the loads on the circuits.
- Transfer loads to other substations.
- Install new substations and circuits.
- Install substation transformers with reduced reactance.

Methods that can be used on the distribution circuit include:

- Increase the primary system voltage of the circuit.
- Increase the conductor size of the circuit or reduce conductor spacing and, consequently, reduce reactance.
- Change circuit sections from single-phase to three-phase.
- Transfer loads to other circuits.
- Apply voltage-regulating equipment on the circuit.
- Install DG on the circuit.
- Apply shunt (or series) capacitors on the circuit.
- Balance loads.
- Increase the distribution transformer size.
- Increase the conductor size of secondaries and services.

3.2 Distributed Generation Installed at Substation

The generator bus voltage can be regulated to maintain a fixed voltage for changes in load and reactive requirements. The generator field current can be varied to match the changes in load current. The voltage can be increased or decreased as the load increases or decreases.

3.3 Substation Voltage-Regulating Equipment

One of the most common types of substation voltage-regulating equipment is the load tap changing (LTC) transformer. Step- or induction-type VRs may be installed between the secondary of the transformer and the secondary bus or on the secondary bus. Also, step- or induction-type regulators may be installed on individual circuits. Because circuit voltage is a function of voltage spread at the secondary of the substation bus, voltage-regulating equipment allows for a greater voltage drop in the circuit.

3.4 Balancing Loads

If a circuit has poor voltage regulation, it could be due to a significant difference in phase loading. A 20% or more load imbalance on the primary of a circuit, especially during HL conditions, is not uncommon. In addition, a high load imbalance can cause substation transformers and VRs to overload, based on the highest phase load. Balanced loading should be achieved throughout the circuit, not just at the substation.

3.5 Increased Primary System Voltage

Increasing the system voltage reduces the load by the inverse ratio of the voltage change, but the voltage regulation changes as the square of the voltage change. Changing from a three-wire ungrounded delta to a four-wire grounded wye increases the voltage by the √3 but reduces the voltage drop to 1/3 of the drop in the three-wire delta. However, it is common to increase the allowable load when this conversion is made to a higher system voltage; therefore, the voltage drop improvement is less than 2/3. This method is more expensive than using supplemental voltage regulation because it involves re-insulating the line and changing out electric transformation (i.e., transformers) and other equipment.

3.6 Increased Conductor Size or Reduced Conductor Spacing

Increasing conductor size is another expensive method to achieve improved voltage regulation. Increasing the size of the conductor reduces the resistance and, thus, the voltage drop and real losses. However, it may necessitate a rebuilding of the line because of the larger and heavier conductor. An alternative is to reduce the spacing between the phase conductors, which reduces the reactance and lowers the voltage drop.

3.7 Conversion of Single-Phase Sections to Three-Phase

Most general-purpose circuits are single-phase. For single-phase circuits, voltage drop occurs in both the phase conductor and the neutral for the wye systems and in both the phase conductors for the delta systems. Adding two conductors to a single-phase wye system, and assuming the existing load is evenly distributed among the three phases, results in 1/6 of the voltage drop that occurs on the single-phase wye lateral. This is demonstrated below.

$$\Delta V_{s\Phi} = 2\ I_{s\Phi}\ Z \text{ and} \qquad \text{Equation 3.1}$$

$$\%\ \Delta Vs\Phi = 2\ I_{s\Phi}\ Z/VLN \times 100 \qquad \text{Equation 3.2}$$

where

$\Delta V_{s\Phi}$ = Voltage drop per unit length
$I_{s\Phi}$ = Line current
Z = Impedance per unit length
V_{LN} = Line-to-neutral voltage.

For the three-phase case,

$\Delta V_{3\Phi} = I_{3\Phi} Z$ Equation 3.3

$\%\Delta V_{3\Phi} = (I_{3\Phi} Z)/VLN \times 100$ Equation 3.4

where

$I_{3\Phi} = I_{S\Phi}/3$. Equation 3.5

Using equations 3.2, 3.4, and 3.5, the ratio of percent voltage drops is thus:

$$\begin{aligned} \%\,\Delta V_{S\Phi} / \%\,\Delta V_{3\Phi} &= [(2\ I_{S\Phi}\ Z)/VLN]/[(I_{3\Phi}\ Z)/VLN] \\ &= (2\ I_{S\Phi})/I_{3\Phi} \\ &= [(2)\ (3)\ (I_{3\Phi})]/I_{3\Phi} = 6. \end{aligned}$$ Equation 3.6

Therefore, the voltage drop is six times less for the three-phase circuit than for the single-phase circuit for the same load. Of course, undoubtedly, the load will increase over time after the single-phase lateral is converted to three-phase. However, this does illustrate the concerns when single-phase DGs and three-phase DGs are added to the circuit.

If only one phase conductor, rather than two, is added to a single-phase wye system, the problem becomes more complicated because the voltage drop depends on the two phases selected, the R/X ratio of the conductor, and the load power factor (PF).

To describe the differences between the single-phase case and the two two-phase cases, circuit diagrams and phasor diagrams are used. Figure 1 and Figure 2 show the single-phase case, in which I_A is the phase current that is equal to the neutral current I_N.

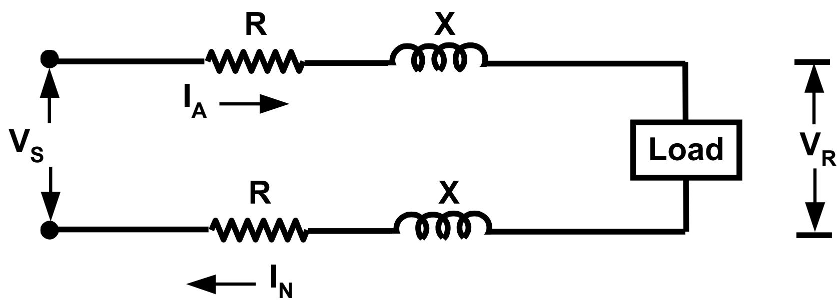


Figure 1. Single-phase equivalent circuit

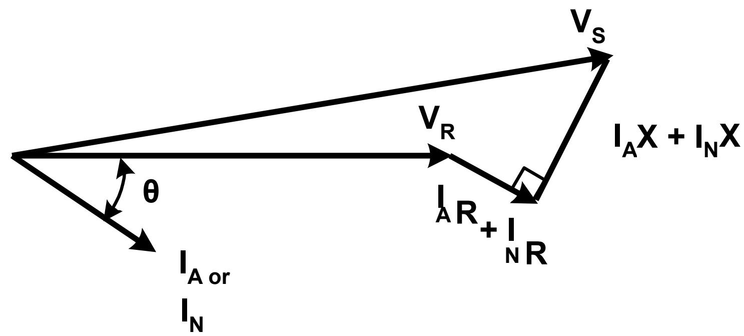


Figure 2. Single-phase phasor diagram

The approximate voltage drop consists of four components:

$$\Delta V = |I_A|R \cos\theta + |I_N|R \cos\theta + |I_A|X \sin\theta + |I_N|X \sin\theta. \qquad \text{Equation 3.7}$$

In each of the two-phase cases, the single-phase load is divided equally among the two phases; therefore, I_A of the single-phase case is twice the magnitude of I_A in the two-phase cases.

In Figure 3 and Figure 4, it should be noted that the sending-end voltage V_{SA} for Phase A with loads connected to phases A and C to neutral, as in Figure 4, is less than the sending-end voltage VSA for Phase A with loads connected to phases A and B to neutral, as shown in Figure 3. The primary reason is because the I_NX term is in phase with V_{RA} in Figure 3, whereas it is rotated counterclockwise in Figure 4. Also, the load power factors and the R/X ratios must be taken into account when calculating the voltage drop.

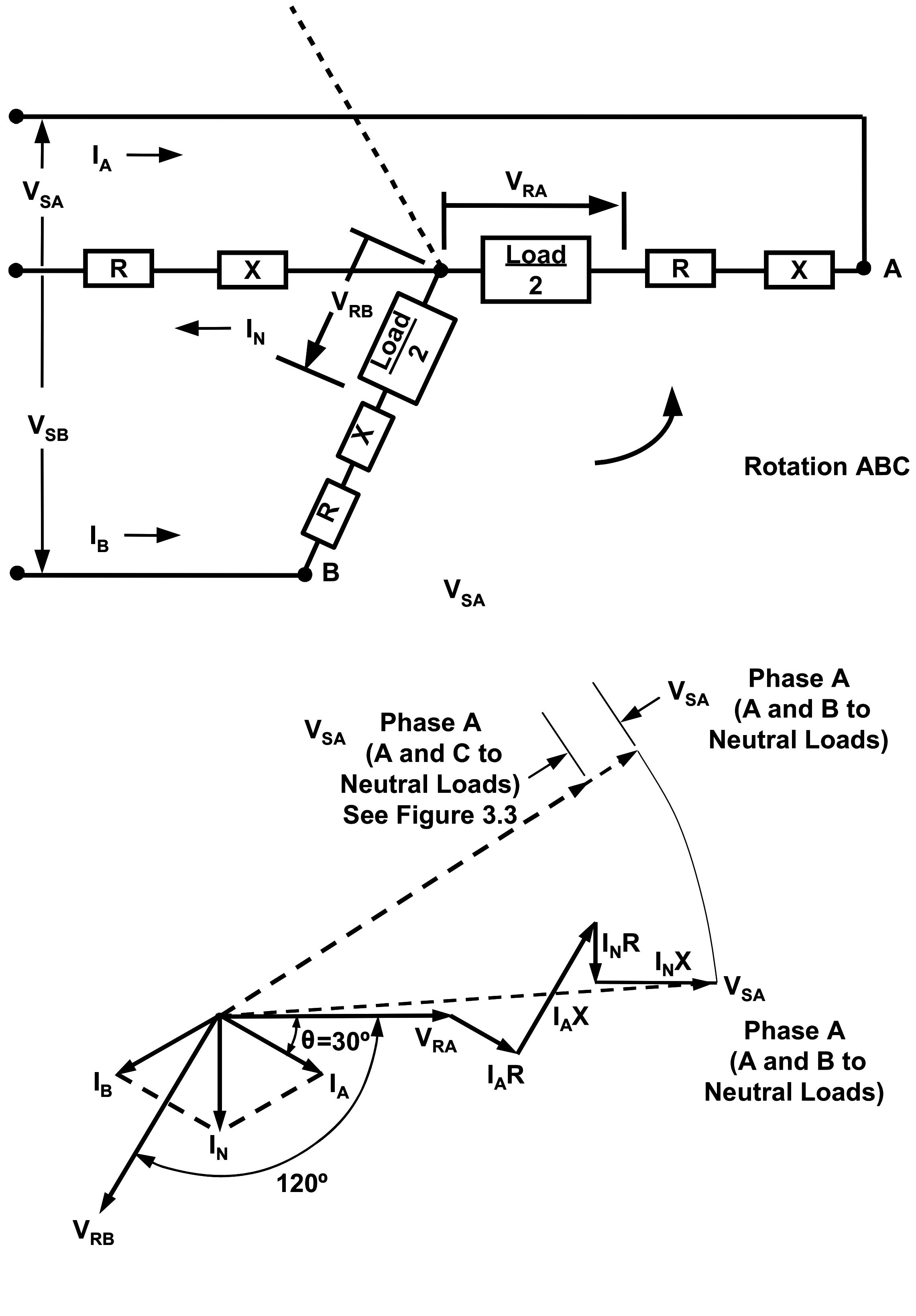


Figure 3. Two-phase lateral – voltage drop for load connected from A and B to neutral

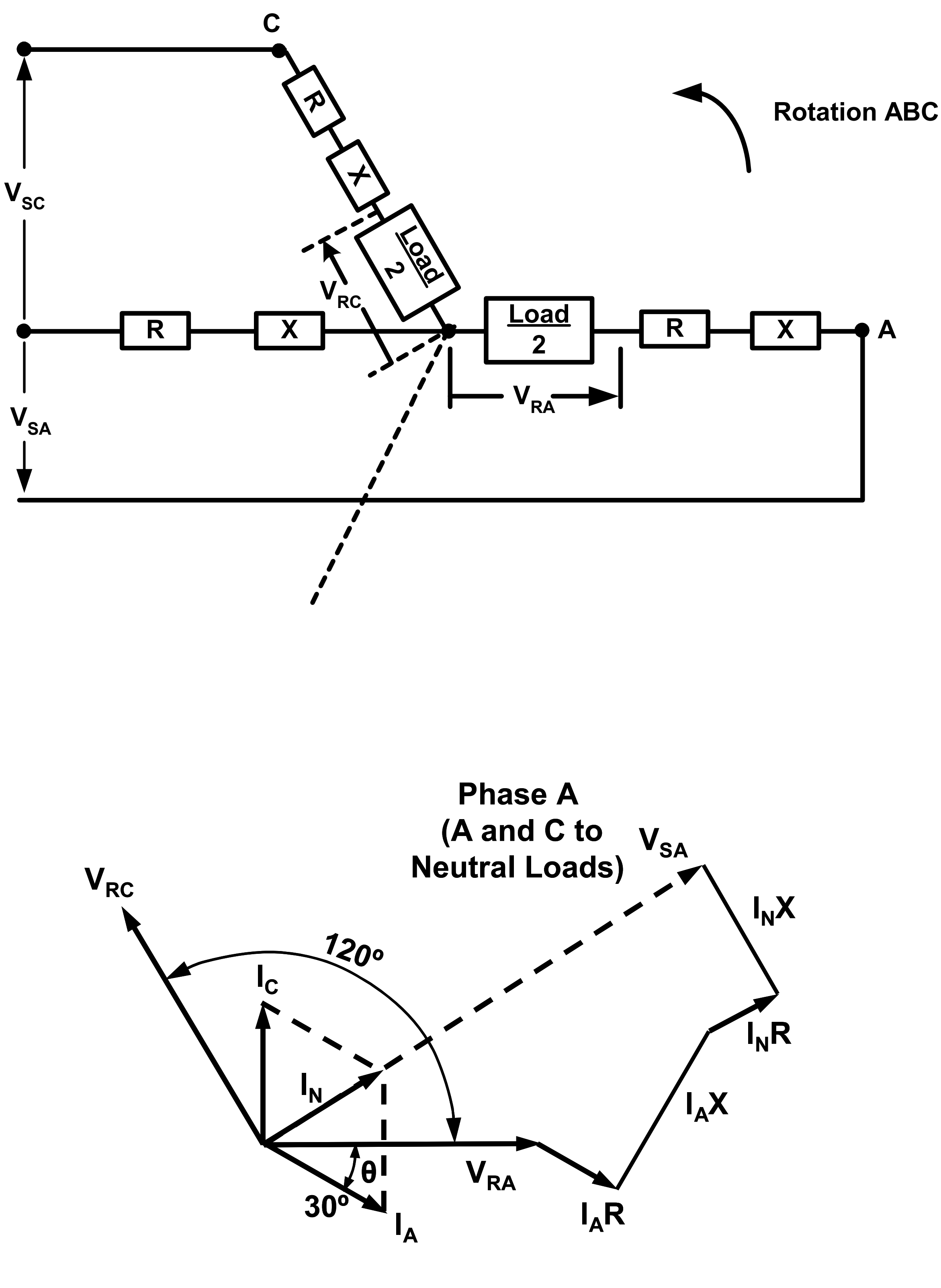


Figure 4. Two-phase lateral – voltage drop for load connected from A and C to neutral

3.8 Voltage-Regulating Equipment

VRs may be installed at the substation secondary voltage bus, at the circuit position of the substation, or out on the circuit. Their primary purpose is to reduce voltage spread so voltage is maintained within American National Standards Institute (ANSI) C84.1 Range A for normal conditions and Range B for infrequent operating conditions. Regulators may be used to “boost” the voltage for heavily loaded circuits or “buck” the voltage for lightly loaded circuits or circuits that have fixed shunt capacitors. For this reason, it may be necessary to use switched shunt capacitors to prevent (LV, switched on) during heavily loaded conditions and HV (switched off) during lightly loaded conditions.

VRs may be applied in series, as shown in Figure 5. Where two or more are needed, fixed boost regulators may solve the LV problem if HV is not experienced during LL conditions. Fixed boost can be achieved by adding taps on the distribution transformers. In the upper portion of Figure 5, the voltage profile is given with the LTC VR installed at the substation. The voltage profile drops below the minimum voltage at the second and third loads. When the first (1) bus VR is added, the voltage at load (2) is within limits, but the voltage at load (3) is still below the minimum level. Adding the second (2) line regulator puts the voltage spread within limits for all three loads.

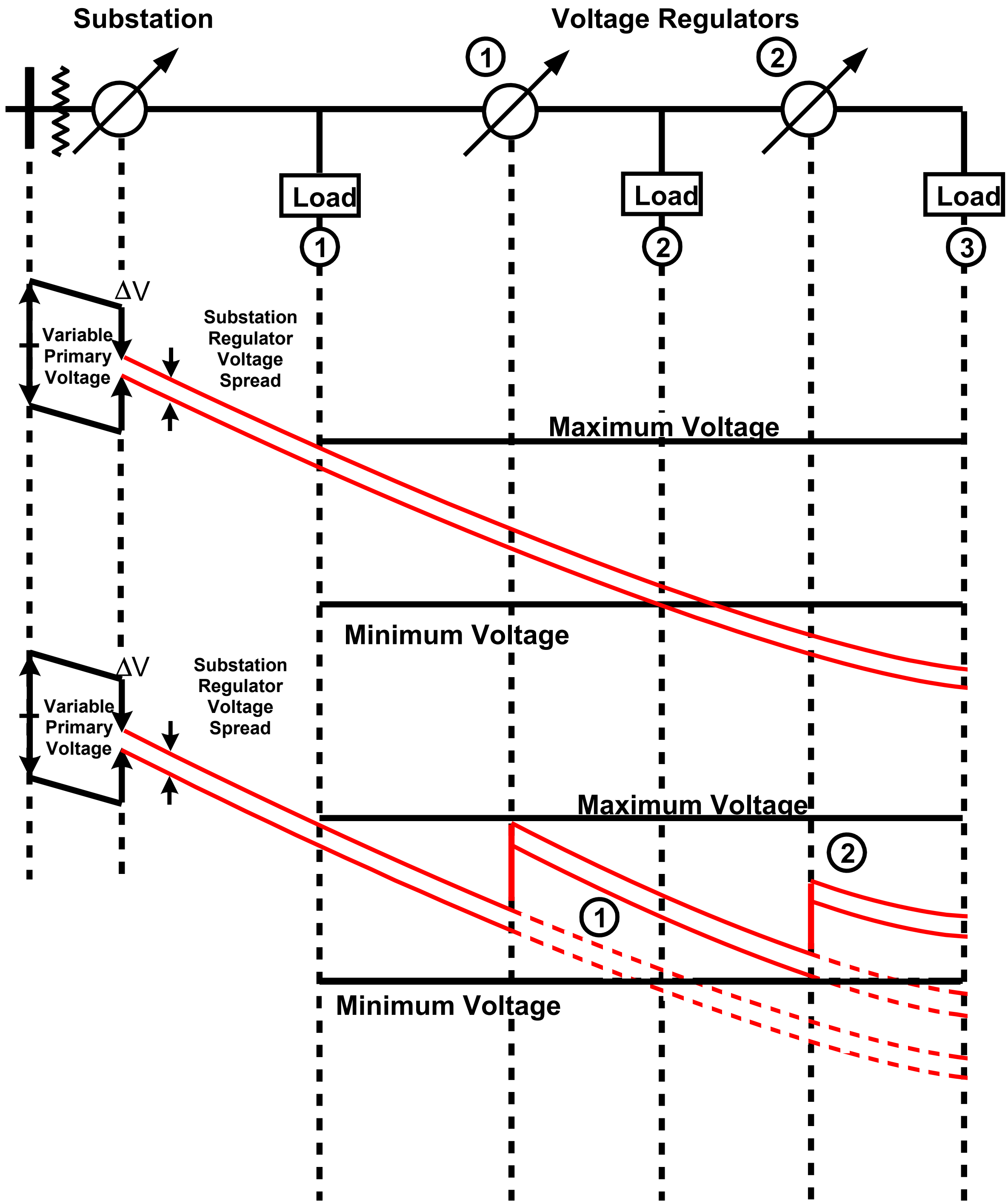


Figure 5. VRs in series

3.9 Shunt Capacitors

Installing shunt capacitors causes a voltage rise or a reduced voltage drop. The capacitor current is leading and, when multiplied by the series circuit (inductive) reactance, causes a voltage rise. This rise is not dependent on load current and is highest at the capacitor location. The percentage of voltage rise is calculated as

$$\% \Delta V \text{ rise} = [(3\Phi kVAr)\ (l)\ (X)] / [kV^2\ (10)] \qquad \text{Equation 3.8}$$

where

> 3Φ kVAr = The three-phase capacitor kVAr or kVA because, for the capacitor, kVAr = kVA
> X = Inductive line reactance in Ω per unit length
> kV = Line-to-line voltage
> l = Distance in unit length from the substation source to the capacitor.

When the capacitor installed is single-phase, SΦ kVAr is used in Equation 3.8. However, the X is multiplied by two because there are two conductors, and kV is the line-to-line voltage between these two conductors. As an example, if a 600-kVAr, three-phase capacitor is installed on a 13.2-kV wye system at 3 miles and the line reactance of a 636-k cmil, all-aluminum conductor is 0.536 Ω/mile/conductor, then

$$\% \Delta V \text{ rise} = [(600)\ (3)\ (0.536)]/[(13.2)^2\ (10)] = 0.554\%. \qquad \text{Equation 3.9}$$

For single-phase,

$$\% \Delta V \text{ rise} = [(200)\ (3)\ (0.536)\ (2)]/[(7.62)^2\ (10)] = 1.108\%, \qquad \text{Equation 3.10}$$

or twice the percent voltage rise. As noted earlier, the voltage rise will be the same for LL and HL conditions. Therefore, it may be necessary to install capacitor switches. The amount of capacitors needed to correct an LV problem is dependent on the conductor size, load power factor, and how the load is distributed on the circuit.

3.10 Load Tap-Changing Transformers

LTC transformers are often referred to as tap-changing under load. Load tap changers are applied to power transformers at the substation. They are used to control the voltage on the LV or secondary side to a fixed value with a variable primary voltage input, as shown in Figure 5. Also, LTCs may be used to control reactive power flow by shifting the phase angle of the transformer secondary voltages. The regulation range is typically 8, 16, and 32 steps with ±10% of rated voltage. The 32-step LTC is the most common for LTC transformers in substations. The 32 steps are divided into 16 steps raise and 16 steps lower, or a 5/8% change per step based on ±10% voltage range. The change in steps is made without interrupting the circuit by using a mid-tapped autotransformer, called a preventive autotransformer. The step-type VR theory of operation is similar to the LTC transformer.

3.11 Voltage Regulator Theory of Operation

In general, the VR is a transformer. If two windings are wound on a common magnetic core and the numbers of turns is different, then the voltages across these windings will be different. The alternating voltage applied to the first coil will induce a voltage in the second coil, and the magnitude of voltage induced will be dependent on the turn ratio between these two windings. In the case of a regulator, the first coil is referred to as the primary, or exciting, winding and the second as the regulating, or series, winding.

The step regulator is an autotransformer, the windings of which are connected in series and wound on the same magnetic core. There are two types of autotransformers: step-up and step-down. Figure 6 shows a step-up transformer with a turn ratio of 10. For example, if $N_1 = 100$ and $N_2 = 10$, then $a = N_1/N_2 = 10$. If the series winding is connected in series with the exciting or shunt winding that has the polarity, as shown in Figure 6, then 120 V applied to the exciting winding will result in 12 V on the series winding, which, when added to the primary voltage, results in a 132-V output. When the polarity of the series winding is reversed, as shown in Figure 7, then the 12 V on the series winding is subtracted from the 120 V primary voltage, and the output is 108 V. This is called a step-down transformer. To obtain a smaller change in voltage, the series winding is divided into eight equal parts, called taps, as shown in Figure 8.

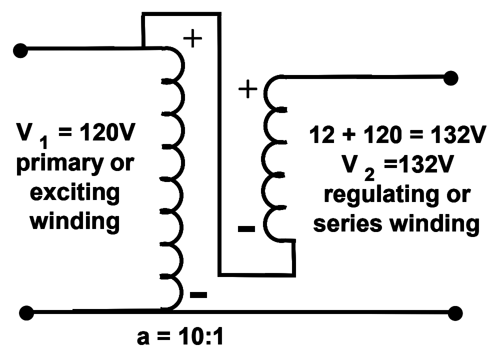


Figure 6. Step-up transformer

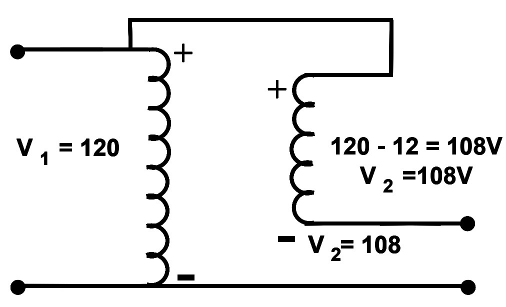


Figure 7. Step-down transformer

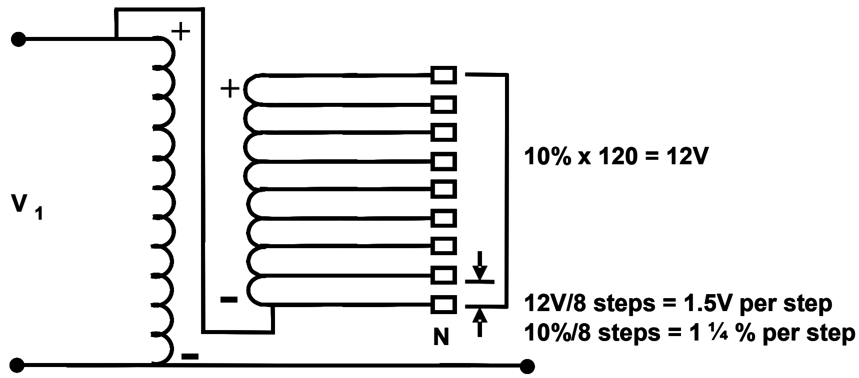
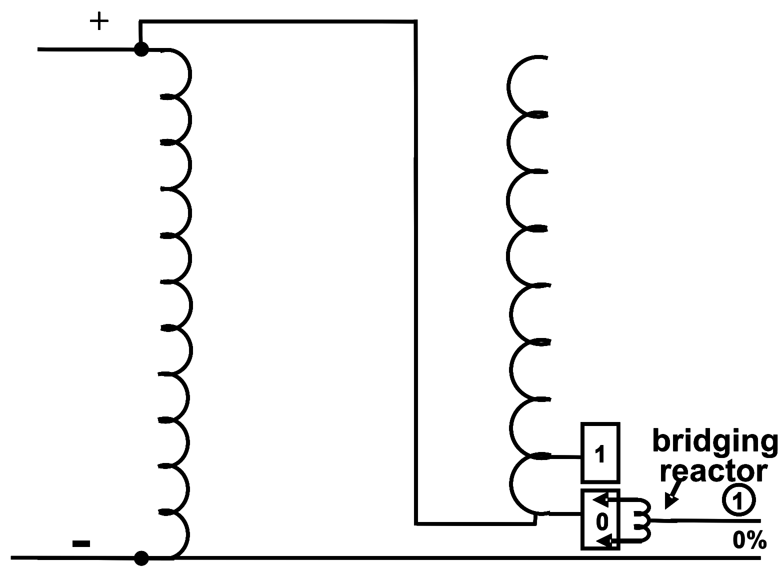
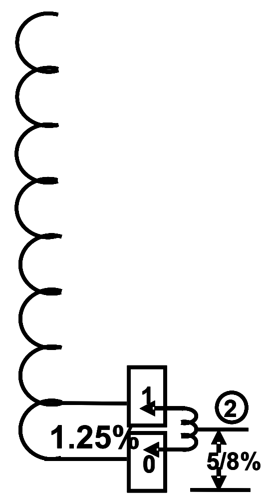


Figure 8. Step regulator

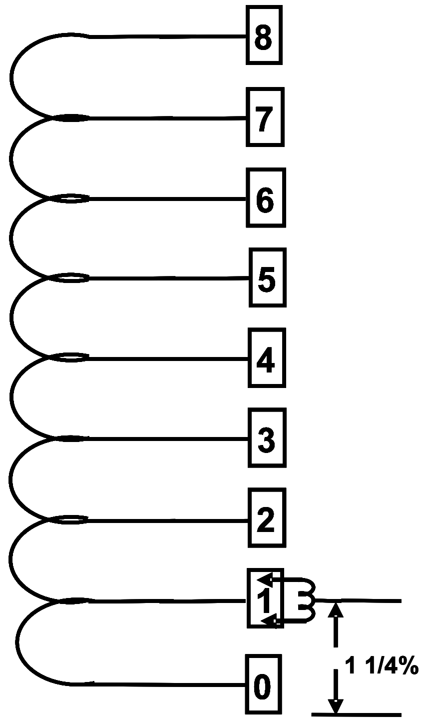
The output voltage can be varied from 120 V if tapped at the neutral position, N, up to 132 V, with steps of 12 V divided by 8 or 1.5 V per step, or 1 1/4% changes in voltage per tap setting. The problem with this arrangement is the interruption of the circuit each time the tap changes. To avoid this, the moving tap can be broken into two fingers such that, as the moving tap changes from one tap position to the next, one finger is always in contact with a tap. This is shown in Figure 9. To prevent shorting out the turns of the series winding, as shown in Figure 9b, when one finger is on one tap and the other finger is on the next tap, a preventive autotransformer is midtapped and connected to each finger. The center tap of this autotransformer is connected to the load bushing (L). In Figure 9a, when both fingers are on the neutral tap "0," they are at the same voltage, and the center tap of the preventive auto is at the same voltage. When 120 V is applied to the primary, the voltage from the preventive auto, sometimes referred to as a bridging reactor, is at 120 V. When the moving fingers move toward Tap 1, the top finger is on Tap 1, while the bottom finger is on Tap 0. As shown in Figure 9b, there is a 1 1/4% voltage difference between Tap 0 and Tap 1 and the two fingers. But when the bridging reactor is connected between these two fingers and its center tap is connected to the load, the load will see one half of the 1 1/4%, or 5/8%, as shown in (2) of Figure 9b. This is called the bridging position 5/8%. When the top finger moves farther up and is resting on Tap 1, and the bottom finger is resting on Tap 1, then the center tap is at the same voltage as the two fingers and Tap 1. Now the voltage at the load is up 1 1/4% voltage (see Figure 9c). For higher-voltage outputs, this process repeats where the fingers are in non-bridging and bridging positions until the top tap is reached and a full 10% voltage increase is attained.



a. Non-bridging position 0%



b. Bridging position 5/8%



c. Non-bridging position 1 1/4%

Figure 9. Step VR sequence of operation

For decreases in voltage, the process is reversed until both fingers are resting on Tap 0. This process has addressed only increases in voltage above the primary voltage. To lower the voltage below the primary voltage, it is necessary to reverse the polarity, which is similar to the step-down transformer of Figure 7. This is accomplished by adding the reversing switch of Figure 10, which changes the polarity of the series winding. Now, the regulator can raise or lower the voltage by ±10%.

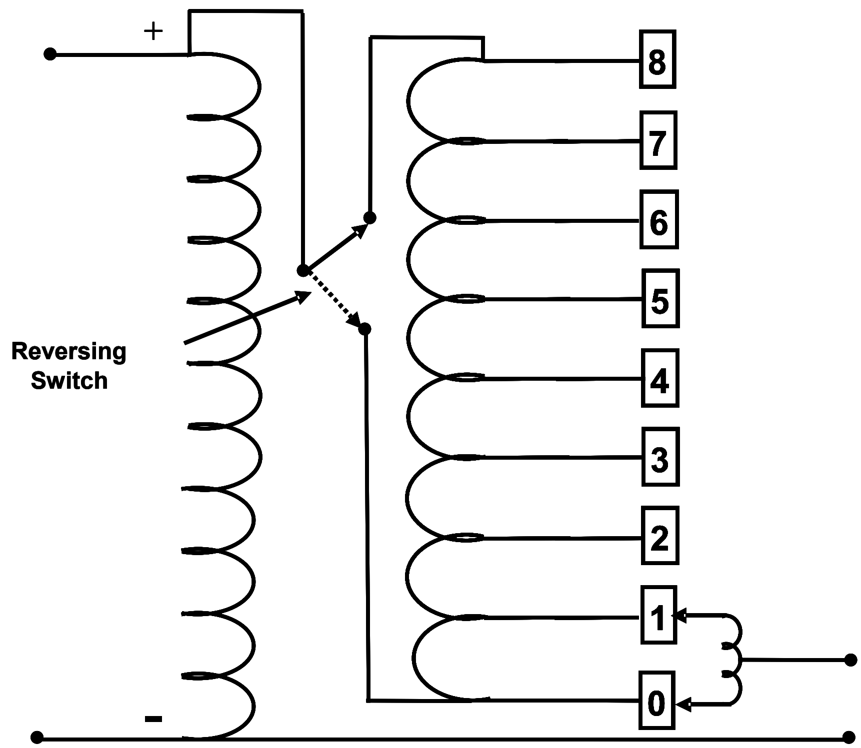


Figure 10. Step VR with reversing switch

3.12 Bridging Reactor or Preventive Autotransformer

Before, the bridging reactor was introduced to achieve one-half of a voltage step between taps and eliminate shorted turns when the moving fingers were on different taps. The current in these fingers is not the same when moving from non-bridging and bridging positions.

Four conditions are examined: (1) non-bridging no-load, (2) bridging no-load, (3) non-bridging load, and (4) bridging load. Figure 11 illustrates the non-bridging no-load condition. When both fingers are on the same tap (1) and no load, there is no voltage difference across the bridging reactor and the load current $I_L = 0$. When the top finger moves to Tap 2, and the bottom finger remains on Tap 1 (bridging position), a voltage appears across the reactor. A circulating current (IC) flows from the higher voltage of Tap 2 to the lower voltage of Tap 1. See Figure 12. The current through the top finger is the same as the bottom-finger current because there is no load. With no load, there is a current in the reactor for every bridging position. This explains why current is flowing even though there is no load current on the circuit.

When load (I_L) is applied and the top and bottom fingers are on the same tap (Figure 13), the current is equal in the two fingers because since the ampere turns in the reactor are balanced and $I_a = 1/2\ I_L$ and $I_b = 1/2\ I_L$. When the fingers are on different taps, such as the bridging position of Figure 14, a circulatory current flows. Now, the top-finger current $I_a = 1/2\ I_L + I_C$, and the bottom-finger current $I_b = 1/2\ I_L - I_C$. The circulatory current is approaching 50% of the value of the load current and flows from the higher voltage on Tap 2 to the lower voltage on Tap 1.

The current in the top finger is higher than the current in the bottom finger because of this circulating current. This difference can be reduced with equalizer windings.

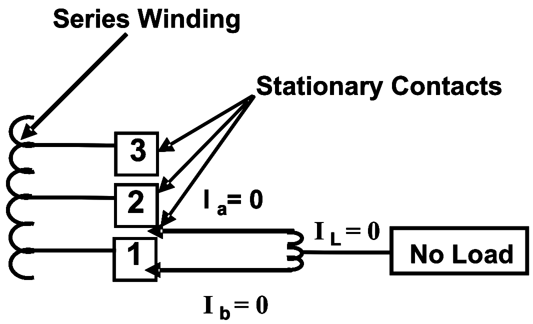


Figure 11. Non-bridging no load

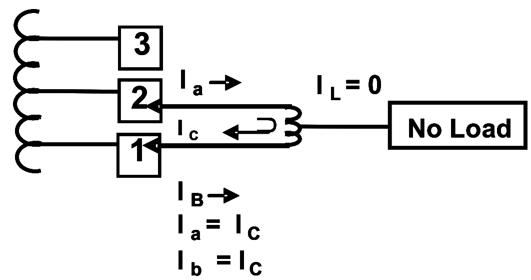


Figure 12. Bridging position no load

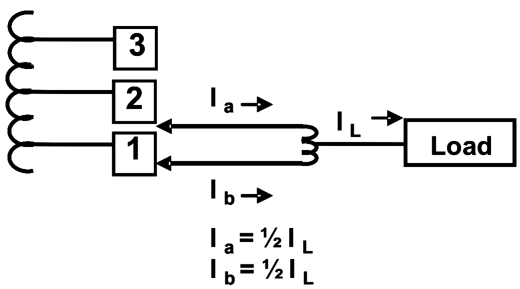


Figure 13. Non-bridging load

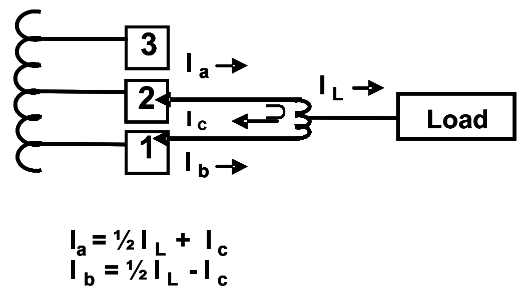


Figure 14. Bridging position load

3.13 Equalizer Windings

Equalizer windings are wound on the same central core as the primary and series windings and equal about 1/2 the number of turns between each tap on the series winding. These windings reduce the voltage during switching and thus prolong the life of the tap changer and equalize the current on the fingers because the net circulating current reverses for odd- and even-numbered taps. Figure 15 shows the application of the equalizer windings.

Four cases are studied: one set without equalizer windings and one set with equalizer windings. Case A, Figure 16, shows what happens when the lower finger moves from Tap 2 to Tap 1. When the lower finger, b, moves off Tap 2, the voltage between b and 2 is V, which causes an arc on b and contact erosion. But when the lower finger, b, moves from Tap 2 of Case B to Tap 3 (Figure 17), there is no arc because there is no voltage difference.

When equalizer windings are present in Case C (Figure 18) and finger b moves to Tap 1, the voltage difference between b and 2 is 1/2 V. Therefore, the contact erosion is reduced. Case D (Figure 19) shows the non-bridging case, in which finger b moves from 2 to 3. Here, when b moves off of 2, a voltage difference of 1/2 V appears between 2 and b, so that the arcing is the same as in Case C. The contact wear is thus equalized between bridging and non-bridging positions.

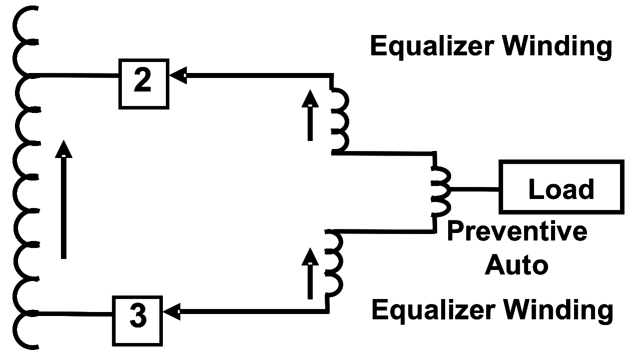


Figure 15. Application of equalizer windings

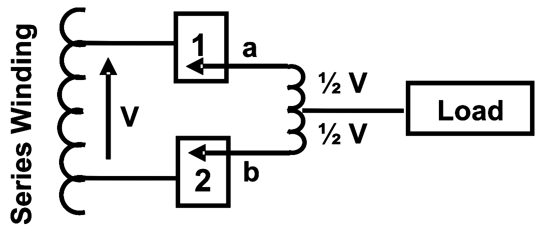


Figure 16. Case A – without equalizer windings

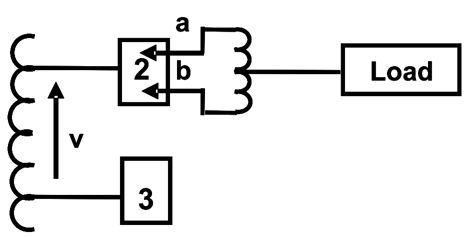


Figure 17. Case B – without equalizer windings

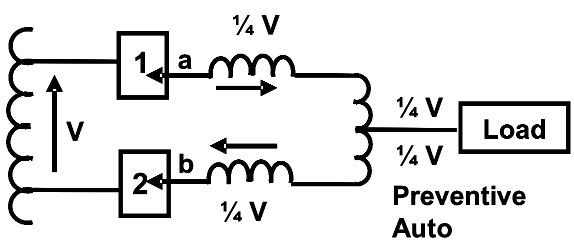


Figure 18. Case C – with equalizer windings bridging position

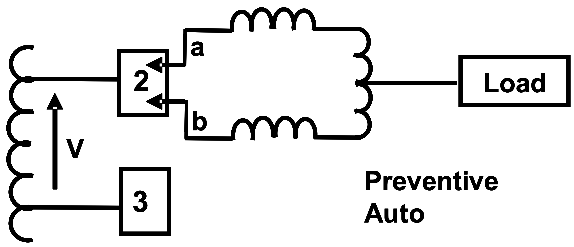
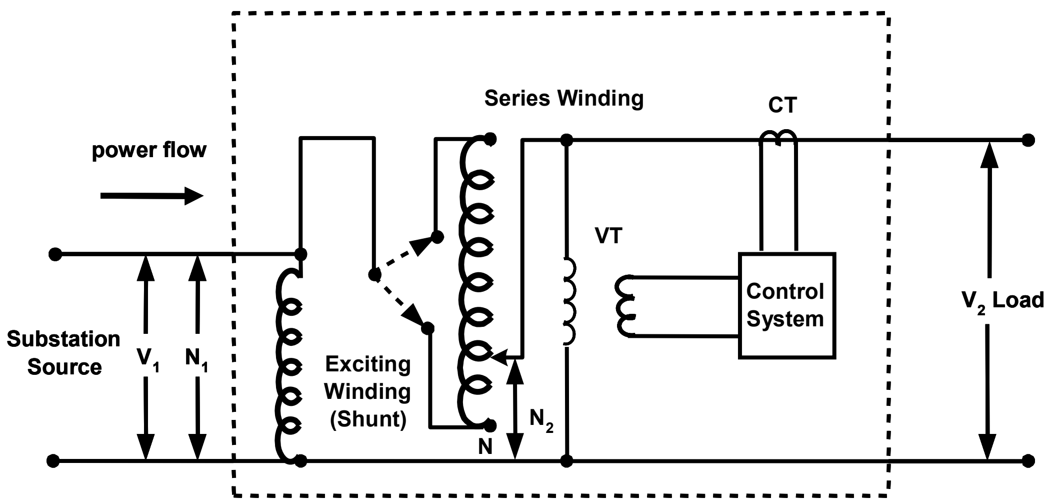


Figure 19. Case D – with equalizer windings non-bridging position

3.14 Types of Step Regulators

There are three types of VRs: Type A, Type B, and bi-directional (or cogeneration). For Type A, the primary is connected to the exciting winding or the shunt winding. See Figure 20. The series winding is connected to the shunt winding via the reversing switch, as shown in Figure 10. Therefore, the series winding is connected to the load side. Type B, shown in Figure 21, is more common. Its series winding is connected to the source side.



$$\frac{V_1}{N_1} = \frac{V_2}{N_2}$$

Figure 20. ANSI Type A – series winding located on load side

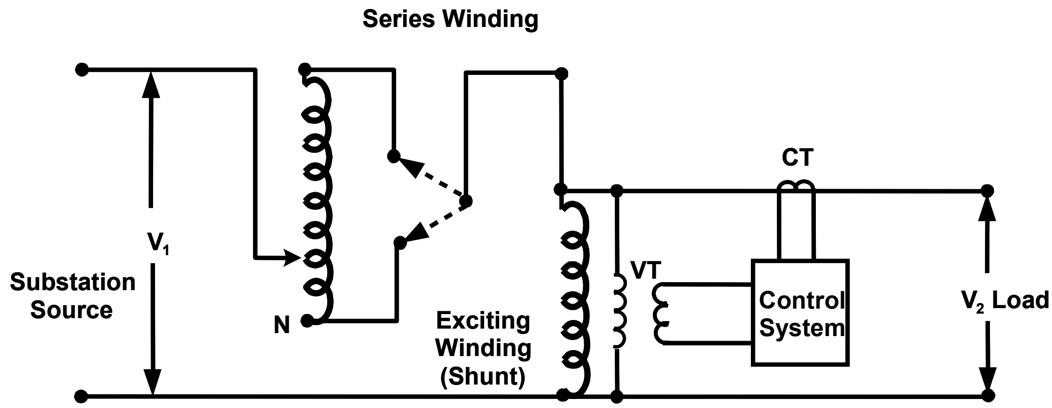


Figure 21. ANSI Type B – series winding located on source side

When applying Type A and B regulators, there is only one source of power (e.g., the substation source). However, there are applications in which power may flow from either direction through the regulator, as shown in Figure 22. In this figure, the regulator is located between two power sources: the substation and a distributed resource (DR). In Figure 23, assume the power flows from left to right. The voltage transformer (VT) VT_2 is connected across the load side. When the VT_2 senses LV and the regulator voltage is adjusted up, the voltage at the output is increased. Now, suppose the power flows in the reverse direction because of the operation of the DR in Figure 22. Because VT_2 is now connected across the source side, it will measure the V_2 voltage. When the V_2 voltage is low, the control system will cause the voltage to rise and thus insert more series winding, N_2. The voltage turns ratio equation,

$$\frac{V_1}{N_1} = \frac{V_2}{N_2}, \qquad \text{Equation 3.11}$$

shows that increasing N_2 will cause V_1/N_1 to change. Because N_1 is the turns on the exciting winding, which is a constant, V_1 voltage will drop even further, thus lowering voltage V_1 rather than raising the voltage. This will cause the regulator to go to the maximum raised position. If the voltage V_2 changes, then the regulator will chase up and down continuously between all raise and all lower.

Changes must correct this problem. First, the regulator must recognize the power flow has reversed. This can be accomplished using the current transformer (CT) input to the control system. Second, the VT must sense the voltage on the V_1 side or the load side for the reverse-power use. Third, there must be a change in the line drop compensator settings because the regulation point has now changed to a different location with different circuit R and X values and voltage settings. Another solution is shown in Figure 24, in which the change in power flow is sensed, but a differential transformer reads the difference between V_1 and V_2. Here, the control system will compensate for the voltage difference between V_1 and V_2 and correct for the LV or HV problem, which is independent of the power flow. This is called a bidirectional VR.

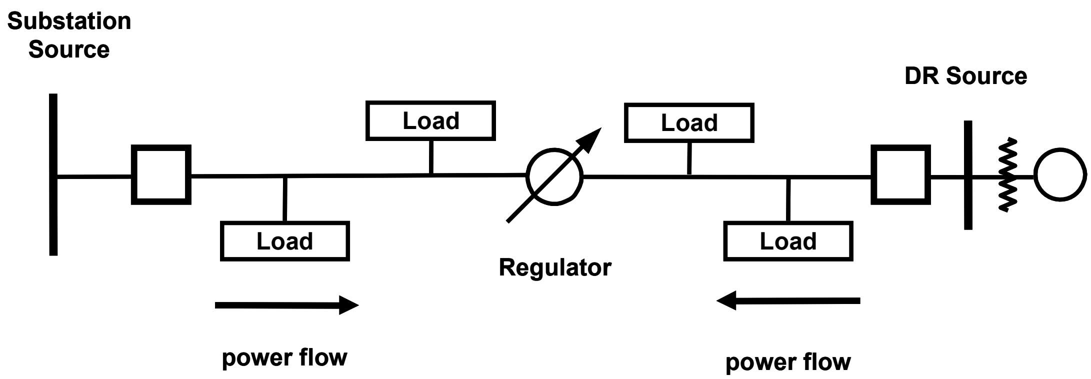


Figure 22. DR sources create bidirectional flows through a step VR

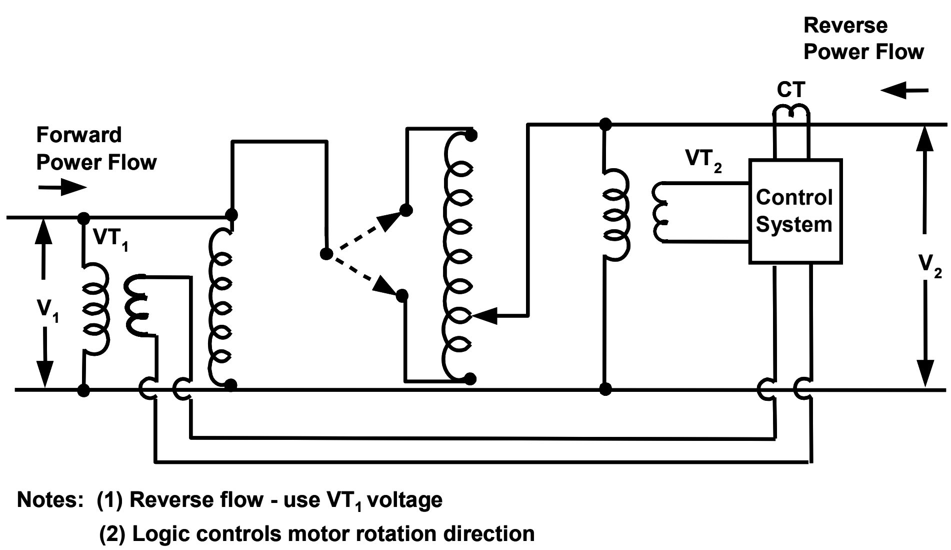


Figure 23. Reverse power flow – additional VT required VT_1

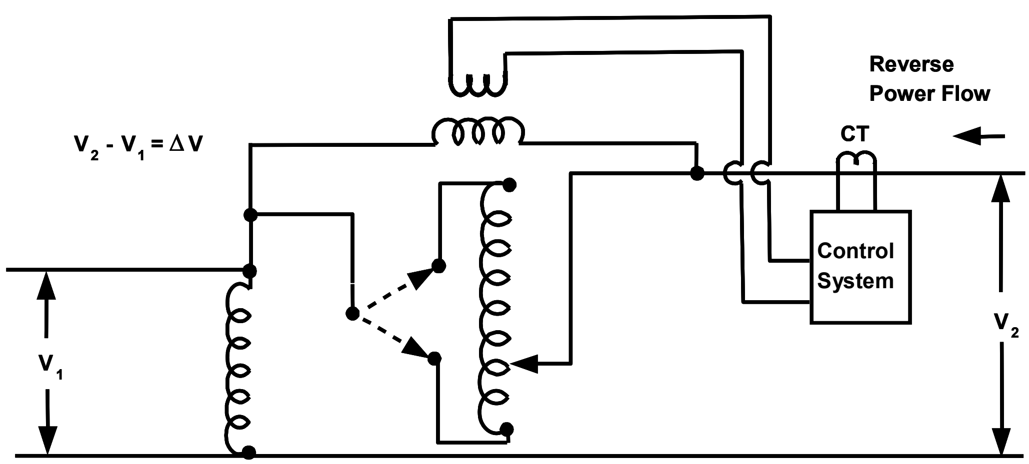


Figure 24. Reverse power flow – differential transformer

3.15 Bidirectional Voltage Regulator

The bidirectional VR may use either of the methods outlined in Figure 23 or Figure 24, but a VT must be added for the method shown in Figure 23. Therefore, it is common to have the logic, based on the direction of current flow, calculate the voltage on either the source or load side based on one VT voltage measurement. Also, the logic in the control system knows the position of the reversing switch and the tap position number by counting the number of tap positions from neutral, either raise or lower. This results in a lower-cost regulator for DR applications. In addition, the R_L and X_L settings are usually different when the current reverses direction; therefore, this regulator must have a set of forward settings and a set of reverse settings.

Figure 25 shows four application cases—a, b, c, and d—for the unidirectional step VR. The first case (a) is a simple application of an LTC transformer (1) at the substation. The voltage drop in the feeder to the feed point is compensated using the R_1 and X_1 values of the circuit to provide a fixed voltage VR_1 at the regulation point as the load current and load power factor change and as the primary voltage on the LTC transformer changes. The second case (b) shows the LTC transformer regulation device (1) regulating to VR_1 and a DR (2) regulating voltage at VR_2. The third case (c) uses an LTC transformer (1) regulating to VR_1 and a unidirectional step regulator (2) regulating to voltage VR_2. It is not necessary to know the R_2 and X_2 values for this case, but they must be known for cases e, f, and g, which follow in Figure 26. For consistency, these values are shown in all the latter application cases. The fourth case (d) has three methods of voltage regulation: the LTC (1), the unidirectional regulator (2), and a capacitor (3). All of these cases are used in the modeling and circuit simulation studies to determine resultant voltage profiles.

Figure 26 consists of three additional cases—e, f, and g—in which bidirectional VRs and DR are applied to regulate the voltage on the circuit. The fifth case, e, shows LTC regulation (1), bidirectional voltage regulation (2), DR regulation (3), and a reactive compensation capacitor (4). If the DR is an induction generator, a capacitor is often used to provide the voltage if it becomes isolated from the circuit because an induction generator does not create voltage. But, the kilowatt injection at 3 will improve the voltage because less load current flows through the circuit elements. The sixth case, f, adds an additional bidirectional regulator (3). The final case, g, involves the addition of a second DR, which does not regulate voltage. However, the DR at 4 does provide Var production and Var absorption to regulate voltage. It should be remembered the loads in Figure 25 and Figure 26 are shown as lumped loads. In actual applications, the loads are distributed throughout the circuit. All these cases will be analyzed in detail to show the effects of DR generation, DR voltage regulation on a normal voltage- regulated circuit that contains an LTC, step regulators, and capacitors.

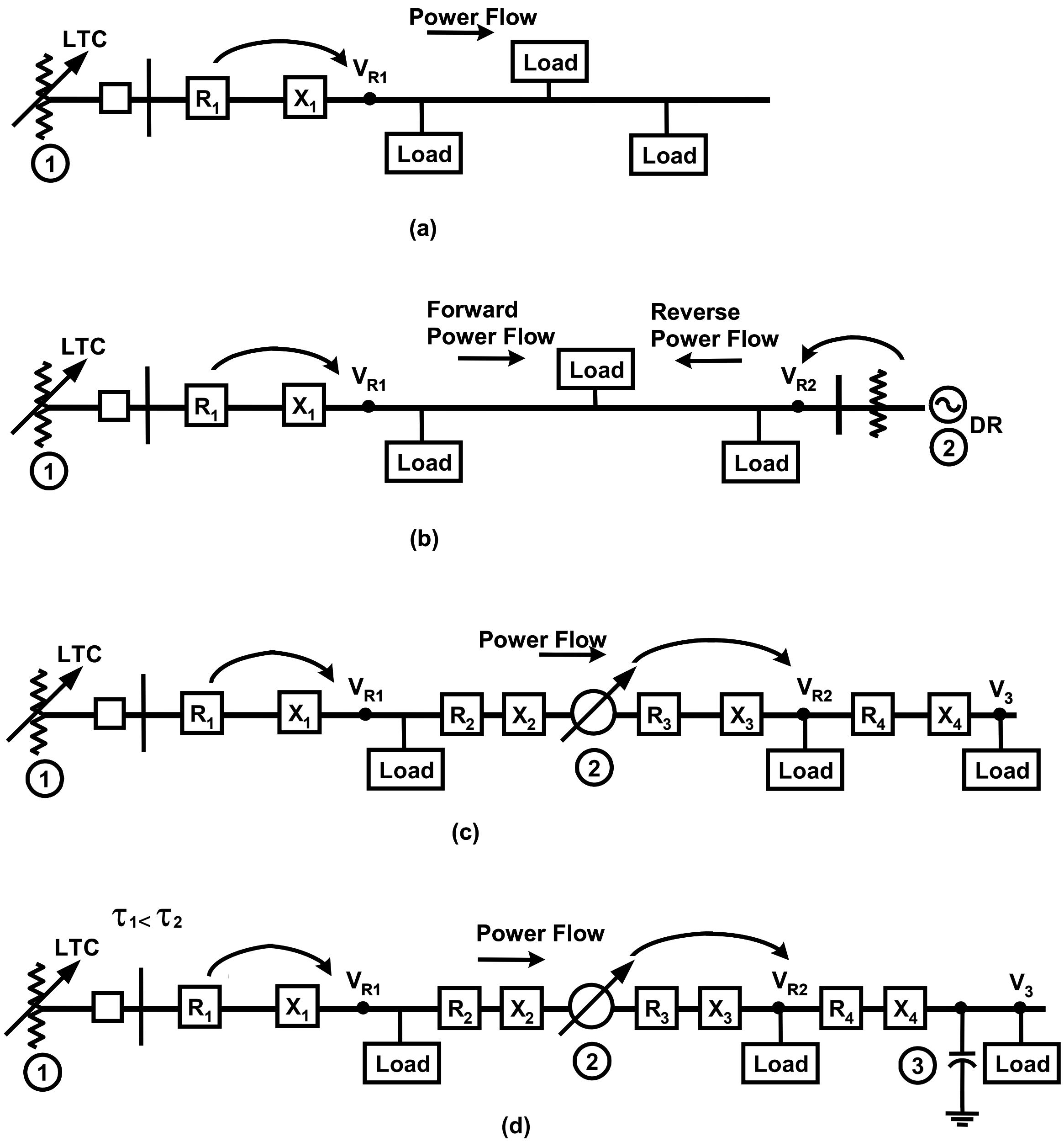


Figure 25. Examples of unidirectional VRs and DR

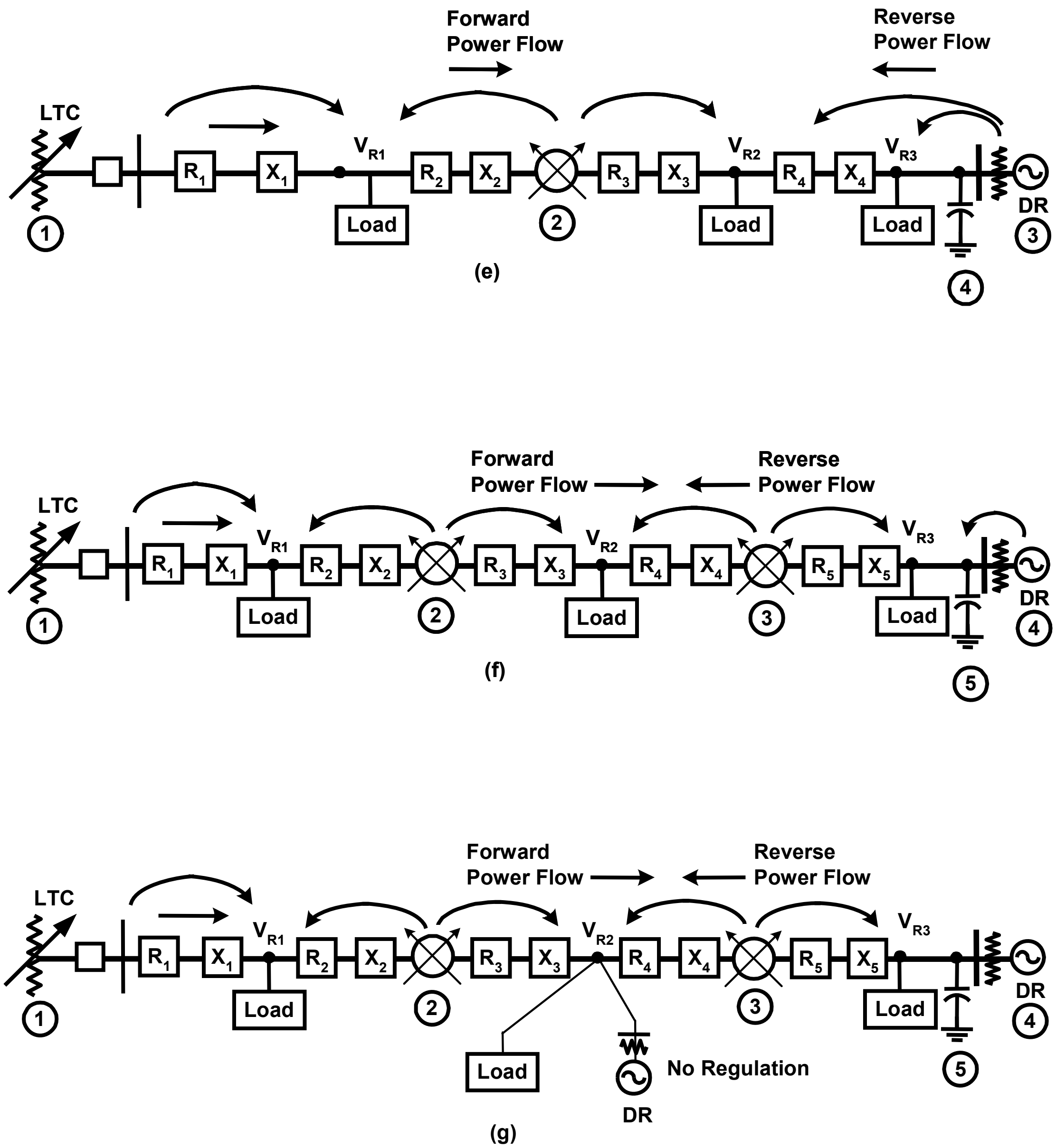
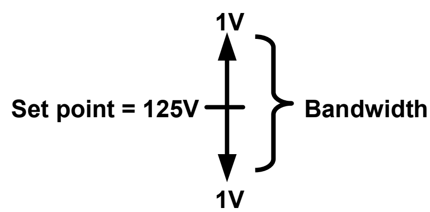


Figure 26. Examples of bidirectional VRs and DR

3.16 Step Voltage Regulator Control System

Four settings are required to control voltage:

- Set point voltage – The voltage required at the load on a 120-V base
- Voltage bandwidth – The voltage variation from the set point voltage at the load. If the set point voltage is 125 V and the bandwidth is 2 V, the regulator will control the voltage within 126 V and 124 V



- Time delay – The time between when a change in voltage is sensed and when the change in voltage occurs. The time delay allows for the short-term surge currents, such as motor-starting currents, to occur so that tap changing does not occur during these temporary periods of voltage drop
- Line drop compensator – The compensator for the voltage drop in the circuit between the regulator and the load. The R and X values of the line are set to determine the voltage drop in the line.

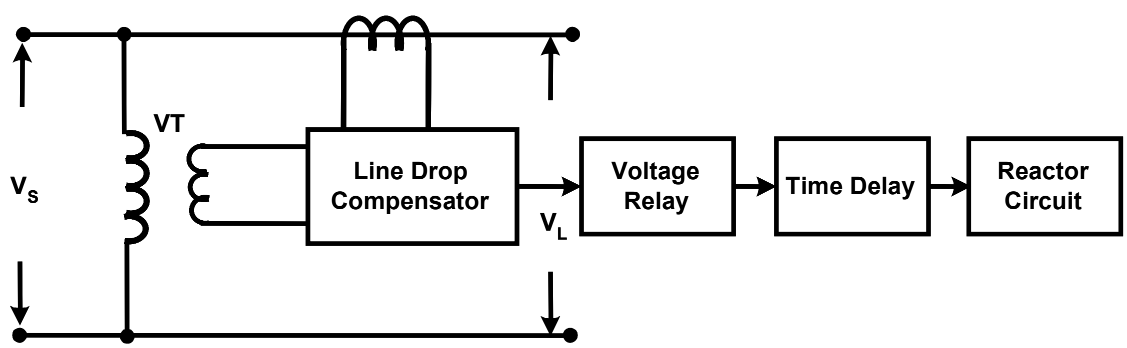


Figure 27. Control circuit of step VR

The components of the control circuit are illustrated in Figure 27. The kilovolt-ampere rating of the regulator is determined using the same approach as that used for the autotransformer because since the shunt and series windings form an autotransformer. The kilovolt-ampere rating is usually 10% of the rated current flowing through the series winding.

3.17 Voltage and Current Equations

As previously noted, there are three types of VRs: Type A, Type B, and bidirectional. The most common is Type B. Figure 28 shows Type A. Here, the preventive autotransformer winding is connected to the load terminal (L). The regulator is in the raise, r, position; the I_2 current is "up"; and the excitation current of the shunt winding, I_1, is "down." The exciting current varies because it is connected to the source, S. When the reversing switch is connected to the lower terminal (l), the I_2 current is reversed ("down"), as in Figure 29, and the I_1 current is "up." This is because the polarity of the series winding has changed because of the reversing switch changing its polarity.

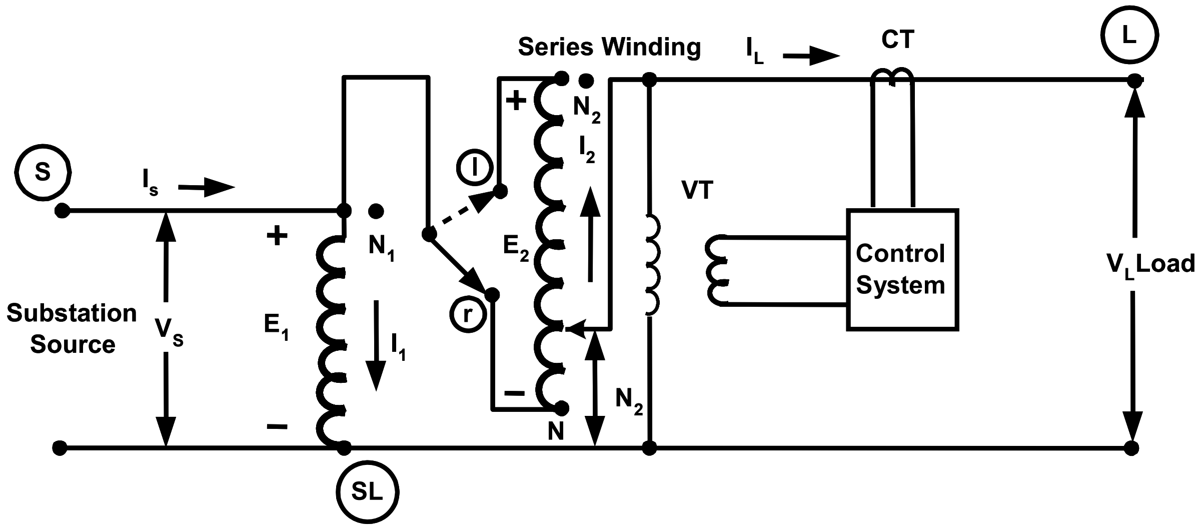


Figure 28. Type A step regulator – raise position

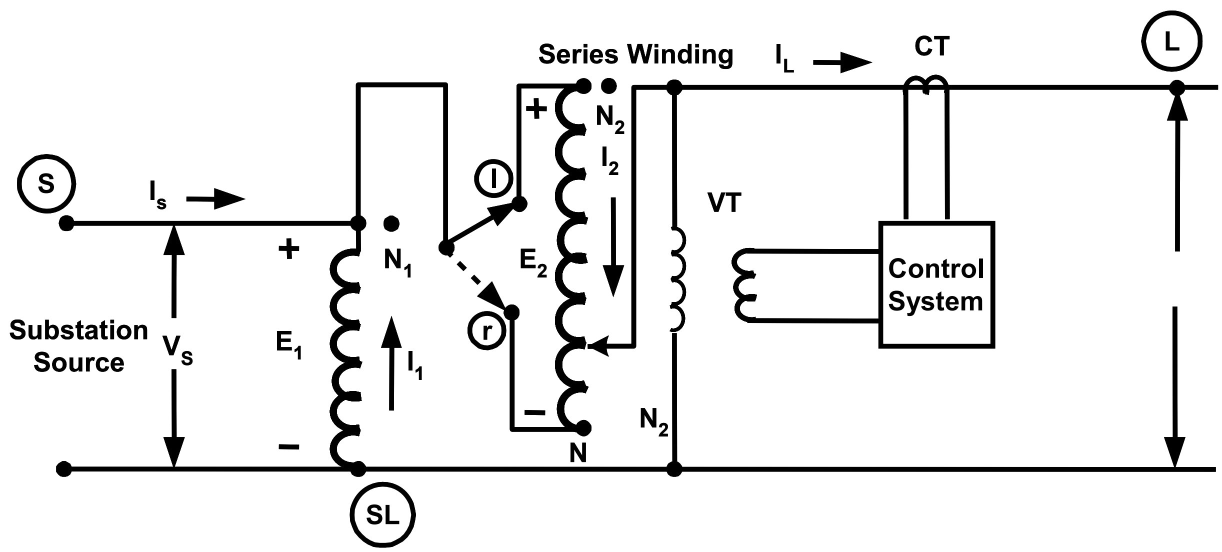


Figure 29. Type A step regulator – lower position

For the Type B regulator, the preventive auto is connected to the source terminal (S). Figure 30 shows the Type B regulator in the raise position (r).

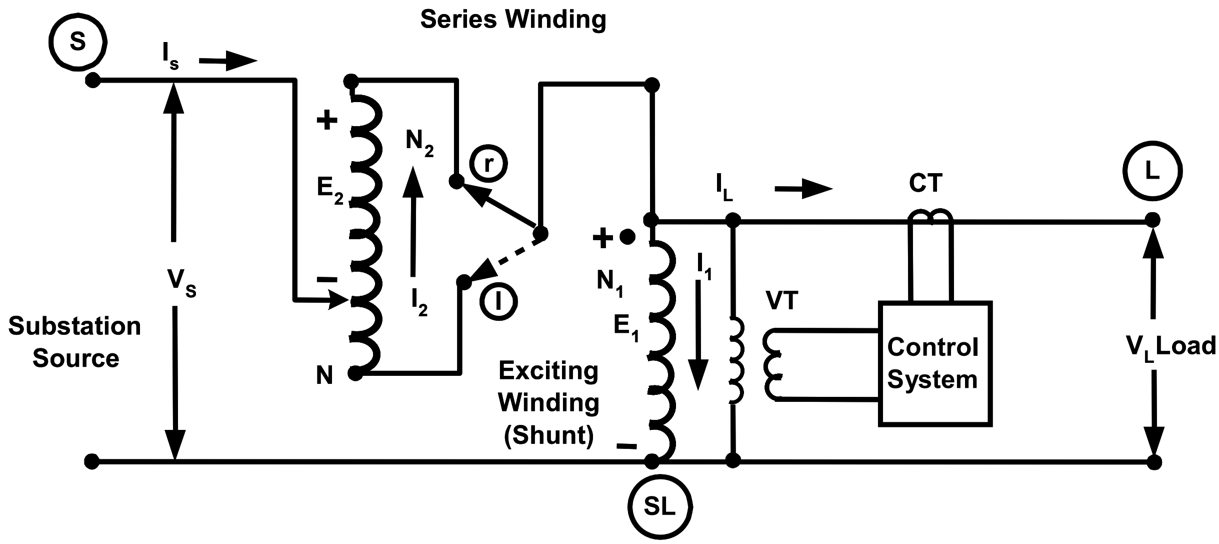


Figure 30. Type B regulator – raise position

Here, the excitation current is constant because the shunt winding is connected to the load side (L) or the regulated circuit side.

For the Type B regulator in the raise position of Figure 30, the voltage and current equations may be written as:

Raise Position Equations

$N_1 I_1 = N_2 I_2$ Equation 3.12

$$\frac{E_1}{N_1} = \frac{E_2}{N_2}$$ Equation 3.13

$I_L = I_S - I_1$ Equation 3.14

$V_S = E_1 - E_2$ Equation 3.15

$I_L = I_S - I_1$ Equation 3.16

$E_1 = V_L$ Equation 3.17

$I_S = I_2$ Equation 3.18

From equations 3.13 and 3.17,

$E_2 = (N_2/N_1)\, E_1 = (N_2/N_1)\, V_L.$ Equation 3.19

From Equations 3.12 and 3.18,

$$I_1 = (N_2/N_1)\ I_2 = (N_2/N_1)\ I_S. \qquad \text{Equation 3.20}$$

From Equations 3.15, 3.17, and 3.19,

$$V_S = E_1 - E_2 = E_1 - (N_2/N_1)\ V_L = V_L - (N_2/N_1)\ V_L$$
$$V_S = (1 - (N_2/N_1)\ V_L. \qquad \text{Equation 3.21}$$

From Equations 3.16 and 3.20,

$$I_L = I_S - I_1 = I_S - (N_2/N_1)\ I_S$$
$$I_L = (1 - N_2/N_1)\ I_S. \qquad \text{Equation 3.22}$$

Defining the raise turns ratio term as

$$a_r = (1- N_2/N_1) \qquad \text{Equation 3.23}$$

and substituting into equations 3.21 and 3.22,

$$V_S = a_r\ V \qquad \text{Equation 3.24}$$
$$I_L = a_r\ I_S. \qquad \text{Equation 3.25}$$

Using Figure 31, the voltage and current equations for the lower regulator position may be defined as:

Lower Position Equations

$$N_1\ I_1 = N_2\ I_2 \qquad \text{Equation 3.26}$$

$$\frac{E_1}{N_1} = \frac{E_2}{N_2} \qquad \text{Equation 3.27}$$

$$I_L = I_S + I_1 \qquad \text{Equation 3.28}$$

$$V_S = E_1 + E_2 \qquad \text{Equation 3.29}$$

$$E_1 = V_L \qquad \text{Equation 3.30}$$

$$I_S = I_2. \qquad \text{Equation 3.31}$$

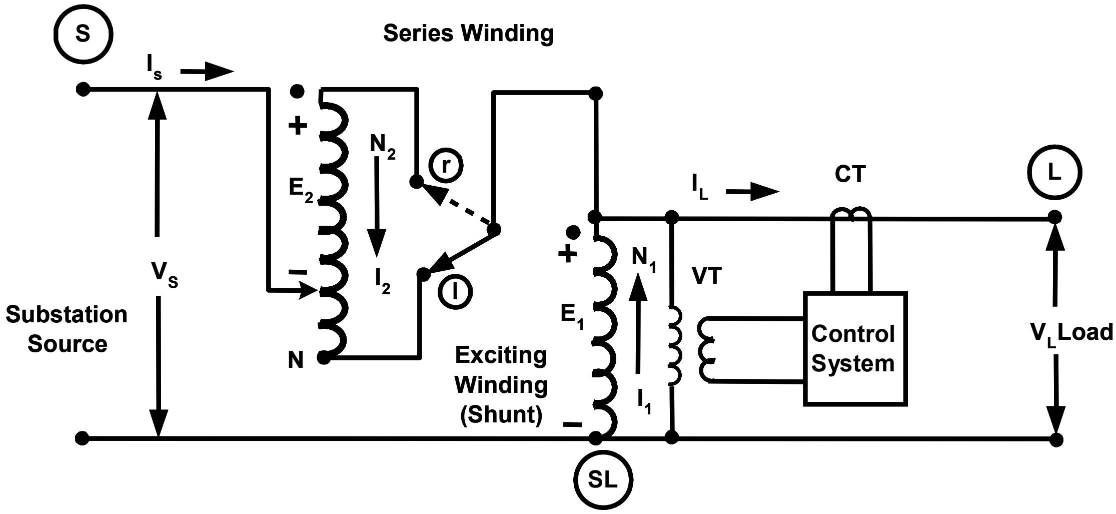


Figure 31. Type B regulator – lower position

From equations 3.27 and 3.30,

$$E_2 = (N_2/N_1)\ E_1 = (N_2/N_1)\ V_L. \qquad \text{Equation 3.32}$$

From equations 3.26 and 3.31,

$$I_1 = (N_2/N_1)\ I_2 = (N_2/N_1)\ I_S. \qquad \text{Equation 3.33}$$

From equations 3.29, 3.30, and 3.32,

$$V_S = E_1 + (N_2/N_1)\ E_1 = V_L + (N_2/N_1)\ V_L$$
$$V_S = (1 + N_2/N_1)\ V_L. \qquad \text{Equation 3.34}$$

From equations 3.28 and 3.33,

$$I_L = I_S + I_1 = I_S + (N_2/N_1)\ I_2$$
$$I_L = I_S\ (1 + N_2/N_1). \qquad \text{Equation 3.35}$$

Defining the lower position turns ratio term as

$$a_l = \ (l + N_2/N_1), \text{ then} \qquad \text{Equation 3.36}$$

$$V_S = a_l\ V_L \qquad \text{Equation 3.37}$$

$$I_L = a_l\ I_S. \qquad \text{Equation 3.38}$$

Notice that the only difference between voltage and current raise equations 3.21 and 3.22 and voltage and current lower equations 3.34 and 3.35 is the sign of the turns ratio N_2/N_1. The sign of the raise position is negative, and the sign of lower position is positive. It is not necessary to know the turns ratio of equations 3.21, 3.22, 3.34, and 3.35 because each tap represents a voltage change of 5/8% or 0.00625 p.u. Therefore, a_r and a_l can be described as

a_r, a_l = 1 -, + (0.00625) tap position for a Type B regulator. Equation 3.39

For the Type A regulator, the a_r and a_l are

a_r, a_l = 1 +, - (0.00625) tap position. Equation 3.40

3.18 Equivalent Circuits

Because the series impedance and shunt admittance of a step VR are negligible, their effects can be ignored. But if desired, this effect can be included in the same manner as the equivalent circuit for an autotransformer.

3.19 Line Drop Compensator

For VRs to operate properly, when applied at a substation or on a circuit, and maintain voltage at the regulation point, line drop compensators are required. The voltage at the regulation point is to be constant even through the load power factor and the load change. This is achieved by setting the resistance and reactance controls on the control panel of the regulator.

The voltage-regulating relay of Figure 32 causes the regulator to return to the preset voltage, VR, when a change in voltage occurs. For the VR to compensate for the voltage drop in the circuit to the regulation point, an additional voltage must be added between the VT output and the voltage-regulating relay (VRR) so that the VRR sees a reduced voltage proportional to the load current and load power factor. The current from the VT is almost in phase with the voltage because the resistance of its secondary circuit is high compared with the reactance of this circuit. The current from the CT adds current through the R_L and X_L that has the same phase angle as the load current and is proportional to the load current. The VRR is adjusted so that, with no load current, the regulator output is equal to the set point voltage at the regulation point. The compensator R_L and X_L elements are adjusted so they are proportional to the R_L and X_L of the circuit between the regulator and regulation point. The phasor diagram of Figure 33 shows how the regulation point voltage, V_R, or the voltage across the VRR is determined from the output voltage of the regulator, V_O (from the VT), and the R_L and X_L values of the circuit. I_L is the load current, and θ is the power factor angle of the load current from the CT. The I_LR_L voltage drop is the voltage drop across the R_L of the compensator, and I_LX_L is the voltage drop across the X_L of the compensator.

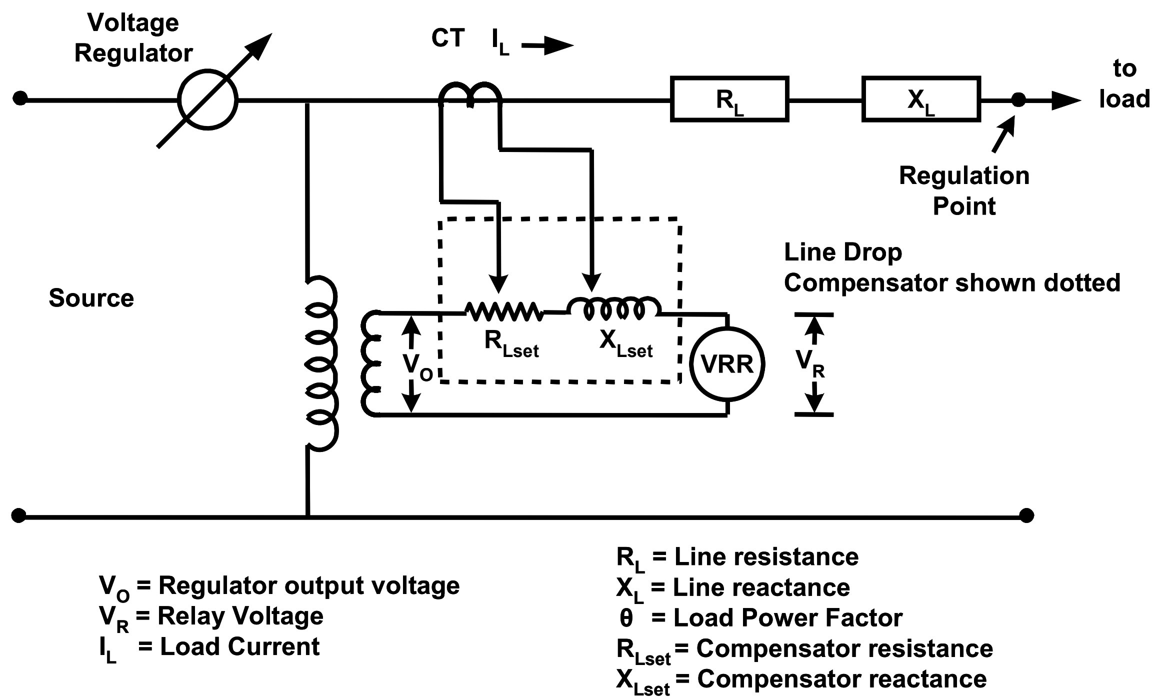


Figure 32. Control system and line drop compensator

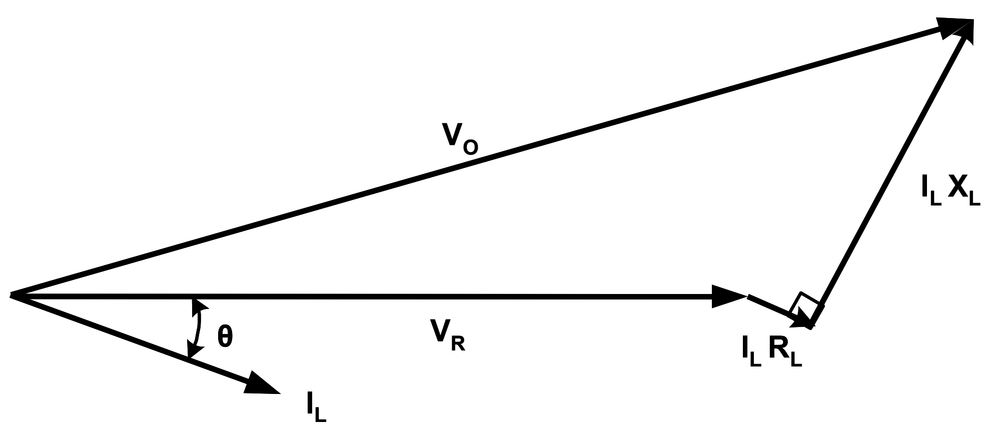


Figure 33. Phasor diagram for line drop compensator

The values R_L and X_L are calibrated in volts on the dials of the compensator panel. When the dial is set at a voltage value, this is the voltage compensation at rated current in the secondary of the CT. The regulator rating must be determined before the R_L and X_L settings can be defined.

3.20 Regulator Ratings

If V_O is the output voltage and V_i is the input voltage for a single-phase regulator, then the percent regulation range is

$$\% R = [(|V_o| - |V_i|)/|V_i|] \times 100 \qquad \text{Equation 3.41}$$

in either the buck or boost direction. The regulation kilovolt-amperes is defined as

$$kVA_{Regulation} = [(|V_o| - |V_i|)/|V_o|]\ kVA_{S\Phi}\ \text{circuit}, \qquad \text{Equation 3.42}$$

and the regulator kilovolt-amperes rating is

$$\{[(|V_o| - |V_i|)/|\ V_i|][100 \times kVA_{S\Phi}\ \text{circuit}]\}/100 \qquad \text{Equation 3.43}$$

$$kVA_{S\Phi}\ \text{Rating} = [\% R\ (kVA_{S\Phi}\ \text{circuit})]/100 = (\% R\ |kV_{LL}|\ \ |I_L|)/100, \qquad \text{Equation 3.44}$$

where kV_{LL} is line-to-line voltage, and I_L is the load current. For the three-phase, four-wire wye system of Figure 34, Equation 3.44 is used, but the kilovolt-amperes of the circuit are now three-phase.

$$kVA_{3\Phi\ Rating} = [\% R\ (kVA_{3\Phi}\ \text{circuit})]/100 \text{ or}$$

$$kVA_{3\Phi\ Rating} = [\% R\ \sqrt{3}|kV_{LL}|\ \ |I_L|]/100. \qquad \text{Equation 3.45}$$

Figure 35 shows the phasor diagram for the wye connection. Notice that the regulated voltages are in phase with the input voltages. For a 13.2-kV three-phase, four-wire wye system and an 8,000-kVA circuit load, I_L = 350 A. With ±10% regulation, the rating is

$$kVA_{3\Phi\ Rating} = [(10)\ (\sqrt{3})\ (13.2\ kV)\ (350\ amps)]/100 = 800\ kVA. \qquad \text{Equation 3.46}$$

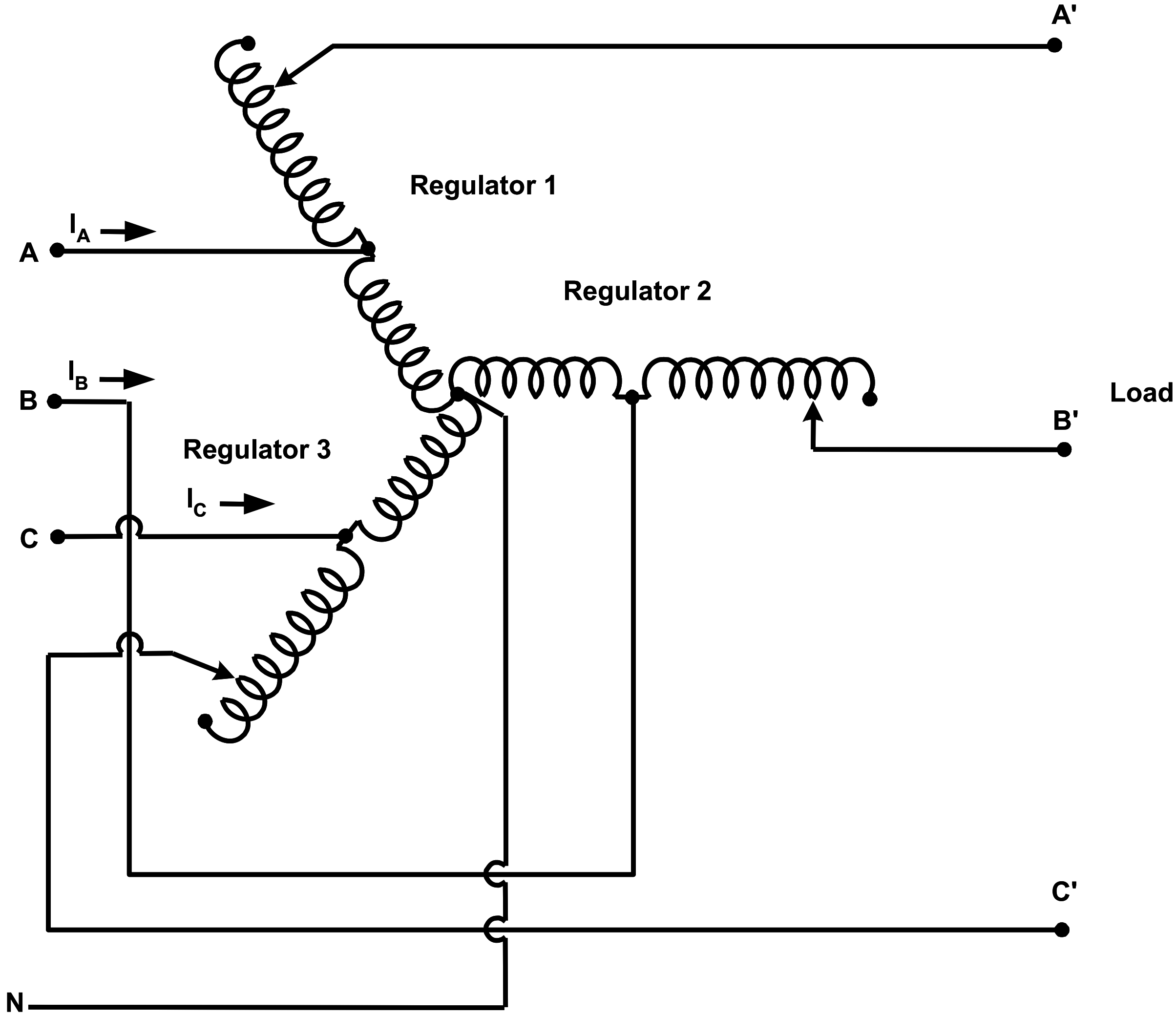


Figure 34. Three single-phase VRs connected wye on a four-wire, three-phase circuit

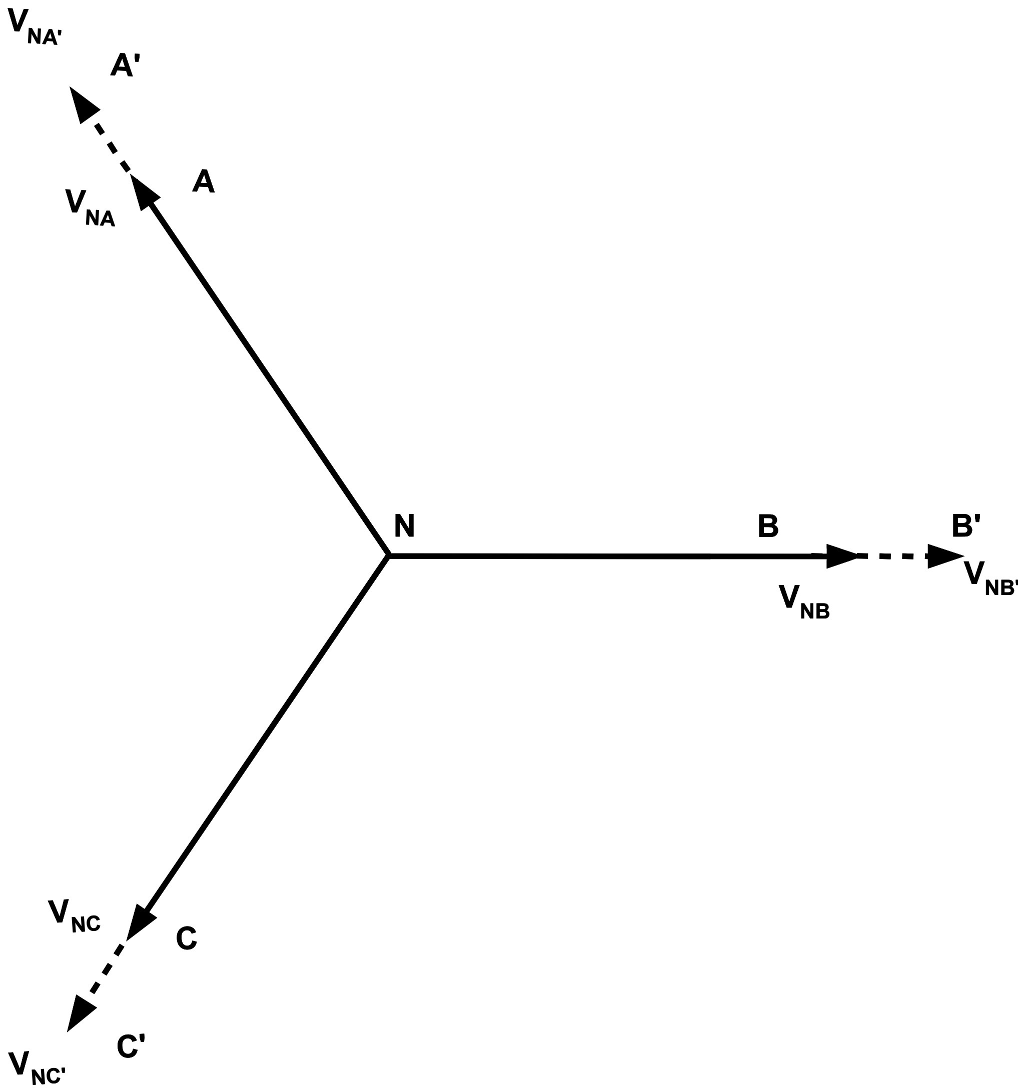


Figure 35. Voltage phasor diagram of wye-connected, three single-phase VRs

Notice, from Equation 3.46, that the kilovolt-ampere three-phase rating of the ±10% regulator is just 10% times the three-phase circuit load. For a three-phase, three-wire circuit, Equation 3.46 applies because the regulator is connected in wye, but there is no connection to the neutral of the regulator.

Sometimes, two single-phase regulators are connected open delta or "vee" to obtain voltage regulation on a delta three-wire system. This connection is shown in Figure 36. For its phasor diagram, see Figure 37. The same percentage increase in voltage on V_{CB} to $V_{C'B}$ and V_{BA} to $V_{BA'}$ causes the same percentage increase on V_{AC} to $V_{A'C'}$. The input to the regulator is the line voltage, not the line-to-neutral voltage, as in Figure 34. From Equation 3.44, the single-phase rating can be used because the voltage is line-to-line. The-three phase circuit kVA = $\sqrt{3}\ kV_{LL}\ I_L$, and each single-phase regulator kilovolt-ampere rating is

$$kVA_{S\Phi\ Rating} = [(\%R \sqrt{3}\ |kV_{LL}|\ |I_L|)]/[(100)(\sqrt{3})]. \qquad \text{Equation 3.47}$$

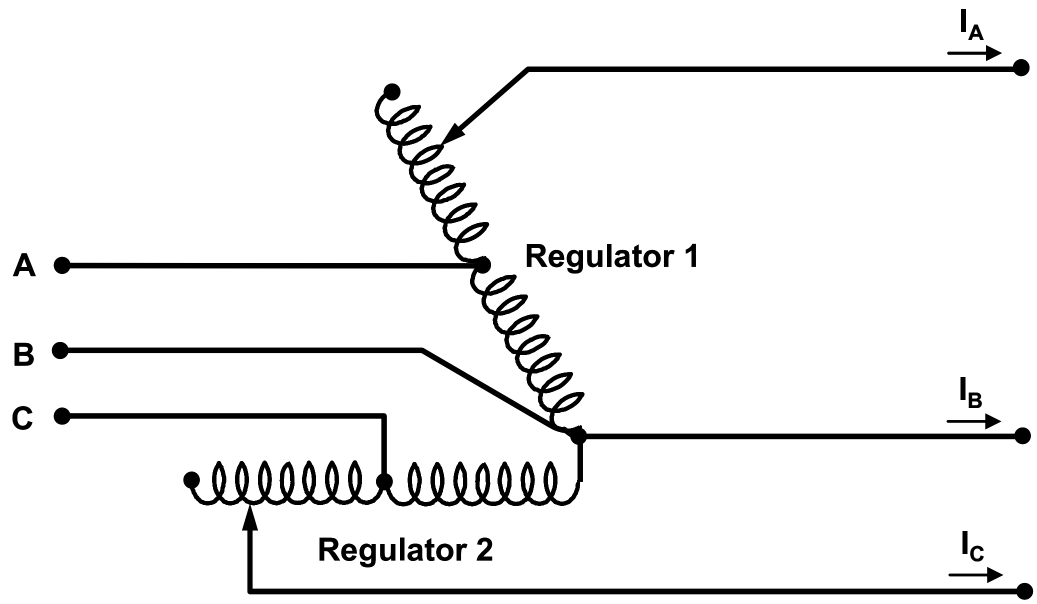
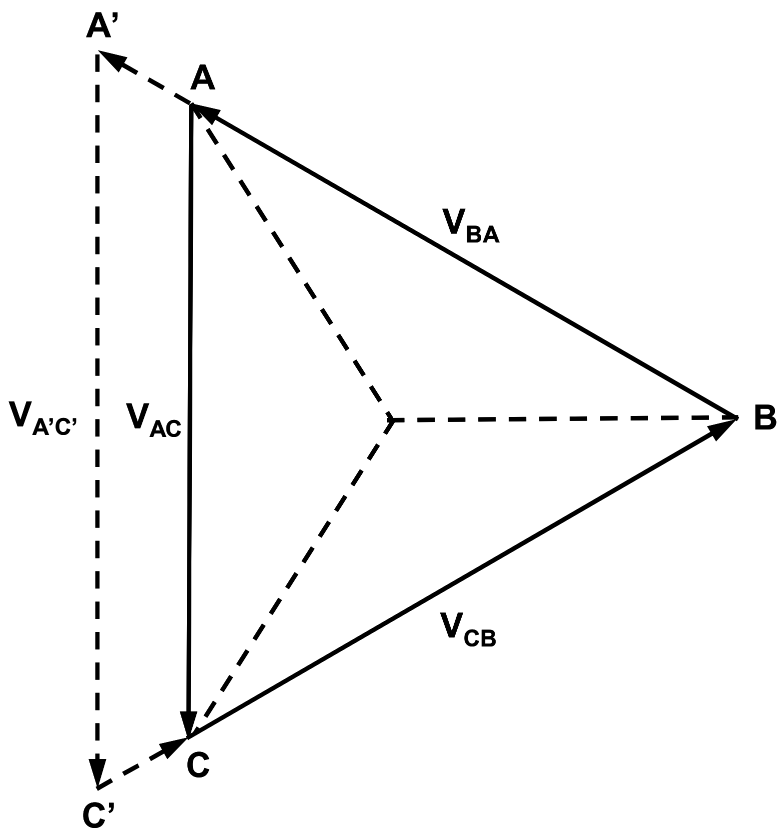


Figure 36. Two single-phase VRs connected open delta on a three-wire, three-phase circuit



Regulator Input Voltages V_{BA} V_{CB} V_{AC}

Regulator Output Voltages $V_{BA'}$ $V_{C'B}$ $V_{A'C'}$

Figure 37. Voltage phasor diagram of open delta-connected two single-phase VRs

The √ 3 is needed in the denominator to obtain the phase current. When a ±10% regulation is substituted for %R in Equation 3.47., the kilovolt-ampere rating is

$$\text{kVA}_{S\Phi\ \text{Rating}} = [(10)\ (\text{kVA}_{3\Phi}\ \text{circuit})]/[(100\sqrt{3})]$$
$$= (\text{kVA}_{3\Phi}\ \text{circuit})/(17.32). \qquad \text{Equation 3.48}$$

For a 4.8-kV, three-phase, three-wire delta system and a 2,000-kVA, three-phase circuit load, the load current is 241 A. Applying Equation 3.48 and using ±10% regulation, each single-phase unit connected in open delta is

$$\text{kVA}_{S\Phi\ \text{Rating}} = [(10)\ (2{,}000)]/[(100)\ (17.32)] = 115\ \text{kVA}. \qquad \text{Equation 3.49}$$

In this case, the rating is 6% of the three-phase circuit load, not the 10% calculated for the four-wire wye system above.

Three-phase regulation can be achieved for a closed delta. Closing the delta with the third regulator does not allow more circuit load, but it does increase the percentage regulation from ±10% to ±15%. This is shown in the phasor diagram of Figure 38. Each regulator of the closed delta carries the phase load current, as was the case for the open delta, and the regulator rating is determined from equations 3.47 and 3.48, which is identical to the regulator rating obtained in the open delta configuration. There are two possible connections for the closed delta: the load current leading the line-to-line voltage across the shunt winding by 30° and current lagging the line-to-line voltage by 30°. Each of these will be explained.

3.21 Closed Delta – Leading Current and Lagging Current Connections

The leading current connection and its phasor diagram are shown in Figure 39, and the lagging current connection and its phasor diagram are shown in Figure 40. A phase shift results between the input and output voltages, as shown in Figure 38, and different phase shifts occur depending on the tap and boost or buck positions. The smaller phase shifts occur for the lower tap positions. Although there are no advantages to either 30° leading or lagging connections, it may be necessary to go beyond the range of the compensator settings for one versus the other connection. Therefore, one of these connections may be chosen to solve this problem. It is generally not recommended to use wye-connected, single-phase regulators for the delta system because the neutral will shift for unbalanced loads. Because there are separate controls for each regulator, this may cause a different response and result in a neutral shift.

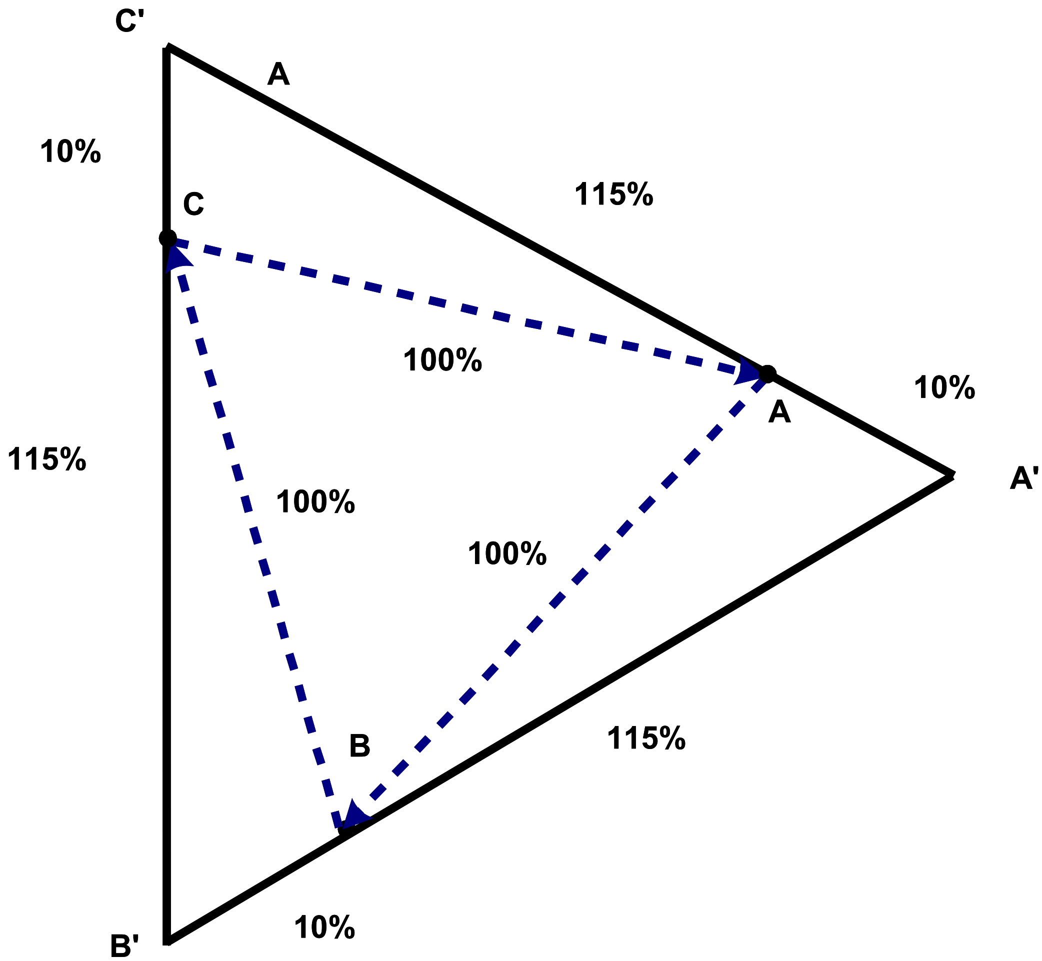


Figure 38. Voltage diagram of closed delta-connected three single-phase VRs

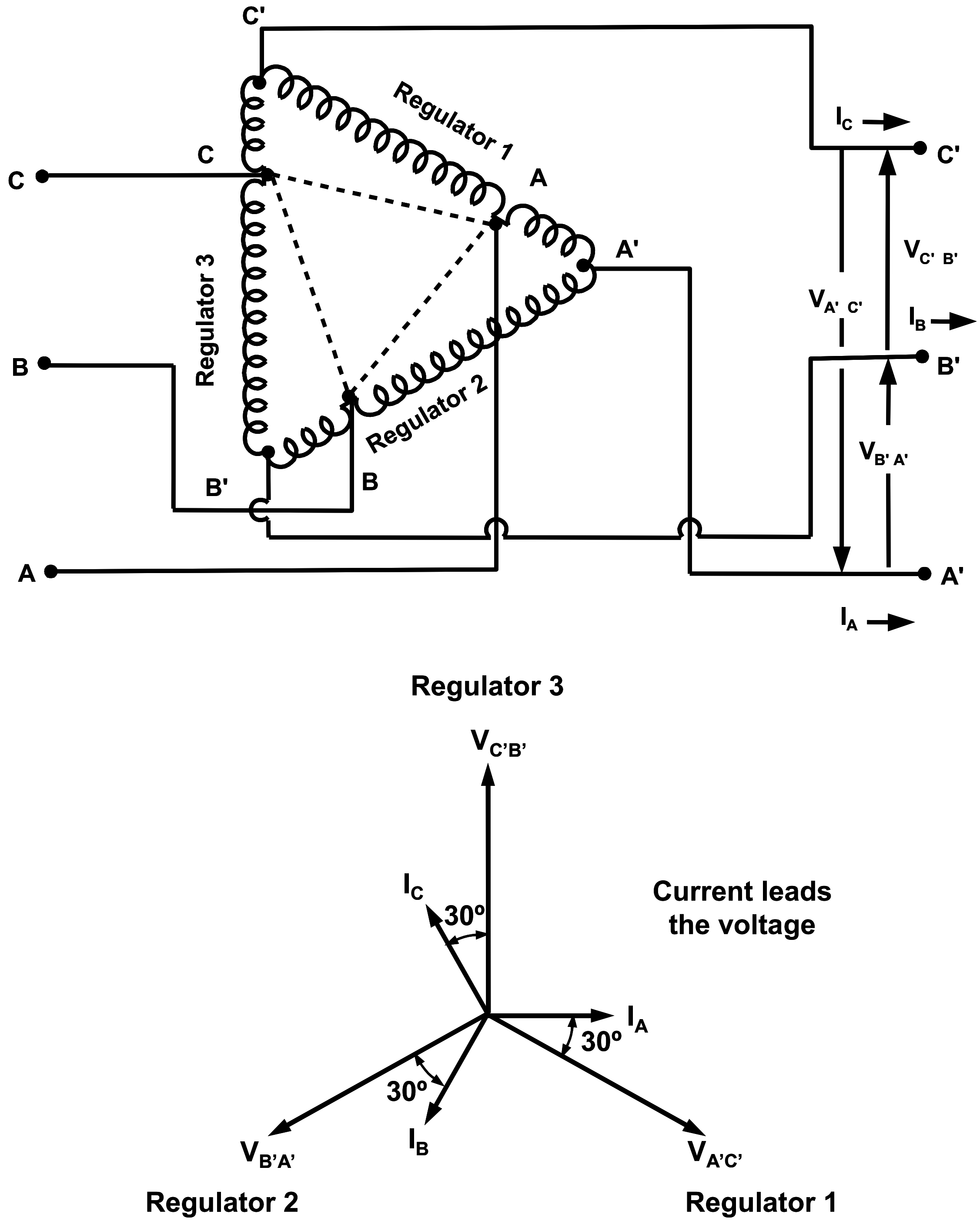


Figure 39. Closed delta-connected three single-phase VRs – leading connection

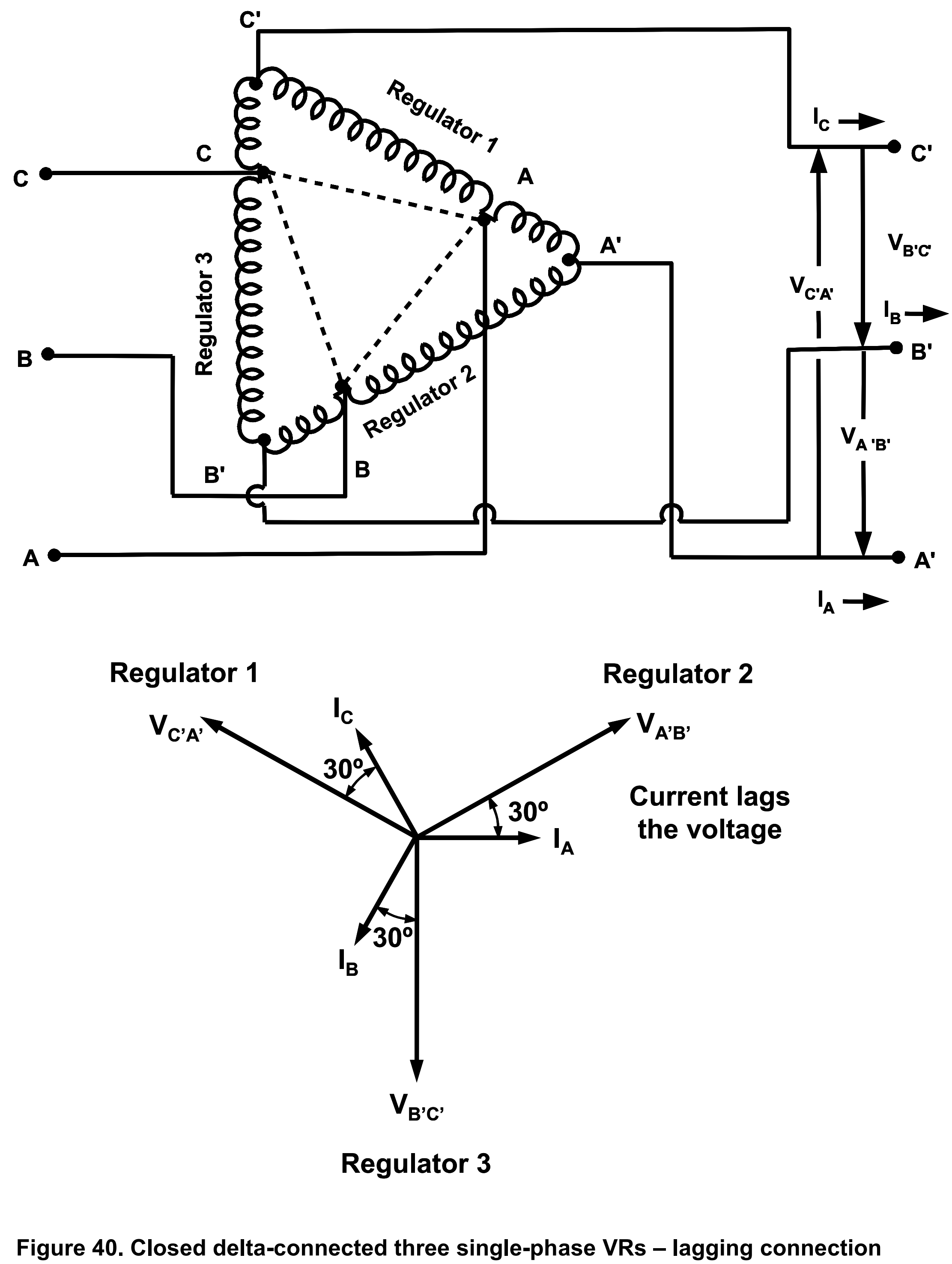


Figure 40. Closed delta-connected three single-phase VRs – lagging connection

3.22 Compensator Settings

If no load is connected between the regulator and the regulation point, it is easy to determine the settings of R_L and X_L. This is the case for a typical substation step regulator, as in Figure 32 and Figure 33. The R_L setting and X_L settings are determined from equations 3.50 and 3.51 as

$$R_{Lset} = [(CT_P/N_{VT})]\ (R_L)\ (l) \qquad \text{Equation 3.50}$$

$$X_{Lset} = [(CT_P/N_{VT})]\ (X_L)\ (l) \qquad \text{Equation 3.51}$$

where

R_{Lset} = Dial setting for the resistance in the feeder portion of the circuit given in volts
X_{Lset} = Dial setting for the reactance in the feeder portion of the circuit given in volts
N_{VT} = VT ratio of primary voltage/secondary voltage
CT_P = Primary rating of the CT given in amperes
R_L = Resistance per conductor in unit length from the LTC to regulation point, normally given in ohms per mile
X_L = Reactance per conductor in unit length from the LTC to regulation point, normally given in ohms per mile
l = Unit length in miles to the regulation point.

The settings for R_{Lset} and X_{Lset} can now be determined. But first, the regulator rating must be calculated.

From Equation 3.46, the rated amperes for three single-phase regulators connected wye and rated 13.8 kV, 1,000 kVA, and ±10 regulation is 418 A. The CT ratio is 500:5, and the VT ratio is 13.8 kV/√3 = 7,960:120. The regulator is located 3 miles from the regulation point, and the conductor size is 636 kcmil all aluminum. From the resistance and reactance values of

$$X = 0.536\ \Omega/\text{mile/conductor (see Equation 3.9)}$$

$$R = 0.164\ \Omega/\text{mile/conductor},$$

and using equations 3.50 and 3.51,

$$X_{Lset} = [(500)/(7960/120)]\ [(0.536)\ (3)] = 12.12\ \text{V} \qquad \text{Equation 3.50}$$

$$R_{Lset} = [(500)/(66.3)]\ [(0.164)\ (3)] = 3.71\ \text{V}. \qquad \text{Equation 3.51}$$

The control panel dial settings are based on the rated current of 500 A for the CT primary, not the load current or the rated current for the regulator. For step regulators installed on the circuit, the primary rating of the CT is the same as the regulator current rating. Hence, the regulator current rating can be substituted for the CT primary current rating in equations 3.50 and 3.51. Load may be connected between the regulator and the voltage regulation point; therefore, the magnitude of the current flowing through the CT of the regulator does not equal the magnitude of the current flowing through the balance of the R_L and X_L of the circuit to the regulation point. This is especially true for regulators installed beyond the feed point voltage V_R. Equations 3.50 and 3.51 can be corrected with the aid of Figure 41.

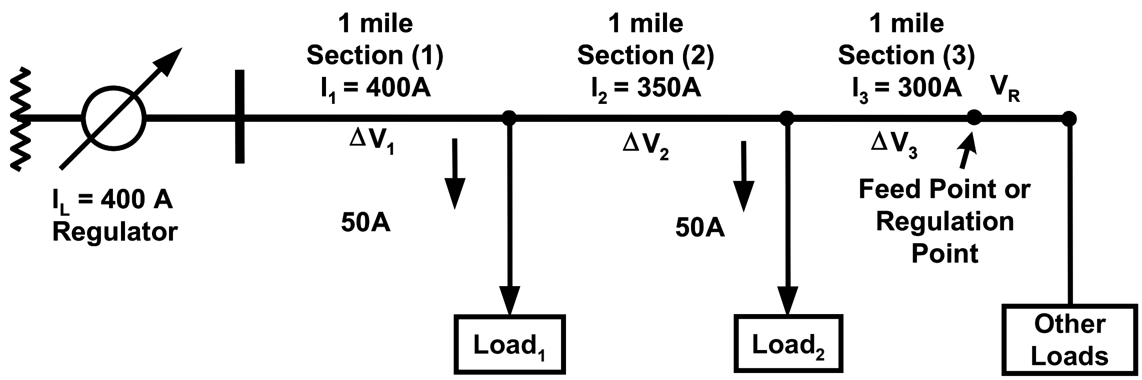


Figure 41. Current at the regulator is not equal to current in the last section before the regulation point

The R_L set and X_L set can be changed to consider the effect of load being served before the regulation point.

$$R_{Lset} = (CT_P/N_{VT}) / (R_{LE}), \qquad \text{Equation 3.52}$$

where the effective resistance R_{LE} when multiplied by I_L gives the same voltage drop as the sum of the drops through the various sections of line (e.g., Section 1, Section 2, and Section 3 in Figure 41). Thus, R_{LE} can be written as

$$R_{LE} = \left(\sum_{i=1}^{n} |\Delta V_{iR}|\right)/I_L \qquad \text{Equation 3.53}$$

$$\sum_{i=1}^{n} |\Delta V_{iR}| = |I_1|R_{L1}\,l_1 + |I_2|R_{L2}\,l_2 + |I_3|R_{L3}\,l_3 \;\ldots\; |I_n|R_{Ln}\,l_n. \qquad \text{Equation 3.54}$$

$\sum_{i=1}^{n} |\Delta V_{iR}|$ = The total voltage drop from regulator to the regulation point.

R_{LE} = Effective resistance
$| I_L |$ = Load current flowing through the regulator
$| I_1 |, | I_2 |, | I_3 |, \ldots | I_n |$ = The load current in each line section to the regulation point
$R_{L1}, R_{L2}, R_{L3} \ldots R_{Ln}$ = The resistance in ohms per mile of each section from regulator to the regulation point
$l1, l2, l3, \ldots l_n$ = The length of conductor in miles for each section from regulator to the regulation point
n = number of line sections.

The

$$X_{Lset} = CT_p/N_{VT} (X_{LE}), \qquad \text{Equation 3.55}$$

where X_{LE} takes on the same form as equations 3.53 and 3.54 for R_{LE}. Based on Figure 41, and Equation 3.54, the R_{LE} is found as follows:

$$\sum_{i=1}^{3} |\Delta V_{iR}| = (400)(0.164)(1) + (350)(0.164)(1) + (300)(0.164)(1)$$
$$= 65.6 + 57.4 + 49.2 = 172.2 \text{ V}. \qquad \text{Equation 3.56}$$

From Equation 3.53,

$$R_{LE} = 172.2/400 = 0.4305\ \Omega \qquad \text{Equation 3.57}$$

$$R_{Lset} = (500/66.3)\ 0.4305 = 3.25 \text{ V}. \qquad \text{Equation 3.58}$$

In reference to the R_{Lset} values of equations 3.53 and 3.58, the value of Equation 3.58 is lower because the load current has stepped down after having served loads 1 and 2. Thus, the total voltage drop is less and the compensation is less.

Equation 3.54 has considered the power factor angle to be the same for each section. However, in fact, this angle may not be the same for each section. A more practical approach is to measure the load current at the regulator, the load power factor, and the voltages at the regulation point and the regulator output at the same time. From these data and the X/R ratio out to the regulation point, and by applying the voltage drop equation, the effective values of R_{LE} and X_{LE} can now be calculated.

$$\Delta V = I_L R_{LE} \cos\theta + I_L X_{LE} \sin\theta \qquad \text{Equation 3.59}$$

3.23 Other Compensator Settings and Corrections

Settings for three-phase regulators connected wye and three single-phase regulators connected wye are determined using the same approach as that outlined above. However, when single-phase regulators are connected in open delta, the control voltage and current in the compensator do have the same phase relationship as the wye-connected regulators. For example, the open delta connection described in Figure 36 and Figure 37 show the control voltage and current as V_{BA} and I_A for Regulator 1 and as V_{CB} and I_C for Regulator 2, which are 30° out of phase with the wye connection shown dashed in Figure 37. The current of one regulator lags the voltage by 30° plus the power factor angle, and the current of the other regulator leads the voltage by 30° minus the power factor angle. Therefore, phase-shifting networks are used, or corrections are made to the settings. On the control panel of substation regulators, a 30° shift forward or 30° shift back is selected to correct this problem.
For single-phase connected open delta regulators applied to the circuit, corrections are made to the settings by using a 30° phase shift in the voltage on the compensator circuit. For the lead unit regulator in an open delta connection, the corrected settings are determined by multiplying the original settings obtained earlier by the quantity cos 30° – j sin 30°, or

$$R_{LC} + jX_{LC} = (0.866 - j0.5)\,(R_L + jX_L), \qquad \text{Equation 3.60}$$

where $R_{LC} + jX_{LC}$ are the corrected values.

For the lag unit regulator in an open delta connection, the corrected settings are found by multiplying the original settings by the quantity cos 30° + j sin 30°, or

$$R_{LC} + jX_{LC} = (0.866 - j0.5)\,(R_L + jX_L). \qquad \text{Equation 3.61}$$

Because these new, corrected settings require the phase angle to be moved back 30° or forward 30°, negative RL values result when increasing the phase angle, and negative X_L values result when decreasing the phase angle.

3.24 Step Regulators in Series

Often, to obtain the needed voltage profile on a circuit and not subject customers to LV or HV, two or more regulators are installed. This was illustrated in Figure 5. The solutions to the problems associated with these installations are dependent on the time delay settings, the bandwidth settings, and the voltage magnitude of the tap position steps. Other factors include changes in voltage at the primary side of the substation transformer, size of loads, location of loads, and the rate of change of load current and the resultant voltage.

Generally, the best solution is a short first regulator time delay, so the voltage is changed before the second regulator begins to make a change. The second regulator then completes its change before the third regulator begins to make a change, and so on. However, the time delay on the last regulator should not be long enough to subject customers to a long period of LV or HV.

However, there are exceptions to this rule if large loads are installed on the tag end of a circuit. In this case, the preferred solution is to have the last regulator respond first to the voltage correction and then readjust after the regulators upstream have operated. The optimum solution is the least number of regulator voltage adjustments for all the regulators on the circuit. The application of capacitors complicates the problem because, when capacitors are switched “on,” the input voltage to the nearby regulators goes up, and the regulators may operate to control the voltage within limits.

3.25 Fixed Capacitors on Circuits with Regulators

When a fixed capacitor is installed at the regulation point or downstream on the circuit, no changes to the compensator settings of equations 3.50 and 3.51 are needed. This is because the capacitor current I_C is included with the I_L current, and the current in the CT of the compensator includes both I_L and I_C. This assumes no load is connected between the regulator at the substation and the regulation point or between the regulator on the circuit and the regulation point. When load is connected between the regulator and the regulation point, then equations 3.52 and 3.55 for the R_{Lset} and X_{Lset} are not correct. This is because the I_CR_E and I_CX_E are not equal to the I_CR_a and I_CX_a, where the actual line resistance is R_a and the actual line reactance is X_a. This is shown in Figure 42. This phasor diagram shows the received voltage difference before and after the fixed capacitor is installed is

$$| V'_{RC} | - | V_{RC} | = | I_C | (X_a - X_E). \qquad \text{Equation 3.62}$$

This equation applies when the capacitor is located at the regulation point or downstream. This effect can be taken into account by changing the compensator settings or the VRR setting. The easiest and most common solution is to change the VRR setting. However, if the compensator settings are to be revised, then equations 3.53, 3.54, and 3.55 must be modified to include I_C, or

$$R_{LE} = [\sum_{i=1}^{n} | \Delta V_{ir} |]/(| I_L + I_C |) \qquad \text{Equation 3.63}$$

$$X_{LE} = [\sum_{i=1}^{n} | \Delta V_{ix} |]/(| I_L + I_C |). \qquad \text{Equation 3.64}$$

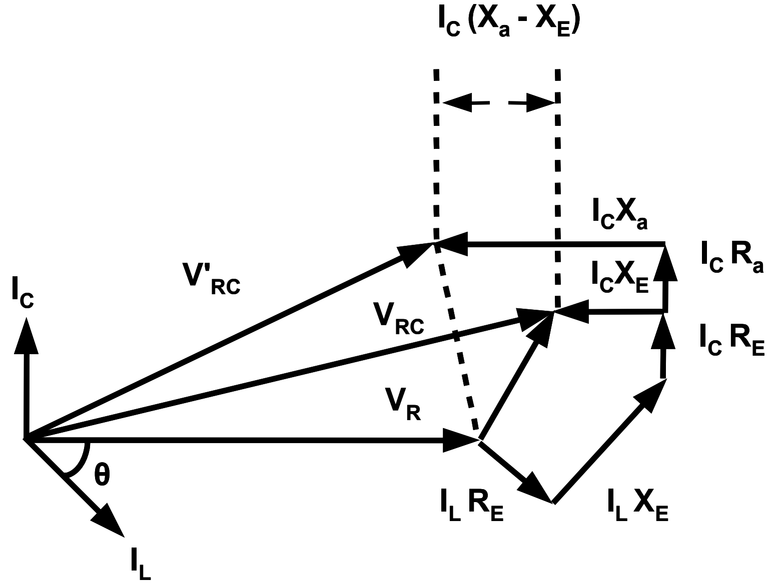


Figure 42. Phasor diagram of the effect of capacitors on the line drop compensator and regulator output voltages before and after relay settings are revised

V_R = Relay setting and regulation point voltage without capacitors
R_a = Actual resistance from regulator to regulation point
R_E = Effective line resistance from the regulator to regulation point or the resistive voltage drop to regulation point.
I_L = Load current at regulator
X_a = Actual reactance from regulator to regulation point
X_E = Effective line reactance from the regulator to the regulation point
V_{RC} = Regulator output voltage (relay R and X settings) after capacitors are "on"
$V_{R'C}$ = Regulator output voltage to have VR at regulation point after capacitors are "on" or $V_R – I_C (X_L – X_E)$
V = Voltage at regulation point with adjusted relay settings because of capacitors

If a fixed capacitor is installed between the regulator and the regulation point, the I_C current flows only to the capacitor and is not in the I_L current at the regulation point. Again, the best method to correct this problem is to change the VRR setting.

3.26 Switched Capacitors on Circuits with Regulators

When a switched capacitor is switched "on," the effect on the regulator settings is the same as that of a fixed capacitor. If a switched capacitor is installed at the same location as the regulator, then the regulator can be operated properly when the capacitor is turned "on" or "off." If the switched capacitor is installed on the source side of the regulator, regulator operation is not affected by the capacitor because the I_C current does not flow through the regulator. However, it is common practice to locate the capacitor on the load side because the capacitive current will lower the I_L current through the regulator. In this case, regulator operation is affected by the capacitor current, and the compensating circuit must be modified. This is explained in Figure 43. If the switched capacitor is voltage-controlled and the capacitor is located on the load side of the regulator, the VT of the capacitor control should be located on the source side because the regulator operation will not affect the capacitor operation. Notice in Figure 43, with a CT in the capacitor circuit connected to the CT of the regulator control, that there is no I_C current in the compensator R_L and X_L.

Another method of control is shown in Figure 44, in which an impedance has been added in series with the R_L and X_L of the compensator circuit that has a voltage drop equal to the voltage rise because of the capacitor. When the capacitor is switched “on,” the auxiliary contact is open, which adds a voltage drop in the compensator circuit. When the capacitor is switched “off,” the contact shorts out the impedance Z, and the regulator operation reverts back to normal, as though the capacitor were not there.

A third method of control is to change the VRR setting or the compensator settings as described earlier. The VRR setting is determined with the capacitor on, but a full setting increase should not be used because too low of a voltage will now occur at LL when the capacitor is off.

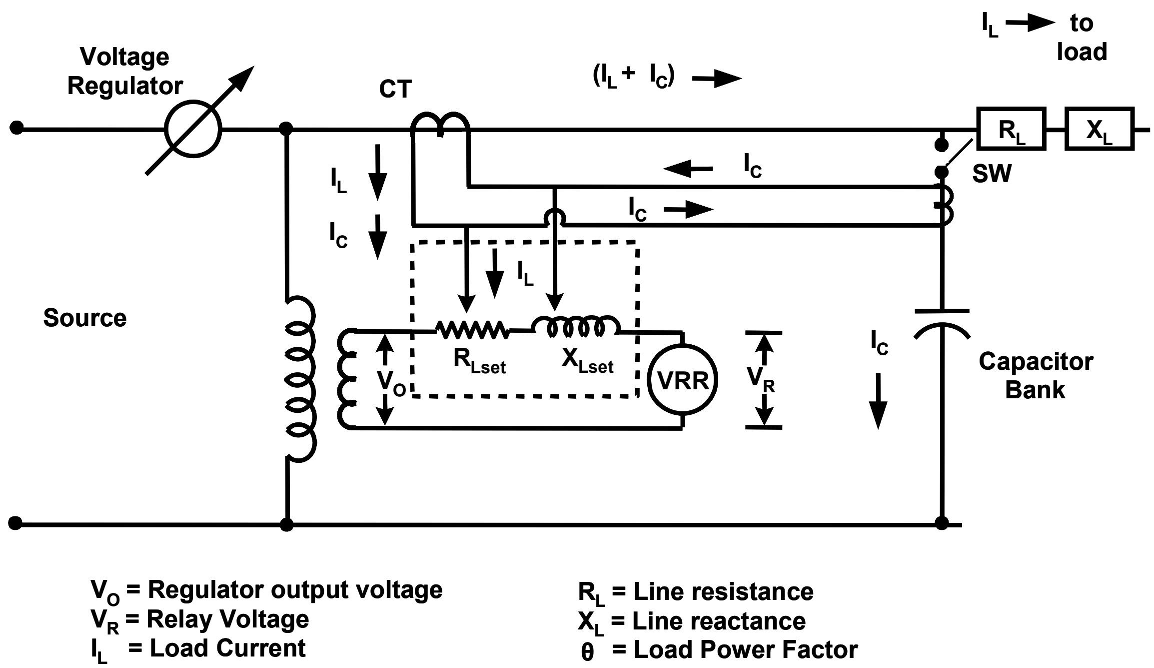


Figure 43. Control system and line drop compensator with use of a shunt capacitor at the location of regulator

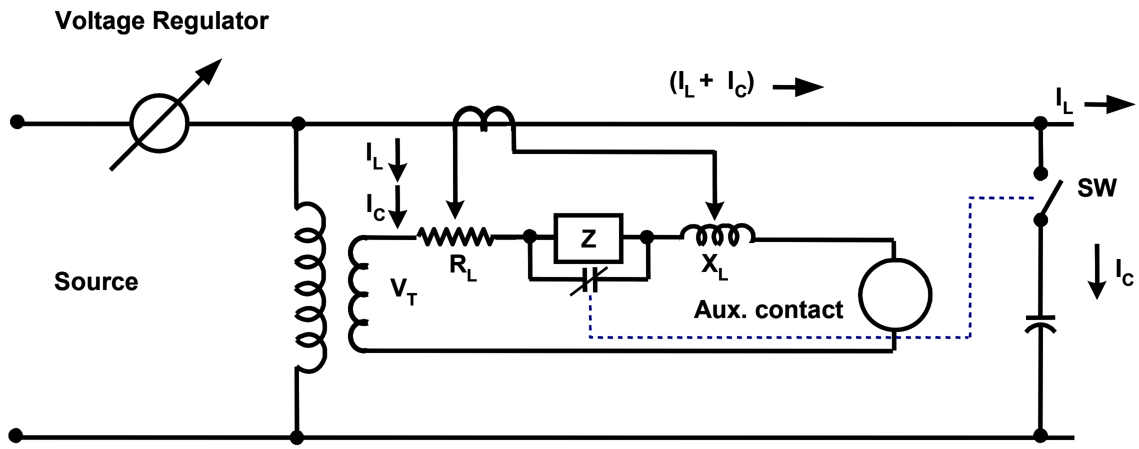


Figure 44. Voltage across impedance Z in relay circuit is equal to voltage rise because of capacitor current I_c

3.27 Switched Capacitors Downstream from Regulators

When switched capacitors are installed downstream from the regulators, the compensator settings or the voltage setting on the VRR can be changed. The easiest approach is to change the VRR setting. Coordination of regulators and switched capacitors on the same circuit is generally not a problem because the bandwidth on the capacitor voltage control relay is greater than the regulator bandwidth and the time delay for the capacitor control is more than the regulator time delay (which is similar to regulators installed in series, in which the downstream regulators have a greater time delay than the upstream regulators). Also, the voltage change at the capacitor when it switches on is high compared with what the upstream regulators see.

3.28 Capacitor Application

As noted earlier, capacitors can be added to distribution circuits to improve voltage regulation. Equation 3.8 showed that voltage rise (a reduction in load current I_L) can be calculated if one knows the single-phase kilovolt-amperes reactive or three-phase kilovolt-amperes reactive, the distance from the source to the capacitor, the inductive line reactance, and the line-to-line voltage. The voltage rise is independent of the load magnitude. Therefore, it is common to install switches to turn them on and off to not subject customers to HV during LL conditions, when the voltage drop in the circuit is low.

Capacitors are rated in kilovars, the value of which is derived from the capacitance C in microfarads, the rms voltage V, and the frequency, or

$$\text{kVAr} = (V^2\, 2\pi f\, C \times 10^{-6})/1{,}000. \qquad \text{Equation 3.65}$$

Notice the kilovar value is proportional to the square of the voltage. As voltage drops on a circuit, the kilovar value decreases, and the voltage rise decreases.

There are two types of capacitors: series and shunt. Series capacitors are not discussed here because their application can cause a sub-synchronous resonance condition. Often, additional resistance must be added to correct this problem. Shunt capacitors supply a source of kilovars similar to an overexcited synchronous generator. They are often applied to induction generators to supply a source of voltage. Shunt capacitors lower or counteract the lagging component of circuit current and, thus, increase the voltage at their location. This improves the voltage regulation. Because the lagging component of current is reduced, capacitors reduce the I_2R_L real losses and the I_2X_L reactive losses. They are a low-cost solution to improving the power factor of load because synchronous generator volt-amperes reactive are about four times the cost of static capacitors. This reduces the kilovolt-ampere loading on synchronous generators, which in turn, allows more kilowatt generation (if this is not limited by the prime mover kilowatt output). When capacitors are added to a circuit, they reduce the load current, release capacity to serve future load, and reduce the cost to serve kilowatts. Correction to unity power factor where no reactive current exists in the load current is generally not economical. Power factors ranging from about 0.975 up to 0.980 are normally the most economic, as seen by the generation source. The diminishing return effect is illustrated in Figure 45.

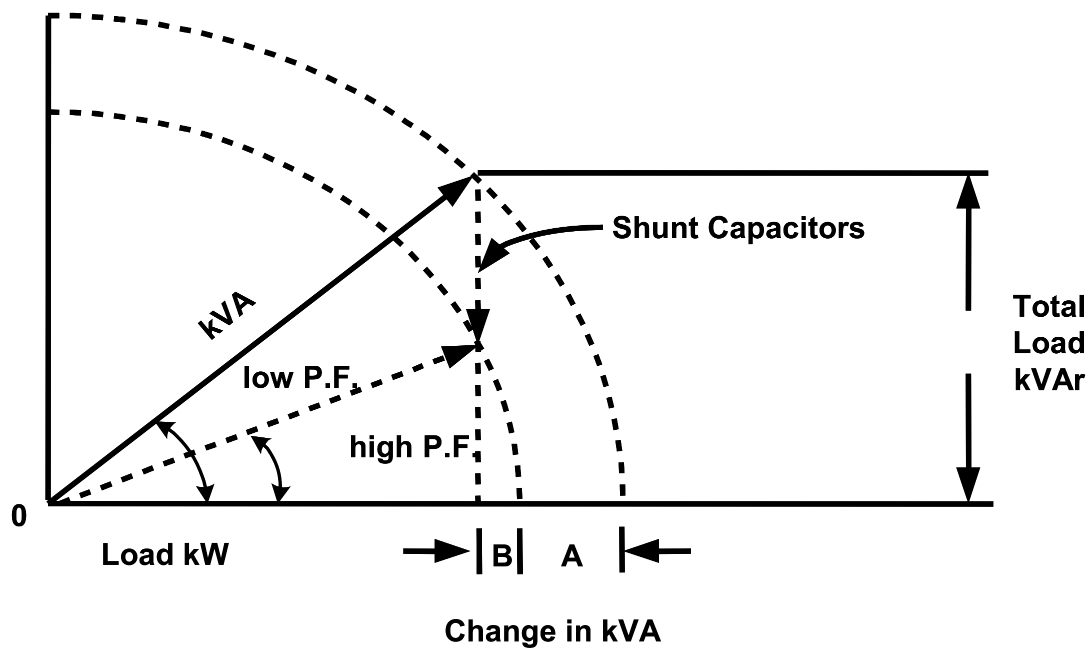


Figure 45. Application of shunt capacitors

Applying enough kilovar shunt capacitance to offset just half the load kilovars results in a large kilovolt-ampere reduction of “A.” If an additional equal amount of kilovars is added, it results in only a small kilovolt-ampere reduction of “B.” Thus, the lower the power factor, the more benefit that is derived from installing shunt capacitors.

The voltage drop ΔV in a circuit can be approximated by

$$\Delta V = I_r R + I_x X, \text{ or} \qquad \text{Equation 3.66}$$

$$\Delta V = I (R \cos \theta + X \sin \theta), \qquad \text{Equation 3.67}$$

where:

I = Load current
I_r = Real component of current
I_x = Reactive component of current
θ = Load power factor angle.

When a capacitor is added, Equation 3.66 becomes

$$\Delta V = I_r R + I_x X - I_c X, \qquad \text{Equation 3.68}$$

where:

I_c = Capacitive reactive components of current.

If too many volt-amperes reactive are added to the circuit during LL conditions, the circuit can become overcompensated because I_C is proportional to V, not the load.
Figure 46 shows the phasor diagram when a shunt capacitor is added at the load. The sending-end voltage with the capacitor applied (V_{SC}) is less than the sending-end voltage without the capacitor (V_S).

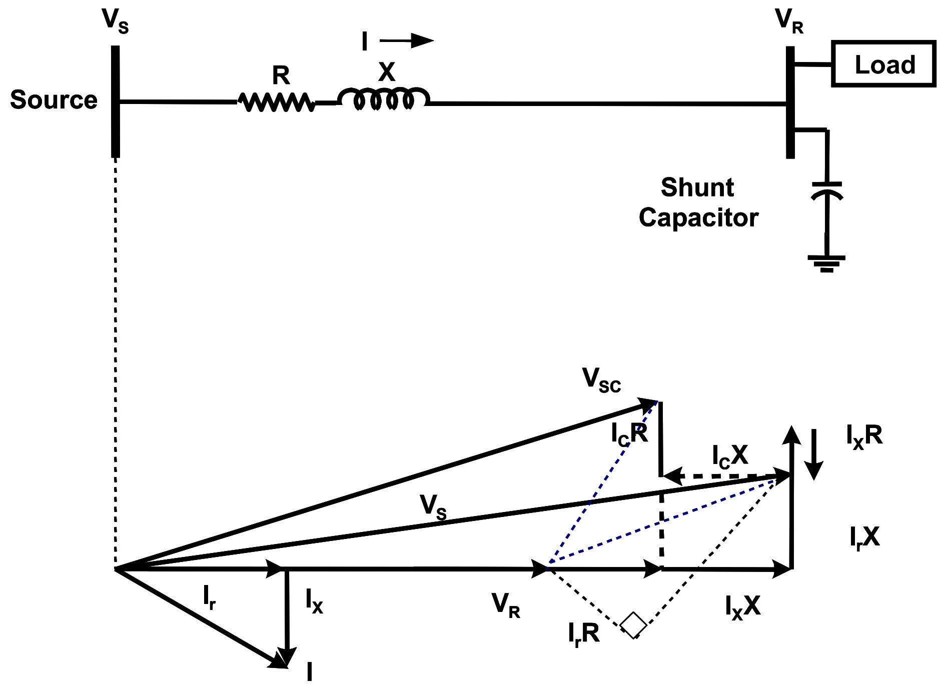
3.29 Capacitor Controls

Capacitor control can be accomplished through the:

- Time clock
- Voltage
- Current
- Temperature
- Time clock with voltage override
- Time clock with different VRR settings
- Current with voltage override
- Radio or other communication medium
- Power factor.

The most common and simplest control is time clock control because the load profile on most circuits is predictable. As such, the time clock turns the capacitor on at a set time in the morning and off at a set time at night.

Figure 47 shows a voltage-current control in which the voltage can be measured at the capacitor or another location on the circuit and the VRR signals the capacitor switch to close.



The I_xX Component is parallel to and opposite to the I_cX component.

V_R = voltage at the load or receiving end voltage.
V_S = sending end voltage
V_{SC} = sending end voltage with capacitor

Figure 46. Phasor diagram of the reduction in the sending-end voltage with a shunt capacitor

The resistor R is chosen so that its voltage drop represents the drop in voltage to the regulation point. If the power factor varies, it may be necessary to add a reactance with the resistance.

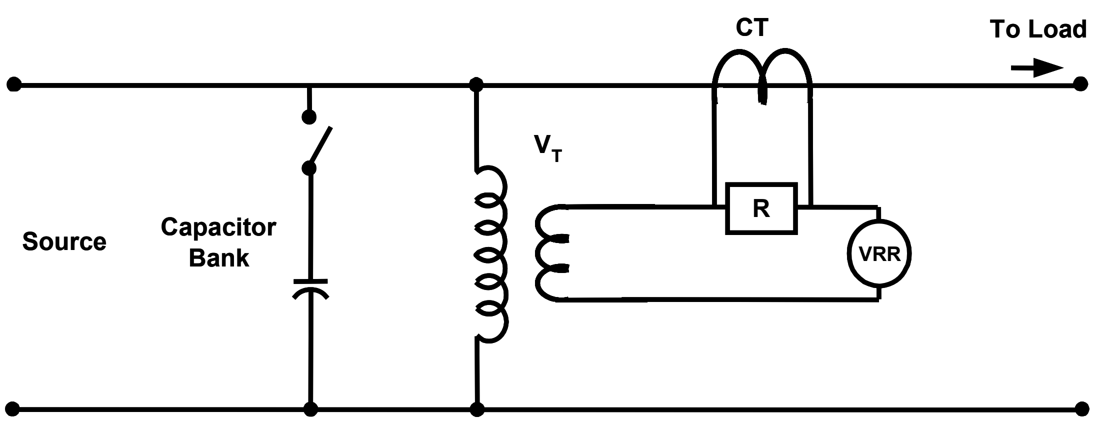


Figure 47. Voltage and current control of capacitor switching

3.30 Capacitor Connections

Three-phase capacitor banks are normally connected delta or wye with the neutral grounded as in Figure 48 or wye with the neutral ungrounded as in Figure 49. Delta-connected capacitors or ungrounded wye-connected capacitors may result in a resonant condition when one or more of the phase conductors on the source is open, as shown in Figure 50. The capacitor bank can provide voltage to the loads when an open phase (or phases) occurs.

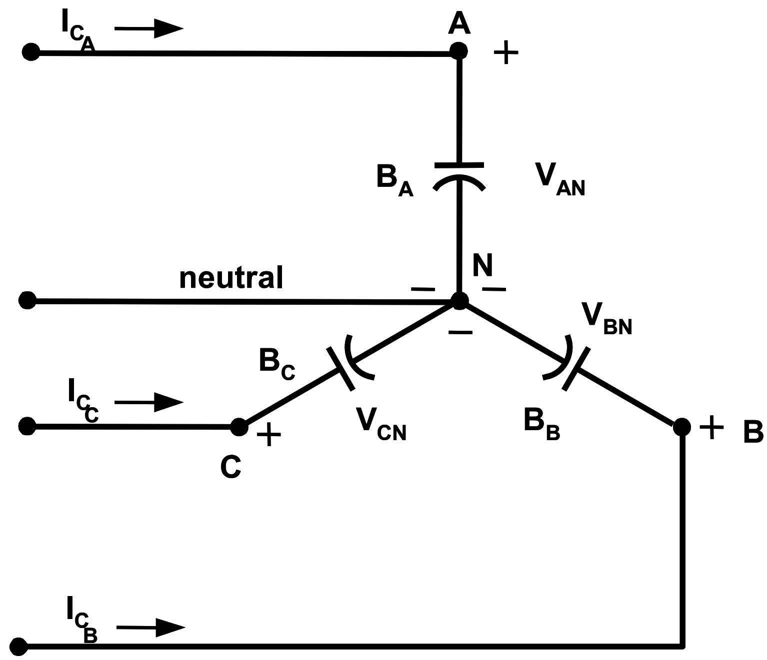


Figure 48. Wye-connected capacitor bank

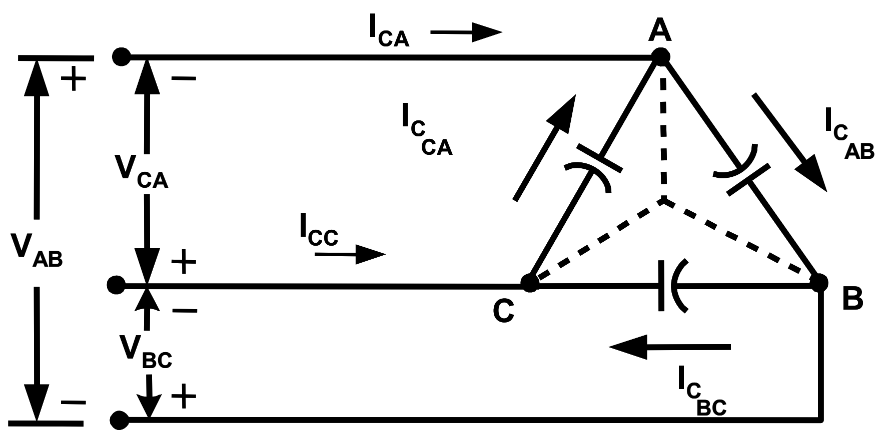


Figure 49. Delta-connected capacitor bank

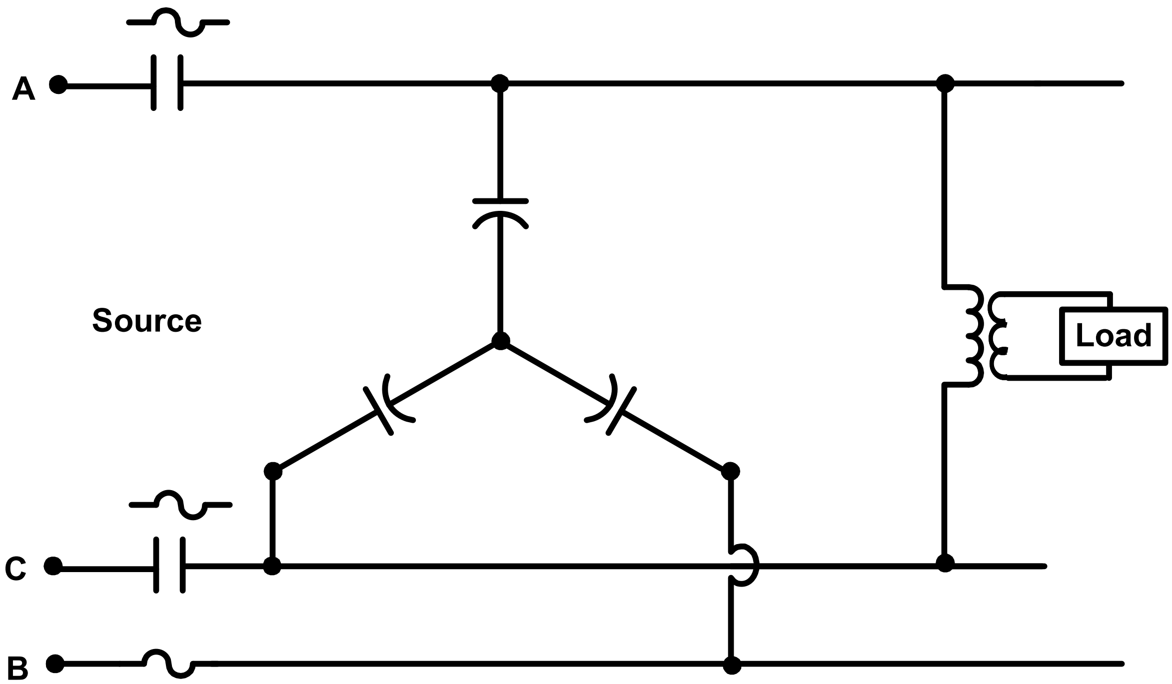


Figure 50. Series resonance condition with open phases

Putting capacitors in series with transformers feeding load may create a series resonant circuit. For this reason, it is not recommended that capacitor banks be put on the load side of single-phase fuses, sectionalizers, or reclosers. Grounded wye capacitors are used on four-wire wye systems. Grounded wye capacitors applied to ungrounded wye or ungrounded delta systems cause ground currents and overvoltages during ground faults. Therefore, grounded wye banks are not used on delta systems or ungrounded wye systems. Delta-connected banks are used on delta systems and ungrounded wye systems.

4 Project Results – Effects of Unbalanced Loading and Voltage on System Protection and Distributed Generation

4.1 Introduction

This section describes the effects of unbalanced voltage and load on system protection. The effects of unbalanced voltage and load on sensitive ground relaying were studied for a selected circuit, and adequate protective relaying limits were determined for different levels of unbalance and different energy conversion devices.

This section includes an overview of system protection philosophy, focused on the issues associated with unbalanced loading. Descriptions of the operation of protective devices under unbalanced conditions are also provided. For a detailed discussion of protective relay theory and operation, consult Elmore (1994), Electrical Distribution (2005), and Mason.

4.2 System Protection Design Philosophy for Grounded and Ungrounded Systems

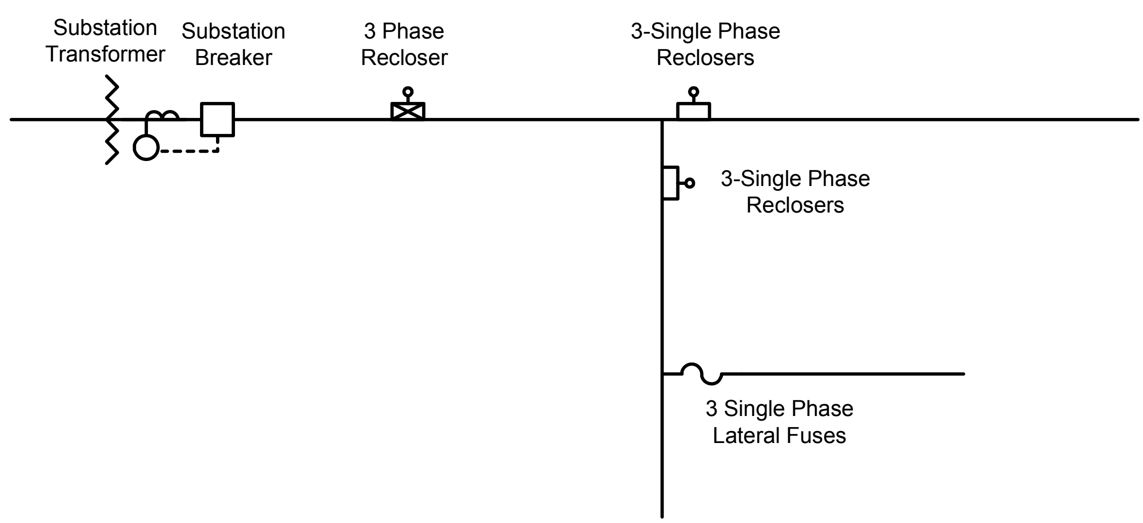


Figure 51. Radial distribution circuit with typical system protection devices

Figure 51 shows overcurrent relaying application for the entire circuit. The protective devices must be capable of carrying the intended load (loadability), sensing and clearing faults (sensitivity), and selectively de-energizing the minimum amount of load to isolate faults (selectivity).

Typical loads, as seen by major protective devices, are shown in Figure 52. Devices at the substation must carry the load of the entire circuit; devices downstream carry less load. The amount of unbalance in the phase currents may or may not be greatest at the substation breaker.

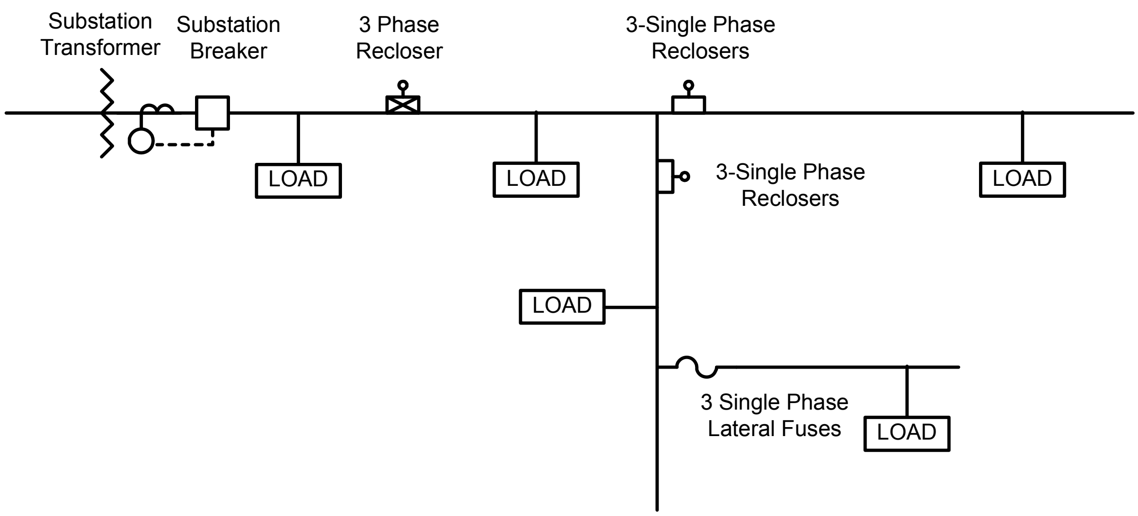


Figure 52. Radial distribution circuit showing load

Figure 53 shows the portions of the circuit where the protective device must sense faults. Note that, for full circuit protection, the zone of protection for the upstream device must extend beyond (overlap) the beginning of the next downstream device.

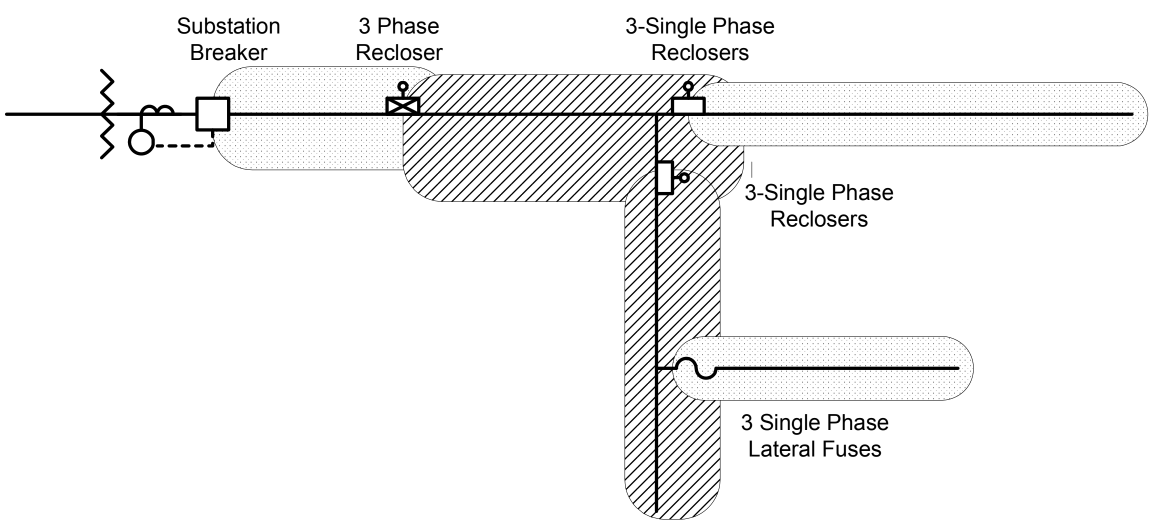


Figure 53. Radial distribution circuit showing protection zones

Figure 54 shows the relative tripping times for the substation breaker, the three-phase recloser, and the single-phase recloser. As the distance between a protective device and a fault increases, tripping time increases. For a fault downstream at point A, the single-phase recloser will trip in about 0.5 seconds. The three-phase recloser will trip in about 0.8 seconds. If the single-phase recloser operates correctly, the three-phase recloser should not operate, and only load beyond B will be interrupted.

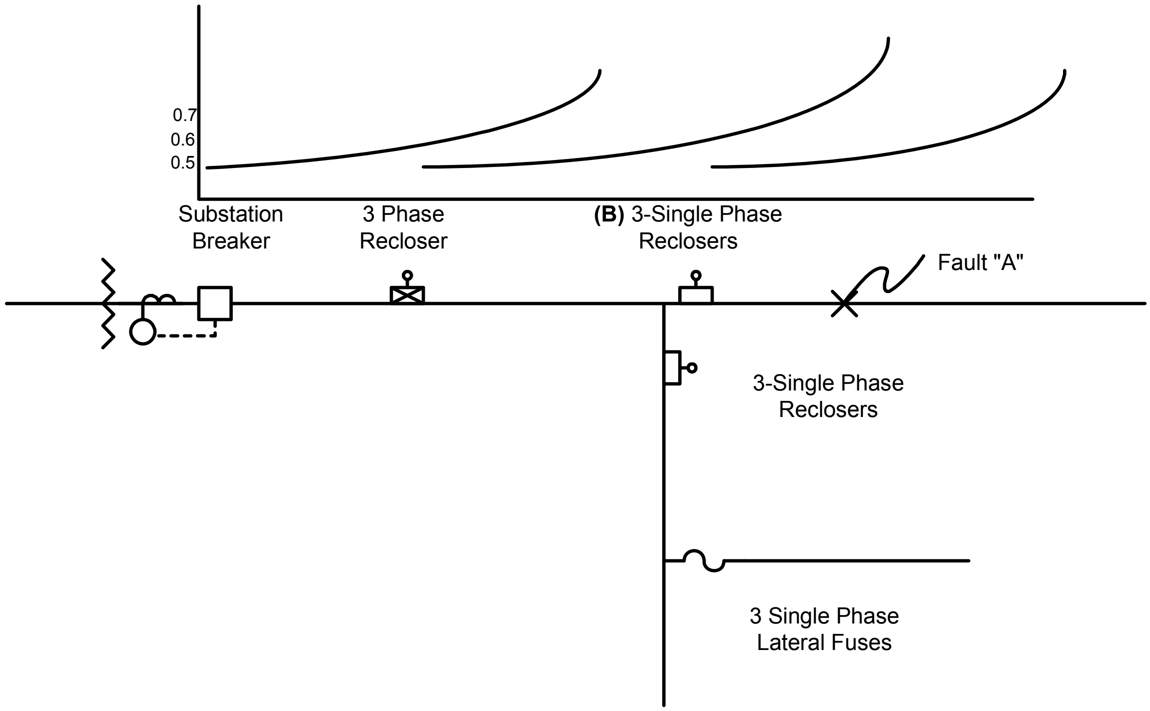


Figure 54. Relative tripping times for protective devices

Figure 55 shows the time-current characteristics for a typical breaker and reclosers. For any specific value of current, the device closest to the substation operates last, and the device furthest from the substation operates first.

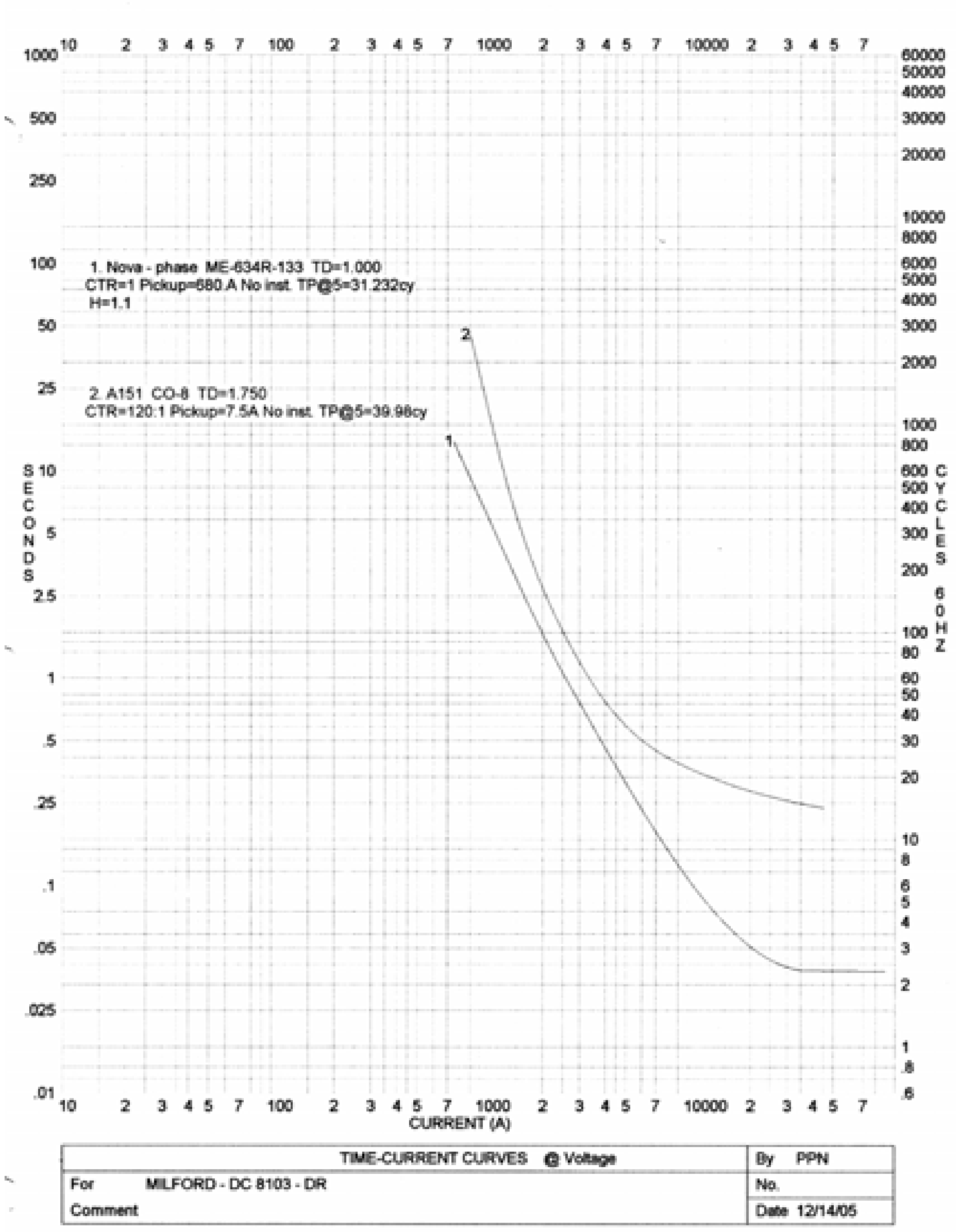


Figure 55. Relative time-current curves for protective devices

4.2.1 Four-Wire Grounded Wye Systems

Four-wire grounded wye systems have a substation transformer with a grounded wye winding sourcing the circuit bus. The primary of the transformer is typically connected in a delta. The neutral point of the transformer secondary is grounded and taken out on the circuit as the neutral with the three-phase conductors. The three-phase diagram in Figure 56 shows details of the connections at the substation and load on the circuit. A single-phase load connected line-to-ground will cause current to flow in the neutral of the system unless it is balanced by equal amounts of other single-phase loads connected to the alternate phases.

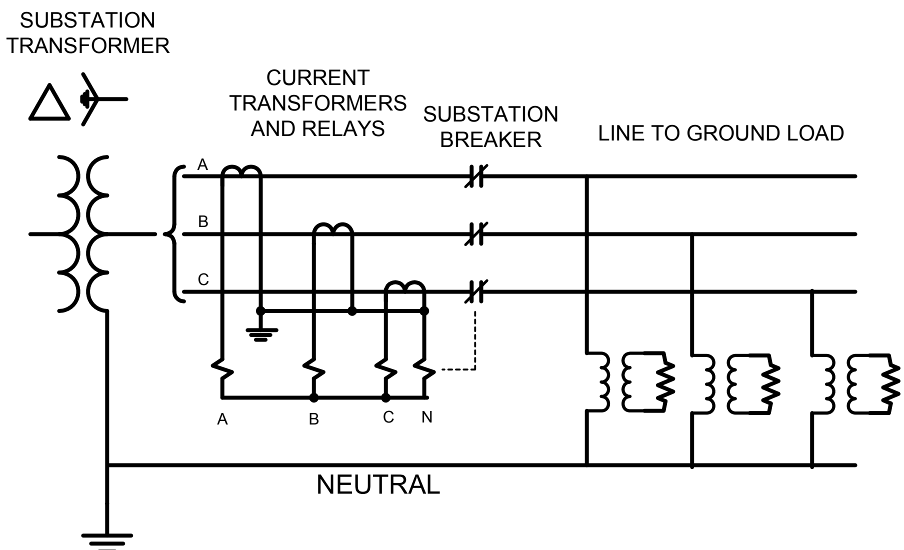


Figure 56. Three-phase diagram of a four-wire grounded system

4.2.2 Three-Wire Ungrounded Delta Systems

Three-wire ungrounded delta systems have a substation transformer with an ungrounded delta winding sourcing the circuit bus. The primary of the transformer may be configured in an ungrounded wye, grounded wye, or delta. Figure 57 shows details of the connections at the substation and load connected on the circuit. The ungrounded delta system differs from the grounded wye system because the load is always connected phase-to-phase. Typically, there is no neutral or ground relay connected to detect ground faults, as is the case for the four-wire grounded wye system. A small amount of current will flow if a phase conductor makes solid contact with ground. Some systems may use a ground current relay to detect this. A ground detector system is typically installed to alarm for unintentional grounds caused by downed conductors or foreign objects making contact with a phase conductor. Ground detector systems and why ground currents will flow on ungrounded systems are explained in Appendix A.

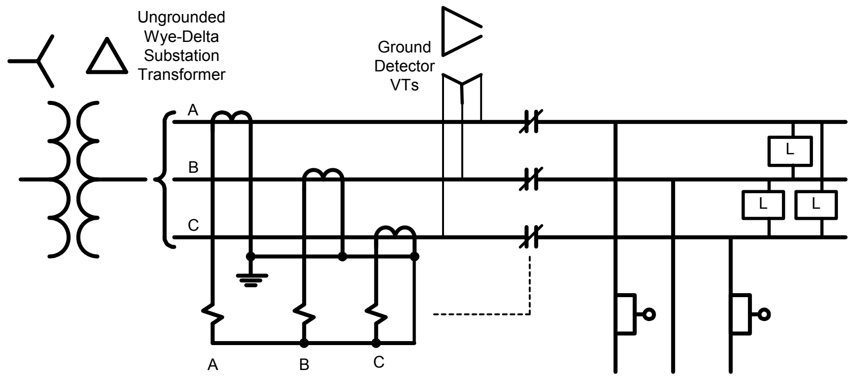


Figure 57. Three-phase diagram of a three-wire ungrounded system

4.3 Unbalanced Voltage Effects on Protective Relaying

Unbalanced voltages can cause an addition to current already in the neutral conductor and relay because of unbalanced load. For the case in which balanced loads are served from a distribution circuit with balanced voltages, no current is in the neutrals of a four-wire system. For the case in which the voltage is unbalanced and the load is primarily resistive and connected line-to-ground, the load will decrease on the lowest voltage phase and increase on the highest voltage phase. The current imbalance will result in a current flow in the neutral conductor and ground (earth). For the case in which the motor load consists primarily of single-phase loads connected line-to-ground, lowering the voltage on one phase will cause the current to increase on that phase. This is due to the essentially constant power (CP) characteristic of the motor. This current imbalance will cause additional neutral current.

Additional unbalance can result from failed capacitor cans (units) within a capacitor bank. The volt-amperes reactive from the capacitor bank are directly proportional to the voltage squared. (See Equation 3.65 in Section 3.) Unbalancing the voltage causes an unequal supply of volt-amperes reactive and an unbalanced loading effect with increased neutral current.

The ultimate effect of unbalanced voltage on the neutral current of the distribution circuit can depend on a number of factors, including:

- The mix of single-phase resistances and single-phase motor load
- Capacitor size, location, and unbalance because of unit failures
- Current unbalance and significant increased losses from unbalanced voltages applied to three-phase induction and synchronous machines
- Unsymmetrical transformer connections (e.g., open-delta, open-wye, and unequal impedances)
- Untransposed lines
- Open phases because of single-phase fuse blowing and single-phase protective devices
- Malfunctioning single-phase VR within a three-phase or open-delta or open-wye configuration

- Single-phase VRs connected in a bank and operating to correct a voltage unbalance condition
- Single-phase VRs operating on a long single-phase portion of a three-phase circuit.

Additional neutral current caused by unbalanced voltage on the circuit will flow in the neutral relay (51N) at the substation if neutral current flows through any three-phase protective device downstream from the substation. However, circuit unbalance can occur on a portion of the circuit but be balanced with other connected load such that no neutral current reaches the neutral relay element of that protective device. This relay must be set to trip for ground faults. The setting may have to be increased to take into account the increased neutral current because of the unbalanced condition.

4.4 Unbalanced Current Effects on Protective Relaying

Unbalanced loading can occur even though voltages are balanced at the source. The factors that affect unbalanced loading are similar to those factors that affect unbalanced voltage.

4.4.1 Single-Phase Operation of Protective Devices

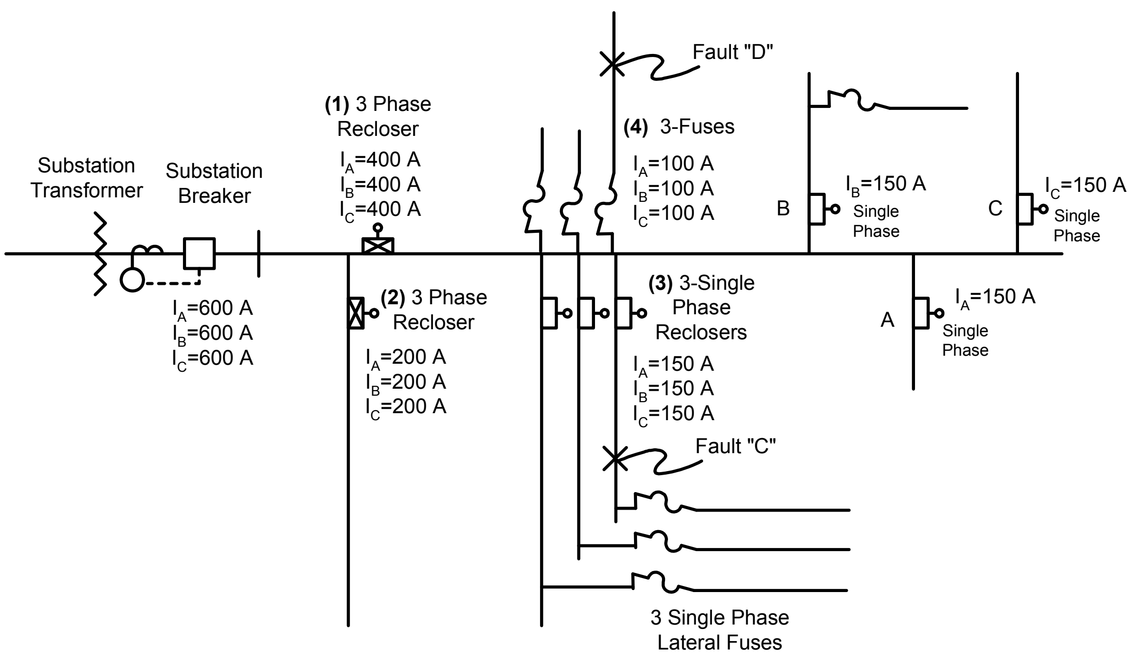


Figure 58. Single-phase operation of protective devices on a four-wire wye circuit of resistive loads

Figure 58 shows that protective devices may be three-phase devices, a set of three single-phase devices, or single-phase devices that protect single-phase laterals. Operation of one of these single-phase devices on a previously balanced loaded circuit will cause unbalanced loading and neutral current. When the circuit is in a normal state with the loads given in Figure 58, the three-phase recloser (1) has no current in the neutral relay element. When the single-phase recloser (3) on Phase C opens because of the fault at C, load of 150 A is lost on Phase C downstream of the recloser. The phase currents on the substation breaker change to:

$$\mathbf{I_A} = 600\ \text{A}\ \angle 0°, \mathbf{I_B} = 600\ \text{A}\ \angle \text{-}120°, \mathbf{I_C} = 600\ \text{A}\ \text{-}150\ \text{A}\ \angle 120° = 450\ \text{A}\ \angle 120°.$$

Current in the neutral element is determined by vectorally adding the three-phase currents.

$$\begin{aligned}\mathbf{I_N} &= \text{I}_\text{A}\ \angle 0° + \text{I}_\text{B}\ \angle \text{-}120° + \text{I}_\text{C}\ \angle 120° \\ \mathbf{I_N} &= 600\ \text{A}\ \angle 0° + 600\ \text{A}\ \angle \text{-}120° + 450\ \text{A}\ \angle 120° \\ &= 150\ \text{A}\ \angle \text{-}60°\end{aligned} \qquad \text{Equation 4.1}$$

4.4.2 Operation of Circuit Protective Devices for Ground Faults

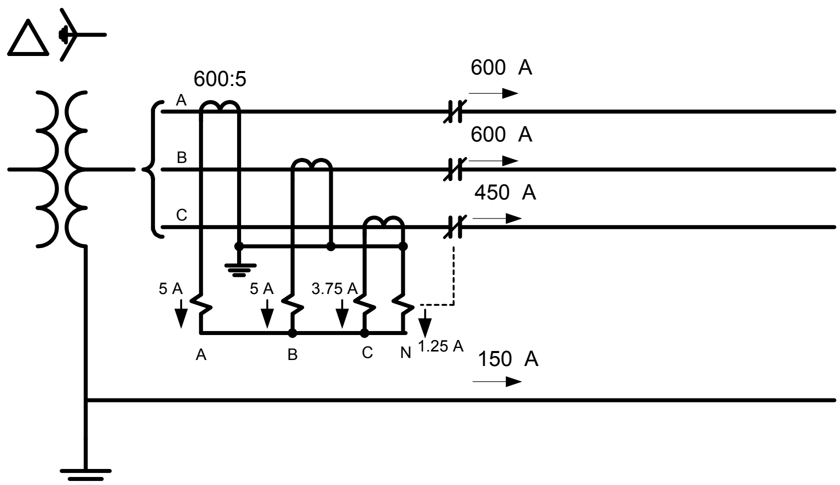


Figure 59. Diagram of substation breaker and relays with ground-sensing circuit

The equipment arrangement shown in Figure 59 is typical for a four-wire grounded system. The substation transformer, CTs, protective relay current coils, and circuit breaker are represented. For simplicity, it is assumed that all load is resistive and connected line-to-ground and that the phase currents are in phase with their respective voltages. Unbalanced currents resulting from phase-to-phase-connected load may not show up in the ground or neutral relay sensing circuits.

Unbalanced current flowing to the load on the circuit will result in current in the neutral relay coil (N). The example shows loads of 600 A, 600 A, and 450 A, respectively, on A, B, and C phases. Taking into account the CT ratio of 120, the neutral current in the relay element is 150/120 = 1.25 A. The setting is based on two times the minimum load, which is 1.8 MVA or 157 A.

$$2\,\text{I}_{\text{min}} = 2\,\frac{1{,}800\ \text{kVA}}{\sqrt{3}\ \ \text{x}\ 13.2\ \text{kV}} = 2\ \text{x}\ 78.73 = 157\ \text{amperes} \qquad \text{Equation 4.2}$$

Because the setting is 157/120 = 1.31 A and neutral current is 1.25 A, the breaker will not open for the unbalance caused by clearing Fault C, but the single-phase recloser (3) will open and lock out for the permanent fault. (See Figure 58.)

Reclosers with ground fault-sensing circuits will be affected similarly by load unbalance. The same equations can be used for the recloser and the circuit breaker.

Another case to consider is the opening of a fuse (4) in Figure 58 for a fault at D. The unbalance current is 100 A, which results in $I_N = 100\text{ A} \angle -60°$ and a relay element current of 0.833 A. Because this is below the setting of 1.31 A, the breaker will not trip, and the fuse (4) will isolate the fault.

The fault current that occurred at D and caused the 150-A fuse (4) to blow was significantly higher than the resultant unbalanced current (neutral current) after the fault cleared. For example, the fault current magnitude could range from 1,500 to 7,000 A. In this case, the neutral relay would see from 12.5 A to 58.3 A for approximately 0.1–0.06 seconds (fuse-clearing time). See Figure 63.

4.4.3 Single-Phase Operation of Disconnect and Isolation Devices

Opening the fused disconnect (5) of Figure 58 has the same effect as the cleared fault D on the neutral current. Disconnects are often opened to allow maintenance and repair of downstream equipment.

4.4.4 Unbalanced Load Connected Line-to-Line

Load that is connected line-to-line will not produce current in the neutral relay element. Even unequal single-phase load connected line-to-line will not produce neutral current in the ground relay. For example, unequal load connected line-to-line will result in negative sequence current but no zero-sequence neutral current because

$$I_A + I_B + I_C = 0. \qquad \text{Equation 4.3}$$

The equations for the substation breaker also apply in this case. However, caution must be exercised to use the correct phase angle of the current in each phase. Figure 60 shows resistive load connected between B and C phases. Current flowing in the load equals the voltage across the load divided by the resistance.

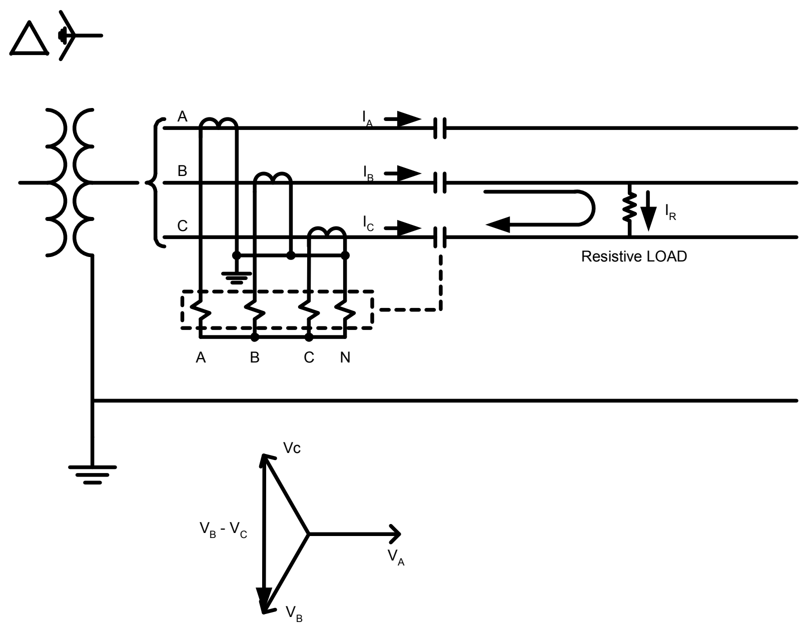


Figure 60. Current flow in phase-to-phase-connected load

For this circuit, assume:

$$\mathbf{V_A} = 7{,}620\angle 0^\circ$$

Equation 4.4

$$\mathbf{V_B} = 7{,}620\angle -120^\circ$$

$$\mathbf{V_C} = 7{,}620\angle 120^\circ$$

$$\therefore V_{BC} = V_B - V_C = 13{,}200\angle -90$$

$$P_L = 100\text{kW} \therefore I_L = 100{,}000 \text{ Watts} \div 13{,}200\text{volts} = 7.56 \text{ amperes}$$

For this circuit, current in Phase B returns on Phase C. Or $I_B = -I_C$.
Voltage across the load equals the difference between the voltages V_B and V_C or $V_B - V_C$.
Current in the load equals the voltage across the load divided by the resistance or $(V_B - V_C)/R_L$. If no other load is on the circuit, then $I_B = I_R = -I_C$ and $I_A = 0$.

Using the equations for the substation breaker:

$$\mathbf{I_N} = \mathbf{I_A} + \mathbf{I_B} + \mathbf{I_C}$$

Equation 4.5

$$\mathbf{I_A} = 0\angle 0^\circ \quad \mathbf{I_B} = 7.56\angle -90^\circ \quad \mathbf{I_C} = \quad 7.56\angle -90^\circ$$

(Current in amperes)

$$\mathbf{I_N} = 0\angle 0^\circ + 7.56\angle -90^\circ \quad 7.56\angle -90^\circ = 0$$

Equation 4.6

Even though the load is unbalanced, it is important to consider how the load is connected, which has an effect on the phase angle of the currents flowing, as seen at the substation breaker and the respective relays.

4.4.5 Fuse Preload Because of Unbalanced Loading or Unbalanced Voltages

Load unbalance can cause fuses to become unselective with other protective devices (such as reclosers). This inselectivity is due to load-unbalanced currents heating the fuse element and causing a shift in the time-current characteristic. In Figure 61, the melting time as a percentage of the published time-current characteristic for a fuse is shown as a function of the load current in percentage of the fuse ampere rating. Notice that the melt time is reduced to 52% when the load current on one of the phases of the three-phase circuit is 150% of the fuse ampere rating.

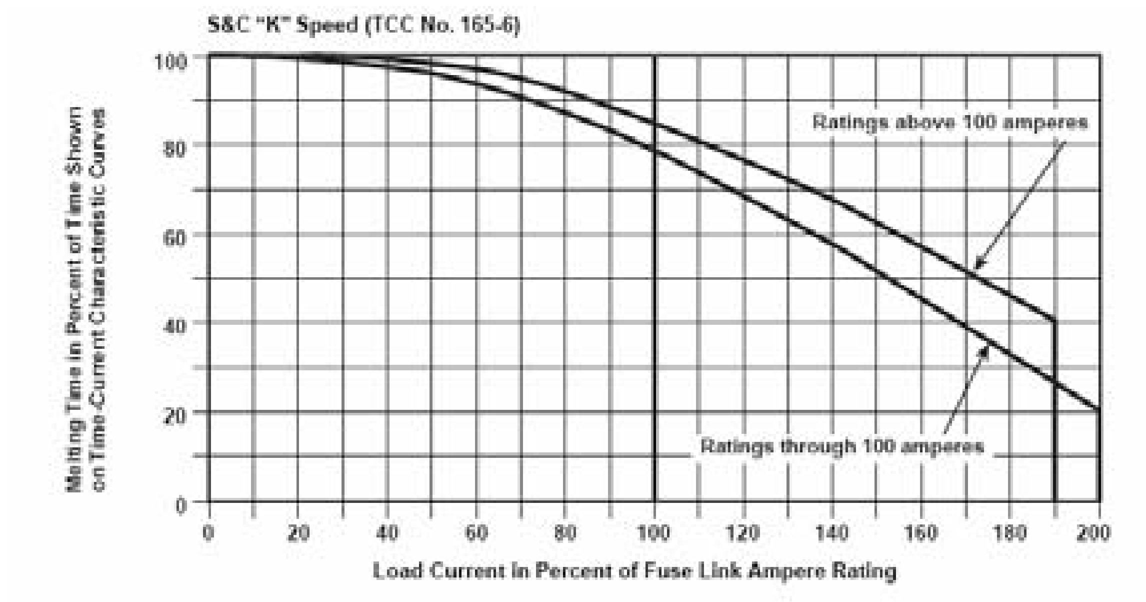
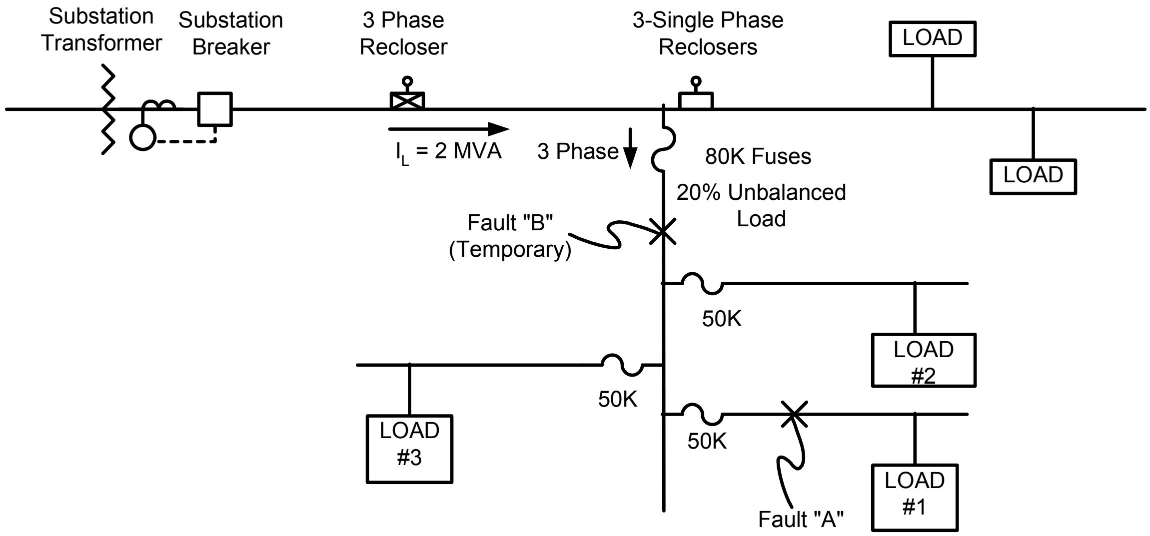


Figure 61. Reduced melt time because of preloading of universal K link fuses (S&C Electric Co. 2000)

To illustrate this coordination issue, Figure 62 shows a distribution circuit with an unbalanced three-phase lateral that serves a number of single-phase loads. For simplicity, each single-phase load is fused with a 50K fuse. The three-phase load, as seen by the 80K fuses, is unbalanced by 20%.



Notes:
Loading of 13.2-kV three-phase lateral:
I_{Lavg} = 87.50 A
$I_{Lhigh\ phase}$ = 105 A

Figure 62. Fuse preloading causes inselectivity

The average current is 87.5 A, and the high-load phase current is 120% of average, or 105 A. Figure 63 shows the fuse time-current for the 80K fuse (Curve 1) and the 50K fuses (Curve 2) with no preloading on any phase. Notice that these curves do not intersect until a fault greater than 2,000 A occurs on this lateral. If a fault, A, of 600 A or greater occurs on this lateral with a 150% preload, then the 80K fuse and the 50K fuses would blow near simultaneously, thus causing the unnecessary loss of loads 1, 2, and 3, rather than only Load 1.

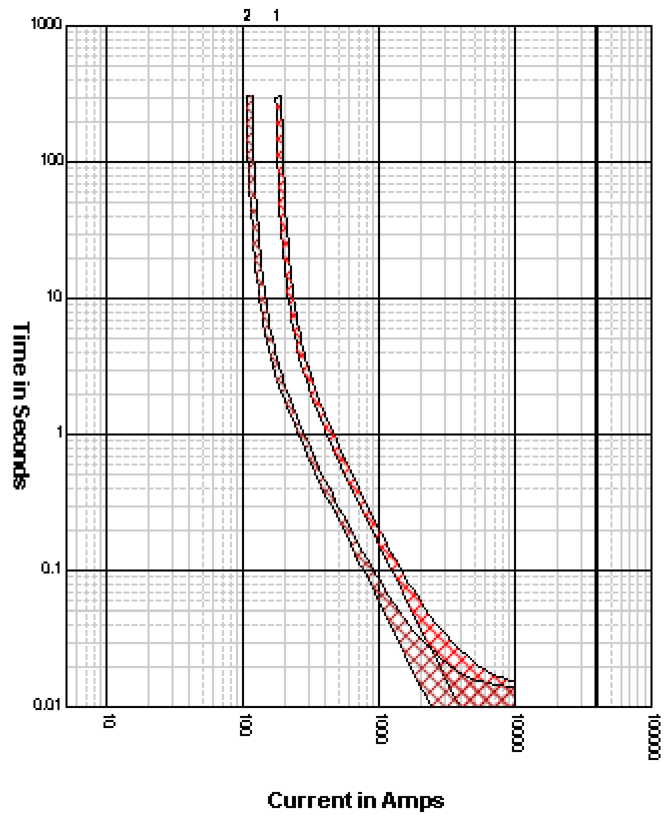


Figure 63. Coordination of 50K and 80K fuses (S&C Electric Co.)

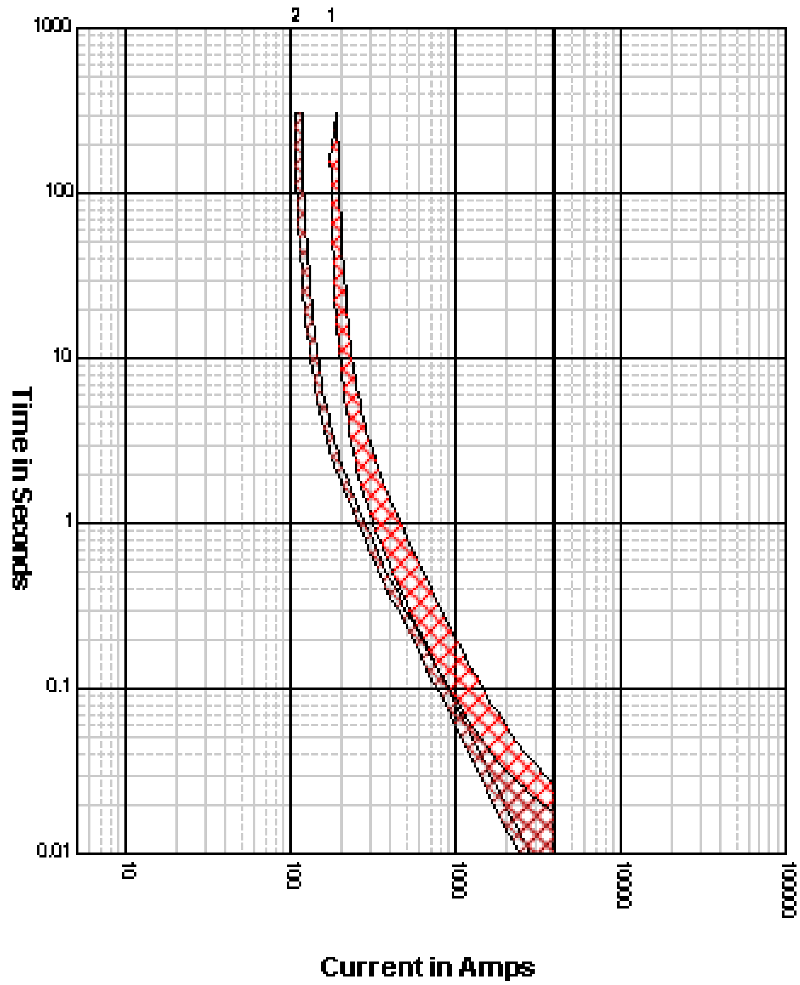


Figure 64. Inselectivity of 80K and 50K fuses for unbalanced loading of 20% (S&C Electric Co.)

Another example of this inselectivity may occur when the 80K fuse is preloaded because of unbalance and a temporary fault is placed at B of Figure 62. The fault would cause the recloser to open on the fast curve, the 80k fuse would blow because of preload, and all of the load on the lateral would be lost before the recloser restores power to the then-unfaulted lateral. Without the preloading because of the unbalance, the 80K fuse would not have blown, and the recloser would have restored power after the temporary fault cleared.

Because unbalanced voltages create unbalanced currents, similar effects of inselectivity can occur between protective devices.

4.5 Unbalanced Voltage Conditions

Unbalanced voltages may exist on distribution primaries and secondaries because:

- The loads on a distribution circuit are not all three-phase but predominately single-phase
- The distribution phases are not fully transposed to balance the line impedances
- The phase conductors are different and thus have different impedances
- The transformer banks serving the three-phase loads are not identical single-phase units of the same size and impedance
- The transformer connections are either open delta or open wye
- One of the phase conductors is open upstream from the load because of a blown single-phase fuse or other open single-phase protective device
- The phase conductor is broken
- Individual units of capacitors within a capacitor bank fail and cause unbalanced conditions.

It is important to keep the three-phase circuits as closely balanced as possible to prevent overloading the equipment on the highest loaded phase. Also, it is recommended that the unbalanced loading be kept to no more than 10%–20% because it permits more sensitivity in setting the ground fault relay.

Reducing the unbalanced loading reduces the losses created by the neutral current in the neutral conductor. Unbalance tends to be greater during off-peak conditions and at points at which the single-phase laterals are tapped to the three-phase primary. Unbalanced three-phase voltages have a significant effect on the design and operation of transformers and induction and synchronous machines. Unbalance causes a voltage with a rotation that is opposite to the voltage of a balanced supply. These opposite rotating voltages, called "negative sequence voltages," produce a flux in the air gap of these machines that counters the rotor rotation and causes high line currents in the phases that feed the machines. These higher line currents cause additional losses in the motors, generators, and distribution system.

4.5.1 Induction Machines Operating on Unbalanced Voltages

The National Electrical Manufacturers Association Standard MG1-14.34 (National Electrical Manufacturers Association 1978) specifies the voltage unbalance at the terminals of the polyphase induction motor is not to exceed 1%. The voltage unbalance, in percentage, is defined as

$$\text{Percent voltage unbalance} = 100 \times \frac{\text{maximum voltage deviation from avg. voltage}}{\text{average voltage}}$$

Equation 4.7

The standard goes on to say that:

> "A relatively small unbalance in voltage will cause a considerable increase in temperature rise. In the phase with the highest current, the percentage increase in temperature rise will be approximately two times the square of the percent voltage unbalance. The increase in losses and consequently the increase in average heating of the whole winding will be slightly lower than the winding with the highest current.
>
> "To illustrate the severity of this condition, an approximate 3.5 percent voltage unbalance will cause an approximate 25 percent increase in temperature rise."

The breakdown torque and locked rotor torque are decreased for unbalanced voltages. The phase currents with unbalanced voltages are greatly unbalanced, on the order of four to five times the voltage unbalance. This creates a problem of choosing the correct overload protection because the proper setting for one unbalanced condition may not be adequate for another unbalanced condition. If the setting is raised, the motor may not be protected against overload and open phases.

The load or generation may have to be reduced below the nameplate output rating to avoid overheating. For example a 5% voltage unbalance might result in a 25% reduction in the nameplate rating. If lowering the load is not possible, the size of the motor would have to be increased if the unbalanced abnormal condition prevails and cannot be corrected.

Equation 4.7 is usually accurate enough to predict the percent voltage unbalance for unbalanced conditions less than 3%, but at 5% or greater, the method of symmetrical components should be used. The example below (Table 1) compares the percent voltage imbalance determined from Equation 4.7 with the correct percent voltage unbalance calculated using symmetrical components. The correct voltage unbalance is calculated by first determining the positive sequence voltage V_1 from the measured line-to-line voltages, V_A, V_B, and V_C. The Law of Cosines is used to calculate the angles once the magnitudes are measured. The positive sequence voltage V_1 is

$$V_1 = 1/3\ (V_A + a\ V_B + a^2\ V_C). \qquad \text{Equation 4.8}$$

The negative sequence voltage, V_2,

$$V_2 = 1/3\ (V_A + a^2\ V_B + a\ V_C), \qquad \text{Equation 4.9}$$

is then determined. Next the negative sequence voltage is divided by the positive sequence voltage. The percent voltage unbalance $\%V_u$ is found from

$$\%V_u = \frac{\mathbf{V_2}}{\mathbf{V_1}} \times 100\,. \qquad \text{Equation 4.10}$$

The zero sequence voltage is

$$V_0 = 1/3\ (V_A + V_B + V_C), \qquad \text{Equation 4.11}$$

which is zero for $V_A + V_B + V_C = 0$. All bolded symbols are vector quantities.

Table 1. Comparison of National Electrical Manufacturers Association Standard Method with Correct Voltage Unbalance Calculations Using Symmetrical Components

	Case I		Case II Rev. Rotation		Case III		Case IV Rev. Rotation	
V_A	232		225		233		226	
V_B	230		230		228		228	
V_C	225		232		226		233	
V_{avg}	229		229		229		229	
V_{A1}	229.0	$\angle 59.7°$	228.9	$\angle 60.7°$	228.9	$\angle 59.3°$	229.0	$\angle 60.3°$
V_{A2}	3.56	$\angle 105.2°$	4.13	$\angle -103.0°$	4.30	$\angle 76.5°$	4.00	$\angle -76.5°$
Equation 4.7	1.75%		1.75%		1.75%		1.75%	
Equation 4.10	1.55%		1.80%		1.88%		1.75%	

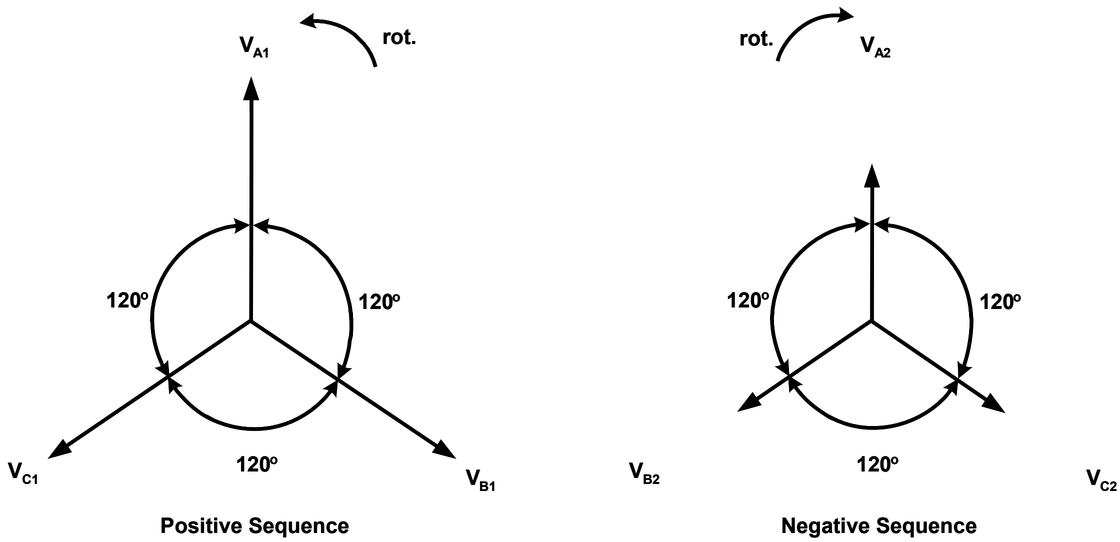
In the above comparison, little difference exists between the percent unbalance using Equation 4.7 and Equation 4.10. Equation 4.10 will be used for all calculations of percent unbalanced voltage beginning at 3%.

The effects of unbalanced voltages are greater unbalanced line currents, significantly increased losses, decreased torques, and increased slip.

4.5.1.1 Positive and Negative Sequence Equivalent Circuits

The positive and negative sequence voltages (Wagner and Evans 1933) are defined in equations 4.8 and 4.9. They each form symmetrical three-phase systems, as shown in Figure 65.

The positive sequence system consists of three equal voltages with an angle of 120° between them. When applied to the stator winding, the rotating field revolves in the positive direction. When the negative sequence system is applied to the stator winding, the field rotates in the opposite direction of the field produced by the positive sequence voltages. The results can be superimposed because they act independently.



Note: Notice the negative sequence system of vectors rotates in the opposite direction to positive sequence. But when vectorally adding positive and negative sequence vectors, both systems must rotate in the counterclockwise direction with V_{A1}, V_{B1}, and V_{C1} for positive and V_{A2}, V_{C2}, and V_{B2} for negative.

Figure 65. Positive and negative sequence system of voltages

4.5.1.1.1 Positive Sequence Equivalent Circuit

The equivalent circuit is shown in Figure 66 for the positive sequence system. The symbols are:

R_s = Resistance per phase for the stator
R_{r1} = Resistance per phase for the rotor referred to the stator
X_s = Leakage reactance per phase for the stator
X_{r1} = Leakage reactance per phase for the rotor referred to the stator
X_m = magnetizing reactance
s = Slip
I_{s1} = Stator current per phase for the positive sequence
I_{r1} = Rotor current per phase referred to the stator for the positive sequence.

$$\frac{R_{r_1}}{s} = R_{r_1} + R_{r_1}\frac{(1-s)}{s} \qquad \text{Equation 4.12}$$

Multiplying by I_{r1}^2 results in

$$I_{r_1}^2\frac{R_{r_1}}{s} = I_{r_1}^2 R_{r_1} + I_{r_1}^2 R_{r_1}\frac{(1-s)}{s}. \qquad \text{Equation 4.13}$$

Now,

$$I_{r_1}^{\ 2} \frac{R_{r_1}}{s} = \text{ Power input to the rotor per phase,} \qquad \text{Equation 4.14}$$

$$I_{r_1}^{\ 2} R_{r_1} = \text{ Copper losses in the rotor per phase,} \qquad \text{Equation 4.15}$$

$I_{r_1}^{\ 2} R_{r_1} \dfrac{(1-s)}{s} =$ Loss in a fictitious resistance that is equal to the gross mechanical power developed by the rotor per phase without including the loss for friction and windage, Equation 4.16

and

$$R_{r_1} \frac{(1-s)}{s} = \text{ Fictitious resistance.} \qquad \text{Equation 4.17}$$

The equivalent circuit of Figure 66 can now be changed to that of Figure 67 using equations 4.15 and 4.16. The gross mechanical power output for three phases without the friction and windage losses subtracted is from Equation 4.16.

$$P_{1(3\ \Phi\ \text{output})} = 3\, I_{r_1}^{\ 2} R_{r_1} \frac{(1-s)}{s}, \text{ watts} \qquad \text{Equation 4.18}$$

The gross mechanical power may be represented in terms of torque, T, or,

$$P_{1(3\ \Phi\ \text{output})} = \frac{(T)\,(2\,\pi\ \text{rpm})\,(\text{h.p.})}{33{,}000}\ . \qquad \text{Equation 4.19}$$

Because the actual revolutions per minute of the rotor are equal to the synchronous revolutions per minute times (1-s) and T is the torque in pound-feet, then

$$\frac{T\ 2\,\boldsymbol{\pi}\ \text{rpm sync.}\,(1-s)}{33{,}000} = \frac{3\, I_{r_1}^{\ 2} R_{r_1}}{746} \frac{(1-s)}{s}\ . \qquad \text{Equation 4.20}$$

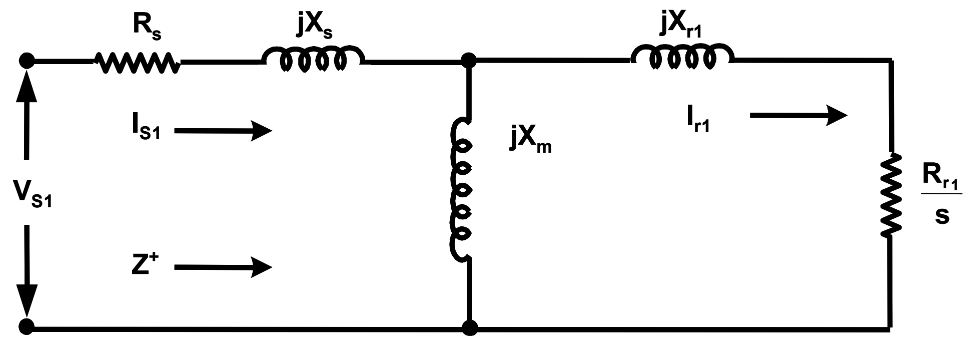


Figure 66. Positive sequence equivalent circuit for induction motor/generator

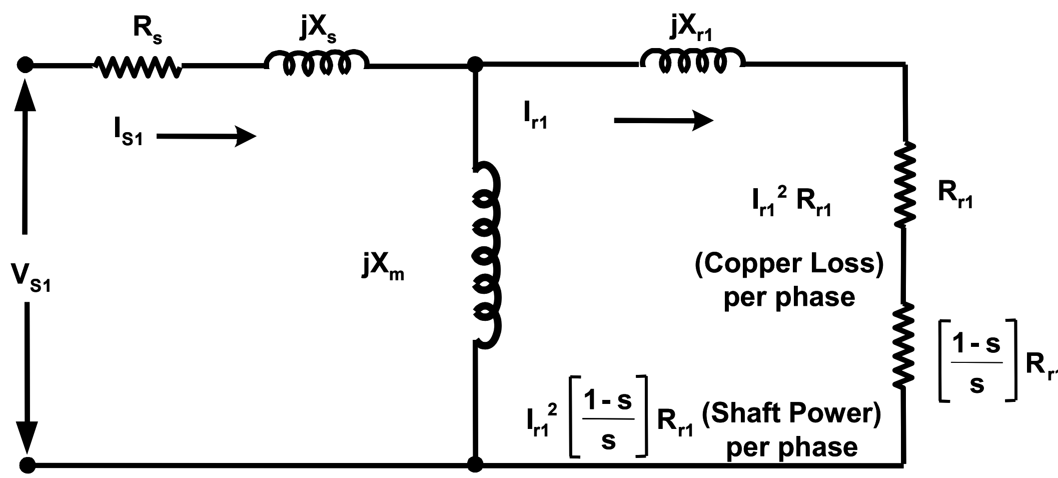


Figure 67. Positive sequence induction motor/generator equivalent circuit for copper losses and shaft power

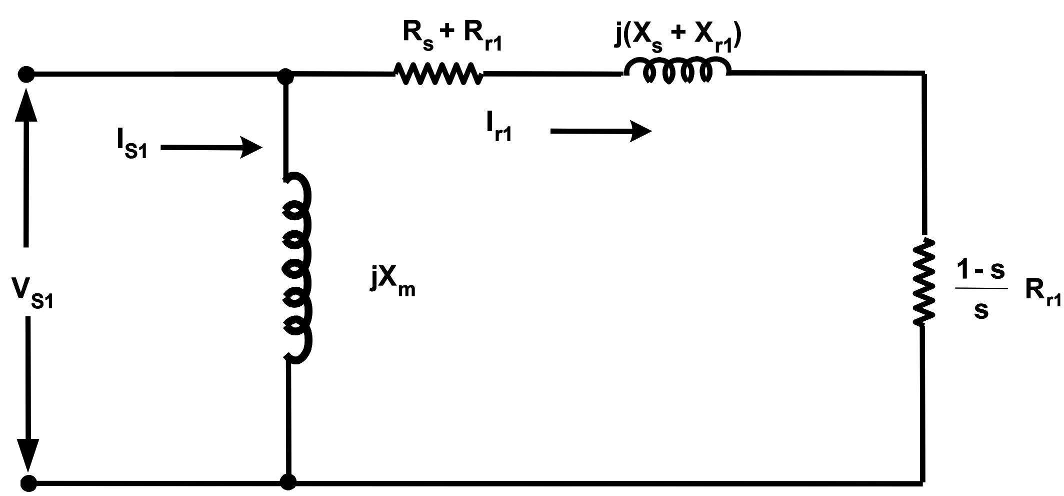


Figure 68. Simplified positive sequence induction motor/generator equivalent circuit

The

$$\text{rpm sync.} = \frac{120\,f}{p} = \frac{120 \text{ x frequency}}{\text{no. of poles}},$$ Equation 4.21

and

$$T \text{ lb-ft} = \frac{33{,}000}{2\pi \text{ x } 746} \quad \frac{p}{120\,f} \quad \frac{3\,I_{r_1}^{\;2}\,R_{r_1}}{s},$$ Equation 4.22

$$T \text{ lb ft} = 0.1765\,\frac{p}{f}\;\frac{I_{r_1}^{\;2}\,R_{r_1}}{s}.$$ Equation 4.23

The equivalent circuit of Figure 68 is an approximation of that in Figure 67, with the jX_m term moved out to the terminals. Because the magnitude of X_m is large compared with those of the other terms in the equivalent circuit, this approximation is acceptable.

4.5.1.1.2 Negative Sequence Equivalent Circuit

The rotor is rotating in the direction of the positive sequence field with slip (s). The negative sequence field is rotating in the opposite direction at synchronous speed.

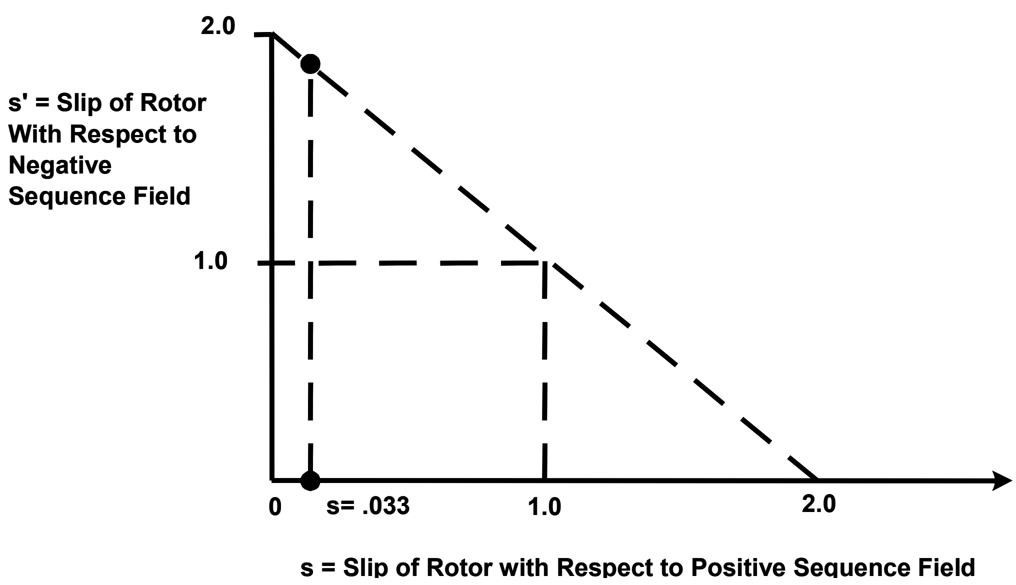


Figure 69. Slip of rotor with respect to negative sequence field and positive sequence field

If the speed of the field in the negative direction is ω and the speed of the rotor in the positive direction is ω (l-s), then the slip, with respect to the negative sequence field, is

$$s' = \frac{\omega + \omega\,(1 - s)}{\omega} = 2 - s.$$ Equation 4.24

Also, this could be obtained from Figure 69. When s = 0, then s' = 2. When the rotor is at standstill or s = 1, then s' = 1. When s = 2, then s' = 0. The negative sequence equivalent circuit of Figure 71 will be similar to the positive sequence of Figure 67, but the term $\frac{(1-s)}{s}$ R_{r1} of the positive sequence will be replaced with $\frac{(1-s')}{s'}$ R_{r2}.

Because s' = 2 – s, from Equation 4.24, then

$$\frac{(1-s')}{s'} R_{r2} = \frac{1-(2-s)}{2-s} R_{r2}$$

$$= -\frac{(1-s)}{2-s} R_{r2}. \qquad \text{Equation 4.25}$$

Because the slip (s) is small, typically 2%–3%,

$$-\frac{(1-s)}{2-s} R_{r2} \cong -\frac{R_{r2}}{2}, \qquad \text{Equation 4.26}$$

which is shown in the simplified equivalent circuit of Figure 72. The negative sequence mechanical power P_2 for all three phases is from Equation 4.25 and equal to

$$P_{2\,(3\phi\,\text{output})} = -3\left(\frac{1-s}{2-s}\right) R_{r_2}\, I_{r_2}^{\;2}, \text{watts} \qquad \text{Equation 4.27}$$

where I_{r2}^2 is the negative sequence rotor current referred to the stator. The gross mechanical power output because of both positive and negative sequence voltages is

$$P_{1\,(3\phi\,\text{output})} - P_{2\,(3\phi\,\text{output})} =$$

$$3\, I_{r1}^{\;2}\, R_{r1}\left(\frac{1-s}{s}\right) - 3\,\frac{1-s}{2-s} R_{r2}\, I_{r_2}^{\;2}, \text{watts}. \qquad \text{Equation 4.28}$$

The gross torque T is

$$T = 0.1765\, \frac{p}{f}\, R_{r2}\left[\left(\frac{I_{r1}^{\;2}}{s}\right) - \left(\frac{I_{r2}^{\;2}}{2-s}\right)\right] \text{lb-ft}. \qquad \text{Equation 4.29}$$

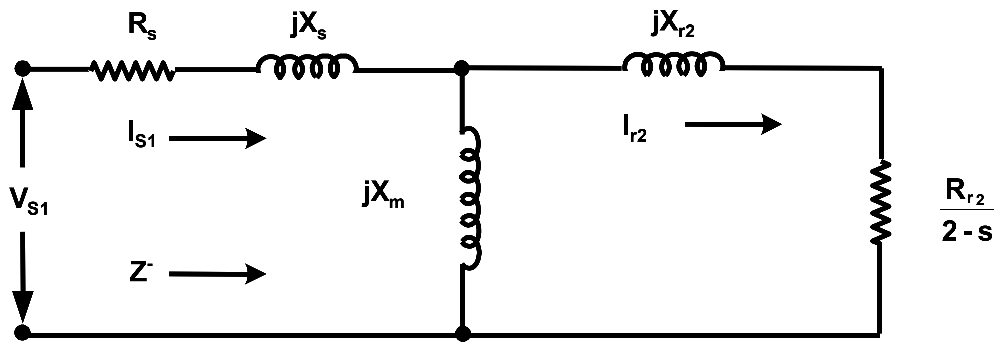


Figure 70. Negative sequence equivalent circuit for induction motor/generator

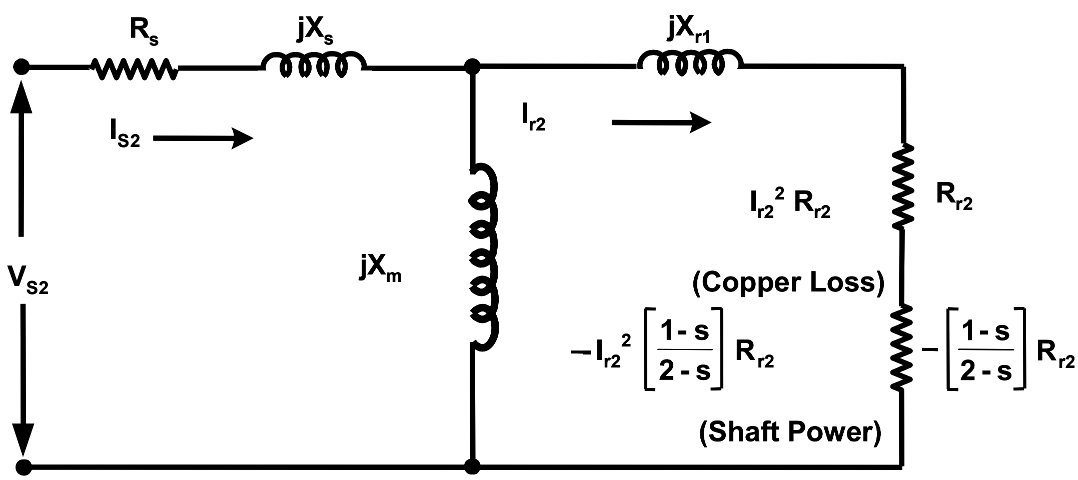


Figure 71. Negative sequence induction motor/generator equivalent circuit for copper losses and shaft power

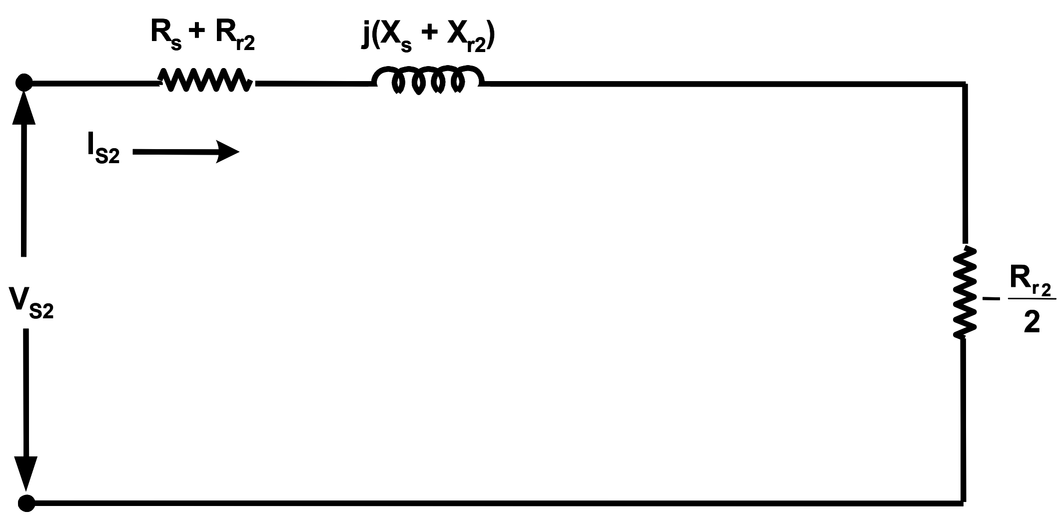


Figure 72. Simplified negative sequence induction motor/generator equivalent circuit operating at small values of slip

Because the negative sequence power output is negative (see Equation 4.27), the power output is reduced with negative sequence voltages, which reduces the nameplate capability of the machine. An example demonstrates the significance of this.

4.5.1.1.2.1 Negative Sequence Voltages Increase Losses

The example uses test data from Williams (1954). Table 2 and Table 3 show the line currents for various percent unbalanced voltages, as measured for single-cage and double-cage induction motors with similar performance characteristics. These motors are 10-hp, four-pole, 220-V, three-phase, and wye-connected ungrounded. The process of determining the effects of unbalanced voltages is detailed below.

1. From the percent unbalanced voltages or the negative sequence divided by the positive sequence voltage, measure the line currents I_A, I_B, and I_C for both ABC and ACB rotation.
2. Calculate the negative sequence currents for 3%, 5%, 8%, 10%, and 11% negative sequence voltages. Repeat this step for the single-cage and double-cage induction machines for both ABC and ACB rotation. See Table 2 and Table 3. Two major conclusions should be noted from the test data of these tables:
    A. Phase rotation affects which of the phases has the highest line current. This presents a real problem for protecting the motor/generator from overcurrent failure. At a 3% negative sequence voltage, for the single cage-motor, Phase C has the highest phase current I_C of 1.12 p.u. for ABC rotation. The Phase A motor has the highest phase current I_A of 1.145 p.u. for ACB rotation. When V_2/V_1% is increased to 5%, I_C increases to 1.19 p.u. for ABC rotation, and I_A is 1.245 p.u. for ACB rotation.

       Overcurrent motor/generator protection is typically installed on two of the three phases. If the protection is installed on phases A and B for the single-cage motor with ABC rotation and set to trip at 115%, then the motor protection will not trip to protect the motor because I_A is 1.09 p.u. and I_B is only 0.760 p.u. However, phase I_C current is 1.19 p.u. Similarly, if this same motor is operated at 5% negative sequence voltage with ACB rotation and the protection is installed on phases B and C, then the I_A current is 1.245 p.u., and the I_B and I_C currents are only 0.980 p.u. and 0.825 p.u., respectively. Again, the protection will not trip to protect the motor because the currents I_B and I_C are below 0.980 p.u., yet I_A current is at 1.245 p.u., or 24.5% over rated current. Following this same case, even with $V_2/V_1\% = 11\%$, the I_B and I_C currents are only 1.040 p.u. and 0.695 p.u., respectively, yet the I_A current is 1.535 p.u., or 53.5% over rated current. The overcurrent protection still has not operated to trip and protect the motor. This conclusion indicates that negative sequence current protection must be used to protect the motor or generator to prevent failure because of unbalanced voltages. This condition is not the same for ABC rotation. In fact, at $V_2/V_1\% = 8\%$, $I_A = 1.165$ p.u., $I_B = 0.620$ p.u., and $I_C = 1.31$ p.u. Therefore, the overcurrent motor protection under worst-case conditions would trip the motor at $I_C = 1.31$ p.u. if the protection was installed on phases A and B.

Although the problem is less severe for the double-cage motor, the phase current I_A for rotation ACB reaches 1.48 p.u., or 48% over rated current at $V_2/V_1\% = 11\%$. Yet overcurrent tripping would occur for ABC rotation at $V_2/V_1\% = 8\%$.

B. The percent negative sequence current is independent of phase rotation. For example, referring to the single-cage motor at $V_2/V_1\% = 5\%$, the $I_2/I_1\% = 25.08\%$ for ABC rotation and $I_2/I_1\% = 25.68\%$ for ACB rotation. The same is true for the double-cage motor. The phase rotation does not affect the result, but the percent negative sequence current is somewhat less at 21.6%. This confirms the need for negative sequence current protection because a safe level of overcurrent can be selected to protect the motor/generator that is independent of phases selected for protection and the phase rotation applied to the terminals of the motor or generator.

3. From the motor characteristics of Table 4, determine the positive and negative sequence equivalent circuits and the positive Z^+ and negative sequence Z^- impedances. The positive sequence impedance Z^+ is shown in Figure 66 and is given as Equation 4.30; the negative sequence impedance Z^- is shown in Figure 70 and is given as Equation 4.31.

$$Z^+ = \left[R_s + \frac{\left(\frac{R_{r1}}{s}\right) X_m{}^2}{\left(\frac{R_{r1}}{s}\right)^2 + (X_{r1} + X_m)^2} \right] + j \left[X_s + \frac{\left(\frac{R_{r1}}{s}\right)^2 X_m + X_{r1} X_m (X_{r1} + X_m)}{\left(\frac{R_{r1}}{s}\right)^2 + (X_{r1} + X_m)^2} \right],$$

Equation 4.30

$$Z^- = \left[R_s + \frac{\left(\frac{R_{r2}}{2-s}\right) X_m{}^2}{\left(\frac{R_{r2}}{2-s}\right)^2 + (X_{r2} + X_m)^2} \right] + j \left[X_s + \frac{\left(\frac{R_{r2}}{2-s}\right)^2 X_m + X_{r2} X_m (X_{r2} + X_m)}{\left(\frac{R_{r2}}{2-s}\right)^2 + (X_{r2} + X_m)^2} \right].$$

Equation 4.31

Table 2. Per-Unit Line Currents for Percent Negative Sequence Voltage Single-Cage Induction Motor

V_2/V_1 %	I_A	Ref Angle = 0	I_B	angle	I_C	angle	I_1	I_2	I_2/I_1 %
			Single Cage ABC Rotation						
3.000	1.045	0.000	0.855	-108.556	1.120	133.638	1.001	0.155	15.437
5.000	1.090	0.000	0.760	-102.181	1.190	141.371	0.999	0.251	25.086
8.000	1.165	0.000	0.620	-91.012	1.310	151.757	0.997	0.399	40.052
10.000	1.230	0.000	0.520	-80.787	1.410	158.652	0.997	0.514	51.565
11.000	1.262	0.000	0.486	-78.353	1.441	160.712	0.999	0.551	55.206
			Single Cage ACB Rotation						
3.000	1.145	0.000	0.975	131.161	0.890	-124.435	0.154	0.997	647.554
5.000	1.245	0.000	0.980	138.578	0.825	-128.196	0.257	0.999	389.448
8.000	1.385	0.000	1.000	148.378	0.748	-135.496	0.400	0.999	249.577
10.000	1.485	0.000	1.030	154.850	0.705	-141.618	0.502	1.001	199.494
11.000	1.535	0.000	1.040	157.737	0.695	-145.465	0.552	1.001	181.522

Table 3. Per-Unit Line Currents for Percent Negative Sequence Voltage Double-Cage Induction Motor

V_2/V_1 %	I_A	Ref Angle = 0	I_B	angle	I_C	angle	I_1	I_2	I_2/I_1 %
			Double Cage ABC Rotation						
3.000	1.065	0.000	0.870	-113.022	1.080	132.150	1.001	0.131	13.121
5.000	1.112	0.000	0.785	-108.867	1.135	139.120	1.000	0.216	21.582
8.000	1.190	0.000	0.660	-102.456	1.230	148.402	1.002	0.343	34.289
10.000	1.250	0.000	0.572	-98.027	1.300	154.171	1.003	0.433	43.226
11.000	1.281	0.000	0.522	-95.401	1.337	157.127	1.001	0.482	48.188
			Double Cage ACB Rotation						
3.000	1.127	0.000	0.960	128.256	0.923	-125.241	0.130	0.999	771.314
5.000	1.215	0.000	0.943	134.158	0.877	-129.519	0.219	0.999	456.403
8.000	1.340	0.000	0.926	142.637	0.825	-137.066	0.348	0.995	286.260
10.000	1.428	0.000	0.930	148.146	0.805	-142.432	0.433	0.998	230.641
11.000	1.480	0.000	0.940	151.019	0.800	-145.298	0.479	1.004	209.439

4. From the negative sequence voltage V_2 and the negative sequence impedance Z^-, the negative sequence amperes are calculated and displayed in Table 5. Calculate the negative sequence stator losses from $3\ I_{s2}^2\ R_1$, where I_{s2} is the negative sequence stator current of Table 5 and Rs is the stator resistance of 0.153 Ω/Φ, shown in Table 4.
5. The negative sequence rotor losses are calculated from $(2 - s)\ 3I^2_{r2}\ (R^- - R_s)$, where the negative sequence rotor current I_{r2} can be approximated with the negative sequence stator current I_{s2} [4], R^- is the resistance portion of the negative sequence impedance Z^- of Table 4, and R_s is the stator resistance. The total negative sequence losses are found by adding the negative sequence stator and rotor losses.

Table 4. Double- and Single-Cage Characteristics for 10-hp, Four-Pole, 220-V, Three-Phase, Wye-Connected Ungrounded Motors

Double-Cage Motor	Single-Cage Motor
R_s = 0.153 Ω/Φ	R_s = 0.153 Ω/Φ
X_s = 0.500 Ω/Φ X_m = 14.3 Ω/Φ	X_s = 0.500 Ω/Φ X_m = 14.3 Ω/Φ
R_{r1} = 0.188 Ω/Φ @ s = 0.033 (2 Hz)	Rr1 = 0.188 Ω/Φ @ s = 0.033 (2 Hz)
Rr2 = 0.507 Ω/Φ @ s = 1.967 (118 Hz)	R_{r2} = 0.205 Ω/Φ @ s = 1.967 (118 Hz)
X_{r1} = 0.760 Ω/Φ @ s = 0.033 (2 Hz)	X_{r1} = 0.420 Ω/Φ @ s = 0.033 (2 Hz)
X_{r2} = 0.482 Ω/Φ @ s = 1.967 (118 Hz)	X_{r2} = 0.415 Ω/Φ @ s = 1.967 (118 Hz)
$Z^+ = 4.01 + j\,2.43 = 4.70\angle 31.2°$	$Z^+ = 4.02 + j\,2.13 = 4.55\angle 28.0°$
$Z^- = 0.395 + j\,0.970 = 1.05\angle 67.8°$	$Z^- = 0.252 + j\,0.903 = .938\angle 74.4°$
@ 10% $\frac{V_2}{V_1}$	@ 10% $\frac{V_2}{V_1}$
$V_2 = \frac{220}{\sqrt{3}}$ x 0.10 = 12.7 volts $I_2 = \frac{V^2}{Z^-} = \frac{12.7}{1.05} = 12.1$ amperes	$V_2 = \frac{220}{\sqrt{3}}$ x 0.10 = 12.7 volts $I_2 = \frac{V^2}{Z^-} = \frac{12.7}{.938} = 13.54$ amperes
$\frac{Z^+}{Z^-} = \frac{4.70}{1.05} = 4.48$	$\frac{Z^+}{Z^-} = \frac{4.55}{0.938} = 4.85$

Table 5. Single-Cage Induction Motor – 10 hp, 220 V, Four Pole, Wye-Connected Ungrounded

V_2/V_1 %	V_2	Z^-	I_2	I_2 angle	Negative Sequence Losses: Stator $3I_{S2}^2R_S$	Negative Sequence Losses: Rotor $(2\text{-}s)3I_{r2}^2(R_2^- - R_S)$	Negative Sequence Losses: Total	% Increased Losses Due to Negative Sequence Current
3.0	3.81	0.938	4.06	-74.4	7.57	9.64	17.21	2.10
5.0	6.35	0.938	6.77	-74.4	21.04	26.77	47.81	5.83
8.0	10.16	0.938	10.83	-74.4	53.85	68.54	122.39	14.93
10.0	12.70	0.938	13.54	-74.4	84.14	107.09	191.24	23.32
11.0	13.97	0.938	14.89	-74.4	101.81	129.58	231.40	28.22

R_S = 0.153 ohms/phase
s = 0.033
R^- = 0.252 Negative sequence equivalent circuit resistance, ohms/phase
2-s = 1.967
$R^- - R_S$ = 0.099 ohms/phase
Full Load Losses = 820 Watts
V_1 = 127 Volts
I rated = 27 amperes
Z^- = 0.938 ohms/phase
Z^- angle = 74.4 Degrees

Table 6. Double-Cage Induction Motor – 10 hp, 220 V, Four Pole, Wye-Connected Ungrounded

V_2/V_1 %	V_2	Z^-	I_2	I_2 angle	Negative Sequence Losses: Stator $3I_{S2}^2R_S$	Negative Sequence Losses: Rotor $(2\text{-}s)3I_{r2}^2(R_2^- - R_S)$	Negative Sequence Losses: Total	% Increased Losses Due to Negative Sequence Current
3.000	3.81	1.05	3.63	-67.8	6.043438	18.80	24.85	3.03
5.000	6.35	1.05	6.05	-67.8	16.78733	52.23	69.02	8.42
8.000	10.16	1.05	9.68	-67.8	42.97556	133.71	176.68	21.55
10.000	12.70	1.05	12.10	-67.8	67.14931	208.92	276.06	33.67
11.000	13.97	1.05	13.30	-67.8	81.25066	252.79	334.04	40.74

R_S = 0.153 ohms/phase
s = 0.033
R^- = 0.395 Negative sequence equivalent circuit resistance, ohms/phase
2-s = 1.967
$R^- - R_S$ = 0.242 ohms/phase

Full Load Losses = 820 Watts
V_1 = 127 Volts
I rated = 27 amperes
Z^- = 1.05 ohms/phase
Z^- angle = 67.8 Degrees

6. The percent increased losses because of the negative sequence currents are determined by dividing the total negative sequence losses of Step 5 by the full load losses.

   An example using the double-cage induction motor applied to a 10% negative sequence supply voltage illustrates steps 3–5. From Table 6:

   The negative sequence stator losses are

   $$3\ I_{s2}^2\ R_s = (3)\ (12.10)^2\ (0.153) = 67.2\ \text{W}. \qquad \text{Equation 4.32}$$

   The negative sequence rotor losses are

   $$(2 - s)\ 3\ I_{r2}^2\ (R^- - R_s) = (2 - 0.033)\ (3)\ (12.10)_2\ (0.395 - 0.153) = 209.1\ \text{W}. \qquad \text{Equation 4.33}$$

   The total negative sequence losses = 276.3 W. Equation 4.34

   The full load losses are equal to 820 W. Therefore, the percent increased losses because of a 10% negative sequence voltage is

   $$\%\ \Delta\ \text{losses}\ (@\ V_2/V_1 = 10\%) = 276.3/820 \times 100 = 33.7\%. \qquad \text{Equation 4.35}$$

   This value is shown in Table 6 for $V_2/V_1\% = 10\%$. The negative sequence losses are proportional to the square of the negative sequence voltage. Or, at 11% negative sequence voltage, the increased losses are, from Equation 4.35, equal to

   $$\left(\frac{11\%}{10\%}\right)^2 33.7\% = 40.7\%\ . \qquad \text{Equation 4.36}$$

   Notice that the percent increased losses are much higher for the double-cage motor/generator than for the single-cage motor/generator at the same percent negative sequence voltage. This is primarily because the negative sequence resistance of the rotor (0.507 Ω/Φ) for the double-cage motor is much higher than the positive sequence resistance of the rotor (0.188 Ω/Φ). By comparison, the negative sequence resistance of the rotor (0.205 Ω/Φ) for the single-cage motor is only slightly higher than the positive sequence resistance (0.188 Ω/Φ). For example, at $V_2/V_1\% = 10\%$, the increased losses are 23.3% for the single cage but 33.7% for the double cage. This is a significant problem because the double-cage machines are typically the larger motor and generator units.

4.5.1.1.2.2 Negative Sequence Voltage Affects Shaft Output Power and Reduces Capacity

The next series of questions involves how negative sequence voltage affects the shaft output power and increased losses reduce the nameplate capacity. The gross mechanical power of the machine because of the positive and negative sequence voltage will be calculated. Again, using the test data, two examples—one for the single-cage motor and one for the double-cage motor—are considered.

For a negative sequence voltage of 10%, applied to a single-cage motor,

$$I_1 = \frac{V_1}{Z^+} = \frac{127}{4.55} = 27.9 \text{ amperes, and}$$

$$I_2 = \frac{V_2}{Z^-} = \frac{12.7}{.938} = 13.54 \text{ amperes.}$$

Because $R_{r1} = 0.188\ \Omega/\Phi$ and $R_{r2} = 0.205\ \Omega/\Phi$, applying equations 4.23 and 4.27 results in

$$P_{1(3\ \Phi\ \text{output})} - P2_{(3\Phi\ \text{output})} = 3\ I_{r1}^2\ R_{r1}\frac{1-s}{s} - 3\,I_{r2}^{\ 2}\ R_{r2}\ \frac{1-s}{2-s}$$

Equation 4.37

$$P_{3\ \Phi\ \text{output}} = (3)\ (27.9)2\ (0.188)\ \frac{(1-.033)}{.033}\ - (3)\ (13.54)2\ (0.205)\ \frac{(1-.033)}{2-.033}$$

$$= (439.02)\ (29.30) - (112.75)\ (0.4916)$$

$$P_{3\ \Phi\ \text{output}} = \underbrace{12{,}863.3 \text{ watts}}_{\substack{\text{Positive Sequence}\\ \text{Power Output}}} - \underbrace{55.43 \text{ watts}}_{\substack{\text{Negative Sequence}\\ \text{Power Output}}}.$$

Equation 4.38

Notice that, at 10% negative sequence voltage, the power because of the negative sequence voltage is only 0.43% of the positive sequence power, or

$$\text{Decreased power} = \frac{55.43}{12{,}863.3} = -\,0.43\%.$$

Therefore, voltage imbalance does not materially affect the power output of the rotor, but the rotor and stator copper losses increased 23.3% because of the negative sequence currents, as shown in Table 4. It is the increased losses, not the reduction in power because of the negative sequence voltage, that derate the motor.

When a 10% negative sequence voltage is applied to a double-cage motor, the negative sequence reverse power as a percentage of positive sequence power is 0.91%, or more than twice that for the single-cage motor. The percentage increase in rotor and stator copper losses is 33.7%, for 44.6% higher losses than for the single-cage motor.

The additional copper losses cause an increase in temperature above ambient temperature and reduce the power output capability of the motor or generator. The effect of this increase in temperature or the derating of the induction machine is illustrated inTable 7 Table 7. The higher the ratio of the positive-to-negative sequence impedances, the greater the capacity reduction. The negative sequence rotor values (R_{r2}, X_{r2}) are not readily known, but Tracey (1954) found the ratio Z^+/Z^- can be approximated by dividing the locked rotor current by the rated full load current.

If one knows the ratio of Z^+/Z^- and the unbalanced voltage applied, an equation can be developed for derating the motor capacity. The equation is based on the assumptions that the total copper loss for the stator and rotor that corresponds to any stator current is proportional to that current squared and the change in rotor resistance with frequency is negligible. Because the positive sequence current will result in the same total copper losses as balanced conditions and rated load,

$$I_s^2 \text{ rated} = I_{s1}^2 + I_{s2}^2, \qquad \text{Equation 4.39}$$

where $I_{s\,rated}$ is the rated stator current, and I_{s1} and I_{s2} are the positive and negative sequence currents.

From Equation 4.39,

$$I_{s1} = \sqrt{I_{s\ rated}^2 - I_{s2}^2}\ . \qquad \text{Equation 4.40}$$

Defining

$$I_{s2} = \frac{V_2}{Z^-},\ \text{and}\ I_{s\,rated} = \frac{V_1}{Z^+},\ \text{then}$$

$$I_{s2} = \left(\frac{V_2}{V_1}\frac{Z^+}{Z^-}\right) I_{s\,rated.} \qquad \text{Equation 4.41}$$

Substituting Equation 4.41 into Equation 4.40,

$$I_{s1} = I_{s\,rated}\sqrt{1 - \left(\frac{V_2}{V_1}\frac{Z^+}{Z^-}\right)}\ . \qquad \text{Equation 4.42}$$

To prevent the motor from overheating, the positive sequence stator current cannot be greater than the value given in Equation 4.42. Remember that the negative sequence torque is very small. Therefore, the rating under unbalance conditions is

$$\begin{bmatrix}\text{Machine Rating} \\ \text{under unbalanced voltages}\end{bmatrix} = \sqrt{1-\left(\frac{V_2}{V_1}\frac{Z^+}{Z^-}\right)^2} \text{ x } \begin{bmatrix}\text{Machine} \\ \text{N.P. Rating}\end{bmatrix} \quad \text{. Equation 4.43}$$

(Note: $\frac{V_2}{V_1}$ is given in p.u. in Equation 4.43, not in percent.)

It will be shown (see Equation 4.75) that when a phase conductor is opened on a three-phase supply to the induction machine, at standstill, the motor will not start. For example, when $Z^+/Z^- = 5$ and $V_2/V_1\% = 20\%$, from Equation 4.43, the machine rating is zero! When Equation 4.43 is applied to a ratio of $Z^+/Z^- = 7$, the zero rating occurs at $V_2/V_1\% = 15\%$; when it is applied to a ratio of 9, the zero rating occurs at $V_2/V_1 = 11\%$. These zero rating values correspond with the value of the $V_2/V_1\%$ unbalance voltage, which occurs when an open phase conductor condition is applied to each of these machines. This result also applies to other Z^+/Z^- ratio machines.

From Table 4, the Z^+/Z^- ratio for the single-cage motor is 4.85, and the ratio for the double-cage is 4.48. Using the approximate ratio value of 5 and applying the results of Table 7, for a $V_2/V_1\% = 5\%$, the motor must be derated to 97% of rated power. Obviously, this is a generalized result, and temperature rise and service factor data must be used from the actual design to obtain realistic and specific results. However, the test results of Gafford, Duesterohoeft, and Mosher (1959) and Tracey (1954), shown in Table 8, have comparable deratings for the same unbalanced voltages.

No single-phase current or percent negative sequence current is indicative of the actual temperature rise. The losses in the stator are unevenly distributed because the line currents are not equal, and this causes hot spots, unbalanced temperatures, and resistances. Double-cage motors have to dissipate more losses than single-cage motors for the same negative sequence voltage. An unbalanced voltage condition not to exceed 3% to 5% is the recommended limit based on the line current not to exceed 120% (i.e., $I_C = 119\%$) to 125% (i.e., $I_A = 124.5\%$) of rated current, as shown in Table 2. This results in percent negative currents of about 25%–22% and increased losses of 5.85%–8.45% for single- and double-cage machines, respectively.

Table 7. Maximum Allowable Power Output in Percent of Rated While Operating at Unbalanced Voltages

$\frac{V_2}{V_1}$	$\frac{Z^+}{Z^-}$ = 5	$\frac{Z^+}{Z^-}$ = 7	$\frac{Z^+}{Z^-}$ = 9
3%	99.8	97.8	96.3
5%	96.8	93.7	89.3
8%	91.7	82.8	69.4
10%	86.6	71.4	43.6
11%	83.5	63.8	0
13%	76.0	41.5	0
14%	71.4	19.9	0
15%	66.1	0	0
20%	0	0	0

Notes:
From Tracey (1954)
(1) Z^+ = Motor impedance to V_1 (positive sequence voltages) at rated
(2) Z^- = Motor impedance to V_2 (negative sequence voltages) at rated load
(3) Z^+/Z^- ≈ Locked rotor current/rated current

Table 8. Comparison of Gafford, Duesterohoeft, and Mosher (1959) and Tracey (1954) Motor Derate Data Operating at Unbalance Voltage

			% Power Derate	
$\frac{V_2}{V_1}$%	P.u. Negative (Gafford, Duesterohoeft, and Mosher) Sequence I_2	P Output (Gafford, Duesterohoeft, and Mosher) p.u. @ Rated Temp. Rise	Δ P% (Gafford, Duesterohoeft, and Mosher)	$\frac{Z^+}{Z^-} = 5$ Δ P % (Tracey)
0	0	1.22	0	0
3	0.160	1.20	1.64	1.0
5	0.265	1.17	4.10	3.0
8	0.420	1.10	9.84	8.0
10	0.515	1.03	15.6	13.0
11	0.570	0.98	19.7	16.5
13	0.660	0.85	30.3	23.5
15	0.750	0.66	45.9	34.0

Note: The phasor diagram of Figure 73 was used as the voltage source by Gafford, Duesterohoeft, and Mosher (1959) to determine the heating condition of phases A, B, and C.

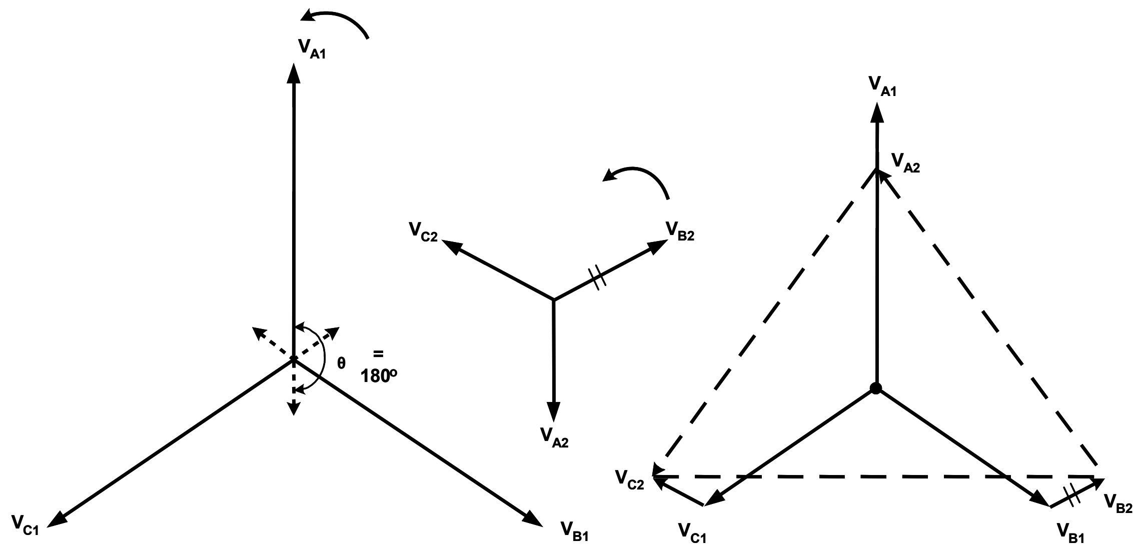


Figure 73. Phasor diagram for minimum heating in Phase A, θ = 180°

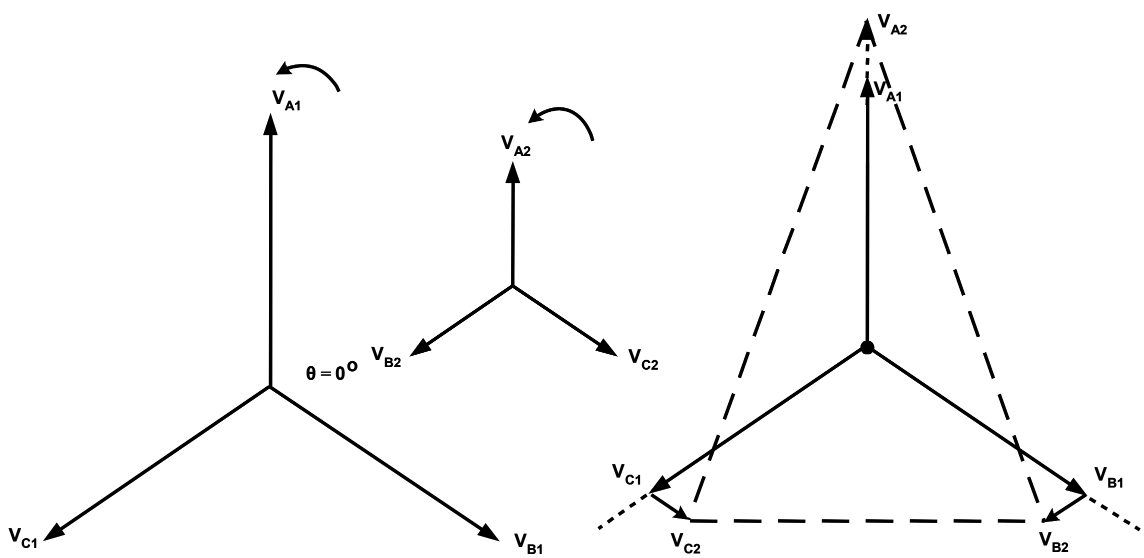


Figure 74. Phasor diagram for maximum heating in Phase A, θ = 0°

4.5.1.2 Unbalance Voltage Survey

The survey results of 13 utility systems are shown in Table 9. The data show the majority of unbalanced conditions occur with open delta transformer connections. But even then, the average unbalance is only 1.98%, with the highest being 10%.

Table 9. Unbalance Voltage Survey Results of Closed and Open Delta Transformer Connections

	Wye and Closed Delta	Open Delta	Total
Total N of Tests	919	290	1209
Max. % Unbal.	5.94	10	10
Min. % Unbal.	0.0	0.0	0.0
Avg. % Unbal.	0.83	1.98	1.10
N of tests @ 0% Unbal.	142	9	151
	% of Tests		
$\frac{V_2}{V_1}$ % NEMA			
0–0.5	25.5	7.9	21.2
0.51–1	47.2	15.5	39.6
1.01–1.5	14.7	21.7	16.4
1.51–2	5.3	12.8	7.1
2.01–2.5	2.7	10.3	4.6
2.51–3	2.2	13.8	5.0
3.01–3.5	0.9	5.9	2.1
3.51–4	0.8	4.8	1.7
4.01–4.5	0.1	2.8	0.7
4.51–5	0.3	1.4	0.6
>5	0.3	3.1	1.0

Notes:
(1) 1209 test (13-utility survey)
(2) Average unbalanced = 1.1%
(3) 12.5% of tests = 0% unbalance
60% of tests <1% unbalance
85% of tests <2% unbalance
(4) Average unbalance = 0.83% for closed banks
(5) Average unbalance = 1.98% for open delta

4.5.2 Synchronous Generators Operating on Unbalanced Voltages

Unbalanced three-phase stator currents applied to synchronous generators cause negative sequence phase currents that, in turn, cause a double frequency current in the surface of the rotor. These currents flow through the retaining rings, slot wedges, and field winding and cause high temperatures and possibly failure.

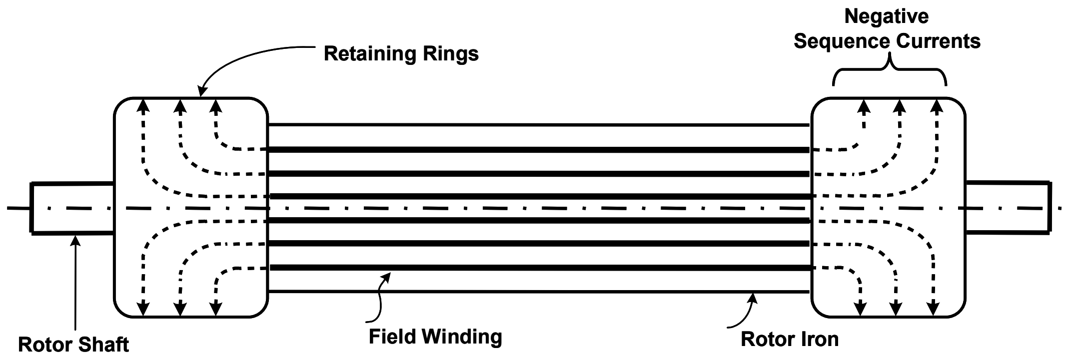


Figure 75. Round rotor synchronous machine showing negative sequence current paths in the rotor surface

Typically, the unbalance comes from single-phase main unit transformers with different impedances, unbalanced loads, open phases, and faults. Phase-to-phase faults create the highest negative sequence currents. A line-to-ground fault on the wye side of a delta-wye step-up transformer creates a line-to-line fault, as seen by the generator. The fault current from a line-to-ground fault on the generator is less than the line-to-line fault, and the open-phase condition produces less negative sequence current than the phase-to-phase or phase-to-ground fault.

Because the negative sequence current components rotate in the opposite direction of the rotation of the rotor, the flux produced by these currents has a frequency twice the synchronous speed. The skin effect causes these double frequency currents to be concentrated on the surface of the poles and the teeth of the rotor. These currents flow along the axial length of the rotor until they contact the retaining rings, which are shrunk onto the ends of the rotor iron, as in Figure 75. A small portion of these negative sequence currents flows in the field winding. The negative sequence current beating of the rotor and retaining rings causes these rings to expand and become loose on the rotor iron.

4.5.2.1 Negative Sequence Heating

As was the case with induction machines, most of the increased losses for the synchronous generator because of negative sequence currents occur in the rotor. The temperature rise over time is proportional to the I_{s2}^2t, where the I_{s2} is the stator negative sequence current, and t is in seconds. The safe limit is established based on

$$K = I_{s2}^2 t, \qquad \text{Equation 4.44}$$

where

K = Constant based or a specific design and size of generator
I_{s2} = The negative sequence stator current (rms)
t = Time in seconds.

The safe limit value of K is determined by measuring the temperature of the rotor with negative sequence current from the stator according to ANSI C50.13 and establishing the safe operating continuous unbalanced current capability of the generator. The safe limit is based on rated kilovolt-amperes and maximum current not to exceed 105% of rated current in any phase. Typically, the maximum permissible stator negative sequence I_{S2} current is 10% of the rated stator current, but the specific value recommended by the manufacturer should be used to set the value for the negative sequence relay.

4.5.2.2 Negative Sequence Relay

The negative sequence relays may be of definite-time-delay type or inverse-time type. The device 46 function is an inverse time overcurrent. Figure 76 shows typical time-negative sequence current curves for the Type SGC relay. Values for K can be calculated (G.E. Multilin 1998) using the p.u. locked rotor current ILR for a motor. If the p.u. ILR = 5,

$$K = \frac{175}{I^2_{LR}} = 7. \qquad \text{Equation 4.45}$$

Values ranging up 40 have been used. Also, synchronous generator values for K vary from about 4 to 8. A negative sequence pickup current setting of about 15% of full load current results in about 300 seconds. As shown in Table 2, a 15.44% negative sequence current results in a 3% voltage imbalance for the single-cage induction motor.

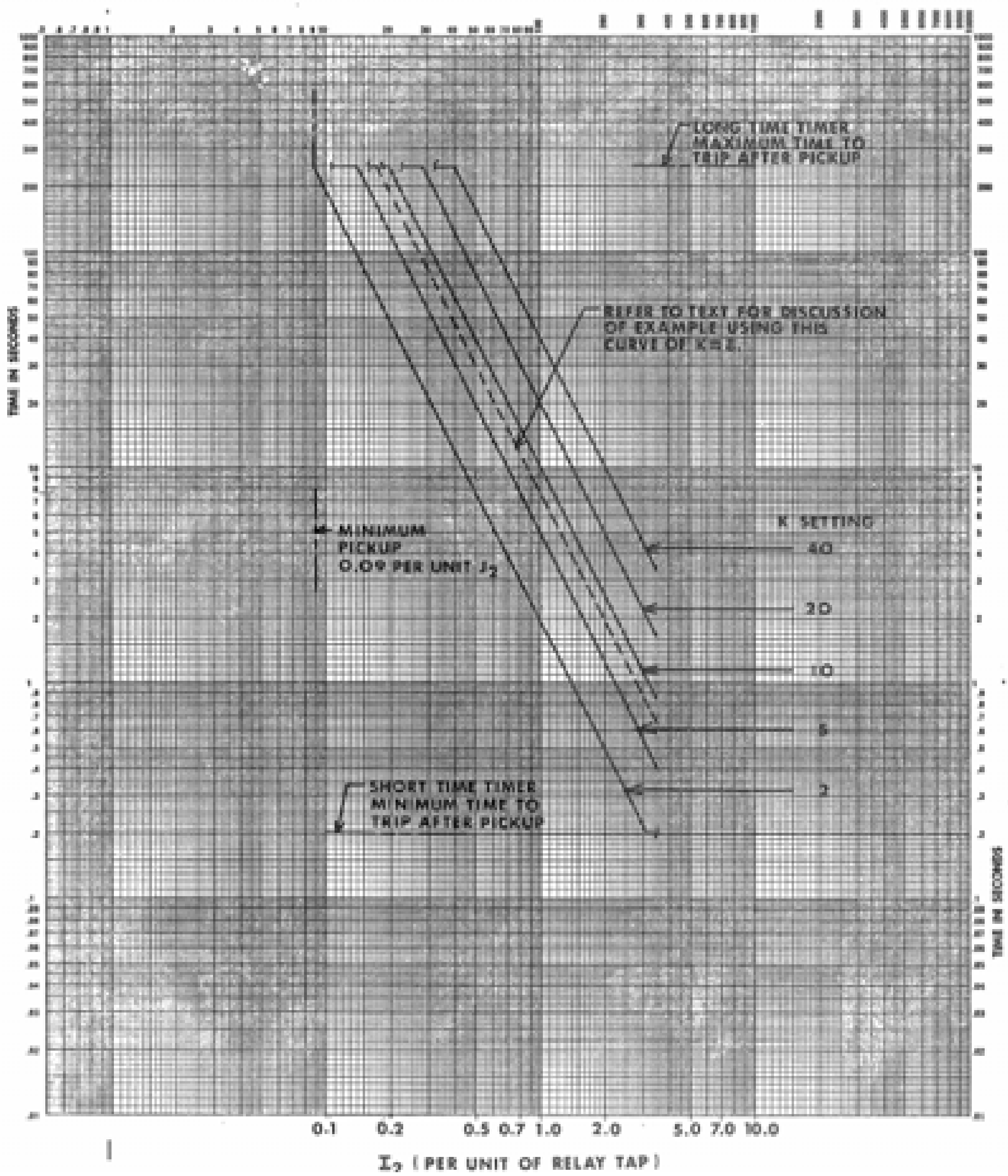


Figure 76. Typical time-current curves for the Type SGC relay

5 Project Results – Development of Models

5.1 Introduction

This section focuses on the development of models for DG and the distribution circuit voltage regulation equipment for unbalanced power systems. The voltage regulation models were developed for the substation LTC transformer, bidirectional step regulator, capacitors, and each of the distribution circuit transformer connections. In addition, line impedance, voltage drop, and losses were modeled, as were secondary and service drop impedance, voltage drop, and losses. Finally, a shunt capacitor model for a wye-grounded connection and models for synchronous, induction, and inverter-based generators were created.

5.2 Three-Phase Substation Transformer Models

Three-phase transformers are used at the distribution substation to transform voltage from the sub-transmission or, in some cases, transmission system down to distribution circuit levels. These three-phase transformers may have HV fixed taps or LV fixed taps or can be LTC or under LTC transformers. The typical distribution circuit is a four-wire wye multi-grounded system fed from a delta-wye-grounded, three-phase substation transformer. However, there are three-wire, ungrounded delta distribution circuits, and they are normally fed from delta-delta three-phase substation transformers. Three-phase and single-phase transformers on the circuit feed three-phase customer load or combinations of single-phase and three-phase loads. Also, single-phase transformers on the circuit feed single-phase loads.

The delta-wye grounded transformer connection is shown in Figure 77.

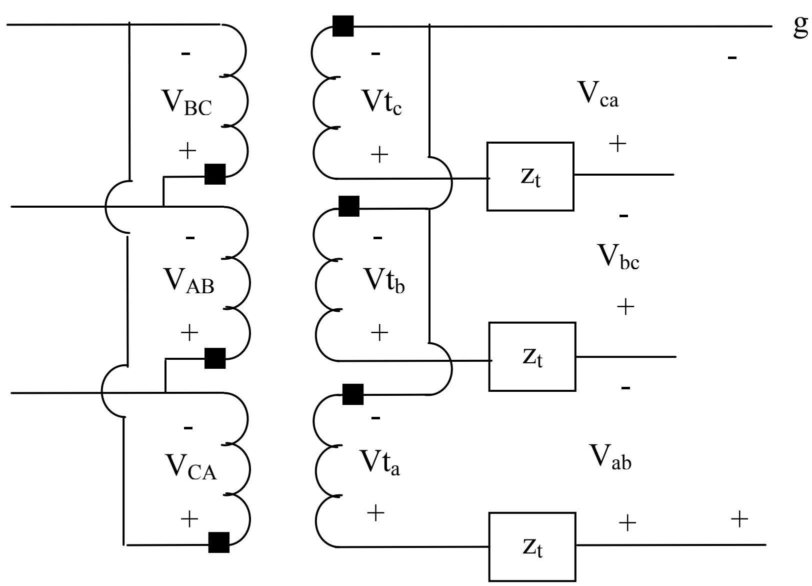


Figure 77. Delta-wye grounded three-phase transformer

From this figure, the primary-side line-to-line voltages can be written as a function of the ideal secondary-side voltages.

$$\begin{bmatrix} V_{AB} \\ V_{BC} \\ V_{CA} \end{bmatrix} = \begin{bmatrix} 0 & -n_t & 0 \\ 0 & 0 & -n_t \\ -n_t & 0 & 0 \end{bmatrix} \cdot \begin{bmatrix} V_{ta} \\ V_{tb} \\ V_{tc} \end{bmatrix}, \qquad \text{Equation 5.1}$$

where the turns ratio n_t is defined as

$$n_t = \frac{V_{LLHS}}{V_{LNLS}}. \qquad \text{Equation 5.2}$$

The ideal secondary voltage can be written as a function of the secondary-side line-to-neutral voltage as:

$$V_{tabc} = V_{LGabc} + Z_{tabc}\, I_{abc} \qquad \text{Equation 5.3}$$

where

$$Z_t = \begin{bmatrix} Z_t & 0 & 0 \\ 0 & Z_t & 0 \\ 0 & 0 & Z_t \end{bmatrix}. \qquad \text{Equation 5.4}$$

The primary line-to-line voltage as a function of the secondary line-to-ground voltage and the secondary current I_{abc} is

$$\begin{bmatrix} V_{AB} \\ V_{BC} \\ V_{CA} \end{bmatrix} = \begin{bmatrix} 0 & -n_t & 0 \\ 0 & 0 & -n_t \\ -n_t & 0 & 0 \end{bmatrix} \cdot \left(\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} + \begin{bmatrix} z_t & 0 & 0 \\ 0 & z_t & 0 \\ 0 & 0 & z_t \end{bmatrix} \cdot \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \right). \qquad \text{Equation 5.5}$$

To make the transformer model consistent with other system models and therefore easier to calculate, the secondary-side line-to-ground voltage should be expressed as a function of the primary-side line-to-neutral voltage. This can be done using the theory of symmetrical components and algebraic manipulation. The resulting expression is

$$\begin{bmatrix} V_{AB} \\ V_{BC} \\ V_{CA} \end{bmatrix} = \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \cdot \begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix}$$

$$\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \cdot \begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix} = \begin{bmatrix} 0 & -n_t & 0 \\ 0 & 0 & -n_t \\ -n_t & 0 & 0 \end{bmatrix} \cdot \left(\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} + \begin{bmatrix} z_t & 0 & 0 \\ 0 & z_t & 0 \\ 0 & 0 & z_t \end{bmatrix} \cdot \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} \right)$$

$$\frac{1}{n_t}\begin{bmatrix} 0 & 0 & -1 \\ -1 & 0 & 0 \\ 0 & -1 & 0 \end{bmatrix} \cdot \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \cdot \begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix} = \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} + \begin{bmatrix} z_t & 0 & 0 \\ 0 & z_t & 0 \\ 0 & 0 & z_t \end{bmatrix} \cdot \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix}$$

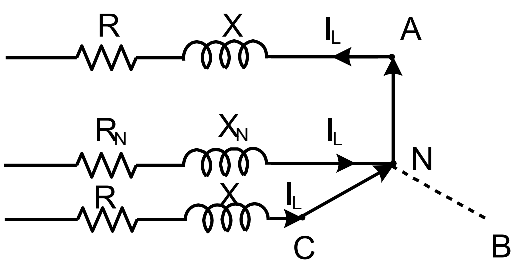
$$\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \frac{1}{n_t}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} \cdot \begin{bmatrix} V_A \\ V_B \\ V_C \end{bmatrix} - \begin{bmatrix} z_t & 0 & 0 \\ 0 & z_t & 0 \\ 0 & 0 & z_t \end{bmatrix} \cdot \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix}.$$ Equation 5.6

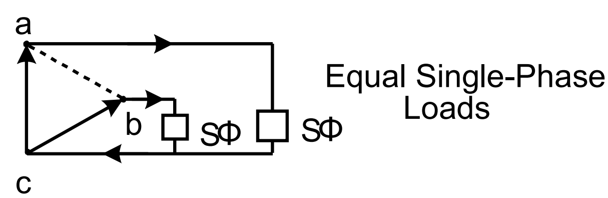
5.3 Three-Phase and Single-Phase Distribution Transformer Connections for Distribution Circuit

The following equations determine the voltage drop on the wye-grounded primary system feeding different transformer connections and three-phase and single-phase loading. The factor 0.9 I_L in some of the equations represents the portion of the neutral current in the neutral conductor, the remainder of which is current in the earth.

Wye-Grounded Primary System Transformer Connections and Voltage Regulation

Case I.





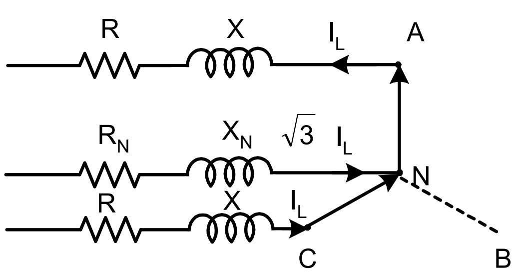
$V_{R_{NA}} = I_L\,[R \text{ Cos } \theta + X \text{ Sin } \theta] + 0.9\, I_L\,[R_N \text{ Cos } (\theta - 60°) + X_N \text{ Sin } (\theta - 60°)]$

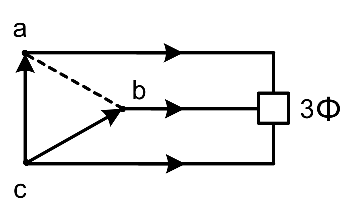
Equation 5.7

$V_{R_{CN}} = I_L\,[R \text{ Cos } \theta + X \text{ Sin } \theta] + 0.9\, I_L\,[R_N \text{ Cos } (\theta + 60°) + X_N\, (\theta + 60°)]$

Equation 5.8

Case II.

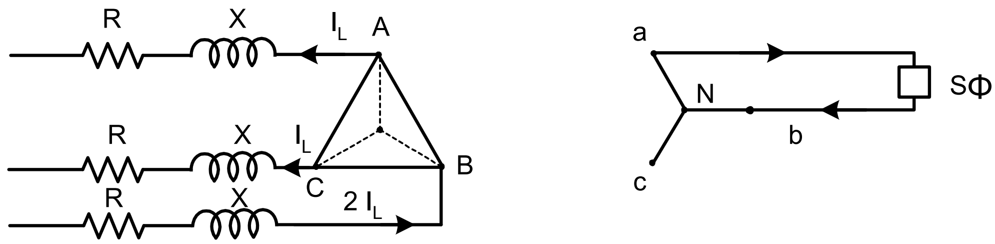




$V_{R\,NA} = I_L$ [R Cos (θ – 30°) + X Sin (θ – 30°)] + 0.9 $\sqrt{3}$ I_L [R_N Cos (θ – 60°) + X_N Sin (θ – 60°)] Equation 5.9

$V_{R\,CN} = I_L$ [R Cos (θ + 30°) + X Sin (θ + 30°)] + 0.9 $\sqrt{3}$ IL [R_N Cos (θ + 60°) + X_N Sin (θ + 60°)] Equation 5.10

Case III.

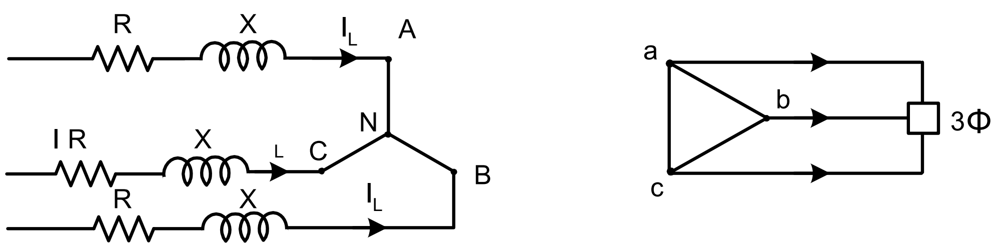


$V_{R\,NA} = I_L$ [R Cos (θ – 60°) + X Sin θ – 60°)] Equation 5.11

$V_{R\,BN} = 2\ I_L$ (R Cos θ + X Sin θ) Equation 5.12

$V_{R\,CN} = I_L$ [R Cos (θ + 60°) + X Sin (θ + 60°)] Equation 5.13

Case IV.

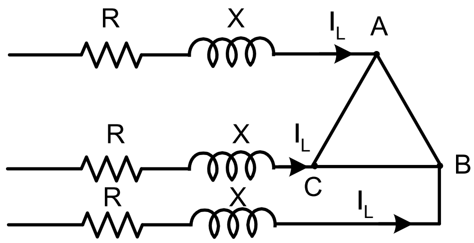


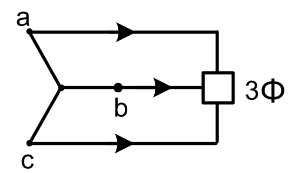
$V_{R\,AN} = I_L$ (R Cos θ + X Sin θ) on L-N Base Voltage Equation 5.14

$V_{R\,BN} = I_L$ (R Cos θ + X Sin θ) on L-N Base Voltage Equation 5.15

$V_{R\,CN} = I_L$ (R Cos θ + X Sin θ) on L-N Base Voltage Equation 5.16

Case V.



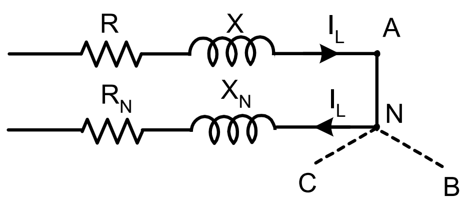


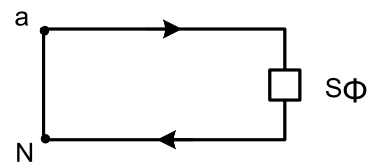
$V_{R\,NA} = I_L\,(R \cos\theta + X \sin\theta)$ Equation 5.17

$V_{R\,NB} = I_L\,(R \cos\theta + X \sin\theta)$ Equation 5.18

$V_{R\,NC} = I_L\,(R \cos\theta + X \sin\theta)$ Equation 5.19

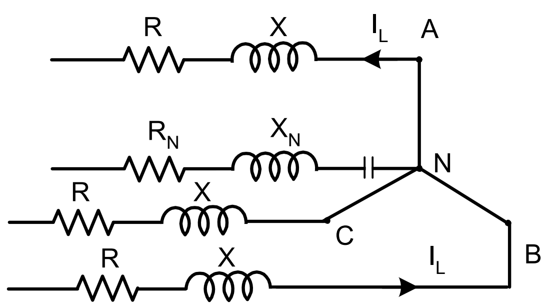
Case VI.

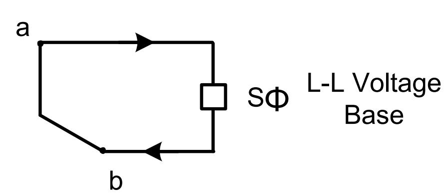




$V_{R\,NA} = I_L\,[R + R_N) \cos\theta + (X + XN) \sin\theta]$ Equation 5.20

Case VII.



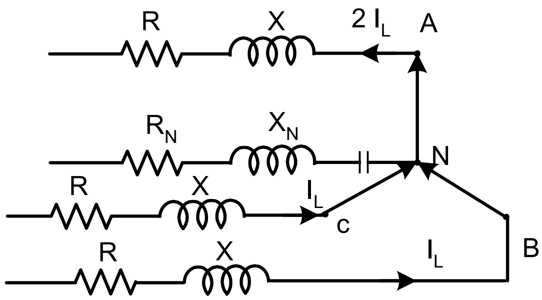


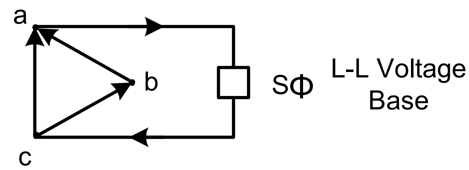
$V_{R\,BA} = 2\,I_L\,(R \cos\theta + X \sin\theta)$ Equation 5.21

$V_{R\,NA} = I_L\,[R \cos(\theta - 30°) + X \sin(\theta - 30°)]$ Equation 5.22

$V_{R\,BN} = I_L\,[R \cos(\theta + 30°) + X \sin(\theta + 30°)]$ Equation 5.23

Case VIII.



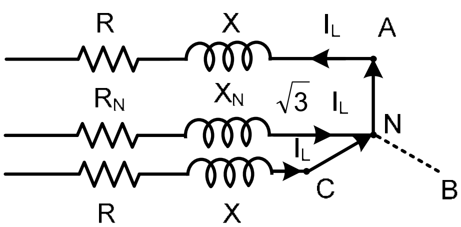


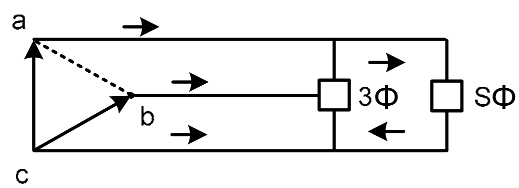
$V_{R\,NA} = 2\, I_L\, (R \cos\theta + X \sin\theta)$ Equation 5.24

$V_{R\,BN} = I_L\, [R \cos(\theta + 60°) + X \sin(\theta + 60°)]$ Equation 5.25

$V_{R\,CN} = I_L\, [R \cos(\theta - 60°) + X \sin(\theta - 60°)]$ Equation 5.26

Case IX.





$V_{R\,NA\,3\Phi\,+\,NA\,S\Phi} = I_{L\,3\Phi}\, [R \cos(\theta_{3\Phi} - 30°) + X \sin(\theta_{3\Phi} - 30°)] + 0.9\,\sqrt{3}\, I_{L\,3\Phi}\, [R_N \cos(\theta_{3\Phi} - 60°) + X_N \sin(\theta_{3\Phi} - 60°)] + I_{L\,S\Phi}\, [R \cos\theta_{S\Phi} + X \sin\theta_{S\Phi}] + 0.9\, I_{L\,S\Phi}\, [RN \cos(\theta_{S\Phi} - 60°) + X_N \sin(\theta_{S\Phi} - 60°)]$ Equation 5.27

$V_{R\,CN\,3\Phi} = I_{L\,3\Phi}\, [R \cos(\theta_{3\Phi} + 30°) + X \sin(\theta_{3\Phi} + 30°)] + 0.9\,\sqrt{3}\, I_{L\,3\Phi}\, [R_N \cos(\theta_{3\Phi} + 60°) + X_N \sin(\theta_{3\Phi} + 60°)]$ Equation 5.28

$V_{R\,CA\,3\Phi} + C_{A\,S\Phi} = I_{L\,3\Phi}\, [R \cos(\theta + 60°) + X \sin(\theta + 60°) + I_{L\,3\Phi}\, [R \cos(\theta - 60°) + X \sin(\theta - 60°)] + I_{L\,S\Phi}\, [R \cos(\theta - 30°) + X \sin(\theta - 30°)]$ Equation 5.29

5.4 Distribution Transformer Impedance

The percent resistance and percent reactance of transformers can be determined from load losses and percent impedance.

The percent Z is defined as

$$\% Z = \sqrt{\% R^2 + \% X^2}, \qquad \text{Equation 5.30}$$

and percent R is determined from

$$\% R = \frac{\text{Load Losses (watts)}}{10\,\text{kVA}}. \qquad \text{Equation 5.31}$$

Using the 25-kVA transformer load losses from Table 10, then

$$\% R = \frac{397\ \text{watts}}{(10)\,(25)} = 1.59\,.$$

From Equation 5.30, the %R of Equation 5.31, and the %Z of Table 10, %X is determined as

$$\% X = \sqrt{\% Z^2 - \% R^2},$$

$$\% X = \sqrt{(2.58)^2 - (1.59)^2} = 2.03\,.$$

5.5 Distribution Transformer Voltage Drop

In one knows the R and X values, the load current, and the power factor, the voltage drop can be determined. The actual R and X values in ohms are found from the %R and %X values as follows:

Voltage Drop for 25-kVA Transformer

Base voltage = 240 V

Base kVA = 25 kVA

Base current = $\frac{25{,}000}{240} = 104.17$ amperes

Base Z = $\frac{240}{104.17} = 2.30\,\Omega$

Table 10. Distribution Transformer No Load (Core Losses) and Load (Copper Losses)

Type	kVA	Phase	Sec. Volt	Pri. Volt	No-Load Losses Watts	Load Losses Watts	Tot Losses Watts	%Z	$\%I_e$
OH	15	S	120/240	4800/7620	34	280	314	2.58	0.51
OH	25	S	120/240	4800/7620	43	397	440	2.58	0.27
OH	50	S	120/240	4800/7620	103	564	667	1.97	0.76
OH	100	S	120/240	4800/7620	165	1150	1315	2.10	0.21
OH	167	S	120/240	4800/7620	267	1749	2016	2.37	0.33
PAD	75	3	120/208	4800x13200/7620	283	836	1119	2.43	0.78
PAD	150	3	120/208	13200/7620	328	2026	2354	2.37	0.34
PAD	300	3	120/208	13200/7620	639	3198	3837	2.50	0.55
PAD	500	3	120/208	4800x13200/7620	1140	4085	5225	3.45	0.46
PAD	1000	3	480Y/277	4160	1160	7601	8761	5.51	0.23
PAD	1500	3	480Y/277	4800x13200	1516	10294	11810	6.04	0.17
PAD	2000	3	480Y/277	4800x13200	1894	12933	14827	5.75	0.15
ISO	333	S	4800/8320	7620/13200	416	2937	3353	3.43	0.35
PAD	50	S	120/240	7620	107	675	782	1.92	0.30
PAD	100	S	120/240	7620	173	1074	1247	2.34	0.26
PAD	167	S	120/240	4800x13200/7620	231	1466	1697	2.72	0.20

$$\text{Actual R ohms} = 1.59\% \times 2.30\ \Omega$$
$$= 0.0366\ \Omega$$

$$\text{Actual X ohms} = 2.0\% \times 2.30\ \Omega$$
$$= 0.0460\ \Omega$$

$$\text{Actual Z ohms} = 2.58\% \times 2.30\ \Omega$$
$$= 0.0593\ \Omega$$

Assuming a power factor of 0.90 (25.84°), a load current of 1.40 times rated kilovolt-amperes, and a voltage of 105% of rated voltage, the current would be

$$I = \frac{(104.17\ \text{amperes})}{1.05} \times 1.40 = 138.9\ \text{amperes}.$$

The approximate voltage drop is then

$$\Delta V = IR \cos\theta + I X \sin\theta, \qquad \text{Equation 5.32}$$

$$= (138.9)\,[(0.0366)\,(0.90) + (0.0460)\,(0.4358)]$$

$$= (138.9)\,[0.03294 + 0.0200]$$

$$\boxed{\Delta V = 7.36 \text{ V @ } 240 \text{ V}}$$

$$\boxed{\Delta V \text{ @ } 120 \text{ V} = 3.68 \text{ V}} \quad . \qquad \text{Equation 5.33}$$

The voltage drop can be reduced if a 50-kVA transformer is substituted for the 25-kVA transformer.

Voltage Drop for 50-kVA Transformer

Base current = 208.34 A

$$\text{Base Z} = \frac{240}{208.34} = 1.15\,\Omega$$

Actual R ohms = 1.13% x 1.15 Ω
= 0.0130 Ω

Actual X ohms = 1.62% x 1.15 Ω
= 0.0187 Ω

Actual Z ohms = 1.97% x 1.15 Ω
= 0.0227 Ω

Using a 0.90 power factor, 1.4 times rated current, and 105% voltage, the current is

$$I = \frac{208.34}{1.05} \text{ x } 1.40 = 277.8 \text{ amperes}$$

and

$$\Delta V = IR \cos\theta + I X \sin\theta$$

$$= (277.8)\,[(0.0130)\,(0.90) + (0.0187)\,(0.4358)]$$

$$= (277.8)\,[0.0117 + 0.00815]$$

$$\Delta V = 5.51 \text{ V @ } 240 \text{ V}$$

$$\boxed{\Delta V \text{ @ } 120 \text{ V} = 2.75 \text{ V}}. \qquad \text{Equation 5.34}$$

5.6 Distribution Transformer Losses

Distribution transformer losses consist of load losses and no-load losses.

5.6.1 Load Losses

The load losses are proportional to the square of the load current. The test data in Table 10 are given at rated load current. The load loss at loads other than rated load is

$$\text{Load loss} = \left(\frac{I_{load}}{I_{rated}}\right)^2 \text{(load loss at rated load),} \qquad \text{Equation 5.35}$$

$$= \left(\frac{kV_{rated}}{kV_{actual}} \quad \frac{kVA_{actual}}{kVA_{rated}}\right)^2 \text{(load loss at rated load).} \qquad \text{Equation 5.36}$$

For the 25-kVA transformer, the load loss at rated load is 397 W. But at peak load, the load may be as high as 140%–200% of rated load. The load losses at 105% of rated voltage and 140% of rated load are from Equation 5.36.

$$\text{Load losses} = \left(\frac{7620}{(7620)\,(1.05)} \text{ x } \frac{(25)\,(1.40)}{25}\right)^2 (397)$$

$$= (1.78)\,(397)$$

$$= 706 \text{ W}$$

$$\text{Percent load loss} = \frac{\text{Load Loss (watts)}}{(1.4)\,(VA_{rated})\,(\text{Cos}\,\theta)} \text{x}100 = \frac{\text{Load Loss (watts)}}{(1.4)\,(10\,kVA_{rated})\,(\text{Cos}\,\theta)}$$

Equation 5.37

For the 25-kVA transformer, the percent load loss is

$$\text{Percent load loss} = \frac{706}{(1.4)\,(10)\,(25)\,(.90)} = 2.24\%\,.$$

5.6.2 No-Load Losses

The no-load losses are the core losses, dielectric losses, and copper losses caused by the excitation current. However, the core losses because of the hysteresis and eddy current losses are the most significant. From Table 10, the no-load losses for the 25-kVA transformer are 43 W. For operation above rated voltage, the no-load losses must be corrected. The correction factors are 1.15 at 105% of rated voltage and 1.30 at 110% of rated voltage. At 105% voltage,

No-load losses = (rated no-load losses) (voltage correction) Equation 5.38

No-load losses = (43 W) (1.15) = 49.5 W.

5.6.3 Total Losses

Adding the no-load losses corrected for voltage and load losses corrected for voltage and current gives 2.4% total losses for the 25-kVA transformer.

$$\text{Total percent losses} = \frac{706 + 49.5}{(1.4)\,(10)\,(25)\,(0.90)} = \boxed{2.40\%} \qquad \text{Equation 5.39}$$

For the 50-kVA transformer, the percent load losses are

$$\text{Load losses} = \left(\frac{7620}{(7620)\,(1.05)} \text{ x } \frac{(50)\;(1.40)}{50}\right)^2 (564)$$

$$= 1{,}003 \text{ W}$$

$$\text{Percent load losses} = \frac{1003}{(1.4)\,(10)\,(50)\,(0.90)} = 1.59\%\,.$$

The percent no-load losses are

No-load losses = (103) (1.15) = 118.5 W,

and the total percent losses are

$$\text{Total percent losses} = \frac{1003 + 118.5}{(1.4)\,(10)\,(50)\,(0.90)} = \boxed{1.78\%}. \qquad \text{Equation 5.40}$$

5.7 Line Impedance Model

A four-wire, wye-grounded, overhead line distribution circuit that consists of three-phase conductors and one neutral can be represented as a four-by-four matrix. With the aid of Figure 78, the resultant matrix, using Kirckhoff's voltage law, is shown below.

$$\begin{bmatrix} V_{A_S} \\ V_{B_S} \\ V_{C_S} \\ V_{N_S} \end{bmatrix} = \begin{bmatrix} V_{A_L} \\ V_{B_L} \\ V_{C_L} \\ V_{N_L} \end{bmatrix} + \begin{bmatrix} Z_A & Z_{AB} & Z_{AC} & Z_{AN} \\ Z_{BA} & Z_B & Z_{BC} & Z_{BN} \\ Z_{CA} & Z_{CB} & Z_C & Z_{CN} \\ Z_{NA} & Z_{NB} & Z_{NC} & Z_N \end{bmatrix} \bullet \begin{bmatrix} I_A \\ I_B \\ I_C \\ I_N \end{bmatrix} \qquad \text{Equation 5.41}$$

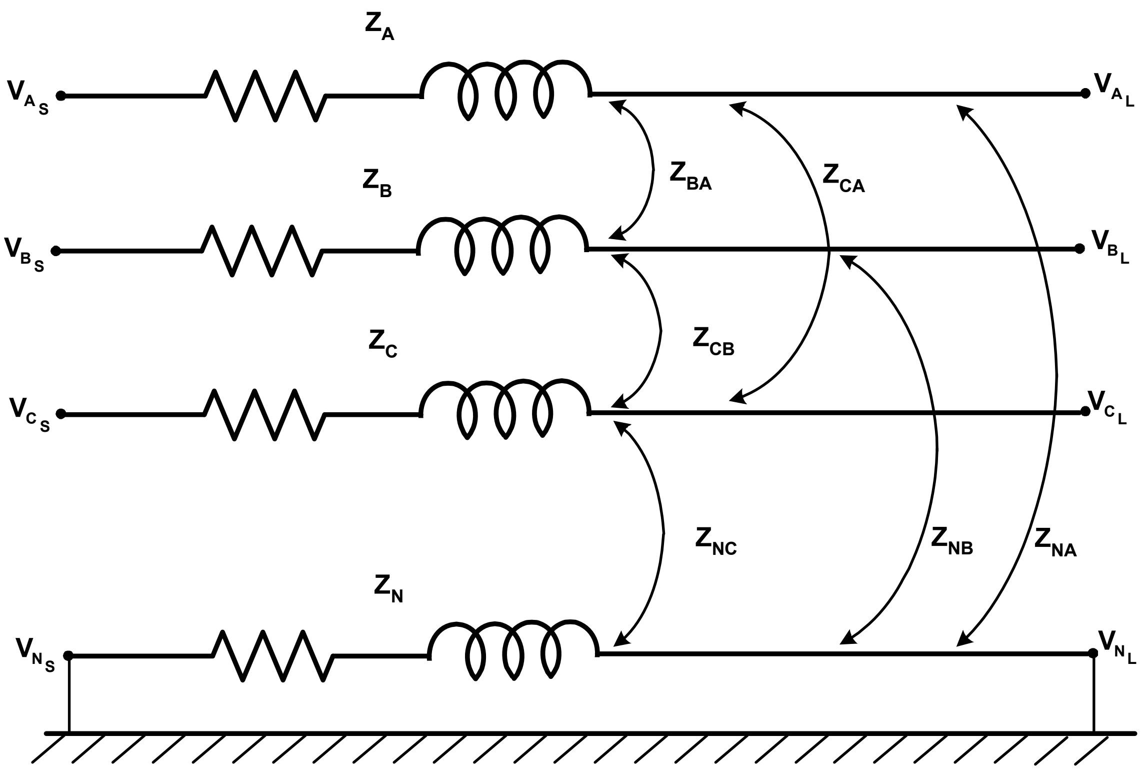


Figure 78. Four-wire, wye-grounded, overhead distribution line with multi-grounded neutral

For a three-conductor cable with one neutral, the impedance matrix is:

$$Z = \begin{bmatrix} Z_A & Z_{AB} & Z_{AC} & Z_{AN} \\ Z_{BA} & Z_B & Z_{BC} & Z_{BN} \\ Z_{CA} & Z_{CB} & Z_C & Z_{CN} \\ Z_{NA} & Z_{NB} & Z_{NC} & Z_N \end{bmatrix}.$$

For the flat-line configuration used in the Milford circuit, the line spacing is:

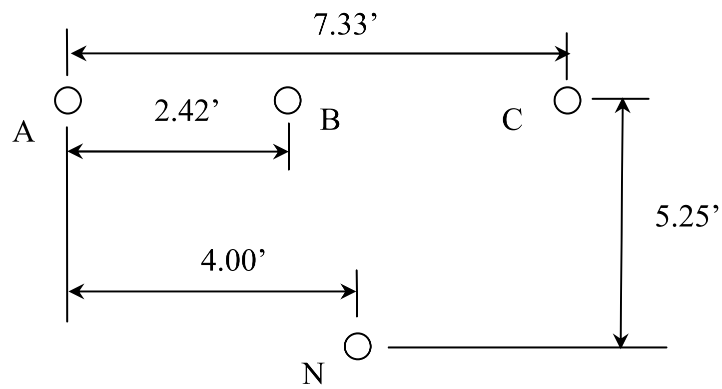


Figure 79. Flat line spacing configuration

The characteristics of the phase and neutral conductors are shown below.

	A	B	C	N
Conductor	636 Al	636 Al	636 Al	1/0 ACSR
GMR (ft)	0.0294	0.0294	0.0294	0.006
Resistance (Ω/mi)	0.146	0.146	0.146	1.153

The diagonal and off-diagonal elements of the impedance matrix (Kersting 2004) are calculated using:

$$z_{ii} = r_i + 0.09530 + j0.12134\,[\ln(1/GMR_i) + 7.93402]\ \Omega/\text{mi} \qquad \text{Equation 5.42}$$

$$z_{ij} = 0.09530 + j0.12134\,[\ln(1/D_{ij}) + 7.93402]\ \Omega/\text{mi}, \qquad \text{Equation 5.43}$$

where

r_i = Resistance of conductor in Ω/mi
D_{ij} = Distance in feet from conductor i to conductor j
GMR_i = Geometric mean radius of the conductor in feet
0.09530 = Equivalent resistance of earth (100 Ω-m)
7.93402 = Equivalent mutual inductive reactance between a conductor and earth @ 60 Hz.

It should be noted that the diagonal terms account for the self-inductance and resistance of the line and also contain expressions that take into account the effects of the earth return path. The off-diagonal elements account for the mutual inductance of the lines and again take into account the effects of the earth return path.

For the flat-line model of Figure 79, the impedance matrix is:

$$Z = \begin{bmatrix} .2413 + j1.3907 & .0953 + j.85548 & .0953 + j.72101 & .0953 + j.70949 \\ .0953 + j.8554 & .2413 + j1.3907 & .0953 + j.76963 & .0953 + j.78573 \\ .0953 + j.72101 & .0953 + j.76963 & .2413 + j1.3907 & .0953 + j.76267 \\ .0953 + j.70949 & .0953 + j.78573 & .0953 + j.76267 & 1.2483 + j1.3907 \end{bmatrix}.$$

Equation 5.44

The Kron reduction technique allows this four-by-four matrix to be reduced to a more-applicable three-by-three matrix Z_{ABC}.

$$Z_{ij} = \begin{bmatrix} Z_A & Z_{AB} & Z_{AC} \\ Z_{BA} & Z_B & Z_{BC} \\ Z_{CA} & Z_{CB} & Z_C \end{bmatrix} = \begin{bmatrix} .2413 + j1.3907 & .0953 + j.85548 & .0953 + j.72101 \\ .0953 + j.8554 & .2413 + j1.3907 & .0953 + j.76963 \\ .0953 + j.72101 & .0953 + j.76963 & .2413 + j1.3907 \end{bmatrix}$$

Equation 5.45

$$Z_{in} = \begin{bmatrix} z_{AN} \\ z_{BN} \\ z_{CN} \end{bmatrix} = \begin{bmatrix} .0953 + j.70949 \\ .0953 + j.78573 \\ .0953 + j.76267 \end{bmatrix}$$

Equation 5.46

$$Z_{nj} = \begin{bmatrix} Z_{NA} & Z_{NB} & Z_{NC} \end{bmatrix} = \begin{bmatrix} .0953 + j.70949 & .0953 + j.78573 & .0953 + j.76267 \end{bmatrix}$$

Equation 5.47

$$Z_N = z_N = 1.2483 + j1.5835$$

Equation 5.48

$$Z_{ABC} = Z_{ij} - Z_{in} Z_N^{-1} Z_{nj} = \begin{bmatrix} .3404 + j1.1566 & .0953 + j.85548 & .0953 + j.7210 \\ .0953 + j.85548 & .2413 + j1.3907 & .0953 + j.76963 \\ .0953 + j.7210 & .0953 + j.76963 & .2413 + j1.3907 \end{bmatrix}$$

Equation 5.49

For a non-transposed line of 6.25 mi (33,000 ft), the impedance matrix becomes

$$Z_{ABC} = \begin{bmatrix} 2.1275 + j7.2289 & 1.3100 + j3.7384 & 1.2750 + j2.9420 \\ 1.3100 + j3.7384 & 2.3108 + j6.9235 & 1.3689 + j3.0904 \\ 1.2750 + j2.9420 & 1.3689 + j3.0904 & 2.2530 + j7.0188 \end{bmatrix}.$$

Equation 5.50

5.8 Line Voltage Drop Model

The voltage drop for a given four-wire line segment is calculated using the impedance and matrix for that line segment.

$$V_S - V_L = Z_{ABC} I_{ABC}$$

Equation 5.51

$$\Delta V = Z_{ABC} I_{ABC}$$

Equation 5.52

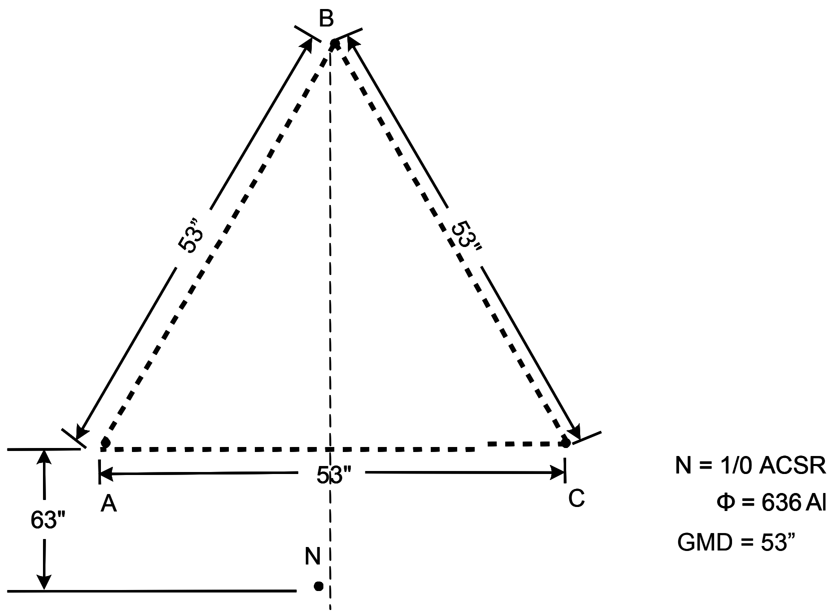
$$\begin{bmatrix} \Delta V_A \\ \Delta V_B \\ \Delta V_C \end{bmatrix} = \begin{bmatrix} z_A & z_{AB} & z_{AC} \\ z_{BA} & z_B & z_{BC} \\ z_{CA} & z_{CB} & z_C \end{bmatrix} \cdot \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}$$ Equation 5.53

The effects of the admittance matrix have been neglected because of the relatively short line length (6.25 mi).

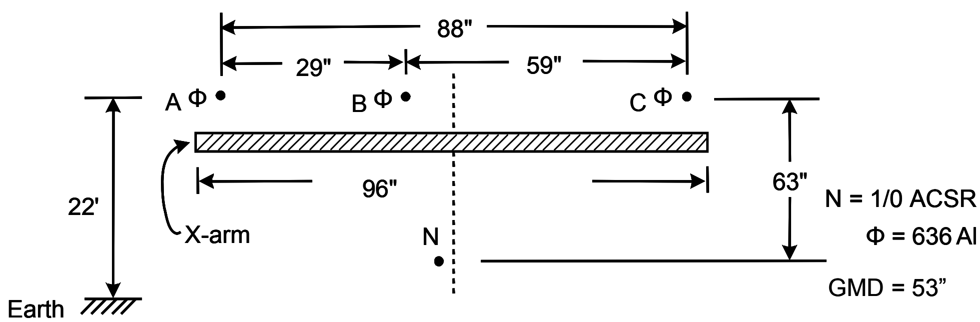
5.9 Line Losses Model and Validation

To validate the line loss model, three line configurations and balanced and unbalanced load conditions are considered. These line configurations are shown in Figure 80. Figure 80a is a balanced impedance triangular or equilateral configuration with a high B phase. The geometric mean distance (GMD) of the phase spacings shown in Figure 80a is 53 in. (4.42 ft), which is the same as the GMD of the flat configuration in Figure 79. Figure 80b is the flat non-transposed line, and Figure 80c is the flat transposed line. The dimensions between phases, neutral, and ground are identical in Figure 80b and Figure 80c, but the flat transposed line of Figure 80c has two transpositions.

Figure 81 shows the flat transposed line, which consists of three line segments of 11,000 ft each, for a total length of 33,000 ft. The source is at Node 0, and the two transpositions are shown at Node 1 and Node 2. The lump load of 9,000 kVA at unity power factor is located at the end of the line at Node 3.

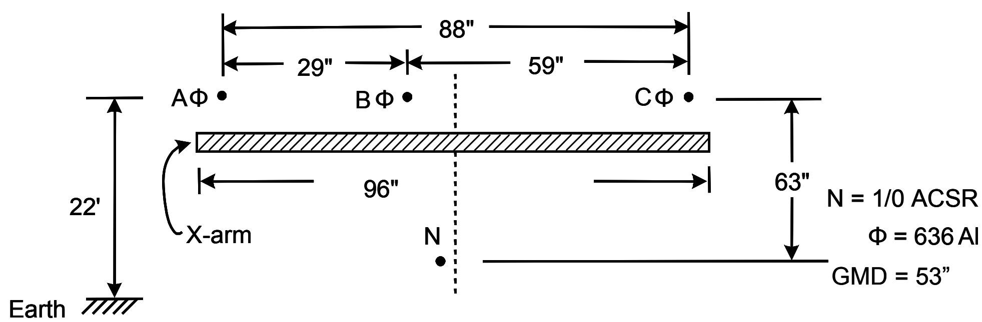


(a) Equilateral Spacing



(b) Flat Non-transposed

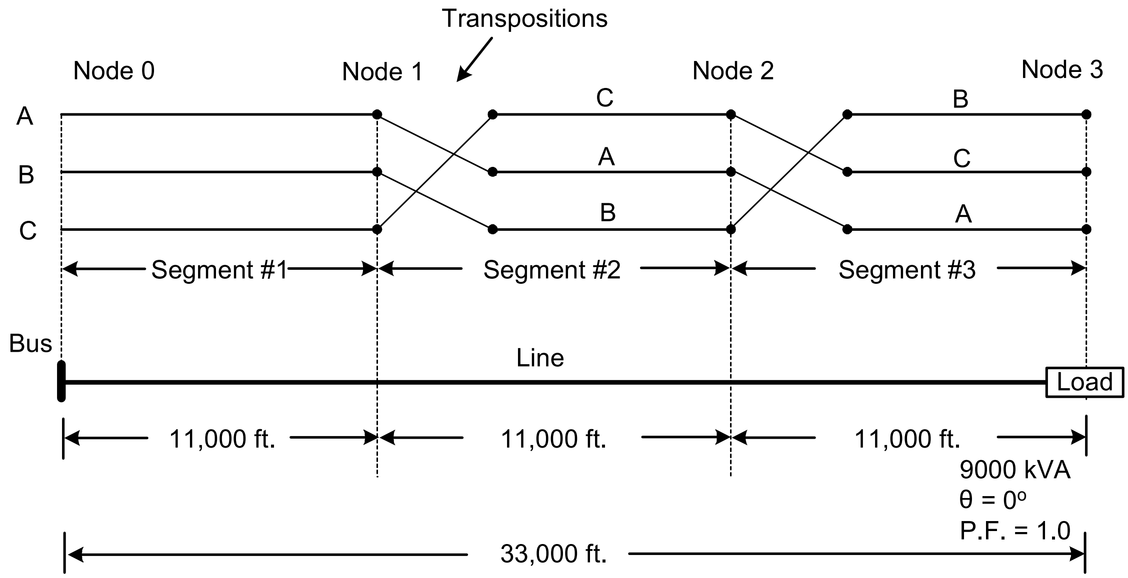
Note: Neutral to ground distance = 22' - 63" = 201" (16.75')



(c) Flat Transposed

Note: Neutral to ground distance = 22' - 63" = 201" (16.75')

Figure 80. Configuration, phase, and neutral spacings; phase and neutral sizes; and conductor types



Flat Transposed Line and Load Characteristics

Figure 81. Line transposition and load

The purpose of this validation is to show that with balanced line impedance and balanced load the kilowatt losses are equal in each phase and total kilowatt losses are lowest. In addition, even though the kilowatt losses per phase may not be correct because of the Kron reduction process (which reduces a four-by-four matrix to a three-by-three matrix) the total losses are, in fact, correct. Table 11, Table 12, and Table 13 and the associated graphs provide a summary of balanced and unbalanced loading for the equilateral line spacing, non-transposed flat line spacing, and transposed flat line spacing configurations.

A balanced load of 3,000 kW per phase, modeled using constant impedance and computed using a nominal voltage of 7.62 kV, is attached at the end of the non-transposed line at Node 3. The load impedance matrix is

$$Z_{load} = \begin{bmatrix} 19.35 & 0 & 0 \\ 0 & 19.35 & 0 \\ 0 & 0 & 19.35 \end{bmatrix} \qquad \text{Equation 5.54}$$

where

$$Z_{load_{ii}} = \frac{(7.62\text{kV})^2}{3\text{MVA}} = 19.35\,. \qquad \text{Equation 5.55}$$

Attaching the load to the end of the above non-transposed line yields

$$V_S = (Z_{load} + Z_{ABC})\, I_{ABC}\,. \qquad \text{Equation 5.56}$$

For a 13.2-kV line, the above load, and the 6.25-mi non-transposed line, solving for I_{ABC} gives

$$I_{ABC} = (Z_{load} + Z_{ABC})^{-1} V_S \qquad \text{Equation 5.57}$$

$$I_{ABC} = \begin{bmatrix} 358.4\angle -10.2 \\ 377.8\angle -130.2 \\ 371.3\angle 108.4 \end{bmatrix}, \text{A}\,. \qquad \text{Equation 5.58}$$

Notice from the non-transposed spreadsheet of Table 12, at Node 3, the magnitudes of phase currents are $I_A = 356.2$, $I_B = 375.9$, and $I_C = 372.0$. These data are based on the voltage-dependent current (VDC) source model rather than the constant-impedance model data in the matrix above.

The load end voltage V load is therefore

$$V_{load} = V_S - Z_{ABC}\, I_{ABC}$$

$$V_{load} = \begin{bmatrix} 6.94\angle -10.2 \\ 7.31\angle -130.2 \\ 7.19\angle 108.4 \end{bmatrix}, \text{kV}\,. \qquad \text{Equation 5.59}$$

The magnitudes of the phase voltages in kilovolts from Table 12 at Node 3 are $V_A = 6.96$, $V_B = 7.31$, and $V_C = 7.24$. The power loss in the line is

$$P_{loss} = \text{Re}[S_{in}] - \text{Re}[S_{out}] = \begin{bmatrix} 200.5 \\ 71.6 \\ 102.8 \end{bmatrix}, \text{kW}\,. \qquad \text{Equation 5.60}$$

The total loss for the line is 374.9 kW. This compares to ΦA = 194.35 kW, ΦB = 72.47 kW, and ΦC = 84.29 kW, for a total of 351.11 kW for the VDC model. If the balanced load impedance matrix is replaced with an unbalanced load impedance matrix, the loss results may appear incorrect.

$$Z_{load} = \begin{bmatrix} 12.90 & 0 & 0 \\ 0 & 25.81 & 0 \\ 0 & 0 & 25.81 \end{bmatrix} \qquad \text{Equation 5.61}$$

The above impedance matrix corresponds to a heavily loaded A phase (4,500 kW) relative to the B and C phases (2,250 kW). The last line of Table 12 at Node 0 shows the voltage magnitudes in kilovolts of $V_A = 7.620$, $V_B = 7.620$, and $V_C = 7.620$. Applying these balanced voltages and unbalanced loads for each phase,

$$Z_A = \frac{(7620)^2}{2250 \text{ x } 10^3} = 12.90,$$

$$Z_B = \frac{(7620)^2}{4500 \text{ x } 10^3} = 25.81, \text{ and}$$

$$Z_C = \frac{(7620)^2}{2250 \text{ x } 10^3} = 25.81.$$

Repeating the above procedure to find the line losses yields

$$P_{loss} = \mathrm{Re}[S_{in}] - \mathrm{Re}[S_{out}] = \begin{bmatrix} 516.0 \\ -164.4 \\ 57.0 \end{bmatrix}, \mathrm{kW}. \qquad \text{Equation 5.62}$$

The total loss for the line is 408.6 kW. The phase losses from the spreadsheet for the non-transposed case are 131.8, 390.5, and -117.4, corresponding to a heavily loaded B phase (4,500 kW) in the simulation case, or a total of 404.96 kW. It is obvious in this unbalanced case that the phase loss calculations do not represent the actual losses in each phase; however, the total line loss is correct. The inclusion of the effects of the earth and neutral in the three-by-three impedance matrix is the reason for the dubious phase loss numbers. To obtain correct losses for the individual phases, the I^2R losses should be calculated. First, the earth and neutral currents should be found.

$$I_N = Z_{Nt}\, I_{ABC} = 60.6\angle 157.5, \mathrm{A} \qquad \text{Equation 5.63}$$

where

$$Z_{Nt}\, I_{ABC} = -Z_N^{-1}\, Z_{nj}\,. \qquad \text{Equation 5.64}$$

The earth current is

$$I_E = -(I_A + I_B + I_C + I_N) = 127.9\angle 126.4, \mathrm{A}\,. \qquad \text{Equation 5.65}$$

Next, the I^2R losses for each phase, earth, and neutral are calculated.

$$P_{lossA} = |I_A|^2 R_A = 209.1, \mathrm{kW} \qquad \text{Equation 5.66}$$

$$P_{lossB} = |I_B|^2 R_B = 88.4, \mathrm{kW} \qquad \text{Equation 5.67}$$

$$P_{lossC} = |I_C|^2 R_C = 75.0, \mathrm{kW} \qquad \text{Equation 5.68}$$

$$P_{lossE} = \left| I_E \right|^2 R_E = 9.7, kW \qquad \text{Equation 5.69}$$

$$P_{lossN} = \left| I_N \right|^2 R_N = 26.4, kW \qquad \text{Equation 5.70}$$

When the losses are summed from the I^2R calculations, the result is 408.6. This exactly matches the previously calculated total line loss. The reason for the slight difference between the total losses from the Table 12 spreadsheet data of 404.96 kW and the total losses of 408.6 kW above is the spreadsheet data are for a VDC model. The total losses above are based on a constant-impedance model.

Note: The PF in Table 11, Table 12, and Table 13 is the percent power flow imbalance (in kilovolt-amperes).

Table 11. Equilateral Spacing Kilowatt Loss Evaluation

Spot Load (kW)			kW Losses			Total kW Losses	kVar Losses			Total kVar Losses	kW Flow			Total kW Flow
ΦA	ΦB	ΦC	ΦA	ΦB	ΦC		ΦA	ΦB	ΦC		ΦA	ΦB	ΦC	
3000.00	3000.00	3000.00	117.17	117.02	116.89	351.08	515.76	515.74	515.68	1547.18	2758.79	2759.06	2759.28	8277.13
3150.00	2925.00	2925.00	143.85	94.42	113.39	351.66	568.41	507.63	472.37	1548.41	2856.88	2713.97	2703.31	8274.16
3300.00	2850.00	2850.00	171.35	72.44	109.62	353.41	622.80	498.63	430.76	1552.19	2951.53	2666.94	2646.96	8265.43
3450.00	2775.00	2775.00	199.93	51.43	104.92	356.28	677.99	489.86	390.41	1558.26	3041.81	2619.49	2589.48	8250.78
3600.00	2700.00	2700.00	228.92	31.27	100.01	360.20	734.23	480.24	351.94	1566.41	3128.22	2570.23	2531.83	8230.28
3750.00	2625.00	2625.00	258.85	11.66	94.75	365.26	792.19	470.22	314.54	1576.95	3211.81	2519.64	2472.90	8204.35
3900.00	2550.00	2550.00	289.23	-6.96	89.03	371.30	850.71	459.93	278.75	1589.39	3291.28	2468.02	2413.32	8172.62
4050.00	2475.00	2475.00	320.05	-24.56	82.79	378.28	909.51	449.56	244.49	1603.56	3366.43	2415.58	2352.90	8134.91
4200.00	2400.00	2400.00	351.17	-41.40	76.48	386.25	969.41	438.57	211.70	1619.68	3438.52	2361.61	2291.72	8091.85
4350.00	2325.00	2325.00	382.50	-57.46	70.17	395.21	1030.43	426.96	180.38	1637.77	3507.79	2306.09	2229.77	8043.65
4500.00	2250.00	2250.00	414.10	-72.43	63.39	405.06	1091.39	415.48	150.55	1657.42	3572.73	2249.97	2166.85	7989.55

Node 0														
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.62	7.62	7.62	0	7620.91	0.11	0.0%	368.22	368.25	368.28	0.02	368.24	0.01	0.0%	0.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	382.16	362.23	360.04	6.44	368.12	8.39	2.3%	4.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	395.74	355.95	351.85	12.85	367.78	16.63	4.5%	8.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	408.87	349.61	343.58	19.24	367.2	24.7	6.7%	11.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	421.56	343.04	335.36	25.53	366.38	32.61	8.9%	15.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	433.99	336.27	327.06	31.87	365.35	40.37	11.0%	19.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	445.97	329.36	318.74	38.14	364.09	47.97	13.2%	22.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	457.5	322.35	310.36	44.35	362.59	55.41	15.3%	26.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	468.72	315.12	301.96	50.54	360.88	62.69	17.4%	30.0%
7.62	7.62	7.62	0	7620.91	0.11	0.0%	479.63	307.68	293.51	56.72	358.97	69.83	19.5%	0.33
7.62	7.62	7.62	0	7620.91	0.11	0.0%	490.12	300.16	284.99	62.84	356.83	76.81	21.5%	0.37

Node 1														
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.44	7.44	7.44	0.1	7444.34	0.08	0.0%	368.22	368.25	368.28	0.02	368.24	0.01	0.0%	0.0%
7.42	7.46	7.45	27.28	7444.34	10.95	0.1%	382.16	362.23	360.04	6.44	368.12	8.39	2.3%	4.0%
7.39	7.48	7.46	54.31	7444.22	21.65	0.3%	395.74	355.95	351.85	12.85	367.78	16.63	4.5%	8.0%
7.36	7.5	7.47	81.21	7444.01	32.15	0.4%	408.87	349.61	343.58	19.24	367.2	24.7	6.7%	11.0%
7.33	7.52	7.48	107.71	7443.74	42.43	0.6%	421.56	343.04	335.36	25.53	366.38	32.61	8.9%	15.0%
7.3	7.54	7.49	134.43	7443.41	52.52	0.7%	433.99	336.27	327.06	31.87	365.35	40.37	11.0%	19.0%
7.27	7.56	7.5	160.86	7443.01	62.4	0.8%	445.97	329.36	318.74	38.14	364.09	47.97	13.2%	22.0%
7.25	7.58	7.51	187.04	7442.55	72.06	1.0%	457.5	322.35	310.36	44.35	362.59	55.41	15.3%	26.0%
7.22	7.59	7.52	213.13	7442.05	81.53	1.1%	468.72	315.12	301.96	50.54	360.88	62.69	17.4%	30.0%
7.19	7.61	7.53	239.13	7441.52	90.81	1.2%	479.63	307.68	293.51	56.72	358.97	69.83	19.5%	0.33
7.16	7.63	7.54	264.96	7440.9	99.88	1.3%	490.12	300.16	284.99	62.84	356.83	76.81	21.5%	0.37

Node 2														
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.29	7.29	7.3	0.19	7294.81	0.15	0.0%	368.23	368.27	368.29	0.02	368.26	0.01	0.0%	0.0%
7.24	7.33	7.31	54.55	7294.79	21.95	0.3%	382.18	362.24	360.05	6.44	368.13	8.39	2.3%	3.0%
7.19	7.37	7.33	108.61	7294.48	43.37	0.6%	395.76	355.97	351.86	12.85	367.79	16.63	4.5%	7.0%
7.13	7.41	7.34	162.42	7293.96	64.36	0.9%	408.89	349.63	343.59	19.24	367.21	24.7	6.7%	10.0%
7.08	7.45	7.36	215.42	7293.28	84.91	1.2%	421.58	343.05	335.37	25.52	366.39	32.61	8.9%	13.0%
7.03	7.48	7.37	268.87	7292.42	105.1	1.4%	434.01	336.28	327.07	31.87	365.37	40.37	11.0%	17.0%
6.98	7.52	7.39	321.72	7291.4	124.86	1.7%	445.99	329.38	318.74	38.14	364.11	47.97	13.2%	20.0%
6.92	7.56	7.41	374.07	7290.21	144.19	2.0%	457.52	322.36	310.37	44.35	362.61	55.41	15.3%	23.0%
6.87	7.6	7.42	426.25	7288.9	163.12	2.2%	468.74	315.14	301.96	50.54	360.9	62.69	17.4%	26.0%
6.82	7.63	7.44	478.26	7287.49	181.69	2.5%	479.65	307.7	293.52	56.71	358.99	69.83	19.5%	0.29
6.77	7.67	7.46	529.91	7285.88	199.83	2.7%	490.14	300.18	284.99	62.84	356.84	76.81	21.5%	0.32

Node 3														
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.17	7.17	7.17	0.29	7174.03	0.24	0.0%	368.24	368.27	368.3	0.02	368.26	0.01	0.0%	0.0%
7.1	7.23	7.19	81.83	7173.95	32.96	0.5%	382.19	362.25	360.06	6.44	368.14	8.39	2.3%	3.0%
7.02	7.29	7.21	162.92	7173.39	65.08	0.9%	395.77	355.97	351.86	12.85	367.8	16.63	4.5%	6.0%
6.95	7.35	7.23	243.63	7172.45	96.57	1.3%	408.9	349.63	343.59	19.24	367.22	24.7	6.7%	9.0%
6.88	7.4	7.25	323.12	7171.2	127.4	1.8%	421.59	343.06	335.38	25.52	366.4	32.61	8.9%	12.0%
6.8	7.46	7.27	403.29	7169.63	157.69	2.2%	434.02	336.29	327.07	31.87	365.37	40.37	11.0%	15.0%
6.73	7.51	7.29	482.57	7167.75	187.32	2.6%	446	329.38	318.75	38.14	364.11	47.97	13.2%	17.0%
6.66	7.57	7.31	561.09	7165.55	216.31	3.0%	457.53	322.37	310.37	44.35	362.62	55.4	15.3%	20.0%
6.59	7.63	7.34	639.36	7163.11	244.72	3.4%	468.75	315.14	301.96	50.54	360.91	62.69	17.4%	23.0%
6.52	7.68	7.36	717.38	7160.47	272.57	3.8%	479.67	307.7	293.52	56.71	358.99	69.83	19.5%	0.26
6.44	7.74	7.38	794.85	7157.47	299.78	4.2%	490.16	300.18	284.99	62.84	356.85	76.81	21.5%	0.28

kVar Flow			Total kVar	kW Native Load			Total kW	kVar Native Load			Total kVar
ΦA	ΦB	ΦC	Flow	ΦA	ΦB	ΦC	Load	ΦA	ΦB	ΦC	Load
513.61	513.62	513.49	1540.72	2641.63	2642.04	2642.39	7926.06	-2.15	-2.12	-2.20	-6.47
566.39	505.01	469.93	1541.33	2713.03	2619.55	2589.92	7922.50	-2.03	-2.62	-2.44	-7.09
620.16	496.25	428.61	1545.02	2780.18	2594.50	2537.33	7912.01	-2.64	-2.38	-2.15	-7.17
675.99	487.17	388.05	1551.21	2841.88	2568.05	2484.56	7894.49	-2.00	-2.70	-2.36	-7.06
732.12	478.01	349.25	1559.38	2899.30	2538.95	2431.82	7870.07	-2.11	-2.23	-2.69	-7.03
789.55	467.89	312.28	1569.72	2952.96	2507.99	2378.15	7839.10	-2.65	-2.33	-2.26	-7.24
847.92	457.62	276.52	1582.06	3002.05	2474.98	2324.28	7801.31	-2.78	-2.31	-2.23	-7.32
907.62	447.15	241.84	1596.61	3046.38	2440.15	2270.11	7756.64	-1.89	-2.41	-2.65	-6.95
967.68	436.16	208.98	1612.82	3087.35	2403.01	2215.24	7705.60	-1.73	-2.42	-2.72	-6.87
1027.84	424.65	177.97	1630.46	3125.30	2363.54	2159.60	7648.44	-2.58	-2.31	-2.41	-7.30
1089.67	412.92	147.93	1650.52	3158.63	2322.40	2103.46	7584.49	-1.73	-2.56	-2.61	-6.90

Plot Information:

Node 0 I2/I1	Total kW Losses	kW Losses / kW Flow	Node 1 V1/V2	Node 2 V1/V2	Node 3 V1/V2	I0	I1	I2
0.0%	351.08	4.2%	0.0%	0.0%	0.0%	0.02	368.24	0.01
2.3%	351.66	4.3%	0.1%	0.3%	0.5%	6.44	368.12	8.39
4.5%	353.41	4.3%	0.3%	0.6%	0.9%	12.85	367.78	16.63
6.7%	356.28	4.3%	0.4%	0.9%	1.3%	19.24	367.20	24.70
8.9%	360.20	4.4%	0.6%	1.2%	1.8%	25.53	366.38	32.61
11.0%	365.26	4.5%	0.7%	1.4%	2.2%	31.87	365.35	40.37
13.2%	371.30	4.5%	0.8%	1.7%	2.6%	38.14	364.09	47.97
15.3%	378.28	4.7%	1.0%	2.0%	3.0%	44.35	362.59	55.41
17.4%	386.25	4.8%	1.1%	2.2%	3.4%	50.54	360.88	62.69
19.5%	395.21	4.9%	1.2%	2.5%	3.8%	56.72	358.97	69.83
21.5%	405.06	5.1%	1.3%	2.7%	4.2%	62.84	356.83	76.81

Table 12. Non-Transposed Kilowatt Loss Evaluation

Spot Load (kW)			kW Losses			Total kW	kVar Losses			Total kVar	kW Flow			Total kW Flow
ΦA	ΦB	ΦC	ΦA	ΦB	ΦC	Losses	ΦA	ΦB	ΦC	Losses	ΦA	ΦB	ΦC	
3000.00	3000.00	3000.00	194.35	72.47	84.29	351.11	468.69	504.08	571.12	1543.89	2673.63	2820.78	2777.24	8271.65
2925.00	3150.00	2925.00	191.64	101.18	59.82	352.64	421.45	558.63	560.65	1540.73	2617.99	2918.11	2734.33	8270.43
2850.00	3300.00	2850.00	187.85	130.92	36.35	355.12	376.15	614.45	549.88	1540.48	2561.96	3010.91	2690.10	8262.97
2775.00	3450.00	2775.00	183.15	161.60	13.77	358.52	332.63	671.65	538.71	1542.99	2505.32	3099.54	2644.44	8249.30
2700.00	3600.00	2700.00	177.65	193.08	-7.92	362.81	290.90	730.13	527.13	1548.16	2448.06	3184.09	2597.33	8229.48
2625.00	3750.00	2625.00	171.40	225.19	-28.66	367.93	250.97	789.76	515.15	1555.88	2390.15	3264.58	2548.82	8203.55
2550.00	3900.00	2550.00	164.51	257.80	-48.44	373.87	212.83	850.44	502.77	1566.04	2331.59	3341.09	2498.88	8171.56
2475.00	4050.00	2475.00	157.03	290.77	-67.24	380.56	176.49	912.05	490.01	1578.55	2272.37	3413.67	2447.55	8133.59
2400.00	4200.00	2400.00	149.06	323.97	-85.02	388.01	141.95	974.51	476.88	1593.34	2212.46	3482.4	2394.83	8089.69
2325.00	4350.00	2325.00	140.67	357.27	-101.76	396.18	109.20	1037.72	463.38	1610.30	2151.87	3547.33	2340.72	8039.92
2250.00	4500.00	2250.00	131.84	390.48	-117.36	404.96	78.33	1101.20	449.63	1629.16	2090.66	3608.08	2285.35	7984.09

Node 0															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.6200	7.6200	7.6200	0	7620.91	0.11	0.0%	356.11	375.94	371.99	3.24	367.98	9.3	2.5%	0.03
7.62	7.62	7.62	0	7620.91	0.11	0.0%	347.9	389.79	366.19	9.06	367.9	15.93	4.3%	0.06
7.62	7.62	7.6200	0	7620.91	0.11	0.0%	339.73	403.15	360.22	15.38	367.57	23.48	6.4%	0.1
7.62	7.62	7.6200	0	7620.91	0.11	0.0%	331.58	416.08	354.06	21.72	367.01	31.17	8.5%	0.13
7.62	7.62	7.6200	0	7620.91	0.11	0.0%	323.45	428.57	347.7	28.05	366.2	38.8	10.6%	0.17
7.62	7.62	7.6200	0	7620.91	0.11	0.0%	315.32	440.64	341.15	34.34	365.14	46.31	12.7%	0.2
7.62	7.62	7.6200	0	7620.91	0.11	0.0%	307.19	452.3	334.41	40.59	363.85	53.68	14.8%	0.24
7.62	7.62	7.6200	0	7620.91	0.11	0.0%	299.04	463.56	327.47	46.8	362.32	60.9	16.8%	0.28
7.62	7.62	7.62	0	7620.91	0.11	0.0%	290.89	474.41	320.35	52.97	360.56	67.97	18.9%	0.31
7.62	7.62	7.62	0	7620.91	0.11	0.0%	282.71	484.88	313.04	59.1	358.57	74.88	20.9%	0.35
7.6200	7.62	7.62	0	7620.91	0.11	0.0%	274.51	494.92	305.56	65.15	356.34	81.62	22.9%	0.38

Node 1															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.38	7.49	7.46	17.54	7442.93	56.3	0.8%	356.11	375.94	371.99	3.24	367.98	9.3	2.5%	0.03
7.39	7.46	7.48	42.54	7442.11	46.62	0.6%	347.9	389.79	366.19	9.06	367.9	15.93	4.3%	0.06
7.39	7.43	7.5	71.6	7441.23	37.83	0.5%	339.73	403.15	360.22	15.38	367.57	23.48	6.4%	0.1
7.4	7.4	7.52	101.14	7440.28	30.53	0.4%	331.58	416.08	354.06	21.72	367.01	31.17	8.5%	0.13
7.41	7.37	7.54	130.7	7439.27	25.77	0.3%	323.45	428.57	347.7	28.05	366.2	38.8	10.6%	0.17
7.42	7.34	7.57	160.16	7438.22	24.81	0.3%	315.32	440.64	341.15	34.34	365.14	46.31	12.7%	0.2
7.43	7.3	7.59	189.47	7437.11	27.84	0.4%	307.19	452.3	334.41	40.59	363.85	53.68	14.8%	0.24
7.43	7.27	7.61	218.59	7435.97	33.64	0.5%	299.04	463.56	327.47	46.8	362.32	60.9	16.8%	0.28
7.44	7.24	7.63	247.53	7434.78	40.92	0.6%	290.89	474.41	320.35	52.97	360.56	67.97	18.9%	0.31
7.45	7.21	7.65	276.27	7433.56	48.93	0.7%	282.71	484.88	313.04	59.1	358.57	74.88	20.9%	0.35
7.46	7.18	7.67	304.7	7432.31	57.25	0.8%	274.51	494.92	305.56	65.15	356.34	81.62	22.9%	0.38

Node 2															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.16	7.39	7.33	35.08	7291.9	112.7	1.5%	356.14	375.94	372	3.24	367.99	9.29	2.5%	0.04
7.17	7.33	7.38	85.08	7290.1	93.32	1.3%	347.93	389.8	366.2	9.06	367.91	15.91	4.3%	0.06
7.18	7.27	7.42	143.2	7288.13	75.74	1.0%	339.76	403.16	360.23	15.37	367.59	23.47	6.4%	0.09
7.19	7.21	7.46	202.27	7285.99	61.12	0.8%	331.61	416.08	354.07	21.72	367.02	31.16	8.5%	0.13
7.21	7.15	7.5	261.4	7283.7	51.56	0.7%	323.47	428.58	347.71	28.04	366.21	38.79	10.6%	0.16
7.22	7.09	7.54	320.31	7281.26	49.59	0.7%	315.34	440.65	341.16	34.34	365.16	46.3	12.7%	0.19
7.24	7.03	7.59	378.92	7278.69	55.61	0.8%	307.21	452.31	334.41	40.59	363.87	53.67	14.7%	0.22
7.25	6.98	7.63	437.17	7276	67.19	0.9%	299.07	463.57	327.48	46.8	362.34	60.89	16.8%	0.25
7.27	6.92	7.67	495.05	7273.19	81.75	1.1%	290.91	474.43	320.36	52.97	360.58	67.96	18.8%	0.28
7.28	6.86	7.71	552.53	7270.27	97.75	1.3%	282.73	484.9	313.05	59.09	358.59	74.87	20.9%	0.31
7.3	6.8	7.75	609.38	7267.27	114.39	1.6%	274.52	494.94	305.57	65.15	356.36	81.61	22.9%	0.34

Node 3															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
6.96	7.31	7.24	52.62	7169.53	169.1	2.4%	356.17	375.94	372	3.24	368	9.27	2.5%	0.05
6.97	7.23	7.3	127.61	7166.6	140.03	2.0%	347.95	389.79	366.2	9.05	367.92	15.9	4.3%	0.07
6.99	7.14	7.37	214.79	7163.34	113.65	1.6%	339.78	403.16	360.23	15.37	367.6	23.47	6.4%	0.09
7	7.06	7.43	303.4	7159.76	91.71	1.3%	331.63	416.08	354.07	21.71	367.03	31.15	8.5%	0.12
7.02	6.98	7.49	392.08	7155.89	77.36	1.1%	323.49	428.58	347.71	28.04	366.22	38.78	10.6%	0.15
7.04	6.9	7.55	480.44	7151.74	74.38	1.0%	315.36	440.65	341.16	34.33	365.17	46.29	12.7%	0.18
7.05	6.82	7.62	568.36	7147.34	83.38	1.2%	307.23	452.32	334.41	40.58	363.88	53.66	14.7%	0.2
7.07	6.74	7.68	655.73	7142.68	100.74	1.4%	299.08	463.57	327.48	46.8	362.35	60.89	16.8%	0.23
7.09	6.66	7.74	742.55	7137.8	122.56	1.7%	290.92	474.43	320.36	52.96	360.59	67.95	18.8%	0.25
7.11	6.58	7.8	828.77	7132.71	146.57	2.1%	282.74	484.9	313.05	59.09	358.6	74.86	20.9%	0.28
7.14	6.5	7.86	914.04	7127.42	171.52	2.4%	274.54	494.94	305.57	65.14	356.37	81.6	22.9%	0.31

kVar Flow			Total kVar	kW Native Load			Total kW	kVar Native Load			Total kVar
ΦA	ΦB	ΦC	Flow	ΦA	ΦB	ΦC	Load	ΦA	ΦB	ΦC	Load
465.92	501.64	569.08	1536.64	2479.28	2748.31	2692.95	7920.54	-2.78	-2.43	-2.04	-7.25
419.06	555.98	558.44	1533.48	2426.36	2816.93	2674.51	7917.80	-2.39	-2.66	-2.21	-7.26
373.75	611.81	547.65	1533.21	2374.11	2879.99	2653.75	7907.85	-2.40	-2.63	-2.23	-7.26
330.22	669.05	536.47	1535.74	2322.17	2937.94	2630.67	7890.78	-2.41	-2.60	-2.24	-7.25
288.48	727.55	524.87	1540.90	2270.41	2991.02	2605.25	7866.68	-2.42	-2.58	-2.26	-7.26
248.53	787.22	512.87	1548.62	2218.75	3039.39	2577.47	7835.61	-2.44	-2.54	-2.28	-7.26
210.38	847.92	500.48	1558.78	2167.09	3083.29	2547.33	7797.71	-2.45	-2.52	-2.30	-7.27
174.03	909.56	487.70	1571.29	2115.34	3122.90	2514.79	7753.03	-2.46	-2.48	-2.31	-7.25
139.48	972.05	474.55	1586.08	2063.40	3158.43	2479.85	7701.68	-2.47	-2.47	-2.33	-7.27
106.72	1035.28	461.04	1603.04	2011.20	3190.07	2442.48	7643.75	-2.48	-2.44	-2.35	-7.27
75.60	1099.26	447.30	1622.16	1958.82	3217.60	2402.71	7579.13	-2.73	-1.94	-2.32	-6.99

Plot Information:

Node 0 I2/I1	Total kW Losses	kW Losses / kW Flow	Node 1 V1/V2	Node 2 V1/V2	Node 3 V2/V1	I0	I1	I2
2.5%	351.11	4.2%	0.8%	1.5%	2.4%	3.24	367.98	9.30
4.3%	352.64	4.3%	0.6%	1.3%	2.0%	9.06	367.90	15.93
6.4%	355.12	4.3%	0.5%	1.0%	1.6%	15.38	367.57	23.48
8.5%	358.52	4.3%	0.4%	0.8%	1.3%	21.72	367.01	31.17
10.6%	362.81	4.4%	0.3%	0.7%	1.1%	28.05	366.20	38.80
12.7%	367.93	4.5%	0.3%	0.7%	1.0%	34.34	365.14	46.31
14.8%	373.87	4.6%	0.4%	0.8%	1.2%	40.59	363.85	53.68
16.8%	380.56	4.7%	0.5%	0.9%	1.4%	46.80	362.32	60.90
18.9%	388.01	4.8%	0.6%	1.1%	1.7%	52.97	360.56	67.97
20.9%	396.18	4.9%	0.7%	1.3%	2.1%	59.10	358.57	74.88
22.9%	404.96	5.1%	0.8%	1.6%	2.4%	65.15	356.34	81.62

Table 13. Transposed Kilowatt Loss Evaluation

Spot Load (MW)			kW Losses			Total kW	kVar Losses			Total kVar	kW Flow			
ΦA	ΦB	ΦC	ΦA	ΦB	ΦC	Losses	ΦA	ΦB	ΦC	Losses	ΦA	ΦB	ΦC	Total kW Flow
3000.00	3000.00	3000.00	117.05	117.04	117.06	351.15	515.80	515.77	515.79	1547.36	2758.93	2758.99	2759.00	8276.92
3150.00	2925.00	2925.00	144.46	91.77	115.41	351.64	570.85	508.10	469.82	1548.77	2854.89	2716.82	2702.11	8273.82
3300.00	2850.00	2850.00	172.80	67.30	112.99	353.09	627.40	500.00	425.46	1552.86	2946.78	2673.22	2644.53	8264.53
3450.00	2775.00	2775.00	201.93	43.65	109.86	355.44	685.35	491.46	382.72	1559.53	3034.65	2628.21	2586.23	8249.09
3600.00	2700.00	2700.00	231.72	20.86	106.09	358.67	744.55	482.47	341.61	1568.63	3118.54	2581.78	2527.21	8227.53
3750.00	2625.00	2625.00	262.04	-1.04	101.75	362.75	804.88	473.04	302.13	1580.05	3198.50	2533.96	2467.46	8199.92
3900.00	2550.00	2550.00	292.76	-22.01	96.92	367.67	866.23	463.17	264.30	1593.70	3274.59	2484.74	2406.97	8166.30
4050.00	2475.00	2475.00	323.76	-42.03	91.64	373.37	928.50	452.87	228.11	1609.48	3346.87	2434.14	2345.73	8126.74
4200.00	2400.00	2400.00	354.91	-61.08	85.99	379.82	991.58	442.13	193.57	1627.28	3415.40	2382.16	2283.73	8081.29
4350.00	2325.00	2325.00	386.12	-79.12	80.03	387.03	1055.39	430.97	160.70	1647.06	3480.26	2328.81	2220.98	8030.05
4500.00	2250.00	2250.00	417.26	-96.12	73.83	394.97	1119.83	419.41	129.49	1668.73	3541.49	2274.10	2157.48	7973.07

Node 0															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.62	7.62	7.62	0	7620.91	0.11	0.0%	368.23	368.24	368.24	0	368.23	0	0.0%	0
7.62	7.62	7.62	0	7620.91	0.11	0.0%	381.96	362.61	359.83	6.43	368.11	8.38	2.3%	0.04
7.62	7.62	7.62	0	7620.91	0.11	0.0%	395.27	356.79	351.42	12.82	367.74	16.59	4.5%	0.07
7.62	7.62	7.62	0	7620.91	0.11	0.0%	408.16	350.78	343	19.18	367.13	24.63	6.7%	0.11
7.62	7.62	7.62	0	7620.91	0.11	0.0%	420.63	344.57	334.58	25.5	366.28	32.5	8.9%	0.15
7.62	7.62	7.62	0	7620.91	0.11	0.0%	432.71	338.18	326.15	31.78	365.19	40.21	11.0%	0.18
7.62	7.62	7.62	0	7620.91	0.11	0.0%	444.38	331.59	317.7	38.03	363.86	47.74	13.1%	0.22
7.62	7.62	7.62	0	7620.91	0.11	0.0%	455.67	324.82	309.22	44.25	362.29	55.12	15.2%	0.25
7.62	7.62	7.62	0	7620.91	0.11	0.0%	466.58	317.85	300.71	50.42	360.49	62.33	17.3%	0.29
7.62	7.62	7.62	0	7620.91	0.11	0.0%	477.12	310.7	292.17	56.55	358.47	69.38	19.4%	0.33
7.62	7.62	7.62	0	7620.91	0.11	0.0%	487.29	303.37	283.59	62.65	356.22	76.27	21.4%	0.36

Node 1															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.36	7.5	7.47	25.23	7444.34	60.26	0.8%	368.23	368.24	368.24	0	368.23	0	0.0%	0
7.33	7.53	7.48	53.13	7445.92	64.24	0.9%	381.96	362.61	359.83	6.43	368.11	8.38	2.3%	0.04
7.31	7.55	7.49	81.93	7447.38	69.72	0.9%	395.27	356.79	351.42	12.82	367.74	16.59	4.5%	0.07
7.28	7.57	7.5	110.8	7448.72	76.26	1.0%	408.16	350.78	343	19.18	367.13	24.63	6.7%	0.11
7.25	7.6	7.5	139.58	7449.95	83.52	1.1%	420.63	344.57	334.58	25.5	366.28	32.5	8.9%	0.15
7.22	7.62	7.51	168.23	7451.06	91.24	1.2%	432.71	338.18	326.15	31.78	365.19	40.21	11.0%	0.18
7.19	7.64	7.52	196.72	7452.07	99.22	1.3%	444.38	331.59	317.7	38.03	363.86	47.74	13.1%	0.22
7.17	7.67	7.53	225.04	7452.99	107.34	1.4%	455.67	324.82	309.22	44.25	362.29	55.12	15.2%	0.25
7.14	7.69	7.54	253.18	7453.81	115.52	1.5%	466.58	317.85	300.71	50.42	360.49	62.33	17.3%	0.29
7.11	7.71	7.55	281.14	7454.54	123.67	1.7%	477.12	310.7	292.17	56.55	358.47	69.38	19.4%	0.33
7.08	7.73	7.56	308.91	7455.2	131.77	1.8%	487.29	303.37	283.59	62.65	356.22	76.27	21.4%	0.36

Node 2															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.27	7.38	7.24	25.24	7294.81	60.31	0.8%	368.26	368.24	368.25	0	368.24	0.02	0.0%	0.01
7.21	7.42	7.25	81.75	7295.27	47.15	0.6%	381.99	362.62	359.83	6.43	368.12	8.39	2.3%	0.02
7.16	7.47	7.26	140.47	7295.49	42.66	0.6%	395.3	356.8	351.42	12.82	367.76	16.6	4.5%	0.05
7.1	7.51	7.28	199.18	7295.5	48.7	0.7%	408.19	350.79	343.01	19.18	367.15	24.64	6.7%	0.09
7.05	7.55	7.29	257.64	7295.3	61.82	0.8%	420.67	344.58	334.59	25.5	366.29	32.52	8.9%	0.12
6.99	7.6	7.31	315.82	7294.91	78.2	1.1%	432.74	338.18	326.15	31.79	365.2	40.22	11.0%	0.15
6.93	7.64	7.32	373.65	7294.34	95.91	1.3%	444.42	331.6	317.7	38.03	363.87	47.76	13.1%	0.18
6.88	7.68	7.34	431.15	7293.6	114.1	1.6%	455.71	324.82	309.22	44.25	362.31	55.13	15.2%	0.21
6.82	7.73	7.35	488.3	7292.7	132.4	1.8%	466.62	317.86	300.71	50.42	360.51	62.34	17.3%	0.24
6.77	7.77	7.37	545.08	7291.65	150.59	2.1%	477.16	310.71	292.16	56.55	358.48	69.39	19.4%	0.27
6.72	7.81	7.38	601.49	7290.47	168.59	2.3%	487.34	303.37	283.58	62.65	356.24	76.29	21.4%	0.3

Node 3															
Voltage			Sequence Voltages (V)				Current			Sequence Currents			Imbalance	
ΦA	ΦB	ΦC	V0	V1	V2	V2/V1	ΦA	ΦB	ΦC	I0	I1	I2	I2/I1	PF
7.17	7.17	7.17	0.02	7174.03	0.06	0.0%	368.26	368.24	368.27	0	368.25	0.02	0.0%	0.01
7.1	7.24	7.19	88.72	7173.81	32.68	0.5%	381.99	362.62	359.85	6.42	368.13	8.39	2.3%	0.03
7.02	7.3	7.2	176.95	7173.18	64.7	0.9%	395.3	356.8	351.44	12.81	367.76	16.6	4.5%	0.05
6.94	7.37	7.22	264.74	7172.14	96.06	1.3%	408.19	350.79	343.03	19.17	367.15	24.64	6.7%	0.08
6.86	7.43	7.24	352.03	7170.74	126.76	1.8%	420.67	344.58	334.61	25.49	366.3	32.51	8.9%	0.11
6.79	7.5	7.25	438.83	7168.98	156.81	2.2%	432.75	338.18	326.17	31.78	365.21	40.21	11.0%	0.14
6.71	7.56	7.27	525.1	7166.88	186.21	2.6%	444.42	331.6	317.71	38.03	363.88	47.75	13.1%	0.16
6.63	7.62	7.29	610.86	7164.47	214.97	3.0%	455.72	324.82	309.23	44.24	362.31	55.13	15.2%	0.19
6.56	7.69	7.31	696.09	7161.77	243.1	3.4%	466.63	317.86	300.72	50.41	360.52	62.34	17.3%	0.22
6.48	7.75	7.33	780.78	7158.78	270.59	3.8%	477.17	310.71	292.18	56.55	358.49	69.39	19.4%	0.24
6.41	7.81	7.35	864.92	7155.53	297.47	4.2%	487.34	303.37	283.59	62.64	356.24	76.28	21.4%	0.27

kVar Flow			Total kVar	kW Native Load			Total kW	kVar Native Load			Total kVar
ΦA	ΦB	ΦC	Flow	ΦA	ΦB	ΦC	Load	ΦA	ΦB	ΦC	Load
513.41	513.32	513.39	1540.12	2641.88	2641.94	2641.95	7925.77	-2.40	-2.45	-2.40	-7.25
568.47	505.63	467.41	1541.51	2710.43	2625.05	2586.70	7922.18	-2.37	-2.47	-2.41	-7.25
625.05	497.51	423.04	1545.60	2773.98	2605.92	2531.54	7911.44	-2.35	-2.48	-2.43	-7.26
683.03	488.95	380.29	1552.27	2832.72	2584.56	2476.37	7893.65	-2.32	-2.51	-2.43	-7.26
742.25	479.94	339.17	1561.36	2886.82	2560.92	2421.12	7868.86	-2.30	-2.52	-2.44	-7.26
802.62	470.50	299.68	1572.80	2936.46	2534.99	2365.71	7837.16	-2.27	-2.55	-2.45	-7.27
863.99	460.61	261.83	1586.43	2981.83	2506.75	2310.05	7798.63	-2.24	-2.56	-2.47	-7.27
926.29	450.29	225.63	1602.21	3023.12	2476.17	2254.09	7753.38	-2.22	-2.58	-2.47	-7.27
989.39	439.53	191.09	1620.01	3060.49	2443.24	2197.74	7701.47	-2.19	-2.60	-2.49	-7.28
1053.22	428.35	158.21	1639.78	3094.14	2407.93	2140.95	7643.02	-2.17	-2.62	-2.49	-7.28
1117.68	416.77	126.99	1661.44	3124.24	2370.22	2083.65	7578.11	-2.15	-2.64	-2.50	-7.29

Plot Information:

Node 0 I2/I1	Total kW Losses	kW Losses / kW Flow	Node 1 V1/V2	Node 2 V1/V2	Node 3 V1/V2	I0	I1	I2
0.0%	351.15	4.2%	0.8%	0.8%	0.0%	0.00	368.23	0.00
2.3%	351.64	4.3%	0.9%	0.6%	0.5%	6.43	368.11	8.38
4.5%	353.09	4.3%	0.9%	0.6%	0.9%	12.82	367.74	16.59
6.7%	355.44	4.3%	1.0%	0.7%	1.3%	19.18	367.13	24.63
8.9%	358.67	4.4%	1.1%	0.8%	1.8%	25.50	366.28	32.50
11.0%	362.75	4.4%	1.2%	1.1%	2.2%	31.78	365.19	40.21
13.1%	367.67	4.5%	1.3%	1.3%	2.6%	38.03	363.86	47.74
15.2%	373.37	4.6%	1.4%	1.6%	3.0%	44.25	362.29	55.12
17.3%	379.82	4.7%	1.5%	1.8%	3.4%	50.42	360.49	62.33
19.4%	387.03	4.8%	1.7%	2.1%	3.8%	56.55	358.47	69.38
21.4%	394.97	5.0%	1.8%	2.3%	4.2%	62.65	356.22	76.27

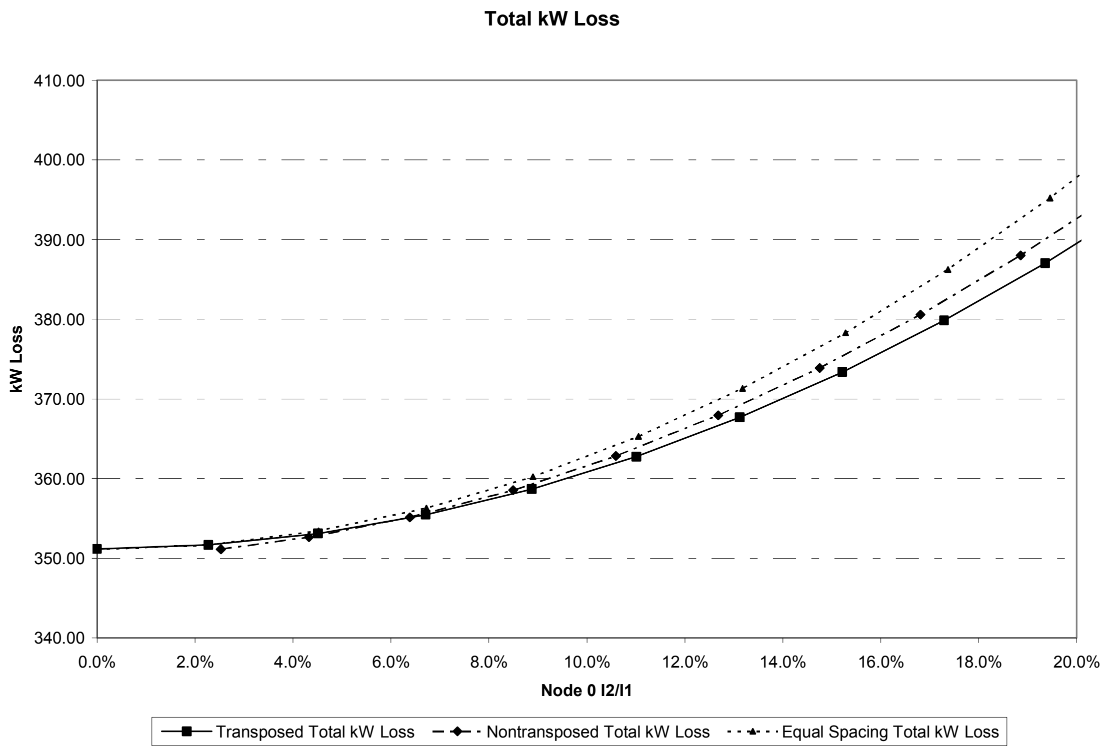


Figure 82. Total line losses versus load imbalance for each line configuration

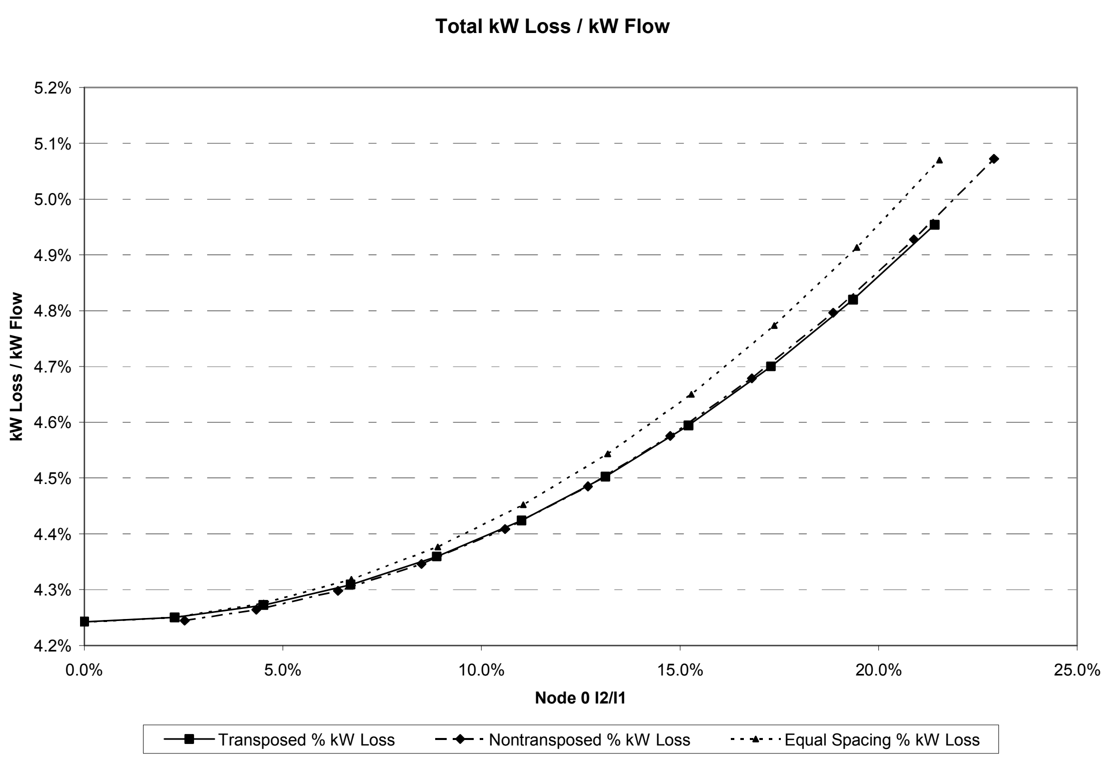


Figure 83. Percent losses versus load imbalance for each line configuration

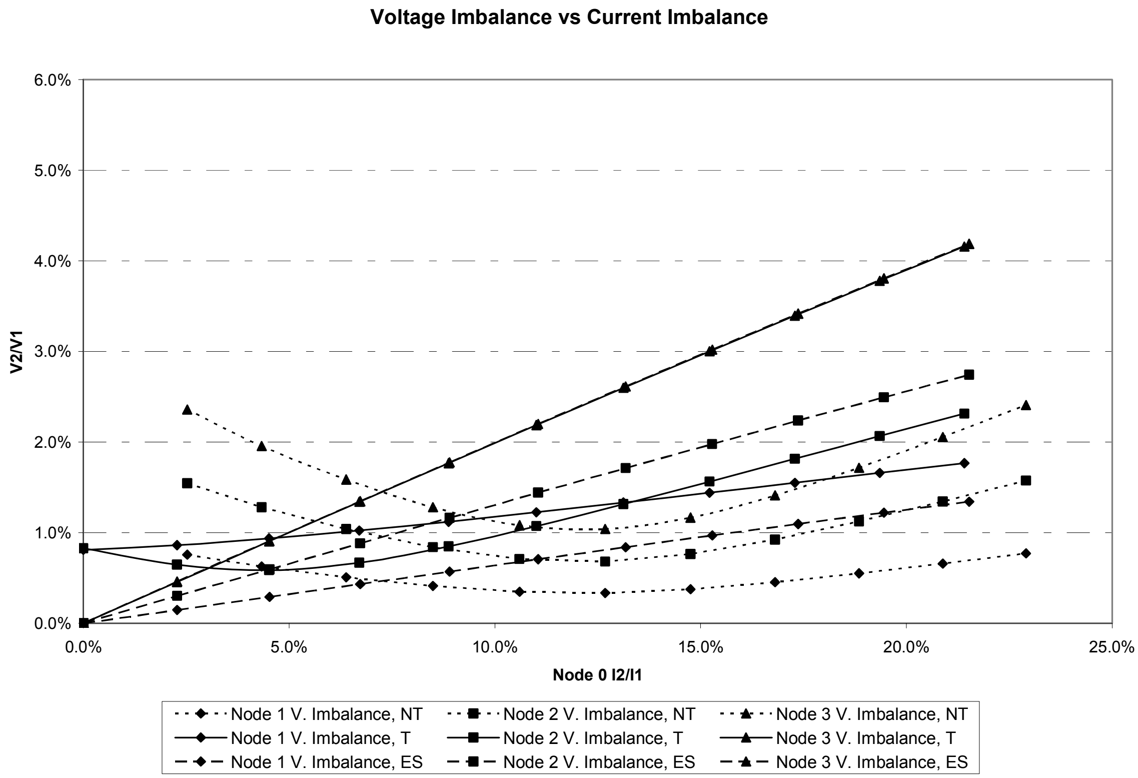


Figure 84. Voltage imbalance versus load imbalance for each line configuration

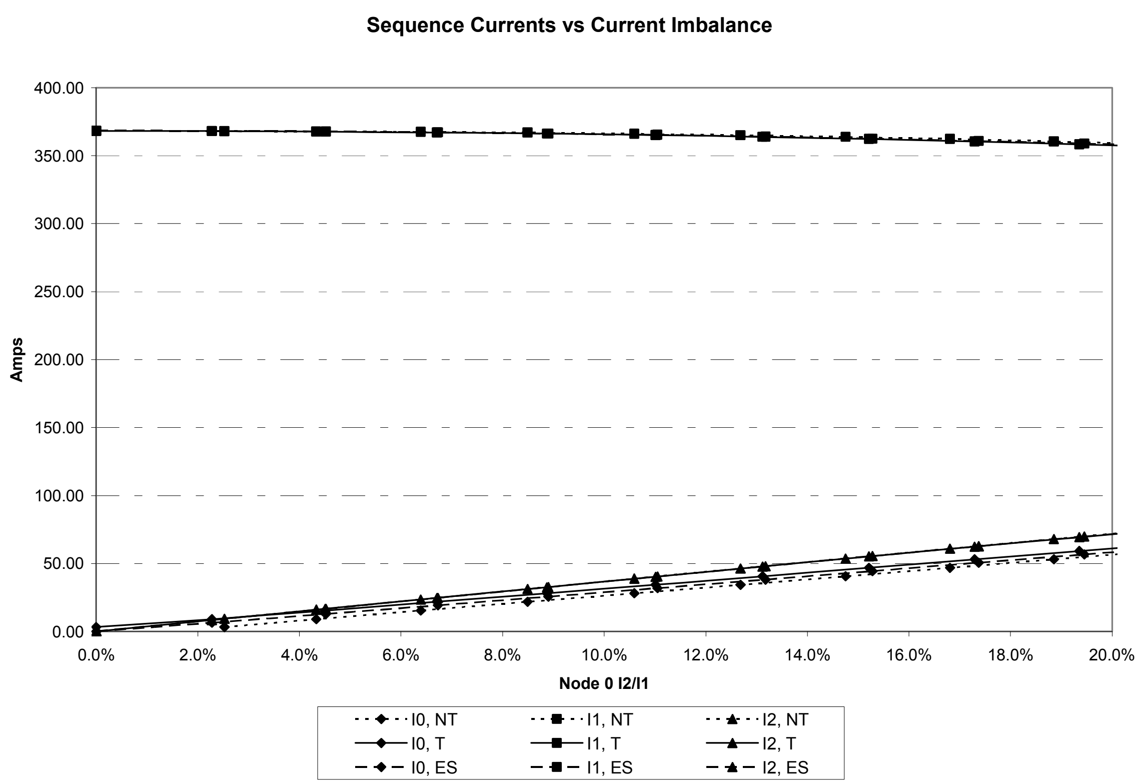


Figure 85. Sequence currents versus load imbalance for each line configuration

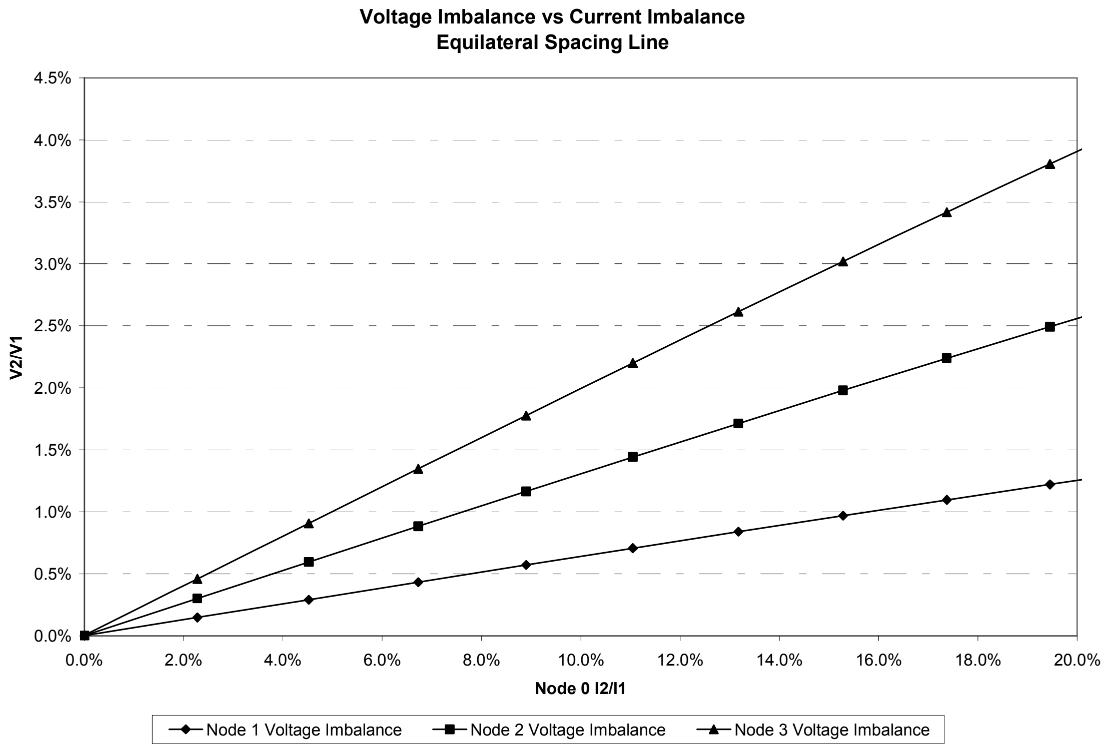


Figure 86. Voltage imbalance versus current imbalance equilateral spacing line

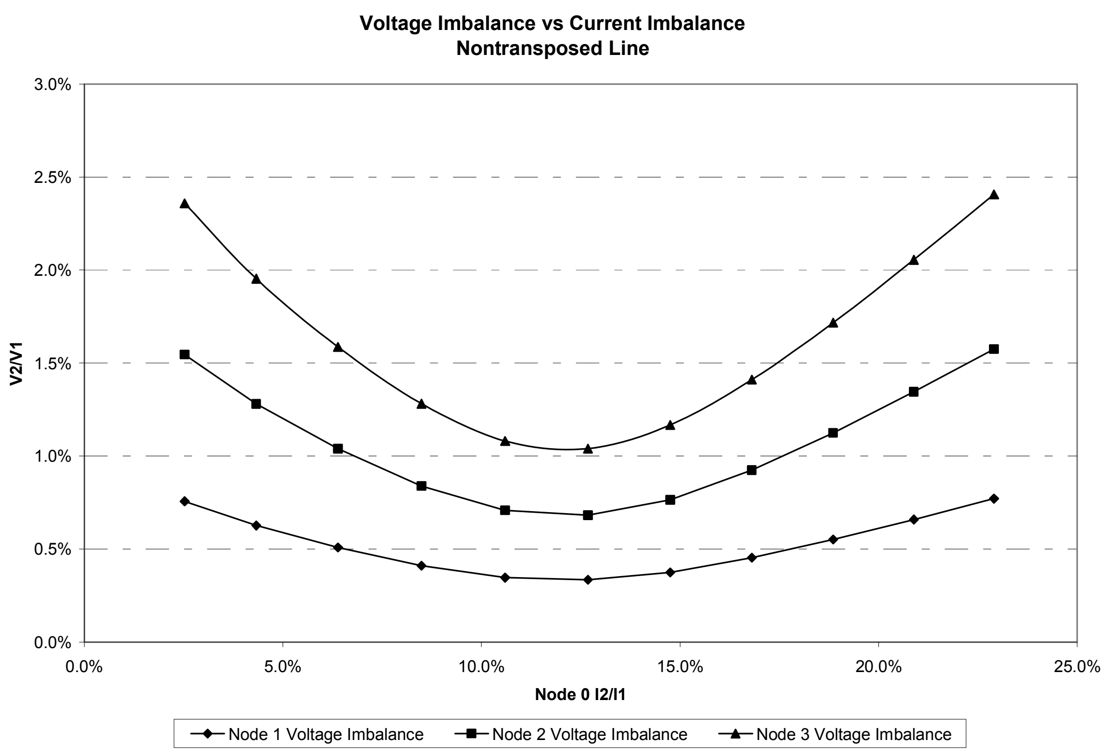


Figure 87. Voltage imbalance versus current imbalance non-transposed line

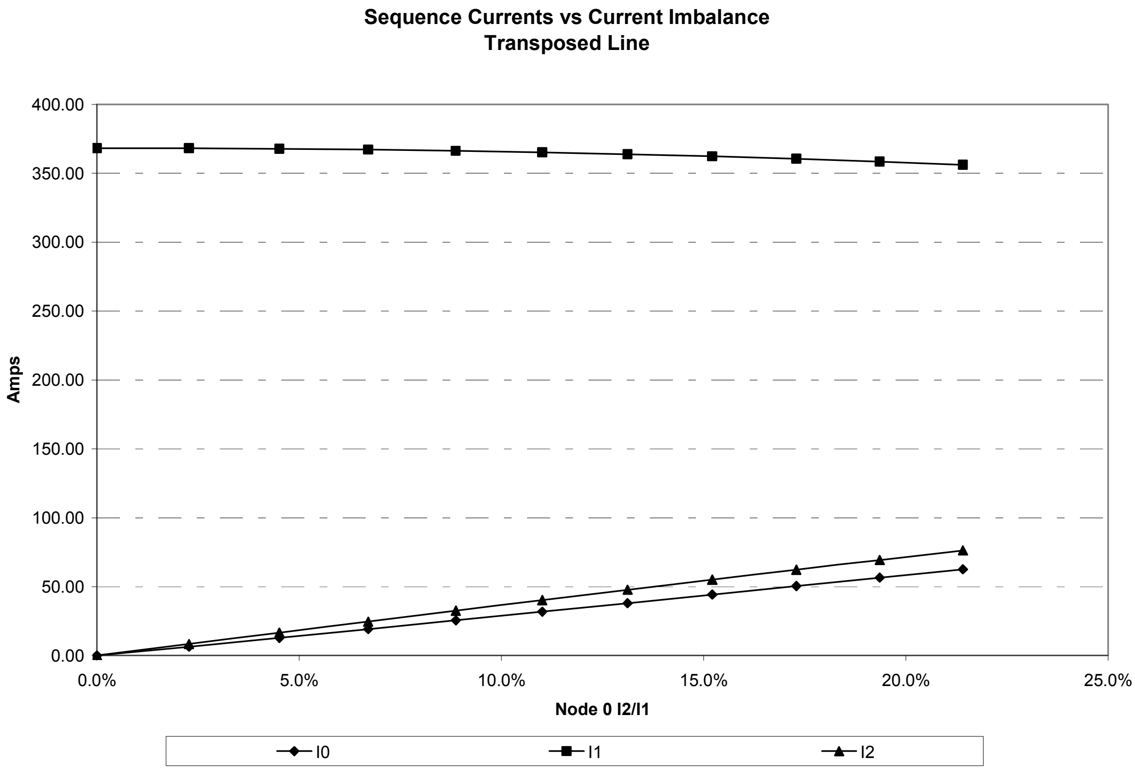


Figure 88. Voltage imbalance versus current imbalance transposed line

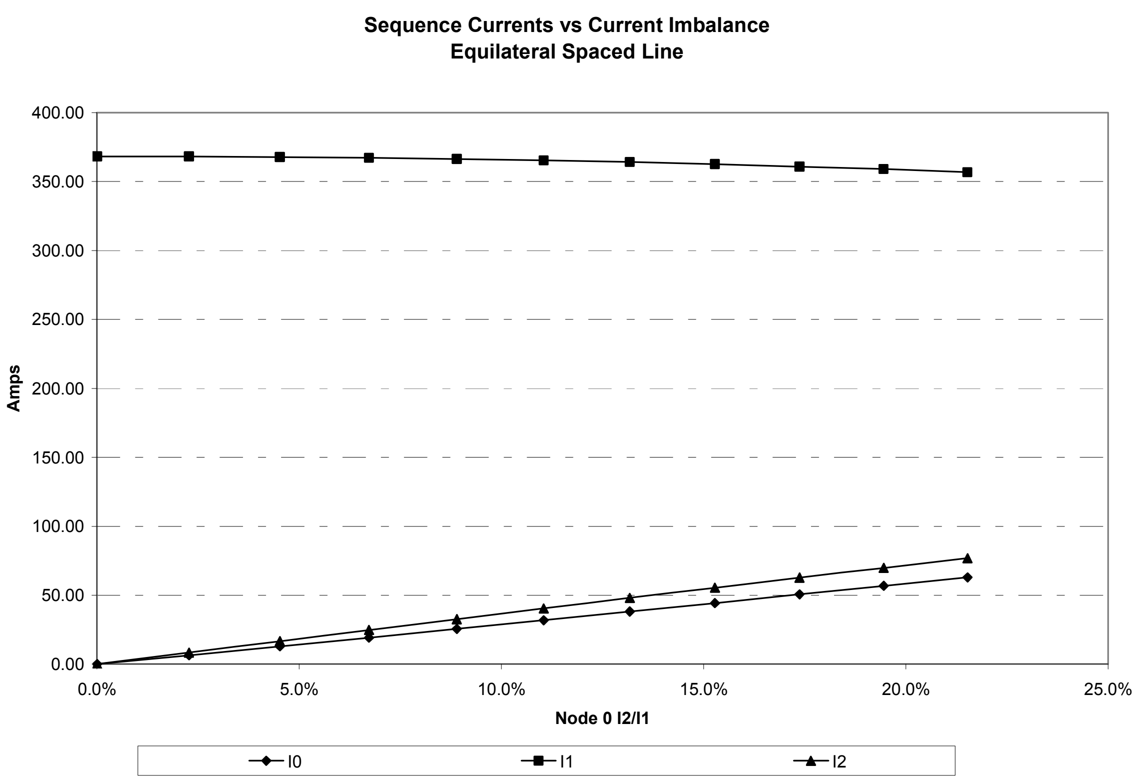


Figure 89. Sequence currents versus current imbalance equilateral-spaced line

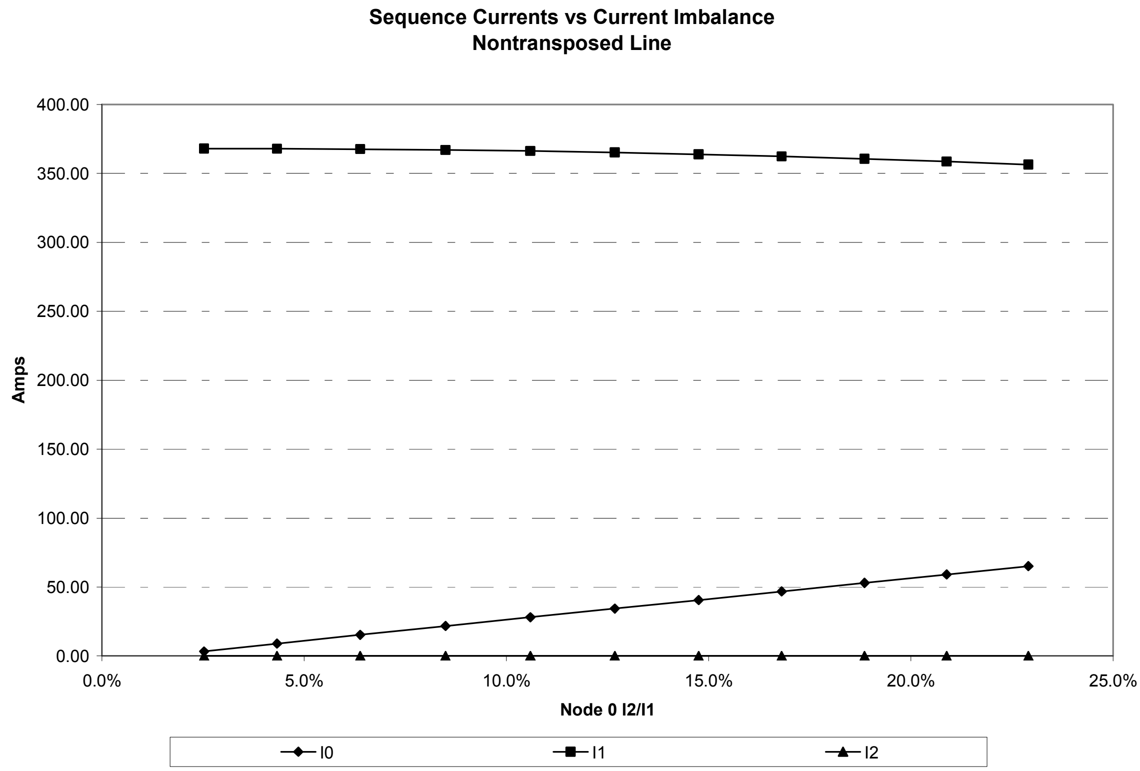


Figure 90. Sequence currents versus current imbalance for non-transposed line

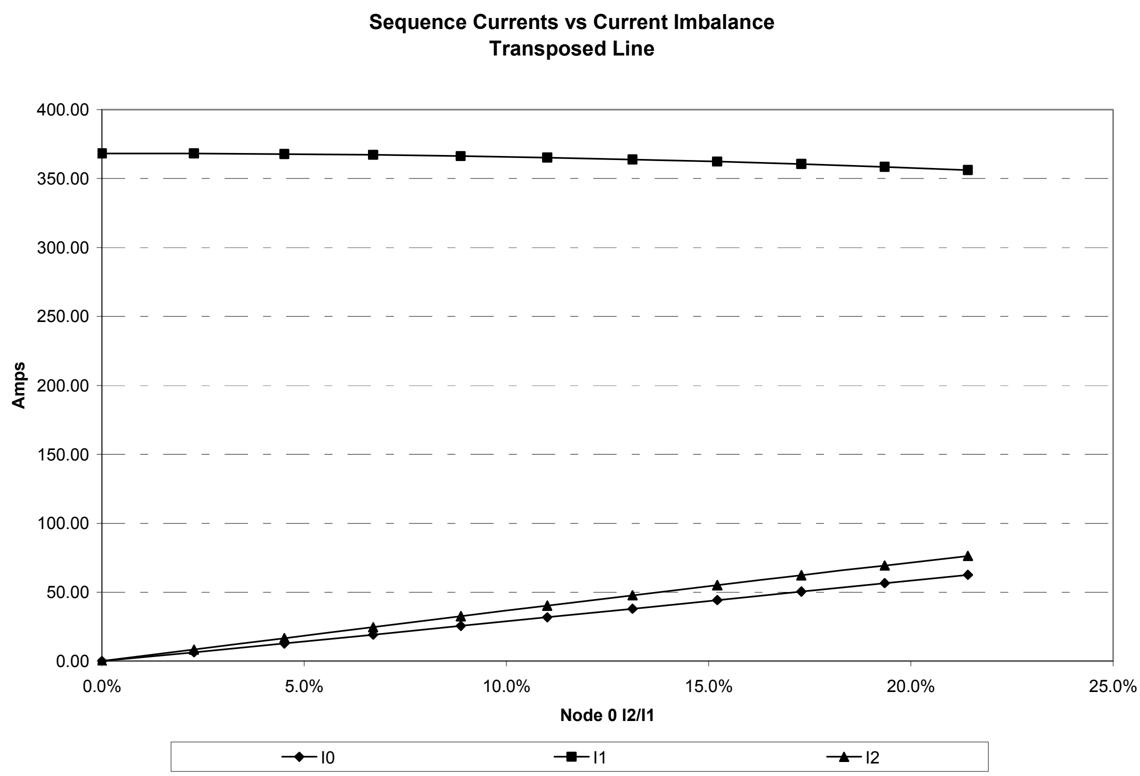


Figure 91. Sequence currents versus current substance for transposed line

Table 14. The Effects of Circuit Spacing and Unbalanced Load on Percent Kilowatt Losses

Equilateral Spacing								
	Balanced Load			**Total**	**Unbalanced Load**			**Total**
	I_2/I_1 = 0%				I_2/I_1 = 21.5%			
	ΦA	ΦB	ΦC		ΦA	ΦB	ΦC	
ΦI's	368.22	368.25	368.28		490.12	300.16	284.99	
kW Losses	117.17	117.02	116.89	351.08	414.10	-72.43	63.39	405.06
% Losses				4.2%				5.10%
Native Load kW				7926				7584
Flat Non-Transposed								
	Balanced Load				**Unbalanced Load**			
	I_2/I_1 = 2.5%				I_2/I_1 = 22.9%			
ΦI's	356.11	375.94	371.99		274.51	494.92	305.56	
kW Losses	194.35	72.47	84.29	351.11	131.84	390.48	-117.36	404.96
% Losses				4.2%				5.10%
Native Load kW				7920				7579
Flat Transposed								
	Balanced Load				**Unbalanced Load**			
	I_2/I_1 = 0%				I_2/I_1 = 21.4%			
ΦI's	368.23	368.24	368.24		487.29	303.37	283.59	
kW Losses	117.05	117.04	117.06	351.15	417.26	-96.12	73.83	394.97
% Losses				4.2%				5.0%
Native Load kW				7925				7578

Notes:

A. Balanced loads result in less loss.

B. Kilowatt losses are greater for the non-transposed line than for the transposed line because $\%I_2/I_1$ is more for the non-transposed line.

C. Unbalanced load is 4,500 kW on Phase A, 2,250 kW on Phase B, and 2,250 kW on Phase C. Balanced load is 3,000 kW on each of the three phases.

Table 14 shows a summary of the effects of circuit spacing and unbalanced load on percent losses. For the balanced load of 3,000 kW on each phase (total load of 9,000 kW), the 4.2% real losses are the same for the equilateral spacing, flat non-transposed, and flat transposed. For the unbalanced load of 4,500 kW on Phase A, 2,250 kW on Phase B, and 2,250 kW on Phase C, the percent losses are 5.1% for the equilateral and flat non-transposed configurations and 5% for the flat transposed configuration.

5.10 Secondary and Service Impedances and Voltage Drops

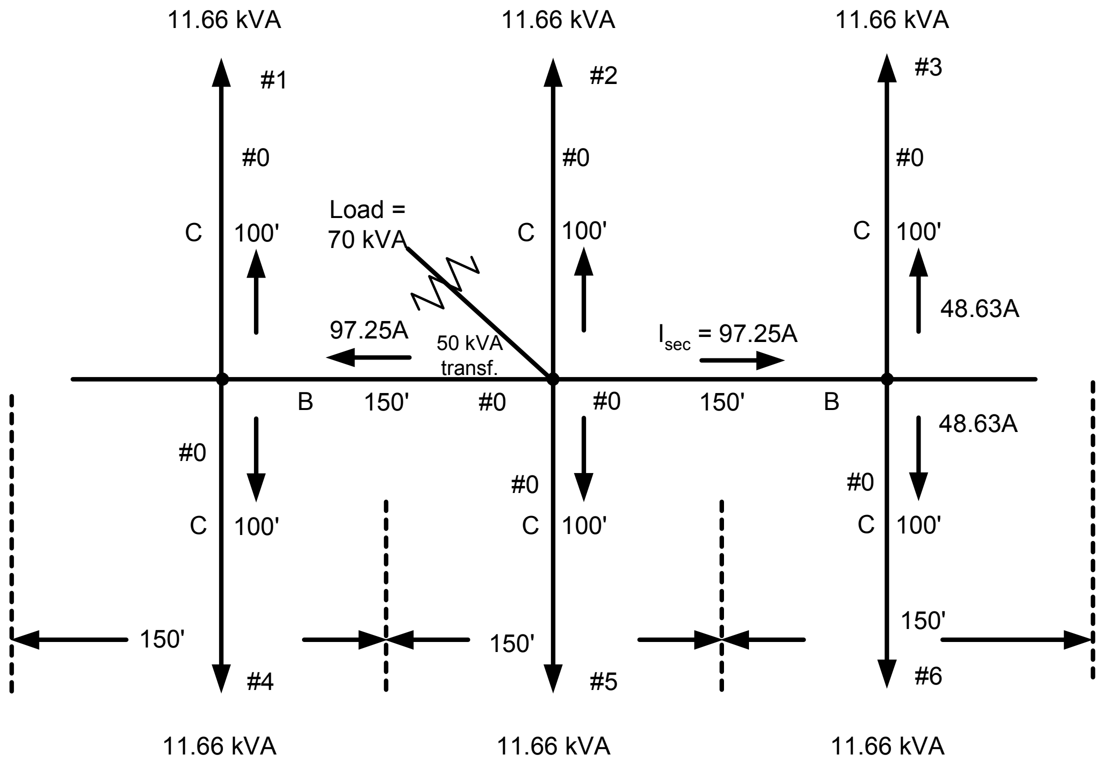


Figure 92. Distribution transformer servicing secondaries and services

Transformer size = 50 kVA
D_m = Maximum coincident total demand on the transformer
D_m = 70 kVA of load and losses
Cos θ = 0.90

$$I_{sec.} = \frac{1}{2}\left[\frac{70\,\text{kVA} - 2\,(11.66\,\text{kVA})}{240\text{V}}\right] = \frac{1}{2}\left[\frac{46.68\,\text{kVA}}{240\text{V}}\right] = 97.25\text{ A}$$

$I_{service}$ = ½ (97.25A) = 48.63 A

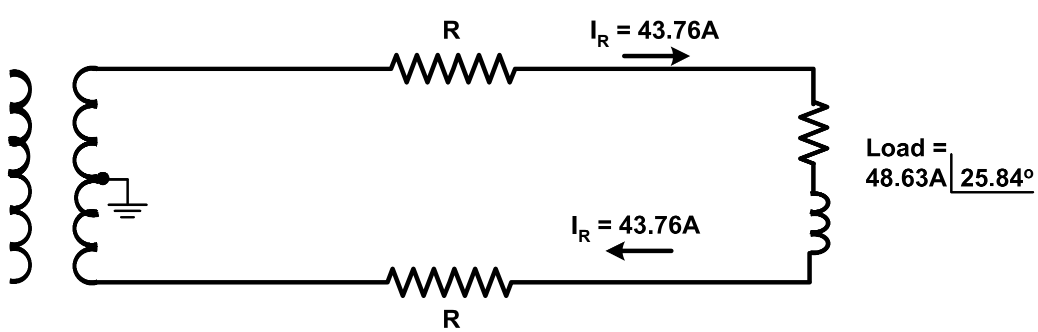


Figure 93. Distribution service drop

The R and X values for the #0 triplex secondary and service are

$R = 0.211\ \Omega/1000'$

$X = 0.031\ \Omega/1000'$.

The voltage drop in secondaries B is

$$\Delta V = 2\ (I\ R\ Cos\ \theta + I\ X\ Sin\ \theta) \qquad \text{Equation 5.71}$$

$$= 2\ [97.25\ (0.211\ \Omega/1000' \times 150')\ 0.90 + 97.25\ (0.031\ \Omega/1000' \times 150')\ .436]$$

$$= 2\ (2.770 + 0.197)$$

$$\boxed{\Delta V = 5.93 \text{ volts @ 240 V or 2.97 volts @ 120V base}} \qquad \text{Equation 5.72}$$

The drop in the services C is

$$\Delta V = 2\ [48.63\ (0.211\ \Omega/1000' \times 100')\ .90 + 48.63\ (0.031\ \Omega/1000' \times 100')\ .436]$$

$$= 2\ (0.920 + 0.067)$$

$$\boxed{\Delta V = 1.97 \text{ volts @ 240 V or 0.99 volts @ 120V base}} \qquad \text{Equation 5.73}$$

The voltage drop for customers 2 and 5 is only 0.99 V, but for customers 1, 3, 4, and 6, it is 3.96 V (2.97 + 0.99).

Table 15. Voltage Drop Summary – Transformer, Secondary, and Service Drop

	25 kVA	50 kVA	
	N = 3 No Secondary	N = 2 No Secondary	N = 4 Secondary
Transformer	3.68	2.75	2.75
Secondary	--	--	2.97
Service	0.99	0.99	0.99
Total	4.67	3.74	6.71

5.11 Secondary and Service Real Losses

Service Drop Real Losses:

The resistance of #0 aluminum service drops for 100' is

$$R_{service} = 2\ (0.211\ \Omega/1000' \times 100') = 0.0422\ \Omega. \qquad \text{Equation 5.74}$$

The resistance is doubled because of the forward and return path of the current.

$I^2_{service}\ R_{\ service} = (48.63)^2\ (0.0422) = 99.80$ watts per service drop

Equation 5.75

Service drop total real losses = (6) (99.80 watts) = 598.8 watts Equation 5.76

Secondary Real Losses:

$R_{\ secondary} = 2\ (0.211\ \Omega/1000' \text{ x } 150') = 0.0633\ \Omega$ Equation 5.77

$I^2_{sec.}\ R_{\ secondary} = (97.25)^2\ (0.0633) = 598.7$ watts per secondary

Equation 5.78

Secondary total real losses = 2 (598.7 watts) = 1197.3 watts Equation 5.79

Total service and secondary real losses = 598.8 + 1197.3 = 1796.1 watts Equation 5.80

$$\text{Percent real losses} = \frac{1.796\ \text{kW}}{(1.4)\,(50\ \text{kVA})\,(0.90)} \text{ x } 100 = \boxed{2.9\%}$$ Equation 5.81

Note: Add kilowatt losses for each circuit element and divide by the total kilowatt flow to obtain total circuit percent losses. Percent losses cannot be added for each element.

A summary of the peak day (July 17, 2006) real power losses for the Milford substation transformer, the DC8103 primary, overhead and padmount transformers, secondary, and services is given in Table 16.

The percent real losses shown in the first column are for the 4.8-kV Hickory Distribution Circuit, the reference of which is given in Note A. These are actual measured losses that total 5.2%, excluding the substation transformer. The next two columns represent the percent real losses for the Milford 8103 circuit. The second column depicts the calculated losses based on the average peak loading of the transformers and services and a lumped load representing the peak circuit load placed at the midpoint to calculate the primary losses. The third column shows the calculated losses determined from the simulation of the circuit for the peak load hour on July 17, 2006.

Table 16. Peak Day Real Losses Comparison

	Percent Losses		
Transmission	--	3.5	--
Sub-transmission	--	4.5	--
	Hickory	**Milford 8103**	**Milford 8103**
Substation transformer	0.70	0.729	0.702
Primary	3.1[A]	3.82[B]	3.59[C]
Overhead and underground transformers	1.3[A]	1.22[B]	1.50[C]
Secondary and services	0.8[A]	0.95[D]	0.89[D] 0.31[E]
Total circuit losses	5.2	5.99	5.98[D] 5.4[E]
Total system losses	13.9	14.72	14.68 14.10

Notes:
A. Data from Davis, Krupa, and Diedzic (1983)
B. Approximate based on average loading of transformers and services and lump load placed at midpoint for the primary losses
C. Distribution Engineering Workstation
D. #4 MXAT Services used
E. #0 MXAT Services used

5.12 Shunt Capacitor Models

When capacitors are connected in parallel, $\text{kVAr} = \text{kVAr}_1 + \text{kVAr}_2 + \text{kVAr}_3 + \ldots$, and when connected in series,

$$\text{kVAr} = \frac{1}{\dfrac{1}{\text{kVAr}_1} + \dfrac{1}{\text{kVAr}_2} + \dfrac{1}{\text{kVAr}_3} + \cdots} .$$

The capacitive reactance in ohms is

$$X_C = \frac{1}{2\,\pi\,f\,C \times 10^{-6}}, \qquad \text{Equation 5.82}$$

where 1 μf is 2,653 Ω at 60 Hz, or

$$X_C = \frac{2653}{C}, \text{ where C is 1 μf.}$$

From Equation 5.82, C is then

$$C = \frac{10^6}{2\,\pi\,f\,X_C}. \qquad \text{Equation 5.83}$$

Now, X_C can be defined in terms of voltage and vars.

$$\text{kVAr} = \text{kV}\ I_X, \text{ where } I_X = \frac{V}{X_C}.$$

Because $\text{kV} = \frac{V}{1000}$, then

$$\text{kVAr} = \frac{\text{kV}^2\ 1000}{X_C}, \text{ and}$$

$$\boxed{X_C = \frac{\text{kV}^2\ 1000}{\text{kVAr}}}. \qquad \text{Equation 5.84}$$

The capacitance C in microfarads can be determined in terms of voltage and Vars by substituting Equation 5.82 into Equation 5.84 and solving for C.

$$\boxed{C = \frac{1000\ \text{kVAr}}{\text{kV}^2\ 2\,\pi f}} \qquad \text{Equation 5.85}$$

If the capacitance C and voltage are known, then KVAr can be found from Equation 5.85.

$$\boxed{\text{kVAr} = \frac{\text{kV}^2\ 2\,\pi\ f\ C}{1000}} \qquad \text{Equation 5.86}$$

Equations 5.84, 5.85, and 5.86 are the most commonly used. Two examples follow.

The ohms per phase for a 300-kVAr, three-phase, 4.8-kV, delta-connected capacitor bank is

$$\text{kVAr}/\Phi = \frac{300\ \text{kVAr}}{3} = 100\ \text{kVAr}.$$

The line-to-line voltage applied across each capacitor is 4.8 kV. Applying Equation 5.84,

$$X_C = \frac{4.8^2\ (1000)}{100} = 230.4\ \Omega.$$

The capacitance from Equation 5.85 is

$$C = \frac{(1000)\,(100)}{(4.8)^2\ (377)} = 11.51\,\mu f\ .$$

The ohms per phase for a 600-kVAr, three-phase, 13.2-kV, wye-connected capacitor bank is

$$\text{kVAr}/\Phi = \frac{600}{3} = 200 \text{ kVAr}.$$

The voltage across each capacitor is $\frac{13.2\text{kV}}{\sqrt{3}}$, . Therefore, using Equation 5.84 results in

$$X_C = \frac{(7.620)^2\ 1000}{200} = 290.3\,\Omega,$$

and the capacitance is

$$C = \frac{(1000)\,(200)}{(7.620)^2\ (377)} = 9.14\,\mu f\ .$$

Capacitor models can be developed using Equation 5.84, which is repeated below.

$$X_C = \frac{\text{kV}^2\ 1000}{\text{kVAr}}\ .$$

The susceptance B_C is the reciprocal of X_C; therefore, B_C from Equation 5.84 becomes

$$B_C = \frac{1}{X_C} = \frac{\text{kVAr}}{\text{kV}^2\ 1000}, \qquad \text{Equation 5.87}$$

where kVAr is the kilovars per phase and kV is the applied voltage across the capacitor. For a wye-connected capacitor bank

$$B_C = \frac{1}{X_C} = \frac{\text{kVAr}}{\text{kV}_{LN}{}^2\ 1000}. \qquad \text{Equation 5.88}$$

For a delta-connected capacitor bank

$$B_C = \frac{1}{X_C} = \frac{\text{kVAr}}{\text{kV}_{LL}{}^2\ 1000}. \qquad \text{Equation 5.89}$$

The line currents for the wye-connected bank are written from Equation 5.88.

$$V_{AN} = I_{C_A}\ j X_A$$

$$I_{C_A} = \frac{V_{AN}}{j X_A} = \text{VAN j BA}, \qquad \text{Equation 5.90}$$

$$I_{C_B} = VBN\ j\ BB \qquad \text{Equation 5.91}$$

$$I_{C_C} = VCN\ j\ BC \qquad \text{Equation 5.92}$$

For the delta-connected bank, the phase currents are:

$$I_{C_{AB}} = VAB\ j\ BAB \qquad \text{Equation 5.93}$$

$$I_{C_{BC}} = VBC\ j\ BBC \qquad \text{Equation 5.94}$$

$$I_{C_{CA}} = VCA\ j\ BCA. \qquad \text{Equation 5.95}$$

The line currents are:

$$I_{C_A} = I_{C_{AB}} - I_{C_{CA}} \qquad \text{Equation 5.96}$$

$$I_{C_B} = I_{C_{BC}} - I_{C_{AB}} \qquad \text{Equation 5.97}$$

$$I_{C_C} = I_{C_{CA}} - I_{C_{BC}}. \qquad \text{Equation 5.98}$$

In matrix form, equations 5.96, 5.97, and 5.98 can be written as:

$$\begin{bmatrix} I_{C_A} \\ I_{C_B} \\ I_{C_C} \end{bmatrix} = \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} \bullet \begin{bmatrix} I_{C_{AB}} \\ I_{C_{BC}} \\ I_{C_{CA}} \end{bmatrix}. \qquad \text{Equation 5.99}$$

5.13 Step Voltage Regulator Models

Both Type A and Type B step VRs are modeled. The relationship between the source voltage V_S and load voltage V_L for the single-phase step VR is:

$$V_S = a_r V_L, \qquad \text{Equation 5.100}$$

where a_r is defined as

$$a_r = 1 \mp \frac{\text{Total \% Range}}{\text{\#of Steps}} \times \text{Tap} \qquad \text{Equation 5.101}$$

with the following sign convention.

	Type A	Type B
Raise	+	-
Lower	-	+

The relationship between source current and load current for the single-phase step VR is

$$I_S = \frac{1}{a_r} I_L \,. \qquad \text{Equation 5.102}$$

5.14 Synchronous Generator Model

The Distribution Engineering Workstation uses two models to represent the synchronous machine: one for power flow and one for transient analysis. Because this study does not involve transient analysis, only the power flow model is considered. Figure 94 is a graphical representation of the power flow synchronous machine model.

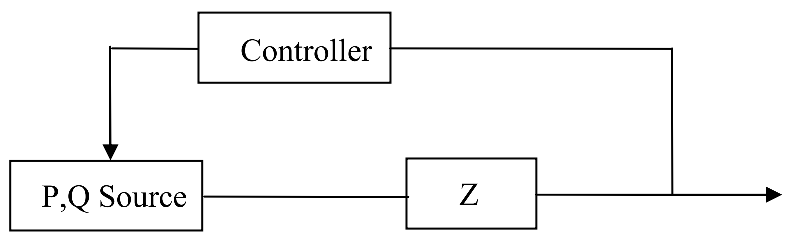


Figure 94. Steady-state synchronous machine model

The synchronous machine model used for power flow consists of a real and reactive power source, along with the impedance Z (in this case, the synchronous impedance). The controller takes measurements (specifically, voltage magnitude and power factor) from machine terminals and allows the machine to operate in two modes: constant P with power factor control or constant P and constant Q.

The model takes into account the minimum and maximum generation limits of the machine, and the controller adjusts the P, Q Source based on the control mode. For example, if the machine is in the constant P with power factor control mode, the controller will maintain real rated power while varying the reactive power within the machine limits in an attempt to hold the power factor at the point of measurement constant.

5.15 Self-Excited Induction Generator Model

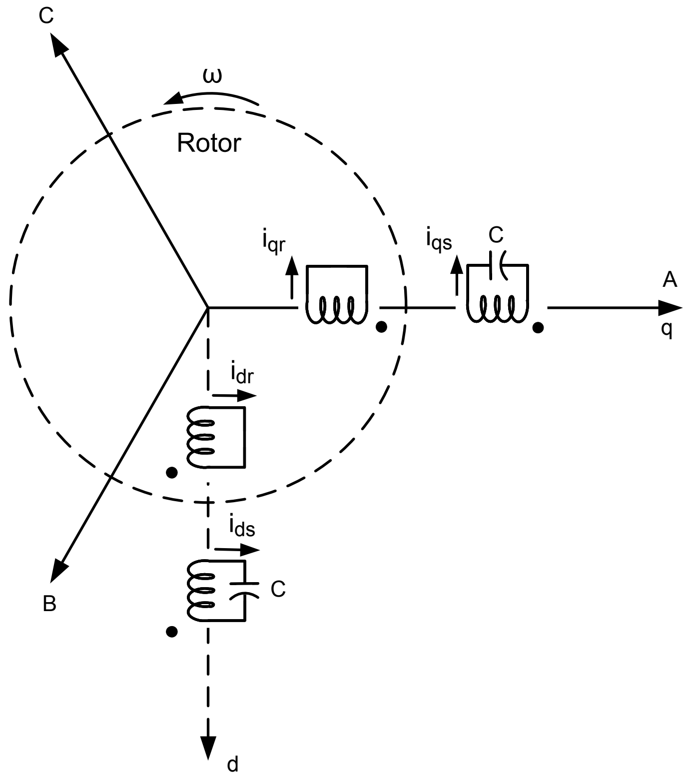


Figure 95. Two-phase primitive machine to be interconnected with an RLC load

A self-excited induction generator can be represented as a two-phase primitive machine with stator windings fixed and rotor windings rotating. The currents i_{ds} and i_{qs} are the stator currents, and i_{dr} and i_{qr} are the rotor currents in the direct and quadrature axes, respectively. Figure 95 shows the mechanical angular speed of the rotor as $\omega = d\theta/dt$. A self-excited induction generator with capacitor added is represented in Equation 5.103. The voltage drop across the capacitor for the direct axis is v_{Cd} and for the quadrature axis is v_{Cq}. The term 1/pC represents this voltage drop because

$$v = \frac{1}{C}\int i\,dt,$$

p = d/dt and

$$\frac{1}{p} = \int^{t} dt$$

$$
\begin{bmatrix} v_{ds} \\ v_{qs} \\ v_{dr} \\ v_{qr} \end{bmatrix} = \begin{bmatrix} R_1 + L_1 p + \dfrac{1}{pC} & 0 & Mp & 0 \\ 0 & R_1 + L_1 p + \dfrac{1}{pC} & 0 & Mp \\ Mp & \omega M & R_2 + L_2 p & \omega L_2 \\ -\omega M & Mp & -\omega L_2 & R_2 + L_2 p \end{bmatrix} \bullet \begin{bmatrix} i_{ds} \\ i_{qs} \\ i_{dr} \\ i_{qr} \end{bmatrix}
$$

Equation 5.103

This equation represents the no-load condition, and the turns ratio is assumed to be unity. Therefore, if needed, the ratio must be included when referring the rotor parameters to the stator.

The mutual inductance M varies with the relative position between the stator and rotor. R_1 and R_2 are the stator and rotor resistances, and L_1 and L_2 are their inductances. The additional voltage drop because of the mutual flux is

$\varphi_m = Mi$, and

$$
\begin{aligned} v = \frac{d\,\varphi_m}{dt} &= M\frac{di}{dt} + \frac{i\,dM}{dt}. \\ &= Mpi + i\,pM \end{aligned}
$$

Equation 5.104

There is a nonlinear relationship between the magnetizing reactance and the magnetizing current. Therefore, the mutual inductance M varies continuously. The term Mpi represents the current variation because of the stator, and the term ipM is because of the rotation of the rotor.

5.15.1 Resistive Load

When a resistive load R is added in parallel with the self-excitation capacitor C, the voltage across this R load is the same as the voltage across the capacitor. In the direct axis stator of Figure 95, the addition of the load resistor changes the equivalent circuit to Figure 96.

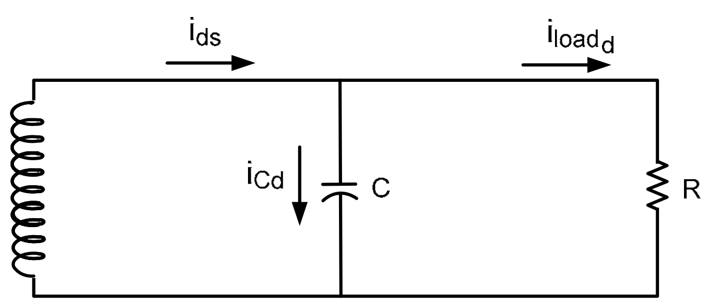


Figure 96. Stator direct axis with an R load added

Because $v_{load\ d} = v_{Cd} = R\, i_{load\ d}$ Equation 5.105

and $i_{Cd} = C \dfrac{d\, v_{Cd}}{dt} = C\, pv_{Cd}$, then

$i_{Cd} = C\, p\, Ri_{load\ d}$.

Because

$i_{ds} = i_{Cd} + i_{load\ d}$,

$i_{ds} = R\, Cp\, i_{load\ d} + i_{load\ d}$ and

$= i_{load\ d}\, (R\, Cpi + 1)$. Equation 5.106

From Equation 5.105,

$$i_{load\ d} = \frac{i_{ds}}{R\, C\, p + 1}. \quad \text{Equation 5.107}$$

Substituting Equation 5.107 into 5.105, results in

$$v\ load\ d = \frac{R\, i_{ds}}{R\, C\, p + 1}. \quad \text{Equation 5.108}$$

The quadrature load voltage is obtained in a similar manner.

$$v_{load\ q} = \frac{R\, i_{qs}}{R\, C\, p + 1} \quad \text{Equation 5.109}$$

Now Equation 5.103 can be rewritten with the addition of the resistive load R from equations 5.108 and 5.109.

$$\begin{bmatrix} v_{ds} \\ v_{qs} \\ v_{dr} \\ v_{qr} \end{bmatrix} = \begin{bmatrix} R_1 + L_1\, p + \dfrac{R}{R\, Cp + 1} & 0 & Mp & 0 \\ 0 & R_1 + L_1\, p + \dfrac{R}{R\, Cp + 1} & 0 & Mp \\ Mp & \omega M & R_2 + L_2\, p & \omega L_2 \\ -\omega M & Mp & -\omega L_2 & R_2 + L_2\, p \end{bmatrix} \bullet \begin{bmatrix} i_{ds} \\ i_{qs} \\ i_{dr} \\ i_{qr} \end{bmatrix}$$

Equation 5.110

5.15.2 RLC Load

When an RL load R_L and L_L is added in parallel with the self-excitation capacitor Cs, or a combination of this excitation capacitor and other capacitors C_L on the circuit in parallel, C in the following equations considers this combination of capacitors. See Figure 97.

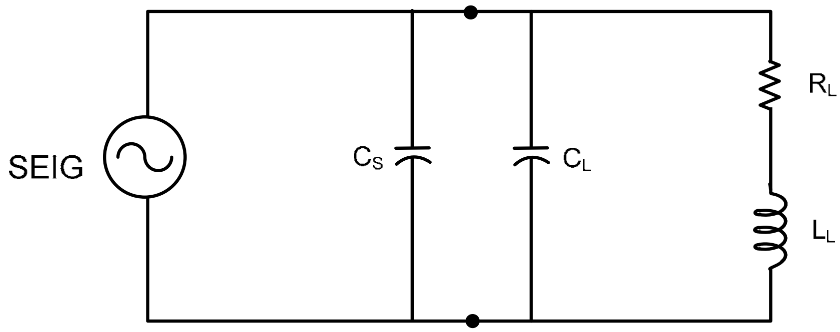


Figure 97. RLC load R_L, L_L, and C_L connected to the self-excited capacitor C_S

Because $v_{load\ d} = R\ i_{load\ d}$ from Equation 5.105, $v_{load\ d}$ with load inductance added is

$$v_{load\ d} = R\ i_{load\ d} + L\ pi_{load\ d}, \qquad \text{Equation 5.111}$$

and

$$i_{Cd} = Cpv_{load\ d} = (R\ C\ p + L\ C\ p^2)\ i_{load\ d}. \qquad \text{Equation 5.112}$$

Now from Equation 5.112,

$$i_{d_s} = i_{C_d} + i_{load\ d} = (R\ C\ p + L\ C\ p^2)\ i_{load\ d} + i_{load\ d} \qquad \text{Equation 5.113}$$

and

$$i_{load\ d} = \frac{i_{ds}}{R\,C\,p + L\,C\,p^2 + 1}. \qquad \text{Equation 5.114}$$

From Equation 5.111,

$$v_{load\ d} = R\ i_{load\ d} + L\ pi_{load\ d}, \quad \text{and}$$

$$v_{load\ d} = (R + L\ p)\ i_{load\ d}. \qquad \text{Equation 5.115}$$

Substituting $i_{load\ d}$ from Equation 5.114 into Equation 5.115 results in

$$v_{load\ d} = \frac{R + L\,p}{R\,C\,p + L\,C\,p^2 + 1}\,i_{ds}. \qquad \text{Equation 5.116}$$

The quadrature load voltage becomes

$$v_{load\,q} = \frac{R + L\,p}{R\,C\,p + L\,C\,p^2 + 1}\, i_{qs}\,. \qquad \text{Equation 5.117}$$

Equation 5.103 can be rewritten with the addition of resistance load R, inductive load L, and capacitive load C using Equation 5.117.

Equation 5.118 is the impedance matrix for a single self-excited induction generator serving an RLC load. It must be remembered that the variation in the magnetizing reactance because of the magnetizing current must be included and corrected as in the development of Equation 5.104.

$$\begin{bmatrix} v_{ds} \\ v_{qs} \\ v_{dr} \\ v_{qr} \end{bmatrix} = \begin{bmatrix} R_1 + L_1\,p + \dfrac{R + L\,p}{R\,Cp + L\,C\,p^2 + 1} & 0 & Mp & 0 \\ 0 & R_1 + L_1\,p + \dfrac{R + L\,p}{R\,Cp + L\,C\,p^2 + 1} & 0 & Mp \\ Mp & \omega M & R_2 + L_2\,p & \omega L_2 \\ -\omega M & Mp & -\omega L_2 & R_2 + L_2\,p \end{bmatrix} \bullet \begin{bmatrix} i_{ds} \\ i_{qs} \\ i_{dr} \\ i_{qr} \end{bmatrix}$$

Equation 5.118

5.16 Inverter-Based Generator Model

The 400-kW, 500-kVA inverter-based generator consists of a high-speed AC generator driven by a 440-kW twin-spool gas turbine engine. Figure 98 is a simplified one-line diagram of the 400-kW, 60-Hz generator and inverter.

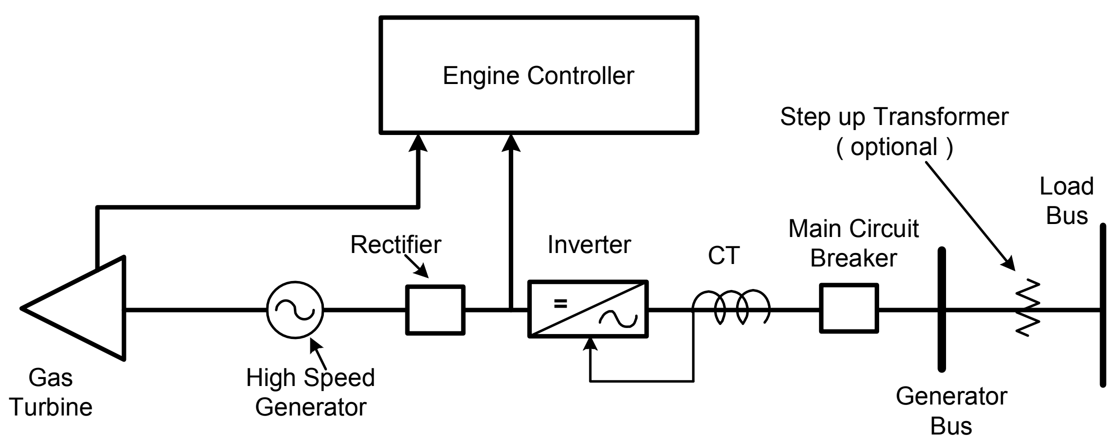


Figure 98. One-line diagram of 400-kW inverter-based generator and prime mover

The unit has seamless transfer capability so it can operate in a current-source mode parallel to the electric power system with only 10% load and switch without outage to deliver power in the voltage-source mode to an islanded load. This generating unit has a continuous overload capability of 110% of rated load at any power factor from -0.8 to 0.8, and it can follow load steps of 25% up or down while maintaining frequency to less than +/-0.1 Hz. The voltage distortion is less than 2%, and it can handle 100% load imbalance. During short circuits, it can deliver 200% of rated current for about 8 seconds.

The inverter model is represented by the voltage pullback curves in Figure 99. The unit can deliver 1.10 p.u. current (602 A rms) at 1.0 p.u. rated voltage (277 V rms) and 2.0 p.u. current at 0.56 p.u. voltage. The inverse time-current characteristic is given in Figure 100.

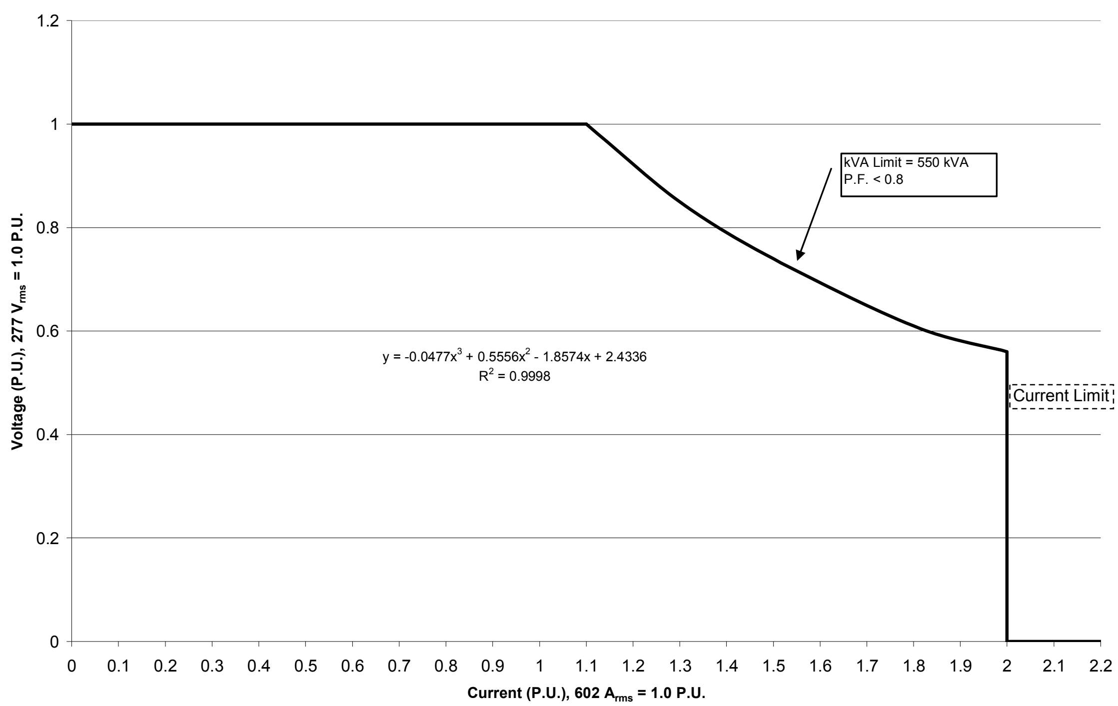


Figure 99. Voltage pullback curves

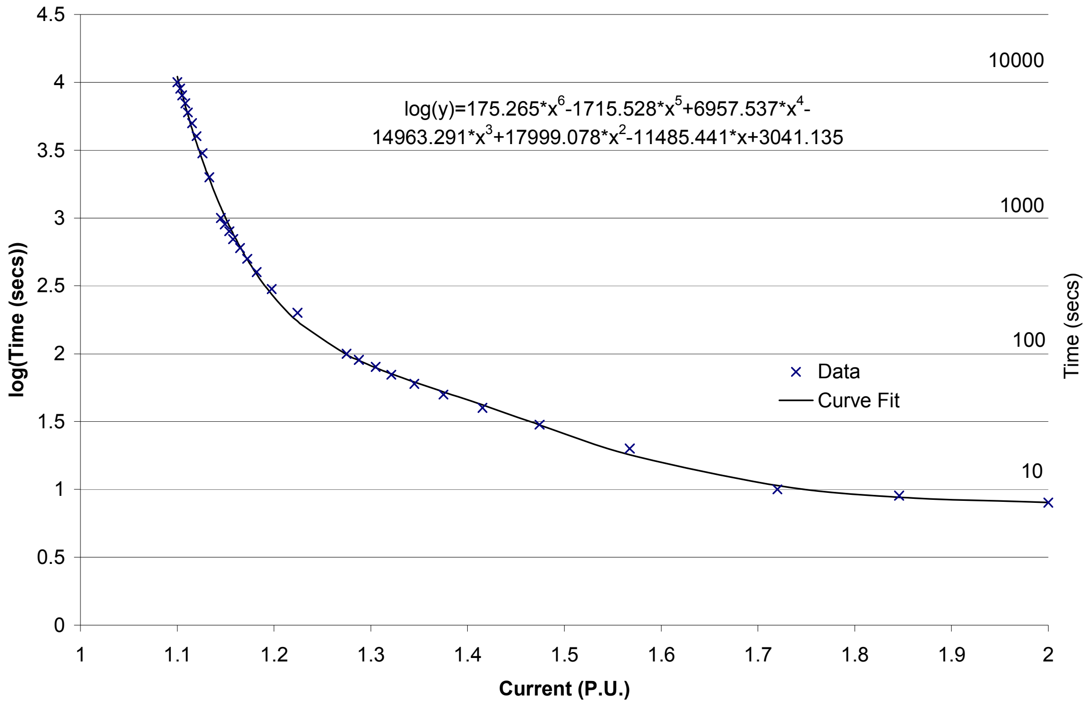


Figure 100. Inverse time-current characteristic

6 Project Results – Circuit Voltage Profiles Under Different Loading Conditions

6.1 Introduction

This section summarizes work to perform simulations to determine the circuit voltage profiles of Milford Circuit DC 8103. The two-transformer Milford substation, shown in Figure 101, is fed from two 41.57-kV tie lines and one 41.57-kV trunk line. The Milford DC 8103 circuit is fed by a delta-wye-connected 10-MVA LTC transformer with ±10% tap positions and 0 to ±5% fixed taps. The primary voltage is 41.57 kV, and the secondary voltage is 13.8 kV. The circuit is a 13.8-kV, multi-grounded, three-phase wye system, and it serves approximately 76.2% residential, 4% commercial, and 19.8% light industrial loads. See Table 17. The circuit summer peak maximum load is 15.3 MVA, and the summer peak minimum load is 5.91 MVA. The annual load factor for the circuit is 0.42.

The circuit is about 31,000 ft, or 5.9 mi. The voltage profiles are determined for the peak load day, referred to as the heavy load (HL) condition, and the minimum load day, referred to as the LL condition, using eight traditional methods of voltage regulation. The voltage profiles are shown for the following voltage regulation cases:

- No circuit voltage regulation, with variable transformer primary voltages (41.57 kV) ranging from 87%, 95%, 100%, and 105% voltage levels on a 120-V base (The 87% voltage level represents the lowest voltage for emergency operation, and the 100% voltage level represents the base case for determining the release capacity. The balance of the simulations represents normal operating conditions for HL and LL conditions with 95% and 105% primary substation voltages.)
- The addition of LTC transformer regulation at the substation
- The addition of step VR 1
- The addition of step VR 1 and VR 2
- The addition of capacitor CAP 1
- The addition of capacitors CAP 1 and CAP 2
- The addition of capacitors CAP 1, CAP 2, and CAP 3
- The addition of all traditional voltage regulation methods (i.e., LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3).

Table 17. Circuit Customer Load Characteristics

Customer Type	Number of Customers	Annual MWH	MW Avg.	Annual Load Factor Typ.	MW Peak	P.F.	MVA Peak	% on an MVA Basis
Residential	3178	32,610	3.72	0.35	10.6	0.91	11.7	76.3
Commercial	120	2,667	0.304	0.57	0.54	0.89	0.60	3.9
Industrial	3	15,529	1.77	0.66	2.67	0.88	3.04	19.8
Totals	3301	50,806	5.79	0.42	13.8	.90	15.3	100.0

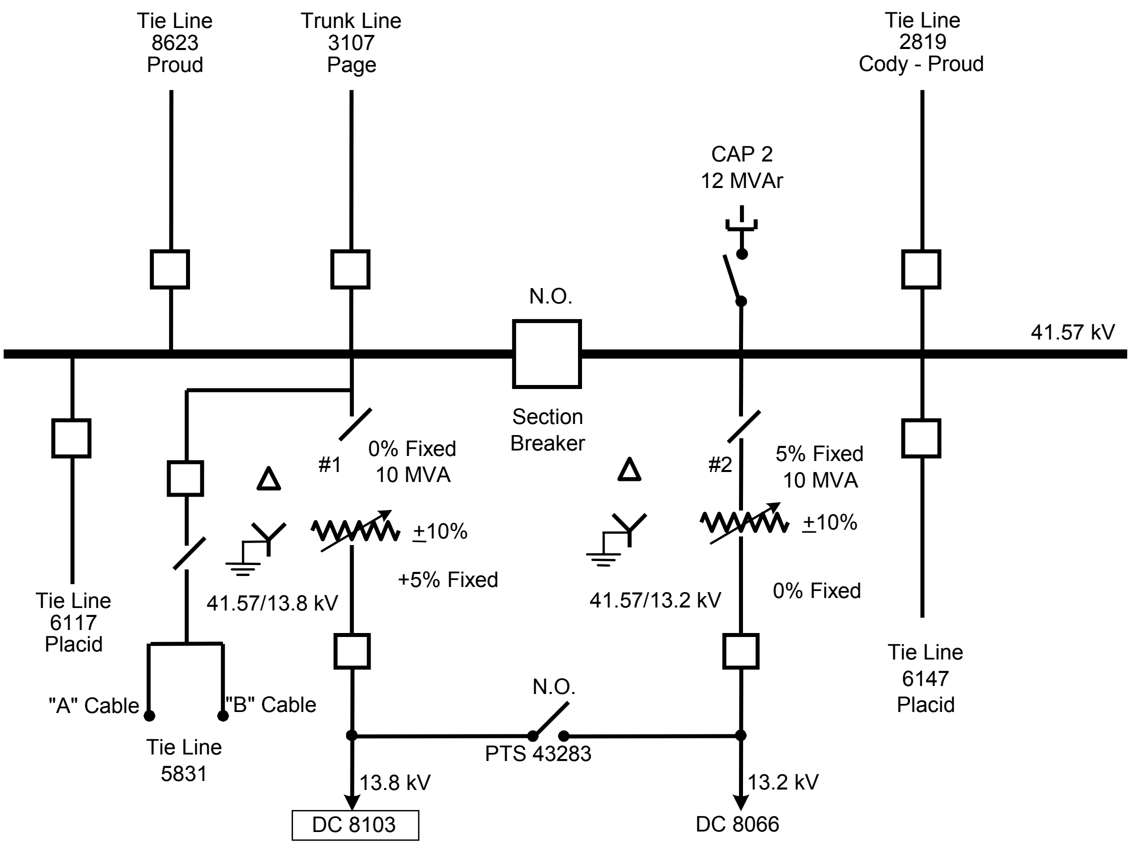
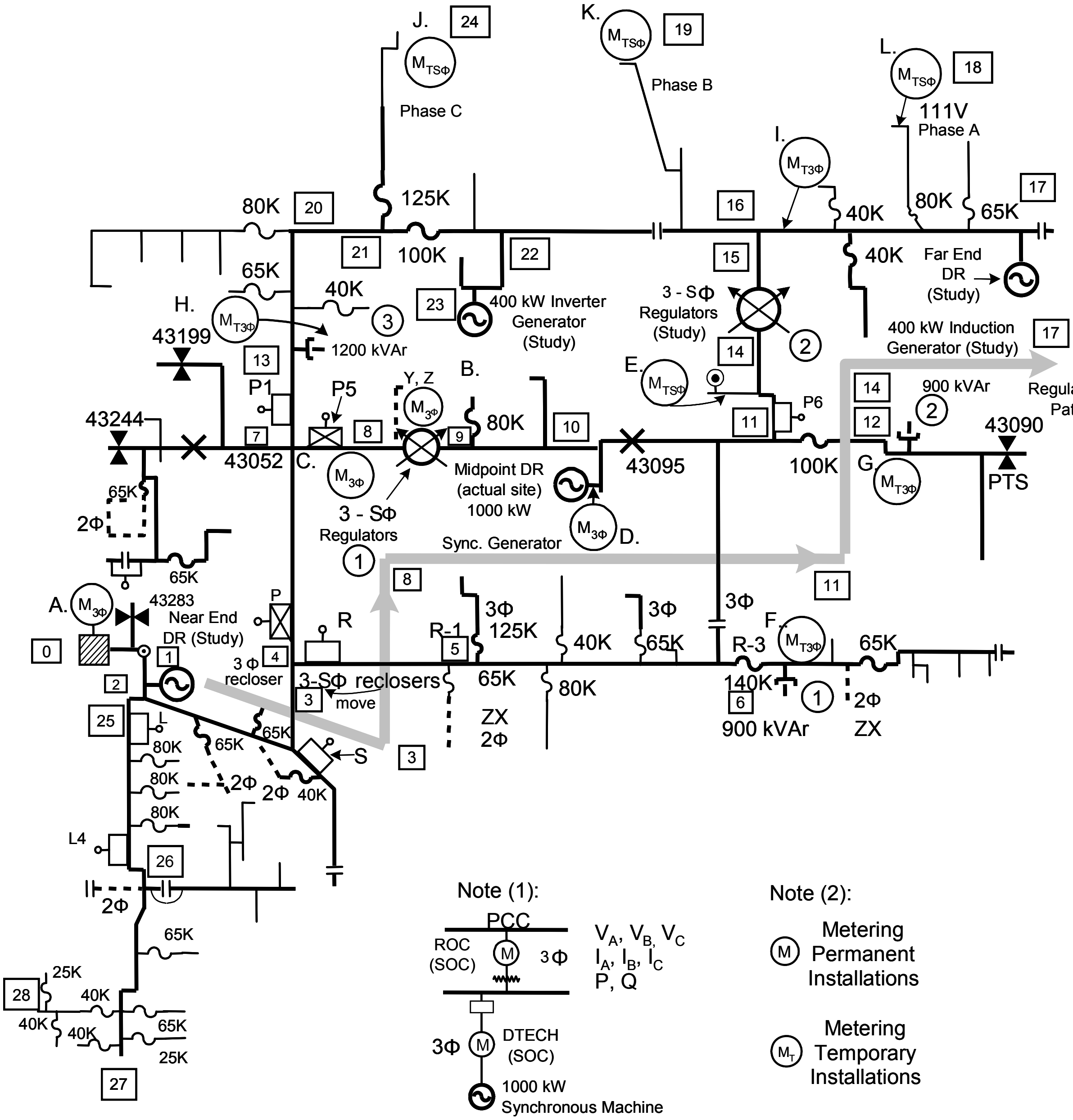


Figure 101. Milford Substation one-line diagram

The Milford Circuit DC 8103 and substation are shown in Figure 102. It consists of a substation, shown as a cross-hatched square and denoted as Node 0; three-phase sections, represented as heavy-weight solid lines; and single-phase sections, represented as light-weight solid lines. The dotted lines represent two phases. The 10-MVA LTC transformer at the substation has an impedance of 7.02%, with 0, ±2.5%, and ±5% fixed taps with high-side and low-side settings of 0 and ±5%. The LTC transformer is ±10% with ±16 steps. The voltage was regulated at 126.0 V on the secondary bus of the transformer. The circuit has three single-phase step bidirectional VRs (1) and three single-phase step bidirectional VRs (2). These single-phase regulators are each rated 167 kVA and connected wye. The second VR (2) is for study purposes. There are three capacitor banks. CAP 1 is a three-phase, 900-kVAr capacity; CAP 2 is a 900-kVAr capacity; and CAP 3 is three-phase, 1200-kVAr capacity. All capacitors are pole-mounted, switched capacitors with wye-grounded connections.



Note (3): Nodes where low voltage, high voltage, highest unbalance voltage, highest unbalanced load and nodes where actual values exceed pre-set values (criteria violations) may be different than the nodes indicated above.

Note (4): The LTC voltage regulator is gang operated using the C phase as reference.

Note (5): The "P" reclosure data is sent to midpoint DR consisting of I_A, I_B, I_C, V_{CN}, V_{BN}, V_{CN}, kW_A, kW_B, kW_C, $kVAr_A$, $kVAr_B$, $kVAr_C$

Figure 102. Milford Circuit DC 8103

A number of circuit protection devices are shown on the circuit. These include a three-phase recloser ( ), three single-phase reclosers ( ), manual switches (×), automatic controlled switches (, in which a filled-in symbol represents the normally open mode), and three-phase and single-phase fuses ( ), which are identified with a number size and Type K.

Finally, there are three DR generators, a 1,000-kW synchronous generator at the midpoint denoted as Node [10], a 400-kW induction generator at Node [17] for study purposes, and, at the tag end of the circuit, and a 400-kW inverter-based generator at Node [23] for study purposes. The generation simulations and their resultant voltage profiles with and without traditional voltage regulation methods are provided in Section 10.

As noted earlier, nodes are placed throughout the circuit. These are points at which the real and reactive power phase quantities, phase power factors, phase currents, and phase voltages are calculated. Nodes are placed on each side of the step VRs to provide calculated values of voltage before and after regulation and at each capacitor location to provide the calculated values of voltage.

Table 18 provides the permanent metering points and quantities measured and the temporary metering points and quantities measured. All metering points are designated by a letter (e.g., A, B, and C) that corresponds to the circuit one-line diagram of Figure 102. Those shown with the letter T are temporarily installed for this project. Also, the metering may be three-phase (3Φ) or single-phase (SΦ). The single-phase metering points J, K, and L are at the tag ends of the circuit. These measured quantities and the three-phase quantities were compared to the calculated values determined from the simulations, and adjustments were made to the circuit models and loads to ensure the simulations agree with field measurements.

Table 18. Measurement Locations and Data Collection

	Permanent Metering Locations				
A.	Substation	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
B.	3 SΦ Bidirectional regulators	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
C.	3 SΦ reclosures	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
D.	1,000-kW Synchronous DR	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
	Temporary Metering Locations				
E.	Customer (LV unbalanced voltage)	$M_{TS\Phi}$	V_{AN}	I_A	P, Q, P.F.
F.	900-kVAr capacitor	$M_{T3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
G.	900-kVAr capacitor	$M_{T3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
H.	1,200-kVAr capacitor	$M_{T3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
I.	3Φ circuit tag end (LV unbalanced voltage)	$M_{T3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, P.F.
J.K.L.	Single-phase tag ends	$M_{TS\Phi}$	V_{CN}	V_{BN}	V_{AN}

6.2 Circuit Simulations and Voltage Profiles

The simulations were extensive. To simplify the explanation of how they were conducted, Table 19 describes the tests run. These tests were organized into four groups. The first group consisted of tests 1–8, to which traditional voltage regulation (i.e., LTCs) was applied. The second group consisted of tests 9–11, to which DG voltage regulation strategy tests were applied. The third group consisted of tests 12–17, to which the combined traditional LTC and circuit regulation tests as well as DG regulation strategy tests were applied. The fourth group consisted of all traditional voltage regulation and all generation voltage regulation strategies (see tests 18–19).

Table 19. Matrix of Voltage Regulation Simulations

Test Numbers	Reference. Section	**Primary Voltage Spread** (a)87% (b) 92% (c)93% (d) 95% (e) 98% (f) 105%	**Peak Load Day 24 Hourly quantities**	**Light Load Day 24 Hourly quantities**	**LTC ± 16 steps & neutral**	**Line Regulator**		**Capacitors**			**DR (Synchronous Machine) Locations (1)** (a)Peak shave, P fixed (b) P.F.= Unity, P variable (c) ± P.F. Constant, Variable P & Q (d) ± Q (Vars Volt reg) P Min (e) P± jQ (Optimizing) (f) Fixed P.F. Anti-island		
						#1	#2	#1	#2	#3	Near End	Midpoint (Actual Site)	Far End
1	I.A.	(a) (d) (f)	x	x									
2	I.B.	(d) (f)	x	x	x								
3	I.C.	(d) (f)	x	x	x	x							
4	I.C '.	(d) (f)	x	x	x	x	x						
5	I.D	(d) (f)	x	x	x			x					
6	I.D '	(d) (f)	x	x	x			x	x				
7	I.D."	(d) (f)	x	x	x			x	x	x			
8	I.E.	(d) (f)	x	x	x	x	x	x	x	x			
9	II.A.	x	x	x							(b) (d) (e)		
10	II.B.	x	x	x								(b) (d) (e)	
11	II.C.	x	x	x									(b) (d) (e)
12	II.D.	Repeat IIA., IIB., IIC. turn on LTC											
13	II.E.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1)											
14	II.F.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2)											
15	II.G.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2) and Cap. (1)											
16	II.H.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2) and Cap. (1), (2)											
17	II.I.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2) and Cap. (1), (2), (3)											
18													
19													
20													
21													
22													
23													
24													
25													

Note (1): DR Control Strategies

(a.) The DR is operated at fixed real power output and normally Is scheduled to run during peak periods when the cost of DR generation is lower than host utility cost. The Q is zero at the PCC. 984 kW rated

(b.) The DR is operated at unity P.F. with variable power output. 492 kW (50%) to 1050 kW max.

(c.) DR is operated at a fixed power factor either lead or lag (for example ± 0.8 P.F.) with variable P and Q to not violate voltage criteria.

(d.) The DR is operated as a synchronous condenser with minimum watts and variable VArs to regulate voltage. 246 kW (25% of rated)

(e.) DR is operated with variable P and Q and is used to optimize to a specific set of criteria such as minimize real losses, minimize reactive losses, regulate voltage and maximize released capacity.

Test Numbers	Reference. Section	**Primary Voltage Spread** (a)87% (b) 92% (c)93% (d) 95% (e) 98% (f) 105%	**Peak Load Day 24 Hourly quantities**	**Light Load Day 24 Hourly quantities**	**LTC $\pm$ 16 steps & neutral**	**Line Regulator**		**Capacitors**			**DR (H.S. Generator and Inverter) Locations** (a)Peak shave, P fixed (b) P.F.= Unity, P variable (c) $\pm$ P.F. Constant, Variable P (d) $\pm$ Q (Vars Volt Reg) P = 0 (e) P$\pm$ jQ (Optimizing) (f) Frequency Dithering Anti-Island		
						#1	#2	#1	#2	#3	Near End	Midpoint (Actual Site)	Far End
1		(a) (d) (f)											
2		(d) (f)											
3		(d) (f)											
4		(d) (f)											
5		(d) (f)											
6		(d) (f)											
7		(d) (f)											
8		(d) (f)											
9	II.A.	x	x	x							(b) (d) (e)		
10	II.B.	x	x	x								(b) (d) (e)	
11	II.C.	x	x	x									(b) (d) (e)
12	II.D.	Repeat II.A., II.B., II.C. turn on LTC											
13	II.E.	Repeat II.A., II.B., II.C. turn on LTC and Regulator (1)											
14	II.F.	Repeat II.A., II.B., II.C. turn on LTC and Regulator (1) and (2)											
15	II.G.	Repeat II.A., II.B., II.C. turn on LTC and Regulator (1) and (2) and Cap. (1)											
16	II.H.	Repeat II.A., II.B., II.C. turn on LTC and Regulator (1) and (2) and Cap. (1) and (2)											
17	II.I.	Repeat II.A., II.B., II.C. turn on LTC and Regulator (1) and (2) and Cap. (1), (2) and (3)											
18													
19													
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													

Test Numbers	Reference. Section	**Primary Voltage Spread** (a)87% (b) 92% (c)93% (d) 95% (e) 98% (f) 105%	**Peak Load Day 24 Hourly quantities**	**Light Load Day 24 Hourly quantities**	**LTC $\pm$ 16 steps & neutral**	**Line Regulator**		**Capacitors**			**DR (Induction Generator) Locations** (a)Peak shave, P fixed (b) P.F.= Unity, P fixed (c) $\pm$ P.F. Constant, P fixed (d) $\pm$ Q fixed, P fixed same as (c)		
						#1	#2	#1	#2	#3	Near End	Midpoint (Actual Site)	Far End
1		(a) (d) (f)											
2		(d) (f)											
3		(d) (f)											
4		(d) (f)											
5		(d) (f)											
6		(d) (f)											
7		(d) (f)											
8		(d) (f)											
9	II.A.	x	x	x							(b) (d)		
10	II.B.	x	x	x								(b) (d)	
11	II.C.	x	x	x									(b) (d)
12	II.D.	Repeat II.A., II.B., II.C. turn on LTC											
13	II.E.	Repeat II.A., II.B., II.C. turn on LTC and Regualator (1)											
14	II.F.	Repeat II.A., II.B., II.C. turn on LTC and Regulators (1) & (2)											
15	II.G.	Repeat II.A., II.B., II.C. turn on LTC, Reg. (1) & (2) and Cap (1)											
16	II.H.	Repeat II.A., II.B., II.C. turn on LTC, Reg. (1) & (2) and Cap (1) and (2)											
17	II.I.	Repeat II.A., II.B., II.C. turn on LTC, Reg (1) & (2) and Cap (1), (2) & (3)											
18	III.	Repeat synchronous and inverter generation											
19	IV.	Repeat synchronous, inverter and induction generation											
20													
21													
22													
23													
24													
25													
26													
27													
28													

The first step of properly setting up the simulations was to ensure the simulated data matched the actual circuit conditions. Two conditions were modeled: the peak load day and the light load day. The Milford Circuit DC 8103 had a maximum load of 15.3 MVA on the peak day and a minimum load of 5.91 MVA on the peak day.

To verify the accuracy of the model, simulation results for a given time were compared with recorded data. The modeled circuit was placed in a state closely resembling the conditions of the actual system when the measurement was made; specifically, the LTC, VR 1, and capacitor banks at nodes 6 and 12 (900 kVAr each) were enabled while at 100% primary voltage. The simulation HL base case feeder currents were 578 A, 654 A, and 637 A for phases A, B, and C, respectively, compared with actual recorded currents of 565 A, 651 A, and 637 A. The simulated megavolt-amperes of the circuit were 14.89, compared to a calculated 15.3 derived from the measured feeder currents and voltages. This was an error of 2.42%.

The program employed to perform the modeling was the Distribution Engineering Workstation. With it, load can be modeled as a constant current (CC), CP (P + j Q), or VDC. At first, CC was selected to best represent the load characteristics of Milford DC 8103. But, as discussed later (see Appendix B.1), all three models were tested by comparing the actual phase currents at Node 0 with the simulated phase currents at Node 0. The VDC model yielded the most accurate results, with only 2% error for Test 8. The CC model had an error of 5.3%, compared with 12.3% error for the CP model. The circuit regulation path shown in Figure 102 illustrates the nodes on this path from the first circuit (Node 1) to the major junction (Node 3) to the first step regulator (VR 1) to the next major junction (Node 8) and then through the second step regulator (VR 2) to the next major junction node (Node 11) and the following major junction (Node 14) and, finally, to the circuit tag end (Node 17). Voltage profiles are shown through each of these major nodes. Base case simulations were conducted for 100% voltage on the primary of the substation using only the LTC transformer regulation for both HL and LL conditions. This case was used to determine the released capacity and the real loss reduction when the 2/3s rule and 2/5s rule was applied for capacitive compensation and when the optimized size and locations were determined by the Distribution Engineering Workstation.

The following circuit voltage profiles are shown for each test (i.e., tests 1–8 with the primary substation voltage set at 95% and 105%). The first set of profiles is for HL conditions at 95% and 105% primary voltage with different traditional voltage regulation methods applied. Simulated voltage data as a function of circuit distance in thousands of meters are given in Table 20 for the HL conditions. Simulated voltage data versus circuit length are given in Table 21 for LL.

Table 20. Voltage Profile Data for HL Tests 1 Through 8 at 95% and 105% Substation Primary Voltage

Distance	Test 8 105 HL	Test 8 95 HL	Test 7 105 HL	Test 7 95 HL	Test 6 105 HL	Test 6 95 HL
0.1034	123.4557	111.3062	123.6329	111.5378	123.2305	111.1696
0.2378	125.708	123.0442	126.1231	123.5816	125.9826	122.6563
0.3218	125.6375	122.9755	126.0558	123.5167	125.9165	122.5933
0.3218	125.6375	122.9755	126.0558	123.5167	125.9165	122.5933
0.5288	125.5127	122.8549	125.9412	123.4071	125.784	122.4678
0.7648	125.3684	122.7151	125.8093	123.2809	125.6336	122.3253
1.3788	124.9925	122.3509	125.4657	122.9521	125.2414	121.9537
2.583	124.2592	121.6403	124.7952	122.3106	124.4755	121.228
2.666	124.2088	121.5915	124.7492	122.2665	124.4228	121.1781
3.206	123.896	121.2882	124.4645	121.9942	124.095	120.8676
3.429	123.7671	121.1633	124.3472	121.8821	123.9599	120.7396
3.716	123.6015	121.0028	124.1965	121.7379	123.7862	120.5751
5.754	122.4322	119.8693	123.1323	120.72	122.5577	119.4114
6.798	121.8696	119.3236	122.6233	120.2335	121.9637	118.8488
6.9262	121.8012	119.2573	122.5615	120.1744	121.8913	118.7803
7.0603	121.7295	119.1876	122.4967	120.1123	121.8155	118.7084
7.2034	121.6533	119.1135	122.4279	120.0464	121.7349	118.6319
7.3784	121.5602	119.023	122.3438	119.9659	121.6365	118.5384
7.7094	121.3851	118.8527	122.1858	119.8145	121.4511	118.3625
7.9064	121.2815	118.7519	122.0923	119.7249	121.3413	118.2582
7.9064	121.2815	118.7519	122.0923	119.7249	121.3413	118.2582
8.2464	121.1003	118.5758	121.9286	119.5681	121.1495	118.0761
8.4174	121.0092	118.4872	121.8462	119.4892	121.053	117.9845
8.8571	120.7771	118.2615	121.6366	119.2883	120.8069	117.7508
9.4411	120.4697	117.9625	121.3589	119.0223	120.4807	117.4411
9.6082	120.3851	117.8803	121.2829	118.9495	120.3907	117.3557
10.0174	120.1793	117.68	121.098	118.7724	120.1715	117.1476
10.3374	120.0189	117.5239	120.9538	118.6343	120.0005	116.9853
10.5075	119.9332	117.4406	120.8768	118.5605	119.9092	116.8986
10.8129	119.78	117.2915	120.739	118.4286	119.7458	116.7434
10.9501	119.7113	117.2247	120.6773	118.3695	119.6725	116.6739
11.0961	119.6384	117.1537	120.6118	118.3067	119.5947	116.6
11.6971	119.3406	116.8639	120.3442	118.0505	119.2764	116.2978
12.0081	119.1878	116.7151	120.2071	117.9191	119.113	116.1427
12.0291	119.1799	116.7074	120.2002	117.9126	119.1063	116.1363
12.0292	119.1799	116.7074	120.2002	117.9126	119.1063	116.1363
12.2671	119.0908	116.6202	120.123	117.8384	119.0306	116.0647
12.3884	119.0454	116.5758	120.0836	117.8006	118.992	116.0282
12.5244	118.9949	116.5264	120.0398	117.7586	118.9492	115.9876
12.6619	123.5833	121.719	119.6677	117.4023	118.5847	115.6436
12.7589	123.5494	121.6858	119.6369	117.3728	118.5546	115.6152
12.9495	123.4828	121.6208	119.5766	117.3149	118.4955	115.5593
13.0549	123.4461	121.5849	119.5434	117.283	118.4629	115.5284

Distance	Test 8 105 HL	Test 8 95 HL	Test 7 105 HL	Test 7 95 HL	Test 6 105 HL	Test 6 95 HL
13.3859	123.3272	121.4686	119.4355	117.1794	118.3572	115.4284
13.6541	123.2372	121.3807	119.3541	117.1013	118.2775	115.3529
13.9121	123.1493	121.2948	119.2746	117.025	118.1997	115.2793
14.1148	123.0811	121.2281	119.2129	116.9659	118.1393	115.2221
14.5219	122.9253	121.0757	119.0711	116.8297	118.0004	115.0905
15.0699	122.7163	120.8712	118.8808	116.647	117.814	114.9139
15.2599	122.644	120.8006	118.8151	116.5839	117.7496	114.8529
15.4019	122.5915	120.7492	118.7674	116.538	117.7029	114.8087
15.5403	122.5407	120.6994	118.7212	116.4937	117.6576	114.7658
15.8453	122.4272	120.5885	118.618	116.3947	117.5566	114.6701
16.1153	122.3263	120.4897	118.5262	116.3065	117.4666	114.5849
17.4453	121.8485	120.0221	118.0925	115.8901	117.0417	114.1825
17.6035	121.7941	119.9687	118.0429	115.8424	116.9931	114.1362
17.8465	121.7104	119.8865	117.9665	115.7688	116.9182	114.0649
18.2915	121.5581	119.737	117.8278	115.6351	116.782	113.9354
18.4488	121.5041	119.684	117.7785	115.5877	116.7337	113.8895
18.6148	121.4471	119.628	117.7265	115.5376	116.6827	113.8409
18.7818	121.3896	119.5716	117.6742	115.4872	116.6313	113.7921
19.1128	121.2759	119.46	117.5705	115.3873	116.5296	113.6953
19.4183	121.1659	119.352	117.47	115.2905	116.431	113.6015
20.0144	120.9738	119.1627	117.2951	115.1221	116.2595	113.4383
20.3923	120.8534	119.0441	117.1854	115.0165	116.152	113.3361
20.7652	120.7479	118.94	117.09	114.9246	116.0583	113.2471
20.9525	120.6938	118.8866	117.0408	114.8773	116.0102	113.2013
21.4666	120.5452	118.74	116.9062	114.7477	115.8781	113.0758
21.7311	120.4684	118.6642	116.8365	114.6806	115.8098	113.0109
21.9173	120.4176	118.614	116.7906	114.6364	115.7648	112.9681
22.0473	120.3945	118.591	116.77	114.6166	115.7445	112.9487
22.1883	120.3691	118.5657	116.7473	114.5946	115.7222	112.9274
22.3543	120.3392	118.5358	116.7206	114.5688	115.6959	112.9022
22.4763	120.3188	118.5153	116.7024	114.5512	115.6779	112.8851
22.8133	120.2615	118.458	116.6513	114.5019	115.6277	112.8371
22.9733	120.2611	118.457	116.6524	114.5029	115.6288	112.8381
23.1957	120.2593	118.4543	116.6526	114.5031	115.6289	112.8383
23.3361	120.2518	118.4463	116.6469	114.4976	115.6234	112.833
23.3575	120.2507	118.4451	116.6461	114.4968	115.6225	112.8321
23.5515	120.2404	118.4341	116.6383	114.4892	115.6149	112.8248
23.7088	120.2324	118.4255	116.6323	114.4834	115.6089	112.8191
24.0118	120.2169	118.4089	116.6207	114.4722	115.5975	112.8082
24.1251	120.2111	118.4026	116.6163	114.4679	115.5932	112.8041
24.3851	120.1984	118.3889	116.6069	114.4588	115.5839	112.7952

Distance	Test 8 105 HL	Test 8 95 HL	Test 7 105 HL	Test 7 95 HL	Test 6 105 HL	Test 6 95 HL
24.6292	120.1855	118.3751	116.5971	114.4493	115.5743	112.786
24.8032	120.1775	118.3664	116.5912	114.4437	115.5685	112.7805
25.0212	120.1669	118.3549	116.5833	114.4361	115.5608	112.7731
25.1302	120.1616	118.3492	116.5794	114.4323	115.5569	112.7694
25.3432	120.1602	118.3468	116.5803	114.4331	115.5578	112.7702
26.3495	120.1169	118.2991	116.5492	114.403	115.5272	112.741
26.5235	120.1087	118.2901	116.5431	114.3971	115.5212	112.7352
26.9295	120.0867	118.2664	116.5263	114.3809	115.5047	112.7195
27.0567	120.0802	118.2593	116.5213	114.3761	115.4998	112.7148
27.3222	120.0613	118.2394	116.506	114.3613	115.4848	112.7004
27.3813	120.0555	118.2334	116.5011	114.3566	115.48	112.6959
27.6828	120.0258	118.2027	116.4759	114.3322	115.4553	112.6722
27.8391	124.8328	125.3121	116.46	114.3168	115.4396	112.6572
27.9641	124.8208	125.3	116.4494	114.3066	115.4292	112.6473
28.1491	124.8031	125.2822	116.4338	114.2915	115.4138	112.6326
28.4312	124.7764	125.2551	116.4102	114.2687	115.3906	112.6105
28.6137	124.7643	125.2429	116.3995	114.2584	115.3802	112.6004
28.983	124.7407	125.2191	116.3787	114.2383	115.3598	112.581
29.633	124.7009	125.1789	116.3436	114.2044	115.3253	112.548
29.925	124.6853	125.1632	116.3299	114.1911	115.3118	112.5351
30.264	124.6764	125.1541	116.322	114.1834	115.3041	112.5277
30.904	124.6626	125.14	116.3098	114.1716	115.2922	112.5163
31.183	124.66	125.1373	116.3076	114.1695	115.29	112.5143
31.4215	124.6582	125.1354	116.3061	114.1681	115.2885	112.5128
31.6365	124.6578	125.1349	116.3059	114.1679	115.2883	112.5126
31.7505	124.6579	125.1349	116.306	114.168	115.2884	112.5127
31.8455	124.6567	125.1337	116.305	114.167	115.2874	112.5117
32.0297	124.6513	125.1283	116.3002	114.1624	115.2827	112.5073

Distance	Test 5 105 HL	Test 5 95 HL	Test 4 105 HL	Test 4 95 HL	Test 3 105 HL	Test 3 95 HL
0.1034	122.938	110.9229	122.3679	110.3743	122.402	110.4374
0.2378	126.1191	122.0339	125.6008	120.704	125.6804	120.8505
0.3218	126.054	121.9726	125.5325	120.6399	125.6127	120.7874
0.3218	126.054	121.9726	125.5325	120.6399	125.6127	120.7874
0.5288	125.9091	121.8367	125.3614	120.4788	125.444	120.6303
0.7648	125.7461	121.6837	125.1687	120.2971	125.254	120.4534
1.3788	125.3209	121.2847	124.6664	119.8238	124.759	119.9924
2.583	124.4898	120.5049	123.6842	118.898	123.7909	119.0909
2.666	124.4327	120.4512	123.6166	118.8343	123.7243	119.0289
3.206	124.0755	120.1161	123.1915	118.4334	123.3056	118.6389
3.429	123.9283	119.978	123.0162	118.2681	123.1329	118.4781
3.716	123.739	119.8004	122.7908	118.0555	122.9109	118.2713
5.754	122.3989	118.5429	121.1944	116.55	121.3383	116.8066
6.798	121.7472	117.9315	120.4109	115.8106	120.5671	116.0882
6.9262	121.6678	117.857	120.3152	115.7203	120.473	116.0005
7.0603	121.5846	117.7787	120.2245	115.6346	120.3839	115.9175
7.2034	121.496	117.6954	120.128	115.5434	120.2891	115.8292
7.3784	121.3878	117.5936	120.01	115.4319	120.1732	115.7213
7.7094	121.1841	117.4019	119.7878	115.2219	119.955	115.5181
7.9064	121.0633	117.2882	119.656	115.0973	119.8256	115.3976
7.9064	121.0633	117.2882	119.656	115.0973	119.8256	115.3976
8.2464	120.8525	117.0899	119.4264	114.8803	119.6	115.1876
8.4174	120.7464	116.9901	119.3108	114.7711	119.4865	115.0818
8.8571	120.4757	116.7354	119.0157	114.4921	119.1966	114.8119
9.4411	120.1168	116.3976	118.6245	114.1223	118.8124	114.454
9.6082	120.0174	116.3041	118.5158	114.0195	118.7057	114.3547
10.0174	119.7751	116.0761	118.2508	113.7688	118.4456	114.1124
10.3374	119.586	115.8982	118.044	113.5732	118.2426	113.9233
10.5075	119.4851	115.8032	117.9336	113.4688	118.1343	113.8224
10.8129	119.3044	115.6332	117.736	113.2819	117.9403	113.6417
10.9501	119.2234	115.5569	117.6474	113.198	117.8533	113.5607
11.0961	119.1373	115.4759	117.5532	113.109	117.7609	113.4746
11.6971	118.7849	115.1443	117.1676	112.7441	117.3825	113.1221
12.0081	118.6037	114.9737	116.9693	112.5565	117.1878	112.9408
12.0291	118.5958	114.9664	116.9603	112.5479	117.1791	112.9326
12.0292	118.5958	114.9664	116.9603	112.5479	117.1791	112.9326
12.2671	118.507	114.8829	116.8581	112.4503	117.0798	112.8402
12.3884	118.4617	114.8403	116.806	112.4006	117.0292	112.7931
12.5244	118.4113	114.7929	116.7479	112.3453	116.9729	112.7407
12.6619	117.9452	114.355	121.8413	117.2531	122.089	117.6882
12.7589	117.9097	114.3217	121.8023	117.2159	122.0512	117.653
12.9495	117.84	114.2562	121.7257	117.1428	121.9769	117.5838
13.0549	117.8016	114.22	121.6834	117.1024	121.9359	117.5456

Distance	Test 5 105 HL	Test 5 95 HL	Test 4 105 HL	Test 4 95 HL	Test 3 105 HL	Test 3 95 HL
13.3859	117.6775	114.1034	121.5472	116.9724	121.8035	117.4223
13.6541	117.5828	114.0144	121.443	116.8729	121.7026	117.3283
13.9121	117.4906	113.9277	121.3415	116.776	121.6042	117.2367
14.1148	117.4189	113.8603	121.2625	116.7006	121.5277	117.1654
14.5219	117.2574	113.7085	121.0856	116.5319	121.3555	117.005
15.0699	117.0407	113.5047	120.8479	116.3053	121.1244	116.7897
15.2599	116.9658	113.4342	120.7657	116.227	121.0445	116.7153
15.4019	116.9111	113.3828	120.7058	116.1698	120.9862	116.661
15.5403	116.8582	113.3331	120.6477	116.1144	120.9298	116.6084
15.8453	116.7402	113.2221	120.5182	115.9909	120.8039	116.4911
16.1153	116.6352	113.1234	120.403	115.8811	120.692	116.3868
17.4453	116.1359	112.6539	119.8544	115.3575	120.1593	115.8906
17.6035	116.0783	112.5995	119.7913	115.2969	120.0982	115.8334
17.8465	115.9897	112.5157	119.6943	115.2037	120.0041	115.7453
18.2915	115.8284	112.3633	119.5176	115.034	119.8329	115.5849
18.4488	115.7711	112.3092	119.455	114.9738	119.7722	115.528
18.6148	115.7107	112.2521	119.3889	114.9103	119.7081	115.468
18.7818	115.6499	112.1947	119.3223	114.8464	119.6435	115.4076
19.1128	115.5294	112.0808	119.1904	114.7197	119.5157	115.2878
19.4183	115.4136	111.9713	119.0638	114.5982	119.3928	115.1727
20.0144	115.2081	111.7771	118.8381	114.381	119.1747	114.9684
20.3923	115.0791	111.6552	118.6963	114.2444	119.0377	114.8401
20.7652	114.964	111.5464	118.5694	114.1218	118.9155	114.7257
20.9525	114.9051	111.4907	118.5045	114.0591	118.853	114.6671
21.4666	114.7434	111.338	118.3264	113.887	118.6815	114.5064
21.7311	114.6599	111.259	118.2343	113.7982	118.5928	114.4234
21.9173	114.604	111.2063	118.1726	113.7385	118.5335	114.3678
22.0473	114.5842	111.1875	118.1498	113.7158	118.5124	114.348
22.1883	114.5622	111.1667	118.1246	113.6908	118.489	114.3261
22.3543	114.5363	111.1422	118.095	113.6614	118.4615	114.3004
22.4763	114.5187	111.1256	118.0747	113.6412	118.4427	114.2828
22.8133	114.4693	111.0789	118.0178	113.5846	118.3902	114.2337
22.9733	114.4702	111.0798	118.0168	113.5821	118.3913	114.2347
23.1957	114.4703	111.0799	118.0142	113.5775	118.3914	114.2348
23.3361	114.4648	111.0747	118.0063	113.5684	118.3856	114.2294
23.3575	114.464	111.0739	118.0051	113.567	118.3847	114.2285
23.5515	114.4564	111.0668	117.9942	113.5546	118.3767	114.221
23.7088	114.4505	111.0612	117.9856	113.5447	118.3705	114.2152
24.0118	114.4392	111.0505	117.9692	113.5258	118.3586	114.204
24.1251	114.435	111.0465	117.963	113.5187	118.3541	114.1998
24.3851	114.4258	111.0378	117.9494	113.5029	118.3444	114.1907
24.6292	114.4163	111.0288	117.9357	113.4872	118.3343	114.1813
24.8032	114.4106	111.0235	117.9271	113.4771	118.3283	114.1757

Distance	Test 5 105 HL	Test 5 95 HL	Test 4 105 HL	Test 4 95 HL	Test 3 105 HL	Test 3 95 HL
25.0212	114.403	111.0162	117.9158	113.4639	118.3202	114.1681
25.1302	114.3992	111.0126	117.9102	113.4573	118.3162	114.1643
25.3432	114.3999	111.0133	117.9078	113.4526	118.3171	114.1651
26.3495	114.3698	110.9849	117.8608	113.3966	118.2853	114.1353
26.5235	114.3639	110.9793	117.8519	113.3862	118.279	114.1294
26.9295	114.3477	110.9639	117.8286	113.3595	118.2618	114.1133
27.0567	114.3429	110.9594	117.8217	113.3515	118.2568	114.1086
27.3222	114.3281	110.9454	117.802	113.3299	118.2411	114.0939
27.3813	114.3234	110.941	117.7961	113.3237	118.2361	114.0893
27.6828	114.2992	110.9181	117.7659	113.2918	118.2104	114.0651
27.8391	114.2838	110.9035	124.8491	125.4185	118.194	114.0498
27.9641	114.2736	110.8939	124.8371	125.4064	118.1832	114.0397
28.1491	114.2585	110.8796	124.8195	125.3886	118.1672	114.0247
28.4312	114.2358	110.8582	124.7928	125.3617	118.1431	114.0021
28.6137	114.2255	110.8484	124.7807	125.3496	118.1322	113.9919
28.983	114.2055	110.8296	124.7573	125.3259	118.111	113.972
29.633	114.1717	110.7976	124.7177	125.286	118.0752	113.9385
29.925	114.1585	110.7851	124.7022	125.2703	118.0612	113.9253
30.264	114.1509	110.7779	124.6933	125.2614	118.0532	113.9178
30.904	114.1393	110.7669	124.6796	125.2476	118.0409	113.9063
31.183	114.1371	110.7649	124.677	125.2448	118.0386	113.9042
31.4215	114.1357	110.7635	124.6751	125.2429	118.0371	113.9027
31.6365	114.1354	110.7632	124.6747	125.2425	118.0368	113.9025
31.7505	114.1355	110.7633	124.6747	125.2425	118.0369	113.9025
31.8455	114.1345	110.7624	124.6735	125.2413	118.0358	113.9016
32.0297	114.1299	110.7581	124.6682	125.2358	118.031	113.897

Distance	Test 2 105 HL	Test 2 95 HL	Test 1 105 HL	Test 1 95 HL
0.1034	122.5967	110.633	122.9494	111.4887
0.2378	126.1397	121.3093	121.7467	110.7418
0.3218	126.075	121.2491	121.6862	110.6914
0.3218	126.075	121.2491	121.6862	110.6914
0.5288	125.9154	121.1006	121.5367	110.5674
0.7648	125.7367	120.9344	121.3694	110.4285
1.3788	125.271	120.5011	120.9332	110.0664
2.583	124.3601	119.6537	120.0801	109.3582
2.666	124.2974	119.5954	120.0214	109.3095
3.206	123.9043	119.2297	119.6533	109.0039
3.429	123.7422	119.0789	119.5015	108.8779
3.716	123.5337	118.885	119.3062	108.7158
5.754	122.0572	117.5112	117.9233	107.5674
6.798	121.3351	116.8394	117.247	107.0059
6.9262	121.247	116.7574	117.1644	106.9374
7.0603	121.1643	116.6805	117.0871	106.8733
7.2034	121.0764	116.5988	117.0048	106.8051
7.3784	120.9689	116.4988	116.9042	106.7217
7.7094	120.7665	116.3106	116.7147	106.5647
7.9064	120.6465	116.1991	116.6024	106.4716
7.9064	120.6465	116.1991	116.6024	106.4716
8.2464	120.4372	116.0044	116.4064	106.3092
8.4174	120.3318	115.9064	116.3078	106.2274
8.8571	120.0629	115.6563	116.056	106.0187
9.4411	119.7063	115.3247	115.7222	105.7419
9.6082	119.6076	115.2329	115.6298	105.6653
10.0174	119.367	115.0091	115.4045	105.4786
10.3374	119.1791	114.8344	115.2287	105.3328
10.5075	119.0789	114.7412	115.1349	105.255
10.8129	118.8994	114.5743	114.9668	105.1156
10.9501	118.8189	114.4994	114.8914	105.0532
11.0961	118.7334	114.4199	114.8114	104.9868
11.6971	118.3833	114.0942	114.4836	104.7149
12.0081	118.2033	113.9268	114.3151	104.5752
12.0291	118.1955	113.9196	114.3078	104.5692
12.0292	118.1955	113.9196	114.3078	104.5692
12.2671	118.1073	113.8377	114.2253	104.5011
12.3884	118.0623	113.7959	114.1832	104.4664
12.5244	118.0123	113.7494	114.1365	104.4278
12.6619	117.5493	113.3197	113.7037	104.0708
12.7589	117.514	113.2869	113.6707	104.0436
12.9495	117.4448	113.2227	113.606	103.9902
13.0549	117.4066	113.1872	113.5703	103.9607

Distance	Test 2 105 HL	Test 2 95 HL	Test 1 105 HL	Test 1 95 HL
13.3859	117.2834	113.0727	113.4551	103.8655
13.6541	117.1894	112.9854	113.3672	103.793
13.9121	117.0978	112.9003	113.2815	103.7223
14.1148	117.0265	112.8342	113.2149	103.6673
14.5219	116.8662	112.6852	113.0649	103.5433
15.0699	116.6509	112.4851	112.8635	103.3767
15.2599	116.5765	112.416	112.7939	103.3191
15.4019	116.5222	112.3656	112.7431	103.2771
15.5403	116.4697	112.3167	112.6939	103.2365
15.8453	116.3525	112.2078	112.5843	103.1458
16.1153	116.2482	112.1109	112.4867	103.0652
17.4453	115.7523	111.6502	112.0228	102.6819
17.6035	115.695	111.5967	111.969	102.6366
17.8465	115.6069	111.5143	111.8861	102.5668
18.2915	115.4466	111.3645	111.7353	102.4398
18.4488	115.3898	111.3113	111.6818	102.3947
18.6148	115.3298	111.2552	111.6254	102.3472
18.7818	115.2693	111.1987	111.5685	102.2993
19.1128	115.1496	111.0868	111.4559	102.2045
19.4183	115.0345	110.9792	111.3476	102.1133
20.0144	114.8303	110.7883	111.1555	101.9515
20.3923	114.7021	110.6684	111.0349	101.8499
20.7652	114.5877	110.5615	110.9273	101.7593
20.9525	114.5292	110.5068	110.8722	101.7128
21.4666	114.3686	110.3566	110.7211	101.5855
21.7311	114.2856	110.279	110.643	101.5198
21.9173	114.2301	110.2271	110.5908	101.4758
22.0473	114.2103	110.2087	110.5722	101.4602
22.1883	114.1885	110.1882	110.5517	101.4429
22.3543	114.1627	110.1642	110.5275	101.4226
22.4763	114.1452	110.1478	110.511	101.4088
22.8133	114.0961	110.102	110.4649	101.37
22.9733	114.097	110.1028	110.4658	101.3708
23.1957	114.0971	110.1029	110.4659	101.3709
23.3361	114.0917	110.0978	110.4607	101.3666
23.3575	114.0908	110.097	110.46	101.3659
23.5515	114.0833	110.09	110.4529	101.36
23.7088	114.0775	110.0845	110.4474	101.3554
24.0118	114.0662	110.074	110.4369	101.3465
24.1251	114.062	110.0701	110.4329	101.3432
24.3851	114.0529	110.0615	110.4243	101.336
24.6292	114.0434	110.0527	110.4154	101.3285

Distance	Test 2 105 HL	Test 2 95 HL	Test 1 105 HL	Test 1 95 HL
24.8032	114.0378	110.0474	110.4101	101.324
25.0212	114.0302	110.0403	110.403	101.318
25.1302	114.0264	110.0367	110.3994	101.315
25.3432	114.0271	110.0374	110.4001	101.3156
26.3495	113.9972	110.0094	110.372	101.2919
26.5235	113.9913	110.0039	110.3664	101.2872
26.9295	113.9752	109.9888	110.3513	101.2744
27.0567	113.9705	109.9844	110.3468	101.2706
27.3222	113.9558	109.9707	110.333	101.259
27.3813	113.9511	109.9663	110.3286	101.2553
27.6828	113.927	109.9438	110.3059	101.2362
27.8391	113.9117	109.9295	110.2915	101.224
27.9641	113.9016	109.92	110.282	101.216
28.1491	113.8866	109.906	110.2679	101.2041
28.4312	113.864	109.8849	110.2466	101.1862
28.6137	113.8538	109.8753	110.237	101.1781
28.983	113.834	109.8568	110.2183	101.1624
29.633	113.8004	109.8254	110.1867	101.1357
29.925	113.7873	109.8131	110.1744	101.1253
30.264	113.7798	109.8061	110.1673	101.1193
30.904	113.7682	109.7952	110.1564	101.11
31.183	113.7661	109.7932	110.1544	101.1083
31.4215	113.7646	109.7919	110.153	101.1072
31.6365	113.7643	109.7916	110.1528	101.107
31.7505	113.7644	109.7917	110.1528	101.1071
31.8455	113.7634	109.7908	110.1519	101.1063
32.0297	113.7589	109.7865	110.1477	101.1027

Table 21. Voltage Profile Data for Light Load Tests 1 Through 8 at 95% and 105% Substation Primary Voltage

Distance	Test 8 105 LL	Test 8 95 LL	Test 7 105 LL	Test 7 95 LL	Test 6 105 LL	Test 6 95 LL
0.1034	125.9754	113.9697	125.9744	113.9687	125.5215	113.4715
0.2378	125.6501	126.1978	125.648	126.1954	126.246	125.7513
0.3218	125.6232	126.1708	125.6211	126.1683	126.2194	125.7247
0.3218	125.6232	126.1708	125.6211	126.1683	126.2194	125.7247
0.5288	125.617	126.1647	125.6149	126.1621	126.1918	125.6973
0.7648	125.6046	126.1523	125.6024	126.1496	126.1567	125.6622
1.3788	125.572	126.1198	125.5696	126.1168	126.0648	125.5707
2.583	125.5091	126.057	125.5064	126.0535	125.8856	125.392
2.666	125.5048	126.0527	125.5021	126.0492	125.8732	125.3798
3.206	125.4822	126.0303	125.4794	126.0265	125.7984	125.3052
3.429	125.4729	126.0211	125.4701	126.0172	125.7676	125.2745
3.716	125.4611	126.0093	125.4582	126.0053	125.7279	125.2349
5.754	125.3787	125.9272	125.3753	125.9223	125.4476	124.9556
6.798	125.3473	125.8961	125.3437	125.8907	125.3146	124.823
6.9262	125.3436	125.8925	125.34	125.887	125.2984	124.807
7.0603	125.3329	125.8817	125.3292	125.8762	125.2746	124.7832
7.2034	125.3214	125.8703	125.3177	125.8647	125.2492	124.7579
7.3784	125.3075	125.8563	125.3037	125.8506	125.2181	124.727
7.7094	125.2813	125.8302	125.2776	125.8244	125.1597	124.6687
7.9064	125.2659	125.8148	125.2621	125.8089	125.1251	124.6342
7.9064	125.2659	125.8148	125.2621	125.8089	125.1251	124.6342
8.2464	125.2381	125.787	125.2342	125.7809	125.064	124.5734
8.4174	125.2241	125.7729	125.2201	125.7668	125.0333	124.5427
8.8571	125.1886	125.7375	125.1846	125.7312	124.9548	124.4646
9.4411	125.1418	125.6906	125.1376	125.684	124.8508	124.3609
9.6082	125.1295	125.6784	125.1253	125.6717	124.8222	124.3324
10.0174	125.1	125.6488	125.0957	125.642	124.7525	124.263
10.3374	125.077	125.6259	125.0727	125.6189	124.6981	124.2088
10.5075	125.0646	125.6135	125.0602	125.6064	124.6691	124.1798
10.8129	125.0425	125.5914	125.038	125.5842	124.617	124.1279
10.9501	125.0326	125.5815	125.0281	125.5742	124.5936	124.1046
11.0961	125.0222	125.5711	125.0177	125.5637	124.5688	124.0799
11.6971	124.9798	125.5287	124.9752	125.5211	124.4674	123.9789
12.0081	124.9582	125.5072	124.9536	125.4994	124.4152	123.9269
12.0291	124.9564	125.5054	124.9517	125.4976	124.4134	123.9251
12.0292	124.9564	125.5054	124.9517	125.4976	124.4134	123.9251
12.2671	124.9358	125.4847	124.9311	125.4769	124.3929	123.9047
12.3884	124.9253	125.4742	124.9205	125.4663	124.3825	123.8942
12.5244	124.9136	125.4626	124.9089	125.4546	124.3709	123.8827
12.6619	124.284	125.3955	124.8416	125.3871	124.3038	123.8159
12.7589	124.2758	125.3873	124.8334	125.3789	124.2957	123.8078
12.9495	124.2597	125.3713	124.8173	125.3628	124.2798	123.7919

Distance	Test 8 105 LL	Test 8 95 LL	Test 7 105 LL	Test 7 95 LL	Test 6 105 LL	Test 6 95 LL
13.0549	124.2508	125.3624	124.8085	125.3539	124.271	123.7831
13.3859	124.2215	125.3332	124.7792	125.3245	124.2419	123.7542
13.6541	124.2	125.3118	124.7578	125.303	124.2207	123.733
13.9121	124.1789	125.2909	124.7368	125.282	124.1998	123.7122
14.1148	124.1626	125.2747	124.7206	125.2656	124.1837	123.6961
14.5219	124.1228	125.2349	124.6808	125.2257	124.1442	123.6568
15.0699	124.0693	125.1816	124.6274	125.1722	124.0912	123.604
15.2599	124.0508	125.1632	124.609	125.1537	124.0729	123.5858
15.4019	124.0375	125.1499	124.5957	125.1404	124.0597	123.5726
15.5403	124.0247	125.1372	124.5829	125.1275	124.047	123.56
15.8453	123.9958	125.1084	124.5541	125.0987	124.0184	123.5315
16.1153	123.9701	125.0828	124.5285	125.0729	123.9929	123.5061
17.4453	123.8498	124.9629	124.4085	124.9525	123.8737	123.3873
17.6035	123.8375	124.9507	124.3962	124.9401	123.8615	123.3751
17.8465	123.8185	124.9317	124.3772	124.9211	123.8427	123.3563
18.2915	123.7842	124.8977	124.3431	124.8869	123.8088	123.3226
18.4488	123.772	124.8855	124.3309	124.8747	123.7967	123.3105
18.6148	123.7591	124.8727	124.3181	124.8618	123.7839	123.2978
18.7818	123.7461	124.8597	124.3051	124.8487	123.771	123.2849
19.1128	123.7203	124.8341	124.2794	124.823	123.7455	123.2595
19.4183	123.6947	124.8086	124.2538	124.7973	123.7202	123.2342
20.0144	123.6585	124.7728	124.2179	124.7613	123.6845	123.1987
20.3923	123.6362	124.7507	124.1957	124.739	123.6624	123.1767
20.7652	123.6182	124.733	124.1779	124.7211	123.6447	123.1591
20.9525	123.6088	124.7237	124.1686	124.7118	123.6355	123.1499
21.4666	123.583	124.6983	124.143	124.6861	123.6101	123.1245
21.7311	123.5696	124.685	124.1297	124.6727	123.5969	123.1114
21.9173	123.5612	124.6768	124.1214	124.6644	123.5886	123.1032
22.0473	123.5534	124.669	124.1136	124.6566	123.5809	123.0955
22.1883	123.5448	124.6605	124.105	124.648	123.5723	123.0869
22.3543	123.5347	124.6504	124.0949	124.6379	123.5623	123.0769
22.4763	123.5277	124.6435	124.088	124.6309	123.5554	123.07
22.8133	123.5082	124.6242	124.0686	124.6114	123.5361	123.0508
22.9733	123.5073	124.6234	124.0678	124.6106	123.5353	123.05
23.1957	123.5057	124.622	124.0663	124.6091	123.5337	123.0485
23.3361	123.5027	124.619	124.0633	124.6061	123.5308	123.0455
23.3575	123.5022	124.6186	124.0628	124.6057	123.5304	123.0451
23.5515	123.498	124.6146	124.0588	124.6016	123.5263	123.041
23.7088	123.4948	124.6114	124.0556	124.5983	123.5231	123.0379

Distance	Test 8 105 LL	Test 8 95 LL	Test 7 105 LL	Test 7 95 LL	Test 6 105 LL	Test 6 95 LL
24.0118	123.4884	124.6053	124.0494	124.5921	123.5169	123.0317
24.1251	123.4861	124.6031	124.047	124.5898	123.5146	123.0294
24.3851	123.4808	124.598	124.0419	124.5846	123.5095	123.0243
24.6292	123.4755	124.5929	124.0367	124.5795	123.5044	123.0192
24.8032	123.4722	124.5897	124.0335	124.5762	123.5011	123.016
25.0212	123.4678	124.5855	124.0292	124.5719	123.4969	123.0117
25.1302	123.4656	124.5834	124.027	124.5697	123.4947	123.0096
25.3432	123.4642	124.5823	124.0258	124.5684	123.4935	123.0083
26.3495	123.4459	124.5648	124.0079	124.5505	123.4757	122.9907
26.5235	123.4425	124.5615	124.0046	124.5472	123.4724	122.9873
26.9295	123.4337	124.553	123.996	124.5385	123.4639	122.9788
27.0567	123.4311	124.5505	123.9934	124.5359	123.4613	122.9763
27.3222	123.4239	124.5435	123.9864	124.5289	123.4543	122.9693
27.3813	123.4218	124.5415	123.9843	124.5268	123.4523	122.9673
27.6828	123.4112	124.5311	123.9738	124.5162	123.4418	122.9568
27.8391	124.232	123.6907	123.9678	124.5102	123.4358	122.9509
27.9641	124.2276	123.6863	123.9634	124.5058	123.4314	122.9465
28.1491	124.221	123.6798	123.9568	124.4992	123.4249	122.9401
28.4312	124.2111	123.67	123.947	124.4893	123.4151	122.9303
28.6137	124.2065	123.6654	123.9423	124.4847	123.4105	122.9257
28.983	124.1976	123.6565	123.9335	124.4758	123.4018	122.917
29.633	124.1829	123.6419	123.9189	124.4611	123.3872	122.9025
29.925	124.1772	123.6362	123.9131	124.4553	123.3815	122.8968
30.264	124.1739	123.6329	123.9098	124.452	123.3782	122.8935
30.904	124.1685	123.6276	123.9045	124.4467	123.373	122.8883
31.183	124.1674	123.6265	123.9034	124.4456	123.3718	122.8872
31.4215	124.1666	123.6257	123.9026	124.4448	123.3711	122.8864
31.6365	124.1662	123.6253	123.9022	124.4444	123.3707	122.886
31.7505	124.1662	123.6253	123.9022	124.4444	123.3707	122.886
31.8455	124.1658	123.6249	123.9018	124.444	123.3703	122.8856
32.0297	124.1639	123.6231	123.9	124.4422	123.3685	122.8838

Distance	Test 5 105 LL	Test 5 95 LL	Test 4 105 LL	Test 4 95 LL	Test 3 105 LL	Test 3 95 LL
0.1034	125.1863	113.1052	124.8272	112.684	124.8297	112.6858
0.2378	126.275	125.6313	126.2478	126.1644	126.2539	126.1689
0.3218	126.2487	125.6051	126.2214	126.1377	126.2276	126.1422
0.3218	126.2487	125.6051	126.2214	126.1377	126.2276	126.1422
0.5288	126.2059	125.5625	126.162	126.0775	126.1685	126.0822
0.7648	126.1545	125.5114	126.0928	126.0072	126.0996	126.0122
1.3788	126.0206	125.378	125.9124	125.8242	125.9201	125.8297
2.583	125.7585	125.1171	125.5592	125.4657	125.5685	125.4725
2.666	125.7404	125.0992	125.5349	125.441	125.5443	125.4478
3.206	125.6284	124.9877	125.3819	125.2857	125.3921	125.2931
3.429	125.5822	124.9417	125.3188	125.2216	125.3293	125.2292
3.716	125.5227	124.8825	125.2376	125.1391	125.2485	125.147
5.754	125.1016	124.4633	124.6618	124.5544	124.6755	124.5643
6.798	124.8962	124.2589	124.377	124.2651	124.3921	124.276
6.9262	124.8712	124.234	124.3422	124.2297	124.3575	124.2408
7.0603	124.838	124.201	124.3088	124.1957	124.3243	124.2069
7.2034	124.8027	124.1659	124.2732	124.1595	124.289	124.1709
7.3784	124.7596	124.1229	124.2297	124.1153	124.2457	124.1268
7.7094	124.6782	124.0419	124.1477	124.0318	124.1642	124.0437
7.9064	124.6299	123.9939	124.0991	123.9823	124.1158	123.9943
7.9064	124.6299	123.9939	124.0991	123.9823	124.1158	123.9943
8.2464	124.5453	123.9096	124.0138	123.8955	124.031	123.9079
8.4174	124.5026	123.8672	123.9709	123.8519	123.9883	123.8644
8.8571	124.3937	123.7588	123.8611	123.7402	123.8791	123.7532
9.4411	124.2491	123.6149	123.7154	123.592	123.7343	123.6055
9.6082	124.2089	123.5748	123.6749	123.5507	123.694	123.5644
10.0174	124.1107	123.4772	123.576	123.45	123.5956	123.4641
10.3374	124.0341	123.4009	123.4987	123.3714	123.5188	123.3858
10.5075	123.9932	123.3602	123.4575	123.3294	123.4778	123.344
10.8129	123.9198	123.2871	123.3836	123.2541	123.4043	123.269
10.9501	123.8869	123.2544	123.3504	123.2203	123.3713	123.2354
11.0961	123.8519	123.2196	123.3151	123.1845	123.3363	123.1996
11.6971	123.7086	123.0769	123.1707	123.0374	123.1926	123.0531
12.0081	123.6347	123.0034	123.0962	122.9616	123.1186	122.9776
12.0291	123.6315	123.0002	123.093	122.9583	123.1154	122.9743
12.0292	123.6315	123.0002	123.093	122.9583	123.1154	122.9743
12.2671	123.5952	122.9641	123.0562	122.9205	123.079	122.9368
12.3884	123.5767	122.9457	123.0374	122.9012	123.0604	122.9176
12.5244	123.5561	122.9251	123.0165	122.8797	123.0396	122.8963
12.6619	123.3715	122.7414	123.5686	125.2723	123.5931	125.29
12.7589	123.3569	122.7269	123.5539	125.2574	123.5785	125.2752
12.9495	123.3283	122.6984	123.525	125.2282	123.5499	125.2462

Distance	Test 5 105 LL	Test 5 95 LL	Test 4 105 LL	Test 4 95 LL	Test 3 105 LL	Test 3 95 LL
13.0549	123.3125	122.6827	123.5091	125.2121	123.5341	125.2302
13.3859	123.2614	122.6319	123.4576	125.1601	123.483	125.1785
13.6541	123.2223	122.5929	123.4181	125.1202	123.4439	125.1388
13.9121	123.1843	122.5551	123.3797	125.0814	123.4059	125.1003
14.1148	123.1546	122.5256	123.3498	125.0512	123.3762	125.0703
14.5219	123.0881	122.4594	123.2827	124.9834	123.3097	125.0029
15.0699	122.9986	122.3704	123.1925	124.8923	123.2202	124.9123
15.2599	122.9677	122.3396	123.1613	124.8607	123.1893	124.8809
15.4019	122.9451	122.3171	123.1385	124.8377	123.1667	124.858
15.5403	122.9231	122.2952	123.1164	124.8153	123.1447	124.8358
15.8453	122.8743	122.2466	123.0671	124.7655	123.0959	124.7863
16.1153	122.8308	122.2033	123.0233	124.7212	123.0524	124.7422
17.4453	122.6228	121.9964	122.8135	124.5093	122.8444	124.5315
17.6035	122.6001	121.9737	122.7905	124.486	122.8216	124.5085
17.8465	122.565	121.9388	122.7551	124.4503	122.7866	124.4729
18.2915	122.5014	121.8755	122.6909	124.3854	122.7229	124.4085
18.4488	122.4787	121.8529	122.668	124.3623	122.7003	124.3855
18.6148	122.4548	121.8292	122.6439	124.338	122.6764	124.3613
18.7818	122.4308	121.8052	122.6196	124.3134	122.6524	124.337
19.1128	122.3831	121.7578	122.5715	124.2648	122.6047	124.2887
19.4183	122.3373	121.7122	122.5253	124.2181	122.5589	124.2423
20.0144	122.2616	121.6369	122.4487	124.1408	122.4831	124.1656
20.3923	122.2142	121.5896	122.4007	124.0924	122.4357	124.1175
20.7652	122.1714	121.5471	122.3574	124.0487	122.3929	124.0742
20.9525	122.1495	121.5253	122.3353	124.0264	122.371	124.052
21.4666	122.0895	121.4656	122.2746	123.9651	122.311	123.9912
21.7311	122.0585	121.4347	122.2432	123.9334	122.28	123.9598
21.9173	122.0377	121.414	122.2221	123.9122	122.2592	123.9387
22.0473	122.0301	121.4064	122.2143	123.9043	122.2515	123.9309
22.1883	122.0216	121.398	122.2057	123.8956	122.2431	123.9224
22.3543	122.0117	121.3881	122.1955	123.8854	122.2331	123.9123
22.4763	122.0048	121.3813	122.1885	123.8783	122.2263	123.9054
22.8133	121.9857	121.3623	122.169	123.8586	122.2072	123.886
22.9733	121.9849	121.3615	122.168	123.8577	122.2064	123.8852
23.1957	121.9834	121.36	122.1662	123.856	122.2049	123.8837
23.3361	121.9805	121.3571	122.1631	123.8529	122.202	123.8807
23.3575	121.9801	121.3567	122.1626	123.8524	122.2015	123.8803
23.5515	121.9761	121.3527	122.1583	123.8481	122.1975	123.8762
23.7088	121.9729	121.3495	122.155	123.8448	122.1944	123.873
24.0118	121.9668	121.3435	122.1485	123.8383	122.1883	123.8668
24.1251	121.9645	121.3412	122.146	123.8359	122.186	123.8645
24.3851	121.9595	121.3362	122.1406	123.8305	122.181	123.8594

Distance	Test 5 105 LL	Test 5 95 LL	Test 4 105 LL	Test 4 95 LL	Test 3 105 LL	Test 3 95 LL
24.6292	121.9544	121.3311	122.1352	123.8252	122.1759	123.8543
24.8032	121.9512	121.3279	122.1318	123.8217	122.1727	123.851
25.0212	121.947	121.3237	122.1273	123.8172	122.1685	123.8467
25.1302	121.9449	121.3216	122.125	123.815	122.1664	123.8446
25.3432	121.9437	121.3204	122.1235	123.8136	122.1652	123.8434
26.3495	121.9262	121.303	122.1046	123.7948	122.1477	123.8256
26.5235	121.9229	121.2997	122.1011	123.7914	122.1444	123.8223
26.9295	121.9145	121.2913	122.0921	123.7824	122.136	123.8138
27.0567	121.9119	121.2888	122.0894	123.7797	122.1335	123.8112
27.3222	121.905	121.2819	122.0821	123.7725	122.1266	123.8042
27.3813	121.903	121.2799	122.08	123.7704	122.1246	123.8022
27.6828	121.8927	121.2697	122.0693	123.7596	122.1142	123.7917
27.8391	121.8868	121.2638	124.5168	125.412	122.1083	123.7857
27.9641	121.8825	121.2595	124.5124	125.4075	122.104	123.7813
28.1491	121.8761	121.2531	124.5059	125.4009	122.0976	123.7749
28.4312	121.8664	121.2435	124.496	125.391	122.0879	123.7651
28.6137	121.8619	121.239	124.4914	125.3864	122.0834	123.7605
28.983	121.8532	121.2304	124.4826	125.3775	122.0747	123.7517
29.633	121.8389	121.2161	124.468	125.3628	122.0604	123.7372
29.925	121.8332	121.2105	124.4622	125.357	122.0548	123.7315
30.264	121.83	121.2073	124.459	125.3537	122.0516	123.7283
30.904	121.8249	121.2022	124.4537	125.3484	122.0464	123.723
31.183	121.8238	121.2011	124.4526	125.3472	122.0453	123.7219
31.4215	121.823	121.2003	124.4517	125.3464	122.0445	123.7211
31.6365	121.8226	121.1999	124.4514	125.346	122.0442	123.7208
31.7505	121.8226	121.1999	124.4513	125.346	122.0441	123.7207
31.8455	121.8222	121.1995	124.4509	125.3456	122.0437	123.7203
32.0297	121.8204	121.1977	124.4491	125.3438	122.0419	123.7185

Distance	Test 2 105 LL	Test 2 95 LL	Test 1 105 LL	Test 1 95 LL
0.1034	124.8365	112.7094	124.8365	112.9372
0.2378	126.2705	126.2252	126.2705	114.2202
0.3218	126.2443	126.199	126.2443	114.1963
0.3218	126.2443	126.199	126.2443	114.1963
0.5288	126.1855	126.1402	126.1855	114.1426
0.7648	126.1169	126.0717	126.1169	114.08
1.3788	125.9383	125.8932	125.9383	113.917
2.583	125.5886	125.5436	125.5886	113.5978
2.666	125.5645	125.5195	125.5645	113.5758
3.206	125.4131	125.3682	125.4131	113.4376
3.429	125.3507	125.3058	125.3507	113.3806
3.716	125.2703	125.2255	125.2703	113.3072
5.754	124.7003	124.6557	124.7003	112.7869
6.798	124.4185	124.3741	124.4185	112.5297
6.9262	124.3841	124.3397	124.3841	112.4983
7.0603	124.3511	124.3067	124.3511	112.4681
7.2034	124.3159	124.2715	124.3159	112.436
7.3784	124.2729	124.2286	124.2729	112.3968
7.7094	124.1919	124.1475	124.1919	112.3228
7.9064	124.1438	124.0995	124.1438	112.2789
7.9064	124.1438	124.0995	124.1438	112.2789
8.2464	124.0595	124.0152	124.0595	112.202
8.4174	124.0171	123.9728	124.0171	112.1632
8.8571	123.9086	123.8643	123.9086	112.0642
9.4411	123.7646	123.7204	123.7646	111.9327
9.6082	123.7245	123.6803	123.7245	111.8962
10.0174	123.6268	123.5827	123.6268	111.807
10.3374	123.5505	123.5064	123.5505	111.7373
10.5075	123.5097	123.4656	123.5097	111.7001
10.8129	123.4366	123.3926	123.4366	111.6334
10.9501	123.4038	123.3598	123.4038	111.6035
11.0961	123.369	123.325	123.369	111.5717
11.6971	123.2263	123.1823	123.2263	111.4414
12.0081	123.1527	123.1088	123.1527	111.3743
12.0291	123.1495	123.1056	123.1495	111.3714
12.0292	123.1495	123.1056	123.1495	111.3714
12.2671	123.1134	123.0695	123.1134	111.3383
12.3884	123.0949	123.051	123.0949	111.3215
12.5244	123.0744	123.0305	123.0744	111.3028
12.6619	122.8905	122.8467	122.8905	111.1349
12.7589	122.876	122.8322	122.876	111.1217
12.9495	122.8475	122.8037	122.8475	111.0956

Distance	Test 2 105 LL	Test 2 95 LL	Test 1 105 LL	Test 1 95 LL
13.0549	122.8317	122.7879	122.8317	111.0813
13.3859	122.7809	122.7371	122.7809	111.0349
13.6541	122.7419	122.6982	122.7419	110.9993
13.9121	122.7041	122.6603	122.7041	110.9647
14.1148	122.6746	122.6308	122.6746	110.9378
14.5219	122.6083	122.5646	122.6083	110.8773
15.0699	122.5192	122.4756	122.5192	110.796
15.2599	122.4884	122.4448	122.4884	110.7679
15.4019	122.4659	122.4223	122.4659	110.7473
15.5403	122.4441	122.4004	122.4441	110.7274
15.8453	122.3954	122.3518	122.3954	110.683
16.1153	122.3521	122.3085	122.3521	110.6435
17.4453	122.145	122.1015	122.145	110.4545
17.6035	122.1223	122.0788	122.1223	110.4338
17.8465	122.0874	122.0439	122.0874	110.4019
18.2915	122.024	121.9806	122.024	110.3441
18.4488	122.0015	121.9581	122.0015	110.3235
18.6148	121.9777	121.9343	121.9777	110.3018
18.7818	121.9537	121.9103	121.9537	110.2799
19.1128	121.9063	121.8629	121.9063	110.2366
19.4183	121.8607	121.8173	121.8607	110.195
20.0144	121.7853	121.7419	121.7853	110.1261
20.3923	121.738	121.6947	121.738	110.083
20.7652	121.6954	121.6522	121.6954	110.0442
20.9525	121.6736	121.6304	121.6736	110.0243
21.4666	121.6139	121.5707	121.6139	109.9697
21.7311	121.583	121.5398	121.583	109.9416
21.9173	121.5623	121.5191	121.5623	109.9226
22.0473	121.5547	121.5114	121.5547	109.9157
22.1883	121.5462	121.503	121.5462	109.908
22.3543	121.5363	121.4931	121.5363	109.899
22.4763	121.5295	121.4863	121.5295	109.8928
22.8133	121.5105	121.4673	121.5105	109.8754
22.9733	121.5097	121.4665	121.5097	109.8747
23.1957	121.5082	121.465	121.5082	109.8733
23.3361	121.5053	121.4621	121.5053	109.8706
23.3575	121.5049	121.4617	121.5049	109.8702
23.5515	121.5009	121.4577	121.5009	109.8666
23.7088	121.4977	121.4545	121.4977	109.8637
24.0118	121.4916	121.4484	121.4916	109.8582
24.1251	121.4894	121.4462	121.4894	109.8561
24.3851	121.4843	121.4411	121.4843	109.8515

Distance	Test 2 105 LL	Test 2 95 LL	Test 1 105 LL	Test 1 95 LL
24.6292	121.4793	121.4361	121.4793	109.8469
24.8032	121.4761	121.4329	121.4761	109.844
25.0212	121.4719	121.4287	121.4719	109.8401
25.1302	121.4698	121.4266	121.4698	109.8382
25.3432	121.4686	121.4254	121.4686	109.8371
26.3495	121.4512	121.408	121.4512	109.8212
26.5235	121.4479	121.4047	121.4479	109.8182
26.9295	121.4395	121.3963	121.4395	109.8106
27.0567	121.437	121.3938	121.437	109.8083
27.3222	121.4301	121.3869	121.4301	109.802
27.3813	121.4281	121.3849	121.4281	109.8002
27.6828	121.4178	121.3746	121.4178	109.7908
27.8391	121.4119	121.3688	121.4119	109.7854
27.9641	121.4076	121.3645	121.4076	109.7815
28.1491	121.4013	121.3581	121.4013	109.7757
28.4312	121.3916	121.3485	121.3916	109.7669
28.6137	121.3871	121.344	121.3871	109.7628
28.983	121.3785	121.3353	121.3785	109.7549
29.633	121.3642	121.3211	121.3642	109.7419
29.925	121.3586	121.3155	121.3586	109.7368
30.264	121.3554	121.3123	121.3554	109.7339
30.904	121.3503	121.3072	121.3503	109.7292
31.183	121.3492	121.3061	121.3492	109.7282
31.4215	121.3484	121.3053	121.3484	109.7274
31.6365	121.3481	121.3049	121.3481	109.7271
31.7505	121.348	121.3049	121.348	109.7271
31.8455	121.3476	121.3045	121.3476	109.7267
32.0297	121.3459	121.3027	121.3459	109.7251

A summary of simulation information for each test, load condition, primary substation voltage, and traditional voltage regulation method is displayed in Table 22. This table summarizes the significant information collected from each simulation to show how these significant data change for each simulation. The data given for each test are:

- Test number
- Primary voltage: 95% or 105%
- Load condition: HL or LL
- Substation transformer LTC tap setting (±16)
- Step VR tap settings (±32)
- Capacitor kVArc applied
- Line currents (I_A, I_B, I_C) at Node [0]
- Lowest three-phase voltage: V_A, V_B, V_C
- Lowest single-phase voltage
- Highest unbalanced current: I_2/I_1%
- Highest unbalanced voltage: V_2/V_1%
- Kilowatt losses per phase and total
- Kilovar losses per phase and total
- Released capacity per phase and total.

Table 22. Simulation Summary Data for Tests 1 Through 8

				Node 01			Lowest 3Φ Voltage			Lowest 1Φ Voltage
Test No.	Pri. Volt %	Load	LTC Tap / Reg Tap	IA	IB	IC	VA	VB	VC	
1	95	HL	NA	451.10	511.63	498.20	101.10	102.32	102.04	100.81
1	95	LL	NA	208.36	240.56	234.39	109.72	110.18	110.01	109.59
1	105	HL	NA	542.98	614.92	598.73	110.14	111.60	111.22	109.80
1	105	LL	NA	228.26	263.55	256.78	123.06	118.60	117.22	121.20
2	95	HL	16	539.33	610.54	594.13	109.78	111.21	110.80	109.44
2	95	LL	16	228.19	263.43	256.63	123.02	118.60	117.22	121.16
2	105	HL	6	579.58	655.94	638.52	113.75	115.29	114.86	113.39
2	105	LL	0	228.26	263.55	256.78	123.06	118.60	117.22	121.20
3	95	HL	16	566.73	640.04	620.83	112.87	113.35	111.81	111.25
	VR (1) 32, 32, 32									
3	95	LL	16	232.26	267.90	260.58	122.89	118.60	117.22	121.79
	VR (1) 14, 14, 14									
3	105	HL	6	608.51	687.11	666.73	117.11	117.64	116.00	115.40
	VR (1) 32, 32, 32									
3	105	LL	0	229.42	264.82	258.19	123.03	118.60	117.22	121.89
	VR (1) 4, 4, 5									
4	95	HL	16	576.90	650.25	626.60	112.49	112.98	111.65	111.10
	VR (1) 32, 32, 32									
	VR (2) 16, 13, 13									
4	95	LL	16	232.70	268.15	260.71	122.87	118.60	117.22	121.78
	VR (1) 14, 14, 14									
	VR (2) 2, 1, 1									
4	105	HL	6	614.37	692.81	669.94	116.90	117.44	115.92	115.32
	VR (1) 32, 32, 32									
	VR (2) 9, 7, 7									
4	105	LL	0	230.08	265.30	258.44	123.00	118.60	117.22	121.93
	VR (1) 4, 4, 5									
	VR (2) 3, 2, 2									
5	95	HL	16	529.93	603.50	586.65	110.75	112.16	111.80	110.40
	Cap (1) 900 kVAr									
5	95	LL	14	211.04	245.95	238.81	122.91	118.60	117.22	121.05
	Cap (1) 900 kVAr									
5	105	HL	5	563.43	641.46	623.81	114.12	115.63	115.26	113.75
	Cap (1) 900 kVAr									
5	105	LL	-1	212.02	247.12	239.99	123.54	118.60	117.22	121.67
	Cap (1) 900 kVAr									

6	95	HL	16	527.76	603.59	586.63	112.50	113.97	113.78	112.14
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
6	95	LL	13	203.64	237.46	230.10	123.83	118.60	117.22	122.74
Cap (1) 900 kVAr										
Cap (1) 900 kVAr										
6	105	HL	4	554.81	634.37	616.83	115.28	116.83	116.64	114.90
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
6	105	LL	-2	204.37	238.34	230.99	124.32	118.60	117.22	123.22
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
7	95	HL	16	524.72	601.75	586.04	114.16	115.66	115.53	113.79
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
7	95	LL	12	205.36	235.24	228.50	125.76	118.60	117.22	124.29
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
7	105	HL	3	545.03	624.99	608.99	116.29	117.87	117.76	115.91
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
7	105	LL	-4	204.54	234.33	227.66	125.21	118.60	117.22	123.75
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
8	95	HL	16	558.30	636.77	616.27	116.97	117.43	116.20	115.60
VR (1) 32, 32, 32										
VR (2) 9, 6, 6										
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
8	95	LL	12	205.19	235.04	228.39	125.77	118.60	117.22	123.47
VR (1) 0, 0, 0										
VR (2) -1, -1, -1										
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
8	105	HL	3	573.87	651.88	632.58	119.45	120.10	118.73	118.11
VR (1) 28, 24, 24										
VR (2) 6, 4, 5										
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										
8	105	LL	-4	203.94	233.47	226.89	125.22	118.60	117.22	123.61
VR (1) -3, -3, -3										
VR (2) 1, 0, 0										
Cap (1) 900 kVAr										
Cap (2) 900 kVAr										
Cap (3) 1200 kVAr										

Highest	Highest	kW Losses/Φ & Total			kVAr Losses/Φ & Total			Released Capacity % / Total		
I2/I1 %	V2/V1 %	A	B	C	A	B	C	A	B	C
100.06	1.32	159.26	131.82	144.29	509.98	664.33	637.60	32.23	32.07	32.03
			435.37			1811.91			32.11	
100.15	1.26	53.79	43.90	53.40	111.47	150.07	146.52	16.88	16.87	16.87
			151.09			408.06			16.87	
100.06	1.43	218.89	180.17	195.86	739.94	959.69	921.89	9.84	9.76	9.72
			594.92			2621.52			9.77	
100.15	1.26	59.67	48.78	58.90	133.79	180.12	175.86	-0.65	-0.66	-0.66
			167.35			489.77			-0.66	
100.06	1.44	218.28	179.34	197.37	768.13	992.13	951.65	10.29	10.25	10.25
			594.99			2711.91			10.26	
100.15	1.26	60.03	48.98	59.62	140.56	188.56	183.80	-0.79	-0.79	-0.78
			168.63			512.92			-0.79	
100.06	1.48	246.50	202.37	220.58	859.41	1111.33	1067.28	-0.10	-0.13	-0.15
			669.45			3038.02			-0.13	
100.15	1.26	59.67	48.78	58.90	133.79	180.12	175.86	-0.65	-0.66	-0.66
			167.35			489.77			-0.66	
100.06	1.49	240.17	192.88	208.79	856.27	1101.07	1048.32	5.73	5.91	6.22
			641.84			3005.66			5.96	
100.15	1.26	61.32	49.78	60.28	145.82	195.31	189.69	-2.59	-2.50	-2.33
			171.38			530.82			-2.47	
100.06	1.52	271.04	217.50	233.26	956.33	1231.29	1173.85	-5.10	-4.88	-4.58
			721.80			3361.47			-4.85	
100.15	1.26	59.99	49.02	59.15	135.22	181.91	177.88	-1.16	-1.14	-1.21
			168.16			495.01			-1.17	
100.06	1.44	251.98	196.59	210.46	894.06	1146.18	1070.86	4.04	4.41	5.35
			659.03			3111.10			4.62	
100.15	1.26	61.52	49.75	60.31	146.51	195.74	189.85	-2.79	-2.59	-2.38
			171.58			532.10			-2.58	
100.06	1.48	278.24	219.52	234.25	979.06	1257.47	1186.79	-6.11	-5.75	-5.08
			732.01			3423.32			-5.64	
100.15	1.26	60.29	49.03	59.19	136.17	182.72	178.21	-1.45	-1.33	-1.31
			168.51			497.10			-1.36	
100.06	1.42	215.79	182.39	200.36	752.38	977.98	941.40	11.85	11.28	11.38
			598.54			2671.76			11.49	
100.15	1.26	56.68	47.82	58.36	124.56	167.85	165.15	7.91	7.04	7.35
			162.86			457.56			7.41	
100.06	1.45	238.77	201.82	219.42	821.34	1069.08	1030.55	3.31	2.72	2.78
			660.01			2920.97			2.92	
100.15	1.26	56.63	47.95	58.06	120.21	162.41	160.21	7.14	6.25	6.55
			162.64			442.83			6.62	

100.06	1.36	213.16	187.86	201.94	739.70	973.85	939.19	12.21	11.27	11.39
			602.96			2652.74			11.60	
100.15	1.26	53.44	47.69	57.06	113.31	153.72	152.76	11.68	10.80	11.28
			158.19			419.79			11.23	
100.06	1.38	231.00	203.74	216.63	786.79	1037.76	1002.45	5.41	4.41	4.50
			651.37			2827.00			4.75	
100.15	1.26	53.28	47.79	56.74	109.03	148.31	147.93	11.09	10.19	10.66
			157.81			405.27			10.63	
100.06	1.31	214.50	191.42	207.62	735.61	974.26	940.81	12.72	11.54	11.48
			613.54			2650.68			11.88	
100.15	1.26	54.09	47.32	57.86	116.29	151.68	151.31	11.49	12.18	12.44
			159.27			419.28			12.06	
100.05	1.33	227.32	203.40	218.10	761.52	1011.00	978.17	7.68	6.44	6.32
			648.82			2750.69			6.79	
100.15	1.26	53.41	47.01	57.10	109.99	143.76	144.07	12.23	12.90	13.15
			157.52			397.82			12.78	
100.06	1.31	242.97	207.48	220.18	843.99	1105.93	1049.85	7.13	6.39	6.91
			670.63			2999.77			6.80	
100.15	1.26	54.02	47.28	57.86	116.06	151.36	151.16	11.56	12.25	12.48
			159.16			418.58			12.12	
100.05	1.27	252.36	214.40	228.29	854.80	1111.50	1061.88	2.80	2.42	2.70
			695.05			3028.18			2.63	
100.15	1.26	53.29	46.80	56.98	109.40	142.70	143.05	12.49	13.22	13.44
			157.07			395.15			13.07	

Because line-to-line loads and line-to-neutral single-phase loads create a 100% load imbalance at that node on the circuit, the highest load imbalance data are not very meaningful. For proof of 100% load imbalance, see Appendix B.2.

Therefore, a separate load imbalance, Table 23, was assembled to show the imbalance at Node 0 and at the source of the circuit and the range of imbalance throughout the circuit (low to high excluding 100%).

Table 23. Simulation Summary Data for Unbalanced Loading (Tests 1 Through 8)

Test No.	Pri. Volt %	Load	LTC Tap / Reg Tap	Node 01	I_2 / I_1% Low	I_2 / I_1% High (<100)	I_2 / I_1% Max
1	95	HL	NA	3.77	1.0444	88.45	100.06
1	95	LL	NA	4.72	2.4117	85.38	100.15
1	105	HL	NA	3.73	1.1119	88.42	100.06
1	105	LL	NA	4.72	2.4123	85.38	100.15
2	95	HL	16	3.70	1.1098	88.41	100.06
2	95	LL	16	4.71	2.399	85.38	100.15
2	105	HL	6	3.71	1.1348	88.40	100.06
2	105	LL	0	4.72	2.4123	85.38	100.15
3	95	HL	16	3.59	1.1817	88.42	100.06
	VR (1) 32, 32, 32						
3	95	LL	16	4.66	2.3741	85.38	100.15
	VR (1) 14, 14, 14						
3	105	HL	6	3.60	1.1907	88.41	100.06
	VR (1) 32, 32, 32						
3	105	LL	0	4.71	2.4308	85.38	100.15
	VR (1) 4, 4, 5						
4	95	HL	16	3.44	0.9068	88.46	100.06
	VR (1) 32, 32, 32						
	VR (2) 16, 13, 13						
4	95	LL	16	4.63	2.3226	85.38	100.15
	VR (1) 14, 14, 14						
	VR (2) 2, 1, 1						
4	105	HL	6	3.51	1.0169	88.44	100.06
	VR (1) 32, 32, 32						
	VR (2) 9, 7, 7						
4	105	LL	0	4.67	2.3681	85.38	100.15
	VR (1) 4, 4, 5						
	VR (2) 3, 2, 2						
5	95	HL	16	3.87	0.7447	88.41	100.06
	Cap (1) 900 kVAr						
5	95	LL	14	5.11	0.291	85.39	100.15
	Cap (1) 900 kVAr						
5	105	HL	5	3.88	0.747	88.41	100.06
	Cap (1) 900 kVAr						
5	105	LL	-1	5.12	0.2758	85.39	100.15

Cap (1) 900 kVAr							
6	95	HL	16	4.02	0.7303	88.43	100.06
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
6	95	LL	13	5.38	0.25	85.40	100.15
Cap (1) 900 kVAr							
Cap (1) 900 kVAr							
6	105	HL	4	4.03	0.727	88.43	100.06
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
6	105	LL	-2	5.38	0.2343	85.41	100.15
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
7	95	HL	16	4.18	0.701	88.45	100.06
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
7	95	LL	12	5.44	0.1901	85.43	100.15
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
7	105	HL	3	4.19	0.6916	88.45	100.05
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
7	105	LL	-4	5.44	0.1729	85.44	100.15
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
8	95	HL	16	3.89	0.6814	88.49	100.06
VR (1) 32, 32, 32							
VR (2) 9, 6, 6							
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
8	95	LL	12	5.45	0.1907	85.43	100.15
VR (1) 0, 0, 0							
VR (2) -1, -1, -1							
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
8	105	HL	3	3.80	0.6566	88.50	100.05
VR (1) 28, 24, 24							
VR (2) 6, 4, 5							
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							
8	105	LL	-4	5.42	0.171	85.44	100.15
VR (1) -3, -3, -3							
VR (2) 1, 0, 0							
Cap (1) 900 kVAr							
Cap (2) 900 kVAr							
Cap (3) 1200 kVAr							

Finally, Appendix B contains selected simulation data by node for each item listed.

6.2.1 Heavy Load Circuit Voltage Profiles (First Set 95% and 105% Primary Voltage)

Figure 103 shows the voltage profiles for each test, 1 through 8, at 105% and 95% substation primary voltage and HL condition. The figure shows a vast range of voltage spread (highest to lowest) throughout the circuit. The voltages shown are located at the secondary of the circuit distribution transformer. Therefore, an additional 3 V have been added to Range A (i.e., 114 V + 3 V = 117 V) for a minimum acceptable level of 117 V and a maximum acceptable level of 129 V (126 V + 3 V = 129 V). This addition accounts for the voltage drop in the secondary and service drop to the customer because Range A of ANSI Standard C84.1 is the voltage at the customer's meter. The regulated voltage is to remain within these maximum and minimum values of 129 V and 117 V.

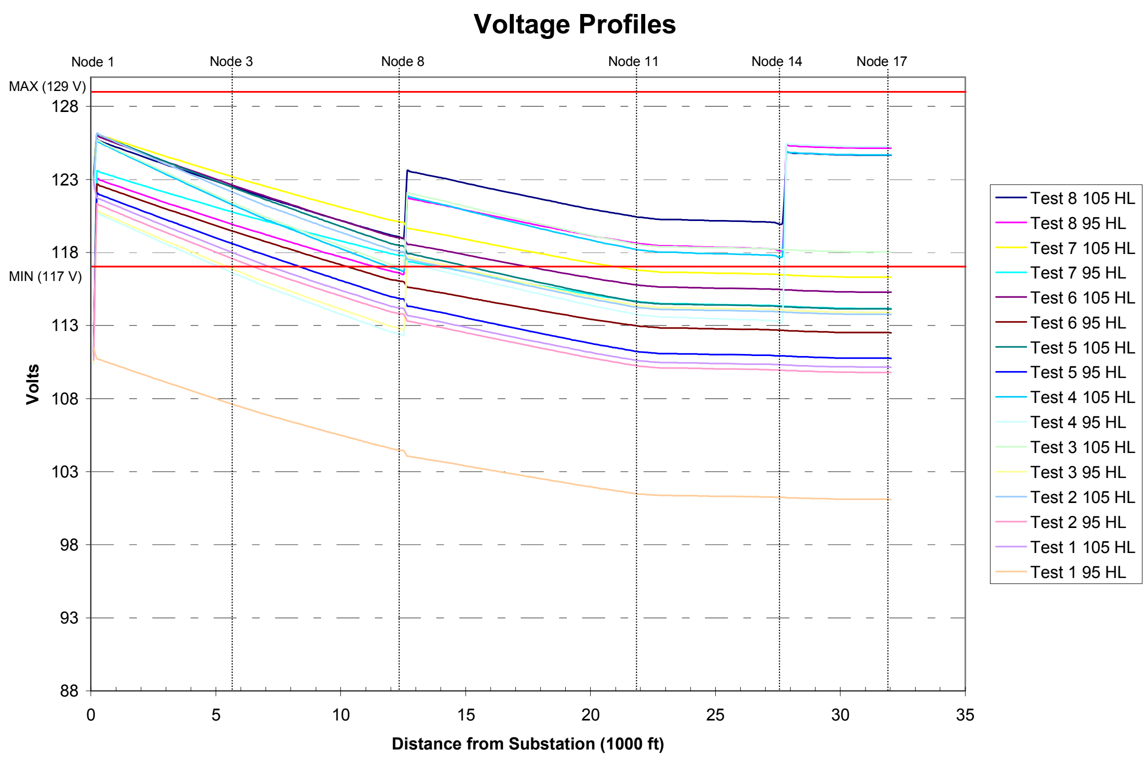


Figure 103. HL circuit voltage profiles for all tests (first set – 95% and 105% substation primary voltage)

In Table 24, the voltage spread throughout the circuit for Test 1 has a range of 25.2 V with no LTC regulation. For Test 8, it is only 10.4 V with all methods of regulation. As more regulation is sequentially added to the circuit, the voltage spread reduces.

Table 24. HL Circuit Voltage Profiles (First Set)

Test No.	Substation Primary Voltage Spread and Load Condition	Voltage Regulation Method	Voltage Spread Highest Three-Phase	Voltage Spread Lowest Single-Phase
Test 1	95%, 105%, HL	No LTC	126.01	100.81
Test 2	95%, 105%, HL	LTC	126.08	109.44
Test 3	95%, 105%, HL	LTC, VR 1	126.00	111.25
Test 4	95%, 105%, HL	LTC, VR 1, VR 2	126.00	111.10
Test 5	95%, 105%, HL	LTC, CAP 1	126.05	110.40
Test 6	95%, 105%, HL	LTC, CAP 1, CAP 2	126.00	112.14
Test 7	95%, 105%, HL	LTC, CAP 1, CAP 2, CAP 3	126.20	113.79
Test 8	95%, 105%, HL	LTC, VR 1, VR 2 CAP 1, CAP 2, CAP 3	126.00	115.6

In the individual voltage profiles for Test 1, Figure 104, the voltage spread because of the 10% change (95% to105%) in the substation primary voltage is 9.05 V (or 110.15–101.1 V).

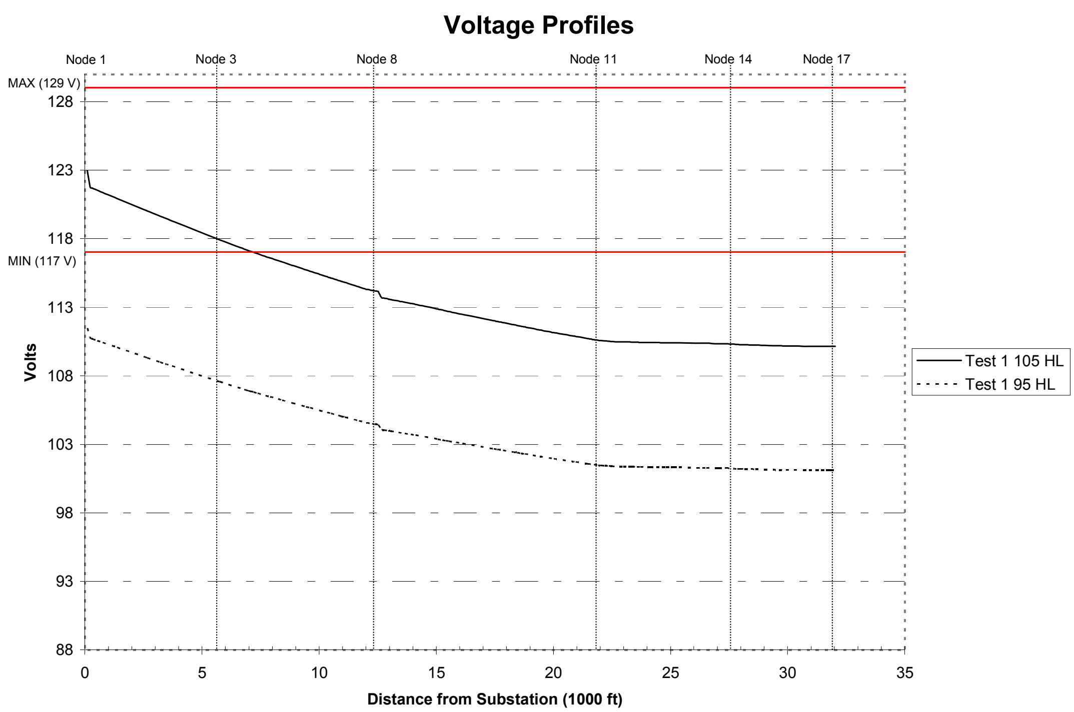


Figure 104. Test 1 HL circuit voltage profiles for 95% and 105% substation primary voltage (no LTC)

For Test 2, Figure 105 shows a significant improvement in voltage spread with the addition of the LTC at the substation, even though the primary substation voltage spread is 10%. Here, the spread is only 3.97 V (or 113.76 V–109.79 V). Because the deadband for the LTC is ±1 V, the spread could be as much as 5.97 V.

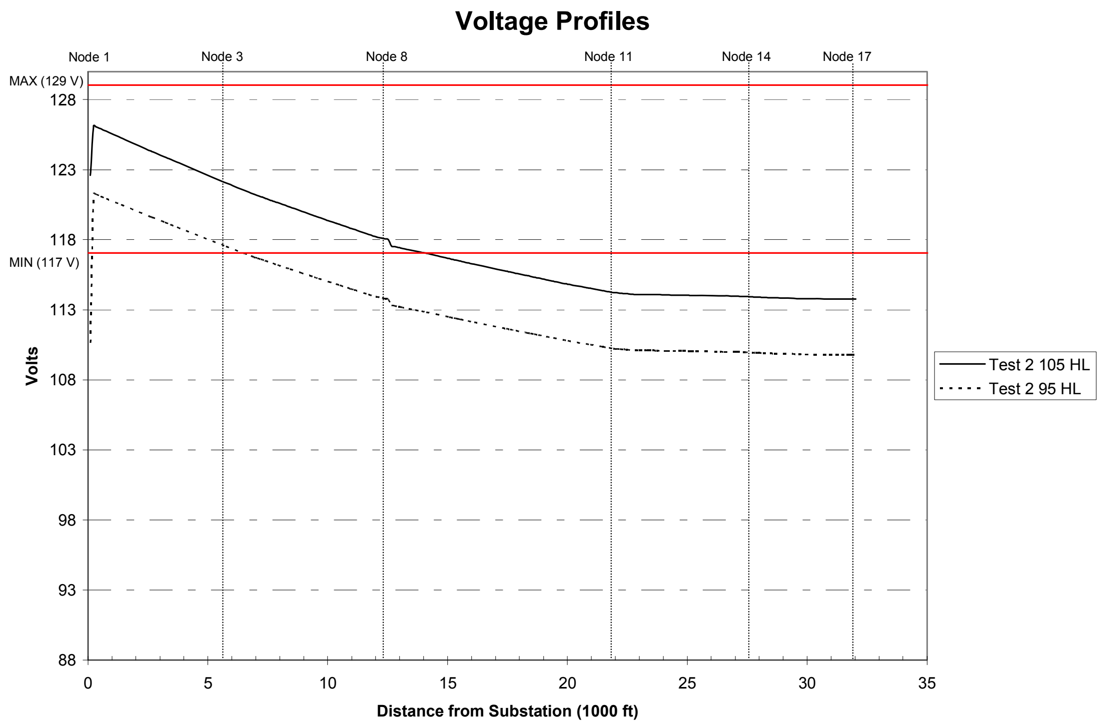


Figure 105. Test 2 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC)

Test 3, Figure 106, shows the benefit of adding the first step VR. The voltage profile with 105% primary voltage bumps the tag end voltage up to 118.04 V, and with a 95% primary voltage, the tag end voltage is 113.9 V.

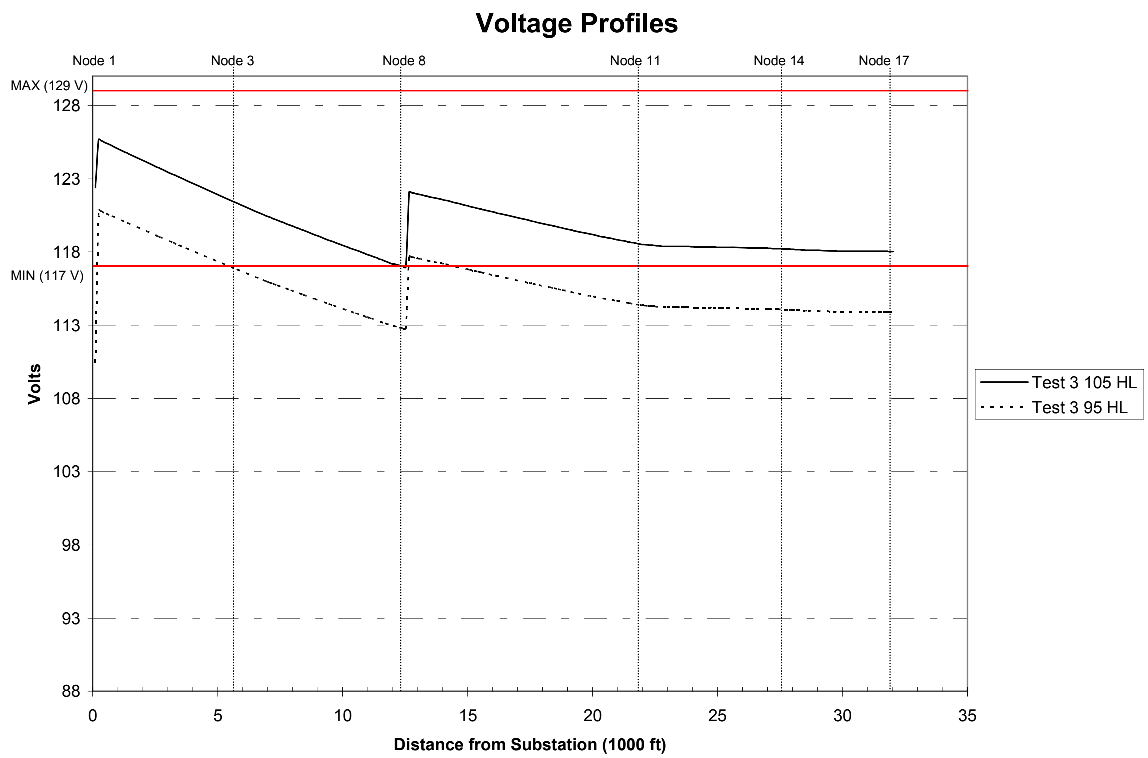


Figure 106. Test 3 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC and VR 1)

When two step regulators are added, as in Test 4 (Figure 107), the tag end voltage at Node 17 reaches almost 124.67 V with 105% primary voltage, but at 95% primary voltage, this becomes 125.24 V. At Node 8 with a primary voltage of 95%, the voltage gets down to 112.34 V.

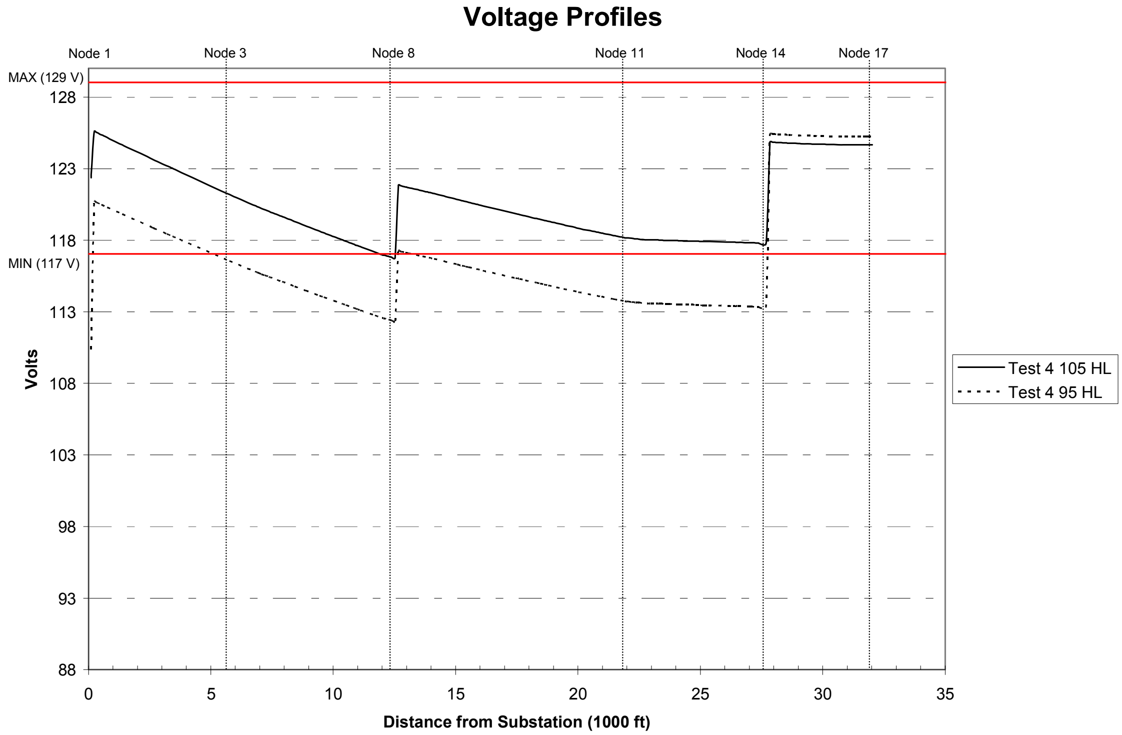


Figure 107. Test 4 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, VR 1, and VR 2)

Test 5 uses the LTC at the substation transformer and Capacitor 1, located at Node 6, which has a reactive capability of 900 kVArc to improve the voltage regulation. Notice that the rate of change of voltage drop (or slope) in Figure 108 is less than that of Test 4 from the substation to Node 8 because of the addition of the capacitor and less reactive current. However, the voltage improvement compared with the two-step regulator test is considerably less. The tag end voltage at Node 17 is 114.13 V for 105% primary voltage and 110.76 V for 95% primary voltage.

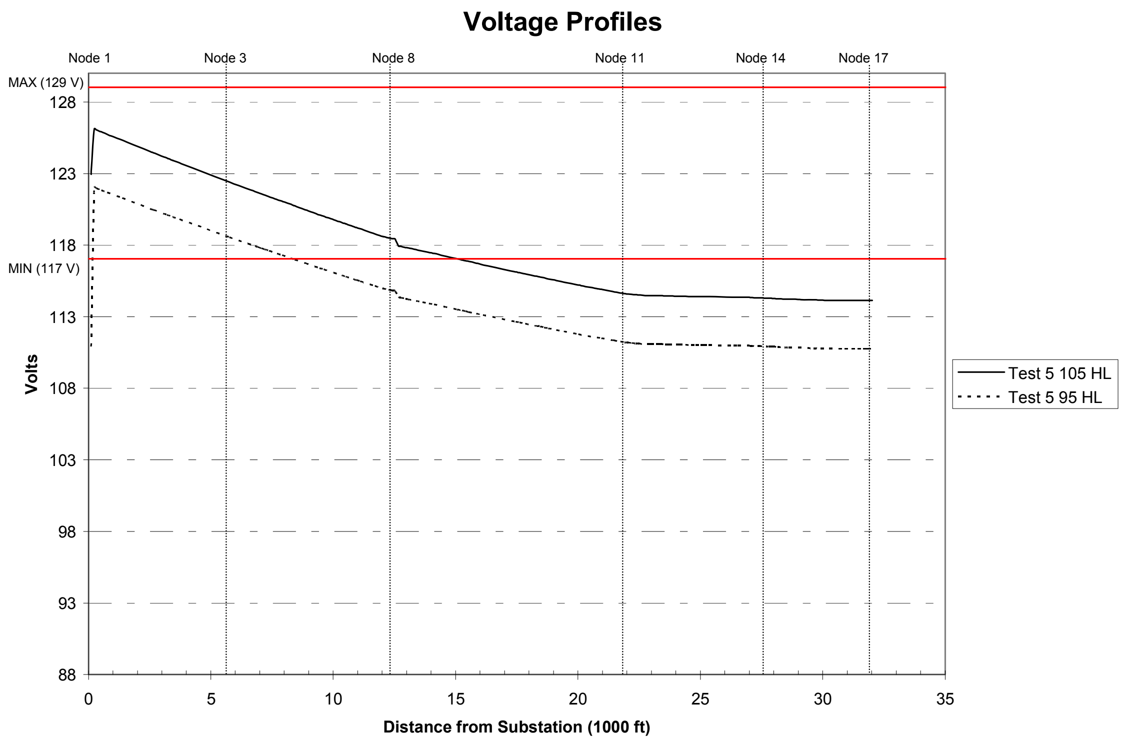


Figure 108. Test 5 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC and CAP 1)

Test 6 results, shown in Figure 109, are based on two capacitors (1 and 2) located at nodes 6 and 12 of Figure 102 and the LTC transformer to regulate the circuit voltage. Here, the voltage gradient is less than that of Test 5 because of the additional capacitor (2), and the tag end voltage at Node 17 is 112.51 V compared with 110.76 V for Test 5 at 95% primary voltage. It is common to gain about 2 V with the addition of the second capacitor.

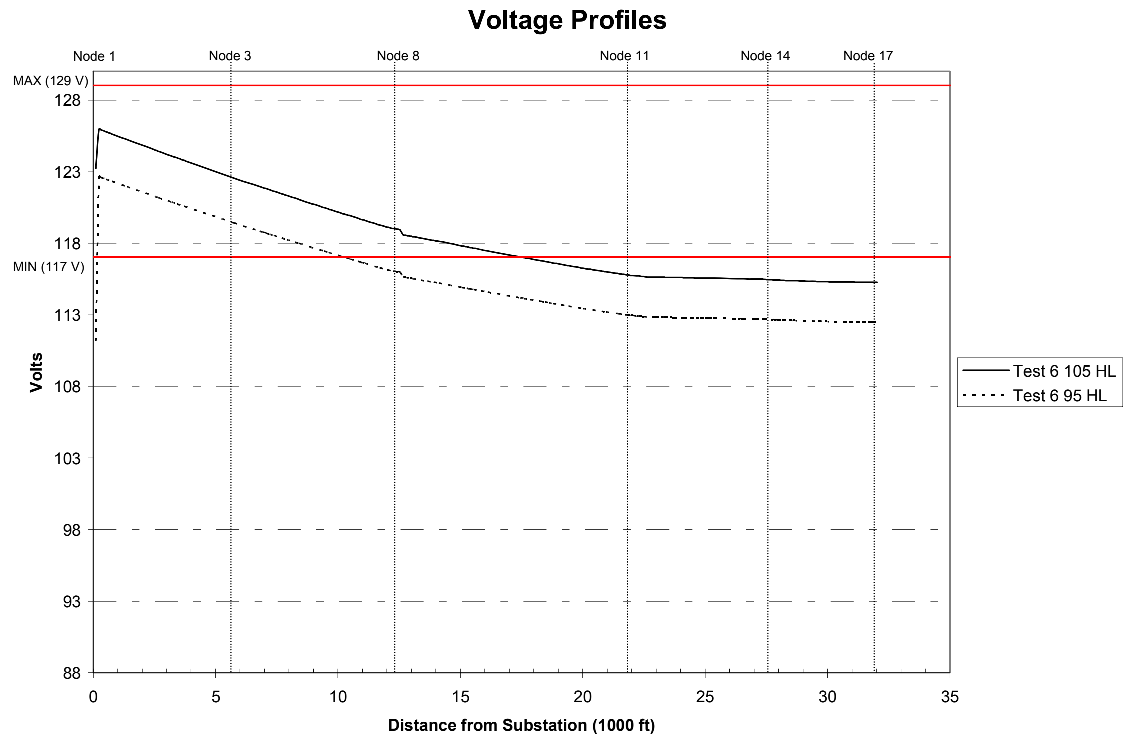


Figure 109. Test 6 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, CAP 1, and CAP 2)

Test 7 involves the LTC and three capacitors. Its results are shown in Figure 110. These capacitors consist of a 900 kVArc at Node 6 (Capacitor 1), a 900 kVArc at Node 12 (Capacitor 2), and a 1,200 kVArc at Node 13 (Capacitor 3). Now, the tag end voltage is up to 114.17 V at 95% primary voltage.

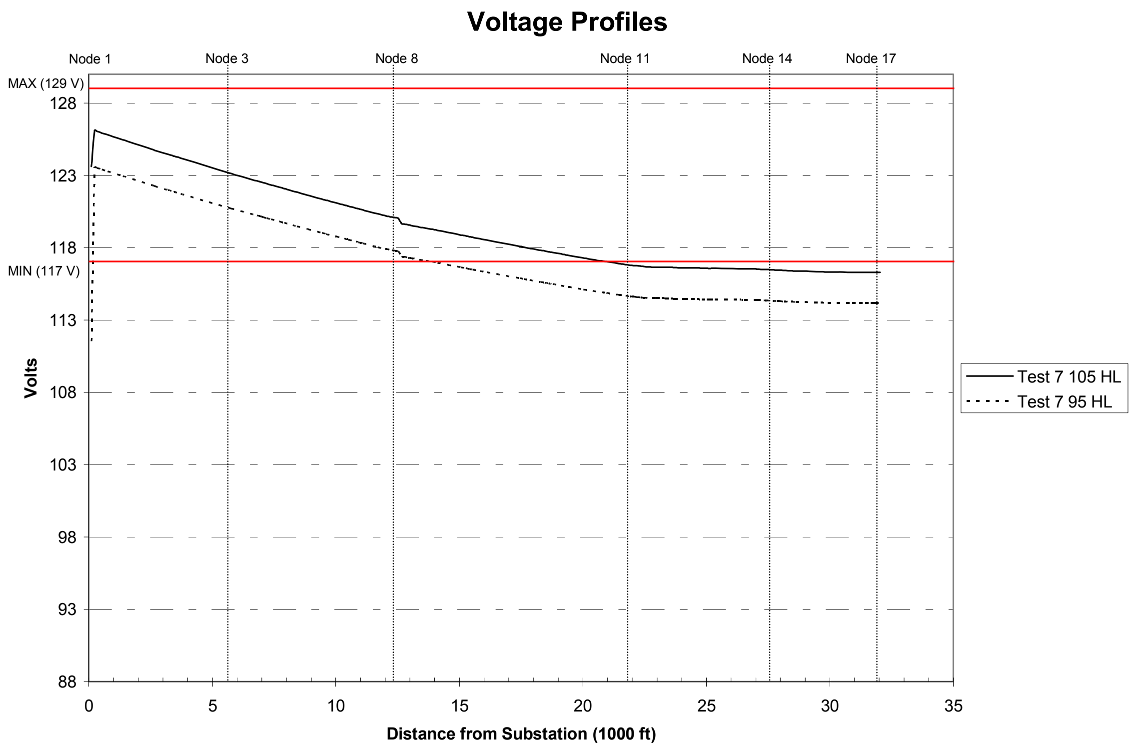


Figure 110. Test 7 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, CAP 1, CAP 2, and CAP 3)

Test 8, which uses all forms of regulation (i.e., the LTC, two step regulators, and three capacitors), yields the best overall voltage profile with the lowest voltage at Node 8 of 116.53 V. The tag end voltage of 125.47 V is almost 11 V (10.96 V) more than that of Test 7 with three capacitors and a primary voltage of 95%. See Figure 111. With105% primary voltage, the lowest voltage of 118.99 V occurs at Node 8, just ahead of the first step regulator. Test 8 is the only voltage profile under HL conditions that almost meets a minimum voltage criteria of 117 V (actual minimum = 116.53 V); all other profiles fail. This indicates a need for DG to add more regulation at Node 10, where the 1,000-kW synchronous generator is sited.

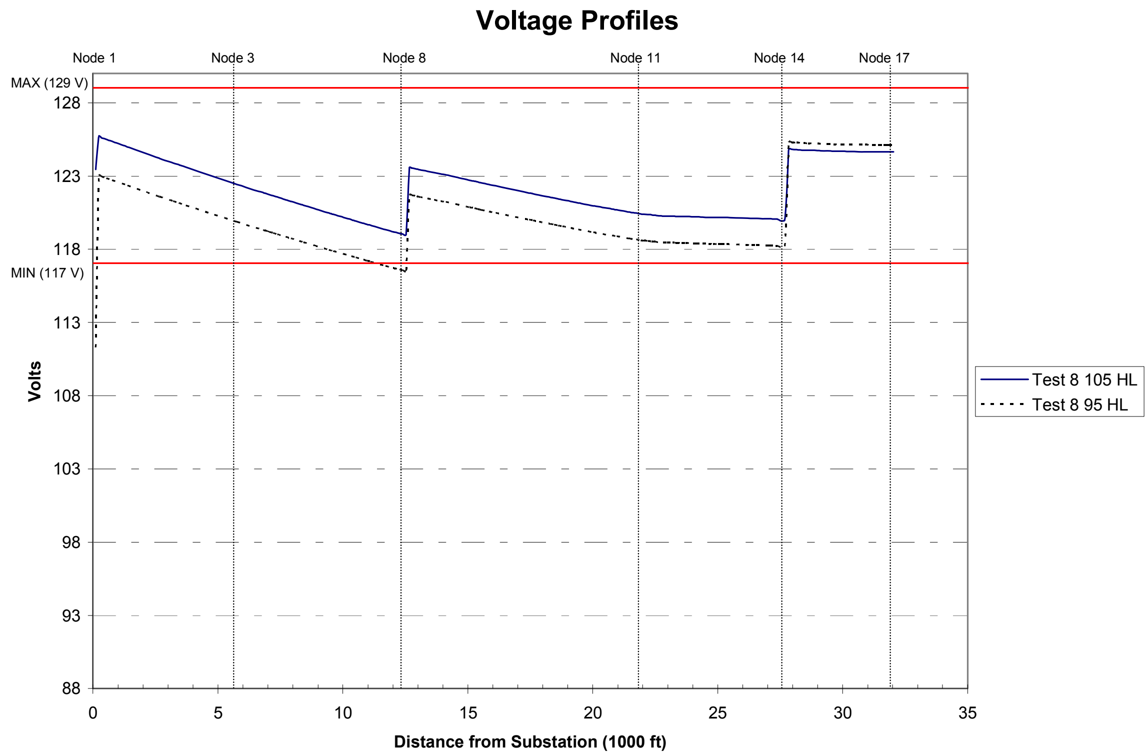


Figure 111. Test 8 HL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3)

6.2.2 Heavy Load Comparison Circuit Voltage Profiles (Second Set 95% Primary Voltage)

Because it is difficult to see how each voltage regulation method taken in succession improves the voltage profile, voltage profile comparisons A through F are given in Figure 112 through Figure 118. The comparisons are also provided in Table 25 at 95% primary voltage.

Table 25. Voltage Profile Comparison for HL and 95% Primary Voltage

Test 2	95%	HL	LTC	
Test 3	95%	HL	LTC	VR 1
Test 4	95%	HL	LTC	VR 1, VR 2
Test 5	95%	HL	LTC	CAP 1
Test 6	95%	HL	LTC	CAP 1, CAP 2
Test 7	95%	HL	LTC	CAP 1, CAP 2, CAP 3
Test 8	95%	HL	LTC	VR 1, VR 2, CAP 1, CAP 2, CAP 3

A B C D E F G

Comparison A, of Tests 2 and 3, is depicted in Figure 112. The Node 17 voltage improvement, from adding the first step regulator, is 4.11 V.

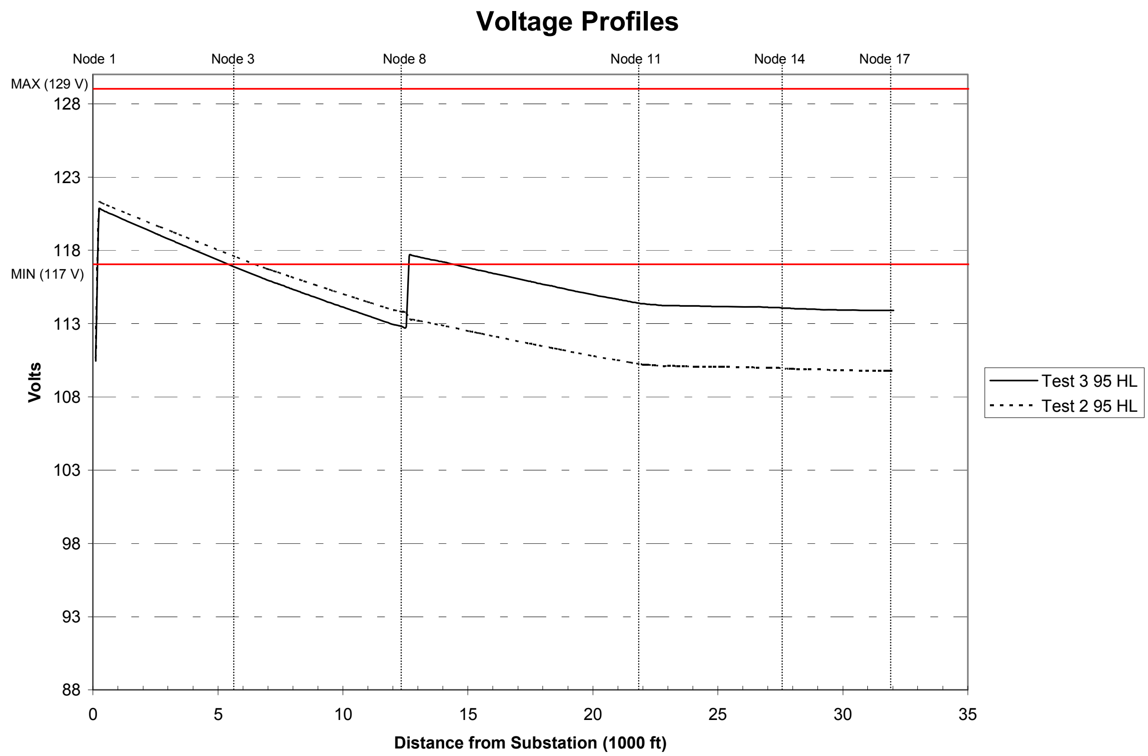


Figure 112. Comparison A: Test 2 and Test 3 HL circuit voltage profiles for 95% substation primary voltage (LTC versus LTC and VR 1)

When the second regulator is added (Comparison B), the tag end voltage, shown in Figure 113 at Node 17, goes up to 125.24 V, for a gain of 11.34 V.

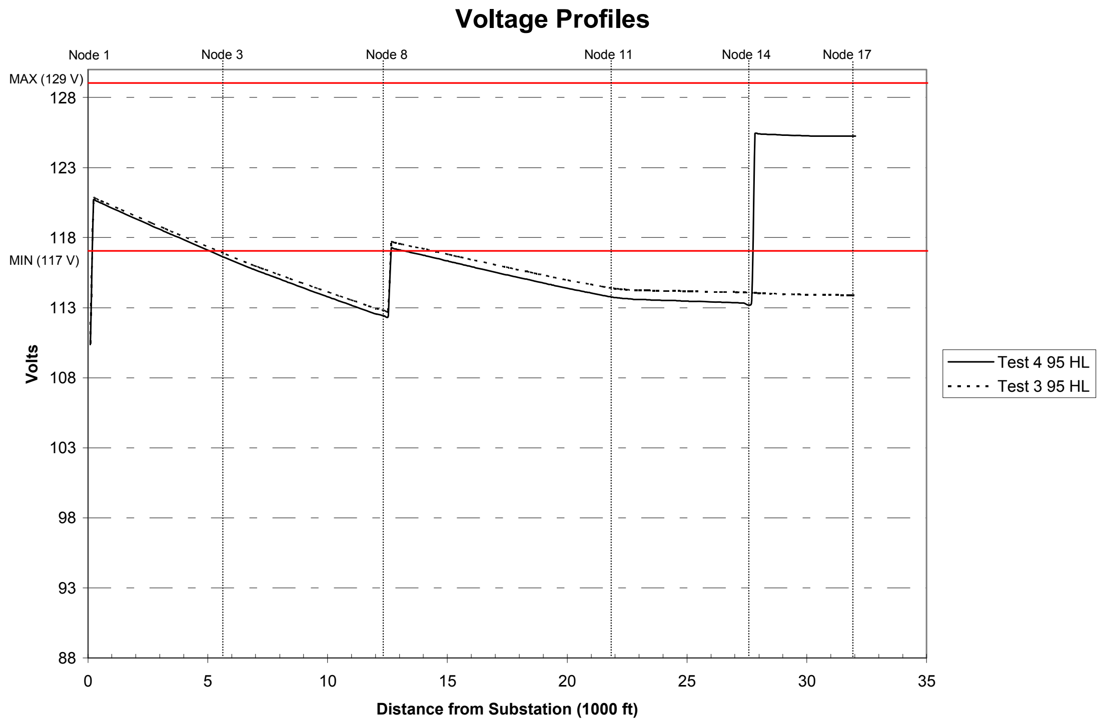


Figure 113. Comparison B: Test 3 and Test 4 HL circuit voltage profiles for 95% substation primary voltage (LTC and VR 1 versus LTC, VR 1, and VR 2)

As seen from Comparison C in Figure 114, the addition of the first capacitor for Test 5 marginally increases the voltage at Node 17 by 0.97 V (110.76–109.79 V).

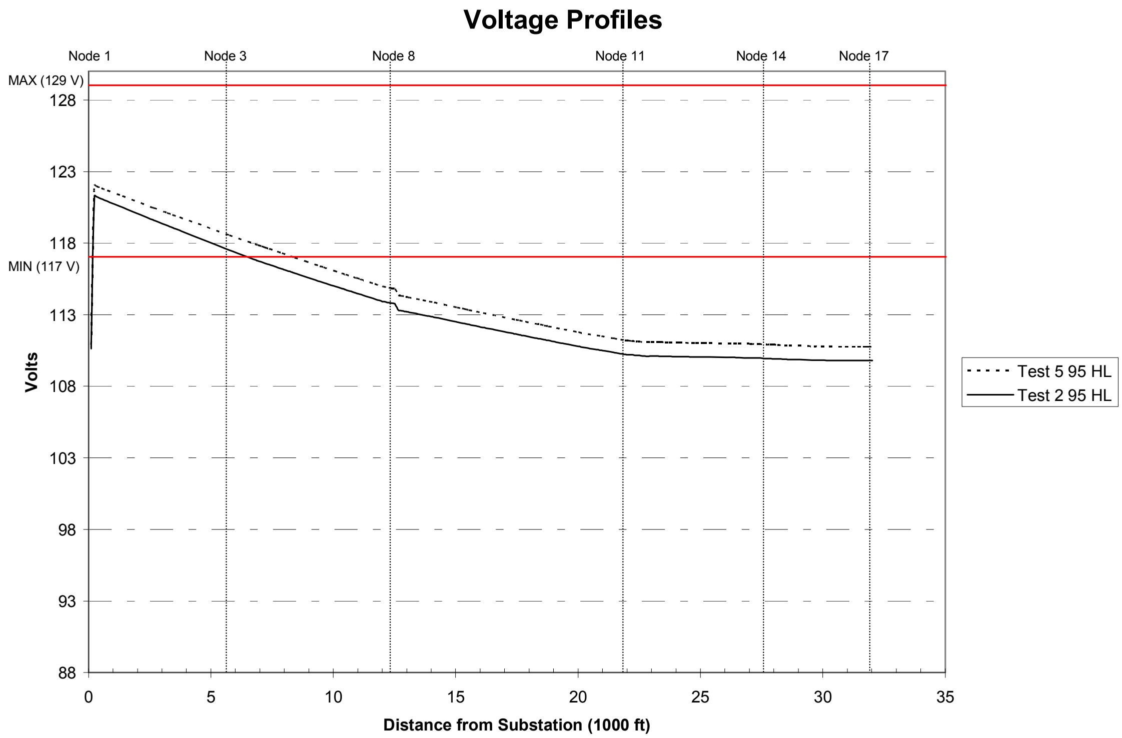


Figure 114. Comparison C: Test 2 and Test 5 HL circuit voltage profiles for 95% substation primary voltage (LTC versus LTC and CAP 1)

Comparison D, for Tests 5 and 6, shows the voltage improvement from adding the second capacitor. Figure 115 at Node 17 shows a 1.75-V improvement.

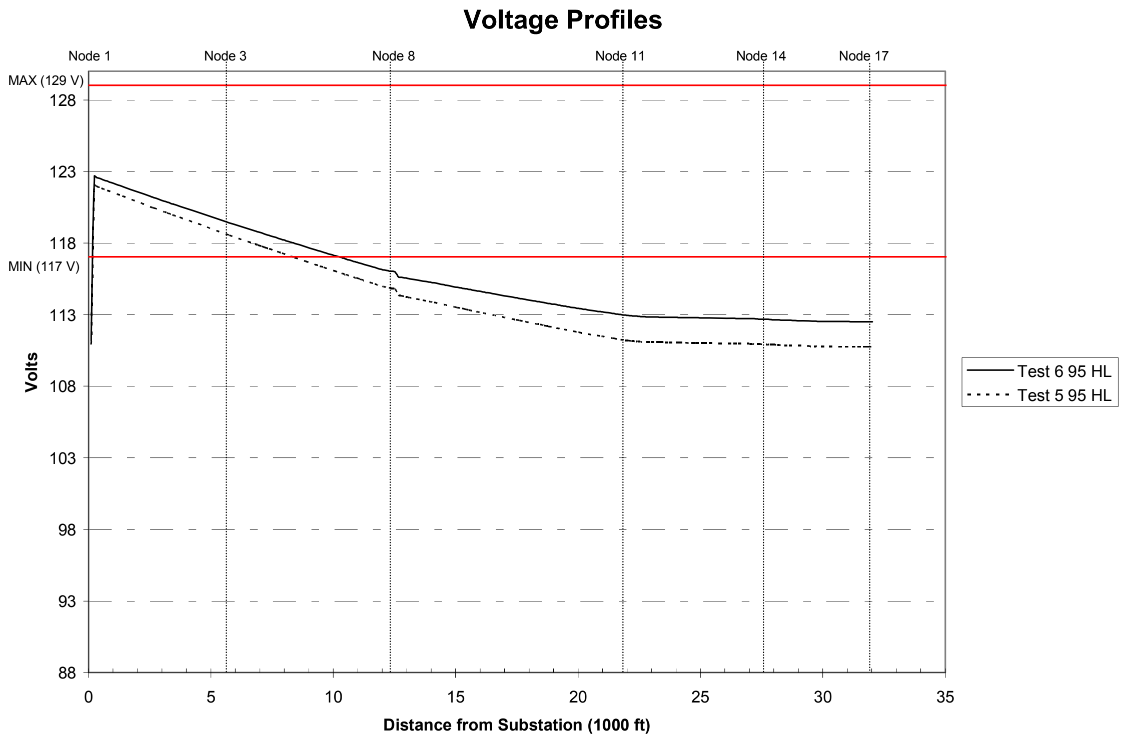


Figure 115. Comparison D: Test 5 and Test 6 HL circuit voltage profiles for 95% substation primary voltage (LTC and CAP 1 versus LTC, CAP 1, and CAP 2)

Comparison E, Figure 116, shows a voltage rise at Node 17 of only 1.66 V with the addition of the third capacitor.

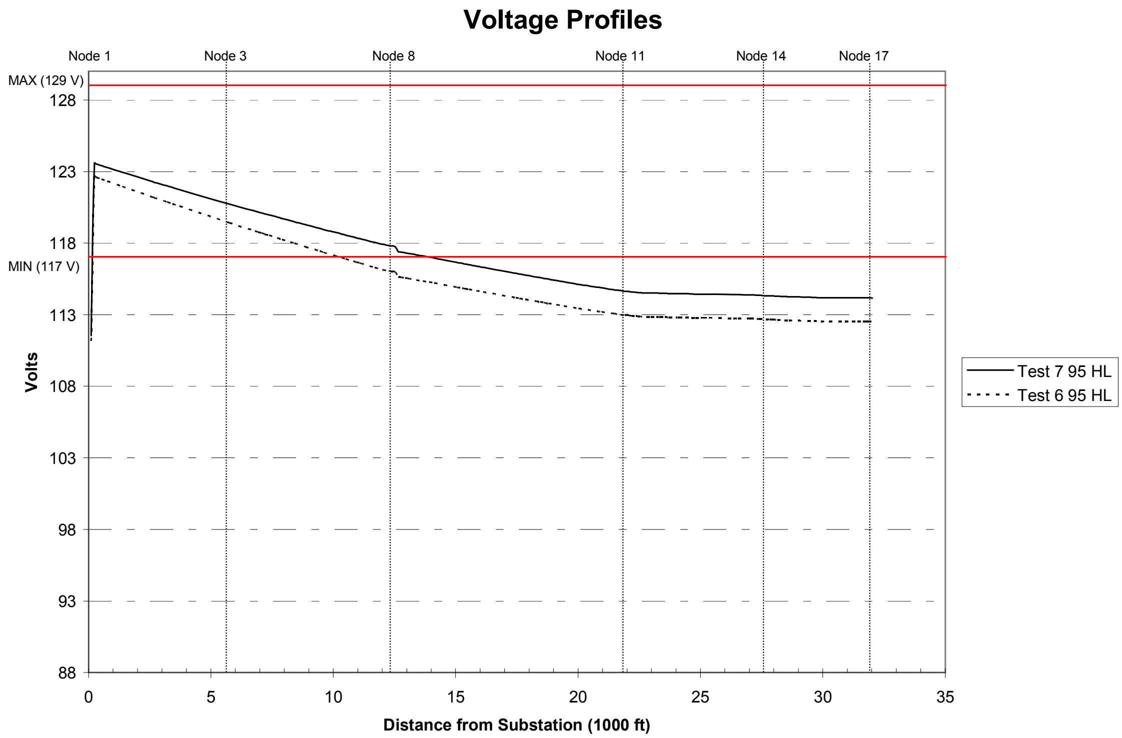


Figure 116. Comparison E: Test 6 and Test 7 HL circuit voltage profiles for 95% substation primary voltage (LTC, CAP 1, and CAP 2 versus LTC, CAP 1, CAP 2, and CAP 3)

Comparison F shows the greatest improvement when Test 2, with the LTC, is compared with Test 8, with all methods of regulation.

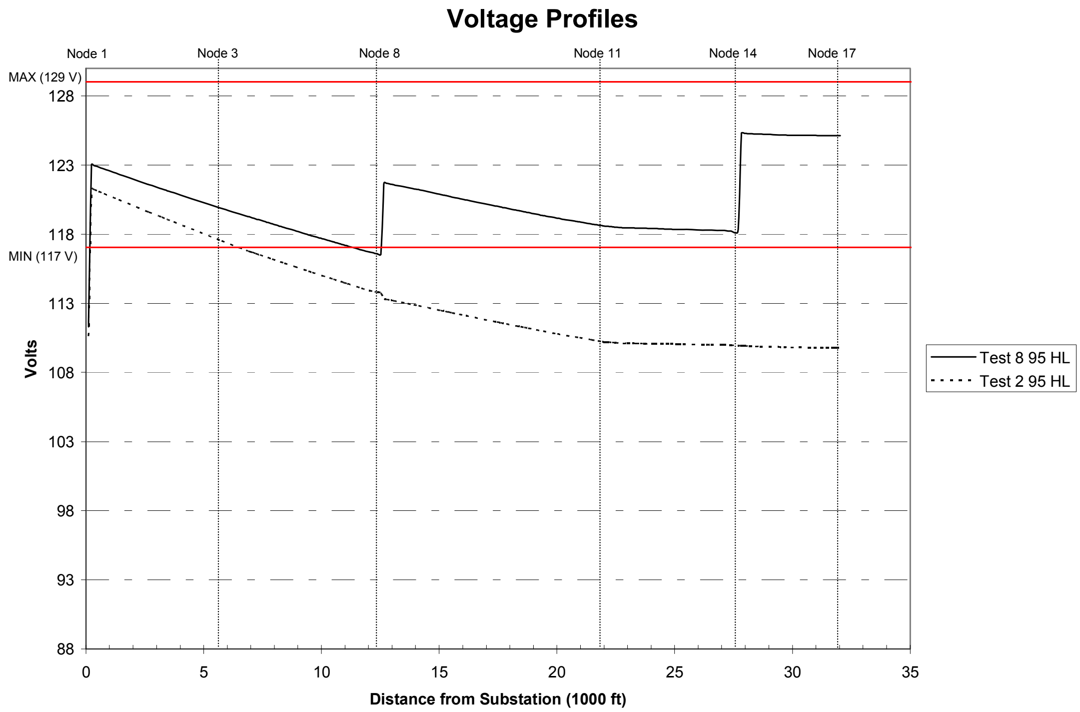


Figure 117. Comparison F: Test 2 and Test 8 HL circuit voltage profiles for 95% substation primary voltage (LTC vs. LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3)

At Node 17 of Figure 117, the voltage difference between the two tests is 15.35 V (125.14–109.79 V). Of course, there are lower voltage gains at Node 8 and Node 14, which are the voltages at the points just before the first and second step regulators.

Comparison G of Figure 118 shows the difference of voltage between Test 7 (with the LTC and all capacitors on) and Test 8 (with all methods of regulation on). The voltage improvement at Node 17 is 10.97 V (125.14–114.17 V).

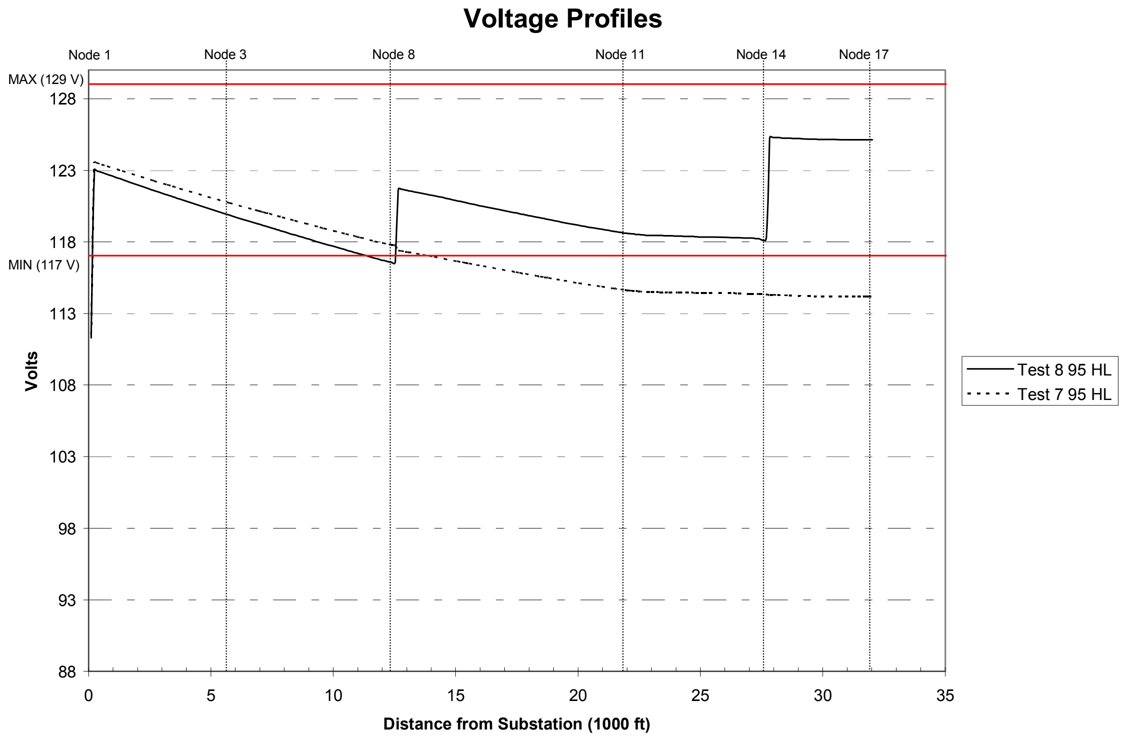


Figure 118. Comparison G: Test 7 and Test 8 HL circuit voltage profiles for 95% substation primary voltage (LTC, CAP 1, CAP 2, and CAP 3 versus LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3)

6.2.3 Voltage Profile Data as a Function of Distance from Substation to Tag End

Specific data for the highest three-phase and lowest single-phase voltage were provided in Table 24 for tests 1–8 at 95% and 105% primary voltage during HL conditions. The distance is given in thousands of feet from the substation to the end of the regulation path in Table 20.

6.2.4 Light Load Circuit Voltage Profiles (Third Set 95% and 105% Primary Voltage)

A process similar to that for the HL voltage profiles is repeated for the LL voltage profiles beginning with Figure 119 and ending with Figure 134. The LL circuit is 5.91 MVA compared with the LL base case of 5.96 MVA. Even though the LL base case is 5.96 MVA compared with the HL base case of 14.89 MVA, there is one test, Test 1 at 95% with no LTC regulation, in which the voltage is below the minimum acceptable level of 114.7 V. All the rest of the test voltage profiles are above the minimum voltage level.

The voltage spread throughout the circuit for Test 1 is shown in Table 26 to be only 16.65 V (126.24–109.59 V). This compares to 25.2 V for the same test during HL conditions and no LTC regulation. As additional regulation is added to the circuit, the voltage spread diminishes to its lowest value of only 2.91 V for Test 8. During the LL period, the highest voltage on the circuit reaches 126.38 V. Care should be exercised not to exceed 129 V when operating distribution generation near the substation bus or near the load side of any of the two step regulators. It may be necessary to operate DG with a strategy to absorb volt-amperes reactive to prevent HV during light load.

Table 26. LL Circuit Voltage Profiles (Third Set)

Test	Substation Primary Voltage Spread and Load Condition	Voltage Regulation Method	Voltage Spread	
			Highest Three-Phase	Lowest Single-Phase
Test 1	95%, 105%, LL	No LTC	126.24	109.59
Test 2	95%, 105%, LL	LTC	126.24	121.16
Test 3	95%, 105%, LL	LTC, VR 1	126.23	121.79
Test 4	95%, 105%, LL	LTC, VR 1, VR 2	126.22	121.78
Test 5	95%, 105%, LL	LTC, CAP 1	126.25	121.05
Test 6	95%, 105%, LL	LTC, CAP 1, CAP 2	126.22	122.74
Test 7	95%, 105%, LL	LTC, CAP 1, CAP 2, CAP 3	126.37	123.75
Test 8	95%, 105%, LL	LTC, VR 1, VR 2, CAP 1, CAP 2, CAP 3	126.38	123.47

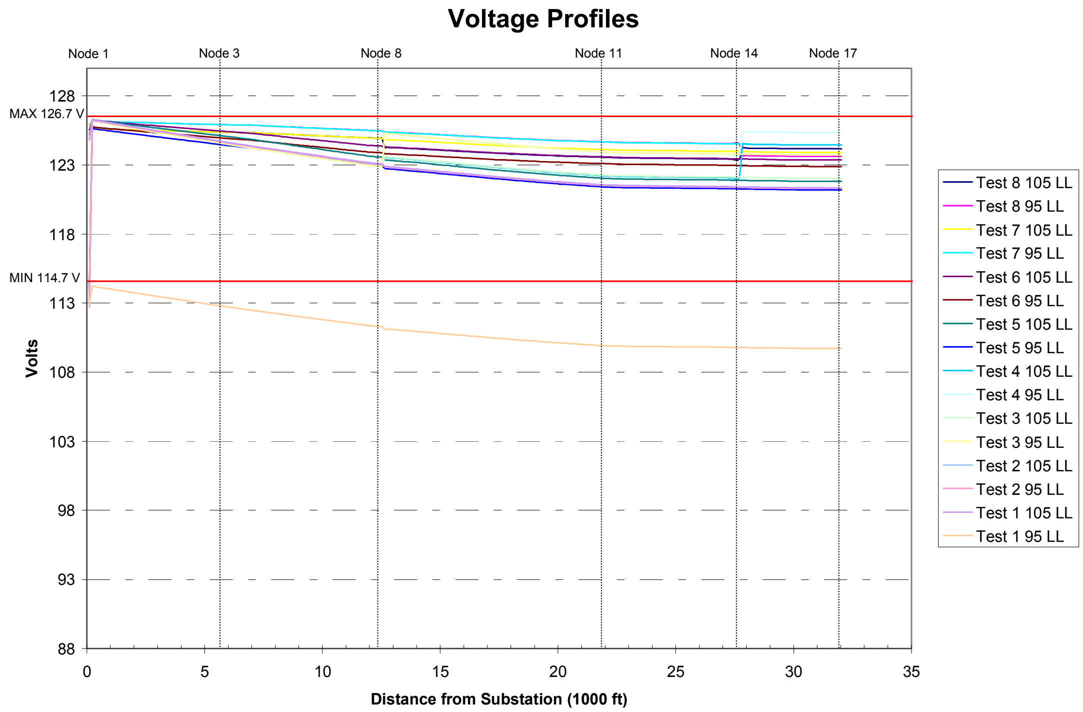


Figure 119. LL circuit voltage profiles for all tests (third set – 95% and 105% substation primary voltage)

The Test 1 voltage profile shown in Figure 120 shows a uniformly wide voltage spread at each node on the circuit as the primary voltage ranges from 95% to 105%. The voltage spread at the tag end is 11.62 V (121.35–109.73 V).

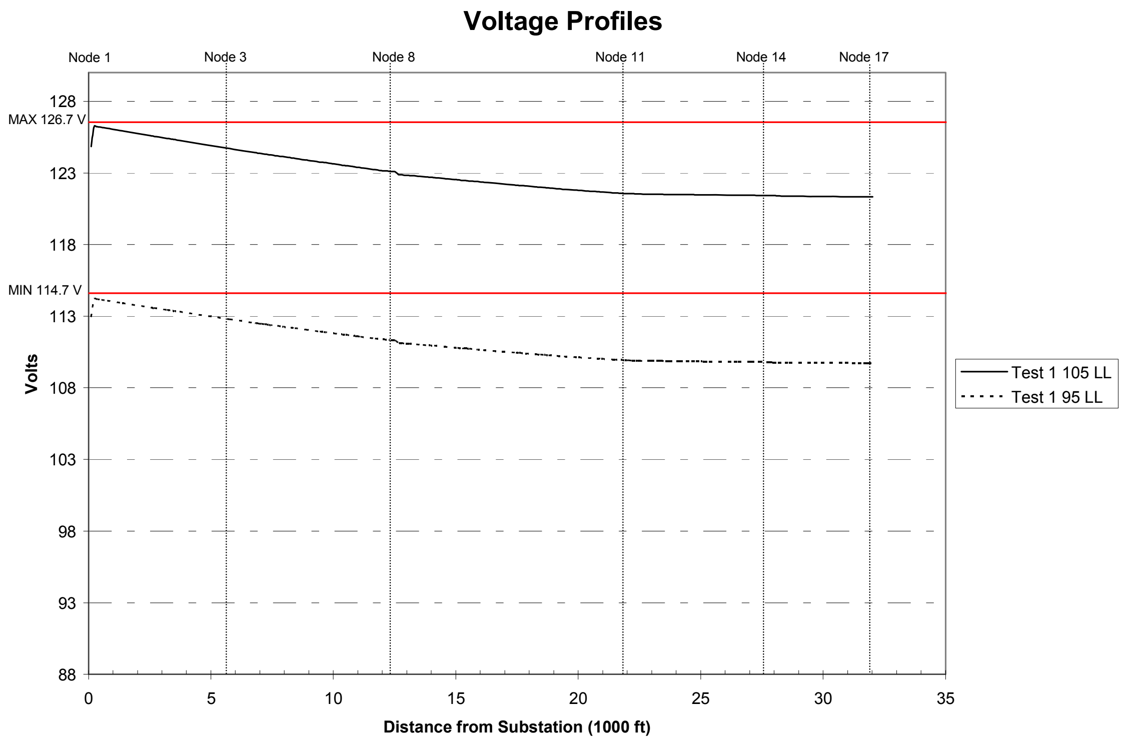


Figure 120. Test 1 LL circuit voltage profiles for 95% and 105% substation primary voltage (no LTC)

When the LTC is added in Test 2, Figure 121, the voltage spread is still uniform, but it is reduced considerably to only 0.05 V (121.35–121.3 V) at Node 17.

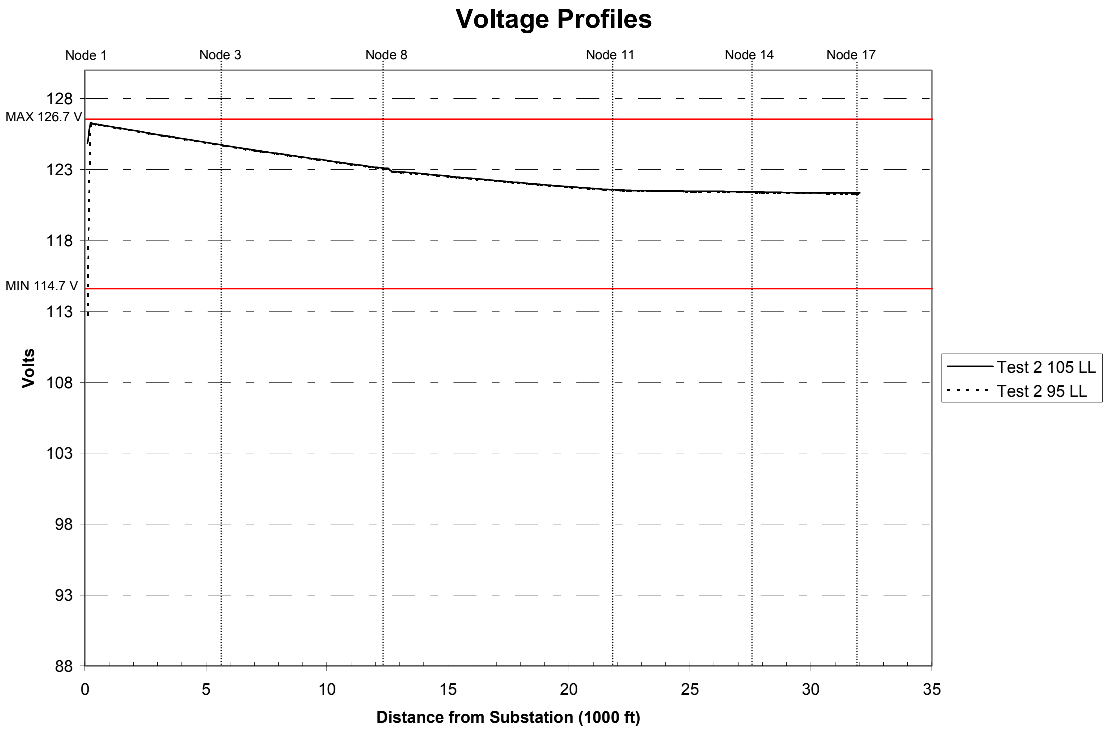


Figure 121. Test 2 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC)

The Test 3 profile, with the LTC and the first step VR, of Figure 122 shows a 1.68-V spread beginning at Node 8 and continuing to the tag end of the circuit.

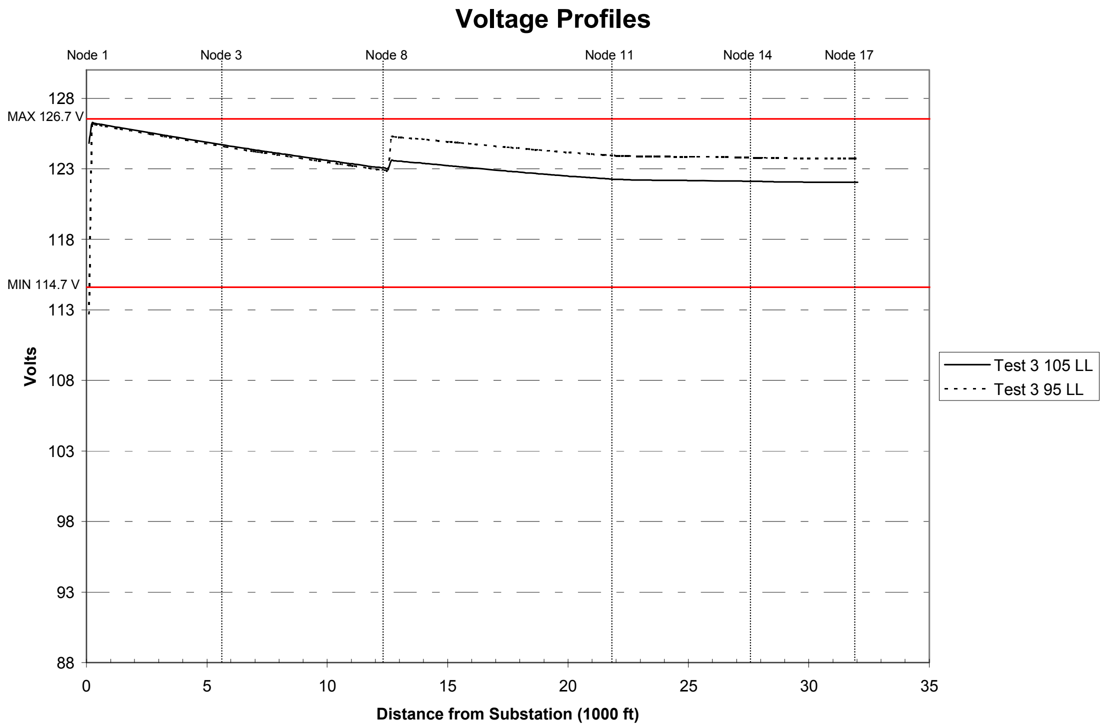


Figure 122. Test 3 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC and VR 1)

Test 4 shows a similar condition when the second regulator is added. As shown in Figure 123, there is no voltage spread up to Node 8, and at the tag end, the voltage spread is only 0.9 V.

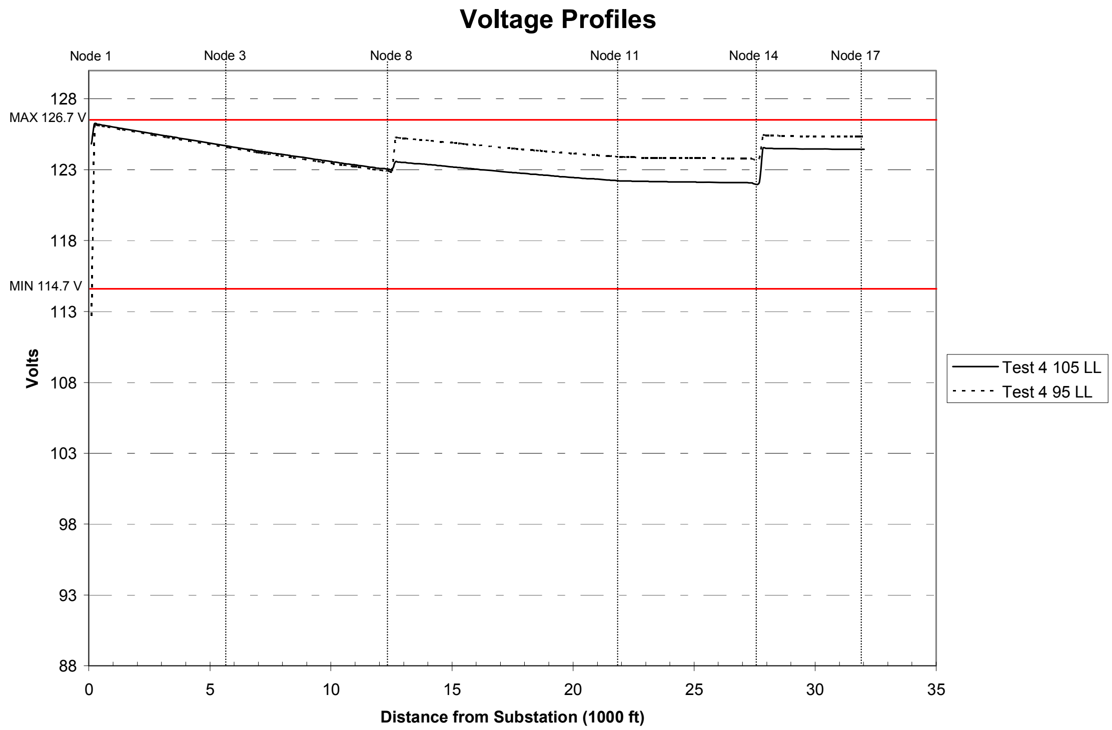


Figure 123. Test 4 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, VR 1, and VR 2)

Test 5, with the first capacitor on, shows a worsening condition in voltage spread. But the voltage spread at any node of Figure 124 is still very small. It is only 0.62 V (121.82–121.2 V).

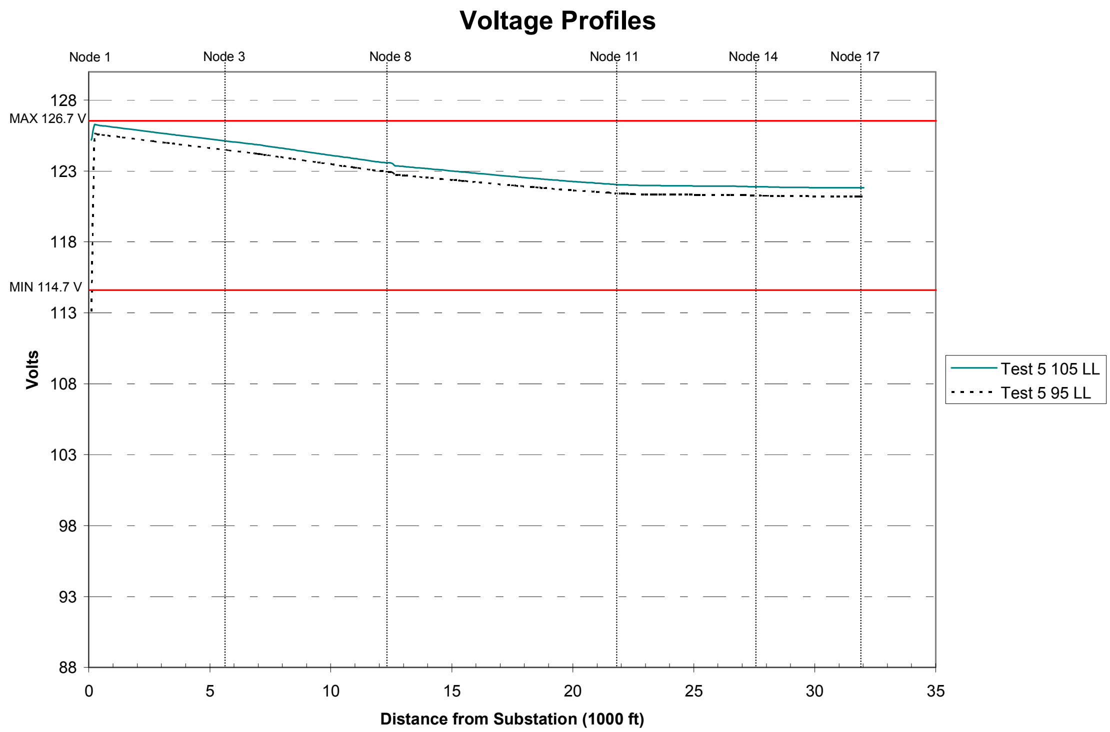


Figure 124. Test 5 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC and CAP 1)

When the second capacitor is added in Test 6, the voltage profile of Figure 125 shows little change throughout the length of the circuit, and the voltage spread is very low—only 0.48 V (123.37–122.98 V) at Node 17.

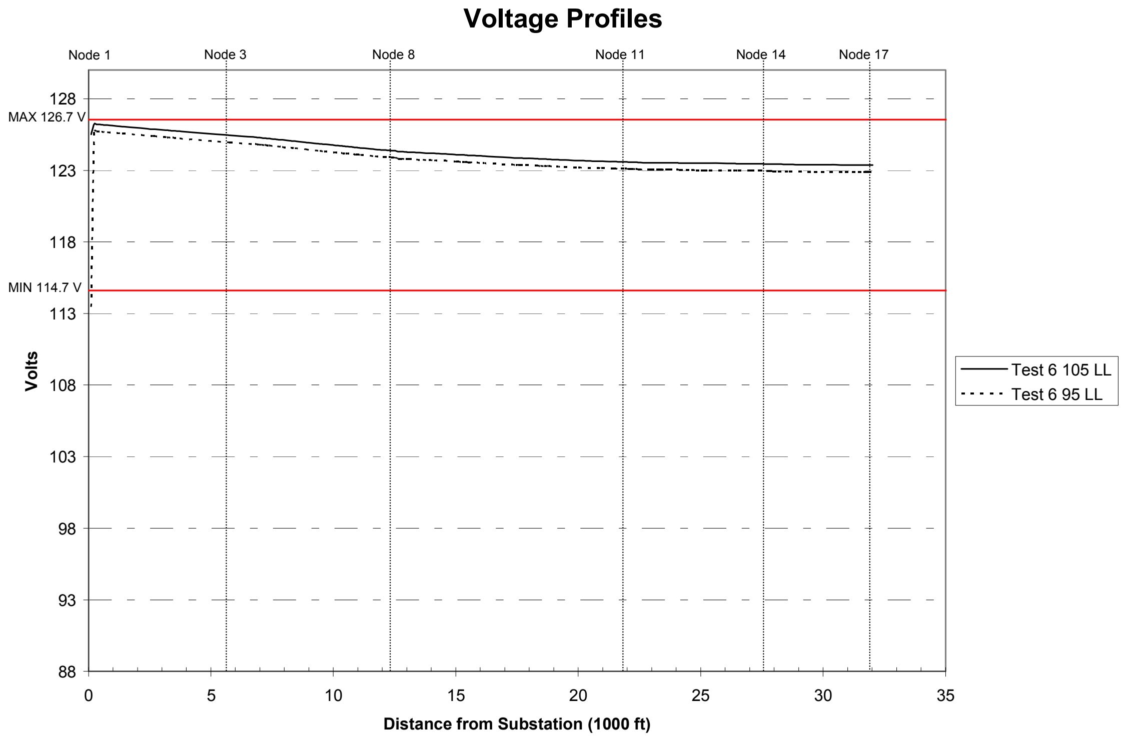


Figure 125. Test 6 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, CAP 1, and CAP 2)

Test 7, shown in Figure 126 and with the LTC and three capacitors on, is near the ultimate voltage regulation test. The voltage profile is nearly at the same level throughout the circuit, and the spread is only 0.54 V (124.44 V – 123.9 V = 0.54 V) at Node 17.

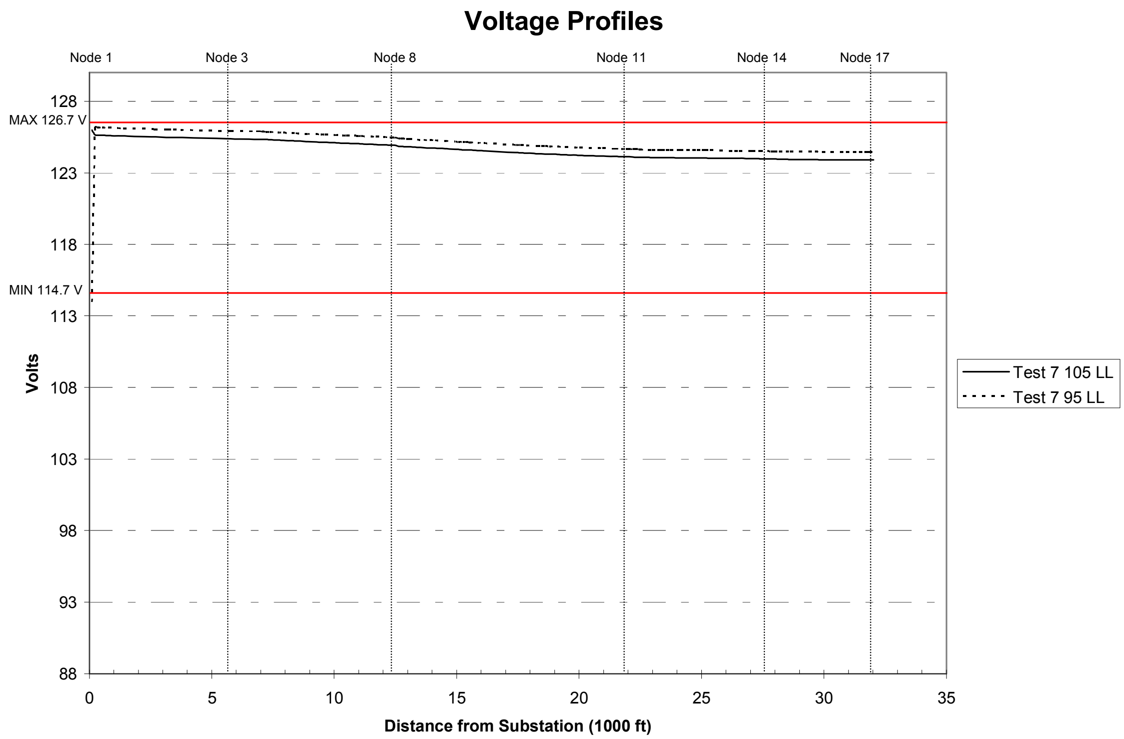


Figure 126. Test 7 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, CAP 1, CAP 2, and CAP 3)

Test 8, with all regulation and shown in Figure 127, is the ultimate test. It has no voltage spread from Node 8 to Node 17 and a spread of only 0.54 V (124.17–123.63 V) at Node 17.

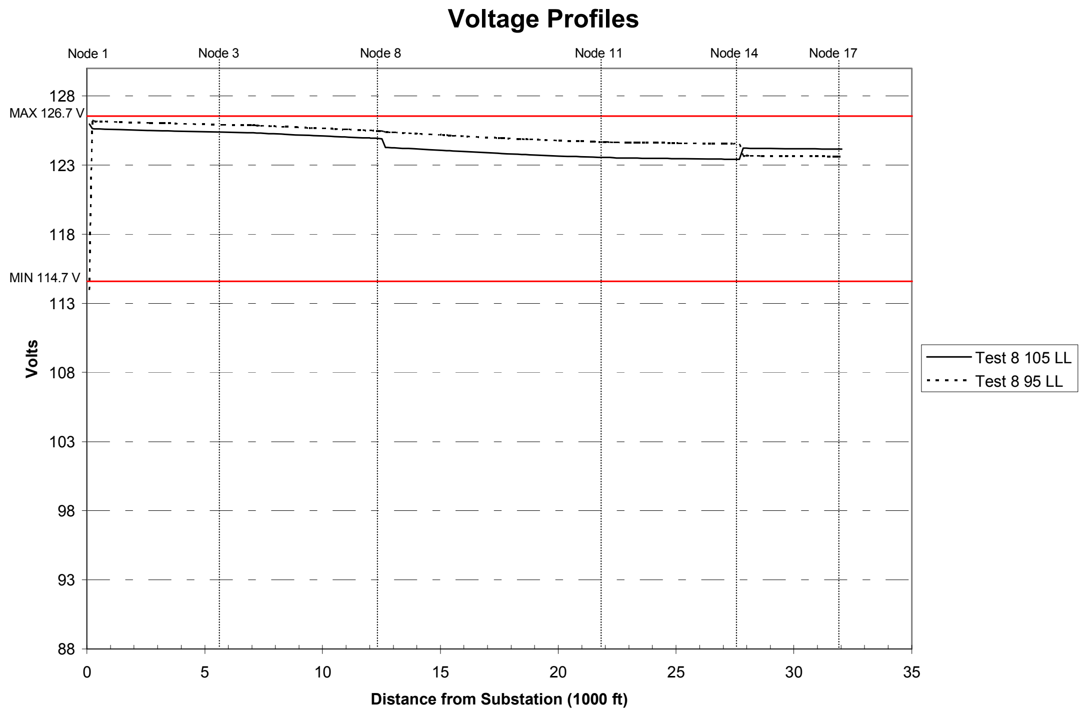


Figure 127. Test 8 LL circuit voltage profiles for 95% and 105% substation primary voltage (LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3)

6.2.5 *Light Load Comparison Circuit Voltage Profiles (Fourth Set 95% Primary Voltage)*

The voltage comparison Test A of Figure 128 shows the improvement in voltage throughout the circuit when the first step regulator is added. The voltage profile drops from 126.07 V at the source (with the LTC) to 121.31 V at Node 17 for Test 2. When the regulator is added in Test 3, the voltage rise at Node 17 is 2.41 V (123.72–121.81 V).

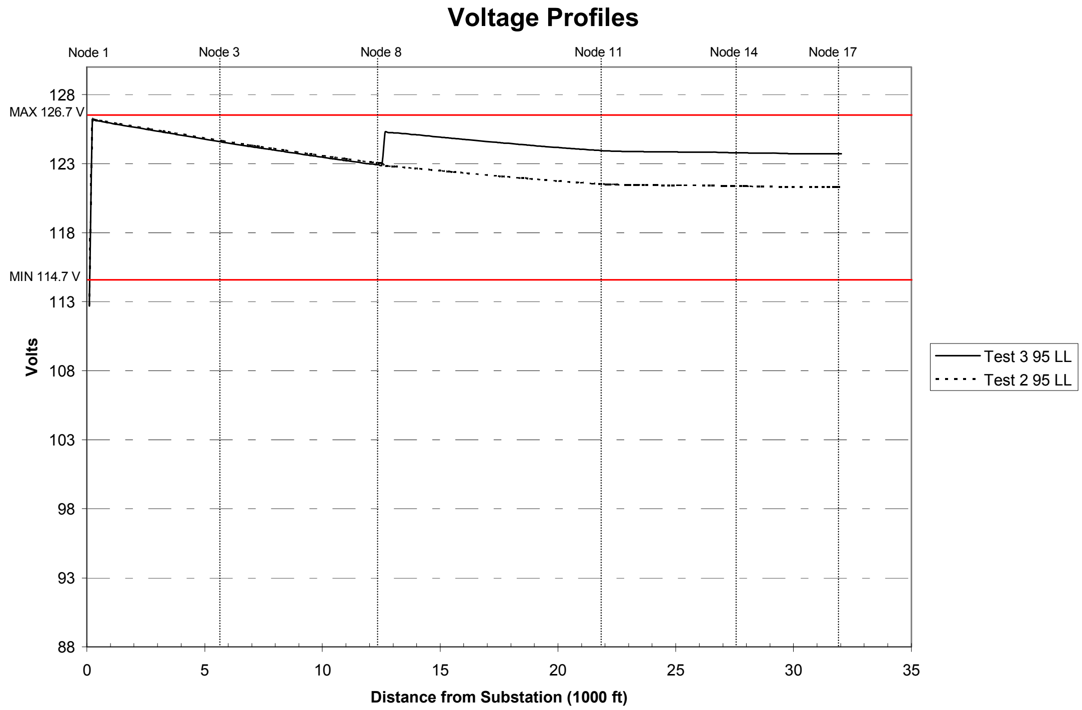


Figure 128. Comparison A: Test 2 and Test 3 LL circuit voltage profiles for 95% substation primary voltage (LTC versus LTC and VR 1)

Comparison B, for Tests 3 and 4, is shown in Figure 129. The profiles of Tests 3 and 4 are the same until the second regulator is added. Beyond Node 14, there is a slight voltage spread of 1.63 V (125.35–123.72 V).

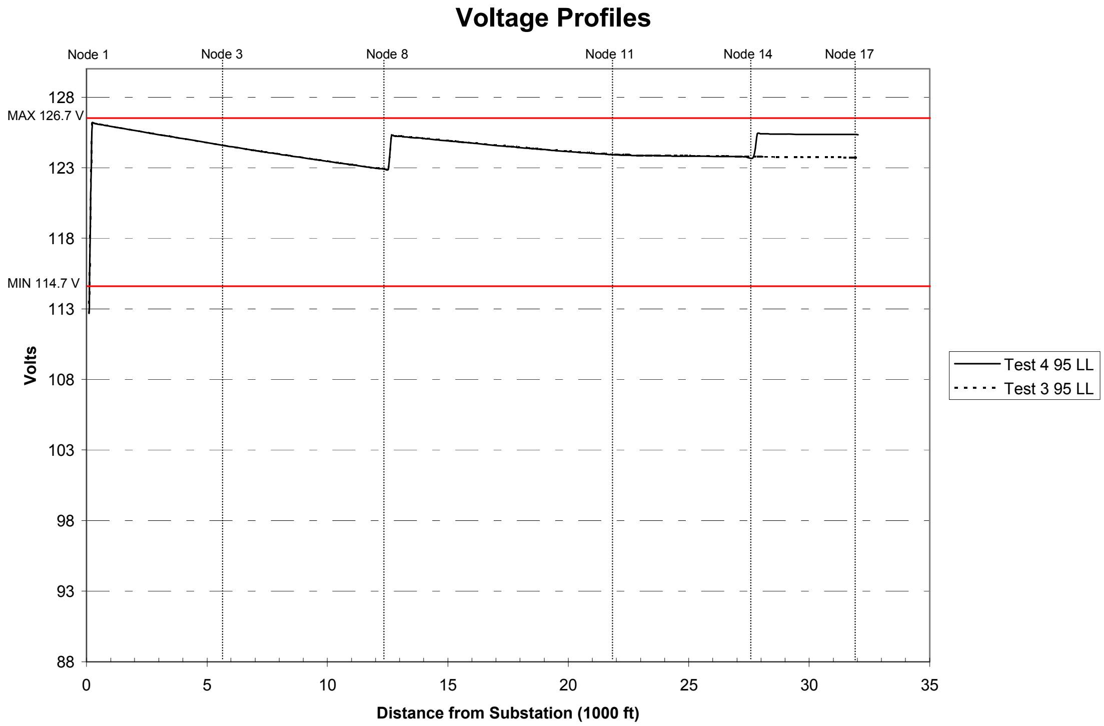


Figure 129. Comparison B: Test 3 and Test 4 LL circuit voltage profiles for 95% substation primary voltage (LTC versus LTC, VR 1, and VR 2)

Figure 130 shows Comparison C, in which a slight voltage spread exists throughout the circuit.

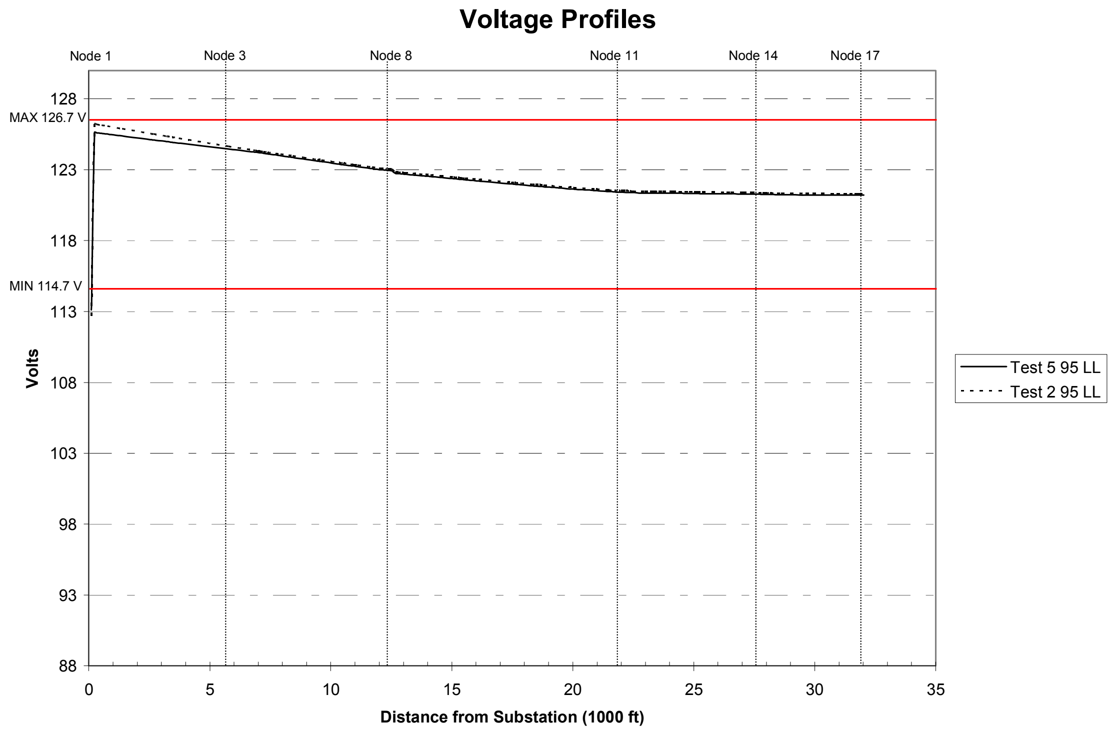


Figure 130. Comparison C: Test 2 and Test 5 LL circuit voltage profiles for 95% substation primary voltage (LTC versus LTC and CAP 1)

The tests 6 and 5 comparison (D) of Figure 131 shows the rise in voltage at the tag end is greater than the rise at the source with the addition of the second capacitor. This is because this capacitor reduces the reactive and total current from its location back to the source.

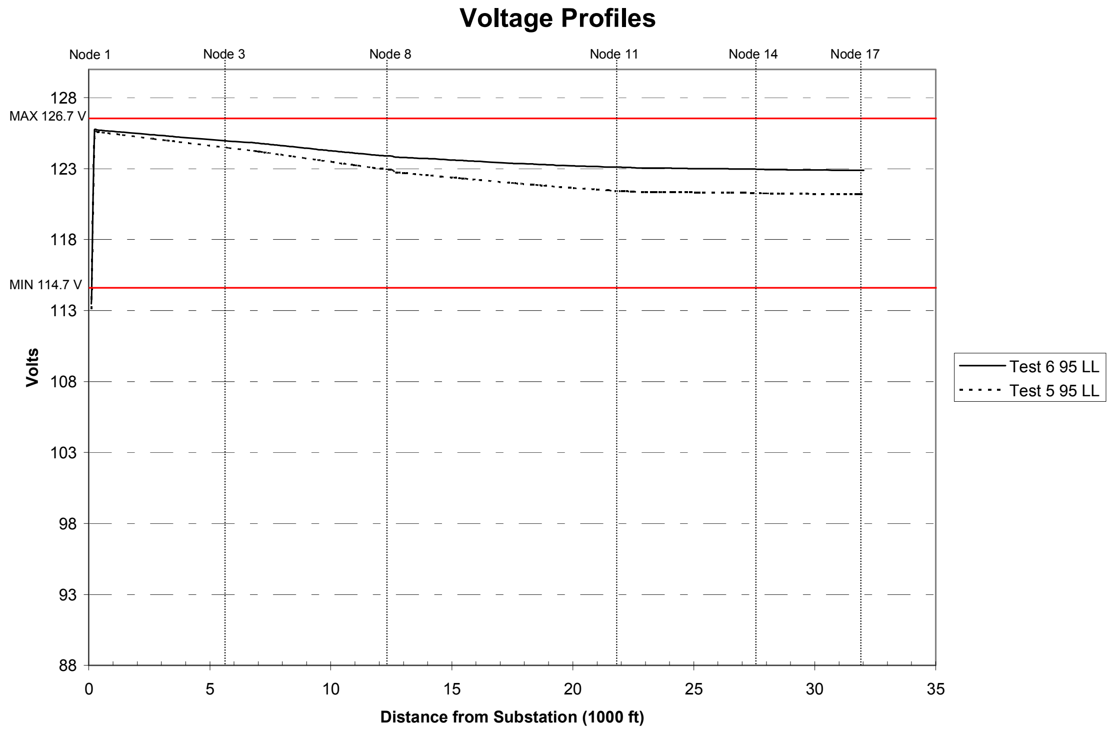


Figure 131. Comparison D: Test 5 and Test 6 LL circuit voltage profiles for 95% substation primary voltage (LTC and CAP 1 versus LTC, CAP 1, and CAP 2)

When all three capacitors are added, as in Comparison E of Figure 132, the voltage rise (less voltage drop) effect is even greater. It shows a nearly level voltage throughout the circuit for Test 7.

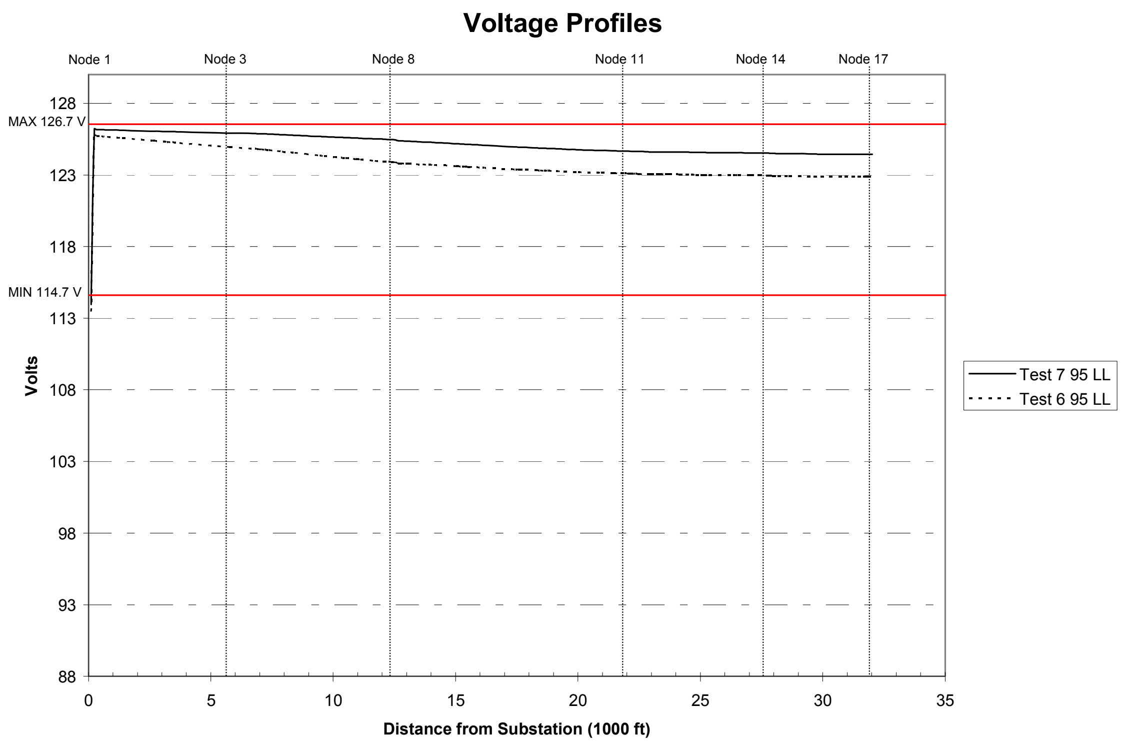


Figure 132. Comparison E: Test 6 and Test 7 LL circuit voltage profiles for 95% substation primary voltage (LTC, CAP 1, and CAP 2 versus LTC, CAP 1, CAP 2, and CAP 3)

Comparison F shows the improvement in regulation between using only the LTC of Test 2 and all the regulation of Test 8. The difference in voltage at Node 17 in Figure 133 is 2.32 V (123.72–121.3 V).

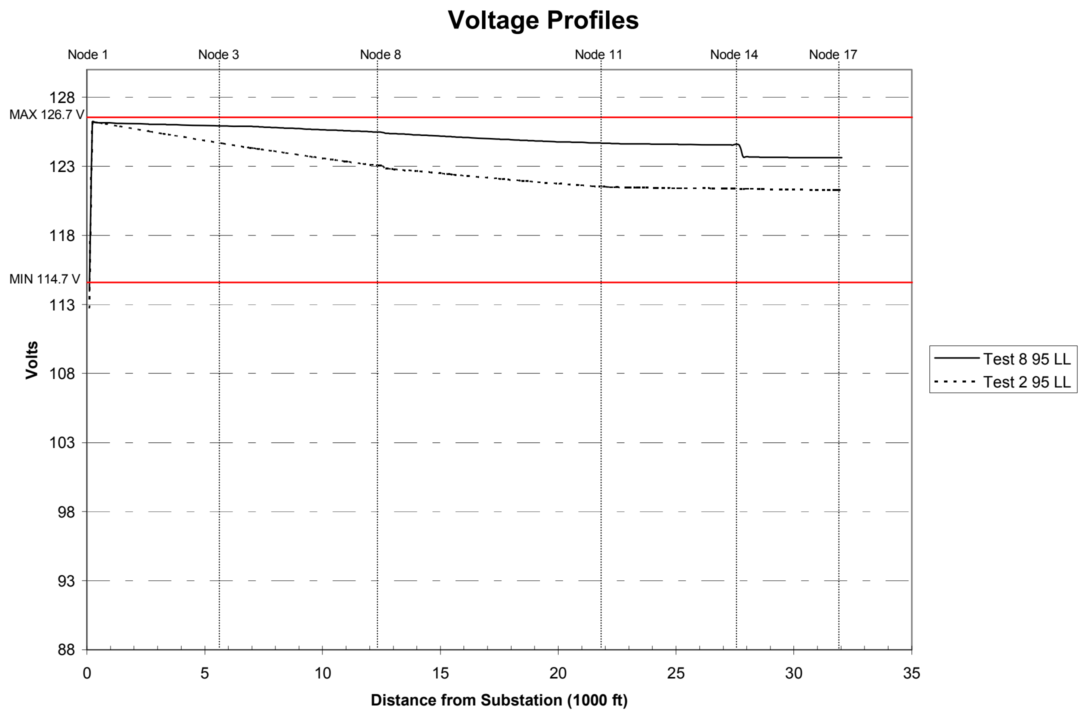


Figure 133. Comparison F: Test 2 and Test 8 LL circuit voltage profiles for 95% substation primary voltage (LTC versus LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3)

Comparison G, shown in Figure 134, shows the effect of adding the two regulators to the three capacitors of Test 7. The voltage is more uniform throughout the circuit for Test 7 than it is with the two regulators added in Test 8. But, as stated earlier, the voltage spread is better with the two regulators turned on when the primary voltage ranges from 95% to 105%.

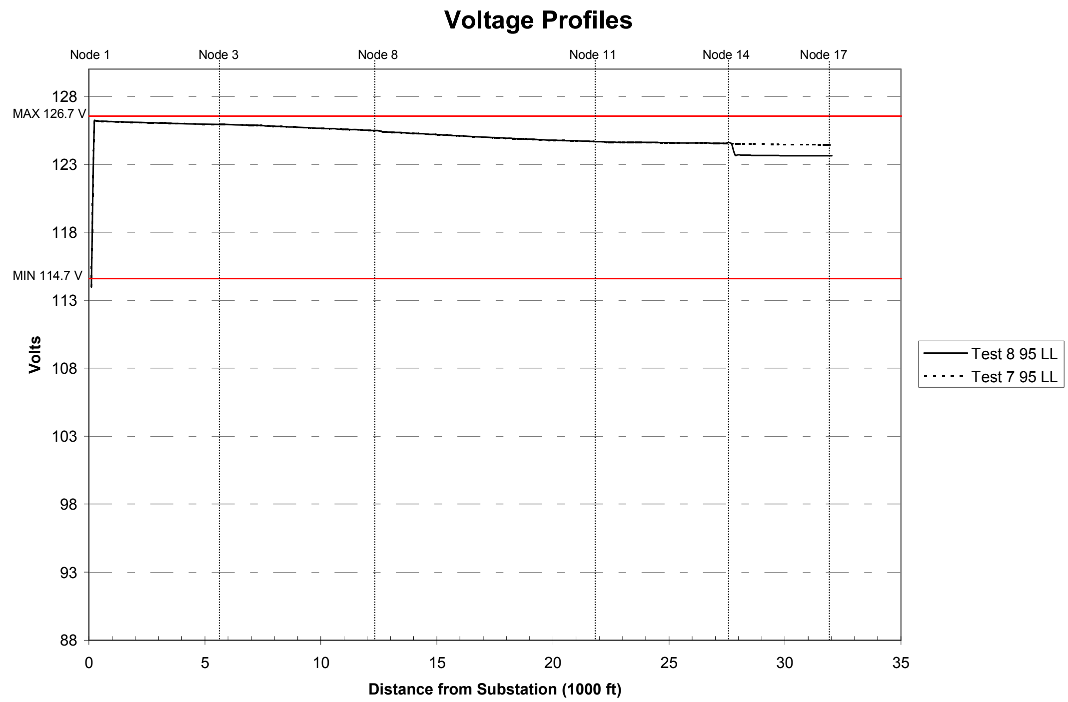


Figure 134. Comparison G: Test 7 and Test 8 LL circuit voltage profiles for 95% substation primary voltage (LTC, CAP 1, CAP 2, and CAP 3 versus LTC, VR 1, VR 2, CAP 1, CAP 2, and CAP 3)

6.3 Distribution Circuit Simulation Summary Data for Tests 1– 8

As noted earlier, for each test, summary data were assembled (see Table 22). These data consist of the primary voltage (either 95% or 105%), load condition (either HL or LL), tap settings for the LTC and step regulators, line currents at Node 0, the lowest three-phase voltage, the lowest single-phase voltage, the highest load imbalance, the highest voltage imbalance, the kilowatt losses per phase and total, the kilovar losses per phase and total, and the release capacity per phase and total when the capacitors are applied. Because the maximum imbalance load can be 100% for any line-to-line load connected to the wye system, Table 23 is provided to show the range of unbalance other than 100%.

6.3.1 Unbalanced Voltage

Unbalanced voltage is determined by calculating the negative sequence V_2 and positive sequence V_1 and dividing V_2 by V_1. Table 22 shows the highest unbalanced voltage in percent for each test. The voltage unbalance is very important for siting DG because most synchronous generators trip when the unbalance reaches 3%. The highest unbalanced voltages on the circuit range from 1.52% to 1.26%. The highest unbalanced voltages for each test are shown in Table 27.

It is interesting to note that the highest measured imbalance from the unbalance voltage survey of Section 4.5.1.2 and Table 9 was 5.94% with the average being 0.83% for wye and closed delta transformer connections. Although these measured data are taken on the secondary side of the distribution transformers, whereas the simulated data are for the primary in Table 27, there is reasonably close agreement—especially when one considers the data in Table 27 are for one circuit while the measured data are for a large population of 1,209 tests across a multiplicity of circuits from 13 utilities.

Table 27. Highest Unbalanced Voltages

	Regulation Method	95% HL	95% LL	105% HL	105% LL
Test 1	No LTC	1.32%	1.26%	1.43%	1.26%
Test 2	LTC	1.44%	1.26%	1.48%	1.26%
Test 3	LTC, VR 1	1.49%	1.26%	1.52%	1.26%
Test 4	LTC, VR 1, VR 2	1.44%	1.26%	1.48%	1.26%
Test 5	LTC, CAP 1	1.42%	1.26%	1.45%	1.26%
Test 6	LTC, CAP 1, CAP 2	1.36%	1.26%	1.38%	1.26%
Test 7	LTC, CAP 1, CAP 2, CAP 3	1.31%	1.26%	1.33%	1.26%
Test 8	LTC, VR 1, VR 2, CAP 1, CAP 2, CAP 3	1.31%	1.26%	1.27%	1.26%

Notice that all the unbalanced voltages are greater during HL conditions. Increasing the voltage increases the load, and thus, the unbalance increases. Adding an LTC increased the voltage unbalance from 1.32% to 1.44% at 95% HL. Another finding was that the highest unbalanced voltages occur at 105% primary voltage, as would be expected. In fact, with no LTC, the voltage unbalance at 105% primary voltage was 1.43% versus 1.32% at 95% primary voltage. Lowering the primary voltage to 95% reduced the voltage unbalance because of the effect of the VDC source model. Adding capacitors reduced the unbalanced voltage, and adding a step VR increased the unbalance from 1.44% with the LTC up to 1.49% with one step regulator and a 95% primary voltage.

When the LTC and all three capacitors were on, the voltage unbalanced was reduced to 1.31% at 95% primary voltage and down to 1.33% at 105% primary voltage. The highest unbalanced voltage on the circuit was reduced to 1.31% with all regulation. It is obvious from these results that the voltage regulation method and the amount of regulation on the circuit are important in reducing the imbalance to acceptable levels.

6.3.2 Unbalanced Loading

Table 23 summarizes the load imbalance for each test. It is calculated as the negative sequence load I_2 divided by the positive sequence load I_1 in percent. Most synchronous generators trip when the load imbalance becomes more than 10%–20%. However, inverter-based generation has been tested and successfully operated even when the unbalance reached 100%. However, the total capability was reduced to 75%. The data in Table 23 show there are locations on the circuit where the unbalanced load was greater than 10%–20%. Care should be given to discover the magnitude of unbalanced load before a synchronous generator is sited on the circuit. At Node 10, where the 1,000-kW generator is interconnected to the distribution circuit, the load unbalance is 1.22% for 95% primary voltage and HL, and when all regulation is turned on, the voltage unbalance is 1.29%. Notice from Table 23 that the load unbalance is always higher at LL than HL. This is good because most DR operate during peak load conditions.

The load imbalance at the substation Node 01 ranges from about 4% for HL and about 5.45% at LL. This is an excellent location to site synchronous generators. There are points on the circuit where the load unbalance is lower than at the substation, but there are many points where the imbalance is up to 90%. Adding regulation did not necessarily improve load imbalance. In fact, with all regulation on, the Node 10 value was 3.89% at 95% primary voltage versus 3.77% with no regulation and HL conditions.

6.4 Significant Results and Conclusions

The Milford Circuit DC 8103 is typical of residential and light commercial load characteristics.

- The CC load model, the CP load model, and the VDC load model were applied in tests 7 and 8 at 95% source voltages for HL conditions. However, as shown in Appendix B.1, the VDC model was better than the CC model (i.e., 2.0% error versus 5.3%). Therefore, the best overall method to represent the load characteristics as a function of source voltage changes was the VDC model.

Heavy Load

- The highest voltage spread, measured as the difference between the highest three-phase voltage and the lowest single-phase voltage, was 25.2 V and occurred with no LTC regulation at the substation transformer during HL conditions and with the primary voltage on the substation transformer ranging from 95% to 105%. This spread was reduced to 10.4 V with all regulation methods turned on.
- When the LTC and first step regulator were added, the tag end voltage improved 4.11 V, and with the second regulator turned on, the voltage increased another 11.34 V.
- When the LTC and first capacitor were added, the voltage increased only 0.97 V, and with the addition of the second capacitor, the voltage gain was 1.75 V at the tag end. The third capacitor added another 1.66 V rise at the tag end.
- When all regulation was turned on, the tag end voltage improvement was 15.35 V over only the LTC transformer to regulate voltage. Also, when DR are added to the circuit, this method of voltage regulation reduces the voltage spread even further.

Light Load

- During LL and no LTC regulation, the voltage spread, as determined by subtracting the highest three-phase voltage from the lowest single-phase voltage, was 16.65 V compared to 25.2 V for HL. With all regulation turned on, this difference diminished to 2.91 V.
- Care should be exercised when operating DR during LL because the highest three-phase voltage on the Milford Circuit was 126.24 V. It may be necessary to operate DR to absorb volt-amperes reactive to prevent HV.

Unbalanced Conditions

- Raising the source voltage during HL conditions with the LTC and a step regulator turned on created the highest unbalance voltage of 1.52%. Most synchronous generators trip at unbalanced voltages more than 3%. Studies should always be conducted to ensure the unbalanced voltage does not exceed 3% at the point of interconnection (not point of common coupling) for the DR. Of course, if an isolation transformer is installed at the point of interconnection with a delta-wye transformer connection, it will improve the voltage unbalance seen by the generator.
- Adding the LTC regulation at HL and 95% primary substation voltage lowered the maximum unbalance voltage to 1.44%. Adding a step regulator worsened the unbalanced voltage by raising it to 1.49%, but adding a second step regulator reduced the unbalanced voltage to 1.44%.
- Adding capacitors reduced the maximum unbalanced voltage. The first capacitor turned on lowered this unbalanced voltage to 1.42%. With both capacitors turned on, the unbalanced voltage went down to 1.36%. All three capacitors turned on lowered the unbalance to 1.31%.
- Having all regulation turned on lowered the maximum unbalanced voltage to 1.31% for 95% primary voltage and HL (worst-case condition). The 13-utility unbalanced voltage survey showed the maximum measured voltage unbalance of 5.94%.
- The highest voltage unbalance during LL was 1.26%, even though the primary voltage on the transformer ranged from 95% to 105%.
- At many locations on the circuit, the current imbalance exceeded 20%. Most synchronous generators trip between 10% and 20% current imbalance. Inverter-based generation can operate under 100% load imbalance, but typically, they do so at 75% of rated capacity. The greatest unbalance current was 100% at locations where line-to-line loads or line-to-neutral loads were connected to the three-phase, wye-grounded system. Unbalances of 20%–90% were apparent at many nodes, but, generally, the load magnitudes were small and, thus, not causing the generator to trip. The greater load imbalances occurred at LL.

- The current imbalance at Node 10, where the 1,000-kW synchronous generator is interconnected, was 1.22% during HL conditions, and the voltage unbalance was 1.29%. Even the load imbalance at the substation was about 4% at HL but reached about 6% at LL. If a DR is installed at the substation and operated in an isolated mode (i.e. as a microgrid), it may see 10% current imbalance during LL. However, on other circuits on the system, the load imbalance at the substation could be as high as 20%. It is important to determine the imbalanced current at the point of interconnection before ever siting a synchronous DR generator.
- The zero sequence current ranged from 45.43 A to 50.24 A for the simulations conducted. See Table B-3. This level of zero sequence current is not a problem from a system standpoint, but when the system is lost, a portion of the circuit is operated as a microgrid or island, and there are line-to-neutral loads and line-to-line loads, high negative sequence currents can be expected. When the wye ungrounded synchronous generator windings are connected to a delta-wye high-side transformer with neutral solidly grounded, zero sequence currents from a line-to-ground load on one phase of the system will create 100% negative sequence currents on the generator windings, or the negative sequence current will be equal to the positive sequence current. Most small generators are wye ungrounded with a delta-wye high-side transformer and grounded neutral connection, so this represents the most common installation. Appendix A.3 shows that a generator with only 33.34 A of zero sequence current on the high side will see 100% unbalanced currents on the generator windings. The negative sequence current is 33% of the full rated three-phase capacity of the generator. This will cause the generator negative sequence relays to trip at 10% negative sequence current. This means the generator will trip if it serves only 30 A of single-phase load, even though the rated current is 100 A per phase of load current. Because the other two phases are unloaded, the generator can produce only 1/10 of its full rated three-phase machine capacity (i.e., 30 A single-phase load ÷ 300 A three-phase capacity).

7 Project Results – Design of Field Voltage Regulation and Metering Equipment

7.1 Introduction

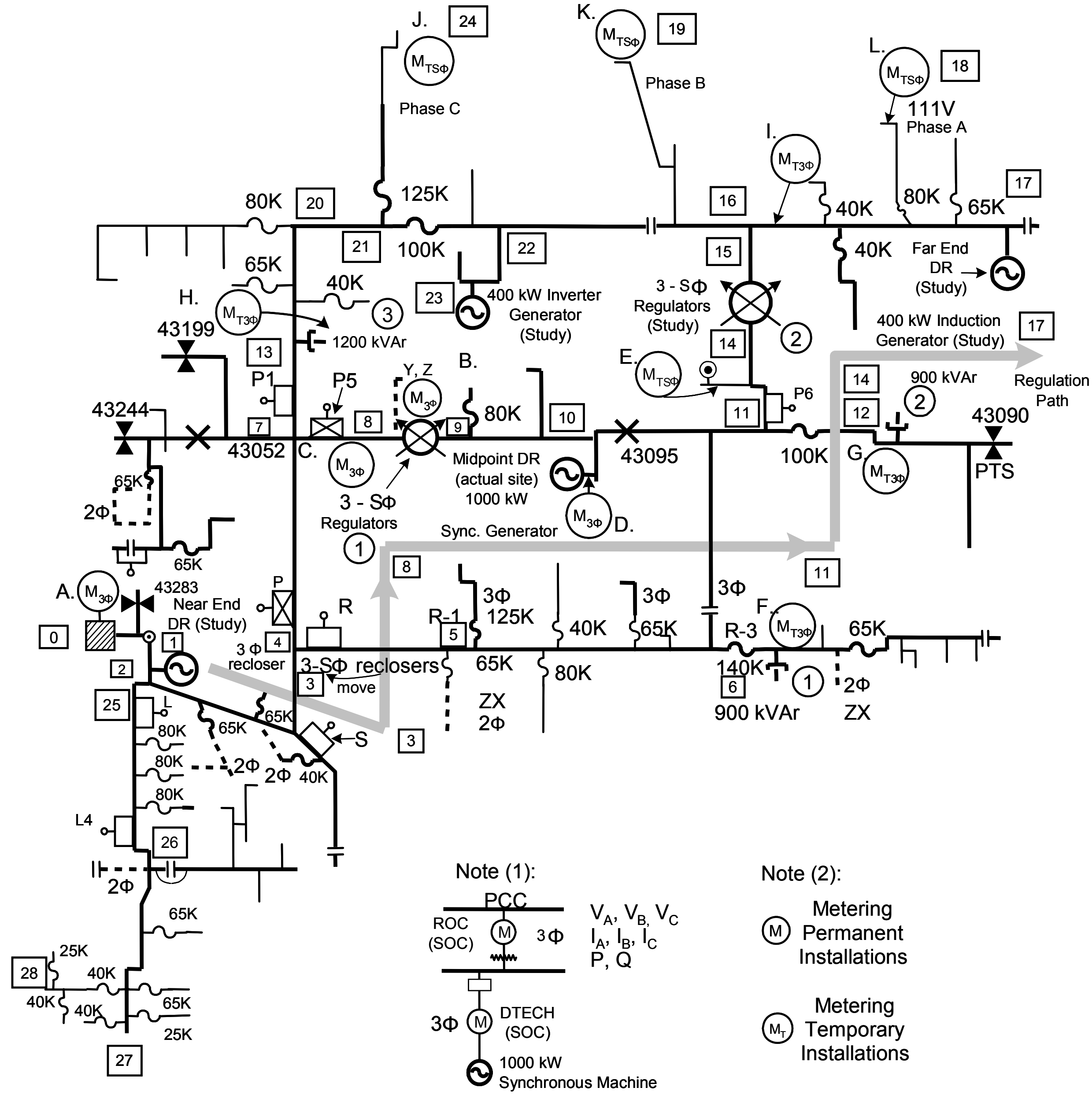
This section defines the equipment installed on Milford Circuit DC 8103 to control voltage and the metering equipment used to validate the models.

7.2 Voltage Regulation Equipment

Figure 135 shows the locations of the voltage regulation equipment on Milford Circuit DC 8103. Table 28 describes this equipment.

Table 28. Voltage Regulation Equipment

Location	Description
A.	10-MVA delta-wye transformer #1 Z = 7.02%, 41.57 kV/13.8 kV, 0, ±2.5, ±5.0 high-side setting = 0, low-side setting = ±5, LTC + 16 steps + 10%, a_N = 3 (See Figure 136)
B.	Three 167-kVA single-phase step VRs, 32 steps
D.	1,000-kW synchronous generator, 1,050-kW power prime mover, rated output = 1,312 kVA @ PF = 0.8, 1,800 rpm, 480 V, 60 Hz, voltage regulation ±5%.
F.	(1) 900-kVAr three-phase capacitor, Y-connected, neutral grounded
G.	(2) 900-kVAr three-phase capacitor, Y-connected, neutral grounded
H.	(3) 1,200-kVAr three-phase capacitor, Y-connected, neutral grounded



Note (3): Nodes where low voltage, high voltage, highest unbalance voltage, highest unbalanced load and nodes where actual values exceed pre-set values (criteria violations) may be different than the nodes indicated above.

Note (4): The LTC voltage regulator is gang operated using the C phase as reference.

Note (5): The "P" reclosure data is sent to midpoint DR consisting of I_A, I_B, I_C, V_{CN}, V_{BN}, V_{CN}, kW_A, kW_B, kW_C, $kVAr_A$, $kVAr_B$, $kVAr_C$

Figure 135. Milford Circuit DC 8103

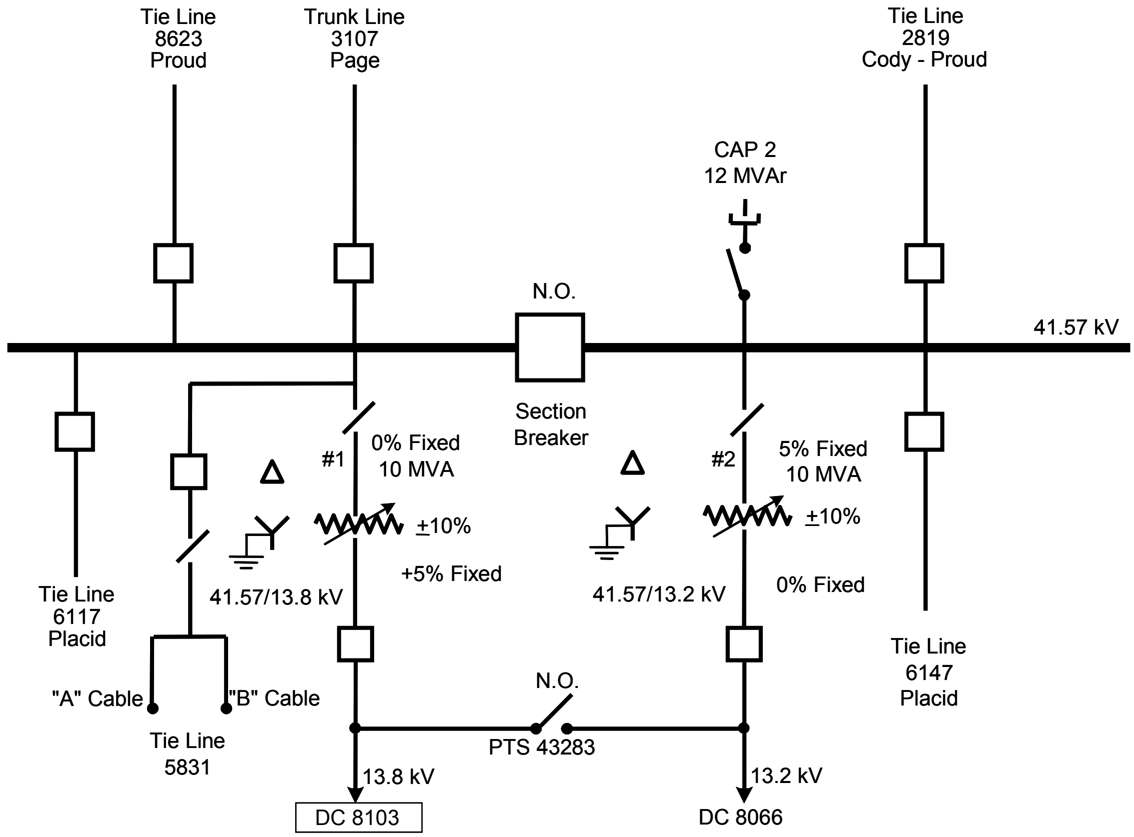


Figure 136. Milford substation one-line diagram

7.3 Major System Protection Equipment

The major system protection equipment is listed in Table 29. It consists of three-phase and single-phase reclosers and single-phase sectionalizers.

Table 29. Major System Protection Equipment

	Location	Description
1.	R	Three three-phase reclosers – 280 A vacuum V4L, 2A, 2D
2.	P	One three-phase recloser – 680 A vacuum VWE, R, C
3.	P5	Three single-phase reclosers – 280 A vacuum V4L, 2A, 2D
4.	P1	Three single-phase reclosers – 280 A vacuum V4L, 2A, 2D
5.	S	Three single-phase reclosers – 140 A vacuum V4L, 1A, 3D
6.	L	Three single-phase reclosers – 140 A vacuum V4L, 1A, 3D
7.	L4	Three single-phase sectionalizers – 140 A hydraulic
8.	P6	Three single-phase reclosers – 140 A V4L, 2A, 2D

Table 30. Measurement Locations and Data Collection

Permanent Metering Locations					
A.	Substation	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, PF
B.	Regulators (1)	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, PF
D.	1,000-kW synchronous DR	$M_{3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	P, Q, PF
Temporary Metering Locations					
F.	900-kVAr capacitor	$M_{T\ 3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	
G.	900-kVAr capacitor	$M_{T\ 3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	
H.	1,200-kVAr capacitor	$M_{T\ 3\Phi}$	V_{AN}, V_{BN}, V_{CN}	I_A, I_B, I_C	
I.	Three-phase circuit tag end	$M_{T\ 3\Phi}$		I_A, I_B, I_C	
K.L.	Single-phase tag ends	$M_{T\ S\Phi}$	V_{AN}	V_{BN}	

7.4 Metering Equipment and Accuracy of Measurements

7.4.1 Substation Metering

The substation metering consists of an ION 7600 Power Measurements Meter, which measures the three-phase voltages, three line currents, and phase power factors and calculates the kilowatts per phase and total kilowatts, kilovars per phase and total kilovars, kilovolt-amperes per phase and total kilovolt-amperes, and unbalanced voltage and current. The integration period is 15 minutes. The accuracy of the metered data is 0.1% for voltage, 0.1% for current, ±0.01 Hz for frequency, and 0.5% for power factor. The kilowatt, kilovar, and kilovolt-ampere accuracy is Class 0.2.

7.4.2 Synchronous Generator Metering

The generator metering is a 3720 ACM meter that measures the three-phase voltages, three line currents, three-phase kilowatts, three-phase kilovars, three-phase kilovolt-amperes, power factor, frequency, and circuit load including generation. The data are 30-second samples integrated over 5 minutes. The SOC data are 5-minute samples averaged over 15 minutes. The accuracy of the measured data is shown in Table 31.

Table 31. Accuracy of 3720 ACM

Parameter	Accuracy
Current	0.2%
Kilowatts	0.4%
Kilovars	0.4%
Kilovolt-amperes	0.4%
Voltage	0.2%
Power factor	1.0%
Frequency	0.05 Hz

7.4.3 Capacitor Location Metering

The metering at the capacitor locations (nodes F, G, and H) is the Line Tracker LT40 from Grid Sense. These metering devices measure the three-phase voltages and three line currents. The voltage is sampled at 600 samples per second, and the current is sampled at 1,200 samples per second. The accuracy of the current measurement is ±5%. The integration period is 15 minutes.

7.4.4 Voltage Regulator Locations

The CL-6 control of the VRs at Location B measures the load and source phase voltages, line currents, phase kilowatts, phase kilovars, phase kilovolt-amperes, and phase power factor. The data are integrated over 15 minutes, and the accuracy is Class 1 metering or 1% for all power quantities (i.e., voltage, current, kilowatts, kilovars, and kilovolt-amperes).

7.4.5 Single-Phase Voltage Customer Metering

The Rustrak measured voltage and current. The accuracy is 0.25% for voltage and 0.5% for current. Each is in percent of reading. The integration period is 15 minutes.

8 Project Results – Distributed Generation Control Strategies for Field Verification

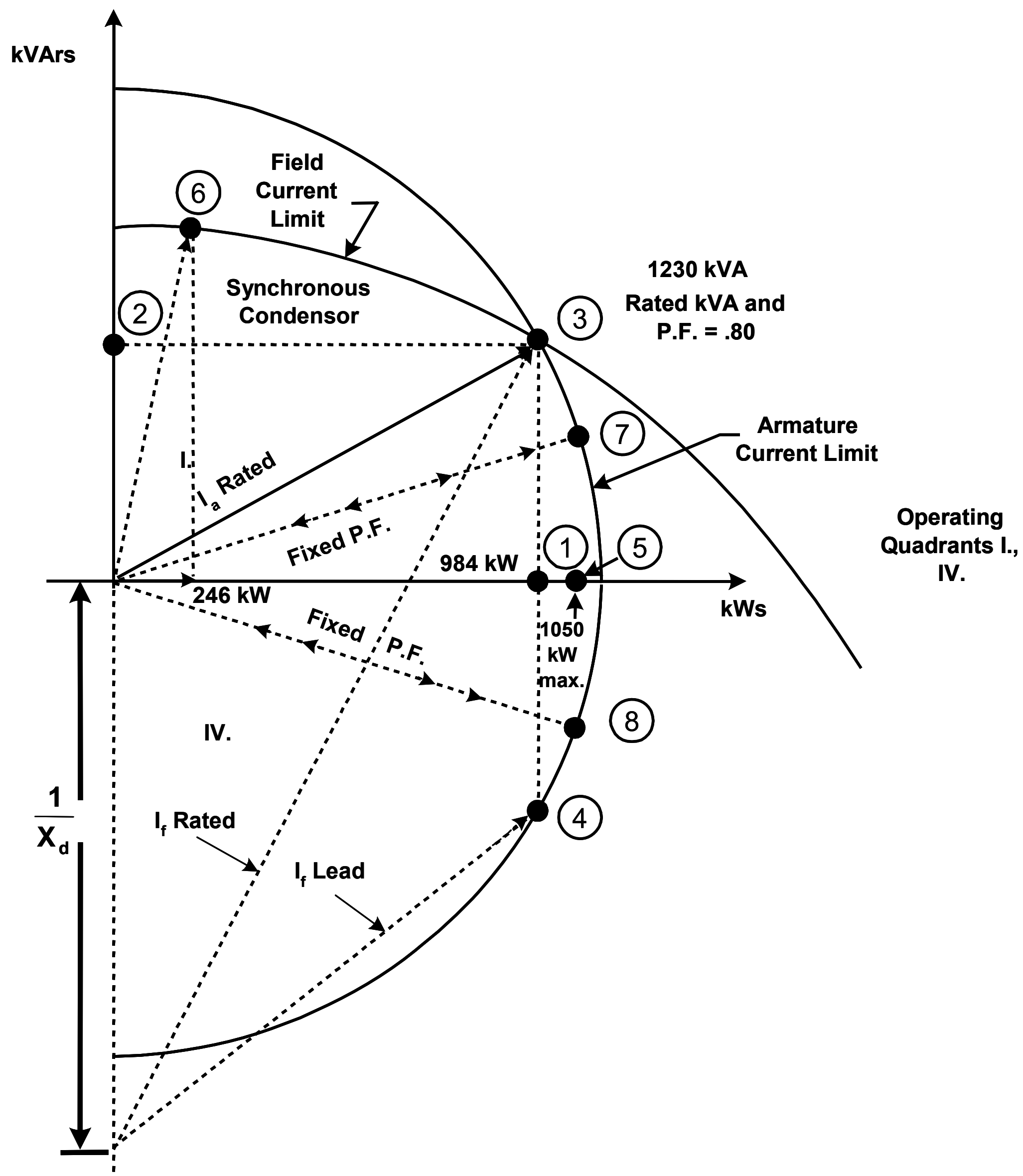
8.1 Introduction
This section defines the generation equipment voltage regulation capability and the control strategies used to regulate voltage on the Milford Circuit DC 8103.

8.2 1,000-kW Synchronous Generator
The voltage regulation control capabilities for the 1,000-kW synchronous generator located at the midpoint on the circuit Node D is given in Figure 137.

8.3 400-kW High-Speed Generator and Inverter
The voltage regulation control capability for the 400-kW high-speed generator and inverter is shown in Figure 138.

8.4 400-kW Self-Excited Induction Generator
The voltage regulation control capability for the 400-kW self-excited induction generator is shown in Figure 139.

8.5 Voltage Regulation Simulations and Field Verification Strategy 17
The voltage regulation simulations and Strategy 17 used for field verification is outlined in Table 32.



Operating Points

(a) points 1 and 2 is rated kW and rated KVArs

(b) point 3 rated kVA and rated lagging P.F.

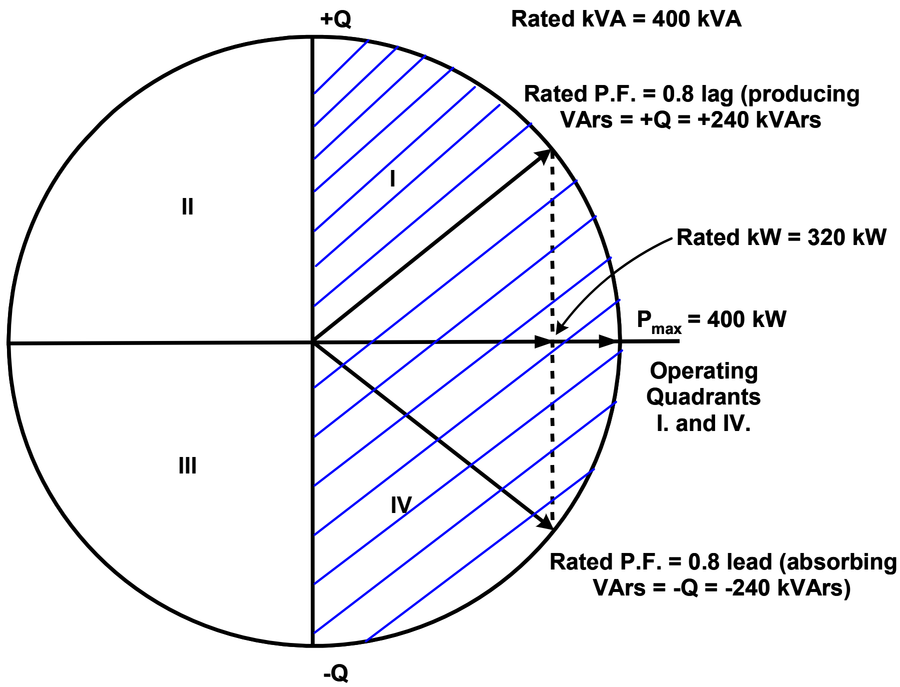
(c) point 4 leading P.F.

(d) point 5 maximum kW

(e) point 6 minimum kW and maximum kVArs (synchronous condensor)

(f) points 7 and 8 fixed power factor lagging and leading

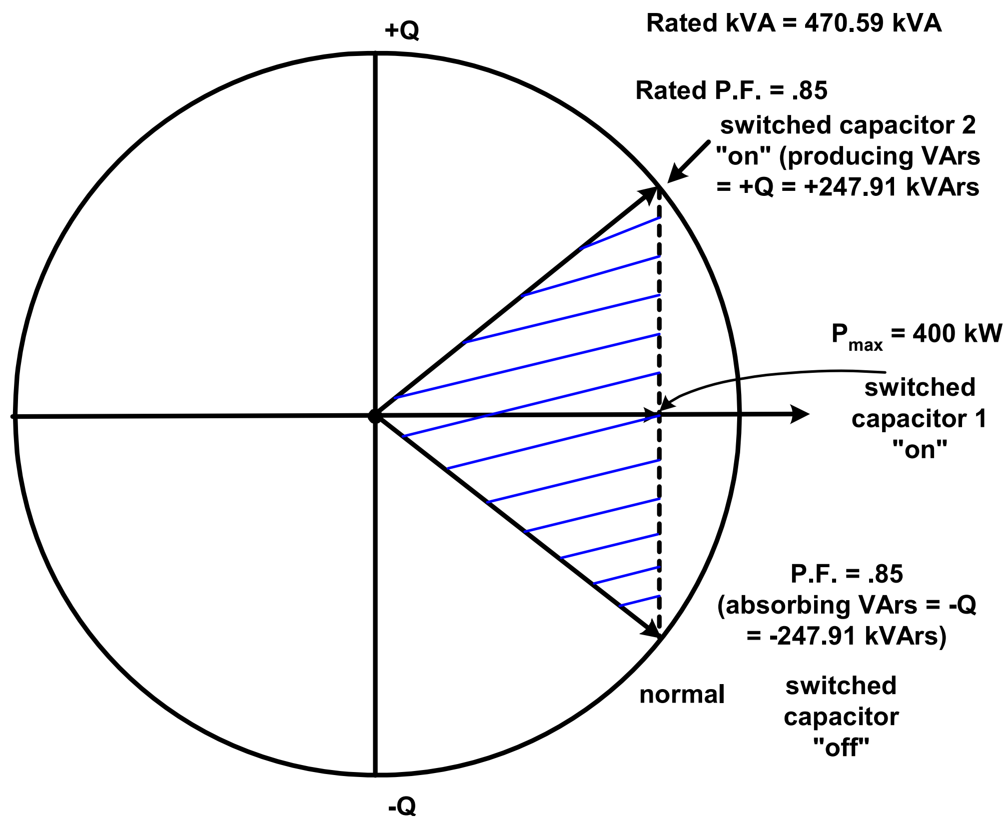
Figure 137. DR control strategies for a 1,000-kW synchronous machine



Note (4): DR Control Strategies
(a) Peak Shave P fixed
(b) P.F. = unity, P variable
(c) ± P.F. constant, P variable
(d) ± Q (VArs volt. reg.) P = 0
(e) P ± jQ (optimizing) - see synchronous machine
(f) Frequency Dithering (anti-islanding)

Note (5): (f) not included in model

Figure 138. DR control strategies for a 400-kW high-speed generator and inverter – current mode



(a) Peak Shave P fixed
(b) P.F. = unity, P fixed
(c) ± P.F. constant at P fixed
(d) ± Q fixed, P fixed same as (c)

Note (4) Induction machine with inverter is the same as Inverter where the speed is varied to create variable dc output after the rectifier and the ac current output from the inverter is phase shifted (switching) to produce a variable P.F. with respect to the system voltage.

Figure 139. DR control strategies for a 400-kW self-excited induction generator

Table 32. Matrix of Voltage Regulation Simulations and Control Strategy 17 for Field Verification

Test Numbers	Reference. Section	**Primary Voltage Spread** (a)87% (b) 92% (c)93% (d) 95% (e) 98% (f) 105%	**Peak Load Day 24 Hourly quantities**	**Light Load Day 24 Hourly quantities**	**LTC $\pm$ 16 steps & neutral**	**Line Regulator**		**Capacitors**			**DR (Synchronous Machine) Locations (1)** (a)Peak shave, P fixed (b) P.F.= Unity, P variable (c) $\pm$ P.F. Constant, Variable P & Q (d) $\pm$ Q (Vars Volt reg) P Min (e) P$\pm$ jQ (Optimizing) (f) Fixed P.F. Anti-island		
						#1	#2	#1	#2	#3	Near End	Midpoint (Actual Site)	Far End
1	I.A.	(a) (d) (f)	x	x									
2	I.B.	(d) (f)	x	x	x								
3	I.C.	(d) (f)	x	x	x	x							
4	I.C '.	(d) (f)	x	x	x	x	x						
5	I.D	(d) (f)	x	x	x			x					
6	I.D '	(d) (f)	x	x	x			x	x				
7	I.D."	(d) (f)	x	x	x			x	x	x			
8	I.E.	(d) (f)	x	x	x	x	x	x	x	x			
9	II.A.	x	x	x							(b) (d) (e)		
10	II.B.	x	x	x								(b) (d) (e)	
11	II.C.	x	x	x									(b) (d) (e)
12	II.D.	Repeat IIA., IIB., IIC. turn on LTC											
13	II.E.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1)											
14	II.F.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2)											
15	II.G.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2) and Cap. (1)											
16	II.H.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2) and Cap. (1), (2)											
17	II.I.	Repeat IIA., IIB., IIC. turn on LTC, and Regulator (1) and (2) and Cap. (1), (2), (3)											
18													
19													
20													
21													
22													
23													
24													
25													

Note (1): DR Control Strategies

(a.) The DR is operated at fixed real power output and normally Is scheduled to run during peak periods when the cost of DR generation is lower than host utility cost. The Q is zero at the PCC. 984 kW rated

(b.) The DR is operated at unity P.F. with variable power output. 492 kW (50%) to 1050 kW max.

(c.) DR is operated at a fixed power factor either lead or lag (for example $\pm$ 0.8 P.F.) with variable P and Q to not violate voltage criteria.

(d.) The DR is operated as a synchronous condenser with minimum watts and variable VArs to regulate voltage. 246 kW (25% of rated)

(e.) DR is operated with variable P and Q and is used to optimize to a specific set of criteria such as minimize real losses, minimize reactive losses, regulate voltage and maximize released capacity.

Test Numbers	Reference. Section	**Primary Voltage Spread** (a)87% (b) 92% (c)93% (d) 95% (e) 98% (f) 105%	**Peak Load Day 24 Hourly quantities**	**Light Load Day 24 Hourly quantities**	**LTC $\pm$ 16 steps & neutral**	**Line Regulator**		**Capacitors**			**DR (Induction Generator) Locations** (a)Peak shave, P fixed (b) P.F.= Unity, P fixed (c) $\pm$ P.F. Constant, P fixed (d) $\pm$ Q fixed, P fixed same as (c)		
						#1	#2	#1	#2	#3	Near End	Midpoint (Actual Site)	Far End
1		(a) (d) (f)											
2		(d) (f)											
3		(d) (f)											
4		(d) (f)											
5		(d) (f)											
6		(d) (f)											
7		(d) (f)											
8		(d) (f)											
9	II.A.	x	x	x							(b) (d)		
10	II.B.	x	x	x								(b) (d)	
11	II.C.	x	x	x									(b) (d)
12	II.D.	Repeat II.A., II.B., II.C. turn on LTC											
13	II.E.	Repeat II.A., II.B., II.C. turn on LTC and Regualator (1)											
14	II.F.	Repeat II.A., II.B., II.C. turn on LTC and Regulators (1) & (2)											
15	II.G.	Repeat II.A., II.B., II.C. turn on LTC, Reg. (1) & (2) and Cap (1)											
16	II.H.	Repeat II.A., II.B., II.C. turn on LTC, Reg. (1) & (2) and Cap (1) and (2)											
17	II.I.	Repeat II.A., II.B., II.C. turn on LTC, Reg (1) & (2) and Cap (1), (2) & (3)											
18	III.	Repeat synchronous and inverter generation											
19	IV.	Repeat synchronous, inverter and induction generation											
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													

Test Numbers	Reference. Section	**Primary Voltage Spread** (a)87% (b) 92% (c)93% (d) 95% (e) 98% (f) 105%	**Peak Load Day 24 Hourly quantities**	**Light Load Day 24 Hourly quantities**	**LTC ± 16 steps & neutral**	**Line Regulator**		**Capacitors**			**DR (Induction Generator) Locations** (a)Peak shave, P fixed (b) P.F.= Unity, P fixed (c) ± P.F. Constant, P fixed (d) ± Q fixed, P fixed same as (c)		
						#1	#2	#1	#2	#3	Near End	Midpoint (Actual Site)	Far End
1		(a) (d) (f)											
2		(d) (f)											
3		(d) (f)											
4		(d) (f)											
5		(d) (f)											
6		(d) (f)											
7		(d) (f)											
8		(d) (f)											
9	II.A.	x	x	x							(b) (d)		
10	II.B.	x	x	x								(b) (d)	
11	II.C.	x	x	x									(b) (d)
12	II.D.	Repeat II.A., II.B., II.C. turn on LTC											
13	II.E.	Repeat II.A., II.B., II.C. turn on LTC and Regualator (1)											
14	II.F.	Repeat II.A., II.B., II.C. turn on LTC and Regulators (1) & (2)											
15	II.G.	Repeat II.A., II.B., II.C. turn on LTC, Reg. (1) & (2) and Cap (1)											
16	II.H.	Repeat II.A., II.B., II.C. turn on LTC, Reg. (1) & (2) and Cap (1) and (2)											
17	II.I.	Repeat II.A., II.B., II.C. turn on LTC, Reg (1) & (2) and Cap (1), (2) & (3)											
18	III.	Repeat synchronous and inverter generation											
19	IV.	Repeat synchronous, inverter and induction generation											
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													

9 Project Results – Field Verification of Models

9.1 Introduction

This section verifies the models using field test data. Voltage regulation models were developed for the LTC transformer at the substation, the bidirectional step regulators, the capacitors, all the distribution circuit transformer connections, and the line sections. In addition, models for synchronous, induction, and inverter generators were created.

The field verification was conducted using the metering equipment defined in Section 7 and the DG control for the 1,000-kW synchronous generator defined in Section 8. The Strategy 17 control strategy was used. In it, all three capacitors (1, 2, and 3), the regulator (1), and the substation LTC were turned on.

The field verification studies were conducted for the circuit peak days of July 17, 2006, at 17:43 and July 29, 2006, at 17:11, when the 1,000-kW DR was running, and on July 31, 2006 at 17:56, when this DR was turned off.

9.2 Circuit and Generation Measured Data

The nodes at which measured data were taken on the circuit and Node D (Node 10), where the generation is interconnected with the circuit, are described in Figure 135. The test dates and data collection periods are shown in Table 33.

Table 33. Test Dates and Data Collection Periods

Date	Circuit Start	Circuit Peak	Circuit End	Generation Start (Post-Generation Start)	Generation End (Pre-Generation Off)
7/17/06	10:42	17:43	23:58	17:28	21:23
7/29/06	00:11	17:11	23:56	17:11	20:16
7/31/06	00:11	17:56	23:56	← generator	→
8/02/06	00:11	17:56	23:56	10:26	12:16

Because there is a time delay between the initiation of the "start" generator command and when the unit is synchronized and carrying load and a delay between the initiation of the "stop" generator command and when the generator is not carrying load, the times given in the Table 33 are the post-generation start (the time the unit is carrying load) and the pre-generation off (the time the unit is still carrying load but has received the "stop" generator command).

Illustrative Example of Generation Run Time and Distribution Circuit Time Stamps for Simulation Studies and Field Verification

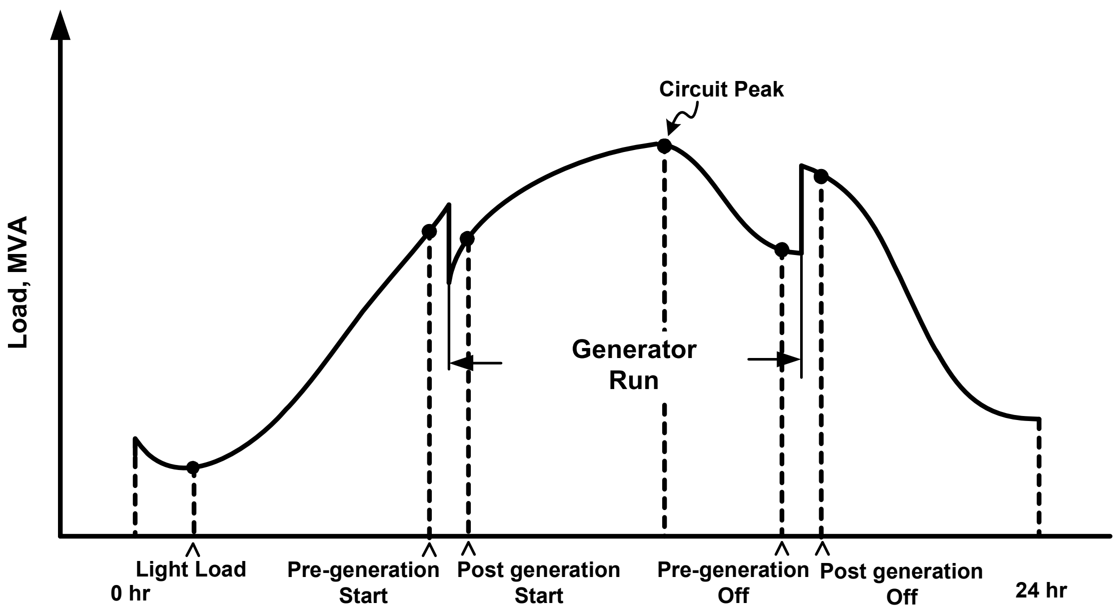


Figure 140. Daily circuit load profile and time stamps

These times are described in Figure 140. As shown in Table 33, there were four days during the summer when tests were conducted and four days when measured data were collected. The first two days, July 17 and July 29, 2006, the 1,000-kW DG was turned on to offset the circuit peak load. On July 31, 2006, this DG was turned off. This was to determine if there is a difference in the variance between simulation and field-measured data when the DG was running and when it was not. Simulations and comparisons with field-measured data were not conducted on the last test day (Aug. 2, 2006) because the load of the South Branch of the Milford Circuit DC 8103 was cut over to a circuit fed from the Page Substation on Aug. 1 at 19:00. This removed approximately 2 MVA of load (i.e., a 15.92 MVA peak prior to cut-over versus a 13.98-MVA peak after the cut-over) from the Milford Circuit DC 8103. See Table 34.

The times of circuit peak data and generation data are given in Table 34 for the four test days. The measured data consist of:

- Circuit peak kilovolt-amperes
- Circuit phase currents at Substation Node 1
- Generation line currents at Node 10
- Generation line-to-line voltages at Node 10
- Generation three-phase PF at Node 10
- Generation three-phase kilowatts, kilovars, and kilovolt-amperes at Node 10.

9.3 Bidirectional Voltage Regulator Measured Data

The bidirectional VR measured data for the circuit peak time of each test day are given in Table 35 and listed below for each phase regulator at Node 9.

- Load current
- Load PF
- Kilowatt load
- Kilovolt-ampere load
- Kilovar load
- Voltage 120-V base

9.4 Circuit Equipment (Capacitors) and Customer-Measured Data

The measured data at the time of circuit peak for each of the three capacitors at nodes 6, 12, and 13 on the respective test days are given in Table 36. They consist of the phase currents and phase voltages. Also, the customer-measured data for Node I, which consist of I_a and I_c phase currents; Node L and the V_C phase voltage; and Node K and the V_A phase voltage are given in this table.

9.5 Percent Variance Between Simulated and Field-Measured Data

Table 37 and Table 38 compare simulated data and field-measured data for the two test days when DG was running. Table 39 shows similar data for when the DG was turned off. The field data for the phase currents, phase voltages, and phase power factors of the circuit, generator, and the VR1 bidirectional regulator are given for Node 1, Node 10, and Node 9 on the left. The corresponding simulation data are shown on the right. The measured phase currents and phase voltages for the three capacitors and their respective simulation data are also given in these tables, but the simulated voltage data have been reduced by 3.67 V to reduce the measured primary voltage to secondary voltage values. Finally, customer-measured current and voltage data and simulation data for Nodes I and L are listed.

Table 40 summarizes the differences between measured and simulated values. For three-phase quantities, the percent variance is calculated as the absolute value of the sum of the differences between the actual and simulated values divided by three and then divided by the average of the actual three-phase values. The result is multiplied by 100 to represent the percent difference using the average of the actuals as the base. For single-phase quantities, the percent variance is the absolute value of the difference divided by the actual as the base, multiplied by 100.

Table 34. Circuit and Generation Measured Data

Circuit	Start: 7/17/2006	10:42	End:	7/17/2006	23:58
Generator	Start: 7/17/2006	17:28	End:	7/17/2006	21:23

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Voltage 120V Base
Circuit Start	7/17/2006	10:42	132.20	0.98	1,039.00	1,021.00	190.00	7,857.51	123.72	126.90	0.99	998.00	984.00	169.00	7,868.23	123.89	120.50	0.98	946.00	929.00	179.00	7,852.46	123.64
Circuit Peak	7/17/2006	17:43	282.60	0.94	2,216.00	2,088.00	742.00	7841.79	123.48	255.70	0.95	2,009.00	1,913.00	612.00	7855.34	123.69	238.00	0.94	1,877.00	1,772.00	619.00	7887.05	124.19

Circuit	Start: 7/29/2006	00:11	End:	7/29/2006	23:56
Generator	Start: 7/29/2006	17:11	End:	7/29/2006	20:16

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base
Circuit Start	7/29/2006	0:11	157.80	0.89	1,248.00	1,110.00	570.00	7,908.95	124.53	138.80	0.90	1,096.00	991.00	468.00	7,896.23	124.33	143.40	0.88	1,133.00	1,000.00	533.00	7,901.98	124.42
Circuit Peak	7/29/2006	17:11	312.30	0.93	2,464.00	2,286.00	917.00	7887.81	124.20	296.60	0.94	2,331.00	2,190.00	798.00	7859.16	123.75	279.70	0.93	2,195.00	2,041.00	806.00	7,847.19	123.56

Circuit	Start: 7/31/2006	00:11	End:	7/31/2006	23:56
Generator	Start: 7/31/2006	16:11	End:	7/31/2006	17:11

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base
Circuit Start	7/31/2006	0:11	271.10	0.89	2,139.00	1,903.00	977.00	7,891.57	124.26	256.90	0.90	2,029.00	1,829.00	878.00	7,898.27	124.37	241.10	0.89	1,892.00	1,680.00	871.00	7,851.34	123.63
Circuit Peak	7/31/2006	17:56	369.00	0.94	2,882.00	2,695.00	1,021.00	7811.26	123.00	355.00	0.94	2,813.00	2,640.00	971.00	7924.79	124.78	314.00	0.93	2,486.00	2,317.00	900.00	7897.24	124.35

Circuit	Start: 8/2/2006	00:11	End:	8/2/2006	23:56
Generator	Start: 8/2/2006	10:26	End:	8/2/2006	12:16

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base
Circuit Start	8/2/2006	0:11	116.00	0.91	917.00	833.00	384.00	7,907.76	124.52	113.00	0.91	895.00	818.00	361.00	7,914.87	124.63	107.30	0.89	845.00	753.00	383.00	7,873.56	123.98
Generator	8/2/2006	12:16	170.10	0.96	1,334.00	1,287.00	352.00	7,844.62	123.52	154.10	0.98	1,210.00	1,185.00	246.00	7,854.76	123.68	149.40	0.97	1,167.00	1,136.00	267.00	7,811.54	123.00
Circuit Peak	8/2/2006	17:56	259.70	0.93	2,059.00	1,924.00	734.00	7,929.52	124.86	247.60	0.95	1,950.00	1,856.00	595.00	7,873.08	123.97	227.90	0.94	1,794.00	1,691.00	599.00	7,872.60	123.96

August 1st moved south branch to Page Substation at 19:00

Table 35. Bidirectional VR Measured Data

Circuit Start: 7/17/2006 10:42 End: 7/17/2006 23:58
Generator Start: 7/17/2006 17:28 End: 7/17/2006 21:23

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Voltage 120V Base
Circuit Start	7/17/2006	10:42	132.20	0.98	1,039.00	1,021.00	190.00	7,857.51	123.72	126.90	0.99	998.00	984.00	169.00	7,868.23	123.89	120.50	0.98	946.00	929.00	179.00	7,852.46	123.64
Circuit Peak	7/17/2006	17:43	282.60	0.94	2,216.00	2,088.00	742.00	7841.79	123.48	255.70	0.95	2,009.00	1,913.00	612.00	7855.34	123.69	238.00	0.94	1,877.00	1,772.00	619.00	7887.05	124.19

Circuit Start: 7/29/2006 00:11 End: 7/29/2006 23:56
Generator Start: 7/29/2006 17:11 End: 7/29/2006 20:16

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base
Circuit Start	7/29/2006	0:11	157.80	0.89	1,248.00	1,110.00	570.00	7,908.95	124.53	138.80	0.90	1,096.00	991.00	468.00	7,896.23	124.33	143.40	0.88	1,133.00	1,000.00	533.00	7,901.98	124.42
Circuit Peak	7/29/2006	17:11	312.30	0.93	2,464.00	2,286.00	917.00	7887.81	124.20	296.60	0.94	2,331.00	2,190.00	798.00	7859.16	123.75	279.70	0.93	2,195.00	2,041.00	806.00	7,847.19	123.56

Circuit Start: 7/31/2006 00:11 End: 7/31/2006 23:56
Generator Start: 7/31/2006 16:11 End: 7/31/2006 17:11

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base
Circuit Start	7/31/2006	0:11	271.10	0.89	2,139.00	1,903.00	977.00	7,891.57	124.26	256.90	0.90	2,029.00	1,829.00	878.00	7,898.27	124.37	241.10	0.89	1,892.00	1,680.00	871.00	7,851.34	123.63
Circuit Peak	7/31/2006	17:56	369.00	0.94	2,882.00	2,695.00	1,021.00	7811.26	123.00	355.00	0.94	2,813.00	2,640.00	971.00	7924.79	124.78	314.00	0.93	2,486.00	2,317.00	900.00	7897.24	124.35

Circuit Start: 8/2/2006 00:11 End: 8/2/2006 23:56
Generator Start: 8/2/2006 10:26 End: 8/2/2006 12:16

	Date	Time	East Regulator Phase A							North Regulator Phase B							South Regulator Phase C						
			Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base	Load Current	Load Power Factor	Load Kva	Load KW	Load Kvar	Load Voltage	Load Voltage 120V Base
Circuit Start	8/2/2006	0:11	116.00	0.91	917.00	833.00	384.00	7,907.76	124.52	113.00	0.91	895.00	818.00	361.00	7,914.87	124.63	107.30	0.89	845.00	753.00	383.00	7,873.56	123.98
Generator	8/2/2006	12:16	170.10	0.96	1,334.00	1,287.00	352.00	7,844.62	123.52	154.10	0.98	1,210.00	1,185.00	246.00	7,854.76	123.68	149.40	0.97	1,167.00	1,136.00	267.00	7,811.54	123.00
Circuit Peak	8/2/2006	17:56	259.70	0.93	2,059.00	1,924.00	734.00	7,929.52	124.86	247.60	0.95	1,950.00	1,856.00	595.00	7,873.08	123.97	227.90	0.94	1,794.00	1,691.00	599.00	7,872.60	123.96

August 1st moved south branch to Page Substation at 19:00

Table 36. Circuit Equipment and Customer-Measured Data

Circuit Start: 7/17/2006 10:42 End: 7/17/2006 23:58
Generator Start: 7/17/2006 17:28 End: 7/17/2006 21:23

	Date	Time	Node F/6 Capacitor 1 (900 Kvar)						Node G/12 Capacitor 2 (900 Kvar)						Node H/13 Capacitor 3 (1200 Kvar)					
			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages		
			Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc
Circuit Start	7/17/2006	10:42	33.50	62.41	8.37	121.40	120.90	121.55	33.36	11.00	12.35	121.85	121.20	120.90	44.01	21.49	42.76	120.15	120.00	120.40
Circuit Peak	7/17/2006	17:43	48.57	108.20	13.00	118.25	117.75	121.08	51.96	14.00	23.83	120.65	118.40	118.65	65.84	27.09	53.70	117.05	116.93	118.15

	Date	Time	Node I			Node K	Node L
			Ia	Ib	Ic	Va	Vc
Circuit Start	7/17/2006	10:42	32.00	-	19.00	-	120.05
Circuit Peak	7/17/2006	17:43	46.00	-	31.00	-	117.60

Circuit Start: 7/29/2006 00:11 End: 7/29/2006 23:56
Generator Start: 7/29/2006 17:11 End: 7/29/2006 20:16

	Date	Time	Node F/6 Capacitor 1 (900 Kvar)						Node G/12 Capacitor 2 (900 Kvar)						Node H/13 Capacitor 3 (1200 Kvar)					
			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages		
			Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc
Circuit Start	7/29/2006	0:11	23.82	47.09	8.78				24.69	5.42	10.78				27.23	12.53	31.53			
Circuit Peak	7/29/2006	17:11	50.45	103.25	10.34				54.29	13.02	24.72				50.05	18.57	47.97			

Circuit Start: 7/31/2006 00:11 End: 7/31/2006 23:56
Generator Start: 7/31/2006 16:11 End: 7/31/2006 17:11

	Date	Time	Node F/6 Capacitor 1 (900 Kvar)						Node G/12 Capacitor 2 (900 Kvar)						Node H/13 Capacitor 3 (1200 Kvar)					
			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages		
			Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc
Circuit Start	7/31/2006	0:11	22.12	44.79	7.74				21.23	5.81	10.16				30.38	14.65	31.88			
Circuit Peak	7/31/2006	17:56	51.53	108.84	11.78				49.30	14.93	23.96				62.18	27.37	54.05			

Circuit Start: 8/2/2006 00:11 End: 8/2/2006 23:56
Generator Start: 8/2/2006 10:26 End: 8/2/2006 12:16

	Date	Time	Node F/6 Capacitor 1 (900 Kvar)						Node G/12 Capacitor 2 (900 Kvar)						Node H/13 Capacitor 3 (1200 Kvar)					
			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages			Phase Currents			Phase Voltages		
			Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc	Ia	Ib	Ic	Va	Vb	Vc
Circuit Start	8/2/2006	0:11	34.58	77.96	10.80				41.65	9.95	18.72				47.89	23.05	52.07			
Generator	8/2/2006	12:16	37.82	86.89	12.02				42.15	13.98	18.46				52.82	23.95	50.02			
Circuit Peak	8/2/2006	17:56	52.56	109.82	13.40				51.40	15.32	24.46				52.27	20.09	55.17			

	Date	Time	Node K	Node L
			Va	Vc
Circuit Start	8/2/2006	0:11		-
Generator	8/2/2006	12:16	119.15	-
Circuit Peak	8/2/2006	17:56	118.25	-

Notes

(1): August 1st moved south branch to Page Substation at 19:00
(2): Voltage Data At Capacitor Locations Not Available from July 26 until August 22
(3): All Capacitor Phase Voltages Are Measured On The Secondary Side At The Customer's Meter
(4): All Capacitor Phase Currents Are Measured On The Primary

Table 37. Field Verification Data – July 17, 2006 – DR Generation On

		Field Data - 7/17/06 - Circuit Peak 17:43									Simulation								
		Current			Voltage			PF			Current			Voltage			PF		
Location	**Node**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**
Start of Circuit	1	565.00	651.00	637.00	126.00	126.00	126.00	0.95	0.95	0.95	554.54	637.77	619.97	125.86	125.80	125.39	0.93	0.92	0.93
			2.2%			**0.3%**			**5.7%**										
Generator	10	18.31	17.24	17.00	122.50	122.50	120.25	0.96	0.96	0.96	17.49	17.25	17.36	121.68	123.38	122.62	0.96	0.96	0.96
			2.3%			**1.1%**			**0.0%**										
VR 1	9	282.60	255.70	238.00	123.48	123.69	124.19	0.94	0.95	0.94	274.07	246.07	227.56	123.60	123.82	123.62	0.93	0.94	0.93
			3.7%			**0.2%**			**2.4%**										
Cap 1*	6	48.57	108.20	13.00	118.25	117.75	121.08				48.03	104.47	13.77	121.25	121.14	123.29			
			3.0%			**0.7%**								*117.58*	*117.47*	*119.62*			
Cap 2*	12	51.96	14.00	23.83	120.65	118.40	118.65				52.18	14.87	24.53	120.51	123.09	121.87			
			2.0%			**1.5%**								*116.84*	*119.42*	*118.20*			
Cap 3*	13	65.84	27.09	53.70	117.05	116.93	118.15				64.44	27.92	50.18	119.04	121.44	120.03			
			3.9%			**1.2%**								*115.37*	*117.77*	*116.36*			
Node I	16	46.00		31.00							32.73		22.94						
			38.3%																
Node L*	18				117.60									121.42					
						0.1%								*117.75*					

*The voltage measurements were taken at the customer's meter. Therefore, an average voltage drop of 3.67 V was included to reduce the primary voltage to the secondary voltage for the comparison shown in the table.

Table 38. Field Verification Data – July 29, 2006 – DR Generation On

		Field Data - 7/29/06 - Circuit Peak 17:11									Simulation								
		Current			Voltage			PF			Current			Voltage			PF		
Location	**Node**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**	**A**	**B**	**C**
Start of Circuit	1	562.00	635.00	615.00							564.59	636.69	616.03	126.46	126.34	125.91	0.91	0.92	0.90
			0.3%																
Generator	10	8.07	7.08	6.84	122.25	122.25	120.75	0.98	0.98	0.98	7.30	7.19	7.22	121.76	123.67	123.17	0.98	0.98	0.98
			5.7%			**1.2%**			**0.0%**										
VR 1	9	312.30	296.60	279.70	124.20	123.75	123.56	0.93	0.94	0.93	316.35	299.29	284.46	123.92	124.46	124.48	0.92	0.92	0.92
			1.3%			**0.5%**			**3.4%**										
Cap 1	6	50.45	103.25	10.34							49.80	100.44	11.10						
			2.6%																
Cap 2	12	54.29	13.02	24.72							54.48	13.91	25.46						
			2.0%																
Cap 3	13	50.05	18.57	47.97							49.11	19.56	45.29						
			4.0%																

Table 39. Field Verification Data – July 31, 2006 – DR Generation Off

		Field Data - 7/31/06 - Circuit Peak 17:56									Simulation								
		Current			Voltage			PF			Current			Voltage			PF		
Location	Node	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
Start of Circuit	1	604.00	696.00	678.00							608.76	699.59	678.97	126.26	126.14	125.58	0.92	0.92	0.91
			0.5%																
Generator	10	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A									
VR 1	9	369.00	355.00	314.00	123.00	124.78	124.35	0.94	0.94	0.93	376.11	362.02	324.22	122.93	123.63	123.61	0.93	0.92	0.92
			2.3%			**0.5%**			**3.4%**										
Cap 1	6	51.53	108.84	11.78							50.82	105.52	12.49						
			2.8%																
Cap 2	12	49.30	14.93	23.96							48.74	15.69	24.55						
			2.2%																
Cap 3	13	62.18	27.37	54.05							60.45	28.03	49.14						
			5.1%																

Table 40. Percent Variance Between Actual and Simulated Currents, Voltages, and Power Factors

Location	Node	Current	Voltage	PF
Test Day 7/17/06 DR Generation Running				
Start of circuit	1	2.2	$\boxed{0.3}$	5.7
Generator	10	2.3	1.1	0.0
VR	9	3.7	$\boxed{0.2}$	2.4
Capacitor 1	6	3.0	0.7	--
Capacitor 2	12	2.0	1.5	--
Capacitor 3	13	3.9	1.2	--
Node I	16	38.3	--	--
Node L	18	--	0.1	--
Test Day 7/29/06 DR Generation Running				
Start of circuit	1	0.3	--	--
Generator	10	5.7	1.2	0.0
VR	9	1.3	$\boxed{0.5}$	3.4
Capacitor 1	6	2.6	--	--
Capacitor 2	12	2.0	--	--
Capacitor 3	13	4.0	--	--
Test Day 7/31/06 DR Generation Off				
Start of circuit	1	0.5	--	--
Generator	N/A	N/A	N/A	N/A
VR	9	2.3	$\boxed{0.5}$	3.4
Capacitor 1	6	2.8	--	--
Capacitor 2	12	2.2	--	--
Capacitor 3	13	5.1	--	--

9.6 Summary of Variance Results

From Table 40, the variance between actual field-measured data and simulated data is less than 6% (i.e., 5.7% actual) for the phase currents throughout the circuit (except for Node I, where the percent unbalanced current is very high). The highest variance for the phase voltages throughout the circuit is 1.5% percent, whereas the highest variance for the PF is 5.7% at the start of the circuit. It should be noted that the lowest variances occur on the load side of the step regulators because these regulators are individually phase-controlled and not gang-operated as the LTC at the substation.

As shown in the variance data in Table 40, the simulated data closely match the actual field-measured data in most cases, and the models developed in Section 5 can be used to estimate phase currents, phase voltages, and power factors without the use of extensive circuit metering. However, knowing the phasing of the loads is paramount to accurate simulated data. No significant difference in percent variance occurred when the DR was turned on or off.

10 Project Results – Distributed Generation Penetration Limits Using Maximum Real Power and Maximum Real and Reactive Power Methods of Voltage Control

10.1 Introduction

In this section, the largest synchronous generator that can be installed on the distribution circuit is determined. This is determined based on three criteria:

- The lowest single-phase voltage must not be less than 114 meter V or 117.67 V on the secondary of the distribution transformer, and the highest single-phase voltage cannot exceed 126 meter V.
- The generator must not exceed 100% of the thermal rating on the most limiting element.
- The generator must not create a reverse-power condition (i.e., there can be no flow back through the substation transformer).

Although these criteria were used for testing, a fourth criterion was that no system protection device could misoperate. This criterion was not applied because it was the subject of a prior Department of Energy contract.

10.2 Real Power Distributed Generation Size Limitation

Table 41 summarizes the results of applying the highest acceptable real power injection at the beginning point, BP, Node 2; the middle point, Node 10; and the end point, Node 17. The limiting criterion in all cases was reverse power. The optimum location was at the midpoint, which had the lowest single-phase voltage improvement of 1.7% and a real power loss savings of 2.04%. The base case real power losses were 5.4%. The largest real power injection was 13,980 kW at the end point; the beginning and midpoints were slightly less at 13,290 kW and 13,740 kW, respectively.

Table 41. Maximum Limit for Real Power Injection

Machine Type	Real Power	Reactive Power	Reason for Failure	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	13290	0	Reverse Power	BP	10	220.1696	271.2878	260.5665	119.6138	120.2031	118.6864	118.0618	100.0552	1.3408	4.5%	1826.3	10.089	0.0029	88.4603	59.5696
		VR (1) 32, 30, 32																		
SG	13740	0	Reverse Power	MP	9	209.6296	236.8509	231.5352	123.4694	121.8682	120.5033	119.8612	100.0533	0.9978	3.4%	1035.66	7.8879	0.7686	88.2549	76.4327
		VR (1) 14, 23, 22																		
SG	13980	0	Reverse Power	EP	11	259.8293	283.9373	288.2117	122.7994	121.6083	119.4167	118.7864	100.0536	1.3867	5.4%	2511.05	6.7255	0.6844	88.1865	71.7475
		VR (1) 11, 17, 21																		

Improvement							
Machine Type	Real Power	Reactive Power	Reason for Failure	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	13290	0	Reverse Power	BP	0.18%	0.93%	59.78%
		VR (1) 32, 30, 32					
SG	13740	0	Reverse Power	MP	1.70%	2.04%	76.64%
		VR (1) 14, 23, 22					
SG	13980	0	Reverse Power	EP	0.79%	0.00%	71.95%
		VR (1) 11, 17, 21					

Table 42. Maximum Limit for Real and Reactive Power Injection

Machine Type	Real Power	Reactive Power	Reason for Failure	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	13220	1893	Reverse Power	BP	8	142.0642	196.0875	183.4428	119.7491	120.385	118.8633	118.2371	100.0551	1.3197	4.4%	1687.92	14.4753	0.0028	88.4668	70.7768
		VR (1) 32, 29, 31																		
SG	14250	3480	Reverse Power	MP	6	67.2904	105.9963	101.8954	126.4554	124.0628	126.3554	123.2218	100.0518	0.7465	3.1%	748.35	22.1997	0.4043	88.3036	84.2032
		VR (1) -10, 0, -2																		
SG	14490	2007	Reverse Power	EP	8	177.3008	200.7446	203.7936	124.1336	122.7252	120.8493	120.205	100.0529	1.2065	5.1%	2227.32	9.7905	0.5588	88.2301	70.0828
		VR (1) 1, 9, 10																		

Improvement							
Machine Type	Real Power	Reactive Power	Reason for Failure	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	13220	1893	Reverse Power	BP	0.32%	1.00%	70.98%
		VR (1) 32, 29, 31					
SG	14250	3480	Reverse Power	MP	4.55%	2.30%	84.41%
		VR (1) -10, 0, -2					
SG	14490	2007	Reverse Power	EP	1.99%	0.28%	70.29%
		VR (1) 1, 9, 10					

10.3 Real and Reactive Distributed Generation Size Limitation

Table 42 shows the results of applying the maximum real and reactive power without exceeding study criteria. Notice that a much larger DG can be used when injecting both real and reactive power because, now, the real power limit is 14,490 kW (versus 13,980 kW for real power injection only). Again, the optimum location is at the midpoint. However, in this case, the lowest single-phase voltage was improved 4.55% versus only 1.7% in the real power case. The real power loss savings were marginally better (2.3% versus 2.04%) than the optimum real power injection case.

10.4 Findings

It should be remembered that the three-phase feeder conductor size of 636 kcmil aluminum is uniform throughout the Milford Circuit. Therefore, maximum size was not limited because of location of DG on the circuit. The optimum location for the greatest voltage improvement and real power loss savings is the midpoint.

11 Project Results – Distributed Generation Voltage Regulation and Optimum Generator Conditions for Maximum Improvement of Voltage Regulation, Loss Reduction, and Released Capacity

11.1 Introduction

In this section, three generation types are employed to determine their effect on distribution circuit voltage regulation when the magnitude of the real power injection and the reactive power export or import (absorption) is varied. The three types of generation are a 400-kW induction generator with two fixed reactive values, a 400-kW inverter-based generator with a ±0.8 power factor, and a 1,000-kW synchronous machine with a ±0.8 power factor.

Three effects may occur when DG is operated on a distribution circuit: voltage regulation improvement, released capacity savings, and real power loss reduction. These improvements were tabulated for each generator type for both high (105%) and low (95%) substation primary voltage. The data are summarized for the actual locations of the induction generator and the high-speed generator and inverter; the data for the synchronous machine are summarized for its actual location on the distribution circuit or the midlocation (ML, Node 10), at the beginning location (BL, Node 1), on the secondary of the substation after the LTC, and at the end location (EL, Node 17) near the tag end of the circuit.

This analysis was conducted for the actual peak-load, or HL, condition at 17:43 on July 17, 2006, and at the LL condition at 05:00 the same day. The results are tabulated and displayed in graphical form for voltage improvement, released capacity savings, and real energy loss reduction.

11.2 Factors to Consider for Test Result Evaluation

Two factors must be considered for simulation test result evaluation: (1) the dead band of the VR and (2) the effect the VDC source model on the increase or decrease in kilowatt and kilovar load as the voltage changes.

11.2.1 Regulator Dead Ban

The regulator dead band is set for 1 V. Because the regulator has a +5% boost in voltage over 32 steps and a -5% buck in voltage over 32 steps, the number of steps within the dead band is

$$\frac{5\%\ \text{voltage change}}{32\ \text{steps}} = 0.15625\%/\text{step x } 120 \text{ volts, or } 0.1875 \text{ volts/tap.}$$

The number of steps within the deadband is then

$$\frac{1\ \text{volt deadband}}{0.1875\ \text{volts}/\text{tap}} = 5 \text{ steps.}$$

So the voltage can change as much as 1 volt and not result in a change of the VR tap setting. When DG is run during an HV condition on the primary of the substation and at different real and plus or minus reactive power flows, the voltage will decrease or increase. This will cause the kilowatt and kilovar loads to decrease or increase. The change in voltage may not be enough to cause a reduction in the regulator settings (see Figure 141, Figure 155, and Figure 161). During the LV condition on the primary of the substation, the LTC and step regulator taps are typically set at the highest tap settings, and there is less effect because of the step regulator step-changing interventions.

11.2.2 Voltage-Dependent Current Source

The model that best represents how load characteristics change with a change in voltage is the VDC source model. Adding real and positive reactive power from DG sources will increase the voltage and cause an increase in current or kilovolt-ampere load, which, in turn, increases the real power energy losses and reduces the released capacity (see Figure 144). The model will cause a 1.8% increase in current with a 1% increase in voltage and a 1.8% decrease in current with a 1% decrease in voltage.

11.3 Interpreting the Distributed Generation Voltage Regulation Application Results

Two sets of tables summarize the results of the DG applications. The first set, Table 44 through Table 51, summarizes the results of applying each of the three generation types for both HV and LV substation primary conditions. Table 43 explains how to interpret the results. In the second set, Table 52 shows a summary of the benefits of running each type of DG. In the cases of the induction and inverter-based generators, the results are given for the location where the units are installed on the circuit. The induction generator is located at Node 17, or the EL, and the inverter generator is located at Node 22, or the midpoint. For the synchronous generator, the findings are summarized for generator locations at the beginning (Node 1), middle or actual location site (Node 10), and end (Node 17).

11.3.1 Induction Generator Voltage Regulation Application (High Voltage) – Heavy Load, Table 44

Each of the generator applications consists of different real power and reactive power injections (+) or absorption (-) for both HV (105%) and LV (95%) conditions on the primary of the substation. The LTC tap setting at the secondary of the substation transformer is recorded for each real and reactive power case considered, as well as the tap settings of the step regulator for each case. The phase currents I_A, I_B, and I_C at Node 1; the lowest three phase voltages V_A, V_B, and V_C; and the lowest single-phase voltage on the circuit are recorded along with the highest current unbalance I_2/I_1%, the highest voltage unbalance V_2/V_1%, the percent circuit losses (excluding the substation transformer), kilovar losses, and capacity savings.

Six cases were studied for the real power and reactive power. These are:

	P (kW)	Q (kVAr)	Substation Primary Voltage
1	400	0	LV
2	400	247.91	LV
3	400	-247.91	LV
4	400	0	HV
5	400	247.91	HV
6	400	-247.91	HV

Table 43 explains the meaning of each improvement from the base case with no DG application. For the substation primary LV case, notice that when plus reactive and real power are injected (400 kW, +247.91 kVAr), the lowest three-phase voltages increase, the lowest single-phase voltage increases, and the percent losses on the circuit are slightly lower (i.e., 5.145% compared with 5.4% for the base case). The percent loss improvement is then 0.25%, and the released capacity savings are 6.10%. For the substation primary HV case, the phase currents I_A, I_B, and I_C are about 20 A more because the higher voltage levels cause an increase in the load. Here, when the DG injects 400 kW of real power and +247.91 kVArs of reactive power, the lowest single-phase voltage improves by 0.12%, the percent energy loss savings improves 0.30%, and the released capacity improves only by 3.80%. This reduction in released capacity is due to the higher voltage and increased load. For the LV case, the released capacity was 6.10%. For the LV case, when the generator is absorbing volt-amperes reactive (i.e., -247.91 Vars), there is a drop in voltage. The lowest single-phase voltage is now 2.63% less than the base case. The loss savings is 0.2%, but the released capacity is 6.44%. For the HV case and the same P and –Q, the lowest voltage drops only 0.06%, the loss savings are 0.19%, and the released capacity is only 2.31%. Again, the higher the voltage, the greater the load and less released capacity.

Table 43. Explaining the Meaning of Positive and Negative Improvements for DG Applications[A, B, C]

Improvement Parameter	Negative % Numbers	Positive % Numbers
% Lowest single-phase voltage	Voltage drop from base case (negative improvement)	Voltage rise from base case (positive improvement)
% Real energy losses	Higher losses than base case (negative improvement)	Lower losses than base case (positive improvement)
% Released capacity	Higher capacity needed to serve the load (negative improvement)	Lower capacity needed to serve load (positive improvement)

Notes:

A. The percent voltage improvement is the percent difference between the lowest single-phase voltage on the circuit for the base case and the lowest single-phase voltage for the DG application being considered divided by the base case and multiplied by 100%.

B. The energy losses are the sum of all feeder lateral distribution transformer, secondary, and service losses, and the percent improvement is the difference between the base case percent losses for the circuit and the percent losses for the DG application.

C. The kilovolt-ampere released capacity percent improvement is the difference between the percent capacity needed to serve the load at Node 1 and the percent base case capacity.

11.3.2 Inverter Generator Voltage Regulation Application (High Voltage) – Heavy Load, Table 45

Because the real and reactive power capability of the high-speed generator inverter is about the same as that of the induction generator, the results are very similar to the induction generator voltage regulation application.

Six cases were studied for the inverter-based generation. These represent a full range of real and reactive capability.

	P (kW)	Q (kVAr)	Substation Primary Voltage
1	400	0	LV
2	320	240	LV
3	320	-240	LV
4	400	0	HV
5	320	240	HV
6	320	-240	HV

The savings in losses, voltage improvement, and released capacity are, in general, less than those of the induction generator application because the real power at maximum +Var output is less.

11.3.3 Synchronous Generator Voltage Regulation Application (Beginning Location, High Voltage) – Heavy Load, Table 46

Thirteen cases, with the range of real and reactive power shown below, were studied for the synchronous generator. Because regulation results differ depending on location, three locations were selected: the BL, ML, and EL.

	Location	P	Q	Substation Primary Voltage
1	BL	50%	0	HV
2	BL	75%	0	HV
3	BL	100%	0	HV
4	BL	106.7%	0	HV
5	BL	100%	100%	HV
6	BL	100%	-100%	HV
7	BL	25%	100%	HV
8	BL	25%	75%	HV
9	BL	25%	50%	HV
10	BL	25%	25%	HV
11	BL	25%	0%	HV
12	BL	25%	-50%	HV
13	BL	25%	-100%	HV

When the synchronous generator is located at the source end (near the substation), its maximum generation of real and reactive power reduces these requirements from the source and, as such, results in the highest released capacity of 7.36% when operated at P = 100% and Q = +100%. Although the losses are less than those of the base case, the loss savings are not as good as when the generation is closer to the load. The lowest single-phase voltage is, in general, better than the previous cases but still less than the base case.

11.3.4 Synchronous Generator Voltage Regulation Application (End Location, High Voltage) – Heavy Load, Table 47

Installing generation at the end of the circuit (EL) resulted in a released capacity savings of 6.85%, a loss savings of 0.53%, and near-base case conditions for voltage when the real power was 106.7% of nameplate and the reactive was 0%. When 100% reactive and 100% real power were applied, the voltage improved above the base case by 0.82%, and the released capacity was 5.97%. The worst-case voltage occurred when the unit was operated at -100% reactive and 100% real power. The lowest single-phase voltage dropped 0.44% below the base case. Both the voltage and the released capacity improvement parameters were worse than those of the base case when the unit was operated at 25% real power and -100% reactive. Here, the voltage dropped -0.7%, and the released capacity was only 1.5%.

11.3.5 Synchronous Generator Voltage Regulation Application (Midlocation, High Voltage) – Heavy Load, Table 48

The mid-location is the actual site of the 1,000-kW synchronous generator. The maximum released capacity of 6.88% occurs when the machine is operated at its maximum real power output of 106.7% and zero reactive power. This is to be expected because this input power to the circuit just offsets the same required power plus losses that the source provides to the circuit. Also, this case results in the second-highest loss savings of 0.48%, the highest loss saving being when the real power and reactive power are 100% each. The minimum released capacity of 1.15%, the lowest loss saving of 0.03%, and the worst-case single-phase voltage improvement of -0.81% occurs when the real power is only 25% and the reactive is -100%. Here, the voltage is reduced because of the high value of the generation reactive absorption. The best-case voltage improvement is 0.5% when the reactive is 100% export.

11.3.6 Synchronous Generator Voltage Regulation Application (Beginning Location, Low Voltage) Heavy Load, Table 49

When the primary of the substation is operating at the LV condition of 95%, the LTC at the substation is in the all-raise position (16), and the step regulator on the circuit operates at the all-raise position on all three phases (32, 32, 32). The released capacity savings reached their highest levels in this case with a 10.44% savings occurring at 100% real power and 100% reactive power. The voltages are lower than those of the base case by about 2% to 3%. The worst case occurred at -2.96% with 25% real and -100% reactive. This is obvious because the negative reactive is reducing the voltage. The best-case voltage of -1.93% occurred when 100% real power and 100% reactive export power were delivered at the BL. The loss improvements are quite low and range from only 0.02% to 0.13%.

11.3.7 Synchronous Generator Voltage Regulation Application (End Location, Low Voltage) – Heavy Load, Table 50

As before (see 11.3.6), the LTC regulator and the step regulator are operating at full-raise position during this LV condition on the primary of the substation. The capacity savings of 9.98% are slightly lower than those of the previous case, with the maximum real power output of 106.7%. All the voltage improvements are still negative, with the worst case occurring at -3.33% when P = 25% and Q -100%. The loss savings were better than the previous cases, with the maximum of 0.56% at P = 100% and Q = 100%. This is because a portion of the tag end load of the circuit is now being served by the DG. Again, this LV condition results in less kilovolt-amperes of load and, hence, lower losses.

11.3.8 Synchronous Generator Voltage Regulation Application (Midlocation, Low Voltage) – Heavy Load, Table 51

The midlocation performance is somewhat between the BL and EL performances. The released capacity is now 10.01% at 106.7% real power, whereas the released capacity was 10.44% at the BL and 9.98% at the EL. The greatest loss savings of 0.51% occurred at P = 100% and Q = 100%, which is slightly less than the maximum loss savings of 0.56% when the DG is located at the EL. The worst-case lowest single-phase voltage was -3.36%, compared with the best case of -2.96% when the DG is located at the BL and operating at P = 25% and Q = -100%. The best-case lowest single-phase voltage is -1.14% when P = 100% and Q = 100%, which is almost the same result as when the unit was located at the EL (-1.15%).

Table 44. Induction Generator Voltage Regulation Application (LV, HV) – HL

						Node 01			Lowest 3Φ Voltage			Lowest					I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
IG	400	0	LV	N/A	16	552.457	630.2362	612.8234	116.9241	117.2165	115.8406	115.1259	100.0563	1.3398	5.2%	2924.33	3.9985	0.7005	88.4458	6.0751
VR (1) 32, 32, 32																				
IG	400	247.91	LV	N/A	16	553.1808	631.4567	614.1055	117.2827	117.5672	116.2048	115.4859	100.0561	1.3216	5.1%	2931.47	4.0372	0.6957	88.4485	5.8932
VR (1) 32, 32, 32																				
IG	400	-247.91	LV	N/A	16	551.9444	629.1895	611.7199	116.5597	116.8611	115.4707	114.7603	100.0564	1.3594	5.2%	2920.77	3.9577	0.7054	88.443	6.2311
VR (1) 32, 32, 32																				
IG	400	0	HV	N/A	3	571.6509	648.8639	632.2462	119.2617	119.7564	118.2793	117.5369	100.0553	1.2632	5.1%	2990.79	3.8551	0.6694	88.4629	3.299
VR (1) 30, 26, 27																				
IG	400	247.91	HV	N/A	3	568.6085	646.8681	629.8217	119.7302	120.1709	118.7389	117.9912	100.0551	1.2666	5.1%	2960.5	3.9362	0.6629	88.4648	3.5964
VR (1) 26, 23, 23																				
IG	400	-247.91	HV	N/A	4	579.2854	656.8888	639.831	119.523	120.0307	118.5256	117.7804	100.0552	1.2836	5.2%	3082.02	3.8059	0.6799	88.4585	2.103
VR (1) 32, 28, 29																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest 1Φ Voltage	kW Losses	Node 1 Capacity
IG	400	0	LV	N/A	-2.32%	0.23%	6.28%
VR (1) 32, 32, 32							
IG	400	247.91	LV	N/A	-2.01%	0.25%	6.10%
VR (1) 32, 32, 32							
IG	400	-247.91	LV	N/A	-2.63%	0.20%	6.44%
VR (1) 32, 32, 32							
IG	400	0	HV	N/A	-0.27%	0.25%	3.51%
VR (1) 30, 26, 27							
IG	400	247.91	HV	N/A	0.12%	0.30%	3.80%
VR (1) 26, 23, 23							
IG	400	-247.91	HV	N/A	-0.06%	0.19%	2.31%
VR (1) 32, 28, 29							

Table 45. Inverter Generator Voltage Regulation Application (LV, HV) – HL

Table 11.2 Inverter Generator Voltage Regulation Application (LV, HV) - Heavy Load

						Node 01			Lowest 3Φ Voltage			Lowest					I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
InvG	400	0	LV	N/A	16	552.4406	630.1595	612.4781	117.0235	117.1949	115.8796	115.1541	100.0562	1.3684	5.2%	2952.59	3.9782	0.6943	82.3537	6.0865
VR (1) 32, 32, 32																				
InvG	320	240	LV	N/A	16	555.3521	633.2756	616.0219	117.5087	117.6895	116.3973	115.6369	107.5141	1.363	5.2%	2985.68	3.9892	0.6889	80.9469	5.6221
VR (1) 32, 32, 32																				
InvG	320	-240	LV	N/A	16	555.7432	633.3703	615.2559	116.3862	116.6189	115.2498	114.5651	100.0565	1.3826	5.3%	2978.01	3.9493	0.7025	68.8583	5.608
VR (1) 32, 32, 32																				
InvG	400	0	HV	N/A	3	570.7684	648.7027	631.0691	119.3939	119.7258	118.3498	117.5964	100.0552	1.3194	5.2%	3013.17	3.8672	0.6628	90.3889	3.323
VR (1) 29, 26, 26																				
InvG	320	240	HV	N/A	3	576.2127	653.6868	637.0627	119.765	120.1514	118.7634	117.9769	122.1077	1.2764	5.2%	3070.41	3.8373	0.6587	77.7744	2.5802
VR (1) 32, 28, 29																				
InvG	320	-240	HV	N/A	4	583.018	660.9927	643.3038	119.355	119.7961	118.3125	117.5922	100.0553	1.3048	5.2%	3139.33	3.7977	0.6769	68.8948	1.4914
VR (1) 32, 28, 29																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
InvG	400	0	LV	N/A	-2.29%	0.22%	6.29%
VR (1) 32, 32, 32							
InvG	320	240	LV	N/A	-1.88%	0.16%	5.83%
VR (1) 32, 32, 32							
InvG	320	-240	LV	N/A	-2.79%	0.13%	5.81%
VR (1) 32, 32, 32							
InvG	400	0	HV	N/A	-0.22%	0.24%	3.53%
VR (1) 29, 26, 26							
InvG	320	240	HV	N/A	0.10%	0.21%	2.79%
VR (1) 32, 28, 29							
InvG	320	-240	HV	N/A	-0.22%	0.16%	1.70%
VR (1) 32, 28, 29							

Table 46. Synchronous Generator Voltage Regulation Application (BL, HV) – HL

Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	50%	0	HV	BL	3	569.7675	647.5676	630.3888	118.9988	119.5496	118.0643	117.3244	100.0554	1.3032	5.3%	3085.62	3.9085	0.6717	88.4676	3.4922
VR (1) 32, 28, 29																				
SG	75%	0	HV	BL	3	560.5307	638.4113	621.1837	119.0267	119.5778	118.0917	117.3515	100.0554	1.3034	5.3%	3040.39	3.9695	0.6718	88.4675	4.8567
VR (1) 32, 28, 29																				
SG	100%	0	HV	BL	3	551.3242	629.2837	612.0087	119.0544	119.6056	118.1188	117.3782	100.0554	1.3037	5.3%	2995.99	4.0321	0.0027	88.4674	6.217
VR (1) 32, 28, 29																				
SG	106.7%	0	HV	BL	3	548.8595	626.8399	609.5523	119.0618	119.613	118.126	117.3854	100.0554	1.3037	5.3%	2984.23	4.0492	0.0027	88.4674	6.5812
VR (1) 32, 28, 29																				
SG	100%	100%	HV	BL	3	545.0327	623.0061	605.5145	119.5898	120.1441	118.643	117.8965	100.0552	1.3085	5.3%	2989.46	4.1082	0.0027	88.4658	7.1526
VR (1) 32, 28, 29																				
SG	100%	-100%	HV	BL	3	565.4395	644.8146	627.551	119.1903	119.6974	118.2112	117.4696	100.0554	1.3253	5.3%	3089.67	3.9899	0.0029	88.4606	3.9024
VR (1) 32, 29, 30																				
SG	25%	100%	HV	BL	3	573.1587	650.8478	633.5213	119.5061	120.0599	118.561	117.8155	100.0552	1.3078	5.3%	3125.69	3.9176	0.6742	88.466	3.0033
VR (1) 32, 28, 29																				
SG	25%	75%	HV	BL	3	574.5047	652.2184	634.9375	119.3716	119.9246	118.4293	117.6853	100.0553	1.3066	5.3%	3126.54	3.901	0.6735	88.4664	2.799
VR (1) 32, 28, 29																				
SG	25%	50%	HV	BL	3	575.9175	653.6441	636.4107	119.2389	119.7912	118.2994	117.5568	100.0553	1.3054	5.3%	3127.81	3.8843	0.6729	88.4668	2.5866
VR (1) 32, 28, 29																				
SG	25%	25%	HV	BL	3	577.4435	655.1716	637.9895	119.1038	119.6552	118.1671	117.426	100.0554	1.3041	5.3%	3129.55	3.8668	0.6722	88.4672	2.3589
VR (1) 32, 28, 29																				
SG	25%	0%	HV	BL	3	579.0334	656.7516	639.6228	118.9705	119.5212	118.0366	117.297	100.0554	1.3029	5.3%	3131.69	3.8492	0.6715	88.4676	2.1235
VR (1) 32, 28, 29																				
SG	25%	-50%	HV	BL	4	588.6396	667.0585	649.8389	119.3703	119.9216	118.4242	117.6801	100.0553	1.3072	5.4%	3211.77	3.8093	0.6749	88.4658	0.5874
VR (1) 32, 28, 29																				
SG	25%	-100%	HV	BL	4	592.5017	671.6892	654.5498	119.1057	119.6124	118.1285	117.3878	100.0554	1.3245	5.4%	3226.28	3.8167	0.6809	88.4608	-0.1027
VR (1) 32, 29, 30																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	HV	BL	-0.45%	0.08%	3.70%
VR (1) 32, 28, 29							
SG	75%	0	HV	BL	-0.43%	0.11%	5.06%
VR (1) 32, 28, 29							
SG	100%	0	HV	BL	-0.40%	0.13%	6.42%
VR (1) 32, 28, 29							
SG	106.7%	0	HV	BL	-0.40%	0.13%	6.79%
VR (1) 32, 28, 29							
SG	100%	100%	HV	BL	0.04%	0.14%	7.36%
VR (1) 32, 28, 29							
SG	100%	-100%	HV	BL	-0.33%	0.08%	4.11%
VR (1) 32, 29, 30							
SG	25%	100%	HV	BL	-0.03%	0.08%	3.21%
VR (1) 32, 28, 29							
SG	25%	75%	HV	BL	-0.14%	0.07%	3.01%
VR (1) 32, 28, 29							
SG	25%	50%	HV	BL	-0.25%	0.07%	2.79%
VR (1) 32, 28, 29							
SG	25%	25%	HV	BL	-0.36%	0.07%	2.57%
VR (1) 32, 28, 29							
SG	25%	0%	HV	BL	-0.47%	0.06%	2.33%
VR (1) 32, 28, 29							
SG	25%	-50%	HV	BL	-0.15%	0.03%	0.79%
VR (1) 32, 28, 29							
SG	25%	-100%	HV	BL	-0.40%	0.02%	0.10%
VR (1) 32, 29, 30							

Table 47. Synchronous Generator Voltage Regulation Application (EL, HV) – HL

						Node 01			Lowest 3Φ Voltage			Lowest					I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
SG	50%	0	HV	EL	3	570.0817	647.3645	630.642	119.2577	119.742	118.2744	117.532	100.0553	1.2618	5.1%	2973.1	3.8604	0.6697	88.4628	3.5224
VR (1) 32, 28, 29																				
SG	75%	0	HV	EL	3	561.0321	638.1117	621.5711	119.4095	119.8616	118.401	117.6572	100.0552	1.2525	5.0%	2875.42	3.8957	0.6689	88.4604	4.9014
VR (1) 32, 28, 29																				
SG	100%	0	HV	EL	3	552.0319	628.8905	612.534	119.5571	119.9779	118.5236	117.7784	100.0552	1.2434	4.9%	2781.08	3.9317	0.6683	88.4579	6.2756
VR (1) 32, 28, 29																				
SG	106.7%	0	HV	EL	3	549.6257	626.4219	610.115	119.596	120.0085	118.5558	117.8102	100.0551	1.241	4.9%	2756.33	3.9415	0.6681	88.4573	6.6435
VR (1) 32, 28, 29																				
SG	100%	100%	HV	EL	3	553.2643	632.3135	615.4063	120.6019	120.9582	119.5848	118.8273	100.0547	1.2115	4.8%	2797.7	4.0748	0.6528	94.3303	5.7655
VR (1) 31, 28, 28																				
SG	100%	-100%	HV	EL	4	558.1387	634.894	618.1221	119.1788	119.5887	118.0735	117.3335	100.0554	1.2939	5.0%	2867.19	3.8478	0.6961	88.4414	5.3809
VR (1) 32, 29, 30																				
SG	25%	100%	HV	EL	3	581.5285	660.3106	643.6109	120.1129	120.6085	119.1723	118.4197	100.0549	1.2474	5.2%	3101.21	3.9285	0.6554	88.473	1.593
VR (1) 32, 28, 29																				
SG	25%	75%	HV	EL	3	580.7804	659.2589	642.5056	119.8622	120.3626	118.9172	118.1675	100.055	1.2532	5.2%	3091.66	3.9041	0.6591	88.4711	1.7498
VR (1) 32, 28, 29																				
SG	25%	50%	HV	EL	3	580.1452	658.3071	641.5027	119.6129	120.1184	118.6635	117.9167	100.0551	1.259	5.2%	3084.02	3.879	0.6629	88.4692	1.8916
VR (1) 32, 28, 29																				
SG	25%	25%	HV	EL	3	579.605	657.4265	640.572	119.3567	119.8678	118.4028	117.659	100.0552	1.2651	5.2%	3078.1	3.8526	0.6667	88.4673	2.0229
VR (1) 32, 28, 29																				
SG	25%	0%	HV	EL	3	579.1803	656.6483	639.7466	119.1019	119.6189	118.1435	117.4027	100.0554	1.2734	5.2%	3074.16	3.8256	0.6705	88.4653	2.1389
VR (1) 32, 28, 29																				
SG	25%	-50%	HV	EL	4	584.876	663.1896	645.9419	119.2565	119.7462	118.2349	117.493	100.0554	1.3302	5.3%	3152.87	3.8112	0.6902	88.4529	1.164
VR (1) 32, 29, 30																				
SG	25%	-100%	HV	EL	4	584.8512	662.3115	645.7803	118.7268	119.2323	117.6578	116.9226	100.0556	1.3404	5.4%	3161.99	3.768	0.7057	88.442	1.2949
VR (1) 32, 29, 31																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	HV	EL	-0.27%	0.28%	3.73%
VR (1) 32, 28, 29							
SG	75%	0	HV	EL	-0.17%	0.39%	5.11%
VR (1) 32, 28, 29							
SG	100%	0	HV	EL	-0.06%	0.50%	6.48%
VR (1) 32, 28, 29							
SG	106.7%	0	HV	EL	-0.04%	0.53%	6.85%
VR (1) 32, 28, 29							
SG	100%	100%	HV	EL	0.82%	0.56%	5.97%
VR (1) 31, 28, 28							
SG	100%	-100%	HV	EL	-0.44%	0.37%	5.59%
VR (1) 32, 29, 30							
SG	25%	100%	HV	EL	0.48%	0.22%	1.80%
VR (1) 32, 28, 29							
SG	25%	75%	HV	EL	0.27%	0.21%	1.96%
VR (1) 32, 28, 29							
SG	25%	50%	HV	EL	0.05%	0.20%	2.10%
VR (1) 32, 28, 29							
SG	25%	25%	HV	EL	-0.17%	0.18%	2.23%
VR (1) 32, 28, 29							
SG	25%	0%	HV	EL	-0.38%	0.16%	2.35%
VR (1) 32, 28, 29							
SG	25%	-50%	HV	EL	-0.31%	0.09%	1.37%
VR (1) 32, 29, 30							
SG	25%	-100%	HV	EL	-0.79%	0.03%	1.50%
VR (1) 32, 29, 31							

Table 48. Synchronous Generator Voltage Regulation Application (ML, HV) – HL

Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	50%	0	HV	ML	4	576.1912	654.2454	637.2163	119.9124	120.3898	118.9073	118.1577	100.0551	1.2761	5.2%	3062.53	3.8547	0.6735	88.4599	2.497
VR (1) 32, 28, 29																				
SG	75%	0	HV	ML	4	567.1353	645.0019	628.1048	120.0596	120.5	119.0274	118.2764	100.055	1.2599	5.1%	2970.4	3.8887	0.6722	88.4574	3.8745
VR (1) 32, 28, 29																				
SG	100%	0	HV	ML	3	551.7973	628.6983	612.1472	119.5362	119.9369	118.4938	117.7489	100.0552	1.2387	5.0%	2808.4	3.9286	0.6662	88.4572	6.3043
VR (1) 32, 28, 29																				
SG	106.7%	0	HV	ML	3	549.37	626.2141	609.6999	119.5748	119.9656	118.525	117.7798	100.0551	1.236	4.9%	2784.82	3.9382	0.6659	88.4565	6.6745
VR (1) 32, 28, 29																				
SG	100%	100%	HV	ML	3	551.6677	630.5463	613.5866	120.6176	120.9517	119.5915	118.8339	100.0547	1.231	4.9%	2817.49	4.0656	0.6485	88.466	6.0289
VR (1) 31, 28, 28																				
SG	100%	-100%	HV	ML	4	559.1494	636.2131	619.1058	119.1376	119.526	118.0228	117.2833	100.0554	1.3092	5.1%	2891.46	3.8543	0.696	88.4403	5.1843
VR (1) 32, 29, 30																				
SG	25%	100%	HV	ML	3	580.1401	658.7236	642.1133	120.143	120.6317	119.2001	118.4472	100.0549	1.2438	5.2%	3101	3.9212	0.6527	88.4733	1.8296
VR (1) 32, 28, 29																				
SG	25%	75%	HV	ML	3	579.7367	658.0634	641.3639	119.8813	120.3756	118.9341	118.1842	100.055	1.2525	5.2%	3094.6	3.898	0.657	88.4713	1.928
VR (1) 32, 28, 29																				
SG	25%	50%	HV	ML	3	579.4374	657.4961	640.7111	119.6221	120.1221	118.6705	117.9236	100.0551	1.2632	5.2%	3089.47	3.8745	0.6613	88.4693	2.0125
VR (1) 32, 28, 29																				
SG	25%	25%	HV	ML	3	579.2344	657.005	640.1354	119.3568	119.8629	118.4008	117.657	100.0552	1.2744	5.2%	3085.46	3.8498	0.6656	88.4672	2.0857
VR (1) 32, 28, 29																				
SG	25%	0%	HV	ML	4	585.2859	663.5147	646.3563	119.7628	120.2777	118.7848	118.0366	100.0551	1.2926	5.3%	3156.84	3.8214	0.6748	88.4625	1.1155
VR (1) 32, 28, 29																				
SG	25%	-50%	HV	ML	4	585.4652	663.9017	646.5384	119.2355	119.7207	118.2116	117.47	100.0554	1.3345	5.3%	3161.93	3.8146	0.6908	88.4525	1.0579
VR (1) 32, 29, 30																				
SG	25%	-100%	HV	ML	4	586.0652	664.643	647.0848	118.7006	119.1573	117.6306	116.8956	100.0556	1.3769	5.4%	3172.1	3.8039	0.7068	88.4424	0.9474
VR (1) 32, 30, 31																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	HV	ML	0.26%	0.23%	2.70%
VR (1) 32, 28, 29							
SG	75%	0	HV	ML	0.36%	0.33%	4.08%
VR (1) 32, 28, 29							
SG	100%	0	HV	ML	-0.09%	0.45%	6.51%
VR (1) 32, 28, 29							
SG	106.7%	0	HV	ML	-0.06%	0.48%	6.88%
VR (1) 32, 28, 29							
SG	100%	100%	HV	ML	0.83%	0.51%	6.24%
VR (1) 31, 28, 28							
SG	100%	-100%	HV	ML	-0.49%	0.34%	5.39%
VR (1) 32, 29, 30							
SG	25%	100%	HV	ML	0.50%	0.20%	2.04%
VR (1) 32, 28, 29							
SG	25%	75%	HV	ML	0.28%	0.19%	2.13%
VR (1) 32, 28, 29							
SG	25%	50%	HV	ML	0.06%	0.18%	2.22%
VR (1) 32, 28, 29							
SG	25%	25%	HV	ML	-0.17%	0.16%	2.29%
VR (1) 32, 28, 29							
SG	25%	0%	HV	ML	0.15%	0.13%	1.32%
VR (1) 32, 28, 29							
SG	25%	-50%	HV	ML	-0.33%	0.08%	1.26%
VR (1) 32, 29, 30							
SG	25%	-100%	HV	ML	-0.81%	0.03%	1.15%
VR (1) 32, 30, 31							

Table 49. Synchronous Generator Voltage Regulation Application (BL, LV) – HL

						Node 01			Lowest 3Φ Voltage			Lowest					I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
SG	50%	0	LV	BL	16	548.6123	626.86	609.0336	116.7192	117.0647	115.6745	114.9617	100.0564	1.3905	5.3%	2996.76	4.0662	0.7018	88.4496	6.5782
VR (1) 32, 32, 32																				
SG	75%	0	LV	BL	16	539.1941	617.5306	599.6492	116.7506	117.0963	115.7052	114.9921	100.0563	1.3908	5.3%	2948.95	4.1333	0.702	88.4495	7.9686
VR (1) 32, 32, 32																				
SG	100%	0	LV	BL	16	529.8083	608.2319	590.297	116.7817	117.1274	115.7356	115.0221	100.0563	1.3911	5.3%	2902.08	4.2024	0.0031	88.4494	9.3544
VR (1) 32, 32, 32																				
SG	106.7%	0	LV	BL	16	527.2958	605.7425	587.7935	116.79	117.1357	115.7437	115.0301	100.0563	1.3912	5.3%	2889.65	4.2212	0.0031	88.4494	9.7254
VR (1) 32, 32, 32																				
SG	100%	100%	LV	BL	16	523.8771	602.3187	584.1404	117.3644	117.7121	116.3049	115.585	100.0561	1.3965	5.3%	2897.59	4.2846	0.0031	88.4476	10.2357
VR (1) 32, 32, 32																				
SG	100%	-100%	LV	BL	16	537.3505	615.5354	597.8991	116.1926	116.5363	115.1599	114.453	100.0566	1.3855	5.3%	2914.53	4.111	0.0031	88.4514	8.266
VR (1) 32, 32, 32																				
SG	25%	100%	LV	BL	16	552.5664	630.6959	612.7041	117.2703	117.6177	116.213	115.4941	100.0561	1.3957	5.3%	3041.67	4.0744	0.0031	88.4479	6.0066
VR (1) 32, 32, 32																				
SG	25%	75%	LV	BL	16	553.8063	631.9622	614.0214	117.124	117.4709	116.07	115.3527	100.0562	1.3943	5.3%	3041.9	4.0567	0.7039	88.4483	5.8179
VR (1) 32, 32, 32																				
SG	25%	50%	LV	BL	16	555.1215	633.2907	615.4032	116.9796	117.326	115.929	115.2133	100.0563	1.393	5.3%	3042.61	4.0387	0.7032	88.4488	5.6199
VR (1) 32, 32, 32																				
SG	25%	25%	LV	BL	16	556.5554	634.725	616.8951	116.8325	117.1784	115.7852	115.0712	100.0563	1.3916	5.3%	3043.81	4.0199	0.7024	88.4493	5.4061
VR (1) 32, 32, 32																				
SG	25%	0%	LV	BL	16	558.0616	636.2191	618.449	116.6874	117.0328	115.6434	114.931	100.0564	1.3902	5.4%	3045.5	4.0009	0.7016	88.4497	5.1834
VR (1) 32, 32, 32																				
SG	25%	-50%	LV	BL	16	561.387	639.4819	621.8422	116.3935	116.7379	115.3562	114.6471	100.0565	1.3875	5.4%	3050.38	3.961	0.7	88.4507	4.6972
VR (1) 32, 32, 32																				
SG	25%	-100%	LV	BL	16	565.0973	643.0796	625.5829	116.098	116.4414	115.0675	114.3616	100.0566	1.3847	5.4%	3057.28	3.9192	0.0031	88.4517	4.161
VR (1) 32, 32, 32																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	LV	BL	-2.45%	0.07%	6.78%
VR (1) 32, 32, 32							
SG	75%	0	LV	BL	-2.43%	0.09%	8.17%
VR (1) 32, 32, 32							
SG	100%	0	LV	BL	-2.40%	0.12%	9.56%
VR (1) 32, 32, 32							
SG	106.7%	0	LV	BL	-2.40%	0.12%	9.93%
VR (1) 32, 32, 32							
SG	100%	100%	LV	BL	-1.93%	0.13%	10.44%
VR (1) 32, 32, 32							
SG	100%	-100%	LV	BL	-2.89%	0.10%	8.47%
VR (1) 32, 32, 32							
SG	25%	100%	LV	BL	-2.00%	0.06%	6.21%
VR (1) 32, 32, 32							
SG	25%	75%	LV	BL	-2.12%	0.06%	6.02%
VR (1) 32, 32, 32							
SG	25%	50%	LV	BL	-2.24%	0.05%	5.83%
VR (1) 32, 32, 32							
SG	25%	25%	LV	BL	-2.36%	0.05%	5.61%
VR (1) 32, 32, 32							
SG	25%	0%	LV	BL	-2.48%	0.05%	5.39%
VR (1) 32, 32, 32							
SG	25%	-50%	LV	BL	-2.72%	0.04%	4.90%
VR (1) 32, 32, 32							
SG	25%	-100%	LV	BL	-2.96%	0.02%	4.37%
VR (1) 32, 32, 32							

Table 50. Synchronous Generator Voltage Regulation Application (EL, LV) – HL

Type	Power	Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % (<100)	Capacity
SG	50%	0	LV	EL	16	549.006	626.7122	609.3697	116.9842	117.2648	115.8915	115.1763	100.0562	1.3285	5.1%	2886.35	4.0128	0.7003	88.4449	6.6003
	VR (1) 32, 32, 32																			
SG	75%	0	LV	EL	16	539.8146	617.3121	600.1594	117.1419	117.3913	116.0245	115.3077	100.0561	1.2987	5.0%	2787.26	4.0515	0.6999	88.4424	8.0012
	VR (1) 32, 32, 32																			
SG	100%	0	LV	EL	16	530.6745	607.9443	590.9841	117.2951	117.5141	116.1531	115.4348	100.0561	1.2695	4.9%	2691.66	4.0909	0.6994	88.44	9.3973
	VR (1) 32, 32, 32																			
SG	106.7%	0	LV	EL	16	528.2311	605.4366	588.5284	117.3354	117.5464	116.1868	115.4681	100.0561	1.2617	4.9%	2666.6	4.1016	0.6993	88.4393	9.771
	VR (1) 32, 32, 32																			
SG	100%	100%	LV	EL	16	533.2555	611.9855	595.217	118.3551	118.5527	117.2303	116.4997	100.0556	1.2174	4.8%	2719.58	4.2068	0.685	88.4481	8.795
	VR (1) 32, 32, 32																			
SG	100%	-100%	LV	EL	16	530.0755	605.5359	588.4268	116.1839	116.4322	115.0243	114.3189	100.0566	1.3493	5.0%	2696.18	3.9554	0.7147	88.4312	9.7562
	VR (1) 32, 32, 32																			
SG	25%	100%	LV	EL	16	561.0616	640.3213	622.989	117.8818	118.1728	116.8302	116.1042	100.0558	1.3084	5.2%	3021.61	4.0834	0.6866	88.4553	4.5721
	VR (1) 32, 32, 32																			
SG	25%	75%	LV	EL	16	560.1873	639.133	621.7479	117.6192	117.915	116.5635	115.8405	100.056	1.32	5.2%	3010.52	4.0577	0.6901	88.4534	4.7492
	VR (1) 32, 32, 32																			
SG	25%	50%	LV	EL	16	559.4335	638.051	620.6159	117.358	117.6588	116.2982	115.5783	100.0561	1.3322	5.2%	3001.46	4.0314	0.6936	88.4514	4.9104
	VR (1) 32, 32, 32																			
SG	25%	25%	LV	EL	16	558.779	637.0428	619.5591	117.0894	117.3959	116.0254	115.3086	100.0562	1.3453	5.2%	2994.18	4.0034	0.6973	88.4494	5.0607
	VR (1) 32, 32, 32																			
SG	25%	0%	LV	EL	16	558.2482	636.1438	618.6145	116.822	117.1345	115.754	115.0403	100.0563	1.3589	5.2%	2988.98	3.9748	0.7009	88.4474	5.1947
	VR (1) 32, 32, 32																			
SG	25%	-50%	LV	EL	16	557.5336	634.6244	617.0118	116.2731	116.5994	115.1969	114.4896	100.0565	1.3886	5.3%	2984.61	3.9137	0.7083	88.4432	5.4211
	VR (1) 32, 32, 32																			
SG	25%	-100%	LV	EL	16	557.3193	633.5188	615.8361	115.7105	116.0528	114.626	113.9253	100.0568	1.4216	5.4%	2988.86	3.8481	0.7159	88.4389	5.5859
	VR (1) 32, 32, 32																			

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	LV	EL	-2.27%	0.28%	6.81%
	VR (1) 32, 32, 32						
SG	75%	0	LV	EL	-2.16%	0.39%	8.21%
	VR (1) 32, 32, 32						
SG	100%	0	LV	EL	-2.05%	0.51%	9.60%
	VR (1) 32, 32, 32						
SG	106.7%	0	LV	EL	-2.03%	0.54%	9.98%
	VR (1) 32, 32, 32						
SG	100%	100%	LV	EL	-1.15%	0.56%	9.00%
	VR (1) 32, 32, 32						
SG	100%	-100%	LV	EL	-3.00%	0.40%	9.96%
	VR (1) 32, 32, 32						
SG	25%	100%	LV	EL	-1.49%	0.21%	4.78%
	VR (1) 32, 32, 32						
SG	25%	75%	LV	EL	-1.71%	0.20%	4.96%
	VR (1) 32, 32, 32						
SG	25%	50%	LV	EL	-1.93%	0.19%	5.12%
	VR (1) 32, 32, 32						
SG	25%	25%	LV	EL	-2.16%	0.17%	5.27%
	VR (1) 32, 32, 32						
SG	25%	0%	LV	EL	-2.39%	0.15%	5.40%
	VR (1) 32, 32, 32						
SG	25%	-50%	LV	EL	-2.86%	0.10%	5.63%
	VR (1) 32, 32, 32						
SG	25%	-100%	LV	EL	-3.33%	0.04%	5.79%
	VR (1) 32, 32, 32						
	VR (1) 32, 28, 29						

Table 51. Synchronous Generator Voltage Regulation Application (ML, LV) – HL

Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	50%	0	LV	ML	16	548.8954	626.6189	609.1722	116.97	117.2405	115.8728	115.1577	100.0562	1.3534	5.2%	2901.89	4.0115	0.6993	88.4445	6.6142
	VR (1) 32, 32, 32																			
SG	75%	0	LV	ML	16	539.6345	617.1659	599.8566	117.1235	117.3573	115.9993	115.2827	100.0562	1.3356	5.0%	2808.77	4.0498	0.6983	88.4419	8.023
	VR (1) 32, 32, 32																			
SG	100%	0	LV	ML	16	530.4157	607.7407	590.5718	117.2744	117.472	116.1231	115.4052	100.0561	1.3181	4.9%	2717.96	4.089	0.6974	88.4392	9.4276
	VR (1) 32, 32, 32																			
SG	106.7%	0	LV	ML	16	527.9495	605.2168	588.0861	117.3145	117.5024	116.1559	115.4376	100.0561	1.3134	4.9%	2694	4.0996	0.6971	88.4385	9.8037
	VR (1) 32, 32, 32																			
SG	100%	100%	LV	ML	16	531.6213	610.1927	593.3617	118.373	118.547	117.2388	116.508	100.0556	1.277	4.9%	2737.94	4.1987	0.6806	88.4478	9.0622
	VR (1) 32, 32, 32																			
SG	100%	-100%	LV	ML	16	531.0778	606.8617	589.4042	116.1427	116.3682	114.973	114.2682	100.0566	1.364	5.0%	2719.09	3.9633	0.7148	88.43	9.5586
	VR (1) 32, 32, 32																			
SG	25%	100%	LV	ML	16	559.6553	638.7202	621.4732	117.9141	118.1974	116.8601	116.1337	100.0558	1.3311	5.2%	3020.68	4.0764	0.6836	88.4556	4.8107
	VR (1) 32, 32, 32																			
SG	25%	75%	LV	ML	16	559.128	637.9253	620.5903	117.6398	117.9289	116.5818	115.8586	100.0559	1.3409	5.2%	3012.89	4.052	0.6878	88.4535	4.9292
	VR (1) 32, 32, 32																			
SG	25%	50%	LV	ML	16	558.713	637.2304	619.8111	117.368	117.663	116.306	115.586	100.0561	1.3507	5.2%	3006.48	4.0271	0.6919	88.4515	5.0327
	VR (1) 32, 32, 32																			
SG	25%	25%	LV	ML	16	558.3989	636.6144	619.1121	117.0897	117.3909	116.0236	115.3068	100.0562	1.3611	5.2%	3001.22	4.0008	0.6961	88.4493	5.1245
	VR (1) 32, 32, 32																			
SG	25%	0%	LV	ML	16	558.1977	636.0994	618.5182	116.8139	117.1215	115.7437	115.0301	100.0563	1.3715	5.3%	2997.36	3.9741	0.7003	88.4472	5.2013
	VR (1) 32, 32, 32																			
SG	25%	-50%	LV	ML	16	558.1264	635.3429	617.6118	116.2514	116.5729	115.1727	114.4656	100.0566	1.3936	5.3%	2993.51	3.9175	0.7089	88.4428	5.314
	VR (1) 32, 32, 32																			
SG	25%	-100%	LV	ML	16	558.5165	634.977	617.1095	115.6802	116.0168	114.5926	113.8923	100.0568	1.4169	5.4%	2995.16	3.8573	0.7177	88.4382	5.3686
	VR (1) 32, 32, 32																			

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	LV	ML	-2.29%	0.24%	6.82%
	VR (1) 32, 32, 32						
SG	75%	0	LV	ML	-2.18%	0.35%	8.23%
	VR (1) 32, 32, 32						
SG	100%	0	LV	ML	-2.08%	0.45%	9.63%
	VR (1) 32, 32, 32						
SG	106.7%	0	LV	ML	-2.05%	0.48%	10.01%
	VR (1) 32, 32, 32						
SG	100%	100%	LV	ML	-1.14%	0.51%	9.27%
	VR (1) 32, 32, 32						
SG	100%	-100%	LV	ML	-3.04%	0.37%	9.76%
	VR (1) 32, 32, 32						
SG	25%	100%	LV	ML	-1.46%	0.19%	5.02%
	VR (1) 32, 32, 32						
SG	25%	75%	LV	ML	-1.69%	0.18%	5.14%
	VR (1) 32, 32, 32						
SG	25%	50%	LV	ML	-1.93%	0.17%	5.24%
	VR (1) 32, 32, 32						
SG	25%	25%	LV	ML	-2.16%	0.15%	5.33%
	VR (1) 32, 32, 32						
SG	25%	0%	LV	ML	-2.40%	0.13%	5.41%
	VR (1) 32, 32, 32						
SG	25%	-50%	LV	ML	-2.88%	0.09%	5.52%
	VR (1) 32, 32, 32						
SG	25%	-100%	LV	ML	-3.36%	0.04%	5.57%
	VR (1) 32, 32, 32						

11.4 Plotted Performance Data

To help the reader follow the evaluation of the data, Table 52 and Table 53 show the results of each generator application and its improvement for HL and LL conditions. These data are plotted in Figure 141 through Figure 164 for the HL circuit condition.

Table 52. Distributed Generator Voltage Regulation Application Summary – HL

Ind Gen

	LV					HV			
Q	V	V Imp	Loss	Cap		V	V Imp	Loss	Cap
247.91	115.4859	-2.01%	0.25%	6.10%		117.9912	0.12%	0.30%	3.80%
0	115.1259	-2.32%	0.23%	6.28%		117.5369	-0.27%	0.25%	3.51%
-247.91	114.7603	-2.63%	0.20%	6.44%		117.7804	-0.06%	0.19%	2.31%

Inv Gen - P = 400

	LV					HV			
Q	V	V Imp	Loss	Cap		V	V Imp	Loss	Cap
0	115.1541	-2.29%	0.22%	6.29%		117.5964	-0.22%	0.24%	3.53%

Inv Gen - P = 320

	LV					HV			
Q	V	V Imp	Loss	Cap		V	V Imp	Loss	Cap
240	115.6369	-1.88%	0.16%	5.83%		117.9769	0.10%	0.21%	2.79%
-240	114.5651	-2.79%	0.13%	5.81%		117.5922	-0.22%	0.16%	1.70%

SG - Voltage - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	115.585	116.508	116.4997	117.8965	118.8339	118.8273
0	0	115.0221	115.4052	115.4348	117.3782	117.7489	117.7784
-100%	-738	114.453	114.2682	114.3189	117.4696	117.2833	117.3335

SG - Voltage - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	115.4941	116.1337	116.1042	117.8155	118.4472	118.4197
75%	553.5	115.3527	115.8586	115.8405	117.6853	118.1842	118.1675
50%	369	115.2133	115.586	115.5783	117.5568	117.9236	117.9167
25%	184.5	115.0712	115.3068	115.3086	117.426	117.657	117.659
0%	0	114.931	115.0301	115.0403	117.297	118.0366	117.4027
-50%	-369	114.6471	114.4656	114.4896	117.6801	117.47	117.493
-100%	-738	114.3616	113.8923	113.9253	117.3878	116.8956	116.9226

SG - Loss - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	0.13%	0.51%	0.56%	0.14%	0.51%	0.56%
0	0	0.12%	0.45%	0.51%	0.13%	0.45%	0.50%
-100%	-738	0.10%	0.37%	0.40%	0.08%	0.34%	0.37%

SG - Loss - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	0.06%	0.19%	0.21%	0.08%	0.20%	0.22%
75%	553.5	0.06%	0.18%	0.20%	0.07%	0.19%	0.21%
50%	369	0.05%	0.17%	0.19%	0.07%	0.18%	0.20%
25%	184.5	0.05%	0.15%	0.17%	0.07%	0.16%	0.18%
0%	0	0.05%	0.13%	0.15%	0.06%	0.13%	0.16%
-50%	-369	0.04%	0.09%	0.10%	0.03%	0.08%	0.09%
-100%	-738	0.02%	0.04%	0.04%	0.02%	0.03%	0.03%

SG - Cap - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	10.44%	9.27%	9.00%	7.36%	6.24%	5.97%
0	0	9.56%	9.63%	9.60%	6.42%	6.51%	6.48%
-100%	-738	8.47%	9.76%	9.96%	4.11%	5.39%	5.59%

SG - Cap - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	6.21%	5.02%	4.78%	3.21%	2.04%	1.80%
75%	553.5	6.02%	5.14%	4.96%	3.01%	2.13%	1.96%
50%	369	5.83%	5.24%	5.12%	2.79%	2.22%	2.10%
25%	184.5	5.61%	5.33%	5.27%	2.57%	2.29%	2.23%
0%	0	5.39%	5.41%	5.40%	2.33%	1.32%	2.35%
-50%	-369	4.90%	5.52%	5.63%	0.79%	1.26%	1.37%
-100%	-738	4.37%	5.57%	5.79%	0.10%	1.15%	1.50%

SG - VImp - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	-1.93%	-1.14%	-1.15%	0.04%	0.83%	0.82%
0	0	-2.40%	-2.08%	-2.05%	-0.40%	-0.09%	-0.06%
-100%	-738	-2.89%	-3.04%	-3.00%	-0.33%	-0.49%	-0.44%

SG - VImp - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	-2.00%	-1.46%	-1.49%	-0.03%	0.50%	0.48%
75%	553.5	-2.12%	-1.69%	-1.71%	-0.14%	0.28%	0.27%
50%	369	-2.24%	-1.93%	-1.93%	-0.25%	0.06%	0.05%
25%	184.5	-2.36%	-2.16%	-2.16%	-0.36%	-0.17%	-0.17%
0%	0	-2.48%	-2.40%	-2.39%	-0.47%	0.15%	-0.38%
-50%	-369	-2.72%	-2.88%	-2.86%	-0.15%	-0.33%	-0.31%
-100%	-738	-2.96%	-3.36%	-3.33%	-0.40%	-0.81%	-0.79%

Base Case:	
Lowest Voltage:	117.855
Losses:	5.40%
Node 1 Capacity:	-0.21%

Table 53. Distributed Generator Voltage Regulation Application Summary – LL

Ind Gen

	LV					HV			
Q	V	V Imp	Loss	Cap		V	V Imp	Loss	Cap
247.91	122.4196	0.98%	0.37%	2.64%		121.6783	0.37%	0.38%	2.89%
0	121.9696	0.61%	0.31%	2.04%		122.048	0.67%	0.33%	2.02%
-247.91	121.5126	0.23%	0.23%	1.38%		121.6023	0.30%	0.25%	1.31%

Inv Gen - P = 400

	LV					HV			
Q	V	V Imp	Loss	Cap		V	V Imp	Loss	Cap
0	122.0019	0.63%	0.28%	2.01%		122.0808	0.70%	0.30%	1.99%

Inv Gen - P = 320

	LV					HV			
Q	V	V Imp	Loss	Cap		V	V Imp	Loss	Cap
240	122.5691	1.10%	0.29%	2.20%		122.6307	1.15%	0.33%	2.19%
-240	121.361	0.10%	0.18%	0.90%		121.4598	0.19%	0.22%	0.87%

SG - Voltage - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	121.8718	122.7779	122.7609	121.8101	122.7128	122.7038
0	0	121.9196	122.1461	122.1478	121.995	122.2167	122.2183
-100%	-738	121.2282	120.7316	120.7239	121.3707	120.8687	120.8612

SG - Voltage - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	121.8061	122.5474	122.5393	121.7512	122.4923	122.4845
75%	553.5	121.6368	122.2038	122.2004	121.5958	122.1624	122.1591
50%	369	121.4698	121.871	121.8712	121.4425	121.8429	121.8431
25%	184.5	121.2997	122.2507	121.5328	122.0896	121.5158	122.3202
0%	0	121.8535	121.9139	121.9097	121.9358	121.9948	121.9985
-50%	-369	121.5057	121.2191	121.2214	121.6166	121.3288	121.331
-100%	-738	121.1639	120.4784	120.4737	121.3036	120.6267	120.6221

SG - Loss - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	0.26%	0.63%	0.66%	0.27%	0.65%	0.67%
0	0	0.22%	0.49%	0.51%	0.24%	0.51%	0.53%
-100%	-738	0.16%	0.26%	0.23%	0.61%	0.29%	0.26%

SG - Loss - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	0.19%	0.38%	0.39%	0.21%	0.40%	0.41%
75%	553.5	0.18%	0.34%	0.36%	0.20%	0.37%	0.38%
50%	369	0.17%	0.31%	0.32%	0.19%	0.33%	0.35%
25%	184.5	0.15%	0.28%	0.28%	0.19%	0.29%	0.32%
0%	0	0.16%	0.23%	0.24%	0.18%	0.26%	0.27%
-50%	-369	0.12%	0.12%	0.12%	0.15%	0.15%	0.15%
-100%	-738	0.09%	0.00%	-0.04%	0.12%	0.03%	0.00%

SG - Cap - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	7.40%	7.32%	7.20%	7.43%	7.35%	7.28%
0	0	4.93%	5.14%	5.15%	4.91%	5.13%	5.13%
-100%	-738	2.29%	2.56%	2.59%	2.25%	2.57%	2.61%

SG - Cap - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	3.34%	3.13%	3.06%	3.37%	3.15%	3.09%
75%	553.5	2.88%	2.71%	2.66%	2.91%	2.73%	2.68%
50%	369	2.41%	2.31%	2.29%	2.42%	2.33%	2.30%
25%	184.5	1.89%	1.65%	1.87%	1.65%	1.89%	1.63%
0%	0	1.14%	1.19%	1.15%	1.12%	1.17%	1.18%
-50%	-369	-0.06%	0.13%	0.15%	-0.09%	0.10%	0.13%
-100%	-738	-1.31%	-1.20%	-1.16%	-1.34%	-1.19%	-1.15%

SG - VImp - P=100%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	0.53%	1.27%	1.26%	0.47%	1.22%	1.21%
0	0	0.57%	0.75%	0.75%	0.63%	0.81%	0.81%
-100%	-738	-0.01%	-0.41%	-0.42%	0.11%	-0.30%	-0.31%

SG - VImp - P=25%

		LV			HV		
Q	Q - Mag	BL	ML	EL	BL	ML	EL
100%	738	0.47%	1.08%	1.08%	0.43%	1.04%	1.03%
75%	553.5	0.33%	0.80%	0.80%	0.30%	0.77%	0.76%
50%	369	0.19%	0.53%	0.53%	0.17%	0.50%	0.50%
25%	184.5	0.05%	0.84%	0.25%	0.71%	0.23%	0.90%
0%	0	0.51%	0.56%	0.56%	0.58%	0.63%	0.63%
-50%	-369	0.22%	-0.01%	-0.01%	0.32%	0.08%	0.08%
-100%	-738	-0.06%	-0.62%	-0.63%	0.06%	-0.50%	-0.50%

Base Case:	
Lowest Voltage:	121.2343
Losses:	3.40%
Node 1 Capacity:	60.58%

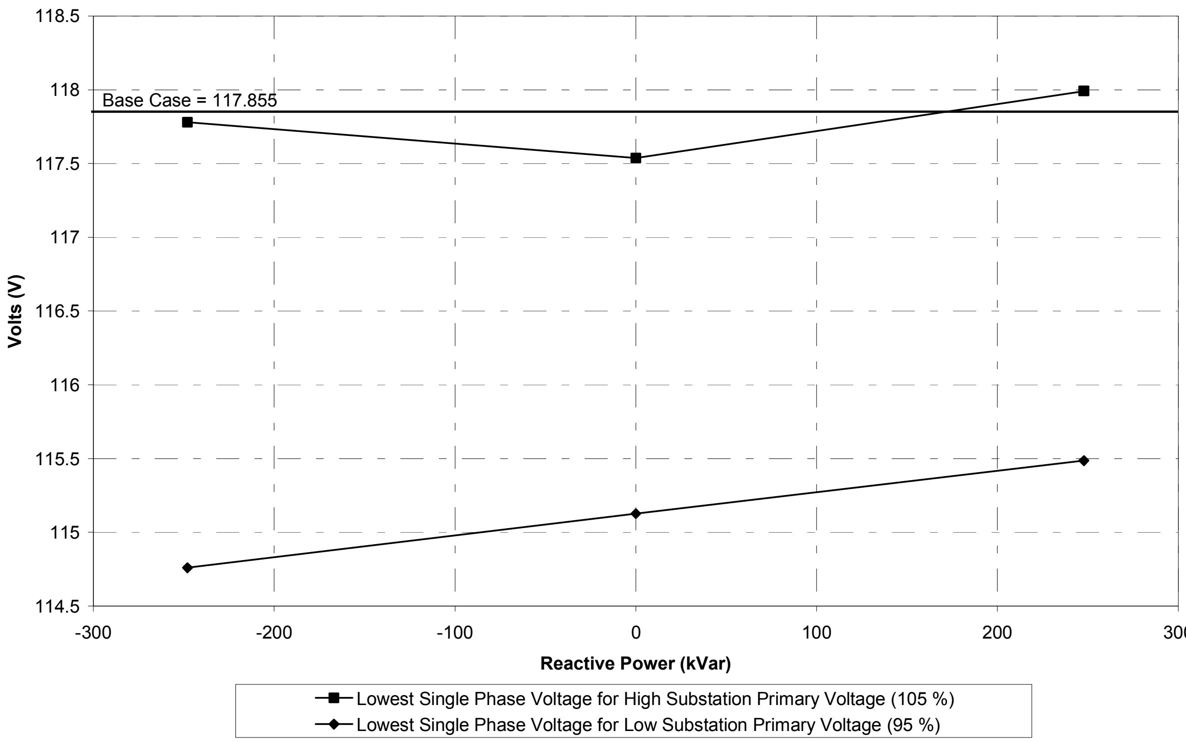


Figure 141. HL condition – voltage rise or drop (in volts on a 120-V base) as a function of induction generator +/- reactive power with a constant real power output of 400 kW

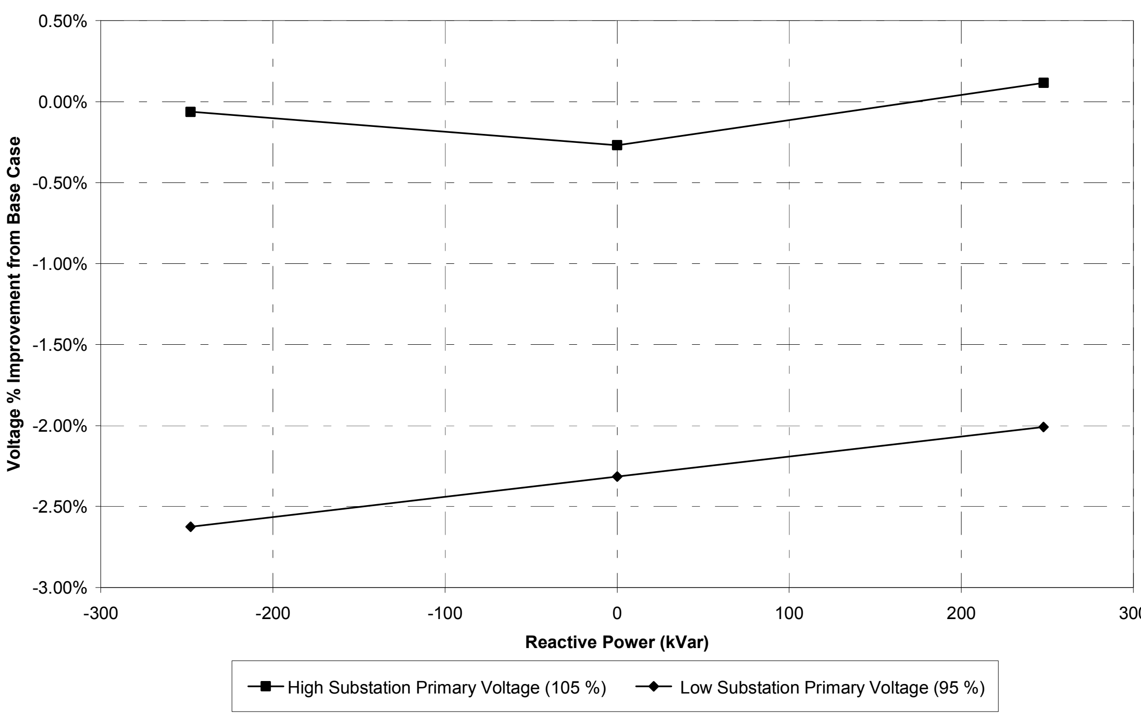


Figure 142. HL condition – reduction or increase in voltage (in percent on a 120-V base) as a function of induction generator +/- reactive power with a constant real power output of 400 kW

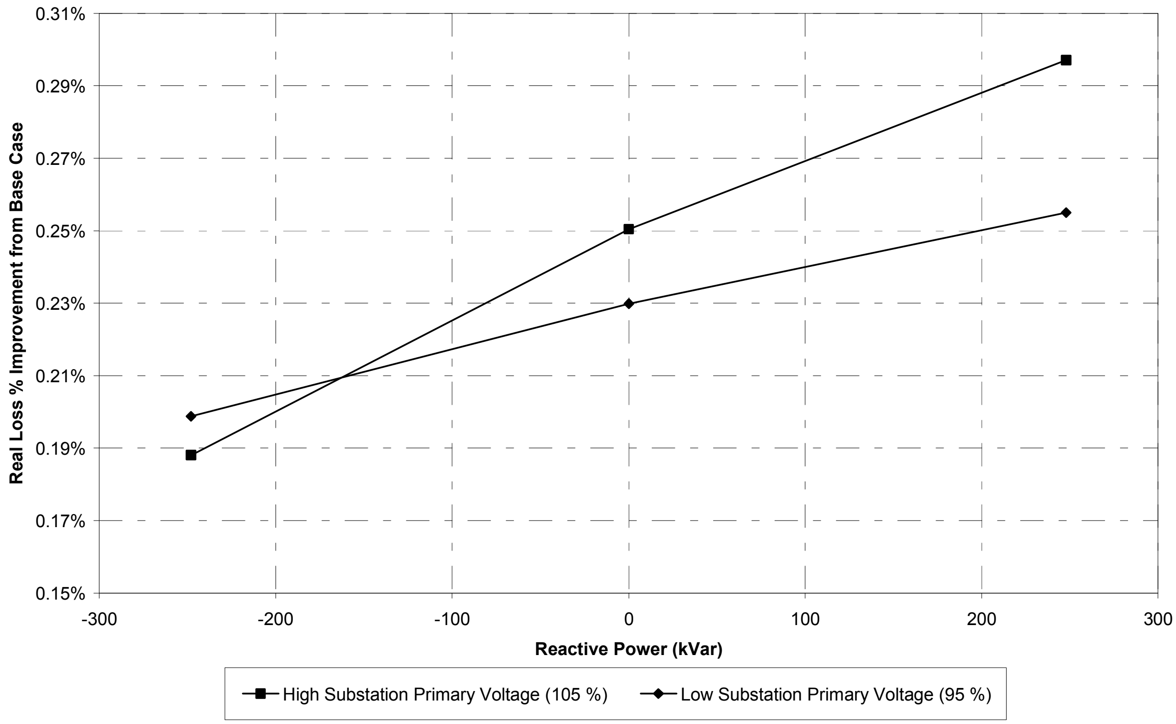


Figure 143. HL condition – reduction or increase of real power (in percent of total circuit kilowatts) as a function of induction generator +/- reactive power with a constant real power output of 400 kW

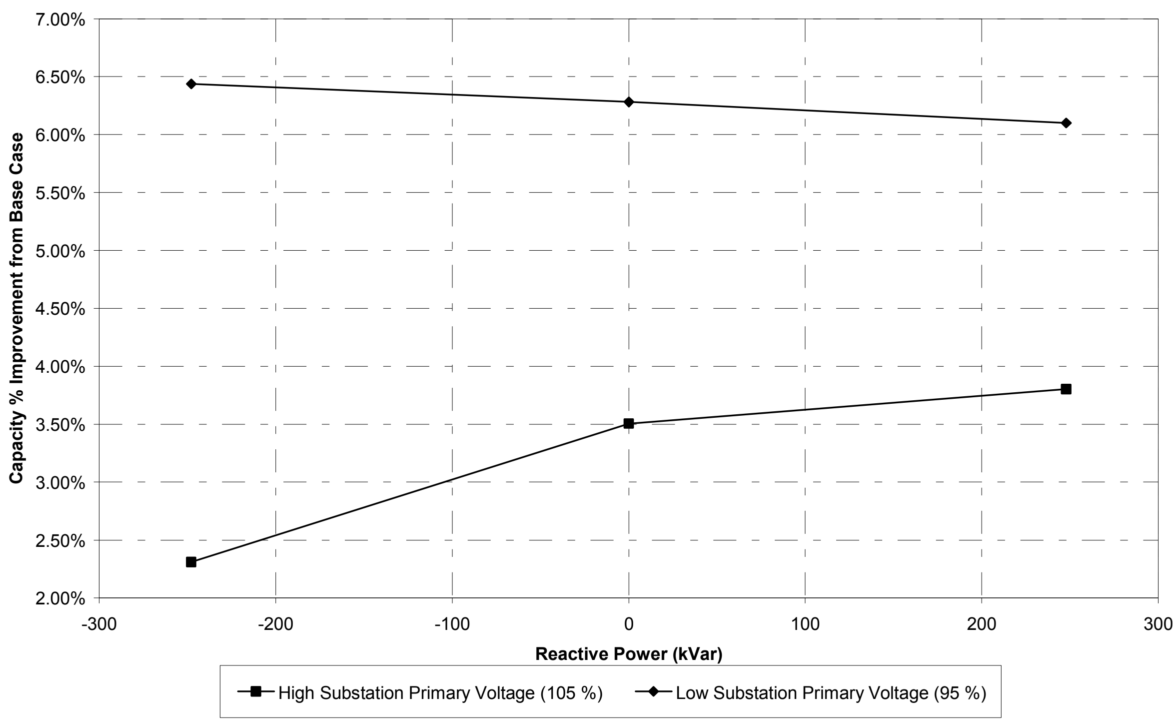


Figure 144. HL load condition – reduction or increase of capacity (in percent of total circuit kilovolt-amperes) as a function of induction generator +/- reactive power with a CP output of 400 kW

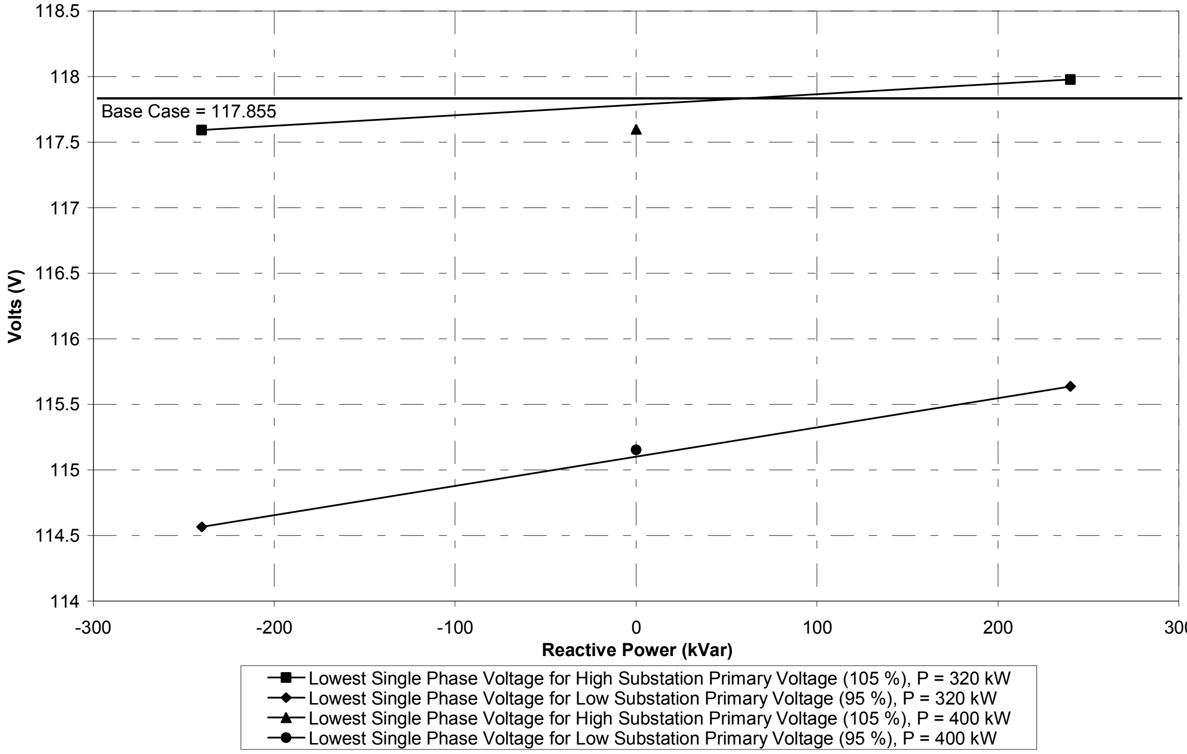


Figure 145. HL condition – voltage rise or drop (in volts on a 120-V base) as a function of inverter generator +/- reactive power with a constant real power output of 400 kW

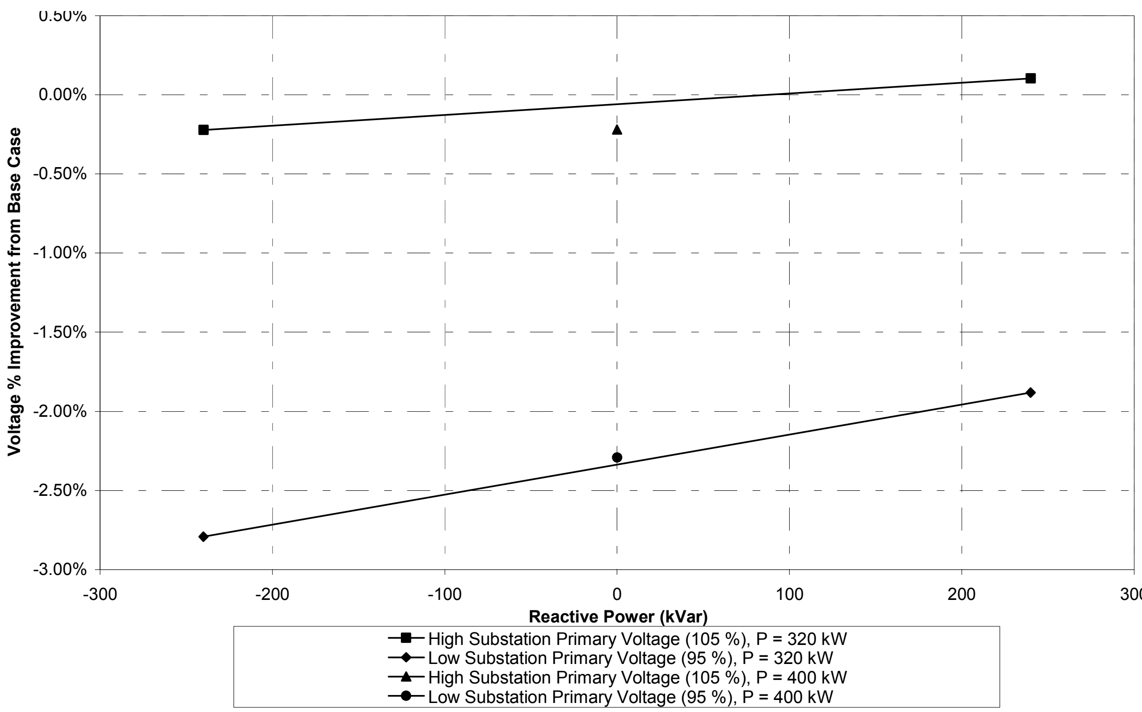


Figure 146. HL condition – reduction or increase in voltage (in percent on a 120-V base) as a function of inverter generator +/- reactive power with a constant real power output of 320 kW or 400 kW

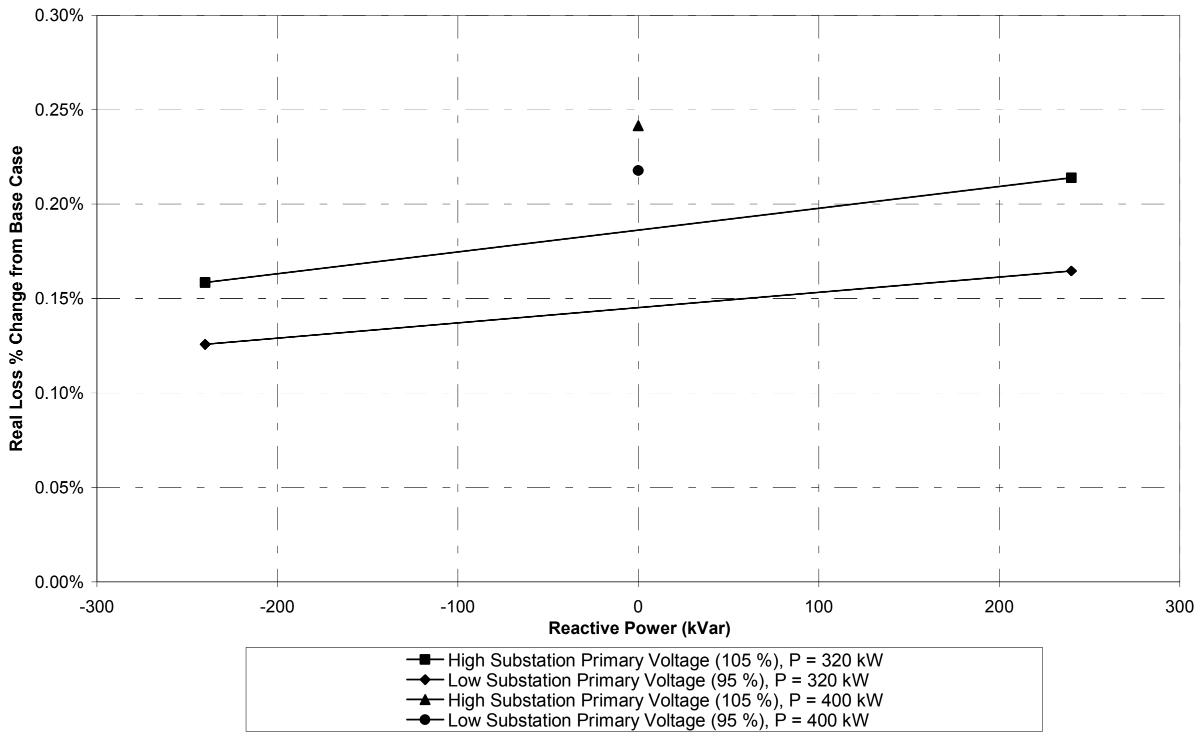


Figure 147. HL condition – reduction or increase of real power (in percent of total circuit kilowatts) as a function of induction generator +/- reactive power with a constant real power output of 320 kW or 400 kW

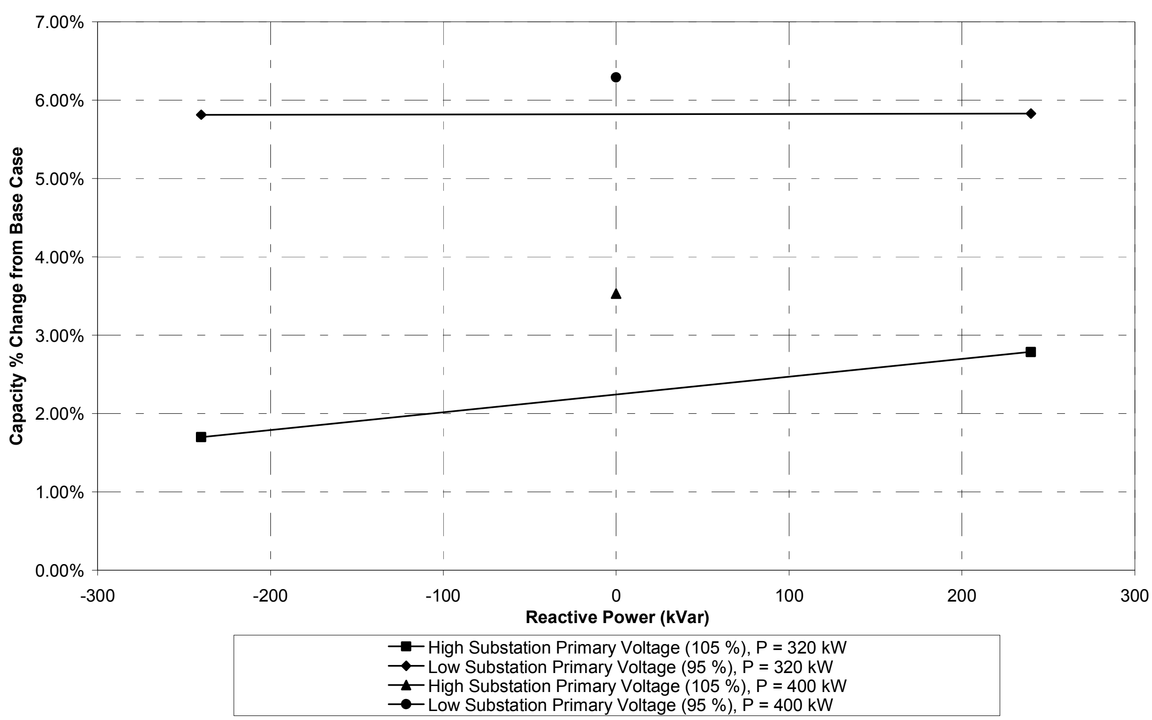


Figure 148. HL condition – reduction or increase of capacity (in percent of total circuit kilovolt-amperes) as a function of induction generator +/- reactive power with a CP output of 320 kW or 400 kW

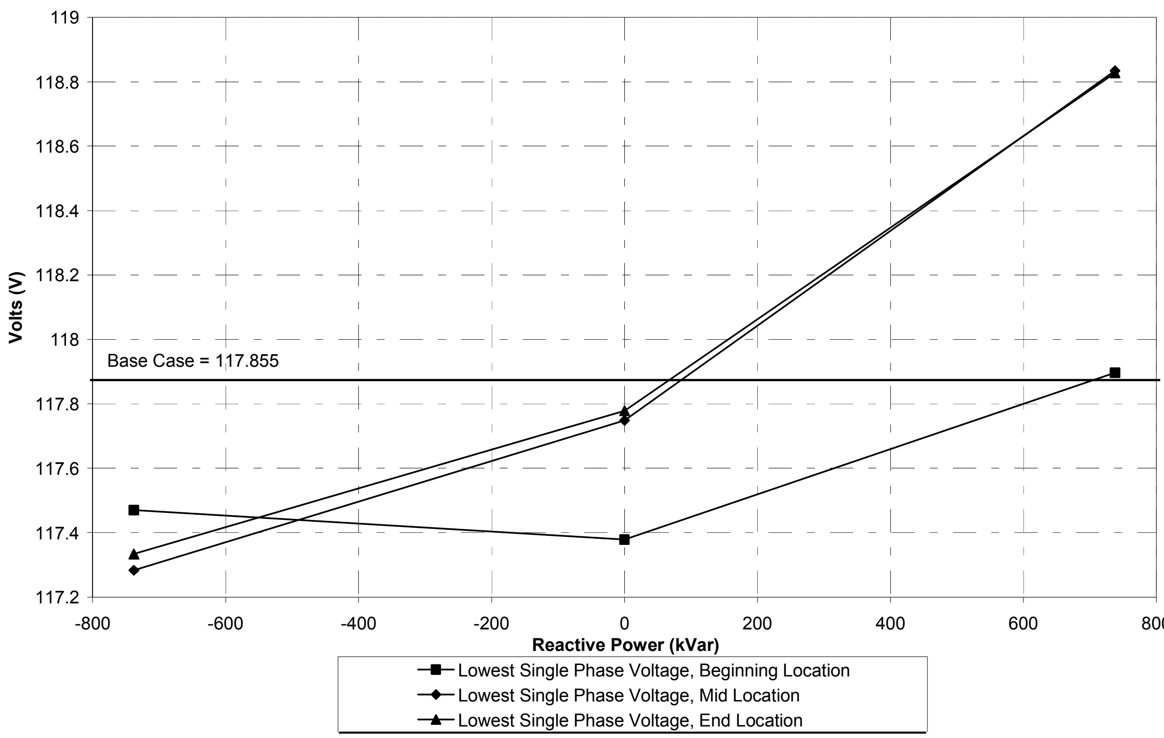


Figure 149. High substation primary voltage, HL condition – voltage rise or drop (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

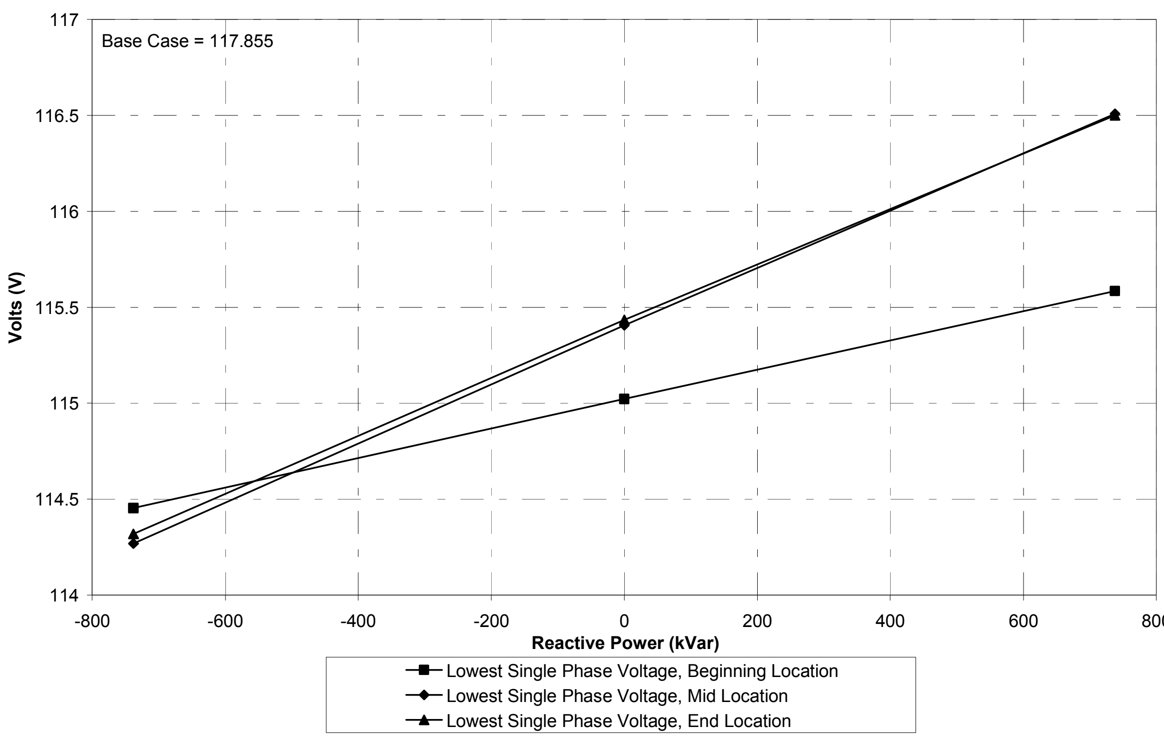


Figure 150. Low substation primary voltage, HL condition – voltage rise or drop (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

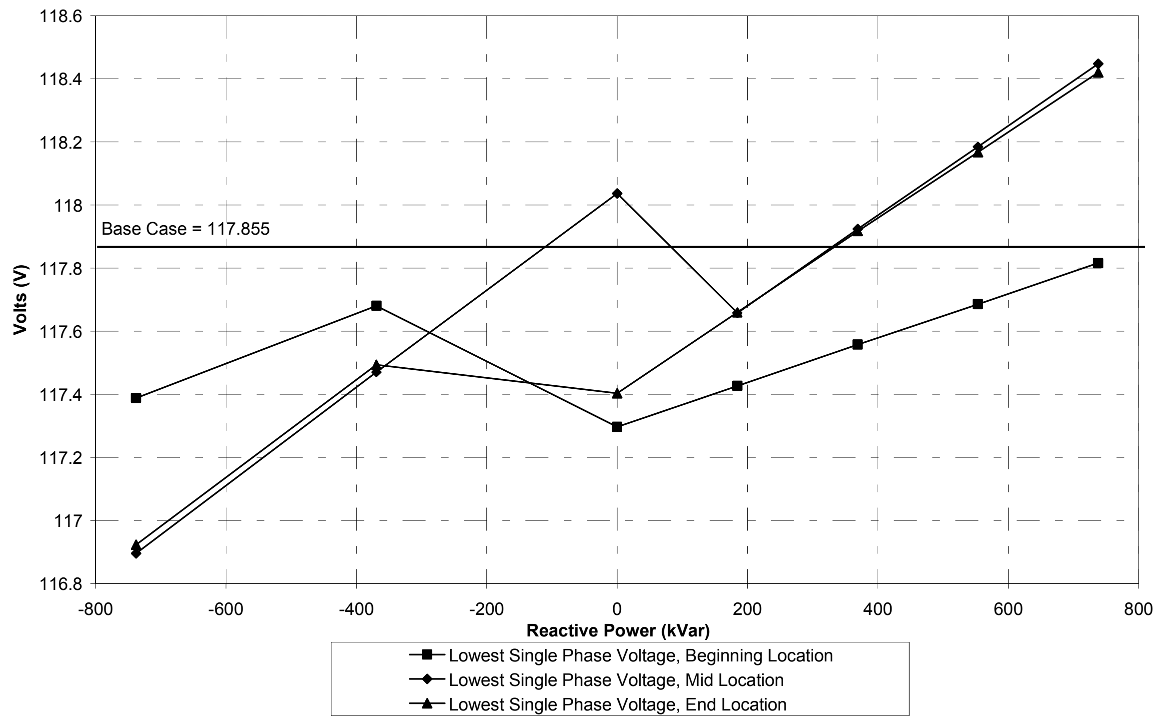


Figure 151. High substation primary voltage, HL condition – voltage rise or drop (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

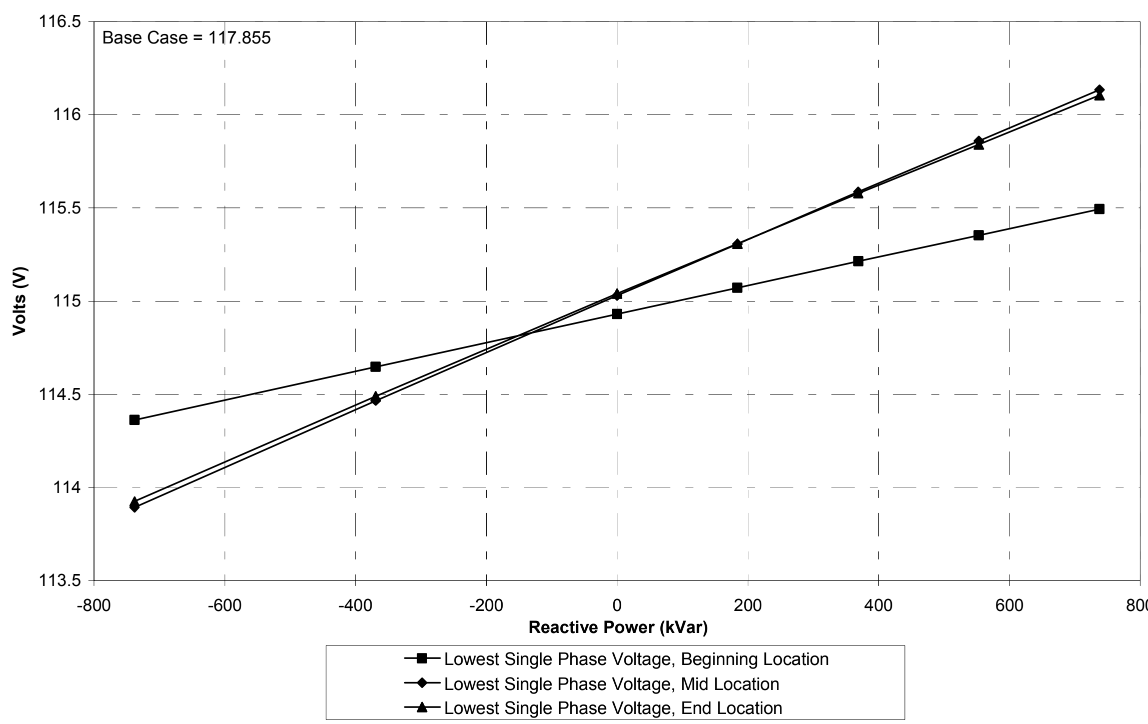


Figure 152. Low substation primary voltage, HL condition – voltage rise or drop (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

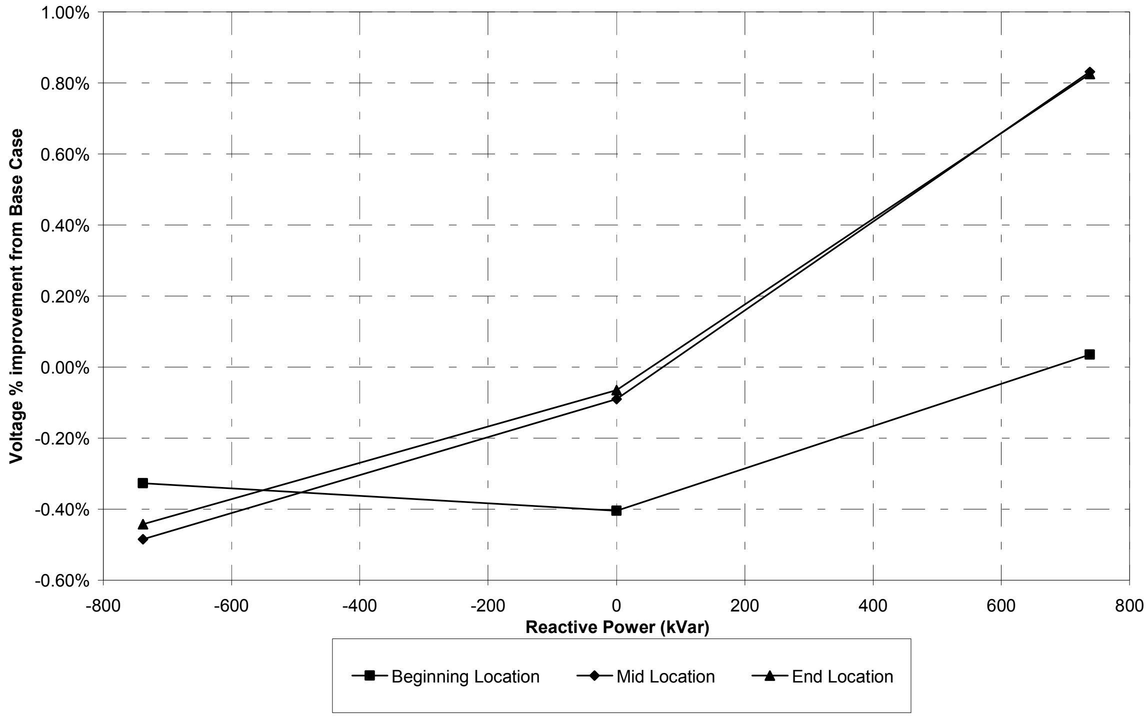


Figure 153. High substation primary voltage, HL condition – reduction or increase in voltage (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

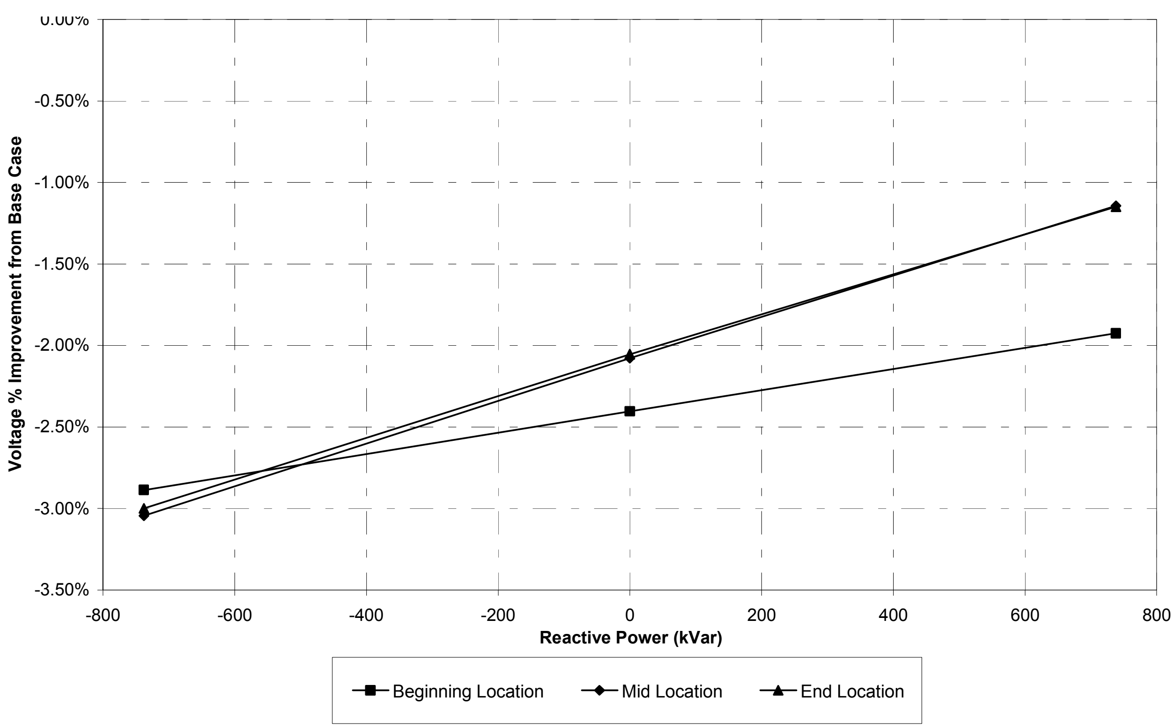


Figure 154. Low substation primary voltage, HL condition – voltage rise or drop (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

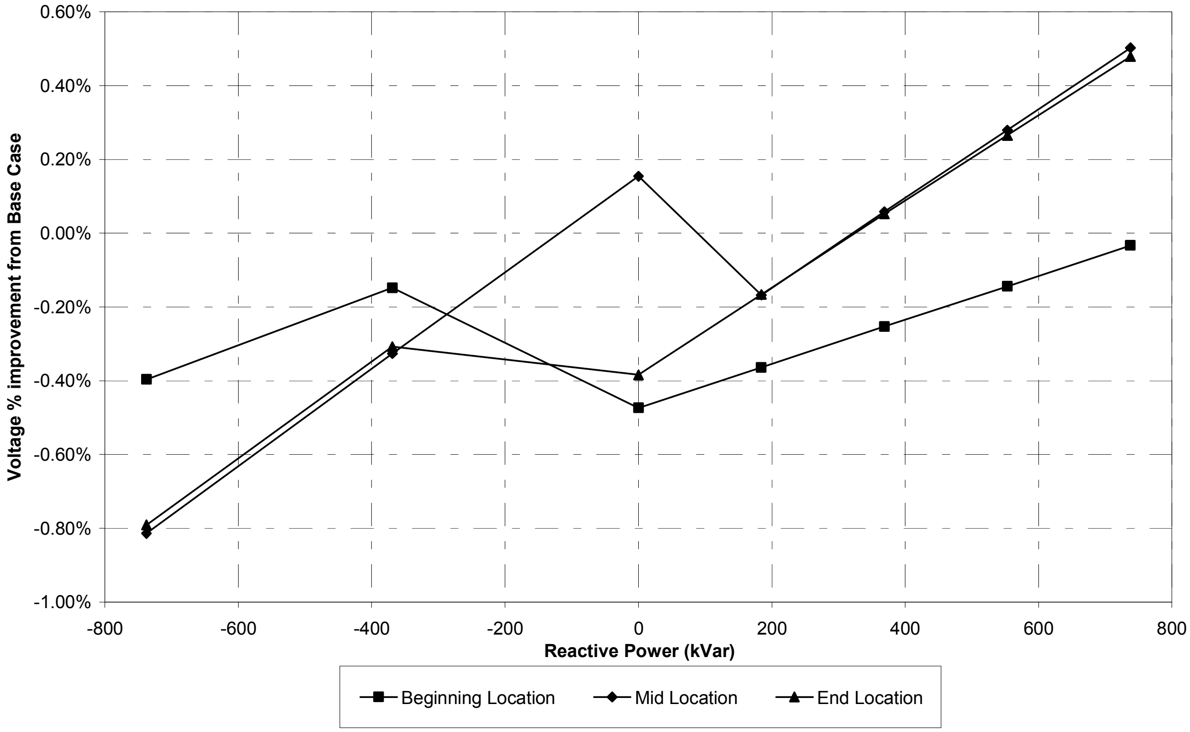


Figure 155. High substation primary voltage, HL condition – reduction or increase in voltage (in volts on 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

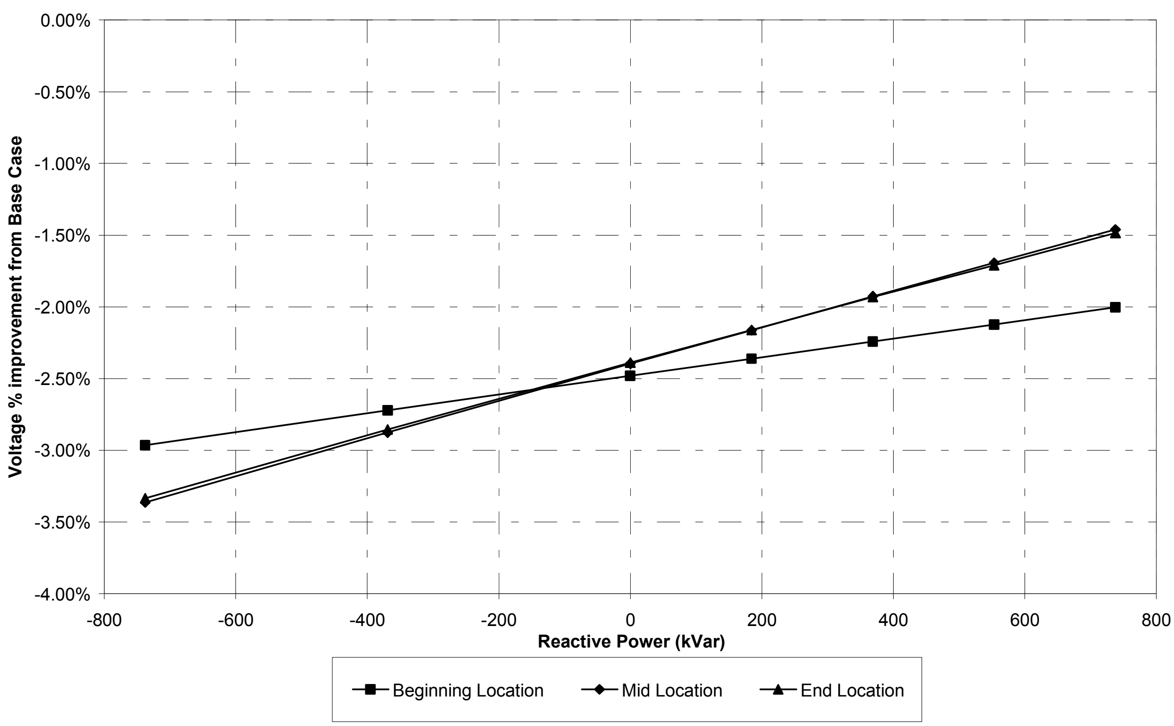


Figure 156. Low substation primary voltage, HL condition – reduction or increase in voltage (in volts on a 120-V base) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

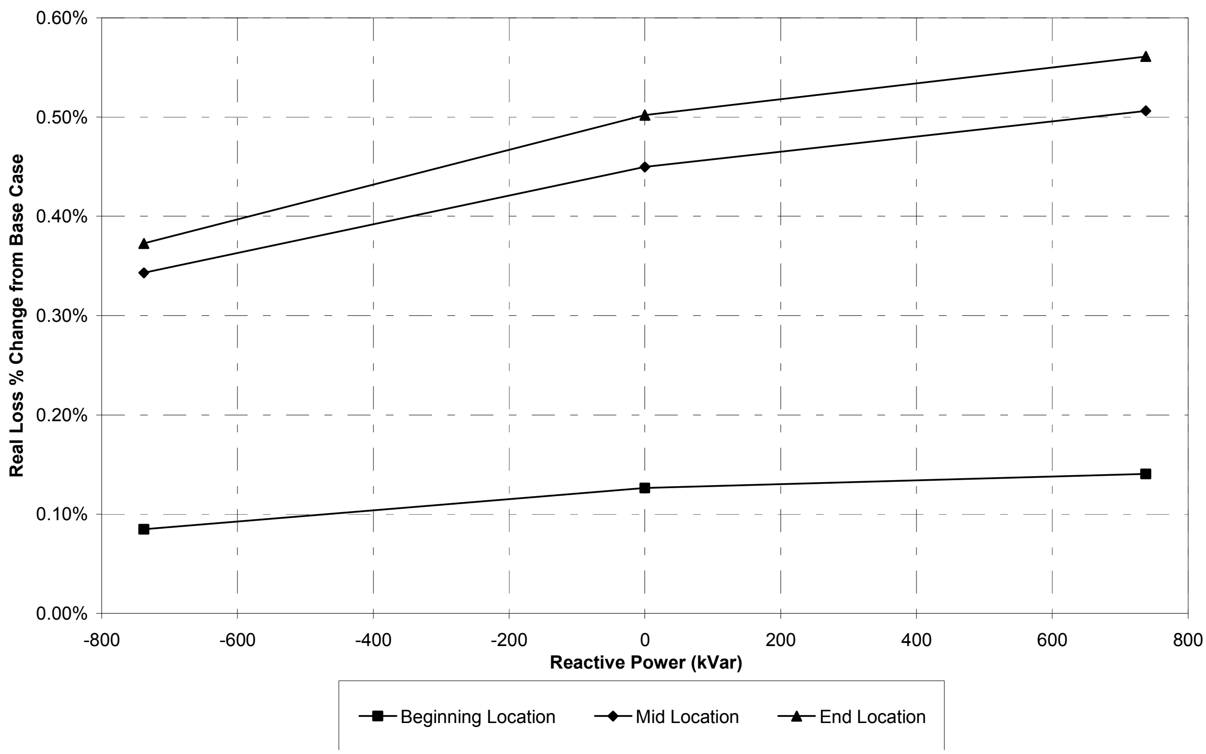


Figure 157. High substation primary voltage, HL condition – reduction or increase of real power loss (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

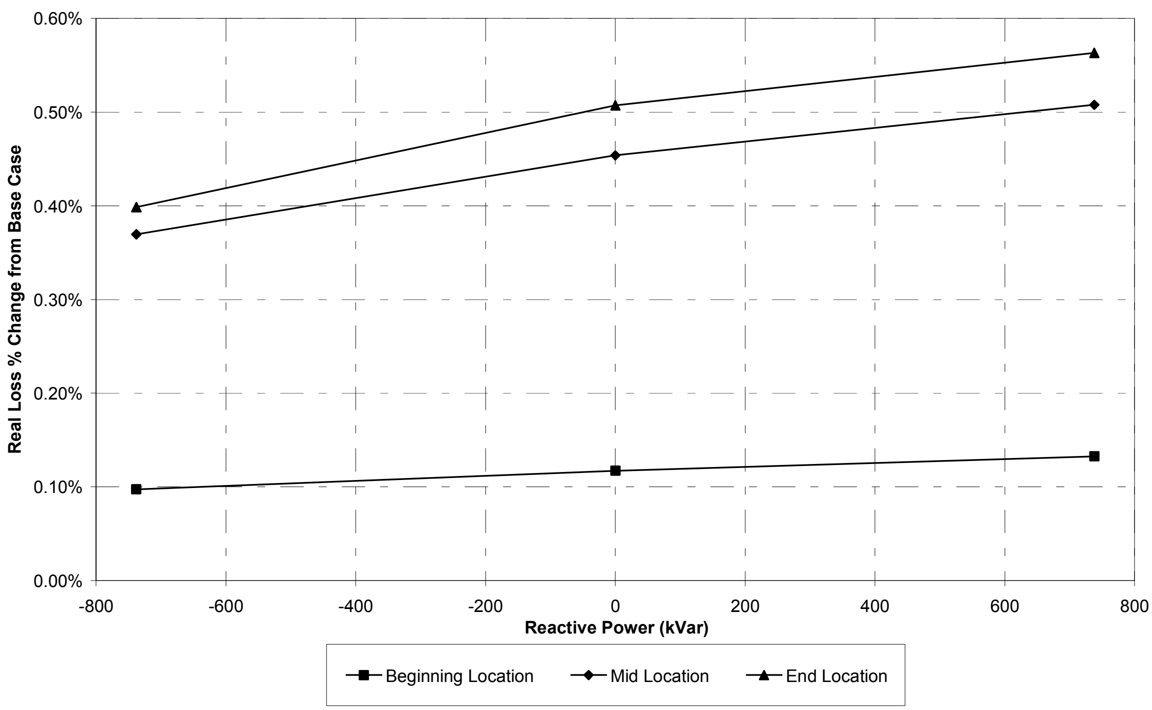


Figure 158. Low substation primary voltage, HL condition – reduction or increase of real power loss (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

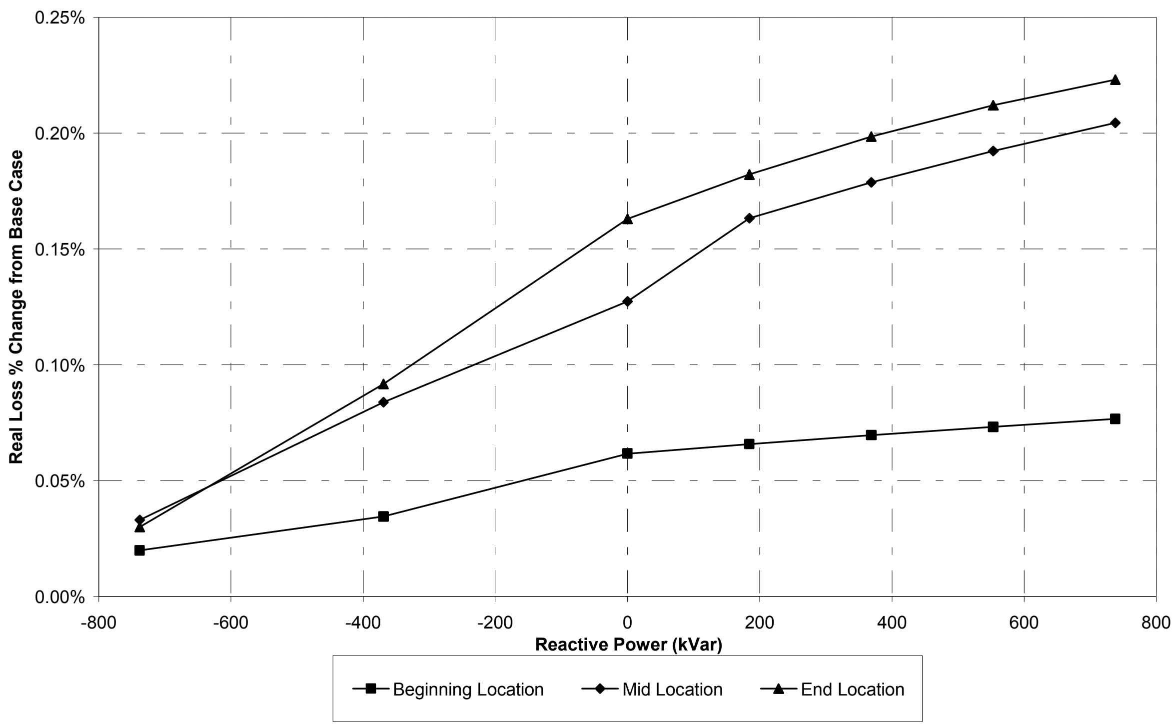


Figure 159. High substation primary voltage, HL condition – reduction or increase of real power loss (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

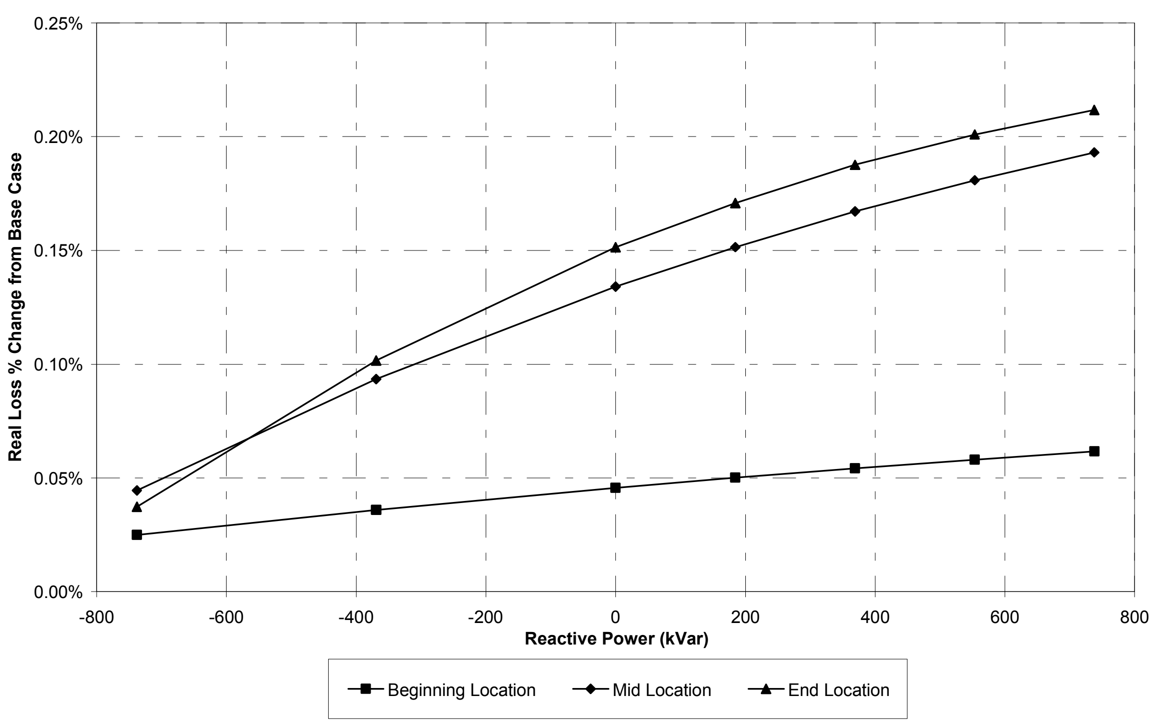


Figure 160. Low substation primary voltage, HL condition – reduction or increase of real power loss (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

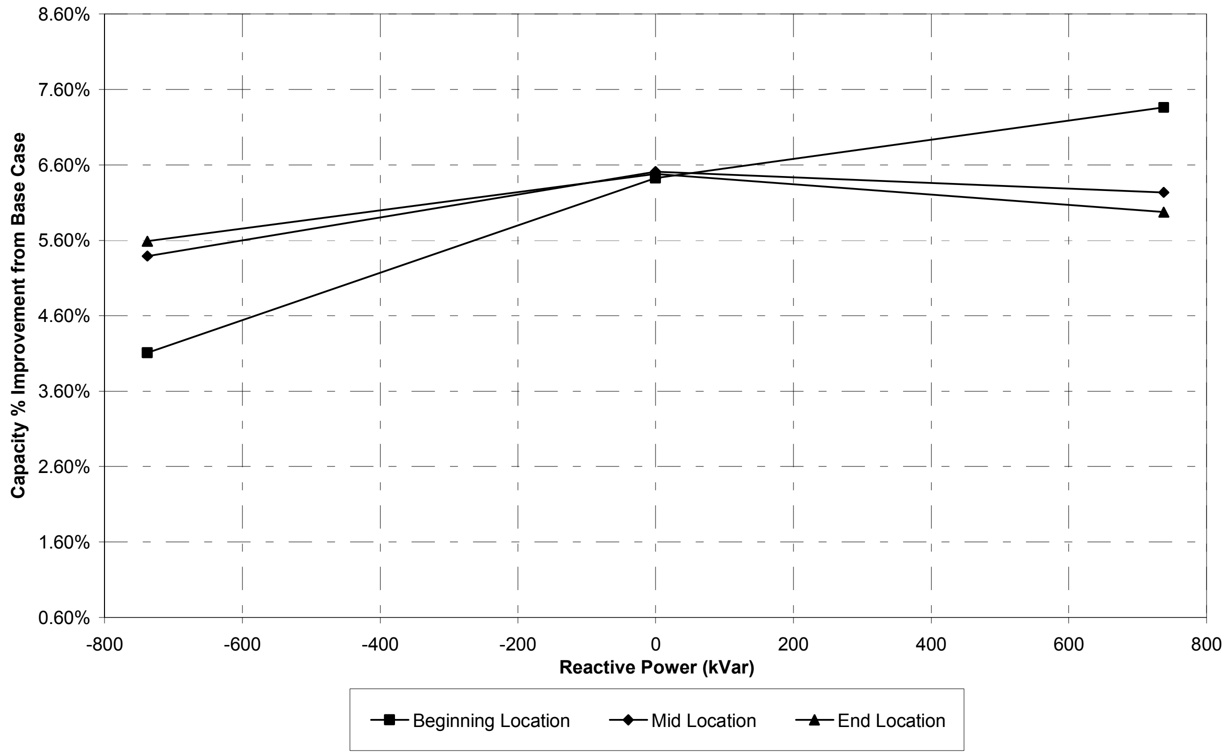


Figure 161. High substation primary voltage, HL condition – reduction or increase of capacity (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

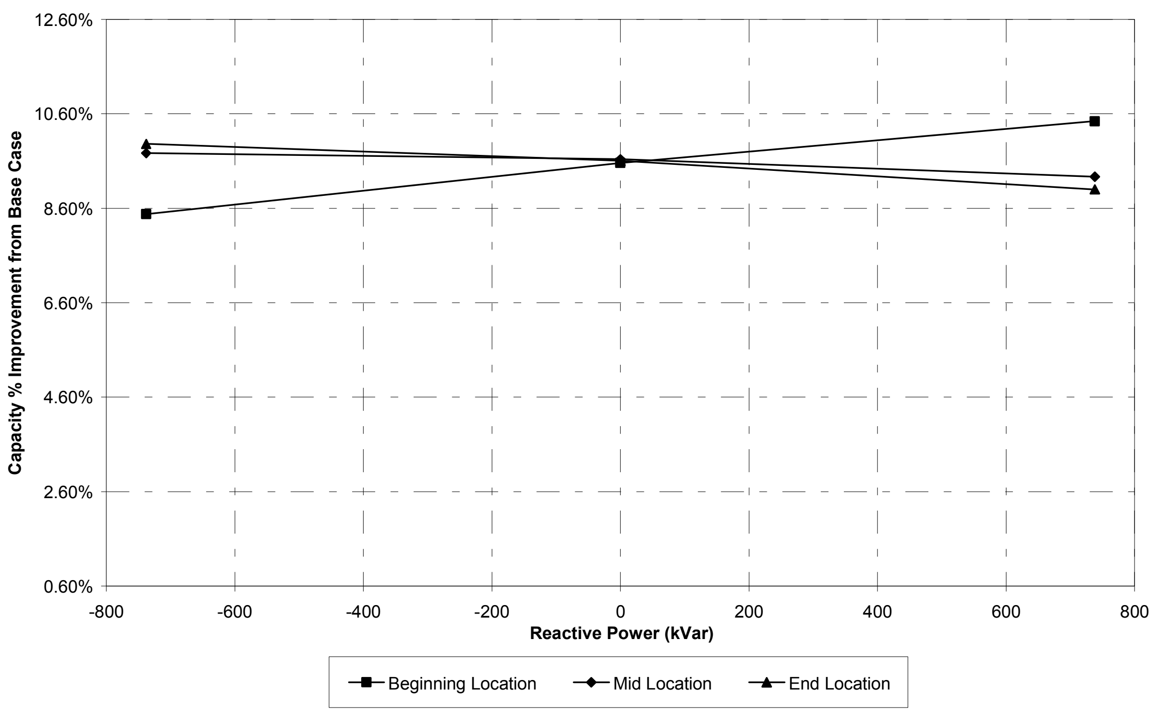


Figure 162. Low substation primary voltage, HL condition – reduction or increase of capacity (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 984 kW

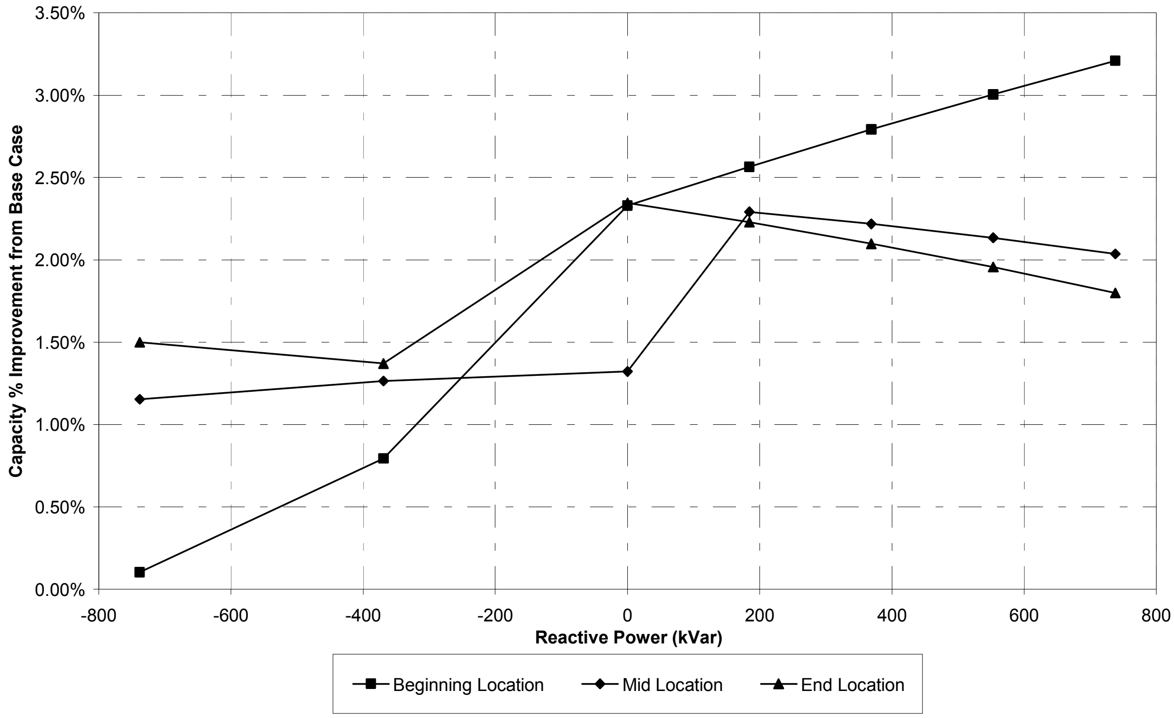


Figure 163. High substation primary voltage, HL condition – reduction or increase of capacity (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

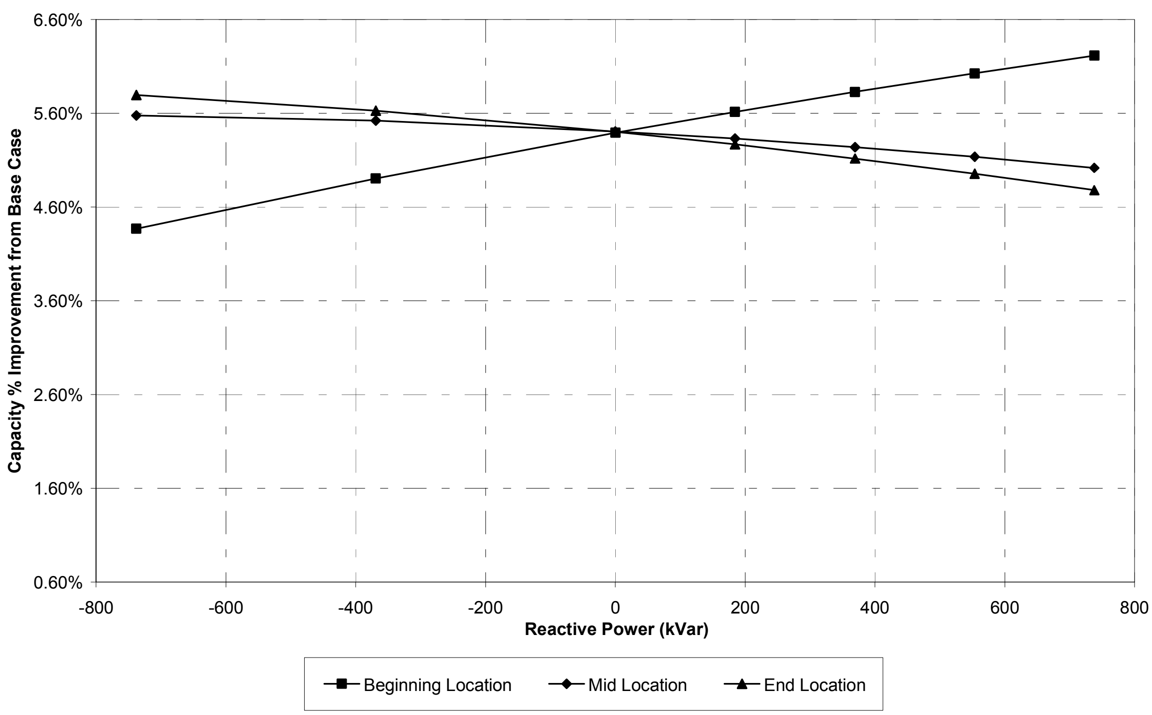


Figure 164. Low substation primary voltage, HL condition – reduction or increase of capacity (in percent total circuit kilowatts) as a function of location and synchronous generator +/- reactive power with a constant real power output of 246 kW

11.5 Findings and Conclusions

11.5.1 Synchronous Generator (Low Voltage on Primary of Substation) – Heavy Load Condition

- Released capacity improvement – BL

  The best-case released capacity improvement occurred when the DG was located at the BL of the circuit, with a 10.44% savings when the synchronous generator was operating at its highest real and reactive power output. This occurred with all LTC regulator taps and step regulator taps in their full-raise position because of the LV condition of 95% on the primary of the substation. Adding reactive from the generator improves the voltage but causes an increase in kilovolt-ampere load that reduces the released capacity.

  There is a 1.8% change in current for a 1% change in voltage. When the primary of the substation is operating at LV, or 95%, there is a 5% drop from nominal (100%) that causes a 9% (1.8% x 5%) drop in current. The base case peak load kilovolt-amperes at the start of the circuit without generation are 14,187 kW + j5846 kVAr, or 15,344 kVA. When the generator is running at 984 kW + j 738 kVAr, or 1,230 kVA, the circuit load drops to 12,347 kW + j 5415 kVArs, or 13,482 kVA. This example shows a released capacity of

  15,344 kVA (w/o generation) – 13,482 kVA (with generation) = 1,862 kVA load reduction.

  The percent load reduction is then

  $$\frac{1{,}862\,kVA}{15{,}344\,kVA} \text{ x } 100\% = 12.14\% \text{ road reduction.}$$

  The example given is based on balanced circuit loading, so the maximum released capacity of 10.44% indicates an unbalanced condition exists and, as such, the released capacity will be less because one of the phases has a lower load current than the other two before the generation is added. Therefore, the reduction in load or released capacity will be less on the phase with the lowest load.

- Loss savings – EL

  The greatest reduction in real power losses occurs when the synchronous generator is located at the EL on the circuit, P = 100%, and Q = 100%. Here, the loss reduction was 0.56% better than the base case (5.7%). There were marginal loss savings (a range of only 0.02% to 0.13%) when the DG was applied at the head-end of the circuit. Locating the generation at the EL with 100% reactive and 100% real power reduces the current magnitude and, hence, the I^2R losses.

- Voltage improvement – ML

  The best case for voltage improvement occurs when the synchronous generator is at the ML of the circuit and delivering 100% real power and 100% reactive power. The lowest single-phase voltage was -1.14% (down from the base case). The EL DG voltage improvement is almost the same (-1.15% from the base case). The BL DG had voltages about 2%–3% less than the base case. It should be noted that the criteria of 114 V could not be met under the LV condition on the primary of the substation for customers with secondary and services.

11.5.2 Synchronous Generator (High Voltage on Primary of Generator Substation) – Heavy Load Condition

- Released capacity improvement – BL

  During HV conditions on the primary of the substation, the highest released capacity of 7.36% occurs when the synchronous generator is located at the head-end of the circuit, P = 100%, and Q = 100%. When the HV condition exists, the load increases so that reactive has to be at its highest value to reduce the load. Notice that the released capacity is lower for the HV case than for the LV case, in which the value was 10.44%. This is because when the voltage increases, the load increases because of the VDC source model, which best represents how the load magnitude changes with changes in voltage.

- Loss savings – EL

  The greatest loss savings of 0.56% was obtained at the EL for the HV case when P = 100% and Q = 100%. This is the same result as for the LV case. For the LV case, the step regulator taps and the LTC tap were at full raise, and the magnitude of the current being served from the source was reduced because of the added generation. In addition, the I^2R losses are less. In the HV case, the step regulator tap settings and the LTC tap setting were low, which reduced the voltage and, thus, the load. The worst-case loss savings at the BL is only 0.02%, whereas the best case at the BL is 0.14% at full real and reactive power. This is because the load being served is just offset by the DG power output at the source end, and the load seen by the circuit is essentially the same.

- Voltage improvement – ML

  The best voltage improvement of 0.83% occurs at the ML when the unit is operated at P = 100% and Q = 100%. The EL had about the same improvement of 0.82%. Notice these voltage improvement levels are better than the LV case, in which the substation primary voltage is 10% less than the HV level of 105%. This is because the LTC and step regulator are not in the full-raise position, as is the case for the LV condition, and, thus, the step regulator and the LTC raise the voltage. The generator is delivering 100% reactive power, thus further reducing the voltage drop. It should be noted that the voltage criteria of 114 V was met during the HV condition.

11.5.3 Induction Generator for Heavy Load Condition

- Released capacity improvement

  The induction generator is located at the tag end of the circuit, so its released capacity is less than the synchronous generator at the BL. The highest released capacity of 6.44% occurs during the LV case when P = 400 kW and Q = -247.91 kVAr. The absorbed kilovars cause the voltage to drop, which causes a lower circuit load, which produces the highest released capacity for the induction generator case. The capacity savings is less than that of the synchronous generator (10.44%) because the maximum real power capability of the induction generator is only 400 kW with a reactive capability of ±247.91 kVAr. The maximum kilovolt-ampere capacity is 1,230 kVA, and the maximum real power output of the synchronous generator is much bigger—1,050 kW (106.7%) with a reactive capability of ±738 kVAr. Obviously, the larger machine will realize a greater released capacity, especially because it is located at the optimum location on the circuit (the BL) for the greatest released capacity.

  The induction generator is located at the tag end, which is the least optimum location for released capacity. With the induction generator operating at 400 kW and a –Q of 247.91 kVAr, this caused the voltage to drop and thus lowered the circuit load. The synchronous generator under the LV case had its highest released capacity at the BL of 10.44% with full-rated real power and full-rated-plus reactive power. Notice that the released capacity for the synchronous generator with zero reactive and maximum real power of 106.7% was 9.93%, which is not that different from the maximum released capacity of 10.44%. The released capacity for the HV case was only 3.8% for the induction generator.

- Loss savings

  The maximum loss savings of 0.3% was achieved at P = 400 kW and Q = 247.91 kVAr during the HV condition because the LTC tap setting was down to 3 and the step regulator tap settings were low (24, 21, 19). The current on the circuit was lowered with the reactive injection, which caused the losses to be at their lowest.

- Voltage improvement

  The best voltage is obtained under HV conditions with full reactive and real power, which is 0.12% better than the base case. With the synchronous machine, the best voltage improvement during HV conditions is 0.83% at the ML with full real and reactive power output. Again, the synchronous machine's better improvement in voltage is due to its ability to produce more real and reactive power.

11.5.4 Inverter Generator for Heavy Load Condition

- Released capacity improvement

  The inverter generator is located near the midpoint of the circuit; therefore, like the induction generator (at the tag end), it will not produce high values of released capacity. Its highest released capacity was 6.29% at P = 400 kW and Q = 0 under LV conditions, which is essentially the same as the induction generator capacity saving of 6.44%, because their real power capabilities are the same. At HV, the released capacity is about half (3.53%) because the load increased because of the higher primary voltage.

- Loss savings

  It would be expected that the inverter generator would have the highest loss savings at full real power and full reactive to reduce the magnitude of the current to its lowest value. But this is not the case because the real power capability drops down to 320 kW when the full reactive capability is 240 kVAr. Here, the greatest loss saving of 0.24% occurs at full rated real power of 400 kW at the HV condition. This is because the LTC and the step regulator reduced the voltage and lowered the current.

- Voltage improvement

  As expected, the best voltage improvement of 0.10% is realized at full real power of 320 kW and full reactive power of 240 kVAr for the HV condition. The voltage improvement is -1.88% at the LV condition with full-rated real (320) and reactive (240).

11.6 Optimum Generator Conditions for Maximum Improvements – Heavy Load Conditions

To summarize the findings and conclusions, Table 54 shows the optimum generator conditions for released capacity, loss savings, and voltage improvement.

11.7 Optimum Generator Conditions for Maximum Improvements – Light Load Conditions

The optimum generator conditions for improvements during light load conditions are given in Table 55.

Table 54. Optimum Generator Conditions for Maximum Improvements – HL

Generator Type	Substation Primary Voltage	Optimum Condition Location	P, %	Q, %	Released Capacity %	Loss[E] Reduction%	Voltage[E] Improvement%
Synchronous generator[F]	LV	BL	100	100	10.44		
	LV	EL	100	100		0.56	
	LV	ML	100	100			-1.14[A]
	HV	BL	100	100	7.36		
	HV	EL	100	100		0.56	
	HV	ML	100	100			0.82
			P, kW	**Q, kVAr**			
Induction generator	LV	EL[B]	400	-247.9	6.44		
	LV	EL	400[B]	247.9[B]		0.25	
	LV	EL	400	247.9			-2.01[A]
	HV	EL	400	247.9	3.80		
	HV	EL	400	247.9		0.30	
	HV	EL	400	247.9			0.12
Inverter generator	LV	ML[C]	400	0	6.29		
	LV	ML	320[D]	240[D]		0.16	
	LV	ML	320	240			-1.88[A]
	HV	ML	400	0	3.53		
	HV	ML	400	0		0.24	
	HV	ML	320	240			0.10

Notes:

A. The voltage criterion of 114 V is not met for customers with secondary and services (3.67 V drop). Only for customers with services is the voltage criterion met.
B. The kilovolt-ampere capability of the induction generator is 400 + j 247.9 = 470.6 kVA. It is located at the tag end of circuit, or EL.
C. The inverter generator location is at the midpoint of the circuit, or ML.
D. The kilovolt-ampere capability of the inverter generator is 320 + j240 = 400 kVA.
E. The base case energy losses are 5.4%, and the base case lowest single-phase voltage is 117.855 V.
F. The kilovolt-ampere capability of the synchronous machine is 984 + j738 = 1,236 kVA. The unit is located at midpoint.

Table 55. Optimum Generator Conditions for Maximum Improvement – LL

Generator Type	Substation Primary Voltage	Optimum Condition Location	P, %	Q, %	Released Capacity %	Loss[D] Reduction%	Voltage[D] Improvement%
Synchronous generator[E]	LV	BL	100	100	7.40		
	LV	EL	100	100		0.66	
	LV	ML	100	100			1.27
	HV	BL	100	100	7.43		
	HV	EL	100	100		0.67	
	HV	ML	100	100			1.22
			P, kW	Q, kVAr			
Induction generator	LV	EL[A]	400	+247.9	2.64		
	LV	EL	400[A]	247.9[A]		0.37	
	LV	EL	400	247.9			0.98
	HV	EL	400	247.9	2.89		
	HV	EL	400	247.9		0.38	
	HV	EL	400	0			0.67
Inverter generator	LV	ML[B]	320	240	2.20		
	LV	ML	320[C]	240[C]		0.29	
	LV	ML	320	240			1.10
	HV	ML	320	0	2.19		
	HV	ML	320	240		0.33	
	HV	ML	400	0			1.15

Notes:

A. The kilovolt-ampere capability of the induction generator is 400 + j 247.9 = 470.6 kVA. It is located at the tag end of the circuit, or EL.
B. The inverter generator is at the midpoint of the circuit, or ML.
C. The kilovolt-ampere capability of the inverter generator is 320 + j240 = 400 kVA.
D. The base case energy losses are 3.4%, and the base case lowest single-phase voltage is 121.33 V.
E. The kilovolt-ampere capability of the synchronous machine is 984 + j738 = 1,236 kVA. The unit is located at midpoint.

Table 56. Induction Generator Voltage Regulation Application (LV, HV) – LL

						Node 01			Lowest 3Φ Voltage			Lowest					I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
IG	400	0	LV	N/A	16	215.5865	250.8556	244.2324	123.2152	123.0762	122.3465	121.9696	100.1499	0.5791	3.1%	457.01	4.9459	0.5876	85.371	62.6147
VR (1) 7, 7, 8																				
IG	400	247.91	LV	N/A	16	211.3691	246.811	240.07	123.6507	123.4998	122.7978	122.4196	100.1498	0.5601	3.0%	438.8	5.0728	0.5724	85.3752	63.2174
VR (1) 7, 7, 8																				
IG	400	-247.91	LV	N/A	16	220.2762	255.3078	248.8162	122.7733	122.6469	121.8883	121.5126	100.1499	0.5984	3.2%	478.96	4.8132	0.6007	85.3667	61.9511
VR (1) 7, 7, 8																				
IG	400	0	HV	N/A	0	215.6606	250.9707	244.3936	123.2559	123.1314	122.4251	122.048	100.1499	0.57	3.1%	436.17	4.9564	0.5879	85.3752	62.5975
VR (1) 7, 7, 8																				
IG	400	247.91	HV	N/A	-1	209.897	245.1622	238.5137	122.8626	122.7266	122.0544	121.6783	100.1497	0.5505	3.0%	411.4	5.0894	0.5725	85.3793	63.4632
VR (1) 7, 7, 8																				
IG	400	-247.91	HV	N/A	0	220.6714	255.7775	249.293	122.8241	122.7128	121.9782	121.6023	100.1499	0.5895	3.1%	458.58	4.8202	0.6019	85.371	61.8811
VR (1) 8, 8, 9																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	kW Losses	Node 1 Capacity
IG	400	0	LV	N/A	0.61%	0.31%	2.04%
VR (1) 7, 7, 8							
IG	400	247.91	LV	N/A	0.98%	0.37%	2.64%
VR (1) 7, 7, 8							
IG	400	-247.91	LV	N/A	0.23%	0.23%	1.38%
VR (1) 7, 7, 8							
IG	400	0	HV	N/A	0.67%	0.33%	2.02%
VR (1) 7, 7, 8							
IG	400	247.91	HV	N/A	0.37%	0.38%	2.89%
VR (1) 7, 7, 8							
IG	400	-247.91	HV	N/A	0.30%	0.25%	1.31%
VR (1) 8, 8, 9							

Table 57. Inverter Generator Voltage Regulation Application (LV, HV) – LL

Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
InvG	400	0	LV	N/A	16	215.7648	251.0805	244.2842	123.3158	123.0805	122.3867	122.0019	100.1498	0.5704	3.1%	467.04	4.9222	0.4231	75.2233	62.5812
		VR (1) 7, 7, 8																		
InvG	320	240	LV	N/A	16	214.3897	249.7643	242.9851	123.8584	123.6347	122.9837	122.5691	189.5674	0.5357	3.1%	461.97	4.9736	0.4169	99.0905	62.7773
		VR (1) 7, 7, 8																		
InvG	320	-240	LV	N/A	16	223.2678	258.5274	251.7314	122.6213	122.4607	121.6974	121.361	100.1499	0.6131	3.2%	495.7	4.7719	0.4153	73.2693	61.4713
		VR (1) 7, 7, 8																		
InvG	400	0	HV	N/A	0	215.8399	251.1973	244.4464	123.3571	123.1364	122.4658	122.0808	100.1498	0.5606	3.1%	446.17	4.9327	0.4232	75.2366	62.5637
		VR (1) 7, 7, 8																		
InvG	320	240	HV	N/A	0	214.4339	249.8456	243.1133	123.8825	123.6733	123.0455	122.6307	189.2126	0.5253	3.1%	441.2	4.9842	0.4169	98.9889	62.7652
		VR (1) 7, 7, 8																		
InvG	320	-240	HV	N/A	0	223.374	258.6802	251.9266	122.6821	122.5365	121.7965	121.4598	100.1499	0.6034	3.2%	473.61	4.7821	0.4166	73.2757	61.4486
		VR (1) 7, 7, 8																		

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
InvG	400	0	LV	N/A	0.63%	0.28%	2.01%
		VR (1) 7, 7, 8					
InvG	320	240	LV	N/A	1.10%	0.29%	2.20%
		VR (1) 7, 7, 8					
InvG	320	-240	LV	N/A	0.10%	0.18%	0.90%
		VR (1) 7, 7, 8					
InvG	400	0	HV	N/A	0.70%	0.30%	1.99%
		VR (1) 7, 7, 8					
InvG	320	240	HV	N/A	1.15%	0.33%	2.19%
		VR (1) 7, 7, 8					
InvG	320	-240	HV	N/A	0.19%	0.22%	0.87%
		VR (1) 7, 7, 8					

Table 58. Synchronous Generator Voltage Regulation Application (BL, HV) – LL

						Node 01			Lowest 3Φ Voltage								I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
SG	50%	0	HV	BL	0	212.8733	248.4197	241.7729	123.0971	123.0572	122.3328	121.9559	100.15	0.5814	3.2%	464.51	5.0537	2.4249	85.3796	62.9777
		VR (1) 7, 7, 8																		
SG	75%	0	HV	BL	0	204.3709	239.9243	233.3379	123.117	123.0771	122.3526	121.9756	100.15	0.5814	3.2%	448.7	5.2441	2.4249	85.3796	64.2438
		VR (1) 7, 7, 8																		
SG	100%	0	HV	BL	0	196.0316	231.5685	225.0531	123.1365	123.0966	122.372	121.995	100.15	0.5813	3.2%	433.75	5.4457	2.4249	85.3797	65.489
		VR (1) 7, 7, 8																		
SG	106.7%	0	HV	BL	0	193.8247	229.3523	222.8581	123.1417	123.1018	122.3772	122.0001	100.15	0.5813	3.2%	429.88	5.5017	2.4249	85.3797	65.8193
		VR (1) 7, 7, 8																		
SG	100%	100%	HV	BL	-1	179.4087	214.7065	207.7869	122.9478	122.9088	122.1866	121.8101	100.1499	0.5809	3.1%	403.36	5.8977	2.4257	85.3798	68.002
		VR (1) 7, 7, 8																		
SG	100%	-100%	HV	BL	0	214.3268	249.4135	243.3793	122.507	122.4672	121.746	121.3707	100.1499	0.5816	2.8%	464.99	5.0029	2.4248	85.3794	62.8296
		VR (1) 7, 7, 8																		
SG	25%	100%	HV	BL	-1	206.9496	241.9569	234.9388	122.8884	122.8494	122.1275	121.7512	100.1499	0.581	3.2%	450.51	5.1888	2.4257	85.3798	63.9408
		VR (1) 7, 7, 8																		
SG	25%	75%	HV	BL	-1	209.9137	245.0483	238.1157	122.7317	122.6927	121.9717	121.5958	100.1499	0.581	3.2%	455.68	5.1136	2.4256	85.3797	63.4801
		VR (1) 7, 7, 8																		
SG	25%	50%	HV	BL	-1	213.0619	248.2864	241.4423	122.5771	122.5382	121.818	121.4425	100.1499	0.5811	3.2%	461.23	5.037	2.4256	85.3797	62.9976
		VR (1) 7, 7, 8																		
SG	25%	25%	HV	BL	0	217.9593	253.4542	246.661	123.232	123.192	122.4669	122.0896	100.15	0.5813	3.2%	474.63	4.953	2.4249	85.3797	62.2274
		VR (1) 7, 7, 8																		
SG	25%	0%	HV	BL	0	221.5205	257.0412	250.3433	123.0768	123.0369	122.3126	121.9358	100.15	0.5814	3.2%	481.16	4.8738	2.4249	85.3796	61.6928
		VR (1) 7, 7, 8																		
SG	25%	-50%	HV	BL	0	229.5958	265.1166	258.5824	122.7537	122.7143	121.9926	121.6166	100.1499	0.5818	3.2%	497.01	4.7075	2.423	85.3795	60.4893
		VR (1) 8, 8, 9																		
SG	25%	-100%	HV	BL	0	238.1321	273.5304	267.2042	122.438	122.3987	121.6786	121.3036	100.1499	0.5819	3.3%	513.6	4.5422	2.4229	85.3794	59.2354
		VR (1) 8, 8, 9																		

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	HV	BL	0.60%	0.20%	2.40%
		VR (1) 7, 7, 8					
SG	75%	0	HV	BL	0.61%	0.22%	3.67%
		VR (1) 7, 7, 8					
SG	100%	0	HV	BL	0.63%	0.24%	4.91%
		VR (1) 7, 7, 8					
SG	106.7%	0	HV	BL	0.63%	0.25%	5.24%
		VR (1) 7, 7, 8					
SG	100%	100%	HV	BL	0.47%	0.27%	7.43%
		VR (1) 7, 7, 8					
SG	100%	-100%	HV	BL	0.11%	0.61%	2.25%
		VR (1) 7, 7, 8					
SG	25%	100%	HV	BL	0.43%	0.21%	3.37%
		VR (1) 7, 7, 8					
SG	25%	75%	HV	BL	0.30%	0.20%	2.91%
		VR (1) 7, 7, 8					
SG	25%	50%	HV	BL	0.17%	0.19%	2.42%
		VR (1) 7, 7, 8					
SG	25%	25%	HV	BL	0.71%	0.19%	1.65%
		VR (1) 7, 7, 8					
SG	25%	0%	HV	BL	0.58%	0.18%	1.12%
		VR (1) 7, 7, 8					
SG	25%	-50%	HV	BL	0.32%	0.15%	-0.09%
		VR (1) 8, 8, 9					
SG	25%	-100%	HV	BL	0.06%	0.12%	-1.34%
		VR (1) 8, 8, 9					

Table 59. Synchronous Generator Voltage Regulation Application (EL, HV) – LL

						Node 01			Lowest 3Φ Voltage			Lowest					
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0
SG	50%	0	HV	EL	0	212.3632	247.6197	241.0869	123.3	123.1564	122.4539	122.0766	100.1498	0.5676	3.0%	423.13	5.0172
		VR (1) 7, 7, 8															
SG	75%	0	HV	EL	0	203.6864	238.771	232.3689	123.415	123.2206	122.5274	122.1499	100.1498	0.5618	2.9%	390.74	5.1848
		VR (1) 7, 7, 8															
SG	100%	0	HV	EL	0	195.2284	230.0957	223.8435	123.5254	123.281	122.5959	122.2183	100.1497	0.5567	2.9%	361.9	5.3601
		VR (1) 7, 7, 8															
SG	106.7%	0	HV	EL	0	192.9993	227.7999	221.5913	123.5543	123.2966	122.6135	122.2358	100.1497	0.5554	2.9%	354.76	5.4084
		VR (1) 7, 7, 8															
SG	100%	100%	HV	EL	-1	180.5095	215.6699	209.1265	123.9599	123.6821	123.0829	122.7038	100.1496	0.4985	2.7%	311.07	5.8389
		VR (1) 6, 6, 7															
SG	100%	-100%	HV	EL	0	212.9442	247.0417	241.1703	122.2241	122.007	121.235	120.8612	100.1499	0.6197	3.1%	440.76	4.8856
		VR (1) 9, 10, 11															
SG	25%	100%	HV	EL	-1	208.4481	243.8298	236.9695	123.6157	123.4901	122.8629	122.4845	100.1497	0.5178	3.0%	408.59	5.2074
		VR (1) 6, 6, 7															
SG	25%	75%	HV	EL	-1	211.1141	246.5272	239.6941	123.2996	123.1822	122.5366	122.1591	100.1497	0.5318	3.0%	417.38	5.1233
		VR (1) 7, 7, 8															
SG	25%	50%	HV	EL	-1	213.7232	249.0965	242.3328	122.9942	122.8849	122.2196	121.8431	100.1498	0.5455	3.1%	426.84	5.0399
		VR (1) 7, 7, 8															
SG	25%	25%	HV	EL	0	218.1168	253.6216	246.8922	123.4912	123.39	122.6982	122.3202	175.2828	0.5601	3.1%	445.68	4.947
		VR (1) 7, 7, 8															
SG	25%	0%	HV	EL	0	221.2389	256.6262	249.9807	123.1805	123.0883	122.3755	121.9985	100.1499	0.5741	3.1%	459.1	4.857
		VR (1) 7, 7, 8															
SG	25%	-50%	HV	EL	0	228.6036	263.6773	257.1874	122.5345	122.4624	121.7061	121.331	100.15	0.6033	3.3%	493.54	4.6634
		VR (1) 8, 8, 9															
SG	25%	-100%	HV	EL	0	237.5644	272.2539	266.1526	120.9778	121.3988	121.4231	120.6221	100.15	0.6374	3.4%	539.55	4.4658
		VR (1) 11, 11, 13															

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	HV	EL	0.69%	0.37%	2.52%
		VR (1) 7, 7, 8					
SG	75%	0	HV	EL	0.76%	0.45%	3.84%
		VR (1) 7, 7, 8					
SG	100%	0	HV	EL	0.81%	0.53%	5.13%
		VR (1) 7, 7, 8					
SG	106.7%	0	HV	EL	0.83%	0.55%	5.48%
		VR (1) 7, 7, 8					
SG	100%	100%	HV	EL	1.21%	0.67%	7.28%
		VR (1) 6, 6, 7					
SG	100%	-100%	HV	EL	-0.31%	0.26%	2.61%
		VR (1) 9, 10, 11					
SG	25%	100%	HV	EL	1.03%	0.41%	3.09%
		VR (1) 6, 6, 7					
SG	25%	75%	HV	EL	0.76%	0.38%	2.68%
		VR (1) 7, 7, 8					
SG	25%	50%	HV	EL	0.50%	0.35%	2.30%
		VR (1) 7, 7, 8					
SG	25%	25%	HV	EL	0.90%	0.32%	1.63%
		VR (1) 7, 7, 8					
SG	25%	0%	HV	EL	0.63%	0.27%	1.18%
		VR (1) 7, 7, 8					
SG	25%	-50%	HV	EL	0.08%	0.15%	0.13%
		VR (1) 8, 8, 9					
SG	25%	-100%	HV	EL	-0.50%	0.00%	-1.15%
		VR (1) 11, 11, 13					

Table 60. Synchronous Generator Voltage Regulation Application (ML, HV) – LL

Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	50%	0	HV	ML	0	212.4129	247.6931	241.1176	123.2956	123.148	122.4488	122.0716	100.1498	0.5669	3.1%	427.69	5.0118	0.5212	85.3742	63.086
		VR (1) 7, 7, 8																		
SG	75%	0	HV	ML	0	203.7158	238.8462	232.3743	123.4114	123.2107	122.523	122.1455	100.1498	0.5606	3.0%	395.73	5.1779	0.5246	85.3715	64.4044
		VR (1) 7, 7, 8																		
SG	100%	0	HV	ML	0	195.2055	230.1473	223.7941	123.5246	123.2713	122.5943	122.2167	100.1497	0.555	2.9%	366.13	5.3526	0.5277	85.3688	65.7008
		VR (1) 7, 7, 8																		
SG	106.7%	0	HV	ML	0	192.9567	227.8406	221.522	123.5546	123.2872	122.613	122.2353	100.1497	0.5536	2.9%	358.59	5.4009	0.5285	85.3681	66.0446
		VR (1) 7, 7, 8																		
SG	100%	100%	HV	ML	-1	180.0864	215.2308	208.6781	123.9702	123.6826	123.0919	122.7128	100.1496	0.4961	2.7%	314.73	5.8244	0.4985	85.3812	67.9239
		VR (1) 6, 6, 7																		
SG	100%	-100%	HV	ML	0	212.9588	247.2812	241.2013	122.231	122.0028	121.2425	120.8687	100.1499	0.6183	3.1%	434.31	4.8977	0.5685	85.3543	63.1474
		VR (1) 9, 10, 11																		
SG	25%	100%	HV	ML	-1	208.0818	243.3935	236.593	123.6243	123.4957	122.8707	122.4923	100.1497	0.5168	3.0%	410.4	5.1974	0.4874	85.3893	63.7267
		VR (1) 6, 6, 7																		
SG	25%	75%	HV	ML	-1	210.8721	246.2299	239.4376	123.3036	123.1838	122.5398	122.1624	100.1497	0.531	3.0%	420.44	5.114	0.4958	85.3863	63.304
		VR (1) 7, 7, 8																		
SG	25%	50%	HV	ML	-1	213.5907	248.9264	242.1842	122.9947	122.8834	122.2195	121.8429	100.1498	0.5449	3.1%	430.49	5.0319	0.5032	85.3831	62.9022
		VR (1) 7, 7, 8																		
SG	25%	25%	HV	ML	-1	216.6113	251.8874	245.2029	122.6785	122.5761	121.8915	121.5158	100.1498	0.5592	3.1%	442.03	4.945	0.5106	85.3799	62.4609
		VR (1) 7, 7, 8																		
SG	25%	0%	HV	ML	0	221.2784	256.6741	250.0092	123.1772	123.0832	122.3719	121.9948	100.1499	0.5738	3.1%	462	4.854	0.5172	85.3769	61.7475
		VR (1) 7, 7, 8																		
SG	25%	-50%	HV	ML	0	228.7312	263.8744	257.3197	122.5323	122.4578	121.704	121.3288	100.15	0.6032	3.2%	492.86	4.6678	0.5316	85.3705	60.6745
		VR (1) 8, 8, 9																		
SG	25%	-100%	HV	ML	0	237.6779	272.5148	266.2969	121.8619	121.8078	120.9998	120.6267	100.15	0.6372	3.4%	532.26	4.4801	0.59	85.3626	59.3868
		VR (1) 11, 11, 13																		

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	HV	ML	0.69%	0.35%	2.51%
		VR (1) 7, 7, 8					
SG	75%	0	HV	ML	0.75%	0.43%	3.83%
		VR (1) 7, 7, 8					
SG	100%	0	HV	ML	0.81%	0.51%	5.13%
		VR (1) 7, 7, 8					
SG	106.7%	0	HV	ML	0.83%	0.53%	5.47%
		VR (1) 7, 7, 8					
SG	100%	100%	HV	ML	1.22%	0.65%	7.35%
		VR (1) 6, 6, 7					
SG	100%	-100%	HV	ML	-0.30%	0.29%	2.57%
		VR (1) 9, 10, 11					
SG	25%	100%	HV	ML	1.04%	0.40%	3.15%
		VR (1) 6, 6, 7					
SG	25%	75%	HV	ML	0.77%	0.37%	2.73%
		VR (1) 7, 7, 8					
SG	25%	50%	HV	ML	0.50%	0.33%	2.33%
		VR (1) 7, 7, 8					
SG	25%	25%	HV	ML	0.23%	0.29%	1.89%
		VR (1) 7, 7, 8					
SG	25%	0%	HV	ML	0.63%	0.26%	1.17%
		VR (1) 7, 7, 8					
SG	25%	-50%	HV	ML	0.08%	0.15%	0.10%
		VR (1) 8, 8, 9					
SG	25%	-100%	HV	ML	-0.50%	0.03%	-1.19%
		VR (1) 11, 11, 13					

Table 61. Synchronous Generator Voltage Regulation Application (BL, LV) – LL

						Node 01			Lowest 3Φ Voltage			Lowest					I2/I1 %			
Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	Node 0	Low	High (<100)	Node 1 Capacity
SG	50%	0	LV	BL	16	212.7966	248.3	241.6071	123.0554	123.0003	122.2526	121.876	100.15	0.5896	3.2%	484.87	5.0431	2.4115	85.3754	62.9955
		VR (1) 7, 7, 8																		
SG	75%	0	LV	BL	16	204.296	239.806	233.172	123.0777	123.0225	122.2747	121.898	100.15	0.5896	3.2%	467.61	5.2333	2.4115	85.3754	64.2614
		VR (1) 7, 7, 8																		
SG	100%	0	LV	BL	16	195.9588	231.4519	224.8876	123.0995	123.0443	122.2964	121.9196	100.15	0.5896	3.2%	451.28	5.4346	2.4115	85.3754	65.5064
		VR (1) 7, 7, 8																		
SG	106.7%	0	LV	BL	16	193.7525	229.2363	222.6927	123.1053	123.0501	122.3022	121.9254	100.15	0.5896	3.2%	447.05	5.4905	2.4115	85.3754	65.8366
		VR (1) 7, 7, 8																		
SG	100%	100%	LV	BL	15	179.6222	214.9111	207.9322	123.0487	122.9945	122.2484	121.8718	100.15	0.589	3.1%	419.17	5.8832	2.4124	85.3756	67.9715
		VR (1) 7, 7, 8																		
SG	100%	-100%	LV	BL	16	214.4479	249.197	243.3917	122.4026	122.3609	121.603	121.2282	100.1499	0.5913	3.2%	485.98	4.961	2.3827	85.3752	62.8618
		VR (1) 8, 7, 9																		
SG	25%	100%	LV	BL	15	207.126	242.1265	235.0549	122.9824	122.9283	122.1826	121.8061	100.15	0.5891	3.2%	470.68	5.177	2.4124	85.3756	63.9156
		VR (1) 7, 7, 8																		
SG	25%	75%	LV	BL	15	210.0627	245.1867	238.2018	122.8117	122.7576	122.0128	121.6368	100.1499	0.5891	3.2%	476.27	5.1021	2.4124	85.3755	63.4595
		VR (1) 7, 7, 8																		
SG	25%	50%	LV	BL	15	213.1836	248.3942	241.499	122.6432	122.5892	121.8454	121.4698	100.1499	0.5892	3.2%	482.29	5.0259	2.4123	85.3755	62.9815
		VR (1) 7, 7, 8																		
SG	25%	25%	LV	BL	15	216.5831	251.8481	245.0485	122.4716	122.4176	121.6747	121.2997	100.1499	0.5893	3.2%	488.93	4.9462	2.4123	85.3754	62.4667
		VR (1) 7, 7, 8																		
SG	25%	0%	LV	BL	16	221.4424	256.9205	250.1782	123.0328	122.9777	122.2301	121.8535	100.15	0.5896	3.2%	503.07	4.8634	2.4115	85.3753	61.7108
		VR (1) 7, 7, 8																		
SG	25%	-50%	LV	BL	16	229.4716	264.9431	258.3683	122.6806	122.626	121.8813	121.5057	100.1499	0.59	3.3%	520.22	4.6972	2.4096	85.3752	60.5152
		VR (1) 8, 8, 9																		
SG	25%	-100%	LV	BL	16	237.9682	273.3106	266.9479	122.3359	122.2815	121.5386	121.1639	100.1499	0.5901	3.3%	538.25	4.532	2.4095	85.3751	59.2682
		VR (1) 8, 8, 9																		

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	LV	BL	0.53%	0.18%	2.42%
		VR (1) 7, 7, 8					
SG	75%	0	LV	BL	0.55%	0.20%	3.69%
		VR (1) 7, 7, 8					
SG	100%	0	LV	BL	0.57%	0.22%	4.93%
		VR (1) 7, 7, 8					
SG	106.7%	0	LV	BL	0.57%	0.23%	5.26%
		VR (1) 7, 7, 8					
SG	100%	100%	LV	BL	0.53%	0.26%	7.40%
		VR (1) 7, 7, 8					
SG	100%	-100%	LV	BL	-0.01%	0.16%	2.29%
		VR (1) 8, 7, 9					
SG	25%	100%	LV	BL	0.47%	0.19%	3.34%
		VR (1) 7, 7, 8					
SG	25%	75%	LV	BL	0.33%	0.18%	2.88%
		VR (1) 7, 7, 8					
SG	25%	50%	LV	BL	0.19%	0.17%	2.41%
		VR (1) 7, 7, 8					
SG	25%	25%	LV	BL	0.05%	0.15%	1.89%
		VR (1) 7, 7, 8					
SG	25%	0%	LV	BL	0.51%	0.16%	1.14%
		VR (1) 7, 7, 8					
SG	25%	-50%	LV	BL	0.22%	0.12%	-0.06%
		VR (1) 8, 8, 9					
SG	25%	-100%	LV	BL	-0.06%	0.09%	-1.31%
		VR (1) 8, 8, 9					

Table 62. Synchronous Generator Voltage Regulation Application (EL, LV) – LL

						Node 01			Lowest 3Φ Voltage			Lowest	Highest	Highest	% kW	Total	I2/I1 %			
Type	Power	Power	HV / LV	Location	LTC Tap	IA	IB	IC	VA	VB	VC	1Φ	I2/I1 %	V2/V1 %	Loss	kVar Loss	Node 0	Low	(<100)	Capacity
SG	50%	0	LV	EL	16	212.2903	247.5062	240.9265	123.2606	123.1026	122.3766	121.9996	100.1499	0.5769	3.1%	443.41	5.0066	0.5875	85.37	63.1138
VR (1) 7, 7, 8																				
SG	75%	0	LV	EL	16	203.6169	238.6617	232.2108	123.3787	123.1704	122.4535	122.0762	100.1498	0.5716	3.0%	409.53	5.1741	0.5871	85.3673	64.4319
VR (1) 7, 7, 8																				
SG	100%	0	LV	EL	16	195.1622	229.9907	223.688	123.4919	123.2341	122.5252	122.1478	100.1498	0.567	2.9%	379.28	5.3492	0.5858	85.3647	65.7242
VR (1) 7, 7, 8																				
SG	106.7%	0	LV	EL	16	192.934	227.6962	221.4365	123.5215	123.2505	122.5436	122.1661	100.1497	0.5659	2.9%	371.78	5.3975	0.5853	85.3639	66.0661
VR (1) 7, 7, 8																				
SG	100%	100%	LV	EL	15	181.0127	216.1996	209.5588	124.0533	123.7631	123.14	122.7609	100.1496	0.5089	2.7%	327.99	5.8192	0.5394	85.3772	67.7795
VR (1) 7, 7, 8																				
SG	100%	-100%	LV	EL	16	213.0625	247.1357	241.1868	122.1223	121.8917	121.0974	120.7239	100.1499	0.6305	3.2%	461.79	4.8718	0.6474	85.3501	63.169
VR (1) 10, 11, 12																				
SG	25%	100%	LV	EL	15	208.6222	243.9988	237.0845	123.7093	123.5693	122.9178	122.5393	100.1497	0.5263	3.0%	429.05	5.1957	0.5371	85.3851	63.6365
VR (1) 6, 6, 7																				
SG	25%	75%	LV	EL	15	211.2622	246.6659	239.7802	123.3795	123.2477	122.5779	122.2004	100.1498	0.5403	3.0%	438.23	5.1119	0.5508	85.382	63.2391
VR (1) 7, 7, 8																				
SG	25%	50%	LV	EL	15	213.8455	249.2062	242.3909	123.0608	122.937	122.2478	121.8712	100.1498	0.5541	3.1%	448.04	5.0287	0.5633	85.3789	62.8605
VR (1) 7, 7, 8																				
SG	25%	25%	LV	EL	15	216.7438	252.02	245.2842	122.7333	122.6182	121.9086	121.5328	173.4712	0.5683	3.1%	460.03	4.94	0.5761	98.6865	62.4411
VR (1) 7, 7, 8																				
SG	25%	0%	LV	EL	16	221.4532	256.8277	250.101	123.1283	123.0217	122.2865	121.9097	100.1499	0.5832	3.2%	482.19	4.8432	0.5886	85.3727	61.7246
VR (1) 8, 8, 9																				
SG	25%	-50%	LV	EL	16	228.481	263.5061	256.9753	122.4626	122.3755	121.5962	121.2214	100.15	0.6122	3.3%	516.53	4.6532	0.6066	85.3663	60.7293
VR (1) 8, 8, 9																				
SG	25%	-100%	LV	EL	16	237.6856	272.3481	266.1733	121.7458	121.681	120.8464	120.4737	100.15	0.6467	3.4%	565.3	4.453	0.6718	85.3584	59.4116
VR (1) 12, 12, 14																				

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	LV	EL	0.63%	0.34%	2.54%
VR (1) 7, 7, 8							
SG	75%	0	LV	EL	0.69%	0.43%	3.86%
VR (1) 7, 7, 8							
SG	100%	0	LV	EL	0.75%	0.51%	5.15%
VR (1) 7, 7, 8							
SG	106.7%	0	LV	EL	0.77%	0.52%	5.49%
VR (1) 7, 7, 8							
SG	100%	100%	LV	EL	1.26%	0.66%	7.20%
VR (1) 7, 7, 8							
SG	100%	-100%	LV	EL	-0.42%	0.23%	2.59%
VR (1) 10, 11, 12							
SG	25%	100%	LV	EL	1.08%	0.39%	3.06%
VR (1) 6, 6, 7							
SG	25%	75%	LV	EL	0.80%	0.36%	2.66%
VR (1) 7, 7, 8							
SG	25%	50%	LV	EL	0.53%	0.32%	2.29%
VR (1) 7, 7, 8							
SG	25%	25%	LV	EL	0.25%	0.28%	1.87%
VR (1) 7, 7, 8							
SG	25%	0%	LV	EL	0.56%	0.24%	1.15%
VR (1) 8, 8, 9							
SG	25%	-50%	LV	EL	-0.01%	0.12%	0.15%
VR (1) 8, 8, 9							
SG	25%	-100%	LV	EL	-0.63%	-0.04%	-1.16%
VR (1) 12, 12, 14							

Table 63. Synchronous Generator Voltage Regulation Application (ML, LV) – LL

Machine Type	Real Power	Reactive Power	HV / LV	Location	LTC Tap	Node 01 IA	Node 01 IB	Node 01 IC	Lowest 3Φ Voltage VA	Lowest 3Φ Voltage VB	Lowest 3Φ Voltage VC	Lowest 1Φ Voltage	Highest I2/I1 %	Highest V2/V1 %	% kW Loss	Total kVar Loss	I2/I1 % Node 0	I2/I1 % Low	I2/I1 % High (<100)	Node 1 Capacity
SG	50%	0	LV	ML	16	212.3396	247.5788	240.9566	123.2559	123.0939	122.3713	121.9943	100.1499	0.5762	3.1%	447.96	5.0013	0.5209	85.37	63.103
		VR (1) 7, 7, 8																		
SG	75%	0	LV	ML	16	203.6459	238.736	232.2155	123.3749	123.1601	122.4489	122.0716	100.1498	0.5704	3.0%	414.53	5.1672	0.5243	85.3673	64.4209
		VR (1) 7, 7, 8																		
SG	100%	0	LV	ML	16	195.1391	230.0414	223.638	123.491	123.224	122.5235	122.1461	100.1497	0.5653	2.9%	383.51	5.3416	0.5274	85.3646	65.7166
		VR (1) 7, 7, 8																		
SG	106.7%	0	LV	ML	16	192.8913	227.7359	221.3666	123.5217	123.2408	122.543	122.1655	100.1497	0.564	2.9%	375.61	5.3899	0.5281	85.3639	66.0602
		VR (1) 7, 7, 8																		
SG	100%	100%	LV	ML	15	180.3035	215.4447	208.831	124.0729	123.7724	123.1571	122.7779	100.1496	0.5063	2.8%	330.64	5.8102	0.4986	85.3772	67.892
		VR (1) 6, 6, 7																		
SG	100%	-100%	LV	ML	16	213.0786	247.3756	241.2184	122.1295	121.8875	121.1051	120.7316	100.1498	0.629	3.1%	455.38	4.8838	0.5683	85.3502	63.1333
		VR (1) 10, 11, 12																		
SG	25%	100%	LV	ML	15	208.257	243.5636	236.709	123.7181	123.5753	122.926	122.5474	100.1497	0.5252	3.0%	430.81	5.1856	0.4877	85.3852	63.7014
		VR (1) 6, 6, 7																		
SG	25%	75%	LV	ML	15	211.0207	246.3693	239.5242	123.3835	123.2494	122.5814	122.2038	100.1498	0.5395	3.1%	441.23	5.1026	0.496	85.3821	63.2833
		VR (1) 7, 7, 8																		
SG	25%	50%	LV	ML	15	213.7131	249.0361	242.2424	123.0612	122.9354	122.2477	121.871	100.1498	0.5534	3.1%	451.66	5.0208	0.5033	85.379	62.8858
		VR (1) 7, 7, 8																		
SG	25%	25%	LV	ML	16	218.0283	253.4786	246.7043	123.4602	123.3425	122.6284	122.2507	100.1499	0.5684	3.1%	470.68	4.9307	0.5103	85.3758	62.2237
		VR (1) 7, 7, 8																		
SG	25%	0%	LV	ML	16	221.202	256.556	249.8464	123.1342	123.0254	122.2907	121.9139	100.1499	0.5826	3.2%	0	4.8436	0.517	85.3727	61.7651
		VR (1) 7, 7, 8																		
SG	25%	-50%	LV	ML	16	228.6085	263.7029	257.1074	122.4603	122.3707	121.5939	121.2191	100.15	0.612	3.3%	515.86	4.6577	0.5312	85.3663	60.7
		VR (1) 8, 8, 9																		
SG	25%	-100%	LV	ML	16	237.7999	272.6093	266.318	121.7498	121.6811	120.8512	120.4784	100.15	0.6466	3.4%	558.04	4.4672	0.5899	85.3584	59.3727
		VR (1) 12, 12, 14																		

Improvement							
Machine Type	Real Power	Reactive Power	HV / LV	Location	Lowest Voltage	Losses	Node 1 Capacity
SG	50%	0	LV	ML	0.63%	0.32%	2.53%
		VR (1) 7, 7, 8					
SG	75%	0	LV	ML	0.69%	0.41%	3.85%
		VR (1) 7, 7, 8					
SG	100%	0	LV	ML	0.75%	0.49%	5.14%
		VR (1) 7, 7, 8					
SG	106.7%	0	LV	ML	0.77%	0.51%	5.49%
		VR (1) 7, 7, 8					
SG	100%	100%	LV	ML	1.27%	0.63%	7.32%
		VR (1) 6, 6, 7					
SG	100%	-100%	LV	ML	-0.41%	0.26%	2.56%
		VR (1) 10, 11, 12					
SG	25%	100%	LV	ML	1.08%	0.38%	3.13%
		VR (1) 6, 6, 7					
SG	25%	75%	LV	ML	0.80%	0.34%	2.71%
		VR (1) 7, 7, 8					
SG	25%	50%	LV	ML	0.53%	0.31%	2.31%
		VR (1) 7, 7, 8					
SG	25%	25%	LV	ML	0.84%	0.28%	1.65%
		VR (1) 7, 7, 8					
SG	25%	0%	LV	ML	0.56%	0.23%	1.19%
		VR (1) 7, 7, 8					
SG	25%	-50%	LV	ML	-0.01%	0.12%	0.13%
		VR (1) 8, 8, 9					
SG	25%	-100%	LV	ML	-0.62%	0.00%	-1.20%
		VR (1) 12, 12, 14					

12 Conclusions and Recommendations

12.1 Conclusions

- Five methods to improve voltage regulation at the substation were explained and seven methods to improve voltage regulation on the distribution circuit were defined. It was shown that the voltage drop is six times less for three-phase circuit than single-phase circuit portions with the same load, yet most of the load is served by the single-phase portions of the circuit. Voltage and current equations were developed for the Type A and Type B step VRs and the bidirectional regulator, which is required for operation of DG on the circuit. The operation of the line drop compensator and how the settings are calculated when loads are tapped off the circuit before the regulation point were explained. In addition, equations were developed to determine the settings of the regulator when shunt capacitors are added to the circuit. Why grounded wye capacitors are used on four-wire wye-grounded systems and why delta-connected capacitors are used on ungrounded systems to alleviate series resonant conditions were explained.
- Causes for unbalanced voltage and current and how these conditions affect protective relaying were explained. The neutral relay is set to trip for ground faults, and the trip value may have to be increased to account for increased neutral current because of unbalance. This may cause a loss of sensitivity in clearing for faults.
- Significant unbalanced loading can occur even though voltages are balanced at the source. Reclosers and the substation breaker with ground fault-sensing circuits are affected by load imbalance. Unequal single-phase load connected line-to-line does not produce neutral current in the ground relay.
- Fuse preload because of unbalanced loading can cause fuses to become unselective with other protective devices such as reclosers and cause misoperation.
- Reducing unbalanced loading reduces the losses created by the neutral current in the neutral conductor.
- Unbalanced three-phase voltages have a significant effect on the heating of induction and synchronous generators. For example, a 5.5% voltage unbalance can cause an approximate 25% increase in temperature rise. The phase currents with unbalanced voltages are greatly unbalanced, on the order of four to five times the voltage unbalance. If overload relay protection settings are raised because of unbalance, the generator may not be protected against overload and open phases.
- Heating of induction generators because of voltage unbalance is affected by phase rotation. Phase rotation affects which of the phases has the highest line currents. This means negative sequence current protection must be used to protect the induction generator to prevent failure because of voltage unbalance. The negative sequence losses are proportional to the square of the negative sequence voltage. The generator may have to reduce output below nameplate rating to avoid overheating with voltage unbalance.

An equation was developed to calculate machine derating with unbalanced voltages with only the percent unbalanced voltage and ratio of the positive-to-negative sequence impedances of the induction generator. It was shown that a 5% voltage unbalance causes a 3.2%–10.7% power output derate, depending on the positive-to-negative sequence impedance ratio.

- The 13-utility voltage survey showed a maximum percent unbalance of 5.94%, with an average of 1.1%. Eighty-five percent of all tests were <2% voltage unbalance. The Milford Circuit showed the maximum percent unbalance to be 1.52% on the primary during HL conditions and 1.26% for LL. Typically, the maximum permissible current unbalance for synchronous generators is 10% of the rated stator current. A 15.44% negative sequence current is produced from a 3% voltage unbalance for a single-cage induction generator, so care must be exercised to locate generating units on a distribution circuit for which the voltage unbalance is less than 3% and the unbalance current is less than 10%–20%.
- Models were developed for the 10-MVA LTC delta-wye-grounded substation transformer, the 167-kVA bidirectional VRs, the three wye-grounded capacitors, the line impedances, and all (nine cases) the distribution circuit transformer connections.
- The line loss model was validated using three line configurations and balanced and unbalanced load conditions. The three line configurations were the balanced impedance triangular spacing configuration, or equilateral; the flat configuration non-transposed; and the flat configuration transposed. The purpose of the validation was to show that, with a balanced line impedance and balanced load, the kilowatt losses are the same in each phase and the total kilowatt losses are lowest. In addition, an example showed that, even though the kilowatt losses per phase are not correct because of the Kron reduction process from a four-by-four matrix to a three-by-three matrix, the total losses for the three phases are, in fact, correct.
- Models were developed for the 1,000-kW synchronous generator, the self-excited 400-kW induction generator, and the 400-kW high-speed generator and inverter system.
- The line, equipment, and generation models were verified with the maximum phase current variance of 3.9% on July 17, 2006, and 5.7% on July 29, 2006—except for Node I, where the percent unbalance current was very high. The maximum phase voltage variance was 1.5% on July 17 and 1.2% on July 29. The maximum PF variance was 5.7% on July 17 and 3.4% on July 29.
- The selected distribution circuit was a 13.2-kV, three-phase wye multi-grounded system that serves approximately 76.2% residential, 4% commercial, and 19.8% light industrial loads. The load on the summer peak day was 15.3 MVA, and the summer peak day minimum load was 5.91 MVA. Eight regulation tests were conducted for the HL load condition, and eight were conducted for the LL condition. The primary voltage to the substation was ranged from 95% to 105%. The regulation methods consisted of the:

- LTC
- LTC and VR 1
- LTC, VR 1, and VR 2
- LTC and Cap 1
- LTC, Cap 1, and Cap 2
- LTC, Cap 1, Cap 2, and Cap 3
- LTC, VR 1, VR 2, Cap 1, Cap 2, and Cap3.

The voltage spread, measured as the difference between the highest three-phase voltage and the lowest single-phase voltage, for the HL condition was 25.2 V with no regulation at the substation and on the distribution circuit. When all regulation was implemented, this voltage spread was reduced to only 10.4 V, and there were no voltage criteria violations. For the LL condition, the voltage spread was 16.65 V for no regulation. With all regulation operating, the spread was only 2.91 V.

- The load imbalance at the substation was 4% for HL and 5.45% for LL. Adding regulation does not necessarily improve load imbalance; in fact, higher voltages generally cause higher loads and more imbalance.
- The VDC model best represented how the circuit load changes with changes in source voltage. The model consisted of $\% \Delta P / \% \Delta V = 1.26$ and $\% \Delta Q / \% \Delta V = 4.66\%$. The CC model percent error was 3.9%, the CP model percent error was 12.5%, and the VDC model percent error was only 2%.
- Three voltage control strategies were tested for the 400-kW induction generator at LV and HV substation primary voltage for a total of six simulations. Three voltage control strategies were tested for the 400-kW inverter-based generation at LV and HV substation primary voltage for a total of six simulations. And 13 voltage control strategies for HV and 13 for LV were tested for the synchronous generator located at the BL, ML, and EL of the circuit, for a total of 78 simulations. The maximum released capacity of 10.44% was achieved with the 1,000-kW synchronous generator with P = 100% and Q = 100%. The voltage improvement was 0.82%, and the loss reduction was 0.56% out of a 5.4% base.
- The optimum location for the DG with the highest released capacity of 10.44% was at the source of the circuit because it directly offset the load current and load losses of the circuit. The optimum DR location to achieve the greatest loss reduction was at the EL of the circuit because adding generation here reduces on a prorata basis the load and the length of the circuit. There was little difference for improving the voltage regulation between locating the DR at the midpoint or end of the circuit. There was a slightly better improvement at the midpoint for circuits in which the conductor size of the entire three-phase backbone was the same.

- The DG penetration study showed that a synchronous DG had a real power limit of 13,980 kW at the tag end of the circuit. The optimum location was at the midpoint, with the lowest single-phase voltage improvement of 1.7% and a real power loss savings of 2.04%. The base case real power losses were 5.4%. The DG penetration study found that the maximum real and reactive power output limit was 14,490 kW and 2,007 kVAr, which allows a larger DG to be installed than when only real power was injected. Again, the optimum location was at the midpoint of the circuit, but, in this case, the lowest single-phase voltage was improved 4.55% versus only 1.7% in the real power limit case. The real power loss savings were marginally better, with a 2.3% savings versus 2.04%. This saving in losses represents a 57.4% reduction when the DG is located at the midpoint of the circuit.

12.2 Recommendations

- This project used validated circuit equipment and line models and a validated VDC source load model to test 78 synchronous generator voltage control strategies. It found the greatest improvement in released capacity reduced real losses and improvement in voltage regulation occurred when the synchronous generator produced the maximum real and reactive power. DG can be sized and located to produce these improvements, but the effects on system protection systems must be evaluated.
- It is recommended that a validated unbalanced three-phase power flow program be used to determine the percent unbalanced voltage and percent unbalanced current throughout the circuit. If the percent unbalanced voltage exceeds 3% and the percent unbalanced current exceeds 10% at the location where a synchronous generator is to be sited, it is highly possible it will never operate and could trip on voltage or current imbalance.
- It is highly recommended that a VDC source be used for the load model because it is more accurate than the CP and CC models.
- The optimum voltage regulation method that produced the least voltage spread used the substation transformer LTC, step regulators, capacitors, and DG. It is recommended that the DG be located at the midpoint of the circuit to produce the best overall improvements in voltage regulation, loss reduction, and released capacity.
- The circuit selected had voltage unbalance conditions that closely agreed with the average voltage unbalance measurements taken at 13 major utilities. Therefore, the results should be representative of what would be experienced on the average distribution circuit.
- Voltage regulation and system protection issues represent the most difficult problems for interconnecting DG with the distribution circuit. This report explains how voltage unbalance and current imbalance can affect system protection performance and the rating of the DG output. It is recommended that inverter-based generation be considered as the preferred DG type if the level of unbalanced voltage and current may prevent synchronous and induction generators from operating on the circuit.

- Future research should fund the development of a real-time optimal control of DG to accomplish the optimum generator voltage control condition, including the control of the substation transformer LTC, the bidirectional step regulators, and the switched capacitors. The cost to perform this development work on the Milford Circuit DC 8103 would be substantially less than installing DG and metering equipment on a new circuit because all of this equipment is already installed and tested. Furthermore, the newly developed control strategies can be tested in the summer of 2008. The estimated cost for this project is less than $500,000, and the development, testing, and analysis schedule is estimated to be approximately 1.5 years.

12.3 Benefits to California

Models were developed and validated with actual measured circuit and generator test data. This project showed that adding DG to a distribution circuit can reduce generation capacity by 10% (released capacity), and these results can be achieved in 1 year—not 7–10 years—for traditional central-station generation. Also, improved voltage regulation results in fewer service voltage criteria violations and less distribution energy losses (i.e., approximately 10%).

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Appendix A: Ground Detector and Ungrounded Systems

For ungrounded delta systems, there is a normal leakage current of about 2 A to ground because of the distributed capacitance, as shown in Figure A-1. The VTs with a ratio of 40:1 are connected in a broken delta configuration on the secondary side. Under normal circumstances, the line-to-neutral voltages on the primary of the VT are 2,770 V, and the voltage vectors on the secondary side have a magnitude of 69 V with an angle of 120° between these vectors. These vectors add to zero, as in the phasor diagram of Figure A-2.

When a ground is applied to Phase Conductor A, as in Figure A-3, this phase goes to ground potential, while the two unfaulted phases have 4,800 V applied across each. This causes an increase in the ground current I_G from 2 A to 6 A and an increase in voltage on the secondary of the broken delta from 0 V to 208 V. This phasor diagram is shown in Figure A-4.

Grounding phase conductors of an ungrounded delta system produces a minimum current unbalance of 3.46 A in this case. Overcurrent relays are not normally installed to detect this small current unbalance. But there are instances in which as much as 20–30 A have been detected. This is still less than the typical overcurrent settings of 70 A for a recloser on the circuit and 1,000 A or higher for a breaker at the substation.

A.1. Ungrounded Delta Ground Detection – Normal Condition, No Ground Applied to Phase Conductor

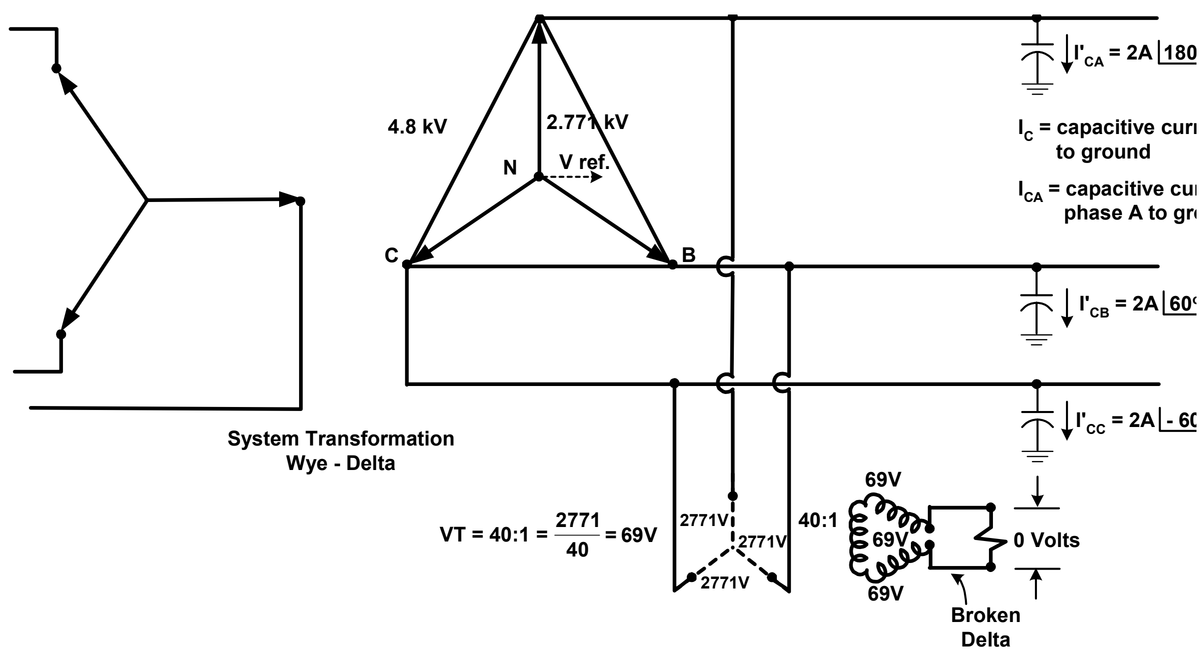


Figure A-1. Normal leakage currents to ground because of distributed capacitance

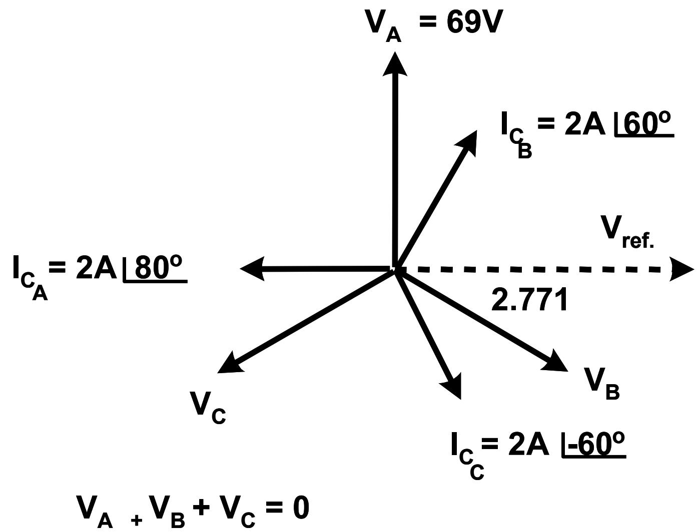


Figure A-2. Normal leakage currents to ground because of distributed capacitance – phasor diagram

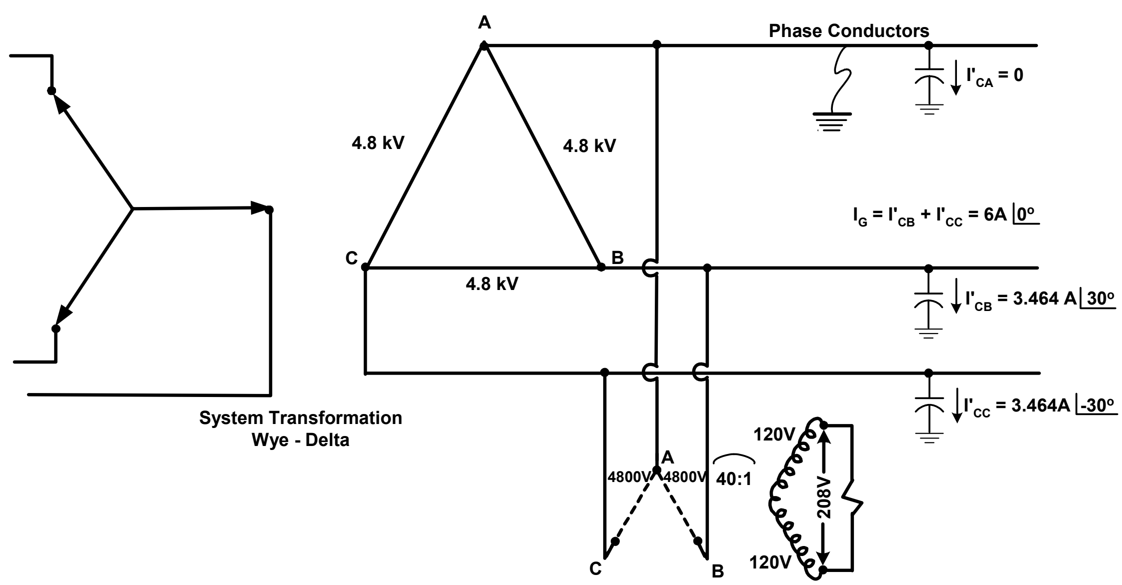


Figure A-3. Increased leakage current on the unfaulted phases and resultant ground current I_G and resultant zero sequence voltage 3 V_O

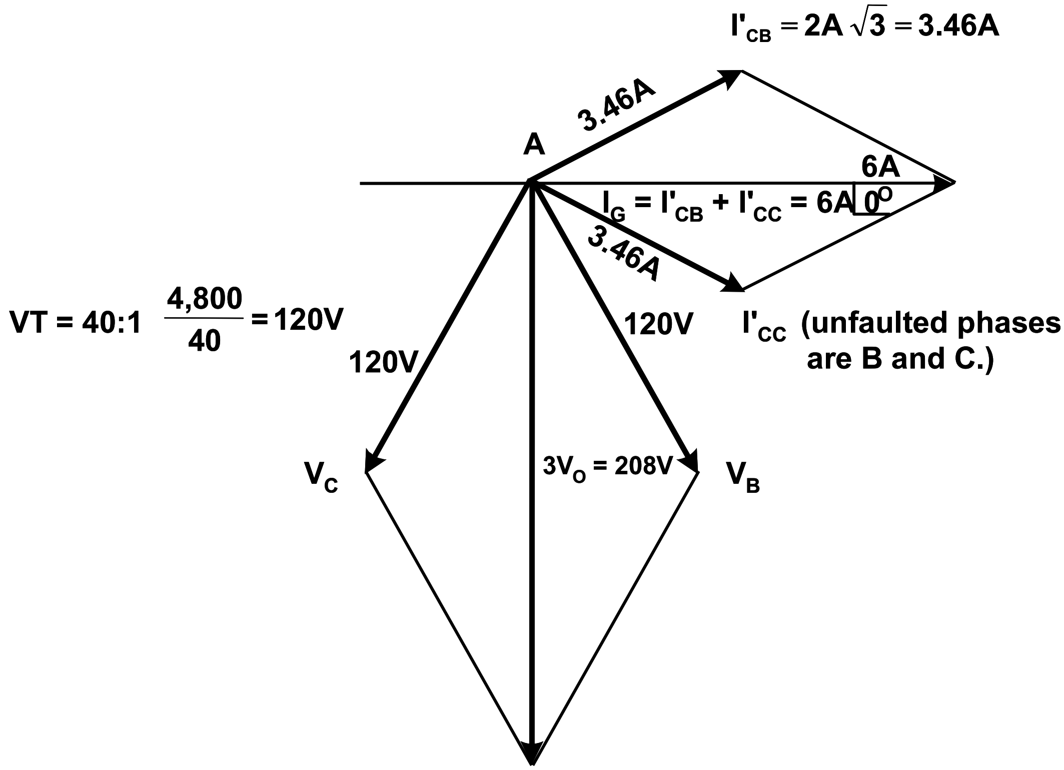


Figure A-4. Increased leakage current on the unfaulted phases and resultant ground current I_G and resultant zero sequence voltage 3 V_O – phasor diagram

A.2. Relay Settings

Phase Settings at Substation

STATION: MILFD POSITION: T1-L SHEET#: 1
EQUIPMENT: TRF 1 TO DC 8103 SCHEME: A_REL

FUNCTION: OVERCURRENT XYZ-51
RELAY TYPE: CO-8 (4-12)
PT RATIO: 0 : 1
CT RATIO: 120 : 1 NORM:
CT NOTE: 600:5 MR T.O.:

PU = 7.5 X 120 10 MVA TRF'S.

L = 1.75

40 CYCLES AT 37.5 AMPS

198 CYCLES AT 15 AMPS

Neutral Settings at Substation

STATION: MILFD POSITION: T1-L SHEET#: 2
EQUIPMENT: TRF 1 TO DC 8103 SCHEME: A_REL

FUNCTION: OVERCURRENT N-51
RELAY TYPE: CO-8 (4-12)
PT RATIO: 0 : 1
CT RATIO: 120 : 1 NORM:
CT NOTE: 600:5 MR T.O.:

EMERGENCY TAP = 5
PU = 9 X 120 (WHEN VWE #47316 IS JUMPERED OUT)

L = 1.5

33 CYCLES AT 45 AMPS

166 CYCLES AT 18 AMPS

Reclosing Settings at Substation

STATION: MILFD POSITION: T1-L SHEET#: 3
EQUIPMENT: TRF 1 TO DC 8103 SCHEME: A_REL

FUNCTION: RECLOSING 179
RELAY TYPE: PART OF PR
PT RATIO: 0 : 1
CT RATIO: 0 : 1 NORM:
CT NOTE: T.O.:

RECLOSE: 30 SEC 30 SEC 30 SEC

RESET: 5 MIN MAX

Phase Settings on Recloser

STATION: MILFD POSITION: 47316 SHEET#: 1
EQUIPMENT: VWE RECLOSER ON DC 8103 SCHEME: OHRCL

FUNCTION: OVERCURRENT (ESSENTIAL ME)
RELAY TYPE: ME RECL - C CURVE STOCK NO. 680-0341
PT RATIO: 0 : 1
CT RATIO: 1000 : 1 NORM:
CT NOTE: T.O.:

PHASE TIME DELAY NOTES: 1) PLUG C CURVE TIMING CAN INTO THE PHASE TRIP TIMING NO. 2 SOCKET
PU = 0.68 X 1000 = 680 AMPS
RESISTOR SIZE: 680 AMPS 2) 3 TIME DELAY OPERATIONS

173 CYCLES AT 1.36 AMPS (+ OR - 17 CYCLES)

47 CYCLES AT 2.72 AMPS (+ OR - 4 CYCLES)

LOCATION: LW N GOING WIXOM 4PS RED OAK LN

FAULT INDICATOR: AUTO

STATION: MILFD POSITION: 47316 SHEET#: 2
EQUIPMENT: VWE RECLOSER ON DC 8103 SCHEME: OHRCL

FUNCTION: OVERCURRENT
RELAY TYPE: ME RECL - R CURVE
PT RATIO: 0 : 1
CT RATIO: 1000 : 1 NORM:
CT NOTE: T.O.:

PHASE FAST TIME NOTES: 1) PLUG R CURVE TIMING CAN INTO THE PHASE TRIP TIMING NO. 1 SOCKET

2) SET PHASE TRIP SOCKET 1 DIAL AT 1
PU = 0.68 X 1000 = 680 AMPS
RESISTOR SIZE: 680 AMPS 3) 1 FAST TIME OPERATION

15 CYCLES AT 1.36 AMPS (+ OR - 1 CYCLE)

7 CYCLES AT 2.72 AMPS (+ OR - 1 CYCLE)

Neutral Settings on Recloser

STATION: MILFD POSITION: 47316 SHEET#: 3
EQUIPMENT: VWE RECLOSER ON DC 8103 SCHEME: OHRCL

FUNCTION: OVERCURRENT
RELAY TYPE: ME RECL - 6 CURVE
PT RATIO: 0 : 1
CT RATIO: 1000 : 1 NORM:
CT NOTE: T.O.:

NEUTRAL TIME DELAY NOTES: 1) PLUG 6 CURVE TIMING CAN INTO THE GROUND TRIP TIMING NO. 2 SOCKET

2) SET GROUND TRIP SWITCH TO NORMAL
PU = 0.80 X 1000 = 800 AMPS
RESISTOR SIZE: 800 AMPS 3) 3 TIME DELAY OPERATIONS

143 CYCLES AT 1.60 AMPS (+ OR - 14 CYCLES)

46 CYCLES AT 3.20 AMPS (+ OR - 4 CYCLES)

STATION: MILFD POSITION: 47316 SHEET#: 4
EQUIPMENT: VWE RECLOSER ON DC 8103 SCHEME: OHRCL

FUNCTION: OVERCURRENT
RELAY TYPE: ME RECL - 4 CURVE
PT RATIO: 0 : 1
CT RATIO: 1000 : 1 NORM:
CT NOTE: T.O.:

NEUTRAL FAST TIME NOTES: 1) PLUG 4 CURVE TIMING CAN INTO THE GROUND TRIP TIMING NO. 1 SOCKET

2) SET GROUND TRIP SOCKET 1 DIAL AT 1
PU = 0.80 X 1000 = 800 AMPS
RESISTOR SIZE: 800 AMPS 3) 1 FAST TIME OPERATION

12 CYCLES AT 1.60 AMPS (+ OR - 1 CYCLE)

4 CYCLES AT 3.20 AMPS (+ OR - 1 CYCLE)

Reclosing Setting on Recloser

STATION: MILFD POSITION: 47316 SHEET#: 5
EQUIPMENT: VWE RECLOSER ON DC 8103 SCHEME: OHRCL

FUNCTION: RECLOSING
RELAY TYPE: ME RECL - RECLOSING
PT RATIO: 0 : 1
CT RATIO: 1000 : 1 NORM:
CT NOTE: T.O.:

1ST - 0 SEC NOTE: SET RECLOSING SWITCH IN
2ND - 30 SEC NORMAL RECLOSING POSITION
3RD - 30 SEC

LOCKOUT DIAL = 4 OPERATIONS

RESET DELAY TIMING PLUG = 45 SEC

Phase Neutral and Reclosing Setting on Form 5 Control

STATION: MILFD POSITION: 47316 SHEET#: 2
EQUIPMENT: VWE RECLOSER ON DC 8103 SCHEME: OHRCL

FUNCTION: OVERCURRRENT
RELAY TYPE: FORM5 (SHEET 2 OF 7)
PT RATIO: 0 : 1
CT RATIO: 0 : 1 NORM:
CT NOTE: T.O.:

NORMAL ALT1 ALT2 ALT3 PHASE PROFILE|NORMAL ALT1 ALT2 ALT3 GROUND PROFILE
OPERATIONS TO LOCKOUT:4 |OPERATIONS TO LOCKOUT:4
NORMAL PU = 0.68 X 1000 = 680 AMPS |NORMAL PU = 0.60 X 1000 = 600 AMPS
ALT1 PU = 0.68 X 1000 = 680 AMPS |ALT1 PU = 0.60 X 1000 = 600 AMPS
ALT2 PU = 0.68 X 1000 = 680 AMPS |ALT2 PU = 0.60 X 1000 = 600 AMPS
ALT3 PU = 0.68 X 1000 = 680 AMPS |ALT3 PU = 0.60 X 1000 = 600 AMPS
TCC1 = KYLE_105 |TCC1 = KYLE_106
TCC2, TCC3, TCC4 = KYLE_133 |TCC2, TCC3, TCC4 = KYLE_136
HOT LINE TAG = KYLE_105 |HOT LINE TAG = KYLE_106
FAST TRIPS DISABLED = KYLE_133 |FAST TRIPS DISABLED = KYLE_136
1ST RECLOSE INTERVAL: 20 SEC. |1ST RECLOSE INTERVAL: 20 SEC.
2ND RECLOSE INTERVAL: 30 SEC. |2ND RECLOSE INTERVAL: 30 SEC.
3RD RECLOSE INTERVAL: 30 SEC. |3RD RECLOSE INTERVAL: 30 SEC.
RESET TIME FOR PHASE AND NEUTRAL: 45 SEC

Appendix B: Circuit Modeling

B.1 Circuit Modeling Verification

The circuit was modeled using CC, CP, and VDC. Based on actual circuit-measured data taken from a circuit with a similar composition of load (Davis, Krups, and Diedzic 1983) as the Milford Circuit DC 8103, equations, B.1 and B.2 were developed for the summer period when the ambient temperature ranged from 80°F to 90°F. The resultant change in real power P and reactive power Q for the range of source voltage -2.8% (119.5 V) to 0% (122.9 V) to +4.2% (128.0 V) was

$$\frac{\%\,\boldsymbol{\Delta}\,\mathrm{P}}{\%\,\boldsymbol{\Delta}\,\mathrm{V}} = 1.26 \qquad \text{Equation B.1}$$

and

$$\frac{\%\,\boldsymbol{\Delta}\,\mathrm{Q}}{\%\,\boldsymbol{\Delta}\,\mathrm{V}} = 4.66\,. \qquad \text{Equation B.2}$$

To see which of the three model simulations best agrees with the measured circuit data, tests 7 and 8 were repeated for 95% primary voltage and HL conditions. By viewing the line current data of Table B-1 and comparing the differences between the actual and simulated values for each load model in Table B-2, it can be seen that the CC and VDC models best represent the load characteristics for the circuit.

To check the accuracy, the actual line currents at Node 0 were subtracted from the simulated values (shown as δ). Then the absolute values of these phase current differences were summed and divided by three (the number of phases). For example, Test 7 for the CC model shows an absolute difference of 94. To obtain a percent difference between the actual and simulated currents, the actual line current magnitudes were summed and divided by three. This value ‡” $\frac{|I_{3\Phi}|}{3}$ forms the basis for comparing the deviation ‡” $\frac{|\,\delta\,|}{3}$ with the basis for each model applied.

This resulted in 3.9% for the Test 7 CC model. The CP model had a deviation of 12.5%. The VDC model was slightly better (3.6%) than the CC model. When this process was repeated for Test 8 at 95% primary voltage, the VDC model had a deviation of only 2%, which is less than the measurement accuracy of 3%.

The change in real power P and the change in reactive power Q as a function of change in source voltage V was defined (in (Davis, Krups, and Diedzic 1983) as

$$\frac{\%\Delta P}{\%\Delta V} = 1.26\% \text{ and } \frac{\%\Delta Q}{\%\Delta V} = 4.66\,.$$

These percent changes in P and Q represent changes in flow at the source for changes in source voltage from 99.58% (119.5 V) to 106.67% (128.0 V).

To implement the load characteristics into the power flow algorithm, it becomes necessary to represent the percent changes in P and Q as percent change in current.

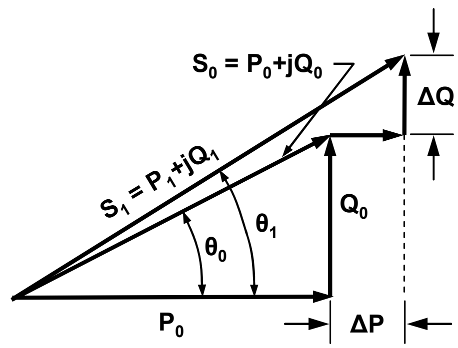


Figure B-1. Percent change in kilovolt-amperes or current from percent change in P and Q

The three-phase kilovolt-ampere flow S is proportional to the phase circuit I. Therefore, the percent change in current (I) for a 1% change in voltage is equal to the percent change in kilovolt-amperes, or

$$\% \, \Delta S = \% \, \Delta I = \frac{S_1 - S_0}{S_0} \text{ x } 100.$$

For this study, at HL condition, the % ΔI = 1.8% for a 1% change in voltage. The example below shows how the percent change in current of 1.9% is calculated for the initial values of P_0 = 2,000 kW and Q_0 = 1,000 kVArs for a 13.2-kV system and a 1% change in voltage at the source.

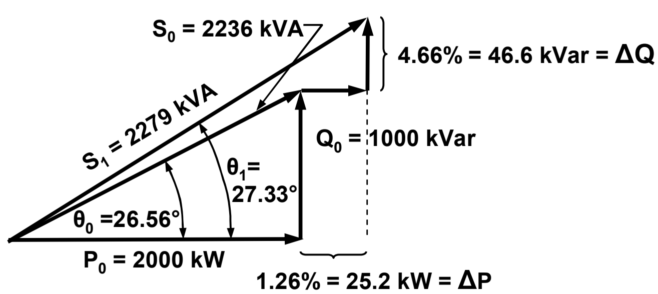


Figure B-2. Percent change in kilovolt-amperes or current

$$\%\Delta S = \frac{S_1 - S_0}{S_0} \text{ x } 100 = \frac{2279 - 2236}{2236} \text{ x } 100 = 1.9\%$$

$$I_1 = \frac{2279\,\text{kVA}}{\sqrt{3}\,13.2\,\text{kV}} = 99.68\text{A}$$

$$I_0 = \frac{2236\,\text{kVA}}{\sqrt{3}\,13.2\,\text{kV}} = 97.80\text{A}$$

$$\%\Delta I = \frac{I_1 - I_0}{I_0} \text{ x } 100 = \frac{99.68 - 97.80}{97.80} \text{ x } 100 = 1.9\%$$

B.2 Load Imbalance

As previously noted, a 100% load imbalance occurs at any node at which a line-to-line load or line-to-neutral load is connected to the wye-grounded systems. Proof of this statement is given below.

In Table B-4 (Test 8) at 95% primary voltage and HL conditions with LTC, VR 1, VR 2, and capacitors 1, 2, and 3 turned on, at Node 22 E, the phase current is 27.153 amperes, which indicates a line-to-neutral load. Now, from the zero sequence I_0, positive sequence I_1, and negative sequence I_2 currents of 9.051 A from Table B-4, it can be shown that

$$\begin{aligned} I_{A1} &= (I_A + I_B\,\mathbf{a} + I_C\,\mathbf{a}^2)/3 \\ &= (27.153\angle 0° + 0 + 0)/3 \\ &= 9.051\angle 0o \end{aligned} \qquad \text{Equation B.3}$$

$$\begin{aligned} I_{A2} &= (I_A + I_B\,\mathbf{a}^2 + I_C\,\mathbf{a})/3 \\ &= (27.153\angle 0° + 0 + 0)/3 \\ &= 9.051\angle 0° \end{aligned} \qquad \text{Equation B.4}$$

$$\begin{aligned} I_{A0} &= (I_A + I_B + I_C)/3 \\ &= (27.153\angle 0° + 0 + 0)/3 \\ &= 9.051\angle 0° \end{aligned} \qquad \text{Equation B.5}$$

Furthermore,

$$I_{B1} = I_{A1}\,\mathbf{a}^2 = 9.051\angle -120° \qquad \text{Equation B.6}$$

$$I_{C1} = I_{A1}\,\mathbf{a} = 9.051\angle 120° \qquad \text{Equation B.7}$$

$$I_{B2} = I_{A1}\,\mathbf{a} = 9.051\angle 120° \qquad \text{Equation B.8}$$

$$I_{C2} = I_{A1}\,\mathbf{a}^2 = 9.051\angle -120° \qquad \text{Equation B.9}$$

$$I_{A0} = I_{B0} = I_{CO} = 9.051\angle 0° \qquad \text{Equation B.10}$$

and

$$I_A = I_{A1} + I_{A2} + I_{A0} \qquad \text{Equation B.11}$$
$$= 9.051 \angle 0° + 9.051 \angle 0° + 9.051 \angle 0°$$
$$= 27.153 \angle 0° .$$

The percent unbalanced current is then calculated from equations B.3 and B.4, or

$$\frac{I_{A2}}{I_{A1}} \times 100 = \frac{9.051}{9.051} \times 100 = 100\% . \qquad \text{Equation B.12}$$

B.3 System Zero Sequence Currents Become Negative Sequence Currents on the Generator Windings

The zero sequence currents for each test are given in Table B-3. The values range from 45.43 A for Test 2 up to 50.24 A for Test 8. Because most small synchronous machines are wye-connected with an ungrounded neutral and the output terminals of these machines are normally connected to delta-wye transformers with the high-side wye grounded, there is no problem with these zero sequence current magnitudes if interconnected to the power system. For machines operating in an islanded mode with a delta-wye high-side transformer and a solidly grounded neutral, high zero sequence currents on the high side will appear as negative sequence currents on the machine windings. This is a very serious problem because it results in 100% negative sequence currents in the generator windings.

The zero sequence relays in the neutral at the substation are set to trip at current levels higher than the phase currents to ensure the neutral relay does not trip for single-phase switching operations on the circuit. But a time delay could be added to permit a lower neutral relay trip setting (to ignore single-phase switching conditions and maintain selectivity) so it becomes more sensitive to line-to-ground faults.

It will be shown that 100-A rated output current (on Phase A only) on the 13.2 kV on the high side of the transformer of a generating unit results in 33.34 A of zero sequence current on the load side of the generator step-up transformer. This is a common value of zero sequence currents. This produces a negative sequence current of 916 A on the generator windings, or a 100% current imbalance or

$$\frac{I_2}{I_1}\% = \frac{916A}{916A} \times 100 = 100\% .$$

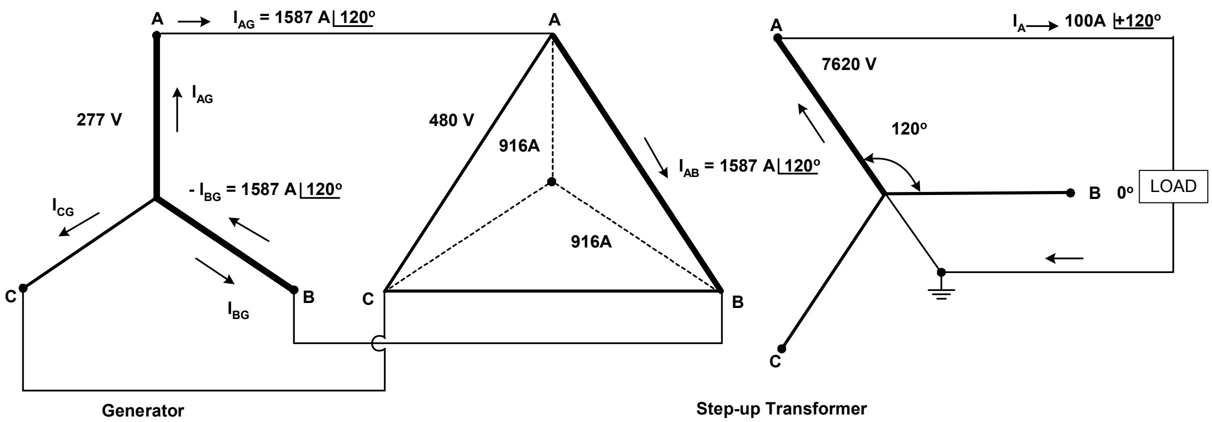


Figure B-3. Zero sequence current on load side becomes negative sequence current to the generator

Let, $\frac{V_1}{V_2} = \frac{7620}{480}$ or $\frac{N_1}{N_2} = 15.875$, where V_1 is the load-side voltage and V_2 is the generator terminal voltage. The turns ratio is 15.875.

By applying symmetrical components to the load side,

$$I_A = I_{A1} + I_{A2} + I_{A0} = 100\text{ A} \angle +120^\circ \qquad \text{Equation B.13}$$

$$I_{A1} = (I_A + I_B\,\mathbf{a} + I_C\,\mathbf{a}^2)/3 \qquad \text{Equation B.14}$$

$$(100 + \angle 120^\circ + 0 + 0)/3$$

$$= 33.34 + \angle 120^\circ$$

$$I_{A2} = (I_A + I_B\,\mathbf{a}^2 + I_C\,\mathbf{a})/3 \qquad \text{Equation B.15}$$

$$= 33.34 + \angle 120^\circ + 0 + 0$$

and

$$I_{A0} = (I_A + I_B + I_C)/3 \qquad \text{Equation B.16}$$

$$= 33.34 + \angle 120^\circ + 0 + 0$$

$$\therefore\ 3\,I_{A0} = 100 \text{ amperes.}$$

Applying symmetrical components to the generator side,

$$I_{AG1} = (I_{AG} + I_{BG}\,\mathbf{a} + I_{CG}\,\mathbf{a}^2)/3, \qquad \text{Equation B.17}$$

$$I_{AG2} = (I_{AG} + I_{BG}\,\mathbf{a}^2 + I_{CG}\,\mathbf{a})/3, \qquad \text{Equation B.18}$$

and

$I_{AG0} = (I_{AG} + I_{BG} + I_{CG})/3.$ Equation B.19

Substituting the rated phase current from the generator into the three equations above results in:

$I_{AG1} = (1{,}587\text{ A} \angle\underline{120°} + 1{,}587\text{ A} \angle\underline{-60°}\ \mathbf{a} + 0)/3,$ Equation B.20

$I_{AG2} = (1{,}587\text{ A} \angle\underline{120°} + 1{,}587\text{ A} \angle\underline{-60°}\ \mathbf{a}2 + 0)/3,$ Equation B.21

and

$I_{AG0} = (1{,}587\text{ A} \angle\underline{120°} + 1{,}587\text{ A} \angle\underline{-60°} + 0)/3.$ Equation B.22

Note: $-I_{BG}$ in Figure B-3 shows the current flow path, but polarity on $-I_{BG}$ must be the opposite direction $+I_{BG}$ for correct symmetrical component calculation (i.e. $-I_{BG} = 1{,}587 \angle\underline{120°}$ □´ $I_{BG} = 1{,}587\angle\underline{-60°}$).

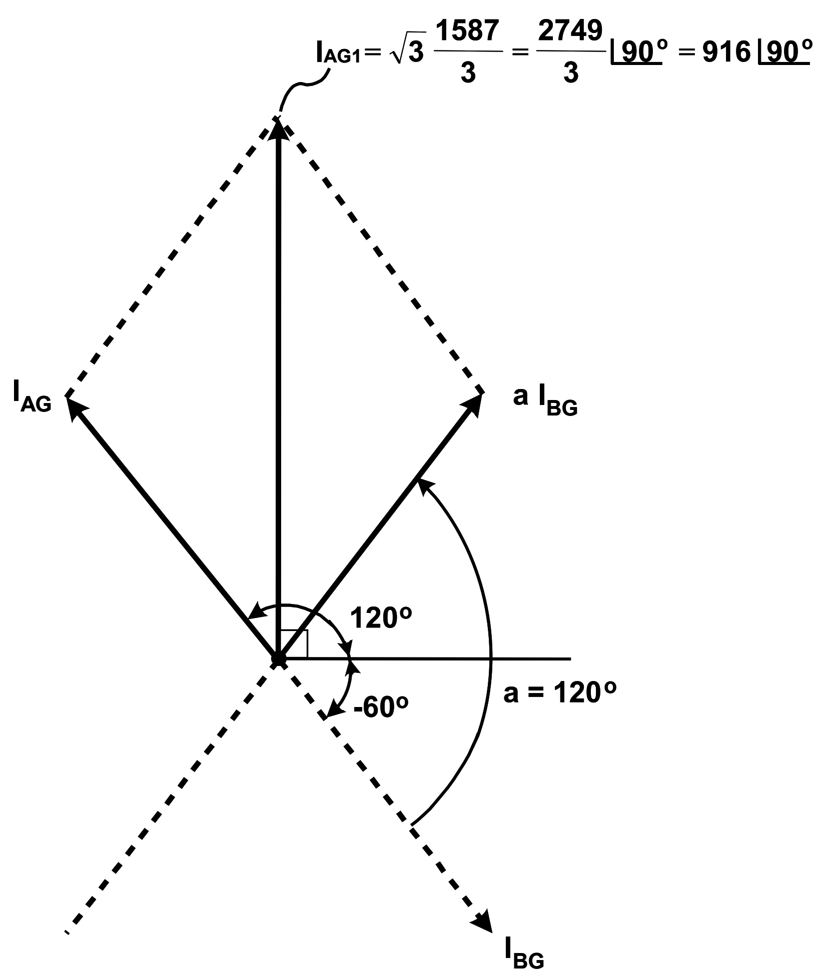


Figure B-4. Determining I_{AG1}

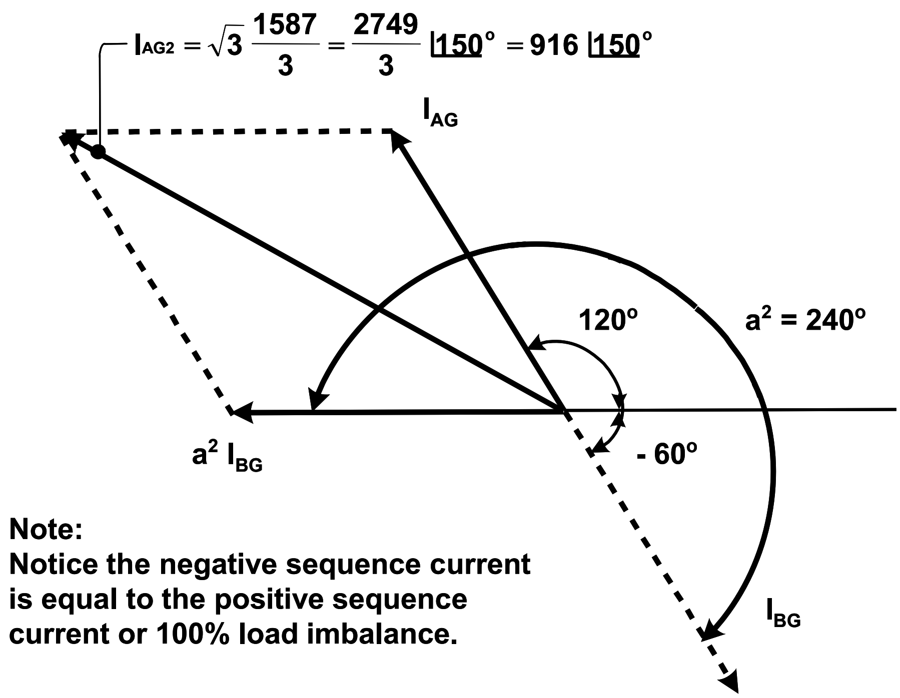
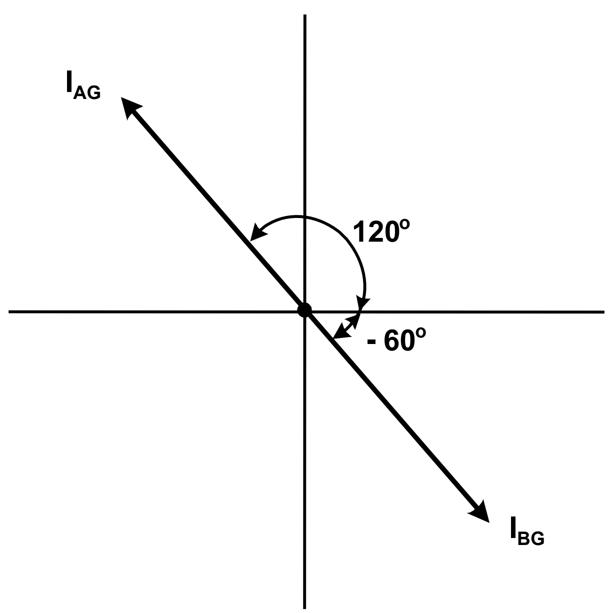


Figure B-5. Determining I_{AG2}



I_{AG0} = 0 because there is no ground on the generator wye connection.

Figure B-6. Determining I_{AG0}

The rated power for the generator is

$$P_{\text{rated generator}} = \sqrt{3}\ V_{L\text{-}L}\, I_L \qquad \text{Equation B.23}$$

$$= \sqrt{3}\ (13.2\text{ kV})\ (100\text{ A}) = 2{,}286\text{ kVA machine rating,}$$

and the rated current is

$$I_{\text{rated generator}} = \frac{2286\,\text{kVA}}{\sqrt{3}\ 480\text{V}} = 2749\text{A} \text{ full-load rated current, or } I_{AG1}.$$

The percent unbalance loading based on machine rating is

$$\frac{I_{AG2}}{I_{AG1}} \mathbf{x}\, 100 = \frac{916\text{A}}{2749\text{A}} \text{x}\, 100 = 33.3\%.$$

For a balanced load, $I_{AG} = I_{BG} = I_{CG}$, and

$$I_{AG1} = (I_{AG} + I_{BG}\,\mathbf{a} + I_{CG}\,\mathbf{a}^2)/3,$$

$$I_{AG1} = (2{,}749\underline{\lfloor +90°} + 2{,}749\underline{\lfloor + 90°} + 2{,}749\underline{\lfloor + 90°})/3,$$

and

$$I_{AG1} = 2{,}749\text{ A}\underline{\lfloor 90°.}$$

Even though the rated output on the high side of the transformer is 100 A, only 33.34 A of zero sequence current (on the high side) causes a 100% unbalanced current $\frac{I_2}{I_1}$% on the generator, which has a rated generator currency of 2,747 A per phase. The negative sequence current of 916 A is 33% of the generator machine rating (2,749 A) current.

This negative sequence current of 916 A will cause the generator negative sequence relay to trip the unit because it is common to set this relay to 10% of the machine rating. Even with 33.4 A of single-phase load, which is one-third of the 100 A of rated phase current on the high side, the negative sequence relay will trip the unit. Notice that the generating unit could only run at 10% of full rated output (or 30 A divided by 300 A full-rated three-phase capacity) without tripping.

Table B-1. Simulation Summary Data for Tests 7 and 8 at 95% Voltage and HL Conditions and a Comparison of Modeling Results for CC, CP, and VDC

				Node 00			Lowest 3Φ Voltage			Lowest 1Φ Voltage	Highest	Highest	kW Losses/Φ & Total			kVAr Losses/Φ & Total		
Test No.	Pri. Volt %	Load Type	LTC Tap / Reg Tap	IA	IB	IC	VA	VB	VC		I2/I1 %	V2/V1 %	A	B	C	A	B	C
7	95	CC	15	807.02	736.28	908.03	109.79	120.08	108.81	109.05	100.05	3.32	210.93	20.38	228.47	1119.86	820.68	1369.59
Cap (1) 900 kVAr														459.78			3310.13	
Cap (2) 900 kVAr																		
Cap (3) 1200 kVAr																		
7	95	CP	16	871.31	720.56	1037.24	108.43	124.00	102.64	102.89	100.04	5.15	204.93	-31.59	419.29	1392.44	729.90	1982.90
Cap (1) 900 kVAr														592.63			4105.24	
Cap (2) 900 kVAr																		
Cap (3) 1200 kVAr																		
7	95	VDC	14	756.47	723.87	844.61	110.88	118.45	110.72	110.79	100.05	2.61	190.80	40.20	170.49	953.41	811.06	1162.98
Cap (1) 900 kVAr														401.49			2927.45	
Cap (2) 900 kVAr																		
Cap (3) 1200 kVAr																		
8	95	CC	15	828.54	744.03	928.42	114.70	122.11	111.24	110.46	100.05	3.08	221.99	16.61	244.04	1205.74	850.27	1447.40
VR (1) 32, 14, 32														482.64			3503.41	
VR (2) 32, 10, 32																		
Cap (1) 900 kVAr																		
Cap (2) 900 kVAr																		
Cap (3) 1200 kVAr																		
8	95	CP	16	866.95	723.58	1038.01	115.00	124.94	106.69	105.38	100.04	4.33	200.30	-18.75	403.81	1371.63	751.93	1988.70
VR (1) 32, 8, 32														585.36			4112.26	
VR (2) 32, 4, 32																		
Cap (1) 900 kVAr																		
Cap (2) 900 kVAr																		
Cap (3) 1200 kVAr																		
8	95	VDC	15	801.31	756.68	888.74	115.48	121.15	113.13	112.50	100.05	2.52	215.99	38.73	193.39	1092.14	894.21	1295.33
VR (1) 32, 22, 32														448.11			3281.68	
VR (2) 32, 15, 32																		
Cap (1) 900 kVAr																		
Cap (2) 900 kVAr																		
Cap (3) 1200 kVAr																		

Table B-2. Comparison of Line Currents for Simulated and Actual Measurements for Each Load Model and Each Test 7 and 8

Test No.	Primary Voltage	Load Type	Voltage Regulation Method	Node 0 Line Amperes	Simulated	Actual	Line Amperes Difference (δ) Amps	%
7	95%	CC	LTC, CAP 1, CAP 2, CAP 3	I_A	807	794	+13	
				I_B	736	764	-28	
				I_C	908	855	+53	
				$\frac{\sum \lvert I_{3\Phi} \rvert}{3} = 804,\ \frac{\sum \lvert \delta \rvert}{3} = \frac{94}{3}$				3.9
7	95%	CP	LTC, CAP 1, CAP 2, CAP 3	I_A	871	794	+77	
				I_B	721	764	-43	
				I_C	1037	855	182	
				$\frac{\sum \lvert I_{3\Phi} \rvert}{3} = 804,\ \frac{\sum \lvert \delta \rvert}{3} = \frac{302}{3}$				12.5
7	95%	VDC	LTC, CAP 1, CAP 2, CAP 3	I_A	757	794	-37	
				I_B	724	764	-40	
				I_C	845	855	-10	
				$\frac{\sum \lvert I_{3\Phi} \rvert}{3} = 804,\ \frac{\sum \lvert \delta \rvert}{3} = \frac{87}{3}$				3.6
8	95%	CC	LTC, VR 1, VR 2, CAP 1, CAP 2, CAP 3	I_A	829	794	+35	
				I_B	744	764	-20	
				I_C	928	855	+73	
				$\frac{\sum \lvert I_{3\Phi} \rvert}{3} = 804,\ \frac{\sum \lvert \delta \rvert}{3} = \frac{128}{3}$				5.3
8	95%	CP	LTC, VR 1, VR 2, CAP 1, CAP 2, CAP 3	I_A	867	794	+73	
				I_B	724	764	-40	
				I_C	1038	855	183	
				$\frac{\sum \lvert I_{3\Phi} \rvert}{3} = 804,\ \frac{\sum \lvert \delta \rvert}{3} = \frac{296}{3}$				12.3
8	95%	VDC	LTC, VR 1, VR 2, CAP 1, CAP 2, CAP 3	I_A	801	794	+7	
				I_B	757	764	-7	
				I_C	889	855	+34	
				$\frac{\sum \lvert I_{3\Phi} \rvert}{3} = 804,\ \frac{\sum \lvert \delta \rvert}{3} = \frac{48}{3}$				2.0

Table B-3. Sequence Currents for Each Test

				Substation Secondary Bus Sequence Currents* Amps		
Test No.	Primary Voltage	Load	Voltage Regulation	I0	I1	I2
1	95%	HL	No LTC	45.46	799.94	45.21
1	105%	HL	No LTC	45.44	780.11	45.08
2	95%	HL	LTC + 16	45.43	780.12	45.08
2	105%	HL	LTC + 1	45.43	780.13	45.08
3	95%	HL	LTC + 16 VR 1, 32, 32, 32	45.86	796.86	45.72
3	105%	HL	LTC + 3 VR 1, 32, 20, 32	47.37	794.95	47.34
4	95%	HL	LTC + 16 VR 1, 32, 32, 32 VR 2, 32, 23, 32	45.82	799.26	45.70
4	105%	HL	LTC + 3 VR 1, 32, 20, 32 VR 2, 32, 11, 32	47.61	796.96	47.69
5	95%	HL	LTC + 16 CAP 1	45.34	760.27	45.87
5	105%	HL	LTC + 1 CAP 2	45.34	760.18	45.87
6	95%	HL	LTC + 16 CAP 1, CAP 2	45.19	744.66	47.59
6	105%	HL	LTC + 1 CAP 1, CAP 2	45.18	744.49	47.59
7	95%	HL	LTC + 15 CAP 1, 2, 3	45.69	724.07	49.55
7	105%	HL	LTC + 1 CAP 1, 2, 3	45.67	723.50	49.54
8	95%	HL	LTC + 15 VR 1, 32, 14, 32 VR 2, 32, 10, 32 CAP 1, 2, 3	48.82	738.71	52.76
8	105%	HL	LTC + 1 VR 1, 32, 4, 32 VR 2, 32, 7, 32 CAP 1, 2, 3	50.24	736.56	53.90

*Note: The sequence currents are measured at the secondary of the transformer to indicate the magnitude of zero sequence current to be used to calculate the neutral relay settings.

Table B-4. Simulation Data by Node for Test 8 at 95% HL with LTC, VR 1, VR 2, and Capacitors 1, 2, and 3 Regulation Methods Implemented (CC Model)

	KW Losses:			KVAR Losses:	
Phase A	Phase B	Phase C	Phase A	Phase B	Phase C
221.99	16.61	244.04	1205.74	850.27	1447.4

LTC Tap		VR 1 A Tap	VR 1 B Tap	VR 1 C Tap
15		32	14	32

Local Name	Amps A	Amps B	Amps C	Cust Volts A	Cust Volts B
======Node 0======					
MILFD8103	828.5427	744.0258	928.4221	114.0001	114.0001
======Node 1======					
Node 1	734.6588	659.7188	823.2208	123.5558	124.6471
======Node 2======					
======Node 3======					
Node 3	622.6234	573.6905	685.2835	118.8883	122.7722
Node 3 N	602.6146	562.2695	673.3692	118.0738	122.4304
Node 3 E	20.145	11.5252	11.923	118.8822	122.7727
======Node 4======					
Node 4	602.6207	553.9184	673.3727	117.9749	122.3914
Node 4 E	57.6258	117.3591	87.9715	117.9713	122.3544
Node 4 N	552.4512	437.5563	589.768	117.8738	122.3733
======Node 5======					
Node 5	51.8035	112.1439	77.187	117.9394	121.8941
Node 5 E	49.3877	112.1465	68.3351	117.937	121.8709
Node 5 N	3.2219	0.0186	9.8124	117.9387	121.8952
======Node 6======					
Node 6	38.6448	39.825	38.713	117.8053	121.4029
======Node 7======					
Node 7	533.9893	425.5483	579.9824	114.3333	121.7128
Node 7 E	370.1802	322.0644	363.0935	114.3225	121.709
Node 7 N	90.3277	48.7249	107.2539	114.33	121.7336
Node 7 W	81.0404	83.8447	114.1217	114.3293	121.7005
======Node 8======					
Node 8	370.1825	312.0715	363.0953	114.0694	121.6228
======Node 9======					
Node 9	370.1834	312.0719	363.0959	119.0288	123.7469
======Node 10======					
Node 10	0	0	0	116.5839	123.0896
======Node 11======					
Node 11	239.1742	154.4999	183.0159	114.7319	122.7623
Node 11 N	167.2796	62.2984	150.2312	114.7044	122.7646
Node 11 E	76.7785	94.8149	43.9618	114.7126	122.7557
======Node 12======					
Node 12	37.5633	40.2759	37.6143	114.5085	122.7774
======Node 13======					
Node 13	50.0483	53.442	49.2189	114.426	122.1848
======Node 14======					
Node 14	61.5139	60.0707	44.4666	114.3284	122.5585
======Node 15======					
Node 15	61.5159	60.0719	44.4681	119.7258	124.3025

======Node 16======					
Node 16	58.7012	55.1948	41.1831	119.6476	124.2664
Node 16 E	40.1441	55.2021	32.9683	119.6339	124.2491
Node 16 W	18.5601	0.0147	8.2176	119.6416	124.2715
======Node 17======					
Node 17	0.002	0.0025	0.0024	119.502	124.0212
======Node 18======					
Node 18	0	1.535	0.0033	0	123.6049
======Node 19======					
Node 19	0.4804	0	0	119.4087	0
======Node 20======					
Node 20	48.058	25.0014	110.0025	114.4173	122.2138
Node 20 W	26.9459	0	0	114.4173	0
Node 20 N	21.113	25.0019	110.003	114.492	122.1791
======Node 21======					
Node 21	21.1279	23.5647	92.8119	114.6153	122.1214
Node 21 N	19.5842	21.9699	56.157	114.6153	122.1214
Node 21 E	1.5578	1.6084	36.794	114.6235	122.1199
======Node 22======					
Node 22	1.5647	0.4098	28.8641	114.6728	122.1126
Node 22 E	0.0064	0.0071	27.1533	114.6955	122.1091
Node 22 S	0.4156	0.4137	1.7122	114.6744	122.1114
Node 22 N	1.1561	0	0	114.2154	0
======Node 23======					
======Node 24======					
Node 24	0	0	0.0076	0	0
======Node 25======					
Node 25	734.6591	659.719	823.2209	123.3711	124.5002
Node 25 W	96.1194	83.4757	130.2754	123.3665	124.4941
Node 25 E	638.7186	576.8384	693.052	123.1598	124.4218
======Node 26======					
Node 26	31.4495	25.1278	86.48	122.9961	124.2321
Node 26 E	0	0	46.5381	0	0
Node 26 W	0	0	0.4618	0	0
Node 26 S	31.4495	25.1278	39.4887	122.9867	124.2275
======Node 27======					
Node 27	0.6914	0.7947	0.003	122.9003	124.2241
======Node 28======					
Node 28	0	0	1.586	0	0
======Node 29======					
Node 29	0	0	0	0	123.4408

======Feeder Path Trace======

Distance (1000r	CustvoltsA	CustVoltsB	CustVoltsC	%CapacityA	%CapacityB
0.1034	114.0001	114.0001	114.0001	23.6916	31.4756
0.2378	123.6421	124.7267	123.8458	21.0044	29.0625
0.3218	123.5558	124.6471	123.7504	-9.4872	1.6813
0.3218	123.5558	124.6471	123.7504	26.8996	34.3563
0.5288	123.3711	124.5002	123.5386	26.8996	34.3563
0.7648	123.1598	124.4218	123.3099	36.4459	42.6031
1.3788	122.6107	124.2194	122.7203	36.4458	42.6031

2.583	121.5436	123.832	121.5709	36.4454	42.7524
2.666	121.4705	123.8056	121.4921	36.4446	42.7622
3.206	121.0131	123.62	120.9913	38.0481	42.7622
3.429	120.825	123.5443	120.785	38.0477	42.8685
3.716	120.5835	123.4475	120.5199	38.0476	42.9016
5.754	118.8883	122.7722	118.6597	38.0474	42.9164
6.798	118.0738	122.4304	117.7378	40.0383	44.0528
6.9262	117.9749	122.3914	117.6237	40.0377	44.8837
7.0603	117.8738	122.3733	117.5038	45.0297	56.4621
7.2034	117.7663	122.3538	117.3759	45.1101	56.462
7.3784	117.6352	122.33	117.2198	45.11	56.462
7.7094	117.3887	122.2846	116.925	45.2256	56.4619
7.9064	117.243	122.2573	116.75	45.3336	56.4618
7.9064	117.243	122.2573	116.75	45.3335	56.4617
8.2464	116.9892	122.2113	116.4532	45.3335	56.4617
8.4174	116.8617	122.1883	116.3046	45.3333	56.4616
8.8571	116.5373	122.1278	115.9235	45.5525	56.4616
9.4411	116.1091	122.0486	115.419	45.5522	56.4911
9.6082	115.9912	122.0231	115.2754	46.5649	56.4909
10.0174	115.7046	121.9659	114.9215	46.5648	56.9883
10.3374	115.4816	121.9213	114.6456	46.5885	56.9882
10.5075	115.3628	121.8978	114.5002	46.5883	56.9881
10.8129	115.1505	121.8583	114.2381	46.5882	57.2977
10.9501	115.0555	121.8415	114.1201	46.588	57.5374
11.0961	114.9547	121.824	113.9944	46.5879	57.6571
11.6971	114.5436	121.7511	113.4784	46.7157	57.6571
12.0081	114.3333	121.7128	113.2125	46.8667	57.6569
12.0291	114.3225	121.709	113.2014	63.1661	67.9538
12.0292	114.3225	121.709	113.2014	63.1661	67.9538
12.2671	114.2006	121.6659	113.075	63.1661	67.9538
12.3884	114.1384	121.6439	113.0107	63.166	67.9537
12.5244	114.0694	121.6228	112.9367	63.1659	68.9481
12.6619	118.9621	123.7245	117.7881	64.8529	69.5867
12.7589	118.9155	123.7084	117.7392	65.0307	69.5867
12.9495	118.824	123.6769	117.6433	65.0527	69.6087
13.0549	118.7736	123.6594	117.5903	65.0905	69.6086
13.3859	118.6107	123.605	117.4322	65.0904	69.6086
13.6541	118.4865	123.5557	117.3054	66.2643	69.6085
13.9121	118.3656	123.5085	117.1863	66.2641	69.6084
14.1148	118.2716	123.4708	117.0929	66.4581	69.6083
14.5219	118.0595	123.4005	116.9433	66.458	69.7846
15.0699	117.7751	123.3105	116.74	66.4578	70.0693
15.2599	117.6769	123.2793	116.6696	66.5157	70.0691
15.4019	117.6053	123.2547	116.6173	67.0263	70.069
15.5403	117.5361	123.2329	116.5651	67.0262	70.6868
15.8453	117.3817	123.1853	116.4533	67.0261	70.6868
16.1153	117.2443	123.1434	116.3557	67.0259	70.6867
17.4453	116.5956	123.0812	115.7992	67.0258	74.9083
17.6035	116.5257	123.0682	115.7365	69.1939	74.9076
17.8465	116.4182	123.0483	115.641	69.1938	74.9076
18.2915	116.2227	123.0111	115.4664	69.3132	74.9075
18.4488	116.1534	122.9981	115.4051	69.313	74.9074

18.6148	116.0804	122.9844	115.3405	69.3129	74.9074
18.7818	116.0068	122.9707	115.2757	69.3128	74.9073
19.1128	115.8612	122.9436	115.1473	69.3127	74.9073
19.4183	115.7205	122.9196	115.0395	69.3125	74.9072
20.0144	115.4673	122.8774	114.9176	74.42	78.4082
20.3923	115.3085	122.8579	114.8363	74.4197	79.167
20.7652	115.1688	122.8272	114.7579	76.2023	79.1669
20.9525	115.0971	122.8121	114.7215	76.2021	79.1668
21.4666	114.9004	122.7715	114.621	76.202	79.2307
21.7311	114.7988	122.7509	114.5703	76.2017	79.2306
21.9173	114.7319	122.7623	114.5207	76.2016	84.6269
22.0473	114.7044	122.7646	114.4802	83.3553	93.8012
22.1883	114.6741	122.7673	114.4374	83.3552	93.8011
22.3543	114.6384	122.7703	114.3869	83.3552	93.801
22.4763	114.6142	122.7716	114.3501	84.0002	93.8009
22.8133	114.5463	122.7752	114.25	84.0002	93.8008
22.9733	114.5484	122.7649	114.2008	91.0257	93.8006
23.1957	114.5496	122.7507	114.135	91.0257	93.8005
23.3361	114.5427	122.7479	114.0953	91.0256	93.8003
23.3575	114.5417	122.7474	114.0893	91.0496	93.8244
23.5515	114.5322	122.7435	114.0346	91.0496	93.8244
23.7088	114.5248	122.74	113.9903	91.1444	93.8243
24.0118	114.5108	122.7334	113.905	91.1443	93.8243
24.1251	114.5055	122.7309	113.8731	91.1441	93.8241
24.3851	114.4941	122.7247	113.8002	91.2696	93.8241
24.6292	114.4822	122.719	113.734	91.2694	93.824
24.8032	114.4753	122.7138	113.687	91.6332	93.8239
25.0212	114.4659	122.7074	113.6295	91.6331	93.8238
25.1302	114.4612	122.7044	113.6006	91.633	93.9099
25.3432	114.4633	122.6909	113.5454	93.7495	93.9098
26.3495	114.4243	122.6322	113.3672	93.7494	93.9098
26.5235	114.4166	122.6221	113.3381	93.7487	93.9094
26.9295	114.395	122.5991	113.2762	93.7486	93.9093
27.0567	114.3887	122.5915	113.2569	93.8795	93.9091
27.3222	114.3686	122.5765	113.2282	93.8794	93.9091
27.3813	114.3621	122.5736	113.2252	93.8792	94.0228
27.6828	114.3284	122.5585	113.2109	93.8792	94.0228
27.8391	119.7117	124.2937	118.5691	94.5939	94.5492
27.9641	119.698	124.2872	118.5641	94.1593	94.111
28.1491	119.6779	124.2782	118.5565	94.1592	94.2556
28.4312	119.6476	124.2664	118.5438	94.1591	94.508
28.6137	119.6339	124.2491	118.5441	95.8614	94.3091
28.983	119.607	124.2135	118.5448	95.9843	94.3089
29.633	119.5614	124.1497	118.5465	96.1026	94.3087
29.925	119.5436	124.1195	118.5476	96.4791	94.3082
30.264	119.5336	124.0781	118.5499	97.7923	94.308
30.904	119.5189	123.9977	118.5547	98.0387	94.3078
31.183	119.5178	124.0023	118.5297	98.0383	99.9981
31.4215	119.5173	124.0062	118.5092	98.1065	99.9985
31.6365	119.5183	124.0089	118.4909	98.3796	99.9987
31.7505	119.5191	124.0102	118.4812	98.4935	99.999
31.8455	119.5177	124.0117	118.477	98.4935	99.9991
32.0297	119.5114	124.0156	118.4756	98.4934	99.9992

kVA Flow SOC			Released Capacity		
Phase A	Phase B	Phase C	Phase A	Phase B	Phase C
5998.63	5386.73	6721.75	6.55	8.84	6.36
				7.17	

VR 2 A Tap	VR 2 B Tap	VR 2 C Tap
32	10	32

Cust Volts C	Seq Amps 0	Seq Amps 1	Seq Amps 2	I2/I1 (%)	Seq Volts 0	Seq Volts 1	Seq Volts 2
114.0001	55.0565	833.1159	59.4993	7.1418	0	7239.8662	0.1059
123.7504	48.8179	738.7138	52.7574	7.1418	0.4098	7873.8943	42.2513
118.6597	34.2333	626.6931	39.1943	6.2542	72.9172	7627.4228	114.1174
117.7378	33.4637	612.2335	40.1371	6.5558	85.5513	7583.3448	127.8616
118.6573	2.7552	14.5262	2.8859	19.8671	73.0231	7627.2546	114.1589
117.6237	36.2142	609.4338	41.6729	6.838	87.2579	7577.9977	129.5801
117.6249	18.2699	87.0192	19.2667	22.1408	85.6853	7577.1623	129.6009
117.5038	50.857	526.0247	46.8835	8.9128	90.0076	7572.923	131.3654
117.6675	18.7746	79.5263	19.8846	25.0038	65.6593	7567.6039	129.5358
117.6747	20.0504	75.5901	21.1139	27.9321	64.5089	7567.2157	129.4562
117.6499	2.8653	4.3419	2.9142	67.1179	66.1558	7567.2383	129.7394
118.0132	0.1811	39.0583	0.6485	1.6602	35.0707	7561.6856	125.5384
113.2125	50.5017	512.5785	47.365	9.2405	188.9092	7392.3764	196.3087
113.2014	16.9106	351.6674	15.4637	4.3973	189.062	7391.8311	196.4311
113.1866	28.4113	76.8408	25.1711	32.7574	190.4583	7392.1802	196.8204
113.1848	10.0303	92.9083	11.8693	12.7752	189.3063	7391.44	196.3231
112.9367	19.9915	348.328	18.7552	5.3844	192.8739	7379.0356	199.3641
117.8575	19.9915	348.328	18.7552	5.3844	152.7909	7633.059	147.8634
115.7925	0	0	0	NA	177.6127	7523.7794	169.5996
114.5207	27.8802	191.9652	23.6843	12.3378	201.5767	7450.8418	184.3941
114.4802	33.0006	126.5865	32.1058	25.3628	203.2963	7449.4322	184.7586
114.5306	18.1433	70.9456	15.5961	21.9831	201.1182	7450.5149	184.3036
114.6636	1.0233	38.4793	0.956	2.4844	198.1103	7449.5857	185.0702
112.5295	1.5608	50.8907	1.4428	2.8351	226.6332	7389.3299	209.4912
113.2109	5.8404	55.3422	5.127	9.2642	231.6821	7409.7747	196.8352
118.5772	5.8404	55.3422	5.127	9.2642	175.4698	7674.5193	132.419

118.5438	5.762	51.6853	4.9805	9.6362	174.758	7671.4176	132.3578
118.5441	6.4845	42.7659	6.6492	15.5479	174.2237	7670.7728	132.2688
118.5394	5.4573	8.9227	5.2855	59.2369	175.0594	7671.3023	132.4698
118.4747	0	0.0023	0	0	169.8666	7661.7073	131.9398
118.7155	0	0.5114	0.5109	NA	0	5128.758	2650.3923
0	0.1601	0	0	NA	2527.8226	0	0
112.0482	25.6513	60.9544	25.2617	41.4437	242.4023	7379.2661	216.0309
0	8.982	0	0	NA	2422.1572	0	0
111.8079	28.4826	51.9765	29.6231	56.9932	248.7786	7374.8441	219.1163
111.3929	23.03	45.7673	24.0853	52.6255	260.5602	7367.1183	224.4831
111.3929	11.3733	32.4807	12.4718	38.3975	260.5602	7367.1183	224.4831
111.3767	11.7106	13.3076	11.7767	88.4961	261.0967	7366.9025	224.7192
111.2784	9.337	10.2756	9.2633	90.1485	264.4658	7365.61	226.1654
111.2374	9.0519	9.0484	9.0526	100.0456	265.8927	7365.1032	226.776
111.2734	0.4259	0.8465	0.4403	52.0152	264.6239	7365.5058	226.2304
0	9.337	0	0	NA	76.1436	0	0
110.4629	0	0	0.0025	NA	0	0	2338.3935
123.5386	48.818	738.714	52.7573	7.1418	3.6133	7862.3871	43.5241
123.5279	14.1559	103.2862	13.8139	13.3744	3.8854	7861.9354	43.618
123.3099	37.0466	635.6931	38.9572	6.1283	6.7013	7851.4117	46.75
122.3175	19.4346	47.6817	19.5383	40.9765	38.9384	7822.8104	60.8002
122.2857	0	0	15.5124	NA	0	0	2588.6705
122.3169	0	0	0.1539	NA	0	0	2589.3317
122.3	4.0966	32.0209	4.2183	13.1736	39.3434	7822.1417	61.0528
121.86	0.2209	0.4938	0.2777	56.238	55.2611	7810.8523	67.7209
121.3932	0	0	0.5287	NA	0	0	2569.776
0	0	0	0	NA	0	2613.1221	0

V2/V1 (%)	pf A	pf B	pf C	kW Flow A	kW Flow B	kW Flow C
0.0015	0.8584	0.8849	0.8406	5149.1606	4766.8566	5650.2696
0.5366	0.8879	0.9128	0.8763	5122.0445	4770.1754	5674.0669
1.4961	0.9047	0.9274	0.8933	4313.6989	4171.0642	4685.7275
1.6861	0.9133	0.933	0.9015	4155.377	4090.1585	4574.6012
1.4967	0.8616	0.8777	0.8942	131.0445	78.8687	80.3424
1.71	0.9167	0.936	0.9056	4142.5374	4031.3237	4559.5452
1.7104	-0.9968	0.9706	0.99	430.3626	885.3978	650.5856
1.7347	0.8965	0.9249	0.8868	3710.6449	3145.7893	3907.0391
1.7117	-0.9868	0.975	0.9965	382.8852	846.4462	574.7759
1.7108	-0.9791	0.975	0.9997	362.179	846.4345	510.4917
1.7145	0.858	-0.081	0.8767	20.7062	0.0117	64.2842
1.6602	-1	-1	-1	0	0	0
2.6556	0.9148	0.9339	0.9025	3553.3654	3073.0376	3772.1753
2.6574	0.8864	0.8959	0.8899	2382.5191	2230.3426	2323.1687
2.6625	0.9993	-0.7408	0.9812	655.4244	279.0285	756.6251
2.6561	0.8719	0.8705	0.8383	513.0646	564.1957	687.8519
2.7018	0.8872	0.8979	0.8906	2380.7169	2164.8146	2320.9673
1.9371	0.8872	0.8979	0.8906	2380.1093	2165.0119	2320.1343
2.2542	0.014	-0.1051	0.101	0	0	0
2.4748	0.92	0.9521	0.932	1604.2112	1146.7663	1241.0627
2.4802	0.8593	0.8597	0.8538	1047.4059	417.5658	932.8863
2.4737	0.9945	0.9868	-0.9626	556.3686	729.4639	307.7802
2.4843	-1	-1	-1	0	0	0
2.835	-1	-1	-1	0	0	0
2.6564	0.8728	0.8599	0.8593	389.9266	402.0834	274.7443
1.7254	0.8728	0.8599	0.8593	389.8517	402.1026	274.7275

	1.7253	0.8735	0.8611	0.8598	389.7086	375.1131	266.6114
	1.7243	0.8755	0.861	0.8619	267.0694	375.1165	213.9266
	1.7268	0.8692	-0.098	0.8514	122.5788	0.0114	52.6708
	1.7221	0.0786	0.0777	-0.1562	-0.0012	-0.0016	0.0028
NA		0	0.8569	-0.2548	0	10.3257	0.0064
NA		0.9293	0	0	3.3855	0	0
	2.9275	0.8611	0.8725	0.8317	300.7089	169.3145	651.1819
NA		0.8602	0	0	168.4344	0	0
	2.9711	0.8624	0.8725	0.8318	132.3024	169.3082	651.1001
	3.0471	0.8627	0.8721	0.8292	132.6442	159.397	544.9446
	3.0471	0.8581	0.8677	0.8043	122.3268	147.8421	319.5401
	3.0504	0.9149	0.9225	0.8652	10.3743	11.5081	225.2152
	3.0706	0.9123	0.8937	0.8678	10.3955	2.8404	177.045
	3.0791	0.1803	-0.1022	0.8683	-0.0084	0.0056	166.6303
	3.0715	0.8774	0.8826	0.8593	2.6557	2.8318	10.3979
NA		0.9209	0	0	7.7537	0	0
NA		0	0	0	0	0	0
	0.5536	0.8877	0.9127	0.8761	5117.5113	4766.5191	5668.3741
	0.5548	0.8613	0.8621	0.8588	648.6462	568.9836	877.767
	0.5954	0.8926	0.9196	0.8804	4466.9384	4194.1674	4787.3572
	0.7772	0.8651	0.8701	0.8628	212.5206	172.4914	579.6498
NA		0	0	0.8562	0	0	309.537
NA		0	0	0.8614	0	0	3.0899
	0.7805	0.8651	0.8701	0.8705	212.5206	172.4914	267.0229
	0.867	0.9235	0.8599	-0.0702	4.9835	5.3911	0.0016
NA		0	0	0.8578	0	0	10.4887
	0	0	0	0	0	0	0

kVAR Flow A	kVAR Flow B	kVAR Flow C
3077.2811	2508.765	3640.9319
2653.9563	2134.0307	3119.0733
2031.446	1682.7564	2357.103
1853.4526	1578.1536	2196.1263
77.2185	43.07	40.2268
1805.4186	1515.9154	2135.9344
-34.6628	219.5798	92.699
1834.1241	1292.804	2035.8337
-62.8923	192.8663	48.3931
-75.2874	193.01	13.1168
12.3951	-0.1436	35.2763
-289.1261	-307.0551	-290.1482
1569.381	1176.185	1800.4953
1244.4147	1105.9595	1190.9072
24.4915	-252.9738	148.9699
288.1546	318.9365	447.3585
1237.9948	1061.1047	1185.0185
1235.644	1059.7503	1182.8978
-0.0028	-0.0027	-0.0025
683.4916	368.2371	482.7818
623.3742	248.0914	568.8417
58.5656	119.7008	-86.6172
-273.1699	-314.0477	-273.9112
-363.7023	-414.6977	-351.747
218.0912	238.7374	163.5691
217.9555	238.5926	163.5184

217.2283	221.5176	158.3322
147.3893	221.5439	125.8585
69.7442	-0.1153	32.4542
-0.0154	-0.02	-0.0175
0	6.2119	-0.0243
1.3455	0	0
177.5406	94.8042	434.753
99.8401	0	0
77.671	94.8264	434.5321
77.7599	89.4539	367.2787
73.1979	84.7146	236.0576
4.5774	4.814	130.505
4.665	1.4261	101.3997
-0.0457	-0.0546	95.1758
1.4522	1.5085	6.1891
3.2815	0	0
0	0	-0.0531
2653.9597	2134.0345	3119.0764
382.6578	334.5056	523.6688
2256.2813	1792.011	2578.3209
123.2254	97.73	339.5784
0	0	186.7663
0	0	1.8222
123.2254	97.73	150.99
2.07	3.2	-0.0231
0	0	6.2854
0	0	0

B.4. Heavy- and Light-Load Base Case Data and Measured Data at Node 01

Table B-5. Summary of HL Base Case

(LTC control only, tap = 14)
[#0 MXAT services included]

Location	Simulated Data			Measured Data July 17, 2006		
Node 01	I_A 578.13	I_B 654.17	I_C 636.62	I_A 565	**I_B 651**	**I_C 637**
Node 01	V_A 125.90	V_B 125.55	V_C 124.98	V_A 126.0	**V_B 126.0**	**V_C 126.0**
Node 01 Node 01	PF_A 0.843	PF_B 0.843	PF_C 0.841			
	kVA Flow			**Total**		
Node 01	Phase A 4,622.62	Phase B 5,216.17	Phase C 5,053.13	14,891.92		
	kW Flow					
Node 01	Phase A 3,897.94	Phase B 4,399.49	Phase C 4,249.92	12,547.35		
	kVAr Flow					
Node 01	Phase A 2,484.88	Phase B 2,802.29	Phase C 2,735.55	8,020.72		
	kVAr Losses			**Total %**		
Node 01	Phase A 877.31	Phase B 1,132.1	Phase C 1,086.42	3095.83 38.59%		
	kW Losses			**Total %**		
	Phase A 246.56	Phase B 202.22	Phase C 221.79	670.57 5.34%		
Node 01	I_0 23.01 V_0 0.1936	I_1 622.96 V_1 7968.87	I_2 23.01 V_2 33.92	I_2/I_1% 3.69 V_2/V_1% 0.4257		

Note: All capacitors and line regulators were turned off. The substation primary voltage was set at 100% (120 V). The base case used for the synchronous generator, inverter-based generator, and induction generator simulations had all three capacitors on one regulator turned on and all generation turned off. The losses in this case were 5.4%.

Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A
246.56	202.22	221.79	877.31	1132.1	1086.42	4622.62

LTC Tap		VR 1 A Tap	VR 1 B Tap	VR 1 C Tap
14		NA	NA	NA

Local Name	Amps A	Amps B	Amps C	Cust Volts A	Cust Volts B	Cust Volts C
======Node 0======						
MILFD8103	648.0396	733.271	713.601	120.0001	120.0001	120.0001
======Node 1======						
StPole_MILFD8	578.1287	654.1653	636.6173	125.9017	125.5546	124.9828
======Node 2======						
======Node 3======						
Node 3	481.8032	564.0023	523.93	121.8937	121.6459	121.6163
Node 3 N	465.5588	552.767	513.7795	121.1734	120.9197	121.0038
Node 3 E	16.2788	11.2809	10.2472	121.889	121.6455	121.6148
======Node 4======						
Node 4	465.5661	544.3872	513.7841	121.0855	120.8334	120.9275
Node 4 E	53.0644	126.2385	80.5565	121.0701	120.7819	120.9227
Node 4 N	412.5386	418.2472	433.3739	121.0031	120.7747	120.8507
======Node 5======						
Node 5	47.2952	121.2589	71.1749	120.8873	120.142	120.8823
Node 5 E	44.7918	121.2666	63.0488	120.8773	120.1099	120.8842
Node 5 N	2.5035	0.0186	8.1287	120.8869	120.1427	120.868
======Node 6======						
Node 6	0	0	0	120.5488	119.378	121.0163
======Node 7======						
Node 7	398.3378	406.7628	425.2631	118.0492	118.635	118.1037
Node 7 E	250.6805	282.5334	245.4241	118.0415	118.6281	118.0974
Node 7 N	81.6264	41.7154	90.1658	118.0364	118.6371	118.0811
Node 7 W	66.1638	82.7247	89.7199	118.0454	118.6206	118.0853
======Node 8======						
Node 8	250.683	273.7643	245.4261	117.8587	118.469	117.9463
======Node 9======						
Node 9	250.6839	273.7649	245.4268	117.4472	118.0253	117.5559
======Node 10======						
Node 10	20.4	20.2112	20.2746	115.5999	116.6792	116.3151
======Node 11======						
Node 11	181.9956	152.9444	140.0598	114.0857	115.7246	115.4564
Node 11 N	118.6435	55.1258	103.8657	114.066	115.7222	115.4317
Node 11 E	63.3539	97.8194	36.195	114.0665	115.7056	115.4596
======Node 12======						
Node 12	0	0	0	113.7463	115.3602	115.4034
======Node 13======						
Node 13	0	0	0	117.8356	118.6261	117.5034
======Node 14======						
Node 14	42.5463	53.1638	27.7177	113.7832	115.4145	114.681
======Node 15======						
Node 15	42.5481	53.1649	27.7191	113.7822	115.4132	114.6804

kW Losses: kVAr Losses:

Node 17	0.0019	0.0024	0.0022	113.6089	115.1328	114.6841
======Node 18======						
Node 18	0	1.3445	0.0032	0	114.7666	114.8794
======Node 19======						
Node 19	0.3952	0	0	113.2432	0	0
======Node 20======						
Node 20	37.9451	26.6195	77.7292	117.8058	118.6012	117.2153
Node 20 W	19.3002	0	0	117.8058	0	0
Node 20 N	18.6457	26.62	77.7296	117.8475	118.553	117.0723
======Node 21======						
Node 21	18.6604	25.3668	65.2933	117.9146	118.4698	116.8272
Node 21 N	17.3276	23.6725	37.8338	117.9146	118.4698	116.8272
Node 21 E	1.3462	1.7079	27.4619	117.9204	118.4682	116.8158
======Node 22======						
Node 22	1.3529	0.411	21.7288	117.9554	118.4604	116.7453
Node 22 E	0.0066	0.007	20.4099	117.9718	118.457	116.7157
Node 22 S	0.3388	0.4147	1.3202	117.9565	118.4591	116.7418
Node 22 N	1.0205	0	0	117.118	0	0
======Node 23======						
======Node 24======						
Node 24	0	0	0	0	0	116.1101
======Node 25======						
Node 25	578.129	654.1655	636.6175	125.7425	125.3385	124.8545
Node 25 W	82.7048	87.1324	106.8792	125.7381	125.3313	124.848
Node 25 E	495.5384	567.2441	530.0965	125.5643	125.1707	124.7026
======Node 26======						
Node 26	26.4142	25.8686	69.1744	125.3649	124.9546	124.0365
Node 26 E	0	0	36.6633	0	0	123.9562
Node 26 W	0	0	0.3888	0	0	124.0349
Node 26 S	26.4142	25.8686	32.1314	125.3562	124.9477	124.0252
======Node 27======						
Node 27	0.6813	0.7658	0.003	125.2701	124.9092	123.7098
======Node 28======						
Node 28	0	0	1.293	0	0	122.477
======Node 29======						
Node 29	0	0	0	0	114.6208	0

======Feeder Path Trace======

Distance (1000r	CustvoltsA	CustVoltsB	CustVoltsC	%CapacityA	%CapacityB	%CapacityC
0.1034	116.4234	116.2687	116.0501	40.3159	32.4661	34.2777
0.2168	125.9662	125.6275	125.0536	37.8356	29.6596	31.5465
0.3008	125.9017	125.5546	124.9828	13.8407	2.5089	5.1241
0.3008	125.9017	125.5546	124.9828	42.4748	34.9089	36.655
0.5078	125.7425	125.3385	124.8545	42.4747	34.9089	36.655
0.7438	125.5643	125.1707	124.7026	50.6927	43.5578	47.2541
1.3578	125.0996	124.7357	124.3115	50.6925	43.5577	47.4227
2.562	124.191	123.8923	123.5481	50.6921	43.7146	47.4224

2.645	124.1284	123.8344	123.4958	50.6912	43.7247	47.4219
3.185	123.7363	123.4468	123.1639	52.0601	43.7247	47.8681
3.408	123.5746	123.2877	123.0271	52.0598	43.8324	47.8679
3.695	123.3667	123.0835	122.8512	52.0596	43.8643	47.8678
5.733	121.8937	121.6459	121.6163	52.0594	43.8804	47.8677
6.777	121.1734	120.9197	121.0038	53.6757	44.9983	48.8777
6.9052	121.0855	120.8334	120.9275	53.675	45.8321	48.8772
7.0393	121.0031	120.7747	120.8507	58.9514	58.3834	56.8782
7.1824	120.9154	120.712	120.7689	59.0161	58.3833	56.8782
7.3574	120.8081	120.6353	120.6689	59.016	58.3832	56.8781
7.6884	120.6062	120.49	120.4802	59.1066	58.3831	56.878
7.8854	120.4865	120.4034	120.3681	59.1883	58.383	56.8779
7.8854	120.4865	120.4034	120.3681	59.1882	58.3829	56.9812
8.2254	120.2777	120.255	120.1788	59.1882	58.3829	57.413
8.3964	120.1726	120.1804	120.0841	59.1879	58.3827	57.4847
8.8361	119.9043	119.9879	119.8411	59.3508	58.3826	57.4846
9.4201	119.5486	119.7333	119.5193	59.3505	58.4097	57.4844
9.5872	119.4502	119.6584	119.4278	60.131	58.4094	57.4842
9.9964	119.2101	119.48	119.2011	60.1309	58.9101	57.4841
10.3164	119.0227	119.3406	119.0243	60.152	58.9099	57.4839
10.4865	118.9227	119.2667	118.9312	60.1518	58.9098	57.6858
10.7919	118.7436	119.1363	118.7632	60.1517	59.188	57.6858
10.9291	118.6633	119.0785	118.6874	60.1514	59.3977	57.6856
11.0751	118.578	119.0175	118.6066	60.1514	59.5265	57.6856
11.6761	118.2288	118.7656	118.2748	60.2484	59.5264	57.6855
11.9871	118.0492	118.635	118.1037	60.3644	59.5261	57.6853
12.0081	118.0415	118.6281	118.0974	75.0567	71.8872	75.5797
12.0082	118.0415	118.6281	118.0974	75.0567	71.8872	75.5797
12.2461	117.9535	118.5502	118.0255	75.0567	71.8872	75.5797
12.3674	117.9086	118.5105	117.9889	75.0565	71.8871	75.5796
12.5034	117.8587	118.469	117.9463	75.0564	72.7598	75.5795
12.6409	117.3969	117.9836	117.5131	75.0563	72.7597	75.5794
12.7379	117.3617	117.954	117.4829	75.1868	72.7597	75.5794
12.9285	117.2927	117.8959	117.4238	75.2038	72.7806	75.5962
13.0339	117.2546	117.8638	117.3911	75.2311	72.7805	75.5961
13.3649	117.1317	117.7635	117.2942	75.231	72.7804	76.3121
13.6331	117.0379	117.6782	117.2165	76.1338	72.7803	76.3119
13.8911	116.9465	117.5965	117.144	76.1336	72.7802	76.6399
14.0938	116.8754	117.5319	117.0871	76.2787	72.7801	76.6398
14.5009	116.7155	117.4069	117.0003	76.2786	72.9292	79.6292
15.0489	116.5008	117.2425	116.8818	76.2783	73.1781	79.629
15.2389	116.4266	117.1856	116.8408	76.3222	73.1779	79.6287
15.3809	116.3724	117.1421	116.8104	76.7063	73.1778	79.6286
15.5193	116.32	117.1016	116.7796	76.7062	73.7591	79.6285
15.8243	116.2031	117.0129	116.714	76.7061	73.7591	79.9307
16.0943	116.0991	116.9345	116.657	76.7059	73.759	80.0757
17.4243	115.6043	116.6686	116.3121	76.7057	77.462	80.0756
17.5825	115.5473	116.6314	116.2701	76.29	75.5126	78.5313
17.8255	115.4594	116.5744	116.2061	76.2899	75.5126	78.604
18.2705	115.2994	116.4695	116.0892	76.391	75.5125	78.6039
18.4278	115.2427	116.4325	116.0483	76.3907	75.5123	78.7047
18.5938	115.1828	116.3936	116.0051	76.3906	75.5123	78.7047

18.7608	115.1225	116.3544	115.9618	76.3905	75.5122	78.7362
19.0918	115.0031	116.277	115.876	76.3904	75.5121	78.7361
19.3973	114.8882	116.2064	115.8045	76.3902	75.512	79.7979
19.9934	114.6846	116.0857	115.7242	80.5779	79.2287	85.5329
20.3713	114.5566	116.0157	115.6697	80.5775	79.9467	85.5325
20.7442	114.4426	115.9384	115.6173	81.8918	79.9466	85.5323
20.9315	114.3841	115.8998	115.5929	81.8916	79.9464	85.9615
21.4456	114.2239	115.7948	115.5258	81.8915	80.0014	85.9614
21.7101	114.1411	115.741	115.4919	81.8912	80.0012	86.0638
21.8963	114.0857	115.7246	115.4564	81.891	84.7817	86.0637
22.0263	114.066	115.7222	115.4317	88.1947	94.5148	89.6651
22.1673	114.0442	115.7197	115.4055	88.1946	94.5148	89.8794
22.3333	114.0185	115.7167	115.3747	88.1946	94.5147	89.8793
22.4553	114.001	115.7138	115.3522	88.6467	94.5146	89.8792
22.7923	113.952	115.706	115.2914	88.6466	94.5145	90.0361
22.9523	113.953	115.694	115.2609	93.6863	94.5143	90.0359
23.1747	113.9531	115.6775	115.2202	93.6862	94.5142	90.3605
23.3151	113.9476	115.6713	115.1959	93.6861	94.5141	90.6615
23.3365	113.9468	115.6704	115.1922	93.7046	94.5372	90.6802
23.5305	113.9392	115.6619	115.1587	93.7046	94.5372	90.6802
23.6878	113.9334	115.6548	115.1315	93.7713	94.5371	90.6801
23.9908	113.9222	115.6412	115.0792	93.7712	94.5371	90.68
24.1041	113.918	115.6361	115.0597	93.771	94.537	90.6953
24.3641	113.9089	115.624	115.015	93.8589	94.5369	90.6953
24.6082	113.8994	115.6128	114.9746	93.8588	94.5368	90.9637
24.7822	113.8938	115.604	114.946	94.1175	94.5368	90.9636
25.0002	113.8862	115.5932	114.9111	94.1173	94.5367	91.1438
25.1092	113.8824	115.5879	114.8935	94.1172	94.6128	91.1437
25.3222	113.8832	115.5721	114.8601	95.6735	94.6127	91.1436
26.3285	113.8533	115.5023	114.7593	95.6734	94.6127	93.4976
26.5025	113.8474	115.4904	114.7431	95.6728	94.6123	93.7918
26.9085	113.8313	115.4628	114.7094	95.6727	94.6122	94.2053
27.0357	113.8266	115.454	114.6989	95.7668	94.6121	94.2051
27.3012	113.8119	115.4363	114.685	95.7667	94.612	95.4719
27.3603	113.8073	115.4327	114.6843	95.7666	94.7101	97.1667
27.6618	113.7832	115.4145	114.681	95.7665	94.7101	97.242
27.8754	113.768	115.3986	114.6763	96.0813	95.1035	97.4471
28.0004	113.7579	115.391	114.6752	95.7663	94.7099	97.3313
28.1854	113.743	115.3805	114.6733	95.7662	94.8365	97.3313
28.4675	113.7204	115.3658	114.6696	95.7661	95.0503	97.3312
28.65	113.7102	115.3493	114.674	96.9771	94.871	97.8451
29.0193	113.6904	115.3154	114.683	97.0786	94.8709	97.845
29.6693	113.657	115.2549	114.6991	97.1762	94.8707	97.8449
29.9613	113.6438	115.2265	114.7065	97.4539	94.8703	97.8447
30.3003	113.6364	115.1891	114.7161	98.4128	94.8701	97.8446
30.9403	113.6248	115.1169	114.7343	98.575	94.8699	97.8444
31.2193	113.6227	115.12	114.7189	98.5747	99.9982	97.8437
31.4578	113.6212	115.1226	114.7062	98.6242	99.9986	97.9187
31.6728	113.621	115.1243	114.6949	98.8229	99.9988	97.9186
31.7868	113.621	115.1251	114.6889	98.9169	99.9991	97.9185
31.8818	113.6201	115.126	114.6859	98.9169	99.9992	98.786
32.066	113.6155	115.1288	114.6849	98.9168	99.9993	99.8769

		kVA Flow SOC			Released Capacity
Phase B	Phase C	Phase A	Phase B	Phase C	
5216.17	5053.13	NA	NA	NA	

Seq Amps 0	Seq Amps 1	Seq Amps 2	I2/I1 (%)	Seq Volts 0	Seq Volts 1	Seq Volts 2
25.7965	698.2907	25.7941	3.6939	0	7620.9118	0.1115
23.0135	622.9587	23.0114	3.6939	0.1936	7968.8747	33.9196
22.4991	523.2323	24.9978	4.7776	49.9693	7729.7254	51.729
23.9031	510.6884	26.5738	5.2035	60.3815	7686.0193	57.4956
1.7735	12.597	1.9806	15.7225	49.9106	7729.5842	51.7098
21.8127	507.8991	24.1295	4.7508	61.516	7680.7011	58.2175
21.6972	86.6161	20.9846	24.2271	63.5193	7679.1639	58.5285
7.5855	421.3687	5.4263	1.2878	61.4762	7676.0831	58.7883
21.9777	79.9071	21.6109	27.045	88.9736	7660.636	62.4304
23.1378	76.367	22.9815	30.0935	90.3389	7659.7703	62.5919
2.3733	3.5412	2.4374	68.828	88.6572	7660.3411	62.6375
0	0	0	NA	122.8907	7639.7369	64.7177
9.2072	410.102	7.2384	1.765	61.7245	7509.8745	83.3577
10.8543	259.536	12.4159	4.7839	61.8074	7509.4287	83.4209
15.1231	71.1666	14.7461	20.7205	60.9885	7509.1726	83.5844
5.932	79.493	8.307	10.45	61.7607	7509.0973	83.4723
7.9299	256.6139	9.5945	3.7389	63.6226	7498.9618	84.9248
7.9299	256.6139	9.5945	3.7389	64.834	7472.586	83.9778
0.2618	20.2921	0.2301	1.1341	83.6019	7378.426	94.7981
11.8567	158.322	13.0377	8.2349	103.7461	7307.7226	101.2307
19.7917	92.5382	18.5969	20.0965	102.826	7306.745	101.1012
17.419	65.7855	18.2442	27.7329	104.7716	7306.9653	101.1667
0	0	0	NA	118.8639	7291.4843	101.5956
0	0	0	NA	47.9228	7492.5132	90.5568
6.7516	41.1329	8.0044	19.4599	87.6444	7278.4331	107.7743
6.7516	41.1329	8.0044	19.4599	87.6602	7278.3672	107.7566
6.15	39.6964	7.3816	18.5952	89.473	7275.8145	107.4898
8.1408	33.3165	8.9997	27.0127	90.1313	7275.3363	107.3031
3.9063	6.3814	3.7501	58.7658	89.2813	7275.737	107.4865

0	0.0022	0	0	96.7325	7268.7484	105.6876
0	0.4479	0.4474	99.8923	0	4861.3551	2416.1432
0.1317	0	0	NA	2397.3029	0	0
15.4031	47.4282	15.5983	32.8881	45.8041	7485.2458	94.603
6.4334	0	0	NA	2493.8892	0	0
18.3321	40.9954	18.6891	45.5884	48.7395	7482.0428	97.0537
14.3794	36.4373	14.735	40.4393	55.2777	7476.4375	101.2469
5.8922	26.2761	6.2311	23.714	55.2777	7476.4375	101.2469
8.6301	10.1643	8.6697	85.2956	55.6248	7476.2813	101.4468
6.9913	7.8281	6.9199	88.3989	57.7939	7475.3449	102.6636
6.8041	6.8009	6.8047	100.056	58.8266	7474.9831	103.1873
0.3134	0.691	0.3175	45.9455	57.9135	7475.2644	102.7101
6.9913	0	0	NA	78.0787	0	0
0	0	0	NA	0	0	2457.9386
23.0135	622.9589	23.0114	3.6939	2.9102	7958.2171	32.5265
7.3151	92.2339	7.587	8.2258	3.0394	7957.833	32.4707
19.3679	530.9452	22.1074	4.1638	4.6354	7947.6736	32.8143
14.1796	40.4839	14.5118	35.8459	19.7449	7924.7918	34.2899
0	0	12.2208	NA	0	0	2624.0328
0	0	0.1296	NA	0	0	2625.6999
1.8314	28.1349	2.1963	7.8065	19.8955	7924.2239	34.3331
0.2178	0.4812	0.267	55.4879	29.4606	7914.9081	35.5305
0	0	0.431	NA	0	0	2592.7205
0	0	0	NA	0	2426.4122	0

pf FLOW

V2/V1 (%)	pf A	pf B	pf C	kW Flow A	kW Flow B	kW Flow C
0.0015	0.7952	0.7913	0.7921	3927.3825	4422.1394	4307.9145
0.4257	0.8432	0.8434	0.841	3897.9469	4399.4995	4249.9173
0.6692	0.8446	0.849	0.8452	3188.3499	3743.2235	3454.8722
0.7481	0.8476	0.8549	0.8514	3054.845	3650.9841	3378.6615
0.669	0.8733	0.8936	0.9131	110.047	77.876	72.2701
0.758	0.8495	0.8578	0.8553	3043.6655	3586.0975	3376.8882
0.7622	0.8675	0.8754	0.883	354.002	848.0526	546.2885
0.7659	0.8474	0.8528	0.8504	2688.3306	2737.1724	2830.3302
0.815	0.8673	0.8779	0.8829	314.935	812.2552	482.4273
0.8172	0.8675	0.8778	0.8814	298.3348	812.2442	426.6433
0.8177	0.8637	-0.0773	0.8939	16.6002	0.011	55.784
0.8471	-1	-1	-1	0	0	0
1.11	0.8568	0.8628	0.8628	2562.5809	2647.2655	2755.9769
1.1109	0.8478	0.8526	0.8594	1593.3367	1815.0299	1582.0433
1.1131	0.8666	0.8835	0.8775	530.33	277.6918	593.4315
1.1116	0.8809	0.8884	0.861	436.9675	553.7387	579.382
1.1325	0.8482	0.8529	0.86	1592.1555	1757.4092	1581.5949
1.1238	0.8482	0.8529	0.86	1591.7548	1757.3321	1581.4082
1.2848	0.9637	0.9637	0.9637	-144.3264	-144.3264	-144.3265
1.3853	0.8659	0.8754	0.8739	1142.3289	984.1866	897.71
1.3837	0.8671	0.8766	0.8741	745.3779	355.1598	665.6767
1.3845	0.8641	0.8751	0.8737	396.658	629.1174	231.8776
1.3933	-1	-1	-1	0	0	0
1.2086	-1	-1	-1	0	0	0
1.4807	0.8804	0.8773	0.8798	270.7401	341.9209	177.6084
1.4805	0.8804	0.8773	0.8798	270.6931	341.9206	177.6115

	1.4774	0.8805	0.878	0.88	270.6305	320.0234	171.8888
	1.4749	0.883	0.8779	0.8817	186.9862	320.0152	134.214
	1.4773	0.8749	-0.0824	0.8738	83.604	0.0084	37.6769
	1.454	0.0586	0.097	-0.1554	0	-0.0017	0.0025
	49.701	0	0.8733	-0.2558	0	8.558	0.0059
NA		0.9297	0	0	2.6429	0	0
	1.2639	0.8665	0.8856	0.8791	245.9844	177.5682	508.7365
NA		0.866	0	0	125.055	0	0
	1.2972	0.867	0.8856	0.8791	120.9412	177.5618	508.7018
	1.3542	0.8669	0.8854	0.8807	121.1206	169.0124	426.8469
	1.3542	0.8622	0.8815	0.879	111.8729	156.9953	246.7566
	1.3569	0.9201	0.932	0.8835	9.2763	11.9755	180.0152
	1.3734	0.9171	0.9059	0.8858	9.2938	2.8014	142.7331
	1.3804	0.1516	-0.0919	0.8862	-0.0075	0.0049	134.0994
	1.374	0.885	0.8955	0.881	2.246	2.794	8.6234
NA		0.9235	0	0	7.0599	0	0
NA		0	0	0	0	0	0
	0.4087	0.8432	0.8434	0.841	3897.9475	4399.4991	4249.9171
	0.408	0.8688	0.8769	0.8799	573.8255	608.1993	745.6672
	0.4129	0.8395	0.8387	0.8338	3322.0806	3786.9672	3504.6396
	0.4327	0.8735	0.886	0.8836	183.6974	181.8916	481.4931
NA		0	0	0.8765	0	0	253.1318
NA		0	0	0.8747	0	0	2.679
	0.4333	0.8735	0.886	0.8916	183.6974	181.8916	225.6823
	0.4489	0.9254	0.875	-0.0565	5.016	5.3157	0.0013
NA		0	0	0.8751	0	0	8.8011
	0	0	0	0	0	0	0

kVAR Flow A	kVAR Flow B	kVAR Flow C
2994.4404	3416.6517	3319.2982
2484.8771	2802.2932	2733.5539
2020.8649	2329.1825	2184.851
1912.3068	2215.1469	2081.2881
61.4043	39.1233	32.2663
1890.091	2148.7621	2045.9234
202.9733	468.2726	290.3765
1684.3503	1676.1461	1751.1922
180.7191	443.0079	256.5759
171.0321	443.1493	228.6038
9.6871	-0.1414	27.9721
0	0	0
1542.3544	1550.7972	1615.0629
996.676	1112.2177	941.1572
305.3682	147.2087	324.3699
234.7624	286.0857	342.3179
994.3771	1075.6567	938.4383
993.5189	1074.3983	937.4523
-40.0011	-40.0009	-40.0006
659.9751	543.3731	499.4587
428.2069	194.9498	369.9944
231.0125	347.9404	129.1095
0	0	0
0	0	0
145.8217	187.0529	95.9727
145.772	186.9251	95.955

145.7273	174.5042	92.7921
99.4138	174.5241	71.8258
46.2855	-0.1015	20.9698
-0.014	-0.0174	-0.016
0	4.7749	-0.0224
1.047	0	0
141.7294	93.1255	275.851
72.193	0	0
69.5248	93.1382	275.7495
69.6617	88.7318	229.5944
65.7403	84.1135	133.8224
3.9478	4.6589	95.4486
4.0411	1.3092	74.7599
-0.0486	-0.0527	70.1198
1.1817	1.3887	4.6312
2.9325	0	0
0	0	0
2484.8807	2802.297	2733.557
326.9982	333.3856	402.7434
2150.222	2459.0224	2320.6186
102.3847	95.1695	255.1357
0	0	139.0539
0	0	1.4846
102.3847	95.1695	114.5972
2.055	2.9415	-0.0236
0	0	4.8678
0	0	0

Table B-6. Summary of LL Base Case

(LTC control only, tap = 7)
[#0 MXAT services included]

Location	Simulated Data			Measured Data July 17, 2006		
Node 01	I_A 227.46	I_B 262.61	I_C 255.85	I_A 225	I_B 260	I_C 254
Node 01	V_A 125.76	V_B 125.60	V_C 125.31	V_A 126.0	V_B 126.0	V_C 126.0
Node 01	PF_A 0.867	PF_B 0.862	PF_C 0.857			
	kVA Flow			**Total**		
Node 01	Phase A 1,816.66	Phase B 2,094.65	Phase C 2,036.10	5,947.41		
	kW Flow					
Node 01	Phase A 1,575.70	Phase B 1,806.23	Phase C 1,743.88	5,125.81		
	kVAr Flow					
Node 01	Phase A 904.12	Phase B 1,060.70	Phase C 1,050.99	3,015.81		
	kW Losses			**Total %**		
Node 01	Phase A 59.58	Phase B 48.67	Phase C 58.98	167.23 3.26%		
	kVAr Losses			**Total %**		
	Phase A 135.74	Phase B 182.47	Phase C 178.03	496.24 16.45%		
Node 01	I_0 9.97	I_1 248.62	I_2 11.71	I_2/I_1% 4.71		
Node 01	V_0 0.084	V_1 7973.66	V_2 16.65	V_2/V1% 0.2088		

Note: All capacitors and line regulators were turned off, and the substation primary voltage was set at 100% (120 V).

kW Losses:			kVAr Losses:			
Phase A	Phase B	Phase C	Phase A	Phase B	Phase C	Phase A
59.58	48.67	58.98	135.74	182.47	178.03	1816.66

LTC Tap		VR 1 A Tap	VR 1 B Tap	VR 1 C Tap
7		NA	NA	NA

Local Name	Amps A	Amps B	Amps C	Cust Volts A	Cust Volts B	Cust Volts C
======Node 0======						
MILFD8103	244.0341	281.7392	274.4897	120.0001	120.0001	120.0001
======Node 1======						
StPole_MILFD8	227.4606	262.605	255.8479	125.7579	125.5965	125.3097
======Node 2======						
======Node 3======						
Node 3	195.3918	233.8487	218.4801	124.2194	124.0145	123.9459
Node 3 N	189.6574	229.6123	213.8667	123.9386	123.7173	123.6939
Node 3 E	5.7509	4.256	4.6576	124.2179	124.0142	123.945
======Node 4======						
Node 4	189.6645	226.3778	213.8713	123.9043	123.6818	123.6624
Node 4 E	17.4388	45.8427	29.0388	123.8995	123.6625	123.6608
Node 4 N	172.2271	180.5432	184.8588	123.8714	123.6565	123.6305
======Node 5======						
Node 5	15.6842	44.2623	25.1048	123.8405	123.4232	123.6495
Node 5 E	14.9015	44.27	22.0038	123.8371	123.4112	123.6505
Node 5 N	0.7828	0.019	3.1026	123.8407	123.4233	123.6441
======Node 6======						
Node 6	0	0	0	123.7265	123.1477	123.7001
======Node 7======						
Node 7	167.4328	176.0287	180.8732	122.6773	122.732	122.4825
Node 7 E	105.0159	118.6366	102.1838	122.6741	122.7292	122.48
Node 7 N	32.9179	20.8533	41.1011	122.6728	122.7314	122.4726
Node 7 W	29.5179	36.562	37.6357	122.6751	122.7259	122.4746
======Node 8======						
Node 8	105.0185	115.4683	102.1858	122.5993	122.665	122.4185
======Node 9======						
Node 9	105.0194	115.4688	102.1865	122.4367	122.4842	122.2595
======Node 10======						
Node 10	0	0	0	121.6699	121.9238	121.7519
======Node 11======						
Node 11	65.79	55.7814	48.2718	121.0926	121.5547	121.4505
Node 11 N	43.6761	19.9716	35.7606	121.085	121.5542	121.4419
Node 11 E	22.1163	35.8106	12.5122	121.0856	121.5474	121.4519
======Node 12======						
Node 12	0	0	0	120.9692	121.414	121.4392
======Node 13======						
Node 13	0	0	0	122.5989	122.6963	122.2159
======Node 14======						
Node 14	17.687	19.3124	9.9032	120.9486	121.4649	121.1777
======Node 15======						
636_B	17.6897	19.3144	9.6032	120.9384	121.4575	121.1755

======Node 16======						
Node 16	17.6916	18.157	9.6048	120.9225	121.4499	121.1732
Node 16 E	12.5106	18.164	7.5572	120.918	121.4443	121.1746
Node 16 W	5.1835	0.0146	2.0498	120.9208	121.4513	121.1721
======Node 17======						
Node 17	0.0021	0.0025	0.0024	120.8743	121.3688	121.1773
======Node 18======						
Node 18	0	0.455	0.0033	0	121.2314	121.2496
======Node 19======						
Node 19	0.2497	0	0	120.7303	0	0
======Node 20======						
Node 20	17.4798	15.5017	36.3913	122.5861	122.6707	122.0873
Node 20 W	6.4988	26.6195	77.7292	122.5861	118.6012	117.2153
Node 20 N	10.9817	15.5022	36.3918	122.5995	122.6446	122.0226
======Node 21======						
Node 21	10.997	15.1054	31.9865	122.6209	122.5986	121.9099
Node 21 N	10.2902	14.1955	21.7833	122.6209	122.5986	121.9099
Node 21 E	0.719	0.9229	10.2065	122.623	122.598	121.9057
======Node 22======						
Node 22	0.7256	0.1491	8.3349	122.6357	122.5952	121.8787
Node 22 E	0.0068	0.0073	7.8109	122.642	122.5939	121.8673
Node 22 S	0.1233	0.1521	0.5253	122.6362	122.5947	121.8773
======Node 23======						
======Node 24======						
Node 24	0	0	0	0	0	121.4917
======Node 25======						
Node 25	227.4609	262.6052	255.8481	125.6992	125.5116	125.26
Node 25 W	27.1253	27.7831	35.5414	125.6979	125.5094	125.2576
Node 25 E	200.3418	234.828	220.3332	125.6309	125.4443	125.1993
======Node 26======						
Node 26	8.9683	8.8416	23.2341	125.5836	125.3932	124.9689
Node 26 E	0	0	11.2573	0	0	124.9446
Node 26 W	0	0	0.1154	0	0	124.9685
Node 26 S	8.9683	8.8416	11.8722	125.5812	125.3907	124.9644
======Node 27======						
Node 27	0.371	0.2275	0.003	125.5605	125.3781	124.8424
======Node 28======						
Node 28	0	0	0.3933	0	0	124.3938
======Node 29======						
Node 29	0	0	0	0	121.183	0

======Feeder Path Trace======

Distance (1000r	CustvoltsA	CustVoltsB	CustVoltsC	%CapacityA	%CapacityB	%CapacityC
0.1034	118.7851	118.7178	118.6043	77.5246	74.052	74.7196
0.2168	125.7839	125.6264	125.3387	75.5419	71.7629	72.4895
0.3008	125.7579	125.5965	125.3097	66.1013	60.8636	61.8707
0.3008	125.7579	125.5965	125.3097	77.3671	73.8702	74.5425
0.5078	125.6992	125.5116	125.26	77.3671	73.8701	74.5425
0.7438	125.6309	125.4443	125.1993	80.0655	76.634	78.0763
1.3578	125.453	125.2693	125.0424	80.0653	76.6339	78.1271
2.562	125.1045	124.9284	124.7351	80.0649	76.6811	78.1268

2.645	125.0805	124.905	124.714	80.0641	76.6837	78.1263
3.185	124.9297	124.7482	124.5792	80.5588	76.6837	78.2612
3.408	124.8674	124.6837	124.5236	80.5584	76.7162	78.2609
3.695	124.7873	124.6008	124.4519	80.5582	76.7257	78.2608
5.733	124.2194	124.0145	123.9459	80.558	76.7315	78.2607
6.777	123.9386	123.7173	123.6939	81.1286	77.153	78.7197
6.9052	123.9043	123.6818	123.6624	81.1279	77.4748	78.7193
7.0393	123.8714	123.6565	123.6305	82.863	82.0355	81.6061
7.1824	123.8364	123.6295	123.5964	82.8828	82.0354	81.606
7.3574	123.7935	123.5965	123.5548	82.8827	82.0354	81.606
7.6884	123.7128	123.5339	123.4762	82.9105	82.0353	81.6059
7.8854	123.6649	123.4965	123.4294	82.9353	82.0351	81.6057
7.8854	123.6649	123.4965	123.4294	82.9352	82.035	81.6379
8.2254	123.5809	123.4326	123.3508	82.9352	82.035	81.8885
8.3964	123.5386	123.4004	123.3114	82.935	82.0349	81.9108
8.8361	123.4305	123.3175	123.2102	82.9856	82.0348	81.9107
9.4201	123.287	123.2075	123.076	82.9853	82.0431	81.9105
9.5872	123.2471	123.1753	123.0377	83.2611	82.0428	81.9103
9.9964	123.1497	123.0984	122.9429	83.261	82.2412	81.9102
10.3164	123.0736	123.0382	122.8689	83.2733	82.241	81.91
10.4865	123.033	123.0063	122.8299	83.2731	82.2409	82.0033
10.7919	122.9602	122.9497	122.7596	83.2729	82.3374	82.0032
10.9291	122.9275	122.9246	122.7279	83.2727	82.4083	82.0031
11.0751	122.8929	122.8981	122.6939	83.2726	82.4851	82.003
11.6761	122.7506	122.7887	122.5546	83.3033	82.485	82.0029
11.9871	122.6773	122.732	122.4825	83.34	82.4847	82.0027
12.0081	122.6741	122.7292	122.48	89.5507	88.1954	89.8325
12.0082	122.6741	122.7292	122.48	89.5506	88.1954	89.8325
12.2461	122.6381	122.6978	122.4507	89.5506	88.1954	89.8325
12.3674	122.6197	122.6818	122.4358	89.5505	88.1953	89.8323
12.5034	122.5993	122.665	122.4185	89.5504	88.5106	89.8323
12.6409	122.416	122.4672	122.2421	89.5503	88.5106	89.8322
12.7379	122.4016	122.4551	122.2298	89.5935	88.5105	89.8321
12.9285	122.3732	122.4315	122.2057	89.5989	88.5171	89.8375
13.0339	122.3575	122.4184	122.1924	89.6074	88.5171	89.8374
13.3649	122.3068	122.3775	122.153	89.6074	88.517	90.1356
13.6331	122.268	122.3427	122.1214	89.958	88.5169	90.1354
13.8911	122.2303	122.3094	122.0917	89.9579	88.5168	90.2428
14.0938	122.2008	122.283	122.0684	90.0051	88.5167	90.2427
14.5009	122.1348	122.2319	122.0327	90.0049	88.5661	91.4448
15.0489	122.0461	122.1643	121.9841	90.0047	88.6493	91.4446
15.2389	122.0154	122.1409	121.9673	90.0186	88.6491	91.4443
15.3809	121.9929	122.123	121.9548	90.16	88.649	91.4442
15.5193	121.9712	122.1063	121.9422	90.1599	88.8767	91.4442
15.8243	121.9227	122.0697	121.9153	90.1598	88.8766	91.5733
16.0943	121.8795	122.0374	121.8918	90.1596	88.8765	91.6211
17.4243	121.6732	121.9215	121.7536	90.1594	90.1983	91.621
17.5825	121.6506	121.9062	121.738	90.7546	90.1974	91.7572
17.8255	121.6158	121.8827	121.7141	90.7545	90.1973	91.7819
18.2705	121.5526	121.8392	121.6706	90.8164	90.1972	91.7818
18.4278	121.5302	121.8238	121.6555	90.8161	90.1971	91.8435
18.5938	121.5065	121.8076	121.6395	90.816	90.197	91.8434

18.7608	121.4826	121.7914	121.6234	90.8159	90.1969	91.8536
19.0918	121.4353	121.7591	121.5916	90.8158	90.1969	91.8535
19.3973	121.3899	121.7297	121.5652	90.8156	90.1968	92.2613
19.9934	121.3147	121.6853	121.5392	93.0173	92.4638	95.0126
20.3713	121.2676	121.6599	121.5211	93.0169	92.7741	95.0121
20.7442	121.2252	121.6321	121.5037	93.4546	92.7739	95.0119
20.9315	121.2035	121.6182	121.4957	93.4544	92.7738	95.1624
21.4456	121.144	121.5803	121.4735	93.4542	92.7918	95.1623
21.7101	121.1132	121.5608	121.4623	93.4539	92.7916	95.197
21.8963	121.0926	121.5547	121.4505	93.4537	94.4496	95.1968
22.0263	121.085	121.5542	121.4419	95.6541	98.0128	96.4417
22.1673	121.0766	121.5536	121.4329	95.6541	98.0127	96.5147
22.3333	121.0667	121.5529	121.4222	95.654	98.0126	96.5146
22.4553	121.0599	121.5522	121.4144	95.8112	98.0125	96.5145
22.7923	121.041	121.5502	121.3934	95.8111	98.0124	96.5674
22.9523	121.0402	121.5465	121.3827	97.5132	98.0122	96.5672
23.1747	121.0387	121.5413	121.3683	97.5131	98.0121	96.6775
23.3151	121.0358	121.5397	121.3597	97.513	98.012	96.7796
23.3365	121.0353	121.5394	121.3584	97.5204	98.0212	96.787
23.5305	121.0313	121.5372	121.3467	97.5204	98.0211	96.787
23.6878	121.0282	121.5353	121.3371	97.5426	98.0211	96.7869
23.9908	121.0222	121.5317	121.3187	97.5425	98.021	96.7868
24.1041	121.0199	121.5303	121.3118	97.5423	98.0209	96.7918
24.3641	121.0149	121.5271	121.2961	97.5718	98.0209	96.7917
24.6082	121.0099	121.5241	121.2818	97.5716	98.0208	96.8826
24.7822	121.0067	121.5217	121.2717	97.6614	98.0207	96.8825
25.0002	121.0025	121.5187	121.2594	97.6613	98.0206	96.9438
25.1092	121.0004	121.5173	121.2532	97.6611	98.0462	96.9437
25.3222	120.9992	121.5125	121.2414	98.21	98.0461	96.9437
26.3285	120.9818	121.4915	121.2059	98.2098	98.0461	97.7627
26.5025	120.9786	121.4879	121.2001	98.2092	98.0457	97.8604
26.9085	120.9702	121.4796	121.1882	98.2091	98.0456	97.9984
27.0357	120.9677	121.4769	121.1844	98.2404	98.0455	97.9982
27.3012	120.9608	121.4715	121.1794	98.2403	98.0454	98.422
27.3603	120.9588	121.4705	121.1791	98.2401	98.0784	98.9894
27.6618	120.9486	121.4649	121.1777	98.2401	98.0784	99.0146
27.858	120.9427	121.4598	121.176	98.3709	98.2212	99.0878
27.983	120.9384	121.4575	121.1755	98.2398	98.0782	99.0445
28.168	120.9321	121.4543	121.1747	98.2398	98.1203	99.0444
28.4501	120.9225	121.4499	121.1732	98.2396	98.1933	99.0443
28.6326	120.918	121.4443	121.1746	98.7102	98.1274	99.2209
29.0019	120.9094	121.4327	121.1777	98.7743	98.1273	99.2208
29.6519	120.8952	121.4116	121.1833	98.8357	98.1271	99.2207
29.9439	120.8896	121.4016	121.186	98.9576	98.1266	99.2205
30.2829	120.8864	121.388	121.1894	99.373	98.1264	99.2203
30.9229	120.8813	121.3619	121.1959	99.4283	98.1262	99.2202
31.2019	120.8802	121.3633	121.1902	99.4279	99.9981	99.2194
31.4404	120.8794	121.3645	121.1855	99.4477	99.9985	99.2464
31.6554	120.8791	121.3653	121.1813	99.5151	99.9988	99.2464
31.7694	120.8791	121.3657	121.1791	99.5744	99.999	99.2463
31.8644	120.8787	121.3661	121.178	99.5744	99.9991	99.5357
32.0486	120.8769	121.3672	121.1776	99.5743	99.9992	99.9585

kVA Flow SOC		Released Capacity		
Phase B	Phase C	Phase A	Phase B	Phase C
2094.65	2036.10	NA	NA	NA

Seq Amps 0	Seq Amps 1	Seq Amps 2	I2/I1 (%)	Seq Volts 0	Seq Volts 1	Seq Volts 2
10.6997	266.7397	12.5661	4.711	0	7620.9118	0.1115
9.973	248.6242	11.7127	4.711	0.084	7973.6646	16.649
10.0093	215.8935	12.4044	5.7456	21.2443	7878.6813	24.3383
10.3777	211.0309	12.9244	6.1244	25.6344	7861.0895	26.6788
0.3748	4.886	0.5281	10.8088	21.2226	7878.627	24.3351
9.6275	209.9567	12.0089	5.7197	26.1204	7858.9441	26.9705
8.3286	30.7726	8.1616	26.5225	26.8884	7858.3973	27.1083
3.754	179.1924	4.3125	2.4066	26.1587	7857.0354	27.1938
8.4174	28.3499	8.3981	29.6229	36.6073	7851.8011	28.8003
8.8219	27.0579	8.8711	32.7856	37.1205	7851.4935	28.871
0.9194	1.2925	0.9472	73.2813	36.506	7851.6931	28.8793
0	0	0	NA	48.6106	7844.5683	29.8772
3.9833	174.7588	4.5671	2.6134	28.0842	7787.8378	36.715
4.5087	108.6062	5.673	5.2234	28.1123	7787.6568	36.7426
5.9934	31.6231	5.769	18.243	27.8664	7787.5197	36.811
1.8431	34.5322	3.5023	10.142	28.1004	7787.4935	36.7669
3.4602	107.5518	4.6405	4.3146	28.733	7783.4062	37.3958
3.4602	107.5518	4.6405	4.3146	29.1752	7772.7694	37.063
0	0	0	NA	35.9934	7733.8786	41.7965
5.0211	56.61	5.1669	9.1272	43.847	7707.4137	44.0908
7.2945	33.1324	6.6414	20.0449	43.514	7707.0621	44.0182
6.6666	23.4789	6.8538	29.1915	44.2314	7707.1408	44.0789
0	0	0	NA	49.8449	7701.5484	44.3862
0	0	0	NA	24.7761	7779.7819	39.7308
2.6065	15.6289	3.198	20.4621	38.0717	7696.7125	45.7633
2.7067	15.5305	3.2965	21.2261	38.2758	7696.2939	45.6723

2.5008	15.1462	3.0505	20.1403	38.6129	7695.7453	45.627
2.8332	12.7392	3.2962	25.8747	38.8364	7695.5626	45.5523
1.55	2.4084	1.4676	60.9367	38.5379	7695.7163	45.6194
0	0.0023	0	0	41.1339	7693.0855	44.9112
0	0.1514	0.1509	99.6866	0	5133.0788	2558.1215
0.0832	0	0	NA	2555.801	0	0
6.6367	23.1235	6.6805	28.8905	25.1359	7776.2405	41.4469
2.1663	47.4282	15.5983	32.8881	2595.0857	7485.2458	94.603
7.7805	20.9578	7.8723	37.5624	26.7462	7774.5972	42.5068
6.3754	19.3623	6.4694	33.4126	29.9628	7771.6767	44.346
3.3308	15.4226	3.4172	22.157	29.9628	7771.6767	44.346
3.1224	3.9442	3.1421	79.6646	30.0955	7771.6168	44.4178
2.659	3.0675	2.619	85.3787	30.9206	7771.2542	44.8628
2.6044	2.6012	2.6051	100.1499	31.3241	7771.1159	45.0595
0.1292	0.2665	0.1305	48.9528	30.9698	7771.2238	44.8812
0	0	0	NA	0	0	2571.8618
9.973	248.6244	11.7127	4.711	1.214	7969.5736	16.1522
2.8208	30.149	2.5843	8.5717	1.2553	7969.4473	16.1338
8.7835	218.4865	11.2937	5.169	1.9729	7965.4167	16.3163
4.7697	13.6807	4.7844	34.9721	7.611	7958.4629	16.5635
0	0	3.7523	NA	0	0	2644.9557
0	0	0.0385	NA	0	0	2645.4616
0.9805	9.8936	1.0013	10.1203	7.7004	7958.2634	16.5774
0.0977	0.1987	0.1188	59.808	11.8744	7954.9772	16.8805
0	0	0.1311	NA	0	0	2633.2957
0	0	0	NA	0	2565.3263	0

pf FLOW

V2/V1 (%)	pf A	pf B	pf C	kW Flow A	kW Flow B	kW Flow C
0.0015	0.8498	0.8427	0.838	1580.4571	1809.311	1752.9747
0.2088	0.8674	0.8623	0.8565	1575.6953	1806.2348	1743.876
0.3089	0.8682	0.8656	0.8586	1344.3375	1601.8058	1482.6379
0.3394	0.8692	0.8676	0.8603	1300.5374	1568.9705	1448.3102
0.3089	0.8833	0.8992	0.917	40.0761	30.1402	33.6184
0.3432	0.87	0.8686	0.8619	1298.7358	1544.9531	1447.9904
0.345	0.8734	0.8766	0.8812	119.8594	315.6539	200.9773
0.3461	0.8697	0.8667	0.8589	1178.6613	1229.138	1246.9655
0.3668	0.8736	0.8777	0.8789	107.7664	304.5262	173.2681
0.3677	0.8739	0.8775	0.8769	102.4174	304.5142	151.515
0.3678	0.8689	-0.0799	0.8928	5.349	0.0119	21.7531
0.3809	-1	-1	-1	0	0	0
0.4714	0.8735	0.8707	0.8631	1140.0921	1195.1526	1215.1032
0.4718	0.8703	0.8658	0.8684	712.0695	800.647	690.2474
0.4727	0.8711	0.8755	0.8713	223.4181	142.3008	278.5733
0.4721	0.8882	0.8844	0.8406	204.2579	252.041	246.0894
0.4805	0.8704	0.8664	0.8686	711.8635	779.4645	690.1703
0.4768	0.8704	0.8664	0.8686	711.792	779.4513	690.1382
0.5404	-0.0038	-0.1003	0.1056	0	0	0
0.5721	0.871	0.8715	0.8649	440.7576	375.3048	322.0443
0.5711	0.8731	0.8727	0.8648	293.2731	134.5544	238.5249
0.5719	0.8669	0.8709	0.8652	147.4439	240.7619	83.502
0.5763	-1	-1	-1	0	0	0
0.5107	-1	-1	-1	0	0	0
0.5946	0.8897	0.8722	0.8735	120.8866	129.9473	66.5753
0.5934	0.8896	0.8722	0.8738	120.8783	129.9443	64.5752

	0.5929	0.8896	0.8729	0.8737	120.8727	122.2559	64.5766
	0.5919	0.8923	0.8725	0.8766	85.7247	122.2442	50.9787
	0.5928	0.8828	-0.0877	0.8621	35.1431	0.0099	13.599
	0.5838	0.0618	0.0941	-0.1546	0	-0.0018	0.0028
	49.836	0	0.8623	-0.2553	0	3.0209	0.0066
NA		0.9291	0	0	1.7787	0	0
	0.533	0.8675	0.8753	0.8709	118.0516	105.7122	245.7587
	1.2639	0.8668	0.8856	0.8791	43.8564	177.5682	508.7365
	0.5467	0.8679	0.8753	0.8709	74.1985	105.7093	245.7518
	0.5706	0.8672	0.8748	0.8714	74.2613	102.8992	215.8611
	0.5706	0.8617	0.8699	0.8684	69.0483	96.1532	146.4653
	0.5715	0.933	0.9368	0.878	5.2243	6.7311	69.3783
	0.5773	0.9273	0.9447	0.8814	5.2405	1.0966	56.8652
	0.5798	0.1525	-0.0924	0.8814	-0.0081	0.0052	53.2874
	0.5775	0.9217	0.9196	0.8792	0.8852	1.0887	3.575
NA		0	0	0	0	0	0
	0.2027	0.8674	0.8623	0.8565	1575.6959	1806.2345	1743.8758
	0.2024	0.8765	0.871	0.8745	189.8084	192.8982	247.2446
	0.2048	0.8664	0.8615	0.8539	1385.5885	1612.6247	1496.6866
	0.2081	0.8819	0.8846	0.876	63.0834	62.2831	161.5408
NA		0	0	0.8606	0	0	76.8906
NA		0	0	0.8599	0	0	0.7877
	0.2083	0.8819	0.8846	0.89	63.0834	62.2831	83.8625
	0.2122	0.9261	0.8671	-0.0568	2.7398	1.5706	0.0014
NA		0	0	0.8601	0	0	2.6726
	0	0	0	0	0	0	0

kVAR Flow A	kVAR Flow B	kVAR Flow C
980.2917	1156.1179	1141.532
904.118	1060.7034	1050.9932
768.4928	926.5778	885.2514
739.75	899.2868	858.1904
21.2659	14.6679	14.6282
736.1879	881.3615	852.071
66.8173	173.2785	107.7932
668.9267	707.346	743.5245
60.0243	166.2396	94.0404
56.9766	166.3883	83.067
3.0477	-0.1486	10.9734
0	0	0
635.5206	675.2037	710.8971
402.9679	462.6705	394.1484
125.9318	78.5502	156.8848
105.6756	133.0068	158.5757
402.5919	449.2327	393.7029
402.4412	449.008	393.533
-0.003	-0.0027	-0.0027
248.6105	211.181	186.9282
163.7406	75.2687	138.5139
84.785	135.8595	48.387
0	0	0
0	0	0
62.0248	72.8681	37.0982
62.046	72.8788	35.9416

62.063	68.3221	35.9626
43.3819	68.4443	27.9884
18.6962	-0.1121	7.9934
-0.0158	-0.0193	-0.0179
0	1.774	-0.0249
0.7079	0	0
67.6977	58.3967	138.6665
25.2285	93.1255	275.851
42.4745	58.4064	138.6507
42.6478	56.9816	121.4951
40.6686	54.5054	83.6167
2.0144	2.5146	37.8295
2.1153	0.3805	30.4788
-0.0525	-0.0563	28.5605
0.3725	0.4652	1.937
0	0	0
904.1216	1060.7072	1050.9963
104.2233	108.7893	137.1452
798.7348	950.3567	912.2053
33.7157	32.8395	88.9252
0	0	45.5001
0	0	0.4675
33.7157	32.8395	42.9576
1.1161	0.9025	-0.024
0	0	1.5853
0	0	0

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14. ABSTRACT *(Maximum 200 Words)*
This paper is a final report on a project to (1) explain how voltage regulation reduces voltage spread; (2) define the effects of unbalanced loading and voltage on system protection and distributed generation output ratings; (3) develop models for an actual distribution circuit, its voltage regulation equipment, and distributed generation; (4) validate the models by comparing power flow simulations and voltage profiles with actual measured circuit data; (5) determine the optimum generator operating conditions to provide the greatest improvement in released capacity, reduced energy losses, and voltage regulation, and (6) determine the maximum distributed generation penetration limits with synchronous generator real and reactive power injections.

15. SUBJECT TERMS
distributed generation; DG; distributed resources; DR; interconnection; voltage regulation; modeling; penetration limit; National Renewable Energy Laboratory; NREL; DTE Energy

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