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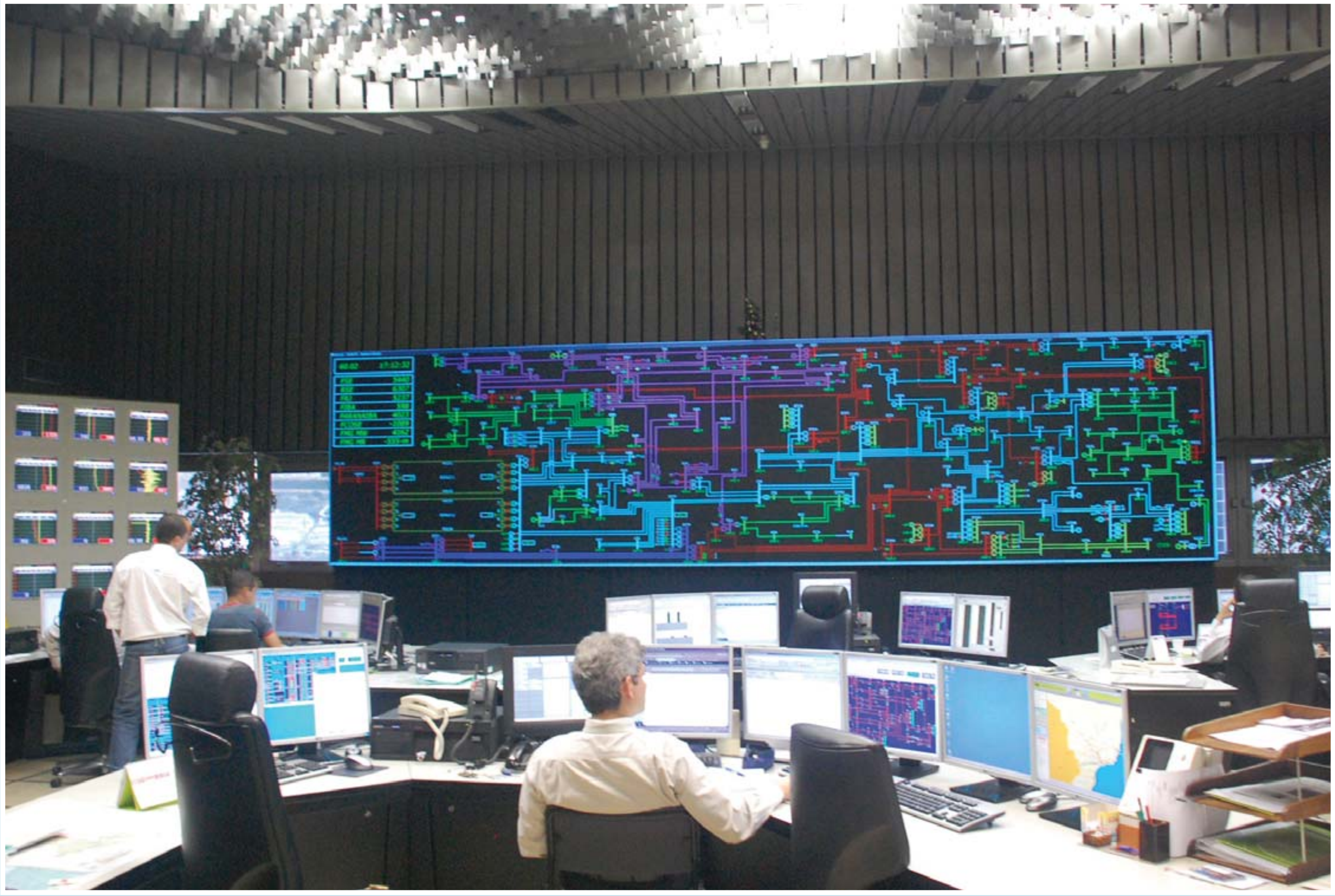
EPRI Power System Dynamics Tutorial without Q/A Section



EPRI Power Systems Dynamics Tutorial without Q/A Section

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REPORT SUMMARY

Operation of today's increasingly complex power systems requires comprehensive training of system dispatchers and operations engineers. By increasing awareness and understanding of dynamic phenomena, EPRI's Power System Dynamics Tutorial can improve an operator's ability to take effective preventive and corrective actions. This latest version of the tutorial represents a complete update of key topics to reflect industry restructuring under the vision of the Federal Energy Regulatory Commission (FERC) as well as current operating procedures and guidelines issued by the North American Electric Reliability Council (NERC). In addition, a new section on system reliability focuses on restoration of the power grid following a blackout.

Background

EPRI developed the first system dynamics tutorial in 1989, with the aim of enhancing training of power system dispatchers. Addressing industry concerns, the tutorial was designed as an easily understandable supplement to utility-specific training materials. Earlier versions of the tutorial were very well received, with thousands of copies in use by power system operators throughout North America. A number of important industrywide changes led to revision of the 1998 tutorial. First, the formation of regional transmission organizations has dramatically increased the geographical area over which an operator has responsibility, with blackouts in one power system potentially affecting a huge portion of North America at one time. Cost-effective training has thus become more and more critical to system reliability. In addition, current NERC requirements that operators be certified via standard examinations coupled with new operating procedures and guidelines also factored into EPRI's decision to revise the tutorial. Finally, and most importantly, comprehensive information was needed to help operators understand how to cost-effectively restore a system following a blackout. This edition substantially revises the earlier tutorials and incorporates many suggestions and requests from tutorial users.

Objective

To address the current needs of North American system dispatchers and operations engineers through a comprehensively updated power system dynamics tutorial.

Approach

In revising the tutorial, the author incorporated material from seminar presentations coupled with industry knowledge and experience. Some unique design features were employed to enhance the effectiveness of the tutorial, both as a training tool and as a reference source. The revised edition features larger margins to accommodate annotation, margin notes to emphasize key concepts, and improved illustrations. The author also added a new section on power grid restoration to address the risk of systemwide blackouts that could impact tens of thousands of customers.

Results

This revised edition includes a tutorial overview and introductory review of power system fundamentals, followed by chapters on active and reactive power flow, frequency and voltage control, voltage and angle stability, and power system oscillations. The tutorial includes chapters on harmonics, resonance, subsynchronous resonance, ferroresonance, and solar magnetic disturbances. An entire chapter is devoted to the construction and operation of high-voltage direct-current systems and phase shifting transformers. This edition has been expanded to explain the causes of power system shutdowns, with emphasis on the theory of power system restoration and the methods used in such restoration. Topics of great interest in this area include voltage and frequency control, equipment and protective relay issues, and synchronizing issues that may be encountered during power system restoration. Also discussed are possible strategies to employ during system restoration along with lessons learned from actual restoration events occurring in North American power systems. Like its predecessors, this edition uses a direct style, relying on physical analogies, intuitive reasoning, and actual case histories rather than on complex engineering terminology and numerous mathematical equations. This tutorial supersedes EPRI reports EL-6360-L and TR-107726-R1.

EPRI Perspective

Thousands of readers in the power system community have benefited from earlier editions of this tutorial as a training tool and reference source on power system operation and engineering. This tutorial—which has become something of an industry phenomenon over the past 13 years—provides a comprehensive overview of the knowledge operators will need in understanding power system dynamics. EPRI's goal with this tutorial is to ensure that operators acquire the necessary knowledge to exercise critical judgment in emergency situations falling outside the scope of step-by-step utility procedures. To assist in this endeavor, EPRI plans to supplement the tutorial later with a companion CD featuring training exercises on generic power systems using the EPRI Operator Training Simulator. EPRI believes that such training—together with application of the tutorial—will promote operator proficiency while supporting economic and reliable power system operation.

Keywords

Power System Operation
Power System Control
Training
Operators
Power System Engineering

ABSTRACT

Significant industry restructuring under the vision of the Federal Energy Regulatory Commission (FERC) is leading to the formation of large regional transmission organizations, which have dramatically increased the geographical area over which an operator has responsibility. Consequently, blackouts in one power system can potentially impact a huge portion of North America at one time—making cost-effective training more and more critical to system reliability. The EPRI Power System Dynamics Tutorial represents a complete update of key topics to reflect this restructuring as well as current operating procedures and guidelines issued by the North American Electric Reliability Council (NERC). This revised edition includes a tutorial overview and introductory review of power system fundamentals, followed by chapters on active and reactive power flow, frequency and voltage control, voltage and angle stability, and power system oscillations. The tutorial includes chapters on harmonics, resonance, subsynchronous resonance, ferroresonance, and solar magnetic disturbances. An entire chapter is devoted to the construction and operation of high-voltage direct-current systems and phase shifting transformers. Finally, and most importantly, this edition has been expanded to explain the causes of power system shutdowns, with emphasis on the theory of power system restoration, methods used in such restoration, and lessons learned from actual restoration events occurring in North American power systems. EPRI plans to supplement this tutorial later with a companion CD featuring training exercises on generic power systems using the EPRI Operator Training Simulator. Such training—together with application of the tutorial—will promote operator proficiency while supporting economic and reliable power system operation

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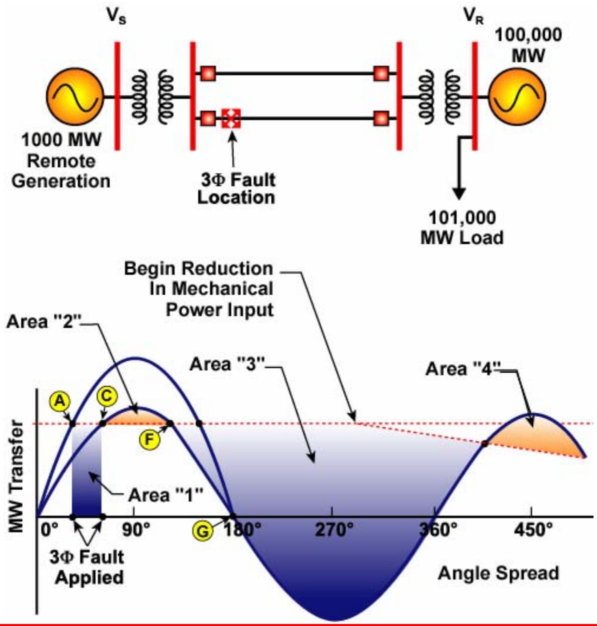

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1. Introduction

This chapter summarizes the contents of the remaining 10 chapters in this tutorial.

2. Fundamentals Review

Chapter 2 provides a review of the basic concepts a reader must understand to gain the maximum benefit from the remainder of the Tutorial. Chapter 2 addresses the following topics:

2.1 Introduction to Fundamentals Review

A brief review of Chapter 2 content.

2.2 Mathematics Review

Review of basic math concepts of use to a system operator.

2.3 DC Electricity Review

Review of DC electrical theory. Topics addressed include current, voltage, resistance, electrical circuits, Ohm's law, Kirchhoff's laws, power and energy.

2.4 AC Electricity Review

Review of AC electrical theory. Topics addressed include the advantages of AC over DC, frequency, vector and phasor diagrams, magnetism and magnetic fields, AC impedance, phase angle, and AC power.

2.5 Protective Relaying Review

Review of basic concepts of power system protection.

2.6 Power System Equipment Review

Review of the function of key types of power system equipment such as transformers, circuit breakers, etc.

2.7 Power System Operations

A brief review of the fundamentals of interconnected power system operations.

3. Active and Reactive Power

Chapter 3 describes the concepts of active, reactive, and complex power. The chapter also derives simple equations that show the dependence of power flow on parameters such as voltage, angle, and impedance. Chapter 3 addresses the following topics:

3.1 Introduction to Active and Reactive Power

A brief review of Chapter 3 content.

3.2 Review of Active and Reactive Power

A review of active, reactive and complex power, and phase, power and torque angles.

3.3 Equations for Power Transfer

Equations are developed for active and reactive power transfer.

3.4 Graphical Tools for Power Transfer

Graphical techniques are developed to analyze power flow including the usage of the power-angle curve to help determine angle stability and the usage of a power-circle diagram to illustrate active and reactive power flow.

3.5 Power Transfer Limits

Active power transfers are constrained by thermal, angle stability, and voltage limits.

3.6 Distribution Factors

Distribution factors are calculated to estimate how MW flow will distribute in the power system.

4. Frequency Control

Chapter 4 describes the cause, effect, and control of frequency deviations. Chapter 4 addresses the following topics:

4.1 Introduction to Frequency Control

The load/frequency effect and system inertia help control frequency deviations caused by a generation-to-load mismatch.

4.2 Governor System Components and Operation

Generating unit governors adjust the MW output of units in the power system in response to frequency deviations.

4.3 Automatic Generation Control (AGC)

AGC calculates an area control error (ACE) signal which is used to adjust the output of regulating units and restore frequency to 60 HZ.

4.4 Reserve Policies

Reserve policies ensure sufficient MW capability to control normal frequency deviations and survive large disturbances.

4.5 Time Error Control

Accumulated time error is corrected by changes to the scheduled frequency.

4.6 NERC Control Performance

NERC has developed performance standards that apply during normal and disturbance conditions.

4.7 Impact of Frequency Deviations

Substantial frequency deviations for prolonged periods can be damaging to power system equipment and performance.

4.8 Underfrequency Protection

Underfrequency protection includes underfrequency load shedding and underfrequency generator tripping.

4.9 Nature of a Frequency Deviation

A frequency deviation includes an undershoot, which varies according to location, and a stabilization point, which is the same everywhere.

4.10 Staged Response to a Generation Loss

A four-stage process describes the response of the system to a generation loss.

4.11 Role of the System Operator

An experienced power system operator uses system frequency and other data to effectively diagnose power system problems.

5. Voltage Control

Chapter 5 describes the cause, effect, and control of voltage deviations. Chapter 5 addresses the following topics:

5.1 Introduction

Voltage Control is closely related to the availability of reactive power.

5.2 Causes of Low Voltage

Heavy power transfers are a major cause of low voltage due to the Mvar usage.

5.3 Causes of High Voltage

Lightly loaded transmission lines are a major cause of high voltage.

5.4 Effects of Low Voltage

Low voltages can impact power system equipment and operations in numerous ways.

5.5 Effects of High Voltage

High voltages can lead to the breakdown of equipment insulation, cause transformer saturation, and adversely affect customer equipment.

5.6 Use of Voltage Control Equipment

Capacitors, reactors, ULTCs, and SVCs supplement the system generators as means of controlling system voltage.

5.7 Role of the System Operator

The system operator is usually responsible for maintaining reactive reserves and controlling voltage deviations.

6. Voltage Stability

Chapter 6 explains the concepts of voltage stability and voltage instability. Voltage instability and voltage collapse are possible results of a shortage of reactive power. Chapter 6 addresses the following topics:

6.1 Voltage Stability

Introduction to an extreme type of voltage deviation that could result in a voltage collapse.

6.2 Definitions

Definitions of voltage collapse and voltage stability are presented.

6.3 Types of Voltage Collapse

Long term voltage collapse, classical voltage collapse and transient voltage collapse.

6.4 Long Term Voltage Collapse

Description of a long term voltage collapse.

6.5 Classical Voltage Collapse

Description of a classical voltage collapse.

6.6 Transient Voltage Collapse

Description of a transient voltage collapse.

6.7 Preventing Voltage Collapse

Techniques to prevent voltage collapse.

6.8 Role of the System Operator

A system operator may be able to recognize the conditions during which a voltage collapse can occur and take appropriate actions.

7. Angle Stability

Chapter 7 describes and provides simple examples of three types of power system angle stability including steady state, transient and oscillatory stability. Chapter 7 addresses the following topics:

7.1 Introduction to Angle Stability

Angle stability is related to the phase angle separation between power system buses.

7.2 Definition of Angle Stability

In an angle stable system the torque and power angles are controllable. In an angle unstable power system angles and power flows are out of control.

7.3 Active Power Transfer and the Power Angle Curve

The power angle curve is used to determine the angle at which the mechanical input to the power system is equal to the electrical power transferred out of the generator.

7.4 Types of Angle Stability

Angle instability can occur in steady state, transient, or dynamic environments.

7.5 Steady State Stability/Instability

Steady state angle instability develops gradually over time without any sudden disturbance.

7.6 Transient Stability/Instability

Transient instability arises rapidly, in the first few seconds after a disturbance.

7.7 Dynamic Stability/Instability

Dynamic angle instability is characterized by power and voltage oscillations.

7.8 Out-of-Step Protection

Out-of-step protection is provided by protective relays that measure the apparent impedance and the time it takes for the impedance to change.

7.9 Angle Instability Example

An example of angle instability is presented that occurred in the summer of 1998 in the MAPP power system.

7.10 Role of the System Operator

The system operator can avoid angle stability problems by adhering to their system's operating guidelines.

8. Power Oscillations

Chapter 8 describes the cause, effect, and control of power oscillations. Chapter 8 addresses the following topics:

8.1 Introduction to Power Oscillations

Low frequency power oscillations may be triggered by many events in the power system. Most oscillations are damped by the system, but undamped oscillations can lead to a system collapse.

8.2 Power Oscillations on a Sample System

Oscillations develop as a result of rotor acceleration and/or deceleration following a change in the MW output of a generator.

8.3 Natural Frequency of Oscillation

Low frequency inter-area oscillations are less damped than higher frequency local area oscillations and are more likely to cause power system problems.

8.4 Oscillations and Excitation Systems

PSS or power system stabilizers are used to correct the harmful effects of fast excitation systems and help reduce system oscillations.

8.5 Additional Causes of Oscillations

Large cyclic loads, incorrect governor droop settings, HVDC systems and generator pole slipping may lead to power oscillations.

8.6 Role of the System Operator

To prevent oscillations, the system operator should hold power transfers within established limits and maintain strong system voltages and adequate reactive reserve margins.

9. Additional Topics

Chapter 9 introduces harmonics, resonance, and solar magnetic disturbances (SMDs). Chapter 9 addresses the following topics:

9.1 Additional Topics

Introduction to the varied topics addressed in Chapter 9.

9.2 Harmonics

Harmonics are integer multiples of the fundamental frequency.

9.3 Resonance

When electrical circuits resonate, high currents and voltages can develop.

9.4 Subsynchronous Resonance

Subsynchronous resonance arises due to an interaction between the power system and the natural oscillations of a turbine/generator.

9.5 Ferroresonance

Ferroresonance is a resonance condition due to a tuning between a circuit's capacitance and iron-core inductance.

9.6 Solar Magnetic Disturbances

Solar magnetic disturbances can lead to geomagnetic induced currents (GICs) that enter the power system through ground connections.

10. Equipment

Chapter 10 describes the construction and operation of high voltage direct current (HVDC) systems and phase shifting transformers (PSTs). Chapter 10 addresses the following topics:

10.1 HVDC Construction and Operation

High voltage direct current (HVDC) systems are used throughout the world.

10.2 Phase Shifting Transformers

Phase shifting transformers (PSTs) are used to control the flow of MW in a transmission path.

11. Power System Restoration

Chapter 11 explains the causes of power system shutdowns and describes how power systems are restored. Chapter 11 addresses the following topics:

11.1 Introduction to Power System Restoration

An introduction to the theory of power system restoration and the methods used to restore a power system.

11.2 Voltage Control and System Restoration

An explanation of voltage control theory and practice during power system restoration.

11.3 Frequency Control and System Restoration

An explanation of frequency control theory and practice during power system restoration.

11.4 Equipment Issues Related to System Restoration

A description of the unique equipment issues that may be encountered during power system restoration conditions.

11.5 Protective Relay Issues Related to System Restoration

A description of the unique protective relay issues that may be encountered during power system restoration conditions.

11.6 Synchronizing and System Restoration

An explanation of the synchronizing issues that may be encountered during power system restoration conditions.

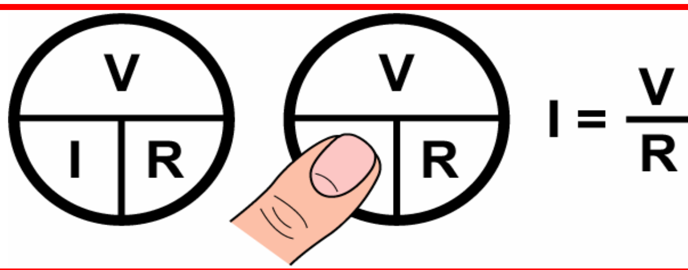
11.7 Power System Restoration Strategies

A description of the possible strategies to utilize during power system restoration events.

11.8 Lessons Learned from Actual System Restorations

A summary of the lessons learned from actual restoration events that have occurred in North American power systems.

2
FUNDAMENTALS REVIEW



2.1 Introduction to Fundamentals Review

This chapter serves as a review of the basic concepts the reader must understand to gain the maximum benefit from the remainder of this text.

2.2 Mathematics Review

Review of basic math concepts of use to a system operator.

2.3 DC Electricity Review

Review of DC electrical theory. Topics addressed include current, voltage, resistance, electrical circuits, Ohm's law, Kirchhoff's laws, power and energy.

2.4 AC Electricity Review

Review of AC electrical theory. Topics addressed include the advantages of AC over DC, frequency, vector and phasor diagrams, magnetism and magnetic fields, AC impedance, phase angle, and AC power.

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2.6 Power System Equipment Review

Review of the function of key types of power system equipment such as transformers, circuit breakers, etc.

2.7 Power System Operations

A brief review of the fundamentals of interconnected power system operations.

2.1 Introduction to Fundamentals Review

This chapter serves as a review of the basic concepts the reader must understand to gain the maximum benefit from the remainder of this text. The chapter is divided into six sections. The sections and a brief description of each are:

- Mathematics Review—A review of math concepts useful to a system operator. Topics addressed include solving right triangles, basic trigonometry and the per-unit system.
- DC Electricity—A review of DC electrical theory. Topics addressed include current, voltage, resistance, electrical circuits, Ohm's law, Kirchhoff's laws, power, and energy.
- AC Electricity—A review of AC electrical theory. Topics addressed include frequency, the use of vector and phasor diagrams, AC impedance, phase angle, AC power and magnetism.
- Protective Relaying—A review of the methods and equipment used for power system protection. Topics addressed include instrument transformers, voltage relays, current relays, impedance relays, differential relays, and synchronizing equipment.
- Power System Equipment Review—A review of key equipment used in the power system. Topics addressed include AC machines, transmission lines, transformers, circuit breakers and thyrister based equipment.
- The Interconnections and NERC—This section describes how the North American power system is divided into Interconnections, and reviews the role of NERC and the Regional Councils.

2.2 Mathematics Review

This section reviews basic math concepts of use to a system operator. Topics addressed include right triangles, basic trigonometry and the per-unit system.

2.2.1 Right Triangles

In order to understand the basic concepts of AC power, the reader must be familiar with the relationships between the angles and sides of a right triangle. A right triangle is a triangle in which one of the three angles is a right angle (90°). Figure 2-1 illustrates two right triangles. Note that the two triangle sides, which form the right angle, are designated as the adjacent side and the opposite side with respect to the angle θ. The remaining side of a right triangle is called the hypotenuse. Figure 2-1 illustrates how the designation of the adjacent and opposite sides is related to the angle designated as θ.

"θ" is the Greek letter "theta". Throughout this text, Greek letters are used to refer to angles.

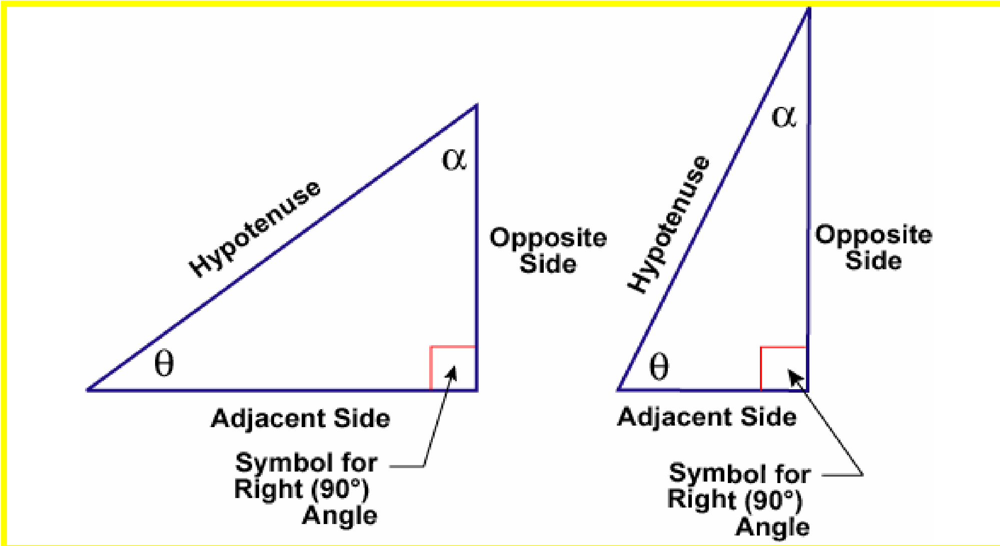


Figure 2-1
Right Triangles

Given the lengths of two of the sides of a right triangle, the third side length is determined by using the Pythagorean theorem. The Pythagorean theorem states that the square of the hypotenuse is equal to the sum of the squares of the remaining two sides. For example, given a right triangle whose hypotenuse is five, and one of the other side lengths is four, the Pythagorean theorem is used to determine the length of the remaining side.

$$\text{Hypotenuse}^2 = \text{Opposite}^2 + \text{Adjacent}^2$$
$$5^2 = 4^2 + \text{Adjacent}^2$$
$$25 = 16 + \text{Adjacent}^2$$
$$25 - 16 = \text{Adjacent}^2$$
$$\sqrt{25-16} = \text{Adjacent}$$
$$\text{Adjacent} = \sqrt{9} = 3$$

As can be seen in the example above, given a right triangle and the lengths of two of the sides, solving for the third side is a simple process. Now that the three side lengths are known, the next step in solving the right triangle is to determine the two unknown angles of the triangle. The fact that the three angles of any triangle always sum to 180°, and that one of the angles of a right triangle is 90°, simplifies this process. Once one of the unknown angles is determined, the remaining angle can be found by subtracting the known angle from 90°. To find the first unknown angle a few basic trigonometric functions must be applied.

2.2.2 Trigonometric Functions

Sine

The sine function is a periodic function. A periodic function continually repeats itself. Figure 2-2 illustrates one cycle or repetition of the sine function. Note that the value of the sine function ranges between maximum and minimum values of +1 and –1. The sine function value is zero at 0°, 180° and 360°. (360° is the same as 0° for the next cycle of the sine function.) In order to solve right triangles, it is only necessary to know the value of the sine function between 0° and 90°.

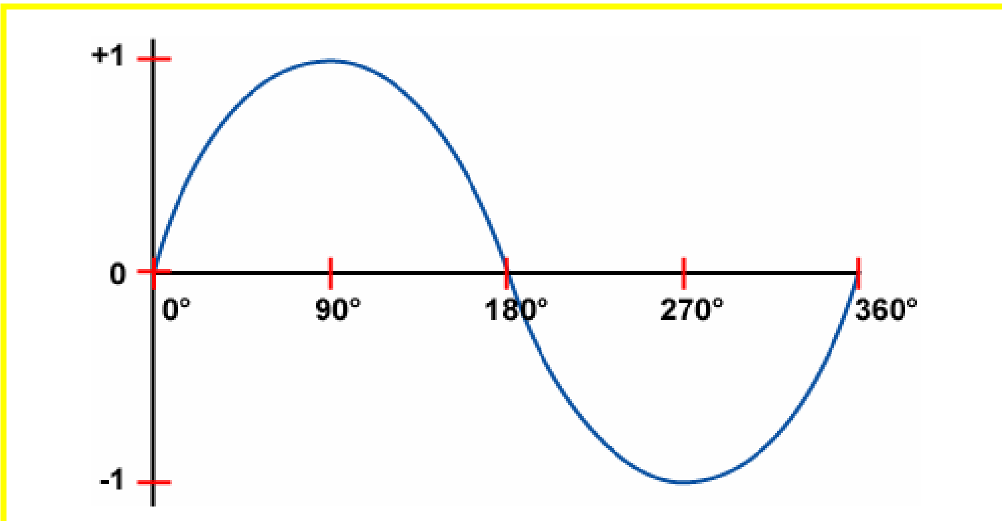


Figure 2-2
Sine Function

The reader does not have to memorize sine function values as most pocket calculators include basic trigonometric functions such as the sine and cosine functions.

A sine function value can also be determined by accurately drawing a right triangle. For example, assume we want to determine the sine of 30° and further assume a calculator is not available. A simple method is to accurately draw a right triangle with one of the angles (θ) equal to 30°, as illustrated in Figure 2-3. Then, the sine of 30° is determined by measuring the lengths of the two sides, and taking the ratio of the side opposite the 30° angle to the hypotenuse. The sine of 30° is determined to be 0.5 in this manner.

The sine of either of the unknown angles of a right triangle is the ratio of the opposite side to the hypotenuse.

Cosine

Figure 2-4 illustrates one cycle of the cosine wave. It is important to note that the cosine function is identical to the sine function except that the cosine leads the sine function by 90°. When we say the cosine function "leads" by 90°, we mean that the cosine function will reach a certain value 90° before the sine

The cosine of either of the unknown angles of a right triangle is the ratio of the adjacent side to the hypotenuse.

function reaches that same value. For example, the value of the cosine function at 0° is one whereas the sine function does not reach one until 90°.

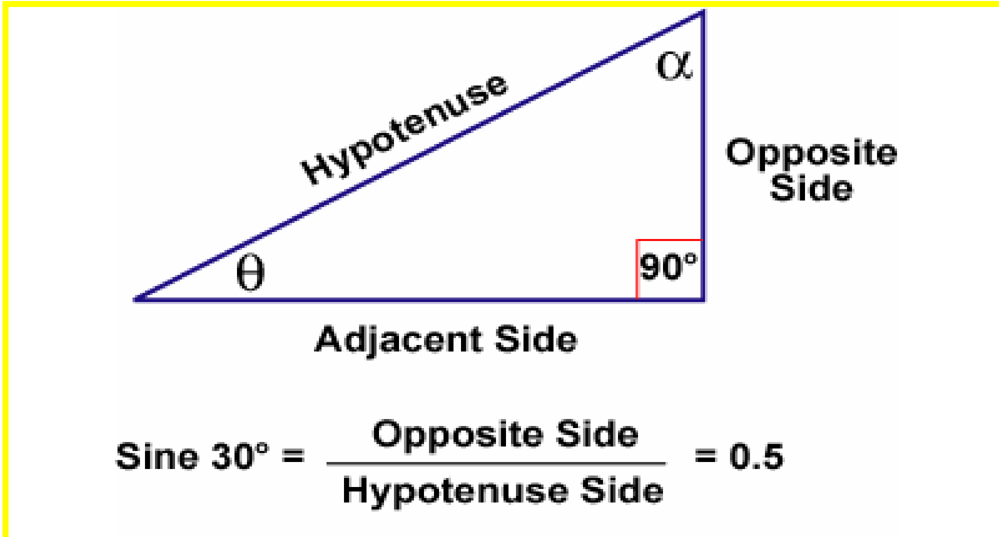


Figure 2-3
Right Triangle and the Sine Function

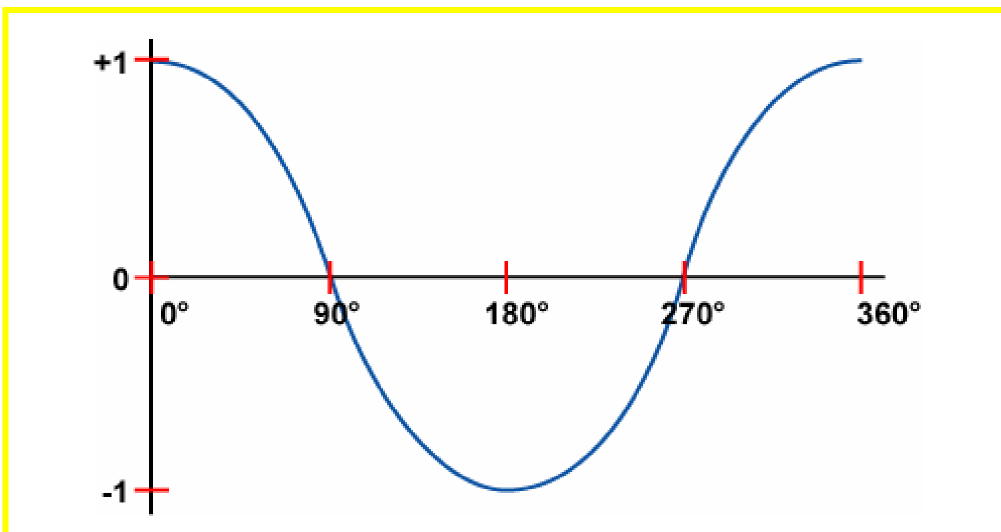


Figure 2-4
Cosine Function

Solving Right Triangles

Given an understanding of the Pythagorean theorem and basic trigonometric functions, one can often determine all the sides and angles of a right triangle. In many power system applications of trigonometry, the length of the hypotenuse and either one angle or one other side length is typically known.

Figure 2-5 and the example box below the figure demonstrate various solutions of a right triangle. To find the angle θ, using the trig functions, you could use the inverse (or arc) function on a calculator. For instance, in the Figure 2-5 example, the sine of θ equals 3/5 or 0.6. This is the same as saying that θ equals the inverse sine (or the arcsine) of 0.6. By taking the inverse sine of 0.6 on a calculator, you should find that θ equals 36.9°. The only remaining angle to determine is α. This angle can be found using trigonometry relationships similar to those used to find θ. However, by remembering that the sum of the angles in a triangle always equals 180°, you can quickly determine that α=53.1° (180°-90°-36.9°=53.1°).

Taking the arcsine (also referred to as the $\sin^{-1}$) of a number "X" will yield the angle whose sine is "X".

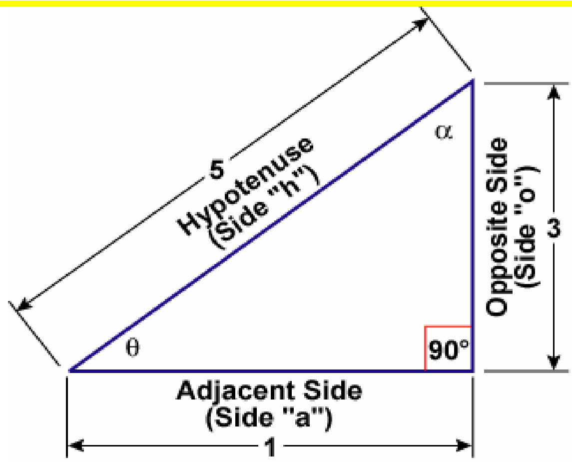


Figure 2-5
Solving a Right Triangle

Example 1:

Given: Side h = 5 and Side a = 4

Find Side o, Angle θ, and Angle α

Solution:

To Find Side o, Simply Apply the Pythagorean Theorem:

$$\text{Side h}^2 = \text{Side a}^2 + \text{Side o}^2$$

$$25 = 16 + \text{Side o}^2$$

$$25 - 16 = \text{Side o}^2$$

$$\text{Side o}^2 = 9$$

$$\text{Side o} = \sqrt{9} = 3$$

To Find θ, We Use Either One of the Trig Functions. That is:

$$\text{Sin } \theta = \text{Side o/Side h} = 3/5 = 0.6 \rightarrow \text{Therefore Using the Arcsine } \theta = 36.9^o$$

$$\text{Cos } \theta = \text{Side a/Side h} = 4/5 = 0.8 \rightarrow \text{Therefore Using the Arccosine } \theta = 36.9^o$$

The Angle α is all That is Left:

$$180^o - 90^o - 36.9^o = \alpha = 53.1^o$$

2.2.3 Use of Ratios

The ability to use ratios can be very helpful to a system operator in estimating power system performance. A ratio is simply a relationship between two numbers expressed as a fraction. Usually ratios are used when the relationship of two pairs of values is the same, and one of two similarly related values is known.

The magnitude of a frequency deviation following a generation loss is described in Chapter 4 in detail.

A system operator can use ratios to estimate power system performance. For example, assume a system operator knows by experience that the loss of a 1000 MW unit typically results in a 0.2 HZ dip in system frequency. The system operator desires an estimate of the frequency dip due to the loss of an 800 MW unit. This estimate can be done using a ratio. The thought process would be as follows: 1000 MW is to 0.2 HZ as 800 MW is to ? HZ. The ratio and cross multiplication would be:

$$\frac{1000\,\text{MW}}{0.2\,\text{HZ}} = \frac{800\,\text{MW}}{?\,\text{HZ}}$$

$$800\,\text{MW x } 0.2\,\text{HZ} = 1000\,\text{MW x } ?\,\text{HZ}$$

$$? = \frac{800\,\text{MW x } 0.2\,\text{HZ}}{1000\,\text{MW}} = 0.16\,\text{HZ}$$

When using ratios, it is important to remember that ratios only provide exact answers in linear systems. A "linear" system means that the relationship between two variables in the system is the same regardless of the magnitude of the two variables. Referring back to our previous example with the frequency, as long as the frequency drops in proportion to the MW loss, regardless of the size of MW loss, ratios can be used. Few power system dynamic events, including the frequency, are truly linear. However, this method at least provides an approximate means to estimate the power system's performance based on past events.

2.2.4 Per-Unit Values

Very often, quantities on the power system are specified as a percent or per-unit of their base or nominal value. For example, suppose the voltage at a 345 kV bus is measured to be 349 kV. If we assume that the base (or nominal) bus voltage is 345 kV, then we can say that the measured voltage is 101% (349/345) percent of nominal, or 1.01 per-unit. Using per-unit values makes it very easy to judge where a system value is with respect to its base value. Per-unit values also makes it easy to compare values between parts of the system with different base values.

Per-Unit Voltages

Figure 2-6 illustrates the use of the per-unit system in a simple power system. The base voltages are 20 kV for the generator, 345 kV for the transmission and 138 kV for the subtransmission. The actual and per-unit voltages are given in the figure.

The per-unit system allows an observer to view a system and rapidly obtain a feel for the voltage profile. For example, Figure 2-6 per-unit data illustrates that the voltage of the lowest magnitude 345 kV bus is 3.2% lower than any other 345 kV bus.

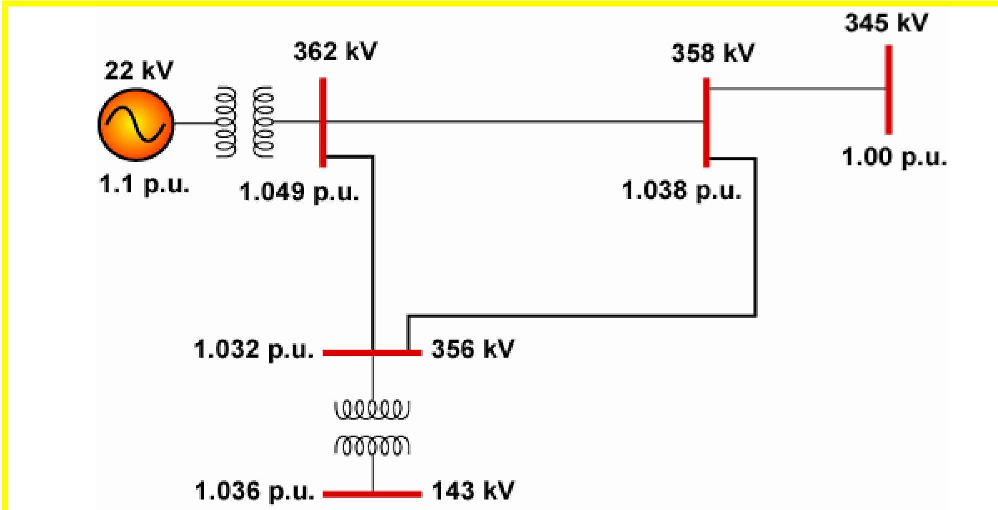


Figure 2-6
Example of the Usage of the Per-Unit System

Per-Unit Impedances

The concept of impedance is explained and illustrated in the two sections (2.3 and 2.4) that follow this section. In these later sections, we will learn that impedance is stated in ohms and is a measure of an element's ability to impede or restrict the flow of current. In general, the greater an element's impedance, the less current that will flow through the element. The only purpose in bringing up the concept of impedance at this point is with respect to per-unit quantities.

The impedance of an element (for example a transformer) is often stated as a per-unit value. For example, a large power transformer may have an impedance of 5%. Stating the impedance in a percentage form is a variation of the per-unit system. To convert from a % impedance value to a per-unit value simply divide the % value by 100. Therefore, a transformer with a 5% impedance has a 0.05 p.u. (5/100) impedance.

To convert from a p.u. impedance value to the actual impedance stated in ohms, multiply the p.u. value by the base impedance. The base impedance is dependent on the voltage level the equipment operates at and the rating (in MVA) of the equipment. The base impedance is equal to the voltage squared divided by the MVA. For example, assume a 345 to 138 kV transformer has a 5% or .05 p.u. impedance. Further, assume the transformer is rated at 100 MVA. To calculate the transformer's impedance in ohms you would first determine the base impedance and then multiply by the per-unit impedance as illustrated in the following example box. Note in this example, that you would calculate the base impedance and the actual ohms differently depending on which voltage level you wished to state the impedance.

$$\text{345/138 kV Transformer}$$
$$\text{Impedance Equals } 5\% = 0.05\,\text{p.u.}$$
$$\text{Rating } = 100\,\text{MVA}$$
$$\text{345 kV Base Ohms} = \frac{\text{kV}^2}{\text{MVA}} = \frac{345^2}{100} = 1190.3\,\Omega$$
$$\text{138 kV Base Ohms} = \frac{138^2}{100} = 190.4\,\Omega$$
$$\text{Actual Ohms On a 345 kV Base} = .05 \times 1190.3 = 59.5\,\Omega$$
$$\text{Actual Ohms On a 138 kV Base} = .05 \times 190.4 = 9.5\,\Omega$$

The Greek letter Ω (Omega) is used to represent the ohms of impedance.

2.3 DC Electricity Review

This section reviews DC electricity. Topics addressed include current, voltage, resistance, electrical circuits, Ohm's law, Kirchhoff's laws, and power and energy.

The fundamental concept of an electrical charge is used to describe many electrical phenomena. Electrical charge can be either positive or negative, and consists of individual quantities equal to the charge of one electron. Electrical effects are associated with the separation of charge, and with charge in motion. The separation of charge creates an electrical force referred to as voltage. The flow of charge is referred to as a current.

2.3.1 Current

Definition of Current

Electrical current is the rate of flow of electrical charge through a conductor. Figure 2-7 illustrates how the electrical charge in a conductor is carried by the electrons in the conductor. Current is measured as the amount of charge passing through a cross section of a conductor over time. Specifically, current is measured in amperes (amps). One ampere of current is equivalent to $6.24\text{x}10^{18}$ (6.24 billion-billion) electrons passing through a cross section of the conductor per second.

The $6.24\text{x}10^{18}$ represents a very large number equal to 6.24 times a 1 with 18 trailing zeros. $6.24\text{x}10^{18}$ is simply a shorthand way of writing this large number.

Current Flow

Electrons in a conductor (like water in a river) need some force to cause a current flow to occur. The force that causes water to flow in a river is gravity. The source of the river is higher than the mouth, and therefore the water flows downhill driven by gravity. The force that causes charge to flow in a conductor is the voltage. Voltage is the separation of charge between two points on a conductor. This separation of charge is represented in Figure 2-7 as a battery connected in series with a conducting path. Electrons have a negative charge and are drawn towards the positive end of the battery. Figure 2-7 illustrates a negative charge flowing from the negative terminal of the battery to the positive terminal of the battery.

Electrons carry a negative charge and are attracted towards the positive terminal of the battery. As the negative charge moves, a positively charged "hole" is left. These holes can be reviewed as moving towards the negative terminal. Conventional current flow is typically thought of as a movement of holes from the positive to the negative terminal.

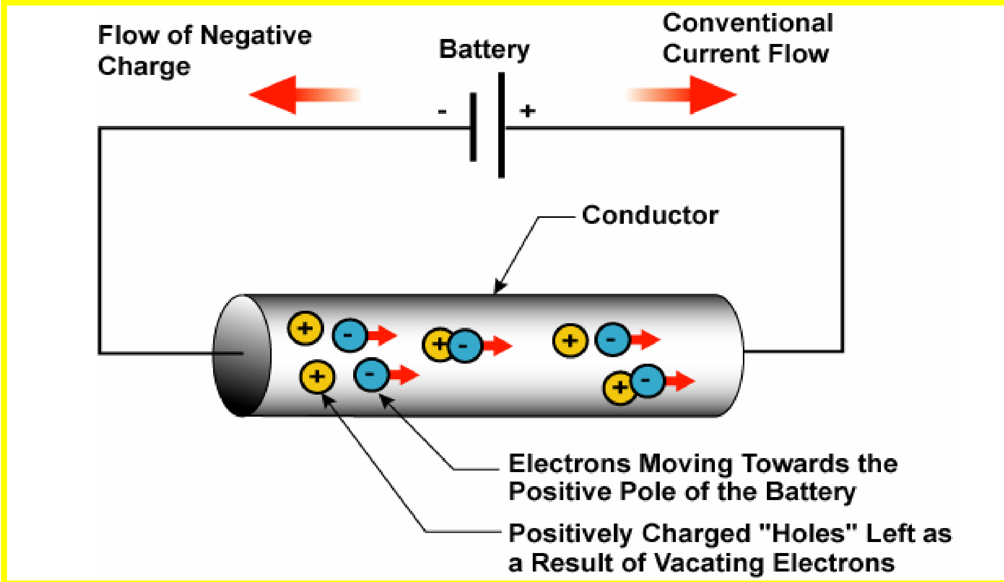


Figure 2-7
Current Flow

Note in Figure 2-7 that the current is shown to be flowing in the opposite direction of the charge flow. The accepted convention in the electric power industry is to designate the current flow as being from the positive to the negative terminal of the voltage source. The electrical current that we have described so far is referred to as direct current (DC) because it flows in one direction. Later we will examine a current that constantly oscillates. This type of current is called alternating current (AC).

Path of Least Resistance

Electrical current flow will always seek the path of least resistance. The flow of current is analogous to the flow of water. Assume you have a piping arrangement as given in Figure 2-8. A pipe with a three ft^2 cross section is feeding two pipes with cross sections of one ft^2 and two ft^2 respectively. It should be apparent that more water would flow into the two ft^2 pipe than the one ft^2 pipe. This is because there is less resistance to the flow in the bigger pipe. The water from the 3 ft^2 pipe will flow into the other two pipes in inverse proportion to the amount of resistance offered by each pipe. Specifically, 2/3 of the water will flow into the two ft^2 pipe, and 1/3 of the water will flow into the one ft^2 pipe.

Electrical current will likewise flow proportionally through the conducting paths that offer the least resistance. When current in a circuit encounters multiple paths, it will divide and flow along those paths in inverse proportion to the paths' resistance.

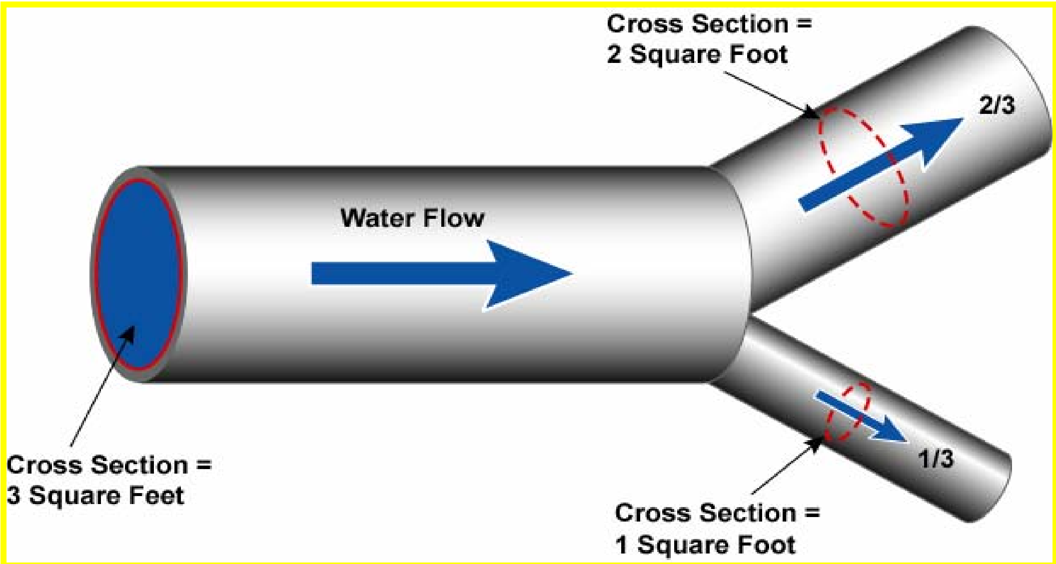


Figure 2-8
Waterflow Analogy

2.3.2 Resistance

Resistance is a measure of the opposition of an electrical circuit to the flow of current. Every component of the power system has a resistance associated with it. The resistance of a component is measured in ohms. The Greek letter omega (Ω) is the symbol used for ohms.

The resistance of a given component is a function of:

- The resistivity of the material that the component is made of
- The length of the component
- The cross sectional area of the component

Definition of Resistance

Referring to Figure 2-9, resistance is defined as:

"p" is the Greek letter "rho" pronounced "row".

$$R = \frac{\rho \times L}{A}$$

Where:

R = Resistance in Ohms (Ω)

ρ = Resistivity of the Material

L = Length of the Material

A = Cross-Sectional Area of the Material

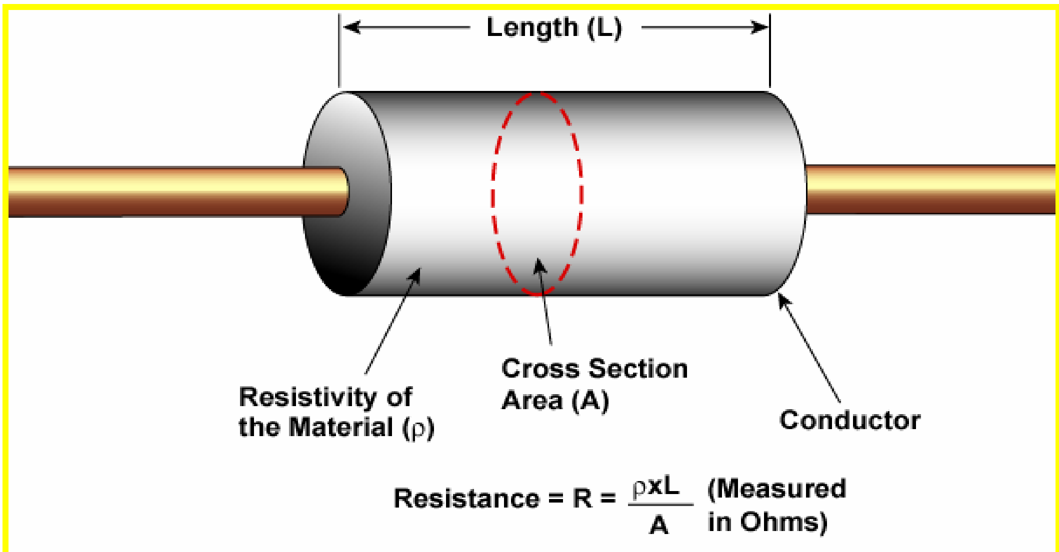


Figure 2-9
Resistance of a Conductor

Why is aluminum used in transmission lines if copper is a better conductor? The answer is that aluminum is much lighter than copper, therefore reducing the construction cost of a transmission line

All materials possess a trait known as resistivity. Materials with lower resistivities are better conductors of electricity. Sample resistivities are:

- Aluminum 0.00000002709 Ω-m (Ohm-meters)
- Copper 0.00000001712 Ω-m

Since copper has a lower resistivity than aluminum, it is a better conductor than aluminum.

The resistance of a material is also temperature and frequency dependent. However, for normal power system operations, the frequency is relatively constant (60 HZ) and the change in resistance due to temperature changes is small.

Adding resistors in series increases total resistance whereas adding resistors in parallel reduces the total resistance.

Resistance in Series Circuits

Resistances connected in series produce a total resistance equal to the sum of the individual resistances. Figure 2-10(a) illustrates this relationship.

Resistance in Parallel Circuits

When resistances are connected in parallel, the inverse of the total resistance is equal to the sum of the inverse of each individual resistance as illustrated in Figure 2-10(b).

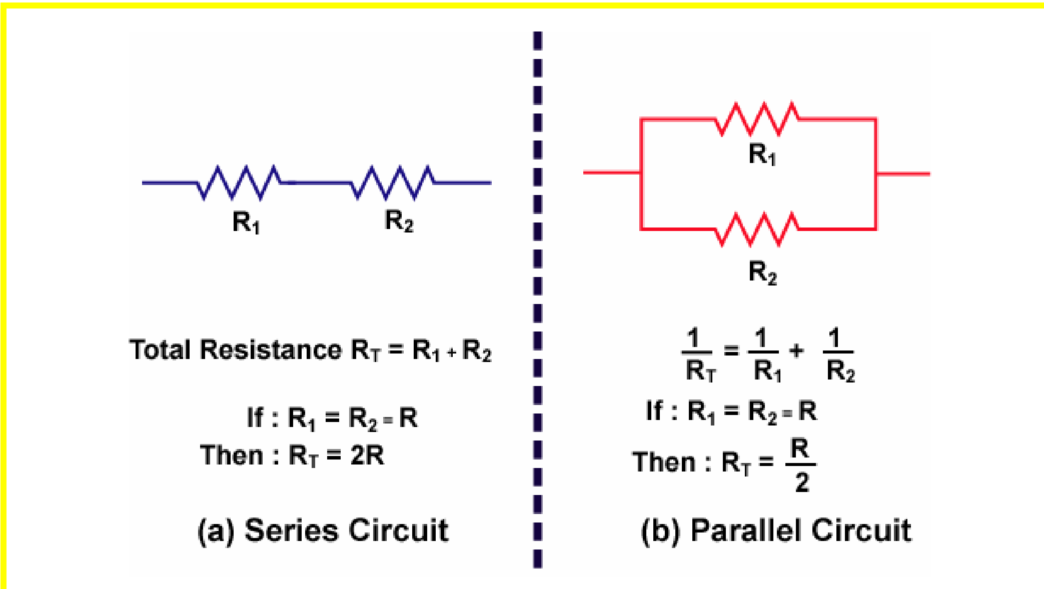


Figure 2-10
Resistance in Series & Parallel

2.3.3 Voltage

The force that causes charge to flow (current) in a conductor is the voltage. The separation of charge between two points in a conductor gives rise to a potential difference or a voltage. Electric charge flows down this potential "gradient", just as water flows down the physical gradient of a hill or slanting pipe. The voltage difference between two points equals the energy that would be lost by a unit of charge as it flowed through the conductor from one point to the next.

Voltage Source

A voltage source is a device that is capable of producing or creating a voltage difference across its terminals. The voltage produced by a generator is called

Generators are a very common voltage source.

an electromotive force (or EMF) by engineers and for this reason is often represented by the letter “E”. Sources of voltage, such as a generator, are typically also used to convert non-electrical energy (coal, water, gas, etc.) to electrical energy.

Measured Voltage

The measured voltage is the voltage seen by a voltmeter connected to a given point in the system. A measured voltage is usually taken between phases in high voltage systems. A measured voltage can also be taken from phase to ground. A measured voltage is typically represented with the letter “V”. Any subscript on the measured voltage indicates where the voltage is referenced. For example, $V_{A\text{-}G}$ is the measured voltage from phase “A” to ground. The voltage $V_{A\text{-}B}$ is the measured voltage between phases “A” and “B”.

Voltage Drop

Recall that voltage is the separation of charge that results in a potential for current flow. Current is the movement of that charge through a conductor. The voltage drop is the amount of potential lost by the charge as it passes through circuit elements such as resistors. The voltage drop across a resistor is equal to the product of the current through the resistor in amperes and the resistance of the resistor in ohms. This relationship is known as Ohm’s law. Ohm’s law will be described later in this section in greater detail.

2.3.4 Electrical Circuits

Any connection between a voltage source and a load is an electrical circuit. When a light bulb is switched on, an electrical circuit is created between the voltage source and the light bulb. By turning the ignition key in a car, an electrical circuit is created from the car’s battery to the car’s starter. Electrical energy can only be utilized if a circuit is created to allow the electrical energy to flow from the source to the load.

Elements of a Circuit

An electrical circuit is composed of a voltage source, a load, and a supply and return path connecting the source to the load. An example of an electrical circuit is the flashlight circuit of Figure 2-11. The voltage source is the two batteries and the load is the light bulb. The supply path is the direct contact between the batteries and the light bulb. The return path is the metal case from the bulb to a spring that the batteries rest on. When the flashlight switch is closed, the circuit is complete and the bulb glows. Each of the ingredients of an electrical circuit is described below:

The Source

A voltage source is any device that can serve as a source of voltage. Sources of voltage typically convert non-electrical energy to electrical energy. Batteries are a typical source of DC voltage, (batteries convert chemical energy to electric energy) whereas generators are typical AC voltage sources.

The Load

Any device that consumes electrical energy is called a load. Lights, motors, heaters and air conditioners are all examples of electrical loads.

The Supply and Return Paths

There must be a physical conducting path to carry electricity from the source to the load and then back to the source. A complete electrical circuit must exist for current flow to occur.

Remember that the driving force behind current is the voltage. For example, for current to flow through a light bulb there must be a voltage difference across the bulb. If we simply connect a wire from the positive terminal of a battery to one side of the bulb, the bulb will not illuminate, as there cannot be any current flow. However, if a return path for the current is provided by connecting the opposite side of the bulb to the negative terminal of the battery, the electrical circuit is completed, current will flow and the bulb will light. Referring back to Figure 2-11, note that the flashlight switch simply opens and closes the return path of the circuit, thus turning the light off and on.

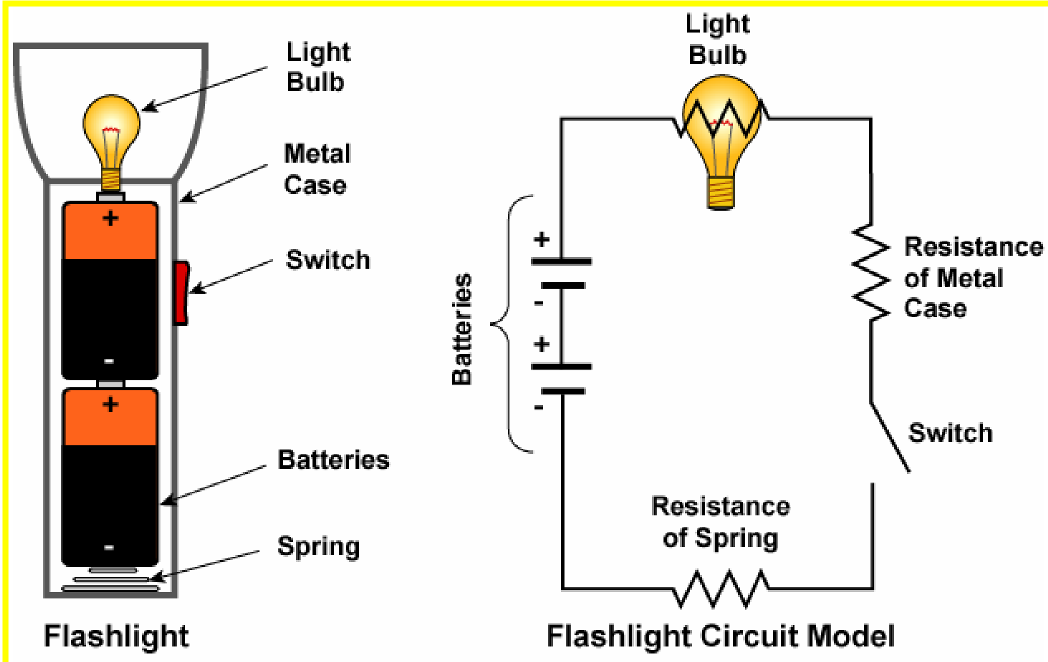


Figure 2-11
Simple Electrical Circuit

The return path for an electrical circuit need only be an electrically common point joining the load and the source. Earth is often the return path in power systems. Electric generators are normally grounded to the earth. Customer load is normally grounded to the earth. A utility need only supply the path from the source to the load and the earth serves as the return path.

2.3.5 Ohm's Law

Ohm's law states that the amount of current flowing through a circuit element is directly proportional to the voltage across the element, and inversely proportional to the resistance of the element. Stated as an equation, Ohm's law is:

$$I = \frac{V}{R} \quad \text{or} \quad I = \frac{E}{R}$$

Where:

I = Current (Amps)

V = Measured Voltage (Volts)

E = Electromotive Force (Volts)

R = Resistance (Ohms)

Ohm's law may also be stated as: E=IxR, V=IxR, R=E/I, or R=V/I. As long as two of the variables in Ohm's law are known, the third variable can be determined. Figure 2-12 illustrates a simple way to remember the Ohm's law relationships. Simply draw a circle with "V" (or "E") in the top half, and "I" and "R" in the bottom half. Now, cover the quantity that you wish to calculate and the relationship between the other two quantities is shown. For example, if you know voltage and resistance and you need to find current, simply cover the "I", and you are left with "V" over "R" as shown in Figure 2-12. Now that you have a way of remembering Ohm's law, we will use the law in DC circuits.

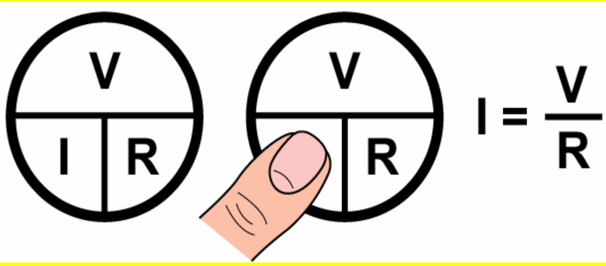


Figure 2-12
Ohm's Law

Use of Ohm's Law

Ohm's law is often used to determine the current flow in a circuit when the voltage and resistance are known. For example, Figure 2-13 contains a simplified circuit for the flashlight example of Figure 2-11. Essentially, the circuit is composed of two 1.5 volt batteries (3 volts total) connected across the light bulb. The circuit resistance includes the light bulb (0.6 Ω), the metal case (0.05 Ω), and the spring (0.1 Ω), which total to 0.75 Ω. The current in the circuit can be found easily using Ohm's law as follows:

$$\boxed{I = \frac{V}{R} = \frac{3\text{ Volts}}{.75\ \Omega} = 4\text{ Amps}}$$

With simple circuits like this example, Ohm's Law alone would be sufficient for determining the voltages and currents. However, circuits that are more complex require additional tools such as Kirchhoff's Laws.

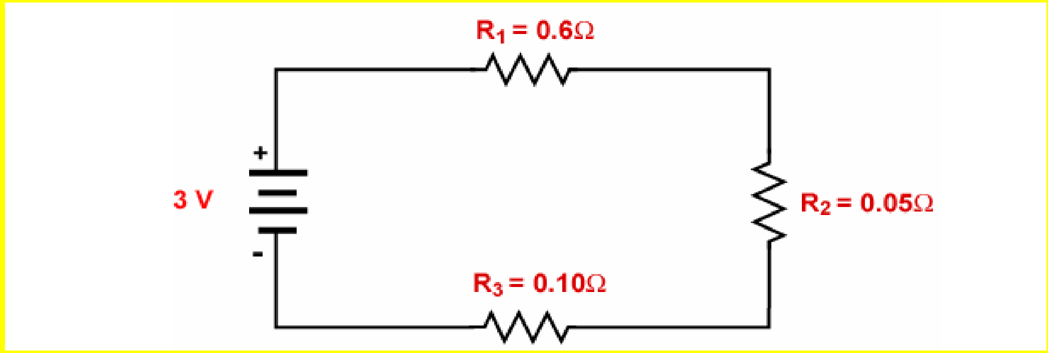


Figure 2-13
Use of Ohm's Law

2.3.6 Kirchhoff's Laws

Two useful tools or laws for solving electrical circuits are named after Gustav Kirchhoff who in 1848 first stated the laws. The first law is known as Kirchhoff's Current Law and is stated as:

> *The Sum of All the Currents Flowing Into and Out of Any One Point In a Electrical Circuit Equals Zero.*

The second law is known as Kirchhoff's Voltage Law and is stated as:

> *The Sum of All the Voltage Rises and Voltage Drops Around Any Closed Path In a Electrical Circuit Equals Zero.*

Use of Kirchhoff's Laws

Figure 2-14 is used to demonstrate the application of Kirchhoff's Laws. The circuit consists of a 12 V battery supplying two resistors in parallel. The objective is to determine the current flowing in each branch of the circuit. The total current I_T flows from the battery. I_1 is the current that flows through R_1 and I_2 is the current that flows through R_2.

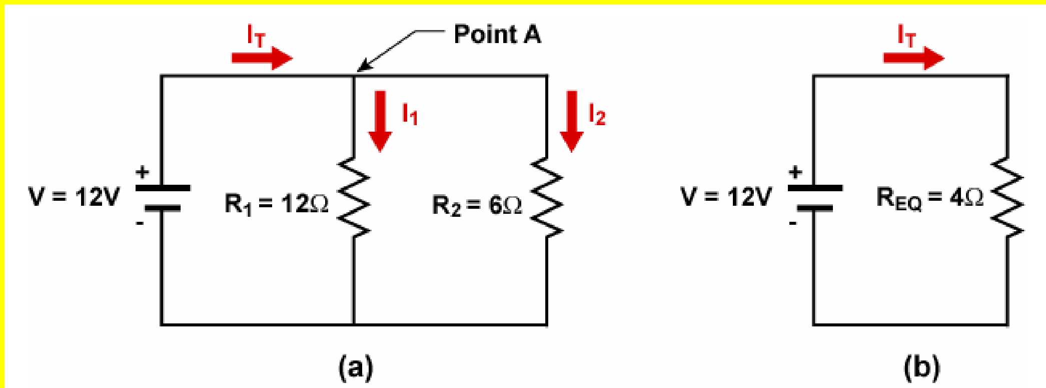


Figure 2-14
Resistors in Series & Parallel

Using the principles introduced in Section 2.3.2, we can combine the two parallel resistors into one equivalent resistor as follows:

$$\frac{1}{R_{EQ}} = \frac{1}{R_1} + \frac{1}{R_2} = \frac{1}{12} + \frac{1}{6} = \frac{3}{12}$$
$$R_{EQ} = 4\Omega$$

The simplified circuit is given in Figure 2-14(b). Ohm's Law can now be used to find I_T.

$$I_T = \frac{V}{R_{EQ}} = \frac{12\,V}{4\Omega} = 3A$$

Using Kirchhoff's second law, which states that the sum of the voltages around any closed path in a circuit equals zero, we can find the current flowing through resistors R_1 and R_2. Applying Kirchhoff's second law to Figure 2-14(a), the voltage drop across resistor R_1 must equal 12 V. Therefore, the current I_1 through resistor R_1 equals:

$$I_1 = \frac{V}{R_1} = \frac{12\ V}{12\Omega} = 1A$$

Kirchhoff's first law can now be used to find the current through R_2. Restated, this law says that the sum of the currents going into a point on a circuit must equal the sum of the currents going out of that same point. In our example, this law applied to point "A" yields:

$$I_T = I_1 + I_2$$
$$3A = 1A + I_2$$
$$I_2 = 2A$$

We have now determined all the currents in this resistive circuit by applying Kirchhoff's and Ohm's laws.

2.3.7 Power & Energy

Energy can be thought of as the capability to do work, whereas power is the rate at which energy is expended in doing work. A car with a full tank of gas has a certain amount of stored energy available. The rate at which the car's engine can convert the energy in the gas to motion of the car is the power of the engine. Similarly, a charged battery has stored energy available and the power delivered by the battery is the rate at which the energy is expended to do work.

Power Definitions

Power is the rate at which energy is expended to do work. DC power is defined as voltage times current and is measured in watts.

$$\boxed{\mathrm{Power}_{DC} = V_{DC} \times I_{DC}}$$

Instantaneous Demand

The instantaneous demand of a power system is equal to the amount of power delivered to the system at one point in time. The instantaneous demand is equal to the voltage times the current and is measured in watts. The instantaneous demand is constantly changing in a power system.

System Load

The system load is equal to the average power delivered over a period of time. On a power system, the system load is usually stated as the average megawatt (a megawatt is one million watts) delivered over a particular hour.

Energy Definitions

Energy is defined as the power used over a period of time and is measured in watt-hours. For example, a 100 watt light bulb which is on for 10 hours uses 1,000 (10x100) watt-hours of energy.

$$\boxed{\mathrm{Energy} = \mathrm{Power} \times \mathrm{Time}}$$

Integrated Demand

Energy is more accurately defined as the integrated demand over time. The integral of demand is equal to the area between the demand curve and the time axis as illustrated in Figure 2-15. For a load with constant demand, such as the light bulb mentioned earlier, the integrated demand is equal to the demand times the period of time that the load is in service. However, if we look at the demand of a typical household load, we would see an instantaneous demand that is constantly changing, as lights and appliances are switched in and out-of-service. The energy consumed by the house is the sum of all the products of instantaneous demand and time for each time period.

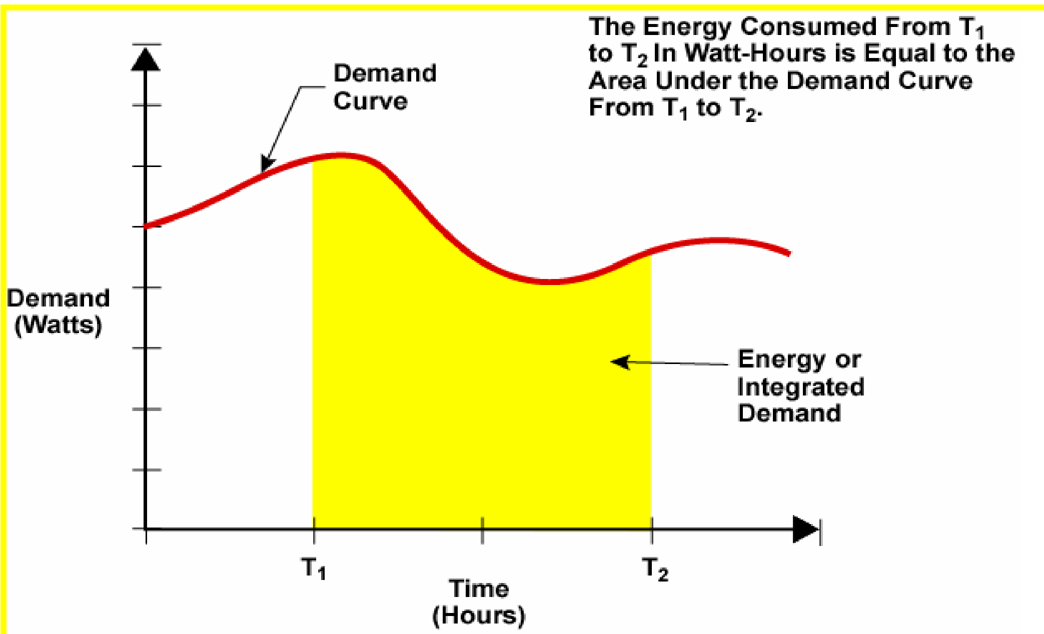


Figure 2-15
Integrated Demand

Use of the “Giga”, “Mega”, and “kilo” Symbols

In the field of power systems, the units of watts and volts are very small. To measure power system values with these units would be equivalent to posting road signs with the number of feet to the next city. The prefixes “Giga”, “Mega”, and “kilo” are used to represent large quantities of watts or volts. Each prefix can be used as a multiplier as follows:

- kilo is a multiplier of 1,000
- Mega is a multiplier of 1,000,000
- Giga is a multiplier of 1,000,000,000

For example, given a power plant which has a power output of one billion watts, we could call it a:

- 1,000,000,000 watt (W) plant
- 1,000,000 kilowatt (kW) plant
- 1,000 Megawatt (MW) plant
- 1 Gigawatt (GW) plant

Power plant capabilities are commonly stated in MW. Transmission line voltages are commonly stated in thousands of volts or kilovolts (kV). Instead of referring to the 138,000 or the 345,000 volt system, it is more common to refer to the 138 kV or 345 kV system.

2.4 AC Electricity Review

This section reviews AC electrical theory. Topics addressed include the advantages of AC over DC, frequency, phasor diagrams, magnetism and magnetic fields, AC impedance including capacitance and inductance, phase angle, and AC power.

2.4.1 Alternating Current Systems

Power in North America is largely generated and delivered via alternating current (AC) systems. The magnitude of alternating current is constantly changing and reversing polarity at regular intervals. Figure 2-16 contains a plot of an alternating current as it varies with time. As can be seen in the figure, alternating current follows the shape of a sine wave. Alternating current could follow any waveform (i.e., triangular, square, etc.) but the alternating current used in power systems is intentionally sinusoidal (shaped like a sine wave). Recall that the sine function is periodic which means that it constantly repeats itself. For each cycle, the sine wave passes through zero twice and has one positive and one negative peak.

AC or DC?

Why use seemingly complicated AC over relatively simple DC? There are several reasons but the most important is that the AC voltage level can be easily adjusted using transformers. With AC one can generate at a medium voltage level, transmit at a high voltage level, and then transform down to a much lower voltage for customer use. As will be explained shortly, the principle of electromagnetic induction, by which AC transformers operate, does not apply to direct current.

Frequency

Power system frequency is the number of sine wave cycles that the alternating current completes each second. In North America, the power system frequency is 60 cycles per second. One cycle per second is equal to one hertz (HZ). Therefore, we say that the power system frequency is 60 HZ. The majority of the countries in the world utilize a 50 HZ frequency.

There are isolated pockets of 25 HZ frequency power systems in North America but, by far, the majority operates at 60 HZ.

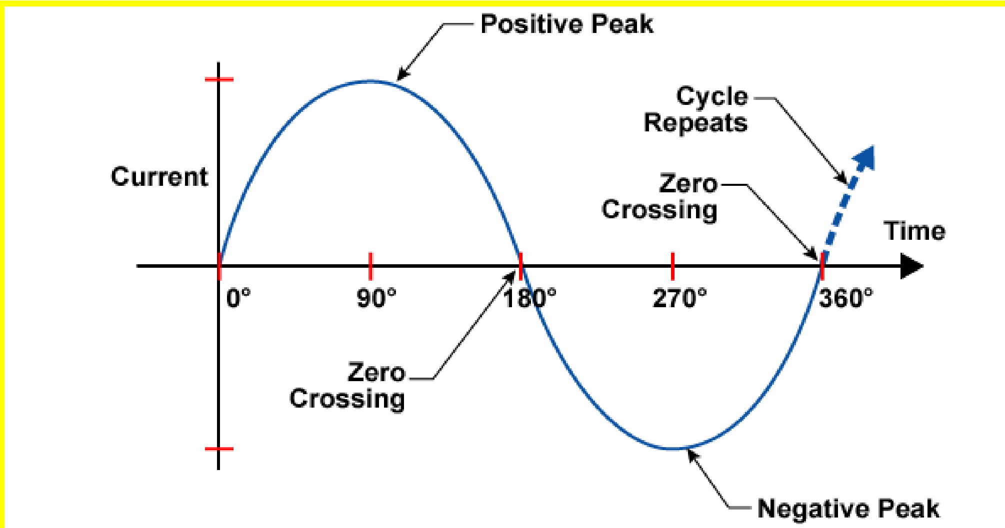


Figure 2-16
A Cycle of Current

Use of Degrees, Cycles & Time

One full sine wave cycle is divided into 360° as illustrated in Figure 2-16. If the frequency of the current in Figure 2-16 is 60 HZ, then Figure 2-16 contains:

- 1 cycle, or
- 360°, or
- $1/60^{th}$ of a second

All three statements represent the same time span; in other words, one can refer to power system time frames in terms of degrees, cycles or time.

2.4.2 Vectors and Phasors

A vector is a quantity that contains both magnitude and direction information. For example, assume you are told to walk 1 mile directly north than one mile directly east. Both of these quantities are vectors as you are given information on both the magnitude (how far to walk) and the direction (north, east, etc.).

The sine and cosine functions can be stated as vectors if we assume they are both oscillating at the same frequency. Recall that the cosine function leads the sine function by 90°. Figure 2-17 illustrates plots of both the sine and cosine functions. Note how the cosine function crosses zero 90° ahead of the sine function. To state the graphical information in Figure 2-17 in a vector format we would say that the sine function has a magnitude of 1 at an angle of 0° or $1\angle 0^\circ$ and the cosine function has a magnitude of 1 at an angle of –90 or $1\angle -90^\circ$. These vector descriptions of the sine and cosine functions simply mean that the cosine and sine have the same magnitude but the cosine waveform leads the sine waveform by 90°.

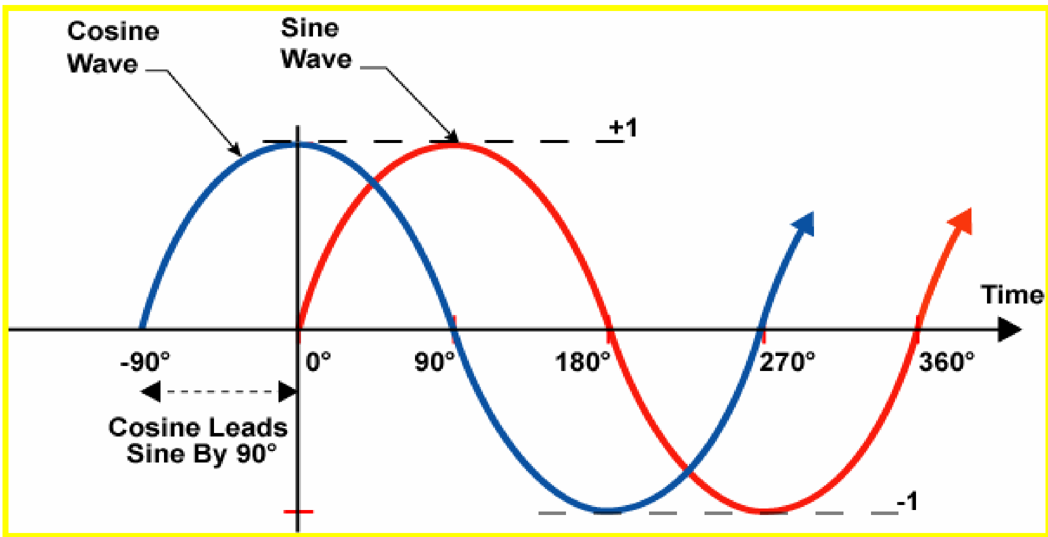


Figure 2-17
Vector Relationship of Cosine and Sine Functions

The difference between a phasor and a vector is that a phasor oscillates or rotates while a vector is stationary.

The concept of a phasor is necessary when you are relating sine and cosine functions that do not oscillate at the same frequency. A phasor is a vector that oscillates at a specific frequency. To specify a vector you state the magnitude and direction. To specify a phasor, you must state the magnitude, direction, and frequency.

This text will assume that the frequency is 60 HZ unless stated otherwise. Therefore, the text will normally not differentiate between vectors and phasors and will generally use the term phasor to represent both phasors and vectors.

To summarize, phasors are vectors that rotate. If a 60 HZ frequency is assumed than vectors and phasors are stated in the following form:

$$345\angle 5^\circ \qquad 138\angle 10^\circ$$

$$115\angle 20^\circ \qquad 12.5\angle -30^\circ$$

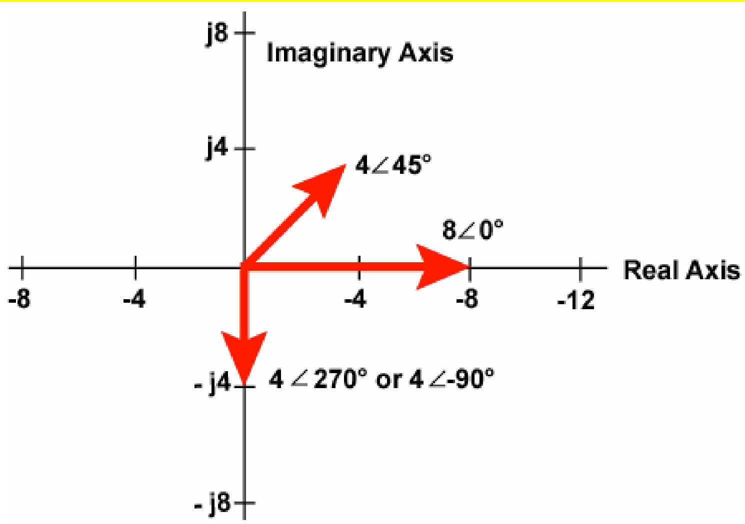
Where the first number is the magnitude and the second number is the phase angle. For example, the first number in the above list has a magnitude of 345 and an angle of +5°.

Construction of Phasor Diagrams

A phasor can be plotted on a diagram with two axes, one called the real axis and one called the imaginary axis. A phasor is represented on the plot as an arrow whose length represents magnitude, and whose angle with respect to the real axis represents the phase angle. Figure 2-18 contains three phasors:

$$8\angle 0^\circ,\ 4\angle 45^\circ,\ 4\angle 270^\circ$$

A positive phase angle is measured in a counter-clockwise direction with the phasor aligned with the real axis having a zero degree phase angle.



The "j" symbol in this figure means the imaginary axis is at a 90° angle to the real axis.

Figure 2-18
Phasor Diagram

Illustration of Phase Angle

When the term phase angle is used, we typically are referring to an angle between a voltage and a current. However, a phase angle can be between two voltages or two currents. If the angle is between two voltages or two currents, this text will clearly state the point.

A phase angle can be conveniently illustrated on a phasor diagram. A phase angle is the angle between any two phasors. The phase angle may be between two voltages, two currents, or between a voltage and a current. Figure 2-19 is a simple phasor diagram. The phase angle for this circuit is the angle (θ) between the voltage and current. For this example, the current phasor “lags” the voltage phasor.

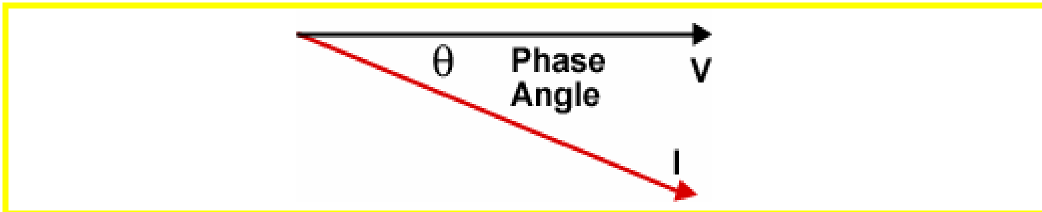


Figure 2-19
Phase Angle Between Voltage & Current

Figure 2-20 contains four simple electrical circuits. One circuit contains only an inductor and the other only a capacitor. Two of the circuits are combinations of resistors with capacitors or inductors. Shown below each circuit is the phasor diagram for that circuits voltage and current. (Capacitor and inductor impact on the phase angle is explained in following sections.)

The diagrams in Figure 2-20 illustrate the relationship between the circuit’s voltage and current. The angle θ is the phase angle for each circuit. The four circuits have different phase angles because the circuits are composed of different elements. Note that the inductive circuits—Figure 2-20(a) and 2-20(b)—have positive phase angles and the capacitive circuits Figure 2-20(c) and 2-20(d) have negative phase angles. It is a convention in the power industry that the angle for an inductive circuit is defined as positive and capacitive as negative.

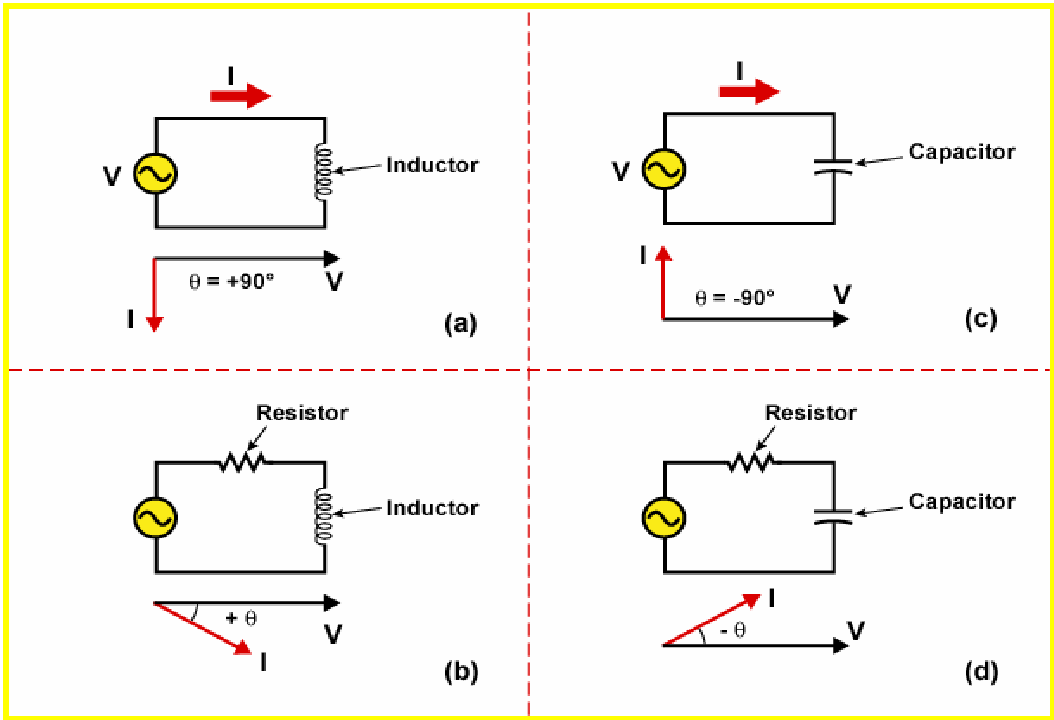
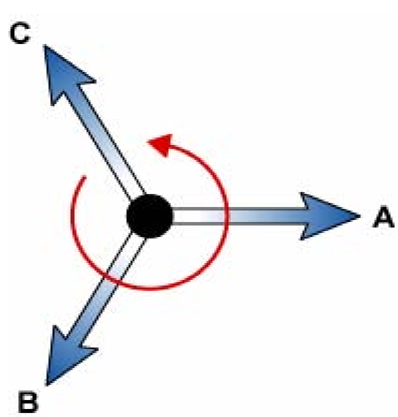


Figure 2-20
Inductive and Capacitive Phase Angle Examples

Inductive circuits have positive or lagging phase angles and capacitive circuits have negative or leading phase angles.

Phasor Diagram Illustration of 3Φ Systems

In a 3Φ system, each of the phase voltages is intentionally 120° out of phase with the other two voltages. For example, if we choose "A" phase to be the reference phase, and assign it an angle of 0°, the "C" phase will have an angle of 120°, and "B" phase will have an angle of 240° or -120°. Figure 2-21 illustrates this concept using a phasor diagram. Note how the three phasors are actually rotating in a counter-clockwise direction.



Φ is the symbol commonly used to mean phase. For example 3Φ means 3-phase.

Figure 2-21
3Φ Phasor Diagram

2.4.3 Magnetism & Magnetic Fields

Electricity and magnetism are closely related subjects. An understanding of magnetic fields is necessary before AC impedance can be described. This section examines the cause and effects of magnetism and magnetic fields.

Sources of Magnetism

Magnetism is a property of matter associated with moving charges. The moving charges may be within the atomic structure of the materials as in magnetized pieces of iron or steel. These type materials are called permanent magnets. Magnetism also arises any time there are moving charges associated with an electric current. For example, an electric current flowing through a straight conductor or a coil produces a magnetic field. The magnetic field is generally much stronger for a coil because of the number of turns of wire in which the current flows. If the coil is wound around a core made of magnetic material, an electromagnet is formed.

Magnetic Fields

A field can be thought of as a force distributed over an area. For example, gravity is a field. The earth's gravitational field can be thought of as lines of force that extend outward from the earth's center, and weaken with distance. Any object within the earth's gravitational field will experience the force of gravity pulling it toward the earth. Similarly, magnetic fields can be viewed as lines of magnetic force. Any other magnet placed within a magnetic field will experience a magnetic force.

Permanent magnets retain their magnetic field strength. Electromagnets require a current source to sustain their magnetic fields.

The geometry of magnetic fields varies depending on the source of the field as illustrated in Figure 2-22. Permanent magnets have two poles designated north and south. The lines of magnetic force run by convention from the north pole to the south pole. The Earth is a permanent magnet with a magnetic field that can be detected with a compass.

The magnetic field due to a current in a straight conductor is concentric about the conductor as shown in the right side of Figure 2-22. The intensity of the magnetic field, due to the current, decreases as the distance from the conductor increases. The magnetic field due to a coil is similar to that of a permanent bar magnet. This type of magnetic field is illustrated in the left of Figure 2-22.

Magnetic fields can be confined within magnetic materials such as the iron in a transformer's core. In other words, if a magnetic field is set up in an iron structure, the lines of magnetic force will tend to be confined to that structure. Figure 2-23 contains a simplified transformer core. The core is a rectangular iron doughnut. If a wire is wrapped around the core and current is passed through it as shown, a magnetic field will be created in the core as illustrated. Because iron is a better magnetic material than air, most of the magnetic field will remain in the core.

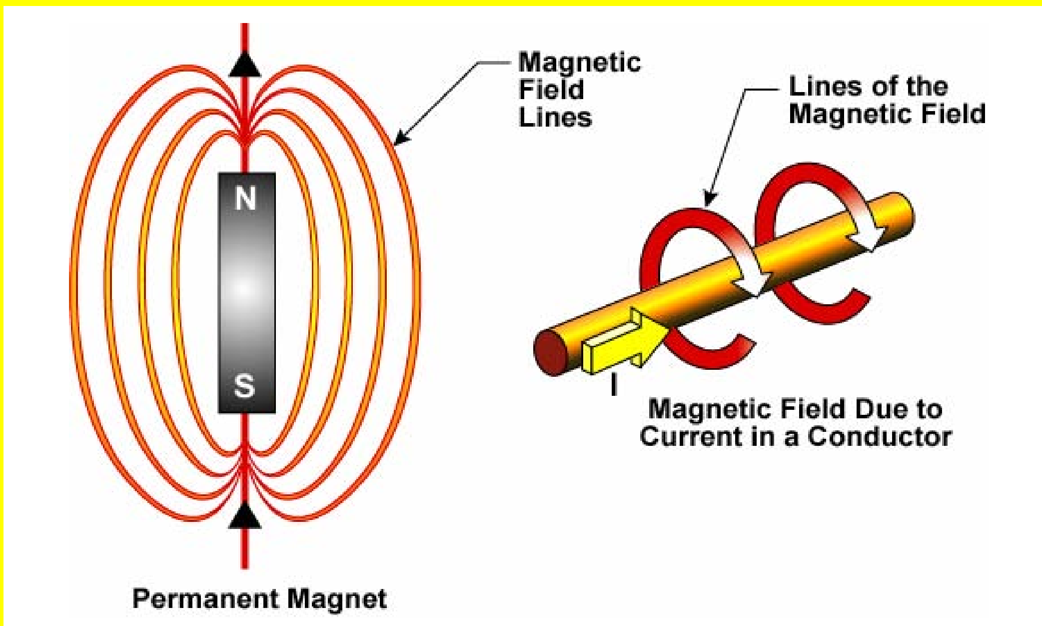


Figure 2-22
Magnetic Fields

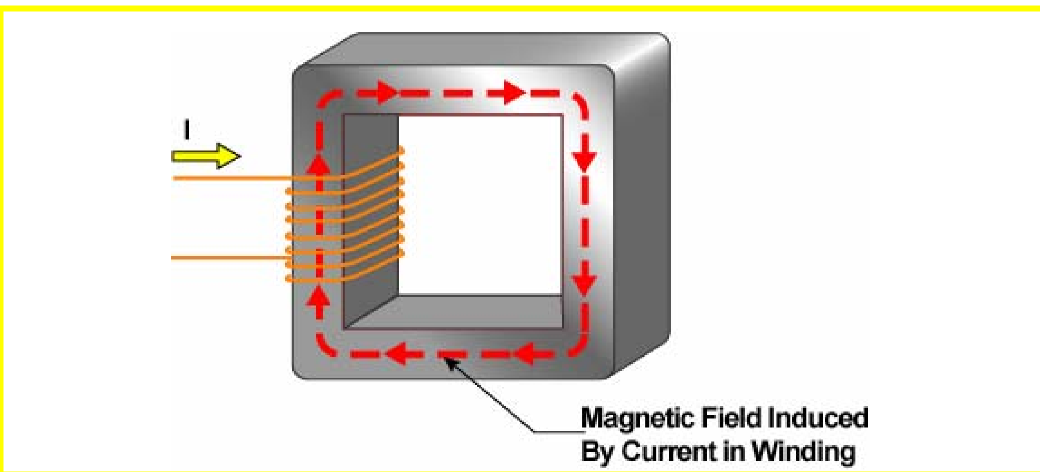


Figure 2-23
Magnetic Field in an Iron-Core

Electromagnetic Induction

A voltage is generated in a conductor if there is relative movement between the conductor and a magnetic field.

If there is relative motion between a magnetic field and a conductor or if there is a change in the magnetic field linking a conductor for some other reason, an electromotive force—or voltage—is generated. This voltage causes current to flow if an electrical circuit is formed. This concept is called the principle of electromagnetic induction. Electromagnetic induction is a very important principle as it is the basis upon which many types of power system equipment (transformers, generators, etc.) operate.

The relative motion between the conductor and the magnetic field may be due to physical motion of the magnetic field or the conductor or both. The relative motion may also be due to changes in the magnitude or direction of the magnetic field. In other words, if a conductor is placed in a fluctuating magnetic field, a voltage will be induced in the conductor.

The magnitude of the induced voltage is dependent on the alignment between the magnetic field and the conductor. For example, if a conductor is passed through the densest part of the magnetic field, a large voltage will be produced. However, if the conductor is passed through the weakest part of the magnetic field a smaller voltage will be produced.

Magnetic Fields and AC Power Systems

AC current flow results in an induced voltage or a "back emf". This back emf both retards and restricts the magnitude of the current flow.

When DC current flows through a conductor a constant magnetic field is created. When AC current flows through a conductor, a variable or alternating magnetic field is created. The variable magnetic field alternately builds and collapses as the AC voltage wave builds and collapses in its normal cycle. This constantly changing magnetic field results in an induced voltage in the conductor. This induced voltage is referred to as a "back emf". The voltage due to the back emf opposes the original voltage that caused the current to flow. The result is to delay the current flowing in the conductor.

This delay or lag in the current due to a back emf is one of the reasons why current and voltage are generally out-of-phase in an AC system. The effect is larger with coils, such as those in a transformer, because of the strong magnetic fields associated with coils. In the next section, we will use this concept in explaining the inductive component of the impedance of an AC circuit.

2.4.4 AC Impedance

Impedance is the AC version of resistance. Actually, resistance is one component of AC impedance. AC Impedance is made up of two components: resistance and reactance. Resistance in a power system consists of the resistance of the conductors and the circuit elements as described earlier in the review of DC electricity. Reactance arises from the presence of capacitive and inductive effects in an AC power system. There are two types of reactance, capacitive reactance and inductive reactance.

Capacitors

A capacitor is a simple and very common electrical device. All that is needed to create a capacitor are two pieces of conducting material and a dielectric between the conductors. A capacitor is a circuit element that stores energy in the form of an electrical charge. A capacitor's stored energy creates an electric field.

A dielectric is an insulator or a material in which an electrical field can be maintained with minimum loss of power.

The concept of an electric field is similar to a magnetic field. An electric field surrounds any electrically charged object. For example, to visualize the electric field surrounding an energized conductor think of concentric circles (electric field lines) that surround the conductor. The voltage level of the electric field shrinks as the distance from the conductor increases. The measure of how much energy a capacitor can store in its electric field is known as its capacitance. Figure 2-24 illustrates a capacitor and its electric field. Note in Figure 2-24 that a capacitor's ability to store energy in its electric field increases with the:

- Increased area of the conducting plates
- The reduced separation between the conducting plates
- The strength of the dielectric between the conducting plates

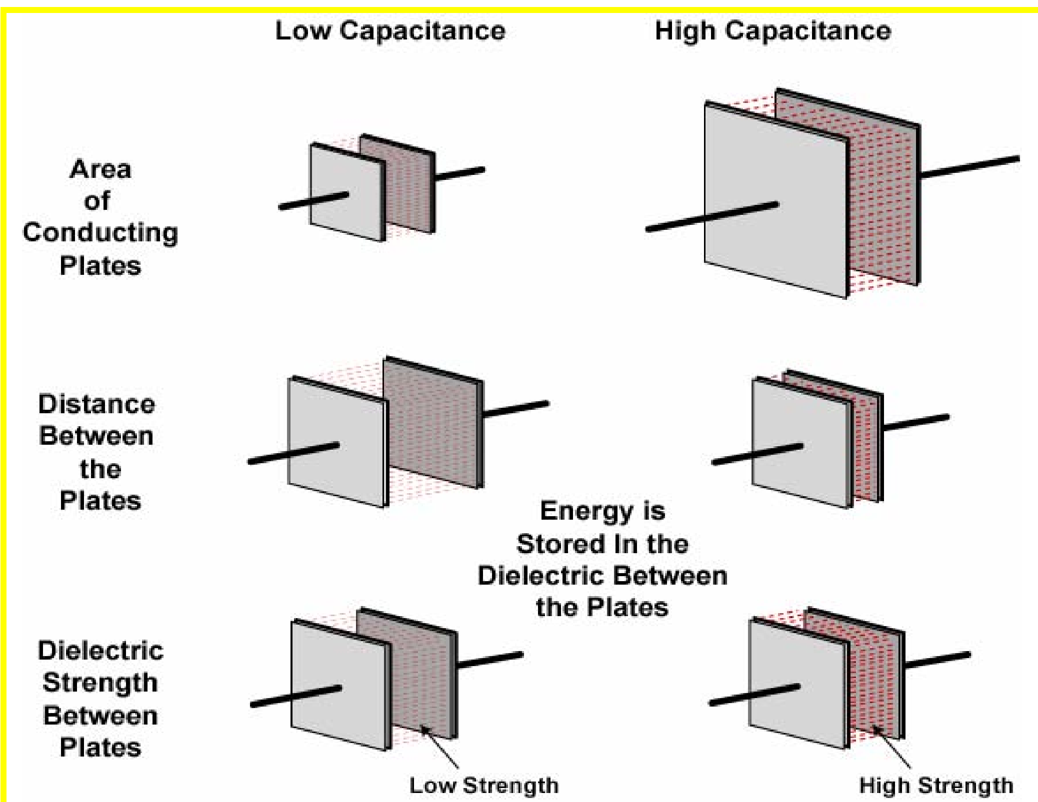


Figure 2-24
Capacitors

Current Flow and Capacitors

Capacitors store energy in their electric fields. As there is an insulator (such as air) between the capacitor's plates, how can current flow through the capacitor? The answer is that current does not actually flow through the capacitor's dielectric. However, current does flow in the electrical circuit that contains the capacitor.

A simple way to view a capacitor in an AC circuit is to view it as a battery whose polarity varies with the system frequency.

When an AC voltage is applied to a capacitor, a current flows from the applied voltage source and an electrical charge builds up on one plate of the capacitor. There is no current through the dielectric itself as the dielectric is an insulator. When the capacitor is being charged by increasing the applied AC voltage, the charging current flows from the voltage source towards the capacitor's plate. When the applied AC voltage is decreasing, current flows away from the capacitor towards the voltage source. With an alternating voltage applied, the capacitor alternately charges and discharges, provided an alternating current flow in the electrical circuit.

Capacitive Reactance

Capacitive reactance (X_C) is a measure of how a capacitor affects the flow of AC current. When a capacitor is placed in an AC circuit, the capacitor builds up a charge and opposes any further change in the voltage. A capacitor's natural opposition to a voltage change is accounted for by calculating the capacitive reactance of the capacitor. Capacitive reactance is measured in ohms. To determine the capacitive reactance, it is necessary to know the value of capacitance (C) in Farads and the frequency (f) of the circuit in Hertz. The formula for determining the capacitive reactance is:

The term "π" (Greek letter PI) refers to a constant. PI is the ratio of the circumference to the diameter of a circle. PI is approximately equal to 3.14.

$$\boxed{X_C = \frac{1}{2\pi fC}}$$

Note that the capacitive reactance varies inversely with the frequency. This point will be important in later Chapters of this text. Capacitive reactance is a vector as it does not rotate but does have both a magnitude and a phase angle. The phase angle for capacitive reactance is -90°.

Inductors

Note that many power system components, such as transmission lines, are naturally inductive.

An inductor is also a simple and common device. An inductor is a coiled conductor. Inductors are circuit elements that store energy in their magnetic fields. Inductance is a measure of how much energy an inductor can store. Figure 2-25 illustrates an inductor and its magnetic field. Note from Figure 2-25 that an inductor's ability to store energy in its magnetic field increases with:

- The number of turns of the coil
- The size of the cross-sectional area of the magnetic core
- The tighter spacing between the coil turns
- The strength of the magnetic core

Inductive Reactance

Inductive reactance (X_L) is a measure of how an inductor affects the flow of current. Inductive reactance is measured in ohms. When AC current flows in a conductor a "back emf" is produced which causes the current to lag the voltage and restricts the magnitude of the current flow. This effect is represented with the inductive reactance. To determine the inductive reactance one must know the value of inductance (L) in Henries and the frequency (f) of the circuit in Hertz. The formula for determining the inductive reactance is:

$$\boxed{X_L = 2\pi f L}$$

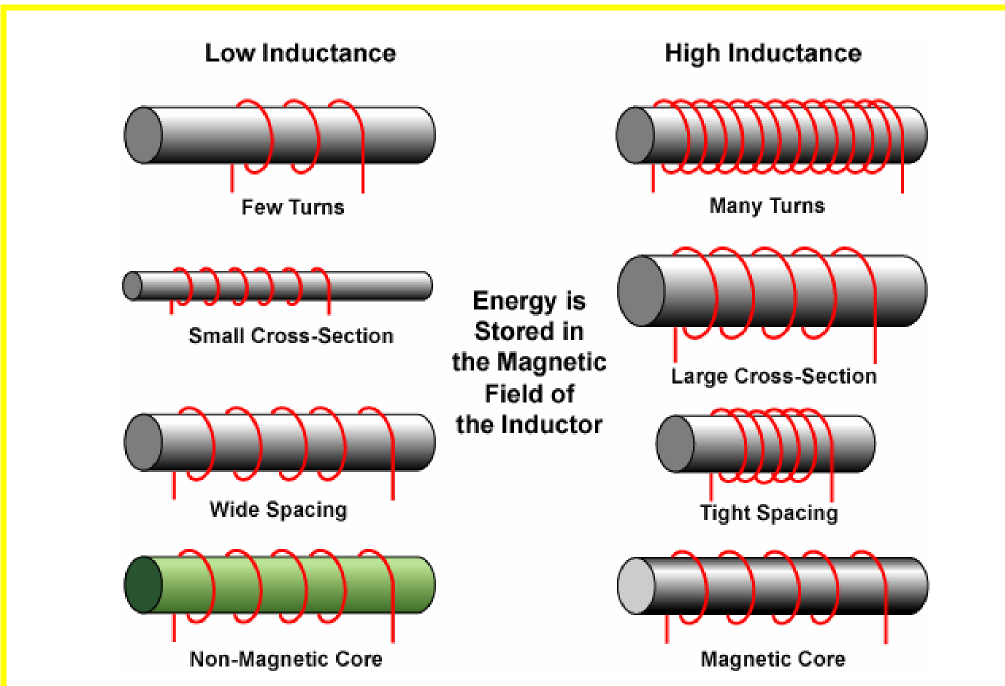


Figure 2-25
Inductors

The fact that both inductive and capacitive reactance vary with the frequency will lead to some interesting phenomena. We will explore these phenomena in Chapter 9.

Note that the inductive reactance varies directly with the frequency. Inductive reactance is a vector as it does not rotate but has both a magnitude and a phase angle. The phase angle for inductive reactance is +90°.

Impedance

The impedance of a circuit is the vector sum of the resistances and reactances of the circuit. Impedance restricts current flow in AC circuits. Impedance (Z) is measured in ohms and defined as follows:

$$Z = R + jX_T$$

Where:

$X_T = X_L + X_C$

R=Resistance

X_T =Total Reactance

X_L =Inductive Reactance

X_C =Capacitive Reactance

Keep in mind that X_L and X_C are 180° out of phase. X_L can be considered a positive reactance while X_C can be considered a negative reactance. If you had a circuit whose inductive reactance was 10Ω and whose capacitive reactance was 5Ω, then the total reactance would be 5Ω (10-5) inductive.

The Impedance Triangle

The impedance triangle illustrates the relationship between AC resistance, reactance, and impedance. Figure 2-26 contains two impedance triangles. The first triangle (2-26a) represents an inductive impedance since the reactance (X_L) is positive. The second triangle (2-26b) has a negative capacitive reactance (X_C). You calculate the overall impedance (Z) by applying the Pythagorean theorem that was explained earlier in this Chapter.

You can calculate impedance, resistance and reactance values using the impedance triangle in the same manner as power values are calculated using the power triangle. (See Section 2.4.5.)

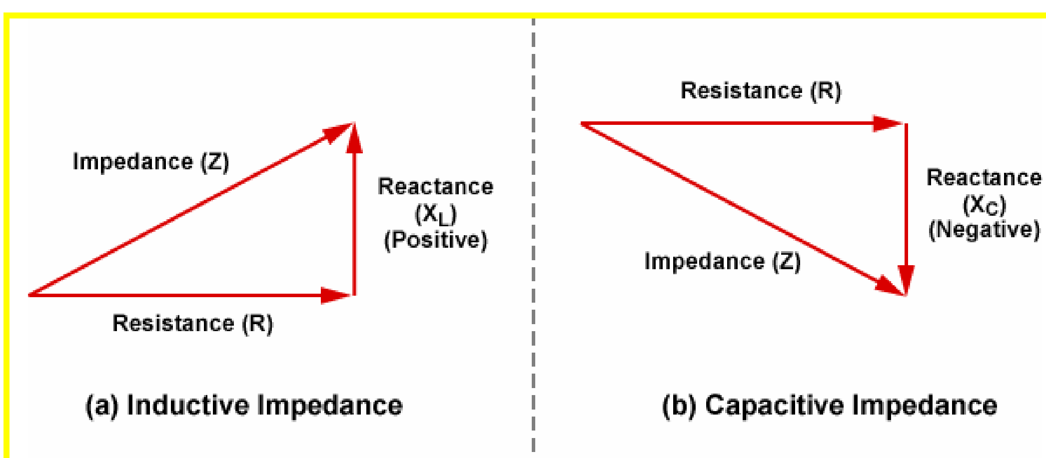


Figure 2-26
The Impedance Triangle

Phase Angle

The phase angle (θ) of a circuit has already been defined as the angular separation between two phasors. Figure 2-27 illustrates portions of the voltage and current sine waves for a circuit. The spacing between the zero crossings of the two waveforms also illustrates the phase angle (θ) of the circuit. The phase angle of a circuit is directly related to the impedance of the circuit. If the impedance of the circuit is purely resistive, then the voltage and current will be in phase, and the phase angle will be zero. However, the impedance of AC power system circuits is rarely purely resistive.

Leading Phase Angle

A circuit is said to have a leading phase angle when the current wave leads the voltage wave. Figure 2-27(a) illustrates a leading phase angle. The current waveform is to the left or ahead of the voltage waveform. Circuits with predominantly capacitive impedance have a leading phase angle. The electric field energy storage in a capacitive circuit causes the current to lead the voltage.

Lagging Phase Angle

A circuit is said to have a lagging phase angle when the current wave lags behind the voltage wave. Figure 2-27(b) illustrates a lagging phase angle. The current waveform is to the right, or behind the voltage waveform. Circuits with predominantly inductive impedance have a lagging phase angle. The magnetic field energy storage in an inductive circuit causes the current to lag the voltage.

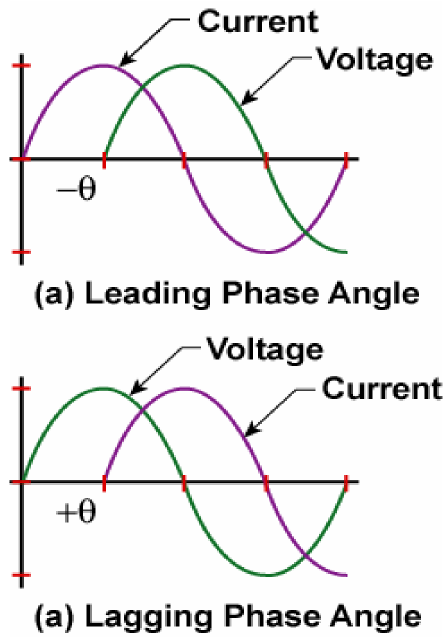


Figure 2-27
Phase Angles in AC Circuits

ELI the ICE Man

A convenient way to remember that in an inductive circuit current lags and in a capacitive circuit current leads, is the expression:

ELI the ICE Man

The ELI portion helps you remember the I (current) lags E (voltage) in an inductive (L) circuit while the ICE portion reminds you that I leads E in a capacitive (C) circuit.

2.4.5 AC Power

The power that flows in a power system is composed of active and reactive power. Both components are necessary to serve customer loads. As we will see, without active power our lights would be dark. On the other hand, all the active power in the world will not turn the shaft of an electric motor without sufficient reactive power.

Active Power

Active power is often referred to as real power to distinguish it from reactive power. Active power is the useful or working energy supplied by a power source. Note that although the term real power is often used, this may be misleading since reactive power is also very real. The term active power is preferred and will be used in this text.

Active power is used to perform work such as lighting a room or heating a building or turning a motor shaft. The unit of active power is the watt (W) but the more common unit is the megawatt (MW)—equal to one million watts. The symbol for active power is the letter "P". The energy a customer consumes and pays for is expressed as power (for example, kW) used per hour (for example, kilowatt-hours or kWh).

A turbine/generator converts energy from one form to another. For example, a generator may convert the potential energy of water to electrical energy, or the chemical energy of coal to electrical energy. When a turbine/generator's MW output is increased, more fuel (water, coal, etc.) must be added to produce more MW. A significant fuel addition is generally not required to produce more reactive power. When more reactive power is required, the generator's excitation system is adjusted or additional capacitors are added to the power system.

A generator does not consume significant fuel to produce reactive power but there still may be a cost associated with the reactive power. Chapter 5 will examine this point.

Reactive Power

Reactive power supports the magnetic and electric fields necessary to operate power system equipment. Reactive power is never used up by the power system. Reactive power is stored in the electrical and magnetic fields that exist in the system. An exchange (at twice system frequency) of reactive power is continually in progress between those devices that produce reactive power and those that store reactive power in their electric and magnetic fields.

When electrical equipment is energized via AC voltage, an electric field is created. When AC current flows through a conductor a magnetic field is created. These electric and magnetic fields continually build and collapse with the changing magnitudes of the AC voltage and current. When the electric and magnetic fields are building, they store reactive power. When these fields are collapsing, they return the reactive power to the system. No actual energy is expended (except losses). Reactive power flow is simply a continual exchange of power and energy.

A look at the inside of a motor—even a small one—will reveal a gap between the rotating component of the motor and the stationary component of the motor. This gap is necessary to allow the rotor to turn and be used to perform some type of work. But how do the watts of power used to run the motor get across this gap to be used to turn the rotor? The answer is that the component of AC power called reactive power creates a magnetic field in this air-gap and serves as a type of bridge to allow active power to turn the motor's rotor.

The "Q" symbol for reactive power derives from the word "quadrature". Quadrature means a 90° phase difference exists between active (P) and reactive (Q) power.

Reactive power is measured in var. Var stands for volt ampere reactive. We use the abbreviation kVar for 1,000 var and Mvar for 1,000,000 var. The symbol for reactive power is the letter "Q".

A large percentage of electrical loads could not run without var. For example, all AC-powered rotating equipment, such as refrigerators, washers, dryers, and industrial motors use var. Transformers could not operate (step-up or step-down voltages) without var.

Reactive Power Analogy

Another commonly heard analogy is that reactive power is the "foam on the beer" while active power is the beer. The analogy is that the foam takes up room in the glass of beer but it is not real beer. In the same manner, reactive power takes up room in the transmission system but does no useful work.

Reactive power is often described in terms of an analogy. A useful analogy is to assume you were to use a wheelbarrow to move a load of bricks along a level road. To do so you must first raise the handles of the wheelbarrow. While raising the handles, you are storing energy in the wheelbarrow. Next, you apply a force to move the wheelbarrow forward. When you arrive at your destination you lower the wheelbarrow handles to the ground and release stored energy.

The raising of the wheelbarrow handles is equivalent to storing reactive power in a magnetic field. This energy is not being used but simply being stored for later retrieval. However, to move the wheelbarrow forward this energy must first be stored. The forward movement of the wheelbarrow is equivalent to active power usage. Real work is being performed as the wheelbarrow moves forward. The lowering of the handles is equivalent to retrieving the reactive power from its storage location. Note that reactive power was stored but later retrieved. This storage was necessary to enable active power to perform the desired work.

Complex Power

Together, active power and reactive power make up complex power, which is the total power flow. Utilities use generators to produce active and reactive power. Utilities then use the transmission and distribution system to distribute this power to the customer loads. Complex power is the combination of active and reactive power. Complex power is the total power the transmission system is carrying. This total flow (the product of voltage and current) has units of volts-amperes (VA). Electric utilities commonly use the abbreviation kVA for 1,000 VA and MVA for 1,000,000 VA. The symbol for complex power is the letter "S".

Active power and reactive power are quantities that have both magnitude and direction so they must be treated as vectors when they are added together. The addition of MW and Mvar will be reviewed shortly.

The Power Triangle

Complex power is the combination of active and reactive power, but this is not a simple summing process. Since active power and reactive power are 90° apart in phase, they must be added vectorially using the power triangle. Figure 2-28 illustrates the power triangle, where the two legs are active and reactive power, and the hypotenuse represents complex power. Because this is a right triangle, the two components can be summed using the Pythagorean theorem as was described earlier in this Chapter.

$$\boxed{MVA^2 = MW^2 + Mvar^2}$$

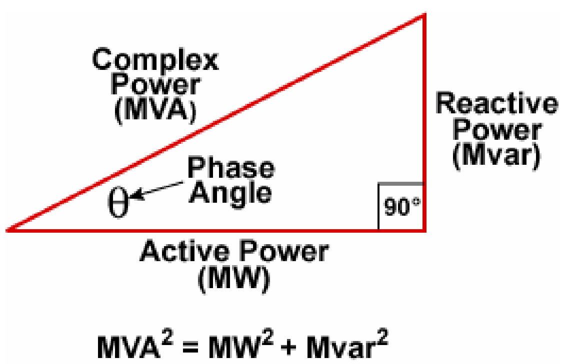


Figure 2-28
The Power Triangle

The phase angle between the MW and MVA is the same as the phase angle between the current and voltage that was described earlier. The angle is the same because the phase angle between the voltage and the current is what creates the Mvar component of complex power in the first place. If the voltage and current were in phase, there would be no Mvar and all the complex power would be MW.

Power Factor

The cosine of the phase angle between the MVA and MW in the power triangle is called the power factor. The power factor is also equal to the ratio of active power and complex power on the system.

$$\text{Power Factor} = \text{P.F.} = \frac{\text{Active Power}}{\text{Complex Power}}$$

If a load has a unity power factor, the load is purely resistive and requires no reactive power. If the power factor were zero, the load would be purely reactive and would not require any MW. Suppose that the load on a power system is 100 MVA with an active power component of 85 MW. We could then calculate that the power factor was 85 MW/100 MW = 0.85.

The power factor of a load is a simple way of determining how many MW and Mvar are needed to serve the load. If the power factor and MVA of the load are known, the Mvar and MW components can be calculated. For example, in Figure 2-29 the MVA is 100, θ is 25.8°, and the power factor is 0.9 (cos 25.8°). The MW can be easily calculated to be 100 x 0.9 = 90 MW and the power triangle can then be used to calculate that Mvar is 43.6.

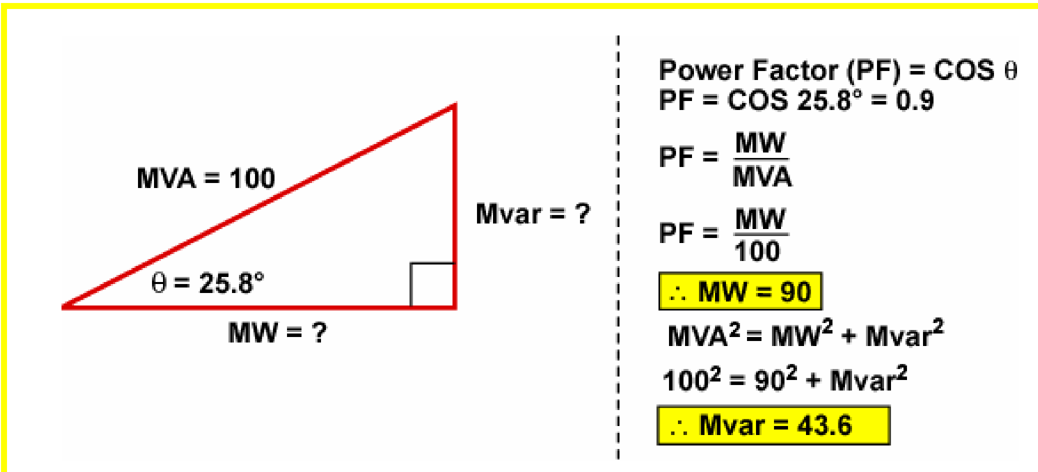


Figure 2-29
Using the Power Triangle

The Greek letter Φ (Phi) is used to represent a phase. Single phase is then 1Φ while three-phase is 3Φ.

Three-Phase (3Φ) Power

Our description of power flow to this point was for 1Φ systems. In 1Φ systems active power flow is the product of the voltage, current and power factor. As one would expect, the power flowing in a balanced 3Φ circuit is simply three times that of a 1Φ circuit. However, when dealing with a 3Φ system, you have to be careful about which voltage you use.

In a 1Φ system, the only voltage that can be specified is the voltage from the line to ground. In a 3Φ system there are two ways of specifying the voltage. First, there is the voltage from each phase conductor to ground, called the phase voltage or line-to-ground voltage. Second, there is the voltage between any two of the three phase conductors. This voltage is called the line voltage or line-to-line voltage.

Line-to-line voltages are usually given when talking about power system circuits. For example, to measure the voltage on a 345 kV line, one would have to connect a voltmeter between two of the phases. The voltage from one of the phases to ground would measure 199 kV ($345 \div \sqrt{3}$).

Figure 2-30 illustrates the relationships between the phase voltage and the line voltage in a balanced 3Φ circuit. The figure illustrates that the magnitude of the line voltage is equal to the magnitude of the phase voltage times the square root of three ($\sqrt{3}$).

A balanced 3Φ circuit means that all three phase voltages and currents are equal in magnitude.

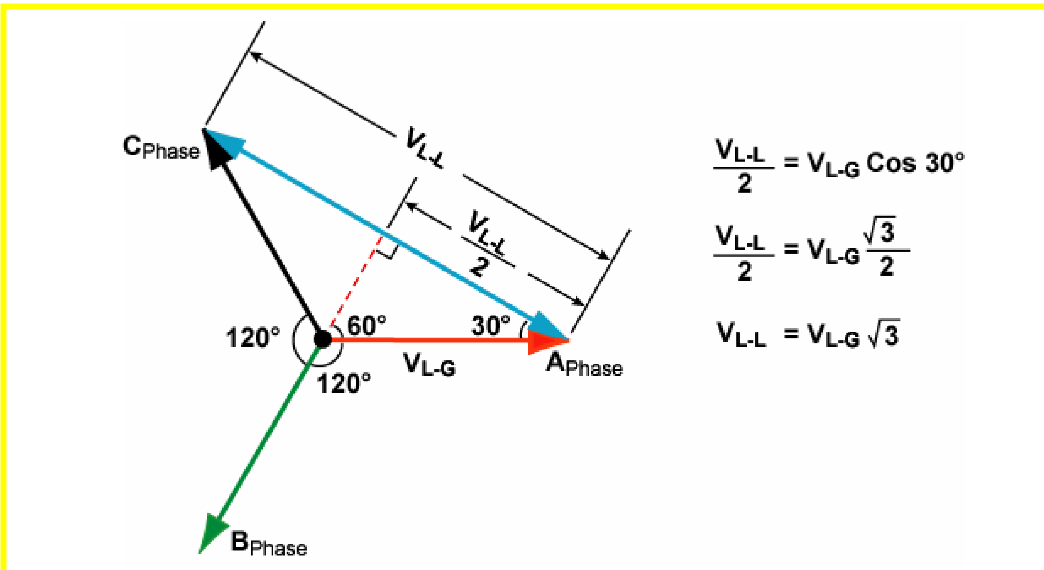


Figure 2-30
Line-to-Line & Line-to-Ground Voltages

Returning to 3Φ power, the active power in a 3Φ circuit is three times the product of the line-to-ground voltage, the current, and the power factor. Since the voltage is usually given as the line-to-line voltage, the 3Φ active power becomes the product of three times the line-to-line voltage, the current, and the power factor all divided by the $\sqrt{3}$. The following equations summarize:

$$\boxed{\begin{array}{l} P_{3\varphi} = 3 \times V_{L\text{-}G} \times I \times p.f. \\ V_{L\text{-}G} = \dfrac{V_{L\text{-}L}}{\sqrt{3}} \\ P_{3\varphi} = 3 \times \dfrac{V_{L\text{-}L}}{\sqrt{3}} \times I \times p.f. \\ P_{3\varphi} = \sqrt{3} \times V_{L\text{-}L} \times I \times p.f. \\ \text{Where:} \\ V_{L\text{-}L} = \text{Line-to-Line Voltage} \\ V_{L\text{-}G} = \text{Line-to-Ground Voltage} \end{array}}$$

The reactive power in a 3Φ circuit is calculated in much the same manner. Recall that the power factor is equal to the cosine θ. The active power is therefore equal to:

$$\boxed{P_{3\Phi} = \sqrt{3} \times V_{L\text{-}L} \times I \times \cos\theta}$$

The formula for 3Φ reactive power is similar:

$$\boxed{Q_{3\Phi} = \sqrt{3} \times V_{L\text{-}L} \times I \times \sin\theta}$$

2.5 Protective Relaying Review

2.5.1 Introduction to Power System Relaying

Power systems are susceptible to a large number of undesired events including:

- Lightning strikes
- Aircraft and motor vehicle encroachment
- Animal encroachment
- Ice and wind storms
- Switching errors
- Power Surges

If any of these events occur, the power system can be damaged and customer service disrupted.

It is the job of power system protective equipment to detect the onset of undesired events and take appropriate action. Appropriate action often includes the tripping of circuit breakers. Circuit breaker tripping isolates the trouble from the remainder of the power system and minimizes damage.

Relays can be broken down into a few major classifications:

- Monitoring relays, such as high temperature or gas-in-oil relays, which monitor power system quantities and initiate an alarm if those quantities are outside of set limits.
- Auxiliary relays, such as timers, tripping, reclosing, or lockout relays, whose job is to supplement the actions of other relays.
- Programming relays, such as automatic synchronizers and generator auto-start relays, which go through a sequence of programmed steps to complete an operation.
- Regulating relays, such as a voltage regulator, which take some action to keep a power system quantity within a desirable range.
- Protective relays, such as overcurrent, overvoltage or distance relays, which protect the power system from damage.

Protective relays are the primary focus of this section.

2.5.2 Purpose and Function of Protective Relays

The purpose of protective relays is to minimize damage and isolate problems. System reliability should not be affected outside the immediate problem area. An important point to remember is that protective relays do not prevent trouble. Relays respond to trouble and minimize further damage. Relays cannot keep animals out of the buswork or lightning from striking a transmission line tower. Relays work quickly, usually in a few cycles, to isolate the source of trouble and avoid further damage.

In the application of relays to the power system, it is desirable to have the relay operate as quickly as possible, so speed is one determining factor in relay selection. Of course, cost will also play a part in the selection. A related factor is complexity—complex relay systems are difficult to work with and are costly to purchase. In judging relay performance: selectivity, sensitivity, and reliability all play a large role.

Selectivity

Selectivity is the ability of the relay to isolate the smallest area of the power system in order to ensure that no further damage is done. The goal is to not disrupt more of the power system than is necessary.

Sensitivity

It is vital that relays be able to detect all faults that jeopardize the power system. Relays must be set sensitive enough to accomplish this goal. However if set too sensitively, a relay may initiate tripping for events which are not a threat to the system.

Reliability

Reliability takes into account most of the principles just described. A reliable protective relay system should operate when called upon with sensitivity and selectivity, yet should be secure against tripping when not necessary.

2.5.3 Power System Faults

In normal 3Φ power system operation, electrical power is generated at the power plant and eventually supplied to the load. Current flows through the transmission and distribution system on one or more of the phase conductors. The current path is then closed via a ground path to the source (the generator) to form a complete circuit. This current path is illustrated in Figure 2-31.

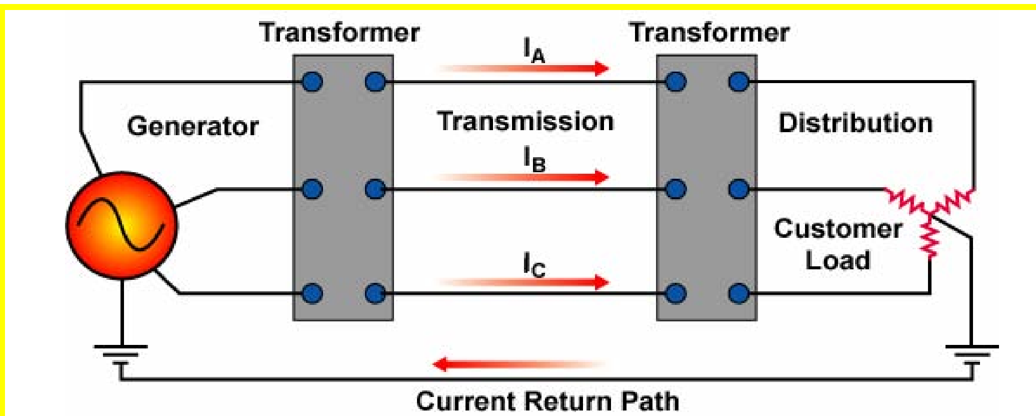


Figure 2-31
Power System Current Flow Path

The term "short-circuit" means that an unusually low impedance current path has been formed. Typically, a short circuit involves bypassing the load impedance.

When a path for current is established that is not desired (a short-circuit) it is known as a fault on the power system. The closer the fault is to generators, which are the source of voltage on the power system, the greater the fault current can be. The fault current is larger because there is less impedance between the fault and the source (the generator). Fault current values in the tens of thousands of amps are common on the high voltage transmission system.

Line-to-Ground Fault

The most common type of fault on the power system is a line-to-ground (L-G) fault. One way of incurring a L-G fault is illustrated in Figure 2-32. The overwhelming majority of L-G faults are caused by lightning either striking or inducing a large voltage on the line conductors.

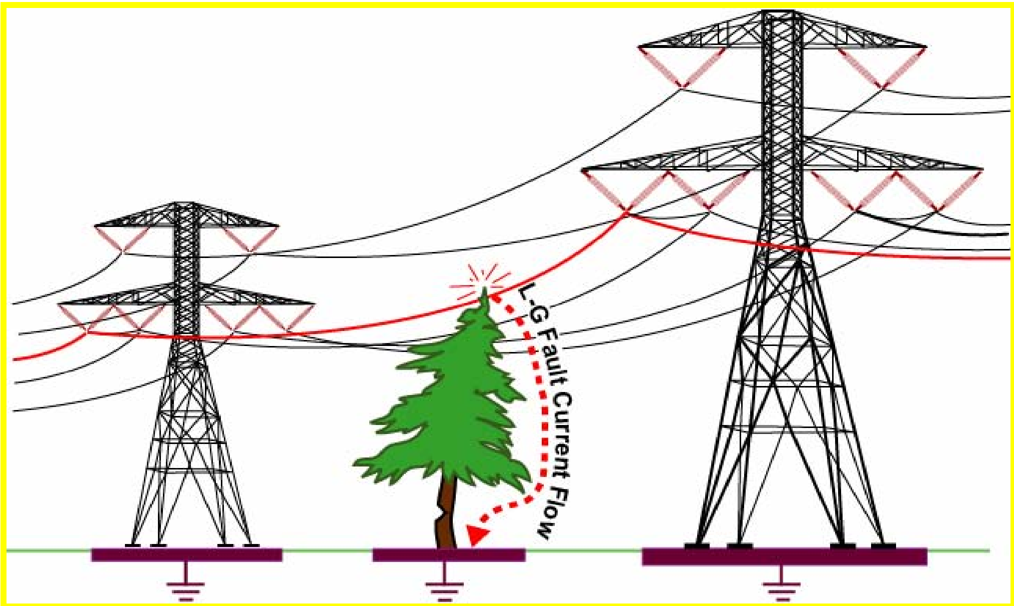


Figure 2-32
Line-to-Ground Faults

A line-to-ground fault is also called a phase-to-ground fault.

L-G fault current magnitudes can range from barely noticeable up to values equal to 3Φ faults. Equipment can be damaged due to the high current magnitudes. L-G faults also create an imbalance in the power system. Balanced power systems have equal currents and voltages on all three phases. During L-G faults, the imbalance may damage rotating equipment such as motors and generators.

Line-to-Line Fault

Line-to-line (L-L) faults are the next most common fault on the power system. L-L faults can be caused by something as simple as wind blowing two phase conductors together as in Figure 2-33. L-L faults also cause an imbalance in the 3Φ system. The imbalance impact on generators is the most severe with this fault type.

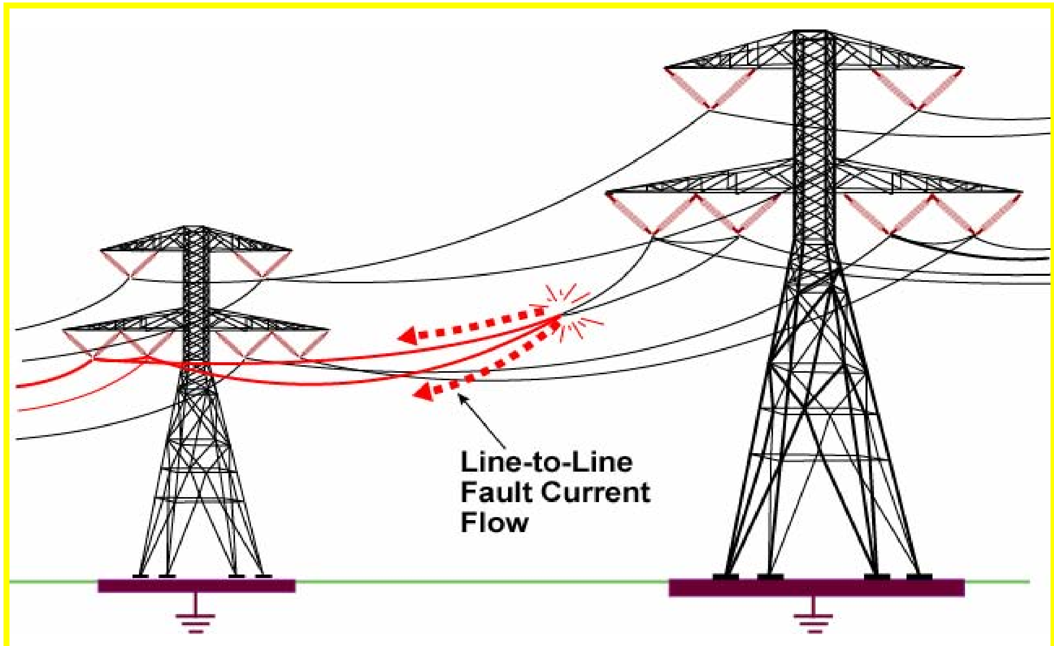


Figure 2-33
Line-to-Line Faults

A line-to-line fault is also called a phase-to-phase fault.

Fault currents are typically high for L-L faults. In addition, ground may or may not be involved. If ground is involved, the fault is called a double-line-to-ground fault.

Three-Phase Faults

Automatic reclosing is an automatic attempt to reenergize a transmission line (following a short time delay) after a transmission line trip.

Faults where all three phases are involved are the least likely to occur. However, 3Φ faults are usually the most severe as far as levels of fault current are concerned. One way of producing a 3Φ fault would be energization of a transmission line with a 3Φ ground switch still closed. Since 3Φ faults are the least likely to occur and are usually of a permanent nature (a structure down or a ground switch closed) automatic reclosing is not permitted on the transmission system for this type of fault.

2.5.4 Instrument Transformers

Instrument transformers reduce power system currents and voltages to lower values. These lower values, called secondary values, can then be input to protective relays, meters, and other devices. The power system voltage and current magnitudes must be reduced as they are simply too large to measure directly in any safe and economical manner. Instrument transformers may be classified into two basic groups: those that are designed to transform high currents, and those that are designed to transform high voltages.

Current Transformers

Instrument transformers designed for transforming current magnitudes are called current transformers (CTs). CTs produce a small secondary current flow (a few amps) that is proportional to a larger primary current flow in the power system. The schematic symbols for CTs are given in Figure 2-34. Two symbols are illustrated. A bushing CT is located in the bushings of electrical equipment. The standard CT is a stand-alone device.

Potential Transformers

Instrument transformers designed for the purpose of transforming voltage are called potential transformers (PTs). Potential transformers are also commonly referred to as voltage transformers (VTs). PTs produce a small secondary voltage (perhaps 120 volt) that is proportional to the higher primary voltage in the power system. The schematic symbol for a potential transformer is given in Figure 2-35.

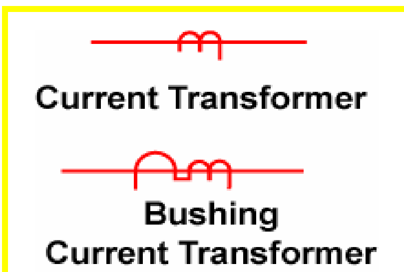


Figure 2-34
CT Symbols

Figure 2-35
PT Symbol

A variation on the PT concept is the capacitively coupled voltage transformer or CCVT. A CCVT is a combination of a PT and a capacitive voltage divider circuit. CCVTs are often used in place of PTs in applications where high accuracy is not required.

2.5.5 Relay Construction & Operation

Relays have been applied in the power system for more than 100 years. The types of relays used have changed over the years. Originally, electro-mechanical relays were applied, then solid state, then microprocessor based. It is essential for system operators to be familiar with the different types of relays and the “targets” (trip indications) or “flags” which relays provide. The targets vary depending on the type of fault, type of relay, and the relay manufacturer.

Electromechanical Relays

Electromechanical (EM) relays were the original type of relays responsible for protection of the power system. EM relays use electrical inputs (voltage or current) to control some form of mechanical operation based on magnetic attraction or induction. Magnetic attraction relay types are either plunger operated or hinged armature operated as illustrated in Figure 2-36. In a magnetic attraction relay, the greater the current through the wires, the stronger the magnetic attraction until electrical contacts close.

Watt-hour meters operate on the same principal as induction relays.

Induction relay types are typically rotating discs as illustrated in Figure 2-37. Induction relays often produce circular motion. The greater the coil current, the larger the force on the rotating disc. Until eventually a set of contacts close initiating an action.

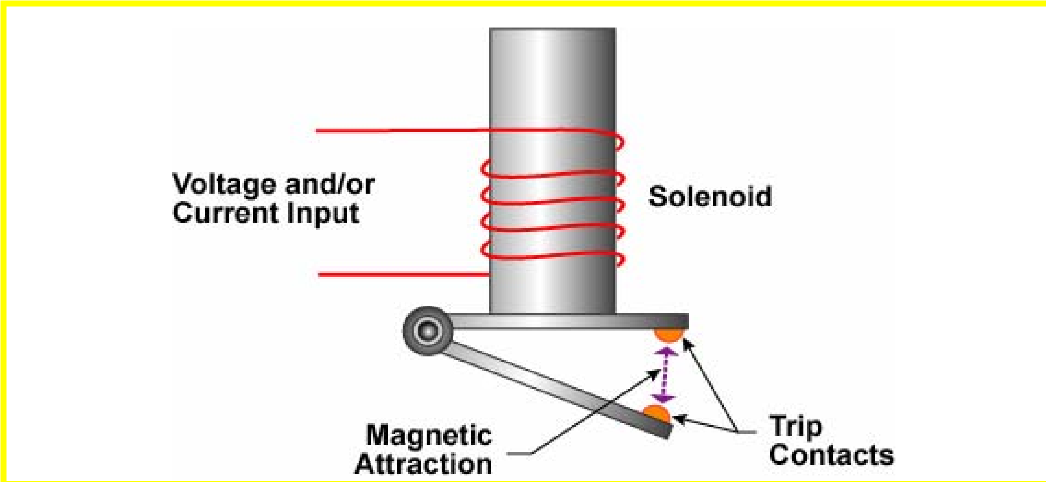


Figure 2-36
Magnetic Attraction Relay Element

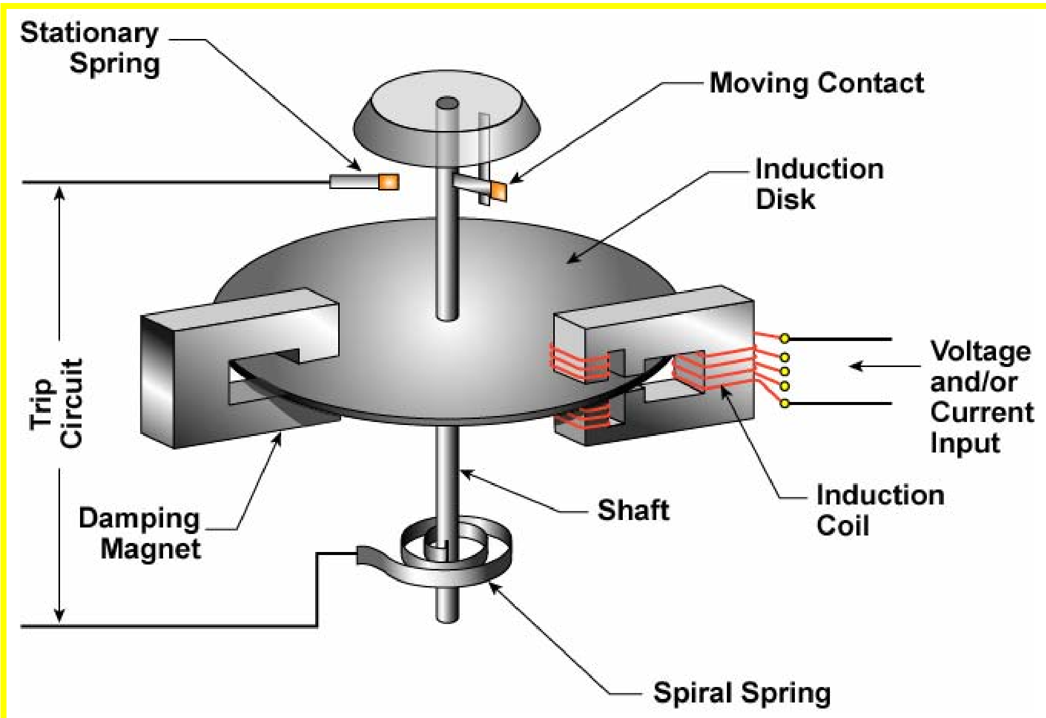


Figure 2-37
Induction Disc Relay Element

An electromechanical (EM) relay is composed of one or more elements similar to the two just illustrated. The actual construction of the relay depends on its function. A typical EM relay is illustrated in Figure 2-38. EM relays have performed well for decades of usage, but most utilities are no longer purchasing EM relays in favor of solid state and/or microprocessor-based relays.

These relays would be mounted in metal relay cabinets. The cabinets are located in substations and in power plants.

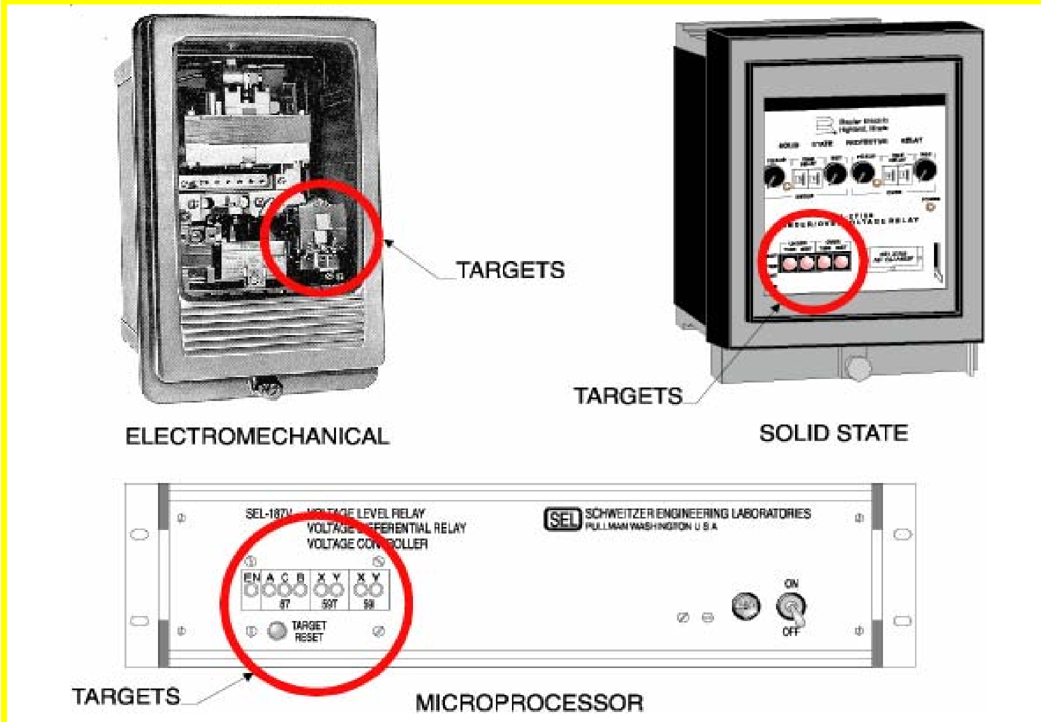


Figure 2-38
Electromechanical, Solid State & Microprocessor Relays

Solid State Relays

Solid-state relays employ electronic components and integrated circuits to detect system conditions and initiate proper actions. Solid-state relays do not use the moving parts associated with electromechanical relays. Modern solid-state relays are generally thought of as maintenance-free and not as susceptible to shock (for example, from an earthquake or being bumped).

Solid-state relays generally cost less than electromechanical relays and are typically packaged with numerous relay functions inside one relay case. For example, one solid-state relay may replace three or four electromechanical relays. This multi-use feature greatly simplifies the space and wiring demands of solid-state relays. Any electromechanical relay function (and then some) can be duplicated using solid-state relays. Figure 2-38 illustrates one type of a solid-state relay.

Microprocessor-Based Relays

A recent advance in relay technology led to microprocessor based relays. Microprocessor relays use the same technology as desktop computers to bring even more functions to relaying. Microprocessor relays can store large amounts of fault data, perform self-checks, monitor line conditions, and carry out the tasks of dozens of individual relays.

A very important feature (from an operations perspective) is that microprocessor relays often have internal fault detectors. A fault detector, combined with telecommunications capabilities, allows system operators to determine the type and location of a fault. Fault locations can be determined almost instantly, which speeds the power system recovery process. Current trends are towards the purchase of microprocessor-based relays if available. Figure 2-36 illustrates one type of microprocessor based relay.

Fault detectors utilize either information on the fault current magnitude or the time delays from voltage and current pulses to determine a fault location.

Relay Targeting

A critical factor for system operators doing system restoration following a fault is interpreting the information provided by the various relays. This information is provided by relay targets or flags. Relay targets are brief descriptions of what caused a relay to operate.

Electromechanical relays have targets that drop down when activated. Figure 2-39 illustrates a typical electromechanical relay target in the reset and tripped state. When the relay trips a “T” symbol (for a timed operation) is visible. Once the cause of the relay operation is identified, a button on the relay is pushed to reset the target. The target for the electro-mechanical relay is visible through the front glass cover of the relay.

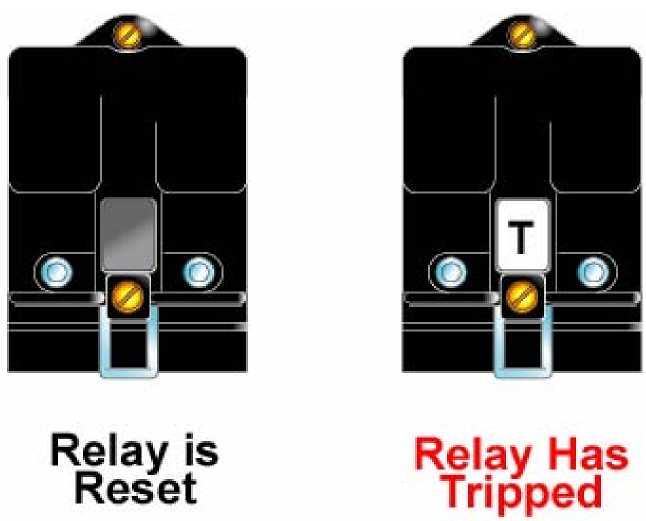


Figure 2-39
EM Relay Target

Solid-state relays typically use light emitting diodes (LEDs) as targets. Depending on the reason for the relay operation, different LEDs will light. For example, the solid-state relay in Figure 2-38 is an under/over voltage relay. Note that various target LEDs will light depending if the voltage is under or over a set limit. LEDs will also light depending on how quickly the voltage changed from its normal value (time or instantaneous) to its trip value.

Microprocessor based relays may use LEDs or character displays as targets. The microprocessor relay in Figure 2-38 uses LEDs. Microprocessor relays can often be contacted via telecommunication systems to gather a wide variety of data concerning an operation.

IEEE Protective Relay Numbering System

A single-line diagram is a drawing that shows one phase of the power system. Important equipment is illustrated on the diagram.

In order to standardize and simplify descriptions of protective relays, the IEEE (Institute of Electrical and Electronic Engineers) created a protective device numbering system. This numbering system is used on power system single-line diagrams, control schematics, etc. Figure 2-40 contains a list and brief description of the device numbers most likely to be encountered by system operators.

Table 2-1
Common IEEE Device Numbers

IEEE Number	Device	Relay Function
21	Distance Relay	Requires a combination of high current and low voltage to operate. The various zones of the distance scheme (Z1, Z2, etc.) assist with determining the location of the fault.
25	Synchronizing Relay	Checks voltage magnitude, phase angle, and frequency to verify synchronism across a circuit breaker before allowing a close.
27	Undervoltage Relay	Operates when voltage falls below a set value.
49	Thermal Relay	Operates when the temperature (usually a winding) exceeds set limits.
50	Instantaneous Overcurrent	Operates with no time delay when current rises above a set level.
51	Time Overcurrent	Operates on a time-delayed basis depending on the amount of current above a set level.
59	Overvoltage Relay	Operates when voltage exceeds a set limit.
63	Pressure Relay	Operates on low or high pressure of a liquid or gas (oil or SF_6) or on a rate-of-change of pressure (sudden pressure).
67	Directional Overcurrent	Operates if current is above a set value and flowing in the designated direction.
79	Reclosing Relay	Initiates an automatic closing of a circuit breaker following a trip condition.
81	Frequency Relay	Operates if frequency goes above or below a set limit.
86	Lockout Relay	An auxiliary relay that can perform many functions (including tripping of breakers) and prevents closing of circuit breakers until it is reset either by hand or electrically.
87	Differential Relay	Senses a difference in currents entering and leaving power system equipment.
94	Tripping Relay	Auxiliary relay which is activated by a protective relay and which initiates tripping of appropriate breakers.

Use of the IEEE Device Numbering System

Figure 2-40 illustrates how device numbers are used in a single-line diagram to identify the location and function of protective relays. Note that device numbers often include a letter, such as in “87T”. In this case, the “T” means that this is a transformer differential, as opposed to a “B” which indicates a bus differential. Other commonly used letters are “G” for generator or ground, “M” for motor, and “N” for neutral.

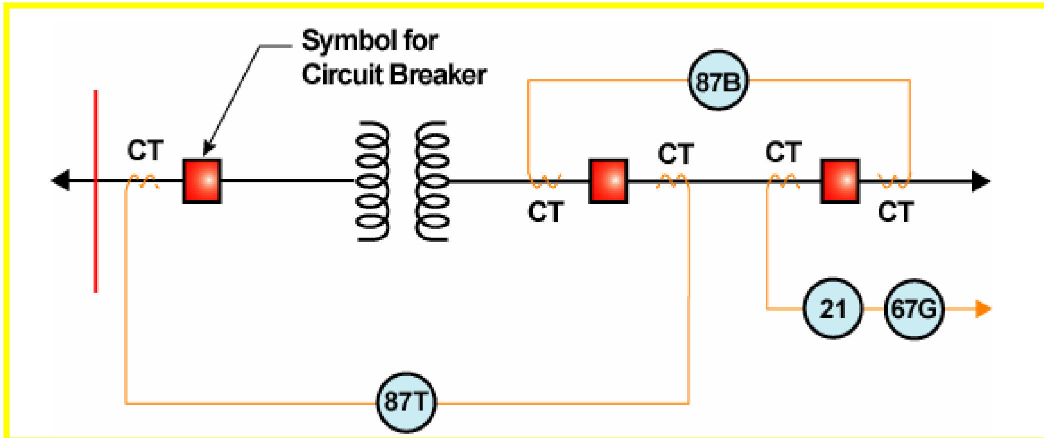


Figure 2-40
Single-Line Diagram Using IEEE Device Numbers

Zones of Protection

It is critical for the proper operation of a power system that all areas of the system be covered by protective relaying. To ensure complete coverage, the power system is divided into zones of protection. Zones are formed around system equipment such as generators, buses, transformers, transmission and distribution lines, and motors. What defines a zone is the limit of the relays sensing ability, which are usually the current transformer (CT) locations.

Figure 2-41 illustrates how a simple power system is broken down into different zones of protection. Note how the zones overlap at the circuit breakers. In this manner, no area of the system is left unprotected. Many areas of the power system are actually in two zones as zone overlap often takes place. When two zones overlap, backup protection is supplied.

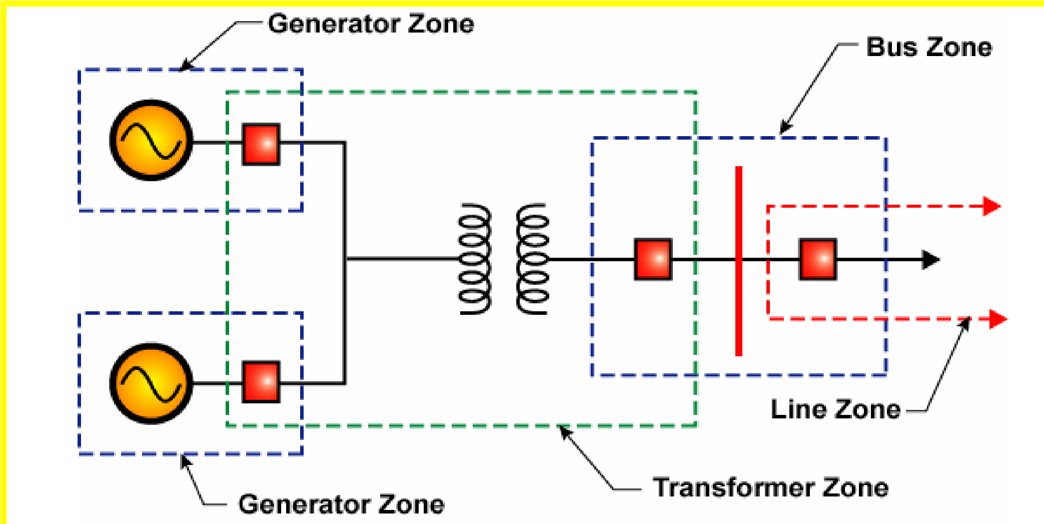


Figure 2-41
Zones of Protection

Primary and Backup Relaying

It would be ideal if all relays correctly identified and tripped for all faults on the system. This is not the case. Relays can be improperly set, sensing inputs can be mistakenly disconnected, and trip outputs can be miswired. Relays can fail to operate due to internal hardware problems. Circuit breakers can fail. It is important to have a backup protective system in case of primary protective system failure.

One way of accomplishing the backup function is to have multiple relays protecting the same equipment. This is especially important on high voltage (230, 345, 500 kV, etc.) transmission lines. For example, 345 kV lines may have two sets of relays performing the same protective function, with one set being the primary relaying and the other set backing up the first set. The primary and backup relays may be identical but are usually from different manufacturers to guard against multiple failures from the same cause.

In the example just described, the second set of relays would be called primary backup because they are located on the same line as the primary relays. If the backup relays are not on the same line but in the same substation, it is known as local backup. An example of local backup would be breaker failure relays.

Breaker failure relays are designed to operate if a breaker fails to open when requested.

Another means of applying backup relaying is through remote backup. Remote backup means that relays at another substation will initiate tripping (usually after a time delay) if the relays responsible fail to operate. Zone #2 and Zone #3 distance relays will act as remote backup relays since they can sense faults on transmission lines past the next substation.

Zone #1, #2, & #3 distance relays are described later in this section.

2.5.6 Types of Relays

Voltage Relays

Voltage relays include undervoltage and overvoltage relays. In an electromechanical voltage relay, as voltage magnitude changes magnetic forces cause relay contact movement. If an overvoltage relay is desired, the relay contacts will be designed to close on increasing voltage. If an undervoltage relay is desired, the relay contacts will close on decreasing voltage.

The value at which a relay begins to operate is referred to as the "pickup" value for the relay.

Voltage relays can be designed to operate with no intentional time delay (instantaneous) or with intentional time delay. Once the voltage hits the pickup value, an instantaneous voltage relay will begin to operate. In a time delay voltage relay, the higher the voltage over (or under) a pickup value the faster the relay will operate.

Voltage relays can also be implemented using solid-state (electronic) construction. In a solid-state relay, input AC voltages are first converted to a low magnitude DC voltage. The DC voltages are then compared to a DC voltage representing the pickup value. In a microprocessor-based relay, input voltages are converted to digital quantities and decisions made from the digital data.

Application of Voltage Relays

Overvoltage relays are frequently used to protect generators and generator transformers from prolonged exposure to high voltages. Overvoltage relays are also used to detect faults within shunt capacitor banks.

Undervoltage relays are often utilized to protect large motors. Motors will automatically draw more current as the motor voltage drops. This current increase can cause overheating and eventual motor failure, hence the application of undervoltage relays. A single-line diagram illustrating the use of voltage relays is given in Figure 2-42. Undervoltage (27) and overvoltage (59) relays are shown connected (via a PT) to a substation bus. The overvoltage relay will operate if the voltage rises too high while the undervoltage relay will operate if the voltage falls too low.

Another common usage for undervoltage relays is to detect if equipment, such as a high voltage transmission line, is energized. For example, a voltage relay may be used to ensure a transmission line is dead prior to allowing a circuit breaker closing.

One relatively recent use of undervoltage relays is to combat the phenomena of voltage collapse. In a voltage collapse, an entire power system can be blacked out due to a deficiency of reactive (Mvar) power. One way to fight the problem is to have undervoltage relays perform load shedding (tripping of customer load) in order to reduce system stress.

Voltage Stability and Collapse are described in Chapter 6.

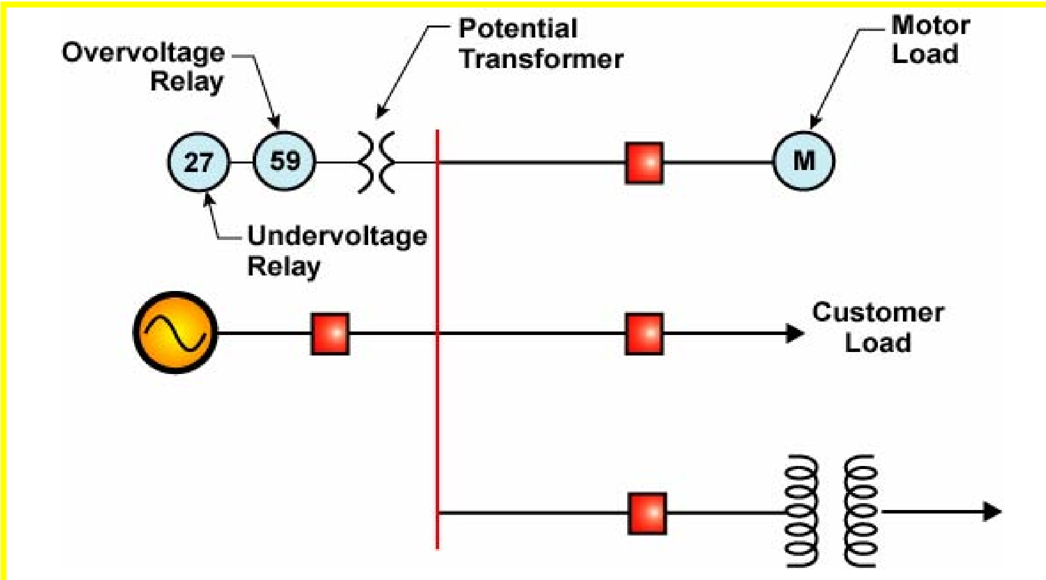


Figure 2-42
Voltage Relays on a Single-Line Diagram

Overcurrent Relays

Overcurrent relays operate if current rises above a pickup value. Overcurrent relay construction is almost the same as that of the voltage relays described earlier. The one difference is the input quantity is current rather than voltage.

For the typical overcurrent relay, the amount of time it takes to operate versus the input current level is known as an "inverse" time characteristic. The inverse term means that the higher the level of current, the less time it takes the relay to operate.

Some possible time characteristic curves for overcurrent relays are illustrated in Figure 2-43. The protection design engineer would choose the correct relay based on how fast they want the relay to operate for a given amount of input current.

Overcurrent relays are divided into two general categories: non-directional and directional.

Non-Directional Overcurrent Relays

Non-directional overcurrent relays do not care what the direction of current flow is on the protected element. Non-directional relays merely sense if the pickup level of current is exceeded and operate when the current is sufficient. Non-directional overcurrent relays do not care which direction the fault current is coming from.

Directional Overcurrent Relays

When restoring a power system, be sure that the polarizing sources for protective relays are energized. See Chapter 11 for more information.

Directional overcurrent relays have additional elements included to determine the direction of current flow through protected equipment. To accomplish directional sensing, the relay checks the relationship between input current and a "polarizing" quantity. The polarizing quantity is simply a reference from which the relay can determine current flow direction. The polarizing quantity can be a voltage or a current. If voltage is used, the relay is voltage polarized. If current is used, the relay is current polarized.

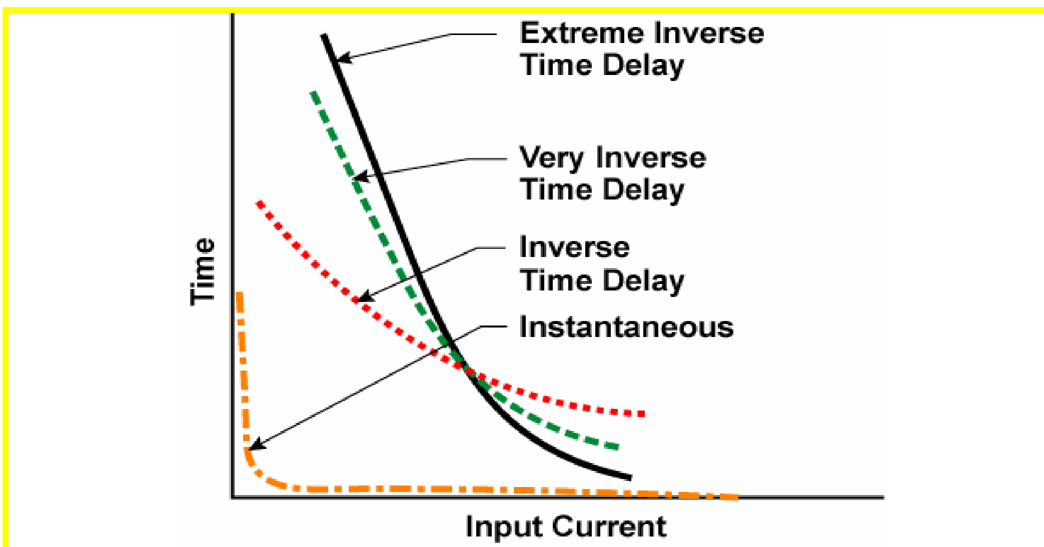


Figure 2-43
Overcurrent Relay—Time Characteristic Curves

Application of Overcurrent Relays

Since high current levels are strongly associated with damage to equipment, overcurrent relays are applied extensively within the power system.

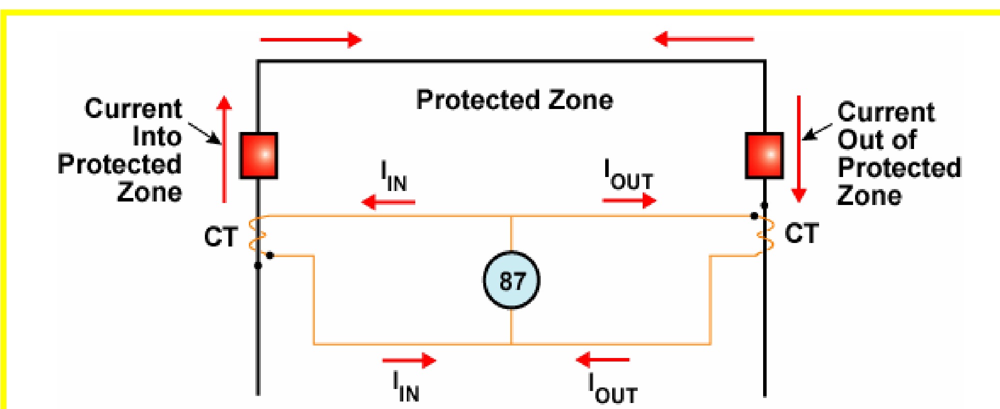
Non-directional overcurrent relays are normally applied where current will only flow in one direction. For example, a distribution line may leave a substation to serve a load area and go nowhere else. This type of line (called a radial line) is a candidate for non-directional overcurrent relay protection.

Non-directional relays can be instantaneous or time delay or a combination of the two. The relays will normally be designed to protect all three phases and the ground conductor. Non-directional overcurrent relays are often used to protect equipment such as motors and generators. Non-directional overcurrents are also used to perform a local backup function. The relays will be set to trip equipment such as substation buses and transformers if primary protection fails to operate.

Directional overcurrent relays may be used to protect transmission lines between substations—where power can flow in either direction. Direction overcurrent relays are more selective than non-directional relays. Directional relays are used to confine a relay's operation to one particular line section. The relay will only trip for faults in the line for which it responsible for. Directional overcurrent relays are often used for ground fault detection. Distance relays (described shortly) are better suited for phase fault detection.

Differential Relays

The operating principle of differential relays is that the current flowing into the protected equipment (or protection zone) must equal the current flowing out. If what flows in does not match what flows out, a fault is assumed present and the relay operates. Current transformers surround the protected area and form the boundary of the zone of protection. The sum of all the CT currents is input to the differential relay. If power system currents are flowing normally, no current flows through the relay as illustrated in Figure 2-44.



Differential relays are simply an application of Kirchhoff's Current Law. Note how the CT currents circulate through the relay wiring but never enter the 87 relay itself. As long as the I_{IN} magnitude is close to the I_{OUT} magnitude, the 87 relay will not activate.

Figure 2-44
Normal (No Trip) Conditions for a Differential Relay

If a fault is present within the zone of protection of the differential, the current flowing into the zone will not match what is flowing out of the zone. The difference between the input and output currents will force current through the differential relay. The relay will operate as illustrated in Figure 2-45.

With a fault in the location shown, the two CT currents I_1 and I_2 sum together and flow through the 87 relay, causing the relay to operate and open the two circuit breakers.

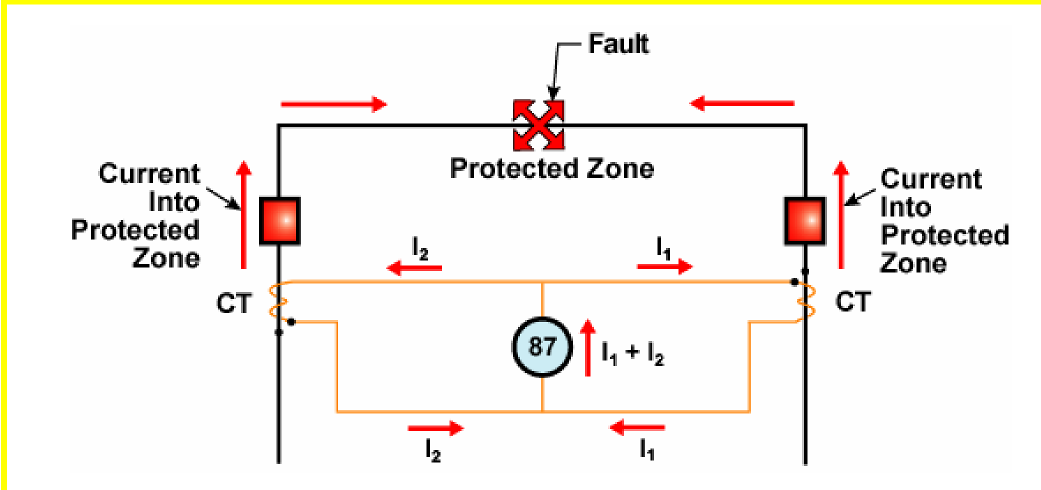


Figure 2-45
Fault Conditions (Relay Trips) for a Differential Relay

Application of Differential Relays

Differential relays are normally utilized to protect important equipment such as substation buses, transformers, and generators. Differential relays are occasionally applied to short transmission lines—especially if the line is short and fiber optic communications channels are available for the line.

Bus Differential

When performing switching, be sure switching actions do not trigger a differential relay operation.

A substation bus is usually protected by a differential relay. The application of a differential relay to a bus is demonstrated in Figure 2-46. The important point is to measure all current flows into and out of the bus. If the current that flows into the bus does not flow out of the bus, a fault is assumed and the 87B relay operates. Problems can arise if the bus configuration is changed through switching. Bus differential relays often have an associated control switch that will change the current paths from the CT's to reflect a new bus configuration.

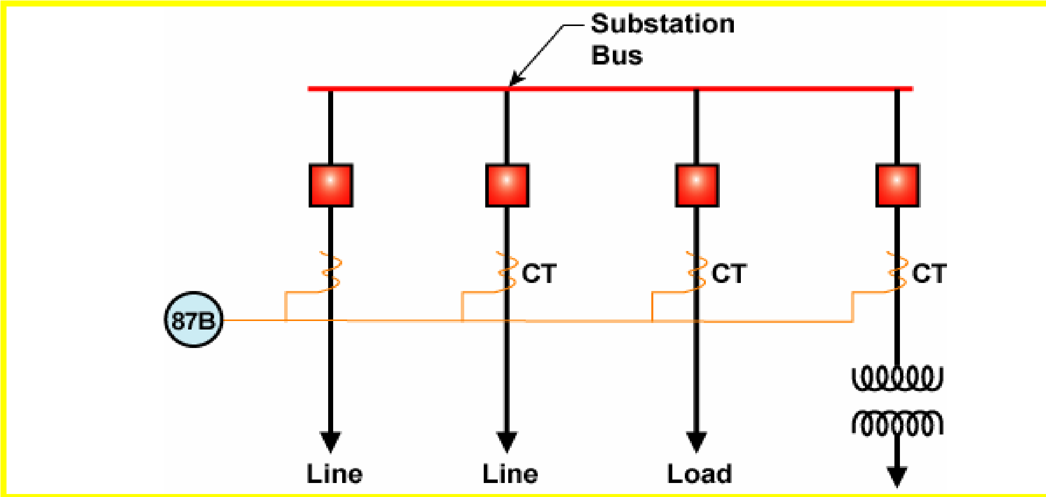
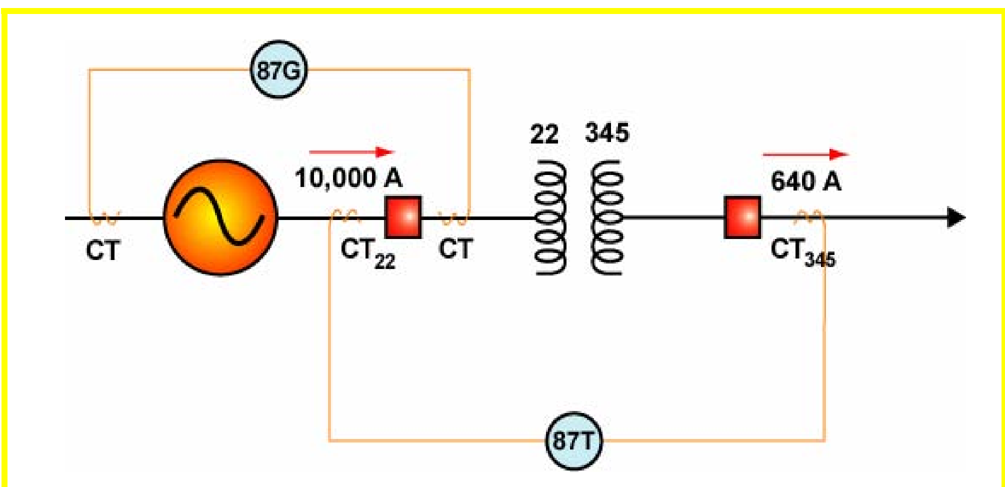


Figure 2-46
One-Line with Bus Differential

Transformer Differential

Differential relaying is applied to most transformers. With transformers, however, a "percentage" differential relay is often used. A percentage differential relay requires that the relay tripping current be a certain percentage (possibly 25%) of the transformer's load current. This helps avoid transformer tripping for external faults, but still allows the relay to detect and operate for internal faults. Figure 2-47 illustrates the application of a transformer differential relay. The 87T is the IEEE device number for a transformer differential.



When protecting a transformer with a differential relay, the protection designer must account for the natural current difference on the high and low sides of the transformer. This is accomplished by properly choosing the CT ratios of the CT_{22} and CT_{345}.

Figure 2-47
Single-line Diagram with Differentials

A problem for transformer differential protection is the high levels of current flow when the transformer is first energized. This "in-rush" current lasts a very short time (a few cycles) but can be several times the full load current rating of the transformer. The in-rush current flows into the transformer to magnetize the core and does not flow out the other side. In-rush current could cause the differential relay to operate unless counter measures are taken. Fortunately, transformer differential relays are available that can tell the difference between load current and in-rush current. These types of differential relays are equipped with a "harmonic restraint" feature. Harmonic restraint enables the differential relay to identify and avoid tripping due to in-rush current.

Harmonics are described in Chapter 9.

Generator Differential

Differential relays used in the protection of a generator's stator windings are similar to a transformer differential. Generator differentials typically operate based on a "variable percentage" characteristic. Recall, a percentage differential relay operates if the relay operating current reaches a specified percentage of the load current. A variable percentage relay operates on the same principle but the percentage required for relay operation varies with the load level. A generator differential at low generator loading would require less of a percentage of load current to trip than at high loading. Figure 2-47 also illustrates the application of a generator differential (87G).

Voltage Differential Relays

In addition to the current operated differential relays just described, there are differential relays that operate based on a difference in voltage. Voltage differential relays are not as common and are used mainly for detection of blown fuses in shunt capacitor banks.

Distance Relays

Impedance is measured in ohms and is a measure of electrical distance. The terms impedance and distance are often used interchangeably to refer to relays that measure

Distance relays have both current and voltage inputs. A distance relay divides its voltage input by its current input (V/I) to calculate the system's "Z" or effective impedance. The effective impedance is the impedance of the power system from the distance relay's perspective.

If a fault occurs close to a distance relay's location, current increases and voltage decreases, and the relay's effective impedance shrinks. If a fault occurs far away from a relay's location, the relay's impedance will not change significantly.

Assume that a distance relay is installed to protect a transmission line. The impedance of the protected line is known and provided to the relay as part of the relay's initial installation procedures. If a fault occurs on the protected line, the impedance measured by the relay will be less than the known line impedance. The relay will then operate and trip the line.

A distance relay is set to operate based on a certain percentage of whatever the protected line's impedance is. This is known as the distance relay's "reach". For example, assume a line section has an impedance of 100 Ω. A distance relay may be set to trip for any impedance detected that is less than 90 Ω. If a fault occurs anywhere within the first 90% of the line's length, the relay will operate. The reach of this relay is then 90Ω or 90% of the lines' natural impedance (100Ω) or length. Distance relay reaches are stated in terms of zones of protection. For example, zone #1 reach is usually set for 90% of the line length. The reach of zone #1 is limited to 90% to ensure that the relay does not "overreach" or trip for faults in an adjacent line section.

Types of Distance Relays

Distance relays can be implemented using either electromechanical or solid state elements, but the operating principles are the same. The basic types of distance relays are reactance, impedance, and MHO. All three types are measuring system impedance, but do so in different ways. The most common distance relay is a MHO relay. An operating characteristic for a MHO type distance relay is illustrated in Figure 2-48.

A MHO relay actually measures the inverse of impedance. MHO is ohm spelled backwards to represent the inverse of impedance.

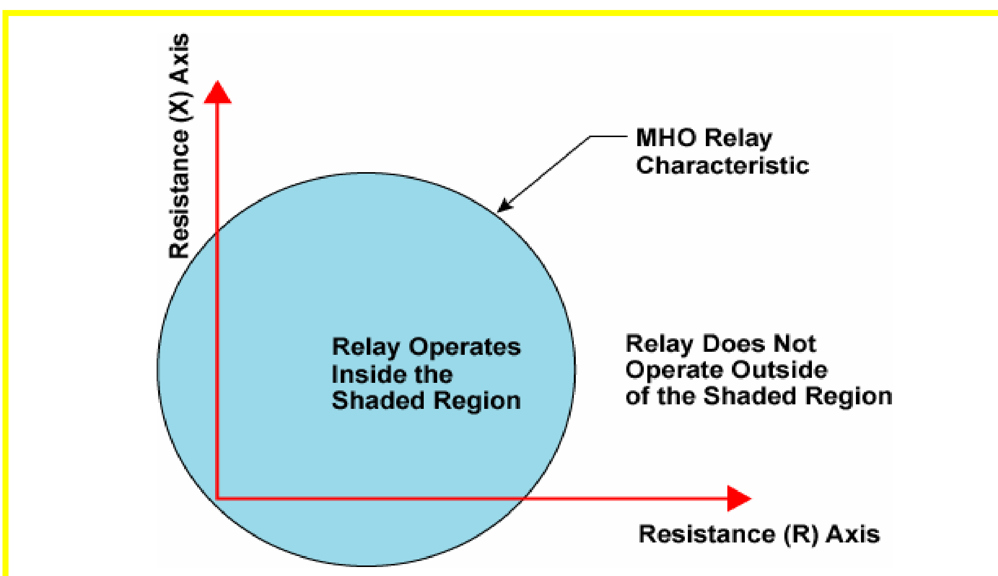


Figure 2-48
MHO Characteristic on an R-X Diagram

This type of plot is known as an R-X diagram.

A distance relay's operating characteristic, illustrated in Figure 2-48, is a plot of the impedance settings for the relay. In other words, the operating characteristic is a plot of the relay reach. Recall that if the distance relay's measured effective impedance is lower than the distance relay's reach, the relay will operate. The reach of the MHO relay illustrated in Figure 2-48 is defined by the circle. If the relay calculates an impedance that is inside the circle, the relay will operate. If the effective impedance is outside the circle, the relay will not operate.

Typical Distance Relay Protection Scheme

Distance relays are most often used to protect transmission lines. Distance relay schemes are typically implemented using three zones of protection. Each zone is formed by a separate distance relay. Zone #1 typically covers 90% of the protected line and is set to trip instantaneously. If a fault occurs within a zone #1 reach, it is rapidly (within a few cycles) cleared. Zone #1 provides the protected line section's primary protection.

Remember, these are general guidelines for distance relay settings. Actual settings for reach and time delay will vary with the utility.

Zone #2 covers approximately 120% of the protected line's impedance. Zone #2 actually looks beyond the end of the protected line into the next line section. Zone #2 tripping is done only after a short (perhaps 1/3 second) time delay. A zone #2 time delay is used to allow the zone #1 relay of that particular line section the first chance to trip. Each zone #2 relay is providing backup protection to zone #1.

Zone #3 reach is usually 150% (or more) of the protected line's impedance. Zone #3 may reach the entire length of the next line section. Zone #3 is also a time-delayed trip. A typical zone #3 time delay may be 1 second. Zone #3 is providing time-delayed backup to both zone #2 and zone #1. It should be apparent to the reader that distance protection schemes are designed to be very reliable.

Figure 2-49 contains a single-line diagram of a simple distance relay scheme incorporating three zones of protection. Note that the zones are only shown for substation "A" of the line. There will be a duplicate set of distance relays at substation "B" looking back towards substation "A". If a fault were to occur at the fault "X" location in Figure 2-49, all three zones of substation "A" would detect the fault. Zones #2 and #3 are time-delayed backups and would not cause any circuit breaker tripping unless zone #1 failed to clear the fault. For the line's protection to completely fail, all three zones of protection would have to fail to operate at both substations, "A" and "B". This is highly unlikely.

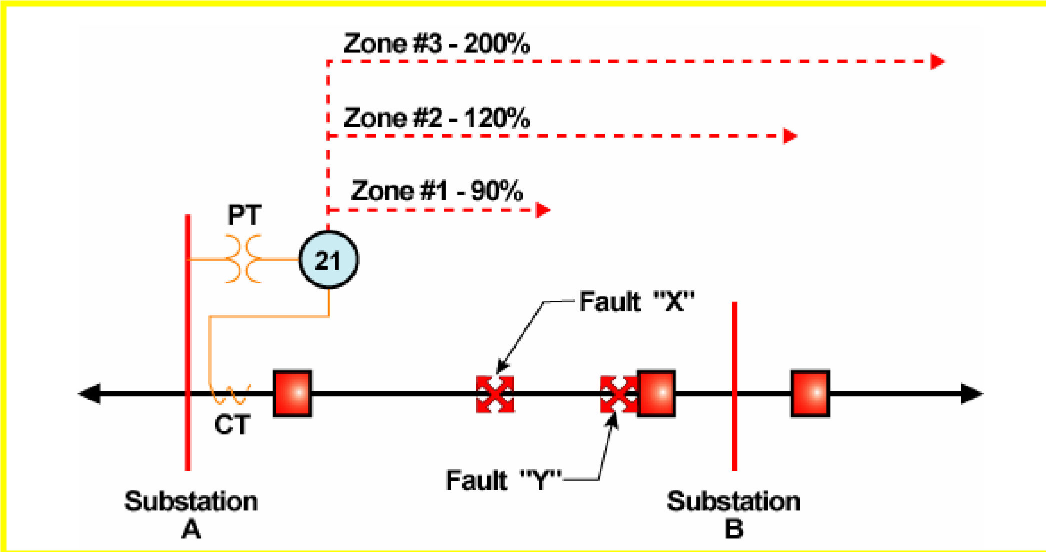


Figure 2-49
Distance Relay Scheme

Application of Distance Relays

Distance relays are typically applied to detect line-to-line and 3Φ transmission line faults. Ground faults are typically detected using overcurrent relays. There are distance relays designed for ground fault detection and their use is becoming more common.

Distance relays are almost universally applied for protection of high voltage transmission lines. Distance relays can also be applied at lower voltages, but are less common. Distance relays are often incorporated into protection schemes that include communications between a transmission line's terminals. These protection schemes are called "pilot" relaying and are briefly described in the next section.

Pilot Relaying

Faults on the high voltage transmission system often involve tens of thousands of amps. It is imperative to "clear" the fault (trip the circuit breakers) in as short a time as possible. Assume we were to rely on zone #2 to trip for faults beyond zone #1 but before the end of the line. Such a fault location is illustrated as fault "Y" in Figure 2-49. Since substation "A" zone #2 trips only after a time delay, we would be allowing a fault to exist for whatever the zone #2 time delay is. This could result in a severe system disturbance or equipment damage.

Pilot relaying is widely used to achieve rapid tripping of all terminals of a transmission line for any fault location on the protected line.

Pilot Relaying Theory of Operation

If a fault is somehow determined to be within a protected line section and not outside it, distance relays at both ends of a line section could be allowed to rapidly trip their respective circuit breakers. Figure 2-50 contains an illustration of a simple pilot relaying scheme. Note the distance relays (21 device) at each substation. Each distance relay's zone of protection reaches past the substation at the far end of the line. If a fault were to occur anywhere within the protected line section, both distance relays would detect the fault. If a fault were to occur outside of the protected line section, one of the distance relays would not detect it.

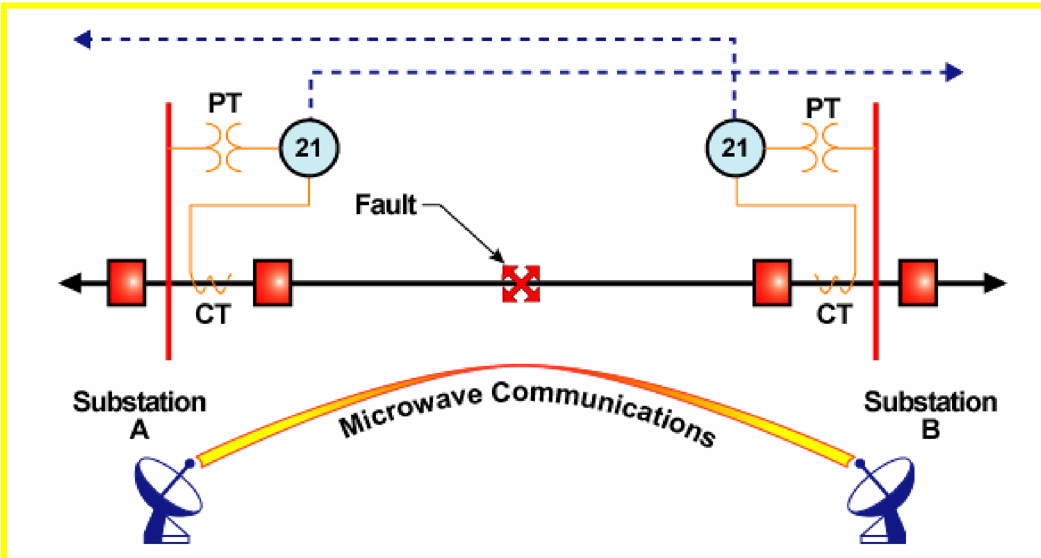


Figure 2-50
Simple Transmission Line Pilot Protection Scheme

If both distance relays detect the fault, the fault is assumed within the protected line section. To verify that both relays see the fault a communications channel is provided between the line's two substations. Once each relay sees the fault it triggers a transmission of this information (sends permission) to the other line terminal.

You may have heard the term "pilot-wire" relay. Pilot-wire relays are an older form of pilot protection that use a hard-wire path for communications.

For tripping to occur, a substation's relays must see the fault in the forward direction and receive "permission" from the other end of the transmission line. This detection of the fault and receipt of permission proceeds very rapidly. Pilot schemes may detect and trip a line's circuit breakers in 3 cycles. The faster the better, as transmission level faults are high current and capable of causing great harm to the power system.

Various methods are utilized for communications between a protected line's substations. Telephone lines, pilot wires, power-line carrier, satellite, microwave, and fiber-optic are a few options. The most widely used medium is microwave. Fiber-optics has the most capability, but is also the most expensive to implement.

There are many different pilot relaying schemes used within power systems. Some common pilot scheme names include:

- Directional Comparison Blocking (DCB)
- Directional Comparison Unblocking (DCU)
- Permissive Overreaching Transfer Trip (PUTT)
- Permissive Underreaching Transfer Trip (POTT)
- Direct Underreaching Transfer Trip (DUTT)

All types of pilot relaying schemes have two things in common:

1. A means to detect if a fault is inside or outside the protected line
2. A means to communicate that information to both line terminals

Pilot schemes are sometimes worthless if the telecommunications equipment for the scheme is out-of-service. Be very careful with disabling telecommunications schemes, you may be compromising critical power system protection.

2.5.7 Synchronizing and Synchronizing Equipment

Theory of Synchronizing

When closing a circuit breaker between two energized parts of the power system, it is crucial to match voltages on both sides of the circuit breaker before closing. If this matching or “synchronizing” process is not done correctly, a power system disturbance will result and equipment (including generators) can be damaged. In order to synchronize properly, three different aspects of the voltage across the circuit breaker must be closely monitored.

The three aspects of the voltage are called the synchronizing variables and are:

1. The voltage magnitudes
2. The frequency of the voltages
3. The phase angle between the voltages

Note that as used here the term “phase angle” is the phase difference between two voltage waveforms.

Voltage Magnitude Synchronizing Variable

If the voltage magnitudes are not closely matched, a sudden rise in Mvar flow will appear across the circuit breaker as it is closed. For example, if a 345 kV circuit breaker were closed with a 20 kV difference in voltage across the open circuit breaker, a large Mvar flow would suddenly occur upon closing. This sudden change to Mvar flow could lead to sudden changes in area voltages and possibly lead to protective relay operation. The allowable voltage magnitude differences across the open circuit breaker are system specific. However, for general guidance, a difference of a few percent is unlikely to cause any serious problem.

Frequency Synchronizing Variable

If the frequencies on either side of an open circuit breaker are not matched prior to closing, a sudden change in MW flow will appear across the circuit breaker as it is closed. The sudden MW flow change is in response to the initial frequency difference as the system seeks to establish a common frequency once the circuit breaker is closed. The allowable frequency difference is again system specific. However, a general guideline would be to have the frequencies within 0.05 HZ of each other prior to closing.

Phase Angle Synchronizing Variable

The third synchronizing variable—and likely the most important of the three—is the voltage phase angle difference. If the phase difference between the voltages on either side of the open circuit breaker is not reduced to a small value, a large MW flow increase will suddenly occur once the circuit breaker is closed.

The Greek letter δ (delta) is used in this text to symbolize the voltage phase angle difference.

The concept of a voltage phase angle difference is illustrated in Figure 2-51. The voltage phase angle difference (δ) is the difference between the zero crossings of the voltages on either side of the open circuit breaker. Ideally, the voltage phase angle should be as close to zero degrees as possible before closing the circuit breaker.

Synchronizing Examples

The importance of synchronizing cannot be overstated. All system operators should understand the theory and practice of synchronizing. If two power systems are synchronized via an open circuit breaker, and the synchronizing process is not done correctly, generators and customer equipment could be severely damaged. Two scenarios for synchronizing are presented to describe the synchronizing process. In addition, Chapters 3 and 11 will further examine this important topic.

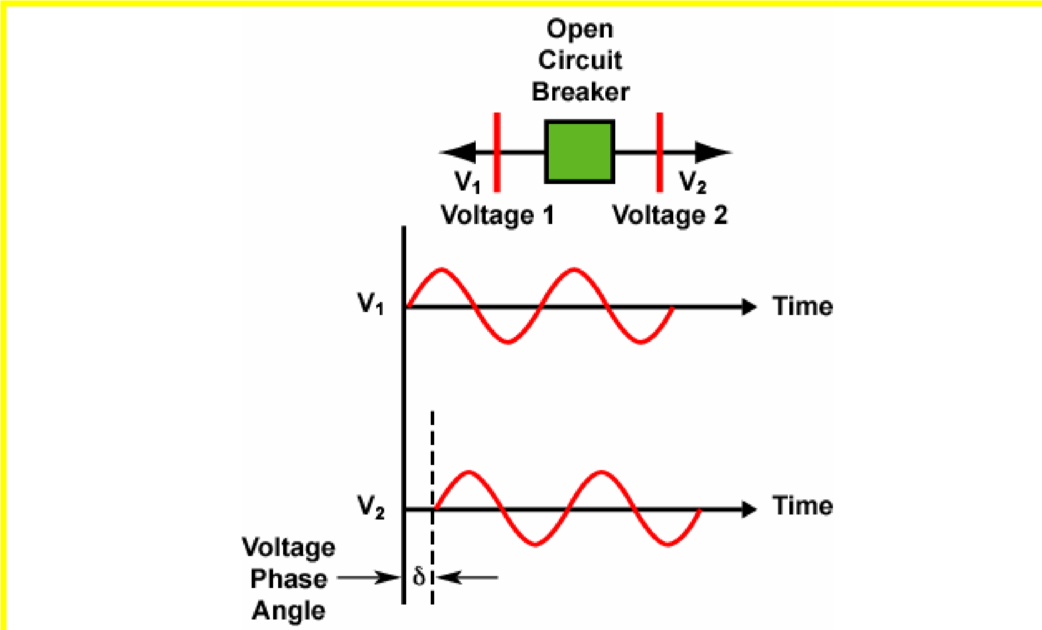


Figure 2-51
Voltage Phase Angle Difference

Scenario #1: Synchronizing Two Islands

The first scenario assumes that two islands are about to be connected together using an open circuit breaker as illustrated in Figure 2-52. The two islands, since they are independent electrical systems, will have different frequencies so all three of the synchronizing variables must be monitored to ensure they are within acceptable limits prior to closing the open circuit breaker.

Note that synchronizing equipment is required to synchronize these two islands. Various types of synchronizing equipment are described in the next section.

The system operators for the two islands will likely have to adjust generator MW output levels (or adjust island load magnitudes) in one or both islands to achieve the desired adjustment in frequencies and phase angles. Voltage control equipment (reactors, capacitors, etc.) may also be used as necessary to change voltage magnitudes to within acceptable levels.

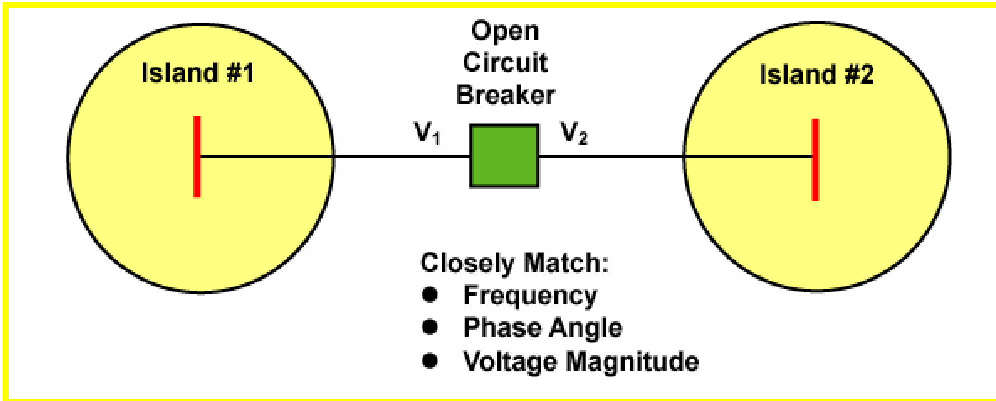


Figure 2-52
Synchronizing Two Islands

Scenario #2: Establishing the Second Tie

While a synchroscope is not required for Scenario #2, some form of synch-check relay (for phase angle monitoring) is required along with voltage magnitude metering.

Once the first transmission line is closed, interconnecting the two islands, the frequency will be the same in the two areas. Therefore, one of the three synchronizing variables (the frequency) is no longer a factor. However, as illustrated in Figure 2-53, the other two synchronizing variables must still be monitored. Generation and/or voltage control equipment may have to be utilized to ensure the phase angle and voltage magnitude differences are within acceptable limits prior to closing the second circuit breaker. This process may be easier than closing the first transmission line (Scenario #1) as frequency is no longer a factor.

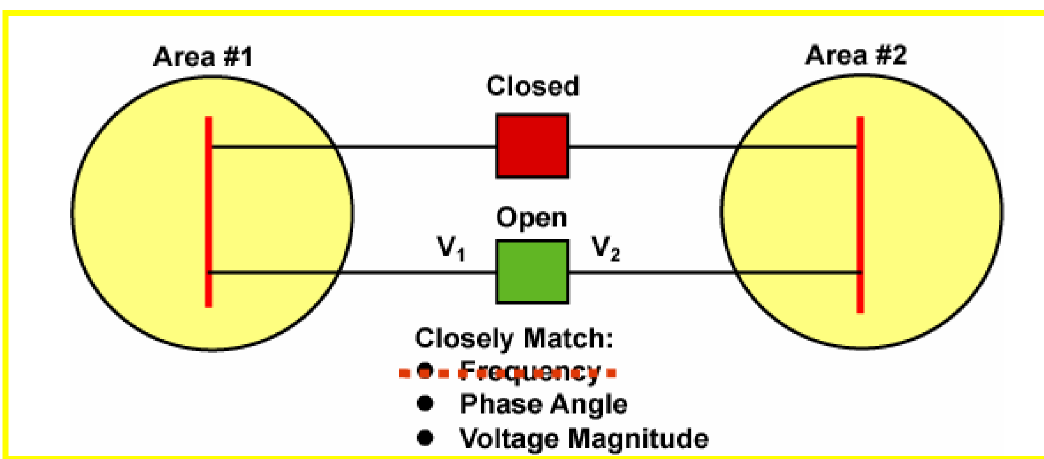


Figure 2-53
Establishing the Second Transmission Tie

Synchronizing Equipment

Synchroscope

A synchroscope is a simple piece of equipment that is used to monitor the three synchronizing variables. A basic synchroscope (illustrated in Figure 2-54) inputs voltage waveforms from the two sides of the open circuit breaker. If the voltage waveforms are at the same frequency, the synchroscope does not rotate. If the voltage waveforms are at a different frequency, the synchroscope rotates in proportion to the frequency difference. The synchroscopes needle always points to the voltage phase angle difference at that moment in time.

If one side of an open circuit breaker is at 61 Hertz and the other side at 60 HZ, the synchroscope needle will rotate at one revolution per second.

A synchroscope is a manual device in that an operator must be watching the "scope" to ensure they close the circuit breaker at the correct time. The synchroscope is normally mounted above eye level on a "synch panel". The synch panel also contains two voltmeters so that the voltage magnitudes can be simultaneously compared.

The synchroscope in Figure 2-54 reflects a slight voltage magnitude mismatch, and a stationary needle with a phase angle of approximately 35°. The fact that the synchroscope needle is not rotating indicates frequency is the same on either side of the circuit breaker.

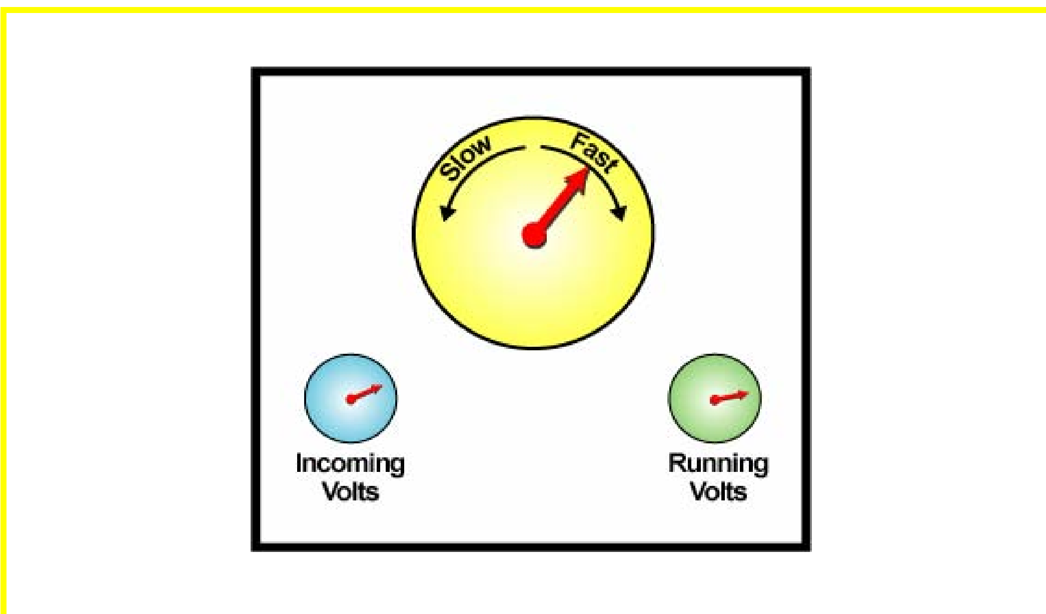


Figure 2-54
Synchroscope In a Synch Panel

Synchro-Check Relays

In some power systems, the operator can monitor the three synchronizing variables via their SCADA system.

A synchro-check or synch-check relay electrically determines if the difference in voltage magnitude, frequency and phase angle falls within allowable limits. The allowable limits will vary with the location on the power system. Typically, the further away from generation and load, the more phase angle difference can be tolerated. Synch-check relays typically do not provide indication of the voltage magnitude, frequency or phase angle. A synch-check relay decides internally whether its conditions for closing are satisfied. The synch-check relay will either allow or prevent closing depending on its settings. A typical synch-check relay may allow closing if the phase angle across the breaker is less than 30°.

Application of Synchronizing Equipment

Some power systems utilize automatic synchronizers in their transmission systems. The system operator activates the automatic synchronizer when desired and as long as the three synchronizing variables fall within allowable limits; the automatic synchronizer will allow circuit breaker closing.

At power plants, synchroscopes are routinely installed to permit manual closing of a circuit breaker. In addition, synch-check relays can be used to "supervise" the closing of the circuit breaker and prevent a distracted or inexperienced operator from initiating a bad close.

Modern power plants typically utilize automatic synchronizers. Automatic synchronizers send pulses to a generator's exciter and governor control systems to change the voltage and frequency of the unit. The synchronizer will automatically close the circuit breaker when the three synchronizing variables are within allowable limits.

Substations in the transmission system have traditionally had synchroscopes installed. However, few substations are now manned due to cost constraints and the availability of powerful SCADA systems. Because of this development, newer substations may or may not have a synch panel, depending on the transmission company procedures. Since most circuit breaker operations are done remotely, transmission companies often rely on synch-check relays to supervise closing of breakers.

Figure 2-55 illustrates a possible synchronizing system for substation circuit breakers. Note the use of a synch scope and a synch-check relay. Electrical contacts can be opened or closed to rearrange the synchronizing system as desired.

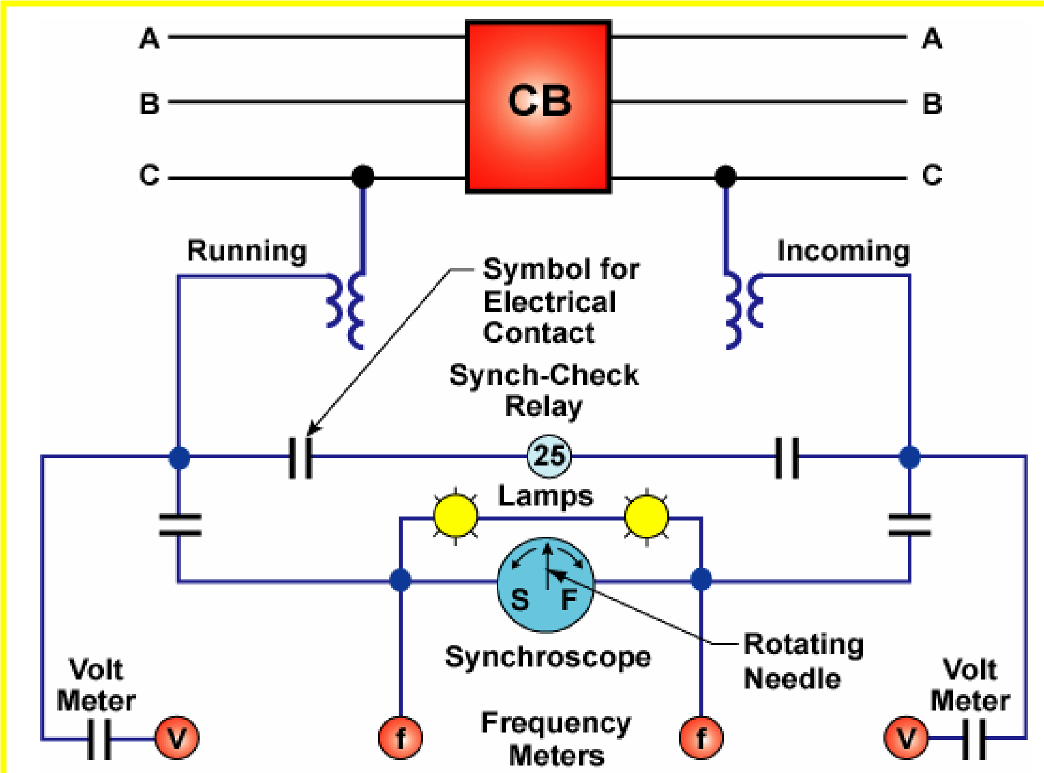


Figure 2-55
Synchronizing System for a Substation Breaker

2.6 Power System Equipment Review

2.6.1 Introduction to Equipment Review

Electrical power is generated at generating stations. The power is then transmitted via high voltage transmission lines to substations near load areas. Lower voltage distribution lines then distribute the power to customer sites. Throughout the generation, transmission, and distribution path, the voltage level of the power is transformed several times.

This section will briefly review the operation of key equipment used in electrical power systems. Among the equipment described are generators, transmission lines, transformers, circuit breakers and thyrister systems.

2.6.2 Generators

Basic Theory of AC Machines

An alternator is a rotating machine that produces AC voltage and current. The armature is the winding in which the AC voltage is induced.

Electric generators have field and armature windings. Mechanical energy is converted to electrical energy through the relative motion of these two windings. The principle of AC generation is now described using an alternator that incorporates a rotating armature winding and a stationary field winding. With this basic understanding, the next step is to describe the common utility practice of using a rotating field winding and a stationary armature winding to create AC power.

Figure 2-56 illustrates an elementary 1Φ AC machine. This machine consists of a conductor (armature) rotating through a magnetic field. The magnetic field path is between the north and south magnetic poles of a permanent magnet. Remember that a magnetic field is composed of lines of magnetic flux flowing between the north and south poles. When the armature coil is placed in a magnetic field, magnetic flux lines cut through the armature coil. A voltage is induced in the armature coil as the amount of magnetic flux cutting through it changes. The amount of voltage induced in the armature coil is directly proportional to the rate at which the flux passing through the coil changes.

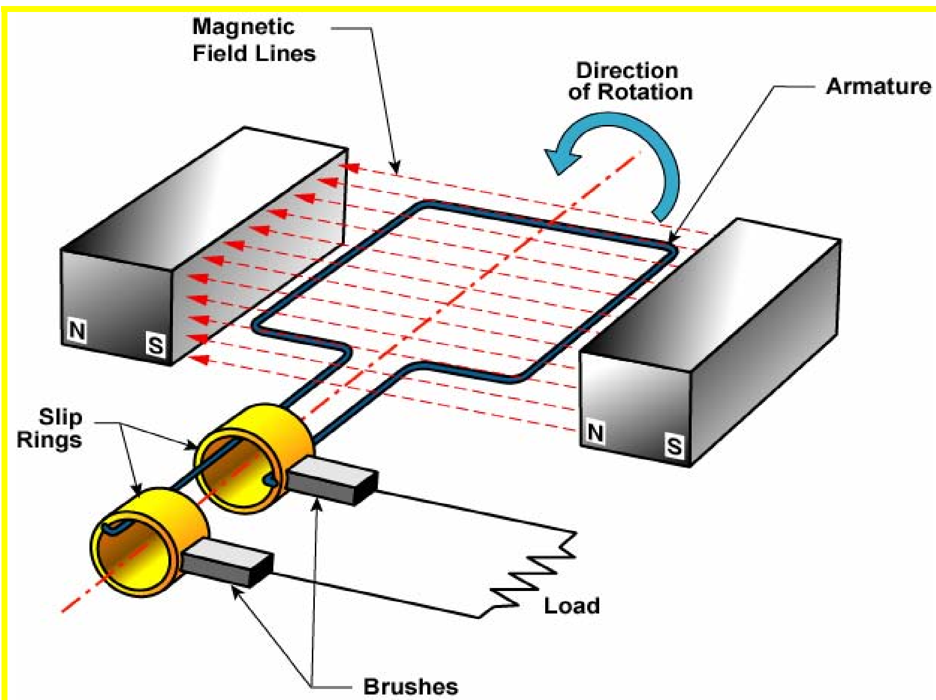


Figure 2-56
Rotating Armature With Stationary Field Winding

As illustrated in Figure 2-57, the armature is physically shaped and it rotates in such a manner that in the vertical position—Figure 2-57(a)—the armature is not cutting through any lines of the magnetic flux. Since the flux is not changing, no voltage is being generated at this position. As the armature rotates counterclockwise, more and more lines of the magnetic flux are cutting through the armature. A peak voltage is reached when the armature is in the horizontal position—Figure 2-57(b).

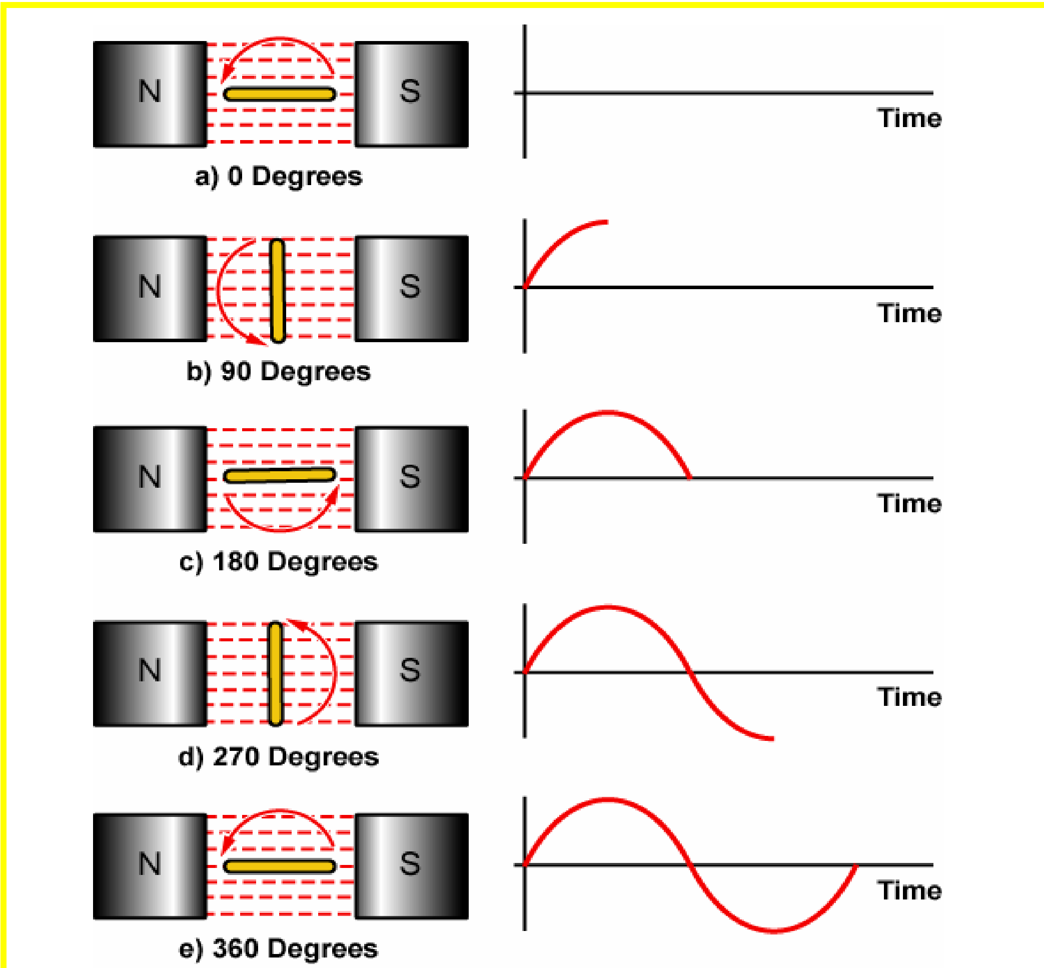


Figure 2-57
Armature Rotation & Voltage

As the armature continues to rotate past the horizontal position, the voltage decreases, reaching zero when the conductor again reaches the vertical position—Figure 2-57(c). When the conductor has finished one complete rotation (360°), an entire AC voltage sine wave has been generated as illustrated in Figure 2-57(e). In order to transfer load current from the rotating armature to a non-rotating load, the armature coil terminates in slip-rings (see Figure 2-56). Carbon brushes are used to deliver load current from the slip-rings to the load. These brushes ride on the smooth surface of the slip-rings.

Utility Scale Power Generators

The elementary AC generator in Figure 2-56 is not practical for large amounts of power generation. The AC load currents on big power generators are too large to use slip-rings. To eliminate slip-rings in the output AC current path, a power generator uses a rotating magnetic field produced about the rotor and a stationary armature coil built into the stator. This is the opposite to the configuration of the simple machine in Figure 2-56

The generator's exciter is the source of the DC excitation current.

The magnetic field in the generator is produced by running a DC current (called an excitation current) through the field windings embedded in the rotor. This DC current turns the rotor into an electromagnet. The strength of this magnetic field can be changed by adjusting the amount of DC excitation current flowing through the field winding.

The rotor is connected to a prime mover, such as a steam or water turbine. The prime mover provides the mechanical input power to turn the generator's rotor. As the rotor turns, a rotating magnetic field is created about the rotor. This field induces an AC voltage in the armature coil that is embedded in the stator. Figure 2-58 illustrates the process used to produce electricity in a typical power generator. The rotating field coil induces an AC voltage in the stationary armature coil. The excitation current is provided to the rotating field winding via a brush and slip-ring assembly.

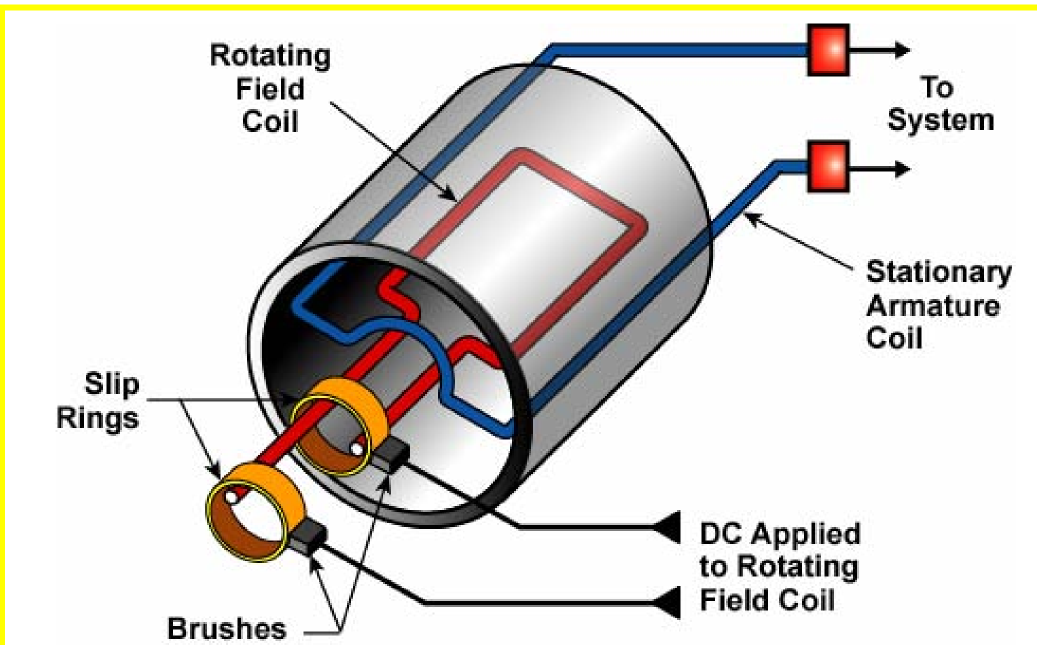


Figure 2-58
Single Phase AC Power Generator

Large power generators are 3Φ generators, not 1Φ as was illustrated in Figures 2-56 and 2-58. Three-phase generators have three sets of stator (armature) windings, one for each phase. Each one of the stator winding sets produces a sine wave of voltage. Each phase voltage has a 120° phase angle separation from the other two phase voltages. The conceptual design of a 3Φ generator and its output voltages are illustrated in Figure 2-59.

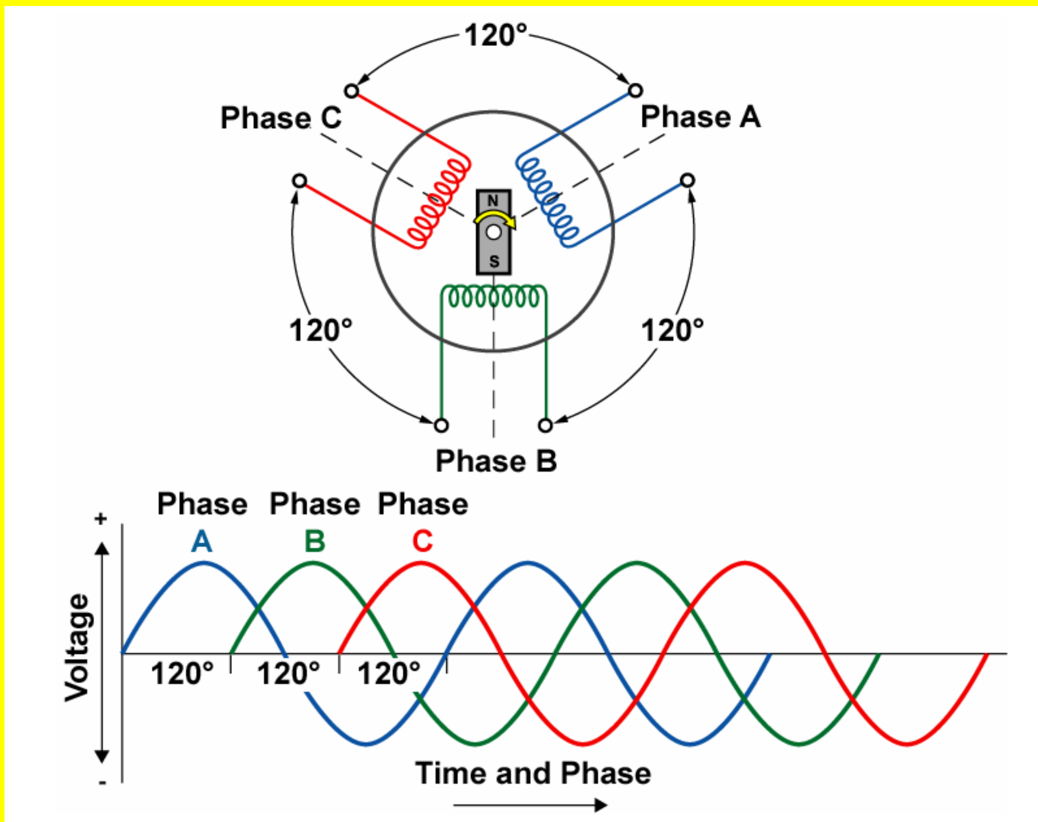


Figure 2-59
Three Phase AC Power Generator

The shape, frequency, and magnitude of the voltage produced by the generator are dependent on the generator design and operation.

There are two general types of AC machine: synchronous and asynchronous. The terms synchronous and asynchronous refer to the relationship between the machine rotor's speed of rotation and the power system speed. Power system speed (or synchronous speed) is the speed of rotation of the AC electrical system to which the generator attaches.

The term "AC machine" can mean either an AC generator or an AC motor.

Magnetic Fields in a 3Φ System

Each of the phase conductors of a 3Φ power system creates its own magnetic field as the individual phase currents flow. If one were to analyze the magnetic field that results from the summation of the three individual magnetic fields, it would be discovered that the resultant field rotates. The resultant field rotates at the system frequency or at synchronous speed. Note that three-phase power systems must have rotating magnetic fields to operate.

A magnetic field that rotates at synchronous speed (typically 60 HZ) is naturally created in a 3Φ power system.

Generators use rotating magnetic fields to generate AC power, and motors use rotating magnetic fields to drive their loads.

When a generator is synchronized to the power system what is actually synchronized is the rotating magnetic field of the generator with the rotating magnetic field of the 3Φ system.

An AC machine can be designed to rotate in-step or in synchronism with the power system's rotating field. We call this type of AC machine a synchronous machine. Most utility power generators and most large motors are synchronous machines. An AC machine's rotor can also be designed to rotate slower or faster than synchronous speed. This type of machine is an asynchronous machine. Most small AC motors are asynchronous machines. Induction machines are the most common type of asynchronous machines. In this text, we will use the term induction machine to refer, in general, to an asynchronous machine.

Induction Machines

An induction machine operates on the same principal as a transformer (electro-magnetic induction). Consider a 3Φ induction motor. The currents absorbed from the power system via the 3Φ conductors of the induction motor, create a rotating magnetic field about the stator of the induction motor. This rotating magnetic field cuts through the induction motor's rotor conductors, inducing a voltage in these conductors. Currents then flow in the rotor conductors creating a rotor magnetic field. The stator magnetic field drags the rotor magnetic field along with it resulting in motor action.

If the rotor of an induction machine rotates faster than synchronous speed, it is an induction generator. (Note that for this to occur there must be a prime mover—steam turbine, etc.—to turn the rotor of the induction machine.) If the rotor spins slower than synchronous speed, it is an induction motor. The difference between synchronous speed and the speed of the rotor is called the slip of the induction machine.

An induction machine (motor or generator) is always a lagging load.

With some modern, large scale, induction generators (such as used in newer model wind turbines) electronic means are used to produce the required reactive power. Therefore, larger size (many MW) induction generators may become a reality.

In an induction machine, the excitation needed to produce the magnetic field about the rotor is supplied by the power system to which the machine is connected. An induction machine draws in reactive power from the external power system to magnetize its rotor. Without Mvar from the power system, the induction machine could not operate. Because induction machines cannot supply Mvar to the system, they are rarely used for large-scale power generation. Typically, induction generators have outputs less than one MW. A common usage for induction generators is either as small hydroelectric units or as wind turbines. The reason for using induction instead of synchronous generators is often cost. Induction generators are considerably cheaper to build due to their relatively simple design.

This text will focus on synchronous generators instead of induction generators. When this text refers to a generator, a synchronous generator is implied unless noted otherwise.

Synchronous Machines

Synchronous machines are the most common type of generator used for large-scale power production. Synchronous machines can be used to produce both active and reactive power. This is in contrast to induction machines, which cannot produce reactive power, only active power. Sizes of synchronous generators range from a few kW to thousands of MW.

In a synchronous generator, a DC current is applied to the field windings of the rotor. This DC current produces a magnetic field about the rotor. As the rotor turns, the magnetic field rotates and induces a voltage in the stator. The voltage induced in the stator causes current to flow out of the stator to the load connected to the generator. The magnitude of the voltage induced in the stator is determined by the strength of the DC current applied to the rotor field winding.

A synchronous generator is characterized by the fact that during steady state conditions the rotor will rotate at synchronous speed. Synchronous speed is determined by the frequency of the power system to which the generator is connected and by the number of rotor poles in the generator's rotor.

The number of rotor poles refers to the number of magnetic poles that exist in the rotor of the machine. Different machines utilize different numbers of rotor poles. There will always be an even number of poles as the negative and positive poles must match one another. Figures 2-60 and 2-61 illustrate two possible rotor designs. One design (Figure 2-60) has two poles while the other has four poles.

Stator windings A and A' together form the phase "A" winding.

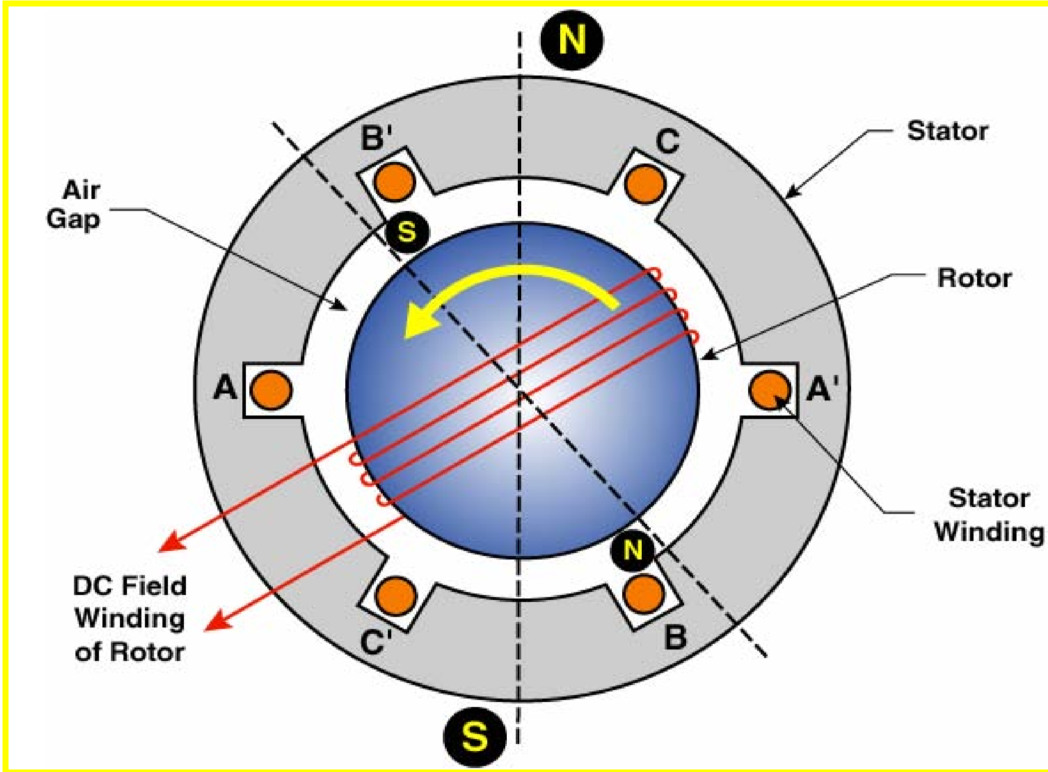


Figure 2-60
Two Pole Rotor

Note that with a four pole rotor, you must have two complete sets of stator windings.

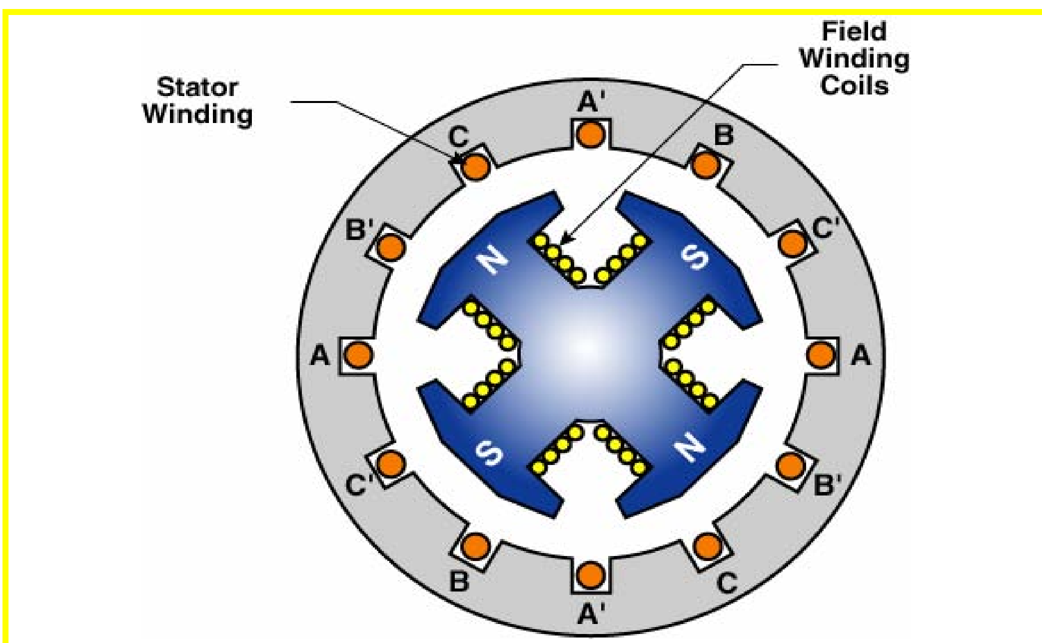


Figure 2-61
Four Pole Rotor

Speed of a Synchronous Machine Rotor

The following formula can be used to determine the synchronous speed:

$$\boxed{RPM = 120 \times \frac{F}{P}}$$

Where:

- RPM (revolutions per minute) is the speed of the generator rotor
- F is the frequency of the power system
- P is the number of magnetic poles in the generator rotor

As can be seen from the formula, as the number of rotor poles increases, the speed at which the generator rotates decreases. For example, assuming a 60 HZ power system, a two-pole synchronous generator's rotor speed is as follows:

$$\boxed{RPM = 120 \times \frac{60}{2} = 3600}$$

For a four-pole synchronous generator, the rotor's speed of rotation is:

$$\boxed{RPM = 120 \times \frac{60}{4} = 1800}$$

Generators for steam turbines typically use two or four pole rotors. Hydroelectric units rotate at considerably slower speeds and have a much larger number of poles. For example, the speed of a 40 pole hydroelectric generator is:

Most 60 HZ steam turbine generators spin at 3600 RPM but a typical nuclear unit spins at 1800 RPM.

$$\boxed{RPM = 120 \times \frac{60}{40} = 180}$$

The Torque Angle

The torque angle is an important factor in determining the active power output of a synchronous generator or the active power consumption of a synchronous motor. The torque angle of a synchronous machine is defined as the angular separation between the rotor and stator's rotating magnetic fields. The rotating magnetic field of the stator is primarily due to the 3Φ system to which

The torque angle is actually measured between the rotor and the air-gap of the machine. We are using stator instead of air-gap to simplify our description.

the generator is attached while the rotating magnetic field of the generator is controlled by the generator operators.

Torque Wrench Analogy

To introduce the concept of a torque angle we start with a mechanical analogy. Visualize a torque wrench connected to a shaft to turn a drum. At a preset amount of torque, the wrench will give way. The wrench can bend as much as 90° before it gives way. The more torque applied, the more the wrench twists until at 90° the torque wrench fails. Our analogy is illustrated in Figure 2-62(a).

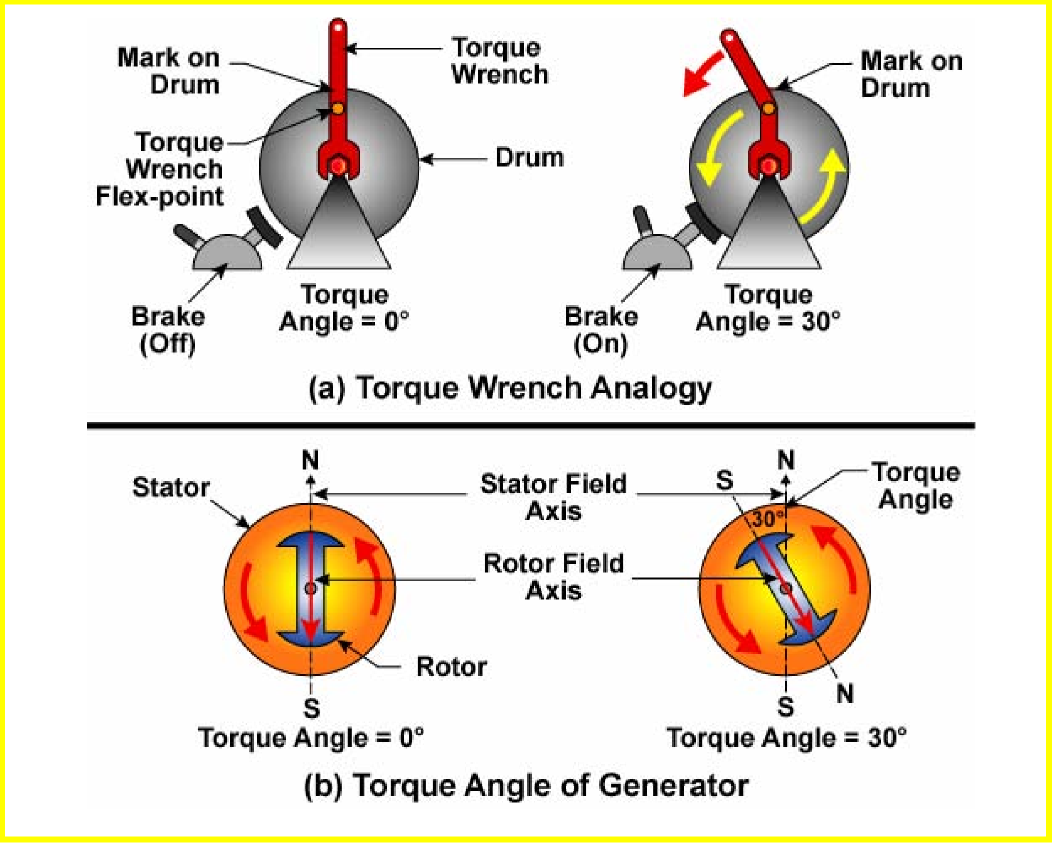


Figure 2-62
Torque Wrench Analogy of a Torque Angle

Our analogy assumes the drum has no mass.

In Figure 2-62(a), a torque wrench is attached to the drum via a shaft through the center of the drum. A mark is made on the drum indicating the position of the wrench when the system is at rest. If the wrench is turned slowly to rotate the drum at a constant speed, with no load on the drum, the wrench will remain aligned with the mark on the drum.

If a braking load is applied to the drum, it will take more torque on the wrench to keep the drum rotating at the same speed. This torque will cause the wrench to bend. The angle between the wrench and the mark on the drum is the torque angle of this system. The maximum amount of load that can be driven by this system is whatever loading causes the torque angle to reach 90°. At this loading point, the torque wrench fails.

In this analogy:

- The force applied to the wrench is equivalent to a prime mover such as a steam or water turbine.
- The wrench is equivalent to the magnetic field about the rotor of a synchronous generator.
- The drum is equivalent to the magnetic field about the stator of the synchronous generator.

In our mechanical analogy, the torque angle was the angle between the axis of the torque wrench handle and the axis of the drum. The axis of the drum was defined as the relative position of the wrench handle on the rotating drum when no brake force was applied. Electrically, the torque angle is the angle between the axis of the rotating magnetic field of the rotor and the axis of the rotating magnetic field of the generator's stator as illustrated in Figure 2-62(b).

To help visualize the magnetic forces inside a generator, we can examine the magnetic forces in a compass. A compass needle is nothing more than a floating magnet that pivots at its center. Due to the laws of physics, magnetic fields will always try to align. That is, when two magnetic fields are not aligned, a force exists between the two that is acting to realign them. For example, if we turn a compass needle and let it go, a magnetic force will act to realign the needle's magnetic field axis with that of the Earth's magnetic field.

In the case of a synchronous generator, the magnetic field of the stator is rotating at synchronous speed. Assume that the rotor is also turning at synchronous speed. If the rotor field axis is perfectly aligned with that of the stator field, no force is exerted by either field on the other. This corresponds to a torque angle of zero and zero active power (MW) output from the generator.

Now assume we increase the input mechanical power (steam, water, etc.) to the turbine. The rotor speed will briefly pick up above synchronous speed and then return to synchronous speed. The angle between the rotor's magnetic field axis and the stator's magnetic field axis (torque angle) will increase during the rotor's acceleration period. A force now exists trying to realign these two magnetic fields. Since this force is a twisting force about the rotor shaft, we refer to the force as a torque.

If the turbine power were to remain constant, the positive torque angle created by our brief rotor acceleration will remain constant. The magnetic forces that result from the existing torque angle will result in a current flow in the stator windings. Active power will flow out of the generator.

If the turbine power is then steadily reduced, the torque angle will return to zero. If turbine power were reduced enough, the torque angle would eventually become negative. A generator with a negative torque angle is actually a motor. The concept of adjusting a torque angle from a positive to a negative value is actually a commonly used operating strategy at large steam power plants. Turbine power is gradually reduced until the plant's anti-motoring protection detects the condition and initiates an orderly plant trip.

An equation for active power flow will be developed in Chapter 3. This equation will illustrate the dependence of active power flow on the sine of the torque angle.

The torque that is created between the two magnetic fields of a generator is proportional to the sine of the torque angle. This is very important as it means that the maximum torque between the stator and rotor fields occurs when the torque angle equals approximately 90°. This is the maximum (theoretical) active power output point of a generator.

Positive Torque Angle for a Generator

When a generator is producing active power, its torque angle is typically between 10° and 30°. If the torque angle is steady, the mechanical force applied by the prime mover is equal to the opposing electrical force applied by the power system to which the generator is attached. To change a generator's torque angle, the generator must slightly accelerate or decelerate with respect to the power system to which it is attached.

Note that a synchronous motor rotates in the same direction as a synchronous generator. What makes one a generator and the other a motor is the sign of the torque angle.

Negative Torque Angle for a Motor

In a synchronous motor, the rotor field lags behind the stator field. A motor is said to have a negative torque angle. Another way to think of it is that a generator applies torque (positive) to the system, whereas a motor draws torque (negative) from the system.

Torque Angle and Voltage

The excitation current that is applied to a rotor can be viewed in terms of voltage. As the excitation current is varied, an internal generator voltage (the air-gap voltage) changes. This voltage, E_G, varies with the excitation current magnitude. Higher excitation current leads to a stronger generator voltage.

The phase relationship between two rotating magnetic fields can be visualized in terms of the induced voltages of the two magnetic fields. For example, Figure 2-63(a) illustrates a generator synchronized to the power system. The rotating magnetic field of the rotor is in alignment with the rotating magnetic field of the stator. The voltage waveform at the bottom of Figure 2-63(a) illustrate how this magnetic field alignment looks in terms of voltage. E_G is the generator's internal voltage and V_S is the stator voltage. E_G and V_S are in-phase with one another. There is no torque angle and no active power output from this generator.

Figure 2-63(b) illustrates a 45° torque angle. The rotor magnetic field leads the stator's magnetic field by 45°. Below this graphic is the voltage equivalent. Note how the torque angle is visible as a difference in-phase between the two voltage waveforms. The Greek letter "δ" (delta) is commonly used to represent a synchronous machine's torque angle.

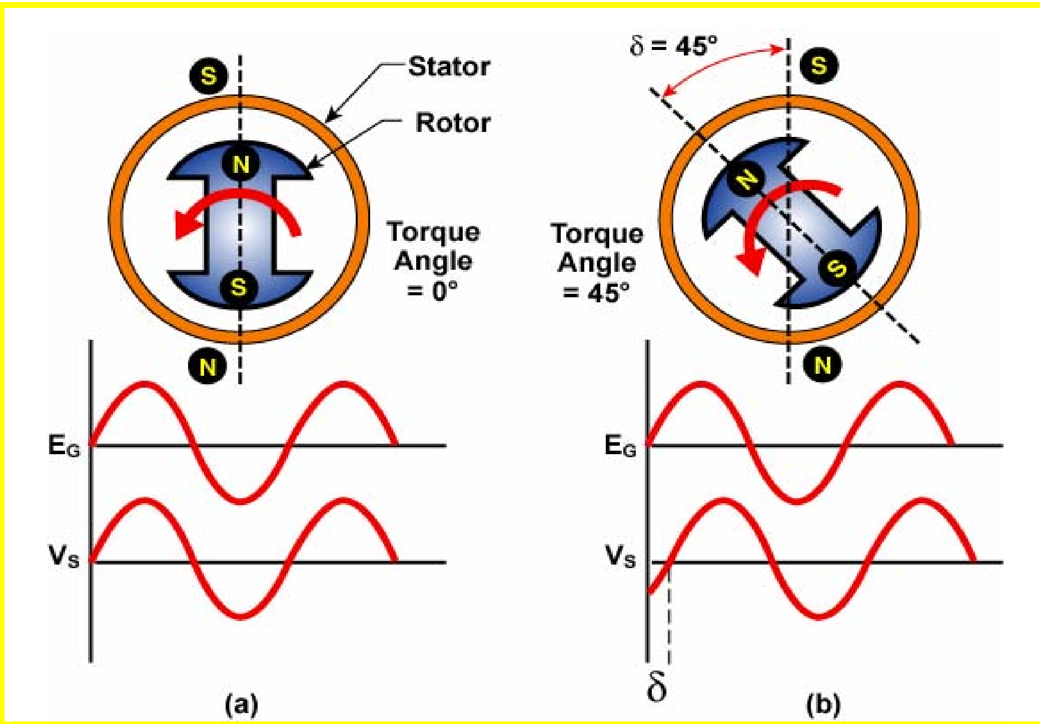


Figure 2-63
Torque Angle & Voltage

The Greek letter "δ" (delta) is used to represent a generator's torque angle.

Generator Turbines

Water Turbines

The prime mover used in hydroelectric power houses is the hydraulic turbine. Hydraulic turbines are classified into two main divisions: impulse turbines and reaction turbines.

The impulse turbine, commonly known as a Pelton Wheel, is a series of buckets that are mounted on the rim of a large wheel. Nozzles control high velocity water jets that strike each of the buckets in-turn and cause the wheel to rotate. The axle of the wheel is connected to the shaft of the electric generator. The rotation of the wheel creates a rotation of the hydroelectric generator's rotor and a voltage is produced from generator action. Figure 2-64 illustrates a Pelton Wheel turbine.

The reaction turbine is based on a different principle. Reaction turbines are divided into two different types: the Francis turbine and the propeller turbine.

The Pelton Wheel is used when high (>3000 feet) heads are available. Head is the difference between the incoming and outgoing water storage elevations. Normally high head turbines use less water flow then low head turbines.

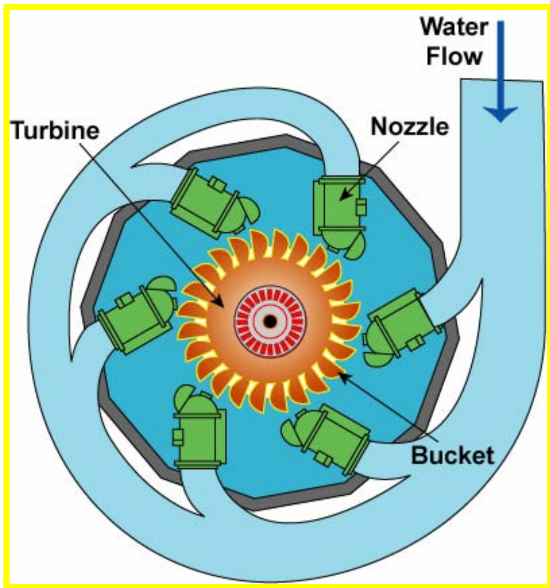


Figure 2-64
Pelton Wheel

The Francis turbine is used for medium (100 to 2400 feet) head applications.

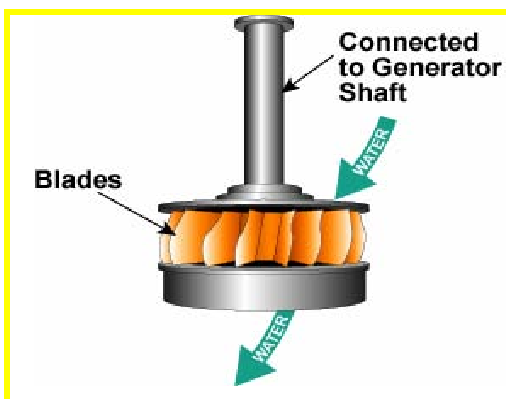


Figure 2-65
Francis Turbine

The Francis turbine consists of a series of blades mounted on a turning element, or runner. In a Francis turbine, water is routed to the turbine through a series of fixed guide vanes and strikes all of the blades simultaneously. A casing (called a scroll case) surrounds the Francis turbine and keeps the turbine emerged in water. Figure 2-65 illustrates a Francis turbine.

The propeller turbine can have either fixed or movable blades. The propeller design of the turbine allows it to operate at higher speeds than the Francis turbines. Propeller turbines with movable blades are called Kaplan turbines. Propeller turbines are used for low (<150 feet) head applications.

The speed control of a hydraulic turbine generator is a function of water flow. As the load on the generator is increased, the turbine speed will decrease. To compensate, and maintain the relatively constant speed that is necessary for system frequency control, more water must be passed through the turbine.

The speed of a Pelton Wheel turbine is controlled using a nozzle-type control valve. The amount of water is controlled by opening, shutting, or changing the direction of needle valves in the nozzles.

The speed of Francis and propeller turbines is controlled using wicket gates. Wicket gates are located around the inlet flow of the turbine. The gates operate as a unit and provide a smooth flow of water to the turbine. Figure 2-66 illustrates wicket gate operation.

The needle valves and wicket gates are managed by the governor control system. The governor system adjusts the control valves and wicket gates to assist with maintaining a constant system speed.

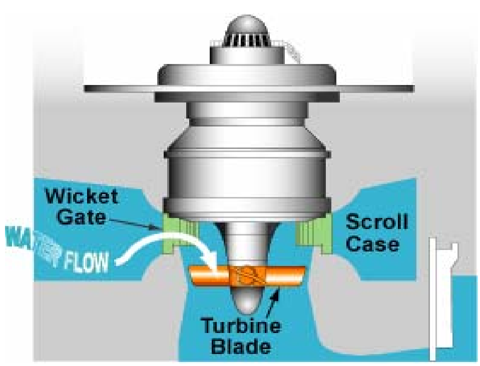


Figure 2-66
Wicket Gate Operation

A major advantage of a hydroelectric power plant is that there are normally no turbine thermal restraints that limit how fast the generator can be loaded. A hydroelectric power plant may be able to supply full electrical power output from a stopped condition in just a few minutes or possibly even in seconds.

The penstock is the water intake structure for the hydro turbine.

Different types of hydro plants can respond with additional MW at different rates. A high head turbine with a long penstock may be severely limited in its MW response rate due to water hammer (pressure transients) impacts on the penstock.

Steam Turbines

A typical steam unit is composed of more than one turbine. The turbines are classified by the steam pressure at which they operate. For example, one unit may include high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP) turbines. Figure 2-67 illustrates an arrangement of multi pressure stages in a steam turbine. The turbines themselves are composed of a series of blades or buckets. Steam strikes the blades and turns the turbine. The blades grow longer as the stage pressure decreases due to the increase in the volume of the steam.

Figure 2-68 contains a more detailed drawing of a typical multi-stage steam turbine. A list and description of the major system components in a steam turbine system follows Figure 2-68.

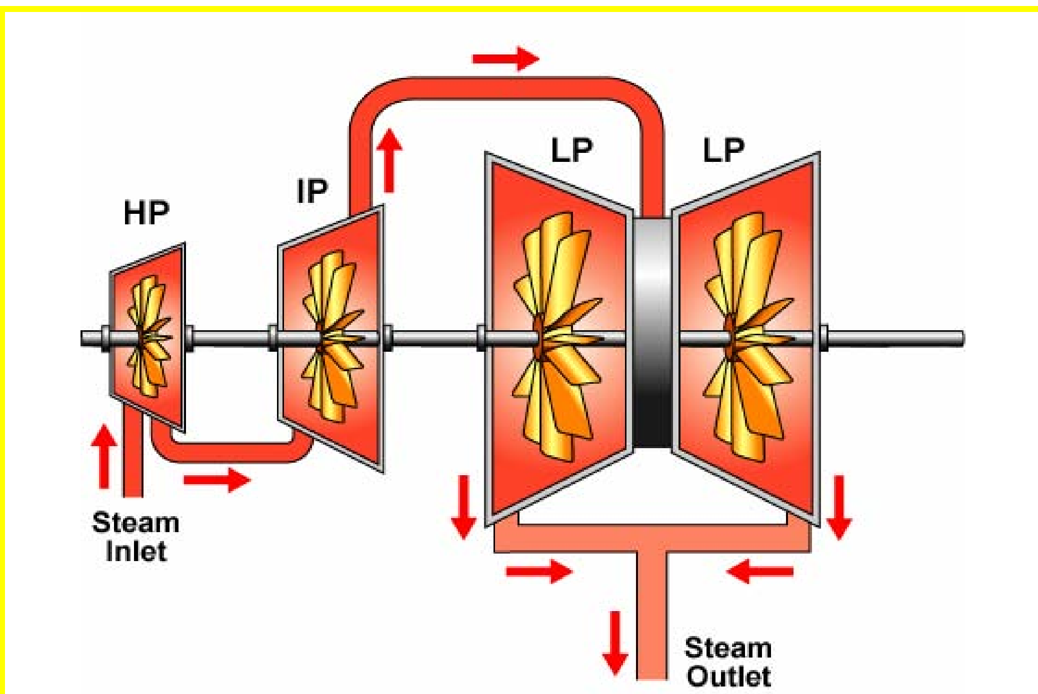


Figure 2-67
Steam Turbine Stages

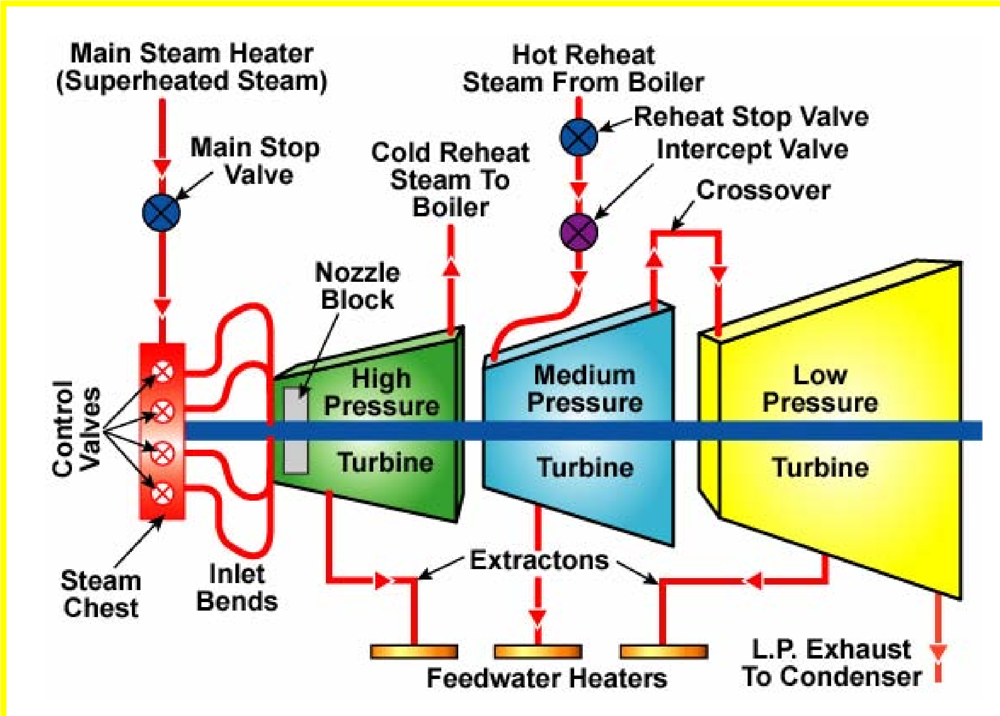


Figure 2-68
Steam Turbine Components

The boiler is the source of the steam. The boiler is a furnace type device where the water is converted to steam using water filled tubes as heat exchangers.

- The main steam header contains and guides the flow of the superheated, high-pressure steam from the boiler to the main stop valves.
- The main stop valves admit steam to the turbine for normal operation or shut off the flow of steam quickly if emergency conditions require it.
- The steam chest is a manifold that contains the control (governing) valves.
- The control (governing) valves are located in the steam chest and control the flow of steam to the high-pressure turbine. Each control valve admits steam through a separate inlet bend (pipe) to a particular location around the nozzle block.
- The inlet bends connect the steam chest with the nozzle block in the high-pressure turbine.
- The nozzle block is the first point in the turbine where the energy within the steam is turned into work. The steam is directed through the nozzle block into the first row of rotating blades.
- The high-pressure turbine contains impulse or reaction blading that converts the stored energy in the steam to work that rotates the shaft. The high-pressure turbine is generally the smallest of the turbines since high-pressure steam is denser and requires less volume than low-pressure steam. As the steam goes through the turbine, it expands, which is why a turbine is larger on one end than the other.

- Extractions are points along the turbine blade path where steam is bled off and piped to the boiler feedwater heaters.
- The exhaust from the high-pressure turbine is piped back to the boiler to become reheated. This exhaust is called cold reheat steam. Cold reheat steam is reheated up to about the same temperature as the inlet to the high-pressure turbine. The steam returning from the boiler returns to the intermediate pressure turbine and is called hot reheat steam.
- The intercept valve is located in the hot reheat steam line before the intermediate pressure turbine. The intercept valve is provided to control the steam flow from the large storage capacity of the reheat boiler.
- The reheat stop valve is also located in the hot reheat steam line near the intercept valve. It is provided for quickly shutting off the supply of reheated steam to the intermediate pressure turbine. This valve works in conjunction with the intercept valve.
- The intermediate-pressure turbine is very similar to the high-pressure turbine. One major difference is that the blades are longer. Again, this is because the steam is expanding as the pressure reduces.
- The crossover is the pipe or duct that contains and guides the steam from the intermediate pressure turbine to the low-pressure turbine. The crossover is likely the largest steam line in the entire turbine, as the steam at this point has expanded 15 to 20 times from the main steam header volume.
- The last bit of work will be extracted from the steam in the low-pressure turbine. After the steam passes through the last row of turbine blades, it will pass into the condenser where it will turn into liquid water and return to the boiler.

Steam is created in fossil plants by burning fossil fuels such as coal, oil, and natural gas. The heat is used to produce steam. The fuel is usually burned in a furnace or boiler. The walls of the furnace or boiler are lined with tubes through which water is run. This arrangement is called a waterwall, and is where the steam is actually created.

In a nuclear plant, heat from a nuclear reaction is used to create steam. The steam may be produced via a heat exchanger arrangement with the reactor or the reactor vessel itself may be the steam generator.

Combustion Turbines

Combustion turbines are rotating internal combustion engines that can be used to turn an electric generator. Combustion turbines—often referred to as gas turbines or peakers—utilize the energy released by the burning of a gas or oil fuel to provide a rotational force to spin the turbine blades.

The basic combustion turbine has three main components as illustrated in Figure 2-69:

1. Compressor

2. Combustor

3. Turbine

In its simple form, as illustrated in Figure 2-69, air is compressed by several rows of blades in the compressor section. Some of this air passes into the combustion chamber where it combines with the fuel to burn. The majority of the air flows around the chamber and is used to cool the chamber and the turbine.

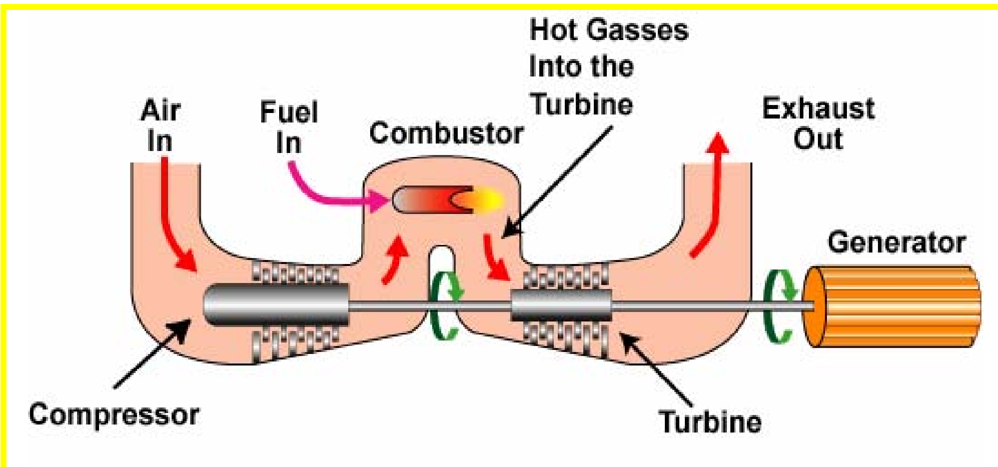


Figure 2-69
Basic Combustion Turbine

A variation on this simple cycle combustion turbine plant is the combined cycle plant. In a combined cycle plant, the combustion gases are not exhausted to atmosphere. The exhaust gas is used to produce heat for a companion steam turbine. The combined cycle process is more efficient than a simple cycle process as less heat is wasted.

After burning occurs, the combustion gases leave the combustion section and strike the turbine blades at a temperature as high as 1600°F and at pressures of approximately 200-225 pounds per square inch (psi).

Introduction to Generator Control Systems

Governor Control Systems

Steam turbine generators rely on a constant supply of steam to maintain proper operation. This steam must be at a sufficient pressure to drive the turbine at its normal operating speed. The steam is created and pressurized by the boiler. The mechanism that controls the release of steam from the boiler is the speed governor. The boiler control system maintains proper steam

Chapter 4 will examine the cause, effects, and control of frequency deviations in detail including the operation of governor control systems.

temperature and pressure by monitoring the steam going to the turbine, and the position of the governor, and making adjustments as necessary.

Electric generators use governor control systems to assist with the control of system frequency. The governor system senses the generator shaft speed and adjusts the input power of the generator to increase or decrease the generator's speed as required. Figure 2-70 illustrates a basic governor control system.

The governor shown in Figure 2-70 senses the speed of the generator shaft. The governor has the ability to adjust the speed of the shaft by adjusting the amount of steam supplied to the turbine. The speed of the shaft is fed back as an input for speed control. A governor control system is an example of a feedback control system. Variations of this type of control system are used in the control of many devices in the modern world.

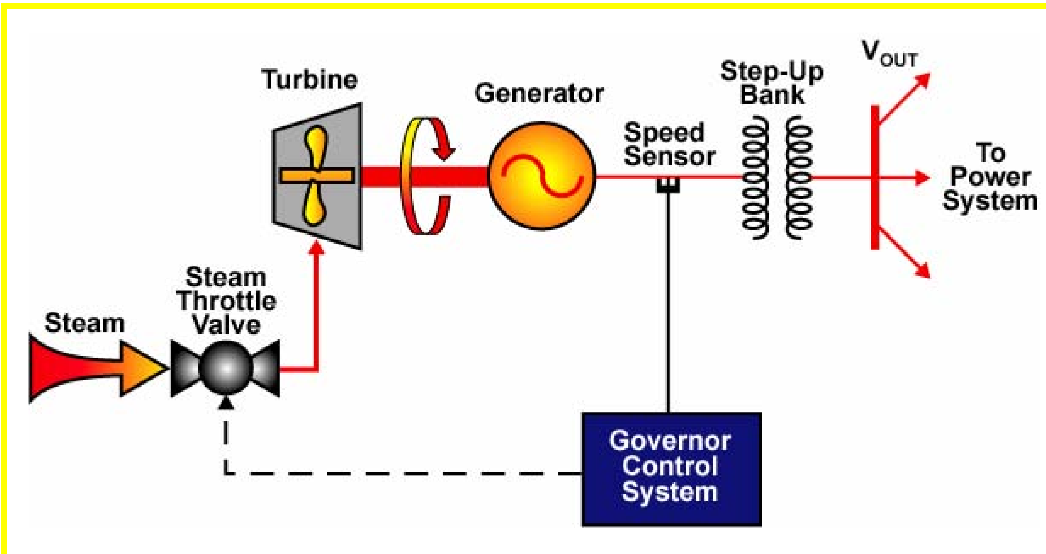


Figure 2-70
Model of Basic Governor Control System

Excitation Control System

Chapter 5 will examine the cause, effects, and control of voltage deviations including the operation of generator excitation systems.

The excitation control system of a generator is used to control the generator's terminal voltage as well as the generator's reactive power (Mvar) output. The level of DC excitation current supplied to the field winding determines the generator's terminal voltage and reactive power output. A basic excitation system block diagram is provided in Figure 2-71.

A potential transformer (PT) senses the unit's high side voltage. The PTs secondary voltage is compared to a target value. If the actual voltage differs from the target value, the excitation current to the field winding on the generator rotor is changed. Excitation systems can only control a unit's terminal voltage within a certain range. How large that control range is depends on the strength (power rating) of the exciter and the strength (MW size) of the power system the generator is tied to. For example, if a small generator is tied to a very strong bus, the generator excitation will have little effect on the bus voltage.

The term "normal excitation" is not meant to imply that a generator normally runs at unity power factor. The term means that the generator's exciter is supplying exactly the excitation the generator needs to operate.

At normal excitation levels, a generator is neither supplying nor absorbing reactive power from the system. The unit is at unity power factor. When a generator is overexcited, it is supplying reactive power to the system. An overexcited generator may be referred to as a boosting, lagging or pushing generator. When a generator is underexcited, it is absorbing reactive power from the system. An underexcited generator may be referred to as bucking, leading, or pulling generator.

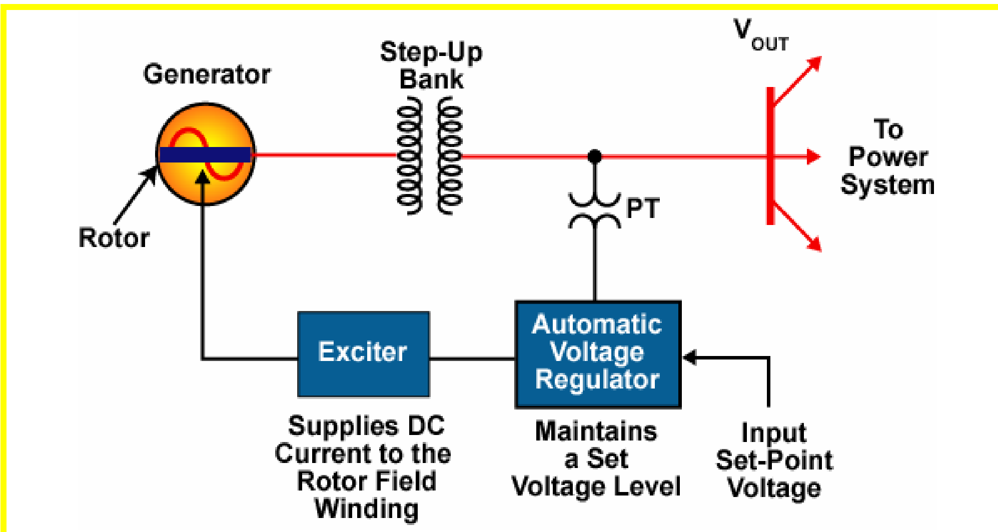


Figure 2-71
Block Diagram of a Generator Excitation System

This diagram illustrates automatic voltage regulation. A voltage regulator can also be operated in manual mode. Chapter 5 explores excitation systems in detail.

2.6.3 Power Transformers

The operation of a transformer is based on the principle that electrical energy can be transferred via electromagnetic induction from one set of windings to another. A transformer consists of at least two windings. The building and collapsing magnetic field caused by alternating current flow in one winding induces an electromotive force (voltage) in the other winding. When this mutual inductance exists, the two windings are inductively coupled. Figure 2-72 illustrates a basic transformer connected between an AC source of power and a load.

The coil connected to the source of power is the primary winding and the coil connected to the load is the secondary winding. The power delivered from the source passes through the transformer and is delivered to the load. Although

In the power system, it is often difficult to designate primary and secondary windings. It is clearer to state whether you are referring to the high or low side winding.

no physical connection exists between the primary and secondary circuits, a connection does exist via a magnetic linkage between the coils. Transformers are in general very efficient devices. Transformer losses will seldom exceed 1 to 2% of their load.

Turns Ratio

The magnitude of voltage induced in a winding depends primarily on the number of turns in the winding. The voltages in the primary or secondary windings are proportional to the total number of turns in each winding. By varying the number of turns between the primary and secondary windings, the voltage that is transformed via the magnetic linkage can be adjusted. The turns ratio of a transformer is defined as:

$$\boxed{\frac{V_P}{N_P} = \frac{V_S}{N_S} \quad \text{or} \quad \frac{V_P}{V_S} = \frac{N_P}{N_S}}$$

The iron core confines the magnetic field to a target area.

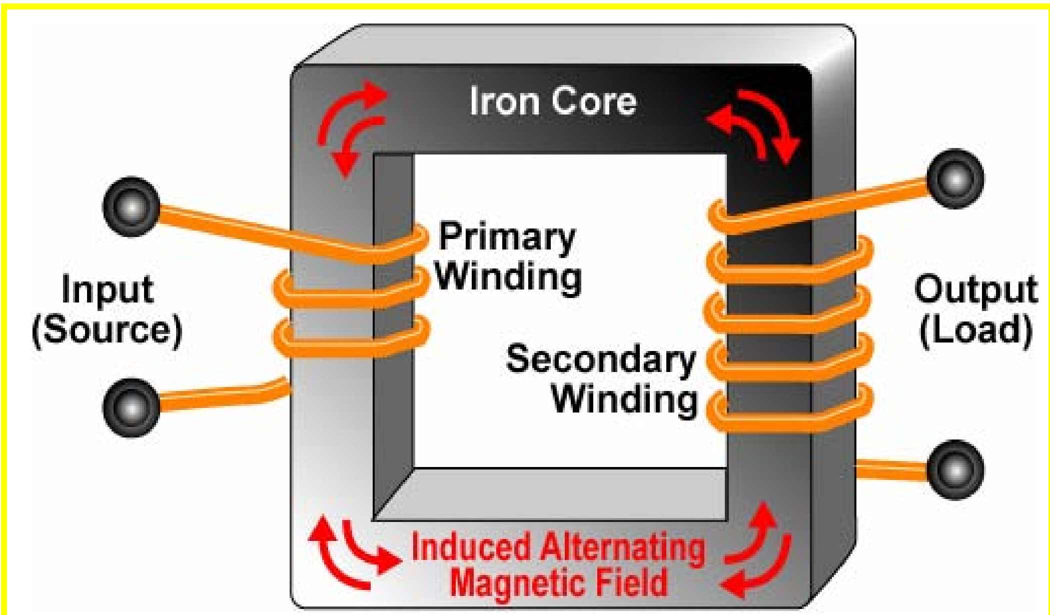


Figure 2-72
Basic Transformer

V_P is the primary voltage, V_S is the secondary voltage, N_P is the number of primary turns, and N_S is the number of secondary turns. N_P/N_S is the transformer turns ratio. Figure 2-73 illustrates the use of the turns ratio. This transformer has 10 primary turns and 5 secondary turns. Note that the voltage is halved while the current is doubled across the transformer.

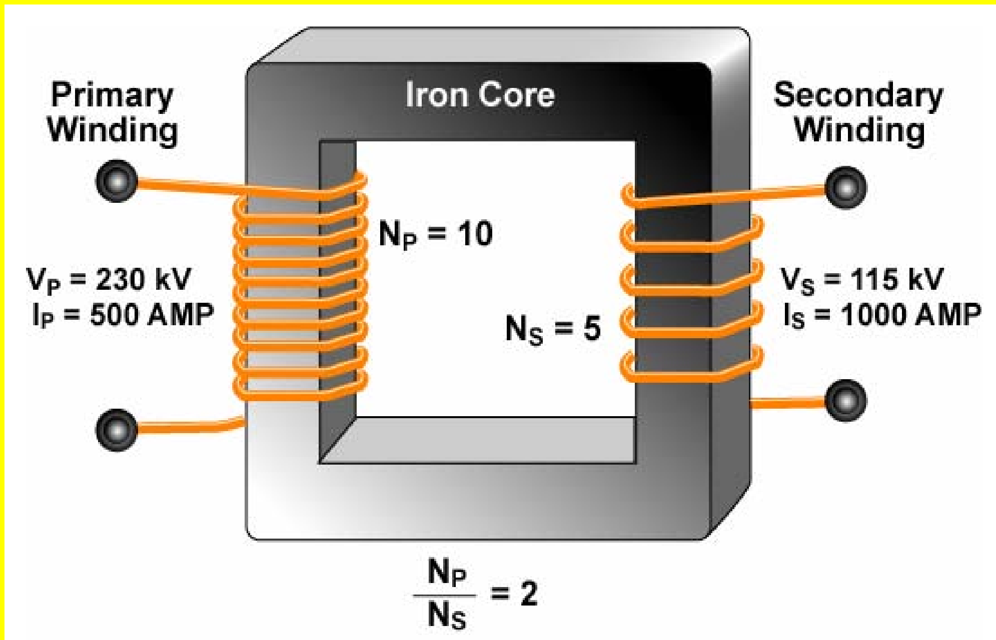


Figure 2-73
Transformer Turns Ratio

If a transformer reduces the voltage level, the current level must be increased.

Types of Transformers

A two winding transformer consists of two windings, which are not physically connected, wrapped around a common core. The transformers illustrated in Figures 2-72 and 2-73 are examples of two winding transformers.

Figure 2-74 illustrates the evolution from a two winding transformer to an autotransformer. In an autotransformer the primary and secondary windings are physically connected. The advantages of an auto-connected transformer include lower impedance, lower losses, and a smaller excitation current than two winding transformers. Autotransformers are typically applied when the primary to secondary voltage ratio is less than 2.5:1. The direct electrical connection between the high and low voltage sides can be a disadvantage. A two winding bank provides a certain degree of electrical isolation between the primary and secondary. Autotransformers do not provide this electrical isolation.

An autotransformer can be created by starting with a two winding transformer and then physically connecting the primary and secondary windings.

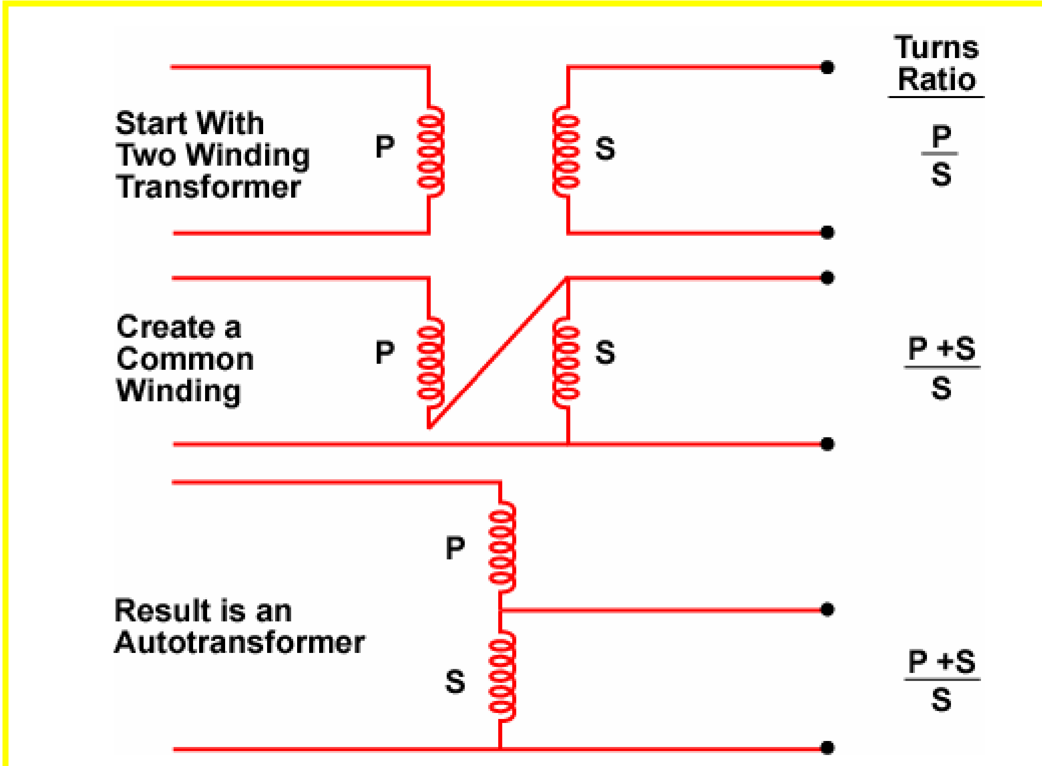


Figure 2-74
Autotransformer Evolution From a Two-Winding Transformer

Transformer Connections

Large power transformers are 3Φ transformers. A 3Φ transformer may be constructed as a 3Φ unit or composed of three separate 1Φ transformers connected for 3Φ operation. The most common 3Φ connections are the delta and wye configurations. Figure 2-75(a) illustrates a 3Φ transformer connected in wye on the high side and delta on the low side. Note that the wye connection has a common point for all windings while the delta has all three windings connected in series.

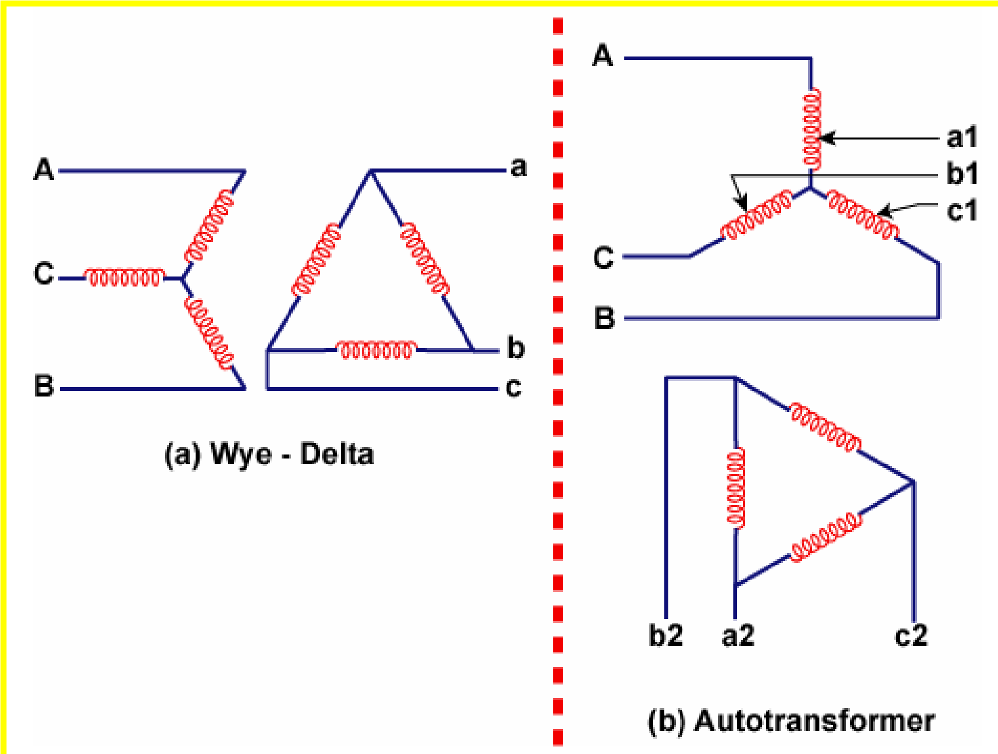


Figure 2-75
3Φ Transformer Connections

A wye winding is also called a star winding.

Tertiary is Latin for third. This tertiary winding is the 3^{rd} winding of this transformer.

Figure 2-75(b) illustrates a wye-connected autotransformer. Note the optional delta winding in the autotransformer. This is a tertiary winding. The tertiary may be used for substation station service, as a connection point for shunt reactors, or for many other uses.

One use for the delta tertiary is to trap harmonics. Harmonics are described in Chapter 9

Transformer Excitation

An energized transformer will draw a certain amount of current even with no load on the secondary. This is because an unloaded transformer still draws current to magnetize its core. This current is referred to as the exciting current of the transformer. There are two components of excitation current. The first is the magnetizing component, which builds the magnetic field in the transformer's core. The second is the loss component, which is drawn due to core iron I^2R losses. The magnetizing component is a reactive current and is much larger than the iron loss component

Transformers are users of reactive power. Transformers require reactive power to support the magnetic field in their core. A large power transformer may use several (possibly five) Mvar to support its magnetic field.

Transformer Capacity

When a company purchases a power transformer, they specify the maximum rated load. The transformer's nameplate will list this rated load. The rated load will be a function of the transformer design and the type of auxiliary cooling systems with which the transformer is equipped. For example, a transformer may have three rated loads such as 30/40/50 MVA. The different rated loads apply depending on the available cooling systems.

A 30/40/50 MVA bank may have a 30 MVA limit if no auxiliary cooling is used. If a first stage of fan cooling is operational, the bank has a 40 MVA limit. If a second stage of fans is operational, the bank has a 50 MVA limit. The maximum temperature rise in a transformer is typically 65° C above ambient. This temperature limit applies no matter what cooling systems are available.

Transformer In-rush Currents

Voltage zero means closing the switch to energize the transformer when the AC system voltage is near a zero crossing.

When a transformer is first energized, it may experience a large in-rush of excitation current. The maximum in-rush will occur if the transformer's core is still magnetized and the transformer is energized near a voltage zero. The in-rush current can be several times (possibly ten) the transformer's normal load current. Magnetizing in-rush currents can cause false protective relay operations (especially differentials) and short term system voltage problems.

2.6.4 Transmission Lines

Lines energized at voltages below 115 kV are either subtransmission (46 kV, 60 kV, 69 kV, etc.) or distribution (12.5 kV, 24.9 kV, etc.) for purposes of this text.

Transmission lines are used to connect electric power sources to electric power loads. In general, transmission lines connect the system's generators to the system's distribution substations. Transmission lines are also used to interconnect neighboring power systems. Since transmission line power losses are proportional to the square of the load current, high voltages are used to minimize losses. Typical transmission voltages include 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 500 kV, and 765kV.

Transmission Line Structures

Overhead transmission lines are supported by towers that are typically built of either wood or steel. Transmission line tower design is governed by many factors. The factors range from the voltage level of the transmission line, conductor size, minimum clearance, and aesthetics, to expected climatic conditions such as wind and ice. The primary function of a transmission tower is to support the transmission conductors at a proper distance above the ground, and with proper separation between phases. Figure 2-76(a) illustrates a typical high voltage steel lattice structure transmission tower while Figure 2-76(b) illustrates a typical wood transmission structure.

The wire positions at the top of the towers in Figure 2-76 are for shield wire connections. Shield wires are used to protect the transmission line from lightning strikes.

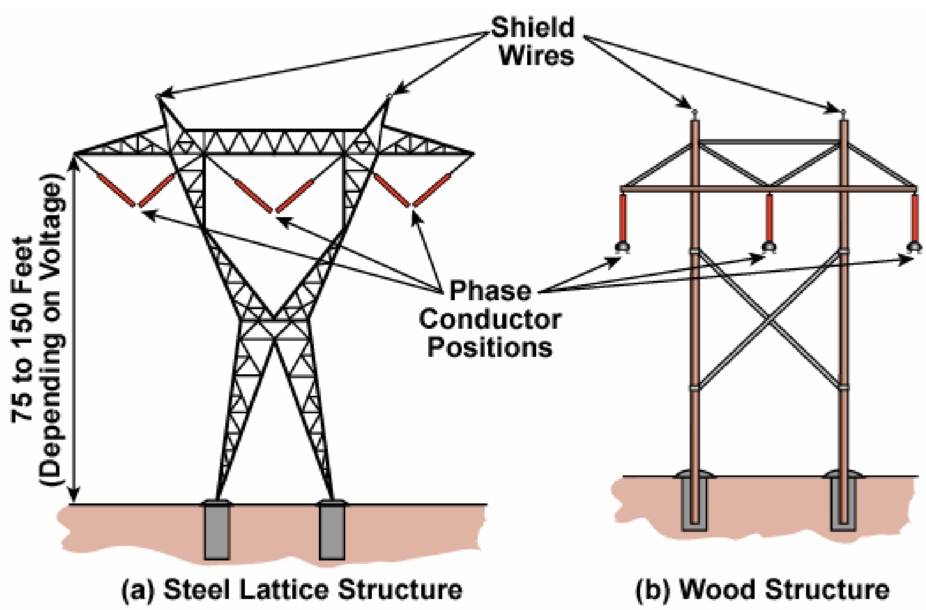


Figure 2-76
Transmission Line Structures

Transmission Line Conductors

In the early days of power transmission, conductors were mostly made of copper. In modern transmission lines, copper has been largely replaced by aluminum. For a slight increase in resistance, aluminum is cheaper and lighter than copper. Aluminum has a relatively low tensile strength, and therefore is usually reinforced with a stronger material. This reinforcement material is usually steel, but can also be an aluminum alloy.

Aluminum conductor that is reinforced with steel is referred to as ACSR (aluminum conductor steel reinforced). ACSR has a core composed of several strands of steel with strands of aluminum wound around the core. Figure 2-77 illustrates a cross section of an ACSR type conductor. This particular conductor has seven steel and 24 aluminum strands.

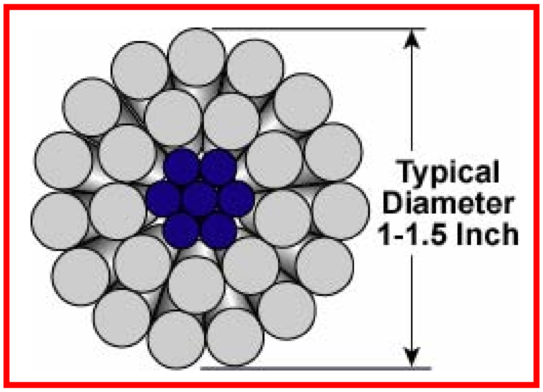


Figure 2-77
ACSR Conductor

Each phase of a transmission line can be an individual conductor, or it can be a group of conductors. Lines that have multiple conductors per phase are said to have bundled conductors. For example, 345 kV lines often have two conductors per phase while a 500 kV line may use two, three, or even four conductors per phase. Bundled conductors reduce the impedance of the conducting path and increase the effective diameter of the conductor. A larger diameter conductor is an advantage because it reduces the corona loss of the conductor. Corona losses are power losses due to the intense electric field that surrounds high voltage conductors. Larger diameter conductors have reduced corona losses.

Transmission Line Capacity

Increased power transfer across a transmission line likely means increased current flow. Increased current flow leads to increased conductor heating. Transmission lines have thermal ratings that limit the amount of current that can be carried by the line. Exceeding the thermal limit of a transmission line can cause the conductors to sag and stretch due to overheating. Extreme overloads may lead to permanent sag. Excessive sag may lead to contact with objects in the line's right-of-way resulting in faults and possible fires.

Figure 2-78 summarizes typical power transfer limits for different voltage transmission lines. These limits are only estimates as actual transfer limits are system specific. Note that the power transfer limits may be due to thermal concerns but they also may be due to voltage limits, angle stability limits, or other possible limiting factors.

Table 2-2
Typical Transfer Limits

Voltage (kV)	Transfer Limit (MVA)
69	75
138	150
230	300
345	700
500	1400

Various types of power transfer limits are described in Chapter 3.

Impedance Model of a Transmission Line

When engineers model a power system component, they are simply representing that component as an interconnection of basic electrical elements such as resistors, capacitors and reactors. Accurate modeling of system components is important for software packages such as power flow programs and training simulators.

A transmission line can be modeled as a series impedance (Z) along with shunt capacitive reactance. The series impedance is composed of the natural resistance (R) and inductive reactance (X_L) of the line. The shunt capacitive reactance (X_C) is due to a transmission line's natural capacitance.

Recall our earlier description of a capacitor. All that is needed to create a capacitor are two conductors, a dielectric such as air, and a potential (voltage) difference between the conductors. As illustrated in Figure 2-78, a transmission line has all the necessary ingredients of a capacitor.

The capacitive effects of a transmission line are commonly referred to as the line's charging. Charging is the current that flows when a line is first energized. This current charges the line's natural capacitance.

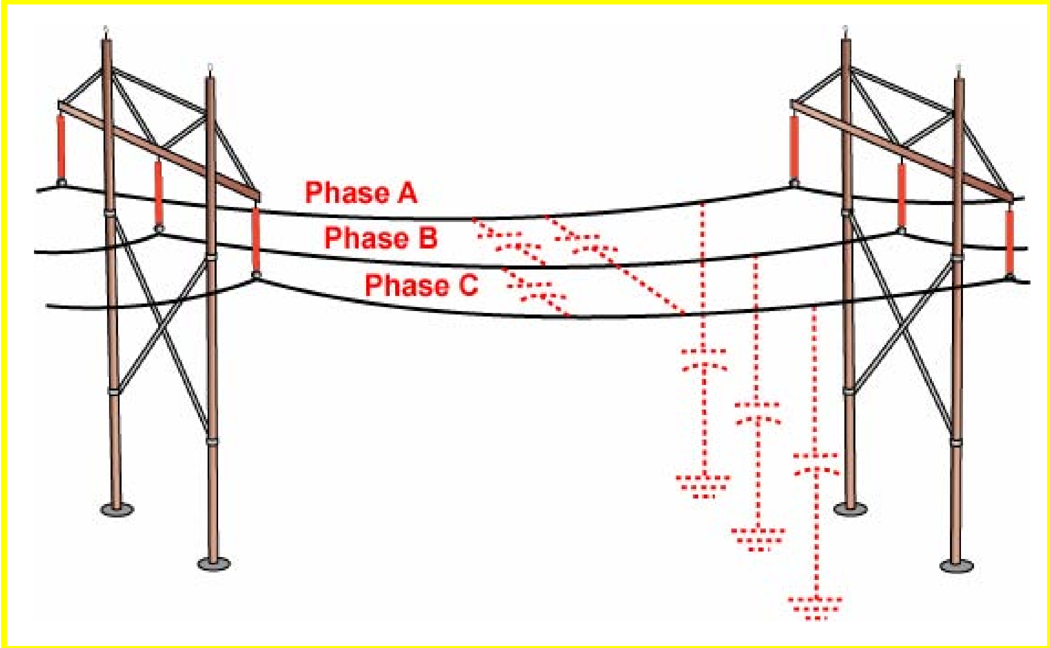


Figure 2-78
Natural Capacitance of a Transmission Line

The three phases of a transmission line are each energized at a different voltage. The air forms a dielectric between the conductors. Transmission lines have capacitive effects between the various conductors and from the conductors to ground. We represent the natural capacitance of a transmission line by placing shunt capacitors at both ends of our transmission line model.

Figure 2-79 illustrates the impedance model of a transmission line. Keep in mind that this is an approximate model. In reality the resistance, inductive reactance, and capacitive reactance values of a line are distributed along the entire length of the line.

This model is called the "PI" model. The name derives from the Greek letter "π" since the model is shaped like the letter π

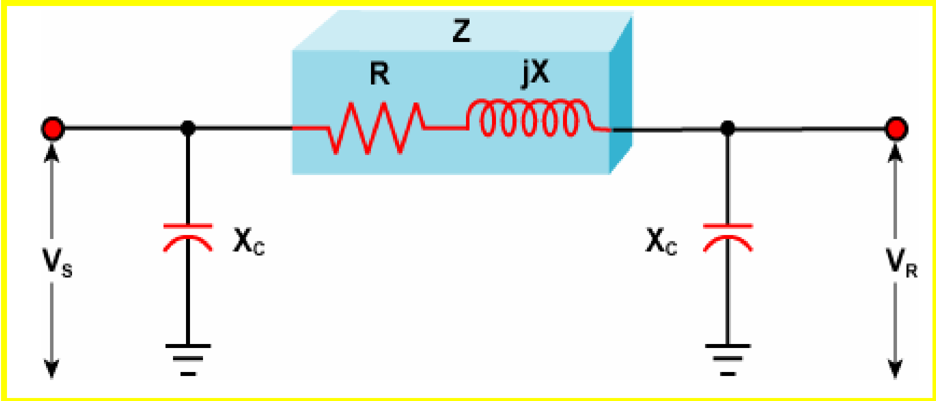


Figure 2-79
Transmission Line Impedance Model

2.6.5 AC Circuit Breakers & Switches

Circuit breakers are used to open or close an electrical circuit. Power system circuit breakers are capable of interrupting load and fault current.

Circuit Breaker Operation

All circuit breakers operate by mechanically opening a set of contacts, then extinguishing the resulting arc. The methods used to open the contacts vary depending on the type and maker of the circuit breaker. As the contacts open, an arc is formed. The arc is extinguished by a combination of stretching and cooling of the arc. Because the arc is formed with alternating current, the magnitude of the current in the arc crosses through zero 120 times a second. A circuit breaker will not actually extinguish the arc—and open the circuit—until a current zero crossing.

Types of Circuit Breakers

There are many different types of circuit breakers including:

- Oil circuit breakers
- Air circuit breakers
- SF_6 gas circuit breakers
- Vacuum circuit breakers

The type of circuit breaker is defined by the medium in which the arc is extinguished.

High Voltage Switches

Circuit breakers are used to switch electrical circuits carrying normal or fault currents. High voltage switches are used both to alter circuit arrangements and to provide electrical isolation for equipment. The current interrupting capability of switches is typically far less than a circuit breaker.

There are three basic categories of power switches. The categories are determined by the switches ability to interrupt current. Plain disconnect switches are normally opened and closed only when there is no current flowing. Air-break switches can be used to interrupt current within the switches rated capacity. The switch opening capacity is limited and only allows interruption of loads such as a transformer's exciting current or an unloaded transmission line. Loadbreak switches use an additional interrupter device to increase their current interrupting capability. One example of a loadbreak switch is a circuit-switcher.

2.6.6 Thyrister Systems

Thyristers are high power semiconductor devices. The technology used in thyristers is similar to the technology used in low power solid state devices such as a transistor. Figure 2-80 illustrates the symbol for a thyrister.

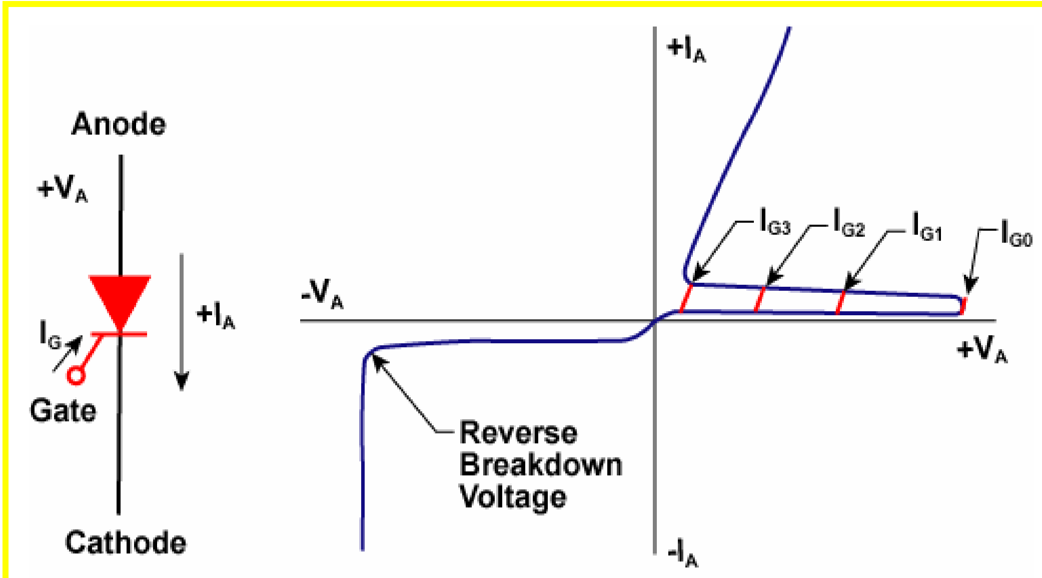


Figure 2-80
Thyrister Symbol & Operation

A thyrister can either allow or block the flow of current. When a thyrister conducts current, it has turned on. When a thyrister blocks the flow of current, it is turned off. A thyrister will turn on if its anode voltage is more positive than its cathode voltage and a pulse of gate current is applied. Figure 2-80 illustrates how a thyrister is turned on. The greater the anode to cathode voltage (V_A), the less of a pulse of gate current is needed to turn the device on. If the anode to cathode or cathode to anode voltage is too large, the thyrister could be damaged.

Once a thyrister has been turned on by a pulse of gate current it can be turned off with changes to its anode or cathode voltage. The gate current is only used to turn the device on, not to turn it off. Thyristers are small devices by power system standards. Each thyrister is about the size of a hockey puck. In a typical power application, thousands of thyristers are arranged in series/parallel combinations to achieve the desired voltage and current ratings. Common utility applications of thyristers are static var compensators (SVC) and high voltage direct current (HVDC) converters.

2.7 Power System Operations

Electric suppliers from throughout North America have many things in common. The shared goal is to provide reliable service to the customers in a safe and efficient manner. This section explains how the North American power system is configured and briefly describes the role of the North American Electric Reliability Council (NERC).

2.7.1 The Interconnections

In the infancy of the electric utility industry, individual utilities operated isolated electrical systems. Most utilities were not interconnected with neighboring utilities via transmission lines. When one system had a problem, that system was more or less on its own to solve the problem.

Eventually utilities began to interconnect with their neighboring systems. Advantages to interconnection included a reduction in the total generation required, reduced power production costs and enhanced reliability. Total generation could be reduced because utilities could now share capacity. When one utility suffered a loss, an interconnected utility was there to supply emergency assistance. Utilities no longer had to go it alone.

Our modern North American power system is composed of four large interconnections. These interconnections are groups of companies that are tied together via AC transmission lines. Every facility in an interconnection is tied electrically to every other facility. For example, a substation in Florida has an electrical connection to a substation in Maine or to a generator in North Dakota.

The electrical connection between widely dispersed points may be via many different transmission lines, but the electrical connection does exist.

The four large interconnections in North America are illustrated in Figure 2-81 and briefly described below:

- The Eastern Interconnection (#1 in Figure 2-81. The Eastern Interconnection is by far the largest of the interconnections. The peak load of the Eastern Interconnection is approximately 950,000 MW.
- The Western Interconnection (#2 in Figure 2-81). The Western Interconnection is the next largest of the major interconnections. The peak load is approximately 150,000 MW.
- The ERCOT Interconnection (#3 in Figure 2-81). The majority of the state of Texas forms a separate interconnection. The peak load of the ERCOT Interconnection is approximately 60,000 MW.
- The Hydro-Quebec Interconnection (#4 in Figure 2-81). Hydro-Quebec is the smallest of the major interconnections with a peak load of approximately 35,000 MW.

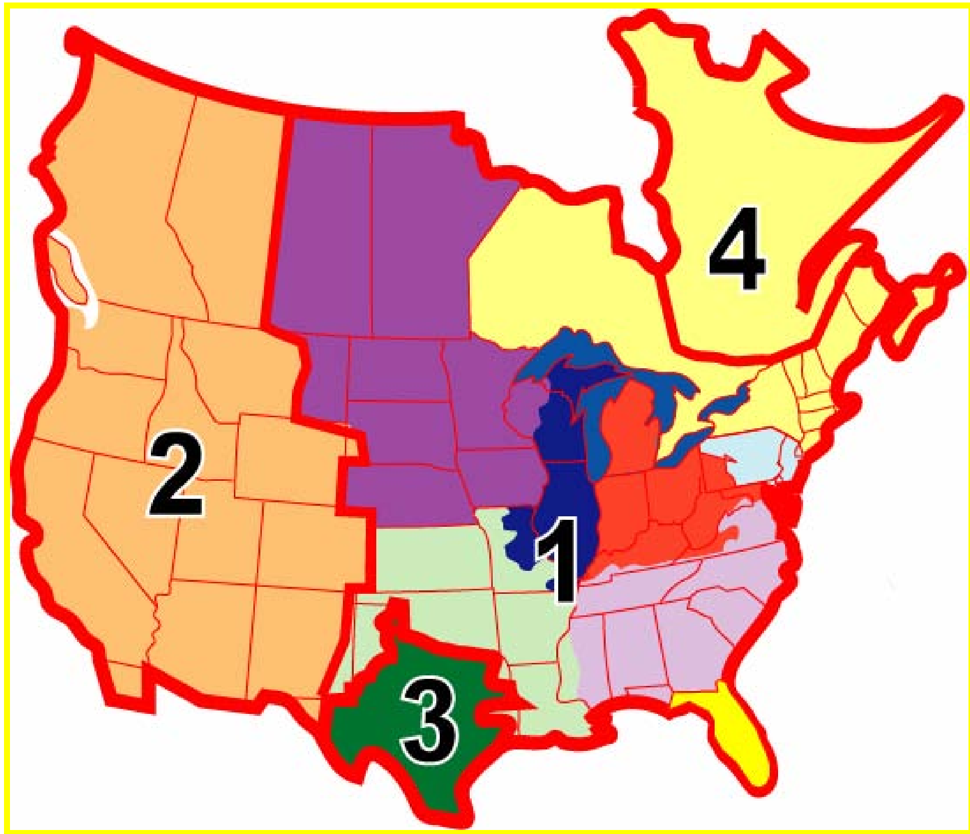


Figure 2-81
The Four Major Interconnections

These four Interconnections are the four largest of many in North America. For example, the state of Alaska is electrically isolated from the rest of North America. The portion of Alaska between Fairbanks and Anchorage forms a small (≈1000 MW) Interconnection. The northern regions of the Canadian provinces also have many small interconnections.

Interconnections and Frequency

Each interconnection in North America maintains a 60 HZ frequency. However, the interconnections each maintain their own version of 60 HZ. For example, the frequency of the Eastern Interconnection has nothing to do with the frequency of the other Interconnections. The only transmission lines connecting the major Interconnections are high voltage DC (HVDC) lines. HVDC lines are used because they operate independent of frequency.

The theory and operation of HVDC systems are addressed in Chapter 10.

In the late 1960's and early 1970's, attempts were made to tie the Eastern and Western Interconnections together with AC transmission lines. The lines frequently tripped and caused more problems than they were solving. The capacity of the lines was simply too small to tie such large systems together. The AC ties were opened permanently in the early 1970's. The East and West

Interconnections are currently tied together but the ties are via HVDC, not AC.

2.7.2 The Role of NERC

U.S. and Canadian utilities, power producers, energy brokers, and marketers have voluntarily organized into a system of ten Regional Reliability Councils. The ten councils are all part of the North American Electric Reliability Council or NERC. The ten councils are illustrated in the map of Figure 2-82.

When this text was written NERC was in the process of reorganizing itself as NAERO, the North American Electric Reliability Organization.

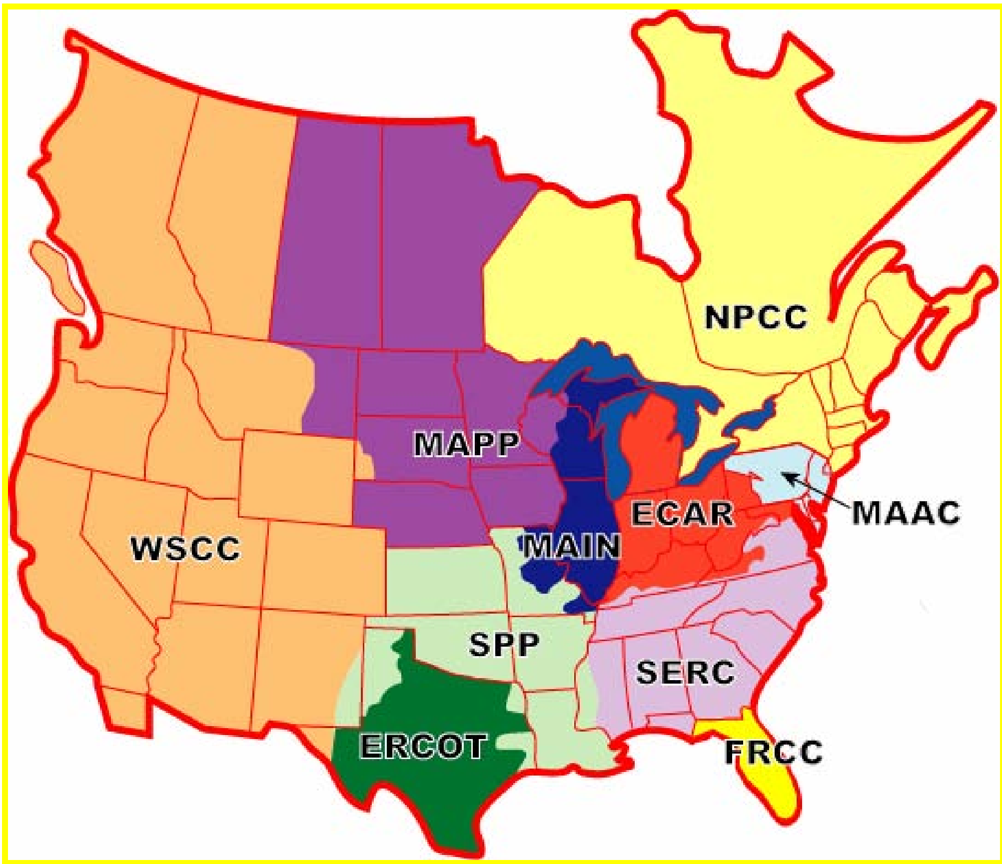


Figure 2-82
The Reliability Councils of NERC

The full names of the ten councils are as follows:

- ECAR—East Central Area Reliability Coordination Agreement
- ERCOT—Electric Reliability Council of Texas
- FRCC—Florida Reliability Coordinating Council
- MAAC—Mid-Atlantic Area Council
- MAIN—Mid-America Interconnected Network

- MAPP—Mid-Continent Area Power Pool
- NPCC—Northeast Power Coordinating Council
- SERC—Southeastern Electric Reliability Council
- SPP—Southwest Power Pool
- WSCC—Western Systems Coordinating Council

NERC was formed by the electric utility industry in 1968 to promote the reliability of electric utilities in North America. Membership in NERC is voluntary. NERC publishes Operating Policies that members pledge to uphold. Every system operator should read and understand the Operating Policies published by NERC. In addition to Operating Policies, NERC also publishes a variety of training materials. These training materials cover a wide array of subjects ranging from generation control to transmission operations.

Fundamentals Review Questions

1. If a generator is producing 500 MW and 200 Mvar, is the generator?
   A. Leading
   B. Lagging
   C. Underexcited
   D. Dropping

2. What is the IEEE device number for a differential relay?
   A. 87
   B. 86
   C. 67
   D. 50

3. Can a synchronous machine have a negative torque angle? What does this mean?
   A. Yes / the machine is absorbing reactive power
   B. No / the machine is absorbing active power
   C. No / the machine is absorbing reactive power
   D. Yes / the machine is absorbing active power

4. A customer load is fed at 120 volts. The customer voltage is doubled while the load magnitude stays the same. What effect does this have on the power losses?
   A. Doubles the losses
   B. Halves the losses
   C. Increases the losses by a factor of four
   D. Decreases the losses by a factor of four

5. In a DC circuit, a 100 volt battery is connected to both sides of a 2 ohm resistor. What is the current through the resistor and the power usage of the resistor?
   A. 50 amps / 5000 watts
   B. 40 amps / 80 watts
   C. 50 amps / 100 watts
   D. 40 amps / 3200 watts

6. The actual voltage is 362 kV on a 345 kV bus. What is the p.u. voltage?

   A. 1.0

   B. 1.05

   C. 1.5

   D. .95

7. A load has a power factor of 0.9 lagging. If the load draws 100 MVA, what is the MW draw?

   A. 100

   B. 90

   C. 111

   D. 44

8. Which of the following is NOT a synchronizing variable?

   A. Phase angle

   B. Frequency difference

   C. Voltage magnitude difference

   D. MW flow differential

9. In a typical multi-stage steam turbine, the governor control valves control the steam entry to the:

   A. high pressure turbine

   B. intermediate pressure turbine

   C. low pressure turbine

   D. crossover

10. The high side of a delta-wye connected transformer is connected to a power system with 199 kV L-G high side voltage. What is the voltage across the winding of the delta transformer?

    A. 199 kV

    B. 230 kV

    C. 345 kV

    D. 500 kV

Fundamentals Review References

1. Electric Power: Motors, Controls, Generators, Transformers—Textbook written by Mr. Joseph Kaiser. Published by Goodheart-Wilcox Co., 1982.

   Excellent reference for basic electrical topics—Very clear explanations for the construction and operation of motors and generators.

2. Protective Relaying Principles and Applications—Second edition of a textbook written by Mr. J. Lewis Blackburn. Published by Marcel Dekker, Inc., 1998.

   Textbook addresses the basic theory of protective relaying. Text is easily read which is unusual for a protective relaying text.

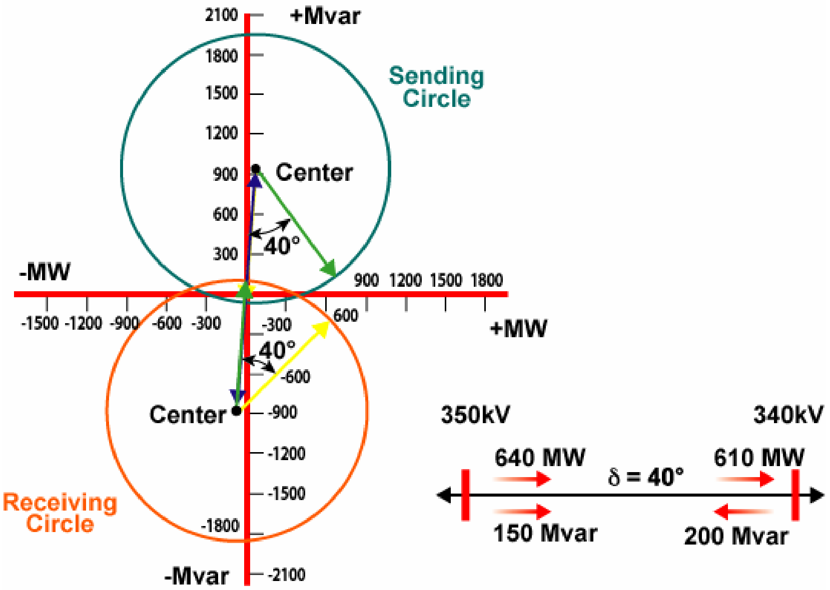
3. Electricity One-Seven—Textbook published by Hayden Books, 1990. Harry Mileaf, Editor-in-Chief.

   Classic textbook on basic electrical theory—Text takes its time developing the theory so everything fits neatly together by the conclusion of the book.

4. Electric Utility Systems and Practices—Textbook written by the engineers of General Electric. Published by John Wiley & Sons, 1983.

   Basic introduction to all facets of an electric utility. Topics addressed include transmission, generation, transformers, substations, protective relaying and system operations.

3
ACTIVE AND REACTIVE POWER



3.1 Introduction to Active and Reactive Power

A brief introduction to the concepts of MW and Mvar.

3.2 Review of Active and Reactive Power

A review of active power, reactive power, complex power, phase angles, power angles, and torque angles.

3.3 Equations for Power Transfer

Equations are developed for active and reactive power transfer.

3.4 Graphical Tools for Power Transfer

Graphical techniques are developed to analyze power flow including:

- Power-angle curve to help determine angle stability
- Power-circle diagram to illustrate active and reactive power flows as voltage, impedance, and power angle change

• 3.5 Power Transfer Limits

Active power transfers are constrained by thermal, angle stability, and voltage limits.

3.6 Distribution Factors

Distribution factors are calculated to estimate how MW flow will distribute in the power system.

3.1 Introduction to Active and Reactive Power

An understanding of the concepts of active and reactive power flow are critical to an understanding of power system dynamics. This chapter first reviews and summarizes the theory related to active and reactive power. Simple equations are developed for the flow of both active (symbol "P" and units MW) and reactive (symbol "Q" and units Mvar) power. Graphical means of describing the flow of active and reactive power are then developed and illustrated.

3.2 Review of Active and Reactive Power

3.2.1 Active, Reactive and Complex Power

The concept of active power is easily grasped. Active power (or MW) performs the actual work. Power plants must consume fuel (coal, water, nuclear, gas, oil, etc.) to produce active power. Active power lights the lights, produces heat, turns the motors, etc. When active power flows from the generator to the load the customer's energy meter spins. The customer is eventually billed for this power usage over a period of time.

The concept of reactive power is also quite simple. Reactive power does not actually flow but rather oscillates. Reactive power or Mvar is constantly being exchanged between those devices that produce it and those devices that store it in their electric and magnetic fields. We designate the movement of reactive power between a generator and an inductive load as positive reactive power flow. AC power systems are dependent upon electric and magnetic fields. Reactive power is the building block for these required fields.

There is no net energy transfer with reactive power flow. Half the time the power is stored in electric or magnetic fields, the other half the power returns to the source. Over time the average reactive power flow is zero. Since the average power flow is zero there is no energy usage. A generator may not have to consume a fuel to produce reactive power.

Active and reactive power are the components of the complex power. Complex power stated in equation form is:

$$\boxed{\begin{array}{c} S = P + jQ \\ MVA = MW + jMvar \end{array}}$$

The "j" symbol next to the "Q" means that reactive power (Q) is at a 90° angle to active power (P). The two powers must be added as vectors to determine the complex power ("S" or MVA).

Complex power is equal to the vector sum of the active (P) and reactive (Q) powers. Since reactive power has a 90° angle with respect to active power the quantities must be added as vectors. The power triangle was presented in Chapter 2 as a graphical method of adding the power vectors together.

3.2.2 Phase Angle, Power Angle, and Torque Angle

Different names are often used for these angles. For example, the terms bus angle, load angle and voltage are sometimes used in place of power angle. The term rotor angle is sometimes used in place of torque angle.

Phase, power, and torque angles are used to describe the operation of a power system. This section will explain the difference between the three angles.

Voltage & Current Angles

To fully understand the concept of a phase angle, we should first understand voltage and current angles. Recall the shape of power system voltage and current waves from Chapter 1. The voltage and current waves are sine waves that repeat themselves every $1/60^{TH}$ of a second. Each full cycle of the voltage and current sine wave can be further broken down into 360°.

At the beginning of the sine wave cycle, the magnitude is zero since the sin 0° is equal to zero (0). The maximum value of the sine wave occurs at 90° and is equal to one (1) while the minimum value occurs at 270° and is equal to minus one (-1). An alternating voltage behaves like a sine wave as illustrated in Figure 3-1(b). Note how the zero crossings and maximum and minimum values for this voltage wave occur at exactly the degree values on the sine wave where you might expect them to occur.

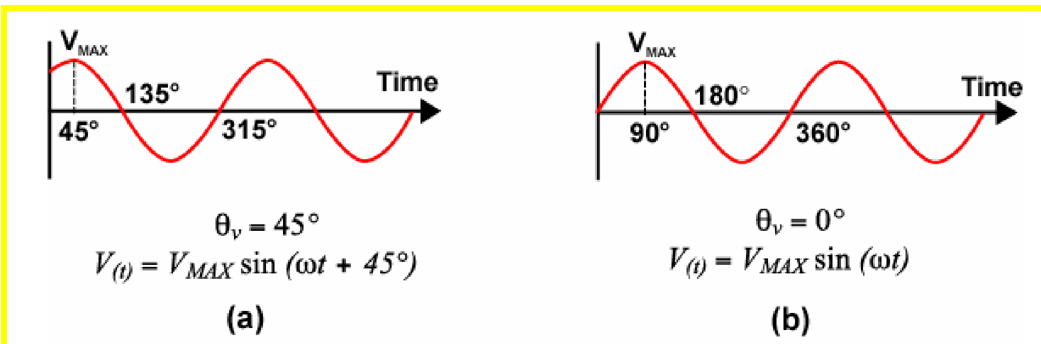


Figure 3-1
Voltage Phase Angle

Look closely at Figure 3-1(a). Notice that the zero crossings and minimum and maximum values are shifted from where you might expect them to occur. The sine wave of Figure 3-1(a) has been shifted 45° to the left. The zero crossings and all other points on the voltage wave have been shifted by the same number of degrees. We say that the sine wave of Figure 3-1(a) has a voltage angle (θ_V) of +45°.

The voltage angle represents the amount by which the voltage sine wave has been shifted left or right with respect to a reference. A positive angle will shift the wave to the left, thus causing it to lead the reference wave. A negative angle will shift the wave to the right, thus causing it to lag the reference wave.

The concept of a voltage angle (θ_V) applies when comparing a voltage wave to another voltage wave. There must be a reference to determine if there has been a shift to the left or the right. The reference for the voltage angles in Figure 3-1 is the voltage waveform in Figure 3-1(b). Note that this voltage angle is 0°.

A voltage angle must be stated with respect to a reference wave.

Current waves may have current angles. The current angle (θ_I) is the angular separation between two current waveforms. As we will see in the following sections it is often useful to look at the voltage angle of a bus with respect to the current angle at the same bus.

The equations for the two voltage waves in Figure 3-1 are written below each wave. The term "ωt" represents the time changing nature of the voltage wave. Notice how in the right Figure 3-1(b) equation the sine value is purely a function of the ωt term. There is no voltage angle in this equation. In contrast, the left Figure 3-1(a) voltage wave equation is for the sine of ωt + 45°. The 45° is the voltage angle and represents a 45° left shift of the voltage wave with respect to the other voltage waveform. The Greek letter "ω" (omega) is the angular frequency. Omega is equal to 2π times the frequency ($\omega=2\pi f$).

The Greek letter "ω" (omega) is the angular frequency. Omega is equal to 2π times the frequency ($\omega=2\pi f$).

Figure 3-1 illustrated how voltage angles are shown graphically and in equation form. Throughout this text we will use a shorthand method of stating a current or voltage magnitude and angle. For example, if the voltage magnitude is 355 kV and the voltage angle is 45°, a shorthand way of showing this is $355\ \angle 45°$.

Phase Angle

The phase angle at a point in a power system is the angular separation, or difference in phase, between the current and the voltage waves. The Greek letter theta with no subscript (θ) is used to represent the phase angle. Recall that if current lags voltage—as in an inductive system—θ is positive. If current leads voltage, as in a capacitive system, θ is negative. The phase angle is defined to be positive when voltage leads current. The phase angle relationships are illustrated in Figure 3-2.

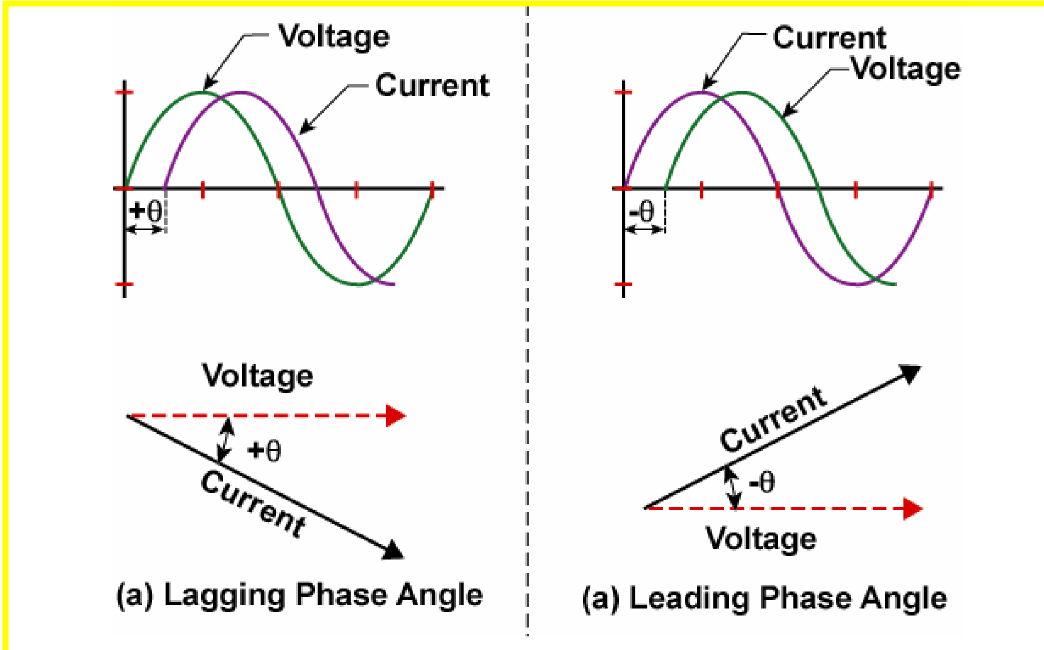


Figure 3-2
Concept of a Phase Angle (θ)

Recall also that the phase angle between current and voltage is the same as the angle between active (MW) and complex power (MVA). The value of θ varies from one point in a power system to another.

Power Angle

The Greek letter δ is also used to designate a generator's torque angle. This is intentional as the torque and power angles are very similar concepts.

The power angle is the voltage angle difference between two locations in the power system. This angular value plays a large role in the magnitude of active and reactive power flow thus the name power angle. The power angle is represented by the Greek letter delta or "δ".

An oscilloscope is an electronic device that can capture and display voltage and current waveforms.

The power angle is the angular difference between the voltage waveforms at two different points in the power system. If one were to plot the voltage waves from two locations and measure the difference between the zero crossings, one would be measuring the power angle. Figure 3-3 illustrates the measurement of a power angle. Assume the two voltage waveforms are oscilloscope traces. Note the difference between the zero crossings. The voltage wave at the sending bus (V_S) leads the voltage wave at the receiving bus (V_R) by the power angle δ.

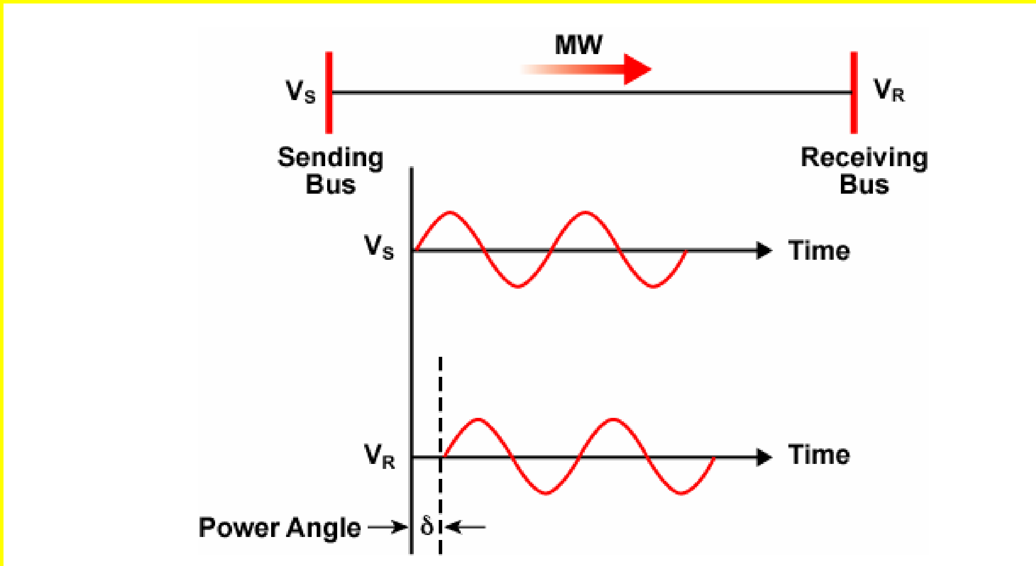


Figure 3-3
Measurement of the Power Angle (δ)

There is a simple rule of thumb that states that active power flows downhill on power angle. Active power flows from points where the measured voltage is more leading to points where the measured voltage is more lagging. In Figure 3-3, the active power must flow from the sending bus (V_S) to the receiving bus (V_R).

Active power flows downhill on power angle.

When we report a phase angle value we do so for a point in the power system. For example, the phase angle for a bus may be 20°. When we report a power angle value we report the value between two locations. The power angle is the angular difference between voltages at two points. In Figure 3-3, the power angle is approximately 90°. A δ of 90° means there is a 90° angle between the sending and receiving buses.

The two voltage waves must be compared at exactly the same time to measure an accurate power angle.

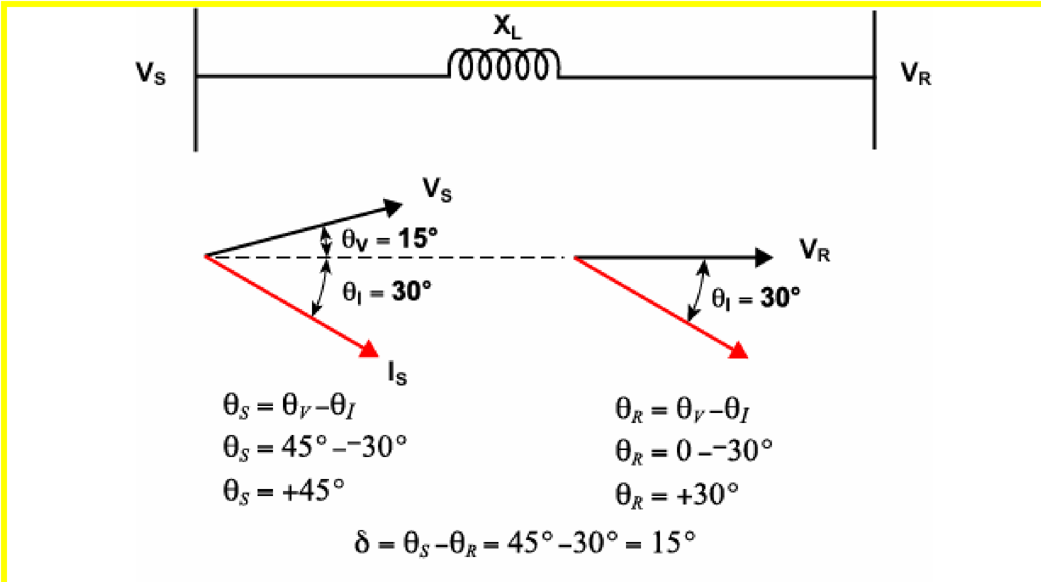
The larger the power angle (up to approximately 90°), the larger the active power flow between the two points. Sustained operation with a δ greater than 90° will likely result in an out-of-step condition.

Out-of-step is defined in Section 3.4 of this chapter.

Approximate Relationship Between Phase & Power Angles

Now that we have defined phase angle and power angle separately, we can describe their approximate relationship to one another. Consider the simple two bus systems of Figure 3-4. Assume that there is no angular difference between the current waves at the two buses (i.e., the two current vectors are in-phase). The power angle is then equal to the difference between the phase angles at the buses or:

$$\boxed{\delta = \theta_S - \theta_R = 45° - 30° = 15°}$$



Note that θ_I is negative in both of these calculations.

Figure 3-4
Determining Approximate Power Angle from Phase Angles

The use of the difference in phase angles to determine the power angle is a rough approximation. In the high voltage system, current is not in-phase throughout the system. There are substantial current angles due to the natural capacitive effect of transmission lines. Accurate high voltage system power angles should be determined based on the difference in voltage angles.

Similarly, the power angle between any two buses or points on the system is <u>approximately</u> equal to the difference in phase angle between the two buses. Values of θ and δ are given in Figure 3-5 to illustrate this approximate relationship. Notice how the phase angles at the generator end of the system are generally leading with respect to other system phase angles. Active power will flow from the generator to the other buses in the system.

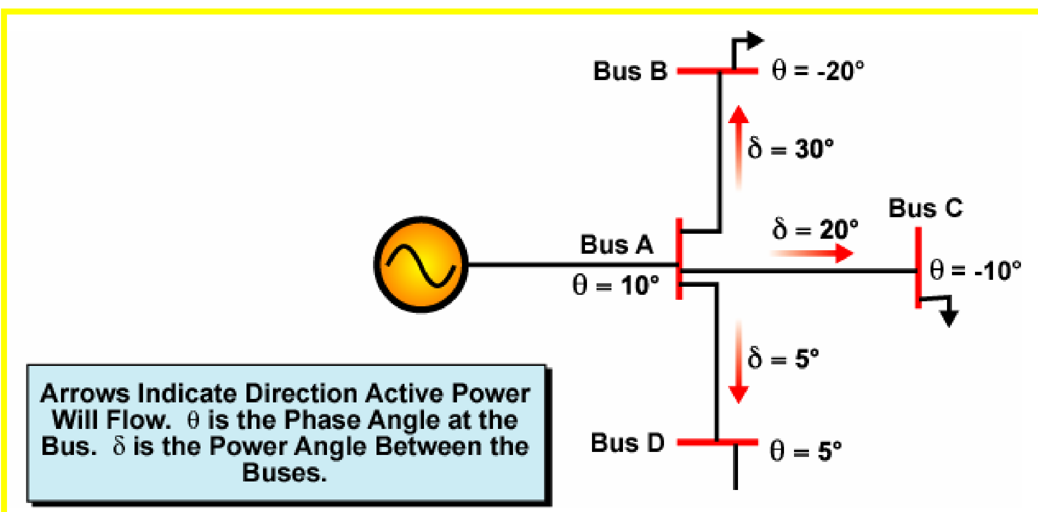


Figure 3-5
Illustration of Phase & Power Angles

The system operator is not normally aware of the phase and power angles in the system. However, every time one uses a synchroscope or a synch-check relay to close a circuit breaker, the power angle is monitored.

Use of Synchroscopes

A circuit breaker synchroscope is illustrated in Figure 3-6. A synchroscope compares the frequency, voltage phase angle, and voltage magnitude on both sides of an open circuit breaker. If the frequency on either side of the circuit breaker is different the synchroscope will rotate. The position of the rotating hand represents the voltage phase angle across the breaker or the power angle. If the hand is at 12:00, the power angle is 0°. If the hand is at 6:00, the power angle is 180°. Ideally, the hand is rotating very slowly and reaches 0° at the instant the circuit breaker is closed.

The three quantities monitored by a synchroscope are called the synchronizing variables. The synchronizing variables are:
1. Frequency Difference
2. Phase Difference
3. Magnitude Difference

When synchroscopes are used in the transmission system, the frequency difference is usually very small. If the power angle measured is too large, a system operator adjusts generation levels in the system to lower the angle and allow a closure.

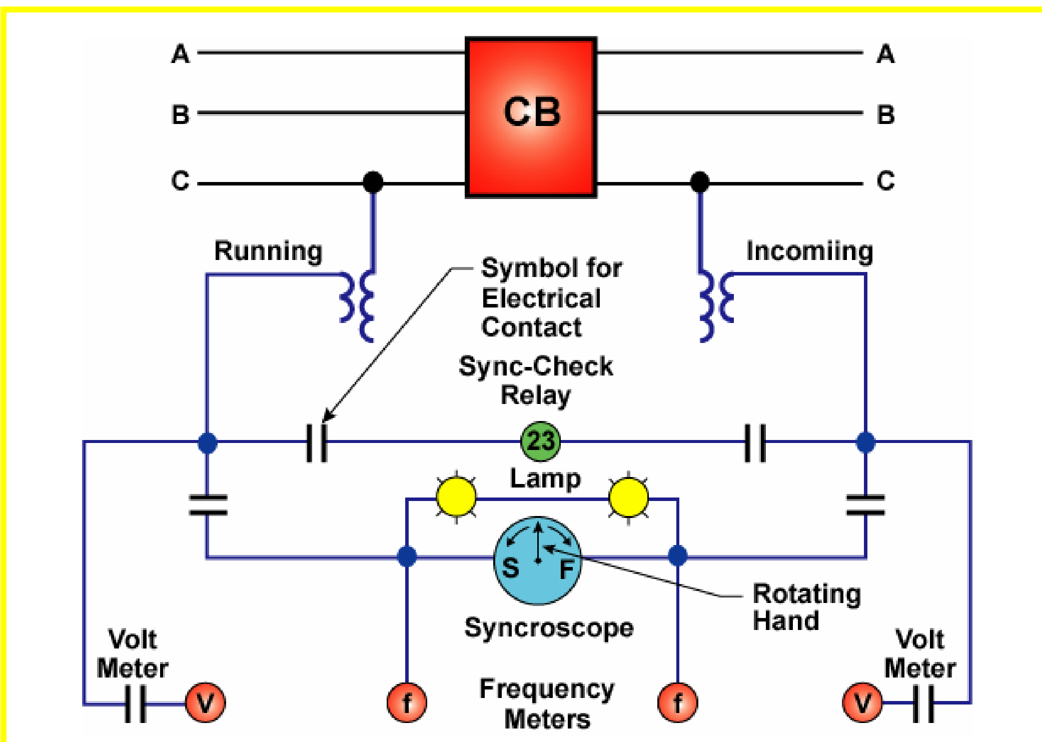


Figure 3-6
Synchroscopes & Power Angles

Generator Torque Angle

As illustrated in Figure 3-7, a synchronous generator is composed of a rotating member called the rotor and a stationary member called the stator. The rotor is attached to the prime mover (often a turbine). When the working fluid (steam, water, etc.) impacts on the turbine blades, it causes the turbine/rotor combination to rotate. The rotor is actually an electromagnet as DC field coils are wound about the rotor and fed DC current from the generator's excitation system. A synchronous generator is designed so that the rotor turns at synchronous speed. This creates a rotating electromagnetic field.

The rotor and stator magnetic fields are actually rotating at synchronous speed but are shown as stationary to simplify their description.

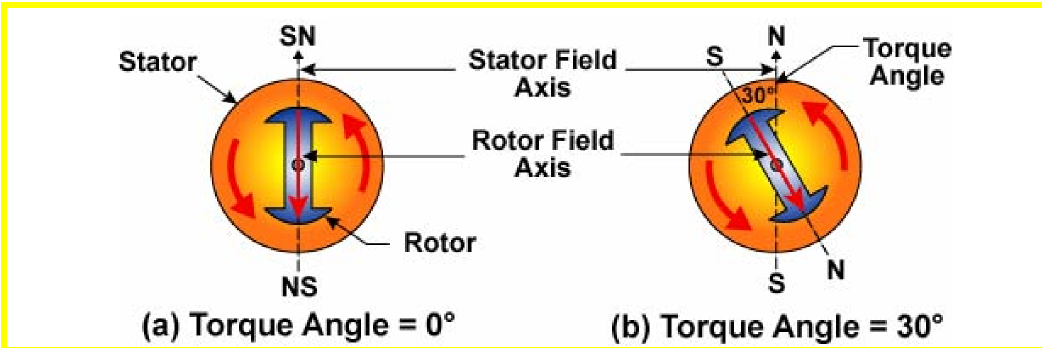


Figure 3-7
Generator Torque Angle Illustration

When a generator is first attached to the power system, the rotating electromagnetic field of the rotor is synchronized to the rotating electromagnetic field that naturally exists in the 3Φ power system. A generator is synchronized by adjusting the generator speed, voltage magnitude, and phase to within a desired range. Once voltage and speed are within this range the generator breaker is closed and the two rotating fields combine. The two rotating fields are "in-step" with one another when they are synchronized.

The torque angle of a generator is the angular difference between the rotor's rotating magnetic field and the rotating magnetic field about the stator of the generator. Figure 3-7(a) represents a generator that is synchronized to the system but has no MW output. The angular difference between the rotor and stator magnetic fields is 0°. Both fields are rotating in lock-step with one another.

Figure 3-7(b) represents a generator that is synchronized and sending MW to the system. Notice that the rotor field leads the stator field by a torque angle of 30°. The magnetic field of the rotor is pulling the magnetic field of the stator along with it. The generator is injecting a large amount of energy into the power system as a result of the magnetic force it is exerting on the system. The generator will have a MW output as a result of this torque angle.

The torque angle of a generator has a large impact on the MW delivered by the generator to the system. Within certain limits, the larger the torque angle the more MW the generator outputs. The torque angle of a generator is very similar to the power angle measured between locations in the power system. A generator's torque angle can be explained as the difference in phase between a generator's internal or excitation voltage and the unit's stator voltage. When this torque angle explanation is used both torque and power angles are voltage angle differences. It is these torque and power angles that determine the direction and magnitude of active power flow in the system.

See Figure 2-58 for an illustration of torque angle in terms of a voltage angle difference.

3.3 Equations for Power Transfer

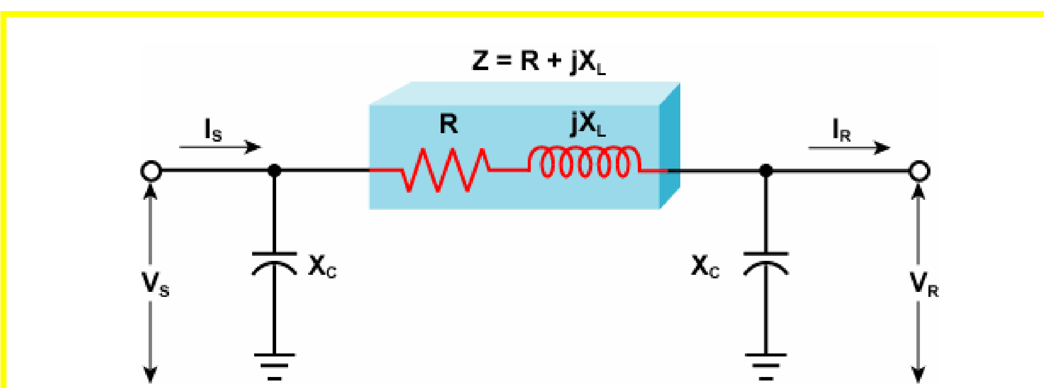
3.3.1 Development of Power Transfer Equations

In order to better understand the factors that influence how active and reactive power flows in the power system, simple equations relating to these factors are now developed. These equations relate the power transfer between two substations to system electrical data. The electrical data includes:

- Sending and the receiving bus voltages
- Power angle between the two buses
- Series impedance of the transmission path connecting the two buses
- Natural capacitance (charging) of the transmission path connecting the two buses

Figure 3-8 is a model for a high voltage transmission line. The impedances that effect the flow of power are represented in this model. In addition, the natural capacitance of the transmission line is represented by two shunt capacitors (with impedance X_C) connected at either end of the line. This transmission line model, called the PI model, approximates the behavior of high voltage transmission lines.

The name PI is used because the model looks like the Greek letter π.



Note that we define positive sending end current as into the line and positive receiving end current as into the receiving bus.

Figure 3-8
Transmission Line PI Model

In the PI model for a transmission line, Z is equal to the series impedance of the transmission line. Z includes both the line's series reactance (X_L) and the line's series resistance (R). X_C is the line's capacitive reactance. The line's capacitive reactance represents the natural capacitive nature of the transmission line.

Also shown on the model are the sending end voltage (V_S) and current (I_S) and the receiving end voltage (V_R) and current (I_R). The model of Figure 3-8 will be used to develop simple equations for the transfer of active and reactive power between the sending and receiving ends of the line.

Using the data from our transmission line model in Figure 3-8 and applying Kirchhoff's voltage and current laws, the four equations given in Figure 3-9. These equations define the sending and receiving end voltages (V_S and V_R) and currents (I_S and I_R). Note the bar symbols above the voltage, current, and impedance values. The bar symbol means the quantity is a vector or phasor. For example, $\overline{V}_R$, means the receiving end voltage is a phasor and has both a magnitude and an angle.

$$\overline{V}_S = \overline{V}_R + \left(\overline{I}_R - \frac{\overline{V}_R}{\overline{X}_C} \right) \overline{Z} \qquad \overline{V}_R = \overline{V}_S - \left(\overline{I}_S - \frac{\overline{V}_S}{\overline{X}_C} \right) \overline{Z}$$

$$\overline{I}_S = \frac{\overline{V}_S}{\overline{X}_C} + \frac{\overline{V}_S - \overline{V}_R}{\overline{Z}} \qquad \overline{I}_R = -\frac{\overline{V}_R}{\overline{X}_C} + \frac{\overline{V}_S - \overline{V}_R}{\overline{Z}}$$

Figure 3-9
Power Transfer Equation Set #1

The complex power (the MVA or S) is always equal to the voltage times the current. The equations in Figure 3-10 are for the MVA flowing out of the sending end of Figure 3-8 and into the receiving end of the line. The sending end MVA is equal to the sending end voltage times the sending end current. The receiving end MVA is equal to the receiving end voltage times the receiving end current.

A few of the symbols used in Figure 3-10 require further explanation.

- The "j" symbol signifies that the reactive power terms are 90° out-of-phase with the active power terms.
- The angle term "δ" (Greek letter delta) is the voltage angle between the sending (V_S) and receiving (V_R) buses.

- The hat symbol (^) is a math concept (called a conjugate) used to ensure the proper sign conventions are used for reactive power.

$$S_S = P_S + jQ_S = V_S \times \hat{I}_S = \frac{V_S^2}{\hat{Z}} + \frac{V_S^2}{\hat{X}_C} - \frac{V_R V_S \angle\delta}{\hat{Z}}$$

$$S_R = P_R + jQ_R = V_R \times \hat{I}_R = -\frac{V_R^2}{\hat{Z}} - \frac{V_R^2}{\hat{X}_C} + \frac{V_R V_S \angle\delta}{\hat{Z}}$$

Figure 3-10
Power Transfer Equation Set #2

Kirchhoff's voltage law was used to construct the two voltage equations.

Kirchhoff's current law was used to construct the two current equations.

Figure 3-11 separates the active and reactive power portions of the equations in Figure 3-10. The two active power equations define the MW out of the sending bus (P_S) and into the receiving bus (P_R). The reactive power equations define the Mvar out of the sending bus (Q_S) and into the receiving bus (Q_R).

$$P_S = \frac{V_S}{Z^2}\left[V_S R - R V_R \cos\delta + X_L V_R \sin\delta\right]$$

$$Q_S = \frac{V_S}{Z^2}\left[V_S X_L - X_L V_R \cos\delta + R V_R \sin\delta - \frac{V_S}{X_C} Z^2\right]$$

$$P_R = \frac{V_R}{Z^2}\left[-V_R R + R V_S \cos\delta + X_L V_S \sin\delta\right]$$

$$Q_R = \frac{V_R}{Z^2}\left[-V_R X_L + X_L V_S \cos\delta - R V_S \sin\delta + \frac{V_R}{X_C} Z^2\right]$$

Figure 3-11
Power Transfer Equation Set #3

The "Z" term has been separated into its R+jX$_L$ components in these equations.

We can simplify the equations of Figure 3-11 by assuming that the series resistance (R) is much smaller than the series reactance (X_L) and then ignore the series resistance. The simplified equations in Figure 3-12 are the result:

Ignoring the series resistance is a good approximation for high voltage transmission lines.

$$P_S = \frac{V_S \times V_R}{X_L}\sin\delta \qquad Q_S = \frac{V_S^2 - V_S V_R \cos\delta}{X_L} - \frac{V_S^2}{X_C}$$

$$P_R = \frac{V_S \times V_R}{X_L}\sin\delta \qquad Q_R = \frac{-V_R^2 + V_S V_R \cos\delta}{X_L} + \frac{V_R^2}{X_C}$$

Figure 3-12
Power Transfer Equation Set #4

The four equations in Figure 3-12 define the sending and receiving end active and reactive power flows. When the bus voltages, the series reactance (X_L), the line charging (X_C), and the power angle (δ) are known, the active and reactive powers can be calculated. If the voltages used are line-to-line values, the power flows calculated are 3Φ values.

To simplify our usage of the power transfer equations, from this point on, we will concentrate on the sending end equations. The sending end equations are listed in Figure 3-13.

$$P_S = \frac{V_S \times V_R}{X_L} \sin\delta \qquad Q_S = \frac{V_S^2 - V_S V_R \cos\delta}{X_L} - \frac{V_S^2}{X_C}$$

Figure 3-13
Power Transfer Equation Set #5

3.3.2 Use of the Active Power Transfer Equation

The active power transfer equation is restated below.

$$\boxed{P_S = \frac{V_S \times V_R}{X_L} \sin\delta}$$

This equation tells us that the MW transfer is determined by multiplying the sending and receiving end voltages together and dividing by the series reactance of the line. This quantity is next multiplied by the sine of the power angle. The quantity [(V_S x V_R) / X_L] is called the maximum power or P_{MAX}.

P_{MAX} is the maximum MW a system is electrically capable of transmitting. How much of this maximum is actually transmitted depends on the sine δ term of the equation. Within limits, the larger the power angle (δ), the more MW that will flow.

Figure 3-14 contains a simple 115 kV two bus power system. The voltage at the sending end is 115 kV and the receiving end voltage is 118 kV. The line series reactance is 100 Ω. The bottom of Figure 3-14 contains a sample use of the active power transfer equation. If you multiply out the numbers, the active power transferred is 24 MW. Note that this power flow is from the sending bus (V_S) to the receiving bus (V_R) since the voltage angle of V_S leads that of V_R.

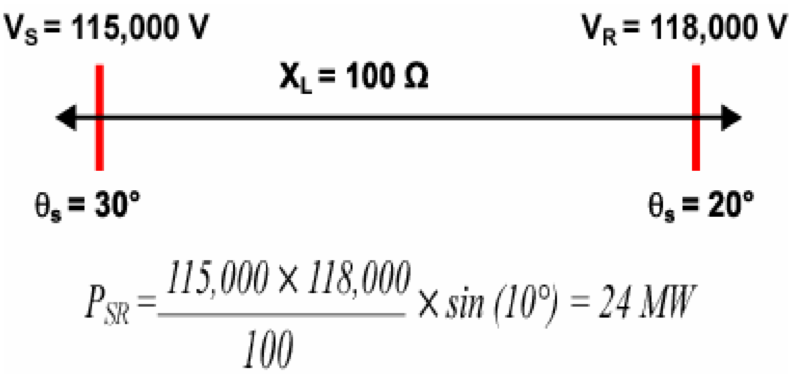


Figure 3-14
Use of the Active Power Transfer Equation

The MW flow is from the leading bus to the lagging bus.

When the active power transfer equation was applied to the simple system of Figure 3-14 the bus voltages at either end of the system were used. The active power transfer equation applies as long as the buses used are strong buses. By strong bus we typically mean the buses have many connecting lines or are close to large sources of reactive power generation. The buses must be strong to ensure they hold their voltage. If the voltage of the bus falls sharply with increasing MW transfer, our simple form of the power transfer equation cannot be used.

The active power transfer equation can be simplified even more if we assume that the power angle (δ) between the two locations is small. By small we mean that δ is less than 20°. If δ is less than 20°, the active power transfer equation can be reduced to:

$$\boxed{P = \frac{V_S \times V_R}{X_L}\delta = P_{MAX}\delta}$$

In this very simple form of the active power transfer equation the angle δ is stated in radians. Angles can be stated in terms of degrees or in terms of radians. To convert from degrees to radians multiply the number of degrees by $2\pi/360$. For example, assume we wanted to determine the MW transfer between two points with a power angle of 20°. To convert 20° to an equivalent number of radians multiply 20 by $2\pi/360$. The result is 0.35 radians. The active power transfer between our two points is now .35 x P_{MAX}. To determine the actual MW transfer, we need determine only P_{MAX}.

This simplification of the active power transfer equation only applies if δ is less than 20° and δ is expressed in radians (not degrees).

Factors that Effect Active Power Flow

By considering the active power transfer equation and other factors we can judge the impact of various actions and system equipment on MW flow. For

$$P_S = \frac{V_S \times V_R}{X_L} \sin \delta$$

easy reference the active power transfer equation is repeated in the right margin.

System Generation & Load

For active power to flow generators must produce the MW and the loads must absorb the MW. Active power always flows from source to load. Within an interconnected power system active power typically has many sources, many loads, and many paths to get from the source to the load. We can control the flow of active power by controlling where it is generated and where it is used.

Voltage Magnitude

If the voltage magnitude of either the sending or receiving bus is increased, either the active power transferred will increase or the power angle will decrease. Higher voltages allow transfer of more active power, or transfer of the same amount of active power with a lower angle. Assume we have a system with several possible paths from the source to the load. If the voltage levels along one of the paths are increased, more power will flow along that path.

Path Impedance

We use "X_L" as the path impedance because we are assuming the resistance (R) is much smaller than the reactance (X_L) and so ignore resistance.

The "X_L" in the denominator of the active power transfer equation is the impedance impact on active power flow. As "X_L" is increased either active power flow decreases or the power angle will increase. As "X_L" is decreased active power flow increases or the power angle will decrease. If two paths exist between a source and a load, more power will flow on the lower impedance path. Every system operator should understand the statement that "power flows the path of least impedance". More power will flow on the lower impedance path.

Power Angle (δ)

Typically, the voltage magnitudes and path impedance are relatively fixed. Active power flow along a path is normally changed by changing the path's power angle. Power angles are not changed via some conscious effort by a system operator. Power angles change as a natural result of actions that change a system's active power needs. For example, assume a utility has generation at one end of a transmission path and load at the other. As the load increases the power angle across the path will also increase.

System Equipment

System equipment can have a large impact on active power flow. As new transmission lines are added system active power flows redistribute to incorporate the new path. System equipment such as transmission lines, transformers, etc., has natural impedance and so impacts the flow of active power.

There are some types of equipment whose primary function is to adjust system active power flows. One example of this type of equipment is a phase shifting transformer (PST). PSTs are transformers whose function is to adjust the flow of active power. Figure 3-15 illustrates the use of a PST. In Figure 3-15(a), 530 MW of active power is flowing into a two path system. Power splits according to the path of least impedance so most flows over the lower impedance underground cable. Assume this power split overloads the underground cable while barely loading the overhead line.

Phase shifting transformers or PSTs may also be called phase angle regulators or PARs.

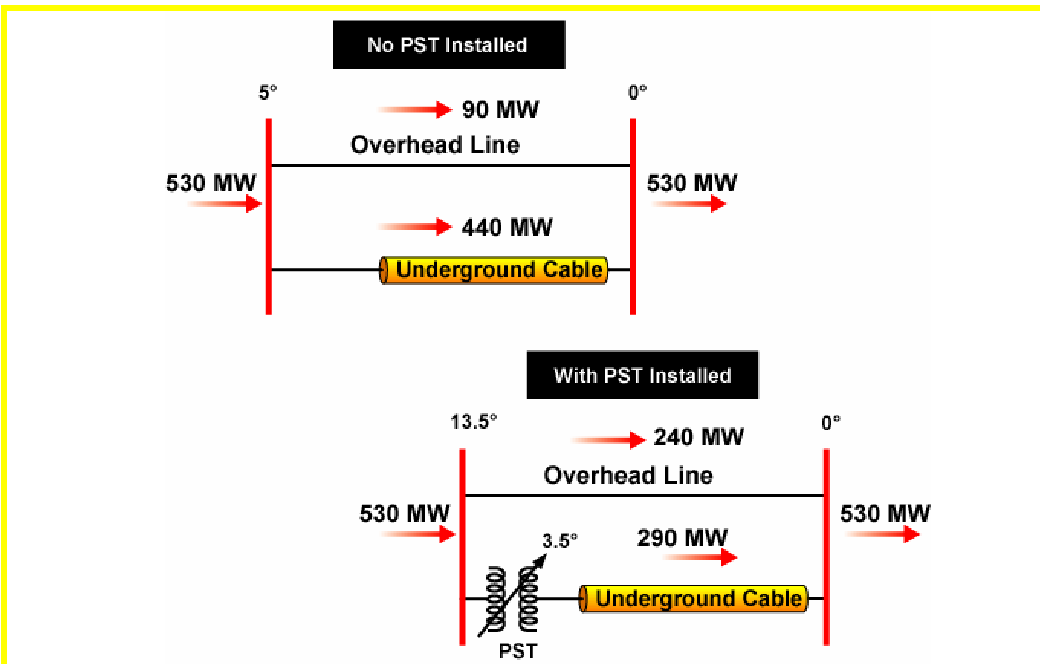


Figure 3-15
Use of a Phase Shifting Transformer

Chapter 10 of this text describes the construction, operation and use of PSTs in greater detail.

From a system operations perspective something must be done to relieve the overloading on the underground cable. An option is to decrease the total system flow below 530 MW to some manageable level for the underground cable. However, this option prevents the transmission path operator from fully utilizing their transmission system.

In Figure 3-15(b) a PST is installed in the underground cable. The PST is used to control the magnitude of the power angle across the underground cable. If the power angle can be controlled, the flow of MW can be controlled. The PST in Figure 3-15(b) pushes a portion of the MW that normally flows across the cable onto the parallel overhead line.

3.3.3 Use of the Reactive Power Transfer Equation

The reactive power transfer equation is more difficult to interpret than the active power transfer equation. However, there are a few simplifications that can be made to make the equation useful to operations personnel. The equation for the Mvar out of the sending end of a system is:

$$\boxed{Q_S = \left[\frac{V_S^2 - V_S V_R \cos\delta}{X_L}\right] - \frac{V_S^2}{X_C}}$$

The last term in the equation (V_S^2 / X_C) represents the effect of transmission line capacitance. (Notice that the higher the line voltage, the greater the line's Mvar production.) For now, we will ignore the line capacitance. The reactive power transfer equation then simplifies to:

$$\boxed{Q_S = \left[\frac{V_S^2 - V_S V_R \cos\delta}{X_L}\right]}$$

The reactive power transferred between two points is therefore determined by the voltage magnitudes at the two points and the cosine of the power angle between the points.

In normal power system operations, the power angle between two connected buses is small. If δ is small (< 20°) the cosine δ term will be very close to one (1). If we assume that the power angle stays small then the reactive power transfer simplifies even further to:

$$\boxed{Q_S = \frac{V_S(V_S - V_R)}{X_L}}$$

The critical part of this equation is the portion in parenthesis or ($V_S - V_R$). This portion tells us that Mvar will flow from the higher voltage to the lower voltage. Reactive power does normally flow from the high to the low voltage bus. This is a rule of thumb of which every system operator should be aware.

However, we have also determined the conditions for which this rule of thumb is true. Recall that we assumed the power angle was small and so ignored the cosine term. If δ had been large (> 20°) we could not have ignored the cosine term. When power angles exceed approximately 20°, the rule of thumb that reactive power flows from high to low voltage no longer applies. Reactive power can flow from the low to the high voltage bus if the power angle between the buses is large.

$$Q_S = \frac{V_S^2 - V_S V_R \cos\delta}{X_L} - \frac{V_S^2}{X_C}$$

Factors that Effect Reactive Power Flow

By considering the reactive power transfer equation and other factors we can judge the impact of various actions and system equipment on reactive power flow. For reference, the reactive power transfer equation is repeated in the right margin.

Reactive Sources and Reactive Loads

Transmission lines can be either a reactive source or a reactive load. Chapter 5 explains this point.

Reactive power flows from sources to loads in the same manner as active power. However, reactive sources are not limited to generators. Shunt capacitors, synchronous condensers, and transmission lines are all possible reactive power sources. Reactive loads include not only the customer load but also shunt reactors and the transmission system.

Reactive power is closely related to system voltage levels. When voltage levels need to be increased the solution is often to increase the reactive supply to the system. Generators may produce more reactive power, or shunt capacitors may be placed in-service. When voltage levels need to be reduced the solution is often to reduce the reactive power supply. Generators may be used to absorb excess reactive power, or shunt reactors may be placed in-service.

Voltage Magnitude

Reactive power flow is strongly tied to voltage magnitudes. When a generator is asked to increase its terminal voltage it does so by increasing its DC excitation current. This increases the generator's internal excitation voltage. The higher internal voltage of the generator leads to more Mvar flowing out of the unit. When shunt capacitors are placed in-service the voltage at the point of the capacitor insertion increases. Reactive power flows from this high voltage point and disperses throughout the power system.

Path Impedance

The "X_L" also appears in the denominator of the reactive power transfer equation. As the "X_L" of a path is increased, the reactive power usage of the path increases (greater I^2X_L) and the reactive power transfer across the path decreases. As the "X_L" of a path is decreased, the reactive power usage of the path decreases and the reactive power transfer increases. In the same manner as active power flow, reactive power will flow the path of least impedance.

Power Angle (δ)

Reactive power is also impacted by the power angle. Active power is a function of the sine of δ while reactive power is a function of the cosine of δ. Typical power angles between buses are less than 20°. When the power angles are this small the cosine of δ is close to one (1). The result is that while MW flow is strongly impacted by power angles, Mvar flow is typically weakly impacted.

System Equipment

System equipment has a very strong impact on reactive power flow. When voltage control equipment such as capacitors, reactors, or tap changing transformers are used to adjust voltage this equipment is actually controlling the flow of reactive power. Voltage control is reactive power flow control. The two cannot be separated. Chapter 5 of this text will examine the operation and use of several types of voltage (reactive power flow) control equipment.

Transmission Line Charging

Note the last term in the reactive power transfer equation. The V_S^2 / X_C term is due to a transmission line's natural capacitance. Transmission lines provide reactive power to the system during light loading. Transmission lines absorb reactive power from the system during heavy loading periods. The amount of reactive power a transmission line provides to the system is related to the line's voltage. The greater the voltage, the more Mvar the line will supply.

3.4 Graphical Tools for Power Transfer

This section will introduce two graphical tools for studying the flow of active and reactive power. The first tool is the power-angle curve and the second the power-circle diagram. The power-angle curve is easily developed and is illustrated and explained first. Power-angle curves are a powerful tool for studying the angle stability of a simple power system. We will use the power-angle curve frequently in Chapter 7 when we study angle stability. The power-circle diagram requires more effort to produce. The effort is worth while, as the diagram is an excellent tool for visualizing how MW and Mvar flow with changing power system conditions.

3.4.1 Power-Angle Curve

Section 3.3 developed a simple form of the active power transfer equation which is restated below.

$$\boxed{P_S = \frac{V_S \times V_R}{X_L} \sin \delta}$$

The $[(V_S \text{ x } V_R)/X_L]$ portion is a relatively constant value and is called P_{MAX}. P_{MAX} is the largest possible MW transfer between two strong buses. The MW transfer can only reach P_{MAX} if the power angle is 90°. The amount of P_{MAX} which is actually transferred between the two points is dependent on the term sine δ. For example, assume the power angle is 30°. The sine of 30° is ½ so ½ of P_{MAX} can be transferred between two points if the power angle is 30°.

Figure 3-16 is a plot of the active power transfer equation. This plot is called the power-angle curve. The power-angle curve is obtained by multiplying the P_{MAX} value by the sine δ term. Since the value of the sine function varies from 0 to 1 to 0 to -1 to 0, the power-angle curve magnitude will vary from 0 to $+P_{MAX}$ to 0 to $-P_{MAX}$ to 0. With active power transfer we are normally only concerned with the first ½ cycle of the power-angle curve so we will ignore the negative half cycle.

The maximum power transfer actually occurs at the transmission line's impedance angle. The impedance angle is dependent on the relative amounts of line resistance and reactance. The line's impedance angle is always less than 90° since there will always be some resistance. Our use of 90° is a simplification that assumes the line's resistance is much smaller than its reactance.

The power-angle curve graphically illustrates that the maximum continuous active power transfer between any two strong buses occurs when the power angle between these same two points is 90°. (This also could be determined from the active power transfer equation as the maximum value of sine δ occurs when δ = 90°.)

Point "A" in Figure 3-16 represents a point at which a medium amount of active power (P_A) is being transmitted from the sending bus (V_S) to the receiving bus (V_R). The power angle for the active power transfer at point "A" is δ_A which is much less than 90°. Point "B" represents a point at which the maximum amount of power (P_{MAX}) is being transmitted between the two buses. The power angle at point "B" is 90°. Point "C" is for a power transfer with a δ greater than 90°. Note that the power transfer at point "C" is less than at point "B". As the power angle rises above 90°, the active power transfer decreases.

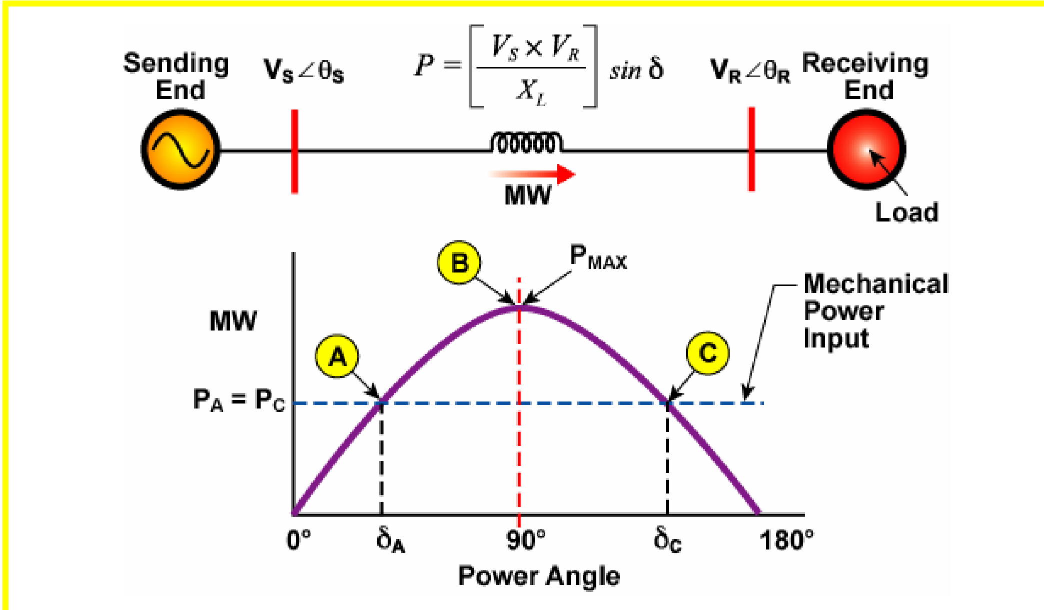


Figure 3-16
The Power-Angle Curve

If the power angle reaches this level (above 90°) and attempts to stay there, synchronism will eventually be lost between the two buses. It is impossible to operate to the right of point "B" for an extended (more than a few cycles) period of time.

There is a very important feature to the power-angle curve of Figure 3-16. The mechanical power input line is the horizontal dashed line through the power-angle curve. This line represents the amount of mechanical power being input to the generator connected to the sending end. The mechanical power input line may cross the power-angle curve at any point. Figure 3-16 shows the mechanical power input line crossing near the middle of the power-angle curve. As the mechanical power input to the generator varies, the mechanical power input line position varies.

The intersection of the mechanical power input line and the power-angle curve yields the possible operating points. One of these points is an acceptable operating point while the other would be unacceptable. For example in Figure 3-16 point "A" is acceptable while point "C" is unacceptable. Operation at point "C" would result in a loss of synchronism.

Introduction to Angle Stability

Power-angle curves are a powerful, yet simple to use, tool for determining the angle stability of a simple power system. Angle stability is the study of whether a power system maintains its magnetic bonds. A power system is angle stable if its generators maintain strong magnetic bonds with the system and with one another. A system is angle unstable if one or more of the magnetic bonds are lost. Other terms used to indicate angle instability are loss of synchronism and out-of-step operation.

When a section of the power system is operated in a state where the power angle between the ends of a transmission line is close to 90°, we say that it is being operated at P_{MAX} or at its steady state stability limit. For example, if a major transmission line was operated with a power angle of 90° it would be at its steady state stability limit. This is not an acceptable normal point of operation as any system disturbance, even minor, would cause the power system to lose synchronism.

When the interconnected power system loses synchronism, portions of the system operate at slightly different frequencies than the remainder of the system. A loss of synchronism means that the magnetic bond that existed between points within the interconnected power system is too weak to maintain a constant frequency. The magnetic bond fails and the system eventually separates into smaller sections or islands. Each island would then attempt to maintain its own separate 60 HZ frequency.

Power systems lose synchronism when power transfers rise to such large magnitudes that power angles reach excessive values. Power systems cannot operate in an interconnected manner after synchronism is lost. When synchronism is lost protective relays will likely operate and system separation may occur. Some portions of the interconnected system may end up as electrical islands that are unable to maintain scheduled frequency. System generators and customer motors in these low or high frequency islands may be damaged if the island is allowed to exist for too long a period with the abnormal frequency.

The term out-of-step is another way of saying that a section of power system has lost synchronism with the remainder of the power system. The magnetic bond between a generator's rotor and the power system the generator is connected to normally holds the generators respective magnetic fields in-step. When this bond is broken, the generators will no longer be in-step with the system but will be out-of-step.

3.4.2 The Power-Circle Diagram

The power-circle diagram is a valuable tool for illustrating how active and reactive power flow vary as voltage magnitude, impedance, and power angle change. This section will describe how power-circle diagrams are created and illustrate their use.

Figure 3-10 contained equations for sending and receiving end MVA flow. These equations were developed using the simple PI model (Figure 3-8) for a transmission line. The equations of Figure 3-10 are repeated in Figure 3-17 with some rearrangement. S_S is the complex power or MVA out of the sending end bus and into the transmission line. S_R is the complex power or MVA out of the transmission line and into the receiving end bus. S_S has two components, S_1 and S_2. S_R also has two components, R_1 and R_2.

$$S_S = \underbrace{\left[+ \frac{V_S^2}{\hat{Z}} + \frac{V_S^2}{\hat{X}_C} \right]}_{S_1} - \underbrace{\left[\frac{V_S V_R \angle\delta}{\hat{Z}} \right]}_{S_2}$$

$$S_R = \underbrace{\left[- \frac{V_R^2}{\hat{Z}} - \frac{V_R^2}{\hat{X}_C} \right]}_{R_1} + \underbrace{\left[\frac{V_S V_R \angle\delta}{\hat{Z}} \right]}_{R_2}$$

Figure 3-17
Equations for the Power-Circle Diagram

The sending and receiving end complex power equations form the outlines of circles when plotted on the appropriate axis. Figure 3-18 is an example of a possible circle if sending end data from the equations of Figure 3-17 are plotted. The complex power out of the sending end (S_S) is equal to S_1 plus S_2. The vector S_1 starts at the origin and determines the center of the sending end circle. The vector S_2 starts at the end of S_1 and determines the radius of the sending end circle. A circle is then drawn with the end of S_1 as the center and with a radius of S_2.

We are assuming that the system voltages and impedance do not change. If we wanted to illustrate voltage or impedance changes we would simply draw a new sending end circle with a different diameter and center location.

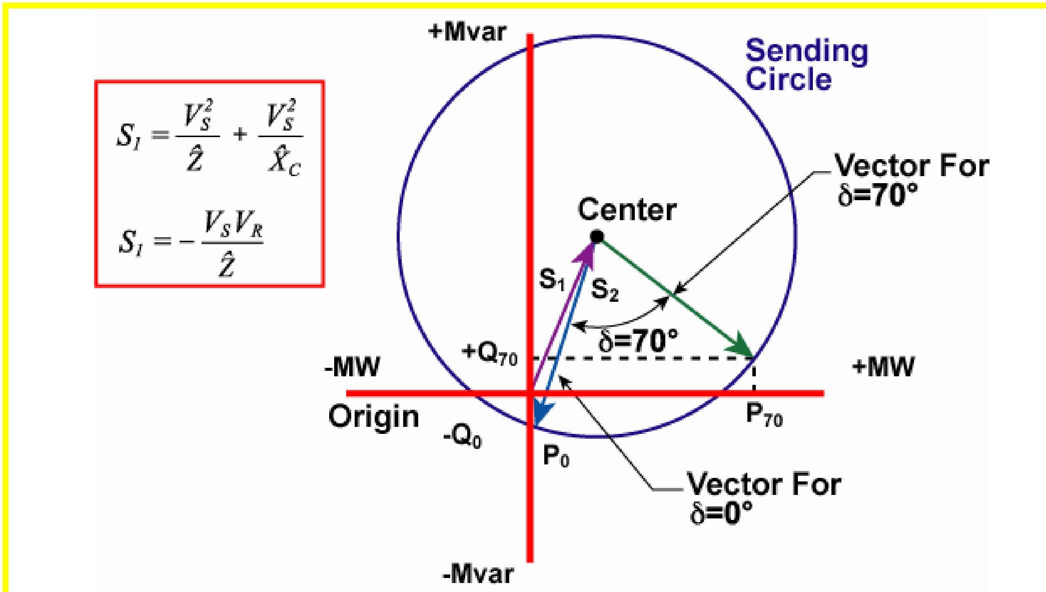


Figure 3-18
Sending End Power-Circle Diagram

The sending end circle in Figure 3-18 can be used to determine the active and reactive power flows out of the sending end for any power angle. For example, Figure 3-18 illustrates that with a power angle of 0° (δ is equal to 0° along the vector S_2) the sending end MW is equal to P_0 and the sending end Mvar is equal to $-Q_0$. The negative sign on the reactive power means the Mvar is flowing from the line into the sending end bus. Figure 3-18 also illustrates the MW and Mvar if the power angle is increased to 70°. Note the MW is P_{70} and the Mvar Q_{70} (the Mvar flow is positive so it has reversed direction.)

By looking closely at the construction of the sending end circle, it can be seen that maximum MW transfer out of the sending end occurs at an angle near, but less than, 90°. The angle of maximum power transfer will actually occur at the line's impedance angle. The impedance angle depends on the relative proportion of resistance and inductive reactance in a line's impedance. The impedance angle is only 90° if we ignore the resistance component of the line's impedance.

Given a simple power system we are often interested in what happens to the sending and receiving end MW and Mvar flows as we vary the power angle. Figure 3-19 expands on the illustration of Figure 3-18 by adding the receiving end circle to the diagram.

The 70° power angle dashed lines illustrate the MW and Mvar flow for a 70° power angle. The dashed lines are used to read the MW and Mvar flows at the sending and receiving ends.

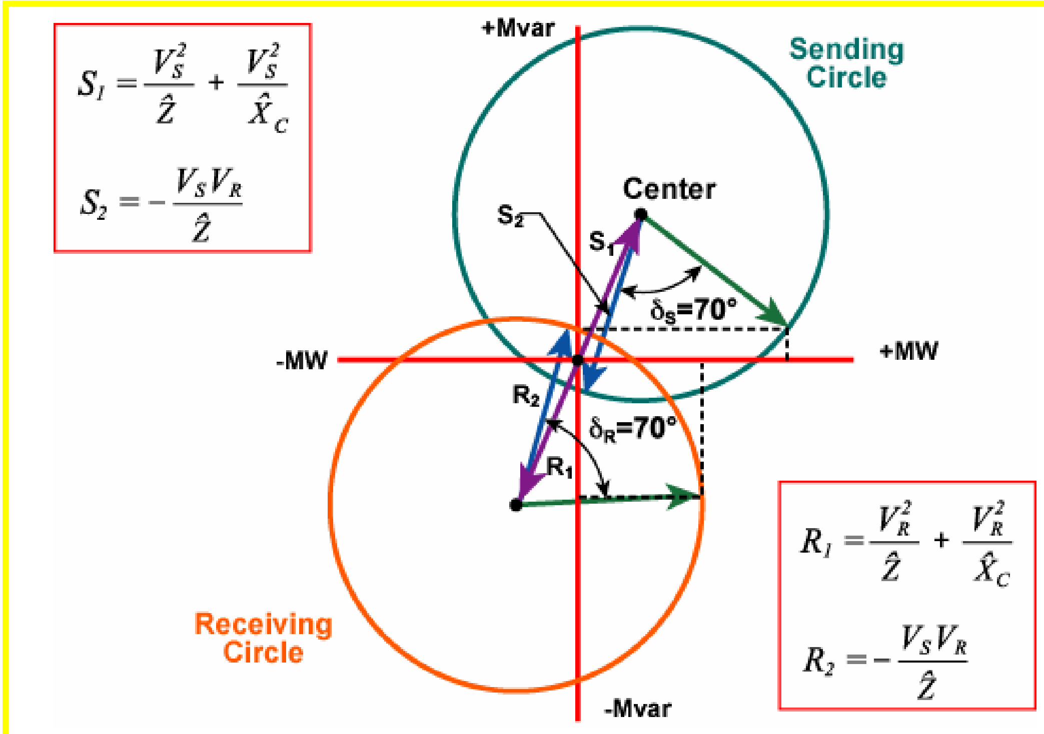


Figure 3-19
Sending & Receiving End Circle Diagrams

The power angle is the angle between the sending and receiving voltages so it is the same from either end of the line. As the power angle is raised to 70°, the MW and Mvar flows for the sending and receiving buses change. You could determine the MW and Mvar flows out of the sending bus and into the receiving bus by noting the positions of the 70° power angle lines in Figure 3-19.

Use of the Power-Circle Diagram

There are many interesting concepts that can be explained using power-circle diagrams. For example, the impact of voltage changes, impedance changes, and power angle changes can be easily illustrated. We will illustrate the use of a power-circle diagram for studying the simple 345 kV power system given in Figure 3-20.

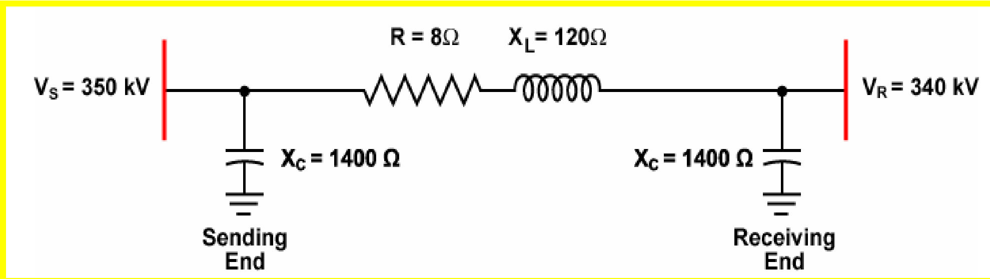


Figure 3-20
System for Illustrating the Use of a Power-Circle Diagram

The magnitudes of V_S, V_R, R, X_L and X_C are input to the equations given in Figure 3-17. Values of S_1 (70 MW & 930 Mvar), S_2 (-70 MW & -990 Mvar), R_1 (-70 MW & -880 Mvar) and R_2 (70 MW & 990 Mvar) result.

Note that the MW portions of S_1, S_2 and R_1, R_2 are opposite. When plotted S_1 and S_2 and R_1 and R_2 are on top of one another. This is due to the small line resistance magnitude as compared to the line's inductive reactance.

These values are plotted in Figure 3-21 to form the sending and receiving power-circle diagrams for the sample system of Figure 3-20. S_1 and R_1 are plotted from the origin and respectively determine the center of the sending and receiving circles. S_2 and R_2 are plotted from the ends of S_1 and R_1 and determine the radius of the sending and receiving circles. Figure 3-21 would apply for a δ of 0°. Figure 3-21 shows us that with a power angle of 0° our simple system has:

- Power flow from the sending bus into the transmission line of 0 MW and -60 Mvar.
- Power flow from the transmission line into the receiving bus of 0 MW and +110 Mvar.

These flow numbers are given in the system one-line in the lower right corner of Figure 3-21. Note the directions of the power flows. The flow numbers derived from the power-circle diagram make sense. The MW value should be zero as there is no power angle. There must be a power angle for MW transfer. The Mvar flows are from the line into both buses. This also is expected as a high voltage transmission line acts as a capacitor when lightly loaded.

This line is lightly loaded and acts like a capacitor. This is expected of high voltage transmission lines when they are lightly loaded.

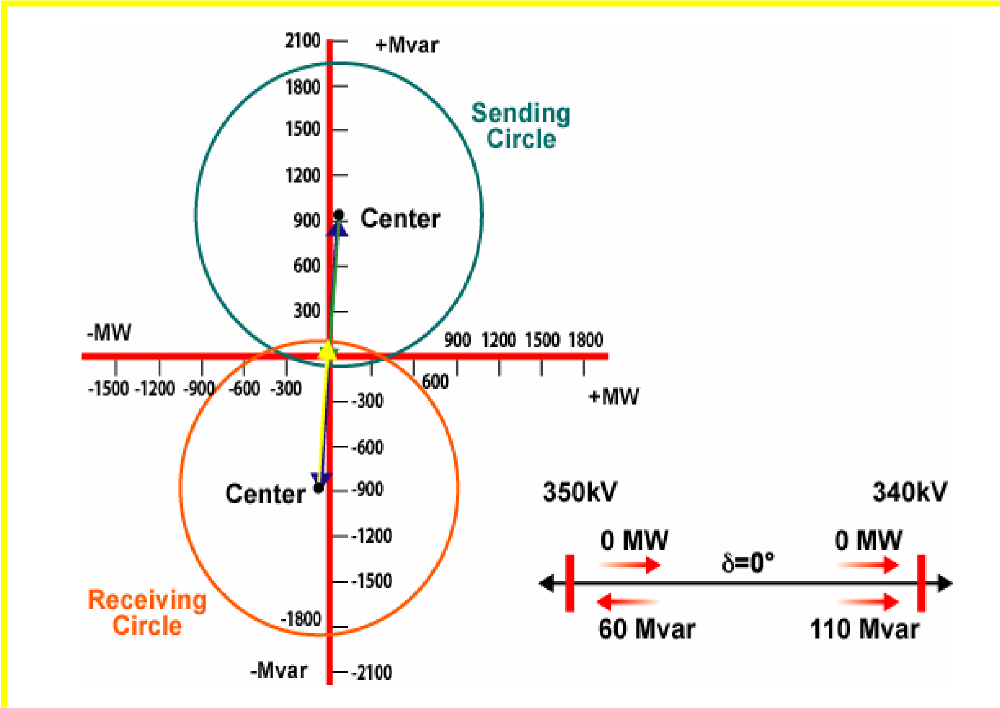


Figure 3-21
Power-Circle Diagram with a δ of 0°

Figure 3-22 is a power-circle diagram for the same system. All that has changed from Figure 3-21 is that power angle has been increased to 40°. Note the increase in both the MW and Mvar flows at both ends of the system. As the power angle is raised the system is pushed harder and harder. Figure 3-22 shows us that with a power angle of 40° our system has a:

- Power flow from the sending bus into the transmission line of 640 MW and +150 Mvar.
- Power flow from the transmission line into the receiving bus of 610 MW and -200 Mvar.

The 40° power angle has resulted in increased MW and Mvar flow. Note the MW flow out of the sending bus is 640 while the MW flow into the receiving bus is 610. The difference is the line losses. The line losses become large as the power angle is increased. Also note the Mvar flow is now into the line from both buses. The heavy current flow on the line has resulted in large reactive power usage. The system must supply this reactive power to the line or the bus voltages will fall.

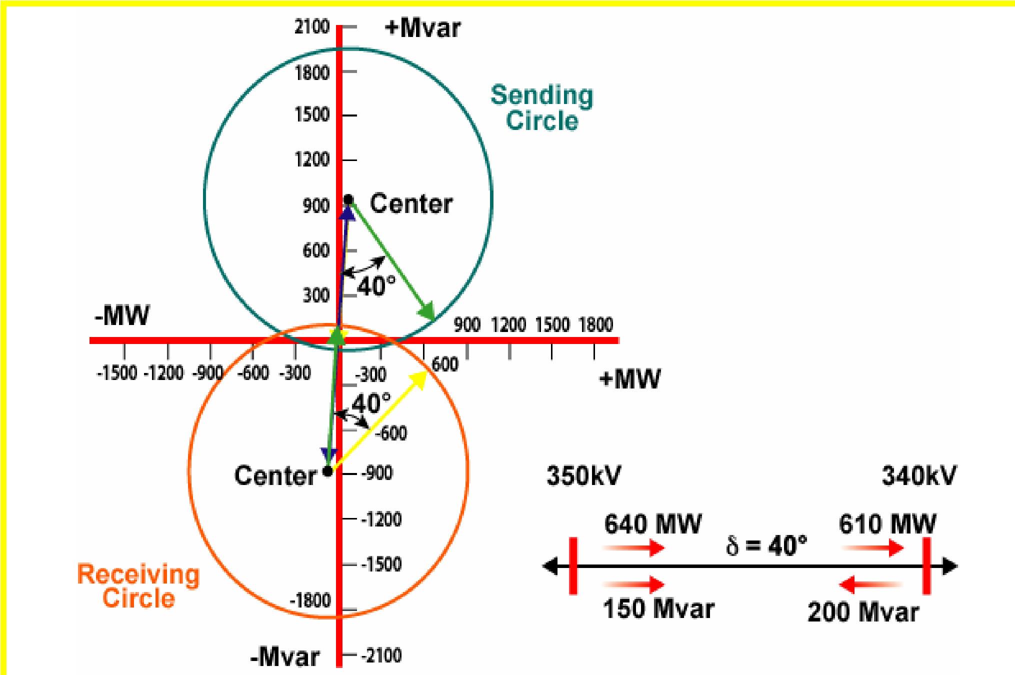


Figure 3-22
Power-Circle Diagram with a δ of 40°

Figure 3-23 illustrates the effect of increasing the power angle to 86°. The impedance angle of the system in Figure 3-20 is 86° (R=8 Ω and X_L=120 Ω yields an impedance angle of 86°). The maximum active power transfer into the receiving bus will occur at the line's impedance angle. Figure 3-23 shows us that with a power angle of 86° our system has a:

- Power flow from the sending bus into the transmission line of 1030 MW and 825 Mvar.
- Power flow from the transmission line into the receiving bus of 900 MW and -870 Mvar.

The active power losses for the system have climbed to 130 MW. The transmission line is absorbing 1,695 Mvar to support its bus voltages. Figure 3-23 has a power angle of 86° which is unacceptably high. Operating at this high an angle would likely be unstable as this angle is across only one line section.

Power circle diagrams are not designed to be used to evaluate a system's angle stability.

The high power flow levels of Figure 3-23 are likely beyond the thermal capability of the transmission line. The equations we have described in this chapter and the graphical tools presented are for calculating the power flows on system elements. The equipment itself may be thermally damaged when the power angle and flows grow to high values. It is often up to the system operator to ensure system power flows do not violate thermal limits.

Section 3.5 of this chapter describes thermal operating limits.

If the power angle is increased above 86°, the MW flow will start to decrease. The Mvar flow, however, will continue to increase. The maximum Mvar flow occurs at an angle near 180°. Remember that any angle greater than approximately 90° cannot be sustained without the power system losing stability.

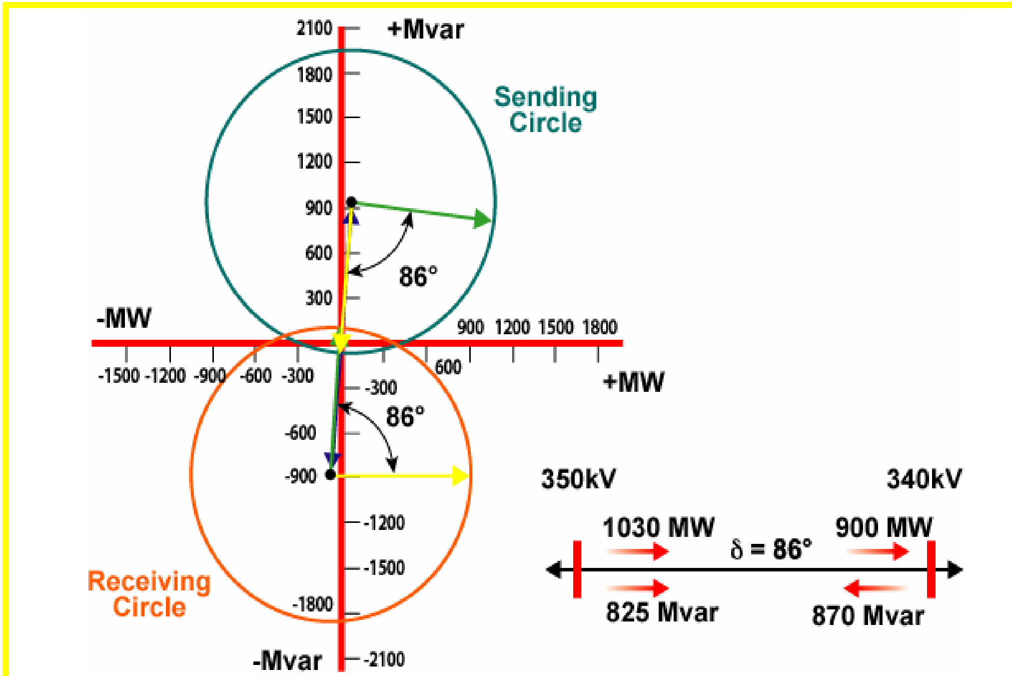


Figure 3-23
Power-Circle Diagram with a δ of 86°

In Figure 3-24 the power angle has risen to 120°. This is not an acceptable operating angle. We illustrate this large of an angle only to show its effect on system power flows. Note that the MW flow has shrunk from its previous peak value. The Mvar flow has climbed to a very high value. With a power angle of 120° we have:

- Power flow from the sending bus into the transmission line of 930 MW and 1360 Mvar.
- Power flow from the transmission line into the receiving bus of 720 MW and -1430 Mvar.

Angles in excess of 90° are not an acceptable operating point but do briefly occur on occasions. When a system suffers a loss of synchronism power angles will grow beyond 90°. As can be seen from Figure 3-24, when power angles grow beyond 90°, Mvar flows can reach very high magnitudes.

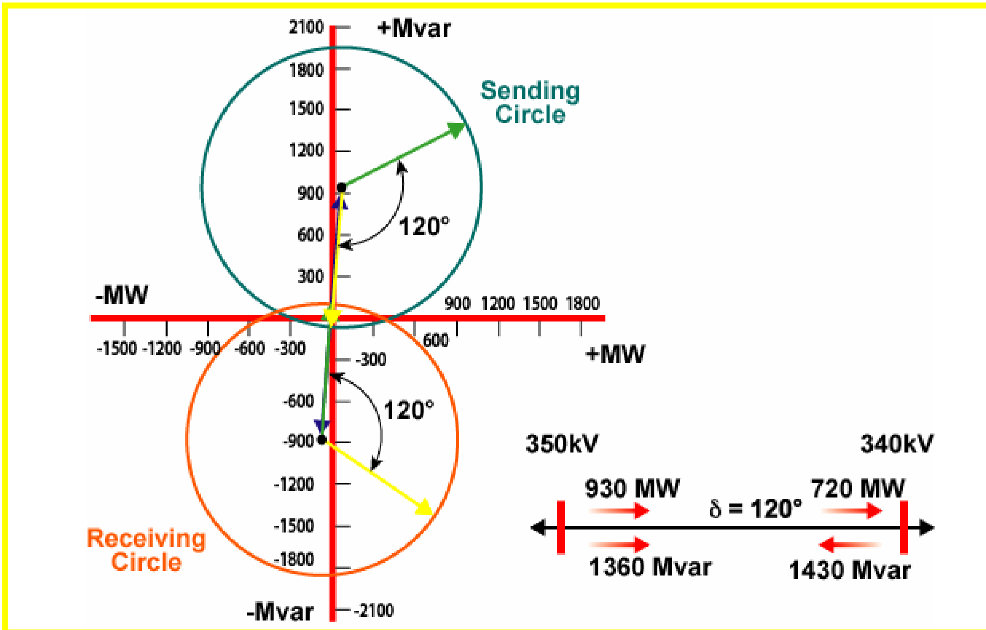


Figure 3-24
Power-Circle Diagram with a δ of 120°

Note the large MW losses. These are due to the very high current flows.

3.5 Power Transfer Limits

To reliably operate a power system, we must recognize that there are power flow or power transfer limits. The limits are to the generation and transmission of active and reactive power in the system. The limits are usually divided into three broad categories: thermal, stability and voltage limits.

3.5.1 Thermal Limits

Thermal limits are due to the thermal capability of power system equipment. As power transfer increases, current magnitude increases. Current magnitudes are the key to thermal damage. Both forms of power flow, MW and Mvar, contribute to the current magnitude. As the current passes through equipment heat is produced. The amount of heat produced is proportional to I^2R. If the equipment cannot safely dissipate the heat generated, it could be thermally damaged.

For example, at power plants, sustained operation of units outside their maximum MW and Mvar capabilities will result in thermal damage. The damage may be to the stator (armature) windings or to the rotor (field) windings of the unit.

Chapter 5 of this text describes the use of generator capability curves. Generators must stay within their capability curve to avoid thermal damage.

Out in the power system, transmission lines and associated equipment must also be operated within thermal limits. Sustained excessive current flow on an overhead line causes the conductors to sag thus decreasing the ground clearance and reducing safety margins. Extreme levels of current flow will eventually damage the metallic structure of the conductors producing a permanent conductor sag.

Unlike overhead lines, underground cables and transformers must depend on insulation other than air to dissipate the generated heat. These types of equipment are tightly restricted in the amount of current they can safely carry. For this equipment, sustained overloading will result in a shortening of service life due to damage to the insulation.

Most power system equipment can be safely overloaded. The key is how great is the overload and how long does it last. Equipment manufacturers and utility experts determine thermal ratings for equipment. Typically, these ratings may allow a specified overload for a specified period of time. These ratings should be followed to avoid equipment thermal damage.

3.5.2 Angle Stability Limits

A second category of power transfer limits are angle stability limits. Angle stability limits are limits imposed to ensure that system torque and power angles remain controllable. When a system is angle stable, power and torque angles are small between connected buses. The angles will change as system conditions change. The important point is that the angles should never grow so large or change so fast that system operators lose their ability to control power flows.

When a system is angle unstable, power and torque angles are no longer controllable. The angles may reach high magnitudes and rapidly vary over a wide range. System operators lose their ability to control power transfer. A system may enter a period of angle instability following a large system disturbance. A system operator is typically helpless once this event starts as the system can enter an unstable condition very rapidly (fraction of a second) following a major disturbance.

In the simple two bus power systems we have used in this chapter power angles could never exceed 90°. Power angles across a large interconnected system with many strong buses can exceed 90°. The angles between adjacent buses are normally very small but there are many buses in an actual power system.

Section 3.3 of this chapter introduced the active power transfer equation. Theoretically, the maximum amount of active power transferred between two strong buses occurs at a power angle of approximately 90°. Unfortunately, there is a substantial difference between our theory and power system reality. In the actual power system power angles can never approach 90° between connected buses. The system would collapse before these high angles are reached.

Utilities study their systems to determine safe power transfer limits. Stability limits are determined using complex computer modeling software. The entire power system is modeled to ensure that allowable power transfer limits do not expose the system to an unreasonable chance of angle instability.

The world is not perfect and angle instability events do occasionally occur. Usually automatic protective equipment will activate to minimize the severity and spread of the disturbance. The critical elements to the study of a system's angle stability are the synchronous generators. Chapter 7 of this text will examine angle stability in detail.

3.5.3 Voltage Limits

A third category of power transfer limits are voltage limits. Both utility and customer equipment are designed to operate at a certain rated or nominal supply voltage. A large, prolonged deviation (high or low) from this nominal voltage can adversely affect the performance of, as well as cause serious damage to, system equipment.

Assume a large amount of power is transferred over a long distance to a load area. The current flowing through the impedance of the lines, transformers, and other transmission equipment may produce an unacceptably large voltage drop at the receiving end of the system. This voltage drop is primarily due to the large reactive power losses which occur as the current flows through the system. If the Mvar produced by generators and other circuit elements are not sufficient to supply the system's usage of Mvar, voltages will fall.

Systems often require reactive support (capacitor banks, etc.) to help prevent low voltage problems. The amount of available reactive support often determines power transfer limits. A system may be restricted to a lower level of active power transfer than desired because the system does not possess the required reactive power reserves to sufficiently support voltage.

Chapters 5 and 6 of this text will examine the role voltage plays in the operation of the interconnected power system.

3.5.4 Determining Power Transfer Limits

We have described three broad categories of power transfer limits. Our conclusion is that power transfer may be restricted due to any of these limits or to combinations of these limits. Figure 3-25 illustrates this point. The figure contains a simple power system. Power transfer experts have studied the system and determined the following power transfer limits:

- A transfer limit of 1000 MVA due to expected low voltage at the receiving bus (voltage limit).

- A transfer limit of 2000 MW due to an expected loss of angle stability if the transfer exceeds 2000 MW (angle stability limit).
- A power transfer limit of 1500 MVA due to thermal limits at the receiving end transformer (thermal limit).

A question for the system operator is: what is the power transfer limit? It would be wise to choose 1000 MVA. Choosing any of the other limits would result in low voltage problems at the receiving end. Perhaps the transmission system operator could install shunt capacitors at the receiving bus. After the installation of the shunt capacitors, the transmission system operator may be able to raise the power transfer limit to 1500 MVA.

It does not matter which way the reactive power is flowing, it still contributes to the current magnitude.

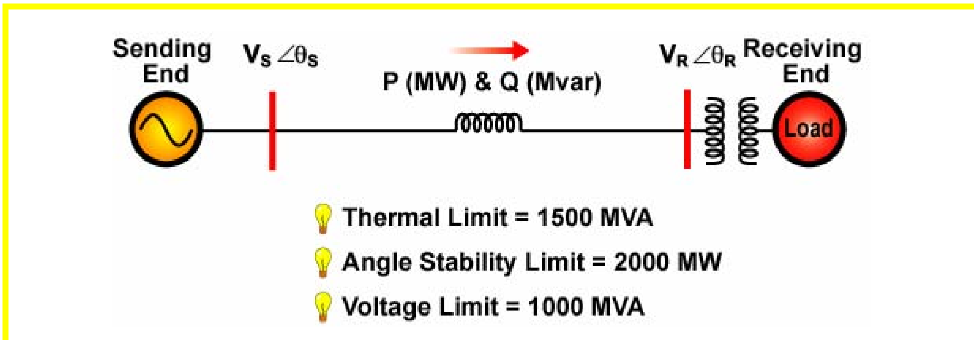


Figure 3-25
Evaluating Power Transfer Limits

3.5.5 Total and Available Transfer Capability

To assist with maintaining the reliability of the transmission system, NERC has defined two terms that relate to transmission system MW transfer capability: TTC and ATC.

The total transfer capability or TTC of a transmission path is the amount of MW that can be transferred across the path while ensuring that the transmission system is able to suffer and recover from a severe outage. NERC operating standards require that the transmission system be operated in such a manner that the single most severe contingency can occur without a severe disruption to the power system.

Figure 3-26 illustrates the concept of TTC. Power system areas 1 and 2 are connected with three transmission lines. Assume engineers have determined that the TTC of this three line path is 1200 MW. These engineers are therefore stating that this path can be loaded to 1200 MW and a major outage could occur (perhaps to the 500 kV line) and the remaining system will not be unduly impacted.

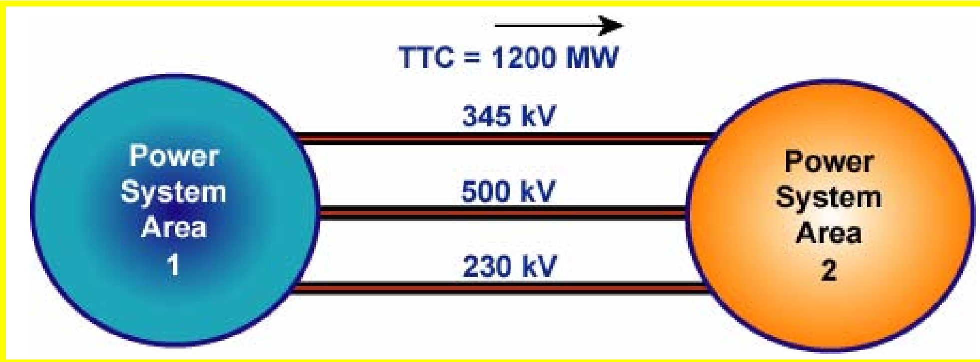


Figure 3-26
Illustration of the TTC Concept

TTC numbers are directional. The TTC in Figure 3-26 is from area 1→2. The TTC from area 2→1 may be more or less than 1200 MW.

The available transfer capability or ATC of a transmission path is the amount of the TTC that the operator of the transmission path has available for sale to any marketing entities that may want to purchase the transfer capability. In other words, the ATC is that portion of the TTC that is available for further commercial activity.

For example, in Figure 3-26, assume the transmission operator sells 1000 MW of the area 1 to area 2 TTC. The ATC from area 1 to area 2 is now reduced to 200 MW.

3.6 Distribution Factors

Power flows in inverse proportion to the impedance of the available transmission paths. In other words, more MW and Mvar will flow on the path with the lowest impedance. Distribution factors are a convenient method of describing how power flow will distribute on the available transmission paths.

3.6.1 Determining Distribution Factors

Consider the simple power system in Figure 3-27. Assume you increase the output of a generator at Bus “A” by 100 MW in order to serve a 100 MW load at Bus “B”. The new MW from the generator at Bus “A” has two options to get to the load at Bus “B”. The MW can flow directly from Bus “A” to Bus “B” or it can take a longer path from Bus “A” through Bus “C” through Bus “D” and finally to Bus “B”.

How much of the 100 MW will take the direct path and how much the longer path? The answer is simple if you remember Ohm’s and Kirchoff’s laws.

MW flows the path of least impedance so you can determine the proportion of the MW flow on each path by comparing the impedance of the two paths.

As illustrated in Figure 3-27 the impedance of path "A-B" is 50Ω. The impedance of path "A-C-D-B" is 150Ω. The total system impedance is therefore 50Ω + 150Ω = 200Ω. Path "A-B" will carry 150/200 or 75% of the 100 MW while path "A-C-D-B" will carry 50/200 or 25% of the 100 MW.

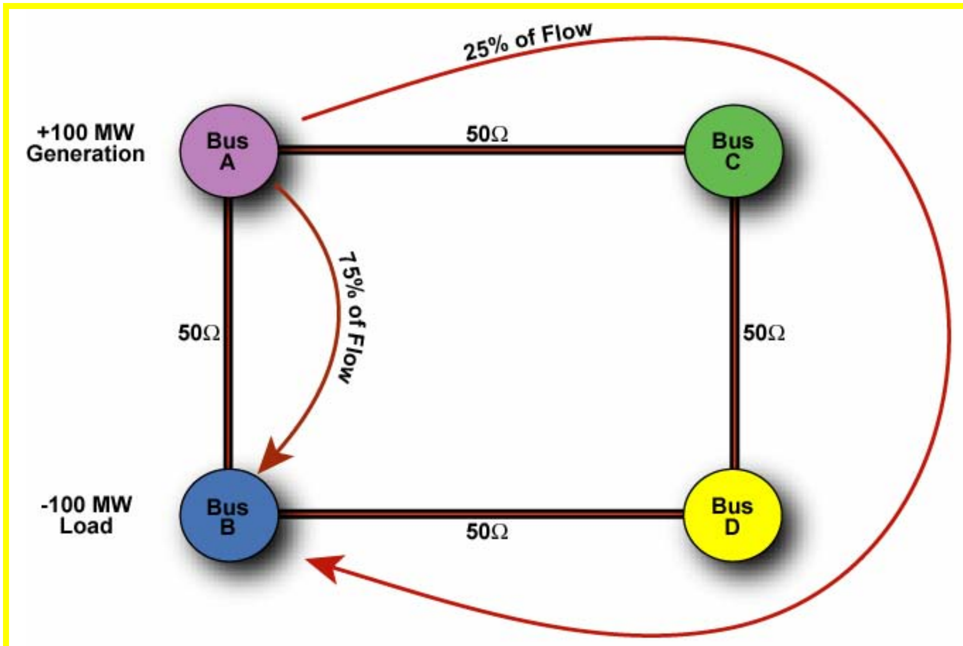


Figure 3-27
Determining Distribution Factors

For a 100 MW intended or scheduled flow from Bus "A" to Bus "B" path "A-B" therefore has a 75% distribution factor and path "A-C-D-B" has a 25% distribution factor. Distribution factors are simply the percentage of a given schedule between any two locations that flows on a specific transmission line.

3.6.2 Using Distribution Factors

If the distribution factors are known for a given scheduled power flow, the impact of that schedule on existing transmission line flows can be estimated. System operators in all of the major Interconnections of North America use databases of distribution factors to guide their actions to both relieve existing overloaded transmission lines and to foresee and prevent future transmission system overloads.

3.7 Summary of Active and Reactive Power

3.7.1 Active, Reactive and Complex Power

- Active power or MW performs the actual work. A utility must consume a fuel (coal, water, nuclear, gas, oil, etc.) to produce MW.
- Reactive power or Mvar is constantly being exchanged between those devices that produce it and those devices that store it in their fields.
- Complex power (symbol "S" units MVA) is a (vector) sum of the active (symbol "P" units MW) and reactive (symbol "Q" units Mvar) powers.

3.7.2 Phase Angle, Power Angle, and Torque Angle

- The voltage angle represents the amount by which a voltage sine wave has been shifted left or right with respect to a reference.
- The phase angle at a point in a power system is the angular separation between the current and the voltage waves.
- The power angle is the voltage angle between two locations in the power system. The power angle is represented by the Greek letter delta or "δ".
- A rule of thumb is that active power flows downhill on power angle.
- The larger the power angle (up to 90°), the larger the active power flow between the two points.
- The torque angle of a generator in the angular difference between the rotor magnetic field and the rotating magnetic about the stator of the generator.
- The torque angle of a generator has a large impact on the MW delivered by the generator to the system. Within limits, the larger the torque angle, the more MW the generator outputs.

3.7.3 Development of Power Transfer Equations

- The following four equations for the active and reactive power transfer were developed in this section. With the bus voltages, the series reactance (X_L), the line charging, (X_C), and the power angle between the buses (δ) known, one can calculate the MW and Mvar flow. If the voltages used are line-to-line values, the power flows calculated are 3Φ values.

$$P_S = \frac{V_S \times V_R}{X_L} \sin \delta \qquad Q_S = \frac{V_S^2 - V_S V_R \cos \delta}{X_L} - \frac{V_S^2}{X_C}$$

$$P_R = \frac{V_S \times V_R}{X_L} \sin \delta \qquad Q_R = \frac{-V_R^2 + V_S V_R \cos \delta}{X_L} + \frac{V_R^2}{X_C}$$

3.7.4 Use of Active Power Transfer Equation

- The active power transfer is determined by multiplying the sending and receiving end voltages together and dividing by the series reactance of the line. This quantity is next multiplied by the sine of the power angle. The quantity $[(V_S \text{ x } V_R)/X_L]$ is called the maximum power or P_{MAX}.
- P_{MAX} is the maximum MW a simple two bus system is electrically capable of transmitting. How much of this maximum is actually transmitted depends on the sine δ term of the equation.
- If the voltage magnitudes or the path impedance are changed, the active power flow level or the power angle will also change.
- MW flow along a path is normally changed by changing the path's power angle. Power angles change as a natural result of actions that change a path's active power flow.

3.7.5 Use of Reactive Power Transfer Equation

- If the line capacitance is ignored and the power angle is assumed small, the reactive power transfer equation simplifies to:

$$Q_S = \frac{V_S(V_S - V_R)}{X_L}$$

- The critical part in the above equation is the portion in parenthesis or $(V_S - V_R)$. This tells us that Mvar will normally flow from the higher voltage to the lower voltage.
- Mvar flows from sources to loads in the same manner as MW. However, reactive sources are not just limited to generators. Shunt capacitors, synchronous condensers, and transmission lines are all possible reactive power sources. Reactive loads include not only the customer load but also shunt reactors and the transmission system.
- Reactive power is closely related to system voltage levels. When voltage levels need to be increased the solution is often to increase the reactive supply. When voltage levels need to be reduced the solution is often to reduce the reactive supply.
- While active power is strongly impacted by changing power angles, reactive power is typically weakly impacted.

- When voltage control equipment such as capacitors, reactors or tap changing transformers are used to adjust voltage, the equipment is actually controlling the flow of Mvar.

3.7.6 Power-Angle Curve

- A power-angle curve is obtained by plotting the active power transfer equation. Power-angle curves are a powerful graphical tool for visualizing the angle stability of a simple power system.

3.7.7 The Power-Circle Diagram

- The power-circle diagram is a valuable tool for illustrating how MW and Mvar flow varies as voltage magnitude, impedance, and power angle change.

3.7.8 Thermal Limits

- Power transfer thermal limits are due to the thermal capability of power system equipment. As power transfer increases, current magnitude increases. Current magnitude are the key to thermal damage. Both forms of power flow, MW and Mvar, contribute to the currents magnitude.
- Most power system equipment can be safely overloaded. Typically, thermal ratings allow a specified overload for a specified period of time. These ratings should be followed to avoid equipment thermal damage.

3.7.9 Angle Stability Limits

- Angle stability limits are limits imposed to ensure that system torque and power angles remain controllable.
- Transmission line operators study their systems to determine safe power transfer limits. Stability limits are determined using complex computer modeling software. The entire power system is modeled to ensure that allowable power transfer limits do not expose the system to an unreasonable chance of angle instability.

3.7.10 Voltage Limits

- A third category of power transfer limits are voltage limits. Both utility and customer equipment are designed to operate at a certain rated or nominal supply voltage.
- If the Mvar produced by generators and other circuit elements are not sufficient to supply the system's need for Mvar, voltages will fall.

3.7.11 Determining Power Transfer Limits

- Three broad categories of power transfer limits were described. The conclusion was that power transfer may be restricted due to any of these limits or to combinations of these limits.
- NERC has defined two terms to assist with determining and marketing transmission capacity:
  - The total transfer capability or TTC is the transmission path's maximum safe MW transfer limit.
  - The available transfer capability or ATC is the portion of the TTC still available for commercial usage.

3.7.12 Total and Available Transfer Capability

- The total transfer capability, or TTC, is the amount of MW that can be transferred across a transmission path while ensuring that a single most severe contingency will not result in unacceptable transmission system consequences.
- The available transfer capability, or ATC, is that portion of the TTC available for further commercial activity.

3.7.13 Determining Distribution Factors

- Distribution factors are used to estimate how much of a specific schedule will flow across a specific path.

3.7.14 Using Distribution Factors

- All of the major Interconnections in North America utilize databases of distribution factors as a tool in determining which schedules impact to power flows on overloaded transmission lines.

Active and Reactive Power Questions

1. Thermal limits are the direct result of?

   A. High torque and power angles

   B. The thermal capability of system equipment

   C. A reactive power deficiency

   D. All of the above

2. Reactive power flow is influenced more by system power and torque angles than reactive power.

   A. True

   B. False

3. At what line power angle does the MW transfer across a transmission path equal ½ of the path's P_{MAX}?

   A. 15 degrees

   B. 20 degrees

   C. 30 degrees

   D. 45 degrees

4. A transmission line is rated at 1000 MVA. The power flow is currently 0 MW and 1001 Mvar. Is the transmission line overloaded?

   A. Yes

   B. No

   C. Impossible to determine

   D. The line has no load

5. The TTC limit has been determine to be 1000 MW from east to west for a particular transmission path. The transmission path operator sells 500 MW of this TTC. What is the path's ATC?

   A. 1000 MW

   B. 1500 MW

   C. 0 MW

   D. 500 MW

6. A distribution line is rated at 50 MVA. The line's power flow is currently 50 MW and -50 Mvar. This distribution line is overloaded.

   A. True

   B. False

7. Angle stability limits are the result of?

   A. High torque and power angles

   B. The thermal capability of system equipment

   C. A reactive power deficiency

   D. All of the above

8. If the resistance is ignored, the maximum theoretical MW flow across a transmission line will occur at a power angle of:

   A. 0 degrees

   B. 45 degrees

   C. 90 degrees

   D. 180 degrees

9. If the resistance is ignored, the maximum theoretical Mvar flow across a transmission line will occur at a power angle of:

   A. 0 degrees

   B. 45 degrees

   C. 90 degrees

   D. 180 degrees

10. 200 MW is scheduled to flow from Bus "X" to Bus "Y". Transmission line "A-B" has a 10% distribution factor for this schedule. How much of the 200 MW schedule will flow on transmission line "A-B"?

    A. 20 MW

    B. 40 MW

    C. 180 MW

    D. 200 MW

Active and Reactive Power Flow References

1. Electric Power Systems Manual—Textbook written by Mr. Geradino Pete. Published by McGraw-Hill, 1992.

   Well written general reference on power systems. Contains material on active and reactive power, development of the power transfer equations and the construction and use of power-circle diagrams.

2. Reactive Power: Basics, Problems and Solutions—Tutorial course text published by IEEE. Course text #87EH0262-6-PWR.

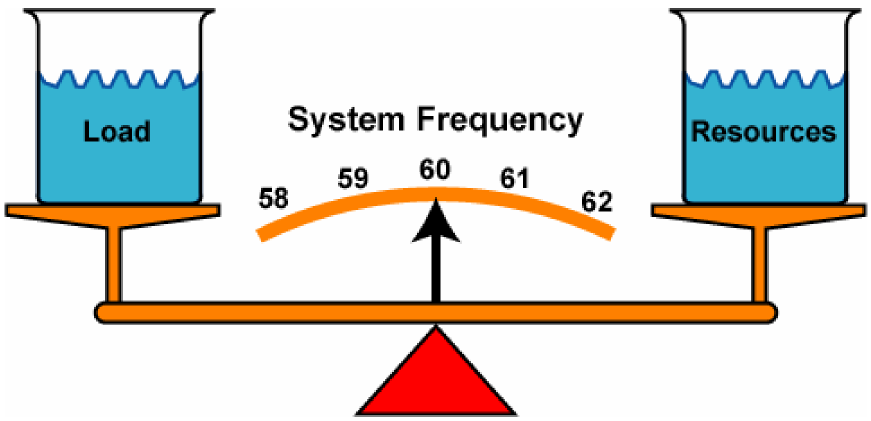
   A collection of IEEE articles that address reactive power. Several articles in the collection address the flow of active and reactive power.

3. Electric Energy System Theory—Textbook written by Mr. Olle I. Elgerd. Published by McGraw-Hill, 1982.

   Chapters 2, 3 and 4 of this text were very valuable in developing the material in this chapter.

4. ATC Reference Document Published Periodically by NERC—NERC periodically updates and publishes a reference document on the methods for determining and utilizing the TTC and ATC. Read this document for the current definitions of TTC and ATC.

4
FREQUENCY CONTROL



4.1 Introduction to Frequency Control

The load/frequency effect and system inertia help control frequency deviations caused by a generation-to-load mismatch.

4.2 Governor System Components and Operation

Generating unit governors adjust the MW output of units in the power system in response to frequency deviations.

4.3 Automatic Generation Control (AGC)

AGC calculates an area control error (ACE) signal which is used to adjust the output of regulating units and restore frequency to 60 HZ.

4.4 Reserve Policies

Reserve policies ensure sufficient MW capability to control normal frequency deviations and survive large disturbances.

4.5 Time Error Control

Accumulated time error is corrected by mutually agreed changes to the scheduled frequency.

4.6 NERC Control Performance

NERC has developed performance standards that apply during normal and disturbance conditions.

4.7 Impact of Frequency Deviations

Substantial frequency deviations for prolonged periods can be damaging to power system equipment and performance.

4.8 Underfrequency Protection

Underfrequency protection includes underfrequency load shedding and underfrequency generator tripping.

4.9 Nature of a Frequency Deviation

A frequency deviation includes an undershoot, which varies according to location, and a stabilization point, which is the same throughout the Interconnection.

4.10 Staged Response to a Generation Loss

A four-stage process is used to describe the response of the power system to a generation loss.

4.11 Role of the System Operator

An experienced power system operator uses system frequency and other data to effectively diagnose power system problems.

4.1 Introduction to Frequency Control

4.1.1 The Changing Load

Loads within the power system are constantly changing. Each time a residential customer starts an electric clothes dryer or an industrial customer ignites a furnace, the power system load changes. This is why the task of matching generation to load is difficult, the target is always moving. An exact match between generation and load is only achieved for a short period of time. Loads change constantly, always creating another imbalance between the generation supply and the system load.

Figure 4-1 illustrates load shapes for the summer and winter seasons for a power system. Assume these curves are historical data from two peak days of the year. Note how the load varies from hour to hour. If we monitored the load change for even smaller time periods, such as seconds, we would see that load is constantly changing. The connected load is never constant; it changes each hour, each minute, each second of the day.

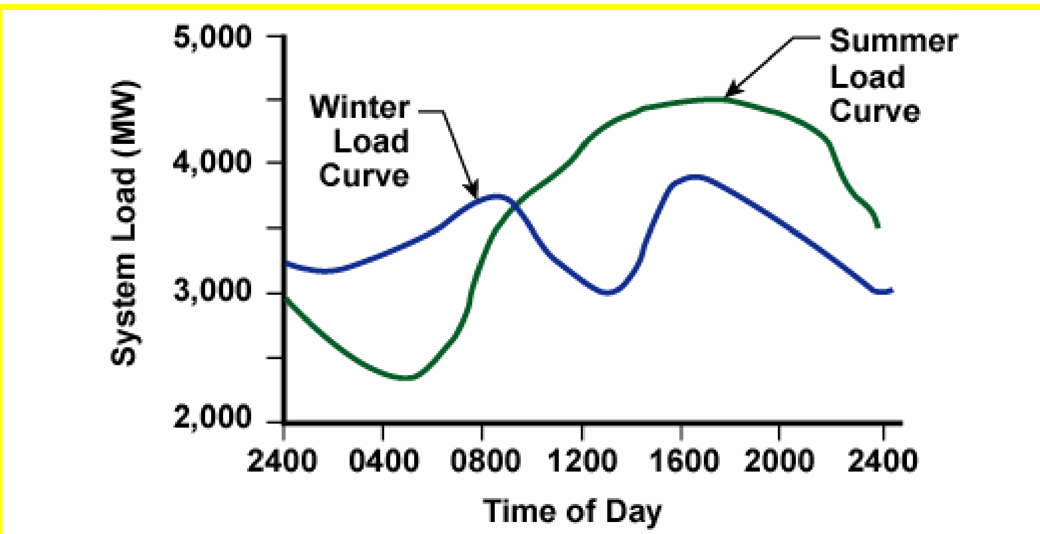


Figure 4-1
Summer and Winter Load Curves

4.1.2 Need for Frequency Control Systems

In the early days of power systems, very basic control systems were used to match generation to load. A plant operator may have used a simple hand adjusted dial control to increase or decrease generator output until the output matched the load. As power systems have grown and customer expectations of power system performance have increased, the equipment used to match

When utilities in the East and Midwest United States first started to interconnect in the mid 1920's, frequency control was typically handled by a single power plant.

generation to load has also grown in complexity. Complex control systems have been developed to achieve the desired match between generation and load. These control systems will be introduced and described in this chapter.

4.1.3 Definition of a Control System

A control system is a means to automatically control the output of a system based on measurements of various system inputs and outputs. For example, Figure 4-2 contains a block diagram of a simple control system that could be used to control the output frequency of a generator. At point 1, the output frequency of the generator is monitored. At point 2, the output frequency is compared to the target or scheduled frequency and a frequency error determined. At point 3, the necessary adjustments are calculated to correct the frequency error and make the actual frequency equal the scheduled frequency. At point 4, the speed controller adjusts a valve position to allow more or less working fluid (steam, water, gas, etc.) into the generator.

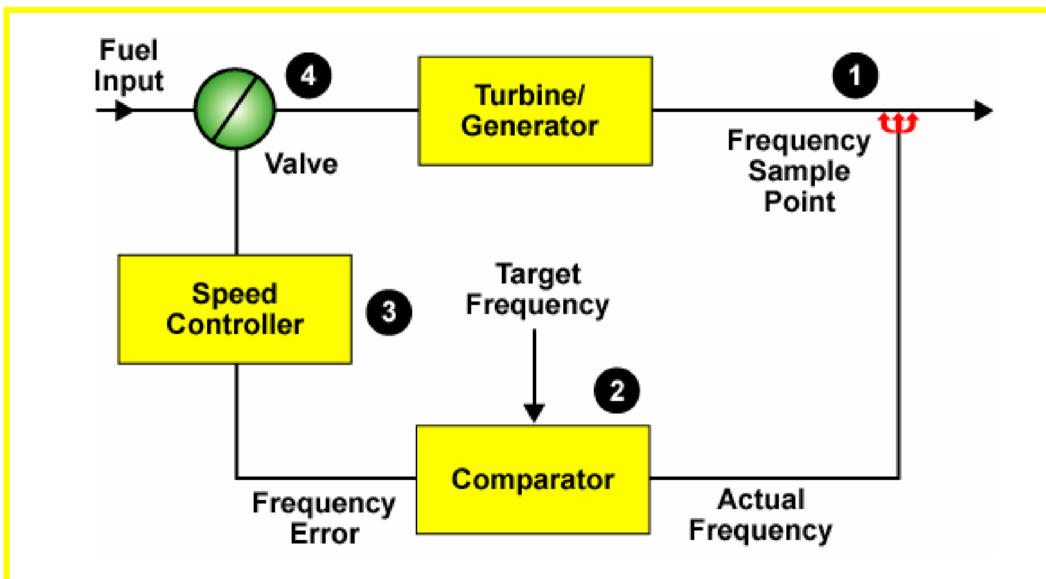


Figure 4-2
Simple Frequency Control System

The North American power system is divided into areas called Interconnections. All the operating companies within an Interconnection are connected together with AC transmission lines.

4.1.4 The Energy Balance Concept

Consequences of Over and Under Generation

The major consequence of over or under generation is the effect on system frequency. When the generation supply within an isolated power system or an Interconnection exactly matches the system load the frequency can be exactly 60 HZ. When not enough generation is supplied the frequency will decrease to a value less than 60 HZ. When too much generation is supplied the frequency will increase above 60 HZ. Figure 4-3 illustrates the need to achieve a balance between the power consumed (load) and the power supplied (resources). Within an Interconnection, the individual power systems assist each other to maintain frequency within a narrow band about the nominal frequency of 60 HZ.

This text assumes a 60 HZ nominal frequency. Many areas of the world target 50 HZ.

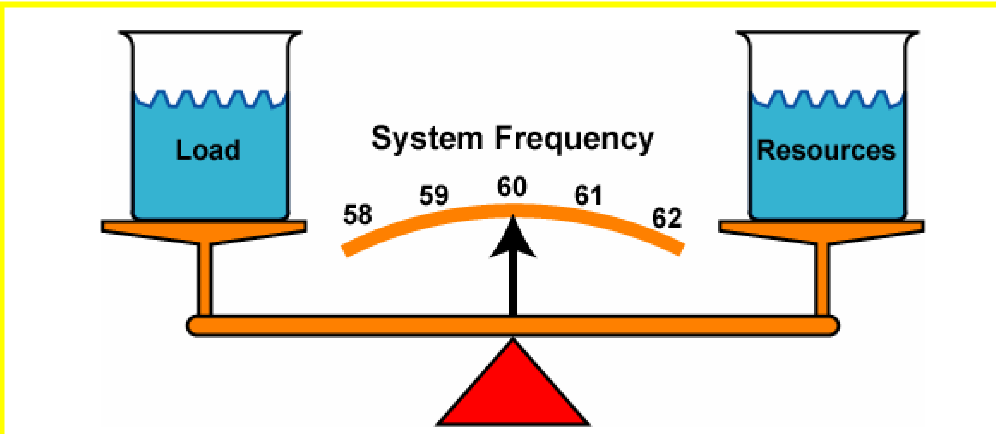


Figure 4-3
Load/Resources Balance Analogy

When resources exceed load, frequency will rise. When load exceeds resources, frequency will fall.

Time Error

A natural consequence of over and under generation is time error. Electric clocks (those driven by motors fed from the power system) keep accurate time by counting the cycles of the power system frequency. If the frequency varies from 60 HZ, the time kept by electric clocks will also vary. Over a period of days the clocks may develop errors, typically of a few seconds.

For example, if frequency decreases to 59.98 HZ and holds that value for two hours, electric clocks will run slower, losing 2.4 seconds in the two hour period. Figure 4-4 illustrates how sustained frequency deviations will lead to time error. Electric utilities have developed methods to correct these time errors that are the direct result of over or under generation.

Section 4.5 will describe time error control in greater detail.

If frequency holds at 60 HZ, no time error accumulates

If frequency holds at less than 60 HZ, clocks run slower and negative time error accumulates.

If frequency holds at greater than 60 HZ, clocks run faster and positive time error accumulates.

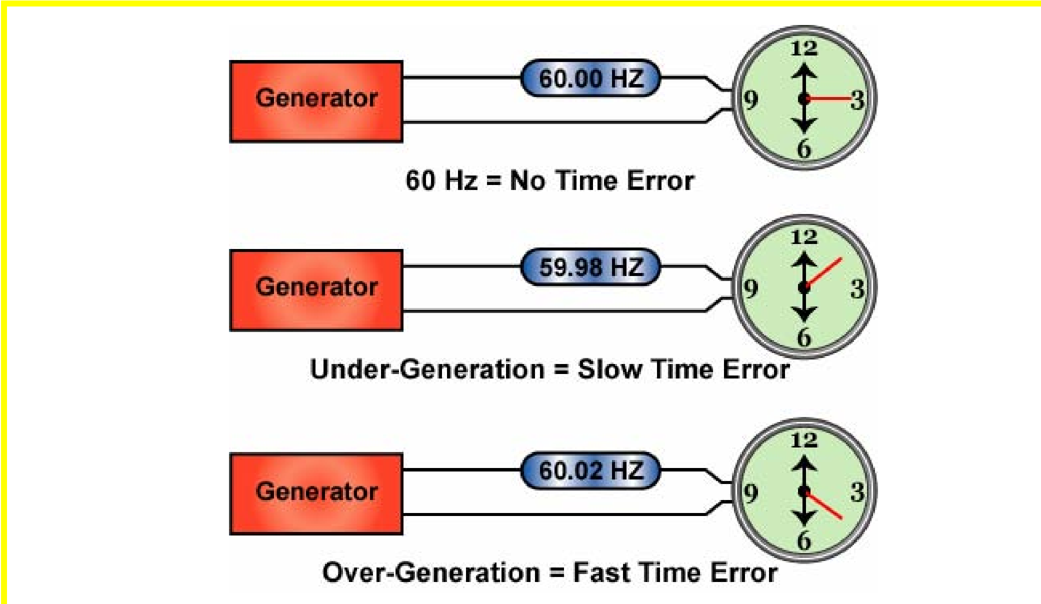


Figure 4-4
Accumulating Time Error

4.1.5 Normal and Abnormal Frequency Deviations

Definition of a Frequency Deviation

As stated earlier, the target frequency is referred to as the scheduled frequency. When the actual frequency deviates from the scheduled frequency a frequency deviation has occurred. For example, the scheduled frequency is typically 60 HZ. If the actual frequency is 59.95 HZ then a -0.05 HZ frequency deviation has occurred.

Normal Frequency Deviation

Under normal conditions, the power system frequency in the Eastern Interconnection varies between approximately 59.98 and 60.02 HZ. These variations are normal and constantly occur due to the varying nature of the Interconnection's load.

Figure 4-5 is an illustration of normal frequency deviations that occur in a large Interconnection. The goal is to ensure that these frequency deviations are small and to ensure that the frequency stays close to 60 HZ. Maintaining the frequency tightly around 60 HZ is achieved by adjusting the generating unit outputs through the various control systems.

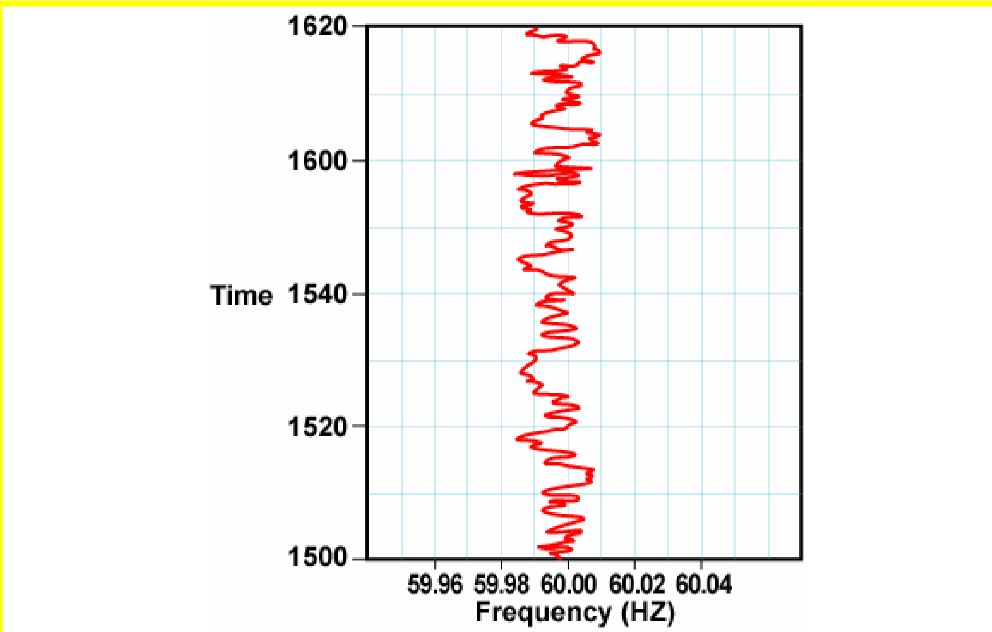


Figure 4-5
Normal Frequency Deviations

These frequency deviations would be typical for a large Interconnection such as the Eastern Interconnection. A smaller Interconnection would routinely experience larger frequency deviations than these.

Abnormal Frequency Deviations

When abnormal events, such as the loss of a large generator, occur in the power system, the frequency will go through more drastic deviations. Figure 4-6 illustrates the change in frequency following the loss and eventual replacement of a large generator. The frequency deviations of Figure 4-5 are normal and not of concern. The frequency deviations of Figure 4-6, however, are large enough to cause concern.

This magnitude of frequency deviation is called abnormal in this text. This does not imply that this size of deviation is rarely seen. In fact, depending on the Interconnection, frequency deviations of this magnitude may be quite common, occurring several times a month.

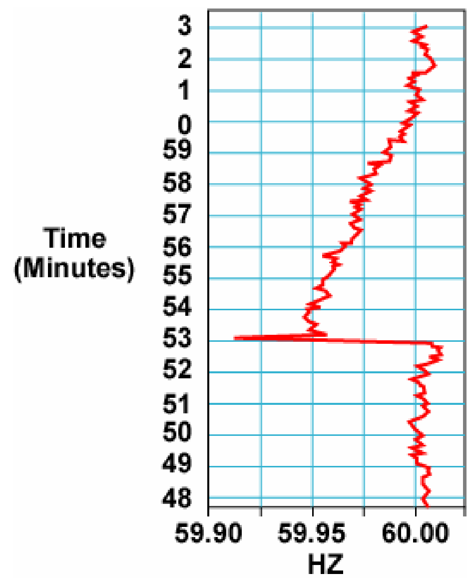


Figure 4-6
Abnormal Frequency Deviations

As seen in Figure 4-6, the frequency has recovered to 60 HZ within a few minutes of the loss of a generator. If frequency deviates by more than ±0.5 HZ for a long period of time, damage to utility generators and customer equipment could occur. Some types of utility and customer equipment are designed for operation within a tight frequency band.

4.1.6 The Load/Frequency Relationship

The load that is connected to the power system will absorb different amounts of MW depending on the frequency and voltage of the system. All load can be divided into two general types; non-motor load (non-spinning load) and motor load (spinning load).

Non-Motor Load

Resistive load is sensitive to the voltage squared. If voltage drops by 10% to 90% of nominal, resistive load will drop to 81% (0.9 X 0.9) of nominal.

Non-motor loads, such as heaters, light bulbs, and electronic equipment, will vary in magnitude (MW) depending on the voltage and frequency of the power system to which it is connected. Non-motor load magnitude is more dependent on voltage than on frequency. It is a reasonably accurate statement to say that non-motor load magnitude does not vary as frequency is varied. In contrast, non-motor load is very dependent on the voltage of the system. For example, if the voltage of the power system drops 10% (to 90% of normal) the power drawn by resistive electric heater loads will fall by approximately 19% (to 81% of nominal).

Motor Load

Motor load makes up a large portion of a utility's total load (typically 40 to 60%). The more populated the service territory, the more common are motor loads. When we refer to motor loads, we generally mean induction motors. Typical uses for induction motors are as air-conditioner compressor motors, vacuum cleaner motors, etc. Large portions of commercial and industrial load are induction motor loads.

Motor load is also dependent on the voltage and frequency of the power system to which it is attached. If the voltage or frequency declines, the connected motor load magnitude will also decline. The frequency has a greater impact on motor load magnitude than the voltage. To simplify the description of the impact of voltage and frequency on motor load magnitude we will ignore the smaller effects of voltage and concentrate on the larger effects of frequency. An approximate rule of thumb is that the connected motor load magnitude will decrease by 3% if the frequency decreases by 1%.

If the voltage level falls enough, motors may stall. Motor stalling is addressed in Chapter 6, Voltage Stability.

The Load/Frequency Relationship

Figure 4-7 illustrates how the two different types of load, non-motor and motor, vary with frequency. Non-motor load remains constant no matter what the frequency. Motor load decreases as the frequency decreases. Note the third curve shown in Figure 4-7, labeled the "total load characteristic". The total system load is composed of portions of both non-motor and motor load. For example, a large factory may have a large amount of electric heat in addition to a large amount of induction motor load. The total load characteristic for the factory load will show the overall change of this load with respect to frequency.

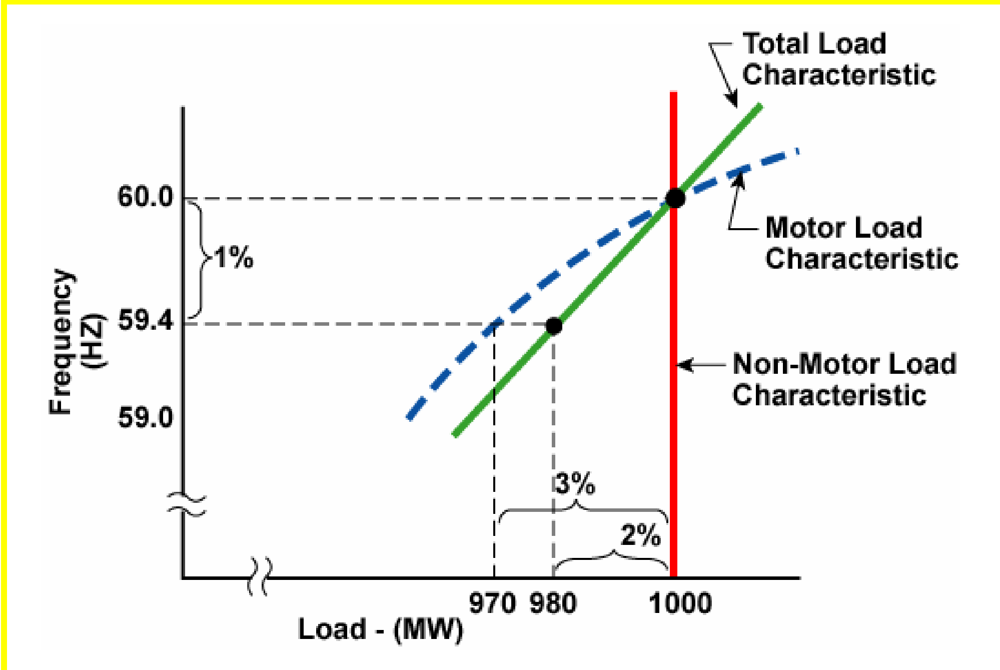


Figure 4-7
Relationship Between Load Magnitude & Frequency

Note the total load curve. This line indicates that a 1% change in frequency (from 60 to 59.4 HZ) will typically lead to a 2% change in the total load. Remember no system is typical, this is just a rule of thumb for estimating purposes.

The importance of the load/frequency relationship will become apparent as we progress in our description of the frequency control process. For now just remember that load magnitude varies with frequency.

4.1.7 Power System Inertia

Energy is stored in the rotating elements of the power system. This energy is often called either inertial, stored, or rotational energy. Inertial energy has an important role in the frequency control process.

Inertia is defined as the property of an object that resists a change to the object’s current speed and direction. The inertia of a generator refers to the generator’s resistance to changes in its speed of rotation. When a large turbine/generator is rotating at 3600 RPM, it is not a simple matter to change its speed. There is a large quantity of energy stored in the rotating elements of the turbine and generator that help to maintain a constant speed of rotation. To change a generator’s speed, it is either necessary to add rotational energy to the unit (to speed up the rotation) or to remove rotational energy from the unit (to slow down the rotation). Figure 4-8 illustrates energy storage in a large steam turbine/generator.

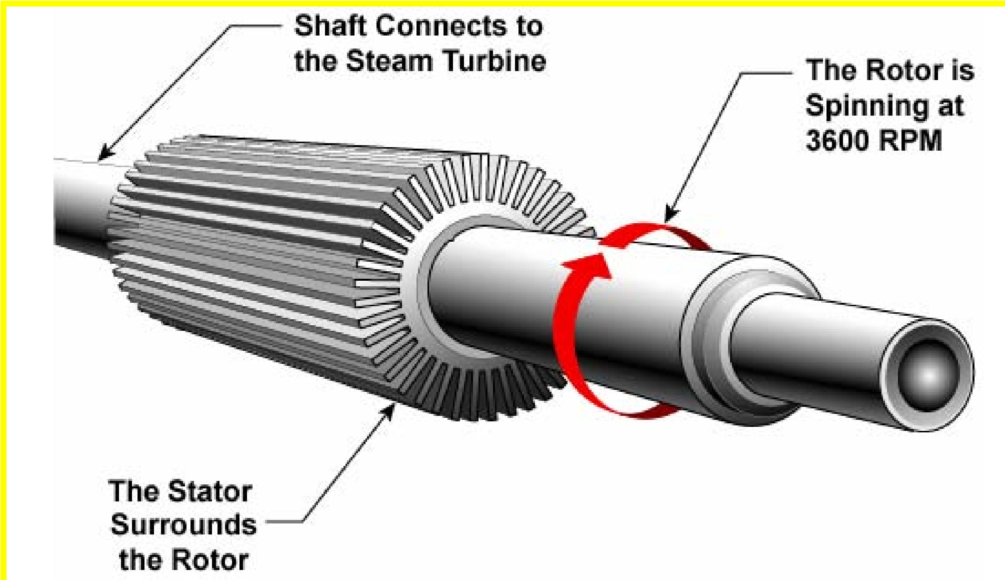


Figure 4-8
Inertia of a Steam Generator Rotor

When a large generator turbine/rotor is spinning at 3600 rpm, it has a large amount of rotational or inertial energy that resists changes to the speed of rotation.

The inertial energy stored in an object is dependent upon the mass, diameter, and speed of rotation of the object. Large steam turbine /generators have a very large mass (the rotating elements alone may weigh more than 200 tons) and, as a result, have a large inertial energy. The inertia of large turbine/generators helps maintain power system frequency at a constant value. Inertial forces resist changes to frequency.

This 200 ton weight for a large steam unit's rotating elements may appear large but an equivalent size hydro unit's rotating elements may weigh 10 times as much or 2,000 tons.

The power system has many sources of inertia. Any rotating equipment that is connected to the system is a source of stored rotational energy or inertial energy. Thus, all generators and spinning loads on the system are sources of inertial energy. For purposes of this text, we will confine our description of inertia to the system's generators but remember that spinning motors also contain inertial energy.

The natural resistance of a generator to a change in speed helps to keep the power system frequency constant. In general, the larger the generator, the larger the inertia and the more rotational energy that must be added or removed from the generator to change its speed of rotation. There are several ways to add energy to or remove energy from a generator:

- Increase or decrease the mechanical power supplied to the generator (for example, increase the steam flow to a steam turbine or the water flow to a hydro turbine).
- Vary the load attached to the generator. If a load is removed from a generator, the generator will initially speed up which is equivalent to increasing the rotational energy to the generator. If a load is added to a

generator, it is initially equivalent to removing rotational energy from the generator.

Small variations in the system load will normally cause little change in frequency. This is because the inertial forces of a typical power system are so large that when compared to the load variation, the generators and motors in the system keep rotating at almost the same speed. When large loads are added to the power system, the utility may see a change in a generator's speed of rotation. For example, if a utility were to suddenly add a 1000 MW load in the vicinity of a generating station, the generator's frequency (speed) monitors would detect a reduction in rotational speed. Note that this reduction in speed should be temporary, as this generator and other system generating units have control systems to eventually return the speed to normal.

Section 4.10 describes the role of inertia following a generation loss in greater detail.

Consider another example. Assume that a utility suddenly loses a large generator. This lost energy causes an under-generation condition and must be made up by other generating resources. Other system generating units will each supply a share of the lost energy by converting a portion of their rotational energy to electric energy to help supply the generation shortage.

These generating units would be using their inertial energy to replace the power shortage caused by the loss of the unit. As a consequence of sacrificing some of their inertial energy, the units will experience a decline in rotational speed.

4.2 Governor System Components and Operation

4.2.1 Introduction to Governors

Electric generators use governor control systems to control shaft speed. The governor system senses generator shaft speed deviations and initiates adjustments to the mechanical input power of the generator to increase or decrease the generator's speed as required. This section will address a governor's role in maintaining shaft speed once a unit is synchronized and carrying load. Governors also have a role during the start-up and shut-down of a generator that is not addressed in this section.

Governor control systems also control wicket gate position in hydro units and fuel inlet pumps in combustion turbines.

Governor control systems control the position of input valves to the turbine of the generator. In this text we will normally assume the turbine for the generator is a steam turbine so the governor controls steam input to the turbine via a control valve.

To illustrate how generator governors operate, suppose that the simple generator system in Figure 4-9 undergoes a large load increase. This creates a system energy deficiency causing the generator shaft speed to fall as energy is quickly drawn from the stored energy of the generator. The governor senses the reduced shaft speed of its generator and acts to further open the throttle valve to the turbine.

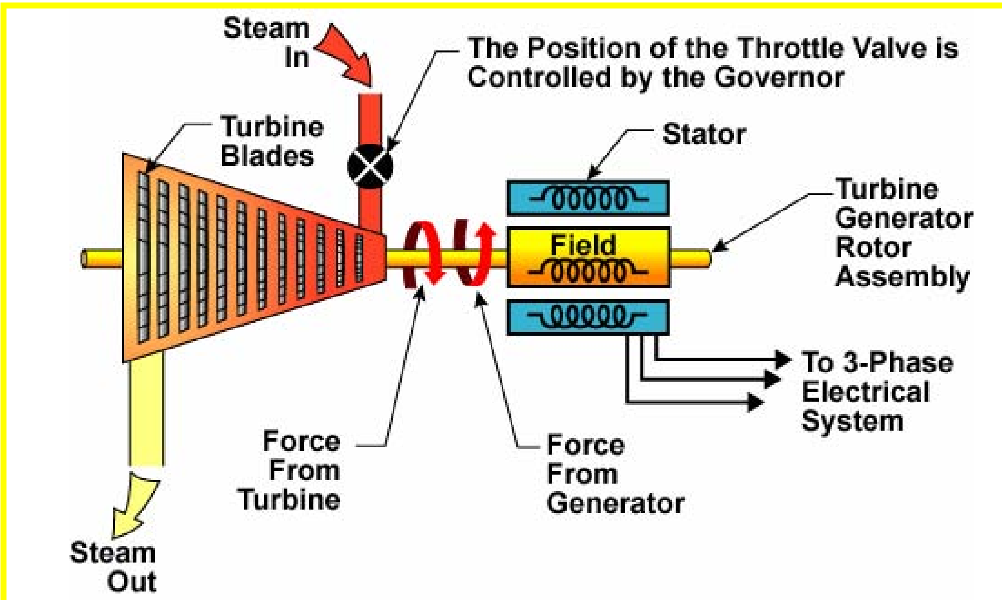


Figure 4-9
Simple System to Illustrate Governor Control

We say "hopefully" increase the shaft speed since it depends on how much rotational energy was drained from the generator shaft as to how much more new input energy will be required before shaft speed starts to increase.

The further opening of the throttle valve increases the steam input to the generator turbine and adds rotational energy to the shaft "hopefully" increasing the shaft speed. If the shaft speed is still less than the desired value, the governor will further open the throttle valve. The process continues over several seconds until the desired shaft speed is attained.

All types of utility generators use governor control systems:

- Hydro turbine/generators use governors to control the water flow to the hydro turbine. The valve for controlling water input to the turbine is either a wicket gate or a nozzle.
- Steam turbine/generators use governors to control the steam flow to the turbine blades. The valves for controlling the steam flow are called throttle valves in this text.
- Combustion turbines use governors to control the amount of fuel input to the combustion chamber.

Centrifugal ballhead governors are common on older units. Many modern units use electronic governors to achieve the same results

4.2.2 Centrifugal Ballhead Governor

Figure 4-10 is a simplified diagram of a centrifugal ballhead governor. This type of governor uses a flyweight arrangement to monitor turbine/generator shaft speed. The rotating ballhead assembly is mechanically geared or electrically driven by the turbine/generator shaft. The spinning force from the shaft causes the flyweights to spread out a distance that is proportional to the current turbine/generator rotational speed.

As shown this governor will control shaft speed to a scheduled value. For example, to the equivalent of 60 HZ. Governors on units in the interconnected power systems use what is called a droop characteristic. This simple governor model will be expanded later to include the droop characteristic.

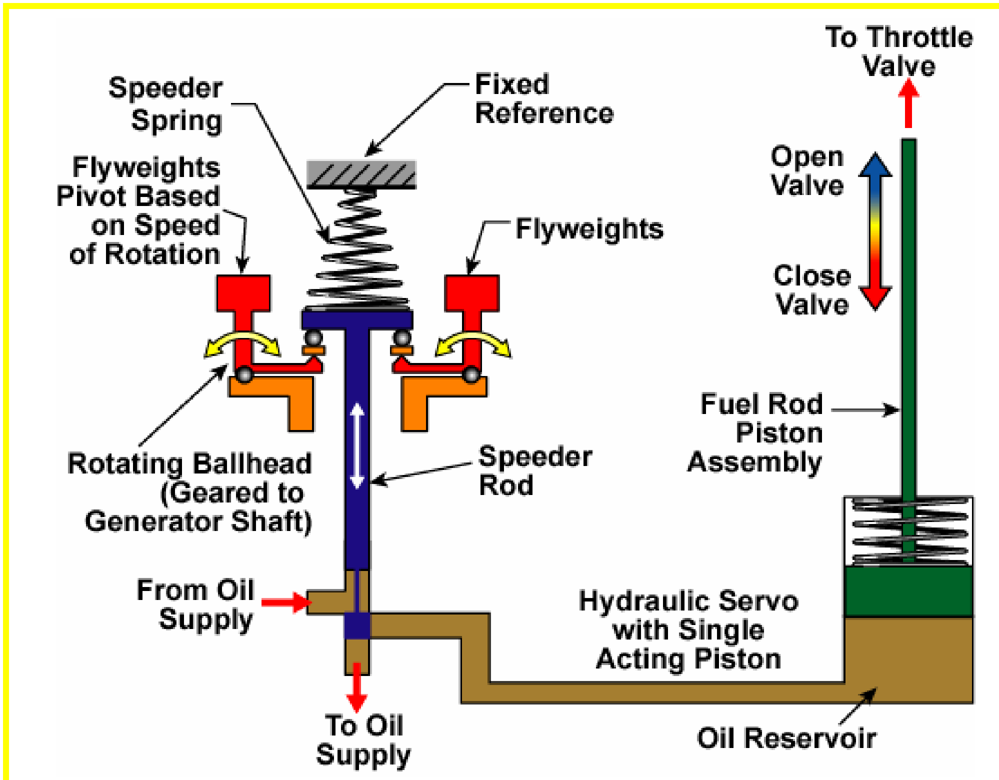


Figure 4-10
Basic Centrifugal Ballhead Governor

When the flyweights pivot in or out, the speeder rod moves up or down which in turn repositions a control valve. The control valve position determines whether oil will be allowed in or out of the oil reservoir. The oil level in the oil reservoir controls the fuel rod piston. If the fuel rod piston moves down, the throttle valve which controls the input (steam, water, etc.) to the turbine is moved towards the closed position. If the fuel rod piston moves up, the throttle valve is further opened.

The speed of the generator is directly tied to the throttle valve position. If the generator governor detects the generator speed is rising, it will close the throttle valve further and arrest the speed increase. If the governor detects that shaft speed is falling, it will open the throttle valve further and arrest the speed increase.

Ballhead governors can be used to control steam inlet valves to a steam turbine, wicket gates or nozzle openings in a hydro turbine, or fuel pumps in a combustion turbine. All systems use hydraulics to amplify the small flyweight forces to make the force large enough to drive the appropriate control valves.

4.2.3 Modern Electronic Governors

Modern generators often use electronic governors. Governors of this type perform the same function as a ballhead (mechanical) governor, it simply uses electronic components to perform these functions. Figure 4-11 illustrates, in block diagram format, the components of an electro-hydraulic governor. An electro-hydraulic governor uses electronic components to sense speed and create the desired control signals, and uses hydraulics to obtain the forces necessary to adjust steam valves or wicket gates.

As illustrated in Figure 4-11 a permanent magnet generator (PMG) is electrically coupled to the turbine shaft. This small generator's rotor is geared to the turbine shaft so its output voltage is representative of shaft speed. The output voltage is fed to a series of electronic components. These components sample the shaft speed and compare it to a target value. The error detected is used to drive the hydraulic system.

Also illustrated in Figure 4-11 are two inputs; "AGC Signal" and "Manual Control Access". The Manual Control input is an access point for a plant operator to assume control of the governor system. The AGC Signal is a control signal sent by a utility's system operations center to adjust governor settings. We will address this AGC signal in great detail in Section 4.3.

Depending on the age of the electronic governor it may be composed of analog or digital electronic components. Latest generation electronic governors use digital components. These governors are provided with data about the generator (speed, target MW, etc.) and use digital components to perform the governor function. Access to the performance characteristics (settings) of a digital governor are often via software. For example, the plant operator may be able to adjust governor characteristics by making adjustments in a software program.

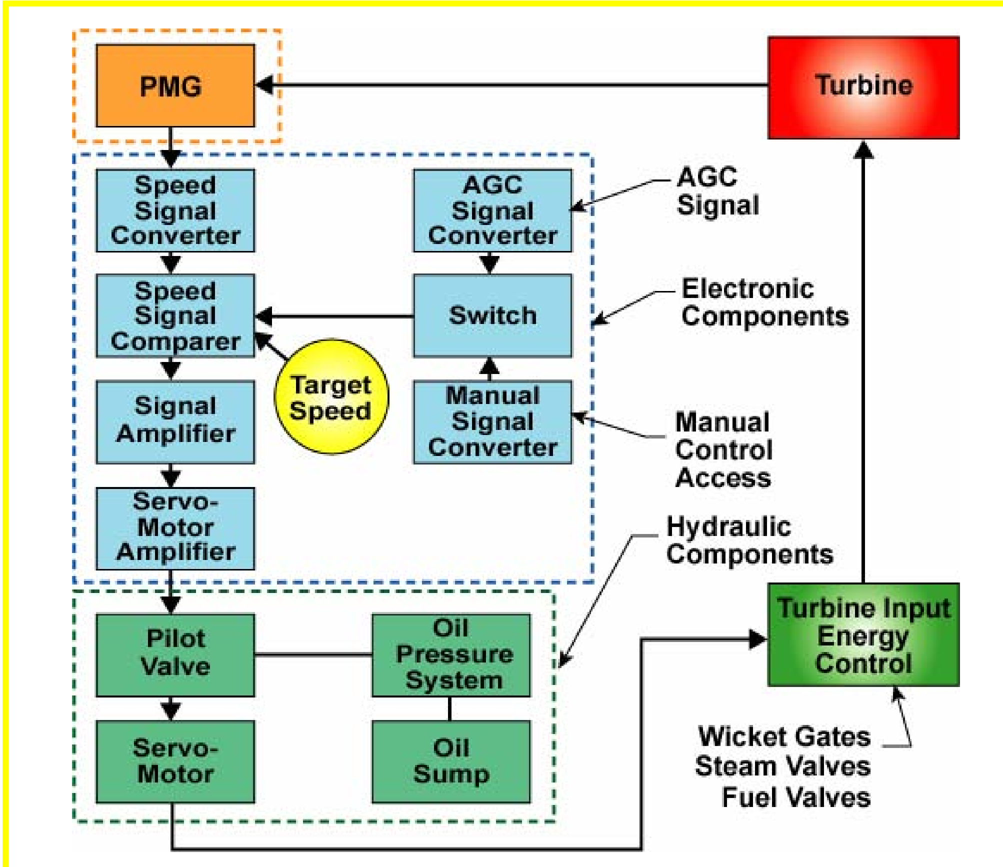


Figure 4-11
Electro-Hydraulic Governor Block Diagram

4.2.4 Governor Droop Curves

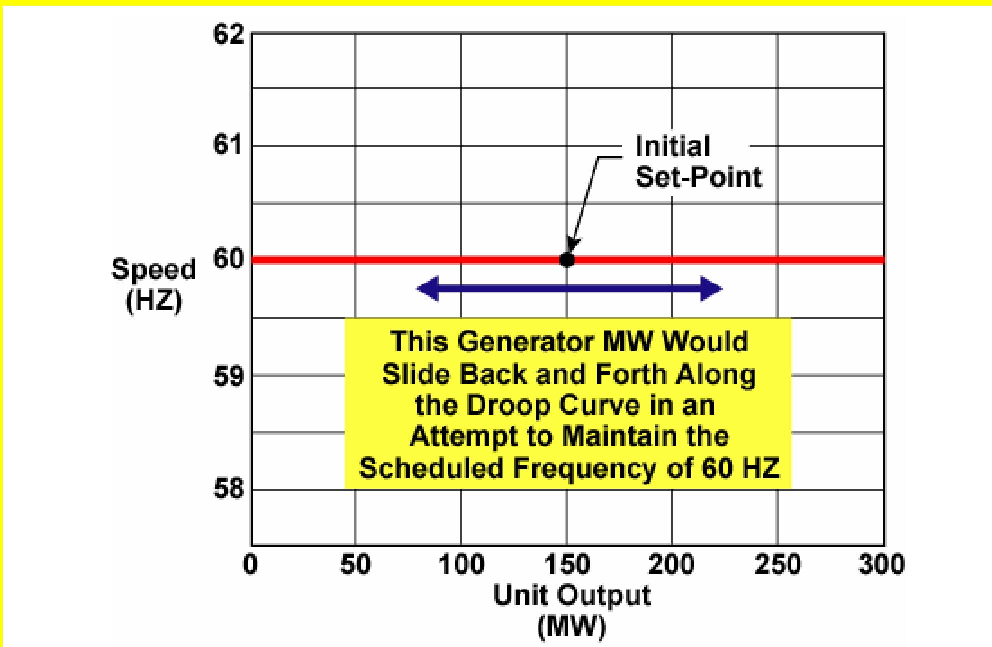
Governor Control & System Operations

Our goal throughout this text is to analyze power system behavior from a system operations perspective. This goal effects how we view a governor's operations. As stated earlier, governors monitor shaft speed and respond by changing a throttle valve position. From a system operations perspective it is clearer if we equate shaft speed to system frequency and throttle valve position to generator output power. Accordingly, from this point forward we will use the approximation that governors monitor system frequency and adjust unit MW output to correct for frequency errors.

Isochronous (Flat-Line) Governor Control

The expected response of a generator's governor to changes in system frequency may be plotted to form a curve. Every generator operation can be illustrated with this tool which is known as a governor characteristic curve or more commonly as a droop curve. This curve shows the relationship between the generator output power and the frequency of the power system to which the generator is connected.

A governor that strives to maintain its target frequency (normally 60 HZ) for all load levels would be called an isochronous governor. A characteristic curve for such a governor is given in Figure 4-12. If the frequency should change, the governor represented by this characteristic curve would try to adjust its generator output until frequency was returned to 60 HZ. An isochronous governor will do everything within its means to maintain 60 HZ.



This figure is for an isochronous governor on a 300 MW unit. Also referred to as a governor with zero droop. The generator controlled by this governor will slide back and forth along its droop curve frequently changing the unit MW output in an attempt to maintain a 60 HZ system frequency.

Figure 4-12
Isochronous Governor Characteristic Curve

The generator illustrated in Figure 4-12 has a minimum output rating of 0 MW and a maximum output rating of 300 MW. In theory, this generator would vary its output in a range from 0 MW to 300 MW in response to system frequency changes. If frequency falls below 60 HZ, this governor will move the generator output towards 300 MW to return the frequency to 60 HZ. If frequency rises above 60 HZ, this governor will move the generator output towards 0 MW.

The cruise control of a car is a simple example of an isochronous control system. This system will attempt to keep the car at the same speed. When the system encounters a change in load, such as when approaching a hill, it will change the gas flow to the engine to try to keep the speed constant. The car's cruise control system would have a characteristic curve similar in shape to that of Figure 4-12.

Need for Droop

In actual practice, an isochronous governor characteristic is rarely used. Interconnected power system generators with isochronous governors tend to be unstable and enter into speed oscillations following sudden load changes. Isochronous governors would continually make minor corrections in search of the target frequency of 60 HZ. In an interconnected power system, multiple generators on isochronous control would compete with each other to follow load changes. The overall power system would suffer due to frequent and conflicting governor adjustments. These excessive governor actions could lead to frequent failure of generator components.

When a droop characteristic is added to a governor it forces generators to respond to frequency disturbances in proportion to their size. For example, a 1000 MW unit would respond with ten times the response of a 100 MW unit.

Islanded power systems are power systems that as a result of a system disturbance are no longer connected via AC lines to any other power system. Chapter 11 will examine the use of isochronous governors in islanded power systems.

The isochronous control mode illustrated in Figure 4-12 could be used by a generator’s governor if it were the only generator on isochronous governor control in the power system. This generator would then provide the majority of governor control response. An islanded power system may use isochronous control. During the restoration of the system following a blackout, a utility may have guidelines for operating islanded sections of the power system with selected generators on isochronous control.

The units chosen to operate on isochronous control must carry sufficient spare capacity to control or regulate the frequency. Assume the frequency drops and the governor exhausts the unit capacity in an attempt to return frequency to 60 HZ. The system frequency could then continue to fall unless additional MW can be found.

Governors with a Droop Characteristic

In practice, governors operate with a droop characteristic. Figure 4-13 illustrates this type of governor characteristic curve. The curve droops from left to right. This means, that as power system frequency increases, the governor will reduce generator output and stabilize at a higher frequency than was initially held. When power system frequency decreases, the governor will increase generation and the generator will stabilize at a frequency lower than initially held. Droop settings on governors are necessary to enable many generators to operate in parallel in the power system while all are on governor control and not compete with one another for load changes.

Governor droop is expressed as a percentage of the frequency change required for a governor to move a unit from no-load to full-load or from full-load to no-load. For example, a 5% droop setting means that a 3 HZ (5% of 60 HZ) change in frequency is required to move the generator across its entire range, from no load to full load or from full load to no load. (Of course, generators can only adjust their output if they have spinning reserve capacity available.)

Spinning reserve is unused capability held in a synchronized generating unit. This spare capability may or may not be responsive to governor commands. Section 4.4 examines reserves.

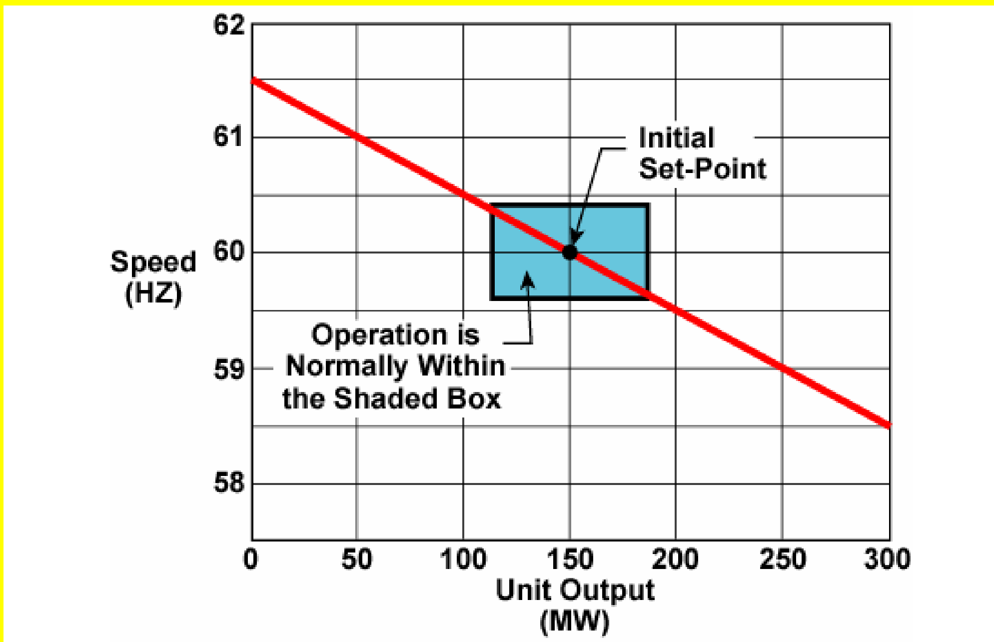


Figure 4-13
Governor Characteristic Curve with 5% Droop

This characteristic curve droops from left to right. The governor will move the generator along the droop curve to arrest frequency changes.

NERC recommends that governors have a 5% droop setting. As stated earlier, this value of droop means that the unit would respond with 100% of its capability to a 5% change in the system frequency. Once the droop value is known the response of the generator to various magnitudes of frequency hits can be determined.

For example, if the 300 MW unit of Figure 4-13 was initially operating at 0 MW it would increase its output by 300 MW if the frequency fell 3 HZ. The example below illustrates how you would calculate this same unit's response to a 1.5 HZ frequency deviation.

If the Interconnection is small, generators may be forced to operate across wider frequency ranges.

A 5% droop setting on a 300 MW unit tells us that a 5% change in the 60 HZ frequency (3 HZ) would change the unit output by 100% or 300 MW. The following ratio can be constructed:

$$\boxed{\frac{3\,\text{HZ}}{300\,\text{MW}}}$$

This ratio simply states the frequency change needed for a 300 MW output change. What if the frequency only dropped by 1.5 HZ?

Using our ratio above for this 5% droop 300 MW unit we can calculate:

$$\boxed{\frac{3\,\text{HZ}}{300\,\text{MW}} \approx \frac{1.5\,\text{HZ}}{?\,\text{MW}}}$$

Using either cross-multiplication or observation the MW response to a 1.5 HZ frequency drop can be calculated as 150 MW.

The definition of a 5% droop setting does not imply that we normally operate a generator with frequencies ranging from 58.5 to 61.5 HZ. The definition of a governor's droop only describes how a generator will behave when confronted with frequencies different than 60 HZ. In actual operation (in large Interconnections), generators are rarely operated under load outside of a 59.5 to 60.5 frequency range.

Achieving Droop in a Centrifugal Ballhead Governor

Figure 4-14 illustrates how droop could be implemented in a ballhead governor. The permanent droop rod across the top of the figure is used to select the % droop. As the connection point between the permanent droop rod and the speeder spring is adjusted, the % droop changes. (The permanent droop rod and speeder spring act like a fulcrum.) When the fuel rod moves up or down the permanent droop rod changes the speeder spring compression. Changes to the speeder spring compression result in changes to the equilibrium position of the control valve and in the speed setting the governor will hold.

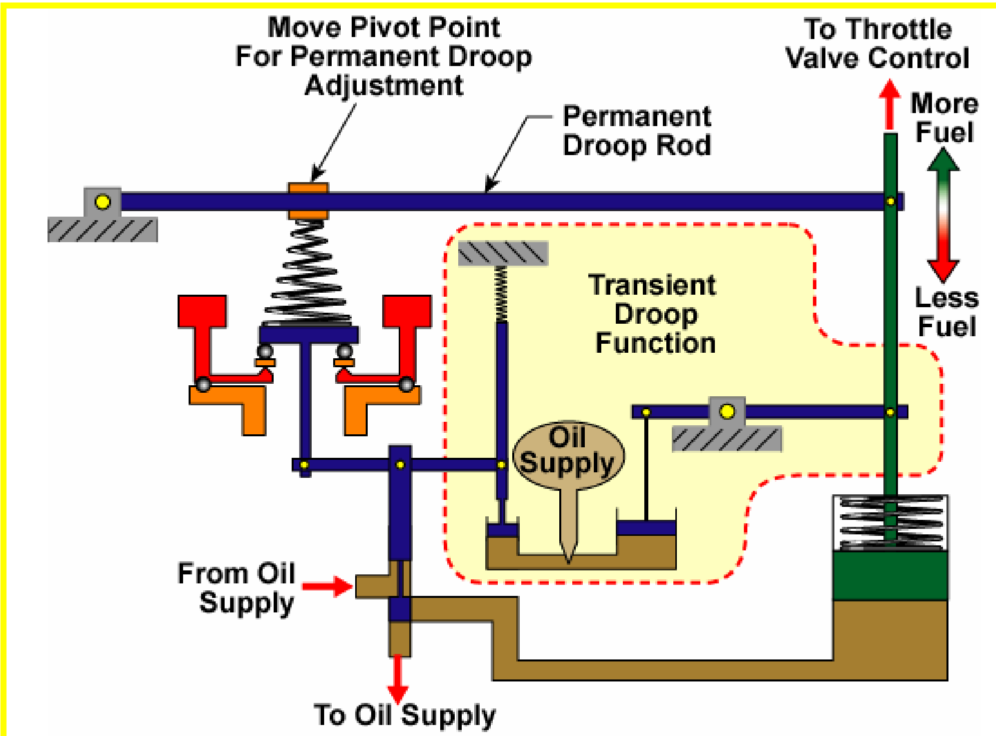


Figure 4-14
Droop in a Centrifugal Ballhead Governor

There are actually two droops illustrated in this figure. A permanent droop and a transient droop (inside the dashed line). The permanent droop is the droop that has been described in this text. The transient droop is often found in hydro governors. Transient droop is a short term droop characteristic that helps avoid unit oscillations and prevents possibly damaging impacts to a hydro unit's water intake system. (See Section 8.5.2 for more information on transient droop.)

For example, assume a governor on an isolated unit is initially operating with an equivalent 60 HZ speed. Further assume the speed suddenly rises and the flyweights pivot out farther. The control valve position will move upward to allow oil to drain from the hydraulic servo reservoir. This allows the fuel rod to move downward reducing the amount of fuel (steam) input to the turbine.

The permanent droop rod also moves when the fuel rod moves. In this case the permanent droop rod will increase the speeder spring compression and force the pilot valve to return to its equilibrium position. The result of this permanent droop rod movement is that the governor reduced the fuel input following a speed increase but does not return the speed to 60 HZ. Rather the governor only arrests the speed increase. The generator will operate at a speed higher than 60 HZ until an adjustment is made to the governor settings to return the unit to 60 HZ.

4.2.5 Governor Control in an Islanded Power System

The operation of a governor with a droop characteristic is initially described in a simple islanded power system with only one generator. Later, the concepts of droop and governor control will be expanded to describe operation within an interconnected power system with multiple generators.

Governor Response to a Frequency Rise

Assume that an isolated generator's governor has the droop curve given in Figure 4-15. Further assume that an event occurs to cause the system frequency to suddenly increase. The governor adjusts generation downward from 150 MW to 140 MW to stabilize the frequency at 60.1 HZ. The frequency might stabilize at 60.1 HZ but this is an unacceptable frequency deviation and we would want to return it to 60 HZ as soon as possible. Returning the frequency to 60 HZ is done by adjusting the load reference set-point of the governor.

The initial load reference set-point of this governor is 150 MW. To recover the frequency to 60 HZ from 60.1 HZ, the load reference set-point has to be changed.

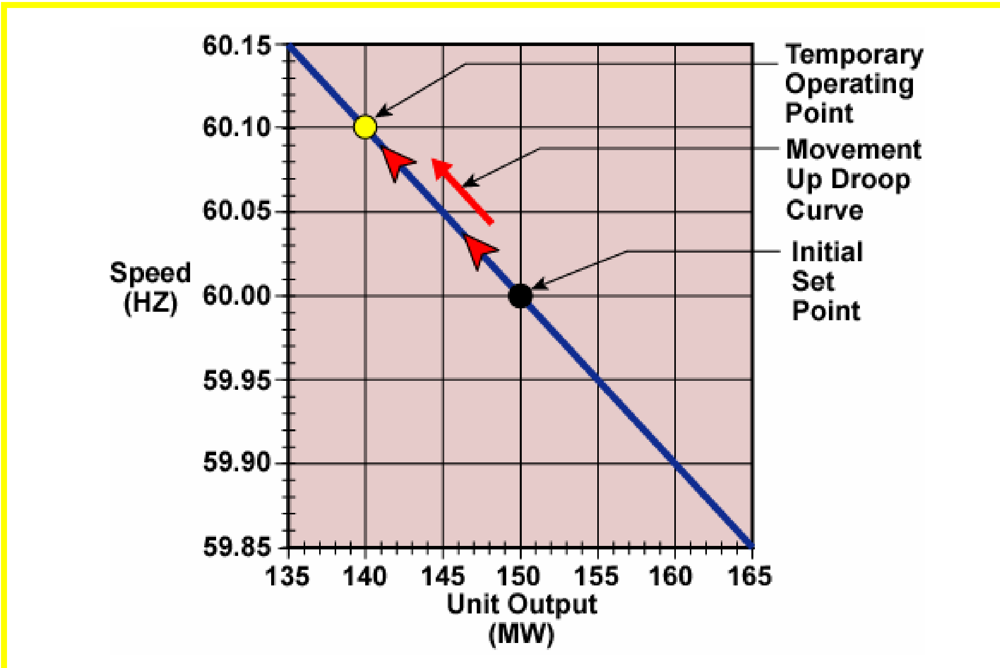


Figure 4-15
300 MW Unit with 5% Droop – Frequency Rise

The Load-Reference Set-Point

The load reference set-point of the governor represents the generation that will be produced by the generator when the frequency is 60 HZ. The set-point in Figure 4-15 was initially 150 MW. The set-point is adjusted so that the generator produces the desired output MW—provided that this is within the range of the unit—when the shaft speed is the equivalent of 60 HZ.

Adjusting the set-point has the effect of sliding the whole governor droop curve. For example, in Figure 4-16 the set-point of the governor has been adjusted from 150 MW to 140 MW and the generator's output frequency has moved from 60.1 HZ back to the target value of 60 HZ. Thus, when the load reference set-point of the governor is adjusted, the MW that the generator will produce at 60 HZ is changed.

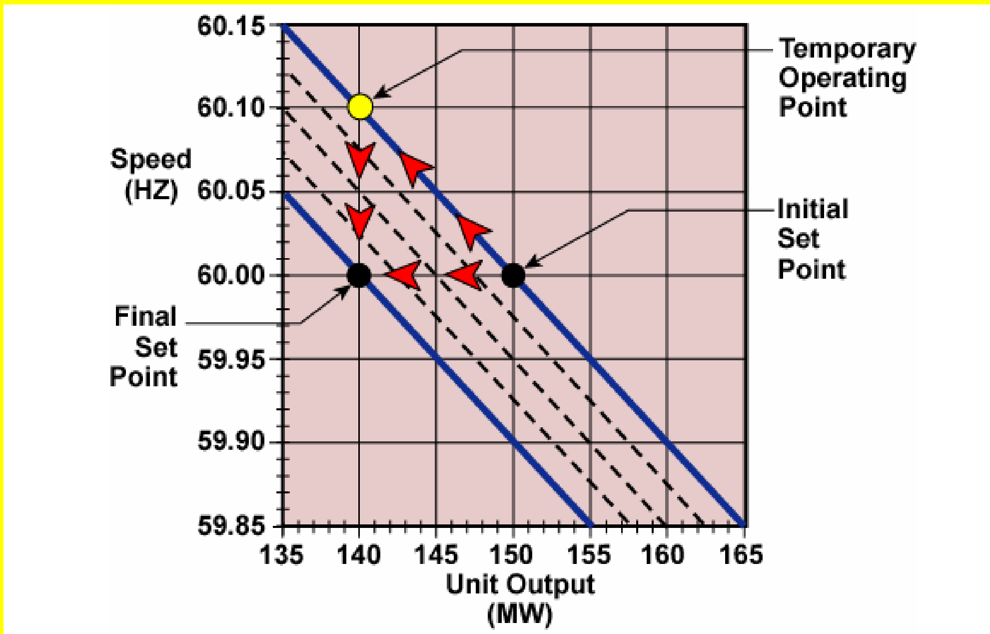


Figure 4-16
Changing the Set-Point to 140 MW @ 60 HZ

The load reference set-point has been adjusted from 150 MW to 140 MW to restore the frequency to 60 HZ. The movement of the set-point is done slowly so as not to disturb the unit.

The load reference set-point adjustment can be made either manually via the power plant controls or automatically via the AGC system. AGC is described in Section 4.3.

An alternate way to visualize a governor set-point is to think in terms of the rotational energy of the generator. By changing an isolated generators governor set-point, the stored or rotational energy in the turbine/rotor is changed. For example, in Figure 4-16 the movement of the set-point from 150 to 140 MW changed the turbine-rotor speed of rotation from 60.1 to 60 HZ. Stored energy is removed from the turbine-rotor which results in a reduction in frequency.

By changing a governor set-point to decrease the 60 HZ generator output we, in effect, decrease the stored or rotational energy in the turbine-rotor and decrease frequency. Similarly, a change in governor set-point to increase the 60 HZ generator output, effectively increases the stored or rotational energy in the turbine-rotor, thereby increasing frequency without significantly adjusting the MW output of the unit.

Governor Response to a Frequency Drop

Governor response typically occurs in response to a low frequency event. Figures 4-17 and 4-18 are used to illustrate the response of an isolated generator's governor to a frequency drop.

In Figure 4-17 the governor settings are such that the generator is maintaining a 150 MW output when the system frequency is 60 HZ. Assume that a load increase causes the system frequency to drop. Figure 4-17 illustrates the governor moving the generator down its droop curve to arrest the frequency drop at 59.9 HZ. As a result of the governor commands the generator output has increased from 150 to 160 MW.

In response to a declining frequency, the governor moves the generator down its droop curve. MW output is increased and the frequency decline is arrested at 59.9 HZ.

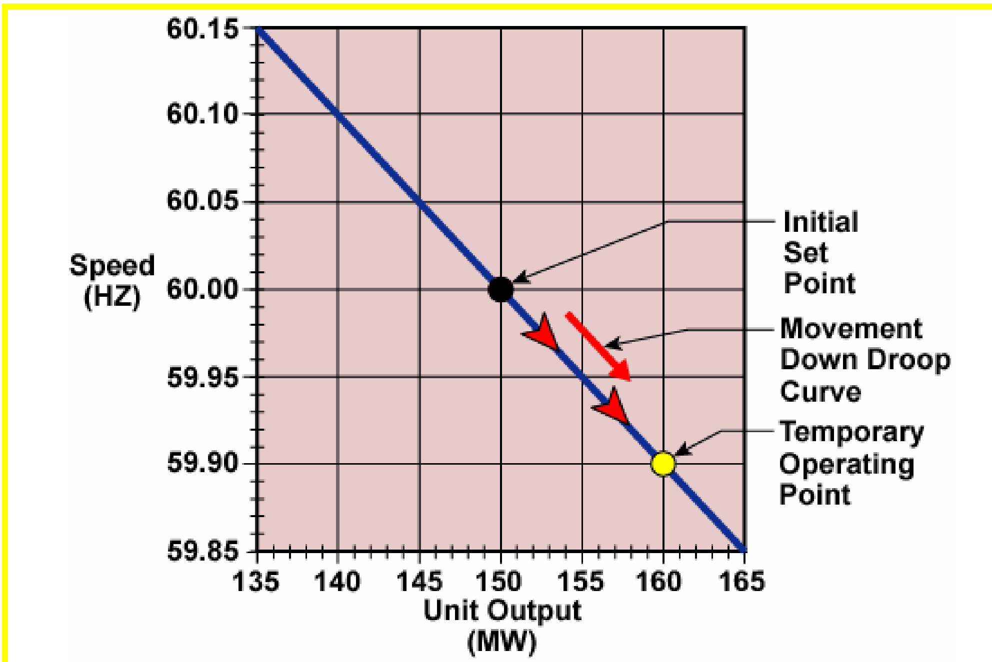


Figure 4-17
300 MW Unit with 5% Droop – Frequency Drop

In an isolated power system, plant operators are often responsible for frequency control. The plant operator may allow the governor to control frequency automatically (isochronous control) or the plant operator may manually adjust the governor set-point to control frequency.

The governor has done its job by arresting the system frequency decline at 59.9 HZ. The eventual goal is to return the frequency to 60 HZ but the governor does not recover frequency on its own. The governor will not return the frequency to 60 HZ unless its set-point is adjusted. For this isolated generator, we will assume it is the plant operator that adjusts the governor set-point.

Figure 4-18 illustrates the movement of the governor set-point from 150 MW @ 60 HZ to 160 MW @ 60 HZ. Notice that as the set-point is moved, the frequency of the isolated power system recovers from 59.9 HZ to 60 HZ.

The set-point adjustment returns lost rotational energy to the system and allows system frequency to recover. The movement of governor set-points may be done by a plant operator as illustrated above, but in practice an additional control system (AGC) is used to adjust set-points. AGC is described in Section 4.3.

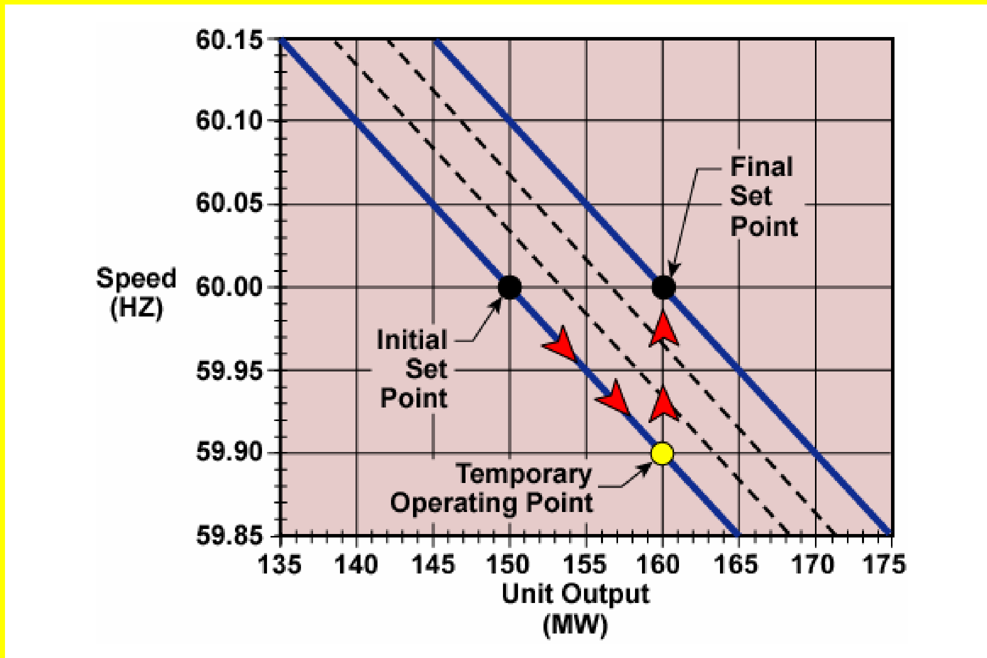


Figure 4-18
Changing the Set-Point to 160 MW @ 60 HZ

The governor completed its mission by arresting the frequency drop at 59.9 HZ. To recover the frequency to 60 HZ, the plant operator adjusted the governor set-point.

Load/Frequency Relationship & Droop Curves

When the governor response of an isolated generator was examined we stated that when the set-point was adjusted the rotational energy of the isolated system was changed and this resulted in a change in frequency. No MW change was shown when in fact a MW change does occur.

Recall Section 4.1.6 on the load/frequency relationship. This section stated that any time the system frequency changes the MW also changes, since MW level is related to frequency. A rule of thumb was given that a 1% change in frequency will typically lead to a 2% change in the total system load.

The fact that MW changes with frequency complicates droop curves. Figure 4-18 illustrated the adjustment of a set-point to recover the frequency to 60 HZ. Note in this figure that as the frequency was recovered the generator MW output did not change. Figure 4-19 illustrates the same set-point movement as Figure 4-18 but the load/frequency relationship is also accounted for in Figure 4-18.

Compare Figure 4-18 and Figure 4-19. Note that the frequency does not drop as much in Figure 4-19 as it does in 4-18. This is due to the load/frequency relationship. As the frequency drops, the load magnitude also drops. In Figure 4-19 if the load/frequency effect was not accounted for frequency would drop down to point 1. Counting the load-frequency effect means frequency only drops to point ❷. When the governor set-point is adjusted to recover the frequency, both frequency and generator MW output increase. The generator output increases because as the frequency is recovered to 60 HZ, the load magnitude also rises to a higher value.

The frequency drops as a result of a load increase. However, the frequency does not drop as much as might be expected. This is due to the load/frequency relationship. When the set-point is adjusted to recover frequency, the load magnitude rises with the recovered frequency.

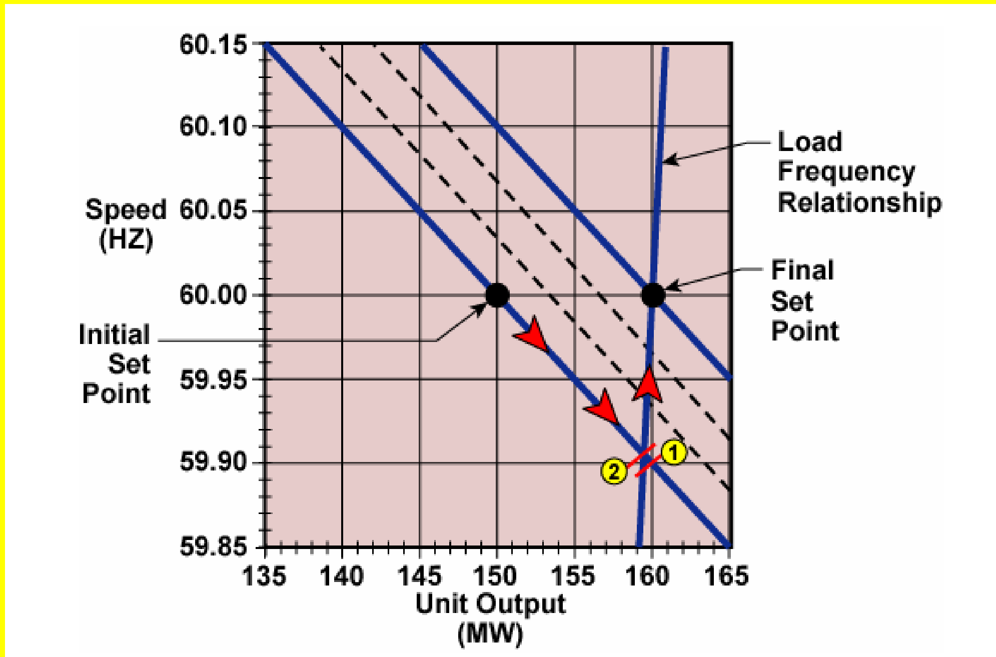


Figure 4-19
Load/Frequency Relationship & Droop Curves

Section 4.2.7 illustrates the differences between governors arresting a frequency deviation and the load/ frequency relationship arresting a frequency deviation.

The load/frequency relationship is very important in the operation of an interconnected power system. In a large power system, the load/frequency relationship is often all that is needed to arrest frequency deviations. A governor system response is required in a large Interconnection only when the mismatch between generation and load is large. For most mismatches, the change in load magnitude that accompanies a frequency deviation is sufficient to arrest the frequency deviation.

We will not include the impact of the load/frequency relationship in future droop curves as it complicates the usage of the droop curve. Just remember that the effect exists and it has a critical impact on power system frequency control.

4.2.6 Governor Control in an Interconnected System

The previous material described governor operation with respect to an isolated generator. Most generators do not operate isolated but rather as part of an interconnected power system. The differences between isolated generator operation and operation within the interconnected power system is explained next.

Figure 4-15 through 4-19 illustrated how the movement of a governor's set-point results in a change to the rotational energy and thus to the frequency of the generator. In our example of an isolated generator, the governor first changed the MW output of the unit in response to a frequency change. The set-point of the governor was then changed to return the isolated system's frequency to 60 HZ. In the interconnected system there are more factors to consider since there are many generators operating at any one time.

To illustrate the differences between isolated generator governor operation and interconnected system governor operation first return to Figure 4-17 and 4-18. Figure 4-17 illustrated an isolated generator under governor control with an initial set-point of 150 MW. In response to a declining system frequency the governor slid the unit down along its droop curve to arrest the frequency decline at 59.9 HZ with a 160 MW output.

The frequency would stay at 59.9 HZ if we relied totally on the automatic response of the governor. The governor has done its job by increasing the unit's MW output and arresting the frequency at 59.9 HZ. Figure 4-18 illustrated the movement of the set-point to restore the frequency to 60 HZ. This set-point movement was performed by the plant operator.

Note that the movement to the final set-point in Figure 4-18 did not involve a change in the MW output of the generator. The set-point change was entirely a change in rotating energy and as a result the system frequency changed. This is true (if we ignore the load/frequency relationship) in our isolated power system because there is only one generator. When the set-point change was made, the unit MW had already been adjusted by the unit's governor. This is not the case in the interconnected system as illustrated in Figure 4-20.

Figure 4-20 illustrates two generators in an interconnected power system. Units "A" and "B" are initially operating at 95 MW as illustrated in the left of the figure. Both units respond to a load increase in the interconnected system by sliding down their respective droop curves as illustrated in the middle of Figure 4-20. On the far right of the figure a set-point change is made to Unit "A" to correct the frequency to 60 HZ. No set-point changes are made to Unit "B".

Notice how the set-point change to the Unit "A" governor is not a straight up and down movement as was illustrated in Figure 4-16 or 4-18, but rather a movement of the characteristic curve up and to the right.

The set-point change is different in Figure 4-20 because both units initially responded to the frequency drop by moving down their droop curves.

However, only one of the units had its set-point changed to restore frequency. The unit that had its set-point changed increased its MW output to replace all of the governor response from the other units in the interconnected system. When set-points are changed in the interconnected system, rotational energy and unit MW output will change simultaneously.

Note how the movement of the Unit "A" set-point does not just correct the frequency but also adjusts the unit's MW output.

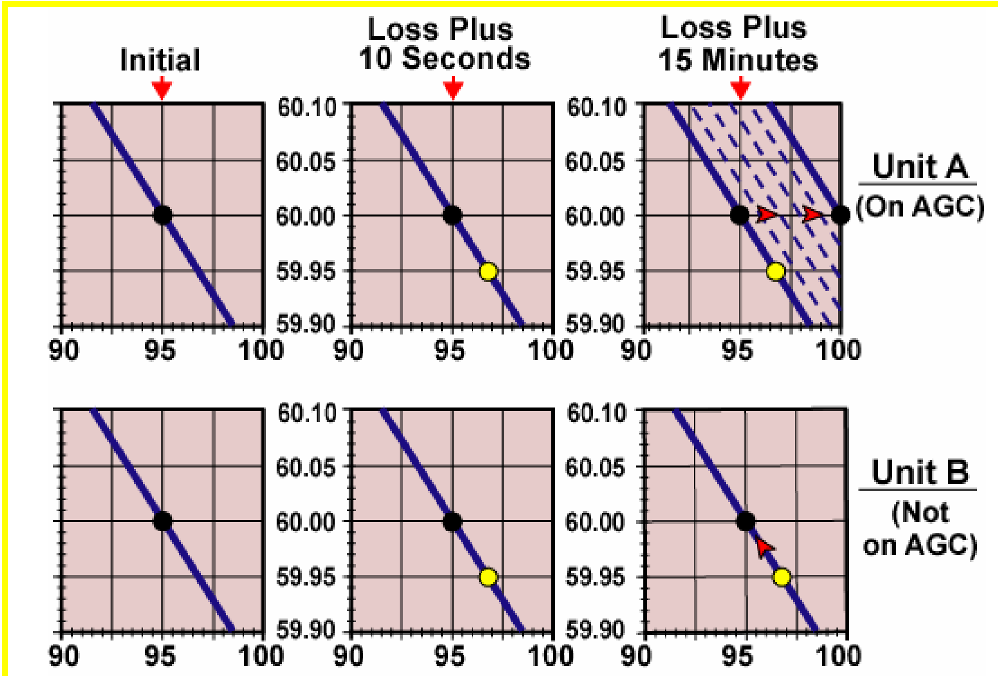


Figure 4-20
Interconnected System Governor Response

When frequency deviations occur within a large interconnected system, such as the Eastern Interconnection, hundreds of units will provide governor response. However, only a few of the units will have their set-points adjusted. These few units will make up for what ever generation excess or deficiency caused the frequency deviation in the first place. All the other units that provided governor response should slide back along their droop curves to their original set-points once the frequency has recovered.

Governors are intentionally designed not to respond to small frequency deviations. Section 4.2.11 describes this design factor called the governor deadband.

Interconnected power systems are constantly experiencing frequency deviations. Governors do not respond unless the frequency deviations are substantial. For a large Interconnection, widespread governor response may occur a few times a month. For a small Interconnection governor response may occur daily. As a mental picture of governor response visualize all the generators in the interconnected system sliding up and down along their droop curves collectively arresting frequency deviations.

4.2.7 Frequency Traces

Figure 4-21 is based on a frequency plot taken in the Eastern Interconnection following the loss of a large generating unit. After the loss of this large unit the frequency in the Eastern Interconnection dropped. The governors on the generators in the Interconnection sensed the system speed change and opened their respective valves to supply more fuel (steam, water, etc.) and together arrest the frequency drop.

Note the tail of the frequency response trace (labeled governor response in the figure). The tail approximates the total governor response. The longer the tail the more governor response. The tail represents the governor's recovering the frequency from the low or undershoot point back to a stabilization point. Once the frequency has stabilized from governor response, the set-points of a portion of the system governors are adjusted to recover the frequency to 60 HZ. The movement of the set-points are also labeled in the figure.

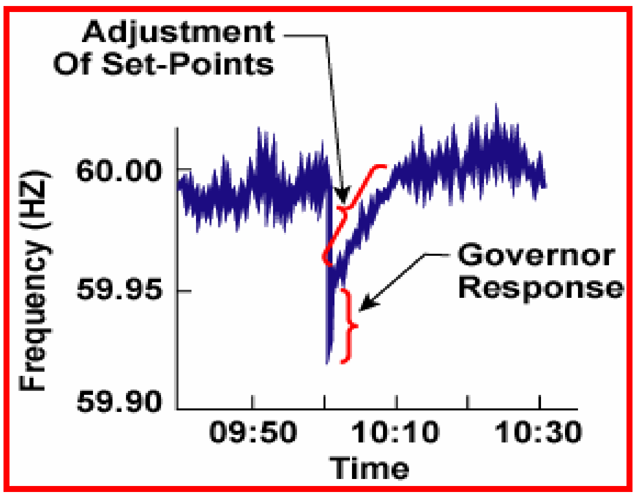


Figure 4-21
Frequency Trace

The tail of the frequency trace represents the governor response. Notice that after the governor response the frequency has recovered to about 59.95 HZ. This is the impact of droop. The governors do not recover the frequency to 60 HZ.

As stated earlier, in a large Interconnection widespread governor response occurs infrequently. The majority of the time the load/frequency relationship is sufficient to arrest frequency deviations. Figure 4-22 illustrates two frequency traces. The trace on the left is for a large frequency deviation in which governor response was necessary to arrest the frequency drop. The tail of the frequency trace approximates the governor response.

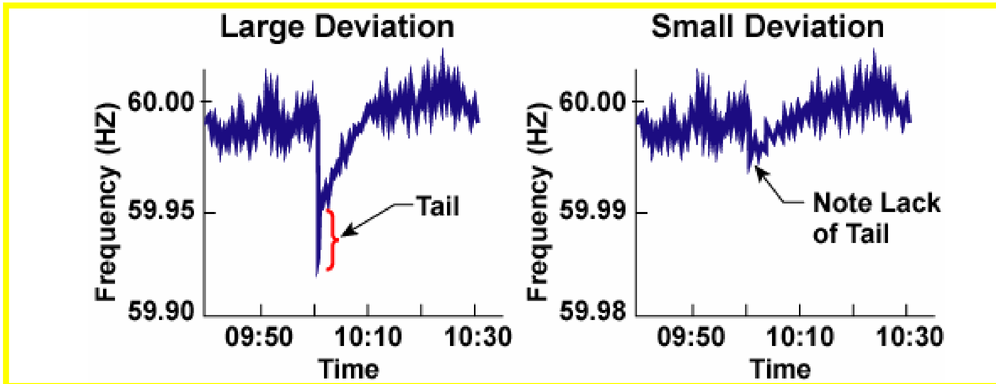


Figure 4-22
Comparison of Large & Small Frequency Deviations

Section 4.2.9 examines frequency plots in greater detail.

The trace on the right is for a smaller frequency deviation. Note there is no pronounced tail to this frequency trace. The absence of a tail indicates that the load/frequency relationship was alone enough to arrest the frequency deviation. The load/frequency effect does not recover frequency, it simply stops the decline. Governor response will show a recovery to frequency which is why the tail exists when widespread governor response occurs.

4.2.8 Generator Response and Droop Settings

To illustrate how governor droop settings impact a generators response to system load changes, assume that a simple power system has two generators as shown in Figure 4-23. Both units (each rated 750 MW) are initially loaded at 600 MW and system frequency is 60 HZ as shown in the figure. When 200 MW of additional load is suddenly added to this small power system, the system frequency declines from 60 HZ. As frequency declines, the governors of the two generators respond to increase MW output in order to arrest the frequency decline. How the two generators individually respond depends on their respective droop settings.

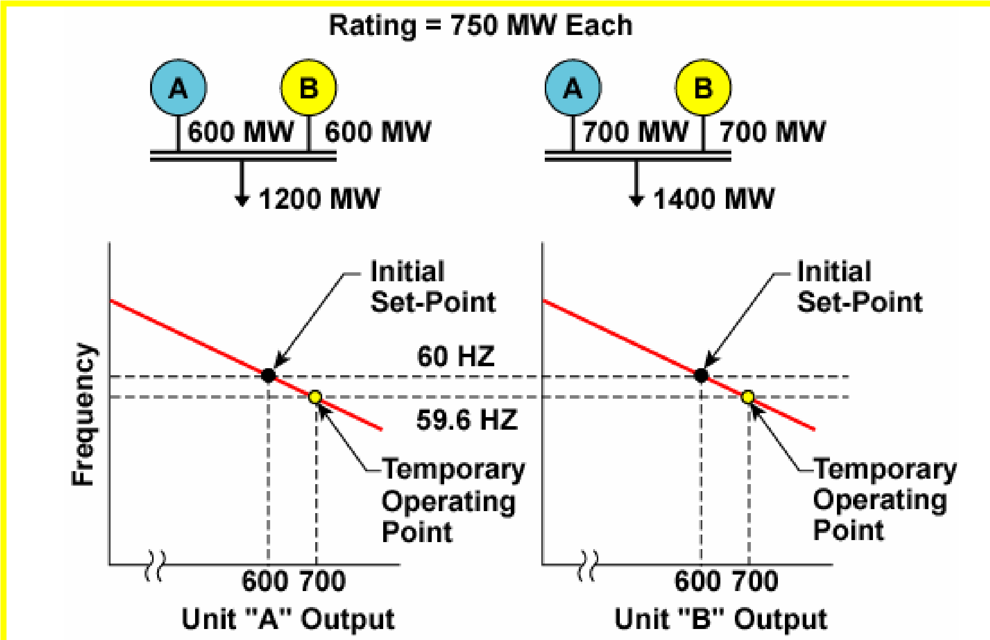


Figure 4-23
Load Sharing – Same Unit Ratings – Same Droop

Note that the two units combined arrested the frequency drop at 59.6 HZ. The more units that respond the less the frequency will drop. If 10 identical units had responded the frequency would only have dropped to 59.92 HZ and each unit would only have needed to pick up 20 MW.

Same Unit Ratings – Same Droops

If the two generators are the same size and have the same 5% droop settings, they evenly split the 200 MW of new load as shown in Figure 4-23. Each unit is now carrying 700 MW of load at a reduced frequency of 59.6 HZ. To bring the frequency of the system back to 60 HZ, the load reference set-points for both generators are adjusted upward so that at an output of 700 MW from each unit the frequency is 60 HZ.

Same Unit Ratings – Different Droops

Now assume that the two generators are the same size but use different droop settings. Unit "A" has a 3% droop while Unit "B" has a 6% droop. Because the droop settings are different, the two generators no longer evenly share changes in load as they did when the droop settings were the same. The generator with the smaller droop setting (Unit "A") assumes a larger portion of any load change as illustrated in Figure 4-24.

Notice that the larger the % droop, the steeper the slope of the droop curve and the more of a frequency change it would take to achieve a given generator output change.

Unit "B" has a larger % droop than Unit "A". This means Unit "A" response will be greater than Unit "B". The greater the % droop, the less the unit response.

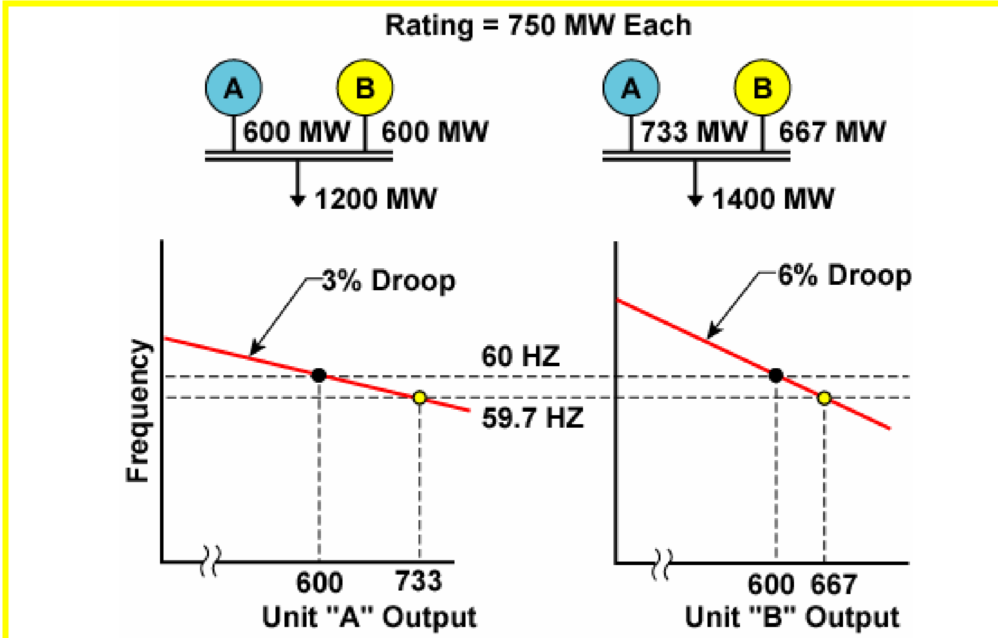


Figure 4-24
Load Sharing – Same Unit Ratings – Different Droop

Figure 4-24 illustrates that if the same 200 MW of load is added to the system resulting in frequency declining to 59.7 HZ, Unit "A" assumes 133 MW of the new MW load while Unit "B" assumes the remaining 67 MW. Unit "A" has ½ the droop setting of generator "B" so it picks up twice as much of the new load.

Same Unit Ratings – One Unit Isochronous Control

To conclude our description of how droop settings impact the response of generators to load changes consider a small isolated power system with two generators. One of the generators has a 5% droop (Unit "A") and the other generator (Unit "B") is on isochronous control (0% droop). Figure 4-25 illustrates the two generators.

When a unit is in isochronous control it will attempt to control frequency as long as it has available MW capability. Unit "B" can add up to 150 MW of output to stop frequency from dropping.

Initially each generator is carrying 600 MW of load. Assume that a 100 MW load addition suddenly occurs. Which unit will pick up the additional 100 MW? Since Unit "B" is on isochronous control it would pick up the entire 100 MW load addition. Unit "A" will not pick up any additional load unless frequency drops. Since Unit "B" is on isochronous control it will not let the frequency drop unless it runs out of capacity. The 100 MW load addition is within the capability of Unit "B" so it picks up the entire 100 MW while Unit "A" loading stays constant.

Now assume that instead of a 100 MW load increase, a 200 MW load increase occurs. Which unit will pick up this load change? Since Unit "B" is on isochronous control it will try to maintain frequency and pick up the entire 200 MW load change. However, Unit “B” only has 150 MW of reserve capacity available. Once Unit “B” reaches its capacity limit, the frequency starts to fall. When the frequency starts to fall, Unit “A” starts to pick up load. Figure 4-25 illustrates the split of the additional load. Notice that the system frequency falls to 59.8 HZ.

If a 200 MW load addition suddenly occurs, Unit “B” cannot maintain frequency. Unit “B” runs to its maximum output while Unit “A” supplies MW as the frequency drops.

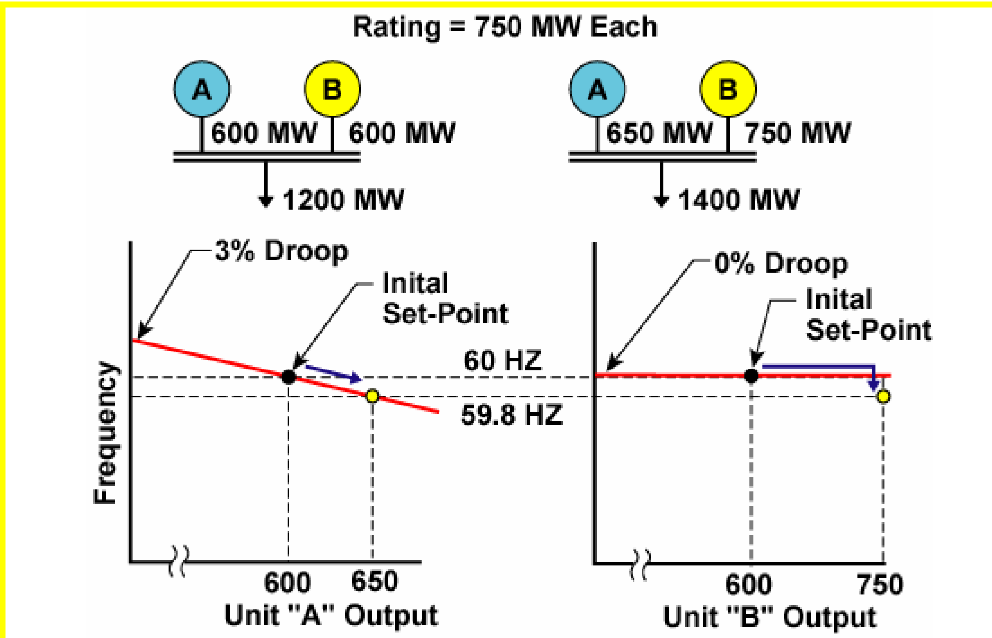


Figure 4-25
Load Sharing – Same Unit Ratings – One in Isochronous

4.2.9 System Frequency Response Characteristic

A power system characteristic, called the frequency response characteristic (FRC), can be developed for any section of a power system. The FRC relates the MW response of the system (or section of the system) to a change in frequency. The FRC is based on the combined response of all the generating units and the spinning (motor) load in the system to changes in system frequency. The FRC includes the governor response of the various units and the frequency response of the loads.

Frequency response data is typically reported in units of MW per 0.1 HZ. For example, a utility may report that their system typically responds with 200 MW for each 0.1 HZ of frequency deviation

- The system FRC depends on:
- The governor droop settings of all on-line units in the system.
- The condition of the power system when the frequency deviation occurs. The condition of the power system includes current generator output levels, transmission line outages, voltage levels, etc.
- The frequency response of the connected load in the system.

Therefore, the FRC of a power system will vary with the current operating conditions. The FRC of a power system following a frequency disturbance will vary depending on the generating units currently on line, the magnitude of the load, the transmission lines in-service, etc. Given the same size loss of generation occurring at two different times, the FRC of the system will be different.

The FRC is similar to a droop characteristic. Both quantities relate MW changes to frequency changes. The FRC for a power system is sometimes loosely referred to as a system droop. One can produce a droop type curve for any area of the power system that describes how that area responds to frequency changes.

Frequency Response of Different Interconnections

Figures 4-26 through 4-28 are based on typical frequency response data for the three major NERC Interconnections. Figure 4-26 is for the Eastern Interconnection, Figure 4-27 for the Western Interconnection and Figure 4-28 for the ERCOT Interconnection. Each of the figures illustrates how the particular Interconnection frequency varies following a significant generation loss.

The time scales on the bottom of each figure are measured in minutes. Time = 0 represents the initiation of the disturbance. The frequency response of a power system takes approximately 10 to 20 seconds to develop following a disturbance. Note in the figures that the frequency continues to improve as indicated by the arrows on the three figures. We will address what happens several minutes after a disturbance in the next section of this chapter.

Figure 4-26 illustrates the Eastern Interconnection frequency response following the loss of 1800 MW of generation. Notice how the frequency plunges to 59.972 HZ and then recovers to 59.985 HZ. The FRC for the Eastern Interconnection is also calculated in Figure 4-26. For a loss of 1800 MW the frequency changes by .03 HZ. This is equivalent to 6000 MW per 0.1 HZ.

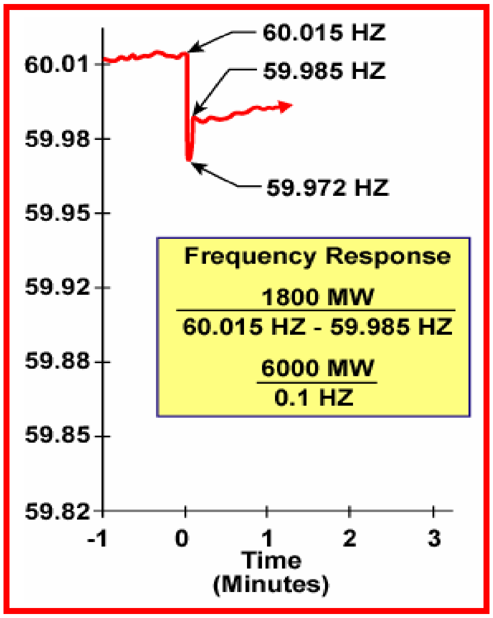


Figure 4-26
Eastern Interconnection

The low point or undershoot of the frequency is 59.972 HZ. The frequency recovers to 59.985 largely due to governor response. The FRC for the Interconnection is based on a comparison of the initial frequency (60.015 HZ) and the point the frequency recovers to (59.985 HZ).

An FRC of 6000 MW/0.1HZ means that given a disturbance in the Eastern Interconnection, for each 0.1 HZ the frequency drops, the Interconnection as a whole will typically respond with 6000 MW to arrest and restore the frequency.

Remember, the FRC will vary depending on current system conditions.

Figure 4-27 illustrates the Western Interconnection's typical frequency response following the loss of 1525 MW. Notice how the frequency plunges farther for less than the generation loss as was shown in Figure 4-26. This is expected as the Western is less than 1/6 the size of the Eastern Interconnection. The FRC for the Western Interconnection is also calculated in Figure 4-27. The value of 2007 MW/0.1HZ indicates that following a disturbance, the Western Interconnection as a whole will respond with approximately 2000 MW for each 0.1 HZ the frequency plunges.

Compare the FRC of the Eastern (6000 MW) to the Western Interconnection (2000 MW). The Eastern Interconnection will respond with 3 times the MW to 0.1 HZ frequency drop as will the Western Interconnection. The Eastern Interconnection is approximately 6 times larger than the Western, so this is expected.

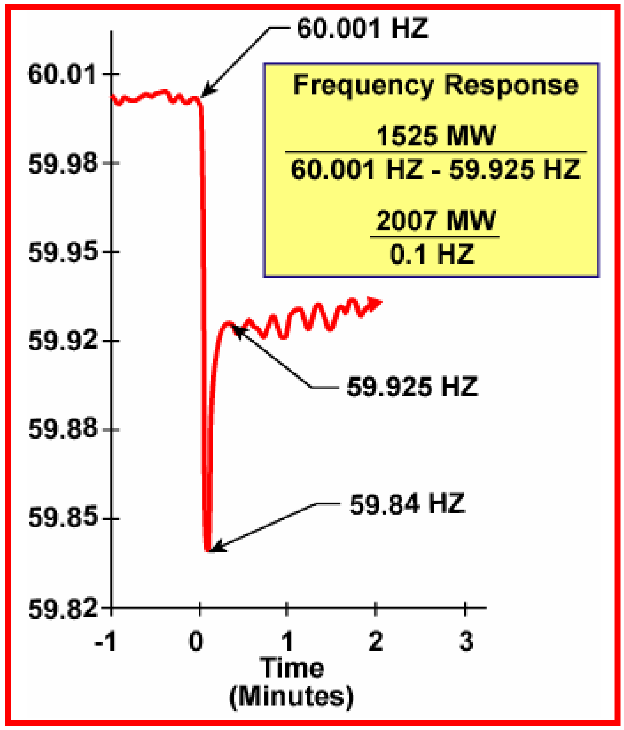
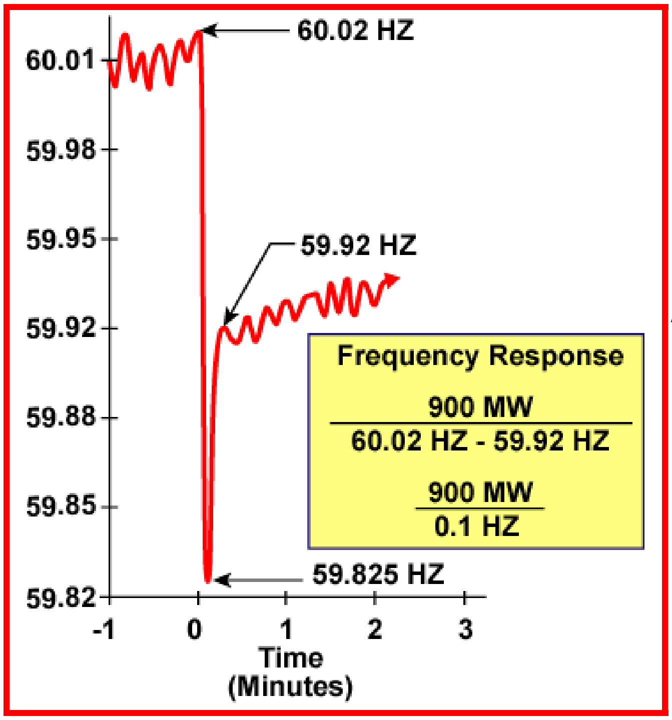


Figure 4-27
Western Interconnection

Figure 4-28 illustrates a typical frequency response of the ERCOT Interconnection. Notice how only a 900 MW loss leads to a rather large frequency deviation. The ERCOT Interconnection is a small Interconnection when compared to either the Eastern or the Western. ERCOT utilities expect large frequency deviations when major generation is lost and they design and maintain their power systems accordingly. The FRC for the ERCOT Interconnection as calculated in Figure 4-28 is 900 MW/0.1 HZ.



The ERCOT Interconnection is a relatively small Interconnection. That is why a 720 MW loss causes such a large frequency deviation. If 720 MW were lost in the ERCOT Interconnection, frequency would likely stabilize at approximately 59.9 HZ following governor response.

Figure 4-28
ERCOT Interconnection

The ERCOT Interconnection is a relatively small Interconnection. That is why a 900 MW loss causes such a large frequency deviation. If 900 MW were lost in the ERCOT Interconnection, frequency would likely stabilize at approximately 59.9 HZ following governor response.

Frequency Bias

The FRC for a control area (a control area is a physical division of a power system) is an important measure of that areas response to a disturbance. An estimate of the FRC (the symbol for the FRC is the Greek letter β) for a control area is an important setting for the automatic generation control (AGC) system of the control area. The term frequency bias or symbol "B" is used when referring to a control area's estimate of their FRC. The correct use and importance of the frequency bias term is described in greater detail in Section 4.3.

4.2.10 Response to a Loss of Generation

When power systems experience frequency deviations, all of the interconnected power system will respond. The magnitude of the responses by the different systems within the Interconnection will depend on their respective FRC and on their location in relation to the source of the frequency disturbance. This means that when a frequency disturbance occurs within an Interconnection, generators throughout the Interconnection will respond.

Section 4.10 describes the system response to a generator loss in greater detail.

The farther (in electrical distance or Ω's) a generator is from a disturbance, the less it will initially respond. A generator in Florida would initially see a large frequency change if a large neighboring Florida unit tripped and would initially respond with a large output change. If a large unit in North Dakota were suddenly lost, that same unit in Florida would also respond with an increase in MW output. However, the initial response would not be as large as the electrical distance is much greater and the Florida unit would not initially see as large of a frequency decline.

The rock in the pond analogy is also similar to a power system frequency disturbance in that it takes time for the waves to propagate throughout the pond. In the same manner, when a generator is lost in the power system it takes several seconds for all the utilities in a large Interconnection to see their maximum frequency disturbance.

One way to visualize frequency disturbances in the interconnected power system is to think of an interconnected power system as a smooth pond. When a frequency disturbance occurs it is equivalent to tossing a rock into the pond. The larger the waves in the pond, the greater the frequency disturbance. Further away from the point where the rock initially struck the pond the waves slowly melt away.

Frequency disturbances damp out in the same manner. The farther away from the disturbance location, the smaller initial frequency change will be. Eventually, after all the interconnected units in the power system have responded, the system will resume operating at a common frequency. This may take 10 to 20 seconds.

4.2.11 Limitations to Governor Response

Governors are not designed nor is it intended that they perform perfect frequency control. Limitations to governor control, both intentional and unintentional, include:

- Spinning Reserve
- Mismatch Size
- Governor Deadband
- Type of Generating Unit
- Boiler Control Modes
- Blocked Governors

Spinning Reserve

If a governor is to move a unit down along its droop curve in response to a frequency drop, it can only do so if the generator has unused MW capability. This unused MW capability is generally referred to as spinning reserve capability. Spinning reserve is the difference between the current output level of the synchronized generator and the maximum sustainable output level of the unit. A generator can have a perfectly tuned governor, but if the unit is not carrying any spinning reserve it will not respond when frequency drops.

A generator may be carrying a large amount of spinning reserve and still not adequately respond to governor commands. Not all spinning reserve is necessarily responsive to governor commands. That portion of the spinning reserve that is responsive to governor commands is called the unit's responsive spinning reserve. In general, the responsive spinning reserve attributable to a generator should be responsive to governor commands and fully available within a few (possibly 15) seconds.

Section 4.4 will describe the types of reserves in greater detail.

A large portion of the spinning reserve carried in hydro units is often responsive spinning reserve. In general, hydro units can respond and sustain large MW response due to their large stored energy reserves. Depending on the size and type of hydro unit, ramp rates of 100's of MW can be accomplished in a few seconds.

The nature of the energy conversion process in a steam unit often limits the responsive spinning reserve to only a fraction of the available spinning reserve. Boiler temperatures and pressures must be maintained within certain limits in a steam unit. These limitations restrict the maximum ramp rates allowed from the unit. The maximum response that can be delivered by a steam unit is approximately 10% of the unit's remaining capability in 15 seconds. For example, a steam unit with a 500 MW rating that is currently generating 300 MW, could possibly deliver (and sustain) 20 MW within 15 seconds in response to governor commands.

It makes no sense to allow a steam unit to over-respond to a frequency disturbance if the consequences include loss of the unit due to boiler troubles. However, preventing unit response due to concerns with the unit boiler-turbine reduces the frequency response of the entire Interconnection. A compromise must be reached wherein the power system's need for rapid frequency response is balanced with the needs of the individual generators.

Size of Mismatch

The size of mismatch refers to the percent mismatch between generation and load that causes a frequency disturbance. The larger the percent mismatch, the greater the frequency deviation. For example, the loss of a 100 MW unit in an Interconnection the size of the Eastern Interconnection (≈900,000 MW peak) is barely noticeable on frequency strip charts. Perhaps the frequency will drop by 0.002 HZ. However, the loss of a 100 MW unit in an Interconnection such as Alaska (≈1000 MW peak) could result in a severe frequency reduction (as low as 59 HZ) and possible system break-up if remedial actions such as underfrequency load shedding are not taken.

Underfrequency load shedding will be addressed in Section 4.8.

Governor response can only arrest the frequency deviation if sufficient capacity under governor control is readily available. If there is too little responsive spinning reserve capacity available or if the time delay to deliver this capacity is too long, governor response alone may not be enough to arrest the frequency deviation. More drastic measures, such as underfrequency load shedding, may be required.

The smaller the Interconnection, the more likely governor response will be inadequate and other, more drastic actions will be taken. The Eastern Interconnection is so large that it is highly unlikely a single contingency loss of generation could lead to an unrecoverable frequency depression. The Alaskan Interconnection, on the other hand, is so small that underfrequency load shedding is routinely used to respond to first contingency generation losses.

Governor Deadband

A control system (such as a governor) maintains a designated variable close to a target value based on a series of measured inputs. There is a certain “dead” area around the target value that the control system does not function within. So instead of a target value, a control system actually maintains a target range. For example, if the controlled variable is frequency, instead of maintaining exactly 60 HZ, a governor control system may maintain frequency within a band of 60.03 HZ to 59.97 HZ. The inactive range around the target value is called the deadband. In our example of a governor holding frequency within a range of 59.97 HZ to 60.03 HZ, the target value is 60.00 HZ and the deadband is ±0.03 HZ.

In older mechanical governor systems, deadband was impossible to eliminate. Friction between moving parts resulted in deadband whether it was desired or not. In newer mechanical and electronic governor systems, deadband can be largely eliminated if so desired. However, in practice some deadband is desired.

The governor’s role is to arrest frequency deviations, not to control frequency within a narrow range of 60 HZ. Other control systems are available to keep frequency within a narrow band of 60 HZ. If governor deadband were eliminated, the governor would be constantly directing the generator to chase minor frequency deviations. Generator components would suffer excess wear for no good reason. Power oscillations could develop as the governor sends the generator conflicting signals in a bid to correct minor frequency oscillations. Power oscillations could also develop between neighboring generators as both try to keep their own, unequal, versions of 60 HZ.

The IEEE (an industry standards organization) and NERC recommend a deadband of 0.036 HZ for governor control systems. By looking closely at plots of frequency disturbances in the interconnected systems, one would note that the “tail” to the frequency trace is normally not visible until the frequency deviation is larger than approximately .03 HZ. This is evidence of an industry practice to set effective governor deadbands in the neighborhood of 0.03 to 0.04 HZ.

Type of Unit

The type of unit (hydro, steam, combustion turbine) has a direct bearing on governor response. While the governor control systems used on different units may be identical, what is more important is the MW response from the unit. If the unit cannot deliver what is asked of it by the governor, it is of less value to the system for frequency control.

Hydro

Hydro units are, in general very responsive to governor commands as they may store a great deal of energy in their storage reservoirs. Depending on the size and type of hydro unit, response rates of 100's of MW can be achieved in a few seconds. Not all hydro units respond well. Those with long penstocks may respond poorly to large frequency deviations due to turbulence in the incoming water.

The penstock delivers the water to the hydro turbine

Combustion Turbine

Depending on the design of the combustion turbine, the unit may or may not be responsive to governor commands. On those systems dependent on combustion turbines for a large part of their generation, difficulties have been encountered with respect to the combustion turbine maintaining their initial governor response. These difficulties center around the reduced compressor output during low frequency conditions.

Steam

Steam units make up the majority of system generators. The governor response of steam units varies from very poor to very good depending on the type of steam unit. The initial governor response from a steam unit is from stored steam. This initial response may be quite fast. The difficulty may be in sustaining this initial response.

Approximately 30% of a generators output power is developed in the high pressure turbine of a typical steam unit. The remaining 70% is developed in the lower pressure stages. The high pressure turbine is very responsive to governor commands as the governor typically directly controls the high pressure turbine control valve. The lower pressure stages are only indirectly controlled by the governor. The lower pressure stages are fed steam via a reheat cycle of the boiler. This adds several seconds of time delay from an initial call for MW from a governor until the generator can actually deliver the majority of its MW response.

Coal Fired Steam Units

Coal fired steam units are capable of strong governor response. A well tuned coal fired unit may respond with 10% of its remaining capability within 10 seconds following a frequency disturbance. The actual response of a coal fired unit will depend on the specifics of the boiler-turbine. For example, units with a drum type boiler have significant steam storage and this steam can be used for rapid, sustained, governor response. In contrast supercritical (once through type) boilers have little steam storage and, in general, cannot sustain a significant governor response.

Nuclear Steam Units

Nuclear units are capable of governor response much the same as coal fired units. Pressurized water reactors being more capable than boiling water reactors. However, nuclear units are often operated at full licensed output. Given a frequency depression, nuclear unit governors are often blocked (see below) to prevent further valve opening and MW response. This is not to infer that all nuclear units have blocked governors. Some utilities are very dependent on nuclear powered generation and achieve satisfactory governor response with their nuclear units.

Blocked Governors

All governor response can be prevented. By adjusting the generator's controls, a generator operator can intentionally prevent the unit from responding to a frequency disturbance. This is called blocking a governor. For example, nuclear units are often operated at their maximum licensed output. The nuclear operating company may choose to prevent steam valves from opening further in response to a frequency decline. In effect, the nuclear plant operator has blocked the governors response to a frequency drop.

4.3 Automatic Generation Control (AGC)

4.3.1 Introduction to Automatic Generation Control

As described in Section 4.1, generation must be matched to load or frequency deviations will occur. Governors on generators are used to adjust the output of the generator in response to frequency deviations resulting from generation/load mismatches. The governors are assisted by system inertia and the load-frequency relationship but all of these actions together will not maintain a constant system frequency.

Governor control does not provide adequate frequency regulation for several reasons including:

- Governors do not return frequency to the scheduled value (normally 60 HZ) due to the required % droop characteristic of interconnected system generator governors.
- Governor control does not adequately consider the cost of power production so control with governors alone is not the most economical alternative.
- Governor control is intended as a primary means of frequency control. As such governor control is course and not suited to fine adjustment of the interconnected system frequency

Therefore, another form of control system is required to balance generation to load and maintain a constant system frequency. This other control system is the automatic generation control (AGC). While governors control individual generators, AGC systems simultaneously control many governors to balance generation to load.

The first AGC system was implemented by an east coast utility in 1927.

An AGC system operates at a much higher level of control than a governor. Where a governor control system monitors and controls only one generator, an AGC system monitors a section of the power system, known as a control area, and controls multiple generators. Governor control is often referred to as primary frequency control while AGC is referred to as secondary frequency control.

Recall from Section 4.2 how a governor arrests changes in generator frequency, and how the governor is not typically used to restore frequency to 60 HZ. Remember how frequency is restored by adjusting the load reference set-point of the governors. AGC is the control system that normally makes these important set-point adjustments. With control over the load reference set-points of the generators, AGC matches its Control Area’s generation to load and maintains frequency.

Power plant operators can also adjust governor set-points. The mechanism for adjusting set-points is commonly called a “speed changer”.

4.3.2 Control Areas

Description of a Control Area

A control area is a part of an interconnected power system which is responsible for meeting its own load. Each control area operates an AGC system to balance its generation resources to its load requirements. The generation resources may be internal or purchased from other control areas and transferred over tie-lines between control areas. Similarly, load requirements may include internal customer load, losses, or scheduled sales to other control areas.

Figure 4-29 illustrates a simple interconnected power system with five control areas. Each of the control areas in this power system must achieve a 60 HZ balance between the power supplied and the power consumed. Normally, control areas achieve this balance with the help of power sales and purchases using the tie-lines between the control areas. These transactions are normally scheduled in advance based on forecast load, the cost and availability of on-line generation, and the ATC available on the tie-lines.

In real-time operation, control areas are responsible for ensuring that the actual flows on their connecting tie-lines are as intended or as scheduled. Any difference between actual and scheduled net tie-line flows indicates an imbalance or error with respect to generation levels in the control area. Some of this difference or error is desired and represents a part of the control area's contribution to system wide frequency regulation.

Each control area operates an AGC system to balance its total generation resources (including energy purchases) to its total load (including energy sales and system losses). The AGC system monitors power system conditions within the control area including generation supply, load demand, losses, sales, purchases, and system frequency. The AGC system analyzes all this data and computes a control error.

This figure illustrates five control areas. The control area in the middle is shown in detail while the other four are just labeled. Each control area will monitor frequency and their tie-line flows to other control areas. Note the meters on the tie-lines. The meters are necessary to monitor actual tie-line MW flows.

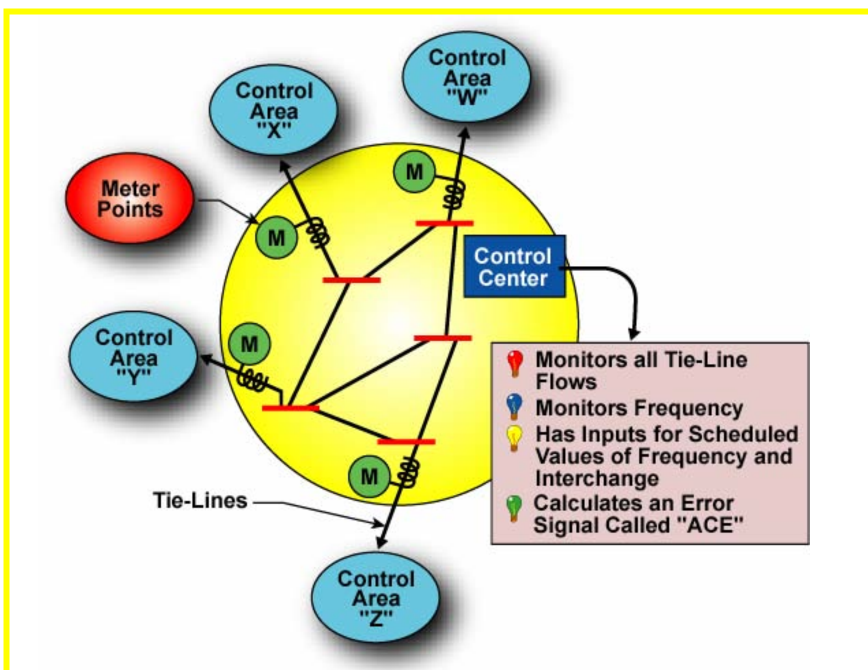


Figure 4-29
Definition of a Control Area

The control error is called the ACE (area control error) signal. ACE represents the discrepancy between the generation supply and total MW obligations of the control area. On the basis of the ACE signal, the AGC system will send signals or pulses to selected generating units within its control area to tell the generators what generation levels to hold (adjust their set-points).

It is not necessary for the AGC system to regulate the output of all the generators in a control area. Most control areas have policies which require that as many units as needed should be on control and able to respond to the control area's continual load changes. Those units that receive and respond to AGC signals are called regulating units.

The number of units that receive AGC signals (pulses) may vary from a few for a small control area to 40-50 for the largest of control areas.

Metering of Control Area Boundaries

Note the MW flow meters illustrated in Figure 4-29. Tie-line metering is required on all transmission lines interconnecting control areas. The metered data from all of a control area's tie-lines or Interconnections are summed together to equal the net MW flow out of or into a control area.

Neighboring control areas, that share tie-lines, should also share the same metered data. It is important that control areas receive identical data concerning actual MW flows on interconnecting tie-lines. The location of the meter is also significant. Tie-line losses may be split between adjacent control areas depending on the location of the meter.

Metering of control area boundaries can get complicated. An important point is that control areas do not have to be contiguous areas. For example, a control area can be formed of many small pieces spread over a large physical area. There are large control areas (1000's of MW) with only a few metered tie-lines. There are also control areas with hundreds of metered tie-lines.

The Control Center

The control center is the headquarters of the control area. The intelligence (digital computer) of the AGC system is typically located in the control center. All the data collected by the AGC system is processed in the control center. Based on the gathered data, the AGC signals are transmitted from the control center to the various generators currently receiving AGC control signals.

Summary of the Duties of a Control Area

The AGC related duties of a control area can be summarized in two statements:

1. To ensure that the sum of the actual MW flows on all tie-lines with neighboring control areas are as intended or as scheduled.

2. To assist all the other control areas in the Interconnection with the maintenance of a relatively constant system frequency.

If every control area in an Interconnection performs these two duties the Interconnection should experience acceptable frequency control.

NERC Control Areas

As described in Chapter 2 of this text, there are four major Interconnections in NERC. Each Interconnection in turn is composed of control areas. Every generator, every load, every piece of the transmission system must reside within the metered boundaries of a control area.

The Eastern Interconnection is composed of approximately 100 control areas. These control areas range in load size from over 60,000 MW peaks to control areas that serve no load but simply use their generation for meeting interchange responsibilities. The Western Interconnection is composed of approximately 25 control areas with a distribution similar to the Eastern Interconnection.

The ERCOT and Hydro Quebec Interconnections are each operated as single control areas. Hydro Quebec has long operated as a single control area while the ERCOT Interconnection implemented single control operation in 2001.

4.3.3 Types of Interchange

There will typically be multiple tie-lines connecting a control area to one or more other control areas. With respect to the operation of an AGC system, the individual tie-line flows are not important. What is important is the total or net flow on all the control area's tie-lines.

The net tie-line flow or interchange of a control area is the difference between the power flowing out of the control area and the power flowing into the control area. When power flow is out of a control area, it is normally referred to as positive (+) tie-line flow or positive (+) interchange. When power flow is into a control area, it is normally referred to as negative (-) tie-line flow or negative (-) interchange.

The net tie-line flow or net interchange for a control area is the sum of all the tie-line flows into and out of the control area. For example, if net interchange is +100 MW, overall a control area is sending 100 MW out to all other control areas. If net interchange is -100 MW, overall the control area is importing 100 MW from all other control areas.

Figure 4-30 illustrates three control areas with each control area connected to the others by two tie-lines. The actual MW flows on the tie-lines are given in the figure. There are three types of interchange - actual, scheduled, and inadvertent. Figure 4-30 is used to illustrate these three types of interchange.

The MW flows shown are actual interchange flows.

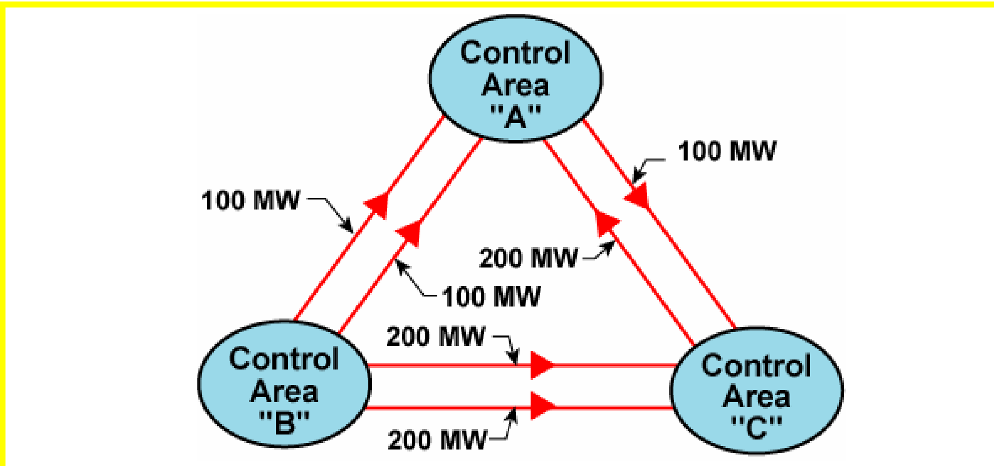


Figure 4-30
Control Area Interchange

Actual Net Interchange

Actual net interchange is the sum of the actual MW flows on the tie-lines. For a control area, it is the summation of the actual flows into and out of the control area on all tie-lines connecting the control area to other control areas. The actual net interchange for the three control areas in Figure 4-30 are as follows:

To compute these numbers you must remember that interchange out of a control area is positive and interchange in is negative.

- Control Area "A" -300 MW
- Control Area "B" +600 MW
- Control Area "C" -300 MW

Notice that the sum of the actual net interchange for the three control areas illustrated in Figure 4-30 is zero. The sum of the actual net interchange should always equal zero for an Interconnection. Whatever is sent out by one control area must be received by another.

Scheduled Net Interchange

Scheduled interchange is the interchange flow that a control area intends. For example, if control area “A” sends 500 MW to control area “B”, there exists a scheduled interchange from control area “A” to “B” of 500 MW. Scheduled net interchange for a control area is the summation of all scheduled sales and purchases to all other interconnected control areas. Sales would be a positive scheduled interchange while purchases would be a negative scheduled interchange.

Actual net interchange is seldom exactly equal to the scheduled net interchange. For example, if generation exceeds demand, the control area will over-generate and excess MW will flow out of the area. Actual net interchange will then be greater than scheduled. Similarly, if the control area under-generates, MW will flow into the area and actual net interchange will be less than scheduled.

Inadvertent Net Interchange

Inadvertent net interchange is the difference between actual net interchange and scheduled net interchange. For example, if a control area schedules 100 MW to flow across tie-lines and only 90 MW actually flows, then there is an inadvertent flow of -10 MW (90-100) on the tie-lines.

Consider control area “A” in Figure 4-31. Assume control area “A” schedules 500 MW to control area “B” but only 400 MW actually flows. Control area “A” has a net inadvertent flow of 400 - 500 = -100 MW. Control area “B” would have a net inadvertent flow of -400 - (-500) = +100 MW.

This inadvertent flow is created because control area “A” is under-generating by 100 MW and control area “B” is over-generating by 100 MW.

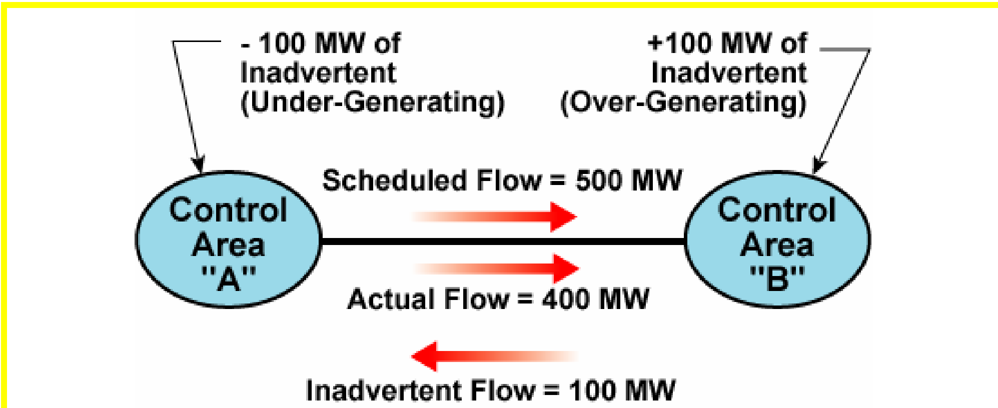


Figure 4-31
Inadvertent Interchange

Accumulated Inadvertent Interchange

Accumulated inadvertent interchange is the amount of inadvertent that flows over time. If, as shown in Figure 4-31, 100 MW of inadvertent flows for an hour, control area “A” would accumulate -100 MWh of inadvertent interchange and control area “B” would accumulate +100 MWh of inadvertent interchange. If the 100 MW of inadvertent only flowed for 30 minutes, control area “A” would accumulate -50 MWh of inadvertent and control area “B” would accumulate +50 MWh.

Control areas cannot operate with constant perfect matches between generation and load. There will typically be some error or inadvertent flow created. What is expected is that over the course of a daily load cycle a control area will over-generate approximately ½ the time and under- generate approximately ½ the time. The positive net inadvertent produced when over-generating should then cancel the negative net inadvertent produced while under-generating. This match between positive and negative net inadvertent does not always occur but in general control areas do a good job of minimizing their net inadvertent flows.

Inadvertent flow is an indication of an imbalance between generation and load in a control area. If the net inadvertent is positive, the system has been over-generating. If the net inadvertent is negative, the system has been under-generating. When a control area has a net inadvertent flow on its tie-lines it may be a signal that there is a difference between power supplied and used. The control area’s AGC system may respond by changing the set-points of the generators on AGC control.

The AGC system and the system operator work to minimize inadvertent interchange. However, even with the AGC system functioning as expected and the system operator doing their best, inadvertent power flows will occur. Over a period of time, a control area may accumulate a considerable amount of net inadvertent, either positive or negative. As net inadvertent represents a mismatch in the interchange of power between control areas, control areas may make special arrangements with each other to reduce their accumulated inadvertent.

The size of a control area’s accumulated inadvertent account is not a good judge of the performance of a control area. Accumulated inadvertent accounts can grow large from responding to other control areas’ poor operations.

When disturbances occur on an interconnected power system, inadvertent interchanges will occur. Power will automatically flow between control areas to supply deficiencies. For example, if in Figure 4-31 control area “B” loses a generator, the generating units in control area “A” would rapidly increase their output and increase actual power flow from control area “A” to control area “B” on the tie-line. This would change the inadvertent flow on the tie-line between the two control areas.

A control areas accumulated inadvertent can be viewed as composed of two components; primary or unintentional inadvertent and secondary or intentional inadvertent. Intentional inadvertent results from a control areas support to external generation/load mismatches. The largest component of intentional inadvertent is due to governor response. Unintentional inadvertent results from internal scheduling errors, metering errors, or failures to keep up with load changes.

The first AGC systems were installed in the mid 1920's and were limited to simple frequency control.

4.3.4 Function of an AGC System

The function of an AGC system is most easily understood in relation to an isolated power system. In an isolated power system, the output of all the generators should ideally equal the total internal system load (including sales and system losses) with the frequency at 60 HZ. The main function of an AGC system in an isolated system is to maintain a 60 HZ balance of the following equation:

$$\boxed{\text{Generation} = \text{Internal System Load} + \text{Internal Losses}}$$

Any difference between generation and load would cause the AGC system to develop and send control signals to selected generators to adjust their MW output. These control signals would be used to adjust the load reference set-points of the generators. If generation in the isolated system was greater than load, the AGC system would call for a decrease in generation. If generation was less than load, the AGC system would call for an increase in generation.

Actual power systems, however, are normally not isolated. They are interconnected with many other systems. The tie-lines between the different control areas allow power to flow between each and enable the system participants to buy and sell energy between one another. In an interconnected power system with multiple control areas, the AGC systems must do more than just match internal generating resources to internal load and losses. AGC must also take into account the power flows that occur back and forth between control areas over the interconnecting tie-lines. An AGC system in a control area must therefore maintain a 60 HZ balance of the following equation:

$$\boxed{\begin{aligned}\text{Generation} = {} & \text{Internal System Load} + \\ & \text{Internal Losses} + \\ & \text{Net Scheduled Interchange}\end{aligned}}$$

The new term in the above equation, net scheduled interchange, is the sum of the scheduled or intended MW flow on all the tie-lines between the control area in which this AGC system is located and all adjacent control areas. The addition of the net scheduled interchange term greatly affects the operation and complexity of an AGC system.

Since power systems are interconnected, it might appear that one AGC system could be used to control the frequency of the entire Interconnection to the desired 60 HZ value, without the need to measure and control power flows between control areas. This is not always feasible, however, due to the sheer size of some interconnected power systems and the fact that utilities often desire control over the operation of their own generating units and transmission system. Instead, the larger interconnected power systems are broken down into smaller sections (control areas) in which individual AGC systems can function.

4.3.5 Components of an AGC System

Figure 4-32 illustrates the basic components of a control area's AGC system. In order for an AGC system to perform its designed function it must be able to continuously determine a system frequency error and a net interchange error. Both of these errors are summed to form the control area's ACE (area control error) value. The ACE value is then distributed to various generators under AGC control.

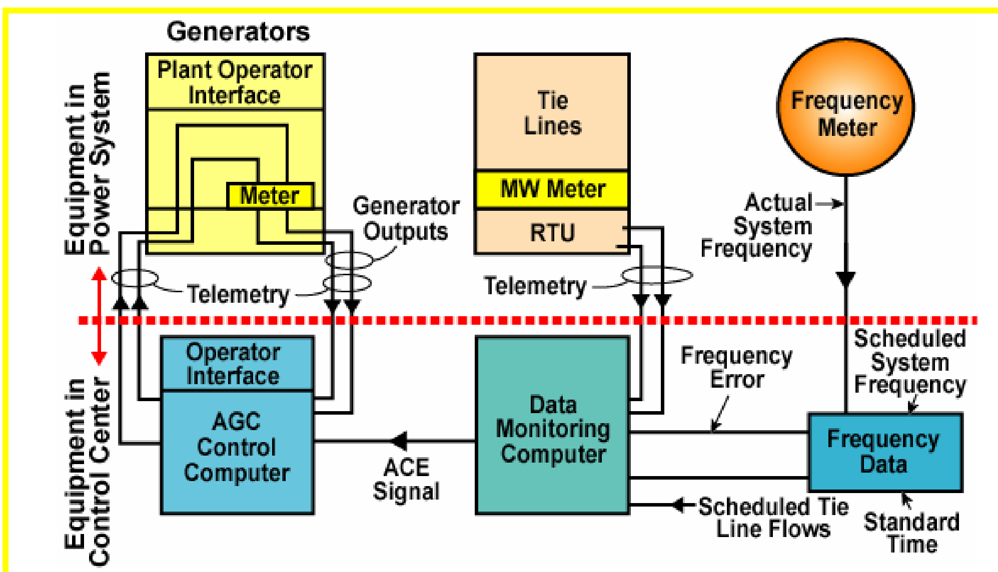


Figure 4-32
Components of an AGC System

The standard time input is a feature of time error control. Time error control is described in Section 4.5.

An AGC system has components in the control center and in the power system. The control center components include the computer equipment that both calculates the ACE signal and distributes the signal to controlled generators. The AGC equipment in the power system includes AGC consoles at controlled generators, frequency meters and tie-line meters. All of the AGC data is transmitted via telemetry.

Figure 4-32 illustrates the following basic components of an AGC system:

- A frequency meter is used to gather actual system frequency data. This data is compared to a scheduled value of frequency (for instance, 60 HZ) and a frequency error is determined and sent to the data monitoring computer.
- The system operators enter scheduled net interchange data into the data monitoring computer. Actual interchange data is gathered from all the control area tie-line meters. Telemetry channels are used to gather the interchange data from remote locations in the transmission system. The actual interchange is compared to the scheduled interchange and a net interchange error value is calculated in the data monitoring computer.
- The data monitoring computer uses the frequency error and the net interchange error to compute an ACE value.
- The AGC control computer distributes the ACE signal to the controlled generators. This can be a complicated process. Not only must the ACE signal be distributed to the proper generators but the results of past ACE signal distributions must be checked to be sure the generators are moving in the direction AGC has sent them.

The process illustrated in Figure 4-32 is continuous. A new ACE signal may be calculated and new set-points distributed to controlled generators every few (2-4) seconds.

4.3.6 Modes of AGC Control

In order to operate within an interconnected power system, each control area must have an AGC system that satisfies the following requirements:

In contrast to AGC, the generator governors in neighboring control areas will initially respond to each other's frequency swings. This is proper operation for governors.

- Each AGC system should control enough generating capacity to supply the control area's loads, losses, and scheduled interchange and also assist the Interconnection with maintaining a constant 60 HZ Interconnection frequency.
- Each AGC system should operate in such a manner that it does not normally cause generation changes and/or respond to normal generation changes in neighboring control areas.
- Each AGC system will maintain the actual net interchange for its control area within a close range of the scheduled interchange.

There are three control modes for AGC operation, namely:

1. Constant Frequency Control (also called Flat Frequency Control)

2. Constant Net Interchange Control (also called Flat Tie-Line Control)

3. Tie-Line Bias Control

In this section, the first two modes of AGC control are only briefly described. These modes, constant frequency and constant net interchange, are rarely used in most Interconnections. We will concentrate on the third and most common mode of AGC control, tie-line bias.

Constant Frequency Control

In constant frequency control, the AGC system monitors only frequency. If frequency deviates from 60 HZ, the AGC system will adjust the load reference set-points of the governors on the generators under AGC control to return the frequency to 60 HZ.

Constant frequency control (CFC) is the normal mode of AGC operation if the Interconnection has only one control area. For example, the ERCOT and Hydro Quebec Interconnections use a form of CFC. However, CFC is seldom used in an Interconnection composed of multiple control areas.

Constant frequency control is different than isochronous governor control. Constant frequency control is AGC control of the governor set-points to maintain frequency. Isochronous governor control is direct control of frequency by the unit governors.

If a control area in a multiple control area Interconnection uses constant frequency control, the AGC system will respond to frequency excursions caused by other control areas. This is not normally acceptable. An AGC system should only respond to events within its own control area. Constant frequency control is not normally used in a multiple control area power system. If two or more control areas tried to control frequency this could result in erratic operation and power swings between the control areas.

Constant Net Interchange Control

In constant net interchange control, the AGC system monitors only the tie-lines connecting a control area to neighboring control areas. If the actual interchange flows deviate from the scheduled values, the AGC system will adjust generation until the flows are returned to scheduled values.

A serious problem with constant net interchange control is that frequency control is ignored. A control area on constant net interchange AGC could end up backing off generation to correct tie-line flows while Interconnection frequency is below 60 HZ. An overriding goal should always be the maintenance of system frequency, and constant net interchange control does not always satisfy this goal.

Tie-line bias control has many advantages over other modes of AGC control. NERC Operating Policies specify that all control areas should use tie-line bias control unless they have a strong reason not to.

Constant net interchange control may be used by control areas during certain emergency conditions. For example, if a control area loses its AGC frequency source, that control area can temporarily use constant net interchange control.

Tie-Line Bias Control

Tie-line bias control is the preferred method of AGC system operation in multiple control area systems. When a control area uses tie-line bias control, its AGC system will not be affected by, or interfere with, the operations of neighboring control areas. Under tie-line bias control, once governor control has arrested the initial frequency deviation, the AGC system in the control area where the disturbance occurred will assume the task of returning frequency to the desired 60 HZ. Neighboring control areas will adjust their generator set-points only if requested to do so by the deficient control area.

When an AGC system is in tie-line bias control mode, the AGC system responds to both frequency and tie-line flow errors. An AGC system in tie-line bias control mode is capable of maintaining a match between actual and scheduled tie-line flows while at the same time assisting the Interconnection with frequency control. Tie-line bias control is actually a combination of constant frequency and constant net interchange control.

We will further describe the use of tie-line bias control as this section progresses. Figure 4-33 summarizes the three possible modes of AGC control.

Note that an ACE signal is developed no matter which mode of AGC a control area is operating in. The ACE for constant frequency is based on the frequency error. The ACE for constant net interchange is based on the interchange error. The ACE for tie-line bias is a combination of the frequency and interchange errors.

AGC Control Method	ACE Signal
Constant Frequency	Frequency Error Only
Constant Net Interchange	Interchange Error Only
Tie-Line Frequency Bias	Combination of Frequency And Interchange Error

Figure 4-33
Summary of Modes of AGC Control

4.3.7 Tie-Line Bias Control

The ACE Equation for Tie-Line Bias Control

In tie-line bias control, an area control error (ACE) signal is calculated based on the differences between scheduled and actual frequency and between scheduled and actual tie-line flows. ACE for tie-line bias control is defined as:

If the ACE equation is negative, the control area is deficient in generation. If the ACE equation is positive, the control area has an oversupply of generation.

$$\boxed{\begin{aligned}\text{ACE} = {} & \left[\text{Actual Net Interchange} - \text{Scheduled Net Interchange}\right] \\ & - \left[(10 \times \text{B}) \times (\text{Actual Frequency} - \text{Scheduled Frequency})\right]\end{aligned}}$$

The first part of the equation, [actual net interchange - scheduled net interchange], is the ACE equation for constant net interchange control. A portion of the second part of the equation, (actual frequency – scheduled frequency), is the ACE equation for constant frequency control. The whole equation is the ACE equation for tie-line bias control.

Frequency Bias Constant (B)

All of the terms in the above ACE equation should be clear with the possible exception of the frequency bias constant, “B”. The frequency bias constant is an estimate of the frequency response of the control area. As described in Section 4.2, the frequency response characteristic or FRC of a power system is the natural response of the power system to changes in system frequency. This natural response is caused by the unique governor, load, and system characteristics of the respective power system.

A control area’s frequency bias value should be based on their FRC. The frequency bias term is included in the ACE equation to allow for the natural response of the control area to frequency excursions. The addition of the frequency bias term also converts the frequency error signal to MW from HZ. (“B” is in units of MW/0.1 HZ, and is a negative number). Note that in the ACE equation “B” is multiplied by 10. This is because the frequency deviation (actual frequency – scheduled frequency) is a deviation in HZ while “B” gives the MW response per tenth of a HZ. The product (10 x B) is the MW response per HZ.

NERC defines the bias term (B) as a negative number.

Calculating the Frequency Bias Constant (B)

“B” values for NERC control areas range from a low of 1 to a high of over 700.

The frequency bias setting should be based on the actual control area FRC. Every control area should monitor power system frequency disturbances to determine what their respective frequency bias value is. At least once a year this value should be checked by analyzing actual system disturbances. The bias value within the AGC computer system should then be updated to reflect any needed changes.

Frequency bias values are reported yearly to NERC. The minimum value that can be reported is 1% of the control area's past year's peak load or peak generation.

Some control areas put a great deal of effort into calculating their bias value. Equations may be used that adjust bias based on the time of day, the size of the load, the size of the disturbance, or other factors. Within the NERC Interconnections several control areas have implemented a form of real time bias calculation. The frequency bias value is continually updated based on what generating units are on-line. This is an accurate way of computing bias as most of the bias is due to the governor response of on-line generators. The importance of the "B" term will become apparent as the use of the tie-line bias control method of AGC is examined.

This diagram illustrates tie-line bias control. The top portion of the figure is for determining the frequency error. The bottom portion determines the net interchange error. The frequency error is multiplied by the bias (B) value. The resultant MW number is compared to the net interchange error to determine an ACE value. The ACE value is then used to adjust control area generation. (The I_{ME} value accounts for known metering errors.)

Figure 4-34 is a graphical summary of the calculation of the ACE value using tie-line bias AGC control. Diagrams similar to Figure 4-34 are now used to illustrate the operation of a control area's use of tie-line bias control.

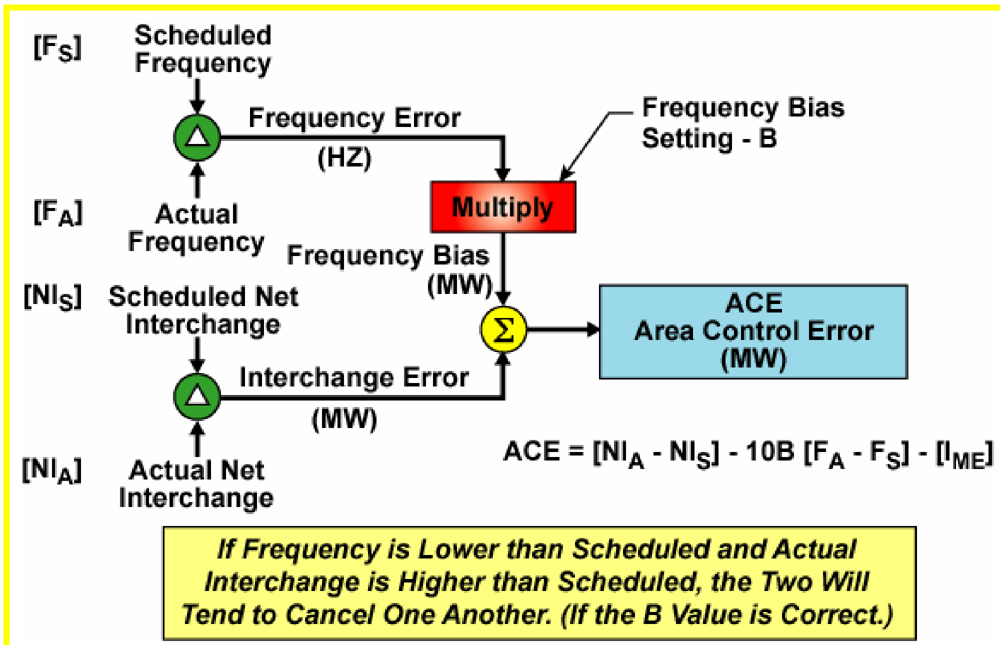


Figure 4-34
Tie-Line Bias Control ACE Calculation

Illustration of Tie-Line Bias Control Mode Operation

The use of the ACE equation in tie-line bias control is illustrated in Figures 4-35 and 4-36. Both figures illustrate the calculation of the ACE value within a control area following a generation loss. (In both of these examples, the I_{ME}—metering error—term is assumed to be 0 MW.) Figure 4-35 is for a generation loss external to the control area. Figure 4-36 is for a generation loss internal to the control area.

External Generation Loss

Figure 4-35 demonstrates how AGC operates when a generator is lost in the Interconnection. The lost generator is not in the illustrated control area but is in some other control area within the Interconnection. Every control area will see a frequency depression. In our example of Figure 4-35 the actual system frequency drops to 59.9 HZ.

The top portion of the figure illustrates how AGC will calculate the frequency error and multiply this error by the frequency bias value. The frequency error of -0.1 HZ when multiplied by the frequency bias value of -200 MW/0.1 HZ yields an expected MW response to the frequency disturbance of +200 MW. This +200 MW value is what the AGC system has calculated as the expected response of this control area to the disturbance.

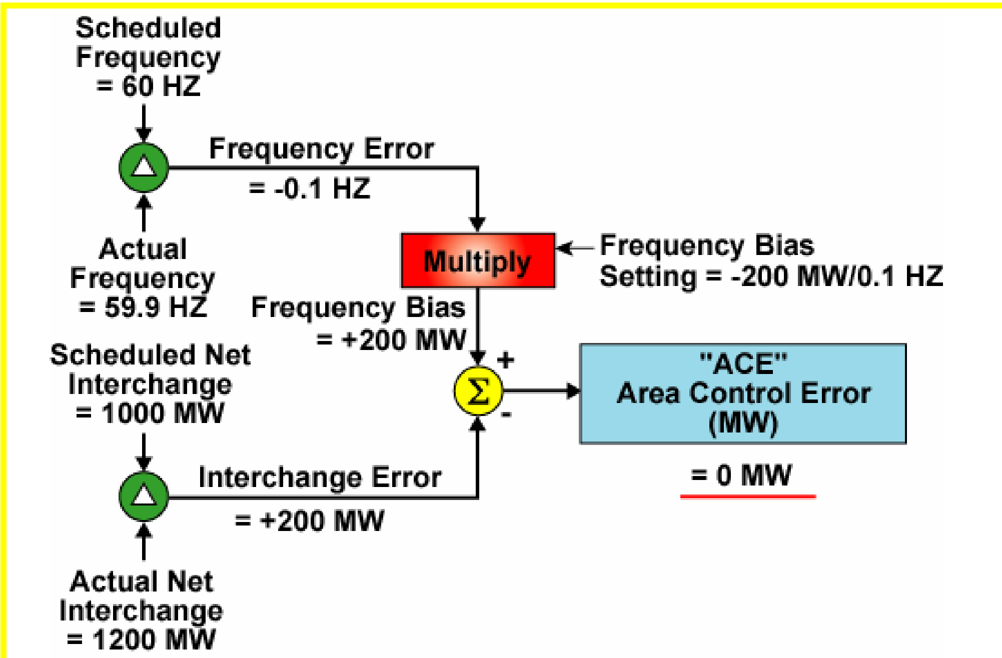


Figure 4-35
ACE for an External Generation Loss

When the disturbance is external and AGC works as intended no ACE value is developed.

The bottom portion of the figure illustrates how AGC calculates the actual response of this control area. Since any MW response to the disturbance must flow out over the tie-lines, the actual response is simply the difference between scheduled and actual tie-line flows. In Figure 4-35 the actual response is found by subtracting the scheduled interchange of 1000 MW from the actual interchange of 1200 MW. The actual is greater than scheduled by 200 MW so the actual response is +200 MW.

When ACE is zero the control area is responding exactly as expected. No generator governor set-point adjustments are needed.

The AGC system now compares the expected response to the actual response. The actual response is +200 MW and the expected +200 MW. Since actual is equal to expected, the error or ACE is equal to zero MW. When ACE is equal to zero it means that the response of the control area is exactly as intended. No adjustment to control area generation is required.

Internal Generation Loss

Figure 4-36 also illustrates the operation of tie-line bias AGC within a control area. This example assumes the same size generator is lost but now it is one of the illustrated control area's generators. This generation loss is internal to the control area. Every control area will again see a frequency depression to 59.9 HZ.

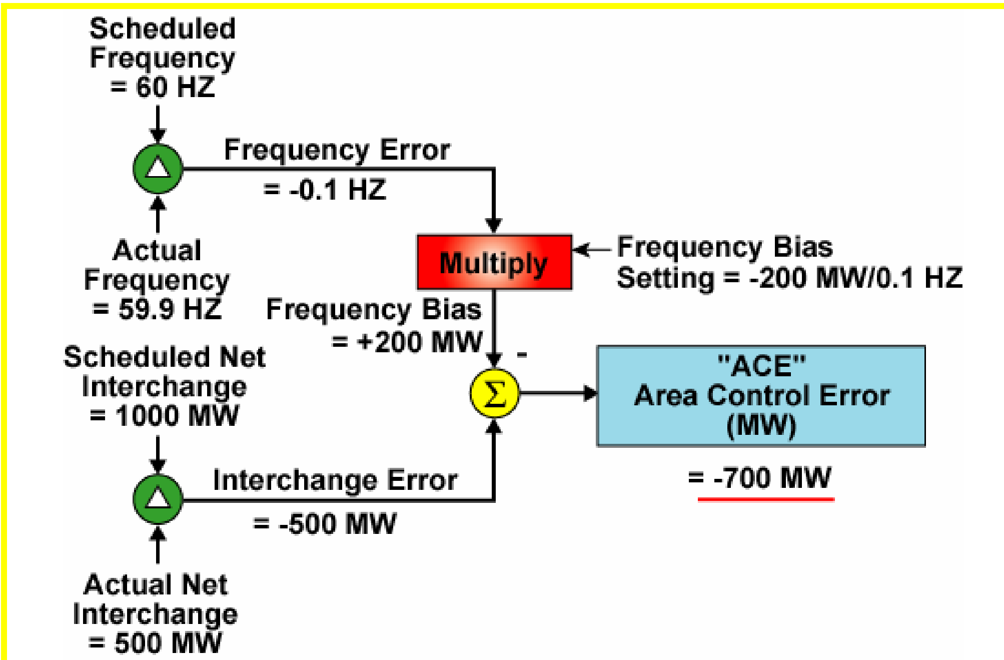


Figure 4-36
ACE for an Internal Generation Loss

The top portion of the figure works the same as in the previous example (Figure 4-35). The frequency error of 0.1 HZ when multiplied by the frequency bias value of -200 MW/0.1HZ yields an expected MW response to the frequency disturbance of +200 MW. The actual response is found by subtracting the scheduled interchange of 1000 MW from the actual interchange of 500 MW. The actual interchange is less than the scheduled interchange by 500 MW so the actual response is -500 MW.

The AGC system now compares the expected response to the actual response. The actual response is -500 MW and the expected +200 MW. The actual response is less than the expected response by 700 MW. The ACE is therefore equal to -700 MW. An ACE of -700 MW indicates that this control area is under generating by 700 MW. To reduce this ACE the generators in the control area under AGC control must have their set-points adjusted to increase MW output. As the generator outputs increase the ACE value will shrink towards zero.

4.3.8 Control Area Implementation of AGC

Figure 4-37 illustrates how a control area implements AGC. Notice that this control area uses tie-line bias control. The frequency error and interchange errors are first used to develop a raw ACE value. This raw ACE value may include telemetry errors and other factors that tend to make raw ACE data unusable. The solution is to modify the raw ACE data using filters. The signal that is actually used to drive the generator governor set-points is commonly called the filtered ACE.

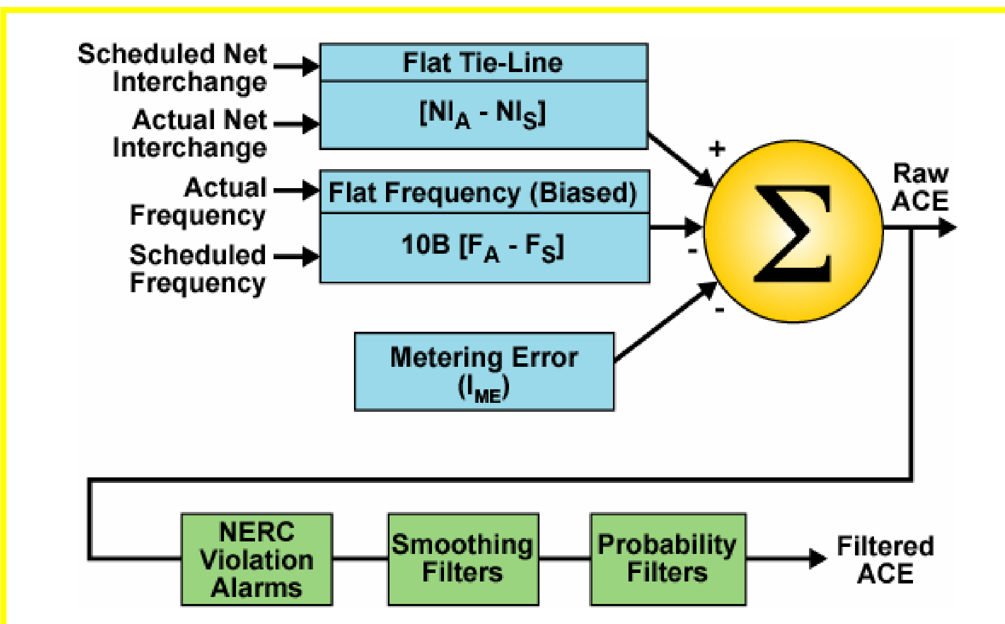


Figure 4-37
A Simple Model of a Control Area AGC System

This AGC system is programmed to automatically alarm if NERC control performance criteria are violated. NERC control performance criteria are addressed in Section 4.6.

Smoothing filters eliminate short term bumps in the ACE value. Probability filters attempt to guess where ACE is going.

Economic Dispatch

Our previous description of how the ACE signal is distributed to the units under AGC control was greatly simplified. The process by which generators are pulsed is actually complex. ACE signals are continually being sent to controlled generators. The AGC system must keep track of what signals have been sent and of where the generator is currently operating. Modern AGC systems are often capable of estimating where the generator will be pulsed in the future.

One important process that has been ignored to this point is the economic dispatch process. Economic dispatch is a process by which a control area attempts to minimize their overall cost of power production. The economic dispatch process is an important part of the AGC process for those companies that choose to implement it. In simple terms, the economic dispatch function is an added feature to AGC systems. Economic dispatch will determine the best economic operating points for controlled generators.

The best operating points are based on many factors including system security and minimizing the cost of power production. Base operating points (MW values) for generators will be determined and signals sent to the generators to move towards these base operating points. When an ACE signal is developed, the signal distribution to the generators will be based on which controlled units can produce the power required at the least cost.

Power systems define reserves in many different ways. The reserve descriptions used in this section are general. Your particular system may have different reserve definitions and policies.

4.4 Reserve Policies

Reserves are unused MW capability. The ability of a power system to control normal frequency deviations and to survive large disturbances is directly related to their reserve policies. All power systems have some rules as to what constitutes reserves and what are sufficient reserve levels. This section will review several general classifications of reserves.

4.4.1 Operating Reserves

Operating reserves consist of the available MW response capability over and above that demanded by the system loads. (Loads include net interchange and losses.) Power systems must carry sufficient amounts of operating reserves to ensure an ability to continually match generation to load during normal conditions and to effectively respond to disturbances. Operating reserves are subdivided into spinning and non-spinning reserves. Figure 4-38 illustrates general categories of operating reserves.

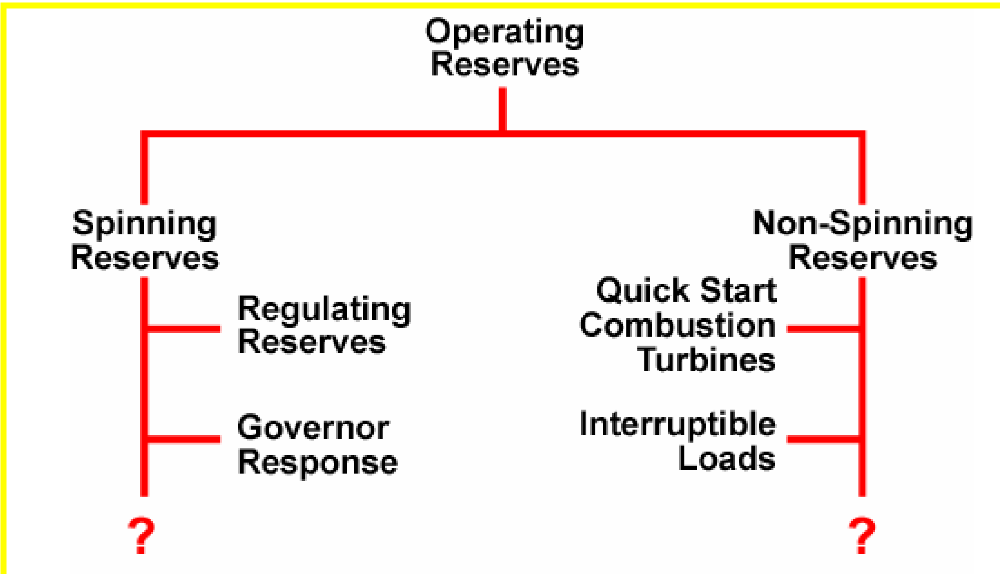


Figure 4-38
Operating Reserves

The question mark is used to indicate that your utility may have other sources of operating reserves.

Spinning Reserves

Spinning reserves consist of the unloaded generating capacity that is synchronized to the power system. Spinning reserves are sometimes called "hot-standby" reserves. A governor can not increase generation in a unit unless that unit is carrying spinning reserves. An AGC system cannot increase a unit's MW output unless that unit is carrying spinning reserves.

A control area monitors both their "boost" and "buck" levels of regulating reserve.

Regulating Reserves

A control area must carry a sufficient amount of regulating reserves. Regulating reserves are a subset of spinning reserves. Regulating reserves are responsive to AGC commands. Without sufficient regulating reserves a control area will not be able to follow normal load changes.

Non-Spinning Reserves

Non-spinning reserve is a reserve MW capability that is not currently connected to the system but that can be available within a specified time period. The exact time period varies but a 15 minute window is common. Examples of non-spinning reserves are combustion turbines while in cold standby. Some power systems count interruptible loads as non-spinning reserves.

4.4.2 Responsive Reserves

The definitions of operating reserves stated above are intentionally general. Given the variety to the interconnected power systems it is difficult to define one set of reserve rules that can apply equally well to all. From the standpoint of this text what is of most concern with respect to reserves is the ability of the system to respond to a frequency depression.

A recent trend in reserve policies is to define a category of reserves called responsive reserves. Responsive reserves are directly related to the ability of the system to respond to frequency depressions. Responsive reserves include MW capability which can be rapidly (for example, within 15 seconds) made available following a frequency deviation. Responsive reserves may include spinning or non-spinning reserves. Figure 4-39 lists several types of responsive reserves.

The ERCOT Interconnection specifies required responsive reserve levels. ERCOT utilities may use all four of these responsive reserve categories.

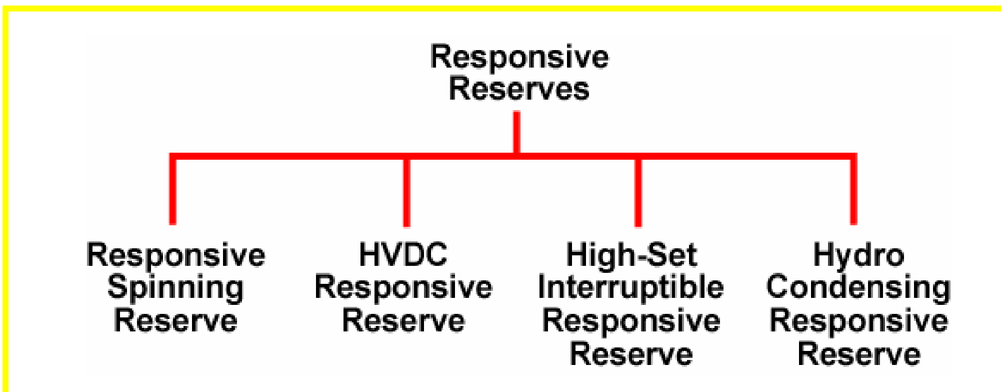


Figure 4-39
Responsive Reserves

Responsive Spinning Reserves

Responsive spinning reserve consists of unloaded synchronized generator capacity that is immediately responsive to governor control. Note that the more general category of spinning reserve is not necessarily responsive to governor control. Sufficient responsive spinning reserves are necessary for effective governor control.

Utilities in the ERCOT Interconnection and in the MAPP area of the Eastern Interconnection use their HVDC systems to simulate governor response.

HVDC Tie Responsive Reserves

HVDC systems are normally not responsive to frequency. However, the control systems that control HVDC power flow can be made to act like a governor control system. If frequency falls, an HVDC system can be rapidly and automatically adjusted to supply more MW to the deficient area.

High-Set Interruptible Responsive Reserves

The classic use of interruptible load is for relieving an energy emergency by shedding customer load. For example, if frequency falls over a several hour period due to a worsening energy shortage, a system operator may be forced to manually interrupt customers. The theory is basically to “cut off the arm to save the body”.

A variation on this classic use of interruptible load is termed “high-set interruptible responsive reserve”. High-set interruptible responsive reserves are interruptible loads that are fed via circuit breakers with automatic load shedding (frequency sensitive) relays attached. For example, an Interconnection may depend on high-set interruptible loads to be automatically shed if frequency falls below 59.7 HZ.

The ERCOT and Alaskan Interconnections use high-set interruptible loads as responsive reserves. In Alaska, the tripping of the high-set interruptibles is expected given a large generator loss. In Alaska, high-set interruptibles can be expected to trip for what other Interconnections would consider small generator losses.

Hydro Condensing Responsive Reserves

A final category of responsive reserves are hydro condensing responsive reserves. Hydro units can often be operated as synchronous condensers. When condensing the hydro unit is actually operating as a synchronous motor. The hydro unit draws MW from the system and can be used to either absorb or supply Mvar. Certain hydro units can be rapidly (less than 10-15 seconds) switched from a condensing mode to a generating mode. If the unit can switch from a load to a generator rapidly, it can assist with arresting a frequency deviation.

4.4.3 NERC Reserve Definitions

The NERC Operating Policies provide general guidance on maintaining acceptable levels of operating reserve. NERC divides operating reserves into two subcategories: regulating reserve and contingency reserve.

A control area shall carry enough regulating reserves so AGC operates effectively and the control area satisfies the NERC control performance standards (CPS1 and CPS2).

A single control area or a group of control areas are required to carry enough contingency reserves so they can recover from a generation (or load) disturbance and satisfy the NERC disturbance control standard (DCS).

CPS1, CPS2, and the DCS are described in Section 4.6.

4.5 Time Error Control

4.5.1 Definition of Time Error

When frequency deviates from 60 HZ, electric clocks driven by motors fed from the Interconnection will sustain time errors. The magnitude of the time errors is dependent on the size of the frequency deviation and the length of time the deviation occurs. If the frequency runs fast, clocks will run faster than desired and positive time error will occur. If the frequency runs slow, clocks will run slower than desired and negative time error will occur.

Frequency is seldom at exactly 60 HZ so time error is almost always occurring. What is desired is that the periods that positive time error occurs will be roughly canceled by the periods in which negative time error occurs. For example, when entering the morning peak, negative time error typically occurs as control areas pursue the building load. In contrast, when load starts to drop in the evening hours, positive time error will typically occur as control areas pursue the declining load. If positive time error cancels negative time error then over a period of time there will be less accumulated time error.

What happens in practice is that some time error does accumulate in either a positive or negative direction. Once the magnitude of the accumulated time error reaches a chosen maximum, time error correction procedures will be used to reduce the accumulated time error to an acceptable value.

4.5.2 Monitoring Time Error

The frequency standard may be obtained from several sources. One source is the National Institute of Standards and Technology (NIST) in Boulder, Colorado.

Each Interconnection assigns a time error monitor. The time error monitor is typically a large control area. Figure 4-40 lists the time error monitors for the three largest NERC Interconnections. The time error monitor has equipment for comparing the actual system frequency to an accurate frequency standard. This comparison detects frequency deviations from 60 HZ and allows the time monitor to keep an accurate record of the time error accumulated.

Interconnect	Time Monitor
Eastern	MISO Saint Paul
Western	California ISO
ERCOT	ERCOT ISO

Other Interconnections such as Hydro Quebec or Alaska, may also designate a time error monitor.

Figure 4-40
Interconnection Time Monitors

4.5.3 Correcting Time Error

We have determined that each Interconnection appoints an Interconnection time monitor. The time monitor has the ability to monitor and record the amount of time error accumulated. The time monitor is also responsible for determining when time error is excessive and initiating time error correction procedures. Figure 4-41 lists the levels of time error that are tolerated by each Interconnection. These levels are published in the NERC Operating Manual. The time error levels are intended as guidelines for the time error monitors.

Type of Correction	Initiate Time Error Correction			Terminate Time Error Correction		
	East	West	ERCOT	East	West	ERCOT
Slow	-10	-2	-3	±6	±0.5	±0.5
Fast	+10	+2	+3	±6	±0.5	±0.5

The time monitor does not have to follow these guidelines exactly and will deviate from the guidelines if needed.

Figure 4-41
Initiating Time Error Corrections

There are three columns across the top of Figure 4-41. Each column is briefly explained below:

- The first column is labeled “Type of Correction”. The two possible types of time correction are slow and fast. If accumulated time error is slow or negative the slow row will be used. If time error is fast or positive the fast row will be used.

- The second column is labeled “Initiate Time Error Correction”. This column contains the level of time error (in seconds) that will be tolerated before time correction procedures are initiated. Note the tolerance levels vary depending on the Interconnection.
- The third and last column is labeled “Terminate Time Error Correction”. This column lists how far the time correction procedures should go before they are terminated.

Illustration of a Time Correction

To illustrate the use of time error correction procedures we will step through a simple example. Assume you are a system operator at MISO Saint Paul. As part of your normal dispatch duties you receive periodic indication of the accumulated time error. Further assume that you receive indication at 20:00 hours that accumulated time error has reached -10 seconds. (Time is 10 seconds slow.)

From the chart in Figure 4-41 you realize 11 seconds exceeds the allowable 10 second slow time error maximum for this time period. Time error correction procedures are required. As the system operator at MISO Saint Paul you initiate a notification procedure that eventually informs every control area in the Eastern Interconnection that a slow time error of 11 seconds has accumulated and a correction is needed.

After the MISO Saint Paul notification, all of the control areas in the Eastern Interconnection shall then adjust the scheduled frequencies (F_S) in their AGC systems. Normally, AGC scheduled frequency is 60 HZ. The scheduled value is changed to 60.02 HZ for this time error correction. Each hour the Interconnection is operated with an actual frequency of 60.02 HZ, 1.2 seconds of positive time error will accumulate. If 60.02 HZ is held for five hours, the accumulated time error will be reduced from 11 seconds to 5 seconds.

Time error accumulates due to periods of excessive over or under frequency operation. Accumulated time error is reduced by intentional periods of over or underfrequency operation. A frequency of 60.02 HZ is targeted to reduce slow time error. A frequency of 59.98 HZ is targeted to reduce positive time error.

4.6 NERC Control Performance

The performance standards officially replaced the old control performance criteria in February 1998.

NERC publishes guidelines for acceptable AGC performance within its control areas. The guidelines address generation control performance during both normal and disturbance conditions. This section will start with a summary of the old NERC control performance criteria (CPC, which included the A1, A2, B1, & B2 criteria). The CPC has been replaced by a new set of performance standards (CPS1, CPS2, and DCS). The new performance standards are the primary emphasis of this section.

4.6.1 NERC's Old Control Performance Criteria

As stated in the beginning of this chapter, the load on the power system is constantly changing. The control systems that have been described in this chapter are designed to match resources to MW obligations and maintain frequency within a narrow band of 60 HZ. An indicator of how well a control area is performing their generation control duties is the control area's ACE signal. It was initially thought that the smaller the integrated ACE value, the better the control area's generation control.

A control area cannot hold ACE constantly at zero. Just as there are constant fluctuations in system frequency, above and below the nominal value of 60 HZ so there are constant fluctuations in the value of the ACE, above and below the desired value.

Normal Conditions

During normal system conditions, the goal was to minimize ACE. The question asked was how much ACE fluctuation was normally admissible? How far above and below zero can ACE deviate? How can a control area ensure that the ACE deviation nets to zero over a period of time? Remember that if ACE was high or low for sustained periods, it was an indication that the control area was accumulating inadvertent interchange and not contributing to frequency regulation.

In 1973, NERC implemented two criteria for control performance during normal conditions, referred to as "A1 - Zero Crossing" and "A2 - L_d Compliance".

A1 – Zero Crossing

The A1 criterion specified that a control area's ACE should return to zero within 10 minutes of previously reaching zero. That is, the time interval between successive zero crossings should never exceed 10 minutes. This criterion was intended to help minimize inadvertent interchange. Periods of over-generation (positive ACE) should be balanced by periods of under-generation (negative ACE).

A2 – L_D Compliance

The A2 criterion was designed to limit the magnitude of ACE. It stated that the average ACE for each of the six ten-minute periods during the hour should be less than or equal to a limit value known as L_d. L_d was representative of the largest hourly load change experienced by the control area in the past year. If the control area's load pick-up was typically steep, L_d would be high. For control areas with a slow, gradual load pick-up, L_d was lower.

Figure 4-42 and Figure 4-43 illustrate the application of NERC's old A1 and A2 criterion. Figure 4-42 is a control area ACE chart that indicates compliance with both the A1 and A2 criteria. Figure 4-43 illustrates violations of both the A1 and A2 criteria.

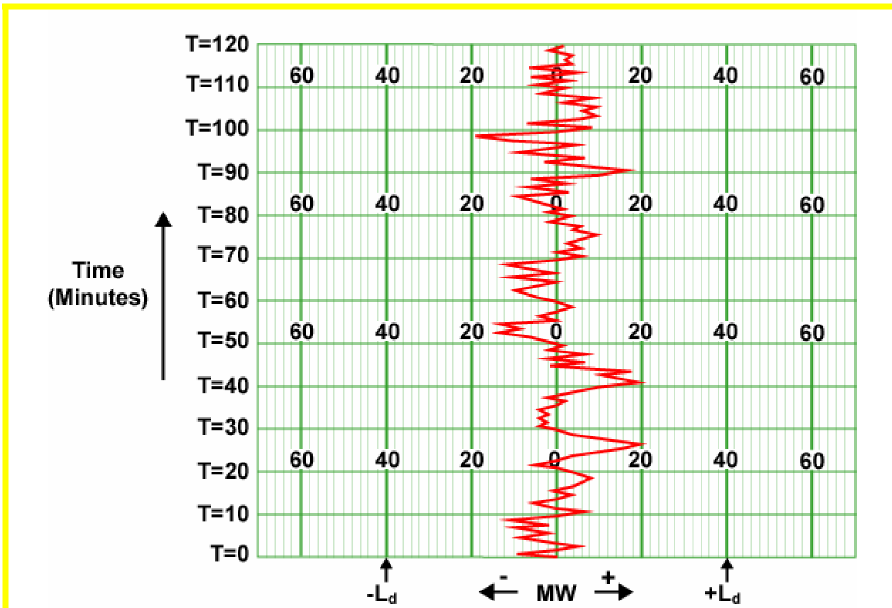


Figure 4-42
Conformance with A1 & A2 Criteria

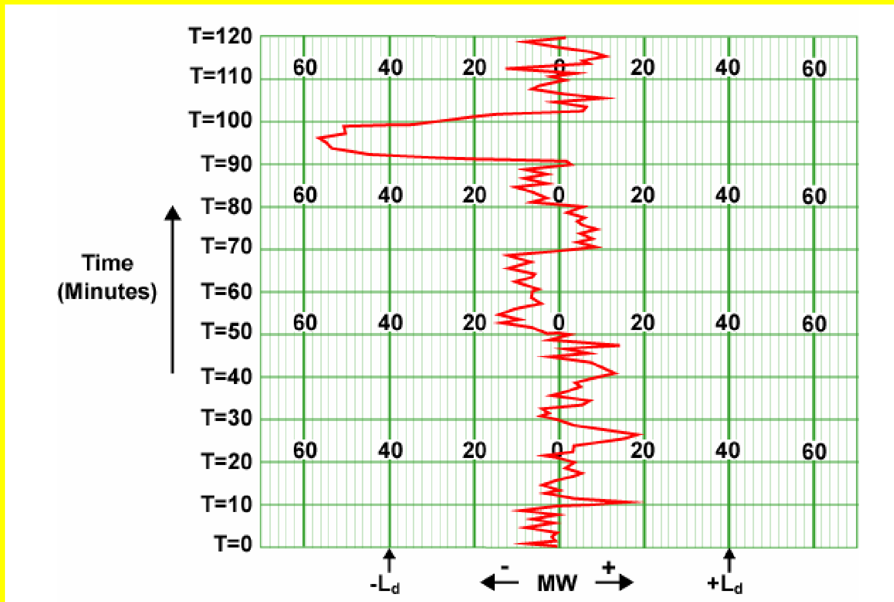


Figure 4-43
Violation of A1 & A2 Criteria

This ACE chart illustrates violations to NERC A1 & A2 criteria. Note the period from T=50 minutes to T=80 minutes. ACE only crosses zero once in this 30 minute period. This was a violation of the A1 criterion. Note the period from T=90 to T=100. The average value of ACE exceeds –L_d. This was a violation of the A2 criterion.

Disturbance Conditions

When a frequency disturbance occurred, the normal conditions criteria were replaced with the disturbance criteria. NERC defined a disturbance as occurring when ACE reached a magnitude of three times the control area's L_d. NERC defined two criteria that apply during disturbances, the B1 and B2 criteria.

Normal load variations should not trigger the use of disturbance criteria.

B1 – System Recovery

The B1 criterion required that ACE return to zero within 10 minutes of the initial disturbance. If a control area lost a generator, their ACE value would not cross zero again until the control area had replaced the lost generation. The B1 criterion gave control areas 10 minutes to recover from disturbances.

B2 – Recovery Initiation

The B2 criterion required that ACE start to return to zero within one minute of a disturbance. Once a disturbance occurred, the control area was obligated to begin recovery within one minute.

Problems with the Criteria

From the beginning of its usage in 1973, various NERC member systems pointed out deficiencies in the performance criteria. The deficiencies identified included:

- There was no technical justification for the usage of the performance criteria.
- The performance criteria were based on operating experience with little technical justification for its existence.
- The A1 and A2 criteria did not provide a direct measure of the impact of a control area's ACE on the Interconnection.
- For example, an A2 violation of 1 MW was treated the same as an A2 violation of 500 MW.
- A1 and A2 were blind to the fact that ACE could be in a direction that supports Interconnection frequency.
- The performance criteria at times required control area's to adjust generation even though they were hurting the Interconnection's frequency.

NERC appointed a task force to investigate options for a new set of control performance standards in 1981. Many options were investigated and in 1996 a new set of standards were agreed upon. The performance standards were implemented on a test basis in 1997 and became mandatory in February of 1998. The next section describes the performance standards.

4.6.2 NERC Performance Standards

Technically defensible performance standards are especially important given the deregulation of the electric industry.

The performance standards have three components. The CPS is composed of CPS1 and CPS2. CPS1 replaces the old A1 criterion while CPS2 replaces the old A2 criterion. Both CPS1 and CPS2 are derived from a frequency based statistical theory and are technically defensible.

CPS1 and CPS2 apply during both normal and disturbance conditions. The performance standards also include a disturbance control standard (DCS) that applies only during disturbance conditions. The DCS replaces the old B1 and B2 criteria.

CPS1

CPS1 is intended to provide a control area with a frequency sensitive evaluation of how well the control area is meeting its demand requirements. CPS1 is a statistical measure of the control area's ACE variability. CPS1 measures ACE in combination with the Interconnection's frequency error.

Each control area is obligated to continually gather sufficient data to determine its "control parameter" for each minute of the day. A control parameter is calculated by every control area using the following equation:

The control parameter can be derived from the ACE equation if you realize that inadvertent sums to zero in an Interconnection.

$$\boxed{\text{Control Parameter} = \frac{ACE_{MINUTE}}{-10B_{MINUTE}} \times \Delta F_{MINUTE}}$$

Definitions for the terms used in this equation include:

- ACE_{MINUTE} is the one-minute average of the control area's ACE value.
- ΔF_{MINUTE} is the one-minute average of the Interconnection's frequency error.
- $-10B_{MINUTE}$ is the one-minute average of the control area's frequency bias value.

Control areas must continually gather the required data to calculate their control parameters.

Every minute of every day, each control area gathers data to calculate their control parameter. The control parameters for each minute are then averaged together to determine the control parameters for each hour, day, month, year, etc. (The control parameters that are most important to the CPS are the control area's monthly average and their sliding 12-month or yearly average value.)

The control parameter values are then used to determine the control area's "compliance factor". The compliance factor is a ratio of the control parameter to the Interconnection's allowable frequency error. In equation form the compliance factor is:

$$\boxed{\text{Compliance Factor} = \frac{\text{Control Parameter}}{(\varepsilon_1)^2}}$$

NERC may change the magnitude of epsilon as operating experience is gained with CPS1.

The term in the denominator (ε_1 or epsilon-one) represents the allowable 1-minute average frequency error for the particular Interconnection. Epsilon's magnitude is determined by NERC. (Think of epsilon as the target bandwidth for the frequency error.) NERC has monitored each Interconnection's historic frequency error to determine an acceptable frequency error. As of the writing of this section, the ε_1 values for the three major Interconnections are:

- Eastern Interconnection — 0.018 HZ
- Western Interconnection — 0.0228 HZ
- ERCOT Interconnection — 0.020 HZ

For the final step in the CPS1 process, the compliance factor is used to determine the control area's CPS1 % conformance. The compliance factor is input to the following formula:

$$\boxed{CPS1 = (2 - \text{Compliance Factor}) \times 100\%}$$

This formula was developed to judge a control area's CPS1 conformance on a percentage scale. The formula can be used to determine a control area's conformance to CPS1 across any time period. The compliance factor would first need to be determined for the desired time period. NERC is most concerned with the value of CPS1 across a sliding one-year period. NERC will also pay attention to one-month averages of the CPS1 to detect problems with a control area's compliance to CPS1 before any major generation control problems develop.

A CPS1 magnitude of 100% is the minimum acceptable performance. When a control area achieves a CPS1 of 100% it means the control area is adjusting their generation in a manner that just meets their obligation to maintaining the Interconnection's frequency. If a control area's CPS1 is greater than 100%, they are doing more than their share of frequency control. If a control area's CPS1 is less than 100%, they are doing less than their fair share of frequency control.

CPS1 and MW-HZ

When the formulae for calculating CPS1 compliance are closely examined, what is actually calculated and monitored is a MW-HZ number. Each control area is monitoring their ACE value in combination with their Interconnection's frequency error.

CPS1 encourages all control areas to control their generation such that their MW-HZ numbers are negative. For example, assume the Interconnection's frequency error is negative (frequency is lower than scheduled). Further assume that a control area has a positive ACE (over-generating). The control area's MW-HZ product would then be a negative number which means the control area is helping reduce the frequency deviation. If the control area's MW-HZ numbers were positive, that control area would be contributing to the frequency deviation.

Figure 4-44 graphically illustrates the concept of MW-HZ. A simple ACE chart and a frequency chart are shown. If a control area is over-generating when frequency is low, they are helping the Interconnection's frequency. If a control area is over-generating while frequency is high, they are hurting the Interconnection's frequency.

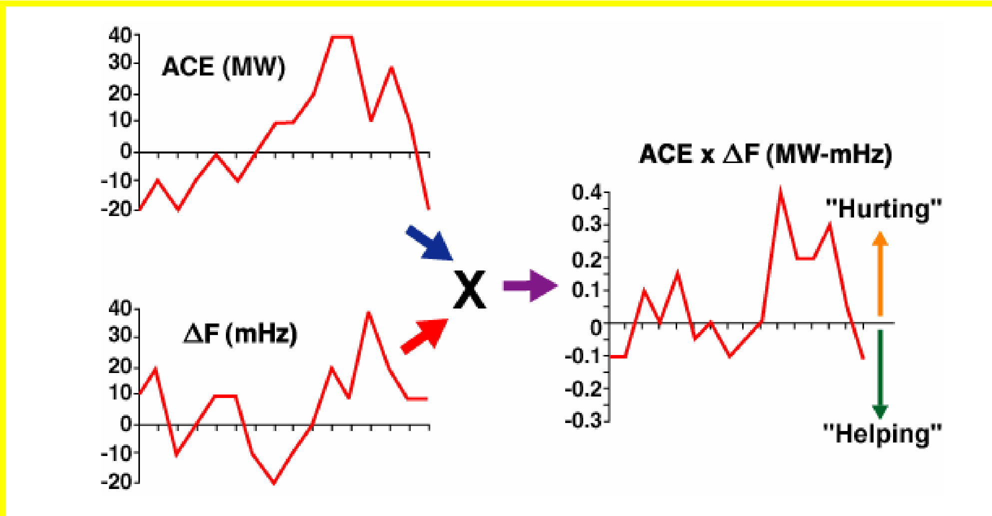


Figure 4-44
Concept of a MW-HZ

The frequency in this plot is shown in milli-hertz. A milli-hertz is a thousandth of a hertz or 1 mHZ = 0.001 HZ.

CPS2

The second component of the CPS is CPS2. CPS2 is designed to limit the magnitude of a control area's ACE. The intent of CPS2 is to limit the unscheduled power flows that can result from excessive ACE values.

Note the strong similarity between CPS2 and the old A2 criterion.

CPS2 states that the average ACE value for each 10-minute period shall not exceed a constant called "L_{10}". L_{10} is calculated for each control area using the following formula:

$$\boxed{L_{10} = 1.65 \times \varepsilon_{10} \times \sqrt{(-10B_C \times -10B_S)}}$$

The variable terms used in the equation are defined as:

The Eastern ε_{10} value is 0.0057 HZ. Western ε_{10} is 0.0073 HZ. ERCOT ε_{10} is also 0.0073 HZ.

- ε_{10} is the 10-minute average of the Interconnection's allowable frequency error. This value is determined by NERC.
- B_C is the control area's frequency bias value.
- B_S is the sum of all the Interconnection's control areas frequency bias values.

Each control area will use the above formula to determine their L_{10} value. To comply with the CPS2, each control area shall keep their average ACE for each of the ten minute periods within the L_{10} bounds 90% of the time.

Pass/Fail CPS

CPS1 and CPS2 must be considered together to determine if a control area has complied with CPS. To pass the CPS standard, a control area must conform to CPS1 100% of the time and conform to CPS2 90% of the time. A control area fails CPS if they fall below 100% compliance with CPS1 or fall below 90% compliance with CPS2.

CPS Enforcement

Compliance with the old performance criteria was voluntary. NERC relied on peer pressure as the driving force to keep control areas in compliance. The new CPS uses more than peer pressure. There are definite penalties for non-conformance. These penalties typically involve monetary fines for non-conformance.

The Disturbance Control Standard (DCS)

Note this standard differs from the old B1 criterion in that ACE does not have to be returned to zero but rather to its pre-disturbance value or to zero.

For DCS purposes, NERC defines a disturbance condition as any event that involves or leads to a loss of generation that is greater than or equal to 80% of the magnitude of the control area's single most severe contingency. The new DCS states that a control area is responsible for recovering from a disturbance within 15 minutes of the start of the disturbance. Recovery means to restore ACE to either zero or its pre-disturbance value. A control area's ability to satisfy the DCS is strongly influenced by its available contingency reserve.

Every control area must comply with the DCS standard 100% of the time. If a control area fails to comply, they will be required to carry additional reserves. Note that if the disturbance is larger than the controls area's single most severe contingency, it is excluded from the DCS. For instance, if a control area suffers multiple generator losses due to severe weather, this disturbance is excludable from the DCS and the control area is not obligated to restore ACE within 15 minutes.

4.7 Impact of Frequency Deviations

Prolonged operation at frequencies above or below 60 HZ can damage power system equipment. The most serious consequences are with respect to the turbine blades of steam turbine/generators.

4.7.1 Effects on Steam Turbine Blades

Mechanical devices have a natural frequency of oscillation. When a mechanical device is exposed to a force which oscillates at a frequency close

A general theory of resonance is presented in Chapter 9.

to this natural frequency of oscillation, the device may amplify the force or enter a resonant condition. The resonant condition can lead to severe vibrations in the device. At times the vibrations grow so large that the device is damaged. Steam turbine blades have a natural frequency of oscillation.

During operation (while under load) at frequencies other than 60 HZ, the natural frequency of oscillation of the turbine blades can be excited, resulting in severe vibration of the blades. This vibration can lead to total failure of the blades. The long blades on the low pressure steam turbine are most susceptible to damage from abnormal frequency operation. Once the first blade fails, other blades and eventually the entire turbine stage may suffer severe damage.

Steam turbine blades can be exposed to only a certain amount of off-frequency operation (while carrying load) over their entire lifetime. The generator operator may track the amount of off-frequency operation and replace turbine blades when they have reached their time limit. This helps to avoid a blade failure.

The best way to prevent this problem is to avoid substantial off-frequency operation while under load. Steam turbine/generators often have under and overfrequency relays installed to trip the unit if it is operated at off-frequency for too long a period.

This 10 minutes is over the lifetime of the turbine. For example, the 10 minutes can be reached via one 10 minute interval or via 10 one minute intervals.

Figure 4-45 illustrates limits of off-frequency operation for a typical steam turbine. These are cumulative limits. This means the limits apply for the lifetime of the turbine. For example, the figure tells us that a typical steam turbine can be operated, under load, for 10 minutes at 58 HZ before damage is likely to occur to the turbine blades.

Actual steam-turbine off-frequency limits will vary with the turbine manufacturer and individual company tolerance

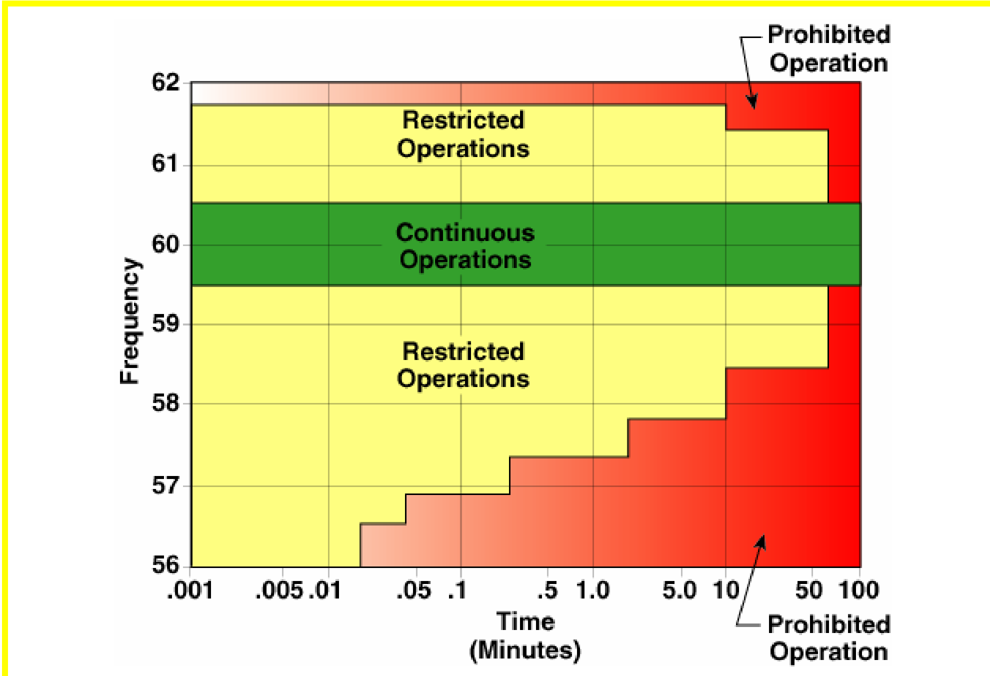


Figure 4-45
Steam Turbine Off-Frequency Limits

4.7.2 Effects on Hydro and Combustion Turbines

Hydro and combustion turbine-generators are less susceptible to the effects of off-frequency operation than steam turbine/generators.

A hydro turbine is much less fragile than a steam turbine. Typically, hydro-electric turbine/generators can be operated, without fear of damage, over a frequency range from 57 to 63 HZ. Hydro units do have "rough-spots" with respect to levels of water flow through the turbine. Certain MW output ranges may need to be avoided to prevent excessive vibration in the hydro unit.

Combustion turbines (CTs) may be protected for off-normal frequency operation but their trip settings are typically more lenient than steam turbines.

4.7.3 Effects on Other Power System Equipment

The majority of the equipment on the power system is not significantly impacted by typically encountered off-normal frequency operation. Some more serious consequences include:

- Motors rotate at a speed that depends on the frequency of the system. If the frequency is low, the torque developed by the motor is reduced. This could have serious consequences if the motor is used to drive key equipment such as a pump or a coal mill. An additional impact on motors involves the natural cooling action of their rotation (like a fan). When frequency of rotation is reduced, this natural cooling action is reduced. This could lead to overheating in the motor.

- As described earlier, the magnitude of motor load varies directly with the frequency. The higher the frequency, the higher the load and vice-versa.
- Transformers can be damaged by low frequency operation. The strength of the magnetic field in a transformer's core is a function of both voltage and frequency. If a transformer is exposed to prolonged underfrequency operation, the transformer can overexcite. Low frequency operation can damage a transformer, especially if it is combined with high voltage.
- Electronic equipment timing circuits may be dependent on a relatively accurate system frequency. If this frequency is abnormal, the equipment may operate abnormally.

Chapter 5 will describe the over-excitation of transformers in greater detail.

4.7.4 Effects on Active Power Flows

In Chapter 2 an equation for active power transfer was developed. The equation is repeated below:

$$\boxed{P_{SR} = \frac{V_S \times V_R}{X_{SR}} \sin \delta_{SR}}$$

According to this simple formula for MW transfer, the largest factor in determining the level of MW flow is the power angle, δ. The power angle can only change if a condition of relative acceleration existed. If power transfer is to increase between two locations, their must briefly be relative acceleration between the two locations. Relative acceleration is simply a difference in frequency. Frequency differences between two locations in the same Interconnection will lead to power angle changes. Section 4.9.4 will explore this point further.

The period of acceleration will be brief (a few seconds) and the frequency difference will be small (fractions of a hertz).

4.8 Underfrequency Protection

This section describes the use of underfrequency load shedding and underfrequency generator tripping relays. Underfrequency protection schemes are required if the Interconnection frequency falls below acceptable levels. In a large Interconnection (like the Eastern) it is unlikely that large mismatches between generation and load will develop unless major disturbances occur. It is therefore unlikely that underfrequency protection will activate unless a large Interconnection splits into islands following a major disturbance.

The Florida power system used to be very susceptible to island formation. At one time Florida was weakly tied to the rest of the Eastern Interconnection. Florida would often separate and form an island when major disturbances occurred in the East. The tie-lines between Florida and the rest of the Eastern system are much stronger now.

In a small Interconnection, underfrequency protection may be required to protect the system even without major system breakups. It is easier to achieve a large generation to load mismatch in a small Interconnection.

4.8.1 Power System Islands

Interconnected power systems operate at one common frequency. The systems are not, however, uniformly distributed. Certain areas of the systems are tied tightly together with many transmission lines while other areas are tied with few lines. Figure 4-46 illustrates a weakly connected system (A) in an Interconnection with other strongly connected systems (W, X, Y & Z).

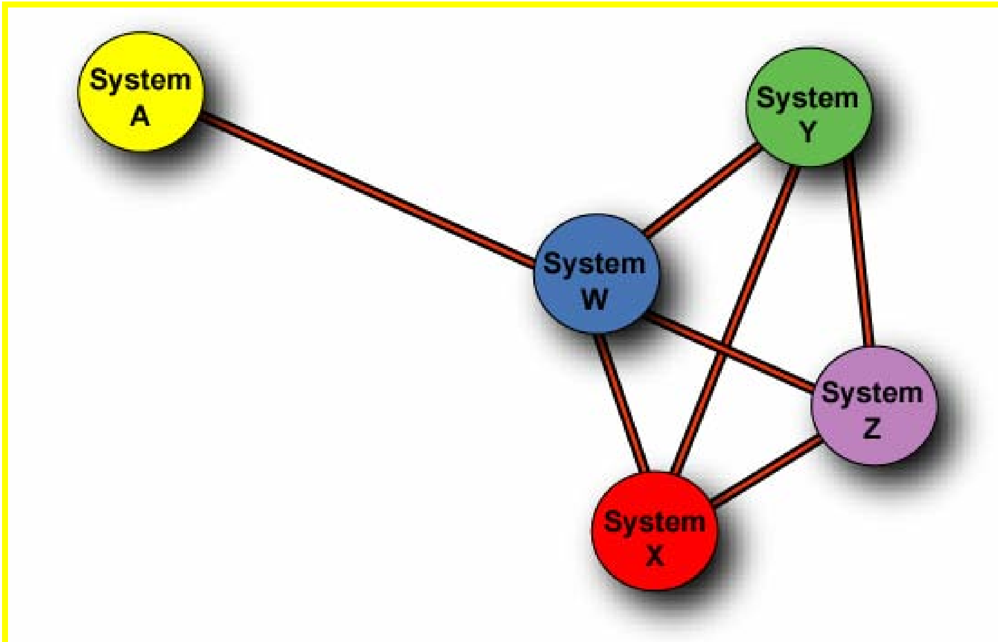


Figure 4-46
Formation of an Island

When severe disturbances occur in the interconnected system the consequences may be transmission line tripping that leads to islanding. Islanding refers to the complete separation of areas of the system from the remainder of the interconnected system.

When major disturbances propagate through an Interconnection, those areas of the system that are tied tightly together tend to stay together. Areas that are loosely tied (such as system "A" in Figure 4-46) tend to form islands. The magnitude of the frequency deviations that occur in an islanded system are greater than those that occur in a large interconnected system. Depending on the size of the island, frequency deviations on the order of 2 to 3 HZ are possible.

4.8.2 Underfrequency Load Shedding (UFLS)

When disturbances result in power system islands, there is no guarantee that the islands that form will have the proper match between generation and load. In fact, there will usually be a mismatch. The frequency in the island will increase or decrease until the correct balance exists between generation and load. If there is too much load, the frequency will drop. If there is too much generation, the frequency will rise.

If there is too much generation, and the frequency rises, the governors on the units will begin reducing generation. This may or may not solve the problem depending on the amount of mismatch. If the frequency rises too high, for example above 62 HZ, overfrequency relays on thermal generators may trip. This will protect the generators but, most likely, lead to a shortage of generation. If there is too much load and the frequency drops, governors on the island's units will attempt to raise generation. Again, this may or may not solve the problem depending on the amount of mismatch. The possibility exists that the mismatch will be too large and governor response will not be able to arrest the frequency decline. Unless drastic measures are taken the system could then collapse.

These drastic measures include underfrequency load shedding or UFLS. UFLS is a protection program that automatically trips selected customer loads once frequency falls below a specified value. The frequencies at which load is tripped and the amount of load tripped vary with the Interconnection. A typical UFLS setting for an Eastern or Western Interconnection utility may include three groups of underfrequency relays set to trip load at three separate frequencies. For example, a utility may trip 10% of their load at 59.3 HZ, 10% at 59.0 HZ and 10% at 58.7 HZ.

In general, the larger the Interconnection, the higher the frequency at which UFLS will begin. Smaller Interconnections may not begin UFLS until the frequency falls below 59 HZ. Smaller Interconnections are susceptible to large frequency swings even during normal interconnected operations and they do not want false tripping of UFLS relays.

Figure 4-47 illustrates the operation of three stages of UFLS. The first stage activates at 59.3 HZ, the second stage at 59 HZ and the final stage at 58.7 HZ. Note that the rate of frequency decline improves after each stage of UFLS. The intent of UFLS is not to recover the frequency but rather to arrest or stop the frequency decline. Once UFLS has operated, manual intervention by the system operators will likely be required to restore the system frequency to a healthy state.

All Interconnections require some form of UFLS be implemented by member systems. Interconnections may coordinate UFLS on an Interconnection basis or divide the Interconnection into smaller regions in which separate UFLS programs are administered. Periodically utilities evaluate their UFLS programs to ensure enough load is being shed and that it is being shed at the proper frequencies. Interconnections typically only give guidelines for UFLS. Individual utilities adjust these guidelines to match their own system characteristics.

The line labeled "governor response" illustrates what frequency would do if no UFLS was activated.

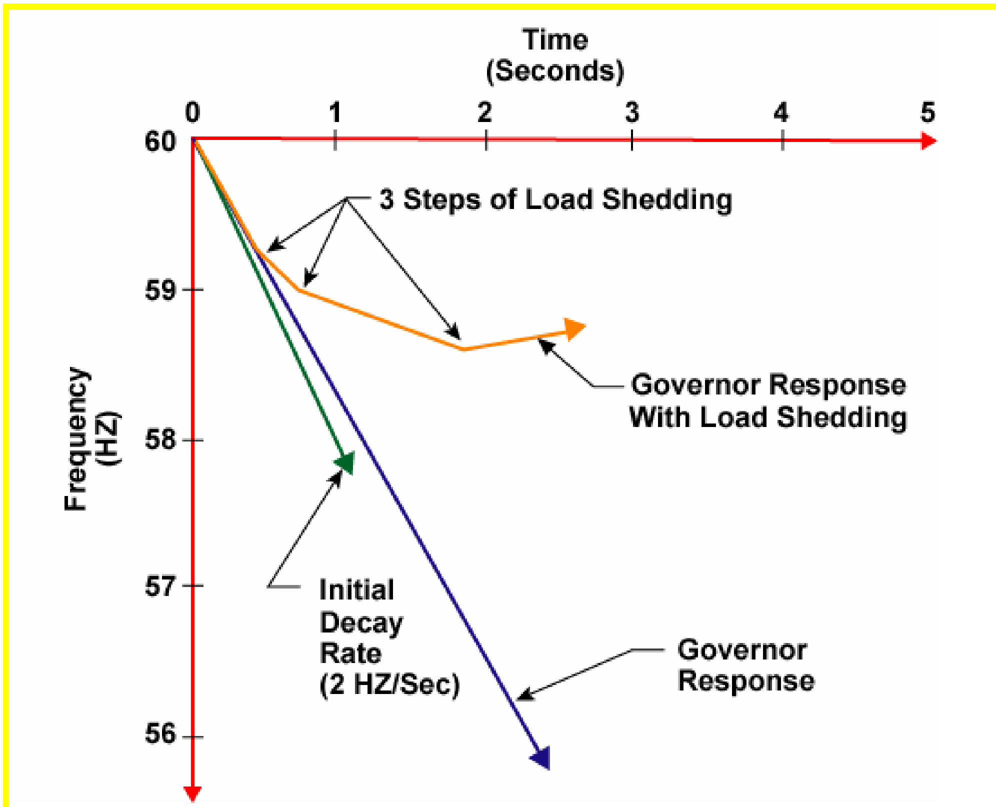


Figure 4-47
UF Load Shedding & Governor Response

Underfrequency Relays on Transmission Lines

The actual frequency the tie-lines will trip at will vary with the size of the Interconnection.

Underfrequency relays (UF) may also be installed on transmission lines. The function of these UF relays is to trip interconnecting lines following major frequency disturbances. Systems that allow the use of UF tie-line tripping typically set rules concerning when these relays may operate. For example, if a utility is providing much needed governor response to a neighboring utility, we would not want UF tripping of their tie-lines if the chance exists that the entire system will recover. All systems have obligations to help their neighbors and UF tripping of tie-lines must not interfere with that obligation.

UF tripping of tie-lines may be appropriate if frequency has depressed to such a low level that the odds of recovery for the whole system are dismal. In such a case, utilities may design their UF tie-line tripping relays to separate themselves from the main system in the hope that their system can recover. The relays will be calibrated to trip only during sustained (a few seconds) low frequency (59 HZ or lower) conditions.

Coordinating UFLS and Reactive Equipment

The use of voltage control equipment such as shunt capacitors is addressed in Chapter 5.

Many systems are dependent on the use of shunt capacitors for voltage control. Typically the shunt capacitors are used to support system voltage during heavy power flow periods. When UFLS programs activate, coordination with in-service reactive equipment may be required. For example, assume a system proceeds through several stages of UFLS. If this system has numerous shunt capacitors still in-service, high voltages could rapidly result.

Several systems within NERC use UF relays to trip shunt capacitors. The intent is to reduce the amount of shunt capacitors at the same time load is being shed in order to control voltage.

Automatic Restoration Following UFLS

The system operators must be aware of automatic load restoration schemes. Unexpected load restoration can delay system restoration.

Several utilities within NERC incorporate automatic restoration following an UFLS event. For example, UFLS may be set to trip load if frequency falls below 59.5 HZ. If as a result of UFLS, governor response, etc., frequency recovers to 60 HZ or more, a portion of the tripped load is automatically restored. The intent of this load restoration is not so much to rapidly recover load, but rather to prevent frequency from rising too much above 60 HZ.

Rate-of-Change UFLS Protection

A rough rule of thumb is that the loss of 1/3 of an area's generation will lead to a 2 HZ per second frequency decline.

When large mismatches between generation and load occur, frequency may drop at a rapid rate. The rate at which the frequency falls is often critical. For example, if the Interconnection (or island) is small, frequency declines may be so rapid that governor response and the normal UFLS program may be inadequate to stop the decline. Some areas have addressed this problem by installing rate-of-change of frequency relays. These type relays respond to the speed at which frequency falls. If rate-of-change of frequency relays operate in a system, the system will quickly trip substantial portions of load in an attempt to arrest the rapid frequency drop.

4.8.3 Underfrequency Generator Protection

If the operation of the UFLS program fails to achieve the desired match between generation and load, the frequency may continue to decline or freeze at a low value. Section 4.7.1 described the impact of sustained low frequency operation on the low pressure turbine stage blades. Many steam/turbine generators are protected with UF tripping relays. These relays are designed to trip the generator if the unit is exposed to sustained low frequency.

The first stages of generator UF tripping typically begin at 59 HZ. The generator may be allowed to operate for several seconds at this frequency before tripping occurs. If frequency declines to 58 HZ or lower the generator may trip with no intentional time delay.

Coordination between a system's UFLS program and their generator UF tripping programs is essential. Every few years a disturbance occurs in which a generator is tripped via UF relays prior to the last stage of UFLS activating. Once the generators start tripping, UFLS is practically useless.

4.9 Nature of a Frequency Deviation

This section describes the nature of a frequency deviation. A frequency deviation is analyzed by breaking it down into smaller components and explaining how the deviation develops. Also addressed in this section are the impact of distance on the magnitude of the frequency deviation, the relationship between frequency and power angle, and the speed of the traveling frequency wave.

4.9.1 Analysis of a Frequency Deviation

A definition of a large or small frequency deviation depends on the Interconnection. Large interconnections, such as the Eastern, experience less frequency deviations than a smaller Interconnection, such as Alaska.

The power system frequency is constantly changing. Small changes are typically due to normal load fluctuations and are of little concern. Larger changes, which are not an uncommon event, may require a system operator's full attention. The majority of the larger frequency deviations that a system operator will see are the result of tripped generators or load switching. Tripped generators and sudden load increases will cause the frequency to spike low while sudden large load decreases will cause the frequency to spike high. This section will be most concerned with frequency depressions due to lost generation.

Figure 4-48 is a plot of how a frequency deviation would look when a time scale measured in seconds is used. Note that the horizontal axis is in seconds and the vertical axis is in hertz. This figure simulates the frequency response following the loss of a generator.

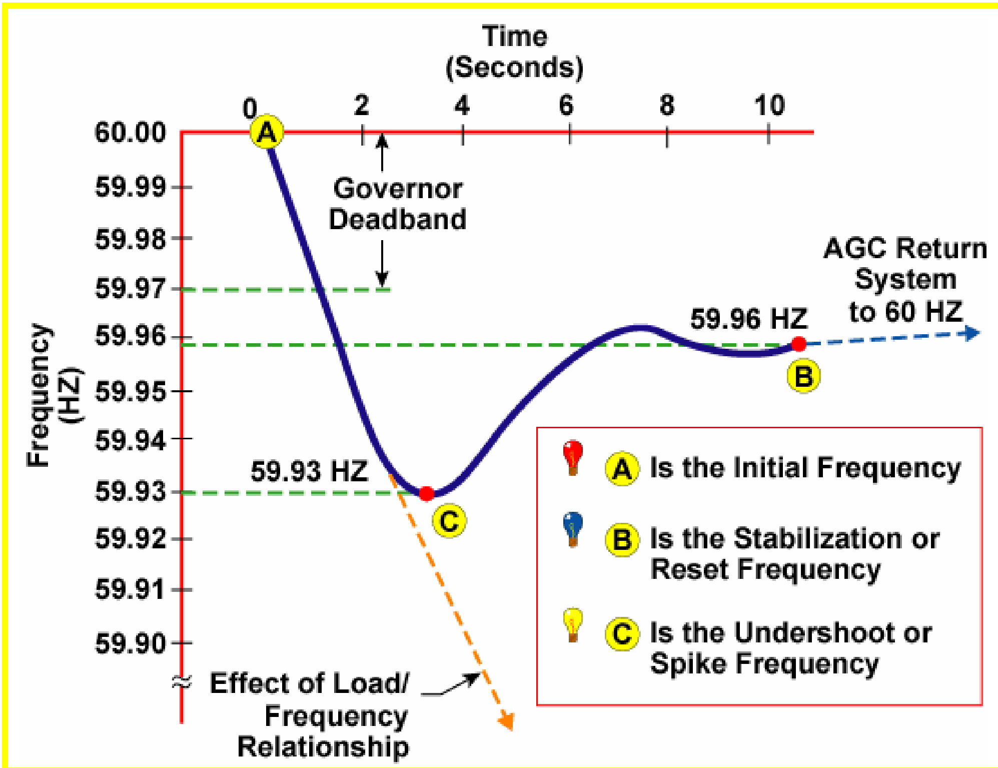


Figure 4-48
Expanded Plot of a Simulated Frequency Disturbance

The frequency plots we typically see are recorded on strip charts. These strip charts have long time scales (10 minutes per inch). The frequency plot illustrated here between points "A", "B", & "C" would appear on a strip chart as the thin "tail" of the frequency plot.

The Initial Frequency

At point "A" (the initial frequency), a generator is lost. The spinning load in the Interconnection will quickly provide inertial energy to replace the lost generation. As the spinning mass in the system supplies inertial energy it slows the speed of rotation. This leads to a reduction in frequency throughout the Interconnection.

Inertial energy is the energy stored in the rotating mass of the system.

As the frequency of the system declines, the load magnitude declines with it due to the load/frequency relationship. If the generation loss was small, the load/frequency relationship may alone be enough to arrest the frequency drop. In the example of Figure 4-48 we are assuming the generation drop is large. The load/frequency relationship is not enough to arrest this frequency drop, governor response is required.

The rate at which the frequency initially declines depends on several factors including:

- The amount of generation that was initially lost. The more generation that is lost, the faster the frequency will decline. Large generation losses—as a percent of system size—could lead to frequency decline rates of several hertz per second.

- The impact of the load/frequency relationship. Earlier in this text we stated that a rule of thumb for the load/frequency relationship is that a 1% change in frequency will lead to a 2% change in total load magnitude. This was only a rule of thumb. In practice, the effect of frequency on load will vary. The more effect, the less the frequency will decline.
- The inertia of the local power system and of the entire Interconnection. The more spinning mass in the Interconnection, the more difficult it is to change the Interconnection's frequency. The local system inertia also impacts the frequency change. In general, the more inertia in the Interconnection and in the local system, the slower the frequency will decline.

The speed and magnitude of the governor and generator response. A rapid, strong governor response is only of value if the generator backs it up with sustained MW support.

The Undershoot or Spike Frequency

The frequency dips all the way down to 59.93 HZ (point "C") in Figure 4-48. This dip is the frequency undershoot or spike. The reason the frequency stopped declining at 59.93 HZ was due to a combination of system inertia, load/frequency, and governor response. The reason the frequency rises from 59.93 HZ towards 59.96 HZ is primarily due to governor response.

The Stabilization or Reset Frequency

A major factor in the delay of a steam unit's governor response is the reheat stages of a steam generator. It takes several seconds to recycle the steam back through the boiler. This delays the unit MW response.

Recall how governor control systems monitor shaft speed and then adjust mechanical input power to increase (or decrease) the speed of the shaft. Governor systems act relatively slowly as it takes time to adjust mechanical power input, especially in a steam unit. Note in Figure 4-48 that it takes approximately 10 seconds to stabilize the frequency at 59.96 HZ (point "B"). This governor time lag allows the system frequency to initially dip lower than the point at which the governor systems will eventually stabilize the system frequency. This is why the frequency dips to point "C" before climbing to the stabilization or reset point at "B". The time period between points "C" and "B" (7 seconds) is again due to the relatively slow response of the governor systems.

Point "B" is the frequency deviation value typically seen in reports of disturbances. The undershoot at point "C" will only show up on control center frequency strip charts as a sharp downward line (the tail of the response). When we talk about frequency deviations we are typically referring to the stabilization point or point "B".

AGC Response

Once the governor response has stabilized the frequency at point “B”, it is up to the AGC system to restore the frequency towards 60 HZ. The AGC system in the control area that suffered the generation loss will pulse those units on AGC control to replace the generation loss. When the loss is replaced the control area’s ACE will move towards zero and the system frequency will be restored. Only a fraction of the AGC response is illustrated on Figure 4-48 since AGC has 15 minutes to recover ACE according to the NERC DCS.

Governor Deadbands

One other important setting for a governor control system is illustrated on Figure 4-48. The deadband setting is 0.03 HZ for the governors of the system represented in the figure. Recall, the governor deadband is a range of frequency around 60 HZ for which the governor will not respond. A typical deadband ranges from 0.02 to 0.04 HZ. For the system in Figure 4-48, the governors will not begin to adjust unit outputs until the frequency has declined to below 59.97 HZ.

4.9.2 Actual Expanded Frequency Plots

Figure 4-49 and Figure 4-50 are based on actual data from frequency disturbances. Note that these plots are using expanded time scales. This frequency response data was gathered using digital frequency recorders.

Note the initial, undershoot and stabilization points. In Figure 4-49 a 1245 MW generator was lost in the Western Interconnection. Frequency was initially 60 HZ and declined to a low point of 59.84 approximately five seconds after the disturbance. Governor response restored the frequency to 59.925. AGC slowly recovers the frequency towards 60 HZ.

In Figure 4-50 a 1100 MW generator was lost in the Eastern Interconnection. Frequency was initially 59.992 HZ and declined to a low point of 59.966 approximately four seconds after the disturbance. Governor response restored the frequency to 59.976. AGC slowly recovers the frequency towards 60 HZ.

This frequency plot looks very smooth. The actual data was not this smooth. The constant frequency "bumps" have been eliminated to emphasize the overall shape of the frequency plot.

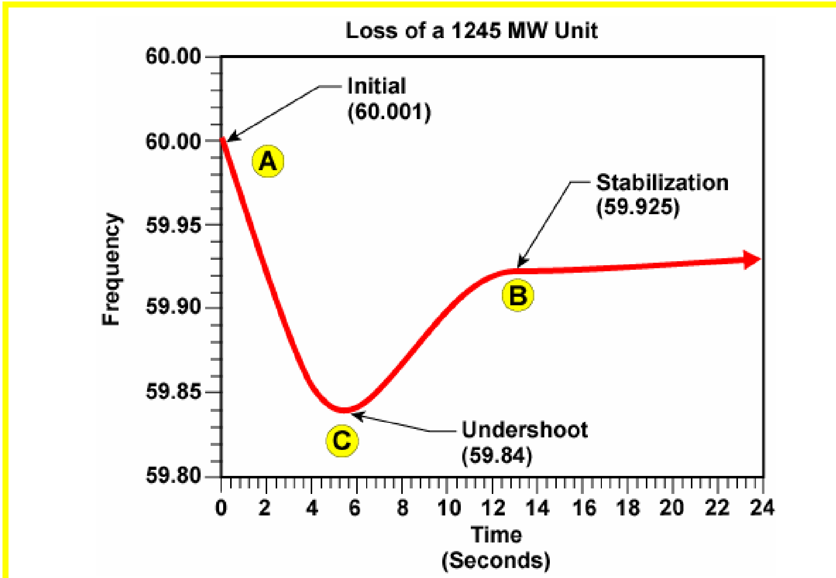


Figure 4-49
Western Interconnection Expanded Frequency Plot

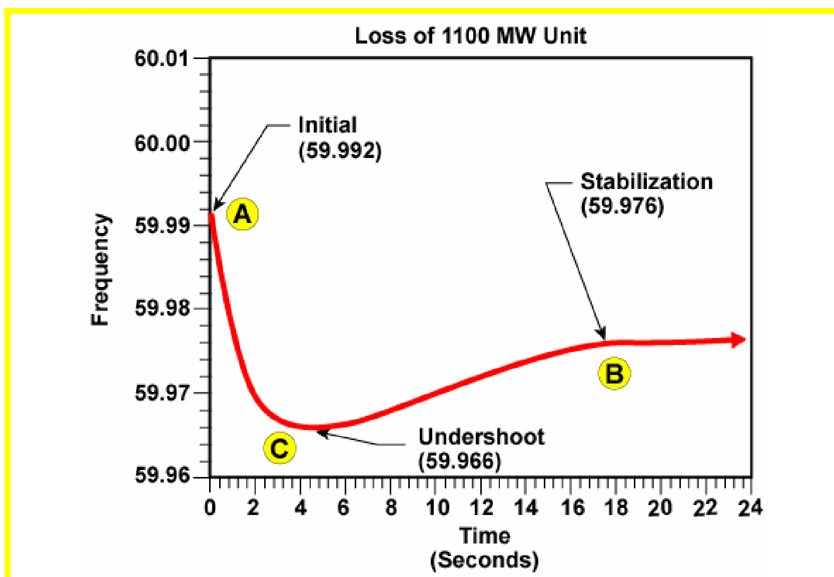


Figure 4-50
Eastern Interconnection Expanded Frequency Plot

The governor response is much greater in Figure 4-49 than in Figure 4-48. This is expected as the disturbance plotted in Figure 4-50 was not that severe for the Eastern Interconnection. It is likely that a large number of Eastern unit governors did not even respond to this disturbance as their deadbands were not exceeded.

4.9.3 Effect of Time and Distance

When frequency disturbances occur within an Interconnection, the magnitude of the disturbance depends on the time it was measured and the observer's position. At different times following the disturbance, an observer will see a different frequency deviation. The farther away one is (in electrical distance or Ωs), the lower the magnitude of the initial disturbance will be.

As seen in the preceding figures, a frequency disturbance will have an undershoot (point "C") and a stabilized value (point "B"). We can observe the effects of distance on frequency plots such as those given in Figure 4-48 through Figure 4-50. When the generation is first lost the frequency starts to decline. How fast frequency drops depends on the size of the loss, the load/frequency relationship, the inertia of the system generators, and the physical location of the generator that was lost.

The magnitude of the frequency undershoot (point "C") will vary with the observer's location. The stabilized value (point "B") will be the same no matter where the location in the interconnected system.

It is the undershoot magnitude that varies. The stabilized frequency is constant throughout the Interconnection.

Earlier in the text we used the analogy of a rock thrown in a pond to visualize a frequency disturbance. When disturbances occur within a power system they propagate out from their point of origin to the rest of the power system. The frequency disturbance itself is called a traveling wave. These traveling frequency waves spread out from their point of origin in the same manner as a rock thrown in a calm pond would cause waves to propagate out from the rock's point of entry.

When a frequency disturbance (for example, one caused by a loss of generation) begins, the disturbance wave will propagate out to the rest of the power system. The traveling wave's strength will be diluted (damped) as it travels farther from its point of origin. Eventually the wave will dissipate. The farther an observer is from a disturbance (in electrical distance or Ωs), the smaller the magnitude of the initial disturbance they will see. After approximately 10 to 20 seconds all observers will see the same frequency. By this time all the interconnected systems governors have responded and the frequency is stabilized at a new value.

4.9.4 Frequency Relation to Power Angle

We can relate frequency deviations to the active power transfer equation first presented in Chapter 2. Recall that the active power transfer equation calculates the MW transferred based on the impedance, voltage and power angle. The equation is repeated here for convenience.

The "SR" subscripts are referring to a measurement between the sending and receiving ends of the system.

$$\boxed{P_{SR} = \frac{V_S V_R}{X_{SR}} \sin \delta_{SR}}$$

Recall from Chapter 2, the amount of MW transferred between two locations is primarily dependent on the impedance and the power angle (δ_{SR}) between the two locations. If the power angle stays the same, the MW transferred will not vary significantly. Following the loss of a large generator, the lost power must be replaced. Neighboring generators supply the lost power from their inertia energy. The power flow must therefore increase on the lines feeding into the area that lost the generator.

If the power flows increase it means that the power angle must have increased. Power angles only change if there has been a momentary change in relative speed or an acceleration between two areas of the power system. When a major generator is lost the areas of the power system that replace the lost generation must briefly accelerate with respect to the area that lost the generation.

If the frequency undershoots (point "C") were measured at the point where the generation was lost and also near the different generators that respond by increasing generation, one would find that these undershoots have slightly different magnitudes. The point where the generation is lost will have a larger frequency undershoot then the points from which the generation is replaced.

The different undershoots represent the supplying areas briefly accelerating with respect to the area that lost generation. For several seconds the supplying areas will run slightly faster than the receiving areas to allow power angles to increase and power flows into the generation deficient area to increase.

Figure 4-51 illustrates the differences in frequency response across a simple system following a generation loss. The loss of generation occurred in area "X". Note the large undershoot in area "X". Area "Y" is strongly connected to area "X". The undershoot in area "Y" is slightly less than that in area "X". Since area "Y" is tightly connected with area "X", it will supply significant MW support to area "X". The undershoot in area "Z" is small. Area "Z" is weakly tied to area "X" and provides little MW support.

Eventually, after several seconds, power angles will stop increasing and the entire power system will stabilize at a new, lower, frequency. (AGC systems will then return the system to the scheduled frequency of 60 HZ.)

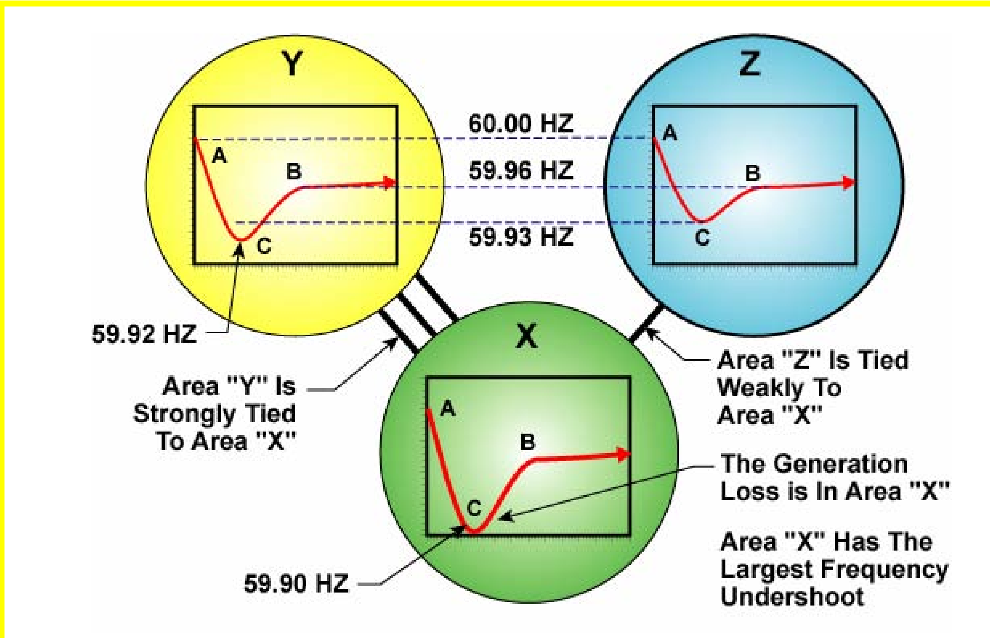


Figure 4-51
Illustration of Frequency Undershoots

The size of the undershoot is directly related to the strength of the tie-lines between the deficient area (X) and the supplying areas (Y & Z).

Figure 4-52 further illustrates this concept. Figure 4-52 (a) represents a simple power system with frequency initially at the normal value of 60 HZ. Assume a large generator is lost. Frequency immediately begins to drop throughout this sample system. At the point where the generation is lost the frequency undershoot reaches its minimum value of 59.9 HZ as illustrated in Figure 4-52 (b). At the ends of the simple power system, the frequency undershoot is 59.95 HZ. The differences in the frequency undershoot values between the ends and middle of the system will result in a power angle change. For example, the difference in undershoots is 0.05 HZ (59.95-59.90). If this difference lasts for 2 seconds then the power angle can change within this two second window. The calculations are shown below:

$$59.95 - 59.90 = 0.05\,\text{HZ}$$

Assume this Difference Lasts for 2 Seconds

$$0.05\,{}^{\text{Cycles}}\!/\!_{\text{Second}} \times 2\,\text{Seconds} \times 360\,{}^{\text{Degrees}}\!/\!_{\text{Cycle}}$$

Equals 36° Change in Power Angle

Following a generation loss, power flows will adjust as the Interconnection supports the deficient area. Power flows do not change significantly unless the power angle changes. To change the power angle you must have relative acceleration. Frequency must be different throughout an Interconnection immediately following a disturbance. This is how you achieve relative acceleration and power angle changes.

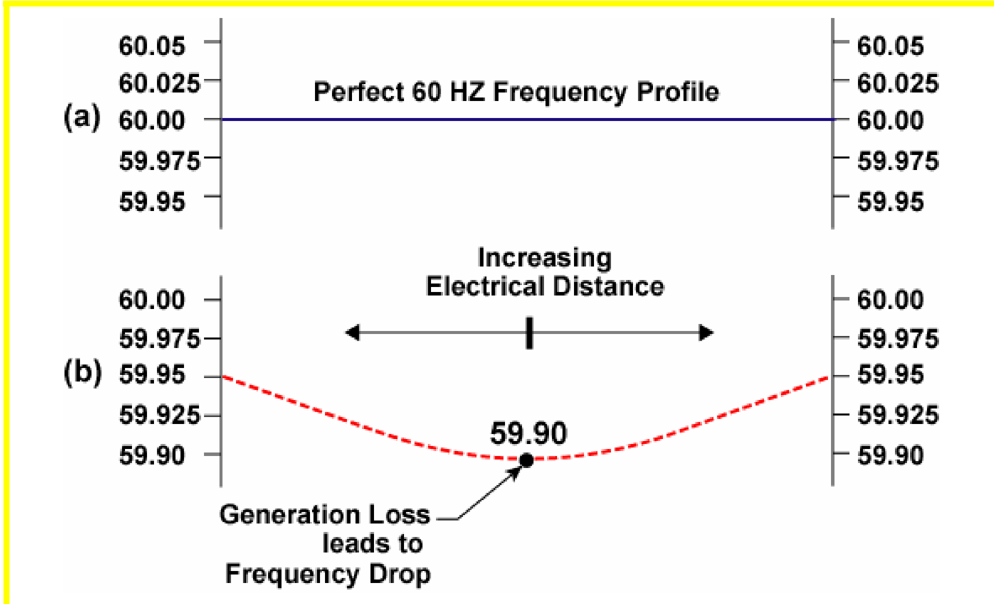


Figure 4-52
Distance and Frequency Undershoots

Given modern telecommunications systems, more accurate methods are now available to calculate the speed of the traveling wave. This example is used due to the interesting manner in which the answer was obtained.

4.9.5 Speed of the Traveling Frequency Wave[1]

If the frequency disturbance following a generation loss travels through the power system as a traveling wave, how fast does it travel? This section will answer that question by recalling some interesting work performed years ago by Mr. A. Doyle Baker of Kentucky Utilities (KU).

In the late 1960’s KU was one of the first utilities to install a digital AGC system. This system had a capability to automatically record frequency data following a disturbance. The frequency recorder was known as a frequency trap. Iowa Public Service (IPS) was a utility located west of KU. IPS also had installed a digital AGC system with frequency trap capability.

In early 1970 Tennessee Valley Authority (TVA) lost a generating unit that was then carrying 800 MW. A frequency disturbance wave propagated throughout the Eastern Interconnection. The KU and IPS frequency traps activated and recorded the frequency disturbance.

Utilities in this time period did not have accurate time measurement equipment. KU and IPS could not tell each other exactly what time there frequency traps were triggered. The two utilities could, however, exchange frequency response data. Figure 4-53 is a plot of both the KU and IPS frequency data following the disturbance. Note that at a plot time of -4

[1] This section is adapted from several writings of Mr. A. Doyle Baker of Kentucky Utilities.

seconds both frequencies start to plunge. This is in response to the TVA disturbance. Also note that at a plot time of 40 seconds both frequencies start to plunge again. This was due to a subsequent disturbance that occurred west of IPS.

The subsequent disturbance was the loss of the tie-lines between the Western and Eastern Interconnections. The Interconnections were connected with AC tie-lines at the time. These lines frequently tripped and were eventually removed from service due to this constant tripping.

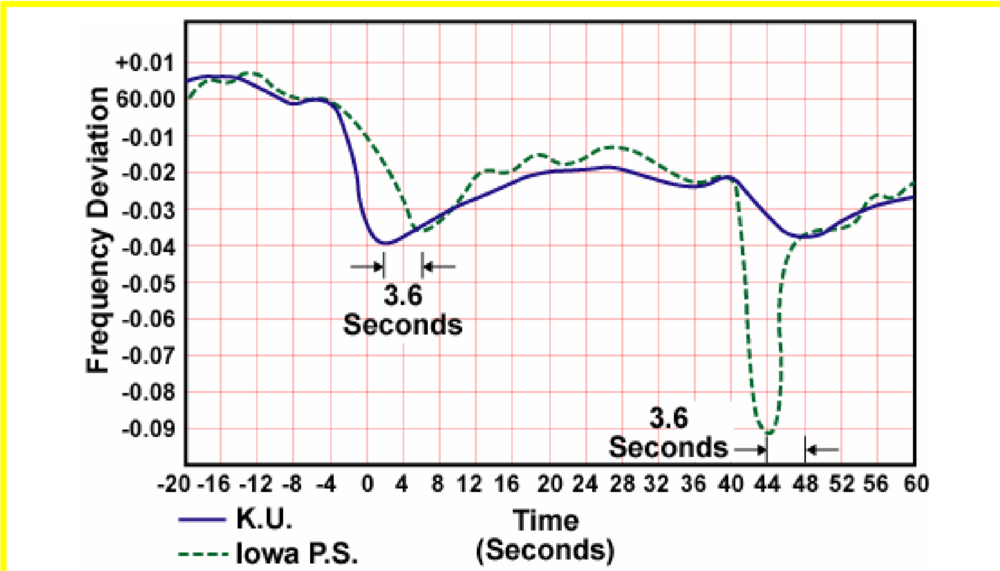


Figure 4-53
Speed of the Traveling Frequency Wave

By lining up the initial frequency plunges due to both disturbances the utilities were able to compare frequency response data with accurate time scales. Note that as the first frequency wave from the TVA disturbance travels through the Interconnection, KU records the maximum frequency plunge 3.6 seconds later than IPS does. For the subsequent disturbance, IPS records the maximum disturbance 3.6 seconds later than KU records it.

The conclusion is that it took 3.6 seconds for a frequency disturbance wave to travel between the KU and IPS frequency recorders. Since the distance between the frequency recorders was known, the utilities were able to estimate that the frequency disturbance wave traveled at approximately 200 miles/second.

Note that this speed was for this particular disturbance. Other disturbances will have different speeds due to changing system conditions

4.10 Staged Response to a Generation Loss[2]

The response of the power system to a major generation loss can be described by a four stage process. Assume that a major generator is lost. The power system will progress through the stages listed in Figure 4-54.

[2] This section was strongly influenced by the teachings of Dr. Aziz Fouad of Iowa State University.

Stages of a Generation Loss

- Electromagnetic Energy Storage
- Inertial Stage
- Governor Response Stage
- AGC Stage

Figure 4-54
Stages of a Generator Response

4.10.1 The Electromagnetic Energy Stage

Immediately following a loss of generation, those generators that are electrically closest to the point of loss will respond first and with the most MW. Recall from the power transfer equation that the amount of power delivered from a generator to a point in the system depends on the impedance from the generator to that point. This impedance is composed of the internal impedance of the generator and the impedance of the transmission path.

When a load is suddenly applied to a generator, its internal impedance reduces sharply and then returns to normal in a few seconds. For generators that are electrically close to the loss of generation, this drop in impedance will significantly lower their impedance, thus enabling the generator to supply more power. The amount of power supplied by each generator in the Interconnection during this stage is directly proportional to their electrical distance (measured in Ωs) from the loss of generation.

How long a generator sustains its response during the electro-magnetic stage and how low the voltage of the generator falls during this stage is dependent on the strength and speed of the generator's excitation system.

The generator delivers this power very rapidly—almost immediately—but only sustains the MW support for approximately 1/3 of a second. The MW the generator supplies does not come from normal MW sources (the turbine) but rather from energy stored within the magnetic field of the generator. This stage is called the electromagnetic energy stage since the generator's own magnetic energy is the source of the generator response. The time frame for stage #1 is from immediately following the loss to approximately 1/3 second after the loss.

4.10.2 The Inertial Stage

Immediately following the loss of generation, the frequency in the area that suffered the loss will begin to fall. We say "begin to fall" as the frequency drop does not occur instantaneously, it takes time to slow down the huge spinning masses in the power system. Visualize the frequency in the area that suffered the generation loss as a “pocket” of depressed frequency or as a frequency pocket.

The remainder of the interconnected system will not yet have experienced a frequency decline. As the frequency pocket develops in the area that suffered the loss, the remainder of the interconnected system will begin to supply inertial (rotational) energy to the low frequency pocket. Over the next several seconds, the frequency throughout the Interconnection will move towards a common lower value. The frequency of the pocket will recover significantly during this period while the frequency of the remainder of the interconnected system will fall slightly. We call this second stage of the response the inertial stage and define an approximate time period for the stage from 1/3 second after the generation loss to 5 seconds after the loss.

The approximate time frames given for each of the stages overlap one another. This is intentional, the stages are not discreet but tend to overlap one another.

During the inertial stage all the interconnected system generators supply MW in proportion to their relative size. Large (massive) generators respond with more MW.

4.10.3 The Governor Response Stage

Stage # 3 is the governor response stage. The generators throughout the Interconnection will respond with MW in proportion to their governor settings. If all the units have the same droop, then all units will respond in proportion to their size. The governor stage will stabilize the frequency throughout the Interconnection at a common value. The approximate time frame for the governor response stage is from 2 seconds after the loss to 20 seconds after the loss.

4.10.4 The AGC Stage

Stage # 4 is the AGC stage. Over the next several minutes the AGC system of the control area that lost the generation will pulse its units to return frequency to 60 HZ. If the control area cannot handle the loss, it should request emergency assistance from neighboring systems. The approximate time frame for the AGC stage is from a few seconds following the loss to 15 minutes after the loss.

The Economic Dispatch Sub-Stage

A final stage in the system response could be called the economic dispatch stage. The economic dispatch stage is a subset of the AGC stage. During economic dispatch AGC control signals are adjusted in such as manner as to ensure the generators supplying the replacement MW are the most economic sources. During the economic dispatch stage the MW production of units in

The response of a generator during the electromagnetic stage is not constrained by the unit rating. A 100 MW generator may briefly provide 200 MW during this stage. This energy is coming from the generator’s magnetic field, not from the prime mover.

the control area that suffered the loss will be rearranged to minimize overall production cost.

4.10.5 Illustration of a Staged Response

Figures 4-55 through 4-58 illustrate a simulated staged response to a generation loss. Figure 4-55 contains a simple power system with four generators. Initially, the system is operating normally. Assume generator "A" trips. The following four stage response occurs.

1. Of the four generators, generator "C" is electrically closest. Note that the transmission path between generators "A" and "C" is composed of two 500 kV lines. Electrically, generator "C" is very close to generator "A". Figure 4-55 lists the change in MW from each generator during the electromagnetic energy stage. Note that generator "C" provides the largest response. Generator "C" may sustain this MW response for approximately 1/3 second.

During the electromagnetic energy stage the generators respond with energy stored in their magnetic fields. Those units electrically closest to the point of loss will provide more MW.

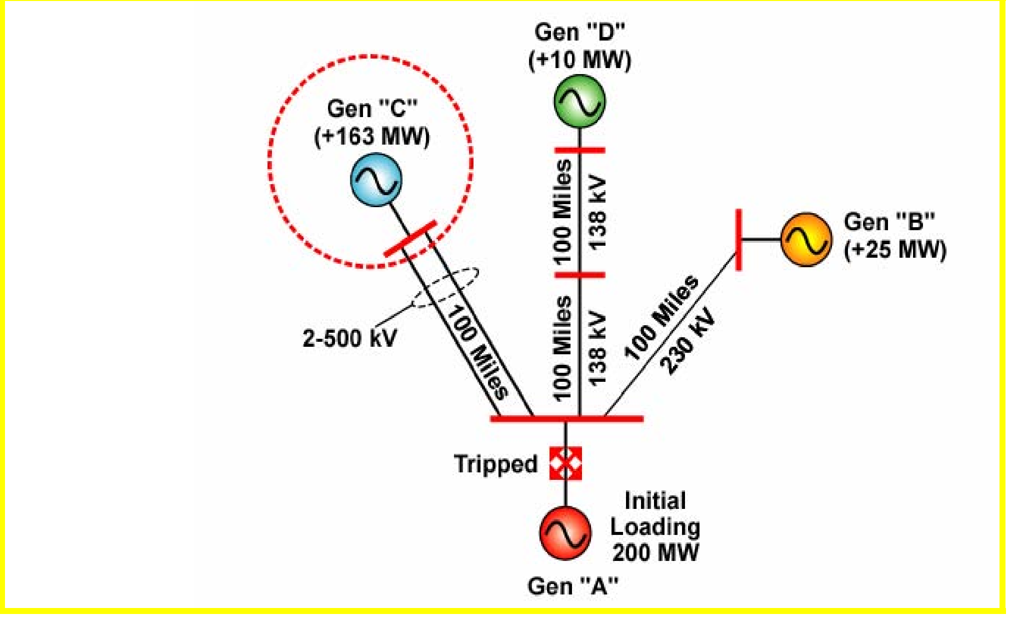


Figure 4-55
Stage #1 – The Electromagnetic Energy Stage

2. Figure 4-56 illustrates stage # 2 of the process. Stage # 2 is the inertial stage. Note that the dominant MW response has shifted from generator "C" to generator "B". Generator "B" has more inertia than generator "C" and provides more of the response during this stage. The time frame for this stage is from 1/3 to 5 seconds following the loss. During this stage the frequency of the entire Interconnection is falling. However, the frequency

is not falling uniformly. Some generators are slowing faster than other generators.

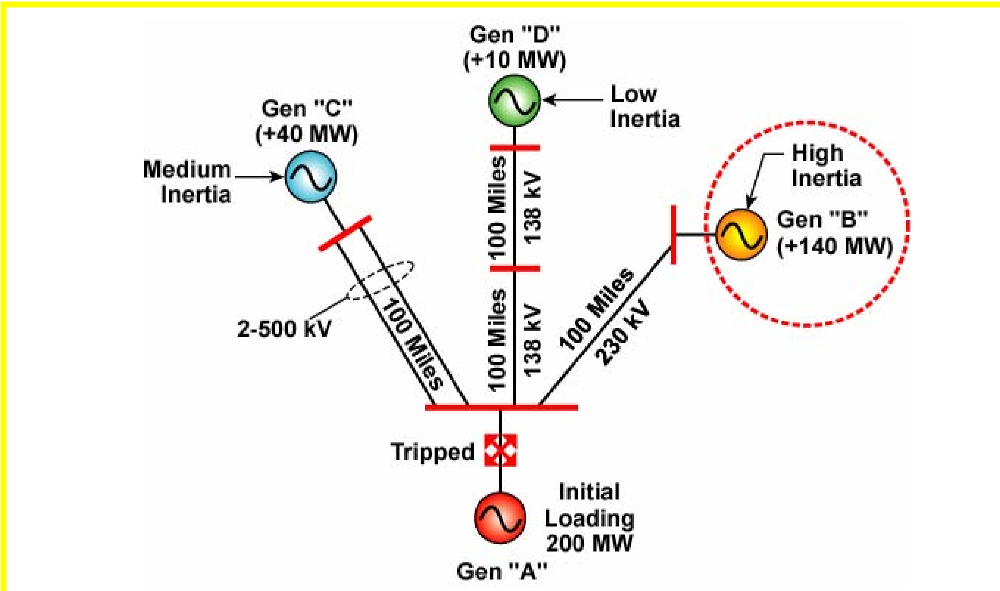


Figure 4-56
Stage #2 – The Inertial Stage

During the inertial stage the generators respond in accordance with their respective inertias. The system generators will slow down at different rates leading to short term frequency differences throughout the Interconnection.

3. Figure 4-57 illustrates stage # 3 of the response. This is the governor response stage and the distribution of the MW response is now dependent on the governor settings of the various units. Generators "D" and "B" provide the majority of the governor response. The generator "C" governor is blocked (it does not respond to a frequency drop) and this unit does not participate during this stage. The time frame for this stage is from 1 to 20 seconds following the loss.

During the governor response stage the generators respond in accordance with their respective governor settings, their spinning reserve levels, and the ability of the generators to provide the requested governor response.

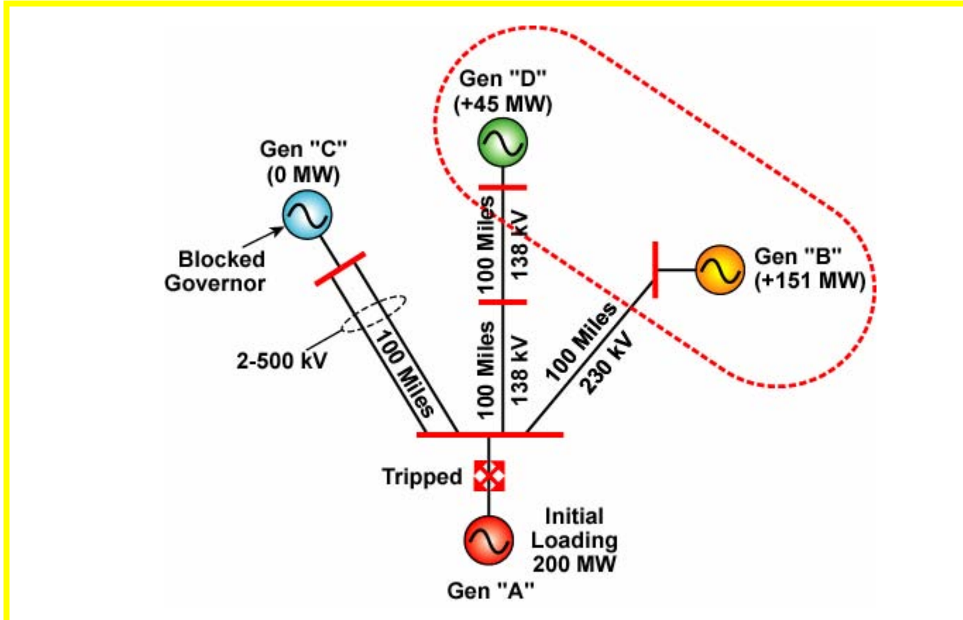


Figure 4-57
Stage #3 – Governor Response Stage

4. Figure 4-58 illustrates stage # 4, the AGC stage. Note that generator "C" is now providing all the MW response. Generator "C" is in the same control area as the generator that was lost. We are assuming that generator "C" was pulsed by AGC and able to provide the 200 MW of lost power.

During the AGC stage the units pulsed by the deficient control area's AGC system provide the MW response.

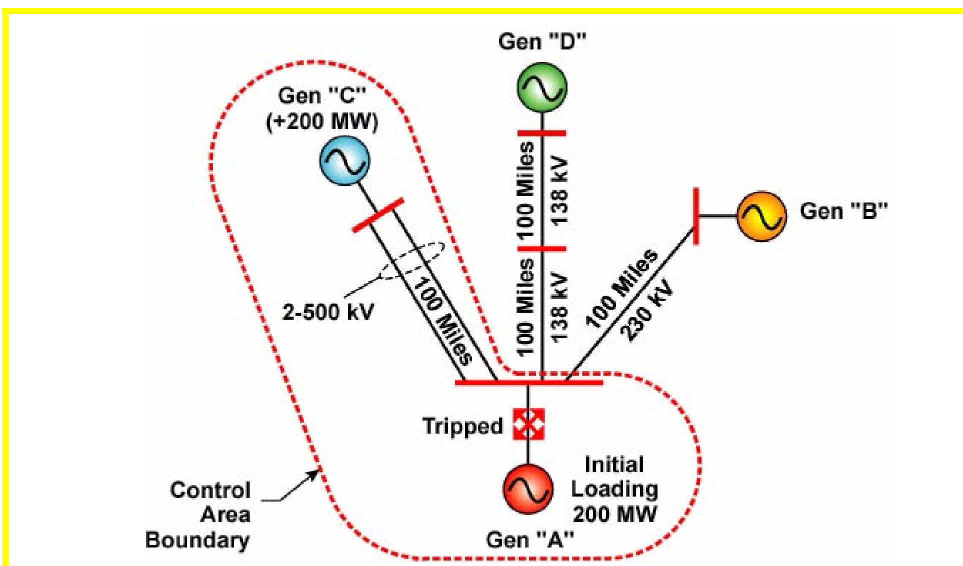


Figure 4-58
Stage #4 – The AGC Stage

In the actual power system, the response of the system to a generator loss does not neatly follow each of these four stages. The stages overlap and at times one stage dominates other stages. The four stages are intended to provide a framework for visualizing the system response to a generation loss.

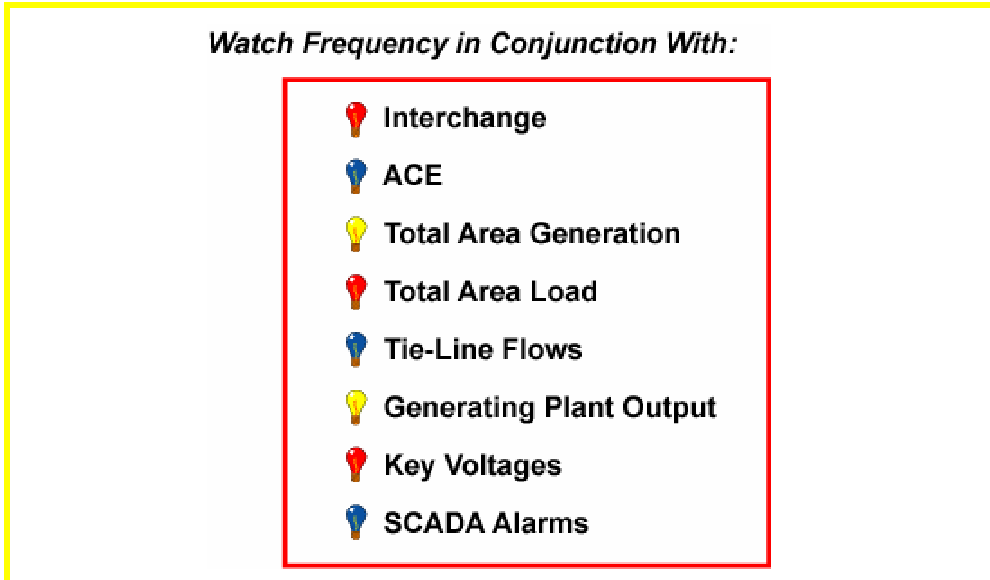
When generators in the interconnected systems respond to a generator trip, the responding generators will enter into a period of oscillations. The oscillations may last several minutes following a large disturbance. If the oscillations grow large enough, responding units could trip and lead to severe consequences in the interconnected system. Chapter 8 will examine generator oscillations in greater detail.

4.11 Role of the System Operator

Many experienced system operators will concur that the single most important piece of information available to an operator is the power system frequency. By monitoring a chart of system frequency along with other available system data, an experienced system operator can estimate the type, size, and perhaps the location, of power system disturbances. Figure 4-59 lists some of the additional data a system operator may consult when evaluating a frequency disturbance.

As an example of a system operator analyzing a disturbance, consider a generation loss. Following a generation loss a control area's ACE should be zero if the loss was external and approximately equal to the loss if the loss was internal. However, in the real world tie-line bias AGC does not work perfectly. A control area will develop a non zero ACE if the loss is external or internal. If the loss is external, the ACE will typically be small. A system operator would note the small value of ACE and note the direction and magnitude of their tie-line flows to verify that the loss was external. If the loss is internal, ACE should roughly approximate the loss and tie-line flows should swing so MW is flowing into the deficient control area.

If the B value is incorrect, ACE will not be zero for an external disturbance.



By simultaneously viewing frequency recordings from several areas of the power system, a system operator can determine if islands have formed.

Figure 4-59
Data Available to a System Operator

4.11.1 Frequency Control Duties

The majority of the time the automatic control systems, such as the governor and AGC, will control frequency. If these systems fail or must be disabled, the system operator may have to take a more active role in the frequency control process. A system operator's frequency control duties range from the routine chores to rare emergency duties.

A routine frequency control duty would include a system operator assisting AGC with the control of frequency during the morning load rise. AGC may not move the units fast enough so a system operator may manually assist the AGC process by pushing the units along a little faster.

In many control areas, AGC is automatically suspended if frequency falls below 59.8 HZ.

An emergency frequency control duty may follow a system disturbance after which a control area's AGC system is automatically suspended. The system operator assumes direct responsibility for frequency control until the power system problems can be diagnosed and corrected and AGC resumed.

4.11.2 Islanded Systems and Frequency Control

Chapter 11, Power System Restoration will expand on frequency control in an island.

When a disturbance occurs that separates the power system into islands, the island may have a generation surplus or deficiency. Governors and UFLS will attempt to achieve a match between generation and load. Assume this is successful and the frequency is stabilized at a new value. Normally the AGC system would return the frequency to 60 HZ. However, islanding may force the control area to suspend AGC. As you recall the AGC sends signals to the control area's generators to adjust governor set-points. If an island occurs within a control area, the AGC system's controlled generators may not be included in the island. Therefore, it is reasonable practice for a control area to disable AGC if the control area breaks into separate islands.

If the AGC is disabled, the system operator must return the frequency of the islands to 60 HZ. To raise an island's frequency, a system operator can have on-line generators raise generation levels, start peaking units, or if no generation is available, manually drop load within the island. To lower frequency, a system operator would request that generators within the islanded area lower generation.

If the interconnected system breaks into or is restored into islands and AGC is used, the method by which AGC controls the power system may be modified. During normal interconnected operations, AGC is typically set in a "tie-line bias" mode of operation. This means that frequency is monitored to maintain 60 HZ but any corrections are "biased" or modified based on the difference between scheduled and actual net interchange.

During islanded operation, the island's tie-lines to neighboring systems are severed. The islanded system cannot control to non-existent tie-line flows so AGC may be switched to a mode of operation called "flat-frequency" control. In this mode of operation the difference between the actual and scheduled frequency is all that drives the AGC control signals.

4.11.3 A Simple Example

Figure 4-60 contains data for an actual event that occurred in the PJM system. The system operator on duty was monitoring the power system. Initially all indications were normal. Suddenly the system operator was presented with the data illustrated in Figure 4-60. What does the system operator conclude?

PJM is the acronym for the Pennsylvania, New Jersey, Maryland area power system.

The data indicates that MW flow has reversed from north to south to south to north. Frequency has risen above 60 HZ. What system event would cause flows to reverse and frequency to rise?

If frequency rises, one can typically assume that load was lost. Based on the new directions for power flow one could further deduce that the load was lost in the south.

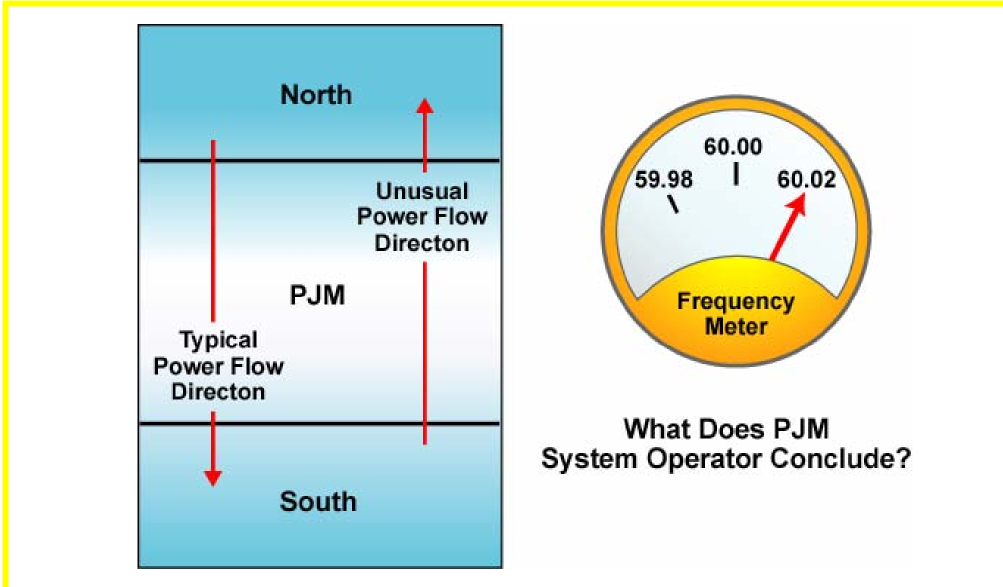


Figure 4-60
Frequency Incident on PJM System

Summary of Frequency Control

4.1.1 The Changing Load

- Power system load is constantly changing. This is why the maintenance of a relatively constant system frequency is difficult.

4.1.2 Need for Frequency Control Systems

- Human, manual based control is not sufficient to maintain frequency. Complex control systems are required.

4.1.3 Definition of a Control System

- A control system automatically controls the output of a system based on measurements of various inputs and outputs.

4.1.4 The Energy Balance Concept

- When generation is lower than load, frequency will fall. When generation is greater than load, frequency will rise.

4.1.5 Normal and Abnormal Frequency Deviations

- When the actual frequency deviates from the scheduled frequency, a frequency deviation has occurred. Normal frequency deviations are small frequency deviations. Normal deviations will always occur due to the constant adjustments to load and generation. Abnormal deviations are larger deviations that result from sudden, large changes to the generation supply or to the load.

4.1.6 The Load/Frequency Relationship

- Non-motor load is not significantly impacted by frequency. Motor load is strongly impacted by frequency. A 1% change in frequency will typically lead to a 2% change in the total system load magnitude.

4.1.7 Power System Inertia

- Inertial energy or rotational energy is energy stored in spinning mass. Power systems hold inertial energy in their generators and motors.

4.2.1 Introduction to Governors

- System generators use governor control systems to control the generator's speed of rotation.

4.2.2 Centrifugal Ballhead Governor

- Centrifugal ballhead governors are mechanical governor control systems in which flyweights rotate in proportion to shaft speed.

4.2.3 Modern Electronic Governors

- Many newer generators use electronic governors. Governor settings, such as droop and deadband, can often be chosen via software.

4.2.4 Governor Droop Curves

- To simplify the description of governors, shaft speed is equated to system frequency and valve position to MW output.
- An isochronous governor will attempt to maintain a 60 HZ system frequency. A governor may be placed in isochronous control mode if its generator is solely responsible for frequency control.
- Droop is required on governors used in interconnected power systems. Without droop characteristics the governors on parallel generators will compete for load changes. Droop forces generators to respond to frequency disturbances in proportion to their size.

4.2.5 Governor Control in an Islanded Power System

- The load reference set-point is the MW the governor will direct the generator to produce when frequency is at the scheduled value.
- For an isolated generator, an adjustment to a governor set-point is equivalent to a change in the stored energy. Set-point adjustments change the target frequency which changes the stored energy.

4.2.6 Governor Control in an Interconnected System

- When a frequency deviation occurs, governors throughout the Interconnection will respond. Once the cause of the deviation is determined, the control area responsible will restore the frequency. As frequency is restored, the majority of the units that provided governor response will slide along their droop curves to their original set-points.

4.2.7 Frequency Traces

- On a strip chart recording of an Interconnection's frequency following a major disturbance, one may notice a "tail" to the frequency chart. The tail approximates the governor response. If no tail exists, the governor response was minimal.

4.2.8 Generator Response and Droop Settings

- If two similar size generators have the same % droop, expect a similar MW response to a frequency disturbance. If two similar generators have a different % droop, expect a different response to a frequency disturbance. The generator with the smaller droop will provide a greater response.

4.2.9 System Frequency Response Characteristic

- The frequency response characteristic (FRC or β) of a power system is that system's natural response to a frequency disturbance. FRC data is often reported in units of MW/0.1HZ. The FRC will vary depending on current system conditions.
- The frequency bias (B) is used in a control area's AGC systems. The B value should be representative of the typical FRC for the control area.

4.2.10 Response to a Loss of Generation

- When frequency disturbances occur in an interconnected power system, the entire system will be impacted. The farther an observer is from the point of the disturbance, the less of a disturbance they will initially see.

4.2.11 Limitations to Governor Response

- Governors do not respond the instant frequency deviates from 60 HZ. Governors have a deadband within which they are designed not to respond. A typical deadband would be 0.036 HZ. A governor with a 0.036 HZ deadband would not respond to frequency deviations within ±0.036 HZ of the target frequency (60 HZ).
- A governor control system can be perfectly designed and tuned. However, if the generator behind the governor is not capable of responding, the governor is useless. The type of unit controlled by the governor strongly impacts the MW a governor will actually respond with. In general, hydro units provide excellent governor response. Steam units can provide good governor response depending on the type of unit.
- Governor response can be intentionally eliminated. When a plant intentionally prevents governor response it is called "blocking" the governor.

4.3.1 Introduction to Automatic Generation Control

- Governor control is primary frequency control while AGC is secondary frequency control. Governors arrest frequency deviations while AGC restores frequency to the scheduled value.

4.3.2 Control Areas

- The entire power system is divided into control areas. Control areas are individually responsible for matching their scheduled net interchange to their actual net interchange. All of an Interconnection’s control areas are jointly responsible for maintaining the scheduled (typically 60 HZ) system frequency.
- The tie-lines that connect control areas must be metered to determine the actual net interchange. The same metered data is sent to all control areas that share the tie-line.
- The AGC related duties of a control area can be summarized in two statements:

    1. To ensure that the sum of the actual MW flows on all tie-lines with neighboring control areas are as scheduled.
    2. To assist all the other control areas in the Interconnection with frequency regulation.

4.3.3 Types of Interchange

- Positive interchange is MW flow out of a control area. Negative interchange is MW flow into a control area.
- There are three types of interchange; actual, scheduled and inadvertent. Actual net interchange is the sum of the actual MW flow on all of a control area’s tie-lines. Scheduled net interchange is the sum of the scheduled MW flow on all of a control area’s tie-lines. Inadvertent net interchange is equal to the difference between the actual and scheduled net interchange.

4.3.4 Function of an AGC System

- An AGC systems function in an interconnected power system is to assist with Interconnection frequency regulation and maintain a close match between the control area’s actual and scheduled net tie-line flows.

4.3.5 Components of an AGC System

- An AGC system has components in the control center, at the controlled generators, and in the transmission system. AGC gathers data to determine frequency and interchange errors. These errors are combined to compute an ACE signal. The ACE signal is used to adjust controlled generators output levels.

4.3.6 Modes of AGC Control

- There are three common modes of AGC control; constant frequency, constant net interchange, and tie-line bias control. Tie-line bias control is normally used by most control areas.
- The constant frequency control mode of AGC compares actual to scheduled frequency and adjusts generation to return frequency to the scheduled value.
- The constant net interchange mode of AGC compares actual to scheduled interchange and adjusts generation to eliminate the interchange error.
- Tie-line bias AGC is a combination of the constant net interchange and constant frequency modes of AGC. In tie-line bias AGC an interchange error is determined. The interchange error is biased by the frequency error to determine an ACE signal.

4.3.7 Tie-Line Bias Control

- The ACE equation for tie-line bias control is:

$$\boxed{ACE = \left[NI_A - NI_S\right] - 10B\left[F_A - F_S\right] - \left[I_{ME}\right]}$$

- The "B" or frequency bias value is based on the frequency response characteristic (FRC) for the control area and is stated in MW/0.1 HZ.

4.3.8 Control Area Implementation of AGC

- The implementation of AGC in actual control areas is a complex task. The actual ACE values calculated based on raw data are called raw ACE. Raw ACE is massaged to determine the filtered ACE. Filtered ACE is used to drive the controlled generators.

4.4.1 Operating Reserves

- Operating reserves consist of spinning and non-spinning reserves.
- Spinning reserves are synchronized to the system. A governor cannot increase a generators output unless that generator is carrying spinning reserves. A subset of spinning reserves is regulating reserves. Regulating reserves are spare MW capability that is responsive to AGC signals.

- Non-spinning reserves are not synchronized to the system but are available as MW capability within a specified time period.

4.4.2 Responsive Reserves

- Responsive reserves are rapidly available to respond to frequency deviations. Responsive reserves can be spinning or non-spinning reserves.

4.4.3 NERC Reserve Definitions

- NERC defines two categories of operating reserve; regulating and contingency.

4.5.1 Definition of Time Error

- Anytime frequency varies from 60 HZ, time error will accumulate. The amount of time error accumulated depends on the magnitude of the frequency deviation and the length of time the deviation is held.

4.5.2 Monitoring Time Error

- Each Interconnection appoints a time error monitor. The time error monitor records the accumulated time error and initiates time error corrections.

4.5.3 Correcting Time Error

- Time error corrections consist of periods in which scheduled frequency is intentionally varied from 60 HZ. If time error is fast, a frequency of 59.98 HZ is scheduled to reduce the fast error. If time error is slow, a frequency of 60.02 HZ is scheduled to reduce the slow error.

4.6.1 NERC's Old Control Performance Criteria

- In 1973, NERC implemented two criteria for control performance during normal conditions, referred to as "A1 - Zero Crossing" and "A2 - L_d Compliance".

4.6.2 NERC Performance Standards

- The performance standards (CPS1, CPS2, DCS) were implemented in February of 1998.
- CPS1 and CPS2 apply during both normal and disturbance conditions. The CPS is supplemented by a disturbance control standard (DCS) that applies only during disturbance conditions.

- CPS1 is intended to provide a control area with a frequency sensitive evaluation of how well the control area is meeting its demand requirements. A CPS1 magnitude of 100% is the minimum acceptable performance.
- CPS2 is designed to limit the magnitude of a control area's ACE. CPS2 states that the average ACE value for each 10-minute period shall not exceed a constant called "L_{10}". To comply with the CPS2, each control area shall keep their ACE within the L_{10} bounds 90% of the time.
- To pass the CPS standard, a control area must conform to CPS1 100% of the time *and* conform to CPS2 90% of the time.
- The DCS states that a control area is responsible for recovering from a disturbance within 15 minutes of the start of the disturbance. Recovery means to restore ACE to either zero or its pre-disturbance value. Every control area must comply with the DCS standard 100% of the time.

4.7.1 Effects on Steam Turbine Blades

- The low pressure stage steam turbine blades may vibrate and eventually fail if operated (while under load) outside of a 59.5 to 60.5 HZ frequency range for a substantial period of time.

4.7.2 Effects on Hydro and Combustion Turbines

- Hydro and combustion turbines are less susceptible to damage during off-frequency operation than steam turbines.

4.7.3 Effects on Other Power System Equipment

- Motor output torque and the motor's natural cooling action may be reduced during low frequency operation.
- Spinning load (motor) magnitude varies directly with the frequency.
- Transformers may overexcite during low frequency operation.

4.7.4 Effects on Active Power Flows

- To change power angle there must be relative acceleration. Low magnitude, transient frequency deviations are required if power angles are to change.

4.8.1 Power System Islands

- Power system islands may be created due to major disturbances. Those areas of an Interconnection that are weakly tied to neighboring systems are candidates for island formation.

4.8.2 Underfrequency Load Shedding (UFLS)

- UFLS is a drastic measure in which customer load is automatically shed to arrest a severe frequency decline. UFLS is designed to supplement governor control.
- Underfrequency tripping of transmission lines is not common but is used by some utilities.
- Automatic load restoration is used in some systems. Following activation of UFLS, if frequency recovers to a specified level, a portion of shed load may automatically be restored to prevent high frequency.

4.8.3 Underfrequency Generator Protection

- UF tripping of generators is typically applied to steam turbine units. The purpose is normally to protect the turbine blades. The UF tripping of steam turbines must be coordinated with the UFLS program.

4.9.1 Analysis of a Frequency Deviation

- The rate at which the frequency declines following a generation loss is dependent upon the amount of generation lost, the load/frequency relationship, the inertia of the system, and the speed and magnitude of the governor response.
- The lowest point of the frequency drop is called the frequency undershoot or the spike. The frequency first spikes low and then recovers to a stabilized value due to the natural time lag in the governor response. Once the full impact of the governor response is available the frequency will recover from the undershoot point to a stabilized value. AGC signals to the units in the deficient control area will recover the frequency from the stabilized value back towards 60 HZ.

4.9.2 Actual Expanded Frequency Plots

- When expanded time scale frequency plots are examined for disturbances in the different Interconnections, the impact of governor response is easily observed.

4.9.3 Effect of Time and Distance

- Following a generation loss, the observed frequency deviation will vary depending on the observers location with respect to the loss. What varies is the short term undershoot magnitude. The stabilized frequency is approximately the same throughout the Interconnection.

4.9.4 Frequency Relation to Power Angle

- Following a generation loss, frequency must be different throughout an Interconnection. The frequency differences are necessary to achieve relative acceleration and power angle changes.

4.9.5 Speed of the Traveling Frequency Wave

- An actual example was described in which the speed of the traveling wave of a frequency disturbance was measured at approximately 200 miles per second.

4.10.1 The Electromagnetic Energy Stage

- The response of the power system to a major generation loss can be described by a four stage process. The electromagnetic energy stage begins immediately and lasts approximately 1/3 second. During this stage the remaining system generators supply energy from their magnetic fields.

4.10.2 The Inertial Stage

- The inertial stage follows the electromagnetic energy stage. During the inertial stage, spinning mass (motors and generators) in the system provide a portion of their rotational energy. The inertial stage lasts from approximately 1/3 second to 5 seconds after the loss.

4.10.3 The Governor Response Stage

- During the governor stage units respond in relation to their governor settings. The governor stage lasts from approximately 2 to 20 seconds after the loss.

4.10.4 The AGC Stage

- During the AGC stage AGC controlled units in the control area that suffered the generation loss attempt to return ACE to zero and restore system frequency.

4.10.5 Illustration of a Staged Response

- A sample system was illustrated and the four stage response to a generation loss described.

4.11.1 Frequency Control Duties

- When the system is normal, automatic systems will typically control frequency. However, a system operator may occasionally need to take active control of the frequency control process.

4.11.2 Islanded Systems and Frequency Control

- When the interconnected system breaks into islands, AGC is often suspended. The system operator must then assume an active role in the frequency control process until the system is restored.

4.11.3 A Simple Example

- A simple example was described to illustrate frequency control related decision making by a system operator.

Frequency Control Questions

1. According to the load/frequency relationship, a 1% change in frequency will lead to what approximate magnitude of load change in a typical 10,000 MW system?

   A. 500 MW

   B. 1000 MW

   C. 200 MW

   D. 50 MW

2. A governor with a 0% droop is called:

   A. Flat frequency control

   B. Transient droop

   C. A blocked governor

   D. An isochronous governor

3. Steam turbine generators typically have better governor response than hydro-electric generating units.

   A. True

   B. False

4. A control area's frequency bias setting is equal to:

   A. The control area's frequency response characteristic (FRC)

   B. The natural response of the control area

   C. The AGC system's bias value

   D. All of the above

5. All of the following are modes of AGC **<u>EXCEPT</u>**:

   A. Flat tie-line control

   B. Isochronous control

   C. Flat frequency control

   D. Tie-line bias control

6. In which stage of a generator's response to a system disturbance is the power flow supported primarily by the generator's excitation system?

   A. Governor response stage

   B. AGC stage

   C. Electromagnetic energy stage

   D. Inertial stage

7. If system frequency were to run at 60.02 HZ for two consecutive hours, how much positive time error would occur?

   A. 2.0 seconds

   B. 2.4 seconds

   C. 1.0 second

   D. 1.2 seconds

8. A control area has a bias of -150 MW. Frequency falls 0.05 HZ due to an external disturbance. How many MW would you expect this control area to provide to the disturbance?

   A. -75

   B. +75

   C. -150

   D. +150

9. An isochronous governor has a droop setting of:

   A. 5%

   B. 0%

   C. 10%

   D. 8%

10. What element of the power system is typically most susceptible to damage from prolonged operation at frequencies above or below 60 HZ?

    A. Transformers greater than 300 MVA

    B. Low pressure turbine stage blades

    C. Synchronous motors

    D. Induction motors

11. Hydro-electric generators typically exhibit better governor response than thermal generators because:

    A. Hydro-electric generators typically have more stored energy

    B. Thermal generators typically do not carry spinning reserve

    C. Water is a better conductor than steam

    D. Hydro-electric generators utilize microprocessor based governors while thermal units utilize mechanical governors

12. A generator with a 6% droop governor is connected to a 60 HZ power system. Initially the generator is at 100% load. Frequency then falls 0.9 HZ. What is the generator's new % output?

    A. 75%

    B. 100%

    C. 0%

    D. 25%

13. What magnitude of frequency change would cause a 10% droop governor to move its generator from zero to full output in a 60 HZ system?

    A. 6 HZ

    B. 10 HZ

    C. 3 HZ

    D. 5 HZ

14. Which component of the CPS is intended to limit the magnitude of unscheduled power flows?

    A. DCS 1

    B. DCS 2

    C. CPS1

    D. CPS2

15. What is the upper limit to the CPS1 magnitude?

    A. 50%

    B. 100%

    C. 200%

    D. No limit

Frequency Control References

1. The Field of System Governing—Article by Mr. Albion Davis that was obtained from IEEE archives.

   This article was written over 50 years ago but is still very applicable to modern governor control systems. The article is an understandable tutorial on utility generator governors.

2. Impacts of Governor Response Changes on the Security of North American Interconnections—EPRI report #TR-101080. October 1992.

   Well written report that examines the state of governor response within NERC. This report includes a bibliography on governor response.

3. CPC Revisited—Article by Mr. Larry R. Day that appeared in the October, 1994 issue of IEEE Computer Applications in Power.

   Well written, short article that examines the history and use of NERC control performance criteria.

4. The Control of Prime Mover Speed—A series of three reports written by the Woodward Governor Company of Fort Collins, CO. Woodward Bulletin #25031.

   The single best source of information the author of this text located on governor control system components and operation.

5. Understanding Automatic Generation Control—Article which appeared in the August, 1992 issue of IEEE Transactions on Power Systems.

   This article reviews the requirements of an AGC system.

6. Power System Response to Frequency Transients—IEEE paper 71-TP-82-PWR.

   Section 4.9.5 of this text was based on this paper (and other writings) by Mr. A. Doyle Baker.

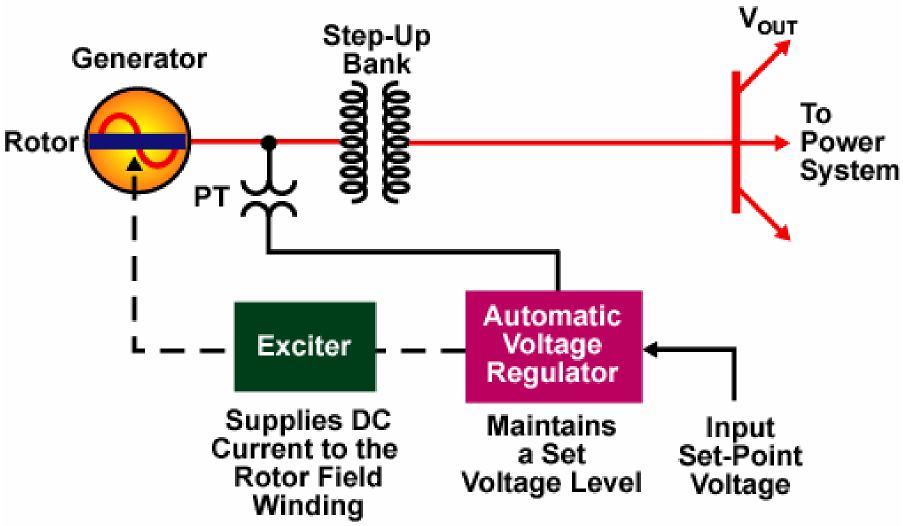
7. Control Area Concepts and Obligations—NERC report published July, 1992.

   Brief report that summarized the duties of a control area and NERC operating criteria and guides related to generation control.

8. <u>NERC Operating Manual</u>

   The current version of the NERC Operating Manual is the definitive source of information concerning NERC Policies.

5
VOLTAGE CONTROL



5.1 Introduction

Voltage control is closely related to the availability of reactive power.

5.2 Causes of Low Voltage

Heavy power transfers are a principle cause of low voltage due to the Mvar losses.

5.3 Causes of High Voltage

Lightly loaded transmission lines are a principle cause of high voltage.

5.4 Effects of Low Voltage

Low voltages can impact power system equipment and operations in numerous ways.

5.5 Effects of High Voltage

High voltages can lead to the breakdown of equipment insulation, cause transformer over-excitation, and adversely affect customer equipment.

5.6 Use of Voltage Control Equipment

Capacitors, reactors, LTCs, and SVCs supplement generators as means of controlling system voltage.

5.7 Role of the System Operator

The system operator is usually responsible for maintaining reactive reserves and controlling voltage deviations.

5.1 Introduction to Voltage Control

5.1.1 Review of Active, Reactive and Complex Power

There are two types of power produced by the system generators, active (MW) and reactive (Mvar). The active power is what does the work in the system. Active power lights the lights, produces heat in the heaters, and turns the motors. Reactive power enables the active power to do its work. AC power systems cannot survive without adequate amounts of both types of power.

A 1Φ system is used to keep this description as simple as possible.

Figure 5-1 graphically illustrates the concepts of active and reactive power. The top portion of the figure is a plot of the voltage and current for a typical 1Φ system. Notice that the voltage and current waves are not in-phase with one another. The voltage wave crosses the zero axis before the current wave. The current wave lags the voltage wave by the phase angle "θ" (Greek letter "theta").

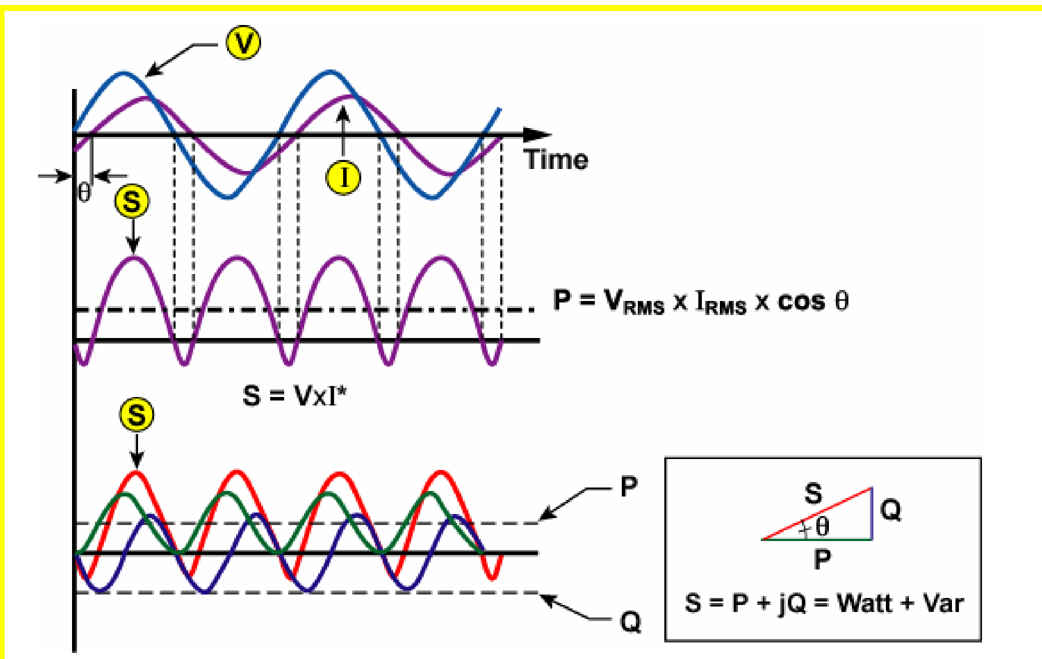


Figure 5-1
Active, Reactive and Complex Power

The asterisk next to the current (I) indicates that the current is a "conjugate". This is required to keep our sign conventions for reactive power consistent.*

The total or complex power being delivered by this 1Φ system is the product of the voltage and current. In equation form this is stated as:

$$\boxed{S_{1\phi} = \text{Complex Power} = I^* \text{ x } V}$$

Complex power (symbol “S”) has units of MVA and is composed of a mixture of MW (symbol “P”) and Mvar (symbol “Q”).

The middle portion of Figure 5-1 is a plot of the complex power (“S” or MVA) being delivered by this system. This complex power wave was formed by multiplying a point on the voltage wave by the corresponding point on the current wave for each point on time. Notice how the complex power wave oscillates up and down and is at times negative. The negative portion of the wave represents periods in which power is actually being absorbed back into the system generators.

The bottom portion of Figure 5-1 breaks down the complex power wave into two separate waves. One wave is always positive and has an average value of “P”. This is the active power or MW portion of the power. The other wave oscillates equally between positive and negative. Over each cycle the average value of this power wave is zero. This wave represents reactive power and has maximum and minimum values of “±Q”. The summation of active (“P”) and reactive power (“Q”) is done using the power triangle as illustrated in the bottom right of Figure 5-1.

Figure 5-2 further illustrates the concepts of active and reactive power. Three types of systems are represented in this figure: pure resistive, pure inductive and pure capacitive. In the resistive system voltage and current are in-phase with one another. The complex power (“S” or MVA) is found by multiplying the voltage and current waves together. Notice that the complex power is always positive. This means that there is no reactive power in a purely resistive system. All the complex power is active power or MW.

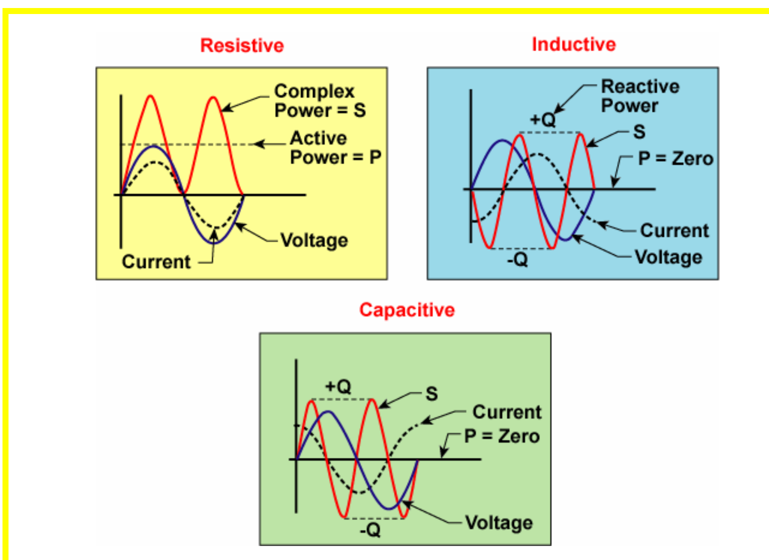


Figure 5-2
Reactive Power Storage

In the pure inductive system of Figure 5-2 the current wave lags the voltage wave by ¼ cycle or 90°. The complex power wave oscillates equally between negative and positive. The complex power has an average value of zero. In a pure inductive system there is no active power; all of the complex power is reactive or Mvar.

The last system illustrated in Figure 5-2 is a pure capacitive system. Notice that the current leads the voltage by 90°. The complex power again oscillates equally between positive and negative and has an average value of zero. In a pure capacitive system there is no active power; all the power is reactive.

5.1.2 Reactive Power & Voltage Levels

We have stated that over a period of time reactive power has an average value of zero. A useful way to visualize reactive power is to think of it as oscillating back and forth between the system's generators and loads. Most of the load in the power system is an inductive type load. Inductive loads alternately store reactive power in their magnetic fields and then return the Mvar back to the system. Inductive loads are constantly repeating this store/return cycle.

Capacitive loads also follow a storage/return cycle. Capacitive loads store reactive power in their electric fields. Compare the inductive and capacitive portions of Figure 5-2, and note that the storage and return cycles of inductive and capacitive loads are opposite one another. When an inductive load needs to absorb reactive power from the system, a capacitive load is ready to return reactive power to the system.

System operators can take advantage of the difference in capacitive and inductive load reactive power storage cycles to help with system voltage control. As stated earlier, most of the load on the system is inductive load. When an inductive load exchanges reactive power with the system, the exchange is between the load and the system generators. This means that current is flowing between the loads and the generator. This current causes voltage drops and power losses as it flows through the system. One way to reduce these voltage drops and losses is to reduce the amount of reactive power flowing through the system.

A simple way to reduce the amount of reactive power flowing is to add capacitors near the inductive load. The capacitor can take the place of the generator as the source of reactive power. When the inductive load needs to store reactive power the capacitor is ready to give its reactive power back to the system. The reactive power does not have to come from the generators so less voltage drop and fewer losses occur across the power system.

Figure 5-3 illustrates the use of a capacitor to supply the reactive needs of an inductive load. As far as the power system is concerned, the capacitor acts like a source of reactive power for the inductive load. The generator's reactive power obligation is reduced when the capacitor is switched in-service. Less reactive power flow from the generator means less system current flow, less power loss, and less voltage drop.

Notice how the reactive power flow from the generator is reduced once the capacitor is switched in-service.

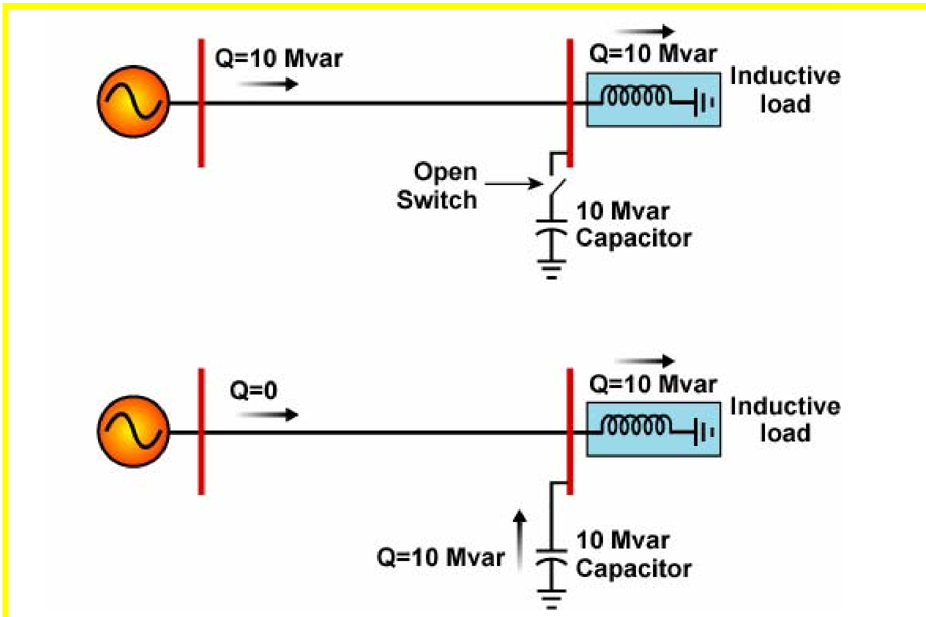


Figure 5-3
Use of a Capacitor

5.1.3 Flow of Reactive Power

The previous section described how reactive power actually oscillates back and forth between the generators and loads. However, it is common practice to think of reactive power as flowing in a certain direction. By convention, when a generator is exchanging reactive power with an inductive load we say that positive reactive power is flowing from the generator to the load. When a generator is exchanging reactive power with a capacitive load we say that positive reactive power is flowing from the load to the generator.

If these conventions for the flow of reactive power are used we can further say that reactive power will normally flow from the high voltage to the low voltage point. For example, to get more reactive power to flow from a generator, simply raise the generator's voltage level.

Figure 5-4 summarizes these conventions for the flow of reactive power. In the top of the figure reactive power is flowing from the generator to an inductive load. In the bottom portion of the figure the generator is absorbing reactive power from a capacitive load.

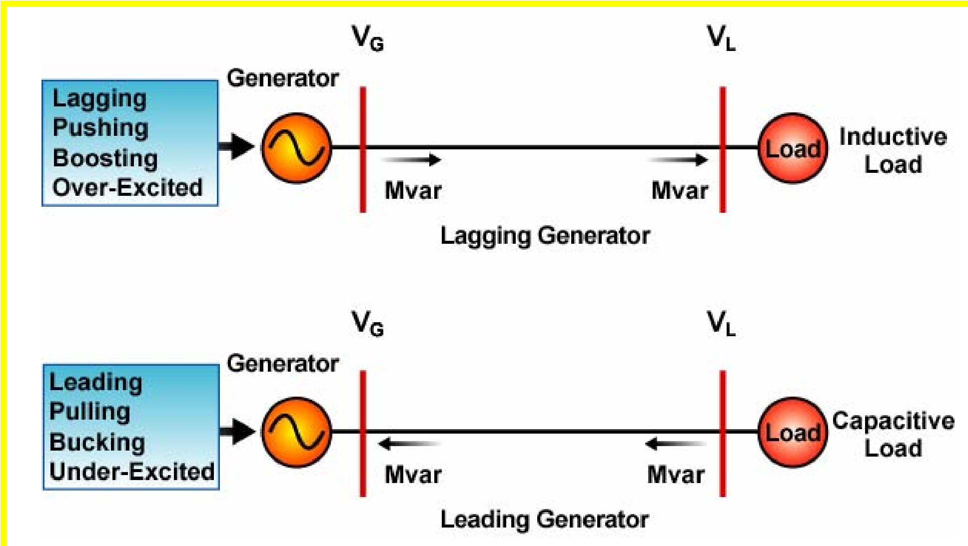


Figure 5-4
Direction of Reactive Power Flow

A generator supplies reactive power to an inductive load. A generator absorbs reactive power from a capacitive load.

When a generator is supplying reactive power to the system, the generator mode of operation can be referred to as lagging, boosting, pushing or overexcited. When a generator is absorbing reactive power from the system, the generator mode of operation can be referred to as leading, bucking, pulling or underexcited.

5.2 Causes of Low Voltage

This section will describe several common causes of low voltages. Voltage levels are directly tied to the availability of reactive power. If adequate reactive power resources exist in the areas where it is needed, system voltages can be controlled. If there is a deficiency of reactive power voltage levels will drop. If there is an excess of reactive power voltage levels will rise.

For the remainder of this text, shunt capacitors are treated as sources of reactive power.

5.2.1 Reactive Power and Low Voltage

The root cause of low voltage is a deficiency of reactive power. There are many ways in which this reactive deficiency can develop. No system is immune from low voltages. A power system may be able to progress through one day’s heavy load periods with no low voltage problems. This same system could experience low voltages if it had a major element out-of-service during the day’s peak load hours. Some common causes of low voltage include:

- Heavy Power Transfers
- Transmission Line Outages
- Reactive Equipment Outages

- Failure to Get Ahead of the Voltage
- Motor Stalling

5.2.2 Heavy Power Transfers

Throughout this section of the text we will often use a simple "radial" power system to illustrate concepts. A radial power system is illustrated in Figure 5-5. A radial power system has generation at one end of the system, load at the other and a transmission path connecting the two.

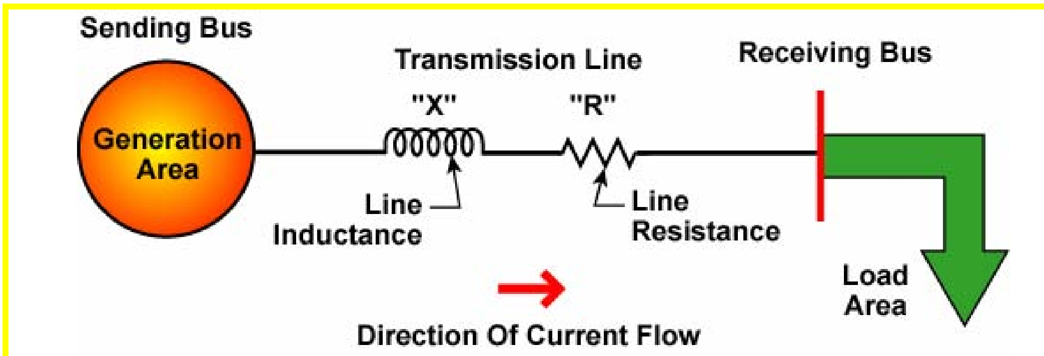


Figure 5-5
Radial Power System

Also note in Figure 5-5 the transmission line's natural inductance and resistance is ignored. (For this description, the line's natural capacitance is ignored.)

Reactive Losses

Reactive power is never actually lost. The term reactive losses is used to refer to reactive power that is in use by a system element.

As complex power (both active and reactive) flows through the radial system of Figure 5-5 voltage drops will occur. The strength of the system voltages is directly related to the availability of reactive power. The greater the amount of spare reactive power, or reactive reserves, the more capable the system is of maintaining its voltages. One way to increase reactive reserves is to minimize the reactive usage by the system, or to reduce the reactive losses of the system.

The formulas given in Figure 5-6 for active and reactive power losses can be easily derived (using Ohm's Law) from the simple radial power system illustrated in Figure 5-5. These two formulas are used to calculate the active and reactive power losses as power flows through the transmission system.

$$\text{MW Loss} = 3\left[\frac{P^2 + Q^2}{V^2}\right] \times R = 3I^2R$$

$$\text{Mvar Usage} = 3\left[\frac{P^2 + Q^2}{V^2}\right] \times X = 3I^2X$$

Figure 5-6
MW & Mvar Losses

There are two forms of each loss equation stated in Figure 5-6. One form is in terms of the complex power and the voltage $[(P^2 + Q^2)/V^2]$ and the other in terms of the current (I^2). The two forms are equal, they are simply different ways of stating the same thing.

Based on these loss formulas, to minimize power losses minimize current and maximize voltage. The lower the current, the lower the losses. The greater the voltage, the lower the losses. An additional method of reducing the losses is to minimize the line's impedance. Note from Figure 5-6 that active power (MW) losses are dependent on the line's resistance while reactive power (Mvar) losses are dependent on the line's inductive reactance. In high voltage transmission systems, the line's inductive reactance is much greater than the line's resistance. A 100 mile long 345 kV line may have a resistance of 6 Ω's and an inductive reactance of 60 Ω's. The fact that the inductive reactance of a line is much greater than its resistance strongly impacts voltage control. It is very difficult to transmit reactive power long distances. When attempts are made to transmit Mvar long distances, the reactive losses are often so large that system voltages will tend to fall as reactive power reserves are used up.

Chapter 6 on Voltage Stability examines the problems associated with transmitting reactive power in greater detail.

MW Transferred Versus Mvar Required Plot

Reactive power losses are directly related to system voltage levels. The heavier the power transferred through the system, the greater the reactive power losses and voltage drop will be. If system loads are high or if power transfers are high, the power system voltages will correspondingly decline unless additional reactive power support can be made available.

If the active power transfer on the system is extremely high, even a small increase in MW transfer could lead to a large increase in Mvar usage. Figure 5-7 illustrates this concept. As MW transfer increases, it takes more and more Mvar to maintain voltages. As illustrated in Figure 5-7 increasing the MW transfer from 600 to 800 increases the Mvar that must be supplied from the system from 75 to 220 Mvar. If this additional Mvar is not supplied by the system voltages will fall.

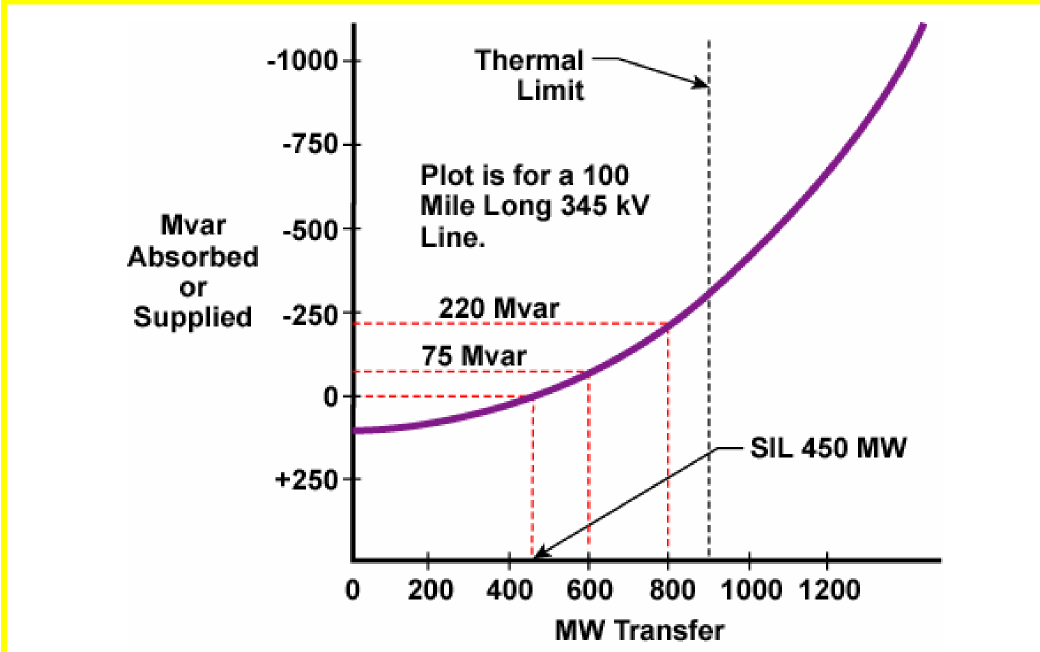


Figure 5-7
MW Required Versus Mvar Transferred

The SIL of this transmission line is 450 MW.

Incremental Increase in Reactive Losses

From the shape of the curve in Figure 5-7 it can be seen that reactive losses do not increase uniformly as active power transfer increases. For each additional increment of active power transfer it takes a larger and larger increment of reactive power to maintain system voltage. In other words, the incremental reactive losses are increasing at an increasing rate.

The amount of the increase in the reactive losses are dependent on the line loading. In practice, the increase will lie between the square rule and the cube rule.

Since reactive power losses are a function of the square of the current, a good rule of thumb is to assume that if you double the active power transfer, you will quadruple (2x2) the reactive power losses. However, this rule of thumb may substantially underestimate the reactive power needs of the system. A more conservative rule of thumb is to assume that in a heavily loaded power system, any increase in active power transfer must be accompanied by the cube of that increase in reactive power injection. For example, if active power transfer is doubled, reactive power needs will increase by a factor of eight (2x2x2).

Significance of Surge Impedance Loading (SIL)

In Figure 5-7, note the point where the active power transfer on the line requires 0 Mvar from the system to support voltage. This point is called the “surge impedance loading” or SIL of the transmission line. The SIL is the point at which the Mvar from the line’s natural capacitance exactly provides the Mvar the line needs to support its voltage. Every transmission line has a SIL.

Lightly loaded lines are capacitive while heavily loaded lines are inductive.

The Mvar provided to the system from a transmission line's natural capacitance can be stated mathematically as:

$$\boxed{\text{Mvar Supplied} = \frac{V^2}{X_C}}$$

Where X_C is the line's capacitive reactance. Note that the Mvar supplied is a function of voltages, not current.

The Mvar used by a line can be stated mathematically as:

$$\boxed{\text{Mvar Used} = I^2\, X_L}$$

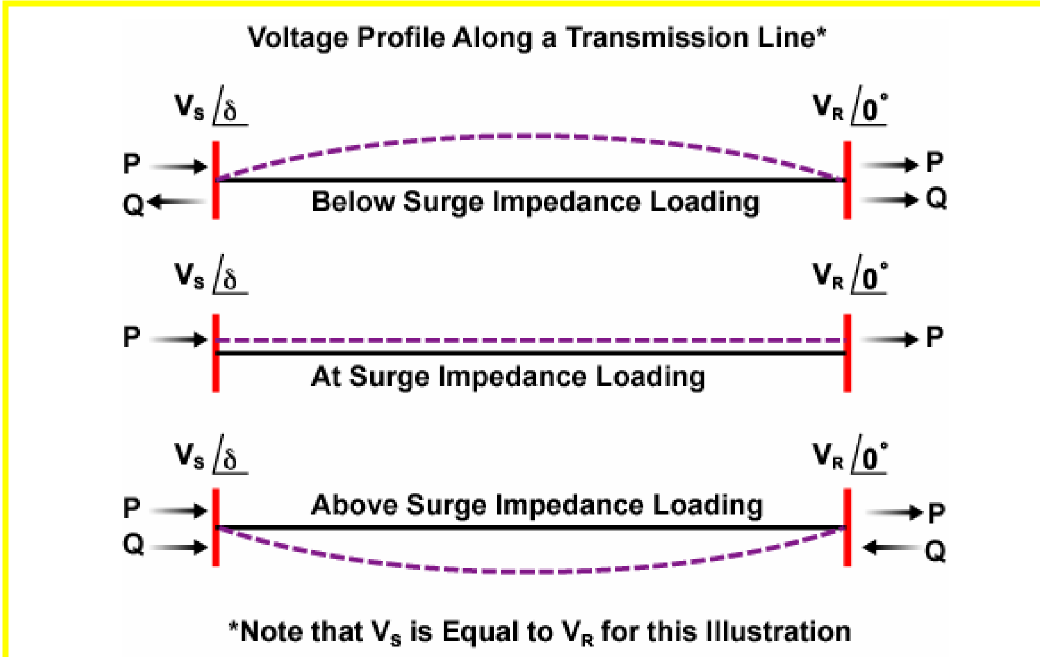
Where X_L is the line's inductive reactance. Note that the Mvar used is a function of current, not voltage.

The SIL of a line occurs when:

$$\boxed{\begin{gathered}\text{Mvar Supplied} = \text{Mvar Used} \\ \text{or} \\ \frac{V^2}{X_C} = I^2 X_L\end{gathered}}$$

When a transmission line is loaded below its SIL, the line is equivalent to a capacitor. The line provides Mvar to the power system. When a transmission line is loaded above its SIL, the line is equivalent to a reactor. The line absorbs reactive power from the system.

Much can be inferred about voltage levels across a transmission line if the SIL of the line is known. When a line is loaded below its SIL, the high voltage point on the line is toward the middle of the line. When a line is loaded at its SIL the line voltage profile is flat. When a line is loaded above its SIL the low voltage point is in the middle of the line. Figure 5-8 illustrates these points. The vertical dashed lines in Figure 5-8 represent voltage levels across a simple transmission system when the line is below, at, and above its SIL.



Note that this figure assumes the V_S and V_R buses are similar strength.

Figure 5-8
Illustration of Surge Impedance Loading

Unscheduled Active Power Flows

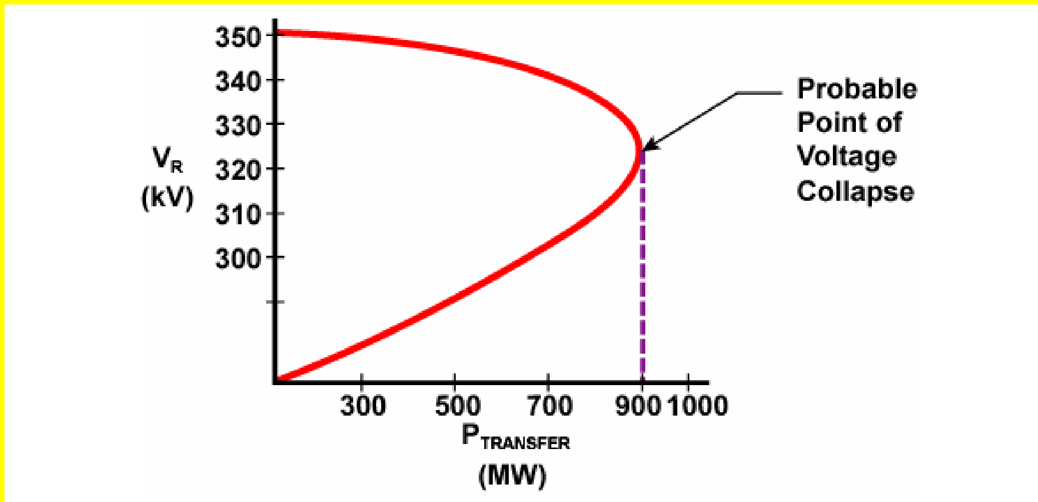
Many NERC systems arrange to compensate their members when unscheduled power flows negatively impact the member's system.

Unscheduled power flows may contribute to voltage drops. Power flow will always divide according to the relative impedance of the available paths. Utility "X" may own a transmission path and have no power schedule to flow across the path. However, other companies may be scheduling power in such a manner that their schedules heavily load Utility "X" lines. These unscheduled flows may lead to significant reactive loses and voltage drops.

Introduction to Power-Voltage Curves

A method of illustrating how voltage levels decrease as active power transfer increases is the power-voltage curve or P-V curve. A P-V curve is illustrated in Figure 5-9. The curve is best introduced for a simple radial power system such as was provided in Figure 5-5. A P-V curve illustrates that as active power transfer across the transmission system is increased, the voltage at the receiving substation gradually declines. This is due to the increased reactive losses in the system.

Note on Figure 5-9 that if the active power transfer is continually increased the system voltages will enter a period of rapid decline and can eventually collapse. The point of voltage collapse is the point at which the system runs out of usable reactive reserves.



Chapter 6 "Voltage Stability" addresses the use of P-V curves in greater detail.

Figure 5-9
P-V Curve

5.2.3 Transmission Line Outages

A transmission line may trip leading to increased loading on parallel lines and subsequent lower voltages. This is due to increased active and reactive power losses. The increase in reactive power losses will typically be more evident than the increase in active power losses.

Figures 5-10 and 5-11 illustrate how the loss of a major transmission line can lead to a large increase in reactive power losses and voltage drops. Figure 5-10 is a simple power system with two 345 kV lines. To maintain voltages in this system the generator is producing 148 Mvar. The system is also absorbing 312 Mvar from a strong neighboring bus (labeled the infinite system). The box in the lower left of Figure 5-10 lists loss data and reactive production data. The MW losses are 28, the Mvar losses 465. Note the total Mvar generation is 460 while the two 345 kV transmission lines' natural charging contributes 355 Mvar.

In Figure 5-11, one of the 345 kV lines trip. The power flows must readjust following the line trip. The remaining line is heavily loaded and active and reactive power losses sharply increase.

The box in the lower left corner of Figure 5-11 again lists loss and reactive production data. The MW losses have increased to 85, the Mvar losses to 1309. Note the total Mvar generation is now 1484 while the line charging has been reduced to 175 Mvar. The net increase in reactive power injection to this system was 1024 Mvar. Voltages in this system did not decline significantly due to the availability of 1024 Mvar of additional reactive power. If this additional reactive power had not been available the simple power system would likely have collapsed due to this outage.

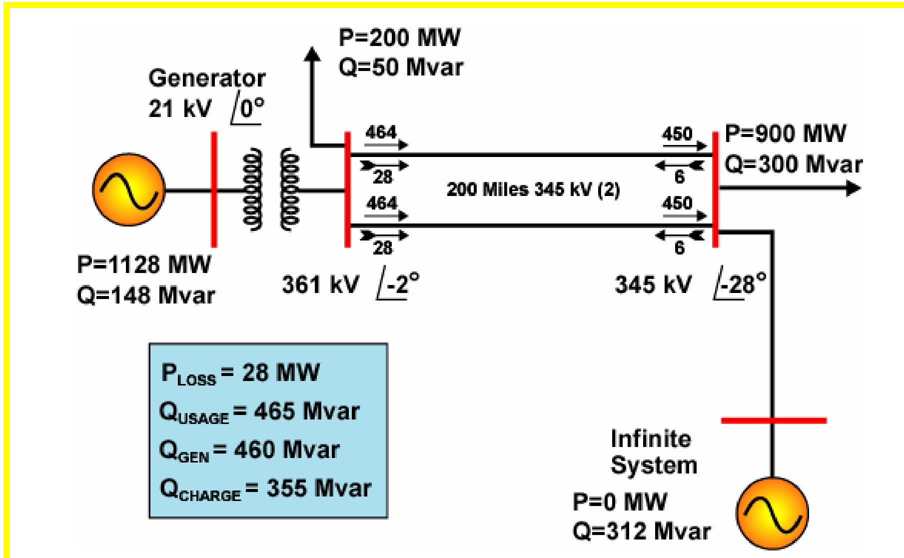


Figure 5-10
Reactive Power & Line Outages – Normal System

An indication of just how heavily loaded the remaining line is can be seen in the line's power angle. Note the angle spread across the transmission path has increased from 26° in Figure 5-10 to 68° in Figure 5-11.

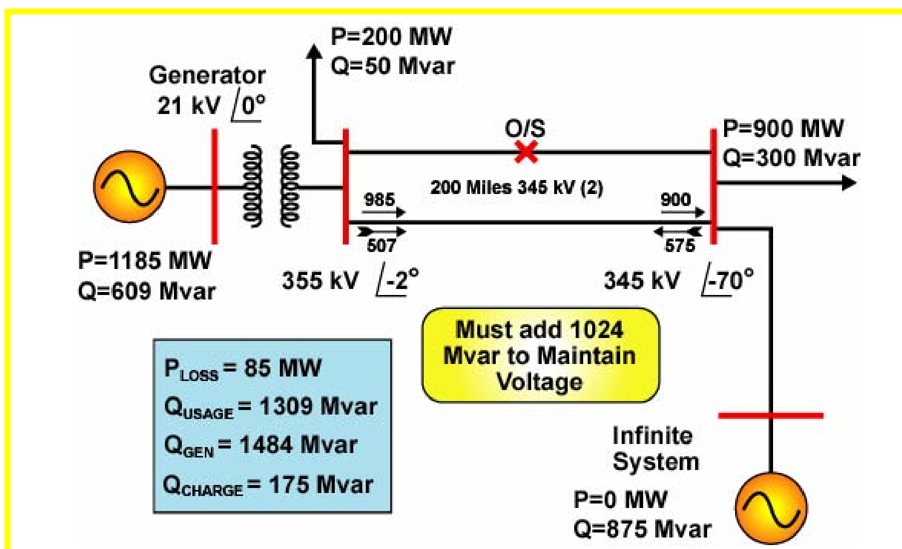


Figure 5-11
Reactive Power & Line Outages – Line Outage

5.2.4 Reactive Equipment Outages

Generators are the primary means of controlling power system voltages. If a generator trips, a portion of the most important source for controlling voltage is lost. Not only is the generator's reactive power supply lost, but the forced rearrangement of the system's generation may lead to further voltage drops as power flow increases over parallel high impedance lines. Loss of reactive power sources other than generators (such as capacitor banks or static var compensators) also reduces the ability of a system to control voltage.

5.2.5 Failure to Get Ahead of the Voltage

The term "shunt" refers to the method of connecting the capacitor to the system. Capacitor banks installed for voltage control purposes are connected in shunt. This concept will be described in greater detail in Section 5.6.1.

In addition to the complete loss of a capacitor bank, the Mvar output capability of capacitor banks is reduced as voltages drop. A shunt capacitor bank's reactive output will vary with the square of the voltage the capacitor is energized at. If system voltage drops to 90% of nominal, a shunt capacitor bank is good for only 81% (0.9 x 0.9) of rated output. Figure 5-12 illustrates the relationship between a 138 kV, 50 Mvar shunt capacitor bank's output and system voltage levels. System operators should place shunt capacitor banks in-service before system voltage falls significantly. This will avoid a reduced shunt capacitor Mvar output. The expression "get ahead of the voltage" emphasizes the need to put shunt capacitors in-service before system voltage drops significantly.

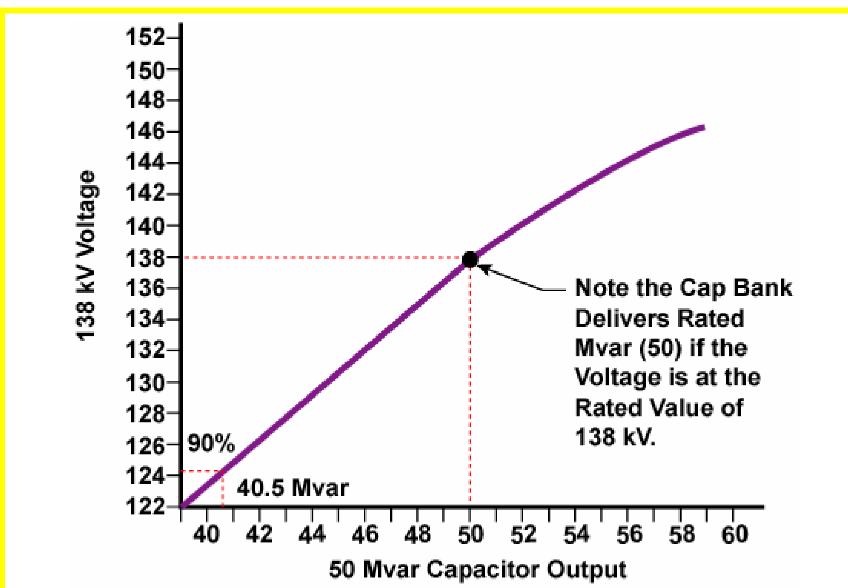


Figure 5-12
138 kV Shunt Capacitor Bank Output

To calculate the actual Mvar produced by a shunt capacitor use the following formula:

$$\boxed{\mathrm{Mvar}_{\mathrm{Output}} = \mathrm{Mvar}_{\mathrm{Rated}} \times \left[\frac{V_{\mathrm{ACTUAL}}}{V_{\mathrm{RATED}}}\right]^2}$$

This formula states that the Mvar output of a shunt capacitor is equal to its nameplate or rated value times the square of the per-unit voltage. As an example, if a 100 Mvar capacitor (rated 100 Mvar at 345 kV) is energized at 362 kV the capacitor output will be:

$$\boxed{\mathrm{Mvar}_{\mathrm{Output}} = 100 \times \left[\frac{362}{345}\right]^2 = 110\,\mathrm{Mvar}}$$

5.2.6 Motor Stalling

Chapter 6 "Voltage Stability addresses induction motor stalling in greater detail.

The behavior of the customer's load can cause low voltages. Induction motor load is especially troublesome. Customers may place induction motors in-service which require large amounts of reactive power (commonly called in-rush current) to start. The in-rush current period does not last long (a few seconds) but the reactive burden on the system is large. When large motors are started, the in-rush can drag down an entire feeder's voltage. Induction motors are designed to operate roughly between 90 and 110% of their rated voltage. If the system voltage declines to values below 70-80% of rated there is a chance that the motors could slow down or stall. Stalled motors may naturally try to regain speed as the system voltage attempts to recover. If enough motors have stalled, their combined reactive power draw could prevent a system voltage recovery.

5.3 Causes of High Voltage

By reactive resources we mean equipment to both supply and absorb reactive power.

As stated earlier, voltage levels are directly tied to the availability of reactive power. If adequate reactive power resources exist in the areas where the Mvar is needed, system voltages can be controlled. If there is a deficiency of reactive power, voltage levels will drop, and if there is an excess of reactive power, voltage levels will rise. This section will describe several common causes of high voltage.

While the root cause of high voltages is an excess of reactive power, the means by which high voltages occur varies across a wide spectrum. This section will first define three time frames for high voltages and then describe several types within each time frame.

5.3.1 Overvoltage Time Frames

Excessively high voltages—or overvoltages—on the power system can be more dangerous than low voltages as high voltage can easily damage expensive power system equipment, such as generators, transformers, or customer equipment. There are three general time frames for overvoltage: long term, short term and transient.

- Long term overvoltages develop and exist over substantial periods of time, from several minutes to several hours. Long term overvoltages will typically exceed scheduled voltages by 5 to 10% but could be much higher.
- Short term overvoltages are typically greater in magnitude than long term overvoltages. A short term overvoltage can easily exceed 200% of a scheduled value. Short term overvoltages may last several seconds.

Transient overvoltages are extreme examples of short term overvoltages. Transient overvoltages can reach very high magnitudes (10 times nominal), however, they last only a very short period of time. A typical transient overvoltage (TOV) will last a fraction of a cycle.

5.3.2 Long Term Overvoltages

Light Power Transfers

System load or power transfer can in some instances be very light, for instance, during the evening hours. The light loading condition often leads to excessive reactive power supply. Overvoltage due to light loading is a recurring problem. During the light load periods of the year off-peak hours may experience sustained overvoltage. System operator action is often required.

The excessive supply of reactive power during light system loads is usually due to the capacitive nature of transmission lines while lightly loaded. Those power systems with an abundance of long, extra high voltage transmission (for example 345 kV & 500 kV) will experience the greatest problems with high voltages during light loads.

Reactive Equipment Outages

Power system equipment is lost, intentionally or forced, that normally helps to reduce voltages. Equipment that is used to absorb Mvar, such as reactors or generators, may be lost leading to excessive Mvar supply. The loss of a critical element, such as a transformer, can lead to overvoltages. For example, assume a transformer is passing large amounts of reactive power from a 230 to a 115 kV system. If the transformer is lost, 230 kV voltages may rise.

Ferranti Rise

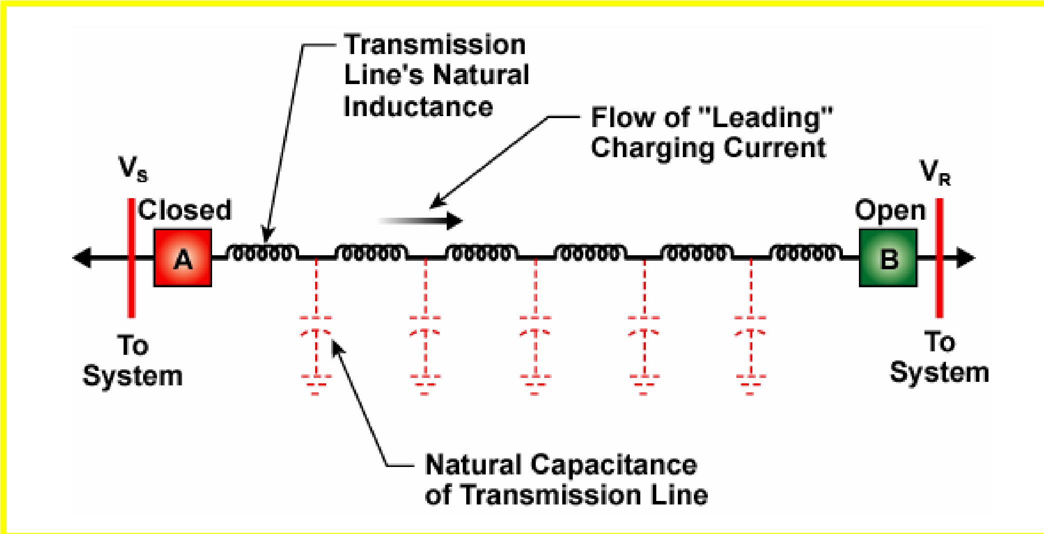
The Ferranti rise effect is a long term overvoltage condition that is associated with high voltage lines that have their receiving ends open. Overvoltages greater than 10% above nominal can easily occur. The magnitude of the overvoltage depends on the length of the open-ended line and the strength of the system tied to the closed-end of the line.

An open-ended line may still have a small MW flow due to line losses.

Figure 5-13 illustrates an open-ended high voltage transmission line. The voltage at the closed or sending end is V_S. The voltage at the open or receiving end is V_R. Since the line is open there will be no significant active (MW) power flow. However, there is reactive power flow on the line. Recall that a transmission line is the equivalent of a shunt capacitor. When a line is open-ended the shunt capacitor effect still exists.

The current flow on an open-ended line is that current needed to charge the line's natural shunt capacitance. In Figure 5-13, the current flow is shown from the system into the closed-end of the line. This current flow is charging the line's natural capacitance which is spread out over the entire length of the line. The current flow into an open-ended line is called the "charging" current since this current is charging the natural capacitance of the line.

Charging current is a "leading" reactive current flow. Normally when we think of reactive current flow we think of lagging reactive current. For example, induction motors draw lagging reactive current from the power system. When lagging reactive current passes through a transmission line's inductive reactance (X) it results in a voltage drop.



Circuit breaker "B" at the receiving end of the system is open.

Figure 5-13
Charging Current Flowing into an Open-Ended Line

Leading reactive current behaves differently with respect to voltage. When leading reactive current passes through the line's inductive reactance it causes a voltage rise. As the charging current flows into the closed-end of the line in Figure 5-13 it will cause a voltage rise from the closed-end to the open-end. The highest voltage occurs at the open-end. Figure 5-14 illustrates the voltage profile for an open-ended line. Notice the voltage rise from the closed to the open-end.

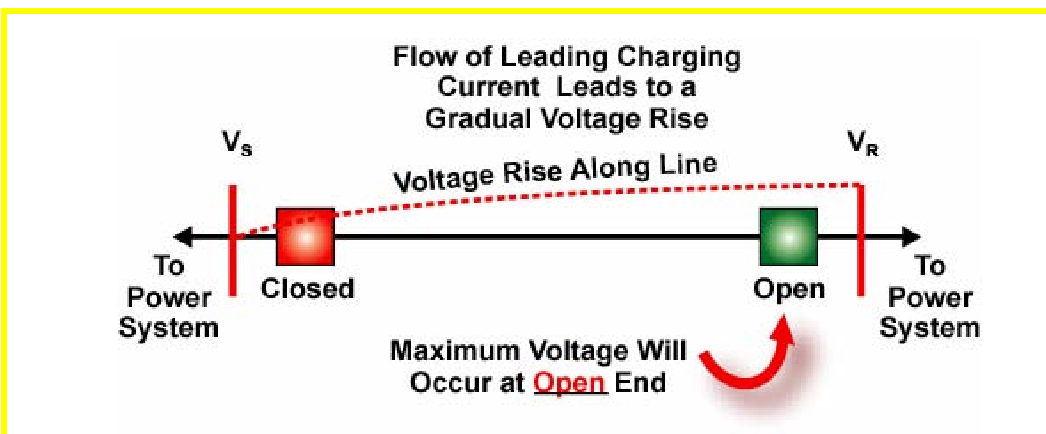


Figure 5-14
Voltage Profile Due to Ferranti Effect

The voltage rise from the closed to the open-end is not a straight-line rise. Notice in Figure 5-14 that the voltage rise is steeper near the closed-end of the line than at the open-end. This is due to the gradual decrease in charging current away from the closed-end and toward the open-end of the line. There is more charging current at the closed-end of the line so it results in a greater voltage rise at the beginning of the line. By the time the charging current reaches the open-end of the line there is not much capacitance left to charge and the incremental increase in voltage is smaller.

Calculating the Amount of Ferranti Voltage Rise

The most important assumption in the development of this equation is that the ratio of the line's inductive reactance to its resistance is large. This means the equation only applies to large conductor lines such as might be used at 230 kV and greater. The equation is also applicable to only 60 HZ systems.

If some simplifying assumptions are made, an easily applied equation for calculating the amount of Ferranti voltage rise for various lengths of high voltage line can be developed. Figure 5-15 illustrates a simple equation, which is also repeated below:

$$\boxed{V_R = \frac{V_S}{\cos\left(L/8.61\right)}}$$

This equation states that the receiving end voltage (V_R) is equal to the sending end voltage (V_S) divided by a cosine term. The cosine term value is only dependent on the length ("L" in miles) of the line. Figure 5-15 contains an example of the use of this equation. Assume we have a 200 mile long open-ended line. If we work through the equation it tells us that this 200 mile long open-ended line will experience an 8.8% voltage rise from the closed to the open-end. This 8.8% voltage rise applies no matter what the nominal voltage level of the high voltage line. If we are dealing with a 200 mile long 230 kV line with a closed-end voltage of 242 kV, the 8.8% voltage rise would mean the open-end voltage is 263 kV. If we are dealing with a 200 mile long 345 kV line with a closed-end voltage of 350 kV, the open-end voltage would be 381 kV.

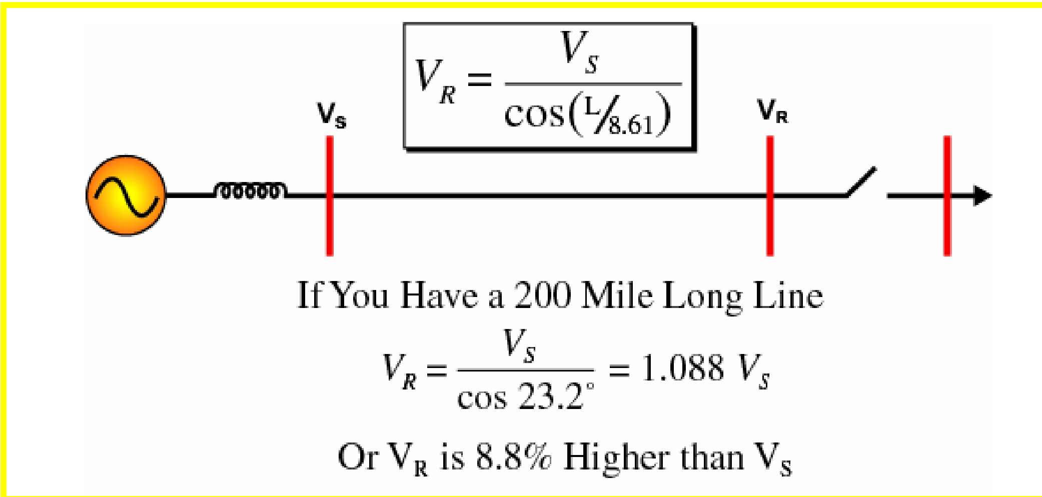


Figure 5-15
Calculating the Ferranti Effect Voltage Rise

This equation is actually based on traveling wave theory. When the line is open-ended a standing wave develops and the open-end voltage magnitude is a function of the length of the line.

Figure 5-16 was developed from our simple equation for the Ferranti voltage rise. This figure plots the expected voltage rise from the closed to the open-end for various lengths of line. The plot can be used to estimate the Ferranti effect for any length high voltage line.

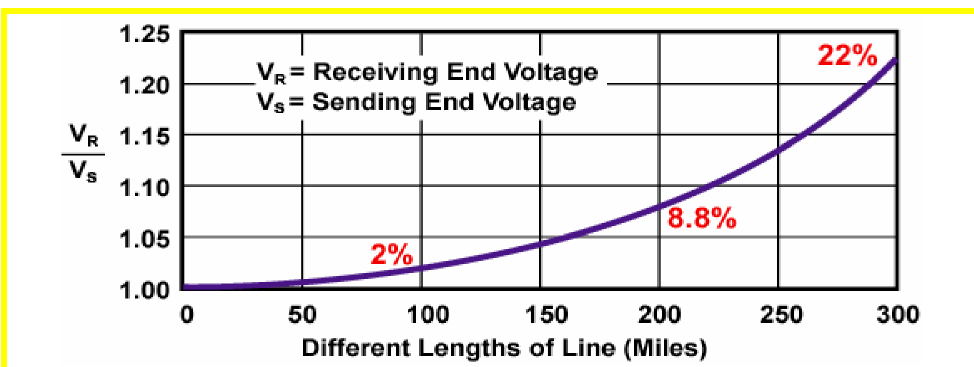


Figure 5-16
Ferranti Voltage Rise for Different Length Lines

These magnitudes of Ferranti rise assume no series or shunt compensation is in use.

Strength of the Closed-end Voltage

The Ferranti voltage rise is a rise in voltage from the closed-end to the open-end. The highest voltage is at the open-end. If the closed-end voltage also rises, the open-end voltage will be even higher. For example, assume we have a 150 mile long 345 kV line with an initial voltage of 348 kV at the closed-end. After opening the receiving end of the line the voltage rise from the closed to the open-end will be 4.8% or 365 kV (348 x 1.048). However, if after opening the breaker at the receiving end of the line the closed-end voltage rises 3%, then the voltage at the open-end will be 376 kV (348 x 1.03 x 1.048).

Whether the closed-end voltage rises after opening the receiving end of the line depends on the strength of the power system attached to the closed-end. If the closed-end is strongly connected to other buses and generators the voltage is not expected to rise very much. However, if the closed-end is weakly connected to other buses and remote from generators, the voltage may rise significantly during open-ended conditions.

Engineers use equivalents to simplify their study of the power system. An equivalent is a simplified representation of an entire section of the system.

Figure 5-17 illustrates the impact of a strong or weak closed-end. The generator and reactance to the left of the sending end bus in Figure 5-17 is referred to as an "equivalent" power system. If the closed-end bus in Figure 5-17 was a strong bus the equivalent generator would be large (a strong voltage source) and the equivalent reactance small. If the closed-end bus were weak, the equivalent generator would be small (a weak voltage source) and the reactance large.

Once the receiving end of the line in Figure 5-17 is opened, the voltage at the closed-end bus will adjust from its initial value to a value close to the equivalent system voltage, E_{EQ}. The equation at the bottom of the figure can be used to calculate the magnitude of E_{EQ}. We will not get into any details concerning the use of this equation except to make one important observation. The magnitude of E_{EQ} strongly depends on how much reactive power is flowing from the equivalent system into the closed-end bus prior to the line being open-ended. The greater the reactive power into the closed-end bus prior to opening the receiving end, the higher the closed-end voltage will rise.

P_S and Q_S are the MW and Mvar flows prior to open-ending the line.

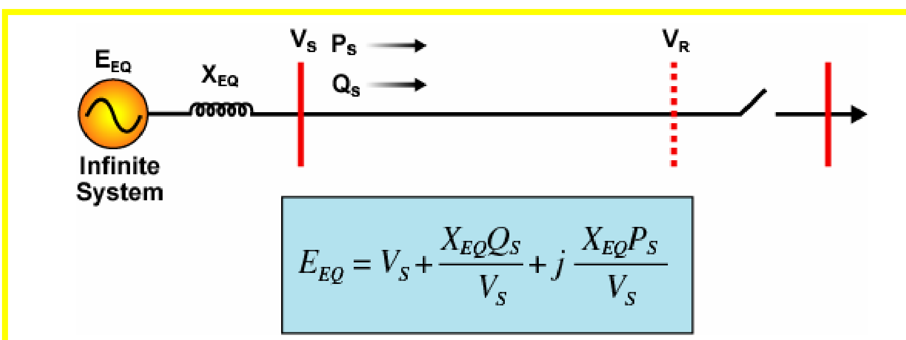


Figure 5-17
Source End Voltage Rise

What this means from a practical standpoint is that you should always be concerned about open-ending a line. However, when open-ending a high voltage line that depended heavily on reactive support from the closed-end, you should be even more concerned. This type of situation occurs if there is a long thin system feeding a remote load, and a line that forms part of this system is open-ended.

5.3.3 Short Term Overvoltages

Generator Load Rejection and Self-Excitation

The sudden loss of a major load can lead to short-term excessive generator production of active and reactive power. This may cause both system voltage and generator overspeed problems. The loss of load may be due to the loss of transmission service to a load, to loss of a major tie-line with another system or to the operation of a load shedding plan. It does not matter what caused the loss of load or the “load rejection”. The generator could overspeed and induce overvoltages until its control systems can match the generator’s output to the new system load. This is classified as a short term overvoltage because the generator has the capability of controlling the system voltages within several seconds of the loss of load.

A severe variation on the load rejection theme described above is when the generator is isolated on a long transmission line. Figure 5-18 illustrates a possible scenario. Assume system events are such that a remote generator ends up tied to one 200 mile long 345 kV transmission line as illustrated in Figure 5-18. If this line should open-end, the generator is tied to the equivalent of a 150 Mvar shunt capacitor.

A rule-of-thumb of ¾ Mvar per mile is used.

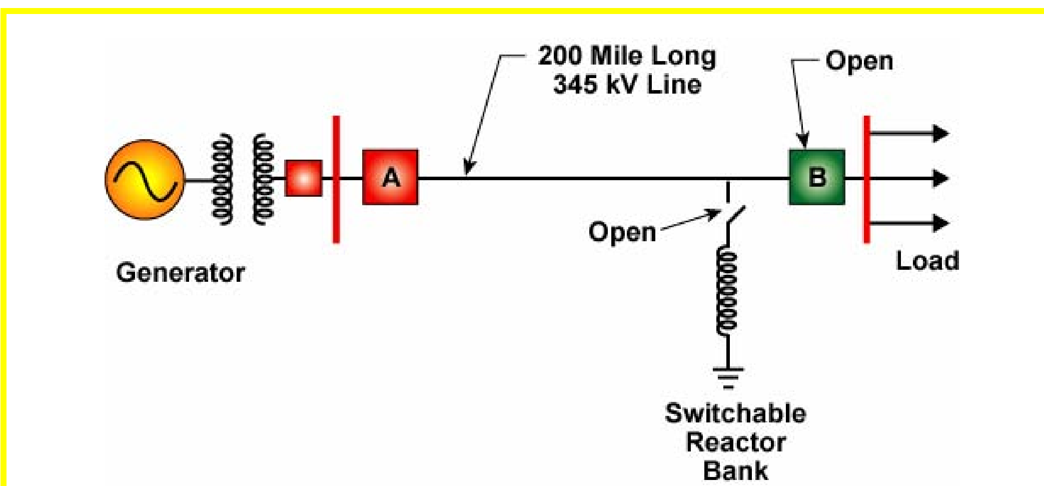


Figure 5-18
Self-Excitation of a Generator

The generator’s excitation system was initially providing field current to hold a scheduled high-side generator bus voltage. Once the 345 kV line open-ended no MW load was tied to the generator. The generator’s bus voltage therefore rises sharply once the line open-ends. The generator's excitation system will rapidly attempt to reduce the high side voltage by absorbing Mvar from the system.

The reactive capability of generators is addressed in Section 5.6.3.

Assume the generator is capable of absorbing 100 Mvar. Once the generator reaches its reactive power absorbing limit there will still be substantial reactive power available from the open-ended line. This excess reactive power will appear to the field winding of the generator to be additional DC field current.

This material addresses self-excitation from a practical approach. The basic theory for self-excitation is that of a resonance condition between the generator and the system to which it is attached. Resonance is described in Chapter 9.

The excess DC field current will take over as the excitation source of the generator. The generator could lose control of excitation and its voltage could rise. As the generator voltage rises, the open-ended transmission line voltage rises. The Mvar of charging supplied by the open-ended line is a function of voltage (recall the voltage squared relationship.) The increase in line charging will further excite the generator. A runaway condition develops. Possible results of this self-excitation include overvoltage damage to the generator and to its step-up transformer.

A further complication to the self-excitation phenomena is the overspeed of the generator. Once the MW load attached to the generator is interrupted the generator's MW production will be automatically stored as additional rotational energy. This will result in an overspeed of the generator.

The capacitive effect of a transmission line is dependent on system frequency. The greater the frequency the more Mvar a line will naturally produce. The overspeed of the generator will lead to more Mvar production from the transmission line and increase the likelihood of generator self-excitation.

Preventing Generator Self-Excitation

If the generator's Mvar absorption capability had been greater than the Mvar production of the open-ended transmission line self-excitation would not have occurred. To prevent generator self-excitation always ensure that a generator has the ability to absorb whatever Mvar may be available at its terminals. To be safe, further ensure there is a large margin of safety. For example, one western utility with self-excitation possibilities has an operating order that no generator may be connected to a transmission system (that has the possibility of open-ending) unless that generator can at least absorb twice the nominal charging of the transmission system.

Note in Figure 5-18 that the shunt reactor attached to the load end of the system was out-of-service. If this shunt reactor had been in-service it would have absorbed some of the available reactive power. This reduction in the available reactive power may have been enough to avoid self-excitation.

Harmonic Overvoltages

Harmonic over-voltages are introduced here. Chapter 9 will provide greater detail.

Harmonic overvoltages (illustrated in Figure 5-19) are caused by the interaction of capacitive and inductive elements, and sources of harmonics. The circuit of Figure 5-19 is typical of the circumstances that can cause harmonic overvoltages. The "L" and "R" of the transformer and the "C" of the capacitor form a natural "RLC" circuit that will "resonate" or oscillate at a certain frequency value. If the harmonics generated by the HVDC converter have a frequency close to this resonant frequency high magnitudes of current could be passed back and forth between the capacitor and transformer. These high currents could produce voltages high enough to damage the transformer or shunt capacitor.

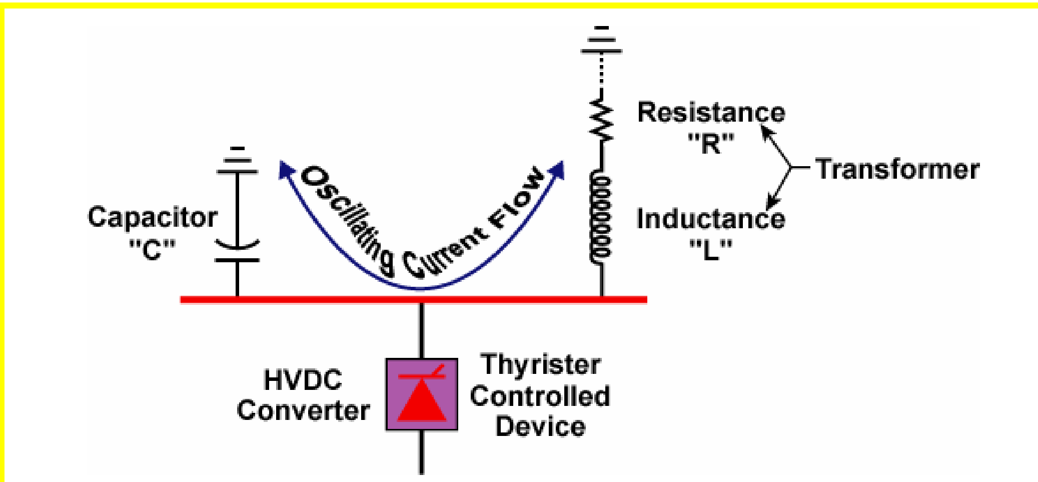


Figure 5-19
Harmonic Overvoltages

Figure 5-20 contains an additional illustration of harmonic overvoltages. The circuit breaker at bus "A" is used to energize a line/transformer combination. When the transformer and line are energized a possibility exists that a resonant condition could develop. The resonance develops due to the combination of capacitance and inductance in the circuit.

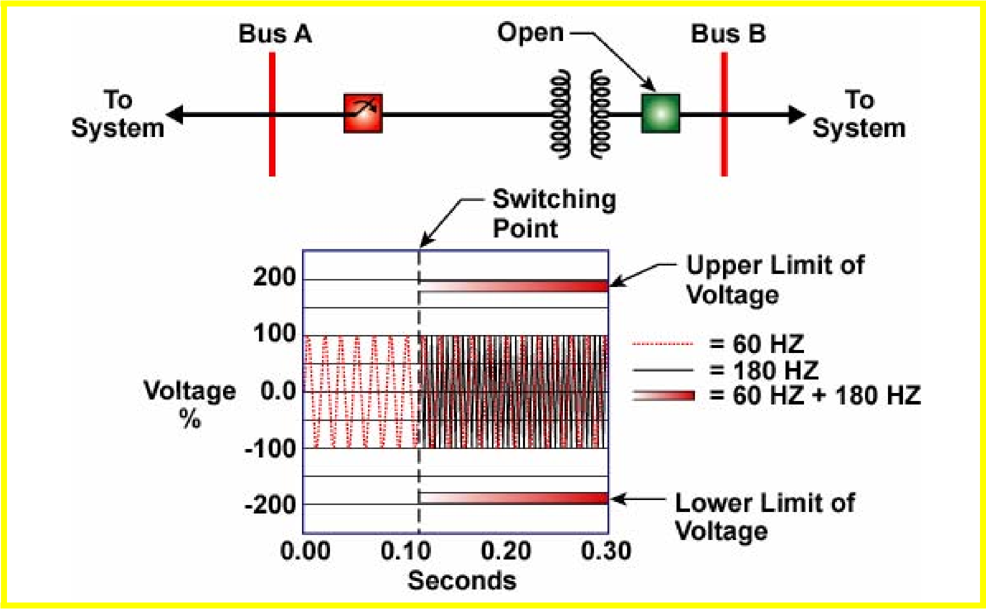


Figure 5-20
Energizing a Line-Transformer Combination

The voltage diagram in the bottom of Figure 5-20 illustrates what can happen to the system voltage. Initially the system voltage (measured at the bus “A” breaker) is 100% of nominal. After the bus “A” breaker is closed a 180 HZ harmonic voltage exists in combination with the 60 HZ system voltage. The combination of the harmonic voltage (180 HZ or the 3^{RD} harmonic) and the 60 HZ voltage exposes the transformer to twice its nominal voltage rating.

5.3.4 Transient Overvoltages

Lightning Overvoltages

Lightning strikes lead to transient overvoltages. This is one reason for installing surge or lightning arresters, to arrest or trap the high voltage surge caused by lightning strikes to a transmission line or substation. Lightning strikes are a very rapid event. A typical lightning strike may last less than 0.00005 seconds. However, a lightning strike packs a large amount of energy in this short period. Transient overvoltages may be in the millions of volts.

Switching Overvoltages

A switching surge is a large change to system voltage that lasts only a fraction of a cycle.

Power system switching also leads to transient overvoltages. Each time a circuit breaker or disconnect switch is opened under load the power system will experience a switching surge. It is not uncommon for lightning arresters to operate in substations during switching of high voltage breakers. These surges are very rapid, lasting only milliseconds, but may exceed 200% of the scheduled voltage. A 500 kV breaker may initiate a switching surge of 1000 kV when first opened.

Capacitive Switching

Switching of capacitors or open-ended lines is especially susceptible to switching surges. When switching a capacitive element, the circuit breaker (or other switching device) could end up with opposite polarity voltages on either side of the switch. This could lead to twice nominal voltage across the circuit breaker. For example, a 500 kV breaker could end up attempting to interrupt near 1000 kV if it was used to open a long unloaded 500 kV line. The voltage that appears across the open switching device is called the “recovery voltage”. The higher the recovery voltage, the greater the likelihood of a restrike occurring.

Figure 5-21 illustrates the opening of a capacitive load. When the circuit breaker interrupts the capacitive current the voltage is at a maximum or minimum value (minimum in the figure). One-half cycle after the circuit breaker opens, the capacitor is still charged to a minimum value but the system voltage has reached a maximum. The circuit breaker now has twice system voltage across it. The probability of a restrike has increased.

When the circuit breaker contacts first separate an arc is formed and then extinguished. A restrike is a resumption of the arc

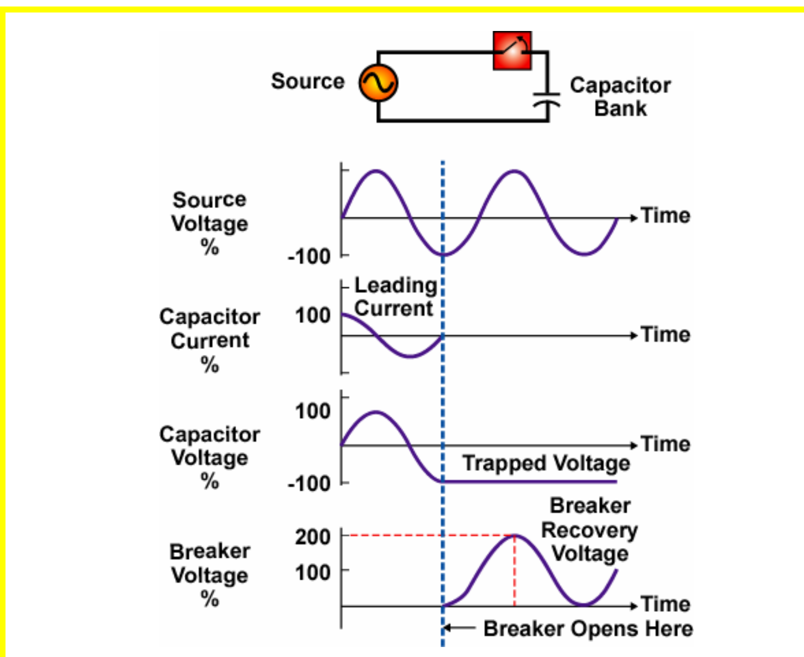


Figure 5-21
Capacitive Switching

Notice that the circuit breaker does not interrupt the circuit until a current zero. When the current is zero the voltage is at a maximum in a capacitive circuit.

Successive restrikes can compound the magnitude of the recovery voltage. For example, if the circuit breaker in Figure 5-21 fails to withstand the recovery voltage and restrikes, the subsequent recovery voltage could reach 400% of the nominal voltage. Power system designers consider the likelihood of switching surges when choosing the interrupting capacity of circuit breakers and switches.

5.4 Effects of Low Voltages

Sustained low voltages can have substantial impact on the power system. This section will address the impacts of low voltage on:

- Power System Equipment
- System Load Magnitude
- Angle Stability
- Customer Equipment
- Power Losses

5.4.1 Effect of Low Voltage on System Equipment

The ability of a transformer to transform voltages is not affected by low power system voltages. The transformer will simply transform the low voltage primary value through the windings to a lower-than-scheduled secondary voltage value. If the transformer is heavily loaded a sustained low voltage may result in a rise in current flow through the transformer. This high current could lead to thermal overloads of the transformer.

When transmission lines are exposed to low voltages the thermal capability of the line can be exceeded. Due to the high currents that may accompany low voltages the transmission line MVA rating may need to be reduced during sustained low voltage periods. Thermal damage to the conductor could occur if no adjustments in the line's MVA loading capability are made.

Utilities frequently take advantage of the dependence of load magnitude on voltage. For example, during an energy emergency a company that serves load may intentionally lower voltage (called brown outs) to reduce customer load magnitude.

5.4.2 Effect of Low Voltage on Load Magnitude

When customer voltage falls, the overall power system load magnitude will normally fall. There are two general types of customer load; motor load and non-motor load.

Motor load does not significantly vary with the voltage magnitude. As long as the voltage is within the normal operating range of the motor (approximately 90% to 110% of rated voltage), the connected motor load magnitude will not drop significantly when the voltage drops. As voltage decreases, current will increase to keep a relatively constant MW load.

Non-motor load magnitude will vary with the voltage. There are two classifications of non-motor load—constant current and constant impedance. Constant current load will vary directly with the voltage while constant impedance loads, such as electric heaters, will vary with the square of the voltage. Studies of load magnitudes have shown that on average the power drawn by non-motor loads will decrease by approximately 6% if the voltage decreases by 5%.

We can conclude that the effect of voltage upon the connected load magnitude is dependent upon the nature of the load. If the load is predominantly induction motors, a typical voltage deviation will have little impact. If the load is predominantly non-motor, such as resistive heating, a voltage deviation could have a large impact. An approximate rule of thumb is that for a typical mix of motor and non-motor load, the total MW drawn will decrease by 3% if the customer's voltage decreases by 5%. This is only a rule of thumb, the actual amount of load magnitude change depends on the relative mix of motor and non-motor load. Figure 5-22 graphically illustrates the effect of voltage on the connected load magnitude.

A rule of thumb is that a 5% reduction in the customer's voltage will result in approximately a 3% reduction in the customer's load magnitude.

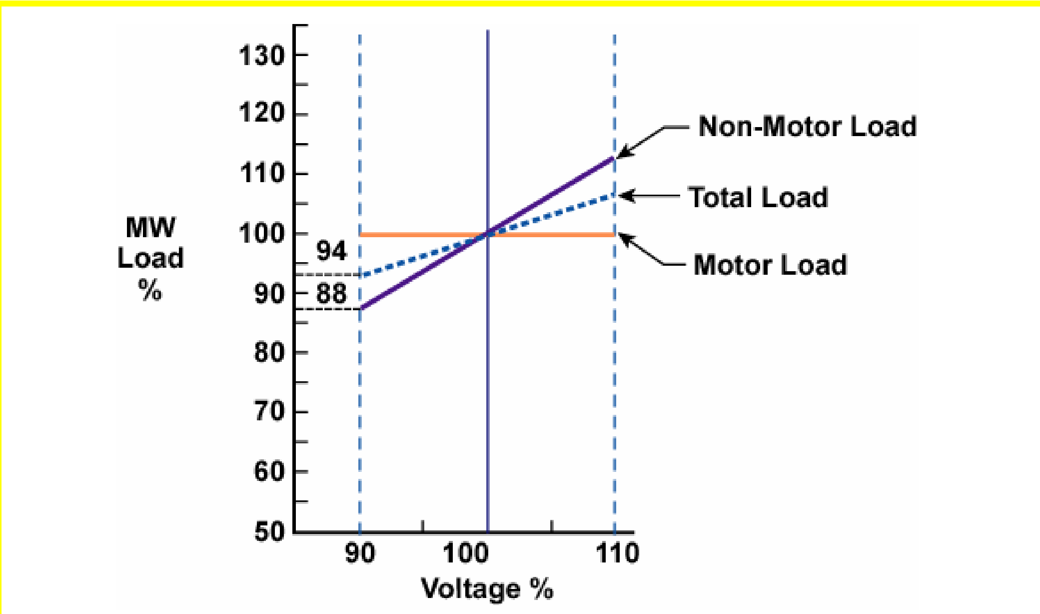


Figure 5-22
Effect of Voltage on Load Magnitude

Effect of Time on Load Magnitude Change

There is little doubt that the magnitude of the voltage impacts the load magnitude. However, there is doubt as to how long this magnitude change actually lasts. Figure 5-23 is a plot of a load magnitude change following an intentional 4.5% voltage reduction on a 69 kV feeder circuit.

The recovery over time of the load magnitude is due to a "loss of load diversity". Loads that normally cycle during a time period are all on at the same time due to the voltage reduction.

Note that both the MW and Mvar load drop sharply when the feeder voltage is reduced. However, after several minutes the MW load is almost fully restored while the Mvar load is about half restored. This test was performed in the winter in an area with substantial non-motor load. A large chunk of the load was heating load. With a voltage reduction, the heating load will initially reduce but after a few minutes more heaters are on at the same time (due to thermostatic control), and the load magnitude begins to recover.

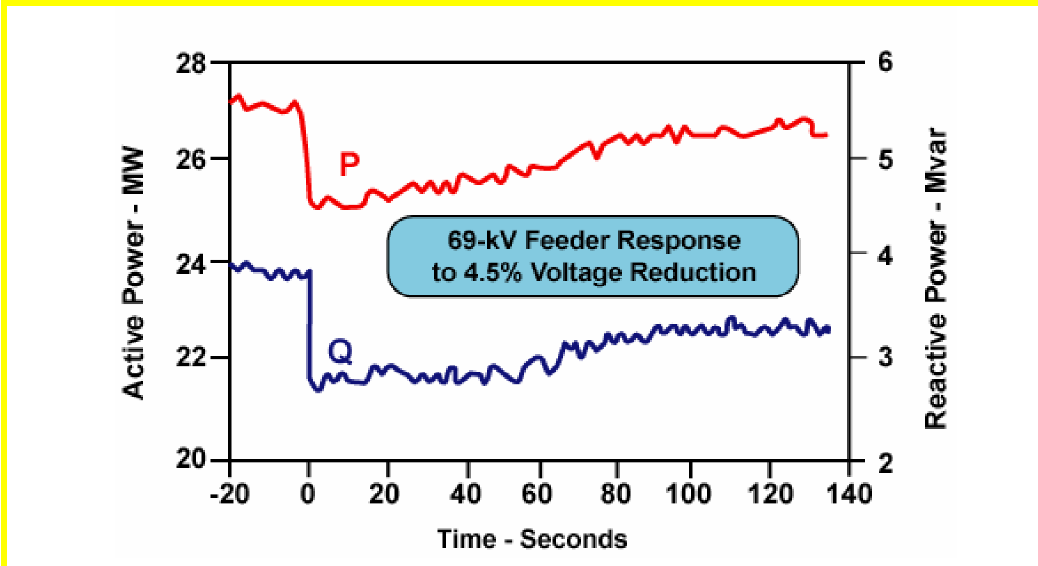


Figure 5-23
Effect of Voltage on Load Magnitude

Load Magnitude Equations

Several EPRI sponsored research projects have dealt with the impact of voltage on load magnitude. The equations and data given in Figure 5-24 are derived from reports for several of these research projects.

There are two equations listed in the bottom right corner of Figure 5-24. One equation is for the MW load (P_{NEW}) and the other for the Mvar load (Q_{NEW}). Both equations are used to estimate a new load magnitude based on deviations from nominal voltage and frequency (recall that load magnitude is also dependent on frequency). For example, assume the initial load magnitude was 100 MW and 20 Mvar. These equations could be used to estimate what the new load magnitude would be if the voltage fell 5% and the frequency rose 1%.

The main part of Figure 5-24 is a table of numbers for many different types of load. Next to each type of load is a horizontal listing of a series of numbers. These numbers are used in the two equations (described above) for estimating how each of the different types of load will vary following changes to voltage and frequency.

Load Type	Characteristics				
	PF	P_V	P_f	Q_V	Q_f
Resistive Space Heater	1.0	2.0	0.0	0.0	0.0
Heat Pump Space Heating	0.84	0.2	0.9	2.5	-1.3
Heat Pump Central Air Cond.	0.81	0.2	0.9	2.5	-2.7
Central Air Conditioner	0.81	0.2	0.9	2.2	-2.7
Room Air Conditioner	0.75	0.5	0.6	2.5	-2.8
Water Heater	1.0	2.0	0.0	0.0	0.0
Range	1.0	2.0	0.0	0.0	0.0
Refrigerator and Freezer	0.84	0.8	0.5	2.5	-1.4
Dishwasher	0.99	1.0	0.0	3.5	-1.4
Clothes Washer	0.65	0.08	2.9	1.6	1.8
Incandescent Lighting	1.0	1.54	0.0	0.0	0.0
Clothes Dryer	0.99	2.0	0.0	3.3	-2.6
Color Television	0.77	2.0	0.0	5.2	-4.6
Furnace Fan	0.73	0.08	2.9	1.6	1.8
Commercial Heat Pump	0.84	0.1	1.0	2.5	-1.3
Heat Pump Commercial A/C	0.81	0.1	1.0	2.5	-1.3
Commercial Central A/C	0.75	0.1	1.0	2.5	-1.3
Commercial Room A/C	0.75	0.5	0.6	2.5	-2.8
Fluorescent Lighting	0.90	1.0	1.0	3.0	-2.8
Pumps, Fans, Other Motors	0.87	0.08	2.9	1.6	1.8
Electrolysis	0.90	1.8	-0.3	2.2	0.6
Arc Furnace	0.72	2.3	-1.0	1.61	-1.0
Small Industrial Motors	0.83	0.1	2.9	0.6	-1.8
Large Industrial Motors	0.89	0.05	1.9	0.5	1.2
Agricultural Water Pumps	0.85	1.4	5.6	1.4	4.2
Power Plant Auxiliaries	0.80	0.08	2.9	1.6	1.8

PF = Typical Power Factor
P_V = Voltage Impact on MW
P_F = Frequency Impact on MW
Q_V = Voltage Impact on Mvar
Q_F = Frequency Impact on Mvar

$$P = P_0 \left[\frac{V}{V_0}\right]^{P_V} \left[\frac{f}{f_0}\right]^{P_f}$$

$$Q = Q_0 \left[\frac{V}{V_0}\right]^{Q_V} \left[\frac{f}{f_0}\right]^{Q_f}$$

Figure 5-24
Load Magnitude Equations[3]

The first column in the table describes the load type. For example, "resistive space heater" and "heat pump space heating" are the first two load types. The second column labeled "PF" is a typical power factor for that particular load. For example, a resistive space heater typically has a unity (1.0) power factor.

The third column is labeled "P_V". The P_V value predicts how that particular load's MW magnitude will vary with a change in service voltage. The greater the positive magnitude of P_V the more that load's MW magnitude will

[3] The data in Figure 5-24 is derived from reference #7.

decrease as its service voltage decreases. The fourth column is labeled "P_f". P_f predicts how the MW load magnitude will vary with frequency. The fifth column is Q_V and the sixth Q_f. Q_V predicts how the Mvar load magnitude will vary with voltage and Q_f predicts how the Mvar load magnitude will vary with frequency. Note that if any of the four load coefficients (P_V, P_f, Q_V, Q_f) is negative then a drop in voltage or frequency will lead to a rise in MW or Mvar load magnitude.

The best way to illustrate the use of these load magnitude equations is to step through a few simple examples.

Load Magnitude Equations Example #1

The frequency is not changed from its nominal value of 60 HZ to keep this example simple.

Our first use of the load magnitude equations is to estimate the load change if a central air conditioning type load (nominal value 100 MW and 60 Mvar) is subjected to a 10% sustained voltage drop. Assume the initial voltage was 100% of its nominal value.

Figure 5-25 illustrates the use of the load magnitude equations. Note the terms P_V and Q_V. These two terms are used to make the load equations specific to a central air conditioner type load. The values for P_V and Q_V are taken directly from the table in Figure 5-24. Simply find the row in Figure 5-24 (4^{th} from the top) for a central air conditioner and read off the values of P_V (0.2) and Q_V (2.2).

Central Air Conditioner	Voltage Drops To 90% Normal
$P_V = 0.2$ $Q_V = 2.2$	$P_{NEW} = 100\left[\frac{.9}{1}\right]^{0.2} = 97.9 \text{ MW}$
$P_{INITIAL} = 100 \text{ MW}$ $Q_{INITIAL} = 60 \text{ Mvar}$	$Q_{NEW} = 60\left[\frac{.9}{1}\right]^{2.2} = 47.5 \text{ Mvar}$

For a Typical Central Air Conditioner Load if Voltage Drops 10% the MW Load Will Drop 2.1% While the Mvar Load Will Drop 21%.

Figure 5-25
Central Air Conditioner Type Load

The new load magnitude as a result of a 10% reduction in voltage is 97.9 MW and 47.5 Mvar. Our conclusion is that the 10% voltage reduction has little impact on the MW load but a strong impact on the Mvar load. This is expected since an air conditioner load is predominantly a motor type load and we would not expect voltage to impact its MW magnitude that strongly.

Load Magnitude Equations Example #2

Our second use of the load magnitude equations (Figure 5-26) is to estimate the load change if a resistive space heater type load (initial value 100 MW and 0 Mvar) is subjected to a 10% sustained voltage drop.

Note that the resistive space heater type load has a unity power factor.

Resistive Space Heater	Voltage Drops To 90% Normal
$P_V = 2.0$ $Q_V = 0.0$	$P_{NEW} = 100\left[\frac{.9}{1}\right]^{2.0} = 81 \text{ MW}$
$P_{INITIAL} = 100 \text{ MW}$ $Q_{INITIAL} = 0 \text{ Mvar}$	$Q_{NEW} = 0\left[\frac{.9}{1}\right]^{0.0} = 0 \text{ Mvar}$

For a Typical Resistive Space Heater Load if Voltage Drops 10% the MW Load Will Drop 19% While the Mvar Load Will Not Change.

Figure 5-26
Resistive Space Heater Type Load

The new load magnitude as a result of a 10% reduction in voltage is 81 MW and 0 Mvar. Our conclusion is that the 10% voltage reduction has a strong impact on the MW load and no impact on the Mvar load. This is expected since resistive type load magnitude varies with the voltage squared. If the voltage drops to 90% of nominal the load magnitude will drop to 81% (0.9 x 0.9) of nominal.

Voltage, Frequency and Load Magnitude

Remember these are approximate rules of thumb. Your particular system will likely behave differently.

Both voltage and frequency impact load magnitude. Two rules of thumb have been given in this text:

- A 1% change in customer frequency will lead to approximately a 2% change in total customer load magnitude.
- A 5% change in customer voltage will lead to approximately a 3% change in total customer load magnitude.

Recall our description of system inertia in Chapter 4. In a large power system, large changes to system frequency (such as 1%) are highly unlikely. It follows that the greatest impact on system load magnitude will likely come from voltage changes. Figure 5-27 illustrates this point. This figure is based on data from a disturbance several years ago. Note the voltage decay is more rapid and reaches a greater magnitude than the frequency decay. The impact of voltage on load magnitude exceeded the impact of frequency on load magnitude during this disturbance. This is typical during power system disturbances.

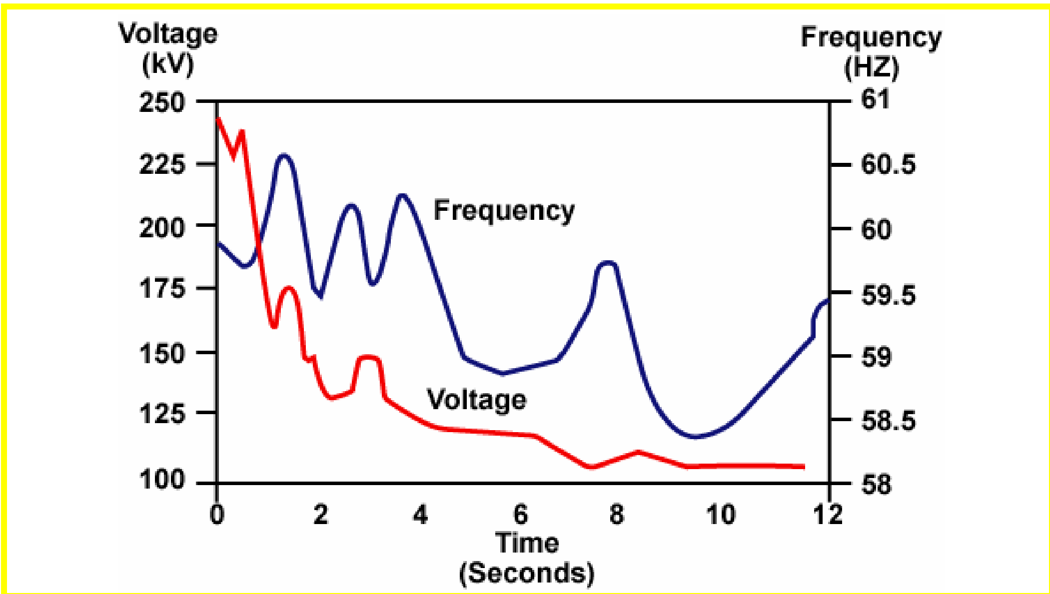


Figure 5-27
Voltage and Frequency Decay

5.4.3 Effect of Low Voltage on Angle Stability

Recall the active power transfer equation first presented in Chapter 3. This equation is repeated below:

$$\boxed{P_{TRANSFER} = \left[\frac{V_S \times V_R}{X_{S-R}}\right] \sin \delta_{S-R}}$$

Note the dependence of active power transfer on the voltage magnitude of the sending (V_S) and receiving (V_R) buses. If either of these bus voltages falls the power angle (δ) must increase to maintain the same active power transfer. If the voltage magnitudes fall far enough the system could lose synchronism. From a system stability perspective, the lower that system voltages are held, the greater the risk of instability.

System (angle) stability is addressed in Chapter 7.

5.4.4 Effect of Low Voltage on Customer Equipment

Low voltage can seriously impact utility customers. The impacts range from minor irritations such as reduced television picture sizes to industrial process interruptions with outage costs exceeding thousands of dollars per minute.

This section addresses only one area of customer load, namely the impact on motor loads. Previous sections described how voltage magnitude does not significantly effect motor load magnitude as long as the voltage stays within the rated operating range of the motor. What concerns us now is what happens if the voltage falls below 90% of the nominal voltage, for example to 70% of nominal? What could happen is that the motor may stall. Stalling means the motor slows below its rated speed and may even stop spinning completely.

Many motors have undervoltage drop-out circuits that trip the motor if the voltage falls too low.

When induction motors are first started the motor draws large amounts of reactive power from the system. This initial reactive power draw is called the "in-rush" and may cause the initial motor current to be 8 to 10 times its normal full load current. The reactive in-rush will cause short term (a few seconds) low voltages depending on the strength of the feeder used to start the motor.

Once motors stall due to exposure to low voltages, the motor will try to recover speed automatically as system voltages recover. To recover speed the motor will draw heavy amounts of reactive power in the same manner as when it was first started. The combined reactive power needs of many motors trying to recover from a stalled condition could prevent system voltage recovery. Eventually an entire power system could collapse.

Chapter 6 on Voltage Stability examines the impact of motor stalling on system voltage in greater detail.

5.4.5 Effect of Low Voltage on Power Losses

Simple Equations for Power Losses

Recall that there are two types of power losses; active and reactive power losses. Active and reactive power losses can collectively be called the MVA loss. Recall from basic AC theory that the equation for 3Φ power is:

$$\boxed{S_{3\phi} = 3 \text{ x } I^* \text{ x } V = MVA}$$

This is the same equation used to calculate the MVA losses in a power system. The "I^*" term is the phase current in the circuit while the "V" term is the line-to-ground voltage drop across the element. To make our study of the effect of low voltage on power system losses clearer this MVA loss equation is broken down into two separate equations—one for the active power losses and one for the reactive power losses (or usage).

Ohm's law states that the voltage is equal to the product of the current and the impedance (*V = I x Z*). It follows then that the MVA loss is also equal to:

$$\boxed{S_{3\phi} = 3 \text{ x } I^* \text{ x } (I \text{ x } Z) = 3I^2 Z = MVA_{LOSS}}$$

"Z" is the series impedance of the power system. As you recall, the series impedance is composed of the inductive reactance (X) and the resistance (R). If the resistance and reactance is substituted for the impedance two simple equations for power loss and usage are derived as stated below:

$$\boxed{P_{LOSS} = 3I^2 R = MW_{LOSS} \qquad Q_{USAGE} = 3I^2 X = Mvar_{USAGE}}$$

Note the dependence of both losses on the current magnitude. If the current magnitude is increased both types of losses will increase. If the current magnitude is decreased both types of losses will decrease.

Impedance also strongly impacts loss magnitude. We are assuming impedance stays constant in this analysis.

Minimizing Power Losses

To minimize power losses in the system, minimize the current flow. It follows from Ohm's Law that you can reduce the current by maximizing the voltage. The higher the system voltage, the lower the current flow for a given power delivery. A transmission operating company can reduce its losses by building a higher voltage system or by operating their existing system with higher voltages. For example, compare the losses on two identical 345 kV systems. One system is operated with all voltages at 345 kV and the other with all voltages 5% lower at 328 kV. If the same power transfer occurs on both

Not only will reactive power losses increase when voltage is low but the transmission system's natural Mvar production will also decrease. Both factors work to reduce the available reactive power reserve.

systems, the higher voltage system will incur a minimum of 10% fewer 345 kV system losses.

System operators can have a substantial impact on power system losses. Many utilities have implemented extensive loss reduction programs. A central feature of most of these programs is for system operators to hold system voltages as high as practical to minimize current and thus minimize losses.

5.5 Effects of High Voltages

5.5.1 General Effects of High Voltages

High voltage limits protect power system equipment (both customer and system) from exposure to voltage levels that exceed the insulating and/or operating capability of the equipment. High voltage can cause system equipment (for example, a circuit breaker) insulation to fail resulting in internal flashovers. The equipment may then have to be removed from service, possibly leading to customer outages and high repair costs.

Under high voltage conditions that exceed the insulation capability of system equipment, a fault can begin as a small leakage current. This current would pass through the insulation to a grounded portion of the equipment that it insulates. The leakage current would gradually increase as the insulation slowly deteriorates until the insulation completely fails and a solid fault occurs.

While high voltages will typically have some negative impact on the power system, many of these consequences have little effect on system operation. For example, transmission lines can withstand long term high voltages if the magnitude does not lead to insulator flash-over. Major areas of high voltage impact include:

- Transformers
- Customer Equipment
- System Load Magnitude
- Angle Stability
- Power Losses

5.5.2 Effect of High Voltage on Power Transformers

Transformer Saturation

Transformers are very susceptible to damage from sustained high voltages. Transformers operate based upon the principle of electro-magnetic induction. Recall from Chapter 1 that a voltage is induced in one of the transformer's windings via an alternating magnetic field that links this winding to the transformer's other energized windings.

A transformer is an inductive load as it draws reactive power from the power system to support its magnetic field. The magnetic field is required to transfer active power between the windings. A transformer is designed to operate at a rated voltage level. This rated voltage level is directly related to the strength of the magnetic field in the core of the transformer. If the transformer's rated voltage level is substantially exceeded (greater than 10-20%) the transformer will draw additional reactive power from the system to support a spread of the transformer's magnetic field. The magnetic field will spread out from the core of the transformer to areas that are not designed for magnetic fields. This could lead to excessive heating in parts of the transformer and eventually may lead to transformer failure.

Figure 5-28 illustrates the relationship between the operating voltage of a transformer and the excitation current it draws to magnetize its core. Note that when the transformer is operated near its rated voltage the excitation current is small. As voltage is increased above rated the excitation current rapidly increases. This excitation current is a reactive current. By noting the rapid increase in excitation current in Figure 5-28 one can see why the reactive needs of a transformer rise sharply when it is operated at too high a voltage.

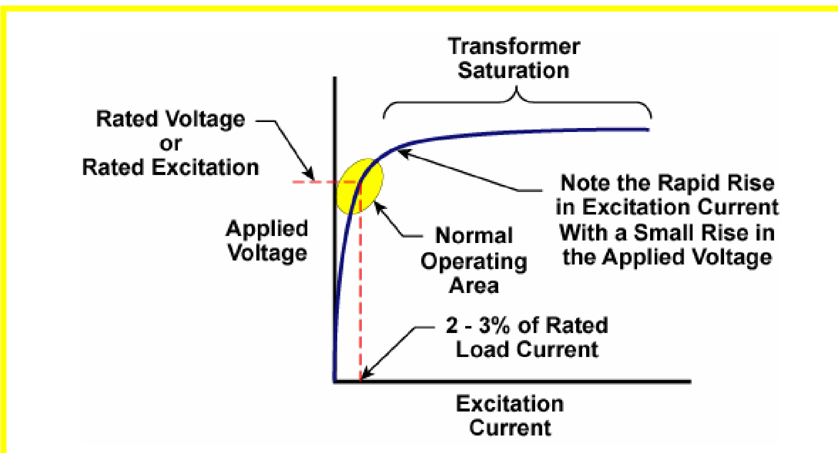


Figure 5-28
Transformer Saturation Curve

The process in which the magnetic field of a transformer spreads from the core is called "saturation". When a transformer is saturated, the internal power losses dramatically increase and can lead to thermal damage and eventual transformer failure.

Transformer Over-Excitation

A transformer can be saturated even when the operating voltage is near its rated value. Transformer saturation is a function of both the operating voltage and the operating frequency since both voltage and frequency impact the magnetic field strength. If the voltage is high, the transformer core is subjected to a sustained high magnitude voltage which increases its magnetic field strength. If the frequency is low, the transformer is subjected to longer periods of the AC voltage wave which also increases the magnetic field strength.

The ratio of the operating voltage to the operating frequency is called the transformers "% excitation". Figure 5-29 is a plot of % excitation versus time of exposure. For example, the figure tells us that a transformer can be exposed to a 20% "over-excitation" for less than 2 minutes before probable failure. The data in Figure 5-29 is for a typical transformer. (Remember, no transformer is typical!) Note that for this typical transformer, a 10% over-excitation can be handled indefinitely.

Transformer over-excitation and saturation is treated in greater detail in the solar magnetic disturbances section of Chapter 9.

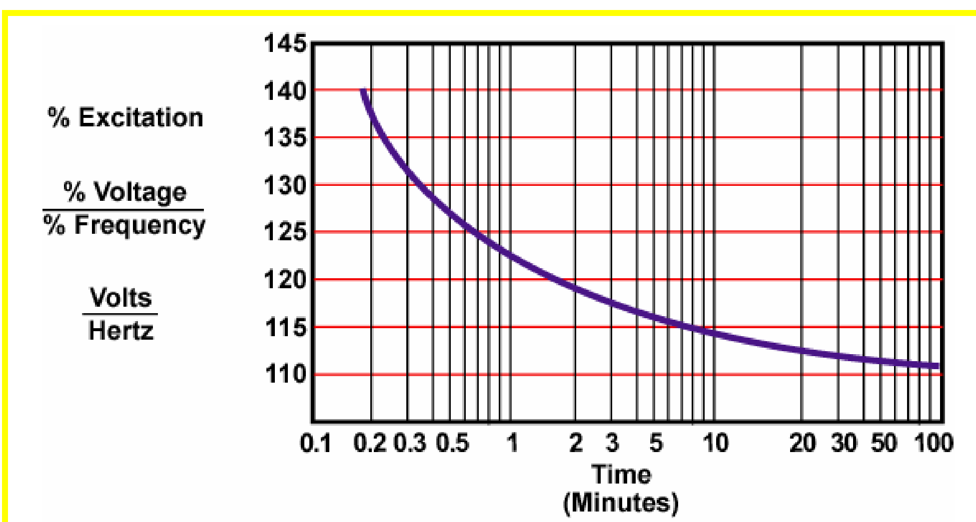


Figure 5-29
Transformer Over-Excitation

Power plant transformers are often protected with over-excitation relays. These relays look at the ratio of voltage to frequency. This type of protection is used in power plants since both high voltage and low frequency operation is possible, especially during start-up of the generator.

5.5.3 Effect of High Voltage on Load Magnitude

As stated earlier (and illustrated in Figure 5-22) for low voltages, load magnitude will vary with the voltage level. When voltages are high, the overall system load magnitude will rise. Non-motor load is most impacted by voltage. In a typical distribution system, if voltages rise to 105% of normal, the total system load magnitude will increase by 3%.

5.5.4 Effect of High Voltage on Angle Stability

The simple equation for active power transfer is repeated below:

$$\boxed{P_{TRANSFER} = \left[\frac{V_S \times V_R}{X_{S-R}}\right] \sin \delta_{S-R}}$$

Note the dependence of active power transfer on the voltage magnitude of the sending (V_S) and receiving (V_R) buses. If either of these bus voltages rise, the power angle (δ) can be decreased and still maintain the same active power transfer. The greater the system voltage, the more MW can be transferred at the same angle spread. High voltages (within operating limits) will help ensure system angle stability.

5.5.5 Effect of High Voltage on Customer Equipment

High voltages can damage customer equipment. Motor load is highly susceptible to high voltages. Motor insulation is designed to withstand specific voltage levels. If these voltage levels are exceeded the insulation may fail. Typically motors are designed to safely operate with voltages 10% above rated.

Electronic equipment manufacturing type load is easily damaged by high voltages. Electronic equipment manufacturers are paying increased attention to their equipments exposure to voltage deviations. The degree of that exposure is illustrated in Figure 5-30[4]. The data in Figure 5-30 is based on actual measurements of voltage deviations at manufacturing sites throughout North America.

The thick lines in the figure are voltage limits. As long as voltages stay within these limits, the typical electronic manufacturing is not susceptible to damage or shutdown. If voltages stray outside these limits damage is possible. The figure shows that not only is the magnitude of the voltage deviation important

[4] Data for Figure 5-30 obtained from the CBEMA.

but also how long the voltage deviation lasts. For example, a -30% voltage deviation can be tolerated if it lasts less than ½ second. The data gathered for this figure indicates that on average each site experienced 443 voltage disturbances a year. The disturbances ranged from large transient overvoltages that lasted less than 0.0001 second to small voltage sags and swells that lasted several hours.

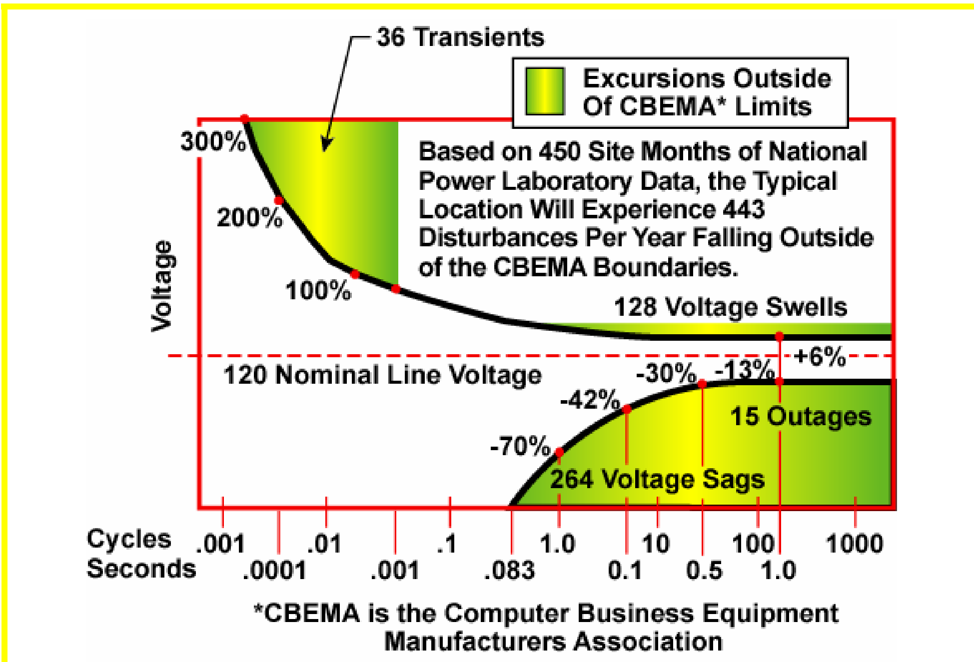


Figure 5-30
Electronic Equipment Manufacturers' Voltage Limits

Voltage swells include overvoltages greater than +6% that last longer than ½ cycle. Voltage sags include undervoltages greater than -12% that last longer than ½ cycle.

5.5.6 Effect of High Voltage on Power Losses

In Section 5.4.5 two equations for active and reactive power losses were developed. These equations are repeated below:

$$P_{LOSS} = 3I^2R = MW_{LOSS} \qquad Q_{USAGE} = 3I^2x = Mvar_{USAGE}$$

Note the dependence of both types of losses on the square of the current. If the current can be reduced both active and reactive losses can be reduced by the square of the current reduction. For example, if current can be reduced to 95% of its initial value then power losses can be reduced to 90% (0.95 x 0.95) of their initial value.

There are obviously limits as to how high the system voltage can be raised before system equipment is damaged.

The fundamental equation for determining power ($P_{FLOW} = I \times V$) tells us that to reduce the current it is necessary to increase the voltage. By increasing system voltage power losses will be reduced. This is not a recommendation that all system operators should raise their system voltage levels as far as they possibly can. What is recommended is that during normal operations power systems should be operated towards the upper end of their allowable voltage range.

5.6 Use of Voltage Control Equipment

This section reviews the purpose and operation of equipment used to control system voltage and describes how a system operator makes use of this equipment.

5.6.1 Use of Capacitors and Reactors

The primary sources of voltage control are the system generators. Capacitors and reactors are an alternate, versatile method of voltage control. Capacitors and reactors are not as expensive as generators, and are easier to construct and locate in the power system. Capacitors and reactors can be designed to be a permanent part of the system (fixed, not switchable) or be switched in and out-of-service via circuit breakers or circuit switchers.

Capacitors

Capacitors are viewed as sources of reactive power. Capacitors can be connected to the power system in either a shunt or series connection. Shunt capacitors are used to supply reactive power to the system. Series capacitors are used to reduce the impedance of the path in which they are inserted.

Shunt Capacitors

Shunt capacitors are a source of Mvar that are installed in close proximity to the point at which the extra Mvar is needed. When a shunt capacitor is switched in the local voltage will rise. Shunt capacitor switching is often used to control normal daily fluctuations in system voltage levels due to load changes. Shunt capacitors are connected to the power system as illustrated in the bottom of Figure 5-31. When the shunt capacitor is in-service it effectively serves as a source of reactive power. System voltages will typically rise as the current draw from other reactive sources is reduced.

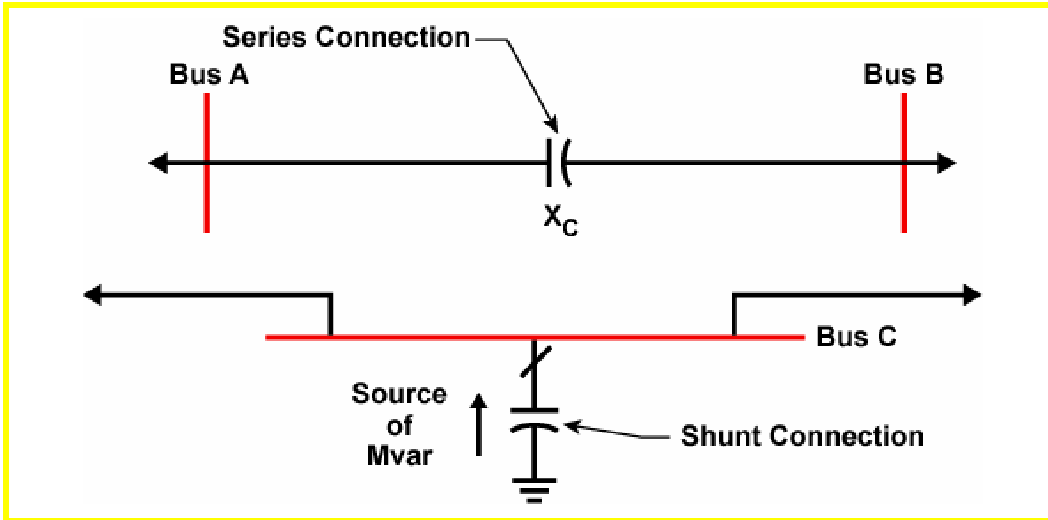


Figure 5-31
Shunt and Series Capacitors

Shunt capacitors are installed in various power system locations including:

- Transmission substations to help supply the reactive power needs of the bulk power system.
- Distribution substations and large customer locations to supply the reactive power needs of the customer loads.

Voltage Squared Output Relationship

As stated earlier in this chapter (see Figure 5-12), the reactive power output of a shunt capacitor bank is dependent on the voltage it is energized at. For example, if a 25 Mvar shunt capacitor normally rated at 115 kV is operated at a 5% low voltage (109 kV) the output of the capacitor will be 90% (0.95 x 0.95) of rated, or 22.5 Mvar.

Series Capacitors

Series capacitors are rare in the Eastern Interconnection with only a few installations. Series capacitors are relatively common in the Western Interconnection where load centers and generators are typically farther apart.

Series capacitors are installed in transmission lines to reduce the line's natural inductive reactance. The reactance of a series capacitor is out-of-phase with a transmission line's natural inductive reactance (X_L). The series capacitor reactance subtracts from the line's inductive reactance, reducing the overall line reactance.

If the line's inductive reactance is reduced, its power transfer capability can be increased. Series capacitors increase the power transfer capability of the transmission system. The top portion of Figure 5-31 illustrates the connection of a series capacitor in a transmission line.

Percent Series Compensation

Figure 5-32 illustrates the impact of a series capacitor on a transmission line's impedance. Assume this figure is for a 100 mile long 345 kV line. The line's resistance (R) is 6 Ωs and its inductive reactance (X_L) is 60 Ωs. A series capacitor rated at 30 Ωs (X_C) is installed in the line as illustrated in the middle of Figure 5-32. The combination of a 60 Ω inductive reactance with a 30 Ω series capacitance yields an effective line reactance of 30 Ωs.

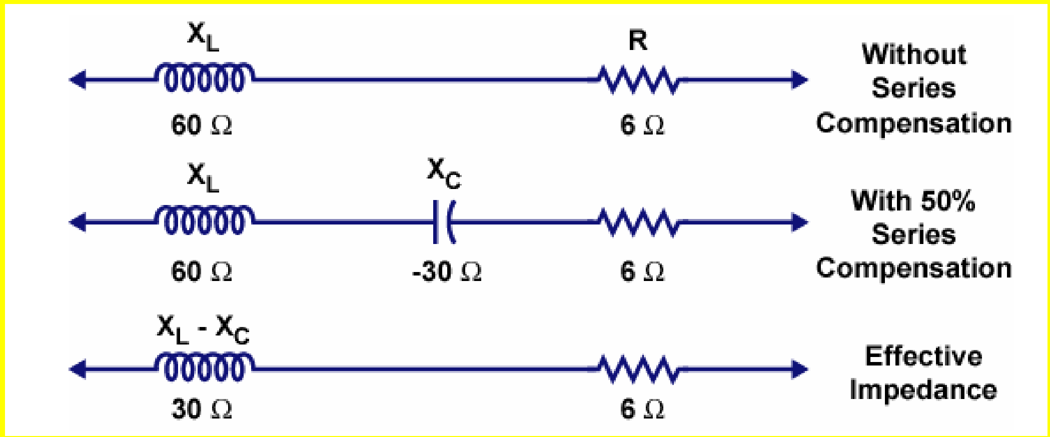


Figure 5-32
Series Compensation

There are limits to the amount of series compensation used. A typical limit might be 70%. The limits are related to allowable voltage rise across the capacitor and the possibility of subsynchronous resonance (SSR). SSR is addressed in Chapter 9.

The series capacitor reactance and the line's inductive reactance have subtracted from one another. The bottom portion of Figure 5-32 illustrates the effective line impedance. The power transfer across this line can now be increased (without increasing the power angle) due to the reduction in line impedance.

The % series compensation of a transmission line is a method of stating the amount of series capacitors used in the line. For example, in Figure 5-32, 30 Ωs of series capacitors were used to reduce the line's reactance by 50%. The % series compensation for this line is 50%.

Self Regulating

Unlike shunt capacitors, whose output decreases when it is most needed, series capacitors are "self-regulating". The term self-regulating means that a series capacitor will adjust its performance to match the needs of the system. When current passes through a series capacitor reactive power is produced by the capacitor and made available to the system. The amount of reactive power produced is proportional to the level of current flow.

When a series capacitor is needed the most, during heavy power and current flows, it produces more reactive power. During light loads on the system, when the series capacitor's Mvar is less important, the Mvar output naturally reduces. Series capacitors therefore regulate themselves or are self-regulating.

Reactors

Reactors can be viewed as absorbers or sinks of reactive power. Reactors can be connected to the power system in either a shunt or series connection. Shunt reactors are used to absorb reactive power from the system. Series reactors are used to increase the reactance of the path in which the series reactor is inserted.

Shunt Reactors

Shunt reactor banks are used to absorb excessive reactive power from the power system and thereby reduce system voltages. When high voltage transmission lines are built, fixed and switchable reactor banks are often installed to help reduce the overvoltages caused by lightly loaded high voltage lines. The switchable reactor banks are typically under SCADA control. Switched reactor banks are often found on transformer tertiary windings. These reactor banks are remotely switched in and out-of-service to control high voltages. The bottom portion of Figure 5-33 illustrates a shunt reactor bank.

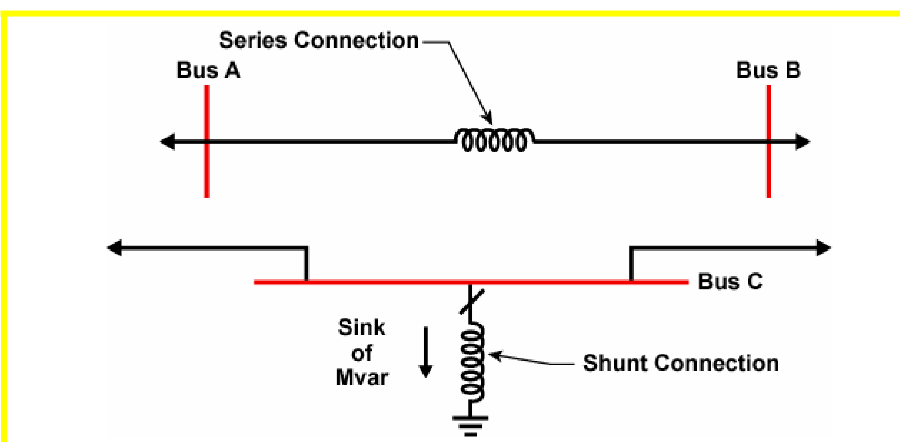


Figure 5-33
Shunt and Series Reactors

Series Reactors

Reactors can also be installed in series. Series reactor installations are not uncommon in the distribution system or within older power plants. Series

Chapter 8 describes power oscillations.

reactors add inductive reactance to a path thereby increasing the overall path impedance. The primary use of series reactors is to limit fault current. Fault current is limited due to the increase in the path's impedance. Series reactors can also be installed in the transmission system to help reduce power oscillations between generators. The top portion of Figure 5-33 illustrates the connection of a series reactor.

5.6.2 Use of Transformers

Transformers in which the number of turns in a winding can be adjusted under load are a valuable tool for voltage control. The construction and operation of tap changing transformers are described in this section.

Tap Changing Transformers

Off-Load Tap Changing (OLTC)

Power transformers are often equipped with a means to vary the number of turns in its primary or secondary windings. If the number of winding turns can be controlled, the voltage induced in the winding can (usually) be controlled. The ability to control the number of winding turns gives the transformer operator a range of control over the primary and secondary output voltages of the transformer.

Figure 5-34 illustrates the control of a transformer's secondary output voltage via a tap changer in the high voltage winding. This transformer normally has a 10:5 turns ratio since it normally has 10 primary turns and 5 secondary turns. If the primary voltage is 100 V the secondary voltage should be 50 V. Note the 9 tap positions on the primary side labeled A - I. If the input connections are switched from H_1 & H_2 to H_1 and G, the number of primary turns, is changed from 10 to 7. The turns ratio is now 7:5 instead of 10:5. If the primary voltage is 100 volts the secondary voltage should be100 x 5/7 = 71.4 volts.

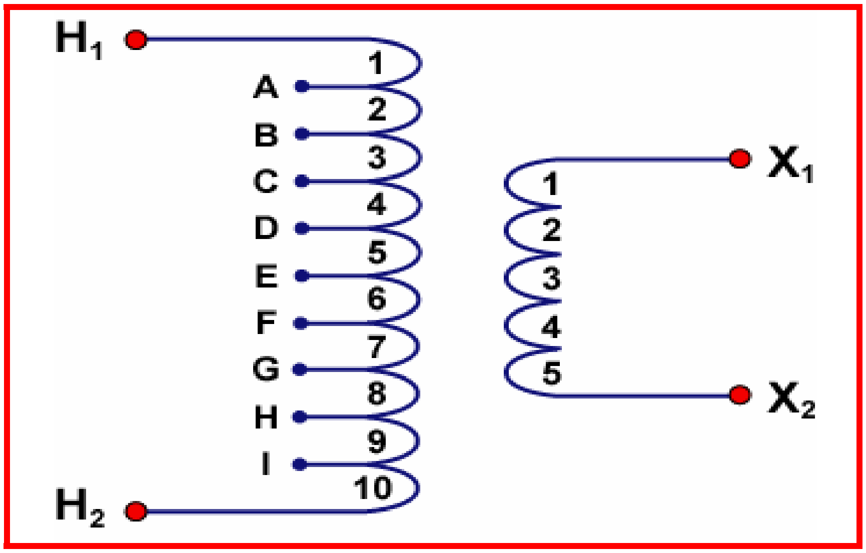


Figure 5-34
Illustration of a Tap Change

Most power transformers include tap changers that can only be adjusted when the transformer is out-of-service. These taps are called "off-load tap changers" or OLTCs. Off-load tap changers are mechanical linkages within the primary or secondary windings of the transformer. The linkages are designed to be adjusted to change the transformer winding turns ratio. These linkages can only be adjusted when the transformer current flow has been completely interrupted.

A typical power transformer may have five tap positions (labeled A - E or 1 - 5) within the off-load tap changer. For example, a 345/138 kV transformer with an OLTC on the 345 kV winding may have five taps: 327,750 - 336,375 - 345,000 - 353,625 - 362,250. Note the nominal or mid-point voltage is 345 kV. The low voltage (327,750) is 5% less than the nominal while the high voltage (362,250) is 5% greater than the nominal. Adjustments to OLTCs are typically made following major changes to the power system. OLTCs are used to correct long term (often seasonal) voltage problems.

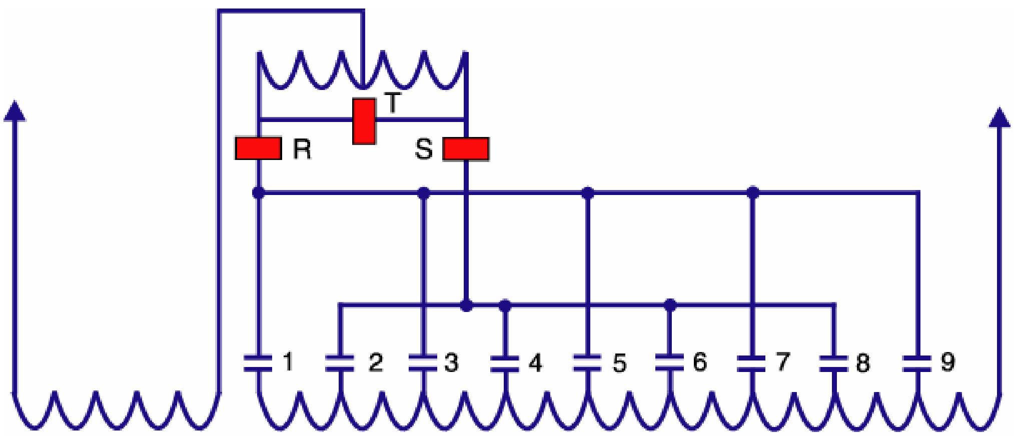
Under Load Tap Changing (ULTC)

Some power transformers possess a more powerful means for changing tap positions. Under load tap changing or ULTC equipped transformers are designed to change tap positions while the transformer is carrying load current. Figure 5-35 illustrates one form of an ULTC mechanism for a power transformer's winding.

The ULTC in Figure 5-35 is a 17 position ULTC with a ±10% voltage range. There is a neutral position (tap position # 9), eight raise positions (taps # 1-8) and eight lower positions (taps # 10-17). Since there are 16 possible tap adjustments spread across a 20% total voltage control range, each tap position is rated for a 1¼% voltage adjustment.

The switches labeled 1-9 in Figure 5-35 are used to select the different tap positions. The switches labeled R, S, & T are used to switch between different tap positions. This method is used to avoid exposing the tap selector switches (1-9) to arcing. Switches R, S, & T are designed to withstand arcing. The table below the graphic in Figure 5-35 indicates the switch positions for each of the 17 different tap positions.

Many new ULTCs are 33 position devices. These ULTCs will have a neutral position, 16 raise and 16 lower taps. The voltage control range is typically ±10% so each tap is good for a 5/8% voltage adjustment. The advantage of a 33 position ULTC over a 17 position is better (more exact) voltage control.



POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
SWITCH – 1	X	X															
- 2		X	X	X													
- 3				X	X	X											
- 4						X	X	X									
- 5								X	X	X							
- 6										X	X	X					
- 7												X	X	X			
- 8														X	X	X	
- 9																X	X
- R	X	X		X	X	X		X	X	X		X	X	X		X	X
- S		X	X	X		X	X	X		X	X	X		X	X	X	
- T	X		X		X		X		X		X		X		X		X

"X" = SWITCH CLOSED

Figure 5-35
Under Load Tap Changing Mechanism

Operation of ULTCs

ULTCs can be operated in either a manual or an automatic mode of operation. When in manual mode, tap positions can be adjusted via selector switches installed in the ULTC control cabinet. These selector switches can also be operated via SCADA if the utility has installed the necessary equipment. While in manual mode the ULTC does not automatically respond to voltage changes in the system. An operator must intervene to adjust the tap positions.

An ULTC can also be placed in an automatic mode of operation. When in automatic mode the ULTC automatically responds to system conditions and adjusts its tap positions without operator intervention. For example a ULTC may be designed to keep a constant secondary voltage. When the secondary voltage deviates from the intended point the ULTC will automatically adjust the tap position in an attempt to return the secondary voltage to the set-point. Whether the ULTC is successful in the attempt to control the secondary voltage depends on several factors including the room left to adjust taps. A ULTC can only make a voltage adjustment if it has taps available to adjust. The ULTC may go to full boost or full buck and still be unable to control the voltage.

The point at which an ULTC controls voltage does not have to be at the ULTC's physical location. For example, an ULTC may be equipped with controls that allow the ULTC to control the voltage well out into a secondary feeder. The ULTCs taps are adjusted to maintain a remote secondary voltage.

Figure 5-36 illustrates an ULTC control scheme. Note the PT and CT used to input secondary current and voltage to the ULTC. The ULTC in this figure will adjust tap positions if either the PT reads a voltage out of range or the CT reads a current out of range. This combination of voltage and current monitoring allows the ULTC to control the voltage at a remote secondary point. The ULTC adjusts tap positions to compensate for changes in load. The load changes are detected by monitoring the circuit current. This control scheme is commonly referred to as load drop compensation (LDC).

The "90" symbol is the IEEE device number for a voltage regulating relay.

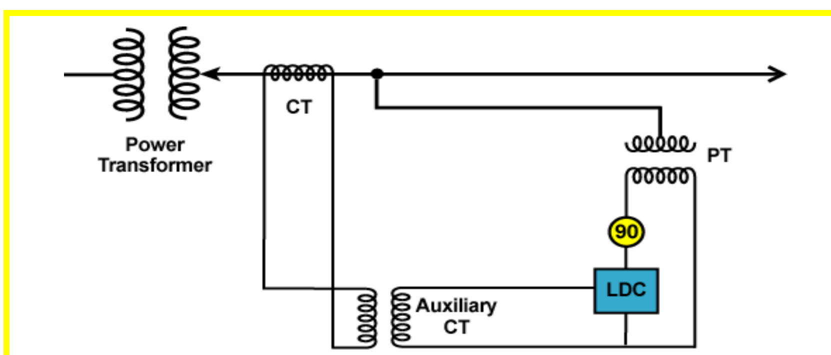


Figure 5-36
A ULTC Control Scheme

Tap Changing and Reactive Power

Tap changers control the voltage of a transformer's winding by adjusting the number of turns in the winding. When the turns ratio is adjusted the flow of reactive power across the transformer is normally adjusted. Changes in reactive power flow are necessary to accomplish the intended voltage change.

Figure 5-37 illustrates the impact of tap changes on the flow of reactive power through a transformer.

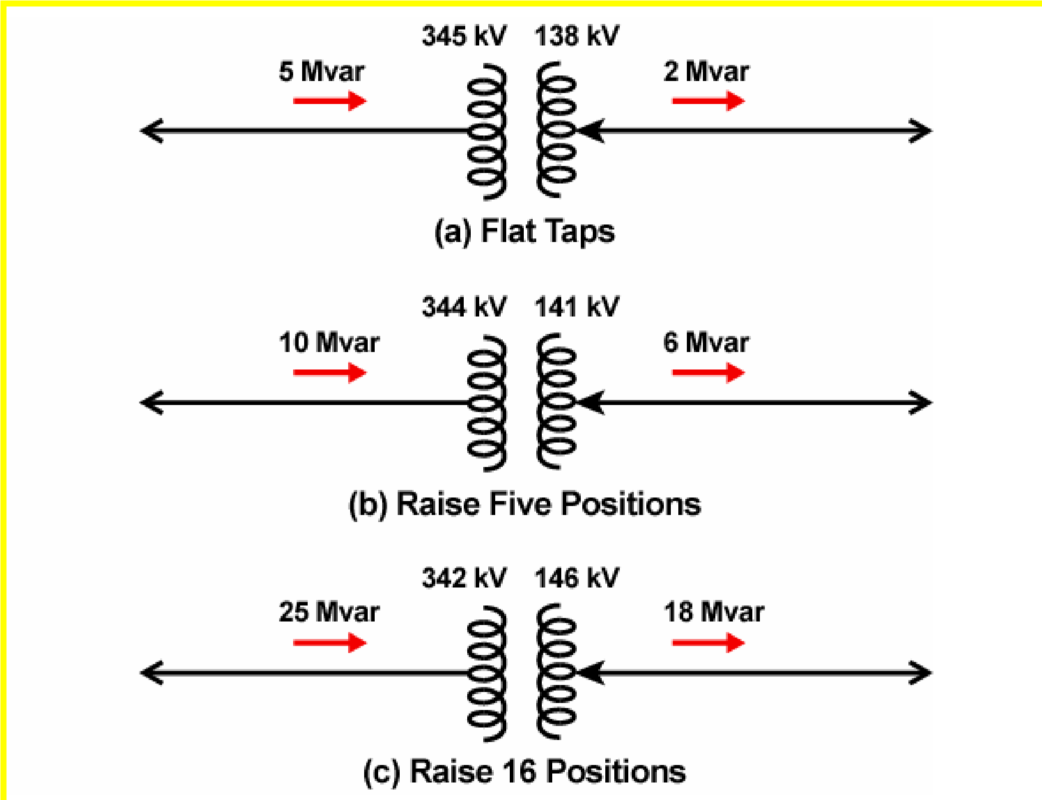


Figure 5-37
Tap Change and Reactive Power

The large arrow on the line connected to the low voltage winding is a common symbol for a ULTC.

In Figure 5-37(a) the ±10% - 33 position ULTC in the secondary winding is set at its neutral point (flat taps). The voltages on the primary and secondary side are initially at their nominal values of 345 kV and 138 kV. There is 5 Mvar flowing into the primary and 2 Mvar flowing out of the secondary. Therefore the transformer is using 3 Mvar to build its internal magnetic field.

In Figure 5-37(b) the secondary taps are raised five positions. Five positions are equivalent to a 3.125% (5/8 x 5) or a 4.3 kV voltage increase if we assume the voltage will change in exact relation to the turns ratio change. However, note the voltage only rises from 138 kV to 141 kV or 3 kV. This is typical. The amount of voltage change a given tap change produces is dependent on the strength of the power system connected to the ULTC. The effects of tap changes on voltage will depend on the transformer's location and the condition of the power system when the tap change is made.

Note the change in reactive power flows after the tap change in Figure 5-37(b). The Mvar into the primary and out of the secondary windings has increased, also the transformers Mvar usage has increased slightly. When the secondary winding size was increased via the five position tap boost the transformer automatically pulled Mvar from the high side in an attempt to support a higher secondary voltage. This tap change resulted in an increase in secondary voltage because the primary side was able to provide the needed reactive power. If the primary side was weak (no spare reactive power) the tap change may not have resulted in a secondary voltage increase. Spare reactive power or reactive power reserves must be available for a tap change to be successful.

In Figure 5-37(c) the secondary taps are raised 16 positions. Sixteen positions is equivalent to a 10% change in winding size. In our example, this tap change has resulted in a 5.7% voltage rise to 146 kV. Note the change in the reactive flows in Figure 5-37(c). The transformer is now pulling a large amount of reactive power from the primary winding. The 345 kV voltage has dropped 3 kV (to 342 kV) as a result of this reactive power flow. When the secondary voltage is raised via a tap change the primary will often drop. Typically the voltage drop will be so small as to not be noticeable. The greater the tap change and the weaker the primary side the greater the primary voltage drop will be.

Circulating Reactive Power

Similar transformers have the same turns ratio, tap changing capability, and impedances.

When similar transformers equipped with tap changing equipment are electrically close together, operating problems may develop if an attempt is made to operate the banks at different tap positions. Figure 5-38 illustrates this concept. Two 345/138 kV transformers (labeled “A” and “B”) are paralleled in Figure 5-38. The high and low voltage sides of the banks are tied together via low impedance paths.

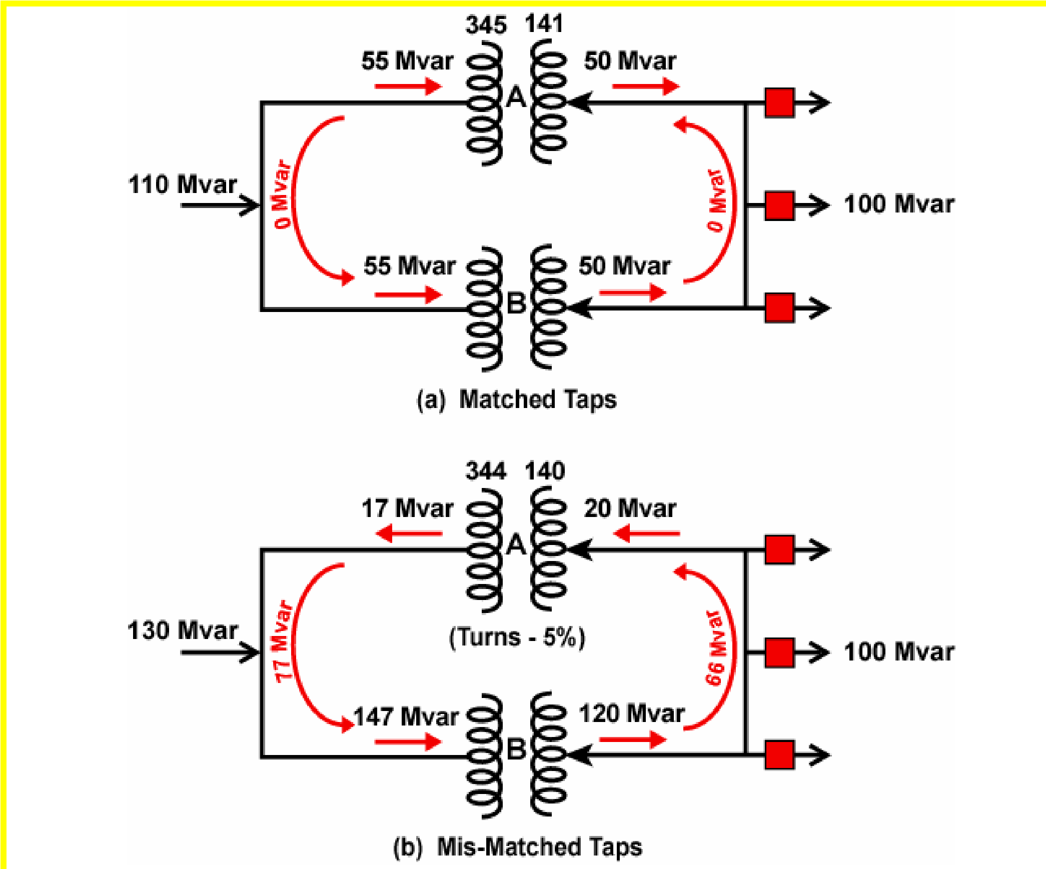


Figure 5-38
Circulating Reactive Power

When the tap positions are mismatched a circulating current flows between the transformers. This circulating current is 90° out-of-phase with the system voltage. This is where the circulating Mvar comes from.

In Figure 5-38(a) both transformer low side tap changers are set at identical positions. If the low sides of the two transformers were opened their respective high and low side open-circuit voltages would be nearly equal. Recall from Section 2.3 how reactive power normally flows from the high to the low voltage. No reactive power flows or circulates between the high and low sides of the two banks in Figure 5-38(a) as their voltages are equal. The two banks then share the 100 Mvar reactive load equally.

In Figure 5-38(b) the “A” transformer’s tap changing equipment has been adjusted to reduce the number of low side turns by 5%. If the low sides of both transformers were now open circuited the “A” transformer would have a smaller magnitude low side voltage than the “B” transformer. The “A” transformer would also have a greater magnitude high side open-circuit voltage than the “B” transformer. Reactive power is forced to flow between the two transformers due to these open-circuit voltage differences. Reactive power circulates from the low side of the “B” transformer to the low side of the “A” transformer. The reactive power then continues to circulate from the high side of “A” to the high side of “B”.

The only time the voltage differences could be seen is when the low sides are open. When the low sides are closed the circulating reactive power eliminates the voltage differences.

The circulating reactive power could take up capacity in the transformers and also lead to increased active and reactive power losses in the transformers. The cause of the circulating reactive power was mismatched low side tap positions. If the tap changers are returned to matched positions, the circulating reactive power flow will disappear.

When two identical transformers are paralleled it is important to match their tap positions. Note that if the banks have different impedances the tap positions may need to be intentionally mismatched in order to eliminate circulating reactive power. Mismatched impedances lead to mismatched open-circuit voltages. The mismatch in the open-circuit voltages can be eliminated by intentionally mismatching the transformer tap positions. Transformer tap position mismatching is normally something to avoid. However during special circumstances, such as during system restoration, transformers taps may be intentionally mismatched to increase the Mvar losses in the transformers. This action could be used to reduce system voltages a few kV.

5.6.3 Use of Generators

Generators are the backbone of voltage control. This section will describe the use of generators for reactive power production and absorption. The section will also illustrate the use of a graphical tool (reactive capability curve) for determining the power production limits of a generator.

Excitation Systems

The excitation systems of the generating units on the power system are used to control the overall voltage profile of the power system. Changes made to generator terminal voltages are subsequently spread throughout the power system. Figure 5-39 illustrates the major elements of a generator’s excitation system. The excitation system is used to control the terminal voltage and Mvar production of the generator.

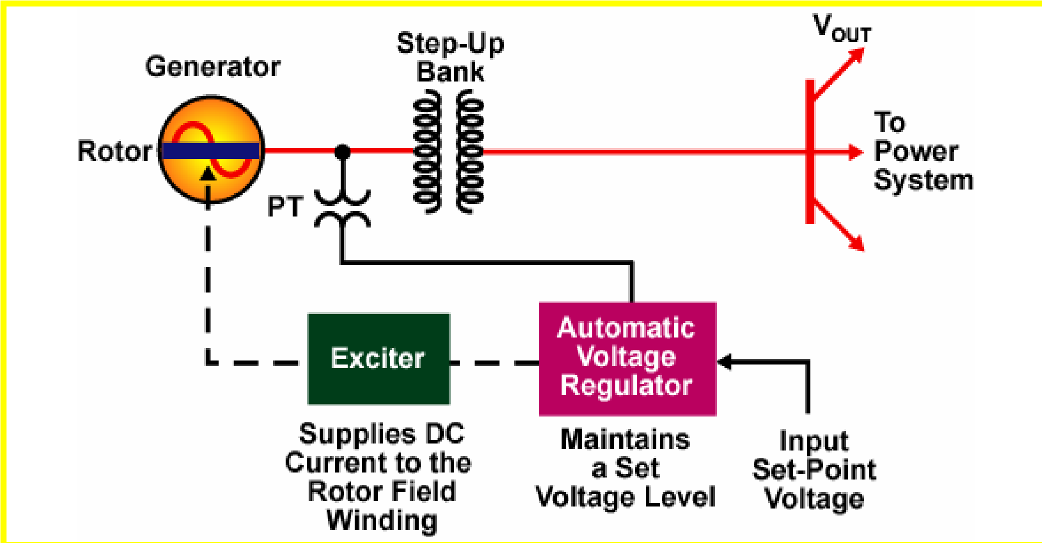


Figure 5-39
Block Diagram of a Generator Excitation System

The automatic voltage regulator (AVR) senses the voltage level at the generator terminals via a potential transformer (PT). Circuitry is included in the voltage regulator to compare the voltage measured to a set-point voltage. If the measured voltage is lower than the set point the AVR will cause the excitation system to increase the DC excitation current. This DC current is applied to the generator's rotor field winding. If the voltage measured is higher than the set-point the excitation system will lower the DC excitation current applied to the field winding. Plant operators control the voltage level of the generator by selecting the proper AVR set-point.

Method of Voltage Regulation

Voltage regulators can be operated in an automatic mode (as described above) or in a manual mode. When in automatic mode the excitation system will try to maintain a specified bus voltage. When in manual mode a plant operator selected magnitude of field current will be provided to the field winding. A voltage regulator in manual mode makes no attempt to automatically control a bus voltage magnitude.

From a system operations perspective all voltage regulators should remain in automatic mode. This ensures the generators will automatically assist with the control of system voltages. When voltage regulators are placed in a manual mode, a major voltage control tool (the generator) is eliminated from the voltage control process. Power plant operators may occasionally need to place voltage regulators in manual mode. The voltage regulators should be returned to automatic mode as soon as possible.

Reactive Capability Curves

The Mvar support capabilities of each generator are defined by each unit's reactive capability curve. Figure 5-40 is an example of a generator's reactive capability curve. This plot illustrates the limits of acceptable generator operation. The horizontal axis of the plot represents the MW produced by the generator. The positive vertical axis represents Mvar produced by the generator and the negative vertical axis represents Mvar absorbed by the generator.

Generators must be operated within the limits of their capability curves. There are three circular sections to a typical capability curve. Note the section labeled "Curve A-B" in Figure 5-40. The generator can not exceed this curve section limits or field winding thermal damage may occur. Note the section labeled "Curve B-C". The generator must stay within the confines of this curve section or stator winding thermal damage may occur. The final section is labeled "Curve C-D". The generator must stay within this section of the curve or thermal damage to the end-turn area of the stator core could occur.

While the magnetic bond is weaker when a generator is leading, this does not imply that generators cannot absorb reactive power. Modern generators have fast, powerful exciters that allow leading operation.

Also illustrated in Figure 5-40 is an under-excitation limit line. This line represents a limit to how far the generator may be taken into the leading region of operation. The farther a generator operates in the lead, the weaker the magnetic bond between the generator and the power system. As a generator's magnetic bond strength reduces the likelihood of a generator losing synchronism increases. Many generators will have protective systems that prevent their operation deep within the leading region of their capability curves.

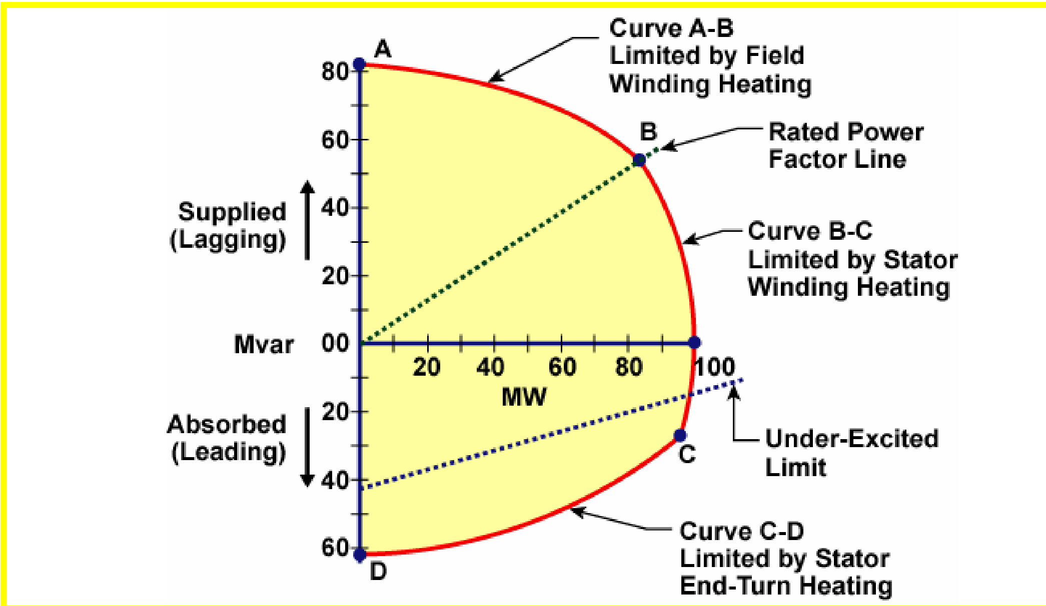


Figure 5-40
Reactive Capability Curve

When operating in the upper half of the curve the generator is supplying reactive power to support the system voltage. This type of operation is called lagging or overexcited. When operating in the lower half of the curve the generator is absorbing reactive power to lower system voltage. This type of operation is called leading or underexcited operation.

Each generator in the power system has a reactive capability curve. Plant operators are primarily responsible for keeping the generator MW and Mvar output within the limits of its capability curve. Generators are often equipped with protective relays to detect operation significantly outside of the rated capability curve of the unit. When activated, these relays may initiate a unit alarm, automatic runback, or unit trip.

Thermal Unit Reactive Capability Curve

Figure 5-41 is a capability curve for an actual thermal unit. An important feature of this capability curve is that there are actually a series of four capability curves illustrated. This is typical for a steam unit as the active and reactive power production capability of the unit is often a function of the stator's hydrogen cooling system pressure. The greater the hydrogen pressure the greater the capability of the unit. Note the hydrogen pressures of the unit illustrated in Figure 5-41 can vary from 5 psig to 45 psig. Also note the series of straight lines crossing the curve. These are constant power factor lines. All points along one of these lines have the same power factor.

The rated power factor of the unit (this unit's is 0.90) defines the break-point between the curve sections related to stator and field winding thermal limitations.

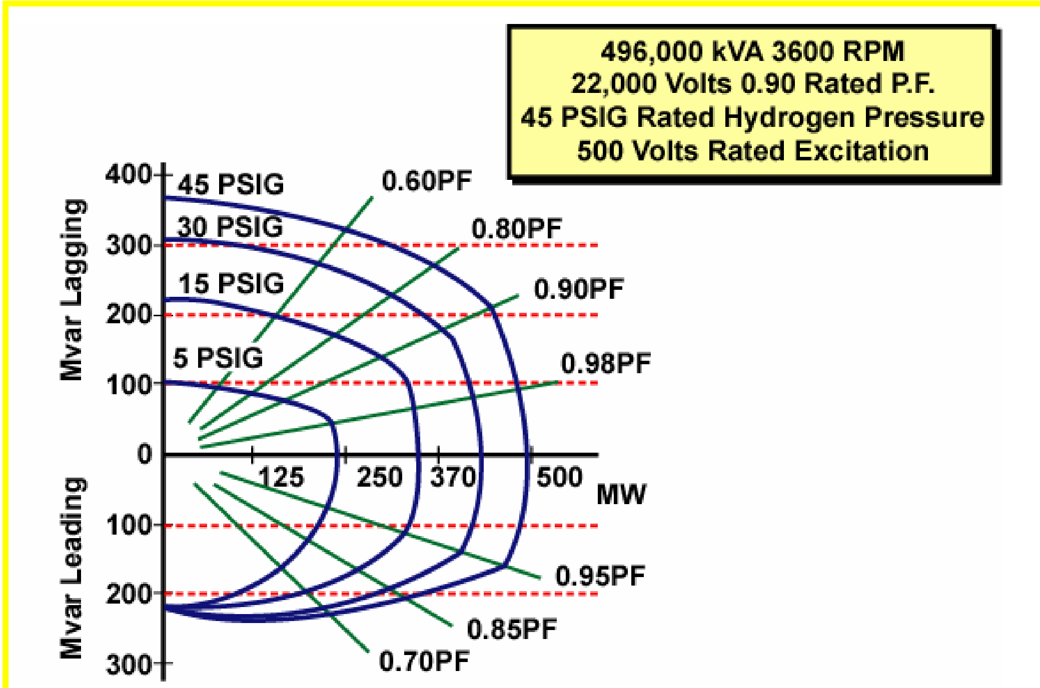


Figure 5-41
Actual Thermal Unit Reactive Capability Curve

A system operator could use the capability curve of Figure 5-41 to estimate the remaining reactive capability of the generator. You must first know the current hydrogen pressure of the unit and the current MW generation. Plot the current MW generation on the curve and determine the remaining reactive capability by noting the reactive limits from the appropriate capability curve. For example, assume this unit is presently operating at 375 MW and 100 Mvar with a hydrogen pressure of 45 psig. From the figure you can determine that the remaining reactive capability is approximately 170 Mvar in the lagging direction and 300 Mvar in the leading direction.

Hydro Unit Reactive Capability Curve

Figure 5-42 is an actual reactive capability curve for a hydro-electric generator. The curve shape is similar to the thermal unit of Figure 5-41 with the exception of the leading region. Hydro units are water cooled and not subject to stator end-turn thermal limitations. The leading reactive capability of a typical hydro unit is therefore much greater than that of a thermal unit.

Also note there are two capability curves given in Figure 5-42. One curve is for rated system voltage and the other is for voltages 15% higher. The power capability limits of a generator are mostly thermal related limits. If the system voltage is raised, the current is lowered and the power capability can be extended.

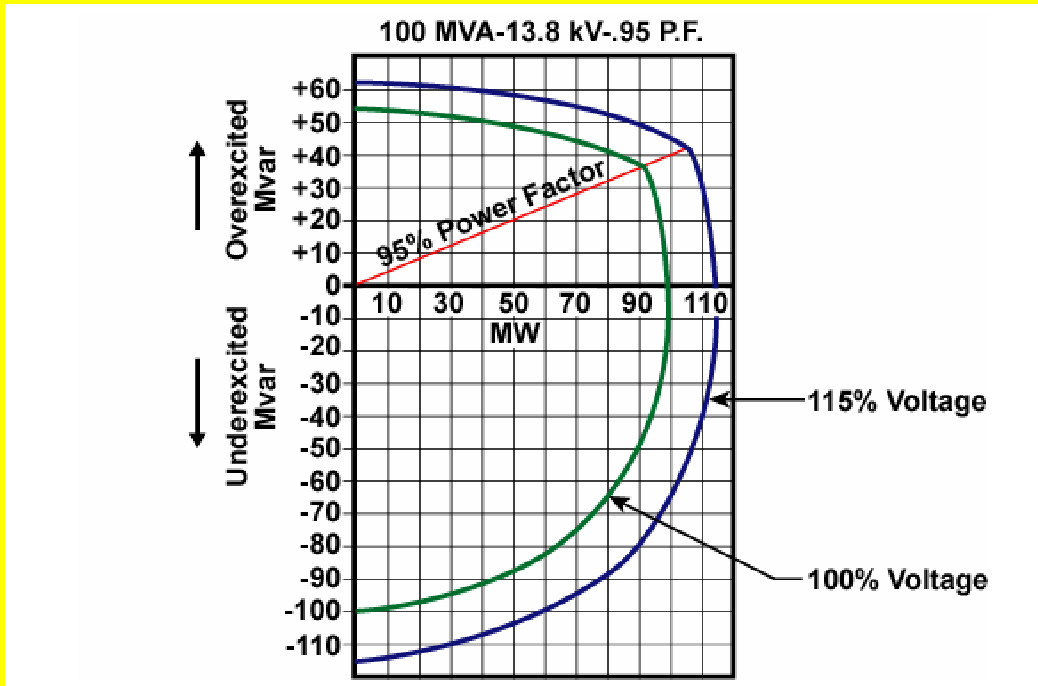


Figure 5-42
Actual Hydro Unit Reactive Capability Curve

The large leading capability of a typical hydro unit makes hydro units very valuable during system restoration.

Constraints on the Capability Curve

A generator's reactive capability curve is what a generator is physically capable of producing. Unfortunately, the power system the generator is attached to, and the auxiliary equipment within the plant itself, often restrict the generator to operating within only a portion of its capability curve.

The shaded region of Figure 5-43 illustrates how a generator may be restricted to only a portion of its capability curve. For example, operation in the upper or lagging portion of the curve may be restricted due to high auxiliary bus voltages within the plant. Operation in the lower or leading portion of the curve may be restricted due to unit stability problems. The actual capability of a generator can only be determined by testing the generator to determine what the reactive limits are. Many utilities have generator reactive capability test programs in place to ensure they know the true reactive capabilities of their generators.

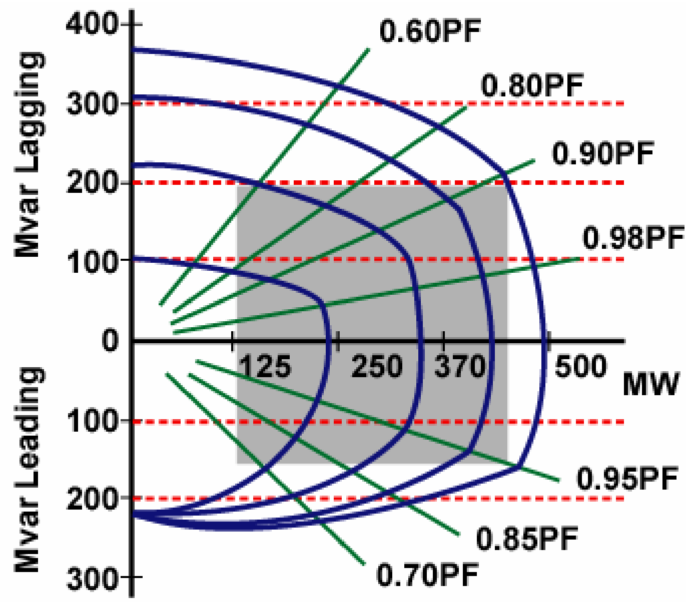


Figure 5-43
Reactive Production Limitations

Synchronous Condensers

A synchronous condenser is very similar to a synchronous generator with the exception that it is not capable of producing any sustained active power. Synchronous condensers produce only reactive power. Synchronous condensers do not need a prime mover as they are operated as a synchronous motor. The power system supplies the active power to turn the rotor. An excitation system is used to control the amount of Mvar produced or absorbed by the synchronous condenser.

Utilities that operate HVDC systems are good candidates for owning synchronous condensers.

Synchronous condensers are a very expensive source of reactive power and are seldom used in modern power systems. However, some companies do use synchronous condensers for Mvar support. The most common reason is that the company also wants the increased inertia from the spinning mass of the synchronous condenser.

Some types of generating units (typically hydro) can be used in a synchronous condenser mode. For example, in light load conditions utilities in the Pacific Northwest may switch hydro generators from a generating to a motoring mode and then use the generator excitation systems to absorb reactive power. Steam units are rarely operated as synchronous condensers, although there are a few exceptions.

5.6.4 Use of Static Var Compensators (SVC)

Components of an SVC

A static var compensator (SVC) is similar to a synchronous condenser in that it is also used to supply or absorb reactive power. However, in an SVC there are no rotating parts, every element is static. SVCs are composed of shunt reactors and shunt capacitors. High speed electronic switching equipment (thyrister switches) are used to adjust the amount of reactors or capacitors in-service at any one time. SVCs have the equivalent of automatic voltage regulator systems to set and maintain a target voltage level.

Thyristers were introduced in Section 1.6.5.

Figure 5-44 is a one-line diagram of a modern SVC. Note there are two shunt capacitor legs and two shunt reactor legs. A control system for the SVC sends signals to the thyristers to control the amount of current flow through the capacitor and reactor legs. For example, if the 230 kV bus voltage were to dip below the target value the control system would send electronic signals to the thyristers. These signals may be either to reduce the current flow to the reactors or to switch more shunt capacitors in-service. Either action will raise the 230 kV bus voltage.

There are many variations to SVCs. The SVC illustrated in this figure is only one possibility.

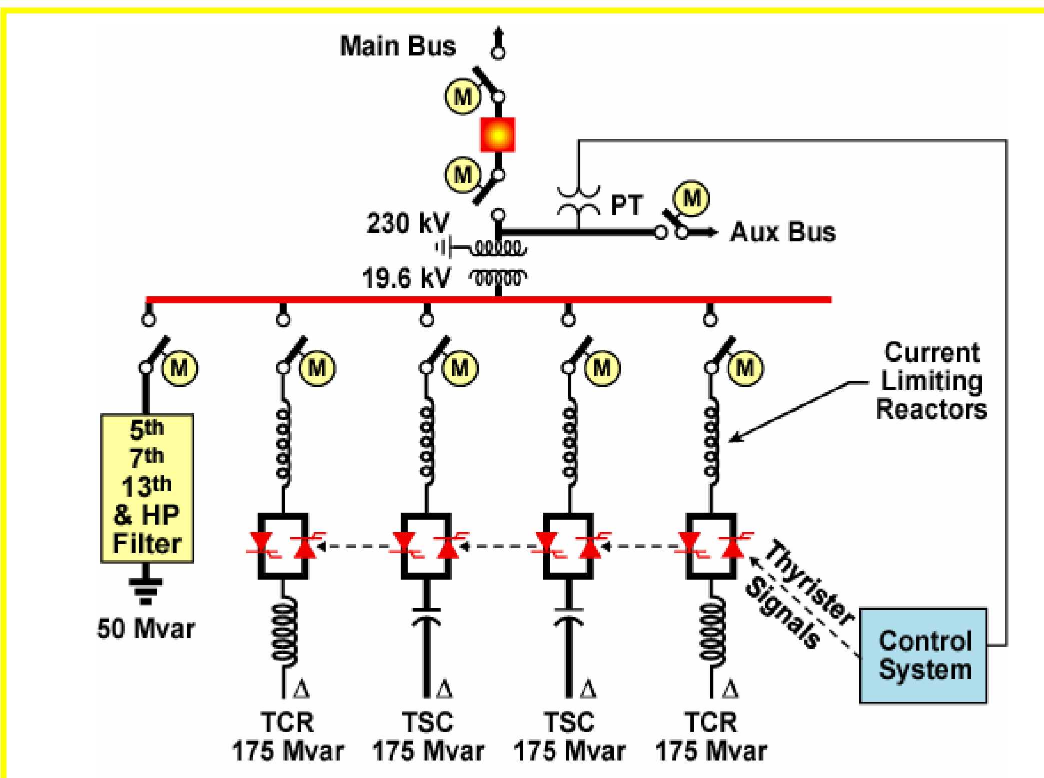


Figure 5-44
Static Var Compensator (SVC)

Thyrister Switched and Controlled Capacitors

Note the shunt capacitors in Figure 5-44. These are thyrister switched capacitors or TSCs. The thyristers controlling these shunt capacitors are similar to a circuit breaker. The thyristers will switch the shunt capacitors in-service or out-of-service very rapidly once a command to switch is received. Note the shunt reactors in Figure 5-44. These are thyrister controlled reactors or TCRs. The thyristers controlling these shunt reactors will continuously control the amount of current flow through the reactors. If the current flow is blocked, the reactors are out-of-service. If the current flow is at a maximum all of the shunt reactors are in-service.

The TSCs, TCRs, and SVC control system work together to control the bus voltage. The current flow through the TCRs is continuously adjusted. When more capacitors are required the TSC is signaled and a shunt capacitor bank is switched in-service. The TCR will then rapidly adjust to move voltage toward the set-point.

SVC Filters

Harmonics are addressed in greater detail in Chapter 9.

When thyristers are used to continuously control a current magnitude (as in the TCRs of Figure 5-44) the 60 HZ current and voltage waveforms will be affected. Harmonics will be created. Harmonics are whole multiples of the fundamental frequency. (For example, the 3^{RD} harmonic is 180 HZ.) When harmonics exist in the power system, the 60 HZ voltage and current waveforms will no longer resemble pure sine waves. There will be some degree of waveform distortion. This distortion can damage utility and customer equipment. Utilities try to remove whatever harmonic content is present in the power system waveforms.

One method of reducing the impact of harmonics is to add harmonic filters. Harmonic filters are combinations of capacitors, resistors and inductors. These filter elements are tuned to absorb specific frequencies of harmonic energy. For example, in Figure 5-44 the far left of the figure illustrates harmonic filters for the 5^{TH}, 7^{TH} and 13^{TH} harmonics. In addition, a “high pass” (HP) filter is included. The HP filter will be tuned to absorb all high frequency harmonics.

Static Var Systems (SVS)

Figure 5-45 contains a one-line diagram of a static var system (SVS). This SVS contains an SVC and also mechanically switched capacitors (MSC). The mechanically switched capacitors are switched in and out-of-service automatically to ensure that enough reactive reserve always exists in the SVC. An SVC may be combined with several types of voltage control equipment to form an SVS. For example, utilities have combined an SVC with local ULTCs to form an SVS. Voltage control is best accomplished within a defined area of a power system. You cannot control one bus voltage and not impact a neighboring bus voltage. SVSs are a natural consequence of this “area” approach to system voltage control.

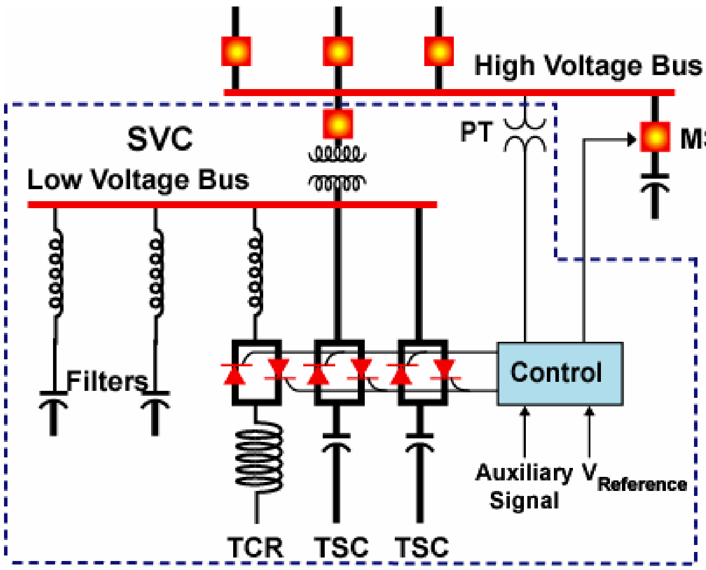


Figure 5-45
Static Var System (SVS)

SVC Limitations

There is a significant disadvantage to SVCs as compared to generators. If system voltage drops low enough to force the SVC output to ceiling its Mvar output will start to drop. One must remember that if system voltage drops low enough an SVC will reach its reactive (capacitive) output limit. At its output limit an SVC will act like a simple shunt capacitor and the reactive power output will drop with the square of the voltage.

In contrast a generator’s reactive output is not a function of the voltage squared relationship. When a generator’s reactive output is most needed the generator can actually exceed its reactive limits (for a short period).

5.6.5 Line Switching for Voltage Control

High voltage transmission lines appear to the power system as shunt capacitors when they are lightly loaded. During light load periods of the year many utilities are forced to take high voltage lines out-of-service to reduce system voltage levels. For example, a utility may remove several long 345 kV lines each spring evening and return the lines to service when the load picks up the next morning.

The lines that are removed from service will be those that contribute significant reactive power and whose removal will not significantly reduce system security. Rules of thumb for charging from high voltage lines are approximately 1/3 Mvar per mile for 230 kV, 3/4 Mvar per mile for 345 kV and 2 Mvar per mile for 500 kV lines. If a utility has a choice between removing either a 100 mile long 230 kV or 100 mile long 500 kV line, the 500 kV line removal would normally have more impact on system voltage.

5.7 Role of the System Operator

The system operator exercises a great deal of control over power system voltages. This control is largely limited to long term (sustained) voltage deviations. A system operator cannot typically respond fast enough to have any impact on short term or transient voltage deviations.

A system operator can often prevent the conditions that lead to short term or transient overvoltages. For example, several utilities have written operating policies that provide guidelines to system operators as to the minimum number of generators on-line at any one time to avoid a self-excitation condition.

5.7.1 Monitoring Voltage

The following are indications that voltage deviations exist that may require system operator response. These indications may be observed on the SCADA system or via reports from field personnel and other system operators.

- Key substations or specific areas of the power system have lower than normal voltages
- Reactive power flows are higher or lower than normal or flowing in unusual directions
- ULTCs are at abnormal positions, such as full boost or full buck
- Generator reactive power flows are higher or lower than normal. Generators may be operating near reactive output limits.
- The power system may enter a period of voltage oscillations. This could be the result of reactive power shortages.

5.7.2 Actions to Raise Voltage

Among the options available to a system operator to respond to low voltage problems on the power system are:

- Ensuring that all available equipment (lines, transformers, etc.) are in-service. For example, a transmission line may have been removed previously for high voltage control or for maintenance.
- Removing switchable shunt reactors
- Inserting switchable shunt and series capacitors
- Adjusting taps on ULTCs
- Requesting all available support from area generating units and neighboring systems. (Request that the units produce more Mvar.)
- Adjusting the output of area generators by changing the mix of generation. For example, reducing active power generation at one power plant and increasing it on another to change system power flows. This action may involve cost to the utility as more expensive generation may have to be brought on-line.
- Requesting that power sales or purchases be cut to lower transfers through a low voltage area.
- Initiating load shedding schemes.

5.7.3 Actions to Lower Voltage

Among the options available to a system operator to respond to high voltage problems on the power system are:

- Removing switchable shunt and series capacitors
- Inserting switchable reactors
- Adjusting taps on ULTCs
- Requesting all available support from area generating units. This would require the generators to absorb (buck) additional reactive power.
- Request help from neighboring systems
- Removing high voltage lines from service that have minimal active power flow but are supplying large amounts of reactive power

5.7.4 Maintaining Reactive Reserves

In the same manner as spare MW capability is held in reserve to respond to unforeseen events, spare Mvar capability should also be held in reserve to respond to unforeseen events.

Reactive reserves are spare reactive capability available to assist with system voltage control. Reactive reserves are composed of both reactive supply (lagging reactive) and reactive absorption (leading reactive) capability.

Reactive reserves include spare shunt capacitors, shunt reactors, SVCs, synchronous condensers, and generators.

Dynamic Reactive Reserves

Some utilities have implemented high speed switching schemes for inserting shunt capacitors following system disturbances.

Dynamic reactive reserves are reactive reserves that can be used to rapidly respond to system voltage deviations. (Rapidly typically means within a few cycles.) Manually controlled shunt capacitors or ULTCs are not dynamic reactive reserves since their control is subject to slow human actions. Most automatic controlled shunt capacitors do not qualify as dynamic reactive reserves as their control systems often limit their response.

Three types of equipment that do fit the definition of dynamic reactive reserves are static var compensators (SVC), synchronous condensers, and synchronous generators. This section will concentrate on the use of synchronous generators as dynamic reactive reserves.

The voltage control capabilities of a generator are a function of the reactive range (both Mvar production and absorption) of the generator and the speed of the excitation system. Modern generators have very rapid excitation systems. The combination of a fast excitation system and a large reactive range creates a powerful voltage control device.

To respond to rapid unexpected system voltage deviations a utility needs to carry sufficient reactive reserves in their better responding reactive resources. For example, if a rapid voltage drop or rise occurs, a utility will often do a better job of correcting the voltage deviation if they are carrying reactive reserves in their generators.

To ensure sufficient response to system voltage changes it is a wise practice to establish limits to the amount of reactive reserves available from system generators. For example, a utility may specify that all generators must have available at least ½ of their lagging and ½ of their leading reactive capability to respond to unforeseen events. To ensure acceptable levels of reactive reserves are kept in the system generators, a system operator may have to switch shunt reactors or shunt capacitors. For example, assume load is rising and the generators are moving well up into their lagging region. By switching in shunt capacitors a system operator can relieve the Mvar supply obligations of the generators and allow an increase to their reactive reserves.

Summary of Voltage Control

5.1.1 Review of Active, Reactive and Complex Power

- When a generator is supplying reactive power to the system, the generator mode of operation can be referred to as lagging, boosting, pushing or overexcited. When a generator is absorbing reactive power from the system, the generator mode of operation can be referred to as leading, bucking, pulling or underexcited.

5.2.1 Reactive Power and Low Voltages

- Voltage levels are directly tied to the availability of reactive power. If adequate reactive power resources exist in the areas where it is needed, system voltages can be controlled. The root cause of low voltages is a deficiency of reactive power.

5.2.2 Heavy Power Transfers

- One way to increase reactive reserves is to minimize the reactive usage of the system or to reduce the reactive losses of the system. To minimize power losses we should minimize current and maximize voltage.
- The fact that the inductive reactance of a transmission line is much greater than its resistance strongly impacts voltage control. It is difficult to transmit reactive power long distances.
- A conservative rule of thumb is to assume that in a heavily loaded power system, any increase in active power transfer must be accompanied by the cube of that increase in reactive power injection.
- The surge impedance loading (SIL) is the point at which the Mvar from a line’s natural capacitance matches the Mvar the line needs to support its voltage. When a transmission line is loaded below its SIL the line is equivalent to a capacitor. The line provides Mvar to the power system. When a transmission line is loaded above its SIL the line is equivalent to a reactor. The line absorbs reactive power from the system.

5.2.3 Transmission Line Outages

- A transmission line outage may lead to increased loading on parallel lines and subsequent lower voltages. This is due to increased active and reactive power losses.

5.2.4 Reactive Equipment Outages

- Generators are the primary means of controlling power system voltages. If a generator trips, a portion of the most important method of controlling voltage is lost.

5.2.5 Failure to Get Ahead of the Voltage

- The Mvar capability of a shunt capacitor is reduced as system voltages drop. A shunt capacitor bank's reactive output will vary with the square of the system voltage.

5.2.6 Motor Stalling

- When large motors are started, the in-rush current drawn can drag down an entire feeder's voltage.

5.3.1 Reactive Power and High Voltages

- While the root cause of high voltages is an excess of reactive power, the means by which high voltages occur vary across a wide spectrum.

5.3.2 Long Term Overvoltages

- The magnitude of the Ferranti overvoltage depends on the length of the open-ended line and the strength of the system tied to the closed-end of the line. An easily applied equation for calculating the amount of Ferranti voltage rise is:

$$\boxed{V_R = \frac{V_S}{\cos\left(L/8.61\right)}}$$

5.3.3 Short Term Overvoltages

- A severe variation on the load rejection theme is generator self-excitation. Generator self-excitation is a possibility if a generator is isolated on a capacitive source and does not have the ability to absorb the available reactive power. To prevent generator self-excitation you should ensure that a generator has the ability to absorb whatever Mvar may be available at its terminals.
- Harmonic overvoltages are caused by the interaction of capacitive and inductive elements and sources of harmonics.

5.3.4 Transient Overvoltages

- Lightning strikes lead to transient overvoltages. This is one reason for installing surge or lightning arresters, to arrest or trap the high voltage surge caused by lightning strikes to a transmission line or substation.
- Power system switching will cause transient overvoltages. Each time a breaker or switch is opened under load, the power system will experience a switching surge.
- Switching of capacitors or open-ended lines is especially susceptible to switching surges.

5.4.1 Effect of Low Voltage on System Equipment

- When transformers and transmission lines are exposed to low voltages, the thermal capability of the equipment can be exceeded.

5.4.2 Effect of Low Voltage on Load Magnitude

- An approximate rule of thumb is that for a typical mix of motor and non-motor load, the total customer load will decrease by 3% if voltage decreases by 5%.
- There is little doubt that the magnitude of the voltage impacts the load magnitude. However, there is doubt as to how long this magnitude change actually lasts.

5.4.3 Effect of Low Voltage on Angle Stability

- From a system stability perspective the lower the system voltages are held the greater the risk of instability.

5.4.4 Effect of Low Voltage on Customer Equipment

- The combined reactive power needs of many motors trying to recover from a stalled condition could prevent system voltage recovery.

5.4.5 Effect of Low Voltage on Power Losses

- There are two types of power losses; active and reactive. A utility can reduce both types of losses by operating their existing system with higher voltages.

5.5.1 General Effects of High Voltages

- High voltage can cause system equipment (for example, a circuit breaker) insulation to fail resulting in internal flashovers.

5.5.2 Effect of High Voltage on Power Transformers

- If a transformer's rated voltage level is substantially exceeded the transformer will draw increased reactive power from the system to support the increased strength of the transformer's magnetic field. This may lead to excessive heating in parts of the transformer and eventually could lead to transformer failure.
- Transformer saturation is a function of both the operating voltage and the operating frequency since both voltage and frequency impact the magnetic field strength. The ratio of the operating voltage to the operating frequency is called the transformers % excitation. For a typical transformer a 10% over-excitation can be handled indefinitely.

5.5.3 Effect of High Voltage on Load Magnitude

- When voltages are high, the overall system load magnitude will rise. Non-motor load is most impacted by voltage. In a typical system, if voltages rise to 105% of normal the total system load magnitude will increase by 3%.

5.5.4 Effect of High Voltage on Angle Stability

- The greater the system voltage the more MW can be transferred at the same angle separation. High voltages (within operating limits) will help ensure system stability.

5.5.5 Effect of High Voltage On Customer Equipment

- Motor load is highly susceptible to high voltages. Motor insulation is designed to withstand specific voltage levels. If these voltage levels are exceeded, the insulation may fail. Typically, motors are designed to safely operate with voltages 10% above rated.

5.5.6 Effect of High Voltage on Power Losses

- Increasing system voltage will reduce active and reactive losses.

5.6.1 Use of Capacitors and Reactors

- Shunt capacitors are a source of Mvar that are installed in close proximity to the point they are needed.
- Series capacitors are installed in transmission lines to reduce the line's natural inductive reactance.
- Shunt reactor banks are used to absorb excessive reactive power from the power system and thereby reduce system voltages.

- Series reactors add inductive reactance to a path thereby increasing the overall path impedance.

5.6.2 Use of Transformers

- Most power transformers include tap changers that can only be adjusted when the transformer current flow is interrupted. These taps are called off-load tap changers or OLTCs.
- Under load tap changing or ULTC equipped transformers are designed to change tap positions while the transformer is under load.
- ULTCs control the voltage on the transformer’s winding by adjusting the number of turns in the winding. Changes in reactive power flow are typically necessary to accomplish the intended voltage change.

5.6.3 Use of Generators

- The excitation systems of the generating units on the power system are used to control the overall voltage profile of the power system.
- Voltage regulators can be operated in an automatic or in a manual mode. When in automatic mode the excitation system will try to maintain a specified bus voltage. When in manual mode a constant magnitude of field current will be provided to the field winding. From a system operations perspective all voltage regulators should remain in automatic mode.
- A generator’s reactive capability curve is what a generator is physically capable of producing. The power system a generator is attached to and the auxiliary equipment within the plant itself often restrict the generator to operating within only a portion of its capability curve.

5.6.4 Use of Static Var Compensators (SVC)

- SVCs are typically composed of shunt reactors and shunt capacitors. High speed electronic switching equipment (thyrister switches) are used to adjust the amount of reactors or capacitors in-service at any one time.
- An SVC may be combined with several types of voltage control equipment to form a static var system or SVS.

5.6.5 Line Switching for Voltage Control

- During light load periods of the year many utilities are forced to take high voltage lines out-of-service to reduce system voltage levels.
- Rules of thumb for charging from high voltage lines are approximately 1/3 Mvar per mile for 230 kV, 3/4 Mvar per mile for 345 kV and 2 Mvar per mile for 500 kV lines.

5.7.1 Monitoring Voltage

- The following are indications that voltage deviations exist that may require system operator response:
    - Key buses have abnormal voltages
    - Reactive power flows are abnormal
    - ULTCs are at abnormal positions
    - Generator reactive power flows are abnormal
    - System voltage oscillations occur

5.7.2 Actions to Raise Voltage

- Voltage raising options include:
    - Ensuring that all available equipment are in-service
    - Removing switchable shunt reactors
    - Inserting switchable shunt and series capacitors
    - Adjusting taps on ULTCs
    - Requesting support from area generating units
    - Changing the mix of generation
    - Cutting power sales or purchases
    - Initiating load shedding schemes

5.7.3 Actions to Lower Voltage

- Voltage lowering options include:
    - Removing switchable shunt and series capacitors
    - Inserting switchable reactors
    - Adjusting taps on ULTCs
    - Requesting support from area generating units
    - Removing lightly loaded high voltage lines from service

5.7.4 Maintaining Reactive Reserves

- In the same manner as spare MW capability is held in reserve to respond to unforeseen events, spare Mvar capability should also be held in reserve to respond to unforeseen events.

- Dynamic reactive reserves are reactive reserves that can be used to rapidly respond to system voltage deviations.

Voltage Control Questions

1. What is the Mvar production of a 50 Mvar shunt capacitor that is energized at 90% of its nominal voltage?

   A. 40.5

   B. 45

   C. 55.6

   D. 61.7

2. A 5% change in voltage will typically lead to what change in the total load magnitude?

   A. 2%

   B. 3%

   C. 5%

   D. 10%

3. A transformer can be overexcited if exposed to:

   A. High voltage

   B. Low frequency

   C. High voltage and low frequency

   D. All of the above

4. What is the approximate Mvar/Mile production for a 345 kV overhead line?

   A. 1/3

   B. 3/4

   C. 2.0

   D. 5.0

5. A 345 kV transmission line operates at various voltage levels throughout the day. At which voltage level will the transmission line produce more reactive power?

   A. 345 kV

   B. 340 kV

   C. 350 kV

   D. 360 kV

6. A transmission line has 50 ohms of inductive reactance. 25 ohms of series capacitors are inserted in the line. What is the line's % series compensation?

   A. 25%

   B. 40%

   C. 50%

   D. 80%

7. A transmission line's __________ is the MW loading at which the Mvar from the line's natural capacitance is equal to the Mvar the line needs to support its voltage.

   A. surge impedance loading

   B. angle stability limit

   C. voltage stability limit

   D. thermal limit

8. What is the approximate Mvar/Mile production for a 500 kV overhead line?

   A. 1/3

   B. 3/4

   C. 2.0

   D. 5.0

9. Given a purely inductive load, what can be said about the MVA this load draws from the power system?

   A. The load draws only MW

   B. The load draws only Mvar

   C. The load magnitude cannot exceed 100 MVA

   D. The load magnitude cannot exceed 1000 MVA

10. A generator with spare Mvar is always a source of dynamic reactive reserve.

   A. True

   B. False

Voltage Control References

1. Power System Analysis—Textbook written by Mr. John Grainger and Mr. William Stevenson. (Actually a revision of an earlier text by Mr. Stevenson.) Published by McGraw Hill, 1994.

   Well written general reference on power system analysis. Chapters on the capacitance and series impedance of transmission lines were useful. This test is advanced and of more value to an engineering audience.

2. Electric Power Systems Manual—Textbook written by Mr. Geradino Pete. Published by McGraw Hill, 1992.

   Collection of descriptions of various power system phenomena. Well written text, suited to a system operator audience. Chapters on power flow and transmission lines were useful.

3. Reactive Power: Basics, Problems and Solutions—Tutorial course text published by IEEE. Course text #87EH0262-6-PWR.

   A collection of IEEE articles that address reactive power. The first paper in the tutorial "Power System Concepts of Reactive Power" contains an excellent description of active and reactive power concepts.

4. Electrical Transmission and Distribution Reference Book—Textbook written by the engineering staff of Westhinghouse. Currently available through Asea Brown Boveri (ABB).

   Chapter 9 of this classic text on power systems contains useful material on Ferranti rise and surge impedance loading.

5. Transients in Power Systems—Textbook written by Mr. Harold Peterson. Published by Dover Books, 1951.

   An older but very useful reference. The text contains useful descriptions of the causes of switching surges.

6. Electric Energy Systems Theory—Textbook written by Mr. Olle L. Elgerd. Published by McGraw Hill, 1982.

   Chapters 1 and 2 of this text contain a useful description of power basics.

7. Load Modeling for Power Flow and Transient Stability Computer Studies—EPRI report EL-5003, January, 1987.

Four volume report on load modeling. The equations for load magnitude in this chapter are based on this series of reports.

8. Reactive Power Control in Electric Systems—Primary author Mr. T. J. Miller. Published by John Wiley & Sons, 1982.

   Advanced text that is more useful to an engineering audience. The equations for the amount of Ferranti rise developed in Section 5.3 are based partly on material from this text.

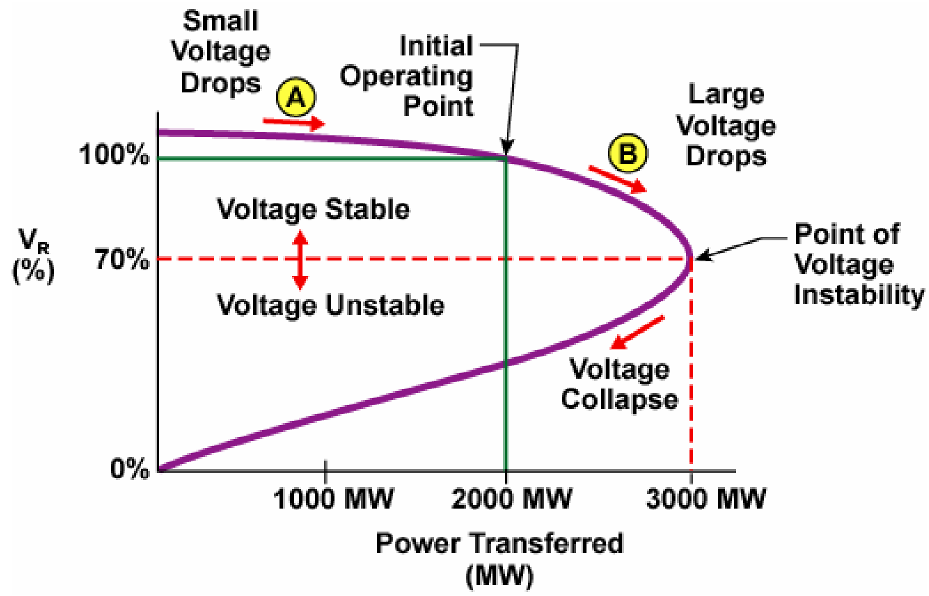
9. Overvoltage Control During Restoration—IEEE paper #92-WM-107-3-PWRS.

   Well written by IEEE Power System Restoration Working Group members. Paper addresses harmonic resonance and Ferranti rise.

10. Reactive Capability Limitation of Synchronous Machines—IEEE paper #93-WM-203-0-PWRS. Written by Mr. Mike Adibi and Mr. D. P. Milanicz.

    Paper contains useful information on the development of reactive capability curves and the limitations to the use of a generator's theoretical reactive power limits.

6
VOLTAGE STABILITY



6.1 Voltage Stability

Introduction to an extreme type of voltage deviation that can result in a voltage collapse.

6.2 Definitions

Definitions of voltage collapse and voltage stability are presented.

6.3 Types of Voltage Collapse

Long term voltage collapse, classical voltage collapse, and transient voltage collapse.

6.4 Long Term Voltage Collapse

Description of a long term voltage collapse.

6.5 Classical Voltage Collapse

Description of a classical voltage collapse.

6.6 Transient Voltage Collapse

Description of a transient voltage collapse.

6.7 Preventing Voltage Collapse

Techniques to prevent voltage collapse.

6.8 Role of the System Operator

A system operator may be able to recognize the conditions during which a voltage collapse can occur and take appropriate actions.

6.1 Voltage Stability

6.1.1 Introduction to Voltage Stability

This chapter introduces an extreme type of voltage deviation called a voltage collapse. When a power system experiences a voltage collapse, system voltages decay to a level from which they are unable to recover. A voltage collapse is a possible result of a period of voltage instability. The effects of a voltage collapse are more serious than those of a typical low voltage. As a consequence of voltage collapse, entire sections of a power system may experience a blackout. Restoration procedures would then be required to restore the power system.

As power systems are pushed to transfer more and more power, the likelihood of a voltage collapse occurring becomes greater. For example, in the past a power system may have had its power transfer limited due to angle stability considerations. Complex protection schemes and new types of equipment may now be used to extend power transfers beyond these angle stability imposed limits. The resulting increase in power transfer limits can make the system more susceptible to voltage collapse.

6.2 Definitions

6.2.1 Voltage Stability & Instability Definitions

Voltage stability is the ability of a power system to maintain adequate voltage magnitudes. When the load connected to a voltage stable system is increased, the power delivered to that load by the system will also increase. In a voltage stable system both power and voltage are controllable. In a voltage unstable system the system operators have lost control of both voltage magnitudes and power transfer.

Nominal Versus Actual Load

Before continuing with definitions of voltage stability and instability, we first distinguish between two types of load. The nominal load is the rated load. Nominal load is the MW the customer load will draw if it is operated at its nominal (or rated) voltage and frequency. The actual load is the actual MW drawn from the power system by a load. The actual load may be different than the nominal load.

Chapters 4 and 5 stated that voltage and frequency levels impact the load magnitude. Assume a 100 MW load is connected to a power system with customer voltages 5% below nominal values. 100 MW is the nominal load. However, since the customer’s voltage is 5% low, the actual load will be less (perhaps 97 MW) than the nominal load.

Given these definitions of nominal and actual load we are now ready to present a concise definition of voltage stability. In a voltage stable system when nominal load is increased, the MW transferred to that load also increases. In a voltage unstable system when nominal load is increased, the MW transferred to that load will decrease. Figure 6-1 restates this definition of voltage stability.

Voltage Stability is the Ability of a Power System to Maintain Voltage so That When the System Nominal Load is Increased the MW Transferred to That Load Will Increase.

Figure 6-1
Definition of Voltage Stability

6.2.2 Voltage Collapse Definition

Voltage collapse is a process in which voltage instability leads to loss of voltage in a significant part of the system. A system will enter a period of voltage instability prior to a voltage collapse. During voltage instability the power system is in grave danger and the system operators have lost control of system voltage and power flow. System voltage levels could be in the neighborhood of 70 to 90% of normal. System reactive supplies are exhausted and motors may begin to stall. If voltages decline any further a voltage collapse will occur.

In simple terms, a voltage collapse occurs when there is not enough Mvar available to serve the reactive power requirements of the area power system and loads. The Mvar deficiency leads to a decay in voltages. If the deficiency in reactive power is great enough, system voltages will decay to a level that they are unable to recover from. Figure 6-2 summarizes our definition of voltage collapse.

Voltage Collapse is a Process in Which a Voltage Unstable System Experiences an Uncontrolled Reduction in System Voltage.

Figure 6-2
Definition of Voltage Collapse

6.3 Types of Voltage Collapse

As a general observation a triggering event is required to initiate a voltage collapse. For example, a key transmission line or generator may trip due to a fault. This could lead to Mvar shortages as remaining lines accommodate the redistributed active and reactive power flows. Reactive power losses may then sharply increase. The low voltages that result from the reactive power deficiency may lead to further line trips. Regional system or a total system collapse is a possibility.

The theory of voltage stability and collapse is examined by describing three general types of voltage collapse:

Every voltage collapse incident does not neatly fit into one of these three categories. The categories are defined to simplify our presentation of the theory of voltage stability and collapse.

1. Long Term Voltage Collapse
2. Classical Voltage Collapse
3. Transient Voltage Collapse

6.3.1 Long Term Voltage Collapse

In a long term voltage collapse a transmission path separates a system's generating sources and load areas. The transmission path used to connect the generation to the load is stressed to the point that the system can no longer maintain voltages. Power system voltages collapse due to a failure to transmit sufficient reactive power to the points (the load area) where the Mvar is needed. This type of voltage collapse may take several minutes to several hours to occur. (Section 6.4 expands on this type of voltage collapse).

6.3.2 Classical Voltage Collapse

In a classical voltage collapse a strongly interconnected power system, with widely dispersed generation, does not have enough Mvar to satisfy the needs of the system and the customer load. A severe disturbance creates this deficiency of reactive power. The greater the deficiency of reactive power, the greater the voltage decline. Eventually the voltages decline to a point from which they cannot recover and the system collapses. This type of voltage collapse may take from 1 to 5 minutes following the disturbance. (Section 6.5 expands on this voltage collapse concept.)

6.3.3 Transient Voltage Collapse

There are several variations to the transient type of voltage collapse. The first variation involves sections of the power system pulling out-of-step from one another. During an out-of-step event, a point between the two systems pulling out-of-step will experience a voltage collapse. A second variation of transient voltage collapse involves large numbers of induction motors stalling and attempting to restart. This leads to large reactive power swings and possible voltage collapse. Both variations of a transient voltage collapse are different from the first two types described in that they happen very rapidly. A transient voltage collapse will normally occur in less than 15 seconds following the initial disturbance. (Section 6.6 expands on the transient voltage collapse concept.)

Modern utilities are increasing the time they spend examining the probability of a voltage collapse. Modern systems must often make do with the transmission lines and generation they currently have in place. The prospects for initiating major new construction projects are dim. Complex protection schemes are often installed to extend system operating limits that were once restricted due to angle stability and thermal loading concerns.

With these equipment additions the existing power systems are stressed to greater limits. An undesirable consequence of extending operating limits is an increased probability of voltage collapse. The complex protection schemes installed to extend angle stability limits may extend the system’s operating limits into the areas of voltage instability and voltage collapse.

Table 6-1 summarizes the three types of voltage collapse that are examined in the next three sections of this chapter.

Table 6-1
Voltage Collapse Types and Time Frames

Type	Cause	Time Frames
1. Long Term	Slowly Uses Up Reactive Reserves, No Outage	Several Minutes to Several Hours
2. Classical	Key Outage Leads to Reactive Power Shortage	One to Five Minutes
3. Transient	Induction Motor Stalling Leads to Reactive Power Shortages	Five to Fifteen Seconds

There are other causes for voltage collapse. The causes listed here are used to describe these types of voltage collapse.

6.4 Long Term Voltage Collapse

6.4.1 Introduction to Long Term Voltage Collapse

This section describes a long term voltage collapse. In a long term voltage collapse slowly developing changes to the power system occur that eventually lead to a shortage of reactive power and declining voltages. A radial power system is used to illustrate a long term voltage collapse.

6.4.2 Radial Power Systems

A radial power system is a power system in which generation and load areas are separated by a transmission path. Several parallel lines may be used to connect generation sources to the load areas. Radial power systems often develop as a means to connect inexpensive sources of generation to large metropolitan load areas. Figure 6-3 illustrates the radial 345/138 kV power system that is referenced frequently throughout this section.

Radial power systems occur in unexpected areas. For example, many metropolitan areas are progressing towards being radial power systems. It is very difficult to build generation in heavily populated areas so utilities build their generation in more remote, distant places and transmit it to the load areas. These types of systems are radial power systems.

The arrow symbol on the low voltage side of each transformer indicates the transformer has under load tap changing capability (ULTC).

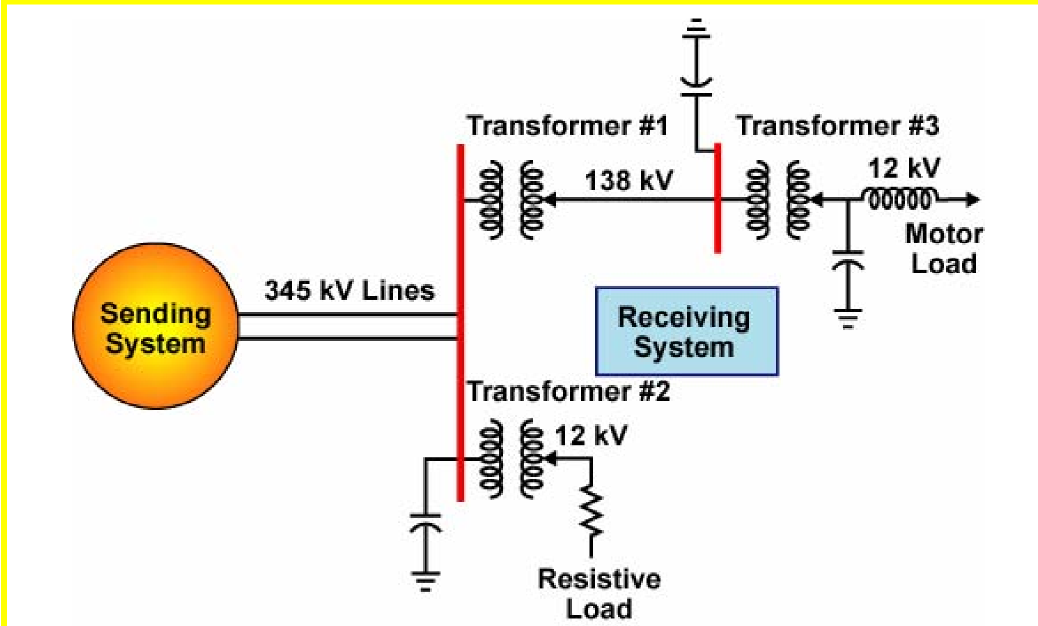


Figure 6-3
A Radial Power System

6.4.3 Use of the P-V Curve

P-V curves were introduced in Section 5.2.2.

When MW is transferred across a radial power system a curve can be created that relates the voltage at the receiving end of the system (V_R) to the MW transferred across the system. Figure 6-4 provides an example of this type of curve (called a power versus voltage curve or P-V curve). Note from this curve that as the MW transfer increases across the system, the voltage at the receiving bus (V_R) slowly decreases.

Eventually a point is reached (the “knee” of the P-V curve) where any further increase in MW transfer will lead to a rapid decrease in voltage. The knee of the P-V curve is the boundary between voltage stability and voltage instability. The voltage and MW transfer levels at the knee of the curve are called the “critical” values. For example, in Figure 6-4, the critical voltage is 70% of nominal and the critical MW transfer is 3000 MW.

Once the critical values are exceeded the system has entered a condition of voltage instability. The system voltage could collapse at any time. When voltage is unstable system operators have lost control of power transfer and voltage magnitude.

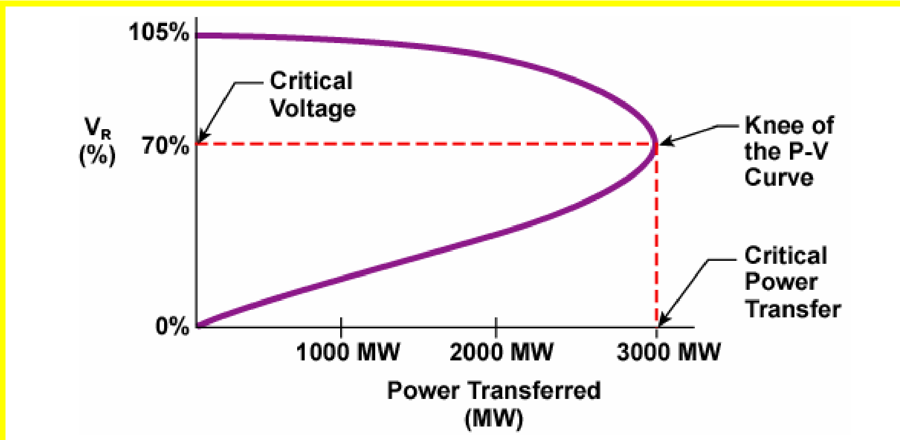


Figure 6-4
A Sample P-V Curve

Assume the power system whose P-V curve is shown in Figure 6-5 is initially operating at an active power transfer of 2000 MW. From the curve the receiving bus voltage will be approximately 100% of nominal at this transfer level. Assume further that the system load (the nominal load) starts to grow. Active power transfer grows with the increasing nominal system load. Eventually the MW transfer grows to 3000 MW.

Recall from Section 6.2.1 the distinction between the nominal and actual system load.

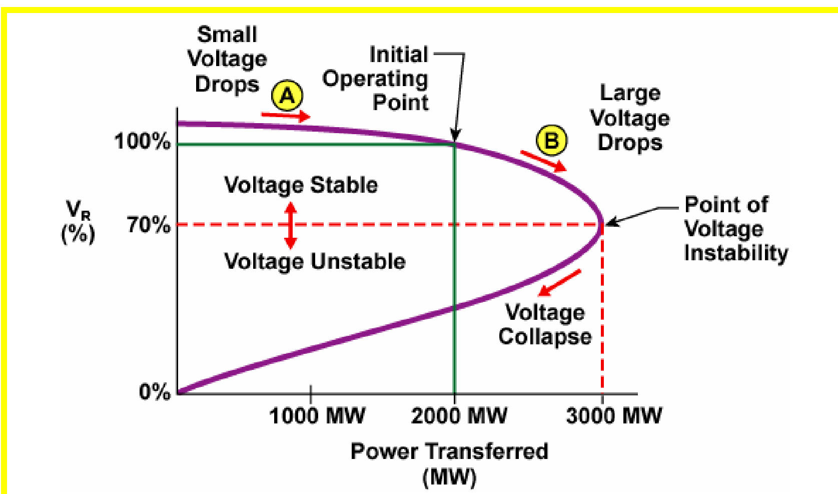


Figure 6-5
P-V Curve Illustration of Voltage Collapse

P-V curves are a tool to avoid voltage collapse. Avoid operating near the knee of the P-V curve.

The system is now on the brink of voltage instability. If the nominal load were to grow any larger, the MW transferred to the load would actually begin to decrease. Once the MW transfer exceeds the critical value the system is voltage unstable and a voltage collapse could occur at any time.

P-V Curves and Reactive Power

Two points are labeled on the curve of Figure 6-5, “A” and “B”. If the power system is operated in the area of point “A”, any small increase in MW transfer will lead to only a small decrease in receiving end voltage, V_R. In contrast, if the power system is operated in the area of point “B”, any small increase in MW transfer leads to a large decrease in V_R. This is due to the heavy Mvar usage of the system in the area of point “B”. Typically, a utility with voltage instability concerns will avoid system operation to the right of point “B” in Figure 6-5.

When a system is heavily loaded current magnitudes are high. Mvar losses are proportional to I^2X. When current increases, Mvar losses will increase at a rate at least equal to the square of the increase in current. The large voltage drops that result from increased MW transfers, in the area of point “B”, are due to the large Mvar losses on the system.

When the sending end system tries to replace these large Mvar losses, current increases even further and voltages may drop even more. Heavily stressed power systems will experience heavy Mvar losses and large voltage drops. The knee of the P-V curve is the point at which the system runs out of usable reactive reserves.

Creating P-V Curves

P-V curves are often used in combination with V-Q curves. V-Q curves are introduced in Section 6.5.

P-V curves are typically created by utility planning and operating engineers as an analysis tool to study voltage collapse in the power system. Many utilities that are concerned with voltage collapse develop P-V curves to help with their study. The P-V curves of Figure 6-4 and Figure 6-5 are provided only as samples. Each system must produce P-V curves for the different operating conditions encountered on their systems. The operating restrictions associated with the curves must then be discussed with the system operators.

Shape of the P-V Curve

Many utilities are increasingly using shunt capacitors to both solve system voltage problems and increase power transfer capabilities. Shunt capacitors are treated as a source of reactive power that are relatively inexpensive to install and maintain. However, shunt capacitors present an interesting operating problem with respect to voltage collapse. Figure 6-6 contains three P-V curves combined in one plot. The three curves are for three different receiving-end load power factors. The 0.9 lagging power factor is the normal case. The unity power factor (1.0) curve is the result of adding shunt capacitor banks at the receiving-end. The 0.9 leading power factor curve is the result of adding still more shunt capacitors at the receiving-end.

Notice the location of the knee of the three curves. Recall that the knee is the boundary between voltage stability and instability. You need to operate the power system far enough behind the knee to avoid the risk of voltage instability and possible collapse. As more and more shunt capacitors are added to the system, the knee of the P-V curve moves out and up into the range of normal system voltages. From a system operator perspective this is very dangerous. The best warning signal—rapidly declining system voltages—is taken away with increased use of shunt capacitors. As more and more shunt capacitors are installed, the point of voltage collapse is hidden or “masked”.

Shunt capacitors can mask the point of voltage instability.

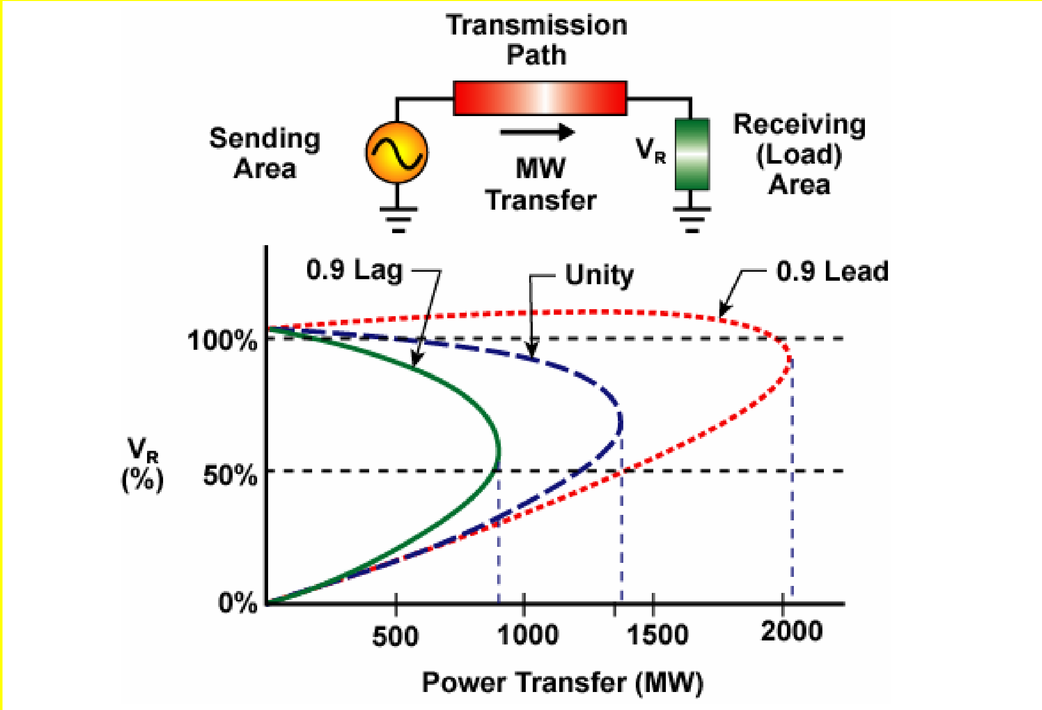


Figure 6-6
Shunt Capacitor Effect on P-V Curves

As additional shunt capacitors are placed in-service the nose of the P-V curve is pushed out and up. The point of voltage instability is “masked”.

6.4.4 Conditions for a Long Term Voltage Collapse

In order for a long term voltage collapse to occur certain initial conditions must exist. The most important prerequisite is for the active and reactive power flows on the system to be heavy. For example, the system would be operated in the area of point “B” in Figure 6-5. Any small increase in active power transfer will then lead to a significant decrease in receiving end voltages.

6.4.5 Long Term Voltage Collapse Process

The simple system of Figure 6-7 is used to summarize a possible long term voltage collapse process on a heavily loaded radial power system. In Figure 6-7 note the three ULTCs and the two shunt capacitor banks. Also note there are two types of load, motor load and non-motor (resistive) load. To set-up our voltage collapse process assume the initial loading on this radial power system is heavy. In other words, the system is operating towards the nose of its P-V curve.

The ULTCs in this system are in automatic mode. No operator intervention is required.

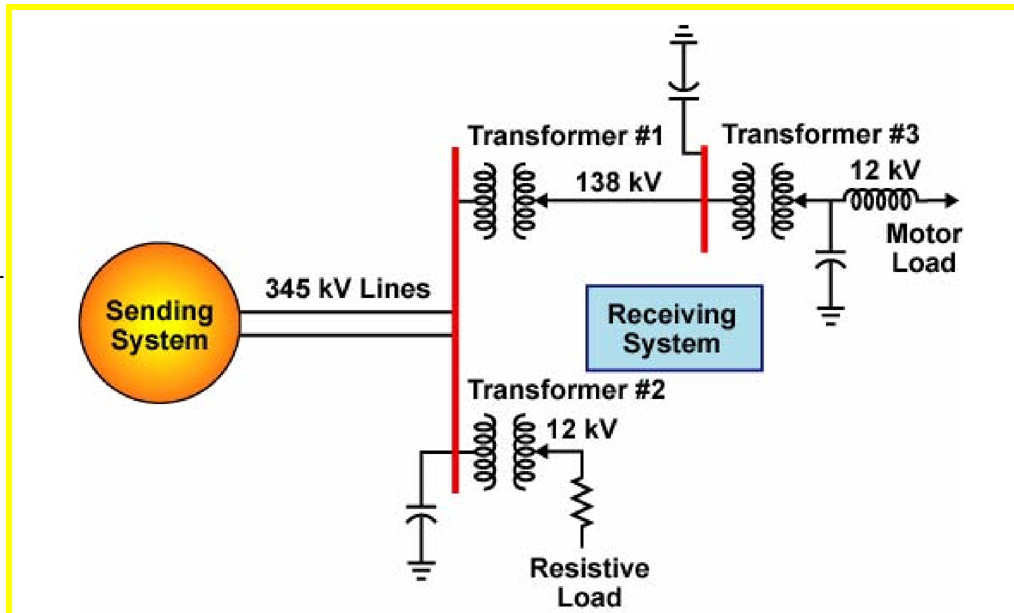


Figure 6-7
Radial Power System for Long Term Voltage Collapse

A summary of the steps to a long term voltage collapse follows. (Refer to Figure 6-7 as you progress through these steps.)

- In response to increasing customer load, the power system ULTCs act to raise declining low-side voltages. ULTCs raise voltage by adjusting the transformer turns ratio. When the low-side turns are increased, the transformer will draw Mvar from the high side to support the larger winding on the low-side. The increased Mvar supply to the low voltage system should raise low-side voltage levels.
- The Mvar supplied to the low voltage system was drawn from the high voltage (345 kV in Figure 6-7) transmission system. This will cause a reduction in the already low transmission system voltage levels. The amount of reduction will depend on how much additional Mvar can be obtained from the sending end sources. (Assume that all available shunt capacitors are already in-service.)

- The generators at the sending system attempt to increase their Mvar output. These generators are already close to their reactive capability limits and can manage only small Mvar increases. In addition, only a small portion of this Mvar makes it to the receiving end. The higher I^2X losses absorb the majority of the increased reactive power generation.
- The failure to obtain additional reactive power results in a system voltage decline. This reduction in voltage reduces the Mvar output of the shunt capacitor banks and reduces line charging. (Recall the dependence of shunt capacitors and line charging on the square of the voltage level.) This further reduces the system voltages.
- Over a several minute to several hour period the customer load increases further. The ULTCs continually attempt to raise low-side voltage. These ULTC adjustments have little impact on low-side voltages as there is little Mvar available from the high side transmission system. Beside being of no help to the low-side voltages, the tap changer action further depresses high side voltages.
- As new load is added the system voltage will decay further, eventually reaching the knee of the P-V curve. Once the system passes over the knee, voltage and power transfer could collapse following minor system condition changes. The only way to save the system is to reduce the MW load, or add additional reactive power, prior to reaching the point of voltage collapse.

6.4.6 Role of Tap Changing Equipment

The ULTCs that acted to increase the low-side voltage performed their job well as long as Mvar was available to be moved from the high to the low-side. When the high side reactive power reserves were depleted, the action of the ULTCs hastened the beginning of the voltage collapse. As the ULTCs attempted to raise low-side voltages they further decreased high side voltages and the outputs of high side capacitive sources. Once the high side voltages decreased far enough it did not matter what level the low-side voltages were at. If the high side is lost the entire system will collapse.

Many systems have recognized the problems with ULTCs during voltage collapse prone operating conditions. These systems often have operating procedures which contain instructions warning system operators to avoid manually adjusting ULTCs or placing the ULTC in automatic mode when the possibility for a voltage collapse exists. However, systems often have little control over the use of voltage regulators. The majority of these devices are on automatic control. The best that can often be done is to consider avoiding the use of bulk power system ULTCs during the operating periods in which the system is susceptible to a voltage collapse.

Voltage regulators are similar to ULTCs with a 1:1 turns ratio. Voltage regulators are commonly used in the distribution system.

Tap Changers and Load Overshoot

In Figure 6-7 a 345/138 ULTC and a 138/12 ULTC are shown in series. This was done intentionally to illustrate a possible phenomena called “load overshoot”. During our voltage collapse process the ULTCs automatically responded to support their low-side voltages as the system loads increased. If the response time of the two series ULTCs is not properly coordinated the MW and Mvar load could overshoot. This load overshoot occurs at the worst possible time and could push the system further toward voltage collapse.

Figure 6-8 illustrates only the two series ULTCs. Assume that system voltages are dropping. After a 30 second time delay the “upstream” ULTC responds first to raise its low-side voltage (V_2). The stair-step rise in voltage V_2 is noted in the voltage plot at the bottom of Figure 6-8. The upstream ULTC moves through a total of eight tap positions.

The “downstream” ULTC starts to raise its low-side voltage after a 45 second time delay. The downstream ULTC moves through three tap positions. Note the period on the voltage plot of Figure 6-8 in which both ULTCs are adjusting taps. The distribution voltage recovers before the transmission voltage. The tap changes by transformer #2 were unnecessary. The result is a voltage overshoot on the 12 kV voltage. The transformer #2 ULTC cannot reverse its tap movement for several (45) seconds as illustrated in the figure.

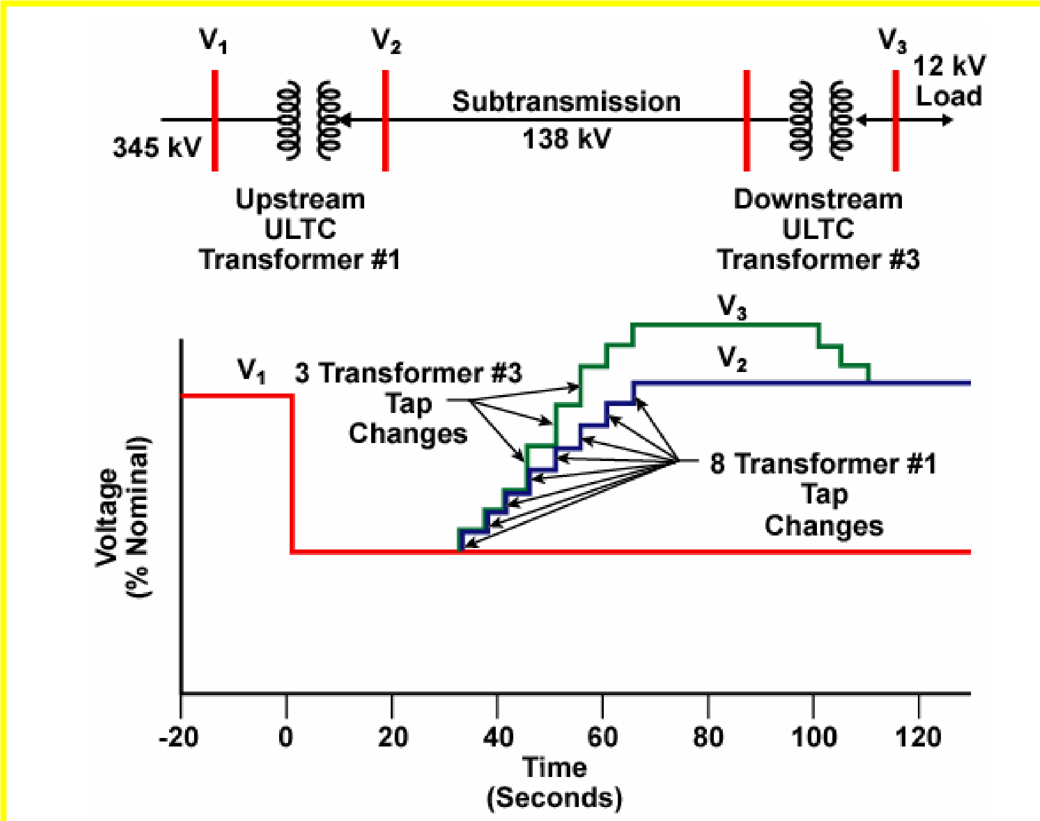


Figure 6-8
Tap Changers and Load Overshoot[5]

Upstream ULTCs should be configured to adjust their taps before downstream ULTCs.

Recall that load magnitude is dependent on voltage. The voltage overshoot will yield MW and Mvar load overshoot. The reactive load increase may be enough to push the system over the brink to voltage instability. The solution to this dilemma is to allow the upstream ULTC to adjust voltage before the downstream ULTC starts its tap movement. ULTCs are equipped with time delays that can be adjusted.

6.4.7 Tap Changing and Load Magnitude

Tap changers are a critical ingredient in voltage stability. Tap changer impact is not only due to their draw of reactive power from the high side but also to their impact on customer load magnitude. To avoid voltage instability, system load should if at all possible be minimized. Since load magnitude is dependent on voltage levels, tap changers strongly impact load magnitude.

[5] Figure adapted from reference #1.

Tap Changing with Non-Motor Load

The effects of tap changers are dependent on the type of load connected to the low-side of the transformer. If the load is primarily non-motor (such as resistive electric heating) the use of tap changers will normally hurt rather than help the situation. Non-motor load will normally decrease when voltage drops, which is a good thing during a voltage collapse. However, if tap changers act to raise taps and voltage, the load magnitude will rise. In general, during conditions that may lead to a voltage collapse you do not want to use tap changers that supply non-motor load. It is typically better to let the voltage drop.

Tap Changing with Motor Load

Motor load is not strongly impacted by voltage as long as you stay within the normal operating range of the motor (typically 90 to 110% of rated voltage).

If the transformer with the tap changer feeds motor load, you may want to use the tap changer. Motor load is not strongly affected by voltage. When voltage drops the motor will draw more current to draw constant power. However, if the motor is heavily shunt compensated, as most large industrial motors are, you would want to increase its voltage during a voltage collapse.

Increasing the voltage to a shunt compensated motor will lower the current drawn (and the reactive losses) while increasing the output from the shunt capacitors. During conditions that could lead to a voltage collapse you may want to use tap changers to raise voltage in heavily industrialized areas of the system. This may lower the reactive power drawn through the power system.

Self-Defeating Tap Change

An interesting situation can develop if automatic load tap changing occurs during the conditions prior to a voltage collapse. Assume that the high voltage system is heavily loaded. As load increases tap changers act to maintain the low-side voltages at their desired values. If the high side is weak the movement of reactive power to the low-side will further reduce the high side voltages. If the high side voltages drop far enough the net result of the tap change may be to lower both the high and low-side voltages.

The tap changer could then runaway and eventually move to full boost. The result of all the tap changes is lower high and low-side voltages. This sequence of events is called a “self-defeating” tap change.

6.4.8 Example of a Long Term Voltage Collapse[6]

One real world case of a long term voltage collapse is illustrated by the Tokyo Electric Power Company voltage collapse of July 23, 1987. In this instance an extremely high unexpected demand caused a sustained decay of voltage that led to a major system shutdown.

Tokyo Electric's major power sources, such as nuclear plants and large-scale thermal power plants, are located in the eastern regions with very few generating facilities in the west. Thus, large blocks of power typically flow east to west on the bulk 500 kV system.

On the day of the failure temperatures reached record highs (100ºF or more) and energy consumption began to rise. By the early afternoon, demand was increasing at a rate of 400 MW/minute, about double the estimated rate of rise. Despite various countermeasures, such as increasing the Mvar supplied by the generators, bringing new generation on-line, arranging for imports, and switching on shunt capacitors, voltage steadily decreased.

In the western part of the system, voltages decayed to 370 kV (70% of the scheduled value of 525 kV) as illustrated in Figure 6-9. About 20 minutes after the voltages began to fall distance-type protective relays operated. The relays interpreted the low voltage and high load current as a fault condition. As a result two 500 kV and one 275 kV substations were shut down, dropping about 8000 MW of load (2.8 million customers affected). Within 20 minutes the three substations were re-energized and about 60 percent of the load was restored.

[6] Description of Tokyo Voltage Collapse based on reference #4.

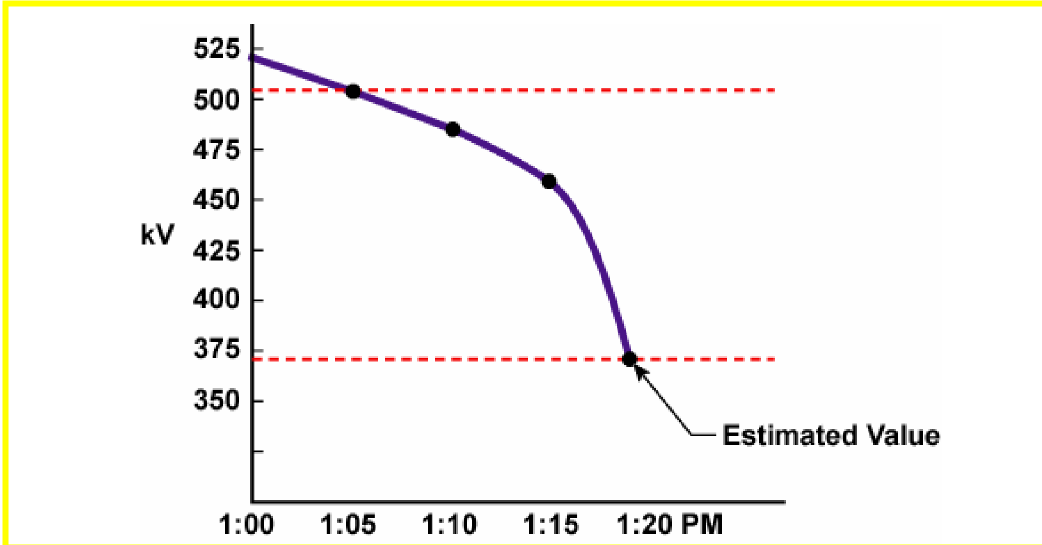


Figure 6-9
Tokyo Electric's Sin-Fuji 500 kV Substation Voltage

In this disturbance demand continued to build without adequate reactive support in the vicinity of the load. The system was stressed to the point where the reactive limits of the generators were reached and shunt capacitor banks were no longer as effective. Tap changer and voltage regulator usage, in an effort to hold load voltage—only made matters worse by depressing transmission voltage further every time a tap step-up occurred. A loss of load diversity served to bring on even more load thus depressing voltage even further until substations began to trip.

6.5 Classical Voltage Collapse

6.5.1 Introduction to Classical Voltage Collapse

This section describes a classical voltage collapse. A classical voltage collapse is similar to a long term voltage collapse with two important differences. First, the time frame is much shorter, lasting from 1 to 5 minutes. Second, a classical voltage collapse requires a severe triggering event such as the loss of a major transmission line. This section will also describe the V-Q curve which is an important tool for studying a classical voltage collapse.

A classical voltage collapse occurs when there is not enough reactive power available to meet the needs of the system and the loads. A power system that is normally strong with many interconnecting lines and sources of reactive power is possibly susceptible to a classical voltage collapse if:

- Loads on the system are heavier than normal
- A contingency occurs such as the loss of a key line or generator

The events described in Section 6.4 for a long term voltage collapse also may occur during a classical voltage collapse. For example, the Mvar contributed by capacitors and line charging will be reduced as voltages drop; tap changer (both from ULTCs and regulators) action may further depress transmission system voltages.

6.5.2 Loss of Load Diversity

The system load may naturally adjust to help avoid a voltage collapse. For instance, when voltage decreases non-motor load magnitude will decrease. This natural response will lower the overall system load magnitude and help reduce voltage drop. This effect is largely eliminated if the heavy load period lasts for a long time.

The reduction in load magnitude is also eliminated if the voltage regulators restore voltage. This is a negative effect of voltage regulator operation.

For example, consider electric resistive heating. When voltages are low the heat output of electric heaters will reduce. The heater thermostat is designed to hold the building temperature at a pre-set level. If the output of a heater decreases the thermostat will simply energize more heaters or keep the heaters on for a longer period. The combined effect of more heaters operating and running the heaters for a longer period will eventually cause an increase in the total system load.

Power system load is constantly changing. Small loads are always being added or removed. When a majority of these loads are running at the same time, such as the electric heaters described above, the condition is known as a "loss of load diversity". A loss of load diversity will lead to an increase in the total system load level.

6.5.3 Simulation of a Classical Voltage Collapse

Figure 6-10 is a simple system put together to illustrate a classical voltage collapse. This is a radial 138 kV power system. Study the figure and note the following points:

- The load is initially 100 MW
- The 138 kV voltage is 4.7% above nominal or 144.5 kV
- The low-side voltage level is 100% of its nominal value of 12 kV
- The generator is providing 14.3 Mvar to the system
- The 35 Mvar capacitor is providing 38.3 Mvar to the system

Note the 35 Mvar capacitor supplies 38.3 Mvar. The capacitor output is proportional to the voltage squared.

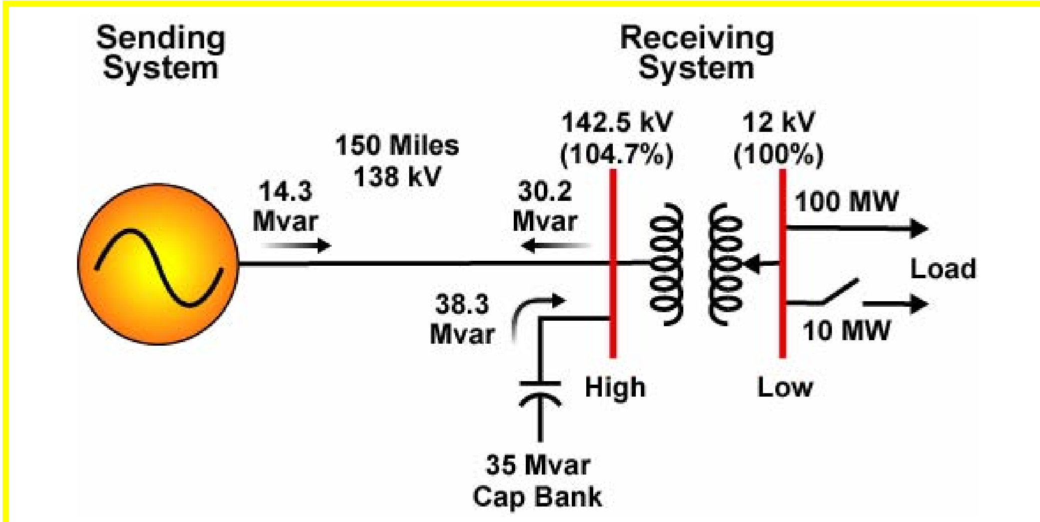


Figure 6-10
Conditions at Receiving Bus Prior to Adding 10 MW Load

A 10 MW load addition may not seem like a large disturbance. However, in the simple system of Figure 6-10 this represents a sudden 10% load increase.

We will trigger a classical voltage collapse in this system by adding 10 MW of load. Figure 6-11 illustrates what happens to the high and low-side voltages. When the 10 MW load is added both voltages initially drop. The ULTC then starts its tap change sequence in an effort to raise the low-side voltage. Notice how this tap change does very little to improve the low-side voltage but causes a gradual reduction in the high side voltage.

Loss of Load Diversity

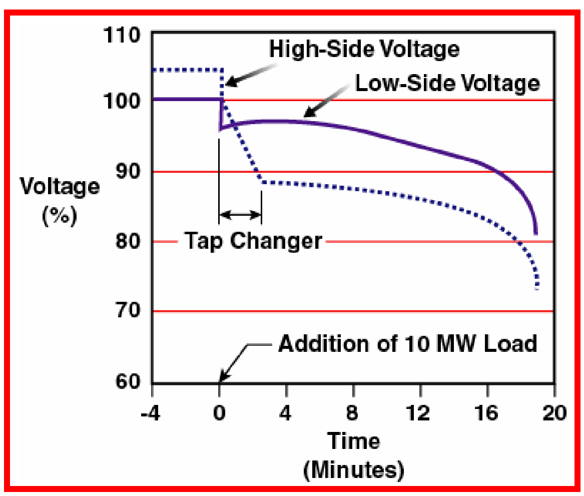


Figure 6-11
High and Low-Side Voltages After 10 MW

Approximately 4 minutes after the 10 MW load addition the system appears to stabilize. This stabilization does not last long as illustrated by the gradual collapse of voltages in Figure 6-11. The gradual collapse is due to two factors. First, the load on this system was non-motor (unity power factor) load. This type of load is very sensitive to voltage. When the voltage is low, the load magnitude shrinks. This load reduction helps the system out, at least for a few minutes. The load relief does not last very long as more and more of the connected load is active at the same time. Over a period of 10 to 15 minutes most of the load reduction due to voltage will disappear.

The second factor which drove this system into voltage collapse is a short term boost of reactive power from local generators. Generators can leave the limits of their reactive capability curves for short periods of time. Eventually the generator’s protective systems will force the generators Mvar output back within limits. This forced reduction in Mvar output contributed to the slow decline of voltages as illustrated in Figure 6-11.

6.5.4 Response of Generation

To avoid a classical voltage collapse, the response of local generation is critical. If local generators are at their reactive power producing limits the system may be in serious trouble. A generator’s reactive power limits are defined by the unit’s reactive capability curve. When conditions are such that a voltage collapse is probable, system operators and plant operators must try every means possible to increase the reactive power reserve.

This may include a re-dispatch of generation. In a re-dispatch of generation, local generator MW levels are decreased to allow an increase in the unit’s reactive power generating capability. The MW output from generators outside the troubled area would then be increased. Figure 6-12 illustrates how cutting back on a generator’s MW generation will increase the available reactive generating capacity.

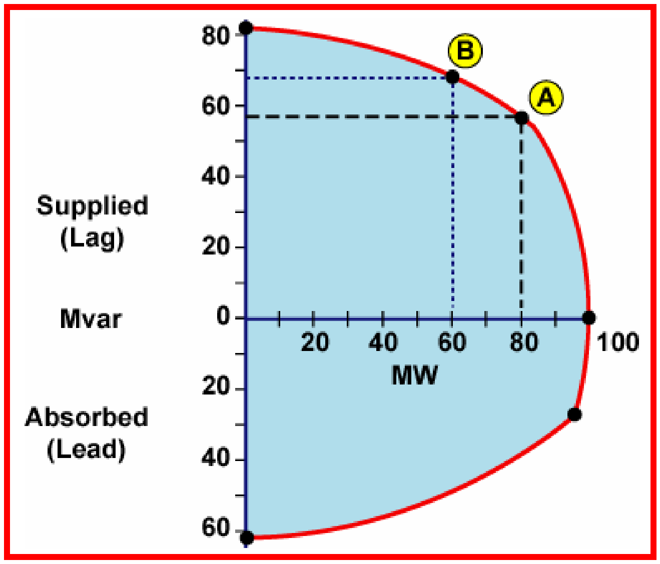


Figure 6-12
Adjusting the Generator Operating Point

Point "A" in Figure 6-12 represents a power output of 80 MW and 57 Mvar. The generator cannot exceed these power limits for sustained periods (a few minutes) without risking damage to the generator. However, if the MW output is reduced to 60 MW, as shown by point "B", the Mvar output can be increased to 68 Mvar.

When voltages drop suddenly following a key line loss, the area generators will at first boost their Mvar output to try to support the system voltage. This is illustrated in Figure 6-13 by the movement from point "A" to "B". Note from the figure that the generator has actually exceeded its reactive capability. After a few minutes the generator's protection systems will return it within its capability curve. This reduction in Mvar output may be enough to cause voltage collapse.

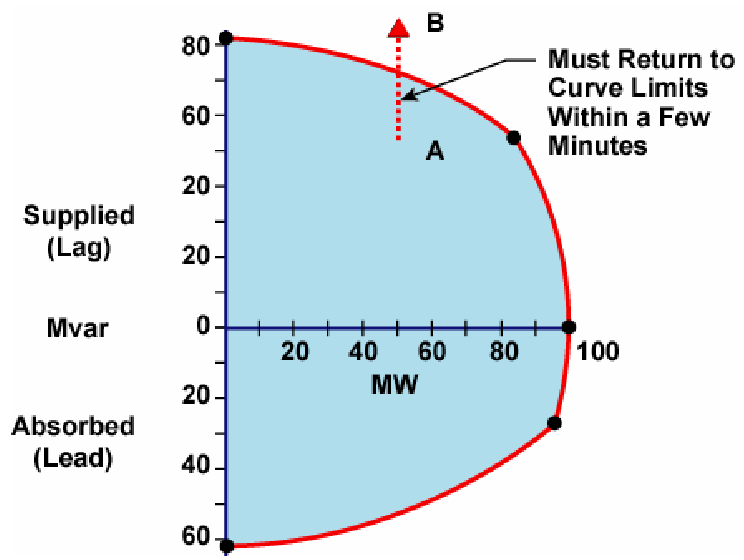


Figure 6-13
Temporary Reactive Power Boost

6.5.5 Phase of a Classical Voltage Collapse

The apparent stabilization of system voltage just described in our simulation of voltage collapse is a common feature of actual classical voltage collapse incidents. Two phases of a classical voltage collapse can be identified.

Phase 1 immediately follows the triggering event. For example, a large line trips quickly driving down local area voltages. Voltages stabilize during phase one at a low value but the system does not collapse. Voltages do not collapse due to a combination of the impact of voltage on load magnitude and the short term reactive boost from area generators. Phase 1 may last for a few minutes, at most, due to the response of the generator overexcitation protection systems.

Phase 2 is the period in which the system actually collapses. As a loss of load diversity develops and generators automatically run-back their Mvar outputs, the system collapses.

6.5.6 Use of the V-Q Curve

The V-Q curve is used to study a classical voltage collapse. Figure 6-14 is a sample V-Q curve. V-Q curves are developed for specific critical buses in the power system. Each curve is a plot of the amount of reactive power that must be inserted at the critical bus to maintain a desired voltage level. The entire

Power flow programs are software tools that are used to create computer simulations of the behavior of a power system.

curve is produced with a constant MW transfer. Power flow studies are run to determine how much Mvar support is needed to achieve a range of critical bus voltage levels.

For example, from Figure 6-14 the bus voltage will be approximately 226 kV if no additional reactive power is injected in the system (point "A" in the figure). The bus would require an injection of approximately 265 Mvar to maintain a voltage of 235 kV (point "B" in the figure). Point "C" is the point of voltage instability. If the critical bus voltage falls to this low a level (200 kV or 87% of normal), the area voltage will likely collapse.

V-Q curves can be used to determine the benefits of system changes and to determine how much of a reactive power margin exists for a given operating condition. For example, system designers may use V-Q curves to determine the impact of a new 100 Mvar shunt capacitor. This is illustrated in Figure 6-15 where the addition of the 100 Mvar bank raises the system voltage to 230 kV (point "D"). If the 100 Mvar bank is in-service the V-Q curve illustrates that the system has a 350 Mvar reactive margin from voltage instability. 350 Mvar is the reactive power difference between points "D" and "C" The more reactive reserve margin, the less likely a voltage collapse will occur.

Point "C" is the "knee" of the V-Q curve.

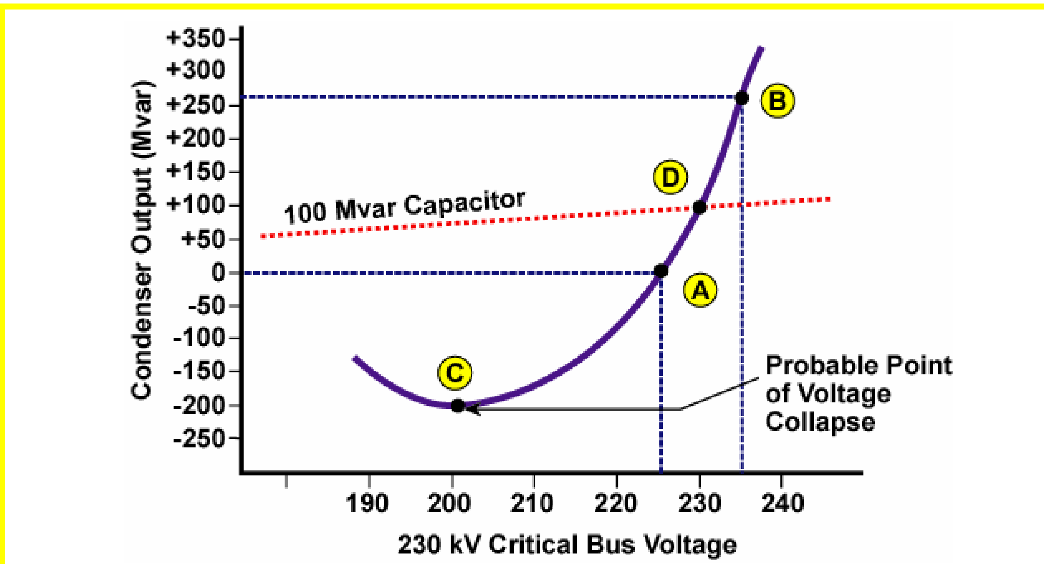


Figure 6-14
The V-Q Curve

6.5.7 Use of P-V & V-Q Curves

Figure 6-15 contains a P-V curve and a V-Q curve. These two types of curves are used to determine a simple system's voltage stability related power transfer limits. First the utility produces many P-V curves by running numerous power flows. P-V curves are developed for all the critical buses in the system and for all critical outages. This must be done to ensure that all operating conditions and all areas of the system are checked and the most restrictive bus identified.

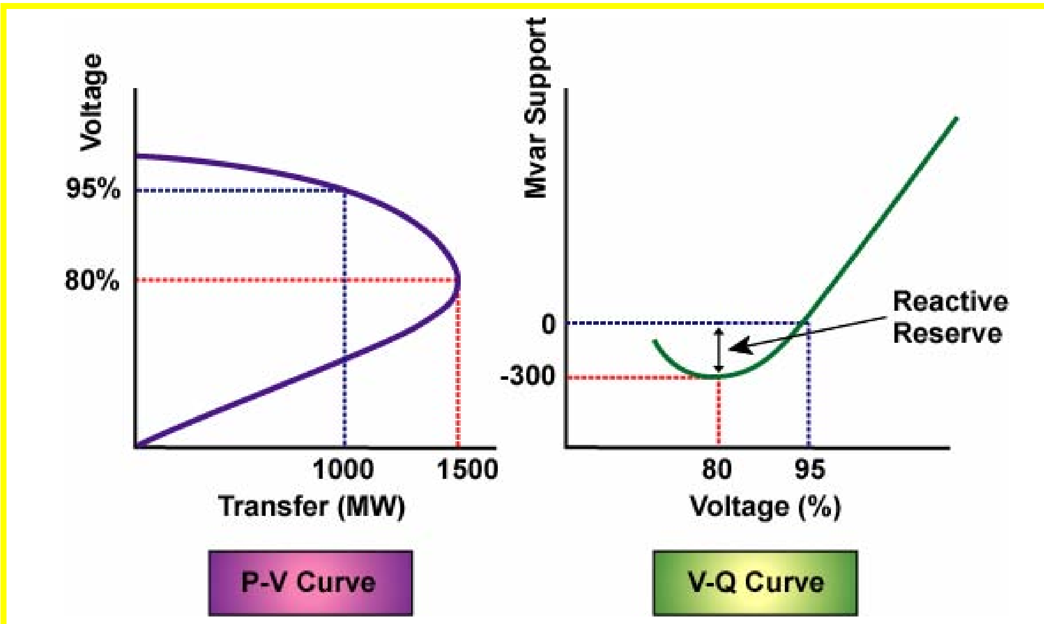


Figure 6-15
Margins to Voltage Instability

Once the critical bus is identified a P-V curve as shown in the left side of Figure 6-15 is created. According to this P-V curve the maximum MW transfer before voltage instability is 1500 MW. The utility will not use 1500 MW but rather 1000 MW as their transfer limit to ensure it has a sufficient safety cushion.

The users of the power flow program place a fictitious synchronous condenser at the critical bus to determine how many Mvar must be supplied to hold a certain voltage level.

Using a 1000 MW power transfer the utility produces a V-Q curve. The V-Q curve is also created using a power flow program. The power flow program is used to determine how many Mvar must be inserted at the critical bus to hold a range of bus voltages. Together the two curves give system operations a great deal of information. From the P-V curve the utility sets a transfer limit of 1000 MW and by looking at the V-Q curve the utility knows they have a 300 Mvar margin before voltage instability occurs at this transfer limit.

Figure 6-16 contains the same P-V and V-Q curves of Figure 6-15. The V-Q curve in Figure 6-16 is simply a rotation and mirror image of the V-Q in Figure 6-15.

The P-V curve is typically developed for the most critical bus given a key facility outage.

The V-Q curve is created using the 1000 MW transfer limit determined from the P-V curve.

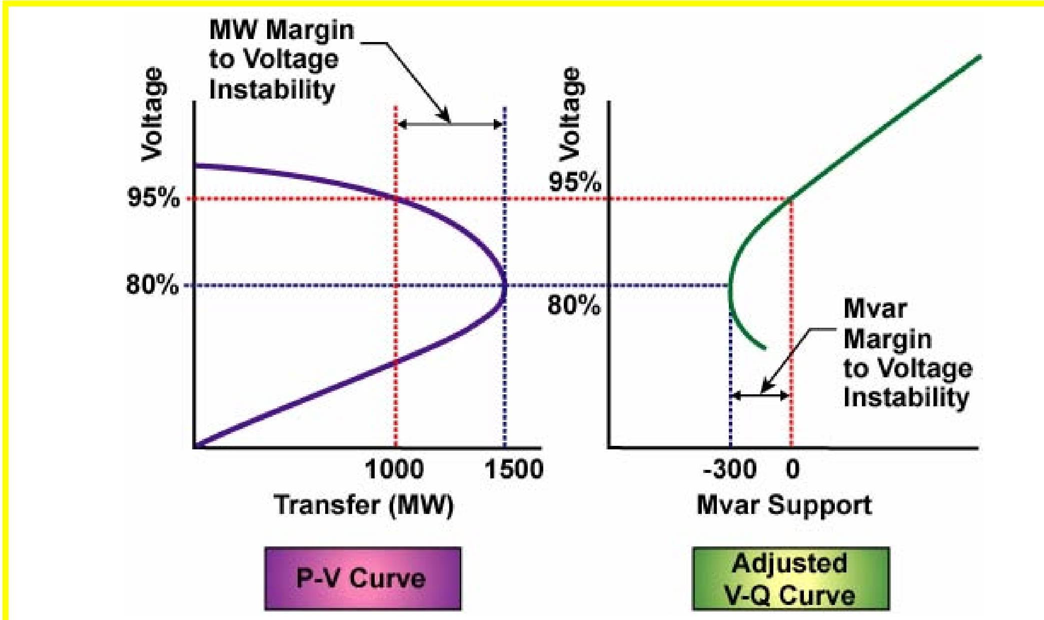


Figure 6-16
P-V & V-Q Curves

6.5.8 Example of a Classical Voltage Collapse

Conditions in the WSCC in the summer of 1996 included heavy loads (several power systems set new peaks) and heavy exports from the hydro resources of the Pacific Northwest to California. On July 2, 1996, at 14:24:37 a conductor of the Jim Bridger-to-Kinport 345 kV line contacted a tree. (Figure 6-17 contains a simple one-line of the area power system.) The line tripped (correctly) via a ground relay. A parallel 345 kV line—Jim Bridger-to-Goshen—then tripped (improperly) due to an overreaching ground relay. A protection scheme (a RAS or remedial action scheme) correctly activated, initiating several actions including tripping two of the four units (1040 MW) in operation at the Jim Bridger steam plant.

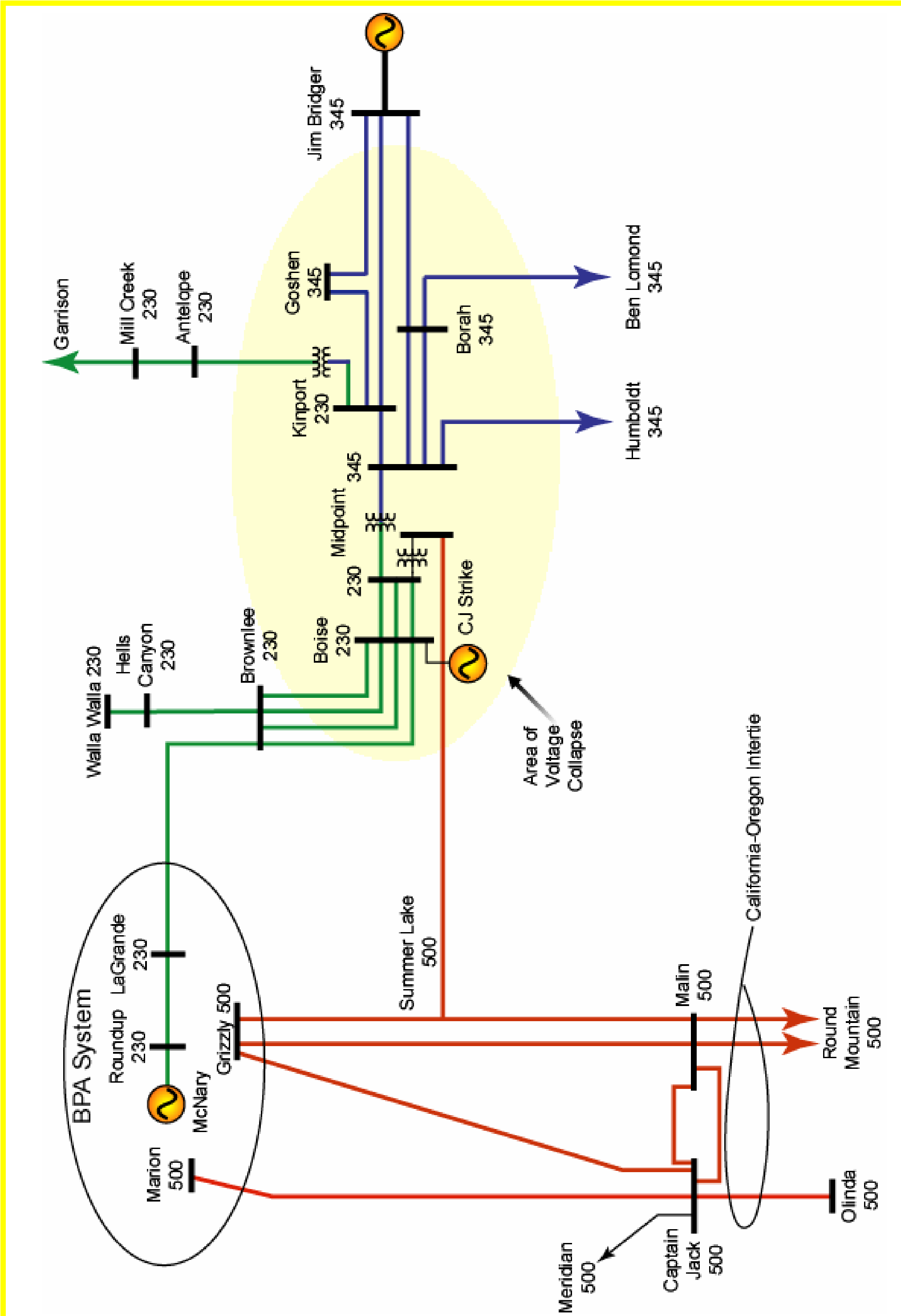


Figure 6-17
WSCC One-Line Diagram for July 2, 1996 Disturbance

Generators throughout the WSCC responded with inertial and governor support. Voltages throughout the area declined slightly, but did not collapse.

At 14:24:39 the LaGrande-to-Round Up 230 kV line tripped via a faulty zone 3 impedance relay. Voltages in the area declined further and at 14:24:51 a CJ Strike unit (key units for Mvar support just south of Boise) tripped on a field overcurrent target.

Power flows from the Pacific Northwest into Idaho increased by approximately 500 MW as a result of these events. Voltages in the 500 kV systems along the California-Oregon border and in the Boise, Idaho area declined and Mvar flow into the Boise area rose sharply in a bid to support declining voltage. (Boise 230 kV voltage is illustrated in Figure 6-18.) The remaining CJ Strike units tripped at 14:25:01 and 14:25:02 along with several other hydro units in the BPA system (at McNary). Also at 14:25:01 the Mill Creek-to-Antelope 230 kV line tripped via a zone 3 impedance relay (the relay saw low voltage combined with high current and activated). At 14:25:04 the four Boise-to-Brownlee 230 kV lines tripped—with distance targets—followed two seconds later by the separation of the 500 kV California-Oregon Intertie. The remaining ties that connected the southern Idaho/eastern Oregon area with the rest of the WSCC open shortly after.

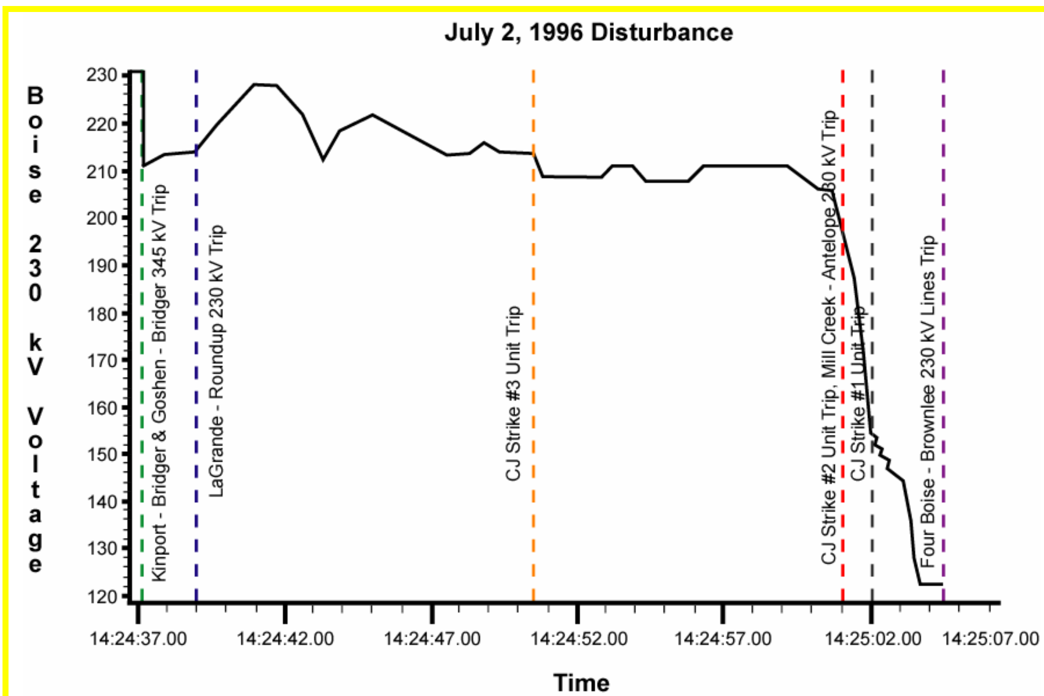


Figure 6-18
Boise 230 kV Voltage Collapse

At this point the entire WSCC was experiencing major difficulties and would shortly split into five islands. The major problem area was the southern Idaho/eastern Oregon island (shaded area in Figure 6-17) as it experienced a complete voltage collapse. 3400 MW of load (425,000 customers) were interrupted for up to six hours. The Boise area system voltage could not be supported with available Mvar sources.

The following day—July 3RD—a similar chain of events unfolded. At 2:03 p.m., the Jim Bridger-to-Kinport 345 kV line contacted a tree and tripped. The parallel 345 kV Jim Bridger-to-Goshen line falsely tripped due to ground relay misoperation. The RAS activated and tripped two units at Jim Bridger. Fortunately, operating conditions on July 3RD were substantially different than July 2ND or a similar system response may have occurred. Schedules and generator outputs had changed substantially from the previous day so area MW and Mvar stress was substantially less. In addition, a key generator in the area (Brownlee #5) was now in-service and delivering needed Mvar support.

Generators throughout the WSCC again responded with inertial and governor support. Voltages in the Boise area declined but stabilized at near normal levels—97% on the 230 kV system. The Brownlee hydro units were the key units in the area. Plant operators were concerned with the high Mvar output of the units (field alarms had triggered) due to their support of the low system voltages. The plant operators began to manually reduce the Mvar output to relieve unit thermal stress. Voltages throughout the Boise area began to decline further. Idaho Power Company system operators noted the declining voltages—recognized the possibility for another voltage collapse—and immediately took the only option available to them; shedding of Boise area load. All load was restored, and the system returned to normal within 1 hour.

These July 2ND and 3RD events in the Boise, Idaho area point out the need for effective and sufficient dynamic Mvar reserve. If large amounts of rapidly responsive dynamic reactive reserve had been available both incidents would likely have resulted in no more than localized system disturbances. The July 3RD events also illustrate how the rapid response of system operators can be the difference between minor inconveniences and major system outages.

6.6 Transient Voltage Collapse

6.6.1 Introduction to Transient Voltage Collapse

This section describes a transient voltage collapse. A transient voltage collapse occurs over a much shorter time period than the first two types of voltage collapse described. From the initial disturbance to voltage collapse it typically takes less than 15 seconds. Two variations on a transient voltage collapse will be presented. The first involves a loss of synchronism while the second type involves the response of induction motor load.

6.6.2 Voltage Collapse & Loss of Synchronism

When a section of the power system loses synchronism or goes out-of-step with remaining portions of the power system, the power angle, δ, between the two sections rises above 90º and moves toward 180º. Figure 6-19 illustrates the concept of out-of-step from a voltage perspective with a simple three bus power system. In part "A" of Figure 6-19 the power system is normal. Both sending and receiving end bus voltages and the voltage at the midpoint are at normal levels, and the power angle (δ_{SR}) between the two buses is well below 90º at 45º.

This example assumes that all mid-point reactive support comes from the ends of the system. The line charging is also ignored.

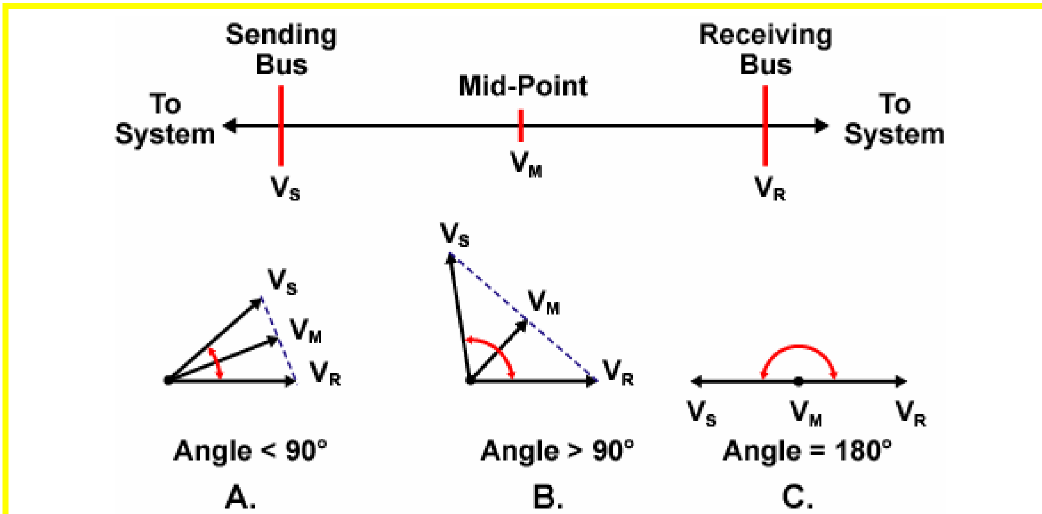


Figure 6-19
Voltage Collapse Due to a Loss of Synchronism

Part "B" of the figure represents an abnormal condition with a power angle greater than 90º. The system is operating above its steady state stability limit. Note the voltage at the midpoint of the power system in Figure 6-19. As the two ends of the power system move farther apart in power angle the voltage at the midpoint decreases. The only sources of reactive power are the ends of the system so the midpoint voltage is dependent on end-bus support.

In part "C" of Figure 6-19, the power system has lost synchronism. The power angle has risen to 180º. With a power angle of 180º the midpoint voltage is reduced to zero volts. A total voltage collapse (voltage decays to zero) will occur between two areas of the power system if the power angle between the two areas reaches 180º. As the power angle increases from a normal level, past 90º, and on toward 180º, power system voltages rapidly decrease. Out-of-step conditions can develop very quickly following a major disturbance. From initial disturbance to instability may be less than a second.

The driving force behind this voltage collapse was a loss of synchronism, not a reactive power shortage. For this reason this type of collapse will not be examined further in this section. Instead, we will concentrate on induction motor stalling leading to a rapid voltage collapse.

6.6.3 Voltage Collapse & Induction Motor Stalling

When a large induction motor is started it places a large reactive burden on the power system. During normal operation a small amount of Mvar is required to maintain the magnetic field in the air-gap of the motor. When an induction motor is first started (or has stalled and is rebuilding speed) it may draw 5 to 8 times its normal Mvar to build its magnetic field. This in-rush of reactive power typically lasts only a few seconds but can severely depress system voltages.

The amount of Mvar an induction motor draws from the power system is directly related to its speed. When an induction motor is first started, it draws high current as it accelerates from a standstill position. Once the motor reaches its operating speed, the current draw reduces sharply.

Torque/Speed Curves

Figure 6-20 and Figure 6-21 illustrate the relationship between motor speed and the available accelerating torque for two types of motors. Figure 6-20 is for a fan type motor. The three curves, labeled rated voltage, 80% voltage and 60% voltage, represent the available torque to accelerate the motor at three different system voltage levels. The fourth curve in Figure 6-20 is for the load torque of the fan. This is the torque applied to the fan shaft. A motor will rise towards rated speed as long as the available accelerating torque is greater than the load torque.

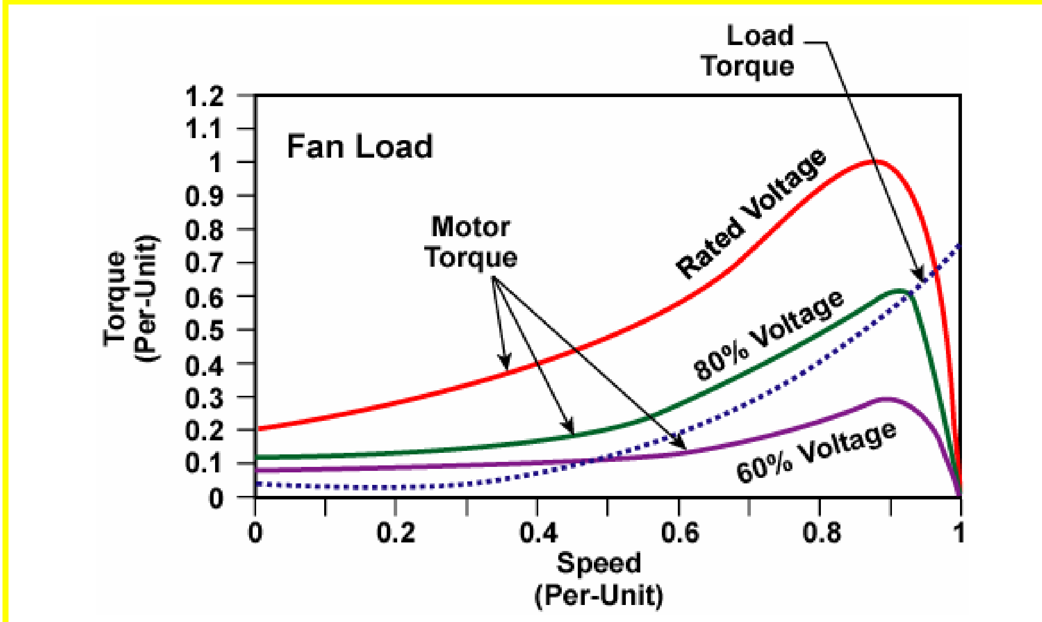


Figure 6-20
Fan Load Torque/Speed Curve

As can be seen from Figure 6-20, the fan motor will accelerate to near rated speed as long as the system voltage is greater than 80% of nominal. If the system voltage drops to 60% of nominal the fan load will be greater than the available accelerating torque. For example, if the motor is running at less than 45% of rated speed and the system voltage is 60% of nominal, the motor will never reach its rated speed. The motor will draw large amounts of reactive current until hopefully its thermal protection trips it off line.

Figure 6-21 contains torque/speed curves for an air-conditioner compressor. Two available accelerating torque curves are shown along with two load torque curves. The two load torque curves are for a hot (pressurized) compressor and a cold (pressure has bled-off) compressor. Notice that if a hot compressor motor slows down below 60% of rated speed it cannot regain speed even if the rated system voltage is available.

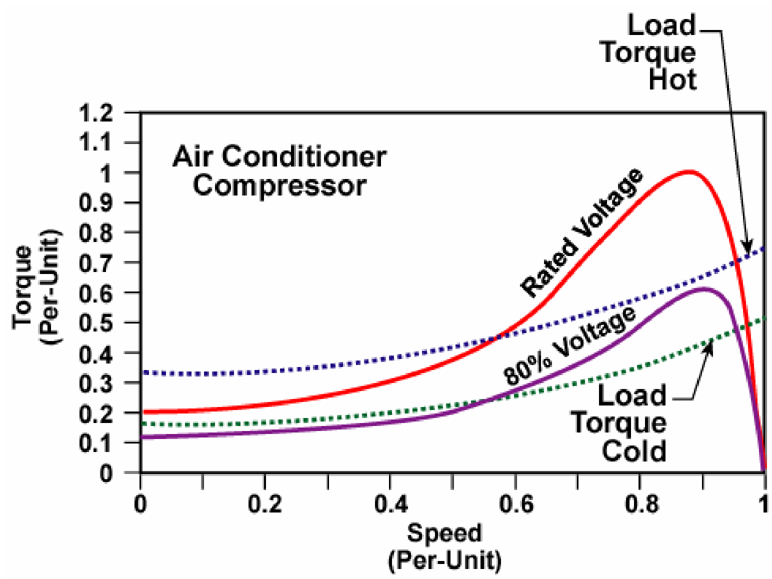


Figure 6-21
Air-Conditioner Compressor Load Torque/Speed Curve

EPRI defines two classes of motors; robust and prone-to-stall. 1Φ air-conditioning compressors are prone-to-stall.

Motor Stalling

Assume a severe voltage disturbance strikes a system with a heavy concentration of induction motors. System voltage declines which causes the induction motors to slow down. Once the system voltage starts to recover the motor load will automatically try to pick up speed. The in-rush of Mvar to return the motors to rated speed may be enough to trigger a rapid (transient) voltage collapse.

The declining voltages due to the sudden increase in Mvar demand may cause uncontrolled tripping and the rapid collapse of the area power system. This sequence of events is classified as a transient voltage collapse due to the speed of the events. The entire process will typically last less than 15 seconds. Systems with dense concentrations of 1Φ air conditioning load are most susceptible to this type of voltage collapse.

6.6.4 Example of Transient Voltage Collapse[7]

An example of a transient voltage collapse due to the stalling of induction motors took place in and around the Memphis Light Gas & Water (MLG&W) power system August 22, 1987. MLG&W was supplied with power by the Tennessee Valley Authority (TVA). TVA is a large federal power agency that covers a five state area with peak loads of close to 25,000 MW. MLG&W is a

[7] MLG&W transient voltage collapse description based on reference #6.

large municipal with a peak load close to 2,500 MW. Figure 6-22 is a one-line diagram of the MLG&W system and the surrounding TVA system.

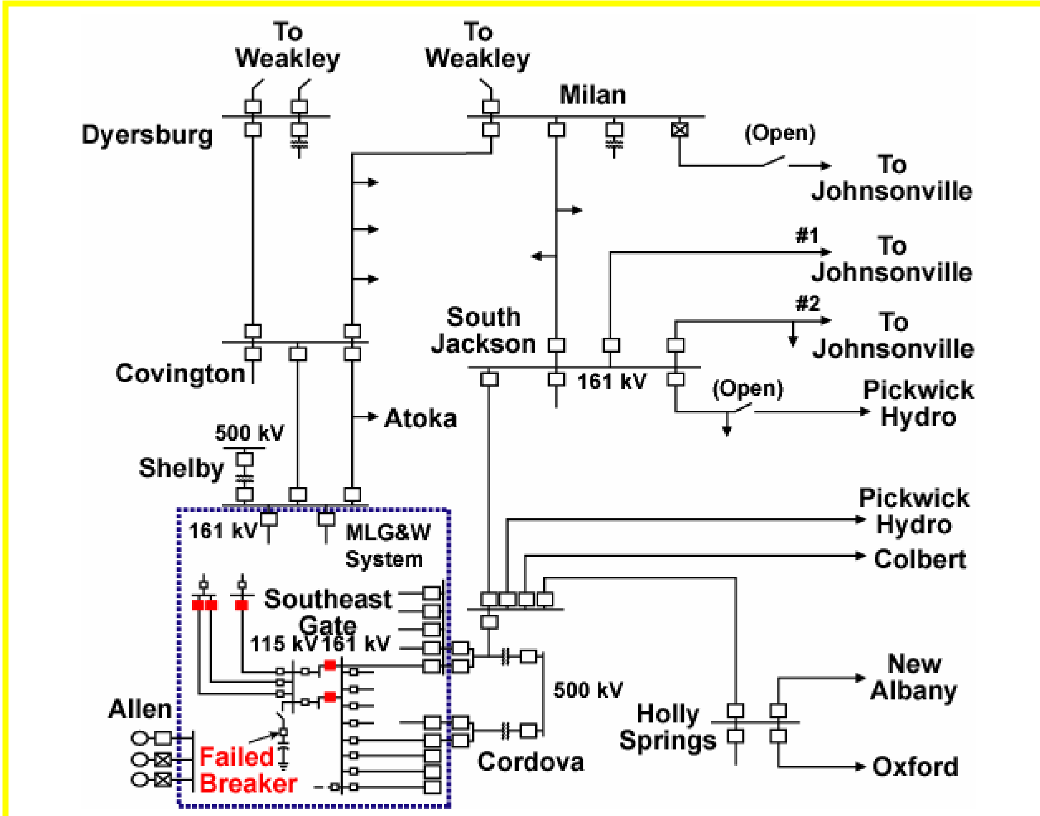


Figure 6-22
TVA and MLG&W Power Systems

The transient voltage collapse was initiated by the failure of a circuit breaker at the Southeast Gate substation. This substation is shown in the lower left of the figure.

At 0120 Saturday morning, August 22, 1987, an air-blast circuit breaker at Southeast Gate substation failed while performing an automatic (voltage controlled) capacitor switching operation. The Memphis dispatcher was not aware of the breaker failure, but noticed some unusual SCADA indications, and was already suspicious of this type of breakers. The dispatcher called out substation personnel to inspect the breaker. The substation inspector noticed obvious damage to the breaker and suggested that it be taken out-of-service.

Current meters and circuit breaker targets indicated that the breaker was open so the decision was made to use disconnects to clear the damaged breaker. At 1302 the operator began to crank open the disconnects and to his surprise all three blades maintained arcs when fully opened. The arcs rapidly formed Φ-Φ faults and eventually Φ-ground faults.

There was no differential relaying on the Southeast Gate 115 kV bus. The fault lasted for 78 cycles until it was finally cleared by various backup relays. (The shaded breakers in Figure 6-22 illustrate where the fault was cleared.)

Bus voltages in the area depressed to as low as 60% of normal during the fault. After the fault was cleared area voltages recovered to about 75% of normal.

The initial low voltage and the subsequent recovery to only 75% of nominal caused many area motors to trip or stall. The tripping of area motors was beneficial since this reduced the connected load. However, many motors simply stalled, and as they attempted to regain speed drew huge amounts of Mvar from the system. As was mentioned earlier, this in-rush current may be 5 to 8 times the normal load current requirements of the motors.

Much of the motor load consisted of 1Φ air-conditioner compressors. These motors often do not have any type of undervoltage protection to trip off-line. Instead the motors stall which aggravates the low voltage situation. During the disturbance, which lasted 10 to 15 seconds, large portions of compressor motor load stalled and tried to regain speed. As the Memphis area reactive demands increased the surrounding TVA system was called upon to supply the additional reactive power.

The most severe impact was 70 miles to the north in the Covington, Jackson, and Milan areas where reactive power is supplied primarily by shunt capacitor banks. The prevailing low voltage resulted in low shunt capacitor reactive output. In addition, several key area lines and generators were out for maintenance. The two 161 kV lines from Johnsonville to South Jackson were heavily loaded with active and reactive power. Within two seconds of the initial disturbance both of these lines tripped due to operation of reverse zone 3 relays. After the loss of these two lines voltage at South Jackson fell to 67% of normal.

A reverse zone 3 relay is a distance relay that is set to look in a reverse direction. This is done to reduce false trips due to line overloads.

Over the next 5 seconds, the rest of the 161 kV lines into Covington, Milan, and South Jackson tripped due to the low voltage and the high current flows. Auto-reclosing efforts failed throughout the system. TVA lost a total of 565 MW of load while MLG&W lost 700 MW of load. Figure 6-23 illustrates the breakers that tripped. The oval boxes state the MW lost and the time it took to restore the load.

In hindsight, the lack of a differential protection scheme on the 115 kV bus at Southeast Gate substation was critical. However, the point to emphasize from this event is the impact of large numbers of small 1Φ air-conditioners. The combined reactive needs of many stalled air-conditioning compressors led to this transient voltage collapse.

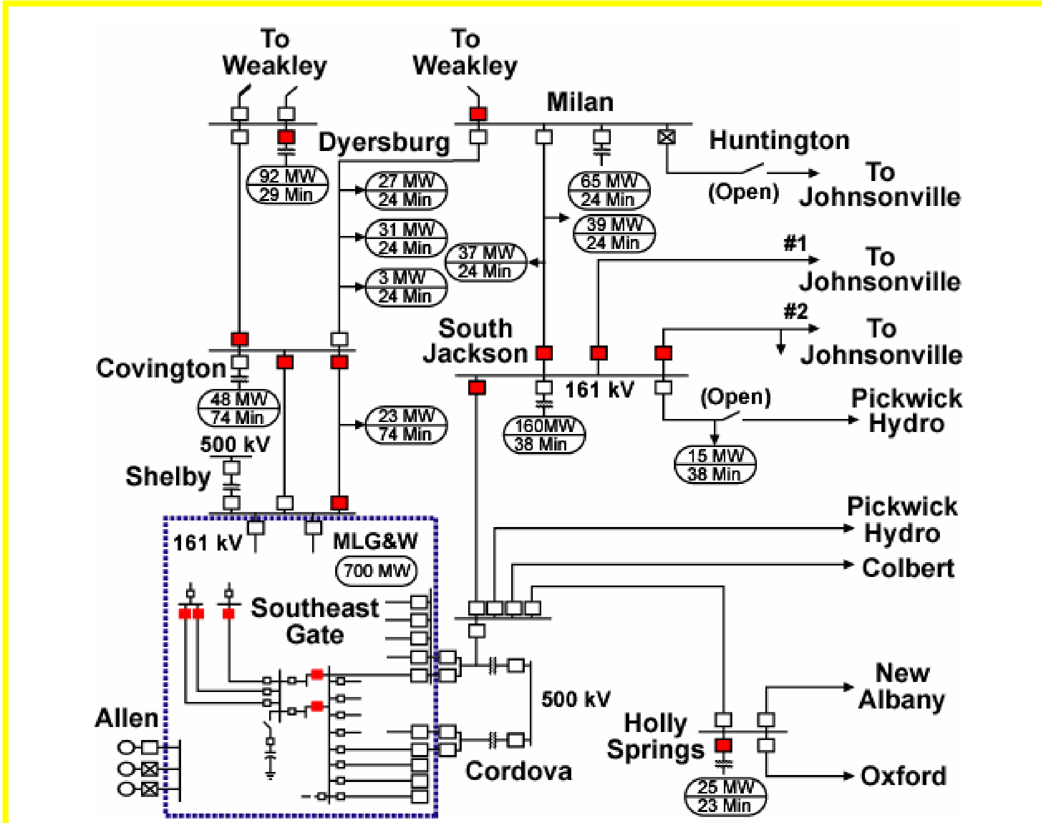


Figure 6-23
Post Disturbance System Conditions

6.6.5 Voltage Instability or Angle Instability?

These are only rules of thumb. Actual collapse voltage data must be studied before a true cause can be determined. This is often very difficult to do.

It is often difficult to determine if a system collapse was due to voltage instability or angle instability. The nature of the power system itself may provide a strong clue.

If voltage collapses in an area of the power system well removed from major load centers it is likely an angle stability problem. For example, a group of generators may be connected via a long transmission path to a major city. If the generation area experiences a voltage collapse it is likely due to the generators pulling out-of-step with the spinning mass of the major city.

If voltage collapses within a major load center it is likely a voltage stability problem. For example, assume the voltage depresses in a major load center. The surrounding system cannot supply the reactive needs of the load center and the voltages collapse. The system may spit apart due to out-of-step conditions but the initial cause was voltage instability.

6.7 Preventing Voltage Collapse

6.7.1 Dynamic Reactive Reserves

Utilities on the west coast of the U.S. do use rapidly switched shunt capacitors as a means of preventing voltage collapse. If major area 500 kV lines trip, the shunt capacitors are quickly inserted (matter of cycles) to help avoid a classical voltage collapse.

Dynamic reactive reserves are automatically controlled reactive reserves that respond rapidly to voltage deviations. Dynamic reactive reserves are typically carried in synchronous generators, synchronous condensers, or SVCs. Manually switched shunt capacitors and most automatically switched shunt capacitors do not qualify as dynamic reactive reserves due to their slow response speed and other control limitations.

To ensure an ability to respond to events that may lead to voltage collapse it is important that utilities carry sufficient dynamic reactive reserves. These dynamic reserves should be strategically placed throughout the power system. It is difficult to transmit reactive power so the location of the dynamic reactive reserves is very important. The reactive reserves should be carried in the areas they most likely will be needed.

6.7.2 Voltage Control Zones[8]

Some utilities are careful about the location of MW reserves. This helps avoid power transfer problems following major disturbances.

Active power reserve requirements are typically carried by individual utilities with few stipulations placed on their locations. This is usually acceptable for active power reserves as it is comparatively easy to transmit active power.

Dynamic reactive power reserves are a different story. It is difficult to transmit reactive power so the locations of the dynamic reactive reserves are critical. The concept of voltage control zones was created to address the importance of the location of reactive reserves. A voltage control zone is a physical section of the power system that responds as a cohesive unit to voltage deviations within that zone. For example, given a voltage deviation within a voltage control zone the reactive sources within that zone will respond together to restore the zone's voltages.

Figure 6-24 illustrates the concept of voltage control zones for a simple power system. This particular system has been divided into four voltage control zones. The reactive reserves within each zone will strongly respond to voltage deviations within that particular zone. As long as minimum levels of reactive reserves are held in each zone the likelihood of a voltage collapse is minimized within each zone.

[8] This section is based on reference #5.

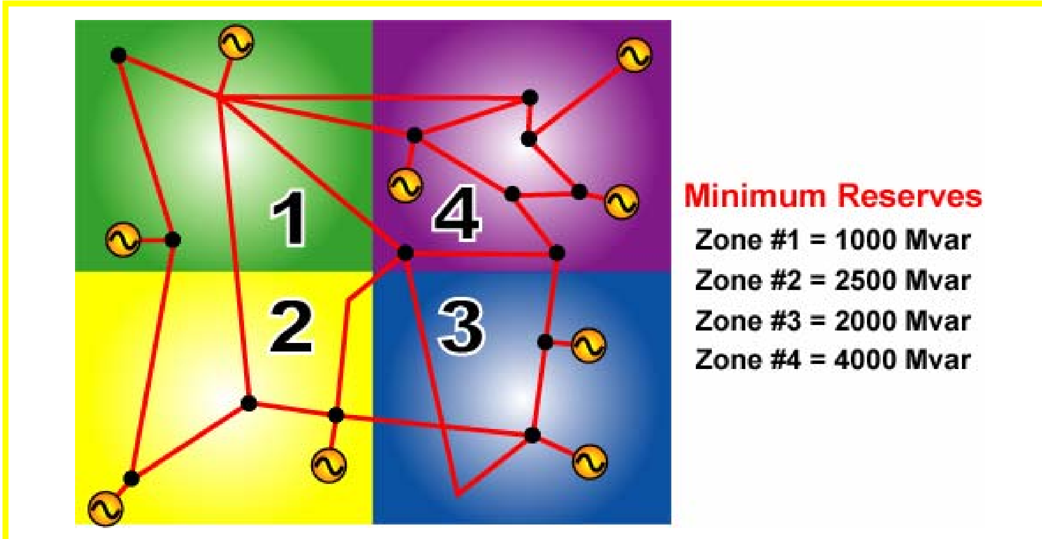


Figure 6-24
Voltage Control Zones

6.7.3 Load Shedding

Assuming that sufficient reactive reserves cannot be made available the primary means to avoid a voltage collapse is to shed load. The ideal load to shed is heavily inductive load. When heavily inductive load is shed, such as uncompensated induction motor load, both the system active and reactive power loads are reduced.

Manual Load Shedding

Manual load shedding may be an option if the voltage collapse develops slowly. (If the voltage collapse develops rapidly a system operator may not be able to shed load quickly enough to arrest the voltage collapse process.) If manual load shedding is to be used to avoid voltage collapse, clear operating procedures must be made available to the system operators. These operating procedures should:

- Provide assistance to the system operator to help identify voltage collapse prone conditions.
- Describe the conditions in which manual load shedding may be used.
- Clearly identify which loads are available for shedding and which loads should be shed for different system conditions.

Automatic Load Shedding

Several systems within NERC have installed protective relays to automatically trip customer load to avoid voltage collapse. Undervoltage load shedding (UVLS) systems are implemented throughout the Pacific Northwest and in several east coast systems.

UVLS systems are similar to UFLS systems. UVLS trips based on voltage while UFLS trips based on frequency.

A UVLS system will automatically trip selected customer loads when voltage falls below a trigger level. The voltage normally must remain below the trigger level for a specified time delay before tripping is allowed. For example, many Pacific Northwest utilities have installed three stages of UVLS relays within their system. The UVLS settings are:

- 5% of load is tripped if voltage falls below 92% of nominal for a minimum of 5 seconds.
- An additional 5% of load is tripped if voltage falls below 92% of nominal for a minimum of 8 seconds.
- An additional 5% of load is tripped if voltage falls below 90% of nominal for a minimum of 3.5 seconds.

Utilities may choose to activate UVLS schemes only during their voltage collapse prone times of year. For example if a utility risks voltage collapse only during the winter heating season, UVLS relays may be enabled from November through February and disabled otherwise. Activating only during certain periods of the year helps to avoid false UVLS relay trips.

6.8 Role of the System Operator

This section provides information and suggestions to the system operator in detecting and responding to a voltage collapse.

6.8.1 Detecting a Voltage Collapse

An important function of the system operator is to monitor and respond to unusual power system events before the events proceed to a point at which they cannot be controlled. As a system operator you can prevent some types of voltage collapse if you can detect the conditions that may indicate a pending voltage collapse. In general, the response of a system operator is limited to a long term voltage collapse. Transient voltage collapse occurs too rapidly for system operator action. Classical voltage collapse that lasts for several minutes may be impacted by a system operator's response if actions are performed quickly. The following power system events may indicate a pending voltage collapse.

- System voltage levels are unusually low. This may be due to heavy loads or heavy power transfer. Voltage levels should be continuously monitored. If a problem can be corrected before the voltages fall too far, voltage collapse may be avoided.
- Unusual magnitudes and directions for reactive power flows. If unusually large amounts of reactive power are flowing to one area of the system it may point to a pending voltage collapse in that area.
- Heavy reactive power generation at key area generators. If key area generators are at their reactive power limit, they will not be available if further reactive power is required. Avoid entering a heavy load period with low dynamic reactive power reserves.
- ULTC adjustments fail to move the voltage. This may indicate a reactive power shortage.

6.8.2 Responding to a Voltage Collapse

The best response to a voltage collapse is to prevent a collapse from occurring in the first place. This will not always be possible. The following methods of response are given as general guidelines. The guidelines are divided according to our three types of voltage collapse.

Long Term Voltage Collapse

Generating resources are often found in remote locations, far removed from any major load centers. Radial power systems are constructed to connect these economical generating plants to the major load centers. Hopefully, the power system designers will have planned for enough Mvar reserves to withstand the tremendous reactive power losses associated with heavily loaded, long radial power systems. The following precautions can be taken to prevent a long term voltage collapse in a radial power system:

- Ensure that the power plants at the sending end of the power system have sufficient reactive power reserves to support the system and the loads. These dynamic reserves must meet the requirements of the heaviest possible load period.
- All available reactive power sources at the receiving end, such as shunt capacitors, should be in-service and in proper working order. (Shunt reactors should be out-of-service.)
- If series capacitors are available in the radial system they should be in-service. Series capacitors lower line reactance. When series capacitors are in-service the system’s Mvar losses will decrease.
- If voltages are low in the transmission system a conservative rule of thumb is to avoid the use of area ULTCs. ULTC operation can impact a voltage

collapse in two ways. System load naturally decreases with decreasing voltage. When an ULTC operates to raise voltage it also increases load magnitude. In addition, when ULTCs raise low-side voltage they often depress high side voltage. ULTC operation may increase the chances of a voltage collapse.

- As a last resort a system operator should consider manually dropping load. If all possibilities to control the voltage collapse are exhausted, it is better to drop load in a controlled manner than to let the system collapse in an uncontrolled manner. Systems may have automatic undervoltage relay schemes installed to trip load during low voltage periods. It is critical that these schemes are in operation during the voltage collapse prone periods of the year.

Classical Voltage Collapse

A classical voltage collapse follows a severe system disturbance. As a result of the disturbance there is insufficient reactive power to satisfy the demands of the system and the customer load. The solution is simple; supply more reactive power where it is needed. The means to achieve this solution may be very difficult. To prevent a classical voltage collapse, a system operator (if time allows) can do the following:

- Maintain transfer limits within established guidelines. As MW transfer increases, reactive power losses escalate. If conditions are ripe for a voltage collapse consider reducing system transfers to limit reactive power losses.
- Ensure that all available static reactive power sources, such as shunt capacitors, are in-service. In addition, make sure that all shunt reactors are out-of-service.
- Ensure that sufficient dynamic reactive reserves exist to handle any probable contingency. The amount of dynamic reactive reserve is typically determined by planning and operating engineers. System operators must ensure that these minimum amounts are actually available.
- Ensure that the plant operators are providing all possible reactive power. This may mean a need to re-dispatch generation.
- Generating plants in the effected area that are normally not run due to economic factors may be run to increase active and reactive power supply.
- Shift system generation patterns to unload heavily loaded lines. This will reduce reactive power losses since these losses are a function of the current squared.
- Consider blocking operation of the effected area’s ULTCs to prevent further drops in transmission voltages.

- Request reactive power support from neighboring power systems. Neighboring systems can raise voltage at common buses. This may help raise voltages throughout the effected area.
- As a last resort consider manually dropping load. (Also be sure all automatic undervoltage load shedding schemes, if they exist, are in-service.)

Transient Voltage Collapse

A transient voltage collapse is a rapid event from the perspective of a system operator. Once the process has begun a system operator has little role in the final outcome. Two types of transient voltage collapse were described in Section 6.6, loss of synchronism and induction motor stalling.

There is little a system operator can do to avoid an induction motor type collapse. One suggestion is to ensure protective systems are in place and functioning properly. However, if collapse of this type does occur, restoration can proceed quickly if the cause of the collapse is quickly identified.

To prevent the loss of synchronism type voltage collapse, the conditions that lead to the loss of synchronism must be avoided. Among the actions that would help to prevent a loss of synchronism are:

- Maintain system transfer limits within acceptable margins. The larger the power transfer, the larger the power angle. If power transfers are limited, the power angle increase following a disturbance will be reduced.
- Keep power system voltage levels as high as allowed by system voltage schedules. The higher the voltage levels, the lower the power angles necessary to transmit a given amount of power. Voltage control equipment should be in-service and in proper working order.
- Generators are the primary means to control normal system voltage levels. In addition, a generator has further voltage control capability during a system disturbance. Many generators have high speed excitation systems that can respond rapidly to increase system voltage levels. For example, during a disturbance that depresses system voltages, such as during a fault, an excitation system can help maintain angle stability. A power system could go unstable because available high speed excitation systems have been intentionally disabled.
- Out-of-step protective relay systems are designed to detect the low voltages that occur during a loss of synchronism. These protective relay systems will detect the out-of-step conditions and initiate a controlled separation of the power system. Be sure these systems are in-service as stated by utility policy. It is better to separate in a controlled manner then to let the system separate in whatever manner it chooses.

6.8.3 Relationship of the Types of Voltage Collapse

The three types of voltage collapse presented in this section are not independent of one another. For example, many of the events that occur during a long term voltage collapse also occur during a classical voltage collapse. In addition, one type can progress into another. For instance, a long term voltage collapse would turn into a transient voltage collapse as time progresses and events occur more rapidly.

Figure 6-25 is provided to relate the time frames for the three different types of voltage collapse. Note that different characteristics of the system are involved with each type of collapse. For example, to understand a transient voltage collapse it is necessary to understand how induction motors behave. To understand a long term voltage collapse it is necessary to understand what is meant by a loss of load diversity.

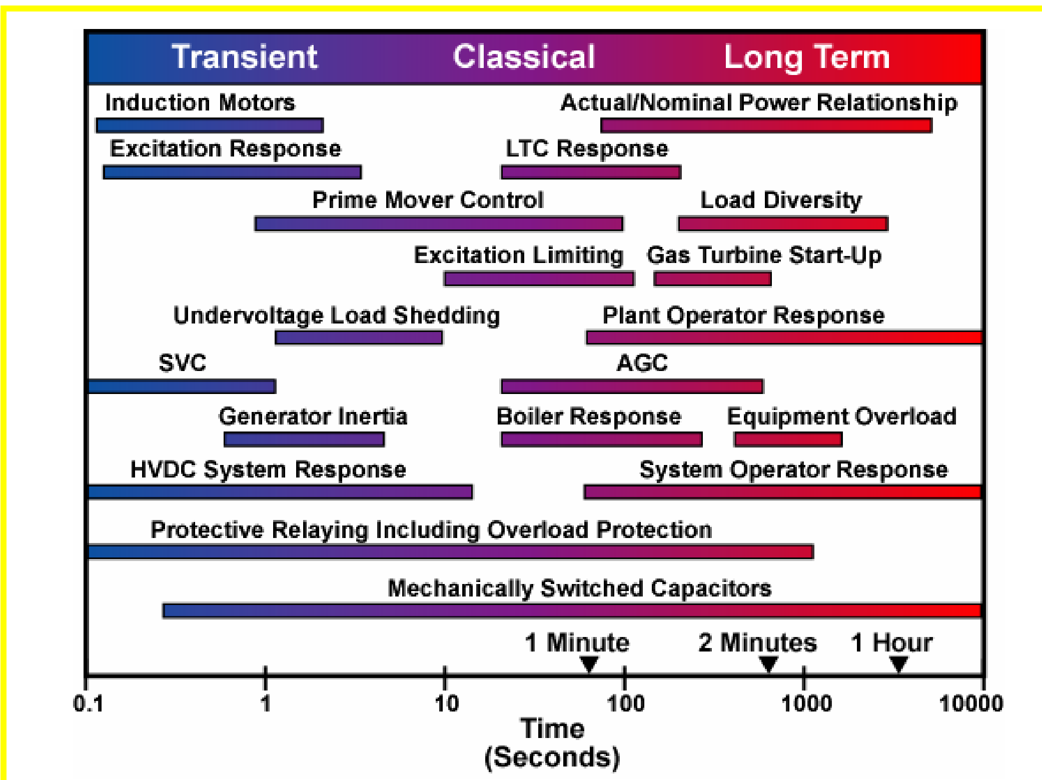


Figure 6-25
Time Frames for Voltage Collapse

Summary of Voltage Stability

6.1.1 Introduction to Voltage Stability

- This chapter described an extreme class of voltage deviation called a voltage collapse. As utility power systems are pushed to transfer more and more power, the likelihood of a voltage collapse occurring becomes greater.

6.2.1 Voltage Stability & Instability Definitions

- Nominal load is the active power the customer load will draw if it is operated at its nominal voltage and frequency. The actual load may be different than the nominal load.
- Voltage stability is the ability of a power system to maintain voltage so that when nominal load is increased the actual power transferred to that load will increase.

6.2.2 Voltage Collapse Definition

- Voltage collapse is a probable result of a period of voltage instability.

6.3.1 Long Term Voltage Collapse

- A long term voltage collapse may take several minutes to several hours to occur.

6.3.2 Classical Voltage Collapse

- A classical voltage collapse may take from 1 to 5 minutes following a disturbance to occur.

6.3.3 Transient Voltage Collapse

- A transient voltage collapse is a rapid event occurring in less than 15 seconds following the initial disturbance.

6.4.1 Introduction to Long Term Voltage Collapse

- In a long term voltage collapse slowly developing changes to the power system occur that eventually lead to a shortage of reactive power and declining voltages.

6.4.2 Radial Power Systems

- A radial power system is one in which generation and load areas are separated by a transmission path.

6.4.3 Use of the P-V Curve

- P-V curves illustrate that as MW transfer increases the voltage at the receiving bus slowly decreases.
- The knee of the P-V curve is the boundary between voltage stability and voltage instability.
- The knee of the P-V curve is the point at which the system runs out of usable reactive reserves. Operation near the knee of the P-V curve should be avoided.

6.4.4 Conditions for a Long Term Voltage Collapse

- For a long term voltage collapse to occur active and reactive power flows on the system must be heavy.

6.4.5 Long Term Voltage Collapse Process

- ULTCs normally draw reactive power from the high side to support the low-side. The amount of high side voltage reduction will depend on how much additional reactive power can be obtained from sending end sources.
- A failure to obtain required reactive power results in a voltage decline. This reduction in voltage reduces the reactive power output of shunt capacitor banks and line charging. This further reduces the system voltages. If load continues to increase, system voltage will decay further, eventually reaching the knee of the P-V curve. Once the system passes over the knee, voltage and power transfer could collapse at any moment.

6.4.6 Role of Tap Changing Equipment

- When high side reactive power reserves are depleted, the action of ULTCs hastens the beginning of voltage collapse.
- Allow an upstream ULTC to adjust taps before the downstream ULTC starts its tap movement. This helps avoid load overshoot.

6.4.7 Tap Changing and Load Magnitude

- The effects of tap changers are dependent on the type of load on the low-side of the transformer.

- In general, during conditions that may lead to a voltage collapse, tap changers that supply non-motor load should not be operated. It is better to let the voltage drop. You may want to use tap changers to raise voltage in heavily industrialized areas of the system.

6.4.8 Example of a Long Term Voltage Collapse

- An actual example of a long term voltage collapse was illustrated by the Tokyo voltage collapse of July 23, 1987.

6.5.1 Introduction to Classical Voltage Collapse

- A classical voltage collapse occurs following a system disturbance when there is not enough reactive power available to meet the needs of the system and the loads.

6.5.2 Loss of Load Diversity

- Power system load is constantly changing. When a majority of loads are running at the same time the condition is known as a "loss of load diversity". A loss of load diversity will lead to an increase in the total system load level.

6.5.3 Simulation of a Classical Voltage Collapse

- A computer based simulation of a classical voltage collapse was presented.

6.5.4 Response of Generation

- When conditions are such that a voltage collapse is probable, system operators and plant operators must try every means possible to increase the affected area's reactive power reserve.
- In a re-dispatch of generation, local generator active power levels are decreased to allow an increase in the reactive power generating capability.
- Generators can exceed their reactive limits for short periods of time. Eventually protective schemes will return outputs to safe levels.

6.5.5 Phases of a Classical Voltage Collapse

- There are often two phases to a classical voltage collapse. Voltages stabilize during phase 1 at a low value but the system does not collapse. Phase 2 is the period in which the system actually collapses. As a loss of load diversity develops and generators automatically run-back their Mvar outputs, the system collapses.

6.5.6 Use of the V-Q Curve

- V-Q curves are a plot of the amount of reactive power that must be inserted at a critical bus to maintain different voltage levels.

6.5.7 Use of P-V & V-Q Curves

- P-V and V-Q curves are used in combination to identify active and reactive power margins from voltage instability.

6.5.8 Example of a Classical Voltage Collapse

- An actual example of a classical voltage collapse was illustrated with the WSCC collapse of July 2, 1996.

6.6.1 Introduction to Transient Voltage Collapse

- A transient voltage collapse occurs over a much shorter time period than our first two types of voltage collapse. From the initial disturbance to voltage collapse is typically less than 15 seconds.

6.6.2 Voltage Collapse & Loss of Synchronism

- A rapid voltage collapse will occur between two areas of the power system if the areas pull out-of-step with one another.

6.6.3 Voltage Collapse & Induction Motor Stalling

- Induction motors may stall following an extended period (many cycles to seconds) of extreme (60 to 70% of nominal) low voltage. As the voltage recovers, the induction motors will try to regain speed. Air-conditioner compressors are difficult to return to speed once stalled. Their high reactive draw may prevent a voltage recovery and lead to system collapse.

6.6.4 Example of Transient Voltage Collapse

- An actual example of a transient voltage collapse was illustrated with the MLG&W voltage collapse of August 22, 1987.

6.6.5 Voltage Instability or Angle Instability?

- If voltage collapses in an area of the power system well removed from major load centers, it is likely do to an angle stability problem.
- If voltage collapses within a major load center it is likely a voltage stability problem.

6.7.1 Dynamic Reactive Reserves

- Dynamic reactive reserves are automatically controlled reactive reserves that respond rapidly to voltage deviations. To ensure an ability to respond to events that may lead to voltage collapse, it is important that utilities carry sufficient dynamic reactive reserves.

6.7.2 Voltage Control Zones

- It is difficult to transmit reactive power so the locations of dynamic reactive reserves are critical. A voltage control zone is a physical section of the power system that responds as a cohesive unit to voltage deviations within that zone. Minimum levels of dynamic reactive reserves should be maintained within each voltage control zone.

6.7.3 Load Shedding

- Assuming that sufficient reactive reserves cannot be made available, the primary means to avoid a voltage collapse is to shed load.
- A UVLS system will automatically trip selected customer loads when voltage falls below a trigger level. The voltage normally must remain below the trigger level for a specified time delay before tripping is allowed.

6.8.1 Detecting a Voltage Collapse

- The following events may indicate a pending voltage collapse.
  - System voltage levels are unusually low
  - Unusual magnitudes and directions for reactive power flows
  - Heavy reactive power generation at key area generators
  - ULTC adjustments fail to move the voltage

6.8.2 Responding to a Voltage Collapse

- The following precautions can be taken to prevent a voltage collapse:
  - Maintain transfer limits within established guidelines
  - Ensure that available static reactive power sources are in-service
  - Ensure that sufficient dynamic reactive reserves exist
  - Shift system generation patterns to unload heavily loaded lines
  - Request reactive power support from neighboring systems
  - Be wary of using ULTCs

  - Ensure appropriate UVLS schemes are in-service
  - As a last resort consider manually dropping load
- To avoid an induction motor stalling voltage collapse ensure protective systems are in place and functioning properly.
- To prevent a loss of synchronism type voltage collapse, a system operator should:
  - Maintain system transfer limits within acceptable margins
  - Keep power system voltage levels as high as allowed
  - Ensure voltage regulators are in automatic mode
  - Ensure required out-of-step protective systems are operational

6.8.3 Relationship of the Types of Voltage Collapse

- The three types of voltage collapse presented in this chapter are not independent of one another.

Voltage Stability Questions

1. The nominal load is:
   A. Equal to the rated load
   B. Dependent on the actual voltage and frequency
   C. Dependent on the scheduled voltage and frequency
   D. Equal to the actual load

2. A period of voltage instability will always result in a voltage collapse.
   A. True
   B. False

3. The critical voltage and critical MW transfer are located at the:
   A. Knee of the V-Q curve
   B. Knee of the P-V curve
   C. Origin of the V-Q curve
   D. Origin of the P-V curve

4. During voltage collapse prone conditions, tap changing to support secondary voltage should generally **NOT** be used if the secondary load is formed by:
   A. Induction motors
   B. Motor type load
   C. Nominal load
   D. Non-motor type load

5. P-V curves indicate the ___________ margin from voltage instability while V-Q curves indicate the ___________ margin from voltage stability.
   A. Mvar / MW
   B. MW/ Mvar
   C. MW / current
   D. Power / Mvar

6. UVLS differs from UFLS in that:
   A. The tripping frequencies are different
   B. The tap changing points are different
   C. UVLS is based on voltage while UFLS is based on frequency
   D. UVLS is based on frequency while UFLS is based on voltage

7. In which type of voltage collapse does a key element outage trigger the collapse?
   A. Oscillation Voltage Collapse
   B. Classical Voltage Collapse
   C. Transient Voltage Collapse
   D. Long Term Voltage Collapse

8. A P-V curve relates:
   A. The Mvar transferred across a system to the voltage at the receiving end of the system
   B. The MW transferred across a system to the voltage at the receiving end of the system
   C. The MW transferred across a system to the voltage at the sending end of the system
   D. The Mvar transferred across a system to the voltage at the sending end of the system

9. In a radial power system, the addition of shunt capacitors at the receiving end of the system tends to:
   A. Decrease the curvature of the P-V curve
   B. Flatten the P-V curve and increase the critical voltage
   C. Increase the curvature of the P-V curve
   D. Flatten the P-V curve and decrease the critical voltage

10. In which type of voltage collapse does a simultaneous stalling of large amounts of induction motor load trigger the voltage collapse?
    A. Oscillation Voltage Collapse
    B. Classical Voltage Collapse
    C. Transient Voltage Collapse
    D. Long Term Voltage Collapse

Voltage Stability References

1. Power System Voltage Stability—A text by Mr. Carson W. Taylor. Published in 1994 by McGraw Hill under the sponsorship of EPRI.

   The best single reference found for voltage stability and voltage collapse. The author is an experienced utility engineer which is evident in his writing style. The text is not extremely technical and is generally readable by operations personnel.

2. Voltage Stability of the Puget Sound System Under Abnormally Cold Weather Conditions—IEEE paper #92-SM-534-8-PSRS.

   Paper contains useful material related to a long term voltage collapse.

3. Voltage Stability in Interconnected Power Systems: A Simulation Approach—Paper that appeared in IEEE Transactions on Power Systems, Volume 7, No. 2, May 1992, p.p. 753-761.

   Paper contains useful material related to a classical voltage collapse.

4. Y. Nomura and K. Takahashi. The Power System Failure on July 23, 1987 in Tokyo—Paper presented at the 1987 CIGRE conference on September 22-25 in Montreal, Canada. Paper #37.87 (JP) 07 (E).

   The Tokyo long term voltage collapse incident presented in this chapter is described in greater detail in this paper.

5. Susceptibility to Voltage Collapse—Paper written by Mr. L. H. Fink of ECC. Presented at EPRI/NERC forum on voltage stability, Breckenridge, CO, Sept. 14-15, 1992.

   The concept of voltage control zones presented in this chapter was largely based on this paper.

6. Cascading Voltage Collapse in West Tennessee August 22, 1987—Paper written by Mr. Gary C. Bullock of Tennessee Valley Authority. Presented at the Georgia Institute of Technology Protective Relaying Conference, May, 1990.

   The MLG&W transient voltage collapse description is largely based on this paper.

7. Voltage Stability of Power Systems: Concepts, Analytical Tools and Industry Experience—IEEE report #90-TH-0358-2-PWR.

   Engineering oriented reports that cover many facets of voltage stability and collapse.

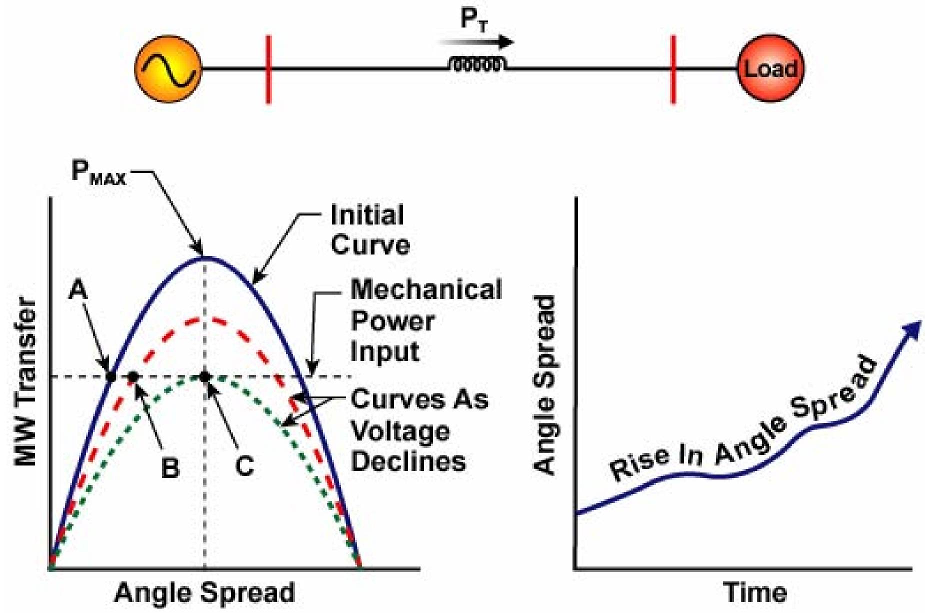
8. Survey of the Voltage Collapse Phenomenon—NERC report published in August 1991.

   A NERC task force prepared this report. Includes selected papers on the subject of voltage collapse and stability.

9. System Protection and Voltage Stability—IEEE report #93-TH-0596-7-PWR.

   An in-depth examination of voltage stability related protective relaying. Includes papers on UVLS.

7
ANGLE STABILITY



7.1 Introduction to Angle Stability

Angle stability is related to the phase angle separation between power system buses.

7.2 Definition of Angle Stability

In an angle stable system the torque and power angles are controllable. In an angle unstable power system angles and power flows are out of control.

7.3 Active Power Transfer and the Power Angle Curve

The power angle curve is used to determine the angle at which the mechanical input to the power system is equal to the electrical power transferred out of the generator.

7.4 Types of Angle Stability

Angle instability can occur in steady state, transient, or dynamic environments.

7.5 Steady State Stability/Instability

Steady state angle instability develops gradually over time without any sudden disturbance.

7.6 Transient Stability/Instability

Transient instability arises rapidly, in the first few seconds after a disturbance.

7.7 Dynamic Stability/Instability

Dynamic angle instability is characterized by power and voltage oscillations.

7.8 Out-of-Step Protection

Out-of-step protection is provided by protective relays that measure the apparent impedance and the time it takes for the impedance to change.

7.9 Angle Instability Example

An example of angle instability is presented that occurred in the summer of 1998 in the MAPP power system.

7.10 Role of the System Operator

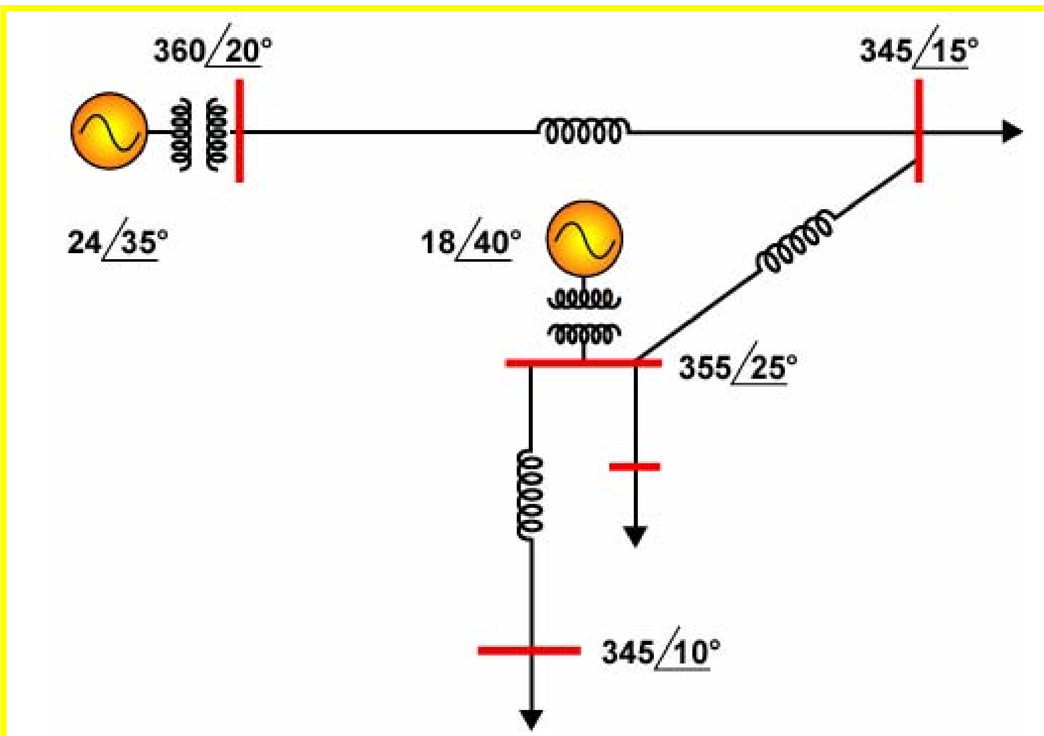
The system operator can avoid angle stability problems by adhering to their system's operating guidelines.

7.1 Introduction to Angle Stability

7.1.1 Angle & Voltage Stability

Figure 7-1 illustrates a simple 345 kV power system. The voltage magnitudes and angles are listed for each bus. Voltage is the key to the overall stability of a power system. In Chapter 6 the concept of voltage stability was explained. Voltage stability is related to the magnitude of the system voltages and reactive power reserves. This chapter will describe the concept of angle stability. Angle stability is related to the angular separation between points in the power system.

Angle stability was introduced in Section 2.4 of Chapter 3.



In a stable power system voltage magnitudes and angle differences have acceptable magnitudes and are controllable.

Figure 7-1
Stability: Voltage and Angle

The angular separation of the voltages (power and torque angles) in Figure 7-1 are small, ranging from 5° to 15°. This is typical for a high voltage transmission system. When a system is angle unstable, angle differences grow to larger values. For example, angle differences may exceed 90°.

7.2 Definition of Angle Stability

When a power system is angle stable it has:

- Sustained generator torque angles of less than 90°. Typically the torque angles are less than 30°.
- Sustained power angles of less than 90°. Typically the power angles between connected buses are less than 10°.

The torque and power angles may temporarily rise above 90° but only for short (fraction of a second) periods of time. A system is angle unstable when system operators lose their ability to control angles and power flows. Torque and power angles grow beyond 90°, up to 180° and larger.

7.2.1 Changing Torque & Power Angles

Chapter 2 described how rotating magnetic fields are intentionally created in generators. The 3Φ currents that flow in the power system create the rotating magnetic field of the system. When generators are in-step with the power system, the generator's magnetic field rotates at the same speed as the system's field. The angular separation of the two fields is the torque angle of the generator. When a generator goes out-of-step, the two magnetic fields must have rotated at a slightly different speed for a period of time.

Torque and power angles are changed by accelerating one section of the power system with respect to another section. For example, to change the torque angle of a generator it is necessary to slightly increase the speed of the generator with respect to the system. As long as a speed difference exists, the torque angle is changing. If the generator is running faster than the system, the torque angle is increasing. If the generator is running slower than the system, the torque angle is decreasing.

Power angles in the system change in the same manner as torque angles. Power angles change when there is relative acceleration. If two sections of a power system somehow experience relative acceleration, the power angle between the two areas will change.

When major transmission lines open it is sometimes difficult for a system operator to reclose the open transmission lines. The synchronizing relays connected to the line's circuit breakers may block a reclosing attempt due to an excessive power angle across the circuit breaker. The system operator may then adjust area generation levels to allow reclosing. What is occurring when the generation levels are adjusted is relative acceleration. Generation is either raised or lowered to slow down or speed up one section of the system with respect to the other. This action reduces the power angle across the circuit breaker and hopefully allows line reclosing.

7.2.2 Out-of-Step / Loss of Synchronism

When trying to visualize the out-of-step concept, one can think of the system frequency as the cadence to which an entire interconnected power system marches. When parts of the interconnection march at a slightly faster or slower cadence (frequency), those parts will eventually be out-of-step with the rest of the interconnection.

There are many terms used to indicate that a system is angle unstable. Loss of synchronism, slipping poles, and out-of-step are a few of the more common terms. All of these terms mean the same thing. When the system is out-of-step, the magnetic forces that normally bind a system together are no longer sufficient. Our interconnected AC power system is a synchronous system that relies on a relatively constant system frequency. When a section of the system goes out-of-step with the remainder, this common frequency bond is lost.

Consider the voltage at the terminals of a generator with a two-pole (north and south) cylindrical rotor. The rotor is spinning at 3600 rpm, which is equivalent to 60 revolutions per second. The terminal voltage of this generator reaches its maximum and minimum peak values once during each revolution. For synchronous power system operation, all of the generators in the interconnection must hit their maximum and minimum voltage values holding a constant relationship to each other.

Figure 7-2 illustrates two units at a power plant. Assume unit “A” is synchronized (paralleled) to the system while unit “B” is about to be synchronized. As illustrated, unit “B” will be 180° out-of-phase with the system when its circuit breaker is closed. Unit “B” will not mesh with the power system’s rotating field. If a synchronizing attempt is made, there could be several consequences. For instance, the synchronizing attempt may be aborted, the unit may rapidly adjust its magnetic field alignment or the unit could be damaged by the attempt to close out of synchronism.

This scenario should not happen in normal system operation because generator synchronization procedures exist to prevent this type of error.

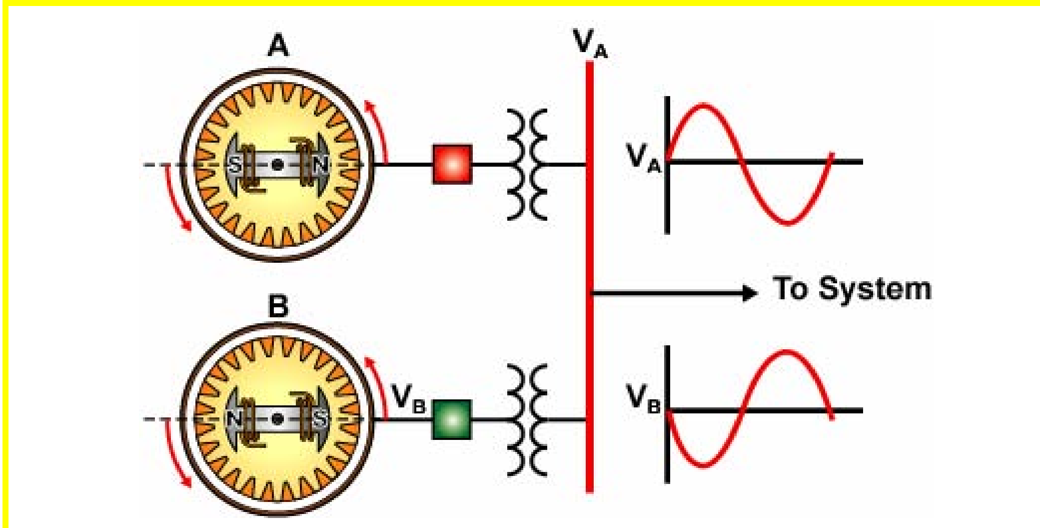


Figure 7-2
Out-of-Step Generator Closing

Visualize a generator that is operating in-step with the power system. The torque angle of this generator must be sustained at a value less than 90°. Assume a metering device (a lap counter) is installed that counts the number of revolutions (or laps) of the rotating magnetic fields of the stator and rotor. The meter would indicate that even though the rotor field is always slightly ahead of the stator field (due to the torque angle) the fields would always be on the same lap.

Recall from Chapter 3 that when the torque angle is less than 90°, a magnetic force exists that attempts to realign the stator and rotor fields. This synchronizing force is holding the stator and rotor fields on the same lap. If for some reason, the generator attempts to sustain a torque angle greater than 90°, the magnetic attraction will weaken. The weakening of the attraction will allow the rotor and stator fields to lap one another thus entering an out-of-step condition.

7.2.3 Angle Stability & Generator Speed

If sections of an interconnected power system continually operate at even slightly different frequencies the power system will suffer. When two points on the power system sustain operation at different frequencies the power angle between the two points will eventually increase past 90° and move on toward 180° and larger angles.

A typical rotor speed for a steam/turbine generator is 3600 rpm. The magnetic fields of the stator and rotor also rotate at 3600 rpm. The torque angle is the angular difference between the rotor field and the field created about the stator. If both fields are rotating at the same speed the torque angle will remain constant. In order to increase the torque angle, the rotor and stator fields must accelerate with respect to one another.

For a machine that normally rotates at 3600 rpm, a relative acceleration of one rpm corresponds to a 6°/sec increase in torque angle. For example, a 36° increase in torque angle could be achieved by accelerating the rotor to 3601 rpm for 6 seconds, or by accelerating the rotor to 3606 rpm for 1 second.

Under normal circumstances the speed of the rotor eventually returns to the nominal 3600 rpm.

An example will demonstrate how critical it is to maintain a constant generator rotor speed. Assume that a generator which is connected to a large interconnection experiences an instantaneous 1% increase in rotor speed. Further assume this speed increase lasts for one second. Assume that the rotor of this machine was initially spinning at 3600 rpm. If the interconnected system frequency remains at 60 HZ the generator's torque angle will advance 216° in the one second period. This machine will lose synchronism and go out-of-step.

All the components of the power system must operate at the same average (synchronous) speed or frequency. Some speed deviation (relative acceleration) is allowed but it cannot be large nor can it last long. A speed change of less than 1% of nominal to a generator's rotor may lead to serious consequences. When generators operate at large torque angles, they risk going out-of-step. Many generators have protective relays to detect out-of-step conditions and quickly trip the generator to prevent damage. The transmission system may also have protective relays to detect and respond to out-of-step conditions.

Section 7.8 will describe out-of-step protection.

7.2.4 Out-of-Step From a Voltage Perspective

When power system generators go out-of-step the torque angles will pass through 90°, 180°, 270°, and 360° relative to the rest of the interconnected system. The cycle will repeat until the generator that is out-of-step is, hopefully, tripped by protective relays. Each time two connected points in the system pass through an angle of 180° the system will experience a point with zero voltage. The transmission system between the two points will behave as if it sees a 3Φ fault.

Figure 7-3 illustrates out-of-step from a voltage perspective. In Figure 7-3(a) a generator is sending MW out to the system with a total angle spread (torque and power angles) of 45°. The voltages at the generator (V_G) and receiving end bus (V_R) are initially both acceptable. Note the mid-point bus voltage (V_M). The mid-point bus voltage magnitude is entirely dependent on the voltages at the generator and receiving ends of the system. Vector diagrams can be used to estimate the mid-point bus voltage magnitude. Connect a line between the ends of the V_G and V_R vectors and the mid-point bus voltage magnitude lies mid-way along this line. This is illustrated in Figure 7-3(a).

The mid-point bus must have not any local reactive support for this vector diagram procedure to work.

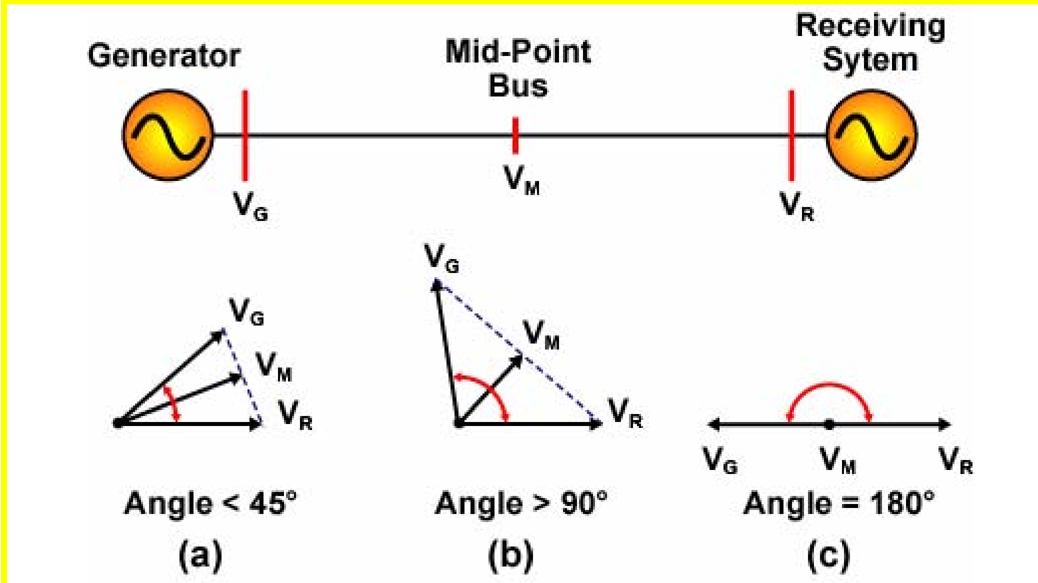


Figure 7-3
Out-of-Step from a Voltage Perspective

In Figure 7-3(a) the mid-point bus voltage is acceptable. In Figure 7-3(b) the mid-point bus voltage has started to decline. As the angular separation between the generator and the receiving bus grows, the mid-point bus voltage magnitude declines. In Figure 7-3(c) the angle has risen all the way to 180°. The mid-point bus voltage has declined to zero volts. As far as the power system is concerned the mid-point bus has experienced a solid 3Φ fault due to the 180° angle.

During an out-of-step condition power system angles will rapidly change across a full 360° range. The system voltage and power flows will vary widely. System equipment may be damaged due to high power flows, low voltages, and abnormal frequency.

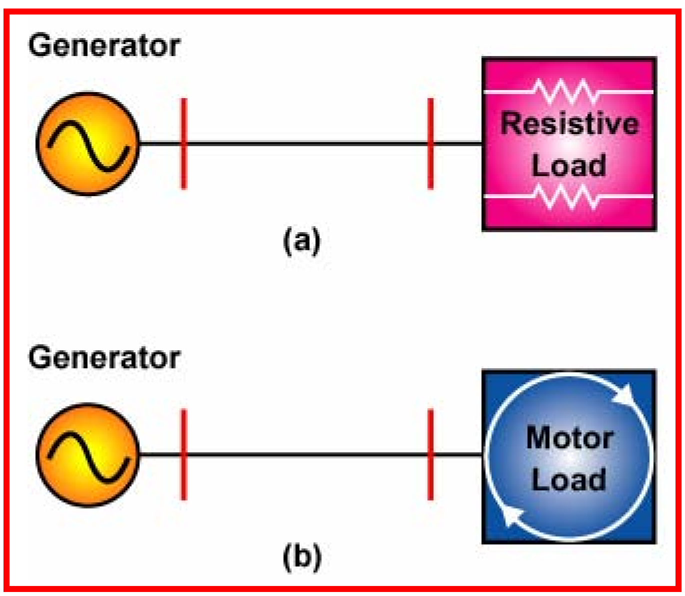
7.2.5 Relative Nature of Angle Stability

Angle stability is a relative measure. A generator cannot be labeled angle stable or angle unstable unless you compare it to some reference. For example, when describing a generator's torque angle, the rotor's and stator's respective rotating magnetic fields are compared. The concept of a generator torque angle means nothing without a reference to compare the generator's rotating magnetic field to.

A system that is angle stable can become angle unstable only after a period of relative acceleration. One part of the system must accelerate with respect to another part for the torque and/or power angles to grow and the system to become unstable.

Assume the angle stability of a simple power system is being studied. The system consists of a generator tied to a load bus. Both systems must have rotating mass before angle stability can be a concern. If the load has no rotating mass there can never be any relative acceleration. Whatever frequency the generator runs at is then, by default, the frequency of the entire power system. The system may be damaged due to abnormal frequency operation, but it will not go out-of-step.

Two examples will further illustrate the relative nature of angle stability. Figure 7-4(a) is a simple power system. A generator feeds into the system to supply the load. Note the load is all of a resistive type. Resistive type load has no rotating mass. Assume the generator is feeding MW to the resistive load. The frequency of this system is totally dependent on the generator. If the generator speed varies, the frequency of the system will vary directly with it. There can not be any angle instability in this system. For angle instability there must be relative acceleration. The speed of rotation of this entire system is determined by the generator so there can never be any relative acceleration.



Resistive type load may include electric heaters and incandescent light bulbs.

Figure 7-4
Relative Nature of Angle Instability

In Figure 7-4(b), the resistive load has been replaced with motor load. Motor load is a rotating type load. Rotating load has stored energy or inertia. The load area therefore has a rotating magnetic field and significant inertia. The magnetic field of the generator can now accelerate or decelerate with respect to the load area. The angle difference between the two fields can grow and the system enter an angle unstable condition.

7.2.6 Rotor Dynamics

As you may suspect by now, angle stability is very much dependent on the behavior of the system's generators. Angle stability is actually dependent on all spinning mass including both generators and motors. As a system operator, you have more control over the generators. Important areas of a generator's rotor are examined in this section.

The prime mover may be a water turbine, a steam turbine, etc.

The motion of a generator's rotor is influenced by two forces (power losses are ignored). These two forces are the mechanical torque applied by the prime mover (T_M), and the opposing electrical torque developed as a result of the electrical power output of the machine (T_E). These two opposing torques are illustrated in Figure 7-5. The accelerating torque (T_A) on the rotor is the difference between T_M and T_E or:

$$\boxed{T_A = T_M - T_E}$$

Where:

T_A = Accelerating Torque

T_M = Mechanical Input Torque

T_E = Electrical Output Torque

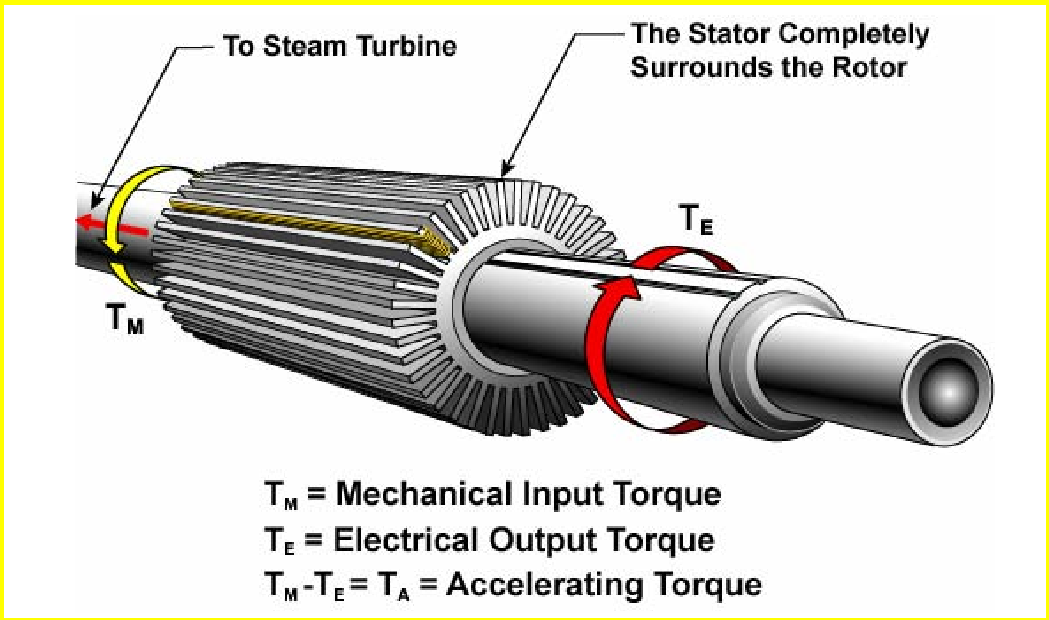


Figure 7-5
Rotor Torques

An accelerating torque will cause the rotor speed to vary. If T_A is positive, the rotor speed will increase above synchronous speed. If T_A is negative, the rotor speed will decrease below synchronous speed.

For purposes of this Chapter, a generator's rotor includes everything that rotates. This includes the turbine.

Since power is directly proportional to torque, power can be substituted for torque in the previous equation to yield:

$$\boxed{P_A = P_M - P_E}$$

Where:

P_A = Accelerating Power

P_M = Mechanical Input Power

P_E = Electrical Output Power

This equation is a power balance equation for the rotor. Whatever mechanical power is input to the rotor should come out as electrical power to the system. If what goes in does not match what comes out then an accelerating term (P_A) exists. When the mechanical power (P_M) input to the generator exceeds the electrical power output (P_E), the rotor will accelerate and in that way store the excess energy. When the mechanical power input to the generator is less than electrical power output, the generator will draw the difference from its stored rotor energy, and decelerate.

Remember, the natural system losses are neglected in this section.

For a generator's torque angle to change there must be accelerating power. Accelerating power is obtained by either varying the mechanical power input or the electrical power output. When a fault occurs near a generator the electrical power output is sharply reduced. This causes the generator rotor to accelerate and its torque angle to increase. If the mechanical power input to a generator is suddenly reduced, the generator rotor will decelerate reducing the unit's torque angle.

The concept of accelerating power will be very important as the types of angle stability are explored. The power-angle curve is a useful tool for examining the impact of accelerating power on a generator's angle stability.

7.3 Active Power & the Power-Angle Curve

This section will review the use of the active power transfer equation and expand on the use of the power-angle curve.

7.3.1 Review of Active Power Transfer Equation

Recall from Chapter 3 that the active power (MW) flow between any two points is strongly dependent upon the torque or power angles. The torque angle is used when calculating the power transfer from a generator to the system. The power angle is used when calculating the power transfer between two locations in the transmission system. Whether using the power angle or the torque angle, the active power transfer is calculated using the same active power transfer equation:

$$\boxed{P_S = \frac{V_S \times V_R}{X} \sin\delta}$$

The [(V_S – V_R)/X] portion is a relatively constant value and is called P_{MAX}. P_{MAX} is the largest possible MW transfer between two locations. The MW transfer can only reach P_{MAX} if the angle spread is 90°. The amount of P_{MAX} which is actually transferred between the two points is dependent on the term sin δ.

The term "angle spread" will be used from this point forward to represent any combination of angles. The angle spread will include both the torque and power angle separation between two locations.

7.3.2 Review of Power-Angle Curves

Figure 7-6 is a plot of the active power transfer equation. This plot is called the power-angle curve. The power-angle curve is a plot of the MW transferred between two buses as the angle spread (δ) is varied. The operating point (MW & δ) will always lie on the power-angle curve. The power-angle curve graphically illustrates that the maximum continuous active power transfer between any two strong buses occurs when the angle spread between these same two buses is 90°.

The mechanical power input line is the horizontal line through the power-angle curve. This line represents the amount of mechanical power input to the generation connected to the sending end. The mechanical power input line may cross the power-angle curve at any point. Figure 7-6 illustrates the mechanical power input line crossing at the top (90° point) of the power-angle curve.

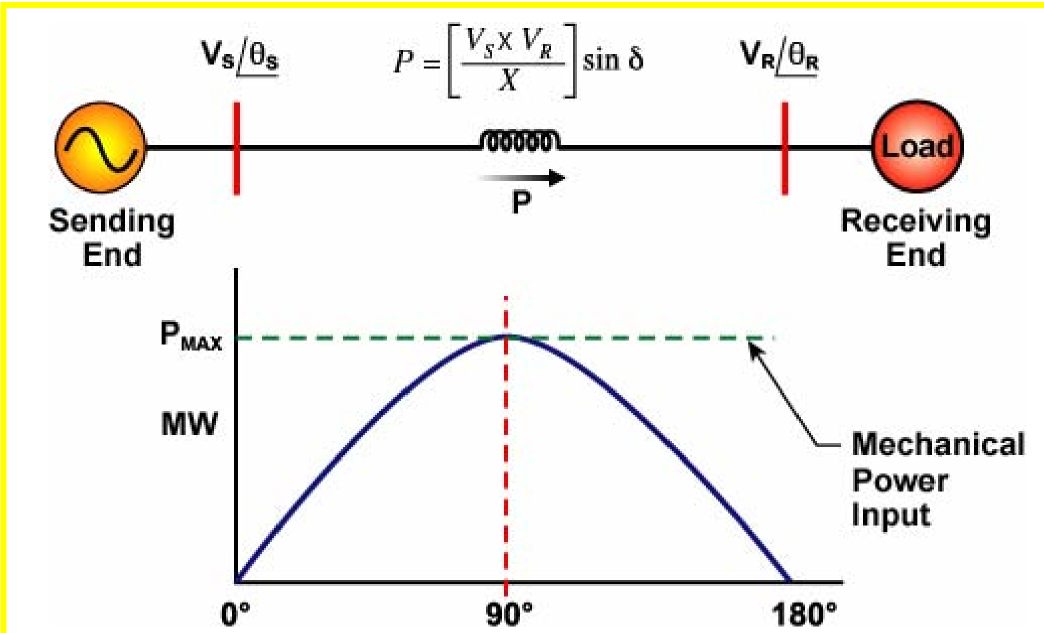


Figure 7-6
The Power-Angle Curve

The mechanical power input line is a critical element on a power-angle curve. This horizontal line can intersect the power-angle curve in two locations. One of these intersections is a stable operating point and one is unstable. The operating point is stable if the angle spread is less than 90°. The operating point is unstable if the angle spread is greater than 90°.

Acceleration & Deceleration

The intersection of the mechanical power input line and the power-angle curve yields the power system's current operating point. In Figure 7-6, the intersection is at the maximum electrical power output or P_{MAX}. The angle spread at this point is 90°. Any further increase in mechanical power input will cause the mechanical power input line to rise above the top of the curve. More mechanical power will then be coming into the generator than can be transferred across the system. The difference will accelerate the generator and cause the angle spread to grow even larger. As the angle spread grows above 90° the MW transfer further shrinks. This will cause the generator to accelerate even faster and the system to go unstable.

Figure 7-7 contains another illustration of a power-angle curve. The power system operates at the intersection of the mechanical power input line and the power-angle curve. The angle spread is approximately 35° and the MW transfer (P_T) is 100 MW. Assume the angle and MW are holding steady at 35° and 100 MW. The mechanical power input to the generator then equals the MW output. There is no accelerating energy. This is a desired point of operation.

The operating point (MW & δ) always lies on the power-angle curve. If operating on the curve portion above the mechanical power input line the generator is decelerating. If operating on the curve section below the mechanical power input line the generator is accelerating.

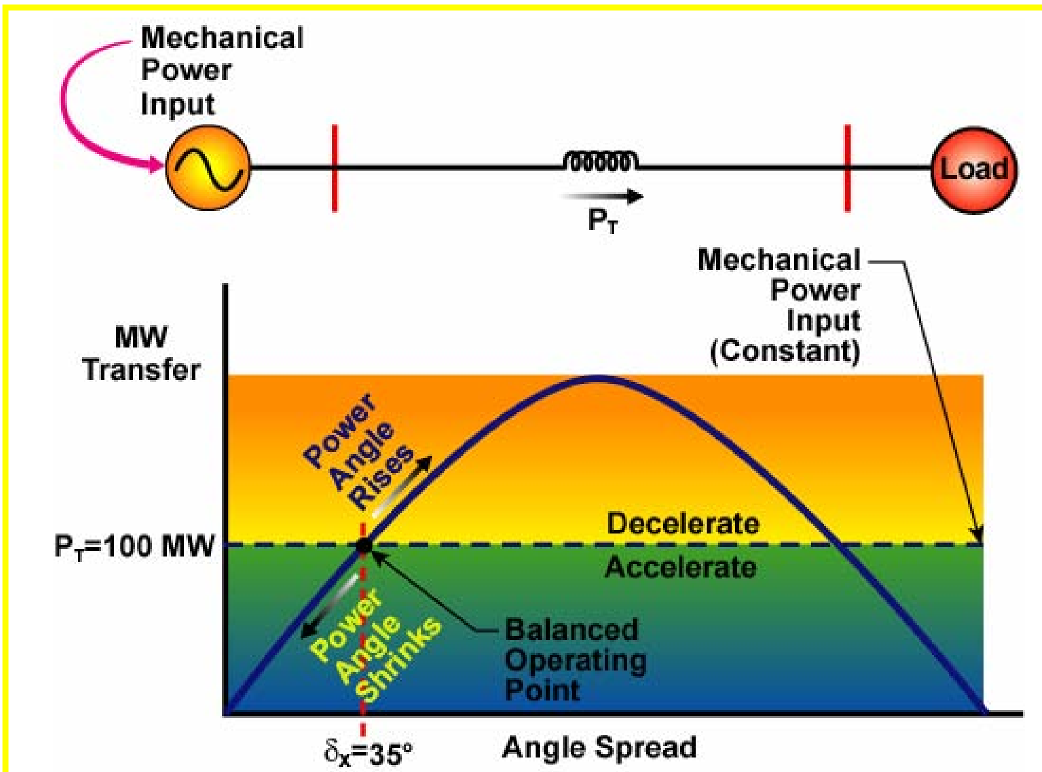


Figure 7-7
Accelerating and Decelerating on a Power-Angle Curve

Assume the mechanical power input stays constant while the angle rises above 35°. As the angle increases, the MW transfer increases. More is now being transferred out of the generator than mechanical power is being brought in. The difference will be automatically drawn from the stored energy in the rotor. This will cause the rotor to decelerate. Anytime the point of operation is above the mechanical power input line, the generator will be forced to decelerate.

Assume the mechanical power input stays constant while the angle falls below 35°. As the angle decreases, the MW transfer decreases. More power is now being brought into the generator than is being transferred out. The difference will be automatically stored in the rotor. This will cause the rotor to accelerate. Anytime the point of operation is below the mechanical power input line, the generator will be forced to accelerate.

The angle can only change if there is relative acceleration or deceleration. When the system operates above or below its mechanical power input line, the angle must be changing. The next several sections of this text will describe how the angle is impacted by various system events.

The simple power systems used to illustrate points in this text always operate on their power-angle curves. The operating point along the curve may be above, at, or below the mechanical power input line and still be a stable operating point. The important consideration is what the angle spread is at the time. If the angle is greater than 90° and the system is operating below the mechanical power input line, the situation is hopeless. The generator's rotor will be forced to accelerate and the generator will pull out-of-step with the remaining power system.

The next sections will examine three general classifications of angle stability. Power-angle curves will be used to illustrate all three classifications.

7.3.3 Maximum Angle Spread

This text has repeatedly stated that the maximum active power transfer between two strong buses occurs at an angle of 90°. There are many strong buses in the system so what is the maximum angle between any two locations in an interconnected system? The theoretical maximum angle spread is 180°.

Remember that an angle of +270° is the same as an angle of -90°.

Consider a three bus power system. Assume that each of these buses is very strong with unlimited reactive support. In other words, these buses will hold their voltage as power transfer levels vary. In theory, an angle spread of 90° between any two of the connected busses can be reached. The maximum possible angle spread across this three bus system is therefore 180°.

In practice, power system buses do not have unlimited reactive support. The largest angle spreads in the interconnected systems of NERC are approximately 120°. There are many strong buses in the NERC systems and the angle spread between connected buses is typically very small, perhaps 5° to 15°.

7.4 Types of Angle Stability

7.4.1 Angle Stability Classifications

Even though we divide our presentation of angle stability into three classifications, always keep in mind that angle stability is one all-encompassing topic.

The analysis of power system angle stability is a study of the dynamic performance of the power system. The term dynamic performance refers to the changing values of power flows, voltages, angles, and frequency that follow large and small system disturbances. For purposes of this text, angle stability is divided into three classifications: steady state, transient, and oscillatory. The three classifications are for ease of understanding the phenomena involved.

- In the steady state stability situation no significant system disturbances are taking place. System parameters such as voltage, angles, frequency, and power flows may be changing but the changes are small and occur gradually.
- The transient stability situation is one where a sudden, large change takes place within the power system. This sudden change could be the loss of a major generator or a severe system fault.
- The oscillatory stability situation is a constantly changing environment. Voltage, frequency, angles, and power flows may be changing or oscillating. The changes may be large and may occur rapidly. An oscillatory situation can follow a transient situation as the system oscillates following a disturbance. An oscillatory environment can also develop without a disturbance when power system oscillations build due to other causes.

These three classification (steady state, transient, and oscillatory) will each be used in this chapter to describe important concepts of angle stability.

7.4.2 Introduction to Angle Stability Classifications

When steady state stability limits are studied we assume that a generator can hold its terminal voltage and the impact of generator excitation systems is ignored.

Steady State Stability / Instability

Our study of steady state stability will start with a normal system. Steadily increasing power transfers and angular separations will eventually lead to steady state instability. No large triggering disturbance need occur. The power system will simply be gradually pushed beyond its means to transfer electrical power.

Figure 7-8(a) illustrates steady state stability and instability. When a system is steady state stable the angle spread is relatively steady. If the angle is changing, it is changing slowly. The magnitude of the angle is less than 90°. When a system is steady state unstable it has been pushed beyond its ability to transfer power. The angle gradually rises until it exceeds 90° and the system enters an unstable condition. Movement from a steady state stable condition to an unstable condition may take hours. Steady state instability is typically not a rapidly developing phenomenon.

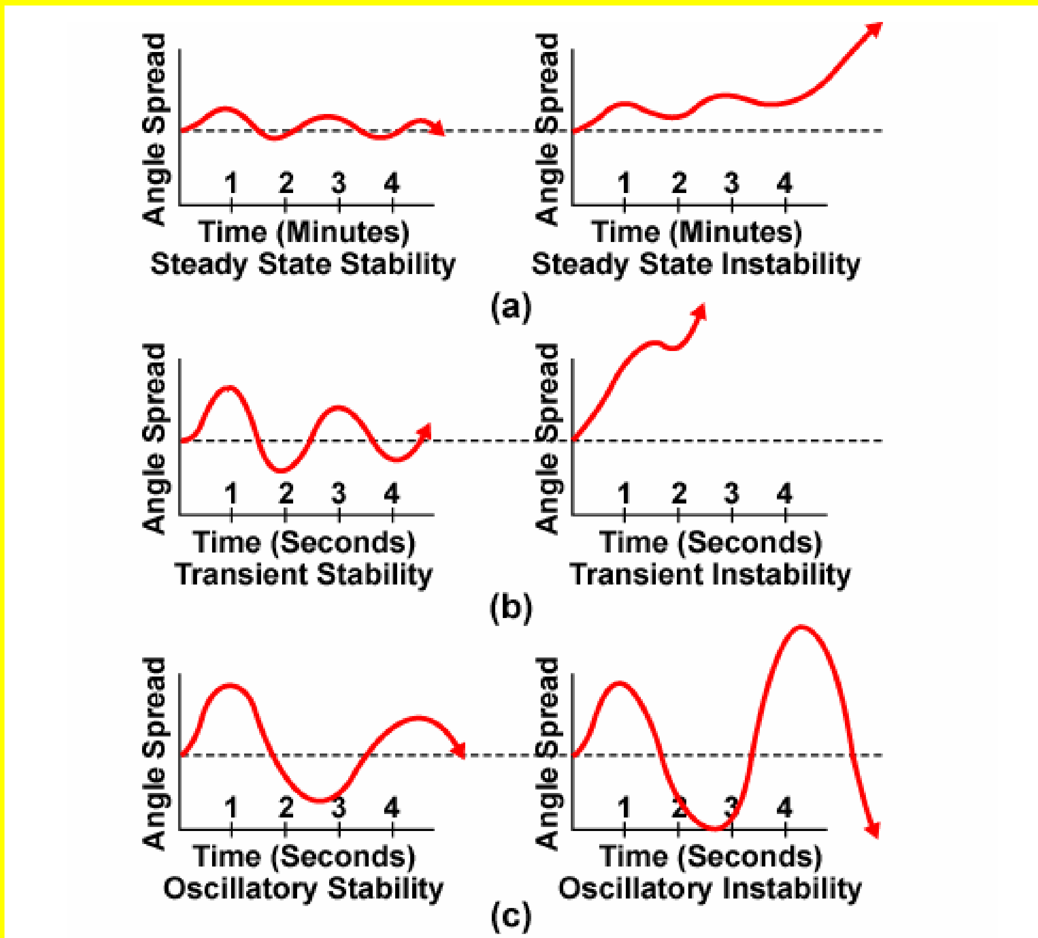


Figure 7-8
Types of Stability / Instability

The power transfer levels at which steady state instability occurs are normally very large, so large that a power system will typically encounter many other limits (voltage, thermal, etc.) before steady state instability transfer levels are reached. It is rare that a system has to restrict its power transfers due to steady state instability concerns.

Transient Stability / Instability

The transient stability or instability of a power system is determined by how the system responds to a severe disturbance. For example, can a power system survive if a 3Φ fault occurs near the high side bus of the largest generating station in the system? A system is transiently stable if it can survive the initial disturbance. A system is transiently unstable if it can not survive.

While transient stability is often determined by the first swing, it may also be determined by the following few swings.

Figure 7-8(b) illustrates transient stability and instability. For the transiently stable system a large disturbance suddenly occurs. The system angle spread starts to increase but reaches a peak and then starts to decline. The system has survived the initial disturbance. Transient stability is sometimes called first swing stability as the instability often occurs during the first angle swing.

In the right of Figure 7-8(b) the system has been exposed to a more severe disturbance. This time the system does not recover from the disturbance. The angle grows and continues to grow until the system is unstable. Following a severe disturbance, a system may become transiently unstable very rapidly. From disturbance to instability will typically be less than a few seconds.

Any power system can be made susceptible to transient instability if it is weakened enough. Remove enough lines from even a strong system and it will eventually be subject to transient instability.

Many power systems restrict their power transfers due to transient stability concerns. In general those power systems with long transmission lines and remote generation are most susceptible to transient instability. Power systems that are most concerned with the possibility of transient instability include:

- The far western portion of the Eastern Interconnection
- Most areas of the Western Interconnection
- Most of the Canadian systems
- Most small, weakly connected systems such as those found in Alaska

Oscillatory Stability / Instability

Oscillatory stability is similar to steady state stability in that no severe disturbance is required to initiate oscillatory instability. Oscillatory stability or instability is characterized by the magnitude and duration of power system oscillations. Oscillations to voltage, frequency, angle, and power flows can be triggered by many different events. Generator control systems are often involved. For example, a malfunctioning excitation system may cause MW and Mvar to oscillate. These oscillations could grow so large that a system becomes oscillatory unstable.

Oscillatory instability may start as a harmless low magnitude power oscillation. Eventually the oscillation could grow so large that the system starts to unravel. Transmission lines and generators may trip due to the oscillations. Oscillatory instability may take hours to develop or it may occur within a few seconds following a severe disturbance. Assume a power system recovers from a severe disturbance. It is transiently stable. However, the system could gradually enter into a period of severe oscillations and become oscillatory unstable.

With the introduction of many complex control systems in the modern utility environment, the occurrence of instances of oscillatory instability may become more common. Oscillatory stability is important to system operators because of all the types of stability this is the one that can be most impacted. An alert system operator may be able to detect the initial signs of oscillatory instability and prevent a severe system disturbance.

This Chapter introduces oscillatory stability. Chapter 8 "Power System Oscillations" will expand on the description of oscillatory stability.

7.5 Steady State Stability / Instability

This section will describe steady state stability and instability and present several illustrated examples.

The steady state environment is characterized by a system that is operating normally. No sudden changes to generation or load are occurring, and the system is not experiencing any oscillations. Figure 7-9 illustrates a simple system with its corresponding power-angle curve. This is a 345 kV system with a path impedance of 100 Ω.

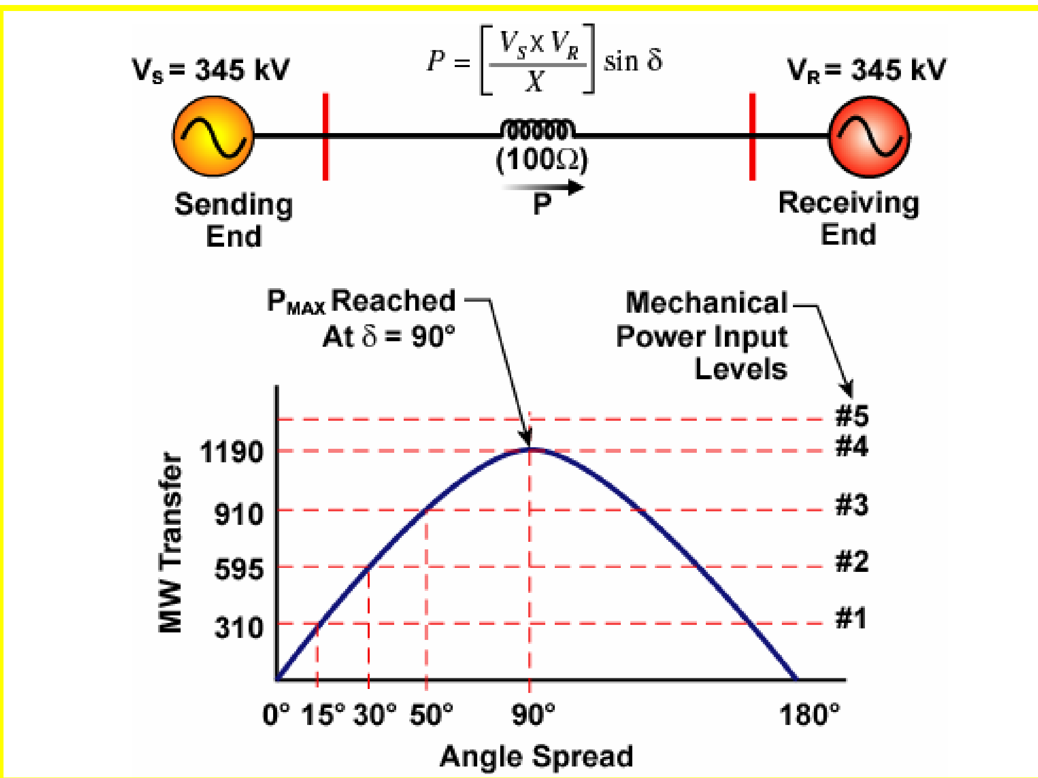


Figure 7-9
Steady State Instability

7.5.1 Process of Steady State Instability

The system is initially operating with a mechanical power input equal to level #1 as illustrated in Figure 7-9. The angle spread is 15° and the MW transfer from the sending to the receiving end is 310 MW. The system is steady state stable at this operating point.

Assume the receiving end load is growing. More mechanical power must be input to the generator to serve this growing load. Mechanical power input rises to level #2. The new angle is 30° and the MW transfer is 595 MW. The system's operating point is now more stressed but well within steady state stability boundaries.

The receiving end load grows further. Mechanical power input rises to level #3. The angle rises to 50° and MW transfer to 910 MW. This system is now highly stressed. The MW loading is likely close, or possibly exceeding, the thermal limit of the transmission system. The angle is less than 90° so the system is still steady state stable.

Receiving end load grows even further. The mechanical power input rises to level #4. The system is now at its steady state stability limit. The power transfer is 1190 MW and the angle 90°. If any disturbance occurs, even a small one, this system could go unstable.

Assume the load grows further by a small amount. The mechanical power input is raised to level #5 to meet the new load. The mechanical power input is now greater than the electrical power the system can possibly transfer. More mechanical power is coming in to the generator than can be transferred across the system. The difference will be stored in the generator rotor. Rotor speed will rise above synchronous speed. The system angle will increase due to this relative acceleration. As the angle rises above 90°, the power transfer will start to shrink. Even more excess energy is now stored in the rotor. The angle spread will increase further and the system will go unstable. This system has become steady state unstable.

The process described just now for steady state stability is theoretically possible but highly improbable in the real world. A realistic power system would collapse long before such high power transfer levels are reached. System voltage limits, thermal limits, or power oscillations would likely limit the loading on this system long before the 90° angle is reached. Even though this scenario is improbable it does illustrate the process of steady state instability. Section 7.5.2 will illustrate a more likely occurrence of steady state instability.

Power-Circle Diagrams & Steady State Instability

Figure 7-10 illustrates the same process and system as Figure 7-9 but with a power-circle diagram. Chapter 2 stated that power-circle diagrams are useful graphical tools for illustrating both MW and Mvar flow.

Remember, in power-circle diagrams, positive MW and Mvar flows are defined as out of the sending end bus and into the receiving end bus.

The corresponding angles for the five levels of mechanical power input are illustrated in Figure 7-10. Note that as the angle spread rises towards 90°, both active and reactive power flows increase. More MW is traveling across the line and more Mvar is being absorbed from the sending and receiving buses to support the line voltage.

Once the angle spread rises above 90° the MW flow starts to decline. The system is now steady state unstable. The power-circle diagram is not the best tool for illustrating angle instability but it does give us some important information. Note that once the angle spread exceeds 90°, MW flow reduces but Mvar continues to increase until the angle reaches 180°. Power-circle diagrams show us that when system angles rise to large values, MW and Mvar flows are swinging wildly.

The power-circle diagram in this figure is a very basic diagram as we have ignored the line resistance and the natural line charging.

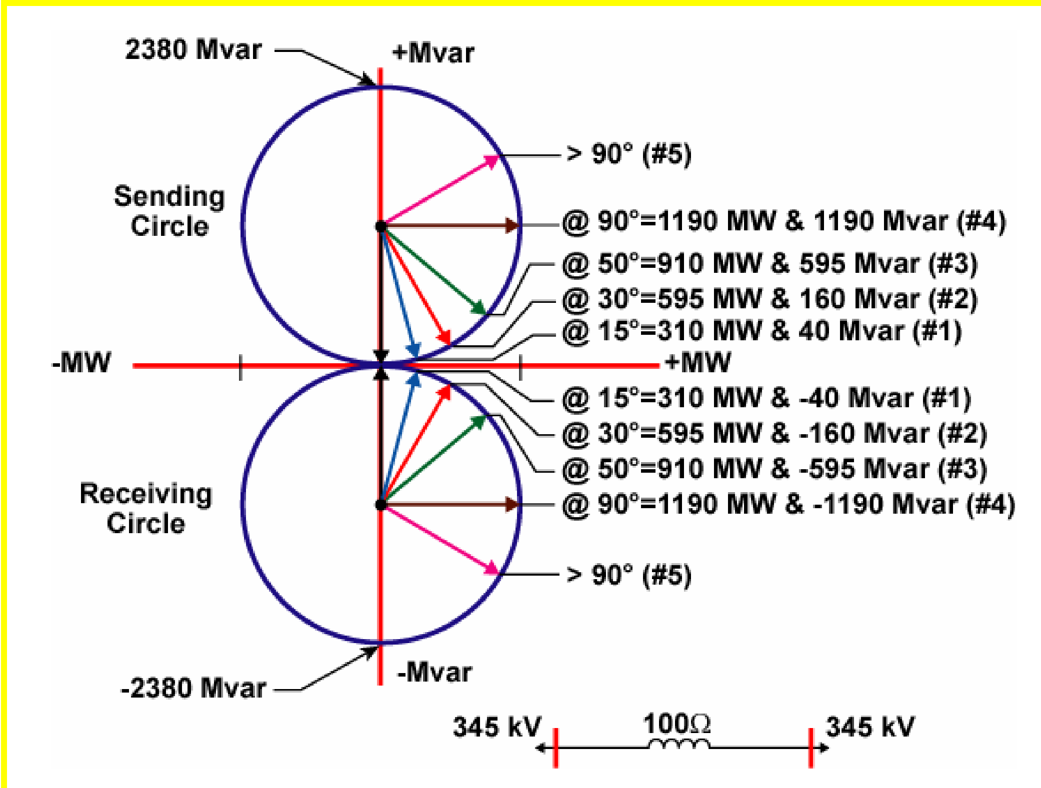


Figure 7-10
Power-Circle Diagram & Steady State Instability

7.5.2 Example of Steady State Instability

As an example of steady state instability, assume that a generator operator has experienced problems with a generator's automatic voltage regulator. The voltage regulator is switched to manual operation to avoid further trouble. When in manual voltage regulation, a generator is no longer responsive to changes to its terminal voltage, the excitation (field) current will remain relatively constant and the terminal voltage will vary with changing system conditions.

When the switch from automatic to manual mode is made, the generator continues to output the same amount of active and reactive power. If system load starts to increase, the generator's terminal voltage will slowly decline. The generator will not respond with additional reactive power to support its declining terminal voltage. Manual excitation holds the excitation current constant. Figure 7-11 is a power-angle curve that illustrates this situation. There are actually three power-angle curves shown in this figure. The generator is initially operating at full load on the curve labeled "initial curve". The initial operating point is labeled "A". The angle and the MW transfer are both acceptable at this point.

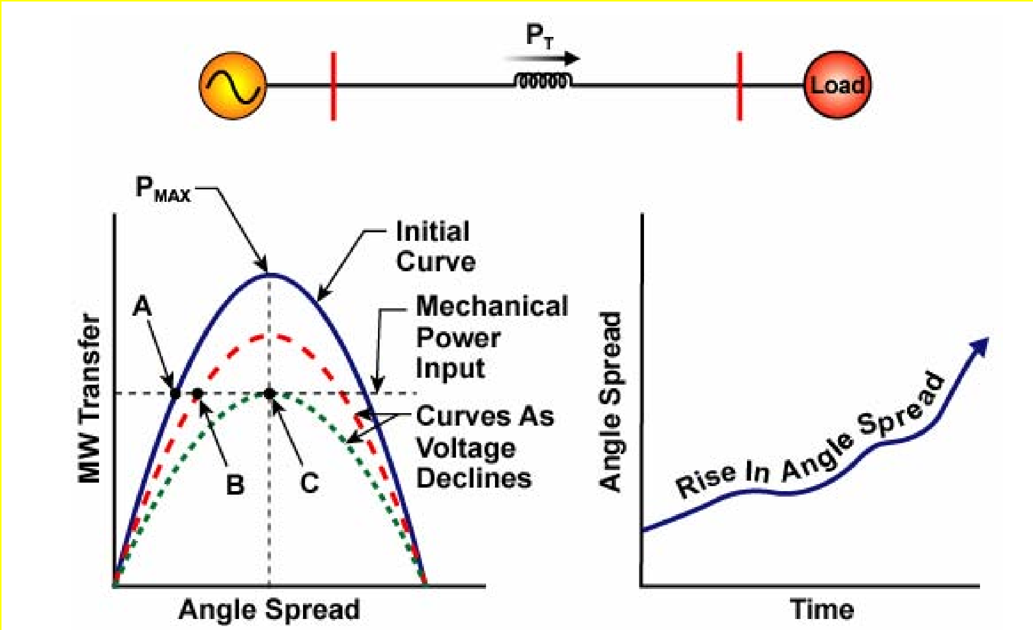


Figure 7-11
Manual Excitation and Steady State Instability

Assume that the system load starts to grow. As the system load grows, system voltages decline. Since the generator is in manual excitation the generator terminal voltage also falls. The peak (P_{MAX}) of the power-angle curve is dependent on the system voltages. As the system voltages fall the P_{MAX} value shrinks. The generator must now operate on a new power-angle curve with a smaller P_{MAX} value. The reduced magnitude of P_{MAX} forces the angle spread to grow larger even though the power transfer level has held steady. The operating point slides from point "A" to point "B".

As the load continues to grow, the P_{MAX} value continues to shrink. Eventually the peak value (P_{MAX}) of the power-angle curve has shrunk to the point where the mechanical power input line intersects the curve at 90°. This point is labeled "C" in Figure 7-11. If system voltages decline any further from this point the system will be steady state unstable.

This example, illustrates a situation where the system "backed" into a steady state instability condition. As the system voltages are reduced, the ability of the system to transfer power is reduced. In order to transmit the same active power, the angle spread had to gradually increase. Eventually the angle exceeded the steady state stability limit and the system was unstable.

An additional point that this example illustrates is the importance of keeping generator voltage regulators in automatic mode. Many power systems have operating guidelines that instruct their system operators to keep their voltage regulators in automatic mode. Plant operators may need to place a voltage regulator in manual mode for system testing, due to component failure, etc. However, it is important that system operators do everything possible to ensure as many regulators are in automatic mode as possible. This action will help ensure adequate reactive power support and may help avoid system instability.

7.6 Transient Stability / Instability

This section will describe transient stability and instability and present several illustrated examples.

7.6.1 Process of Transient Stability

The transient environment is characterized by a system that undergoes a sudden, severe disturbance. In contrast to the steady state environment where changes occur gradually, the transient environment involves rapid changes.

Figure 7-12 contains the power system that will be used to illustrate transient stability and instability. This system has a remote generator feeding through two high voltage transmission lines a large power system.

A remote generator tied to a large power system is used to keep our description simple. The large power system will not be impacted significantly by what happens to the generator or the two-line transmission system.

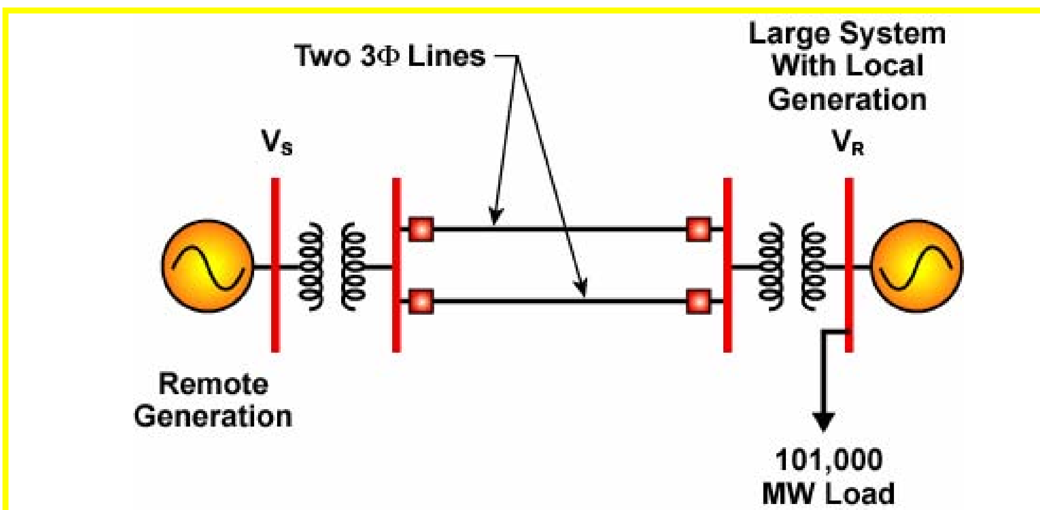


Figure 7-12
Power System for Transient Stability & Instability

The top portion of Figure 7-13 contains our initial or pre-disturbance power system. The remote generator is initially producing 1000 MW. This power is transmitted to a large power system via two transmission lines. The large system has 101,000 MW of load, 100,000 MW of which is fed from local generation.

A disturbance is created in this power system to study the transient stability of the system. The circuit breakers at both ends of one of the transmission lines are opened. From the generator perspective, once a line is opened the generator suddenly has to transmit its mechanical power input across a much higher impedance system. The generator must now work harder to transmit its MW across the transmission system to the load area.

The bottom portion of Figure 7-13 contains power-angle curves for this system. There are two curves; one for pre-disturbance conditions and one for after the line is opened (post-disturbance). Note the pre-disturbance curve has a higher P_{MAX}. Once the line is opened the power transfer path has a sharply higher impedance which results in a lower P_{MAX}. Note in Figure 7-13 that the post-disturbance curve has a significantly lower peak than the pre-disturbance curve.

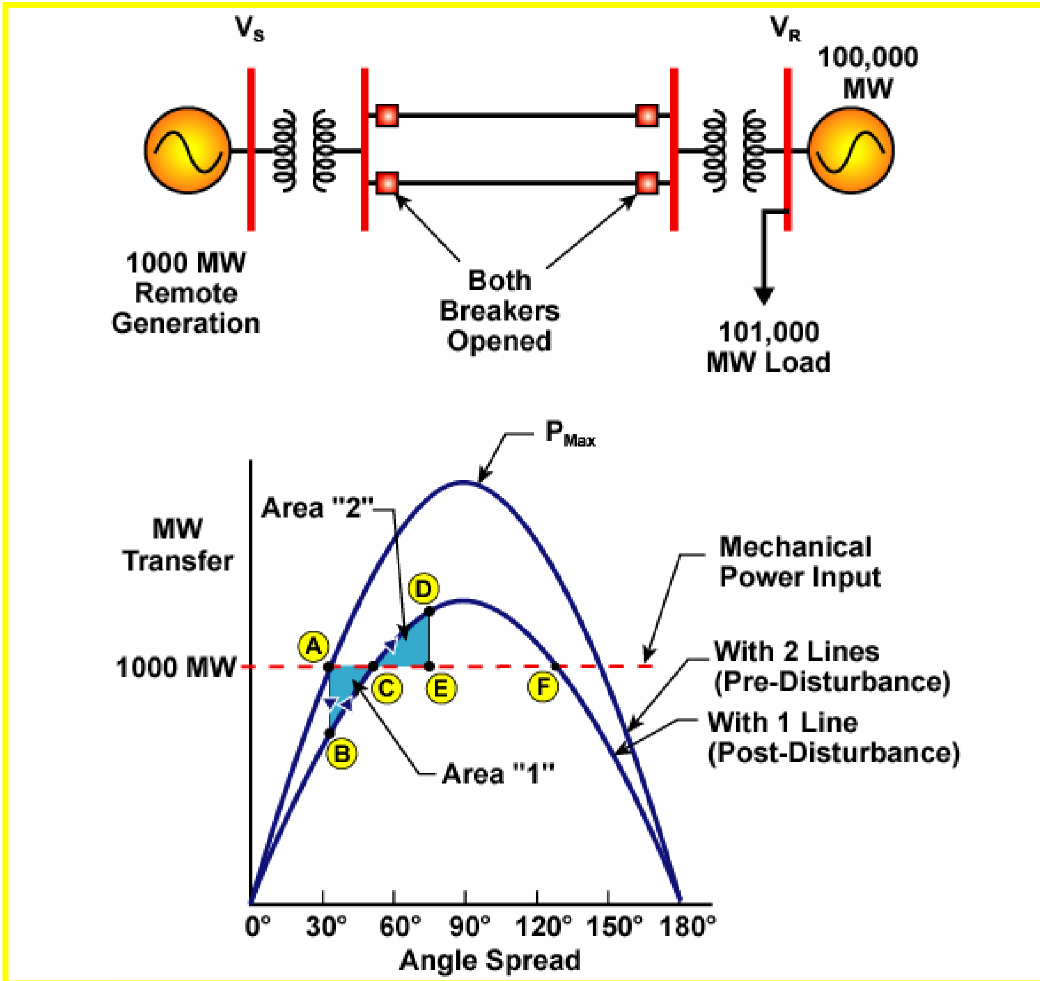


Figure 7-13
Power-Angle Curves for 1000 MW Generator Loading

Transient stability is a rapid event. From the initial disturbance to the peak of the angle swing is, at most, a few seconds.

The movement from point "A" to point "B" is vertical. Horizontal movement requires a time lapse. The movement from "A" to "B" is instantaneous.

Initially the power system is operating at point "A" in Figure 7-13. When the line opens the operating point instantly shifts from point "A" to a position on the post-disturbance power-angle curve at point "B". When at point "B", the generator must accelerate since its mechanical power input is now greater than the electrical power it can push out. As the generator accelerates it turns faster than synchronous speed. The angle spread increases due to this relative acceleration and slides from point "B" towards "C".

When the operating point reaches "C", the generator's MW output is again equal to the mechanical power input. However, the angle cannot stop increasing. The whole time the generator operated below the mechanical power input line it was storing energy in its rotor. The generator is now spinning faster than synchronous speed. The angle will keep increasing as long as the generator's speed is greater than synchronous speed. The generator must rid itself of the excess stored energy before it can return to synchronous speed and stop the angle spread increase.

As the operating point rises above point “C”, the generator starts to slow down. The generator slows because it is now sending out more electrical power than it is taking in mechanical power. The generator will rise above point “C” until it slows down to synchronous speed. This occurs at point “D” in Figure 7-13. If the generator had not slowed down to synchronous speed by the time it reached point “F” it would have gone unstable.

If the generator had not slowed down to synchronous speed by the time it reached point “F” it would have been transiently unstable. This possibility is addressed shortly.

Equal Area Criterion for Transient Stability

Immediately following the line opening the operating point shifted from point “A” on the pre-disturbance curve to point “B” on the post-disturbance curve. This movement represented an immediate reduction in MW transfer due to the opening of the line. The angle then increased from “B” through “C” and on to “D”. The angle stopped increasing at “D”. As the operating point moved, there were two areas created bounded by the points “A-B-C” and “C-D-E”. These two areas are shaded and labeled “1” and “2” in Figure 7-13.

The two areas represent the accelerating and decelerating periods of the generator. Area “1” represents the accelerating period of the generator. The size of area “1” is equivalent to the energy stored in the rotor. Area “2” represents the decelerating period of the generator. The size of area “2” is equivalent to the energy removed from the rotor. The operating point rose above point “C” until area “2” was the same size as area “1”. This is called the equal area criterion for transient stability. If area “2” is not equal to area “1” by the time point “F” is reached, the power system will enter a period of transient instability.

Area “1” represents the energy that is absorbed by the rotor as a result of the reduced MW transfer across the system. This absorbed energy is what causes the rotor to speed-up and the angle spread to increase. Area “2” represents the energy released by the rotor as it decelerates due to the electrical power output exceeding the mechanical power input. The equal area criterion basically states that the amount of energy required to slow the rotor to synchronous speed is equal to the amount of energy that was added to accelerate it from synchronous speed. If the decelerate area cannot match the accelerate area, instability will occur.

Maximum Angle Spread

Our angle stability descriptions to this point have stated that the angle spread between any two points in the power system can never stabilize at a value greater than 90°. Note that we have emphasized “stabilize” at a value. The angle can exceed 90° for short periods of time as long as its final value returns to less than 90°. This can happen if the angle is oscillating about a point that is less than 90°.

Note that the angle in Figure 7-13 could have swung all the way to point “F” as long as it did not pass through point “F”. Once the operating point has passed point “F”, the system will be unstable. Once past point “F”, the electrical power output is again less than the mechanical power input. The angle must increase as energy is again being stored in the rotor. As the angle spread is already greater than 90° when past point “F” the only option is a further angle increase and eventual angle instability.

Figure 7-14 illustrates the same information as Figure 7-13 but in a strip chart format. Points “A”, “B”, “C” and “D” are labeled on the strip chart. These labeled points correspond to Figure 7-13. Note that once disturbed the MW output of the generator oscillates before settling down.

Several points are labeled “C” in this figure. This is intentional as the operating point swings through point “C” several times before finally settling at point “C”.

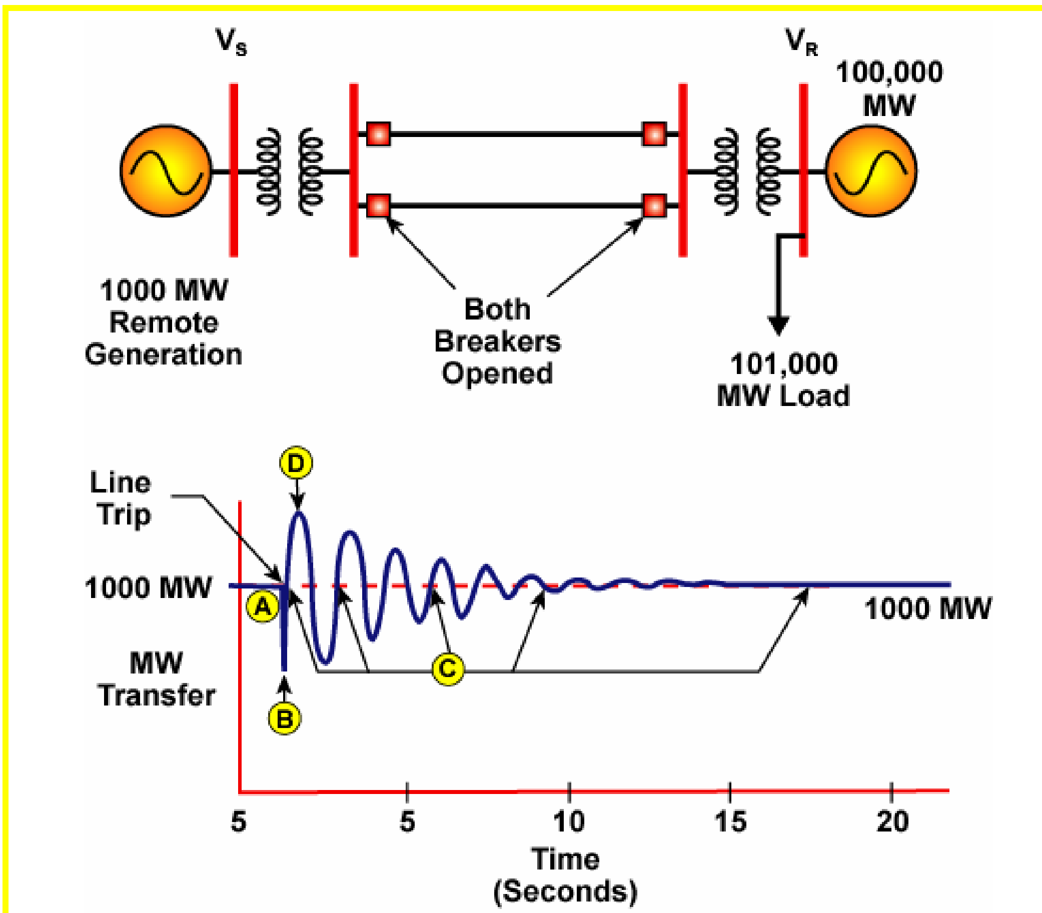


Figure 7-14
Strip Chart Equivalent of Figure 7-13

In our example of transient stability the MW output starts and ends at 1000 MW. During the oscillation the output may swing between 1500 to 500 MW. Note the time frames in Figure 7-14. Once the angle spread started to reduce from point “D”, it indicates that the system was transiently stable. It took approximately 1 second to determine whether this system was transiently stable or unstable.

It takes only a few seconds to determine if the system angle will recover from the first swings. However, the oscillations that follow the first few swings may last for many more seconds. When the oscillations finally settle down or dampen, the operating point is at “C”. The angle at point “C” is greater than the initial angle at point “A”. This is expected since the system has lost a line and the path impedance is now greater. For transient stability we are only concerned with the first several swings. Oscillatory stability concerns itself with subsequent swings.

7.6.2 Process of Transient Instability

The top of Figure 7-15 is the same power system as was used in Figure 7-13 with the exception of the loading on the system. Figure 7-13 had a loading of 1,000 MW on the remote generator. When one of the lines was opened the system remained transiently stable. Figure 7-15 has a loading of 1,500 MW on the remote generator. One of the two lines is again opened. The shock to the system will be greater since greater amounts of initial MW flow are involved.

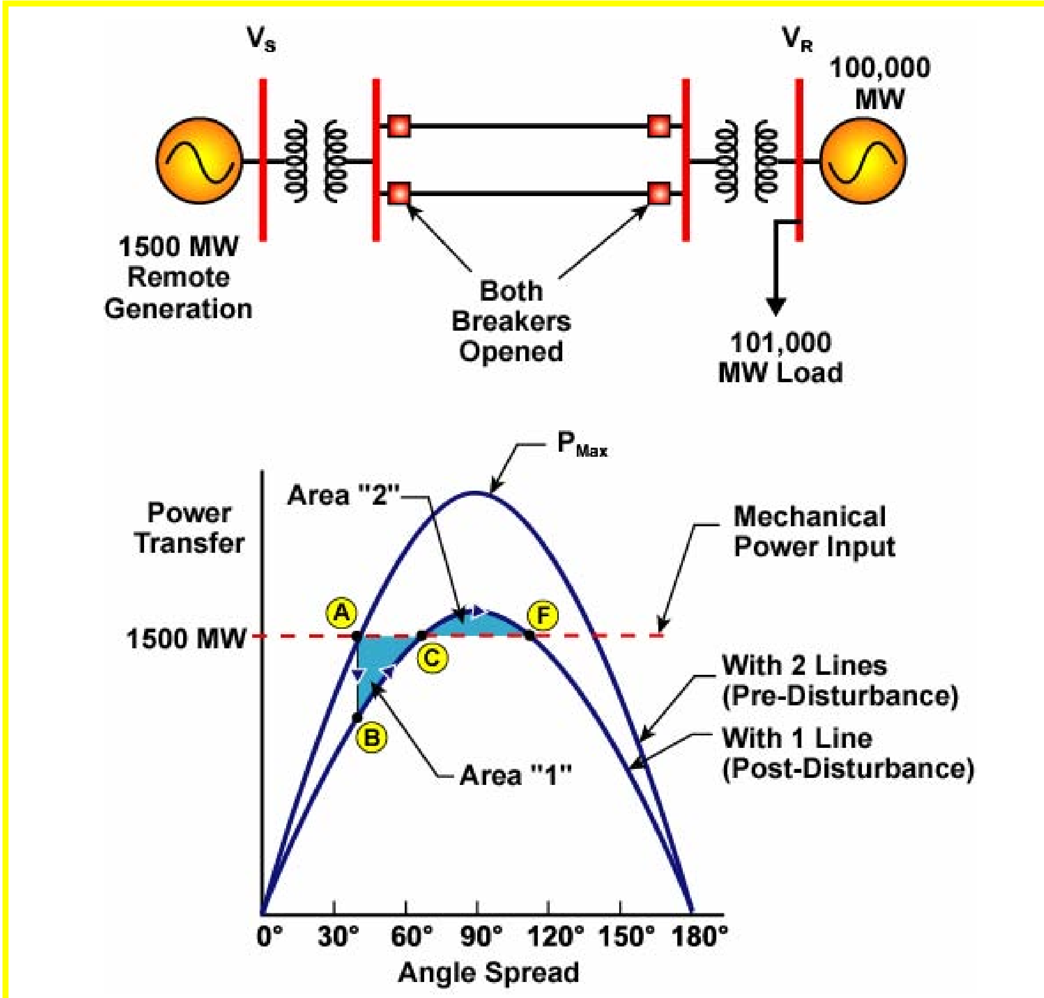


Figure 7-15
Power Angle Curve for Transient Instability

Since the decelerating area (area #2) is smaller than the accelerating area (area #1) this generator will go out-of-step with the larger power system.

The power-angle curve at the bottom of Figure 7-15 illustrates that the operating point shifts from its initial location at point "A" to "B" once the line is opened. The remote generator now has more mechanical power input than electrical power output and must accelerate. As the generator accelerates the angle increases. The angle will keep increasing until the generator can again return to synchronous speed. If the generator does not return to synchronous speed by the time the operating point reaches "F", the system will be transiently unstable.

A close inspection of Figure 7-15 reveals that this generator will go out-of-step as predicted by the equal area criterion. The important point to note is that area "2" is smaller than area "1". This means there is not enough decelerating energy to return the generator's rotor to synchronous speed before reaching point "F". Since the generator is still above synchronous speed after point "F" is reached, the angle will continue to increase. The electrical output will again drop below the mechanical power input line. This will cause the generator to further accelerate and go out-of-step.

The system illustrated in Figure 7-15 is transiently unstable. The generator never recovered from the initial angle swing. Once the generator passed through point “F” it accelerated at a faster and faster rate. Once the angle passes 180°, the generator starts motoring (absorbing MW) and accelerates even faster. Generator protection systems are often designed to detect out-of-step conditions and trip the generator before serious damage occurs.

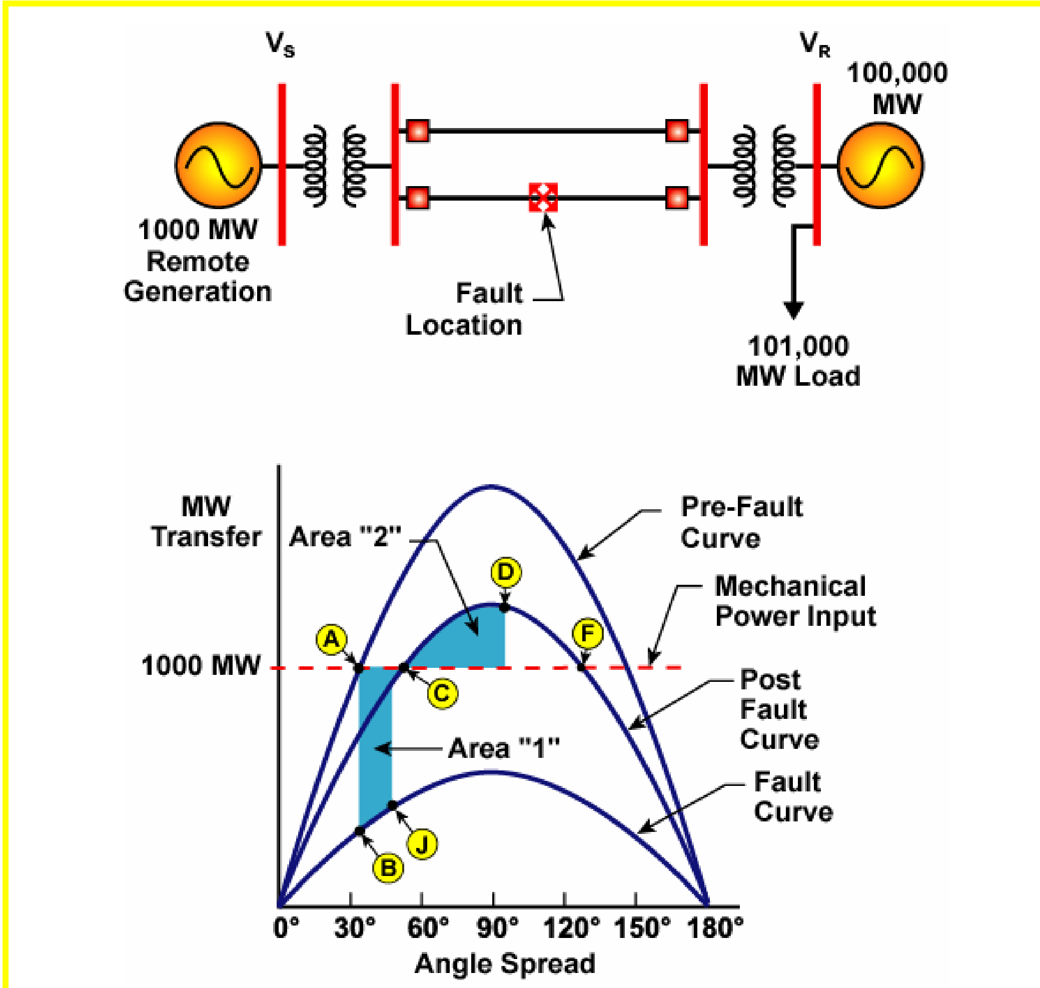
7.6.3 Transient Stability Following a Fault

The top of Figure 7-16 illustrates the same system and generation levels as Figure 7-13 but now, instead of just opening a line’s circuit breakers, a fault has occurred. With a fault there will be three power-angle curves instead of two. One curve for the pre-fault conditions, one curve for post-fault conditions, and one curve for the period of time during which the fault is applied.

While the fault is applied to the system, voltages will be depressed due to the large rush of reactive current to the fault. This depressed voltage is represented by the low peak (low P_{MAX}) of the power-angle curve while the fault is applied. Immediately after the fault is applied, the operating point shifts from the pre-fault curve at point “A” to the fault curve at point “B”. The angle then increases along the fault curve until the fault is cleared at point “J”.

The fault is cleared by the transmission line’s protective relays.

The size of the accelerating area (area “1”) is directly related to the fault clearing time. When the fault is cleared the operating point shifts to the post-fault curve. The post-fault curve is smaller then the pre-fault curve because one of the transmission lines is out-of-service. The power-angle curves of Figure 7-16 indicate that the system is transiently stable as the generator reached synchronous speed at point “D”. The operating point then oscillates back and forth before finally settling at point “C”.



The faulted system curve is the smallest of the three curves as system voltage is depressed during the fault.

Figure 7-16
Transient Stability and a Fault

3Φ Fault and an Extended Power Angle Curve

The top of Figure 7-17 again illustrates our simple power system. A 3Φ fault has now been applied at the remote generator's high side bus. Three phase faults are generally the most severe type of fault. While this 3Φ fault is applied, no MW can leave the generator. All of the generator's mechanical power input is stored in and accelerates the rotor.

The bottom of Figure 7-17 contains an extended power angle curve. Instead of illustrating only 180° this figure illustrates several half-cycles of the sine curve. Note the size of the accelerating area (area "1") in Figure 7-17. The decelerating area (area "2") is no match for the accelerating area and the generator pulls out-of-step from the larger power system.

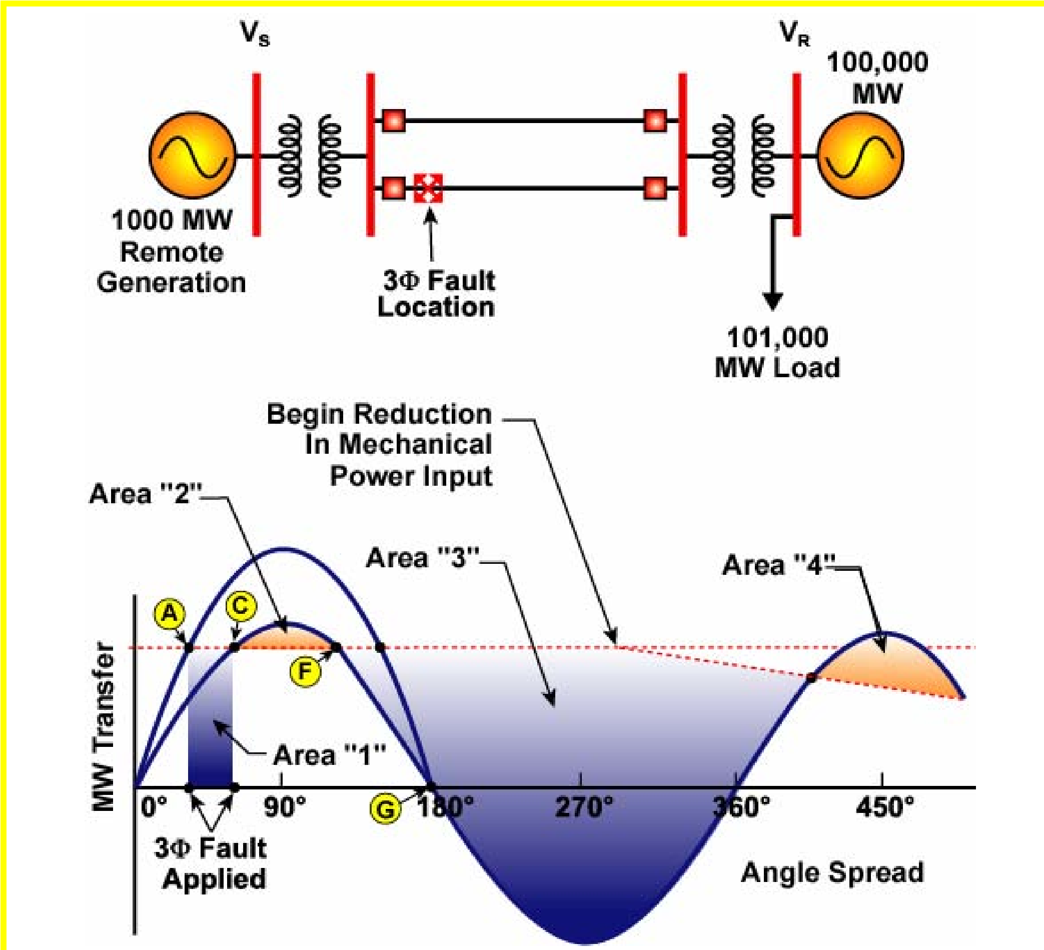


Figure 7-17
Extended Power-Angle Curve

After the operating point passes through point "G" the generator becomes a motor. While motoring the generator absorbs MW from the system which further accelerates the generator's rotor. The combination of the mechanical power input to the generator and the generator acting as a motor creates a second large accelerating area "3". The decelerating area "4" is again no match for the accelerating area "3" and the generator continues its out-of-step operation.

Throughout our description of transient stability we have assumed that the mechanical power input stays constant. This is a reasonable assumption as it is very difficult to rapidly change the mechanical power input. In Figure 7-17 note that after a few seconds mechanical power input is slowly reduced. However, the reduction is too little too late and the generator is unstable. In the next section several methods for achieving rapid, and effective reductions in mechanical power input are described.

7.6.4 Further Observations with Power-Angle Curves

Benefits of High Speed Reclosing

Several additional interesting concepts can be illustrated on a power-angle curve. One concept is the benefit of high speed reclosing following faults. Assume that the fault in Figure 7-16 was a line-to-ground fault. Further assume that the faulted transmission line was equipped with high speed reclosing. If this reclosing had been successful, instead of shifting from the faulted conditions power-angle curve to the post-fault curve, the system would have shifted back to the larger pre-fault curve with two lines in service.

With two lines available to push power out of the generator the chances of remaining stable are greatly increased. If high speed reclosing had been successfully used, area "1" in Figure 7-16 would be slightly smaller. Area #2 would not need to be as large and, if required, area #2 would have more room to grow. The maximum angle spread (point "D") would therefore not be as great.

A risk of high speed reclosing is the chance of closing back into the fault and be worse off than letting the line trip. The effect of closing back into the fault as seen in Figure 7-16 would be a much larger area "1" with the distance from points "B" to "J" being greater. As we now know, the larger area "1" is, the higher the risk of instability.

Need for High Speed Protective Relaying

Power-angle curves also illustrate the need for high speed protective relays in the transmission system. The faster the fault is cleared, the smaller the accelerating area. The smaller the accelerating area, the less the angle will grow and the better the chances to remain angle stable.

Use of Fast Valving

Earlier sections have stated that it is difficult to make rapid changes to the mechanical power input. While it may be difficult to accomplish, this type of action could be well worth the effort. Note the position of the mechanical power input line in Figure 7-17. If following a disturbance, a rapid movement downward could be made to the position of this line, the accelerating area would be reduced and the decelerating area increased. A rapid adjustment to mechanical power input could save a system from transient instability.

While many steam units have the ability to use fast valving, few actually implement the scheme due to the possible harmful impact to the unit.

Steam turbine/generators may use a process called "fast valving" to achieve a rapid reduction in mechanical power input. Figure 7-18 illustrates the fast valving process. The steam flows to the intermediate and low pressure turbine stages through the intercept valve. A fast valving system is designed to rapidly shut the intercept valve when the generator is at risk of transient instability. When the intercept valve is quickly shut possibly two-thirds of the generator's mechanical power input is suddenly removed. This action will greatly reduce the accelerating energy in the system and possibly avoid instability.

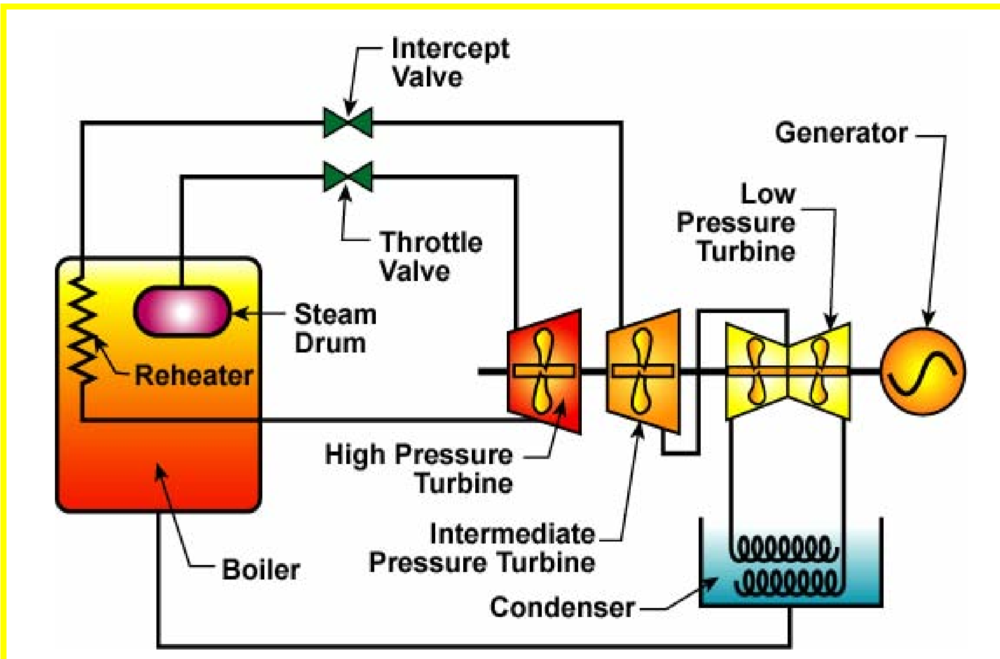


Figure 7-18
Fast Valving in Steam Units

Following a severe disturbance it may take ½ second to shut the intercept valve. The valve then remains closed for a few seconds. Ideally no steam is vented and the generator is rapidly brought back to initial loading.

Hydro units cannot use fast valving but a hydro based system can employ a process with a similar purpose. Braking resistors are sometimes installed in hydro based systems. Braking resistors are large resistive loads. The braking resistor control logic monitors system parameters to determine if the local power system is accelerating. If all the conditions are met, the braking resistor is placed in-service. The braking resistor remains in-service for only a short time, perhaps 20 cycles. While it is in-service the braking resistor slows the system down. This deceleration may be sufficient to avoid instability.

British Columbia Hydro also has a braking resistor installed adjacent to their northern most hydro generation.

Figure 7-19 is a picture of the Bonneville Power Administration (BPA) braking resistor. This large brake (rated 230 kV & 1400 MW) is located in the Pacific Northwest. The brake is inserted if the Pacific Northwest power system accelerates with respect to the rest of the Western Interconnection. While inserted the brake will slow down the system and help reduce the angle spread.

The three towers in the picture form the braking resistor. The towers have hundreds of ½ inch wires stretching from the tower to ground. These wires contain the brake's resistance. 230 kV transmission lines connect the towers to the power system via circuit breakers. When the brake is needed, the circuit breakers are closed and the brake is placed in-service for a short time.

Figure 7-19
The BPA Braking Resistor

Generator Dropping

An additional option for rapidly reducing the power system's accelerating energy is to quickly trip generation. Generator dropping refers to the intentional tripping of generating units. Generators may be tripped to avoid an accelerating condition that could lead to instability.

NERC utilities drop both steam and hydro generation. However the dropping of hydro generation has definite advantages as it is a simple and rapid process to re-synchronize a hydro unit. In contrast, there are many events that could occur which could delay the re-synchronizing of a steam unit.

The causes, effects, and control of the oscillations that accompany oscillatory stability and instability are further addressed Chapter 8.

7.7 Oscillatory Stability / Instability

This section will describe oscillatory stability and instability and present several illustrated examples. The oscillatory environment is characterized by a system that is constantly changing. MW, Mvar, voltage magnitudes, angles, and frequency may be oscillating.

The study of oscillatory stability is similar to steady state stability in that no severe triggering event is required. A system may enter into a period of oscillatory instability as the result of a minor disturbance such as a line switching operation. Oscillatory instability may be a slowly developing event. A system may begin a period of oscillations that last for several seconds, minutes, or even hours. These oscillations do not always result in oscillatory instability. Oscillatory instability occurs when the oscillations grow so large that the system becomes unstable. Transmission lines and generators may trip as a result of the oscillations. In many instances the oscillations may die out as unexplained as the origins that first created them.

An important ingredient in any study of oscillatory stability is the role of control systems. For example, the actions of generator governor and excitation systems are important in the study of a system's oscillatory stability. The control systems may be the cause of the oscillations and, as described in Chapter 8, can also be used to control the oscillations.

7.7.1 Process of Oscillatory Stability

Figure 7-20 contains a diagram of a power system used to illustrate oscillatory stability and instability. This system has a generator feeding through two high voltage transmission lines to a large power system. The receiving power system is so large that anything done to our remote generator will not impact the large system's voltage or frequency.

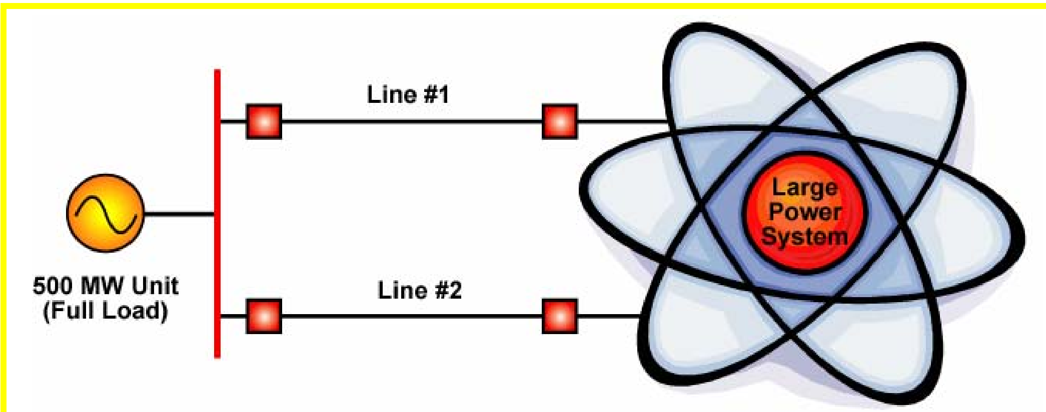


Figure 7-20
Power System for Oscillatory Stability

Initially the remote generator's output splits between the two transmission lines. Assume line #1 is opened. No fault has occurred, the line is simply switched out for maintenance. The power-angle curve of Figure 7-21 illustrates how the MW flow and angle spread vary after line #1 is opened. Initially the system is operating on the pre-outage curve at point "A". As a result of the opening of line #2 the operating point shifts downward to the post-outage curve at point “B”. The mechanical power input is greater than the MW output at point “B”. The generator accelerates and the angle increases. The operating point therefore slides up to point “C”.

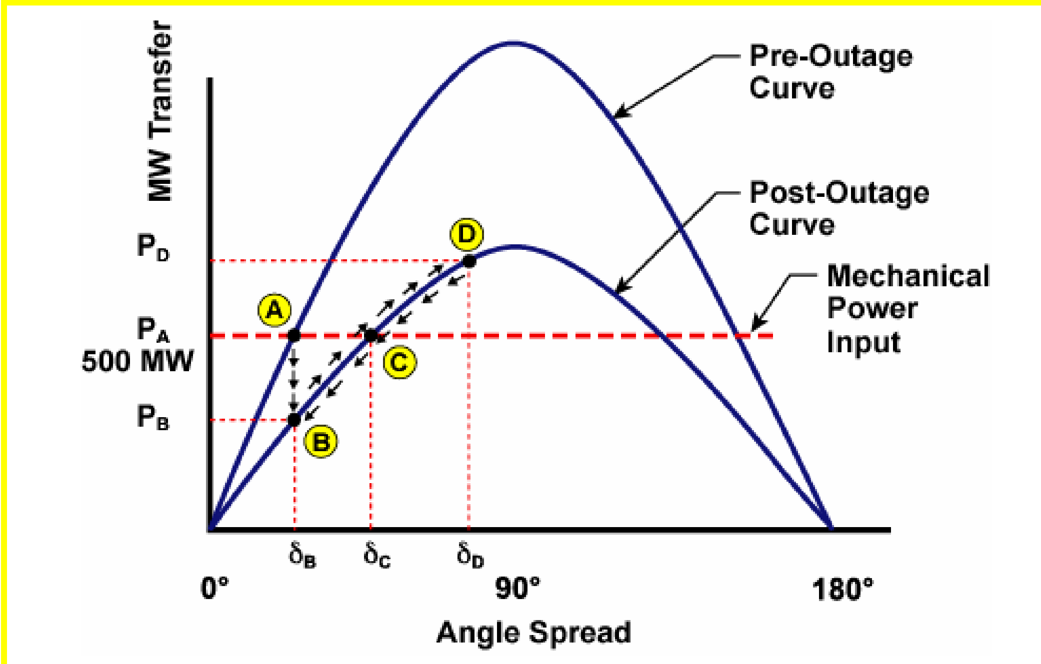


Figure 7-21
Power-Angle Curve for Oscillatory Stability

At point “C” the generator’s mechanical power input and the electrical power output are matched. There is no additional energy being stored in the rotor at point “C”. However, the whole time the power system operated below the mechanical power input line, energy was being stored in the rotor. The energy stored must be removed before the angle spread can stop increasing.

The excess rotor energy is removed by increasing the MW output to a point above the mechanical power input line. The operating point slides along the power-angle curve up to point “D”. By the time the operating point reaches “D”, the generator is back to synchronous speed. All the energy that was stored in the rotor has now been removed and the angle can stop increasing.

When transient stability was examined our only concern was whether the system recovered from the first few swings. Figure 7-21 indicates that this system is transiently stable. With oscillatory stability we are not concerned about the first few swings but rather with subsequent swings.

At point “D” the generator has rid itself of excess rotor energy. The MW output is still greater than the mechanical power input. This deficiency in input power is now drawn from the rotor. This causes the generator speed to slow below synchronous speed. The angle starts to decrease as the operating point slides back towards point “C” and on towards “B”.

The oscillation between points “B” and “D” will continue until system losses dampen the swing. “Dampen” means that as the system oscillates about point “C” energy is expended due to natural system energy losses. Eventually enough energy is lost that the oscillations stop and the system settles at a new operating point (point “C”). This system is oscillatory stable. Note that the new operating point (“C”) is at a greater angle than the original operating point (“A”). Figure 7-22 illustrates how the operating point oscillates back and forth between points “B” and “D” and finally settles at “C”. The time period for the oscillations may last from several seconds to several minutes.

As the power oscillates back and forth in the system, the current also oscillates. Energy losses are created as the current oscillates through the system’s resistance.

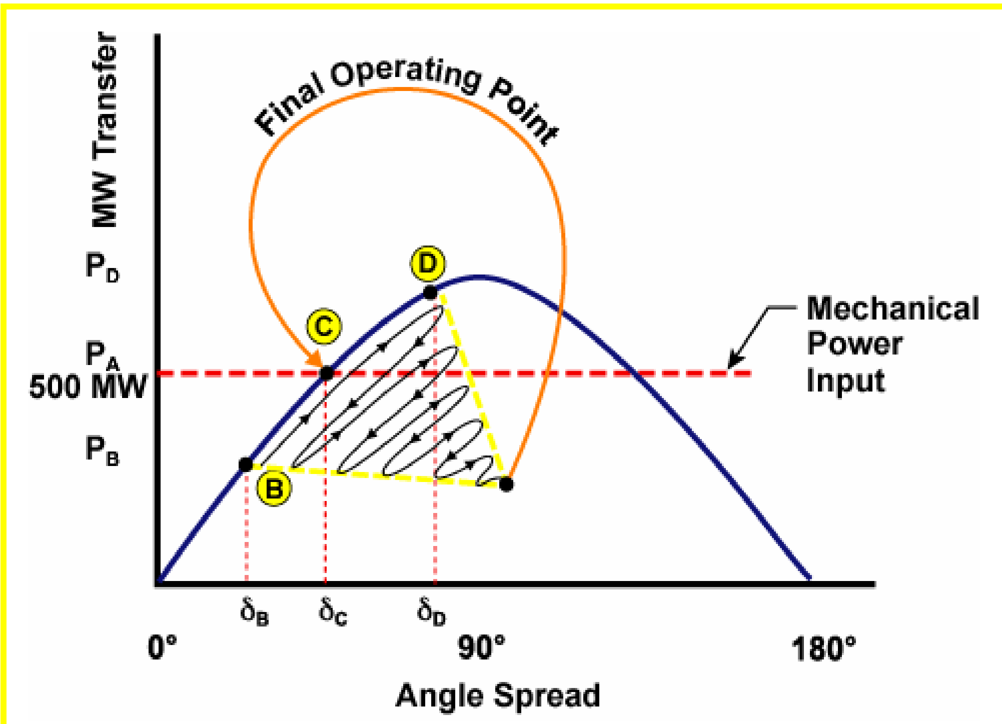


Figure 7-22
Illustrating Oscillations on a Power-Angle Curve

The oscillations are shown in this manner for illustration only. Actually all the movement between “B” and “D” is along the power-angle curve.

Note that the generator is spinning faster than synchronous speed as it moves from point “B” to “D”. The generator is spinning slower than synchronous speed as it moves from point “D” to “B”. The generator is at synchronous speed when it is exactly at points “D” or “B” and when it finally settles at point “C”.

When the operating point finally settles at point “C”, mechanical input is equal to MW output and the generator is spinning at synchronous speed.

Figure 7-23 contains the same data as Figure 7-21 but in a strip chart format. Note how the power oscillations are initially large but gradually dampen. The labeled points on Figure 7-23 correspond to the same points on Figure 7-21 and Figure 7-22.

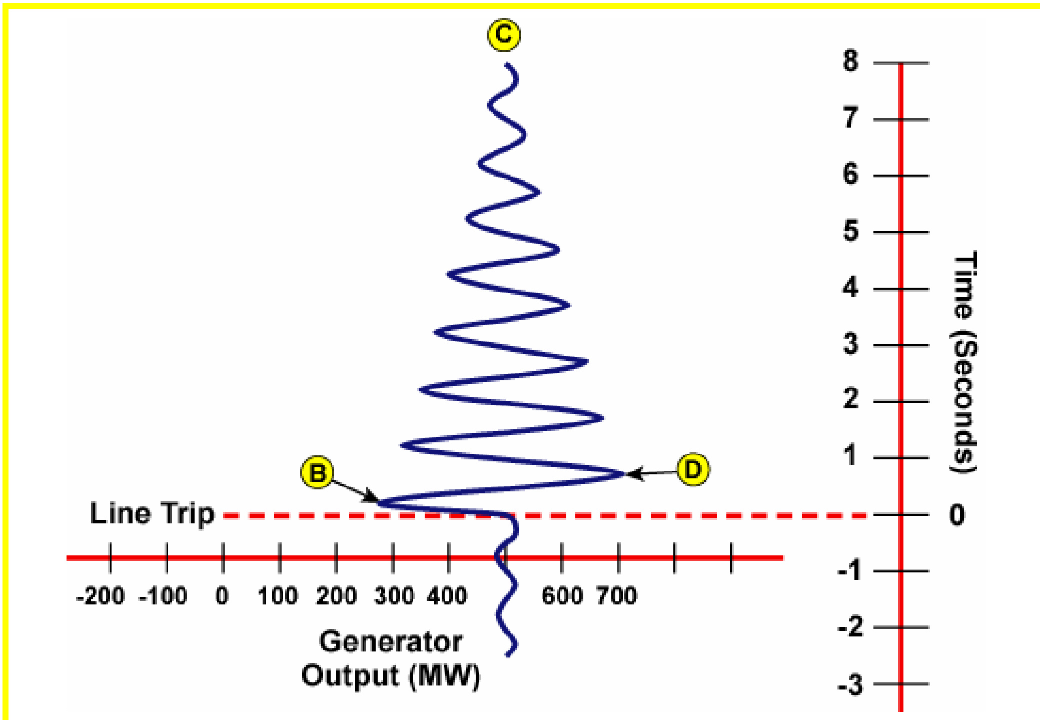


Figure 7-23
Strip Chart Illustration of Oscillatory Stability

7.7.2 Process of Oscillatory Instability

The power system illustrated in Figure 7-20 can also be used to describe oscillatory instability. The system is initially transmitting 500 MW across a two line transmission system to a large power system. The power-angle curve is given in Figure 7-24. The initial operating point is point “A”. Line #2 opens and the operating point immediately drops to point “B_1”.

At “B_1” the mechanical power input is greater than the electrical power output so the operating point slides up towards point “C”. The generator is spinning faster than synchronous speed at “C” so the operating continues on up to point “D_1”. At “D_1” the generator has returned to synchronous speed but the MW output is now greater than the mechanical power input. The generator must now decelerate which forces the operating point to slide back through “C” and back towards “B_1”.

If our system was oscillatory stable the operating point would continue to oscillate between points “B_1” and “D_1”. Each successive oscillation would be smaller (due to losses) until the operating point eventually settled at point "C". However, assume another factor now enters into the process. For example, perhaps this generator's excitation control system is not functioning as desired. This particular generator's excitation system is a modern high power, high speed system. The excitation system is configured to control the generator's voltage to within a target bandwidth.

Excitation systems are one possible cause of power system oscillations. Chapter 8 will expand on excitation system problems and describe several other causes of oscillations.

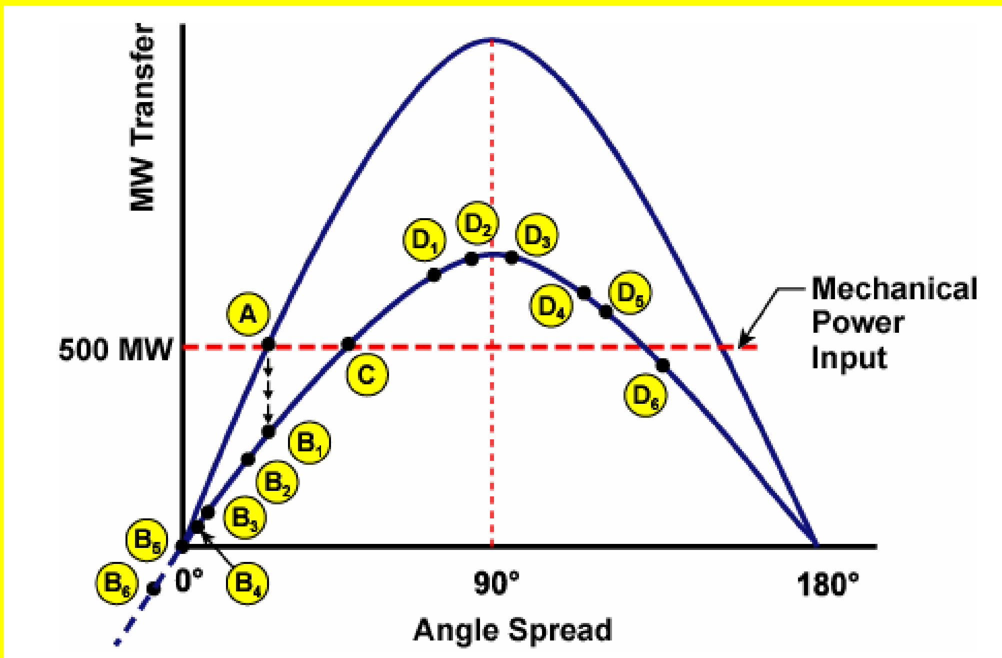


Figure 7-24
Power-Angle Curve for Oscillatory Instability

As the power oscillates back and forth from the generator to the system, the generator's voltage is also oscillating. The excitation system attempts to control this voltage but instead of helping the situation the exciter actually causes more severe problems. The excitation system makes its voltage adjustments at the wrong time. Instead of reducing the magnitude of the oscillations the excitation system causes the oscillations to grow in magnitude.

Return to Figure 7-24. Assume the generator has completed its first swing from "B_1" to "D_1" and is now swinging back towards "B_1". Naturally occurring power losses (damping) would be expected to halt the angle spread short of "B_1" and send the operating point back towards "D_1". However, our excitation system amplifies the oscillation and causes the operating point to swing beyond "B_1" to "B_2".

From "B_2" the operating point reverses itself (as expected) and swings past "D_1" to "D_2". Succeeding oscillations grow larger. From "D_2" the oscillation swings back to "B_3" and then back to "D_3". From "D_3" the swing is back to "B_4". Note that once the operating point swings past "B_5", the generator becomes a motor. This adds more energy to the oscillation. Finally the operating point swings past the mechanical power input line to "D_6".

At "D_6" the generator is oscillatory unstable. The oscillations have grown so large that the operating point has swung past the critical point (the mechanical power input line) and instability has resulted.

Figure 7-25 is a strip chart presenting the same data as is in Figure 7-24. Compare this strip chart with the oscillatory stable system illustrated in Figure 7-23. In the Figure 7-25 power oscillations do not dampen but rather grow in magnitude. Finally the power oscillations grow so large that protective relays in the system are forced to operate.

Note the unusual shape of the power flow oscillations at points D_4 and D_5. The power flow reaches its maximum value at 90°. As the angle increases past 90° the power flow reduces. If the angle spread reduces from a value greater than 90° back towards 90° the power flow will again start to increase. The movement past 90° and subsequent return to 90° causes the unusual shape of these power flow oscillations.

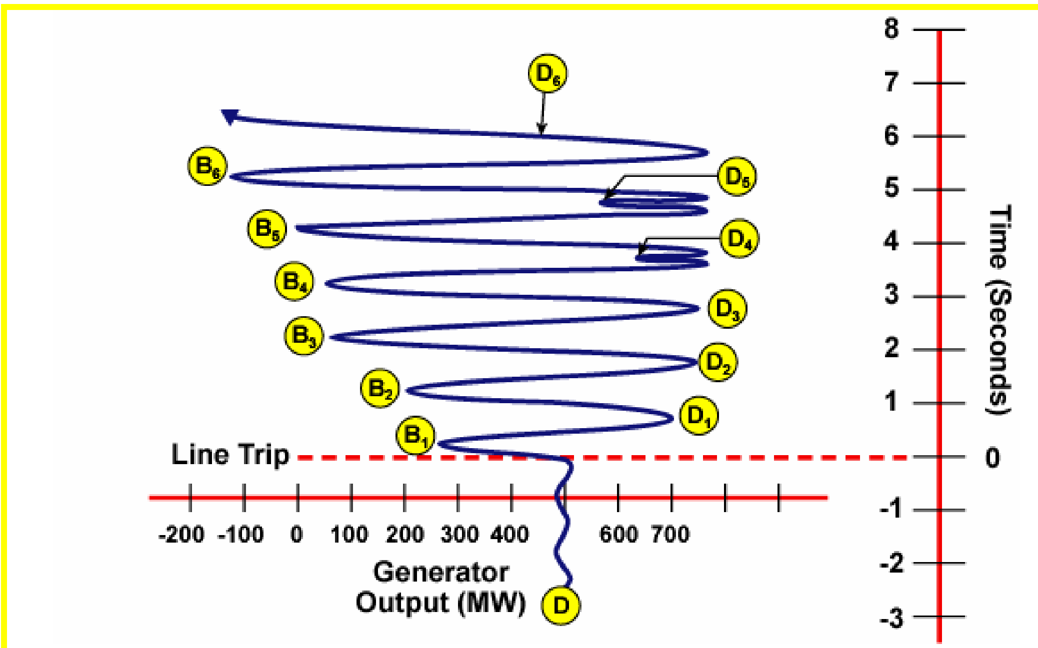


Figure 7-25
Strip Chart Illustration of Oscillatory Instability

7.8 Out-of-Step Protection

This section contains a very brief introduction to the protective relays used to detect out-of-step conditions.

7.8.1 Purpose of Out-of-Step Protection

Out-of-step harmful effects include high power flows, oscillating voltages and frequency deviations.

Out-of-step protective relays are designed to protect the power system from the harmful effects of out-of-step operation. Out-of-step protection may be installed on key transmission lines or in generating stations. When two large power systems are interconnected with a relatively weak transmission path, the weak connecting path is a good candidate for out-of-step protection. Many generators are also equipped with out-of-step protective relays.

7.8.2 Out-of-Step Protection Operation

Figure 7-26 is an "R-X" diagram. In Chapter 2 "R-X" diagrams were used to plot the operating characteristics of impedance relays. The "R-X" diagram in Figure 7-26 is for an impedance relay installed at bus "A". This zone #1 impedance relay is set to protect 90% of line section "A-B". If a fault were to occur within the impedance relay's protective zone, the relay would pick-up (activate) and trip the protected line's circuit breakers.

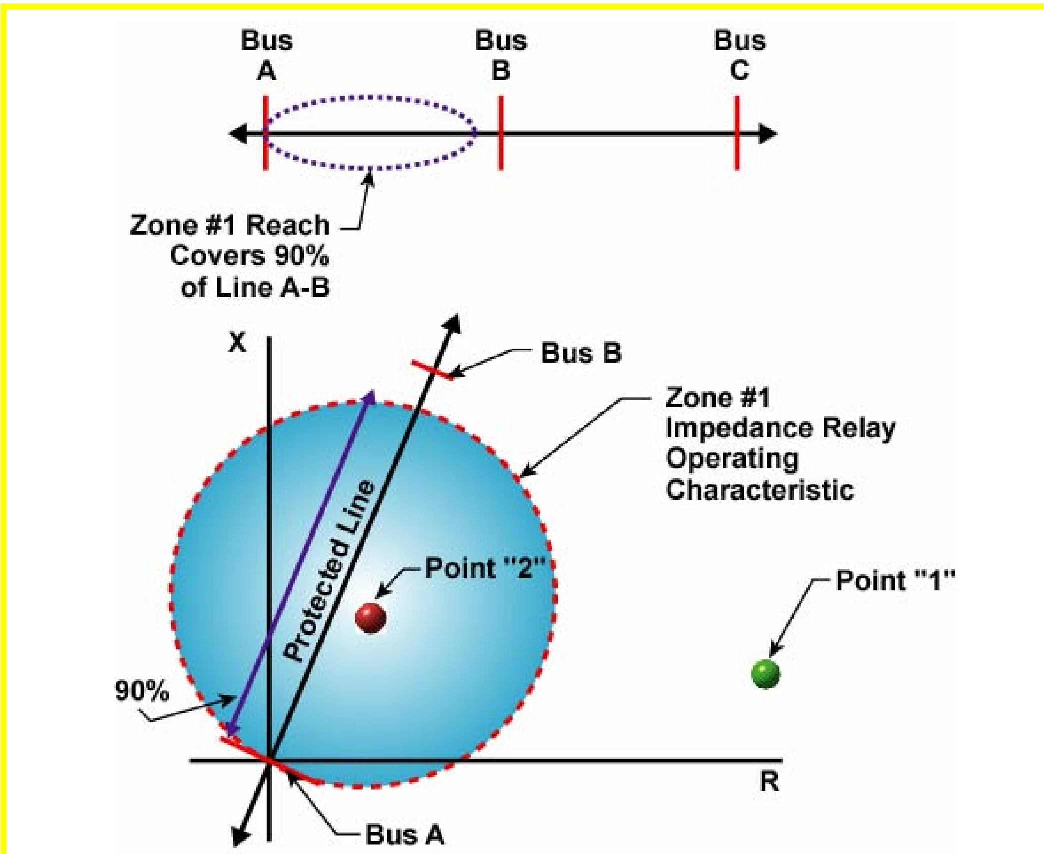


Figure 7-26
R-X Diagram for an Impedance Relay

A slanted line is shown in Figure 7-26 inside of the impedance relay's circular operating characteristic. This line represents the protected transmission line. Bus "A" is located at the origin of the circle. The protected line extends from the origin (bus "A") towards bus "B". Note how the zone #1 relay operating characteristic covers 90% of this protected line.

The impedance relay at bus "A" monitors the ratio of the voltage to the current. This ratio (V/I) is called the apparent impedance. If the relay's measured voltage falls or the measured current rises such that the apparent impedance falls within the circular operating characteristic of the relay, the relay will pick-up.

Any power flow value can be converted from a MW and Mvar format to an equivalent impedance. The formula for the conversion between power flow and impedance is:

$$\boxed{Z_{APP} = R + jX = \frac{|V^2|}{P - jQ}}$$

If the MW and Mvar flow values are known, the power numbers can be converted to an equivalent impedance. Assume that the power flow on the protected line in Figure 7-26 is 500 MW and 100 Mvar. This flow is out of bus "A" and into the protected line. If these flow numbers are converted to an equivalent impedance, the impedance value might plot on the "R-X" diagram as point "1". Note that this point is not within the relay operating characteristic so the relay will not activate for this flow level.

Assume that a fault occurs on the protected line. The power flow out of bus "A" to the fault changes immediately to 100 MW and 5000 Mvar. This flow is plotted as point "2" in Figure 7-26. Note that this apparent impedance will activate the relay. This is correct operation as a fault occurred on the protected line and the relay should activate.

When out-of-step conditions occur, power flows will swing wildly. MW and Mvar flow levels may get very large and also change directions. When the flow levels rise to high magnitudes impedance relays may falsely assume that a fault has occurred. Critical transmission lines may trip which further weakens the system and enhances the chances for system collapse.

Out-of-step protective relays are designed to distinguish between a fault and out-of-step conditions. Figure 7-27 illustrates a possible out-of-step protective relay. Out-of-step relays are impedance relays with additional features. Assume flow levels are such that the normal operating point is as labeled in Figure 7-27. If a fault were to occur on the line section that contains this impedance relay, the apparent impedance would rapidly move to within the relay operating characteristic. The important point is that the movement of the apparent impedance is very rapid following a fault.

If an out-of-step condition developed between the two ends of the system in Figure 7-27 the apparent impedance would also change. The time for the apparent impedance to move within the relay operating characteristic would be considerably longer that for a fault condition. It may take several cycles for the apparent impedance to move from the normal operating point to within the operating characteristic circle.

By measuring how long it takes for the apparent impedance to change one could tell if the impedance change was due to a fault or out-of-step condition. This is how out-of-step relays operate, by measuring how fast the apparent impedance changes.

Note the out-of-step tripping line in Figure 7-27. As the impedance changes it will first cross the operating characteristic at point "A". By measuring the time difference as the impedance locus moves from point "A" to "B" the relay can decide if a fault or out-of-step condition has occurred.

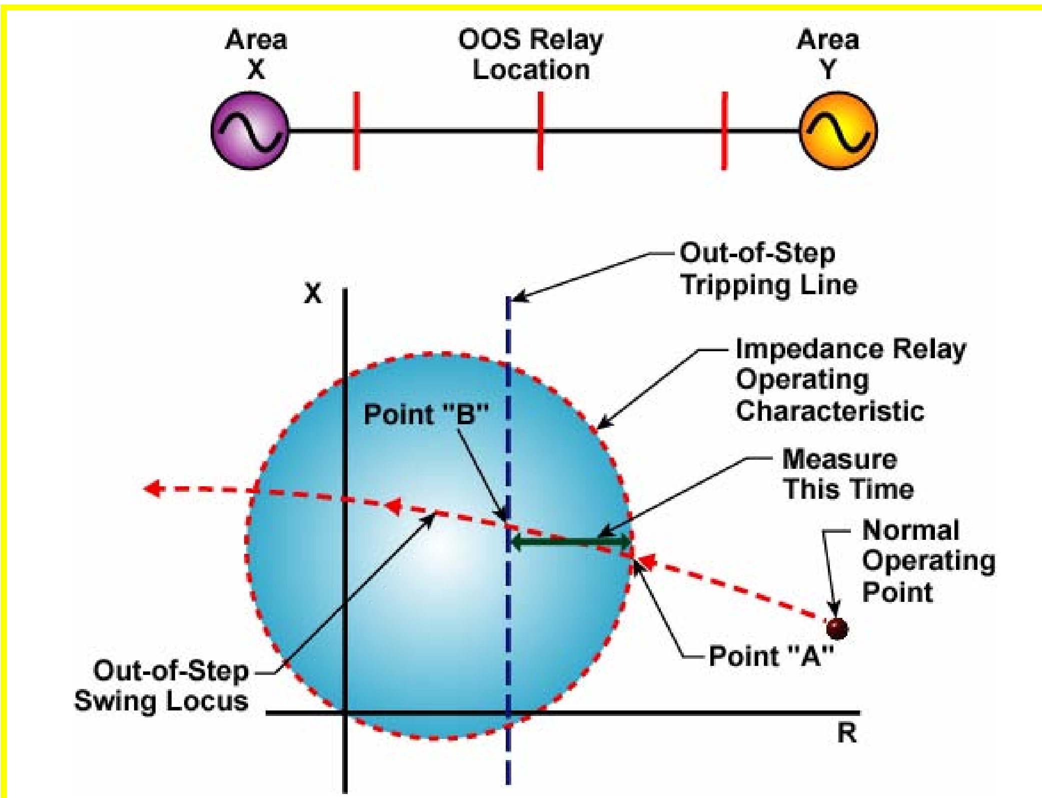


Figure 7-27
Out-of-Step Relay Characteristic

Out-of-step relays can be designed to be either tripping or blocking relays. Out-of-step blocking relays will prevent a relay operation if an out-of-step condition occurs. Out-of-step tripping relays will ensure relays activate during out-of-step conditions. Both types of relays are used to design an out-of-step protection program that trips only those lines the utility wants to trip and prevents (blocks) the tripping of others.

7.9 Angle Instability Example[9]

During the early morning hours of June 25th, 1998 the MAPP system was operating with heavy power transfers out of the MAPP Region east to the MAIN Region and south to the SPP Region. The sum of the loading on the three 345 kV lines connecting east and south from the Twin Cities of Minneapolis and St. Paul, Minnesota was approximately 1575 MW. 1575 MW is near the operating security limit for this transfer path. This transfer path is called the Twin Cities Export or the TCEX. Figure 7-28 contains a simple map which illustrates the physical location of the three 345 kV lines that form the TCEX.

[9] The disturbance description in this section is based on reference #8.

TCEX

1	Prairie Island – Byron 345 kV
2	King – Eau Claire 345 kV
3	Wilmarth – Lakefield Junction 345 kV

Figure 7-28
Twin Cities Area Map

At 01:34 CDT a west to east moving thunderstorm initiated a single line-to-ground fault on the Prairie Island to Byron 345 kV line (line #1 in Figure

7-28). This line is one of the three lines that form the TCEX and connects the Twin Cities south into Iowa and eventually to the Saint Louis area. The line was carrying approximately 640 MW at the time of the fault. While the fault was only temporary, a large power angle (approximately 42°) across the line's open circuit breaker prevented the system operator from reclosing the line. The 42° power angle exceeded the line's synch-check relay setting of 40°.

Note that this power system was in violation of NERC Policy #2 as it took longer than 30 minutes to return the system to within its operating security limits.

To return the tripped line to service, system operators ordered reductions in the TCEX scheduled power flow. The reductions in TCEX schedules were intended to reduce the power angle and allow the open circuit breaker to close. While this schedule adjustment and reclosing effort was in progress the King-Eau Claire 345kV line (line #2 in Figure 7-28) tripped from another single line-to-ground fault at 02:18 CDT. This line is also part of the TCEX transfer path and connects MAPP to MAIN and eventually to the Chicago area. This line is typically the most heavily loaded of the three 345 kV lines that form the TCEX. At the time of the trip the King-Eau Claire 345 kV line was loaded at approximately 1050 MW and the TCEX flow was approximately 1000 MW.

Shortly after the loss of the second 345 kV line critical lower voltage subtransmission lines began to trip due to the overloads caused by the outages of the two 345 kV TCEX lines. At 02:21 CDT cascade tripping of the remaining ties (including the last 345 kV line of the TCEX) between the northern MAPP Region and the rest of the Eastern Interconnection occurred. The islanded area initially consisted of large portions of Minnesota, North Dakota, South Dakota, Montana, and Wisconsin in the U.S. and the Canadian provinces of Manitoba and Saskatchewan.

In terms of the amount of load loss (approximately 1000 MW) this disturbance was not that severe. However, two very interesting events occurred during this disturbance that make it a valuable learning tool.

The initial island was quite large and included several states and provinces. Shortly after the initial island formation, an HVDC line connecting the western and eastern portions of the island tripped. This HVDC line trip caused cascading AC line tripping and the initial island broke into two separate islands. Figure 7-29 illustrates the boundaries of the initial and subsequent islands.

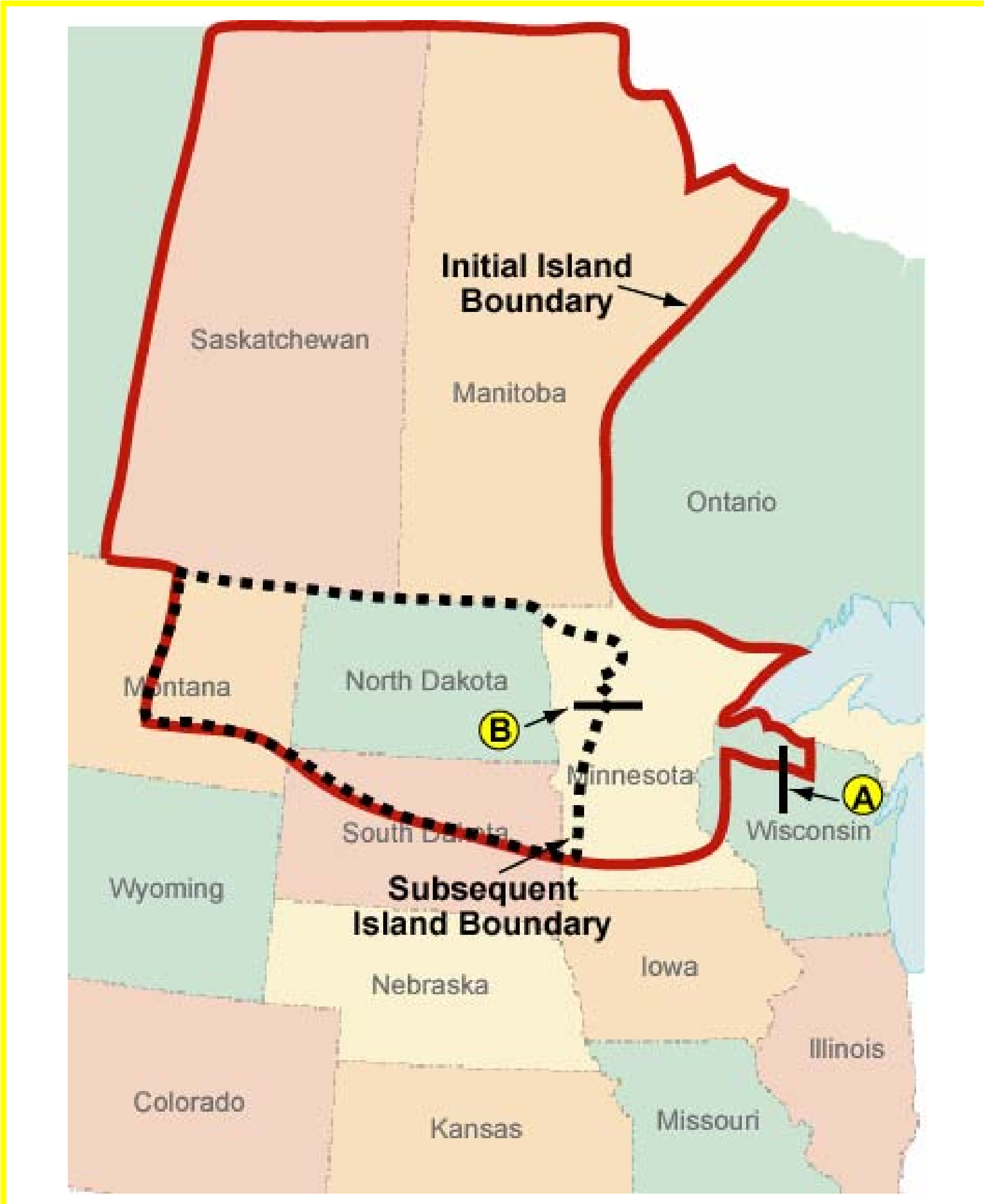


Figure 7-29
Island Formations

Ontario also suffered during this disturbance. The entire western portion of the province was blacked out.

Figure 7-30 is an illustration of the frequencies during the disturbance. Note in the figure that initially the entire island frequency rose to about 61 HZ. Then several minutes after the initial disturbance the initial island breaks into two islands. The initial island frequency rapidly settles back close to 60 HZ while the subsequent island frequency rises almost to 62 HZ and it takes almost an hour before it is back to 60 HZ.

When the initial island broke into two pieces, the eastern and northern portions automatically closed back in to the rest of the Eastern

Interconnection. A 115 kV line (point A in Figure 7-29) had an automatic synchronizer installed in its circuit breaker. Twelve seconds after the breakup of the initial island into two pieces, this automatic synchronizer was able to close the 115 kV circuit breaker and the Manitoba, Saskatchewan, Wisconsin and eastern Minnesota portions of the initial island were reconnected to the Eastern Interconnection. The North and South Dakota portions of the island were not reconnected until approximately one hour later.

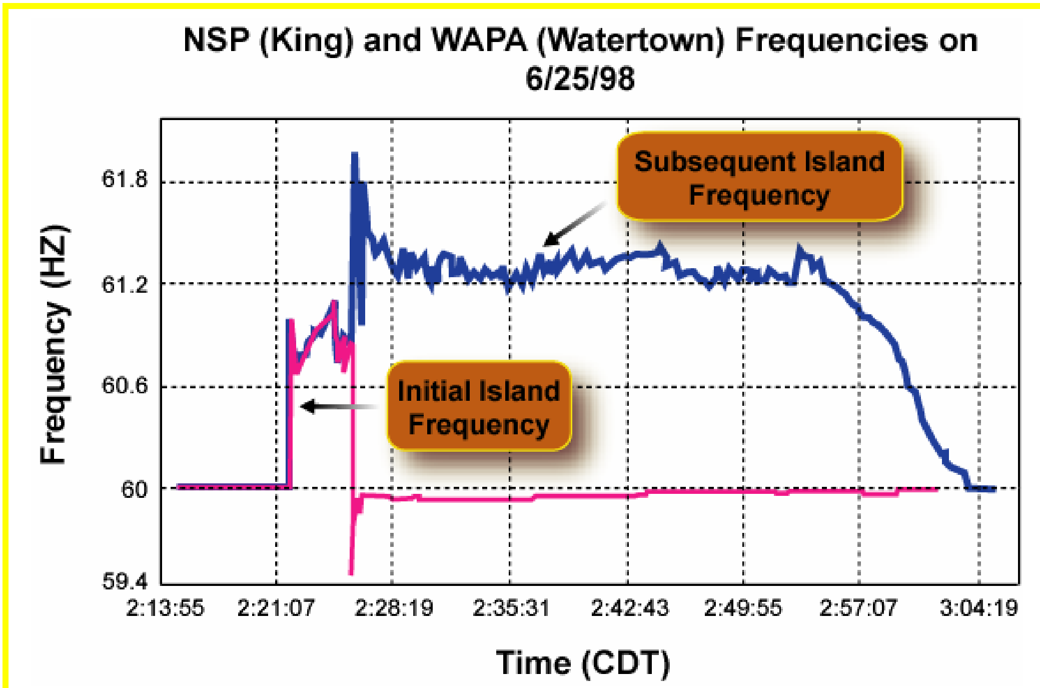


Figure 7-30
Island Frequencies

The two islands remained connected through the 115 kV line even though their frequencies were different by 1.5 HZ.

Figure 7-31 is a plot of a 138 kV voltage in the area of point B in Figure 7-29. Note the oscillations in this voltage plot. There are two oscillations present in the plot. One oscillation is at approximately 1.5 HZ and the second, slower oscillation, is at 0.15 HZ. This plots voltage data was taken immediately after the initial island broke into two separate islands. There was an out-of-step blocking relay on a 115 kV line in the area of point B. This relay prevented the 115 kV line from tripping during an out-of-step event. The plot in Figure 7-31 is actually showing the slip frequency between the subsequent island and the rest of the Eastern Interconnection. The slip frequency is 1.5 HZ.

The second lower frequency (0.15 HZ) is due to the weak nature of the power system during this disturbance. These low frequency oscillations are described in Chapter 8 of this text. These low frequency oscillations are the main reason for the installation of power system stabilizers (PSS).

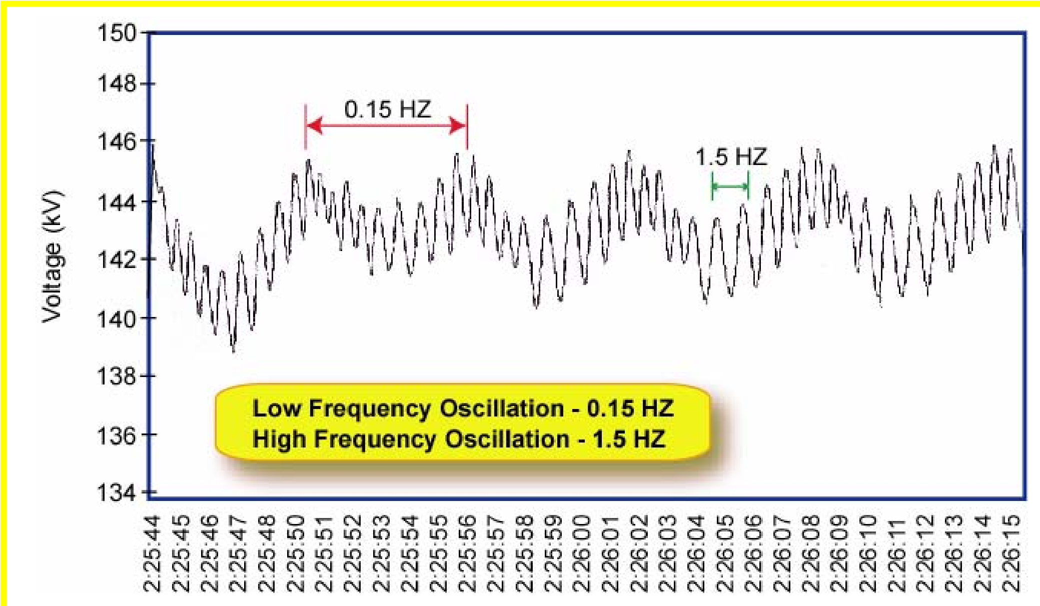


Figure 7-31
Out-of-Step Voltage Oscillations

7.10 Role of the System Operator

A system operator's role in avoiding angle instability is important but often limited. Angle stability is not like voltage control in which a system operator may have the luxury of time to correct a voltage deviation. Angle instability can develop very rapidly, before an operator has a chance to respond. This section will state some actions that a system operator can take to assist with maintaining angle stability.

7.10.1 Enforce System Operating Guidelines

The most important role a system operator can perform to maintain angle stability is to operate the power system within the published operating guidelines for their particular system. These operating guidelines often address power transfer limits for major transmission paths. Depending on the power system, the transfer limits may or may not be based on angle stability considerations.

Engineering support personnel do not use power-angle curves to determine angle stability related power transfer limits. The interconnected power systems are much too complicated for these simple graphical tools. Engineers use computer simulations of power systems to determine stability limits and system transfer capabilities. These computer software tools are collectively called angle stability programs.

Where possible, stability programs are validated by comparing their predicted results to actual system disturbance.

Angle stability computer studies are a simulation of the power system's response to disturbances. For example, engineers may study the system's response to a 3Φ fault on the high side bus of the largest system generator. The study results are usually more conservative than the actual system response. Many experienced system operators voice their complaints about leaving too much transfer capability unused. The problem is that the computer simulations do not completely represent the actual power system. If errors are going to be made, they should be made on the conservative side. This is why conservative operating limits are often used.

7.10.2 Additional Actions to Maintain Angle Stability

Other actions available to a system operator to assist with maintaining angle stability include:

- Maintaining system voltage levels as high as possible (within safe voltage limits). The higher the voltages on the system, the less the required angle to transmit a given amount of active power. The lower the initial angle, the more likely the system will survive a severe disturbance.
- Maintaining the system impedance as low as possible. The lower the system impedance, the lower the required angle to transmit a given amount of active power. Keeping all transmission lines in service and (when available) inserting series capacitors lowers system impedance and reduces the needed angle.
- Ensure that generator voltage regulators are operated in automatic mode. Strong system voltages help avoid angle instability. When disturbances occur, system voltage will be impacted. Generators can respond with additional reactive power if their voltage regulators are in automatic mode. This reactive support could be the difference between angle stability and instability.

Pilot schemes were introduced in Chapter 2. Pilot schemes are transmission line protection schemes that rely on telecommunication between the line's terminals.

- Ensure that high speed protective relay systems are in-service as intended. If faults occur within the transmission system it is important that these faults be cleared as soon as possible. The longer the faults persist, the greater the accelerating energy and the more likely that instability will result. System operators should pay special attention to pilot protective schemes. When protective relay telecommunication systems are removed from service, critical system protection may be compromised.

Summary of Angle Stability

7.1.1 Angle & Voltage Stability

- Voltage is the key to the overall stability of a power system. Voltage stability is related to the magnitude of the system voltages. Angle stability is related to the angular separation between points in the power system.

7.2.1 Changing Torque & Power Angles

- When a power system is angle stable it has sustained torque and power angles of less than 90°. The torque and power angles may temporarily rise above 90° but only for short periods of time.
- When a generator is in-step with the power system its rotating magnetic field rotates at the same speed as the system's field. When a generator is out-of-step, its magnetic field must have rotated at a different speed than the system.
- Torque and power angles are changed by accelerating one section of the power system with respect to another section. If a generator is running faster than synchronous speed, its torque angle is increasing. If a generator is running slower than synchronous speed, its torque angle is decreasing.

7.2.2 Out-of-Step / Loss of Synchronism

- There are many terms used to indicate that a system is angle unstable. Loss of synchronism, slipping poles, and out-of-step are a few of the more common terms.

7.2.3 Angle Stability & Generator Speed

- When two points on the power system sustain operation at different frequencies the angle between the two points will eventually increase past 90° and move on toward 180° and even larger angles.

7.2.4 Out-of-Step From a Voltage Perspective

- Each time two connected points in the power system pass through an angle spread of 180°, the system will experience a point with zero voltage. The transmission system between the two points will behave as if it sees a 3Φ fault.

7.2.5 Relative Nature of Angle Stability

- A system that is angle stable can become angle unstable only after a period of relative acceleration. One part of the system must accelerate with respect to another part for the angle spread to grow and the system to become unstable.

7.2.6 Rotor Dynamics

- When the mechanical power input to the rotor exceeds the MW output, the rotor will store the excess energy and accelerate. When the power input to the rotor is less than the MW output, the generator will draw the difference from stored energy and decelerate.

7.3.1 Review of Active Power Transfer Equation

- Whether using the power angle or the torque angle, the active power transfer is calculated using the same active power transfer equation:

$$\boxed{P_S = \frac{V_S \times V_R}{X} \sin \delta}$$

7.3.2 Review of Power-Angle Curves

- The power-angle curve is a plot of the MW transferred between two buses as the angle spread is varied. The operating point (MW & δ) will always lie on the power-angle curve.

7.3.3 Maximum Angle Spread

- The theoretical maximum system angle spread is 180°. The largest angle spreads across the interconnected systems of NERC are approximately 120°.

7.4.1 Angle Stability Classifications

- There are three environments in which angle stability can be viewed: steady state, transient, and oscillatory.

7.4.2 Introduction to Angle Stability Classifications

- For steady state instability to occur, the power system is gradually pushed beyond its means to transfer electrical power. No large disturbance needs to occur.

- Transient stability is the study of whether a power system can survive following a severe disturbance.
- Oscillatory stability is the study of whether a power system can survive periods of oscillations.

7.5.1 Process of Steady State Stability

- The process of steady state stability was described and illustrated using power-angle curves and power-circle diagrams.

7.5.2 Example of Steady State Instability

- An example of steady state instability was illustrated. A generator's voltage regulator was placed in manual mode. The system backed into a condition of steady state instability as voltage declined.

7.6.1 Process of Transient Stability

- The process of transient stability was described and illustrated using power-angle curves.
- The equal area criterion states that the amount of energy required to slow the rotor to synchronous speed is equal to the amount of energy that was added to accelerate it from synchronous speed. If the decelerate area cannot match the accelerate area instability will occur.

7.6.2 Process of Transient Instability

- The process of transient instability was described and illustrated using power-angle curves.
- The initial system loading level is key to transient stability. The more stressed the system is initially, the greater the chances for transient instability following a disturbance.

7.6.3 Transient Stability Following a Fault

- How long a fault is applied is critical to transient stability. The faster the fault is cleared, the greater the chances of avoiding angle instability.

7.6.4 Further Observations with Power-Angle Curves

- High speed reclosing may enhance or detract from transient stability depending on if the reclosing effort is successful.
- Steam generators may use a process called fast valving to achieve a rapid reduction in mechanical power input.

- Braking resistors are large resistive loads. While in-service a braking resistor slows the system down.

7.7.1 Process of Oscillatory Stability

- The process of oscillatory stability was described and illustrated using power-angle curves and simulated power flow strip charts.

7.7.2 Process of Oscillatory Instability

- The process of oscillatory instability was described and illustrated using power-angle curves and simulated power flow strip charts.
- Excitation systems are a key factor in the process of oscillatory instability.

7.8.1 Purpose of Out-of-Step Protection

- Out-of-step protective relays are designed to protect the power system from the harmful effects of out-of-step operation.

7.8.2 Out-of-Step Protection Operation

- Out-of-step relays are impedance relays with additional features.
- Out-of-step relays distinguish faults from out-of-step conditions by measuring how fast the apparent impedance changes.
- Out-of-step relays can be designed to be either tripping or blocking relays. Out-of-step blocking relays will prevent a relay operation if an out-of-step condition occurs. Out-of-step tripping relays will ensure relays activate during out-of-step conditions.

7.9.1 Angle Instability Example

- An angle instability example that occurred June 25, 1998 in the MAPP Region was described.

7.10.1 Enforce System Operating Guidelines

- The most important role a system operator can perform to maintain angle stability is to operate the power system within the published operating guidelines for their particular system.

7.10.2 Additional Actions to Maintain Angle Stability

- Other actions available to a system operator to assist with maintaining angle stability include:

- Maintaining system voltage levels as high as possible
- Maintaining the system impedance as low as possible
- Ensuring that generator voltage regulators are in automatic mode
- Ensuring that high speed protective relay systems are in-service

Angle Stability Questions

1. The loss of the magnetic bonds that bind together the elements of a power system is known as:

   A. Angle stability

   B. Loss of synchronism

   C. Out-of-step

   D. All of the above

2. If a 2-pole generator's rotor is spinning at 3601 RPM while the generator is connected to a 60 HZ system, how fast is the generator's torque angle changing?

   A. 3 degrees per second

   B. 0 degrees per second

   C. 9 degrees per second

   D. 6 degrees per second

3. Neglecting losses, the difference between a generator's mechanical power input and electrical power output is called:

   A. Relative power

   B. Synchronizing power

   C. Stability power

   D. Accelerating power

Match a type of angle instability from the left column with a unique definition from the right column:

4. Steady state instability	A. Rapidly developing event
5. Transient instability	B. Excitation systems are common cause
6. Oscillatory instability	C. Slowly developing event

7. According to the equal area criterion for transient stability:

   A. The torque angle must never exceed 90 degrees

   B. The accelerating area must exceed the decelerating area

   C. The decelerating area must at least match the accelerating area

   D. None of the above

8. A generator is angle unstable whenever its torque angle exceeds 90 degrees.
   - A. True
   - B. False
9. High speed transmission protection is a benefit to angle stability because:
   - A. Fault duration is reduced
   - B. Accelerating time is reduced
   - C. Angle spread is reduced
   - D. All of the above
10. The primary difference between an out-of-step event and a fault is:
    - A. Out-of-step events are detected by distance relays while faults are not
    - B. Faults are detected by distance relays while out-of-step events are not
    - C. The location at which the low voltage occurs
    - D. The speed at which the impedance changes

Unfortunately most of the available references for angle stability tend to be very theoretical and not well suited to a system operator audience.

Angle Stability References

1. Electrical Transmission and Distribution Reference Book—A text by the Westinghouse Electric Co. (Now published and owned by ABB Power Systems, Inc.) Copyright 1964, fourth edition.

   This is the most complete reference available on power systems theory and operation although somewhat out-of-date. Chapter 13 addresses angle stability including the use of power-angle curves.

2. Power System Analysis—A revision of the text by Mr. William Stevenson. Revision authors were the late Mr. Stevenson and Mr. John Grainger. Text was published by McGraw-Hill in 1994.

   An excellent text that while engineering oriented may still be useful to system operators. Chapter 16 addresses angle stability.

3. Power System Control and Stability—A text by Mr. A.A. Fouad and Mr. P.M. Anderson. Text was published by Iowa State University Press in 1977.

   This text contains a wealth of information on angle stability. The reading level is engineering oriented and the text is likely not suitable for a system operator audience.

4. Electrical Power Systems Design and Analysis—A text by Mr. Mohamed E. El-Hawary. Text was published by Reston Publishing Co. in 1983.

   This text is more easily read than most of the available references on angle stability.

5. Power System Stability—A three volume set of texts by Mr. Edward W. Kimbark. These texts were originally published in the 1950s.

   Volume #3 was a useful reference in the preparation of this chapter.

6. Power System Stability and Control—A volume in the EPRI Power System Engineering Series. Written by Mr. Prabha Kundar and published by McGraw-Hill in 1994.

   An advanced, highly mathematical text that includes a complete treatment of the topic of angle stability.

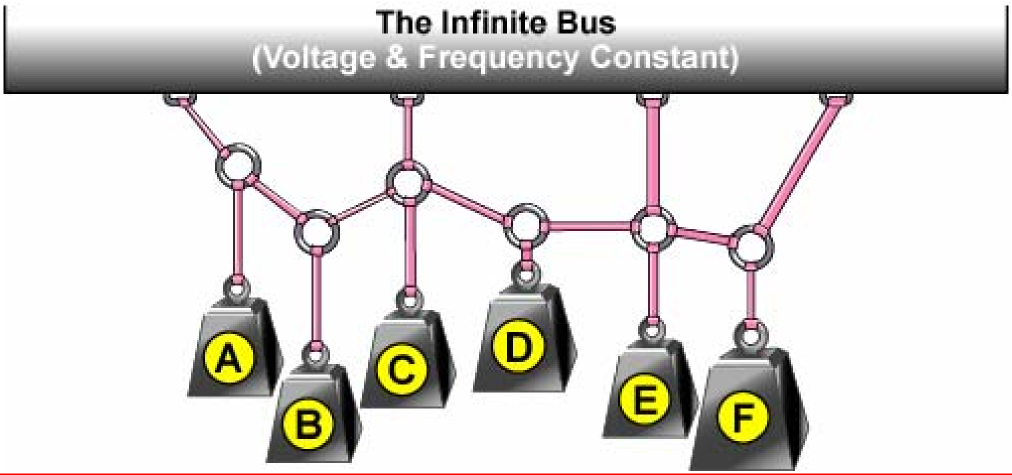
7. Electric Energy Systems Theory—A text by Mr. Olle I. Elgerd. Published by McGraw-Hill in 1982.

   This text was valuable in the preparation of this chapter. Chapters 4 and 12 are useful for understanding the basic angle stability concept.

8. Northern MAPP/Northwester Ontario Disturbance June 25, 1998—Disturbance report by MAPP written September 2, 1998.

   Excellent disturbance report. Clearly written with many insights into how a power system reacts in a disturbance.

8
POWER OSCILLATIONS



8.1 Introduction to Power Oscillations

Low frequency power oscillations may be triggered by many events in the power system. Most oscillations are damped by the system, but undamped oscillations can lead to system collapse.

8.2 Power Oscillations on a Sample System

Oscillations develop as a result of rotor acceleration and/or deceleration following a change in the MW output of a generator.

8.3 Natural Frequency of Oscillation

Low frequency inter-area oscillations are less damped than higher frequency local area oscillations and are more likely to cause power system problems.

8.4 Oscillations and Excitation Systems

PSS or power system stabilizers are used to correct the harmful effects of fast excitation systems and help reduce system oscillations. PSS usage is mandatory in some operating regions.

8.5 Additional Causes of Oscillations

Large cyclic loads, incorrect governor droop settings, HVDC systems, and generator pole slipping may lead to power oscillations.

8.6 Role of the System Operator

Power system oscillations are difficult to monitor. To prevent oscillations, the system operator should hold power transfers within established limits and maintain strong system voltages and adequate reactive reserve margins.

8.1 Introduction to Power Oscillations

This chapter describes the causes, effects, and methods of controlling low frequency power system oscillations. Any disturbance to the system—even minor—will lead to the system's generators oscillating about their eventual operating point. Oscillations occur when load changes, when lines are switched, when generators trip, and when faults occur. Oscillations may also be triggered by generator controls, such as the exciter or governor control systems.

An oscillating power system can be visualized with the help of an equivalent system. Figure 8-1 is the mechanical equivalent of a power system. The weights represent generators while the rubber bands represent transmission lines. The more massive the rotating components of the generator, the larger the weight. The higher the voltage (and greater the capacity) of the transmission line, the thicker the rubber band.

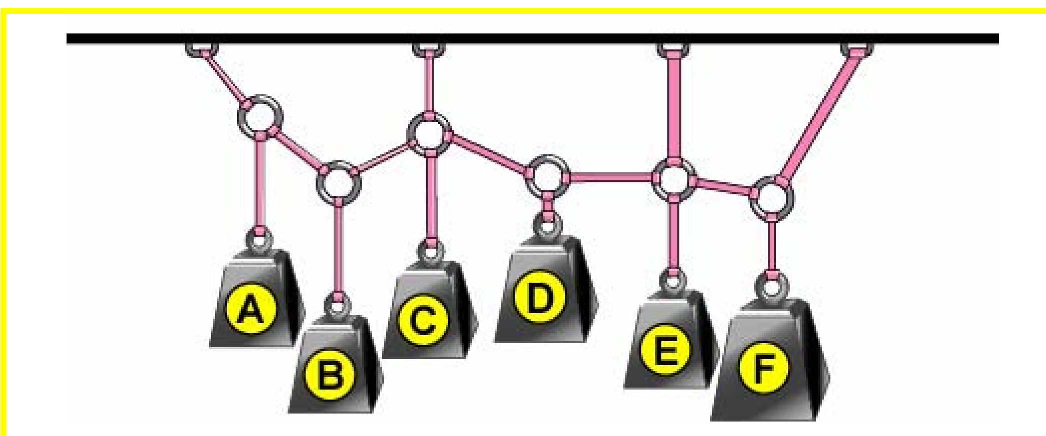


Figure 8-1
Rubber Band – Weight Analogy

Damping refers to the ability of the power system to reduce the oscillation amplitude. Damping consists of energy losses (I^2R) and several other factors. Damping is described in greater detail in Section 8.1.6.

A disturbance to the power system is equivalent to tugging on one of the weights (generators) or cutting one of the rubber bands (transmission lines) in Figure 8-1. Once a weight is tugged or a rubber band cut, the entire system will enter into a period of rhythmic oscillations. The oscillations will last until the damping effects of the power system reduce their magnitude to harmless, unnoticeable levels.

Oscillations are hardly an unusual event. The power system will naturally enter periods of oscillation as it continually adjusts to new operating conditions. Typically the amplitude of the oscillations is small and their lifetime short. When the amplitude of the oscillations becomes large or the oscillations are sustained a response may be required. A system operator may have the opportunity to respond and eliminate harmful oscillations or, less desirably, power system relays may activate to trip system elements. In Chapter 7, three types of angle stability were described. Oscillatory stability was one of the three types. Growing or large sustained oscillations are a symptom of oscillatory instability.

The focus of this Chapter is on the oscillatory behavior of the power system. The means by which low frequency oscillations occur, how they are controlled, and the role of the system operator in responding to these oscillations will be explored.

8.1.1 Definition of Oscillations

Apparent impedance is the ratio of voltage to current (Z=V/I) that distance (impedance) relays measure.

The power system normally oscillates at a frequency of 60 HZ. This 60 HZ oscillation of the voltage and current is expected and desired in an AC power system. When unwanted oscillations occur it is not only the MW and Mvar that oscillate. Voltage, current, frequency, and apparent impedance will also oscillate at frequencies other than 60 HZ. This type of oscillation may be damaging to the power system. When the terms oscillating, ringing, beating, or swinging are used these terms are referring to these unwanted oscillations.

All oscillations are triggered by a change to system equipment status or in system conditions. For example, a change in load, a fault, or a control system (exciter, governor, etc.) adjustment can trigger an oscillation. The power system's generating units respond to the system change and drive the system into oscillations in an attempt to find new operating points. The movement of the system's generators is typically the driving force behind oscillations.

When considering the composition of an electric power system it is understandable that oscillations occur. A power system contains several types of energy storage mediums. Energy is stored in the rotating mass of system equipment. Energy is stored in the electric fields of capacitors and the magnetic fields of inductors. When the storage balance is disturbed, oscillations will occur.

In Chapters 2 and 7 the need for relative acceleration to change a generator's torque angle and increase its MW output was emphasized. Energy must be added to the generator's rotating mass to increase its speed of rotation above synchronous speed. This rotational energy storage increase results in a torque angle change and an increase to MW output. Before the generator can settle down to its new operating point the energy used to increase its speed must be removed. An oscillation follows as the extra stored energy is gradually removed and the generator settles down to its new operating point.

Any time MW flow changes, the power system's generators will adjust their operating points. These adjustments result in oscillations. The oscillations may be small—such as the oscillations caused by normal load changes—or may be large, such as the oscillations caused by the loss of a major generating unit. When a small or large system disturbance occurs, the system's generators will respond by varying power outputs. Typically, all the system's generators will eventually settle at new operating points. When all the units have settled at new operating points the units are in equilibrium and the oscillation has dissipated.

8.1.2 Triggering Events

Oscillations require some initiating or triggering event to start. The event may not be noticeable. For example, a gradual increase in system load level may trigger an oscillation. Power system equipment, such as large motors or high voltage direct current (HVDC) systems may trigger an oscillation. The size of the triggering event usually has an impact on the resultant oscillation.

HVDC systems are described in Chapter 10.

For example, if a large generator trips, one typically would expect larger power oscillations than if a small, lightly loaded transmission line trips. Note how the preceding statement is qualified with the word "typically". At times even a minor event, such as the addition of a small load, may trigger an oscillation. This oscillation may then grow in size until the system is forced to respond with generator trips, line trips, etc.

8.1.3 Mechanical Analogy for Oscillations

Our equivalent mechanical system for viewing oscillations is enhanced and repeated in Figure 8-2. In this equivalent system the rotating mass of the system generators is represented by weights. The heavier the weight, the greater the inertia of the generator. As you recall from Chapter 4, the inertia of a generator is a property of the generator that resists changes to its speed of rotation. In general, the larger the generator, the greater its inertial energy. Large generators with high inertia will not change speed easily, which is good for normal frequency control. Once a steady 60 HZ frequency is established, the large generators assist the system in maintaining a 60 HZ frequency.

The infinite bus represents a large power system in which the voltage and frequency do not change.

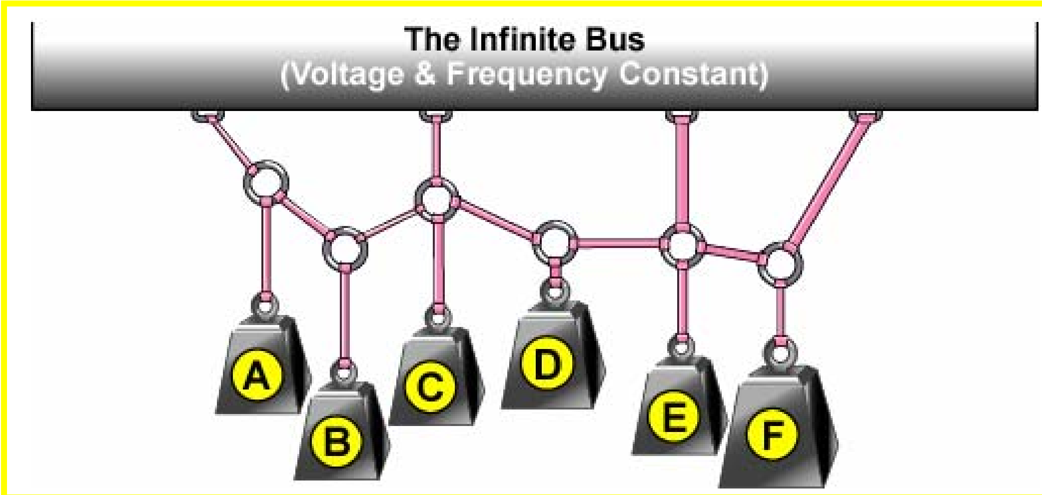


Figure 8-2
Rubber Band – Weight Analogy

The rubber bands represent the transmission line's inductive reactance. (The transmission line's resistance is ignored in this section.) The infinite bus at the top of Figure 8-2 represents a very large power system to which our smaller system is connected. Nothing we do within our small system noticeably affects this infinitely large power system. An infinite bus will maintain a constant voltage and a constant 60 HZ frequency.

Disturbing a real power system is equivalent to tugging on a weight in the equivalent power system of Figure 8-2. If you pull on weight "D" and then release, weight "D" will oscillate. In addition, all the other weights attached to the entire rubber band system will oscillate. Disturbing the generator represented by weight "D" disturbs the entire system. This is also true in the interconnected power system. When one generator starts oscillating it will likely cause other system generators to start oscillating. (The magnitude of the oscillations depends on several factors including the strength of the power system.) Eventually the oscillations will die out as system losses and other damping effects reduce the oscillation's amplitude.

Several other points can be illustrated with the equivalent system of Figure 8-2:

- If you pull on weight "A" it will oscillate. Weight "B" will also oscillate but not as much as weight "A". Weights "C", "D" "E", and "F" will oscillate even less than weights "A" and "B". The farther away a weight is from the initial disturbance, the less it oscillates. This is typical in a real power system. Generally, the closer (in electrical distance or ohms) to the disturbance, the greater the oscillations experienced.
- Weights "E" and "F" represent two generators. Weight "F" is larger than weight "E" so it has a larger inertia and, most likely, is a larger generator.

If weights "E" and "F" are pulled on with the same force it will be easier to start weight "E" oscillating. It takes a greater tug to get the larger weight "F" moving. However, once weight "F" starts moving it is difficult to stop it. The larger the inertia of the generator the harder it is to start oscillating. However, once you initiate oscillations in a large generator it will typically sustain the oscillations for a longer period of time than the small generator.

- Small generators may start oscillating easily but typically have little effect on the power system. Larger generators are more difficult to start to oscillate but once started, may trigger oscillations so large that the entire system suffers.
- If you tug on weight "A", it will cause a larger oscillation than if you tug on weight "E". Both generators may be the same size but weight "A" is connected to a thinner set of rubber bands. The weaker the system the generator is tied to, the larger the oscillations that will result following a disturbance. In addition, if a large enough oscillation is started in weight "A" it could break the weak rubber bands used to connect it to the system. This is equivalent to a generator going out-of-step.
- If any of the rubber bands in Figure 8-2 are cut oscillations will begin. This is equivalent to tripping a transmission line. The thicker the rubber band that is cut the greater the ensuing oscillations. The location of the rubber band is also important. For example, cutting one of the large rubber bands that connect to weights "E" or "F" will have a significant impact.

8.1.4 Typical Oscillation Frequencies

When oscillations appear on the power system, they will typically be at much lower frequencies than the standard 60 HZ power system frequency. Typical oscillations may vary from three cycles per minute (0.05 HZ) to 180 cycles per minute (3 HZ). The frequency of the oscillation will depend on what portions of the system are oscillating. For example, the most noticeable power flow oscillations on a major 500 kV line may have a frequency of 0.3 HZ (18 cycles per minute), while oscillations confined to a single generating unit may be in the neighborhood of 2 HZ or 120 cycles per minute.

Oscillations can also occur at much higher frequencies than 3 HZ, such as from 30 to 50 HZ. A type of higher frequency oscillation called sub-synchronous resonance (SSR) is described in Chapter 9.

8.1.5 Oscillation Envelopes

Three-phase power flow oscillations are easy to visualize as normal power flows are relatively constant values. Figure 8-3 contains a section of a strip-chart that illustrates how 3Φ power flows might typically vary across an hour. Note that this strip-chart does not show the complete power oscillation but only the end-points of many oscillations. If the time resolution was smaller, a strip-chart could show the actual power oscillations. For example, if the power oscillation had a 1 HZ frequency, the strip chart would need to record an entire cycle of oscillation each second. Most control center strip-charts are not capable of this fine a time resolution.

The time scale for this strip-chart is not fine enough to show the actual power oscillations. Only the end-points of many oscillations are recorded.

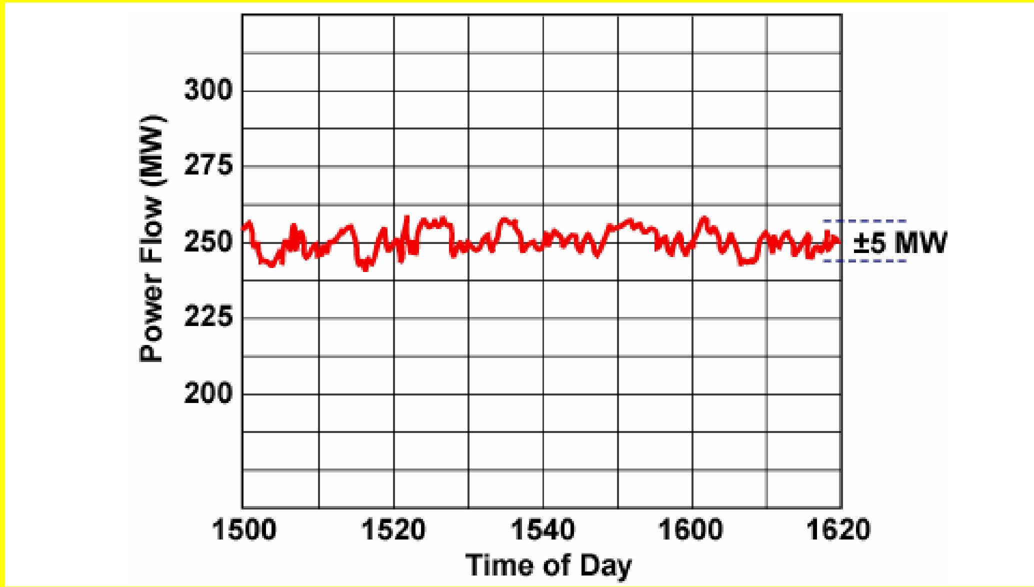


Figure 8-3
Three-Phase Power Flow on a Strip-Chart

Oscillations in voltage and current values are not as simple to view as power flow oscillations. Voltage and current are already oscillating at the 60 HZ power system frequency. When an additional oscillation (at a lower frequency) appears in a voltage or current waveform, the two oscillations are combined with one another.

Figure 8-4 illustrates how 60 HZ oscillations and unwanted low frequency oscillations combine. Figure 8-4 (a) is a normal 60 HZ waveform for the system current. Figure 8-4 (b) is a low frequency power oscillation that was caused by some disturbance. Figure 8-4 (c) illustrates the impact of the low frequency power oscillation on the 60 HZ current waveform. This is how the system current would appear in an oscillograph.

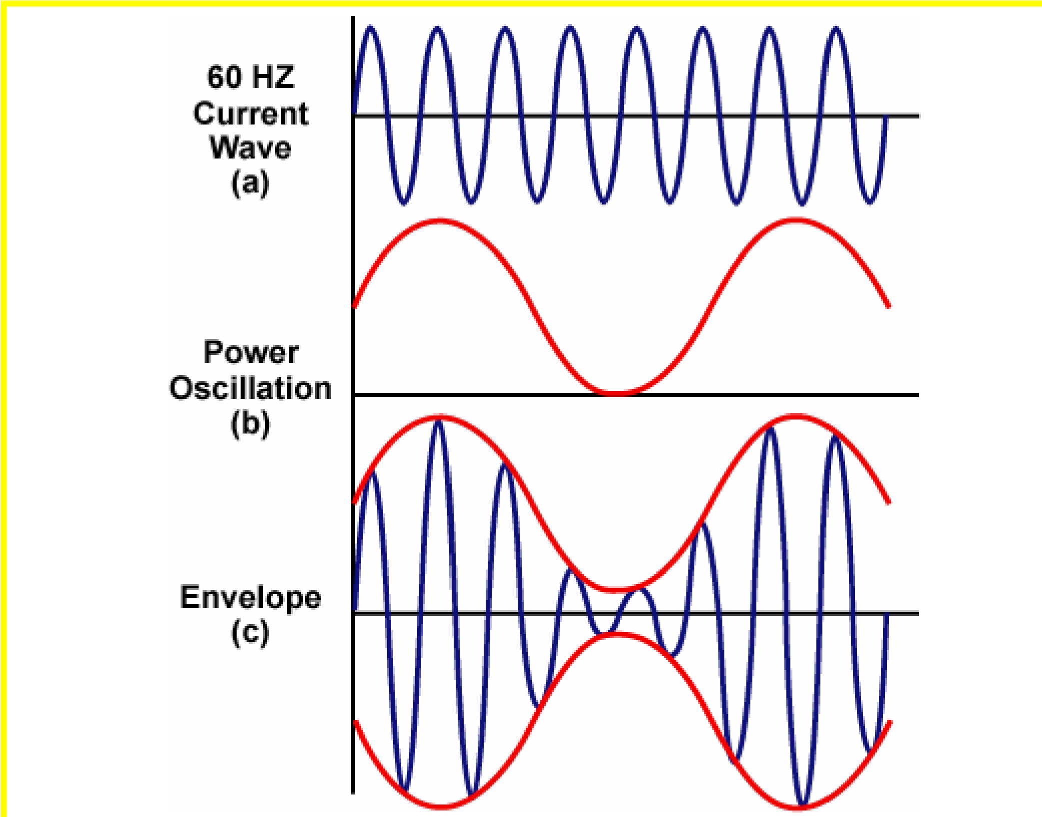


Figure 8-4
Current Oscillation Envelope

Note how the power oscillation forms an invisible boundary for the current wave to oscillate within. The boundary is referred to as the oscillation envelope. The frequency of the envelope is the same as the frequency of the power oscillation.

Note that in Figure 8-4 the current magnitude changes with the oscillating power flow level. The current magnitude must increase when the power flow oscillation represents an increase in power and decrease when the power oscillation decreases. The shape of the power flow oscillation forms an envelope about the current wave. The current will oscillate within new boundaries defined by this oscillation envelope. You can determine the frequency of the power oscillation from the frequency of the current (or voltage) oscillation envelope.

8.1.6 Oscillation Damping

Damping refers to the ability of the power system and its equipment to reduce the amplitude of oscillations. Damping can be either positive or negative. When damping is positive the amplitude of the oscillation is reduced. When damping is negative the amplitude of the oscillation is increased.

Ideally the power system will always provide positive damping and reduce the amplitude of system oscillations. Unfortunately, at times the damping is negative, and the oscillations grow. This could eventually lead to oscillatory instability. Major sources of damping include:

- The load/frequency relationship (first described in Chapter 4) normally provides positive system damping. As you recall the load/frequency relationship is the dependency of the load magnitude on system frequency. As frequency rises, the load magnitude rises which tends to oppose the frequency rise and provide positive damping.
- The natural energy losses in the system provide positive damping as current flows through the system resistance. Any time resistance exists, I^2R losses will occur. These losses tend to remove energy from the oscillation and dampen the amplitude.
- Frictional losses within rotating machinery (motors and generators) provide damping as the speed of the machine varies with the power oscillation. Frictional losses reduce the amplitude of the oscillation.

Amortisseur windings are also called damper windings. Amortisseur is a French word which loosely translates to "killer". Amortisseur windings kill oscillations!

- Generators are often equipped with an extra set of windings called "amortisseur" windings. Amortisseur windings are conducting bars embedded in the magnetic poles of the generator's rotor. When a generator experiences oscillations, currents are induced in the amortisseur windings. The induced currents create torques which tend to reduce the amplitude of the oscillations that caused the torque in the first place.
- Even if a generator does not have amortisseur windings it may exhibit an amortisseur effect. Oscillations will induce currents in the rotor iron which create torques that oppose the oscillations.

Section 8.4 of this Chapter will expand on the role of an excitation system in providing both positive and negative damping.

- Excitation systems can be a source of either positive or negative damping. The negative damping can occur due to an excitation system changing the generator voltage in such a manner that an oscillations amplitude is increased. Power system stabilizers (PSS) are additional equipment added to an excitation system to enhance its ability to provide positive damping.

8.1.7 Oscillation Classifications

Using the types of damping as our criteria for classifying oscillations, oscillations are separated into three categories; normal or positively damped, sustained or undamped, and negatively damped.

Normal (Positively Damped) Oscillations

Oscillations may occur due to routine events on the power system. Load changes, generator trips, or switching actions may cause oscillations in power flow, voltage, current, and frequency. For example, if a 345 kV line is switched out for routine maintenance, the power that was flowing on the line will redistribute to other area lines. This redistribution of power flow will cause temporary oscillations in power flows of neighboring generators and transmission lines.

The power system typically has no difficulty providing sufficient positive damping to quickly reduce the amplitude of these oscillations. The routine, positively damped oscillations are classified as normal oscillations. Figure 8-5 illustrates what positively damped oscillations would look like on a strip-chart with a high resolution (seconds) time scale.

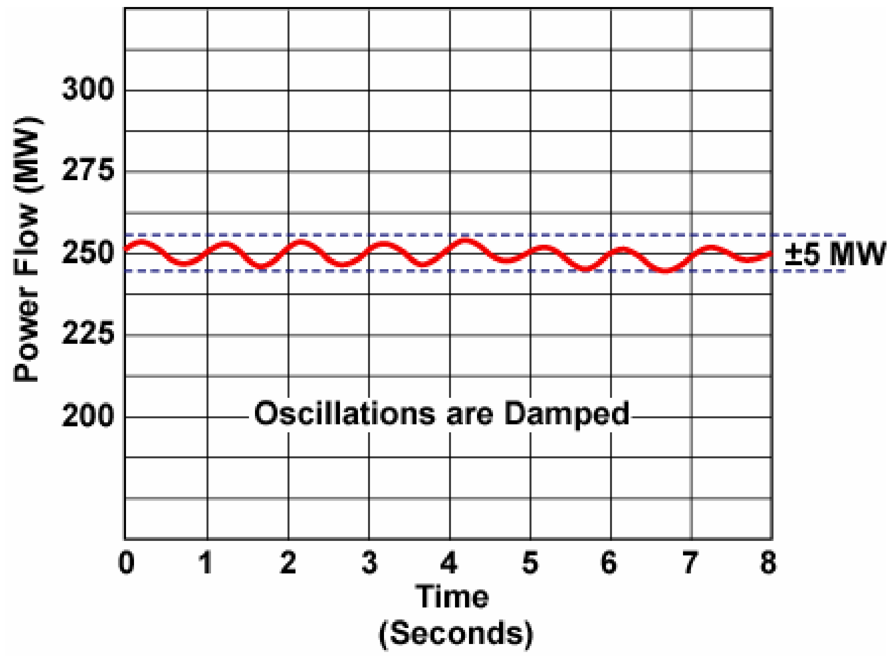


Figure 8-5
Normal (Positively) Damped Power Oscillations

Normal oscillations are always occurring. The power system provides enough positive damping to quickly reduce their amplitude to harmless values.

Normal oscillations are temporary events and typically die out after several seconds. Normal oscillations may appear to be constant due to the dynamic nature of the power system. Something is always happening within the power system to cause normal (a few MW) power flow oscillations.

Sustained (Undamped) Oscillations

Sustained oscillations are oscillations that appear on the power system and sustain themselves. The cause of normal and sustained oscillations may be the same. The difference is that a normal oscillation will eventually disappear (positively damped), while a sustained oscillation will not go away (undamped) without corrective action. Sustained oscillations are undamped oscillations. The oscillations are not growing, but neither are they shrinking.

Sustained oscillations can be harmful if they have a large enough amplitude. Even small amplitude sustained oscillations can be dangerous under the right circumstances. For example, several sustained oscillations, each with a separate cause or source, may appear on the power system at the same time. Taken individually, they will not harm the power system but, collectively, may cause a great deal of trouble. Figure 8-6 illustrates a sustained or undamped oscillation.

Sustained oscillations are neither positively nor negatively damped. They are undamped.

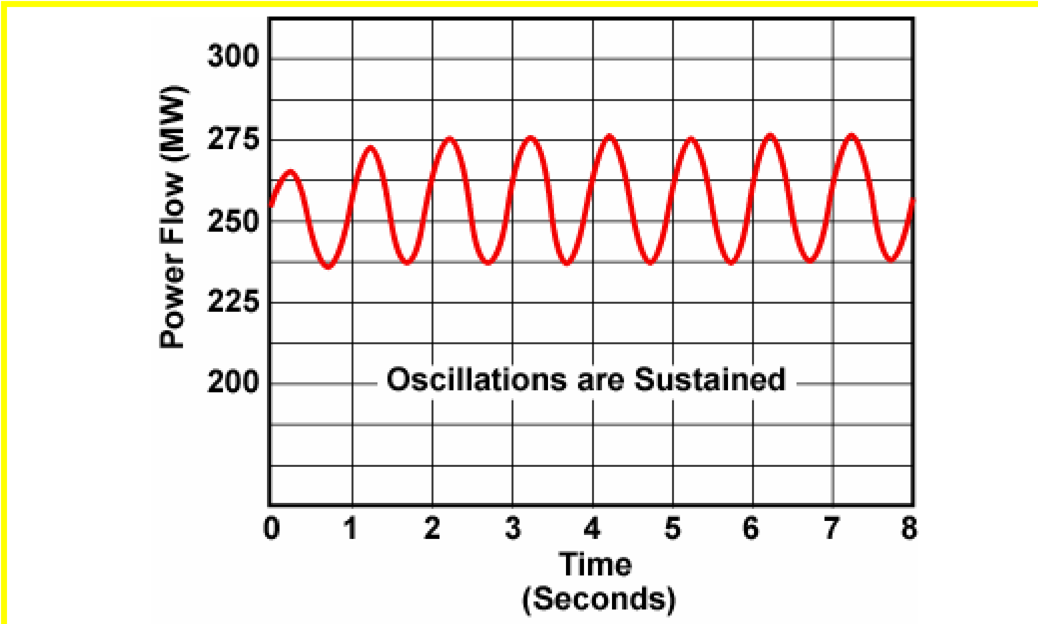


Figure 8-6
Sustained (Undamped) Power Oscillations

Negatively Damped Oscillations

Negatively damped oscillations are the most damaging type of oscillation. If an oscillation appears and then gradually grows in magnitude, it is negatively damped. A negatively damped oscillation may initially appear as a normal or sustained oscillation. As time passes, the oscillation may grow in size until it reaches an amplitude that the power system can no longer withstand.

For example, a normal MW flow oscillation of a few MW may exist on a major tie-line. The system operator may notice it but pay no particular attention. Eventually, the oscillation grows to 20 or 30 MW. The system operator may grow concerned and attempt to find the cause and begin corrective action. If left unchecked the oscillation could grow to 100, 200, 300 MW, or even larger. Protective relay systems may then be forced to trip lines or generators to protect system equipment. This type of growing, large magnitude oscillation can be very harmful to the power system. Figure 8-7 illustrates a negatively damped oscillation.

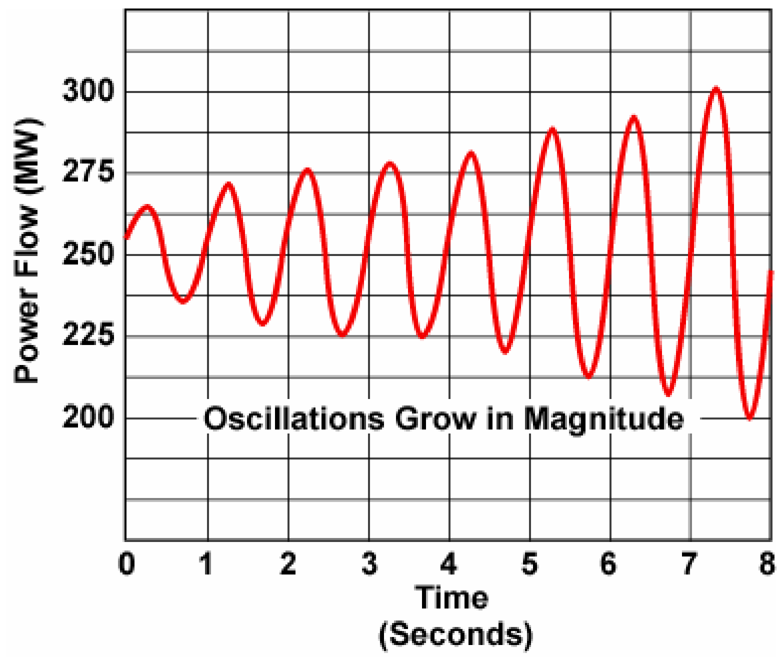


Figure 8-7
Negatively Damped Power Oscillations

The power system is not damping these oscillations. Rather, something is causing the oscillation's amplitude to grow. These oscillations are negatively damped.

8.2 Power Oscillations on a Sample System

Figure 8-8 illustrates a simple power system consisting of one generator connected to a much larger power system. Initially, the generator is feeding power to the larger system over two transmission lines. Assume that one of the lines is suddenly opened. When the line is opened it causes a substantial shock to the system. Suddenly the generator has lost one-half of its transmission path. This disturbance is now used to step through the response of the generator to this event and the creation of an oscillation.

While this is a substantial shock to the system, the shock is not so great as to risk transient instability.

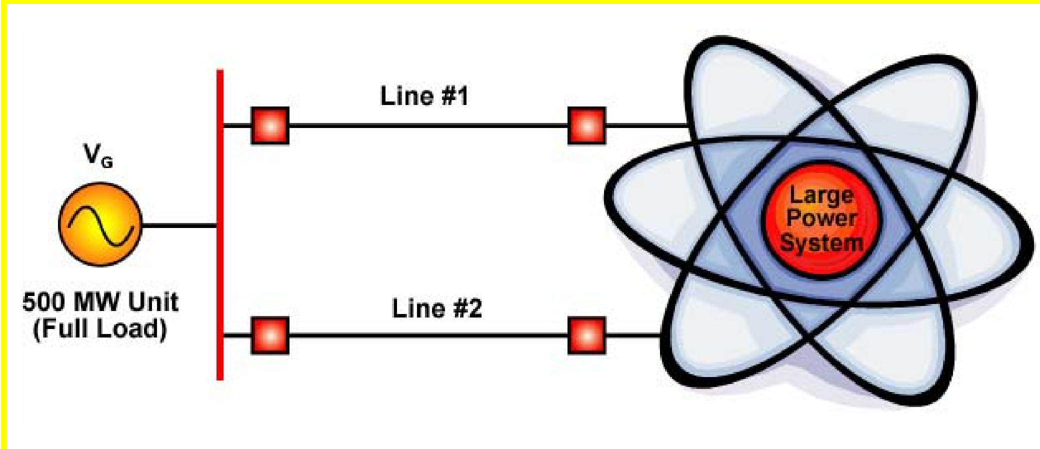


Figure 8-8
Loss of a Line to Start an Oscillation

8.2.1 Changes to Power, Speed, and Angle

Since it is rotating at 3600 RPM and feeding into a 60 HZ system, this must be a two-pole generator.

Assume that before the line tripped, the generator was rotating at a constant speed of 3600 RPM or at synchronous speed. The large rotating mass of the generator's turbine/rotor will attempt to maintain this speed. However, the loss of line #2 will force an immediate reduction in MW output from the generator since the generator is now connected to a much weaker transmission system. The MW that the generator cannot transmit to the system must be absorbed by the generator's rotating mass.

Change to Power Output

Recall the active power transfer equation:

$$\boxed{P_{G-S} = \frac{V_G \times V_S}{X} \sin \delta_{G-S}}$$

The loss of line #2 will immediately increase the reactance (X) of the system. An inspection of the above equation tells us that the increase in reactance will force an immediate decrease in the generator's MW output (P_{G-S}).

Change to Rotor Speed

The generator's sudden MW output decrease creates an imbalance between the generator's mechanical power input and electrical power output. The difference between the power input and output becomes the generator's accelerating power. Accelerating power is stored in the spinning mass (rotor

& turbine) of the generator. The increase in stored energy causes the speed of the generator to rise above synchronous speed (60 HZ).

Change to Angle Spread

The generator is now rotating faster than synchronous speed. A condition of relative acceleration exists. Recall from Chapter 7 that relative acceleration is required for a change in the angle spread. The angle between the generator and the large system will now start to increase.

The increase in the angle spread will allow an increase to the generator's MW output. This reduces the accelerating power and slows down the turbine/rotor. This forces another change to the angle spread. An oscillation has begun.

8.2.2 Feedback Loop for Power, Speed, and Angle

Figure 8-9 summarizes the relationship between the generator's MW output, the generator's speed, and the system angle spread. The relationships are presented in terms of a "feedback loop". Feedback loop means that initial changes to the generator's MW output will be fed back to determine another cycle of changes to speed, angle spread, and electrical power output. The concept is described below.

It takes time for an oscillation to proceed. Movement around this loop is not instantaneous.

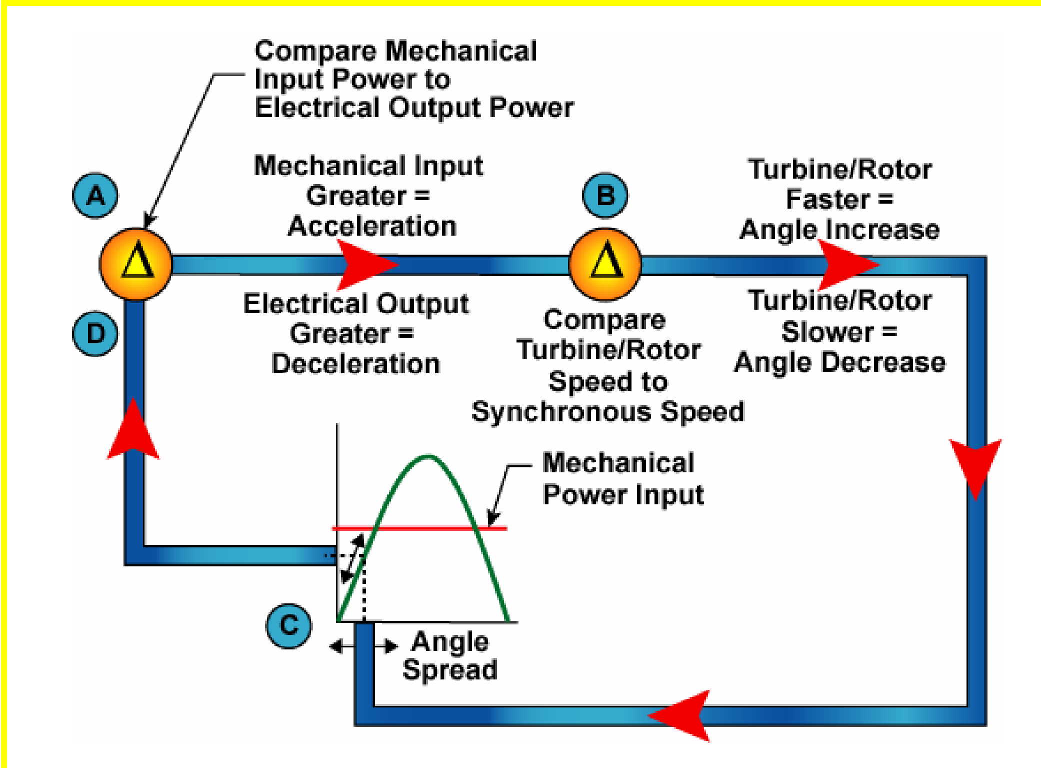


Figure 8-9
Feedback Loop for Power, Speed & Angle

At point "A" in Figure 8-9, the generator's mechanical power input is compared to its electrical power output. If the mechanical power input is greater than the electrical power output an accelerating condition exists. The turbine/rotor speed will then increase above the synchronous speed. If the electrical power output is greater than the mechanical power input a deceleration condition exists. The turbine/rotor speed would then decrease below the synchronous speed.

At point "B" relative acceleration is analyzed. If the generator is running faster than synchronous speed the angle will increase. If the generator is running slower than synchronous speed the angle will decrease.

At point "C" a power-angle curve is used to illustrate changes to electrical power output. If the angle is increasing, the operating point will move up the curve and increase the MW output. If the angle is decreasing the operating point will move down the curve and decrease the MW output.

At point "D" the change in MW output is "fed back" and adjusts the original comparison of mechanical power input and electrical power output. A new comparison between input and output determines the conditions for the next oscillation cycle. The process repeats itself again and again until damping reduces the amplitude of the oscillation. Oscillations are occurring with each loop around Figure 8-9. The oscillations will not stop until the mechanical power input equals the electrical power output with the generator running at synchronous speed.

8.2.3 Comparison of Power, Speed, and Angle

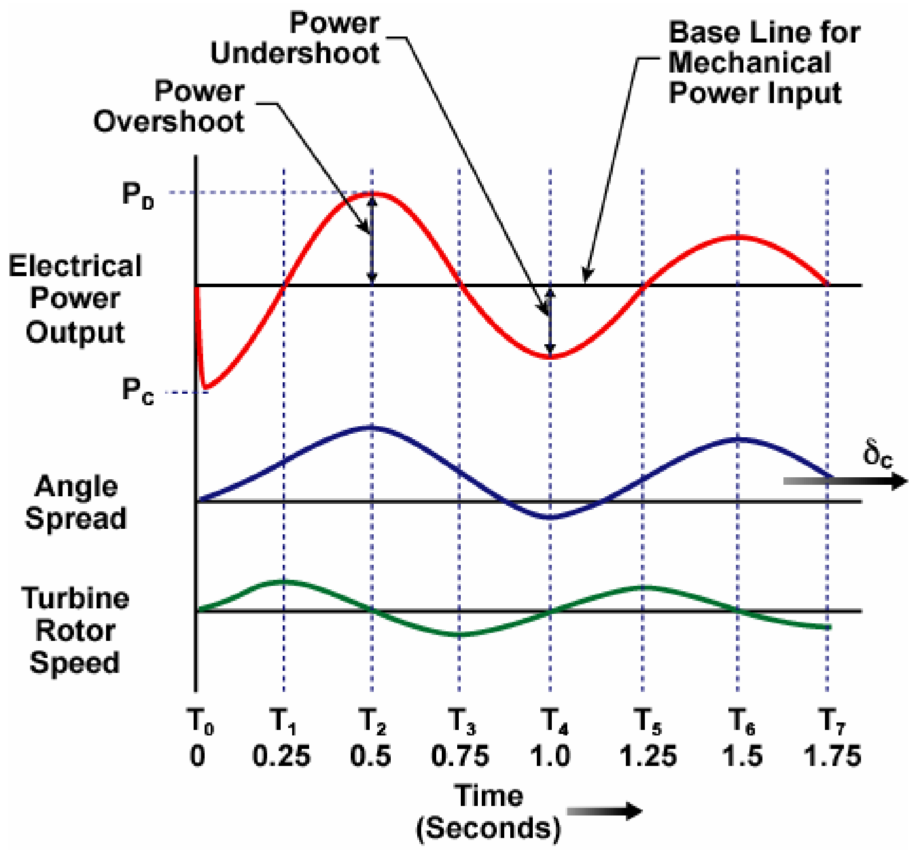
Initially, the MW output from the generator drops sharply and the generator starts to accelerate. As the generator speed rises above synchronous speed the angle increases and the MW output increases.

Once a generator's speed has risen due to an increase in stored energy, it is difficult to return the unit to synchronous speed. The generator will continue to spin faster than synchronous speed and increase the angle until the MW output actually exceeds the output of the generator before transmission line #2 opened.

Figure 8-10 contains plots of power output, angle spread, and turbine/rotor speed for the system in Figure 8-8 as it oscillates as a result of the loss of line #2. The time frame from T_0 to T_7 is 1.75 seconds. The figure assumes that the mechanical power input to the generator remains constant during this entire period.

From the graphs of Figure 8-10 it is easy to see that the MW output is in-phase with the angle spread. When the angle is increasing, the MW output is increasing. When the angle is decreasing, the MW output is decreasing. At points T_1, T_3, T_5, and T_7, the MW output is equal to the output level prior to losing line #2. These four points are at the mid-point of the output power swing from maximum to minimum and coincide with maximum and minimum turbine/rotor speed levels.

Note that at points T_2, T_4, and T_6, the turbine/rotor is again matched to synchronous speed. The points at which the turbine/rotor is at synchronous speed correspond to the positive and negative peaks of the MW output and angle spread curves.



From Figure 8-10 you can determine that the oscillation frequency is approximately 1.0 HZ.

Figure 8-10
Plots of Power Output, Angle Spread & Rotor Speed

The same simple power system used in this section (Figure 8-8) was also used in Section 7.7.1 on oscillatory stability. Compare the power-angle curve description of oscillatory stability in Section 7.7.1 to the material in this section.

There are many other interesting comparisons that can be made between the plots in Figure 8-10. Take a few minutes to study these plots to determine further relationships between power output, angle spread and generator speed. For instance, note in Figure 8-10 that the angle spread can only increase if the turbine/rotor speed is greater than synchronous speed.

8.2.4 Summary of the Power Oscillation Process

Figure 8-11 is provided to summarize the steps that may lead to a power system oscillation. These steps are very general in nature but are representative of how most generator oscillations develop.

1. A change takes place in the power system.
2. The turbine/rotors of the system generators change speed (from synchronous speed) in response to the system change.
3. The speed change to the turbine/rotors leads to a change in angle spreads.
4. When the angles change, the MW outputs of the generators change.
5. When the MW outputs of the system generators change, the the turbine/rotors change speed again. An oscillation has begun.
6. The generators will oscillate about an operating point until system positive damping (hopefully) reduces the amplitude of the oscillations.

Figure 8-11
Steps in a Generator Oscillation

8.3 Natural Frequency of Oscillation

In the rubber band/weight analogy of Figure 8-1 and Figure 8-2, a weight's (generator) oscillation was triggered by tugging on the weight and releasing it. The weight oscillated against the rubber band (transmission) system at a certain frequency. The frequency of the oscillation was dependent on the size (mass) of the weight and the strength of the rubber bands in the system. The frequency at which each weight oscillates is called the weight's natural frequency of oscillation. Each weight will have its own natural frequency of oscillation. The natural frequency will vary with changing system conditions.

8.3.1 Natural Frequency Analogy

For a visualization of a natural frequency of oscillation consider a simple, 20 foot long, arched bridge crossing a small stream. A person walks across the bridge and it behaves properly, appearing well constructed. Then a second (taller) person walks across the bridge with a longer stride length. This longer stride length happens to be just the right repetitive force to excite the natural frequency of the bridge. The bridge enters a period of noticeable oscillations which last for several seconds.

The concept of a natural frequency of oscillation applies to any mechanical device including large bridges. When excited by the right stimulus, large bridges could enter a period of oscillations the frequency of which is the natural frequency of the bridge.

The public was fascinated with the oscillating Tacoma Narrows bridge. "Galloping Gertie", as it was known, became a short-lived tourist attraction.

A classic example of the possibly destructive effects of a natural frequency of oscillation occurred in 1940. The Tacoma Narrows bridge connected the Olympia peninsula with the mainland of Washington state. The suspension bridge was more than a mile long and built with a very thin roadway. Even while the bridge was under construction the builders knew it was susceptible to oscillations. One day the bridge was exposed to the right stimulus (approximately a 40 MPH wind) and the bridge failed. Large oscillations developed in the bridge's roadbed and eventually these oscillations toppled the bridge into the water below.

8.3.2 Factors that Impact the Natural Frequency

Every generator on the power system has a natural frequency of oscillation. This frequency is dependent on the inertia of the generator, the strength of the power system to which the generator is attached, and the generator's power output level. A generator's inertia is constant but the transmission system's strength and the generator's output level are variable. A generator's natural frequency of oscillation will vary with the changing strength of the transmission system and the changing loading of the generator. A typical range for a generator's natural frequency of oscillation is from 0.75 to 3.0 HZ.

Effect of Inertia on Natural Frequency

The inertia of a generator is dependent on its physical size and geometry. A generator with a large diameter, heavy turbine/rotor assembly will have a large inertia. The smaller the diameter and lighter the turbine/rotor, the lower the inertia of the unit. To compare the inertia of two generators you should compare inertias on a "per unit" basis. You are then comparing the inertias per MVA of unit capacity. In general, hydro units will have a greater per-unit inertia than steam units.

The greater the inertia of a generator, the lower its natural frequency of oscillation. For example, assume a power system has two 500 MW units: one is a coal unit, and the other a hydro unit. The hydro unit will typically have a higher inertia. A hydro unit will oscillate, when disturbed, at a lower natural frequency of oscillation than the coal unit. For example, the coal unit may oscillate at 1.5 HZ while the hydro unit may oscillate at 0.8 HZ.

Effect of System Strength on Natural Frequency

The strength of a transmission system is a function of the number and size of the lines in the system and the power loading on these lines. If a system is composed of many high voltage lines that are lightly loaded it is a strong transmission system. If a system is composed of only a few low voltage lines that are heavily loaded it is a weak transmission system. Most transmission systems are somewhere between these two extremes.

When a generator is disturbed it will oscillate at a higher frequency if it is connected to a strong transmission system. The generator will oscillate at a lower frequency if it is connected to a weak transmission system.

Effect of Generator Output Level on Natural Frequency

The output level (MW and Mvar) of a generator also effects its natural frequency of oscillation. In general, as the loading of the generator increases its natural frequency of oscillation reduces. The generator and system voltages stay relatively constant, the loading level of the generator can be related to its torque angle. As the generator's torque angle rises toward 90° its natural frequency of oscillation reduces.

8.3.3 Oscillation Frequency Effect on Damping

The power system will naturally try to reduce the amplitude of power system oscillations. It does this by removing energy from the oscillations. For example, if a power oscillation occurs you could visualize it as an exchange of power between two points on the system. When power flows, I^2R losses will occur. These energy losses help to reduce the amplitude of the oscillation. In other words, the losses dampen the oscillation. The higher the frequency of the oscillation, the more positive damping the power system can provide. High frequency (greater than 1.0 HZ) oscillations will be damped or reduced in amplitude more rapidly than low frequency (less than 1.0 HZ) oscillations.

As power system operators, you do not want any oscillations. However, it is better to have high frequency oscillations than low frequency. The power system can naturally dampen high frequency oscillations. Low frequency oscillations may exist for a long time. Low frequency oscillations could become sustained (undamped) oscillations. Worse yet, the oscillations could grow in size (negatively damped) until system operators or protective relay systems are forced to respond and trip elements.

Because of the differences in naturally occurring power system damping, low frequency oscillations are more damaging to the power system than high frequency oscillations. To summarize the occurrence of high and low frequency oscillations two general scenarios are stated:

- Low frequency oscillations occur when high inertia generators are operating with large torque angles and are tied to weak transmission systems.

- High frequency oscillations occur when low inertia generators are operating with small torque angles and are tied to strong transmission systems.

With respect to the operation of the power system, the oscillations that cause problems are the low frequency ones. Figure 8-12 summarizes the factors that could cause harmful system oscillations.

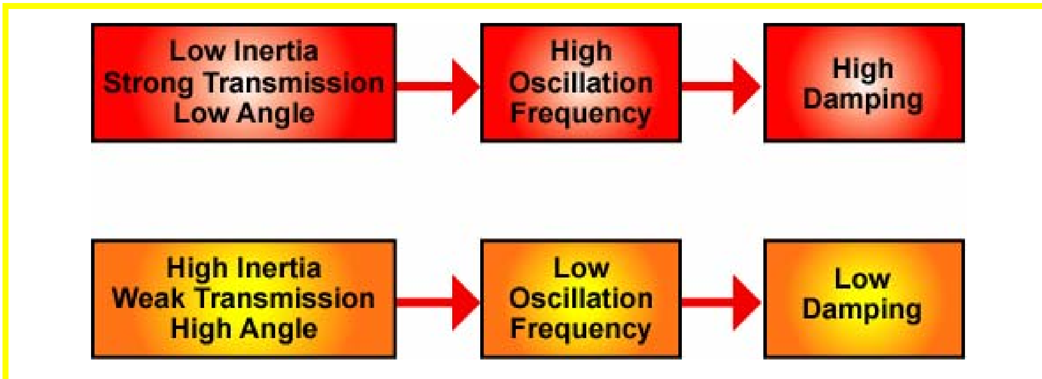


Figure 8-12
High & Low Frequency Oscillations

8.3.4 Modes of Oscillation

It was stated previously that individual generators typically oscillate at frequencies varying from 0.75 HZ to 3.0 HZ. A power system is composed of many generators and many transmission lines. When the effects of all the different system components are accounted for, the range of typical system oscillations extends from approximately .05 HZ to 3.0 HZ.

The frequencies above 1.0 HZ are relatively high frequency oscillations and are normally well damped by the power system. The frequencies below 1.0 HZ are relatively low frequency oscillations. These are the frequencies that may cause system problems. Low frequency oscillations may be undamped or negatively damped.

Since several different frequency oscillations can occur at the same time it may be difficult to pick out one specific frequency of oscillation.

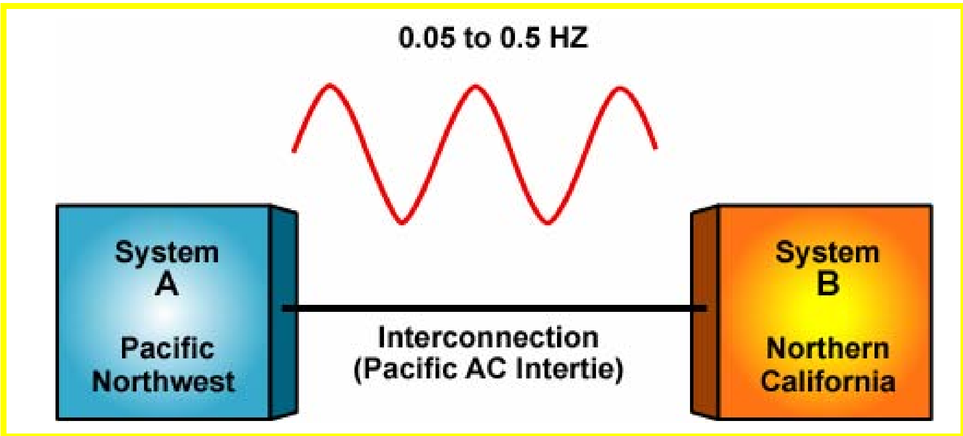
At any one time there may be several distinct oscillations occurring within a power system. Different frequency oscillations may occur simultaneously. The situation is similar to mechanical systems, such as in an automobile. For example, as a car increases its speed, different frequency oscillations may be triggered. At one speed the car may violently shake while at a higher or lower speed this shaking stops. At a different speed some other mode of oscillation may be triggered.

To simplify our description of the frequencies at which the power system oscillates, the typical frequencies of oscillation (0.05 to 3.0 HZ) are divided into four modes of oscillations. Each mode covers a range of frequencies. This section will describe each of the four modes of oscillation:

- Inter-Area Mode (0.05 to 0.5 HZ)
- Intra-Area Mode (0.4 to 1.0 HZ)
- Local Mode (0.8 to 2.0 HZ)
- Intra-Plant Mode (1.5 to 3.0 HZ)

Inter-Area Mode of Oscillations

Oscillation frequencies from 0.05 to 0.5 HZ are called the inter-area mode of oscillation. These low frequency oscillations are formed when entire power systems oscillate with respect to other power systems. The oscillations cause the two power systems to exchange power in a cyclical fashion at a frequency typically ranging from 0.05 to 0.5 HZ. Inter-area mode oscillations are dangerous as the power system is not adept at providing natural damping for low frequency oscillations. Figure 8-13 illustrates inter-area mode oscillations.



This figure illustrates the inter-area mode as it might apply in the western United States. This mode can also appear in other power systems.

Figure 8-13
Inter-Area Mode of Oscillation

An example of the occurrence of the inter-area mode of oscillations is the Pacific Northwest oscillating against Northern California. These two large power systems are connected with a relatively weak transmission path (Pacific AC 500 kV Intertie). In the late 1960's and early 1970's inter-area mode oscillations were very noticeable on the transmission lines connecting these two systems. These oscillations had a frequency of approximately 1/3 HZ.

Even today oscillations occur on these 500 kV lines. A typical frequency is ¼ HZ.

Anytime two large power systems are interconnected via a relatively weak transmission path, those systems are at risk of inter-area mode oscillations. Experience has shown that in order to safely interconnect two large systems, the connecting lines should, at a minimum, have a capacity of at least 10% of the smaller system. For example, assume we wanted to interconnect the Western and Eastern Interconnections. To assure a reliable tie, the connecting lines should be rated at approximately 15,000 MW.

Intra-Area Mode of Oscillations

Oscillation frequencies from 0.4 to 1.0 HZ are called the intra-area mode of oscillation. These low frequency oscillations are formed within power systems when pockets of generation oscillate with respect to one another. The mode is different from the inter-area mode in that the oscillations are internal to a large power system and not between two distinct power systems. This mode is a low frequency oscillation and is not well damped. Figure 8-14 illustrates intra-area oscillations.

When a group of generators oscillate together the group is referred to as "coherent" generators. A coherent group acts as if it is one large generator.

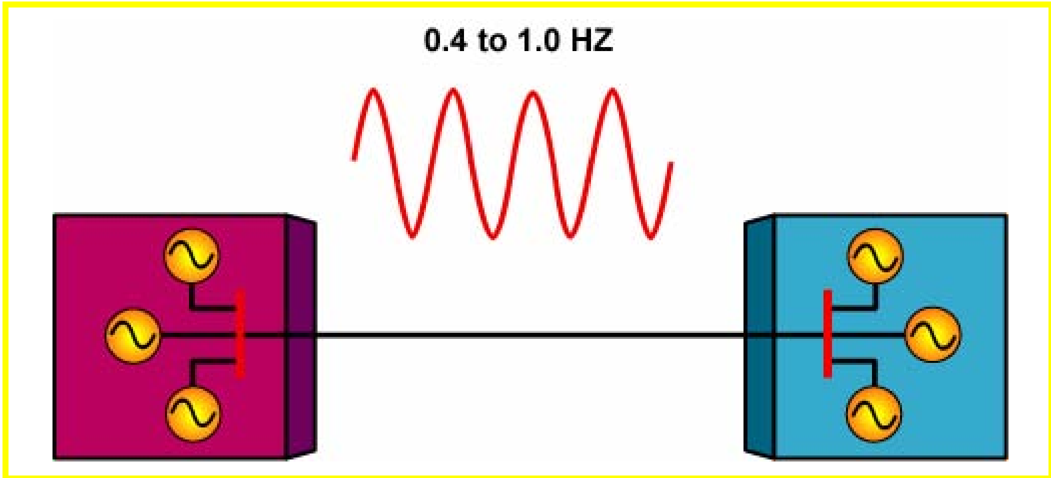
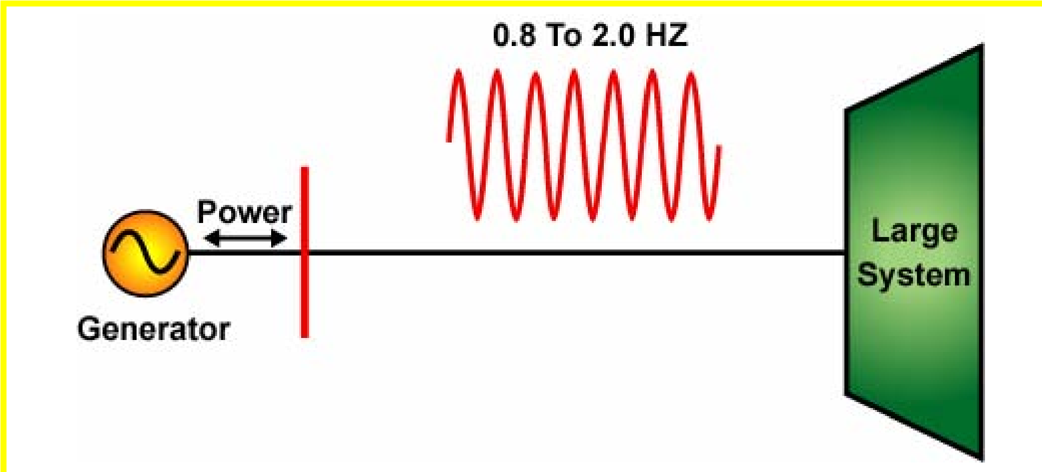


Figure 8-14
Intra-Area Mode of Oscillation

Local Mode

Oscillation frequencies from 0.8 to 2.0 HZ are called the local mode of oscillation. In this mode of oscillation each generator oscillates with respect to the rest of the power system. When a generator is tied to a large power system via a long radial line, it is especially susceptible to local mode oscillations. The local mode is a high frequency oscillation and is usually well damped by the power system. Figure 8-15 illustrates local mode oscillations.



The local mode frequency is that generator's natural frequency of oscillation.

Figure 8-15
Local Mode of Oscillation

Intra-Plant Mode

Intra-plant mode oscillations range from 1.5 to 3.0 HZ. In multi-unit stations, the generators may oscillate with respect to neighboring units. These high frequency oscillations are called intra-plant oscillations. Intra-plant oscillations are well damped and usually do not cause any problems. Figure 8-16 illustrates intra-plant mode oscillations.

Note that as a progression was made from the inter-area mode to the intra-plant mode the oscillation frequency increased while the amount of oscillating inertia decreased. This is expected as the natural frequency of oscillation increases with decreasing inertia.

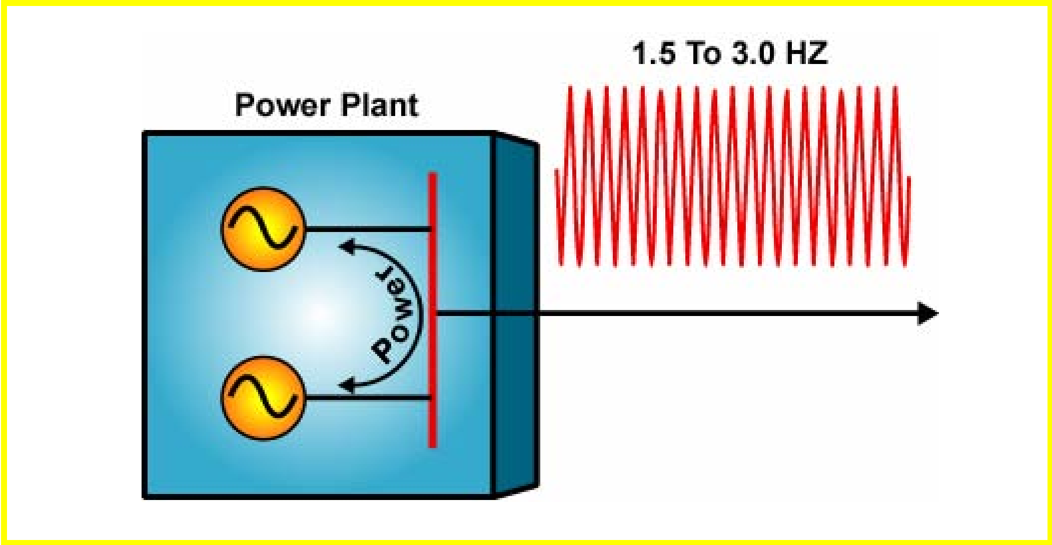


Figure 8-16
Intra-Plant Mode of Oscillation

The intra-plant and local modes of oscillation are both high frequency oscillations. The power system is normally capable of damping these oscillations. However, the inter-area and intra-area modes are low frequency oscillations. Once these oscillations start, they may either sustain themselves or grow larger.

Assume that system events have led to the simultaneous presence of both local mode and inter-area mode power flow oscillations. Figure 8-17 plots and compares these two power flow oscillations. Note that the higher frequency local mode damps out rapidly. The lower frequency inter-area mode sustains itself. The inter-area mode oscillations are the oscillations that should most concern system operators.

Equipment has been designed to assist with damping low frequency oscillations. The next section will describe the use of a type of this equipment called a power system stabilizer or PSS.

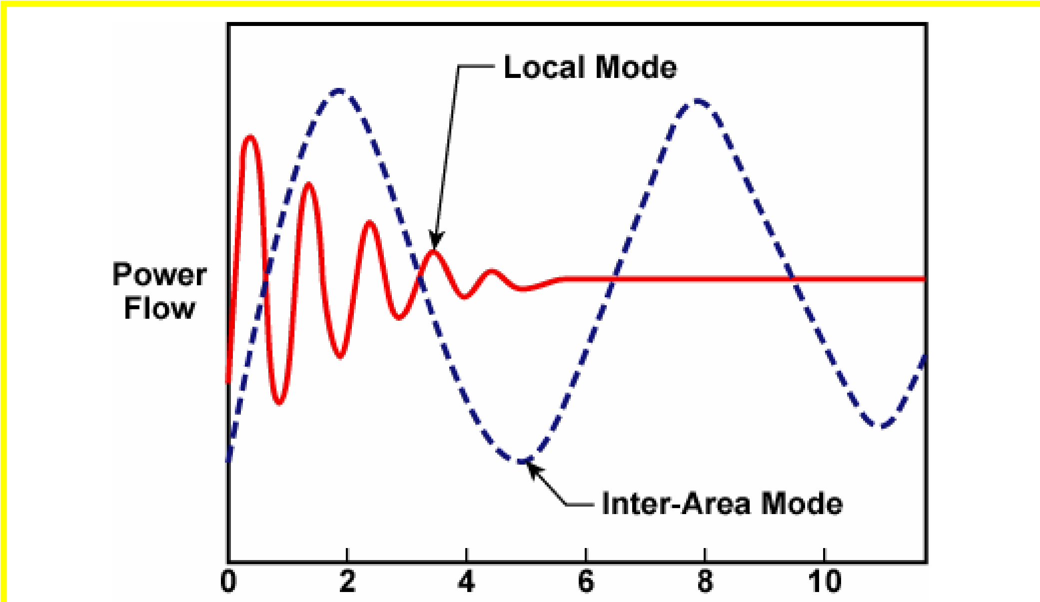


Figure 8-17
Comparison of Local and Inter-Area Mode Oscillations

By counting the cycles and noting the time lapse, the frequency of this local mode can be calculated as approximately 1.0 HZ. The inter-area mode as 0.17 HZ.

8.4 Oscillations & Excitation Systems

This section begins a description of the causes of power system oscillations by examining the role of generator excitation systems. Excitation systems can both cause oscillations and be used to dampen oscillations. The following section (Section 8.5) will describe several additional causes of oscillations.

8.4.1 Operation of an Excitation System

A block diagram for a generator's excitation system is illustrated in Figure 8-18. Excitation systems are composed of two major components, the voltage regulator and the exciter. The voltage regulator can be set in a manual or automatic mode. When in manual mode, the voltage regulator maintains an operator chosen excitation current level. When in automatic mode, the voltage regulator attempts to automatically maintain a terminal voltage (V_T) output level.

An automatic voltage regulator (AVR) monitors the generator's output voltage (V_{OUT}) and compares this voltage to a plant operator selected set-point. If the actual output voltage is lower than this set-point, the AVR will send a correction signal to the exciter to increase the generator excitation. This raises the generator's output (V_{OUT}) voltage and terminal voltage (V_T). If the voltage measured by the AVR is high, the AVR sends a correction signal to the exciter to lower the excitation level and the output and terminal voltages.

Generator capability curves were described in Section 5.6.3.

The exciter is the source of the DC power used to turn a generator's rotor into an electromagnet. The exciter receives directions from the regulator on what amount of DC current to send to the rotor field winding. The combination of the AVR and exciter maintains a constant terminal voltage and allows the generator operators to choose (within capability limits) the voltage at which the generator operates.

The purpose of the PSS input will be stated shortly.

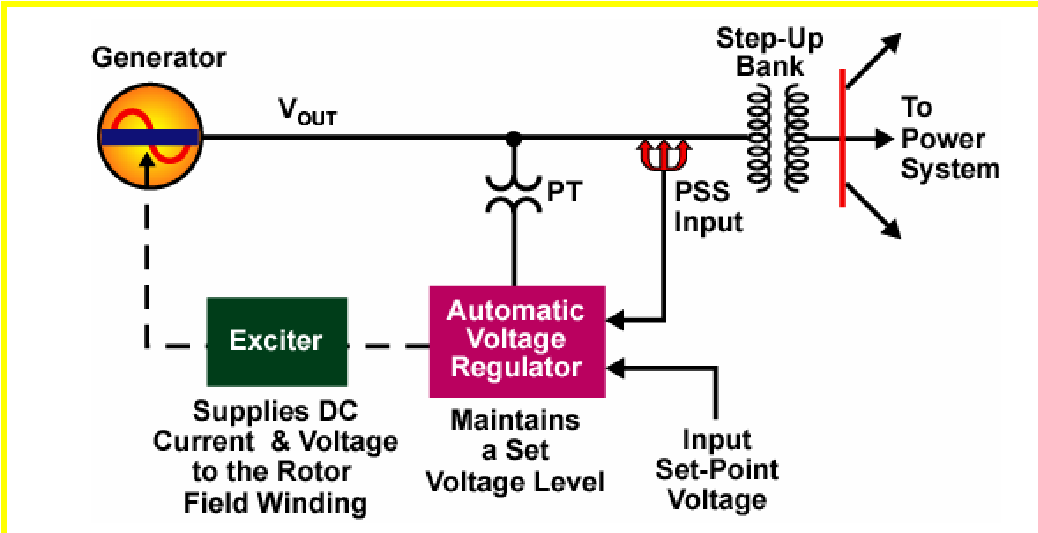


Figure 8-18
Generator Excitation System Block Diagram

8.4.2 Modern Excitation Systems

Excitation systems have been in use since the first synchronous machines were built. These early excitation systems were very slow to operate. It would take several seconds from the time the AVR first detected a low voltage until the time the excitation system boosted the generator's field voltage. Early exciters were also low power. If large changes in a generator's terminal voltage were desired, the excitation system could not offer much help. Older types of exciters were simply too weak to force a substantial change to a generator's terminal voltage.

The older excitation systems were electro-mechanical designs. Modern systems use solid state electronic components.

Modern excitation systems are often faster and more powerful. A modern high initial response (HIR) excitation system can force a change in a generator's field voltage in less than 1/100 of a second. Modern exciters are also very powerful. A typical generator rated field voltage may be 400 to 600 volts. A modern excitation system may be capable, for short periods of time, of forcing the generator field voltage to four or more times this rated value in an emergency.

8.4.3 Benefits of Fast, Powerful Excitation

Modern excitation systems, that are both fast and powerful, are installed on many of the generators in the interconnected power systems. These excitation systems help improve several areas of system operation including:

- Extending steady state stability limits. The active power transfer equation states that the MW transfer between two locations is partially dependent upon the voltages at the receiving and sending ends. Fast, powerful excitation systems can increase these voltage levels and ensure that voltage is highest when needed. For example, if the angle rises to a high value, a powerful excitation system can be used to ensure voltages stay high thus limiting any further increase to the angle spread. If voltages were allowed to decline, the angle would increase and the system could go unstable.
- Extending transient stability limits. Transient stability is determined within the first few swings of the disturbance. Fast excitation systems can rapidly change generator field voltages during these first few swings. This rapid action helps reduce angle spreads and maintain transient stability.

8.4.4 Excitation Systems and Oscillatory Stability

Fast, powerful excitation systems may help the power system by extending steady state and transient stability limits but they may also cause their share of trouble. Normal load changes cause generator power output levels to vary. Minor generator power oscillations will occur due to these load changes. Fast excitation systems may try to make corrections to voltages during these routine power oscillations. If the voltage adjustment made by the excitation system occurs at the wrong time, the excitation system may increase, rather than decrease, the amplitude of the oscillations. Fast excitation systems can contribute to the amplitude of oscillations and possibly cause oscillatory instability.

Figure 8-19 illustrates how a fast excitation system can increase the amplitude of a power oscillation. Figure 8-19 (a) is a plot of a power oscillation. Figure Figure 8-19 (b) is the excitation system’s voltage output in response to this power oscillation. If the excitation system forces the output voltage higher when the power oscillation is also high, the combined effect is to increase the amplitude of the oscillation.

Note the flat-top appearance to the excitation system voltage output. This is an indication that the excitation system is repeatedly reaching its output limits. The flat-top nature of the exciter output is called a "limit cycle".

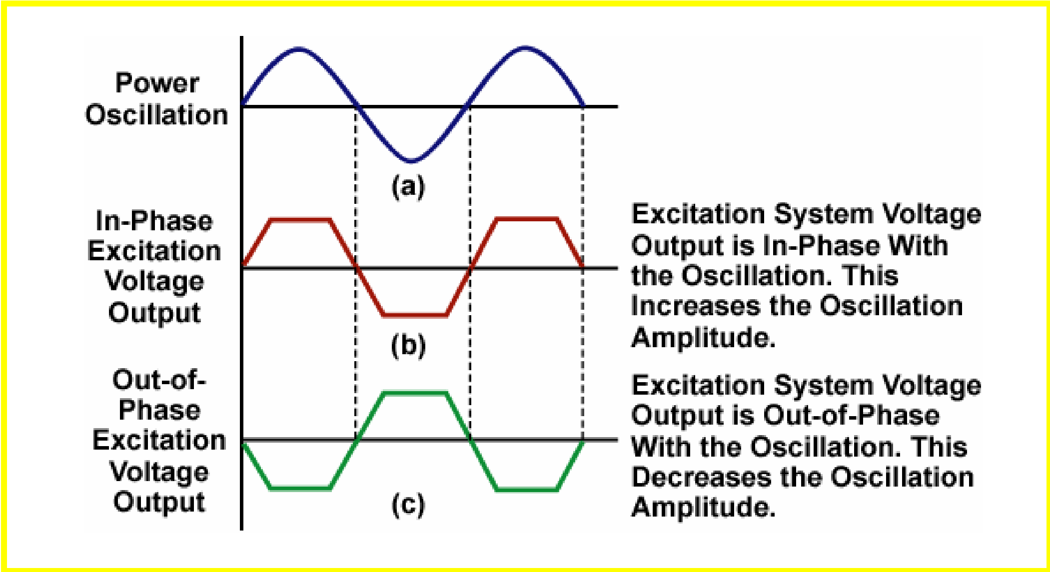


Figure 8-19
Exciter Output Effect on Oscillations

Figure 8-19 (c) is the desired method of eliminating a power oscillation with a fast excitation system. In Figure 8-19 (c) the excitation system voltage output has the desired phase relationship with the power oscillation. When the excitation system voltage output has the proper phase with respect to the system oscillation the excitation system will help reduce the magnitude of the power oscillation. When the excitation system has the wrong phase relationship it may increase the oscillation amplitude.

8.4.5 Power System Stabilizers (PSS)

Power system stabilizers, or PSS, are designed to correct the phase error present in fast excitation systems. PSS typically monitor the system frequency or MW output at the generator terminals. Based on the changes the PSS detects in system frequency or MW, a voltage signal is input to the automatic voltage regulator. The automatic voltage regulator compares the PSS voltage signal, the monitored voltage, and the set-point voltage to calculate an error signal to send to the exciter.

The PSS portion of the voltage regulator's input helps ensure that any adjustment the excitation system makes to generator voltage (based on the voltage regulator's error signal) is done in a manner that helps reduce system oscillations. The PSS will ensure that the excitation system voltage output has the correct phase relationship with the oscillation it is trying to eliminate. (Figure 8-18 illustrated where the PSS signal is input to the automatic voltage regulator.)

The power system can naturally damp most higher frequency (above 1.0 HZ) oscillations. The power system may require assistance with damping some low frequency oscillations. PSS are tuned to correct an excitation system's response to low frequency oscillations. A PSS is typically set to detect oscillations in the inter-area or intra-area modes (approximately 0.05 to 1.0 HZ). If these frequency modes are present, the PSS will send corrective voltage signals to the automatic voltage regulator. If the oscillations are outside of the PSS's tuned range, the PSS will not send any corrective signals.

PSS may also be tuned to provide positive damping at frequencies different than the inter or intra-area modes.

Without a PSS, fast excitation systems may cause system oscillations to sustain themselves or to grow in magnitude. With PSS installed, fast excitation systems can perform their job of increasing steady state and transient stability limits and also help eliminate oscillations. This may prevent oscillatory instability. Figure 8-20 illustrates the effect a PSS can have on reducing low frequency (approximately 1.0 HZ in Figure 8-20) power system oscillations.

The WSCC and the MAPP Regions have operating guidelines that mandate the use of PSS. All units with fast excitation systems should be equipped with well tuned PSS in these regions. It is important that a large number of units have operational PSS. A 1000 MW generator with a properly tuned PSS may only contribute one to two MW of damping. This small amount of damping from an individual unit is not enough damping to make much of a difference. PSS are typically installed in the majority of larger units in the problem area. The combined effect of many PSS has a significant impact in damping oscillations.

PSS can also be used for local oscillatory stability concerns. These PSS are typically designed and tuned to deliver a substantial amount of damping. Several units in the PJM system are equipped with PSS to address local oscillatory stability concerns.

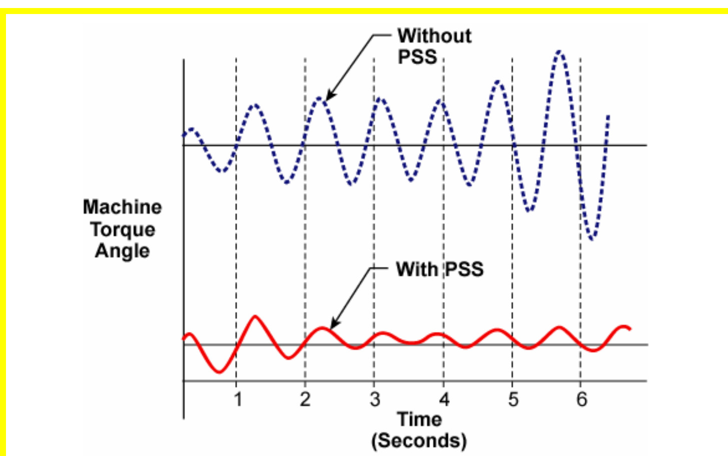


Figure 8-20
Power Oscillations With and Without PSS In-Service

8.5 Additional Causes of Oscillations

Chapter 9 will describe oscillations related to resonance including ferroresonance and sub-synchronous resonance.

Power system oscillations are started when changes, such as the loss of an element or a load adjustment, are made to the power system. In addition, certain characteristics or equipment in the power system can either cause or effect power system oscillations. Generator excitation system effects on oscillations were described in Section 8.4. This section describes the effects of additional characteristics and equipment including:

- Cyclic Loads
- Governor Control Systems
- HVDC Systems
- Generator Pole Slipping

8.5.1 Cyclic Loads

Power system load constantly changes. Most of the time, the changes are small when compared to the total system load. At times, however, major loads may be added and removed in a cyclic nature. From a power system perspective these cyclic loads are similar to power oscillations. Large cyclic loads are especially dangerous if connected to weak transmission systems.

Examples of cyclic loads are arc furnaces and coal mine drag lines. Coal mine drag lines are coal digging systems that use extremely large scoop shovels. Drag lines change from absorbing MW during their coal digging and hoisting period to a generating mode during the coal dumping portion of their load cycle. From a system perspective the drag line appears to be a cyclic load with a very low frequency (perhaps 0.02 HZ). In general, the impacts of large cyclic loads can be minimized by providing dedicated feeders from the main transmission system.

8.5.2 Governor Control System

Chapter 4 provided details on the operation of governor control systems.

Generator governor control systems arrest frequency deviations. Depending on the size of the detected frequency change, the governor will adjust the working fluid (water, steam, etc.) input to the turbine/generator. Governors have droop settings to allow generators to share and respond to load changes in proportion to their size.

If the droops are set incorrectly, generators could compete for load changes. The result would be power oscillations as the system's generators fight each other to make load changes. For example, assume that an isolated system with several generators operates all governors with 0% droop. When load changes occur, every generator could try to respond. The result would be an oversupply of generation. Next, every generator would cut generation. Power and frequency oscillations would result as the system's generators repeatedly increase then decrease generation levels.

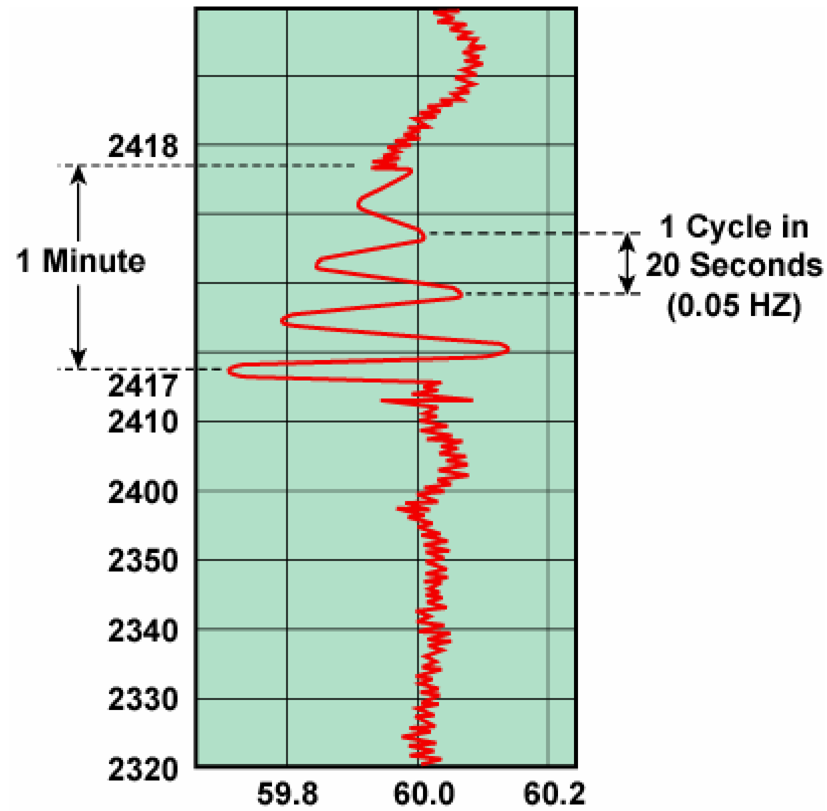
Transient Droop

The transient droop feature may be used in any type of unit that is susceptible to governor induced oscillations. If a unit can be operated in an isochronous control mode it most likely has a transient droop feature or the functional equivalent.

We stated in Chapter 4 that hydro units are often equipped with two types of droop function; permanent droop and transient droop. The transient droop is a short term (a few seconds) droop function that is used to prevent damage to water intake (penstock) structures and to avoid generator power oscillations. The transient droop function is used to intentionally limit, for a brief period of time, the response of a unit to frequency deviations.

Hydro units are typically the best responding units a utility operates. The initial response from a hydro unit must, however, overcome a natural time delay due to the inertia of the intake water supply. (It is difficult to rapidly change the flow of a large mass of water.) For example, assume a hydro unit's governor requests a MW increase. There is a time delay before that MW can actually be delivered. In the meantime the governor requests more MW. Eventually all the MW is delivered, which is more than the governor intended due to the time delays of the initial response. The governor now requests a MW decrease; an oscillation may develop as the unit attempts to follow these cyclic governor commands.

This type of governor induced oscillation occurred in the Pacific Northwest in the early 1960's. Figure 8-21 is a strip-chart of the system frequency from this period. Note the large frequency oscillations in the figure. It was the practice during this period that once large hydro units were synchronized and carrying load their transient droop features were disabled. The large frequency oscillations are due to several large hydro units adjusting their MW outputs as they search (hunt) for an operating point.



This strip-chart automatically switched to a finer resolution time scale when the oscillations grew in amplitude.

Figure 8-21
Oscillations Due to Disabling Transient Droop

8.5.3 HVDC Systems

Chapter 10 describes the components and operation of HVDC systems.

HVDC (high voltage direct current) systems can cause frequency and power oscillations. The power converters at the ends of an HVDC transmission line convert power between AC and DC. The HVDC control system's operation must be coordinated with AC system generation levels to ensure the HVDC does not cause AC system frequency disturbances.

For example, assume an HVDC control system is functioning improperly. This HVDC converter is absorbing power from the AC system in an unexpected and undesired manner. The AC system generation is not coordinated with the power absorbed by the HVDC converter. Figure 8-22 illustrates the kind of frequency oscillations that could occur due to a misoperating HVDC control system.

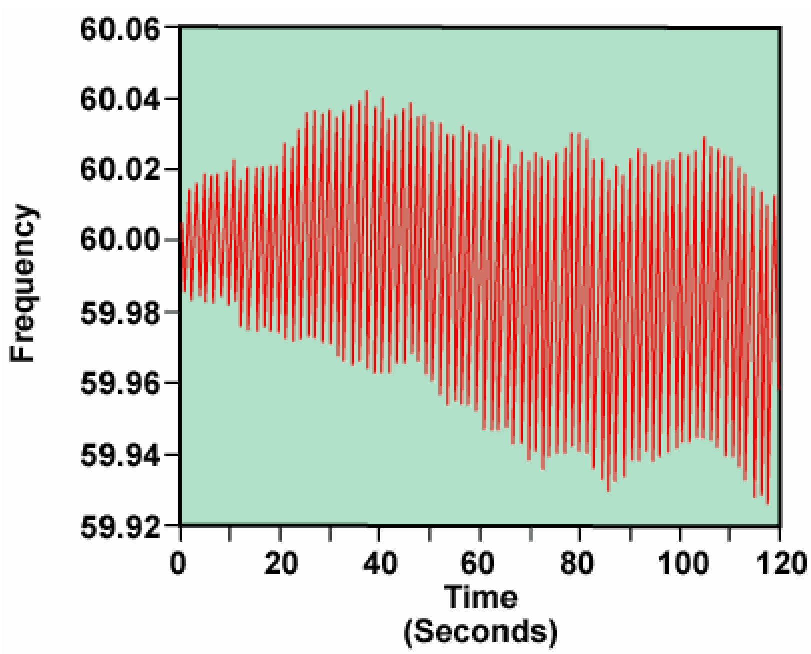


Figure 8-22
Oscillations Caused by Misoperating HVDC Controls

HVDC Modulation

HVDC systems can also be used to dampen AC system power oscillations. The power that flows in an HVDC system is removed from the AC system at the rectifier end of the HVDC. Assume that a low frequency oscillation is occurring in the AC system. If power could be removed from the AC and input to the HVDC at the proper frequency, the AC system oscillation could be dampened or modulated. HVDC modulation systems remove AC system energy in such a manner as to dampen AC system oscillations. Several of the HVDC systems in use within NERC use forms of HVDC modulation.

HVDC systems within the MAPP Region are used to dampen AC power oscillations in much the same manner as PSS.

8.5.4 Generator Pole Slipping

Power transfer from a generator is dependent on the angle spread between the generator and the system. A generator will transmit the maximum amount of MW to the system when the angle is 90°. Figure 8-23 is a sketch of a generator's stator and rotor illustrating changes to the angle spread. When the angle is 0° the MW output from the generator is zero. When the angle is 90° the MW output is at a maximum. If the angle spread goes beyond 90° the generator will likely lose control of its torque angle and enter an unstable condition.

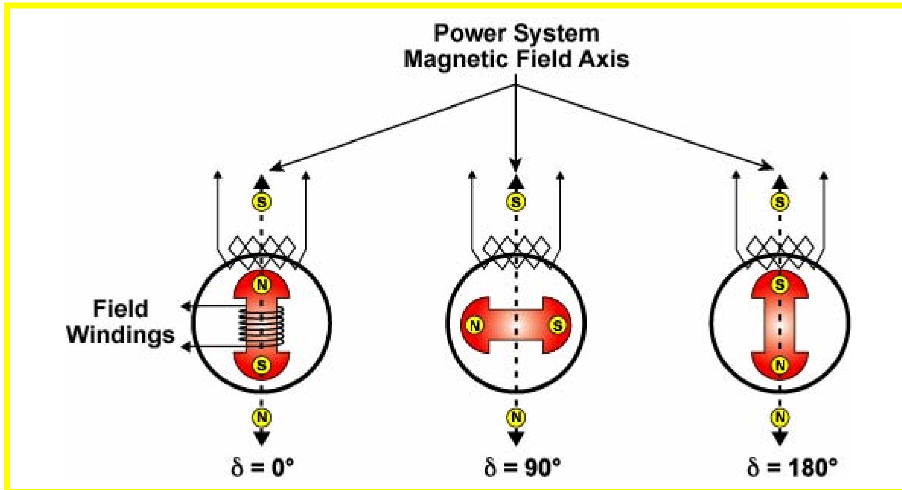


Figure 8-23
Increasing Angle Spread

Note how the MW and Mvar power oscillations are almost 180° out-of-phase with one another. The two flows are out-of-phase because the MW flow is based on the sine of the torque angle while the Mvar flow is based on the cosine of the torque angle.

If the MW output of a generator is less than its mechanical power input and the torque angle is greater than 90°, there is too little strength in the magnetic bond that holds the rotor in-step with the stator. The torque angle will rise above 90° and on towards 180°. At a torque angle of 180° system voltages are very low and Mvar output from the generator very high. The rotor will spin out of control with the rotor field poles slipping past the stator windings. This is called slipping poles.

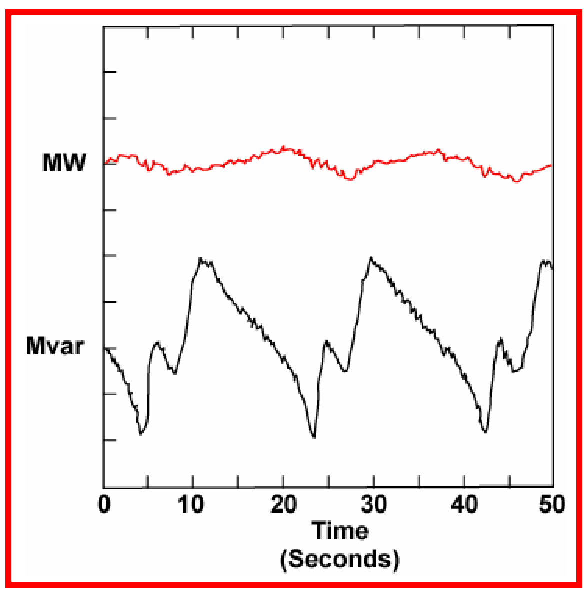


Figure 8-24
Generator Out-of-Step Oscillations

When a generator slips poles it will alternately send MW and Mvar out to the system and absorb it from the system. This creates a very large power oscillation. Figure 8-24 illustrates pole slipping in a generator. Note the oscillations to the generators MW and Mvar output.

8.6 Role of the System Operator

A system operator may from time to time detect oscillations in the power system. Most oscillations will be damped by the system with no need for system operator response. However, some oscillations may sustain themselves or grow in magnitude until a system operator response is needed. This section will describe methods of detecting oscillations and offer suggestions on how to respond.

Individual systems will know the best way to respond to their specific operating problems. This section is meant only as a general guideline.

8.6.1 Detecting Oscillations

During the normal monitoring duties of a system operator oscillations may be detected. For example, a strip-chart recorder or SCADA indication may signal the presence of oscillations. Most oscillations are difficult to monitor on a typical control center's equipment due to the slow (several second) sampling rates often used to gather data. For example, an oscillation may only be detected as an unexplained "hash" on a strip-chart. Some control centers have specially designed monitoring equipment that is fast enough and accurate enough to record the actual oscillations.

To start an oscillation, a triggering event is required. However, the triggering event may not be noticed. The triggering event may be so small, such as a minor load change or a control system action, that it goes completely unnoticed. These types of oscillations are the most difficult to detect. In contrast, if a severe disturbance happens in the power system some degree of oscillations is assured while the power system attempts to establish a new operating point.

8.6.2 Responding to Oscillations

The typical case is that a system operator will not become aware of oscillations unless a severe disturbance occurs or the oscillations reach large enough amplitudes to register on strip-chart recorders. Once a system operator determines that oscillations are present, the following guidelines are offered:

- The most effective tool to preventing and controlling oscillations is to hold power transfers within established limits as contained in system operating guidelines. A weak power system (excessive transfer or elements out-of-service makes any system weak) is more susceptible to oscillations than a strong power system. A proven way to dampen oscillations is to strengthen the power system.

- A system operator can strengthen a power system by either returning elements to service or reducing power transfers. If lines are out-of-service, the system operator should return the lines to service as soon as possible. If series capacitors are out-of-service a system operator should consider returning the capacitors to service. Adjusting system generation patterns may be an option (though possibly a costly one) for reducing power transfers. Shedding load is an option that all system operators should be empowered to use but typically only after less drastic options are attempted.
- Maintaining high system voltages will also strengthen the system as it allows a reduction in the angle. Generator voltage regulators should be in automatic mode to ensure dynamic reactive support when needed.
- System operators should ensure that all available PSS are in-service as intended. PSS are designed to dampen low frequency oscillations, and system transfer limits may be dependent on maintaining PSS in-service.
- If oscillations are strongest in the area of a particular generator consider reducing load on that generator. If the oscillations persist and could lead to serious trouble consider tripping the offending generator. A system operator must often rely on power plant operators for early detection of generator oscillations. The staff at the plant is often the first to know if their plant is oscillating.
- If oscillations are strongest in the area of a particular load, the load may be the problem. Is it a cyclic load? Are large motor loads causing the area power system to oscillate? A system operator may have to trip a load to rid the system of these type oscillations.

Summary of Power Oscillations

8.1.1 Definition of Oscillations

- Energy is stored in the rotating mass of system equipment, in the electric fields of capacitors, and the magnetic fields of inductors. When the storage balance is disturbed, oscillations will occur.

8.1.2 Triggering Events

- Oscillations require some initiating or triggering event to start. This event may not be noticeable.

8.1.3 Mechanical Analogy for Oscillations

- Small generators may start oscillating easily but typically have little impact on the power system. For larger generators, it is difficult to initiate oscillations, but once started may trigger oscillations so large that entire power systems suffer.

8.1.4 Typical Oscillation Frequencies

- Typical oscillations may vary from three cycles per minute (0.05 HZ) to 180 cycles per minute (3.0 HZ). The frequency of the oscillation will depend on what caused the oscillation and what portions of the system are oscillating.

8.1.5 Oscillation Envelopes

- The frequency of the power oscillation can be determined from the frequency of the oscillation envelope.

8.1.6 Oscillation Damping

- Damping refers to the ability of the power system and its equipment to reduce the amplitude of oscillations. Damping can be either positive or negative. When damping is positive, the amplitude of oscillations is reduced. When damping is negative, the amplitude of the oscillations is increased.
- Major sources of damping include the load/frequency relationship, transmission losses, generator losses, amortisseur windings, and excitation systems.

8.1.7 Oscillation Classifications

- Positively damped oscillations are temporary events and typically die out after several seconds.
- Undamped oscillations are oscillations that appear on the power system and sustain themselves.
- Negatively damped oscillations are the most damaging type of oscillation. If an oscillation appears and then gradually grows in magnitude it is negatively damped.

8.2.1 Changes to Power, Speed, and Angle

- When a power system is disturbed, adjustments occur to power flows, generator speeds, and angle. The changes to each (power flow, speed, and angle) impact one another.

8.2.2 Feedback Loop for Power, Speed, and Angle

- Changes to a generator's accelerating power lead to turbine/rotor acceleration or deceleration. Acceleration or deceleration leads to changes in angle and power flow. Power flow changes lead to accelerating power changes. The process then repeats itself.

8.2.3 Comparison of Power, Speed, and Angle

- Graphs of a generator's power output, angle spread, and turbine/rotor speed were presented. The three graphs shared a common time scale and contain useful information for understanding the oscillation process.

8.2.4 Summary of the Power Oscillation Process

- The power oscillation process can be summarized in the six step process presented in Figure 8-11.

8.3.1 Natural Frequency Analogy

- Every mechanical or electrical system has a natural frequency of oscillation.

8.3.2 Factors that Impact the Natural Frequency

- Every generator on the power system has a natural frequency of oscillation. The frequency is dependent on the inertia of the generator, the strength of the power system to which the generator is attached, and the generator's power output level. A typical range for generator natural frequencies of oscillation is from 0.75 to 3.0 HZ.

- The greater the inertia of a generator, the lower the generator's natural frequency of oscillation.
- A generator's natural frequency of oscillation increases with increasing transmission system strength.
- A generator's natural frequency of oscillation decreases as the generator's MW loading increases.

8.3.3 Oscillation Frequency Effect on Damping

- The higher the frequency of the oscillation the more positive damping the system can provide. Low frequency oscillations (< 1.0 HZ) are typically not well damped by the power system.
- Low frequency oscillations generally occur when high inertia generators are operating with large torque angles and are tied to weak transmission systems.
- High frequency oscillations generally occur when low inertia generators are operating with small torque angles and are tied to strong transmission systems.

8.3.4 Modes of Oscillation

- Oscillations are divided into four modes.

  1. Inter-Area Mode (0.05 to 0.5 HZ)
  2. Intra-Area Mode (0.4 to 1.0 HZ)
  3. Local Mode (0.8 to 2.0 HZ)
  4. Intra-Plant Mode (1.5 to 3.0 HZ)

8.4.1 Operation of an Excitation System

- The automatic voltage regulator inputs a signal representative of the generator's output voltage and compares it to a set-point value. The resultant error signal is used to determine the required level of generator excitation current.

8.4.2 Modern Excitation Systems

- Older excitation systems were slow and low power. Modern exciters are typically faster and more powerful.

8.4.3 Benefits of Fast, Powerful Excitation

- Modern exciters have helped extend steady state and transient stability limits.

8.4.4 Excitation Systems and Oscillatory Stability

- Fast, powerful excitation systems can contribute to the amplitude of power oscillations and possibly cause oscillatory instability.
- When the exciter output has the proper phase with respect to the system oscillation, the excitation system will help reduce power oscillations. When the excitation system has the wrong phase relationship, it may increase the power oscillation amplitude.

8.4.5 Power System Stabilizers

- Power system stabilizers, or PSS, are designed to correct the phase error present in fast excitation systems. PSS are tuned to correct an excitation systems response to low frequency oscillations. A PSS is typically set to detect oscillations in the inter-area or intra-area modes (approximately 0.05 to 1.0 HZ).

8.5.1 Cyclic Loads

- Major loads may be added and removed in a cyclic nature. From a power system perspective, these cyclic loads are similar to power oscillations.

8.5.2 Governor Control Systems

- If governor droops are set at 0%, generators could compete for load changes. The result would be power oscillations as the system's generators fight each other to make load changes.
- Transient droop is a short term (a few seconds) droop function that is used to prevent unit oscillations following governor directed power output changes.

8.5.3 HVDC Systems

- HVDC (high voltage direct current) systems can cause frequency and power oscillations. An HVDC control system's operation must be coordinated with AC system generation levels to ensure the HVDC does not cause AC system frequency disturbances.
- HVDC systems can also be used to dampen AC system power oscillations. HVDC modulation systems remove AC system energy in such a manner as to dampen AC system oscillations.

8.5.4 Generator Pole Slipping

- When a generator slips poles it will alternately send MW and Mvar out to the system and absorb it from the system. This creates a very large power oscillation. Utilities often employ protective relays to trip the generator if pole-slipping occurs.

8.6.1 Detecting Oscillations

- Oscillations are difficult to monitor on typical control center equipment due to the slow (several second) sampling rates used to gather data.

8.6.2 Responding to Oscillations

- The most effective tool to preventing and controlling oscillations is to hold power transfers within established limits.

Power Oscillations Questions

1. Typical power oscillation frequencies vary from:
   - A. 0.001 HZ to .0001 HZ
   - B. 100 HZ to 80 HZ
   - C. 60 HZ to 30 HZ
   - D. 0.05 HZ to 3.0 HZ
2. Amortisseur windings are:
   - A. Extra windings in a transformer's magnetic core
   - B. Conducting bars embedded in the magnetic poles of a rotor
   - C. A type of hydro generator stator winding
   - D. A type of circuit breaker tripping coil typically used in SF_6 breakers
3. Which of the following will tend to increase a generator's natural frequency of oscillation?
   - A. Strong transmission system
   - B. Higher inertia
   - C. Weak transmission system
   - D. High power output
4. Which mode of power oscillations typically appears on the major tie-lines that connect large power systems?
   - A. Intra-area mode
   - B. Inter-area mode
   - C. Intra-plant mode
   - D. Local mode
5. High speed excitation systems tend to extend _____ stability limits but may lead to _____ instability.
   - A. Transient / steady state
   - B. Oscillatory / transient
   - C. Steady state / transient
   - D. Transient / oscillatory

6. Which of the following are used to dampen power system oscillations?

   A. HVDC modulation

   B. Amortisseur windings

   C. PSS

   D. All of the above

7. Which type of power oscillations are of most concern?

   A. Negatively damped

   B. Damped

   C. Undamped

   D. Positively damped

8. Which of the following will tend to decrease a generator’s natural frequency of oscillation?

   1) Higher inerti
   2) Weak transmission system
   3) High power output
   4) Strong transmission system

   A. 2 and 4

   B. 1 and 2

   C. 4

   D. 1, 2, and 3

9. Which mode of power oscillations does every generator participate in?

   A. Intra-plant mode

   B. Inter-area mode

   C. Intra-area mode

   D. Local mode

10. On August 10, 1996, large 0.224 HZ power oscillations were measured in the Pacific AC Intertie 500 kV lines. These oscillations were:

    A. Intra-area mode

    B. Local mode

    C. Inter-plant mode

    D. Inter-area mode

Power Oscillations References

The author consulted several textbooks during the preparation of this chapter. Unfortunately, none of the texts are suitable for a system operator audience. The first reference listed is, in the author's opinion, the most readable. Hopefully, the material in this chapter has answered questions about power oscillations. If further information is desired consult your utility's engineering staff.

1. Power System Control and Stability—A text by Mr. A.A. Fouad and Mr. P.M. Anderson. Text was published by Iowa State University Press in 1977.

   This text addresses oscillatory stability and power oscillations. The text is very engineering oriented and likely not suited for system operators.

2. The Control of Prime Mover Speed—Part three of a series of three reports written by the staff of the Woodward Governor Company of Fort Collins, CO, Woodward Bulletin #25031A.

   This well written paper describes the problems encountered when alternators are paralleled. An easily understood description of a generator's natural frequency of oscillation is included.

3. System Frequency Stability in the Pacific Northwest—AIEE paper that appeared in "Transactions on Power Apparatus and Systems", Number 64, February 1963.

   This paper was the reference for Figure 8-21.

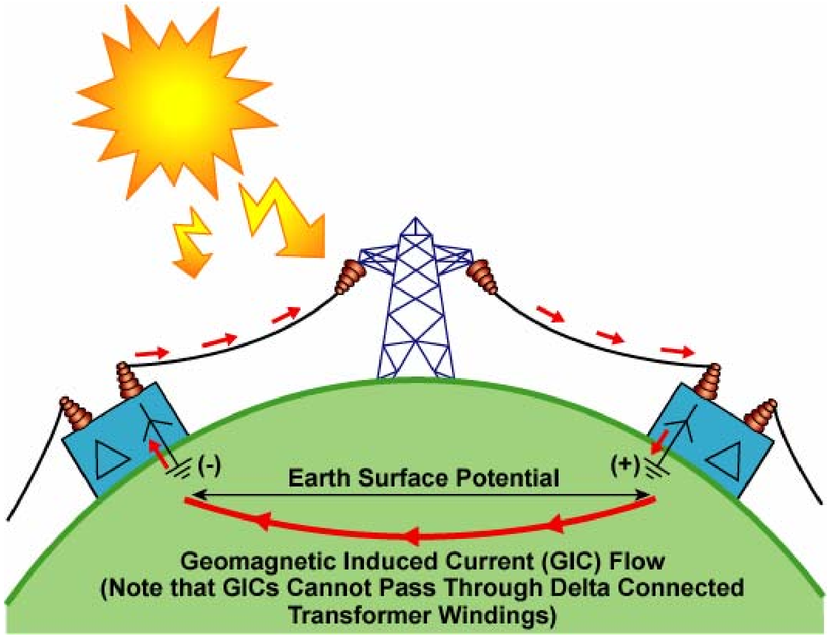
4. WSCC Abbreviated Disturbance Report for the Intermountain Power Project at 2310 Pacific Standard Time on March 6, 1987—Report prepared by Los Angeles Department of Water and Power, December 1987.

   This report was the reference for Figure 8-21.

5. Determination of Synchronous Machine Stability Study Constants—EPRI report EL-1424, June 1980.

   This report was the reference for Figure 8-24.

9
ADDITIONAL TOPICS



9.1 Additional Topics

Introduction to the varied topics addressed in this section.

9.2 Harmonics

Harmonics are integer multiples of the fundamental frequency. For example, the 3rd harmonic is 180 HZ.

9.3 Resonance

When electrical circuits resonate, high currents and voltages can develop.

9.4 Subsynchronous Resonance

Subsynchronous resonance arises due to an interaction between the power system and the natural oscillations of a turbine/generator.

9.5 Ferroresonance

Ferroresonance is a resonance condition due to a tuning between a circuit's capacitance and iron-core inductance.

9.6 Solar Magnetic Disturbances

Solar magnetic disturbances can lead to geomagnetic induced currents (GICs) that enter the power system through ground connections.

9.1 Additional Topics

9.1.1 Introduction to Additional Topics

This chapter addresses three related subjects; harmonics, resonance and geomagnetic disturbances.

Harmonics

Harmonics are integer multiples of the fundamental frequency. The fundamental frequency of North American power systems is 60 HZ. The second harmonic is therefore 120 HZ, the third 180 HZ, etc. A system operator may think all power system voltages and currents are 60 HZ but in practice the voltage and current are formed of the fundamental frequency plus various harmonics. Modern power systems cannot avoid harmonics but utilities strive to control the amounts of harmonics.

Resonance

A possible result of harmonics is a condition called "resonance". During resonance, power system voltages and currents can reach very high magnitudes. The magnitudes can grow so large that power system equipment, such as transformers, are destroyed. This chapter will concentrate on two resonance phenomena; ferroresonance and subsynchronous resonance.

Solar Magnetic Disturbances

Solar magnetic disturbances (SMDs) are solar induced disturbances to the earth's magnetic field. SMDs can damage power systems by causing low frequency currents to flow in the grounded neutrals of power system equipment. SMDs are related to harmonics and resonance in that the low frequency currents may saturate transformers. A saturated transformer is a source of harmonics. Once harmonics exist, resonance effects may follow.

9.2 Harmonics

9.2.1 Introduction to Harmonics

Electric power systems in North America are designed to produce and transmit 60 HZ power. However, if a voltage or current waveform were viewed on an oscilloscope the waveform may not be a perfect 60 HZ wave. The waveform will normally have some harmonic content.

An oscilloscope is an electronic instrument capable of displaying voltage and current waveforms.

9.2.2 Description of Harmonics

North American power systems operate with a 60 HZ power system frequency. The designers of the electric generators used to produce the 60 HZ power are largely responsible for ensuring that the voltage and current sine waves produced are 60 HZ waves. In ideal conditions a voltage or current wave is as illustrated in Figure 9-1. The generators must turn at just the right speed, the generator components such as the stator and rotor must have a specific shape and fit together perfectly, and the stator and field coils must be located in just the right positions to produce the 60 HZ voltage and current values expected.

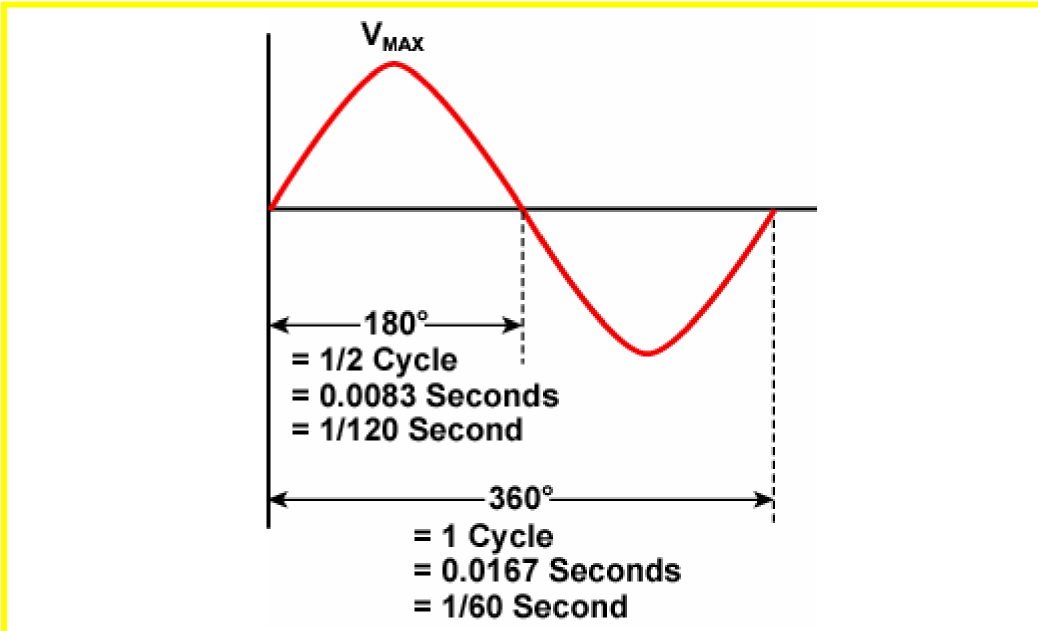


Figure 9-1
The Ideal 60 HZ Wave

Fundamental Frequency

The ideal 60 HZ wave is called the fundamental wave or the fundamental component. As illustrated in Figure 9-1 the fundamental wave is a sine wave that repeats itself 60 times per second. The positive and negative ½ cycles of the wave are identical.

Manufacturer's electrical equipment often counts on the repetitive nature of the fundamental wave. For example, an electronic device may produce timing signals based on the expected zero crossings of the fundamental wave. The voltage or current should cross zero every 0.0083 seconds for a 60 HZ wave.

If the wave does not cross zero every ½ cycle or 0.0083 seconds, the manufacturer's equipment may malfunction.

The power system is not a perfect world and the 60 HZ power system is, in reality, not composed of pure 60 HZ waves. There are always some additional frequency components mixed in with the fundamental component. Figure 9-2 illustrates a voltage wave that might occur in a heavily industrialized area. Notice that the waveform in Figure 9-2 is not a pure sine wave but has jagged edges and may not cross zero at the expected time. In addition to the fundamental component, this wave contains frequency components of other than 60 HZ. These additional components are called the harmonic components.

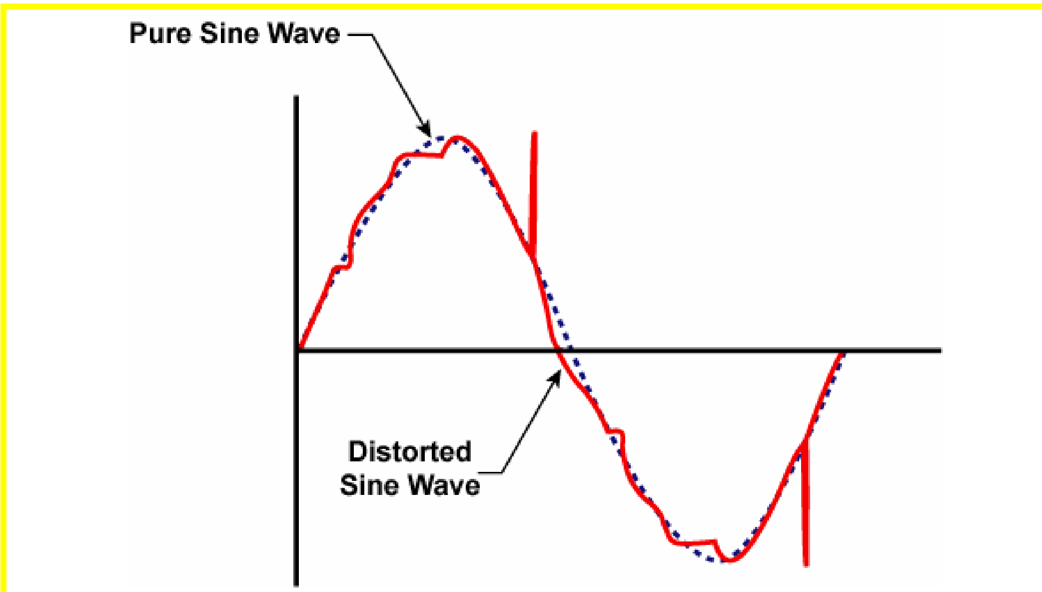


Figure 9-2
Voltage Wave with Harmonic Content

Fourier Analysis

Fourier was a 19th century mathematician who helped develop the science of frequency analysis.

Methods have been developed to study and quantify the harmonic content of repeating waveforms. These methods, called Fourier analysis, assign harmonic numbers or harmonic orders to the different frequency components. For example, if there is a 120 HZ component mixed in with the fundamental component, this component is called the 2nd harmonic.

The 2nd title refers to the fact that the component's frequency is a multiple of two (x2) of the fundamental frequency of 60 HZ. Harmonic components of any integer multiple of the fundamental frequency can exist. For example, the 3rd harmonic (180 HZ) is very common but the 25th harmonic (1,500 HZ) or the 47th harmonic (2,820 HZ) may also exist.

Figure 9-3 illustrates the impact of harmonic components on the shape of a voltage or current wave. Figure 9-3(a) is a perfect 60 HZ fundamental wave. Figure 9-3 (b) is a large 3^{rd} harmonic (180 HZ) component that was somehow injected into the power system. Figure 9-3 (c) is what is actually viewed on an oscillograph when the fundamental frequency and the 3^{rd} harmonic are combined. Notice how the addition of this large 3^{rd} harmonic component has made the resultant wave assume a more square wave shape.

Notice that the 3^{rd} harmonic is added "in-phase" with the fundamental. If the 3^{rd} harmonic wave had been shifted 90° an entirely different wave shape would have resulted from the summation.

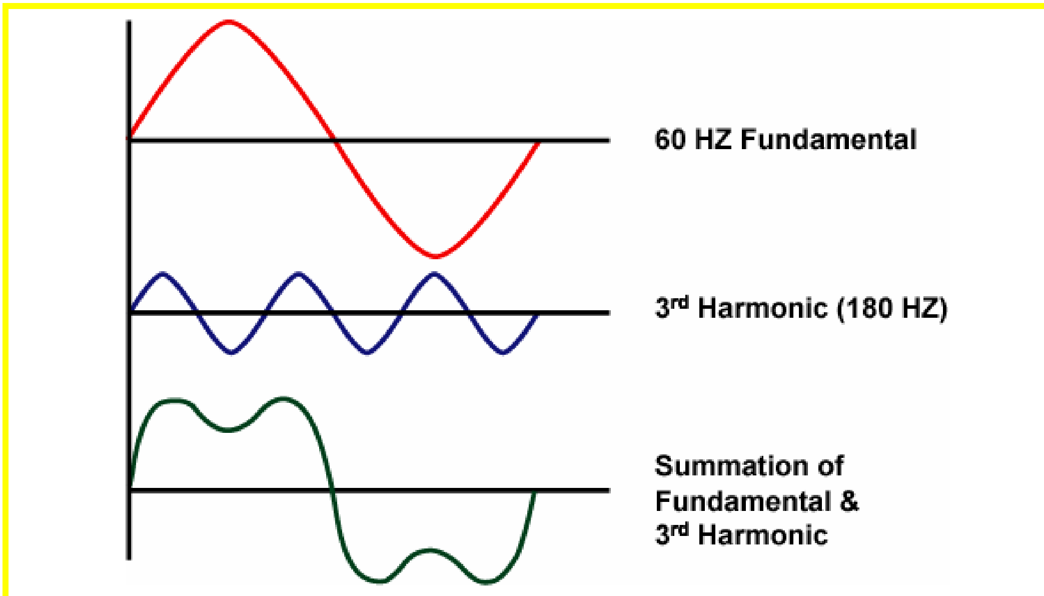


Figure 9-3
Summation of Fundamental with Harmonic

Personnel experienced in harmonic analysis can often look at a voltage or current waveform and rapidly estimate the frequency, magnitude, and phase relationship of the harmonic components contained in the wave. There may be several harmonic components mixed into a wave. For example, a wave shape similar to Figure 9-4 is the result of the summation of the fundamental, 5^{th}, 7^{th}, 11^{th}, 13^{th}, 17^{th}, 19^{th}, 23^{rd} and 25^{th} harmonics.

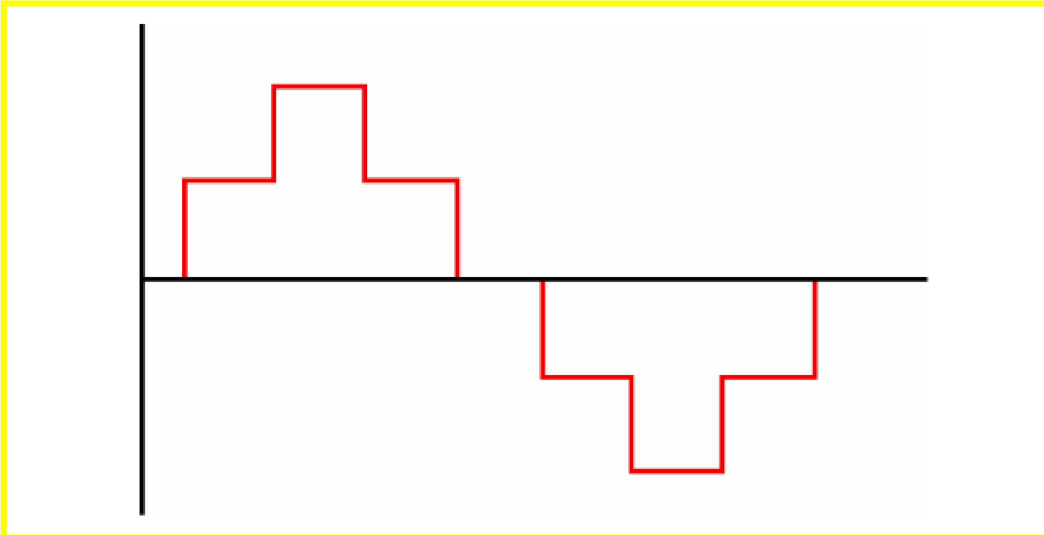


Figure 9-4
Sum of Fundamental, 5th, 7th, 11th, 13th, 17th, 19th, 23rd, & 25th

9.2.3 Harmonic Content

The THD for voltage is often called the harmonic factor for voltage or HF_V while the THD for current is often called the harmonic factor for current or HF_I.

A factor called the total harmonic distortion (THD) is used to quantify the harmonic content of a given voltage or current wave. The THD is given as a percentage figure. THD is a measure of the magnitude of all the harmonic components present in the wave as compared to the magnitude of the fundamental component.

The THD is calculated by taking the square root of the sum of the squares of all the amplitudes of the harmonic components and then dividing this value by the amplitude of the fundamental component. A THD of 5% for a voltage wave means that the harmonic content is 5% of the fundamental component. Allowable harmonic contents will depend on where the THD is measured and the type of equipment exposed to the harmonics. A 5% harmonic content is a high harmonic content and values exceeding 10% would likely be intolerable.

The harmonic source is the equipment that produces or creates the harmonics.

A study of the theory of harmonics yields upper limits to the possible magnitudes of each of the harmonic orders from each harmonic source. In other words, there is a limit to the amount of harmonic currents that each harmonic source can contribute to the system. This is not a limit to the total amount of harmonics in the power system as this can be multiple sources of harmonics.

For example, the maximum possible value of the 3rd harmonic contributed from each source is limited to 1/3 of the fundamental component from that source. The maximum possible value of the 5th harmonic contributed from each source is limited to 1/5 of the fundamental. As the harmonic order rises the possible maximum value it can reach, as a percentage of the fundamental, reduces.

This does not mean we can simply ignore the higher order harmonics. For example, the 47^{th} harmonic's magnitude may be limited to 1/47 of the fundamentals magnitude but its frequency of oscillation happens to fall within the voice range. The presence of the 47^{th} harmonic can be very disruptive to nearby telecommunication systems. In addition, multiple harmonic sources may raise the magnitude of the 47^{th} harmonic to very high levels.

9.2.4 Sources of Harmonics

There are many sources of harmonics on the power system. The generators themselves are not immune. Generator designers strive to produce the purest 60 HZ voltage wave but no design is perfect. There will always be some harmonic content to the voltages produced by generators. However, for practical purposes, the voltages developed by the large utility generators can be considered perfect 60 HZ waves. The major sources of harmonics in the power system are utility equipment and customer loads.

Utility Equipment as Sources of Harmonics

In general, any utility equipment that changes the shape of the system's voltage and current sine waves is a source of harmonics. Transformers, power (AC to DC) converters, and thyrister based devices are included in utility equipment harmonic sources.

Transformers

Transformers are a common source of 2^{nd} harmonics when they are first energized. When a transformer is energized, a large current in-rush occurs to magnetize the transformer's core. This reactive in-rush current will have a high concentration of 2^{nd} harmonic current. This harmonic content is short lived.

Transformer saturation was introduced in Chapter 5 and is further described in Section 9.6.7.

Transformers are even more important as harmonic sources when they are saturated. A transformer can saturate when it is exposed to voltages above its design rating. When saturated, a transformer's magnetic field spreads from the core area of the transformer. The magnetizing current drawn from the system to support the spread of the magnetic field also grows. The magnetizing current is very high in harmonics. Saturated transformers are sources of odd harmonics such as the 3^{rd}, 5^{th}, etc.

Power Converters

Another common utility source of harmonics is the power converters used to convert between AC and DC. These converters function by passing only a portion of the incoming voltage waveform to produce either an AC or DC output. For example, consider the conversion of an incoming AC voltage to a DC voltage. The peaks of the incoming phases of the AC voltage positive and negative waveforms are clipped off via high speed switching equipment to produce relatively constant positive and negative DC voltages. The AC waveforms that remain on the AC side of the conversion process are no longer pure 60 HZ waves but are now combinations of many harmonic components. The harmonics exist on the AC side due to the selective clipping of the waveform's peak values.

The harmonic content of the AC side of AC/DC converters has been analyzed and is well understood. Depending on the type of converter used, the AC side may have high concentrations of the 5th, 7th, 11th, 13th, 17th, 19th, 23rd, 25th, etc. harmonics.

Chapter 10 will describe the construction and operation of high voltage DC (HVDC) systems including harmonics and filtering.

The possible harm that harmonics can cause has not yet been described, but severe consequences can result. It is best to get rid of the harmonics, if this is possible. HVDC (high voltage DC) converters are always equipped with filters that are designed to absorb the expected harmonics created from the power system.

Thyrister Based Equipment

Thyristers were introduced in Chapter 2 while SVCs were described in Chapter 5.

An emerging type of utility equipment that is often a strong source of harmonics is the class of equipment that is controlled via high powered electronic switches called thyristers. Thyrister based equipment is capable of very rapid switching actions.

Figure 9-5 illustrates a static var compensator or SVC. SVCs are rapidly adjustable sources or sinks of reactive power. SVCs use thyristers to quickly adjust the reactive power the SVC is taking from or inserting into the power system.

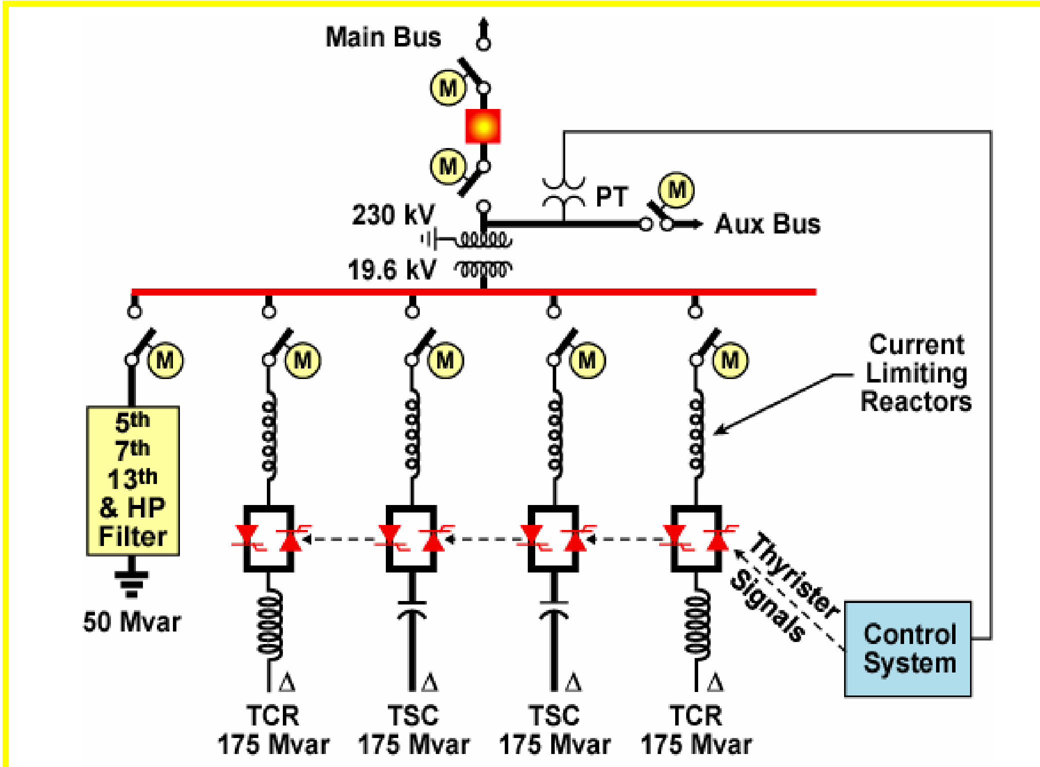


Figure 9-5
Static Var Compensator

Note that the capacitors in Figure 9-5 are thyrister switched capacitors (TSC) while the reactors are thyrister controlled reactors (TCR). Thyrister switching is similar to a circuit breaker's operation and does not produce harmonics. Thyrister control involves the continuous control of the magnitude of the current allowed to pass through the reactor. Thyrister control is a strong source of harmonics. Note the filters illustrated in the left side of Figure 9-5. These filters are designed to absorb the harmonic currents produced by the thyrister controlled reactors.

Customer Load as Source of Harmonics

Non-linear customer loads are sources of harmonics. If a sinusoidal voltage is applied to a load from which the load draws a non-sinusoidal current, it is a non-linear load. Examples of non-linear loads include:

- Discharge lighting such as florescent and mercury arc lighting are sources of harmonics, especially the 3rd harmonic. Discharge lighting produces small arcs which in combination with the light's ballast results in harmonics.
- Arc furnaces and arc welders which have a changing load characteristic during each ½ cycle. These type loads produces harmonics.

- Electronic equipment powered via switch mode power supplies. Switch mode power supplies are economical power supplies used in most modern electronic equipment. This type of load draws current for only a portion of each ½ cycle thereby producing harmonics.
- Rotating machinery will produce harmonics if the phase coils are not sufficiently symmetrical. In addition, the machinery stator iron may saturate which leads to harmonic production.
- Industrial static power converters that use thyristers to control the speed and torque of AC and DC motors. Harmonics are produced by industrial power converters in much the same manner that utility HVDC converters produce harmonics.

9.2.5 Flow of Harmonic Current

Figure 9-6 illustrates how harmonic currents can be produced by a utility's equipment or customer load and flow into the power system. The figure consists of a source of harmonics, a tie to the utility system, an additional load, and power factor correction shunt capacitors.

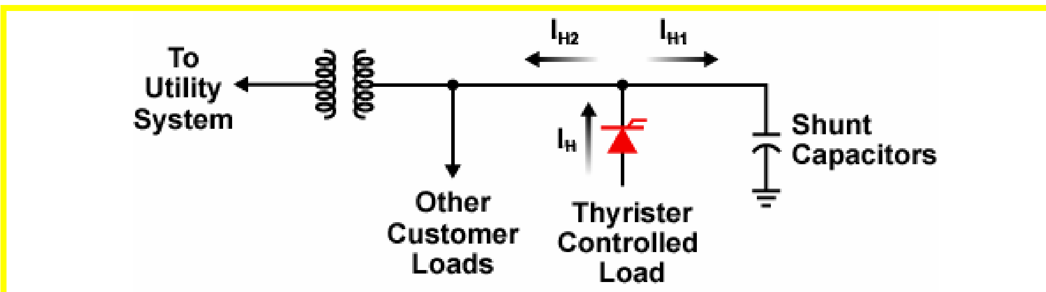


Figure 9-6
Flow of Harmonic Current

Assume that the thyrister controlled load is a big steel plant that uses large DC motors. This load is a source of harmonics as far as the utility is concerned. Think of the load as a harmonic current generator. The harmonic currents, I_H, will flow into the connected power system. The harmonic currents will distribute, like any other current, according to the path of least impedance.

For example, some portion of I_H will flow towards the other customer loads and the utility system (I_{H2}), while some portion will flow into the shunt capacitor (I_{H1}). In subsequent sections of this chapter the damage that can be caused by harmonic currents will be described. The harmonic currents that flow into the capacitor may cause the capacitor's protective relays to function while the harmonic currents that flow into other customer loads or the utility system may result in thermal damage to equipment.

9.2.6 Effects of Harmonics

The impact of harmonics on the power system depends on the harmonics' relative magnitude and the type of equipment exposed to the harmonics. If the equipment is relatively unaffected by harmonics, it follows that the harmonic content can be very large and cause little damage. For example, heating equipment such as residential resistive heating or industrial ovens is normally not severely impacted by harmonics. However, other types of equipment may be damaged by harmonics.

Rotating Equipment

Section 9.4 will describe an extreme example of this torque creation called SSR or subsynchronous resonance.

Rotating equipment such as motors and generators are very susceptible to harmonics. Different order harmonics will have different effects. In general, the harmonics will induce current flows in areas of the rotating equipment that are not designed for current flow. Overheating could then result. The harmonics can also create torques or forces in the rotating equipment shafts which may lead to cracking and eventually failure of the shaft.

Transformers

Transformers are susceptible to harmonics due to the overheating that may occur. As the frequency of the harmonic rises, its impact on overheating rises. High frequency harmonics increase the intensity and spread of the magnetic field and induce currents in areas that are not designed for currents. These induced currents lead to overheating. An audible sign of harmonic content in a transformer is the loud buzzing sound that often accompanies the harmonics.

Transformers may also be exposed to high harmonic overvoltages. These overvoltages are likely due to a resonance condition developing between the transformer and a local capacitance. Voltages can rapidly rise to 20 or 30% above nominal values and lead to saturation with accompanying transformer loss of life or even internal faults within the transformer.

Shunt Capacitors

As you may recall from Chapter 3, the capacitive reactance, X_C, in ohms is equal to: $X_C = \frac{1}{2\pi fC}$. What is important in this equation is the frequency term in the denominator. The higher the frequency the shunt capacitor is exposed to, the lower its capacitive reactance will be. Currents with high frequency (high harmonic orders) will be drawn to the grounded shunt capacitors in the system since the capacitor presents a low impedance path to these currents. This can (and has often done so) lead to false tripping of capacitor banks when high order harmonics are present.

For example, certain system conditions (such as geomagnetic storms) may create an abundance of harmonics. The high frequency harmonics seek out the local grounded capacitor banks. The capacitor's protective relaying may falsely assume the sudden in-rush of current is due to a fault and trip the capacitor. Individual capacitor cans are often protected with fuses. High harmonic currents can blow these fuses and lead to tripping of the capacitor bank.

Protective Relaying

Protective relays may misoperate due to harmonic currents and voltages. Both electro-mechanical and solid-state relays are impacted. Electro-mechanical relays may respond to the harmonic voltages and current in the same manner that they respond to the fundamental component. For example, a high harmonic current magnitude may cause enough disk rotation in an induction disk overcurrent relay to activate a trip circuit even though a high fundamental fault current does not exist. Solid-state relays may respond to transient values of voltage and current. Often the harmonic components are large but short lived. A solid-state relay may act quickly enough to falsely trip for a very rapid harmonic transient.

Manufacturers have designed versions of solid-state and electro-mechanical relays to be less susceptible to harmonics. However, not all the relays in the power system are equipped with these features. One relay that is typically equipped with "harmonic restraint" circuitry is the differential relay for a large power transformer. As mentioned earlier, when a transformer is first energized the in-rush current includes a large 2^{nd} harmonic component. Power transformer differential relays are often designed to recognize and prevent false tripping due to the 2^{nd} harmonic component of the in-rush current.

Telecommunications Equipment

A common result of harmonics is interference with the local telephone systems. When harmonic currents and voltages exist they produce electric and magnetic fields of a like harmonic frequency. These fields can induce voltages and currents in neighboring telephone equipment. The unwanted fields can easily disrupt telephone communications and anger both the telephone company and the local telephone system users. Low frequency harmonics (less than the 10^{th}) do not significantly impact telephone systems. Higher frequency harmonics (15^{th} to 60^{th}) are often troublesome as their frequency of oscillation is within the audio frequency range that is used by telephone systems.

The effects of harmonic interference between electric and telephone systems can be reduced by proper shielding of telephone equipment or filtering of utility power supplies. However, shielding and filtering are expensive and not used unless required.

Additional Effects of Harmonics

The effects of harmonics are widespread, only a few possibilities have been described. Other effects of harmonics include:

- Interference with power line carrier (PLC) telecommunication systems
- Metering errors
- Interference with generator excitation systems

9.2.7 Control of Harmonics

There are many methods used to control the spread of harmonics and reduce their impact. For example, telecommunications equipment is often shielded to prevent interference by harmonically induced electric and magnetic fields. This section describes two types of harmonic control methods. The first method is the use of delta connected tertiary windings and the second method is the use of harmonic filtering.

Delta Connected Tertiary Windings

Delta connected windings on 3Φ transformers have a special property that enables the winding to make a large contribution to system harmonic control. Delta connected windings will naturally absorb the “triplen” harmonics. The triplen harmonics are the 3^{rd}, 6^{th}, 9^{th}, 12^{th}, etc. Recall from Chapter 3 that the system’s 3Φ voltages are 120° out-of-phase with one another. In contrast, triplen harmonic voltages are in-phase with one another. When three in-phase voltages energize a delta winding they are essentially trapped since their return path to the source is blocked.

Figure 9-7 illustrates an autotransformer with a delta connected tertiary winding. The delta connected winding will trap the triplen harmonics and prevent them from impacting the power system. The 3rd harmonic is the major concern since as the harmonic order increases its impact on the power system generally diminishes.

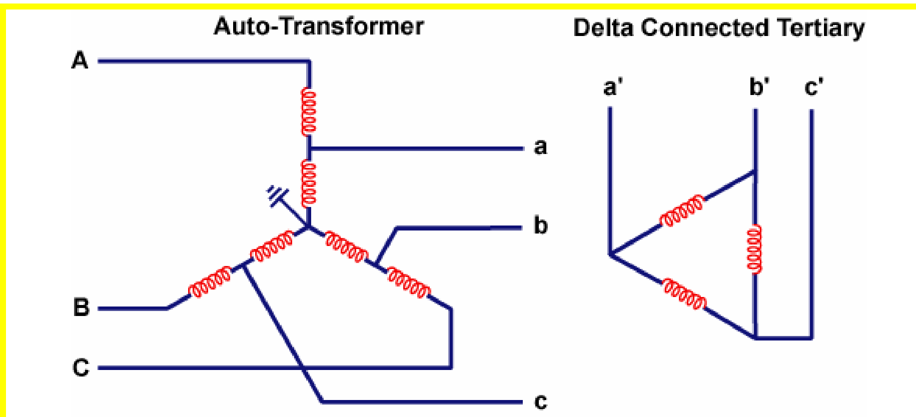


Figure 9-7
Autotransformer with Delta Tertiary

Harmonic Filtering

A simple harmonic filter is illustrated in Figure 9-8. This particular filter is a series combination of an inductor, capacitor, and a resistor. Variations of this filter can be connected in parallel or in shunt to the power system. The filter will be tuned to present a low impedance to whatever frequency harmonic the utility wants to remove from the power system. The tuning can be accomplished by varying the size of the inductor or capacitor but is normally done by adjusting the capacitor size.

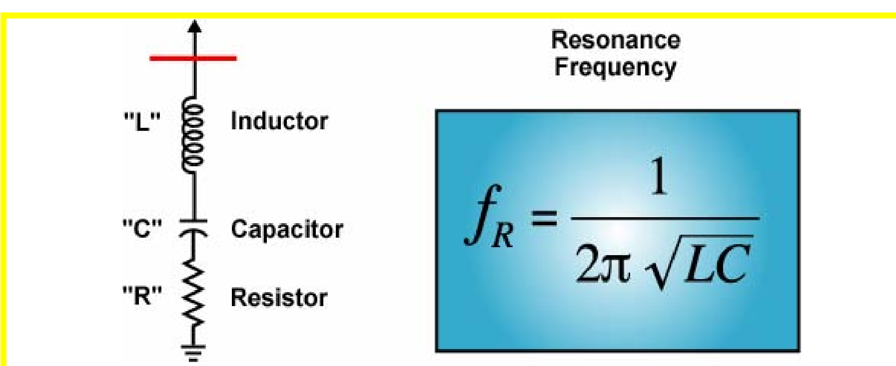


Figure 9-8
Harmonic Filter

A series circuit consisting of an inductor and a capacitor can be tuned to pick the frequency at which the circuit will have a minimum impedance. The frequency for minimum impedance is called the resonance frequency. An example of the application of this type filter will clarify its use. Figure 9-9 is a simple one-line diagram of an HVDC converter. Assume the converter is a source of 11th and 13th harmonics.

Remember that capacitance is measured in farads and inductance in henrys.

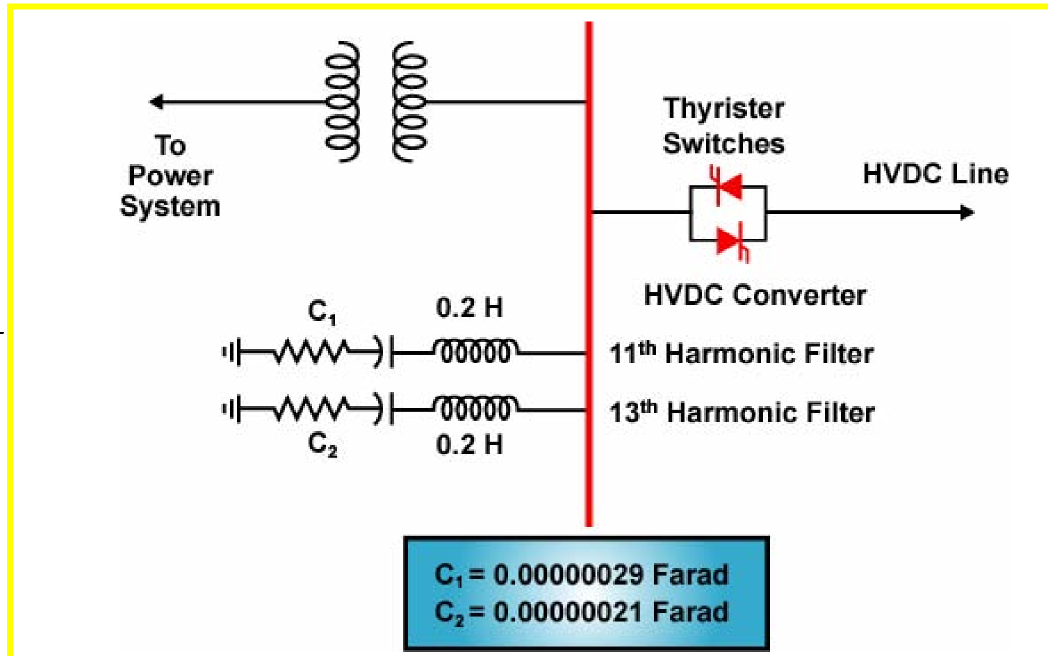


Figure 9-9
Sample Tuning of a Filter

Two series filters are illustrated in Figure 9-9. Assume that both filters came with a 0.2 Henry (fixed size) inductor. The equation for the resonance frequency that was given in Figure 9-8 is used to determine the capacitance, C, values required for each filter. One filter's "C" value would be chosen to achieve resonance at the 11th (660 HZ) harmonic and the other filter's "C" value chosen to achieve resonance at the 13th (780 HZ) harmonic. Both calculated "C" values are listed in Figure 9-9.

Once capacitors with the required "C" values are installed, the filters will be operational. Now anytime the 11th or 13th harmonics appear in this system, the filters will absorb these currents since the filters present a very low impedance path to currents of these frequencies. Filters of this type of design are very common in HVDC converter stations. HVDC converters naturally produce harmonics so filters are used to absorb the harmonics from the power system before they can cause any damage.

9.3 Resonance

9.3.1 Introduction to Resonance

Perhaps the simplest way to visualize the concept of resonance is to think in terms of a musical analogy. When a musical instrument is being tuned, the sound produced by a known source is compared to the sound of the instrument that is being tuned. The goal of tuning a musical instrument is to match the frequency of oscillation of a known source to the frequency of oscillation of the instrument that is being tuned.

For example, to tune a guitar's strings, one could first use a piano to sound an accurate "b" note. The "b" string of the guitar is then plucked. If the guitar is tuned properly, the "b" string of the guitar will vibrate at the same frequency as the piano's "b" note. When the two musical sources produce sound at the same frequency, they are in resonance or resonant with one another. The goal of musical tuning is to achieve resonance with a known frequency source.

With musical resonance, you can hear or feel the resonance condition. For example, in our musical analogy, if the two "b" note sources are tuned properly, the two sounds will appear to add to one another and produce one unique sound at a clear distinct frequency. If the two sources are out of tune, the sounds will interfere with one another and their combination appears garbled.

Electrical resonance is similar to musical resonance in that electrical circuit elements are somehow adjusted so that they are tuned to one another. However, instead of notes from guitar strings and pianos, the circuit's capacitive and inductive elements are tuned to one another. When an electrical circuit resonates, high currents and voltages can develop.

Electrical resonance is often used to achieve desired results. For example, when a radio station is tuned-in, a resonant condition at the desired station frequency is intentionally created. This section will address the undesirable results of creating resonance in the power system. Power system resonance can lead to high currents which may cause thermal damage to system equipment, and to high voltages, which may saturate transformers and lead to insulation failures.

In more technical terms, electrical resonance occurs when the capacitive reactance of a circuit matches or is tuned to the inductive reactance of a circuit. When the capacitive reactance is tuned to the inductive reactance the two reactances will compensate one another. The capacitive reactance is composed of capacitive circuit elements which may include line charging and series and shunt capacitors. The inductive reactance is composed of the inductive circuit elements which may include the line reactance, transformer reactance, and series and shunt reactors. There are two general types of resonance; series resonance and parallel resonance.

9.3.2 Series Resonance

Figure 9-10 will be used to describe series resonance. The figure illustrates a high voltage transmission line section. The transmission line has inductive reactance, X_L, and resistance, R. There is also a series capacitor, X_C, installed in the line.

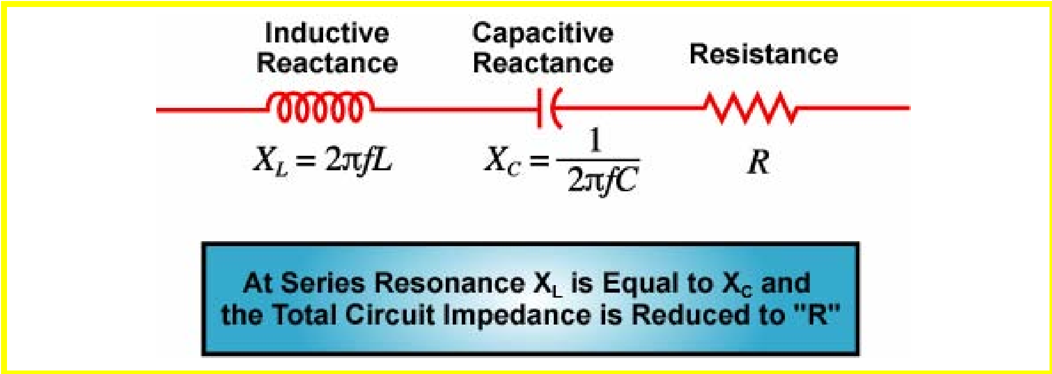


Figure 9-10
Series Resonance

Note that when the magnitude of X_L equals X_C they cancel one another as they are 90° out-of-phase.

Series resonance will occur in the system of Figure 9-10 if, at some specific frequency, the inductive reactance of the transmission line is fully compensated by the line's capacitive reactance or when the magnitude of X_L equals X_C. At series resonance the total circuit impedance is reduced to the series resistance or R value. The circuit of Figure 9-10 would present the low resonance impedance (the R value) to currents near the resonance frequency. Currents of frequencies other than the resonance frequency would see a higher impedance. This is an important point to remember. The resonant condition applies to currents close to the resonant frequency. Currents at other frequencies would see higher circuit impedance values.

A series resonant condition can be achieved using two possible methods; either by adjusting the frequency of the system, or by changing the size of the system's series capacitance or reactance.

Series Resonance by Changing the Frequency

As stated earlier, at series resonance the magnitude of X_L equals X_C. By studying the reactance equations for X_L and X_C one can deduce that a series resonant condition can be created by changing the system frequency to a value where X_L equals X_C. This will occur at a frequency of f_R, or at the resonant frequency. Figure 9-11 illustrates how a frequency adjustment can be used to produce series resonance. If a power source with a frequency of f_R was inserted into the circuit of Figure 9-11, the circuit impedance would reduce to R, as X_L and X_C equal one another.

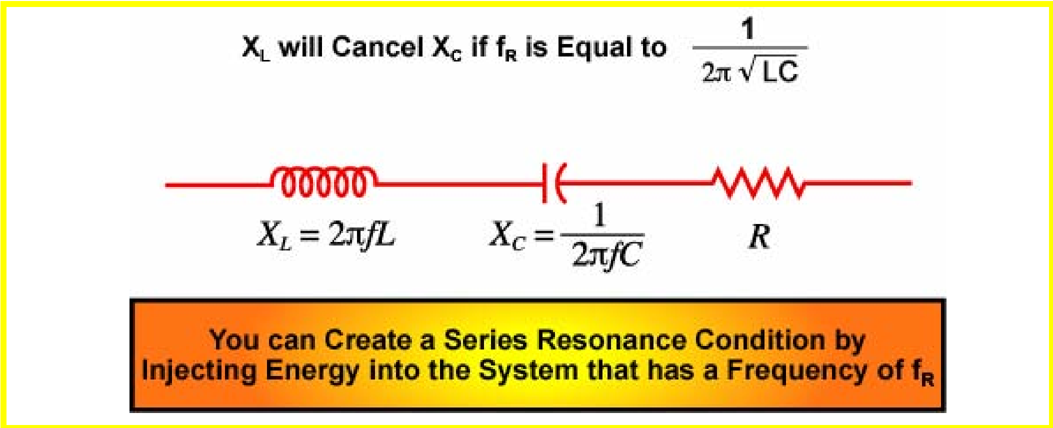


Figure 9-11
Series Resonance by Varying Frequency

For example, assume that the X_L and X_C values in Figure 9-11 are such that the resonance frequency, f_R, is equal to 180 HZ. Assume the current flowing in this circuit has two components, one with the fundamental or 60 HZ frequency and one with the 3rd harmonic or 180 HZ frequency. The fundamental frequency current would see the normal 60 HZ circuit impedance. This higher impedance will include both reactance and resistance. The 3rd harmonic currents will only see the resistance since the capacitive and inductive reactance values are equal to one another at this frequency.

Series Resonance by Changing the Reactance

The second method that can be used to create a series resonant condition is accomplished by varying the size of the series inductive and capacitive elements in the system. At series resonance X_L equals X_C. If the size of the X_L or X_C values are adjusted until they are equal in magnitude, a series resonant condition is produced.

Section 9.2.7 of this chapter described the use of filters to provide low impedance paths to harmonic currents. These filters were intentional creations of series resonant conditions. The capacitive and inductive parts of the series filter are chosen to achieve resonance at whatever harmonic frequency the designer wants the filter to absorb energy from the power system. For example, the filters described in Figure 9-9 were designed to absorb currents with 11th and 13th order frequencies. Anytime currents of these frequencies appear in the area of the filter they will be absorbed by the filters and passed harmlessly to ground.

Use of Series Capacitors

A series capacitor was illustrated in Figure 9-10. Utilities may choose to install a series capacitor as a means of increasing a transmission line's MW transfer capability. (This is in contrast to the use of shunt capacitors which are installed for voltage control.) A series capacitor works by compensating for a portion of a transmission line's natural inductive reactance.

Consider the transmission line section of Figure 9-12 (a). This 100 mile long 345 kV line has a resistance of 6Ω and an inductive reactance of 60Ω. (Both of these impedance values are functions of the size of conductor and the line's design.) The MW transfer capability of the line would increase if the line's impedance were reduced. The largest part of the line's impedance is the inductive reactance at 60Ω. If a series capacitor is added to this line, the capacitive reactance of the series capacitor subtracts directly from the line's inductive reactance. For example, in Figure 9-12 (b) a 30Ω series capacitor is added to the line. The sum of the 60Ω inductive reactance and 30Ω series capacitor is a net reactance of 30Ω.

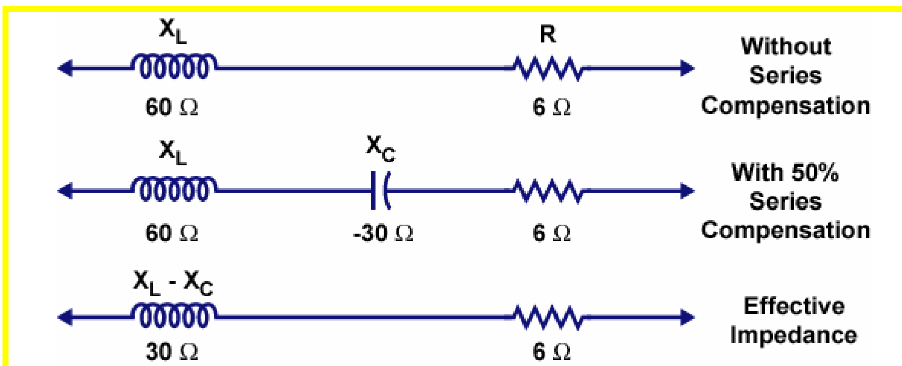


Figure 9-12
Use of Series Capacitors

This line's effective impedance after installation of the series capacitor is illustrated in Figure 9-12 (c). The addition of the series capacitor has reduced the reactance of the line by 50%. Power engineers would say this line has been 50% series compensated. More MW can now flow over the line increasing the line's MW transfer capability.

If 60Ω of series capacitance had been inserted in this line a 60 HZ series resonant condition would have been intentionally created. Normal 60 HZ power would then have only the circuit's resistance to limit the current flow. This would maximize the power transfer of the line. Unfortunately, in the real world 100% series compensation likely cannot be used. Severe consequences may result. Among the consequences is a phenomenon called subsynchronous resonance (SSR) which is described in Section 9.4.

Before we leave series resonance, two important points are emphasized:

- At series resonance the circuit impedance is at a minimum and equal to the circuit resistance. The normal inductive reactance of the circuit is compensated by the circuit's series capacitive reactance. The low impedance of the series resonant condition applies to currents at and/or near the series resonant frequency. The series resonance frequency can be any frequency value including the fundamental.
- The impedances of the inductive and capacitive elements cancel one another during series resonance. However, remember that these reactive elements are still in the power system.

Assume that the inductive element is a 345/138 kV auto transformer and the capacitive element a series capacitor as illustrated in Figure 9-13. During series resonance, fundamental and resonance frequency currents flow through both the inductive and capacitive elements. Both currents result in voltage rises across the capacitor and voltage drops across the transformer. The rises and drops cancel one another out so an observer will not detect these voltage changes at the ends of the circuit. However, the internal circuit elements, especially the transformer, are exposed to the summation of the fundamental and resonance voltages and may be damaged by the resultant high voltages.

A delta connected tertiary is normally installed in an auto-transformer to assist with harmonic control and help prevent resonance problems.

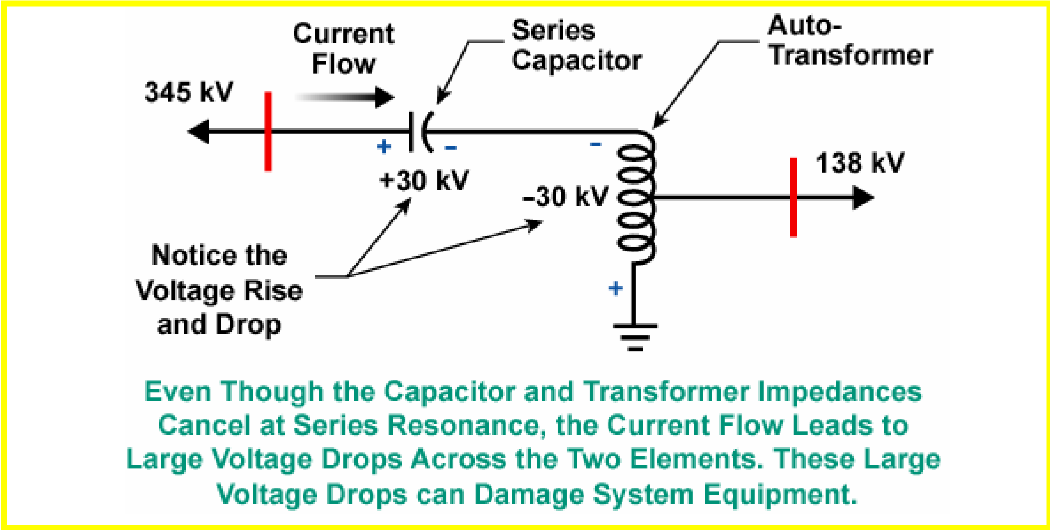


Figure 9-13
Voltages During Series Resonance

When a series resonance condition exists, the elements in the resonance circuit can be exposed to voltages that are much higher than the source voltage.

9.3.3 Parallel Resonance

Parallel resonance is similar to series resonance but occurs when the capacitive and inductive elements are in parallel and their impedances are equal in magnitude. Figure 9-14 is used to illustrate parallel resonance. The figure contains an autotransformer and a shunt capacitor bank connected in parallel (assume both are tied to the same bus). This circuit can enter into parallel resonance by either inputting resonant frequency energy or by changing the size of the capacitive and/or inductive elements. A common method of creating a parallel resonance condition is by injecting energy into the system at the resonance frequency.

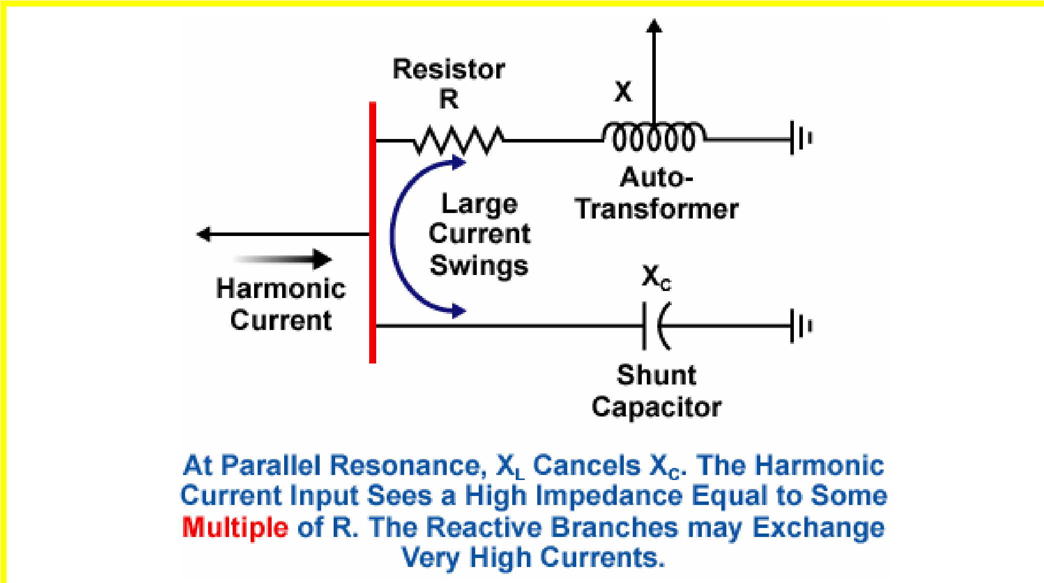


Figure 9-14
Parallel Resonance

If energy at the resonant frequency is somehow injected into the circuit of Figure 9-14 it would result in parallel resonance. The X_L and X_C values would then cancel. At parallel resonance the incoming current would "see" a very high impedance that is almost purely resistive and possibly equal to many times the circuit's resistance value. The total current that passes through the circuit would be at a minimum. The reactive branches (the capacitor and transformer) would still be in the circuit even though their impedances canceled. These two branches would exchange large amounts of reactive current as illustrated in Figure 9-14.

The magnitude of the effective resistance depends on the square of the ratio of X_L/R. This ratio is known as the circuits quality or Q value.

Even though the total current flowing through the circuit is at a minimum, the current that circulates internally between the parallel capacitance and inductance can reach very high magnitudes. This large circulating current creates voltage drops across the transformer and capacitor. The voltages may reach high enough magnitudes to damage equipment, especially transformers.

Parallel Resonance in HVDC Converters

The parallel resonance condition is likely to occur in high voltage direct current (HVDC) converter stations. HVDC converters produce harmonics that can excite parallel resonance if the proper X_L and X_C values exist in the area of the HVDC. For example, consider the simplified one-line diagram of Figure 9-15. The transformer supplies AC power to the HVDC converter station. HVDC converters are heavy users of reactive power. The reactive power is supplied from shunt capacitors connected in parallel to the AC power transformer. (Assume the filters are initially out-of-service.)

Chapter 10 includes a description of the construction and operation of HVDC systems.

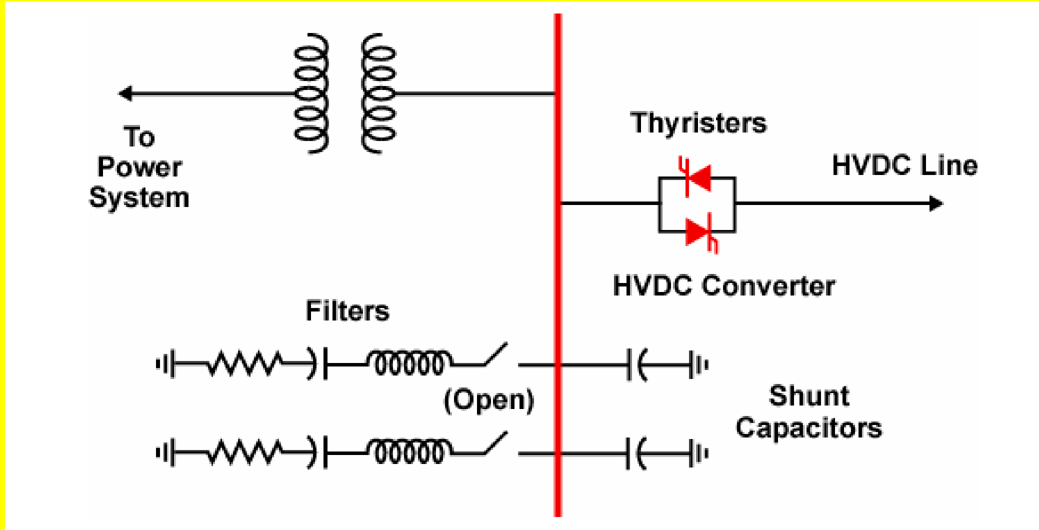


Figure 9-15
HVDC Converter Simplified One-Line

Assume that this is the type of converter that produces 5th (300 HZ), 7th (420 HZ), 11th (660 HZ), 13th (780 HZ), 17th (1,020 HZ), 19th (1,140HZ), 24th (1,440 HZ), and 25th (1,500 HZ) harmonic currents. These harmonic currents will flow from the converter into the parallel combination of the transformer and capacitor. Further assume that the "R-L-C" circuit has values of inductance and capacitance such that the parallel resonance frequency is very close to the 11th harmonic. These 11th harmonic currents would excite parallel resonance in the circuit.

A large 11th harmonic current would circulate between the inductive and capacitive branches. Large 11th harmonic voltages may then develop across the transformer and capacitor. These large voltages would be in addition to the normal circuit fundamental frequency voltages. The combination of normal fundamental frequency voltage and current and high 11th harmonic voltage and current could:

- Thermally damage the transformer and capacitor
- Blow capacitor fuses
- Overexcite and damage the transformer
- Lead to insulation failure in the capacitor
- Interfere with telecommunication systems
- Interfere with protection systems

Unfortunately, every HVDC converter station has a transformer to connect it to the AC power system and shunt capacitors to supply reactive power. These are just the ingredients needed for parallel resonance. To avoid parallel resonance, HVDC converters are equipped with special filters to absorb the harmonic currents that could give rise to parallel resonance. Two filters are illustrated in Figure 9-15. One of these filters could be tuned to absorb 11th harmonic current. In an actual HVDC station the utility would analyze the converter to determine just what harmonics are created. Individual filters would be tuned to absorb the most critical harmonic frequencies and then a special type of filter—called a high pass or HP filter—would be tuned to absorb all the higher order harmonics.

9.4 Subsynchronous Resonance

9.4.1 Introduction to Subsynchronous Resonance

As you recall from Section 9.3, series resonance occurs when the magnitude of the series inductive reactance of the circuit is equal to the series capacitive reactance. Subsynchronous resonance or SSR is similar to series resonance and occurs due to an interaction between a system's generators and the local transmission system. This section will review series resonance as it relates to SSR and then explore the topic of SSR.

9.4.2 SSR and Series Capacitors

Figure 9-16 illustrates a simple power system that consists of a steam generator tied to a load through a 345 kV transmission path. The utility that operates this system has determined that a series capacitor is required to increase the MW transfer capability of the transmission path. The size of the series capacitors installed will depend on how much of the normal line reactance the utility wishes to compensate. For example, if the utility chooses to reduce the line reactance by 50% they would install 50% series compensation. If the utility chooses to cancel 60% of the line's reactance they would install 60% compensation. Figure 9-16 illustrates 50% compensation.

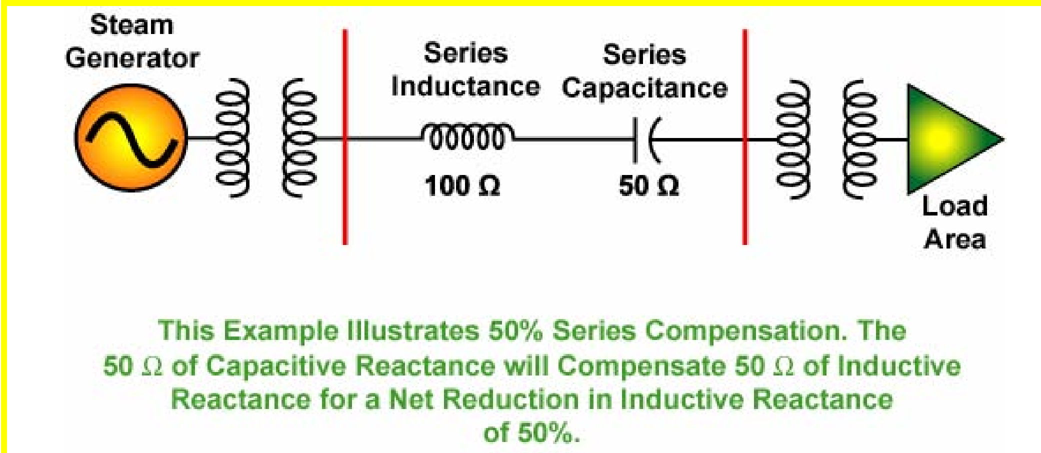


Figure 9-16
Series Compensation

The lower the system reactance, the more MW that can be transmitted across the transmission line. In theory, a utility could completely eliminate the line's reactance and maximize MW transfer capability by adding enough series capacitors to completely compensate the line's inductive reactance. This would be referred to as 100% compensation. In practice, however, this is not practical.

The use of series capacitors also complicates power system protection.

The amount of series compensation used will be limited by several restrictions. A first restriction is that series capacitors cause a voltage rise when inductive (lagging) current passes through. This limits the amount of series capacitance to the tolerable voltage rise at the series capacitor's physical location. A second limitation to the use of series capacitors is that the probability of SSR problems increases with the increasing amount of series capacitance.

9.4.3 Resonance Frequency

When series capacitors are added to the power system the frequency at which series resonance occurs is changed. In Section 9.2 a simple formula for calculating the resonance frequency was introduced. This formula is repeated and expanded below:

$$\boxed{f_R = \frac{1}{2\pi\sqrt{LC}} = 60 \times \sqrt{\frac{X_C}{X_L}}}$$

This formula tells us that the frequency at which series resonance occurs (f_R) is dependent on the ratio of the series capacitive (X_C) and series inductive reactance (X_L). For example, if the series capacitive reactance is 2Ω and the series inductive reactance is 400Ω,the series resonance frequency can be calculated from the above formula to be approximately 4.2 HZ.

Normally, the high voltage transmission system is an inductive power system. The series impedance is primarily composed of inductive reactance. The ratio of X_C to X_L is very small so the series resonance frequency is well below 60 HZ. When the series resonance frequency is this low it normally does not cause any significant problems. When a utility inserts series capacitors and increases the series X_C value the series resonance frequency will rise. If enough series capacitors are added to the system to raise the series resonant frequency to a value in the neighborhood of 10 to 50 HZ, SSR problems can occur.

9.4.4 Definition of Subsynchronous Resonance

The Institute of Electrical and Electronic Engineers (IEEE) defines subsynchronous resonance (SSR) as follows:

"Subsynchronous resonance (SSR) is an electric power system condition where the electric network exchanges energy with a turbine/generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system."

Every transmission system has a series resonance frequency. Turbine generators used within the electric system also have natural frequencies of oscillation. When the turbine/generator's natural frequencies of oscillation are close to the series resonance frequencies of the transmission network the generator is attached to, severe forces can develop within the turbine/generator shaft. These forces can damage the shaft and lead to considerable generator damage. The term subsynchronous resonance, or SSR, is the name given to this possibly damaging interaction between the turbine/generator and the power system.

9.4.5 Components of System Current

The current that flows in a power system is always composed of several frequency components. The several components include the primary current, which is a 60 HZ current, and currents whose frequencies depend on the impedances (the L and C values) of the local power system. Disturbances to the power system will create current flows at these natural or resonant system frequencies. These additional current components collectively represent a non-60 HZ content to the power system current. The non-60 HZ current component magnitudes are usually quite small when compared to the 60 HZ component.

When a disturbance occurs, such as a transmission line trip, oscillations are triggered at the power system's natural frequencies of oscillation.

The currents flowing in the power system are also flowing in the generator stator windings and affect the current flow in the generator rotor windings. For example, when 60 HZ currents flow in the power system these same 60 HZ currents flow in the generator stator windings. Recall that the rotors of the generators are rotating at synchronous speed. The 60 HZ currents flowing in the generator stator windings induce current flows in the rotor. However, rotor currents induced by 60 HZ stator currents would not be AC currents but rather DC currents.

DC currents would be induced in the rotor because the rotor is spinning at the same electrical speed (synchronous) as the stator currents. This is the normal mode of operation of a synchronous generator; DC currents flow in the rotor while 60 HZ AC currents flow in the stator.

The two induced rotor currents are called complimentary currents.

The non-60 HZ currents that flow in the generator stators also induce current in the generator rotors. The non-60 HZ currents are not at synchronous speed so the currents induced in generator rotors are not DC currents. Each non-60 HZ stator current will induce two rotor current components. One rotor current component will have a frequency equal to 60 plus the stator non-60 HZ current frequency. The other rotor current component will have a frequency that is equal to 60 minus the frequency of the non-60 HZ stator current. For example, if a 40 HZ stator current is flowing a 60-40 or 20 HZ current and 60+40 or 100 HZ current will flow in the rotor.

Generator rotors are not designed to carry AC currents such as the 20 HZ and 100 HZ currents just described. The high frequency currents are not as significant as the subsynchronous currents and these high frequency currents will be ignored. However, the subsynchronous (below 60 HZ) currents that flow in the rotor may initiate a response from the generator and power system that causes the original stator non-60 HZ current component to grow in magnitude. The subsynchronous currents in the rotor and in the system may grow large enough for the generator to be damaged.

9.4.6 Generator Modes of Oscillation

Chapter 8 of this module described how generators are prone to oscillate at their natural mode of oscillation. The natural mode of the generator refers to the tendency of a generator to enter into periods of power oscillations at this natural frequency. The natural mode of a generator is dependent on its inertia, speed of rotation, current output level, and the system to which it is attached. There are also mechanical modes of oscillation within a turbine/generator. These mechanical modes of oscillation refer to the tendencies of sections of the turbine/generator shaft to oscillate with respect to other sections of the shaft and with respect to the electrical system to which the generator is attached.

Figure 9-17 illustrates a simple turbine/generator shaft. In a steam generator the high and low pressure turbines, generator rotor, and exciter are often connected to a common shaft. Each of these shaft sections will have different weights and diameters so each section will have a different inertia. Since the various shaft sections have different inertias, different natural oscillating frequencies would be expected for each section of the shaft.

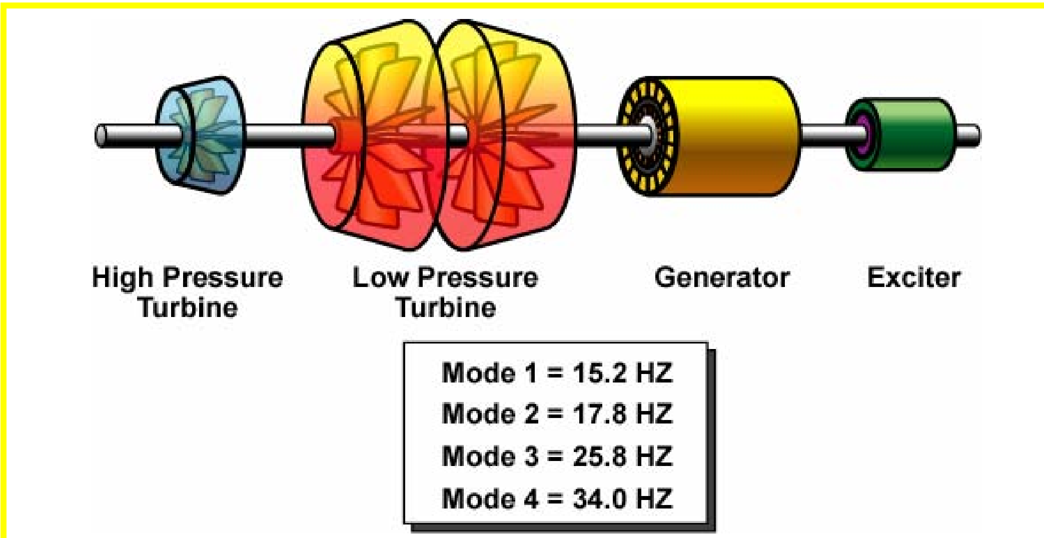


Figure 9-17
Turbine/Generator Shaft Modes

In the box at the bottom of Figure 9-17 is a listing of the natural modes or frequencies at which this particular turbine/generator shaft is prone to oscillate. When manufacturers build steam turbine/generators they tell the purchaser what the natural frequencies or modes are of the shaft. When the manufacturer informs the purchaser of the shaft modes they are warning the purchaser that they should not expose this turbine/generator shaft to electrical currents at frequencies close to any of the modes of oscillation. If the turbine/generator shaft is exposed to these frequency currents, the shaft could be excited and the resulting forces could damage the shaft or attached shaft elements.

Exciting a Turbine/Generator Natural Mode

SSR occurs when the frequency of the currents that are flowing in the generator rotor are close to one of the natural modes of the turbine/generator shaft. As an illustration of SSR, the following paragraphs will step through an SSR scenario for the turbine/generator of Figure 9-17.

The local power system's inductance and capacitance was such that the resonant frequency is 26 HZ.

Assume that a large bank of series capacitors has been switched in-service at a location close to the turbine/generator of Figure 9-17. Further assume that the correct amount of series capacitors were switched to induce a power oscillation in the local system of 26.0 HZ. This 26 HZ subsynchronous current also flows in the generator's stator winding. The 26 HZ stator currents will induce 34 HZ rotor currents (since 60 - 26 = 34). The 34 HZ rotor current could excite mode 4 of the turbine/generator in Figure 9-17

Sections of the shaft would then oscillate at a frequency of 34 HZ. The shaft oscillations induce more 26 HZ stator currents which in turn will increase the rotor 34 HZ currents. The cycle repeats itself with the shaft oscillations and subsynchronous current magnitudes growing. The turbine/generator shaft and the power system have entered into an exchange of energy. This leads to large subsynchronous power oscillations and repeated twisting of the turbine/generator shaft. If enough force is concentrated on the shaft it could lead to severe thermal damage to shaft components and lengthy repair outages for the generator.

The likelihood or impact of an SSR condition depends on the specific turbine/generator and the local power system to which the unit is attached. Some turbine/generators and power systems are constructed in such a manner that they are not susceptible to SSR even when one of the shaft modes has been excited. This type of power system exhibits a high degree of damping. If SSR currents were to appear in this system, the turbine/generator and local power system will combine to quickly reduce the current magnitudes. However, not all power systems are this fortunate. Many turbine/generators have been identified as being susceptible to SSR.

SSR problems, such as described above, have occurred within NERC systems. In the 1970s, Southern California Edison's Mohave units experienced damaging SSR events on two separate occasions. Mojave station is composed of coal-fired steam units that are connected to the Western Interconnection via series compensated 500 kV lines. The generator shafts were damaged and have subsequently been repaired and returned to service after lengthy outages. The units are now protected from the affects of SSR by protection systems and operating guidelines as described later in this section. A detailed description of the Mohave SSR incident is included in Section 9.4.9.

9.4.7 Forms of SSR

To this point we have described SSR as if the only possibility for occurrence is by the series resonant frequency of the local power system exciting a natural mode of the turbine/generator shaft. Actually this is only one of three common SSR scenarios. All three scenarios for an SSR occurrence are similar but there are important differences. The three scenarios are described below.

SSR Scenario I – Torsional Interaction

This is the classic type of SSR that has already been described. Normally, this type of SSR event is initiated by a system disturbance. For example, a section of a series capacitor bank is switched in-service that creates a power oscillation. If a local generator's induced rotor current frequency is close to a natural mode of the turbine/generator's shaft, large oscillations in power and severe forces on the turbine/generator shaft could occur. Figure 9-18 illustrates this type of SSR.

The 26 HZ stator currents will induce 34 HZ rotor currents. This will excite mode #4 of the generator shaft.

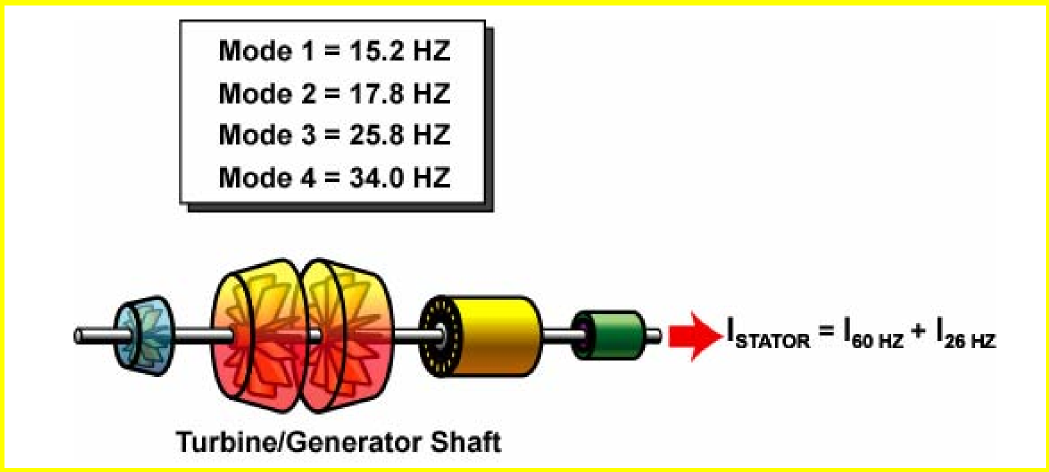


Figure 9-18
SSR Scenario I – Torsional Interaction

One method to prevent this type of SSR is to avoid any system conditions that could lead to power oscillations at a frequency that initiates the SSR. Utilities that are susceptible to this type of SSR will study their system to determine what system conditions could lead to SSR. For example, the utility must know what the limits are to the use of series capacitors. Operating procedures to prevent this form of SSR may forbid any switching on local area lines if the current system operating mode is in a specified state.

SSR Scenario II – Transient Torques

If series capacitors had not been installed, the fault current would steadily decay without oscillations.

This type of an SSR is similar to the torsional interaction mode described above but is initiated by a severe system disturbance. When a severe disturbance occurs (for example, a fault) large currents will flow from the system generators. If series capacitors are installed in the area of the fault, the fault current will tend to oscillate at the local series resonant frequency of the system. The natural modes of nearby turbine/generator shafts may be excited if they are close to the frequency of the oscillating fault current.

The forces on the generator shafts do not build up slowly as in Scenario I, but appear suddenly in direct proportion to the amount of fault current from the generator. Shaft damage may quickly follow the disturbance. Figure 9-19 illustrates this type of SSR.

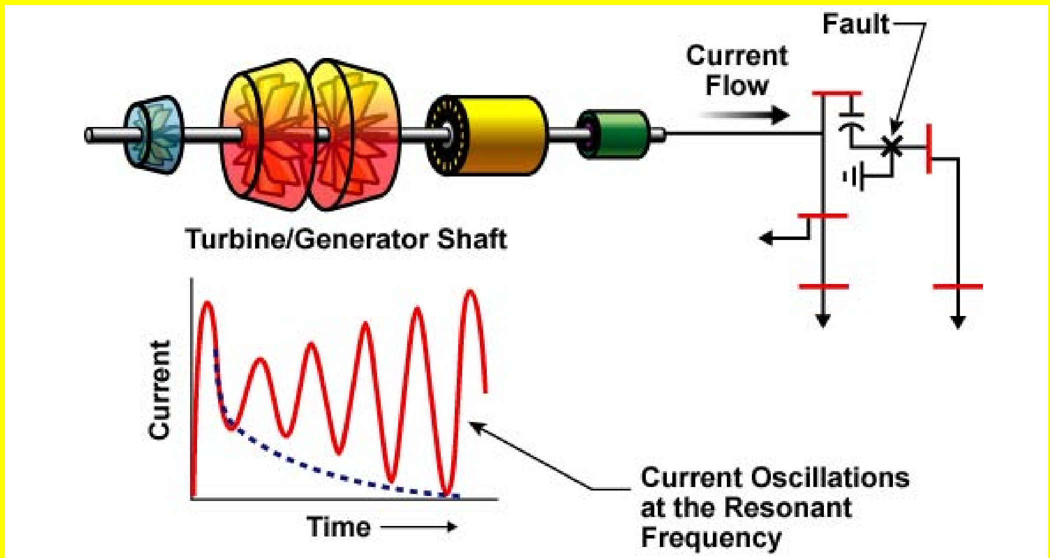


Figure 9-19
SSR Scenario II – Transient Torques

SSR Scenario III – Induction Generator Effect

The first two scenarios for SSR are similar. The third scenario is different in that it does not depend on exciting a turbine/generator shaft's natural modes.

One difference between an induction generator and a synchronous generator is that a synchronous generator's rotor turns at synchronous speed. In contrast, an induction generator's rotor is designed to turn slightly faster than synchronous speed.

A synchronous generator could be made to appear as if it were an induction generator if the synchronous generator's rotor were somehow rotated faster than synchronous speed. This is exactly what happens when subsynchronous currents flow in the power system. The rotor of the synchronous generator appears to be turning faster than the frequency of the subsynchronous currents that are flowing in the generator's stator.

The subsynchronous currents that flow in the stator induce complementary (subsynchronous frequency ±60 HZ) currents in the rotor. These rotor currents may in-turn induce a greater subsynchronous current into the stator. The induction generator effect is actually an amplifier effect. When the rotor appears to be spinning faster than the stator, the rotor may amplify the subsynchronous stator currents.

If a rotor has a negative resistance to subsynchronous currents it is equivalent to the rotor acting as an amplifier to these currents.

Another way of describing the rotor's amplifier effect is to say that the rotor resistance appears negative to the subsynchronous currents. If the negative rotor resistance overcomes the positive resistance of the power system to which the generator is attached, the subsynchronous currents will grow larger and larger until the generator must be tripped. Figure 9-20 summarizes the induction generator scenario for SSR. The induction generator effect is typically not as severe a scenario for SSR as when a shaft's natural mode is excited.

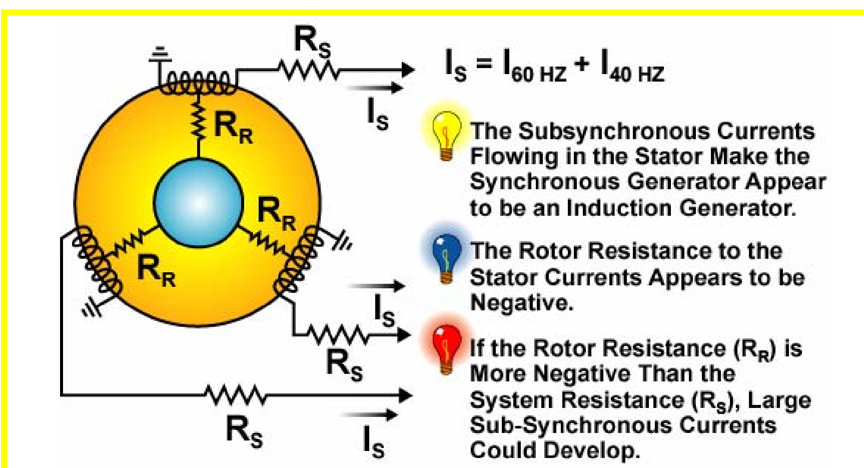


Figure 9-20
SSR Scenario III – Induction Generator Effect

R_R is the per-phase rotor resistance. R_S is the per-phase system resistance. I_S is the per-phase

9.4.8 When is SSR a Concern?

SSR is not a common condition but it can occur for many different combinations of system elements and operating conditions. Fortunately for a system operator, it is up to the system planners and designers to design the power system to avoid most scenarios for SSR.

Due to the design of their respective power systems, western utilities (especially Arizona, New Mexico, and Nevada) are more susceptible to SSR than eastern utilities.

A system operator should be concerned about SSR if their power system has steam turbine/generators that are connected to long, high voltage series compensated lines. (An important limitation to SSR is that it is only a concern with steam units; hydro units are not susceptible to most forms of SSR.) In these types of system configurations, a system operator's switching actions could trigger SSR.

As stated previously, the series resonance frequency that gives rise to the subsynchronous currents that produce SSR is dependent upon the series capacitive and inductive reactance of the power system. Anytime a transmission line is switched in- or out-of-service or a series capacitor is switched in or out, the series resonance frequency is changed.

If a power system has generating units that are susceptible to SSR, the system designers should have studied the characteristics of the generators and transmission system to determine when SSR could occur. Operating guidelines should then be prepared (in consultation with system operations) to avoid the conditions that may lead to SSR.

For example, several western utilities have system operating guidelines that forbid switching of specific high voltage lines when system conditions are within certain limits. Many utilities with series capacitors limit the amount of series capacitors or the amount of series compensation which can be used at a time. This avoids raising the series resonance frequency to levels that could induce SSR.

The likelihood of SSR occurring is also a function of the loading on the local turbine/generators. SSR is more likely to occur when generating units are lightly loaded and their natural damping action reduced.

9.4.9 SSR Example[10]

This incident was one of the first recorded of SSR so the team that analyzed the incident was exploring unknown territory.

Southern California Edison (SCE) operates the coal fired Mohave power station in Nevada. Two incidents of SSR occurred at the Mohave plant in the early 1970's. Figure 9-21 is a one-line diagram that illustrates the major transmission in the area of the Mohave station. Note the series capacitors in the 500 kV lines.

[10] Mohave SSR example is based on reference #7.

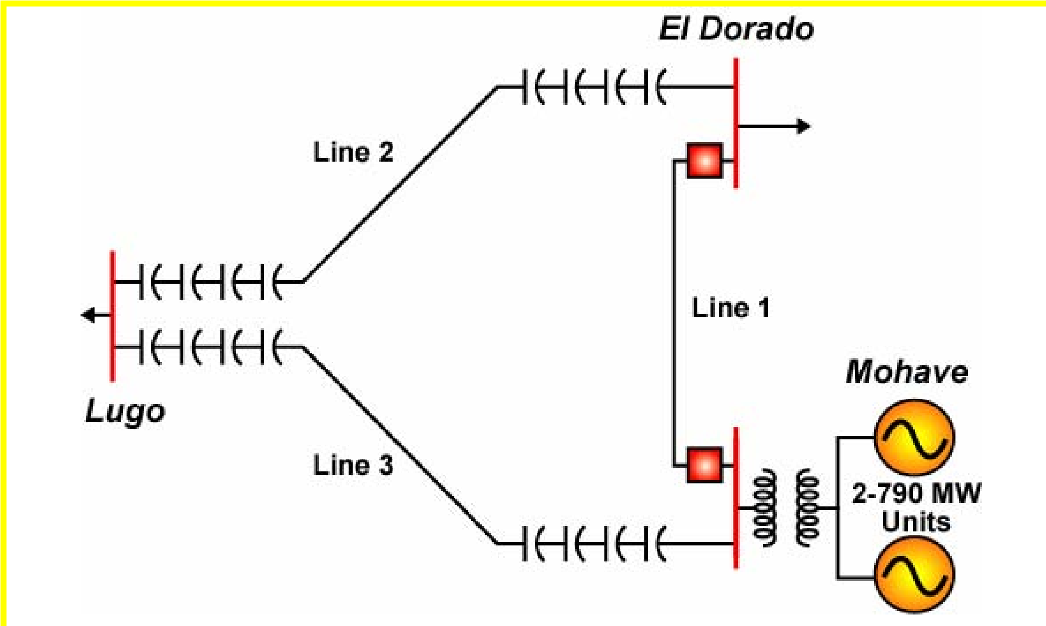


Figure 9-21
Mohave SSR Case Study

For both incidents only one Mohave generator was in-service with a light load of approximately 300 MW. Both incidents were triggered by the opening of the Mohave-El Dorado line. After the line was opened at the remote terminal (El Dorado), the plant operators observed flickering lights in the Mohave control room. Excitation voltage and current levels and the unit MW output remained steady. After a few minutes plant operators noticed a vibration in the control room floor. The plant's first indication that something was seriously wrong was the generator's field ammeter movement from a normal excitation current of 1220 amps to a full scale reading of over 4000 amps. Alarms for excessive vibration, field ground, and negative sequence current were then received. A manual shutdown of the plant was immediately initiated.

Subsequent study of the incident revealed the following:

As a result of these SSR incidents both generator shafts were removed for extensive maintenance. The units were out-of-service for several months at substantial cost to the utility.

- A 30.5 HZ component to the system current was noticeable on oscillographs of both incidents.
- Couplings between various parts of the turbine/generator shaft (turbine to generator, generator to exciter, etc.) were damaged.
- The slip-rings (for providing excitation current) and the generator shaft in the area of the slip-rings had sustained major heat related damage (sections of the shaft steel had melted).

Subsequent study identified this event as an incident of SSR due to an interaction between a turbine/generator shaft natural mode and a resonant frequency of the local power system. When the Mohave-El Dorado 500 kV was opened the series capacitors in the Mohave-Lugo 500 kV line were charged due to a sudden increase in current flow. The local power system entered a resonant oscillation (30.5 HZ) after Mohave-El Dorado was opened as the system's series capacitors exchanged energy with the system's natural inductance.

The transmission system oscillation frequency of 30.5 HZ induced a Mohave generator rotor oscillation of 29.5 HZ. A natural mode of the turbine/generator shaft (30.1 HZ) was close enough to 29.5 HZ for the turbine/generator to join in an exchange of energy with the local power system. The exchange of energy grew so large that substantial forces were applied to the turbine/generator shaft. These forces led to excessive heat build up in the area in which the slip-rings attach to the generator shaft. The forces also caused the plant vibration and the damage to the coupling points between various elements of the shaft.

The Mohave plant is now protected from SSR by the installation of filtering devices to detect the presence of subsynchronous oscillations. Various methods of preventing SSR are briefly described in the next section.

9.4.10 Preventing SSR

There are several methods in use by utilities throughout NERC to prevent SSR. What follows is a brief summary of these methods:

- As mentioned earlier, many utilities that have series capacitors limit the amount of series compensation. For example, a line near a steam generator may have enough series capacitors to compensate 75% of the line's reactance. The utility operating guides may specify that no more than 50% of the series compensation can be in-service at any one time. This is done to avoid conditions that may lead to SSR.
- Power systems may be equipped with filters that are designed to limit the flow of subsynchronous currents. Common locations for these filters include between the generator and its step-up bank or parallel to a local series capacitor installation. The filters are basically parallel "RLC" circuits that will present a high impedance to the subsynchronous currents they are designed to limit.
- Modifications can be made to generator excitation systems to limit the occurrence of subsynchronous oscillations. These modifications involve a sensing circuit to detect subsynchronous oscillations and rapid adjustments to unit excitation to dampen the detected oscillations.
- Protective relays may be installed in turbine/generators that detect subsynchronous currents over a specified magnitude or that monitor the

turbine/generator shaft for speed variations that indicate SSR oscillations. The generator could either be tripped or an alarm could sound.

- An emerging method for SSR control is the use of thyrister switched devices to rapidly change the effective impedance of a circuit and thus change the resonance frequency. The goal would be to move the resonance frequency to a value that will not initiate SSR in local generators. A variation of this method was eventually used to solve the SSR problems at the Mojave station in the western United States. Thyrister switched series capacitors can also be used to rapidly adjust the amount of series compensation and prevent growing SSR oscillations.

9.5 Ferroresonance

9.5.1 Introduction to Ferroresonance

Ferro is Latin for iron. Ferroresonance is a resonance condition involving an iron-core inductance.

Ferroresonance is an overcurrent and overvoltage condition that can be the result of either series or parallel resonance. The most common ferroresonance circuit in power systems is a series resonance condition which will be used to describe ferroresonance in this section. As in any series resonance circuit, ferroresonance involves a tuning between the circuit's capacitance and inductance. However, the inductance must be of a particular type for ferroresonance to occur, a type called an "iron-core" inductance. Transformers (both power and instrument) are common examples of iron-core inductances. An iron-core inductance has the unique property that its inductance will vary depending on whether it is saturated.

Two scenarios of ferroresonance will be examined; one in a distribution system and one in a transmission substation. This does not mean that there are only two ferroresonance possibilities. These two ferroresonance scenarios are simply typical and offer a varied picture of this interesting phenomena. The section describes the cause of ferroresonance for each of the examples given and methods of avoiding its occurrence.

9.5.2 Definition of Ferroresonance

In the series resonant circuits described earlier a resonant condition was achieved by either varying the source frequency or adjusting the size of the reactive elements. Whatever method was used, resonance was achieved at only one frequency per circuit configuration. This is not the case with ferroresonance as the iron-core inductance of the transformer changes with the applied voltage. The frequency at which ferroresonance occurs will vary even during the ferroresonance condition itself.

A low magnitude voltage that sustains itself for a long period (low frequency) will also saturate an iron-core.

If a high enough magnitude voltage is applied to an iron-core transformer, overexcitation and saturation result. When the iron-core is saturated, the transformer inductive reactance reduces sharply. As described earlier, the resonance frequency is directly related to the magnitude of the inductance. This means that the frequency of the ferroresonance currents and voltages will vary depending on the voltage to which the transformer is exposed.

If a voltage or current waveform for a circuit in the midst of ferroresonance was viewed, the waveform would typically be varying at the fundamental frequency of 60 HZ. The waveform would not be a pure sine wave due to the presence of a range of other frequency components that represent different resonant frequencies.

Once a ferroresonance condition develops, high currents will oscillate in the circuit. These high currents will result in large voltage drops across the reactive elements of the circuit. The large voltage drops can impact circuit elements. For example, lightning arresters may operate or fail. In extreme circumstances transformers may be damaged. The magnitude of the overvoltage condition that develops depends on the relative size of the capacitive and inductive reactance and the circuit resistance.

9.5.3 Distribution Ferroresonance

Example of Distribution System Ferroresonance

A distribution line crew is completing the installation of a 750 kVA transformer at a shopping center. The new transformer is fed from a 2500 foot long underground cable that is connected to a 13.2 kV overhead line. There are lightning arresters and fuse cut-outs at the pole. The fuse cut-outs are initially open. One lineman is on the pole waiting to energize while another is at the transformer waiting to check voltages. Figure 9-22 is an illustration of this system.

When the first fuse cut-out is closed, the transformer gives off a loud hum. Assuming it was just an unusual noise the crew closes the next cut-out. The transformer hum grows in magnitude and the transformer is noticeably vibrating. When the third cut-out is closed the hum and vibration stop. The voltages are checked and appear normal. The line crew decides that “if it isn’t broke, don’t fix it” and wraps-up the job.

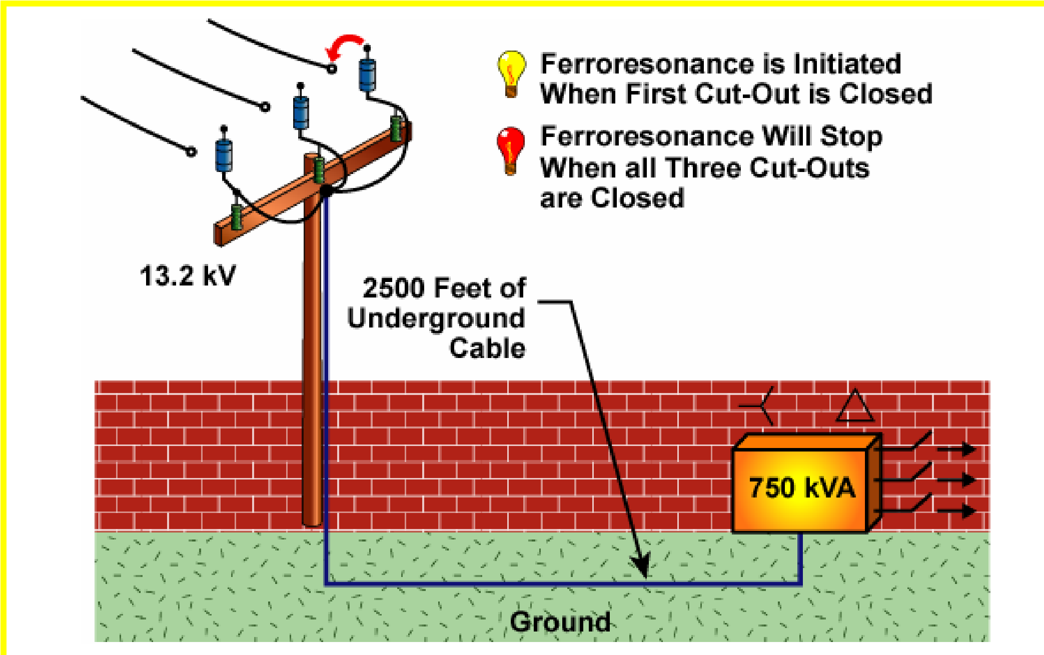


Figure 9-22
Distribution System Ferroresonance

The line crew did not realize it at the time but this was an example of ferroresonance on the distribution system. If the ferroresonance condition had reached a greater magnitude a possible result could have been damaged lighting arresters or a damaged transformer.

Explanation of Distribution System Ferroresonance

Distribution ferroresonance occurs when a resonant circuit is set up in the distribution system. Figure 9-23 is a model of the conditions that are necessary for distribution ferroresonance. A source of voltage and current, an iron-core inductance (for example, a transformer), a capacitance, and a ground point must be provided. The ground point may seem obvious but it is very important. It is necessary to complete the circuit and allow current to flow from the source.

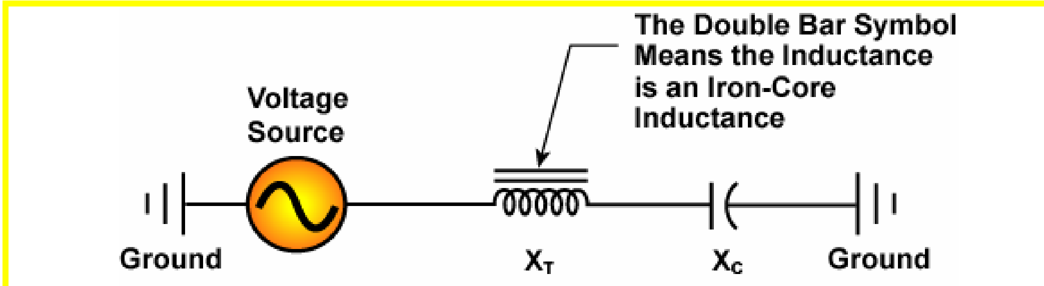


Figure 9-23
Series Resonance Circuit

If the values of the circuit's inductive and capacitive reactance are close to one another ferroresonance can occur. Note that the phrase "close to one another" is used, X_T and X_C do not have to be exactly equal. The rule of thumb is if the reactance ratio (X_C/X_T) is anywhere from 0.1 to 10, distribution ferroresonance problems may occur. Ferroresonance problems are more likely if the reactance ratio is 1.0, where X_C and X_T are equal. If the reactance ratio is well toward 0.1 or well toward 10 the worst that could happen may only be slight overvoltages to the transformer. However, if the reactance ratio is close to 1.0 a transformer could be exposed to voltages up to six times the normal value.

The transformer's inductance reduces due to transformer saturation.

An additional complication to the magnitude of the series inductance is the iron-core nature of a transformer's inductance. The steady state (normal conditions) value of the transformer's inductance may yield an X_C/X_T ratio that is well below 0.1. This value of reactance ratio means that the likelihood of experiencing a ferroresonance problem is very low. However, if a sudden voltage rise occurs, such as may happen during switching, the transformer inductance may reduce to a low enough value that the reactance ratio rises until it is close to 1.0. At this new reactance ratio, the possibility of damaging ferroresonance is very high.

Figure 9-24represents a distribution system. The load is to the right of a 3Φ wye-delta transformer. The transformer is fed from the overhead system via an underground cable. Each phase is individually switched. The dotted lines for shunt capacitors simulate the cable's natural charging current which is relatively high in underground cables. Notice how this line charging is in shunt or parallel with the distribution line. As long as the capacitance is in parallel, ferroresonance is not a concern.

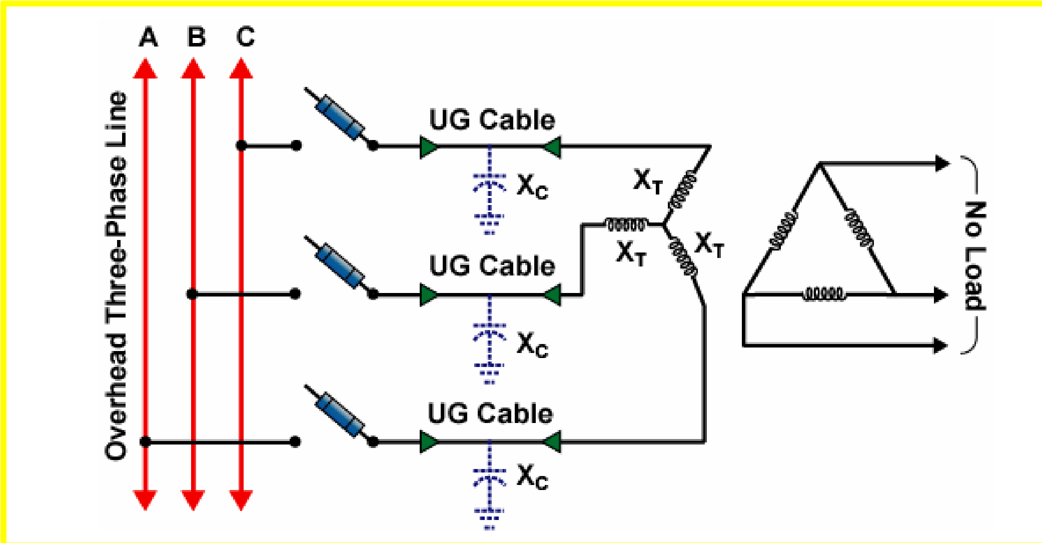


Figure 9-24
One-Line for Distribution Ferroresonance

Initially, all three phases are open. When all three phases are open there is no source voltage so there can be no ferroresonance. In addition, there is no load connected to the transformer. If load were connected to the low side of the transformer, the probability of ferroresonance would be reduced.

Figure 9-25 is a simplified sketch of the circuit in Figure 9-24 after the phase "C" fused switch is closed. The left side of Figure 9-25 is easily derived from Figure 9-24. The right side of Figure 9-25 is a further simplification of the left side impedance diagram. Note how the source, portions of the transformer (represented by X_T), and portions of the cable's shunt capacitance are now in series. If the X_C and X_T values are reasonably close to one another the reactance ratio may fall between 0.1 and 10 and ferroresonance conditions could develop. The closer X_C and X_T are to one another the higher the chances of ferroresonance and the more damage to the transformer due to high voltages.

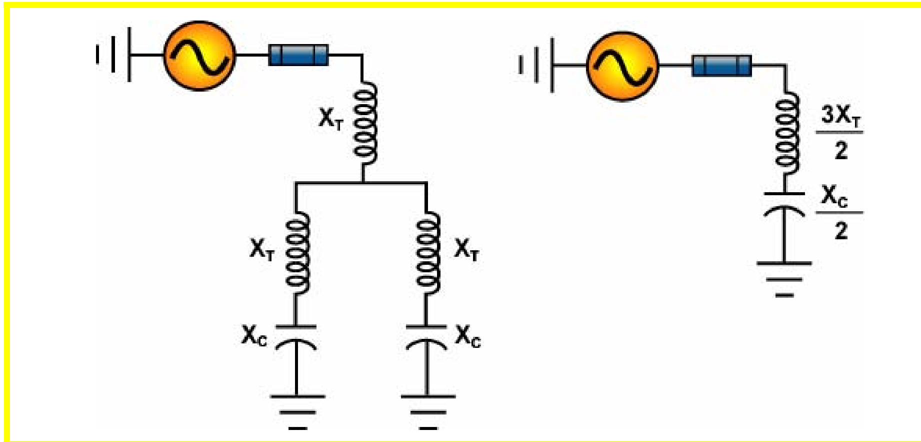


Figure 9-25
Circuit Phase "C" is Closed

Figure 9-26 is a simplified sketch of the circuit in Figure 9-24 with phases "B" & "C" closed. The right side of the figure is a simplification of the impedance diagram on the left side. The source, transformer, and capacitance are still in series. The magnitudes of the inductance and capacitance are different because two phases are closed. The severity of the ferroresonance may be worse with either one or two phases closed depending on the relative size of the X_C and X_T values.

Once the third phase is closed, the possibility of ferroresonance is eliminated. Ferroresonance can only occur if a series capacitance (the open-ended cable) is hanging off the transformer. Once the third phase is closed, there is no series capacitance tied to the transformer.

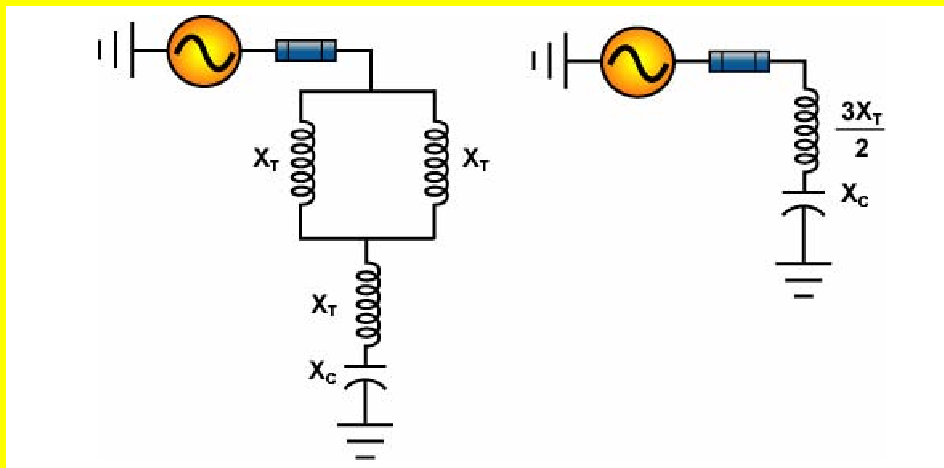


Figure 9-26
Circuit After Phases "B" & "C" are Closed

Typically, when a distribution system ferroresonance condition occurs it is triggered by a switching transient such as the closing or opening of a 1Φ switch. When a switching transient occurs the distribution transformer may be exposed to a large overvoltage. This voltage spike can saturate the transformer and substantially reduce its inductance. The inductance may be reduced enough to increase the reactance ratio to a value between 0.1 and 10 and initiate ferroresonance. This variable nature of the iron-core transformer inductance means that a system may not be susceptible to ferroresonance during normal conditions but may enter into a period of ferroresonance due to a switching transient or other abnormal event.

Preventing Distribution System Ferroresonance

There are several methods and procedures available to reduce the chances of distribution system ferroresonance occurring. The most common methods are briefly described below:

- Keep the reactance ratio (X_C/X_T) higher than 10. If this ratio is normally higher than 10 then the reduction in X_T caused by an overvoltage condition will only make the reactance ratio greater and ferroresonance less likely. Typically, this is an impractical solution because the reactance ratio is determined by system design and not by an operating action. For example, the X_C value is determined by the length, voltage, and size of the underground cable and cannot be easily changed via system operator actions.
- Use 3Φ switching instead of 1Φ switching. Ferroresonance will be minimized if all phase conductors are switched rapidly. 3Φ switching avoids hanging an energized 1Φ cable off a transformer. Again, this is

usually impractical because installing all 3Φ distribution switches would be very expensive.

- Instead of switching at the source end of the underground cable, switch at the transformer end. Then by using proper switching sequences a switchman can avoid hanging an energized, open-ended cable off the transformer. This method may be practical in some situations.

While energizing a transformer with load attached minimizes ferroresonance, it also exposes the customer to a disturbance.

- Energize or de-energize the transformer with resistive load attached to the secondary winding. The secondary resistive load will appear to be much larger in the primary and damp out any ferroresonance condition that develops. Generally, a resistive load of 10% of the transformer kVA rating is adequate to prevent sustained ferroresonance.
- Use a grounded-wye winding connection for the primary winding. This type of winding offers a parallel path to the line's natural capacitance for current flow.
- Examples of distribution transformer connections which will reduce the likelihood of ferroresonance occurring are:
  - Grounded Wye - Grounded Wye
  - Grounded Wye - Wye
  - Grounded Vee - Open Delta (2Φ connections)

Figure 9-27 summarizes methods used to avoid ferroresonance in the distribution system.

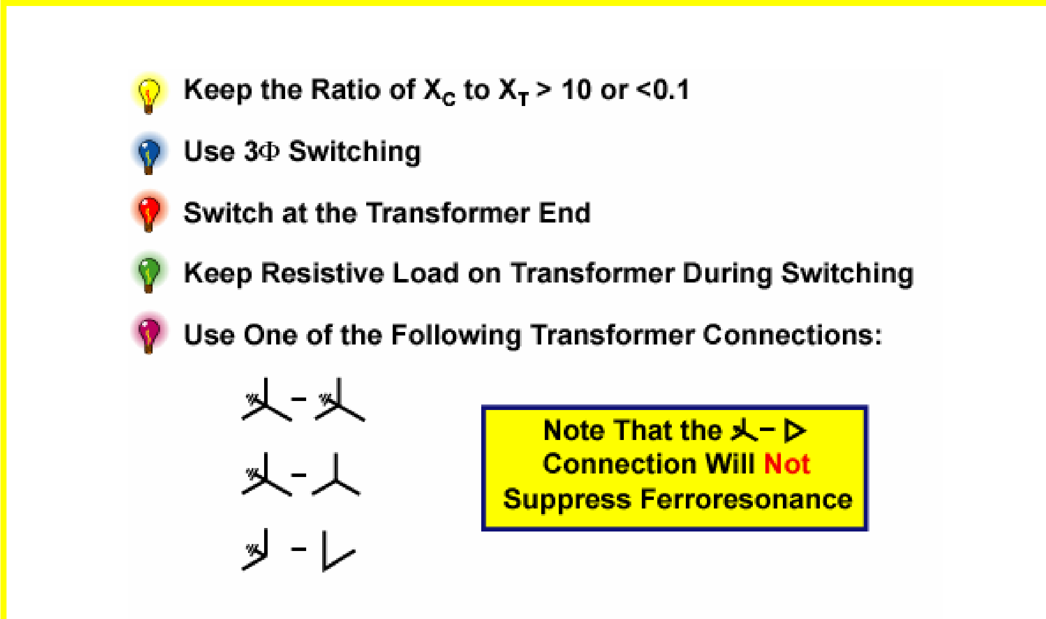


Figure 9-27
Preventing Distribution Ferroresonance

9.5.4 Ferroresonance in a Transmission Substation

Example of Transmission System Ferroresonance[11]

A short, open-ended 345 kV line is attached to a substation as illustrated in Figure 9-28. When the switchmen at substation "A" opened the last 345 kV breaker to drop line "A-B", the switchmen at substation "B" made several interesting observations. The switchmen noticed that line "A-B" potential lights—which should have been off—were glowing brightly. In addition, when the switchmen looked at the jaws of the line switch at the open end of line "A-B" bright corona rings were observed.

Corona rings are rings of light surrounding energized power system equipment. The rings are due to the electric field of the energized equipment.

[11] Ferroresonance example based on reference #10.

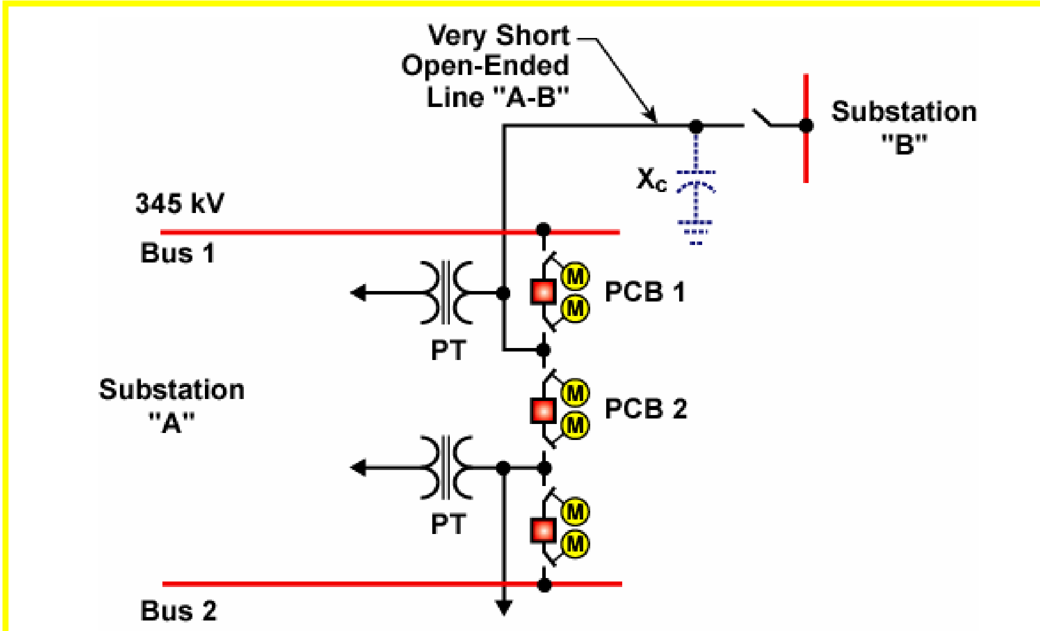


Figure 9-28
One-Line for Transmission System Ferroresonance

Both of these observations indicated that the line must still be energized. However, the two breakers at the source end (substation "A") of the line were definitely open. The potential lights and the corona rings did not disappear until the motor operated breaker disconnects at the source end of the line were opened. Subsequently, an inspection of substation "A" revealed that the iron-core PT for line "A-B" had ruptured. The substation crews did not realize it at the time but this was an example of ferroresonance in the transmission system.

Explanation of Transmission System Ferroresonance

Not all transmission substations are susceptible to ferroresonance. It depends on the type of equipment used in the substation and how this equipment is arranged. The key factors that led to the ferroresonance condition described above were:

- Line A-B was very short. This produced a value of capacitance to ground that could result in ferroresonance. If the line was significantly longer the capacitance to ground value would have been incorrect to result in ferroresonance.

PTs are often preferred over CCVTs as they tend to more accurately

- PTs (potential transformers) with iron-cores rather than CCVTs (capacitively coupled voltage transformers) were used to obtain line potentials. The use of PTs provided an iron-core inductance. If CCVTs had been used instead, ferroresonance would not have occurred.

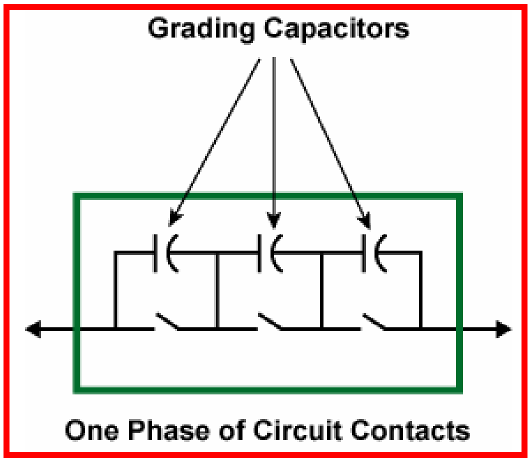


Figure 9-29
One-Line for Transmission System Ferroresonance

- The modern SF_6 circuit breakers that are used in the substation of Figure 9-28 often incorporate multi-break contacts. Multi-break contacts separate the circuit arc into several sections to assist with extinguishing the arc. These circuit breakers use grading capacitors across their contacts to equalize the voltage across the contact prior to interruption. Figure 9-29 illustrates this type of breaker contact. The use of this type circuit breaker provided the capacitance which is required for ferroresonance.

Figure 9-30 is a one-line diagram for the circuit of Figure 9-28 after the line breakers are opened. The capacitive reactance of the multi-break contacts, X_{CG}, is shown in series with the source voltage. The capacitive reactance value, X_{CS}, represents the capacitance to ground of the open-ended line plus other natural substation capacitance. The inductive reactance value, X_T, is the iron-core inductance of the PT. The R value represents any series resistance that exists in the circuit.

The capacitive reactance values, X_{CG} and X_{CS}, must be near the correct size and ratio to both achieve series resonance and to properly divide the source voltage:

- The ratio of X_{CG} to X_{CS} must be within a certain range to initiate saturation of the iron-core PT. Note in Figure 9-30 that X_{CG} and X_{CS} form a capacitive voltage divider circuit. Their relative magnitudes must be such that the voltage drop across X_{CS} is large enough to saturate the PT.

- The magnitude of the equivalent capacitance (formed by X_{CG} and X_{CS}) must be near the magnitude of X_T. The equivalent capacitance and X_T will form the capacitive and inductive legs of the series resonance circuit.

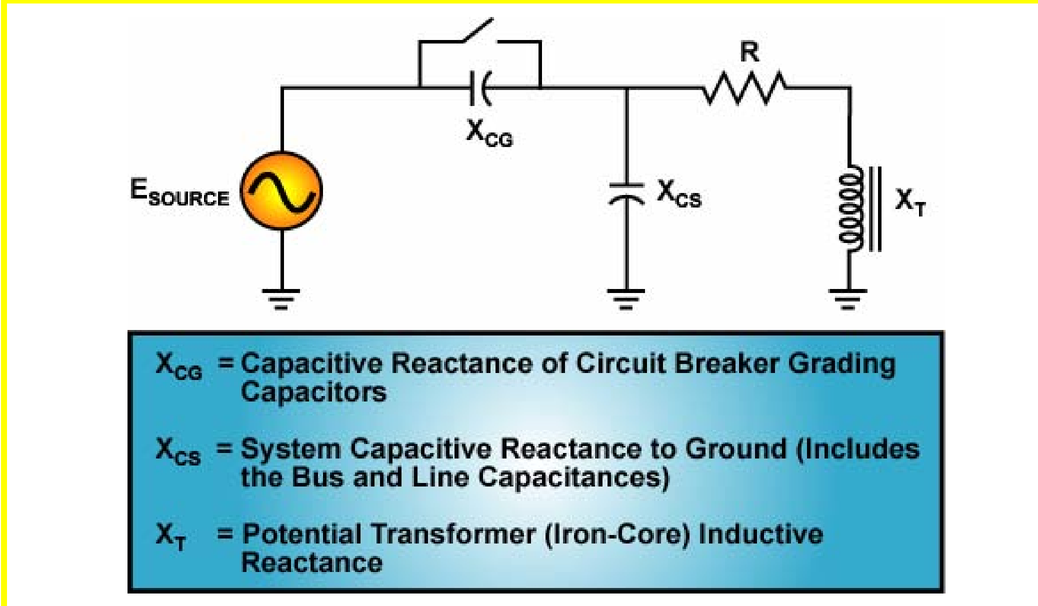


Figure 9-30
Equivalent One-Line of Figure 9-28

When the last breaker was opened the circuit of Figure 9-30 was set up. To simplify our illustration, ignore the X_{CS} leg. The circuit is now a simple "R-L-C" series resonant circuit. The source voltage, E_{SOURCE}, supplies 60 HZ energy to the "R-L-C" circuit. The opening of the last breaker produced a voltage spike that saturated the iron-core PT. The iron-core inductance reduced to a value at which ferroresonance could occur. An oscillating current at a resonance frequency determined by the circuit's inductance (X_T), and capacitance (X_{CG}) values developed in the circuit. This current resulted in an oscillating component of voltage across the PT.

Coupled and Oscillating Components

The overvoltages that appear across the PT during a ferroresonance event can be viewed as a summation of two separate components; a coupled component and an oscillating component. The coupled component is that portion of the 60 HZ source voltage which continues to provide energy to the circuit. The magnitude of the coupled component that appears across the PT is a function of the capacitive voltage divider circuit that was illustrated in Figure 9-30.

The oscillating component results from the series resonant circuit between X_T and X_{CG}. The oscillating component will only sustain itself if the coupled component provides enough energy to replace losses. Ferroresonance studies have proven that the oscillating component will sustain itself only at certain frequencies. These frequencies are the fundamental (60 HZ) or an odd subharmonic such as 20 or 12 HZ.

Figure 9-31 is a plot of an actual 20 HZ ferroresonance event. This figure is a plot of the voltage that appeared across a PT. Note the 20 and 60 HZ components of the ferroresonant voltage. The 20 HZ is the oscillating component while the 60 HZ is the coupled component.

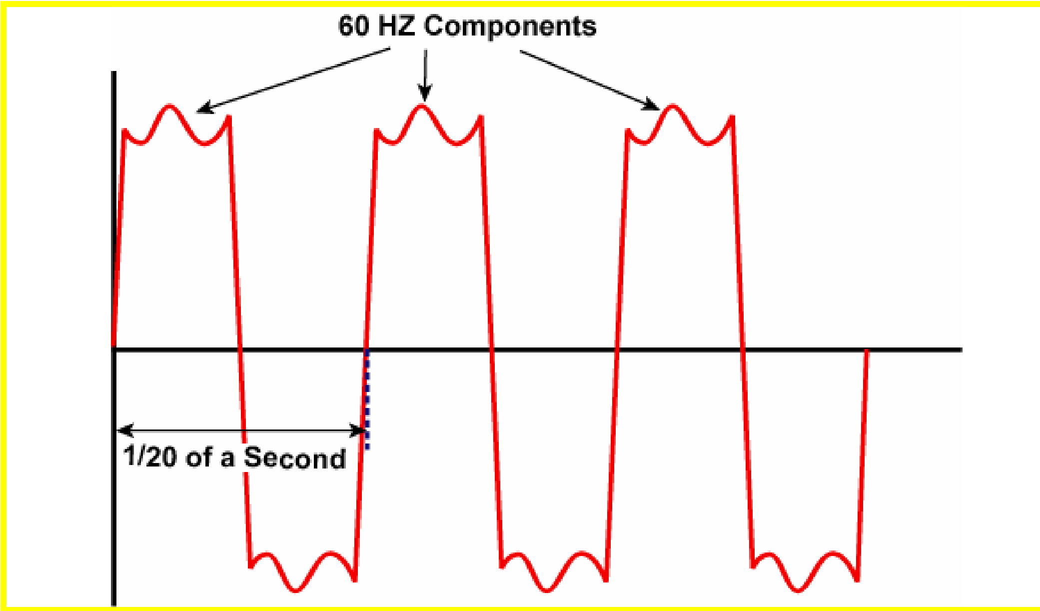


Figure 9-31
Ferroresonance Voltage Waveform

The end result, if a sustained ferroresonance condition does occur, is possibly large current oscillations. These large current oscillations will lead to high voltages within the substation and force high magnitudes of current through the PTs. Lightning arresters may operate or be damaged, protective relays may falsely operate, insulation damage could occur, and PTs may experience thermal damage. The PT in this example failed due to thermal overload.

Preventing Transmission System Ferroresonance

The substation described in this example of transmission system ferroresonance was susceptible to ferroresonance due to the substation configuration and the length of the transmission line that was open-ended. If the transmission line had been longer or if a power transformer had been connected directly to Bus #1 of Figure 9-28, ferroresonance may not have occurred. The longer line or presence of a large power transformer may have changed the relationship between the circuit's capacitance and inductance enough to avoid ferroresonance.

If we assume that the substation design is fixed and there are no switching options available, there is one commonly used method for reducing the impact of ferroresonance. Utilities can add resistance to the system to dampen the ferroresonance current oscillations. If enough resistance is added, a utility can prevent ferroresonance entirely. There is, however, a limit to the amount of resistance which can be safely added since adding resistance will cause losses and could lead to thermal problems.

Resistance could be added to the actual high voltage circuit. This method could in theory be used to eliminate ferroresonance but it is not practical. The large high voltage resistance would be expensive and would likely cause more problems than it solves including thermal and system stability difficulties. A better method is to add resistance to a PT secondary circuit.

The resistor need only be connected in the PT secondary when the last substation breaker is opened. Control schemes are used to switch in the resistor only when needed.

For example, the PT circuits in Figure 9-28 could be equipped with a delta connected secondary winding as illustrated in Figure 9-32. A small resistance of several ohms would be tied in the delta secondary. This resistance would be reflected through to the primary based on the square of the turns ratio of the PT. This method of reducing the impact of ferroresonance is commonly applied in high voltage substations.

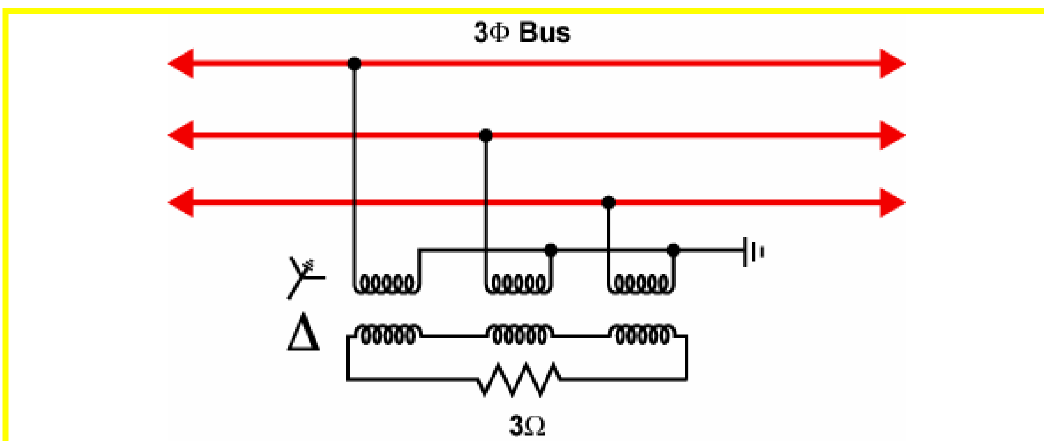


Figure 9-32
Resistor in a Delta Connected Secondary

9.6 Solar Magnetic Disturbances

9.6.1 Introduction to Solar Magnetic Disturbances

SMDs are also called geomagnetic disturbances or GMDs.

Solar magnetic disturbances (SMDs) are a naturally occurring phenomena that have caused severe operating problems for power systems. SMDs are disturbances to the earth's magnetic field that are a consequence of disturbances on the sun. When solar (sun) disturbances occur, currents may be induced in the earth's surface. The currents can work their way into telecommunication and utility power systems. Earth surface currents are the primary utility hazard from SMDs.

Brief History of SMDs

Throughout history there are instances where man has recorded the effects of SMDs. The beautiful light shows that occur in northern latitudes (aurora borealis or the northern lights) and southern latitudes (aurora australis) have long fascinated man. These light shows are a consequence of SMDs.

The first recorded instance in which SMDs disrupted utility systems occurred in the mid-1800s when several countries at northern latitudes reported telegraph system misoperations. A telegraph engineer monitoring one SMD occurrence in 1859 noted that the telegraph system continued operating even though its power source was disconnected. From the 1940s to the present electric utilities have reported strange happenings that were likely the result of SMDs. Initially, these events were relatively minor problems such as blown distribution fuses or unexplained tripping of small transformers.

During this hour long 1859 incident, Mr. G. B. Prescott, an engineer with American Telegraph Co., noted that the telegraph operated "with the aid of celestial batteries alone".

Our perception of SMDs causing only minor problems ended in the spring of 1989. Early on the morning of March 13, 1989, an SMD occurred that blacked out the entire Canadian province of Quebec. Over 21,000 MW of load suffered an extended outage including the major cities of Quebec and Montreal. (This incident is described in greater detail in Section 9.6.10.)

The SMD of March 13, 1989, served the useful purpose of alerting power system operators to the possible effects of SMDs. Utilities throughout the world have studied SMD effects. Power system design changes and operating guidelines have been implemented to limit the damage caused by the unavoidable occurrence of SMDs.

9.6.2 Sunspots

The sun is 93,000,000 miles away from earth. Currently, little is known about the mechanics of the sun's operation. Scientists have for years observed sunspots which appear from earth to be small dark spots on the surface of the sun. Very little is known about these sunspots except that they indicate areas of intense solar activity.

Sunspots are indicators of several types of energy disturbances on the surface of the sun. The types of solar disturbances include solar flares and coronal mass ejections. These disturbances are solar energy storms which eject charged particles from the surface of the sun into the surrounding outerspace. After one to six days a portion of these charged particles will reach the earth's surrounding space.

Cyclic Sunspot Activity

Figure 9-33 is a chart of the monthly sunspot activity which has been recorded over the last fifty years. Notice that the average monthly count of sunspots follows an approximate eleven year cycle. For example, in 1987 the average monthly number of recorded sunspots was very low, approximately 10-15. Three years later, 1990, the average monthly number of sunspots was very high, close to 200. The cycle completed itself in 1996-97 when the average number of recorded sunspots was again very low. Each eleven year sunspot cycle is given a number for record keeping purposes.

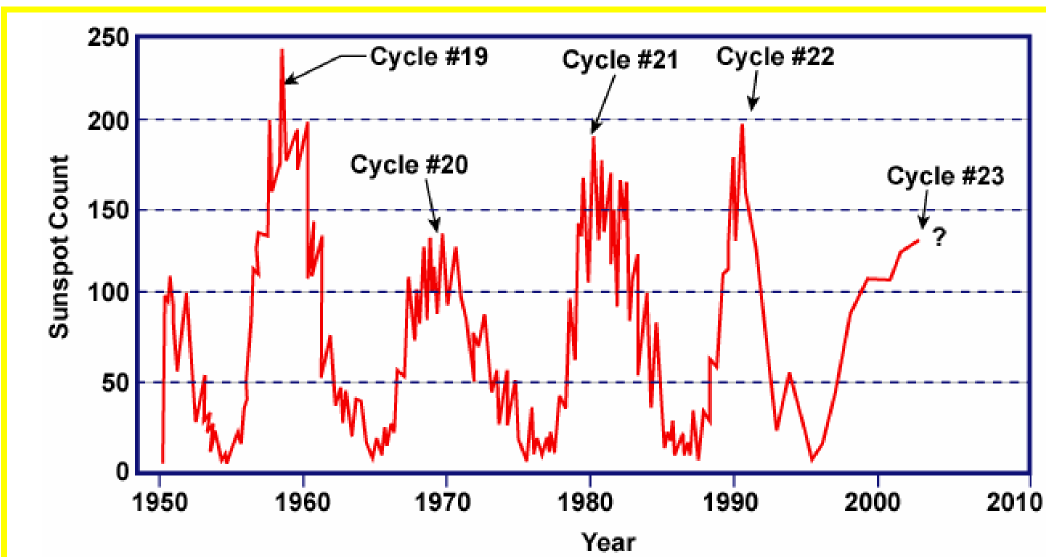


Figure 9-33
Monthly Sunspot Count 1950 – Present

Cyclic SMD Activity

The patterns of sunspot activity are not directly related to the severity of the SMDs that cause disruptions to the earth's utility systems. For example, 1991 was a peak year for sunspot activity but it was not a peak year for earth SMD activity. Peak years of SMD activity generally lag behind peak years of sunspot activity by 3 to 5 years. Past peak years of SMD activity have included 1951, 1960, 1974, 1982, and 1993. Another peak year should occur between 2002 and 2004.

This does not mean that SMDs will only occur during forecasted peak years. SMDs can occur at any time (recall the March 13, 1989, SMD). The forecasted peak years are simply when current scientific knowledge expects heavier SMD activity.

9.6.3 The Solar Wind

Even during normal times the sun is constantly pushing a stream of charged particles (electrons and protons) towards the earth. This stream of charged particles is called the solar wind. The solar wind is equivalent to current flow as current flow is the movement of charged particles. When the solar wind approaches the earth it encounters the earth's magnetic field. The earth's magnetic field channels the charged particles towards the earth's magnetic poles. (Figure 9-34 illustrates this concept.) The charged particles of the solar wind end up as a current circulating in a donut shaped path about 60 miles above the poles of the earth. Scientists refer to this donut shaped container of current as an electrojet. Electrojet current magnitudes can exceed one million amperes.

The circulating currents above the earth's poles are called "electrojets".

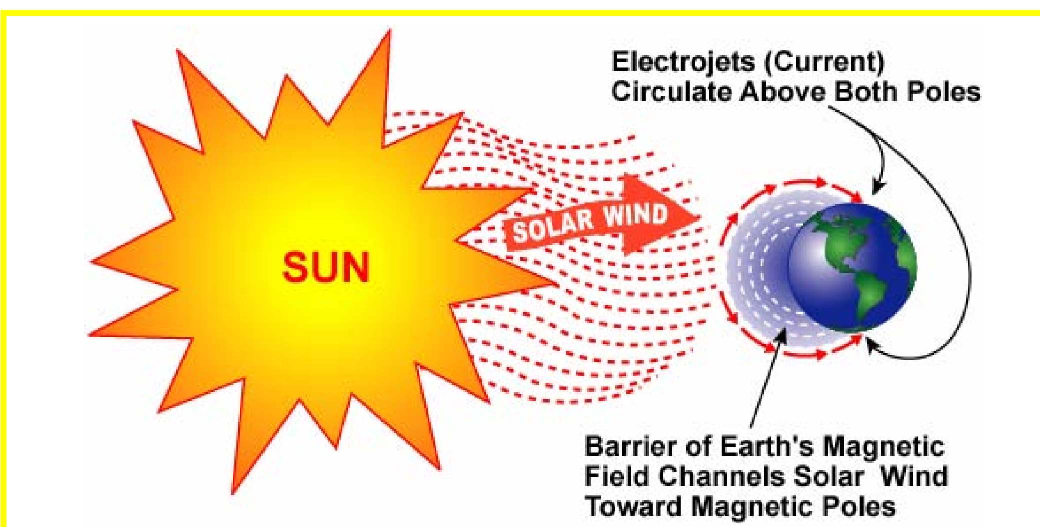


Figure 9-34
Solar Wind and Earth Currents

Our major concern is with the impact of SMDs on power systems. Our concentration will therefore be on the electrojet circulating about the north magnetic pole and ignore the south pole.

Normally, the electrojets circulating above the earth's poles are of minor consequence. As the currents strike particles in the earth's atmosphere, lights are emitted which are called the aurora borealis (northern lights) and the aurora australis (southern lights). The lights are attractive shows but cause no disruption to the power system. However, when abnormally high solar storm activity occurs, the magnitude of the solar wind may increase. The electrojet current level may also increase.

The increased electrojet current levels result in brilliant displays of the northern lights. If the electrojets have moved down into more southern latitudes (which they sometimes do) the northern lights may become visible even to people in the southern U.S. and the Caribbean. The high magnitudes of circulating current also disrupt the earth's magnetic field. Solar magnetic disturbances or SMDs are the name given to these disturbances to the earth's magnetic field.

As the electrojets circulate above the earth they induce current flows into the surface of the earth. These induced currents are the cause of most utility system SMD problems.

9.6.4 ESPs & GICs

In Section 9.6.3 the presence of increased solar activity was related to the occurrence of SMDs on the earth. The means by which SMDs cause havoc within electric power systems is via currents which are induced in the surface of the earth.

The electrojets which circulate about the north magnetic pole of the earth may increase in magnitude and move southward when the solar wind increases in magnitude. Visualize large magnitudes of current circulating above the earth's surface. The current magnitudes in the electrojet are not steady but fluctuate, similar to an AC current. The changing current magnitudes result in the creation of an alternating magnetic field. As this alternating magnetic field links the surface of the earth it induces voltages in the earth's surface. Figure 9-35 illustrates the process.

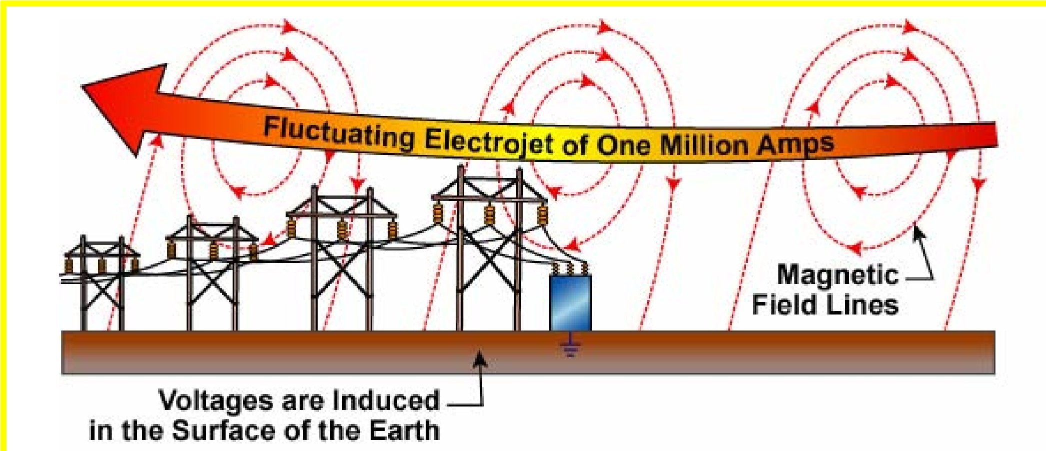


Figure 9-35
Creation of Earth Surface Potentials

Earth Surface Potentials

The voltages that are induced on the surface of the earth are called earth surface potentials or ESPs. The magnitude of the induced voltages will depend on the physical location on the earth. The greater ESPs will, in general, occur in northern areas since these areas are closer to the electrojets circulating about the earth's north magnetic pole.

Factors such as rocky soil or the presence of bodies of water also play an important role in the magnitude of the ESPs. The impact of location and the geography of the earth will be described in greater detail in Section 9.6.5.

Geomagnetic Induced Currents

Since the electrojet current is fluctuating, different magnitudes of ESPs will be induced in different locations on the earth. This results in potential differences between points on the earth's surface. The potential differences will lead to the flow of low frequency currents (approximately 0.01 HZ) called geomagnetic induced currents or GICs. The amount of GIC that flows in the earth's surface is not related to the magnitude of the ESP but rather to the difference in the magnitudes of ESPs between two locations. The larger the potential difference, the more current will flow. When ESP values are reported they are listed as voltage differences per mile. For example, a very severe SMD may cause ESPs of 10 volts/mile.

Assume that an SMD occurs and causes an ESP of 10 volts/mile to be developed over a 10 mile stretch as illustrated in Figure 9-36. If the average resistance of the earth between the two points was measured to be 0.1Ω per mile then the amount of GIC would be 100 amps as calculated in Figure 9-36.

This current flows in the surface of the earth. As long as this current stays in the earth it is not harmful to power systems. The trouble begins when the current somehow enters the power system.

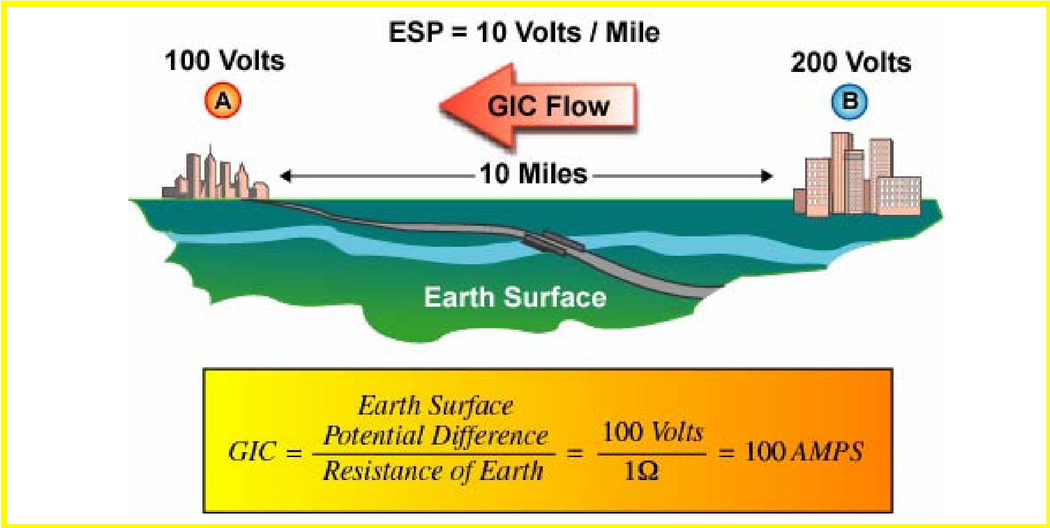


Figure 9-36
Geomagnetic Induced Currents

9.6.5 Factors that Influence the Impact of SMDs

The severity of the effects of SMDs varies depending on the utility's physical location on the earth. This section will describe how geography impacts SMDs. If GICs only circulated in the earth's surface there would be little impact on the power system. Unfortunately, the GICs can enter into the power system. This section will describe how GICs work their way into the power system.

Role of Geography in Magnitude of ESPs & GICs

There are two primary geographical factors that effect the magnitude of the ESPs and GICs:

- Latitude
- Earth resistivity

Individually these factors will impact the level of SMD effects. The factors must be taken together to determine an area's overall susceptibility to SMDs.

Latitude

Positions on the earth are pinpointed with latitude and longitude measurements. Latitude indicates how far north or south a position is relative to the equator. SMD activity is typically confined to northern latitudes since these areas are closest to the electrojets circulating about the north magnetic pole. In general, Canadian utilities are more impacted by SMDs than U.S. utilities. This is due to the northern latitudes of Canadian utility service territories.

However, latitude is not everything. A utility's proximity to the earth's magnetic pole is equally important. For example, the utilities in the northeast U.S. are strongly impacted by SMDs. This is not simply due to their northern latitudes but to a peculiarity of the earth's magnetic field. The north pole of the earth's magnetic field is not located at the geographic north pole but rather at the magnetic north pole. The magnetic north pole location is variable and is currently north of Quebec, Canada. The location of the magnetic north pole creates a tilt in the earth's magnetic axis. This tilt places the northeastern U. S. about 600 miles closer to the earth's northern magnetic pole than any other area of the U.S.

Earth Resistivity

When large magnitudes of current are circulating about the earth's surface, changes occur to the earth's magnetic field and ESPs are created. The magnitude of the ESPs that develop depend on the positions proximity to the north magnetic pole and on the type of soil contained in the area. Soils with very low resistance will change their ESP magnitudes very slowly. For example, a large area with a low resistance soil may only develop an ESP of ½ volt per mile. As long as the potential difference between two points within an area remains small the magnitudes of the resulting GICs will remain small. Low resistance soils limit the size of the ESP and reduce the impact of SMDs.

In contrast, high resistance soils increase the potential differences across the earth's surface and lead to increased magnitudes of ESP. The GICs that flow in high resistance soils are more likely to enter the power system since they see the power system as a more attractive current path than the high impedance earth. Many sections of the earth are formed of rock that was the result of long ago volcanic eruptions. Rock from volcanic origins is called igneous rock. Igneous rock has a high resistivity. Areas of the earth that contain igneous rock will be more prone to damaging SMD. Figure 9-37 illustrates those areas of North America that contain igneous rock.

Remember that the presence of igneous rock alone does not guarantee damaging SMD effects. For example, as illustrated in Figure 9-37, there is a section of igneous rock in central Texas. Someone may (falsely) assume this area will experience high magnitudes of GIC during an SMD. However, Texas is so far south that the SMD would have to be extremely powerful before any significant GICs developed.

An additional geographic feature related to earth resistivity is the presence of large bodies of water. Water, especially salt water, is a relatively good conductor with a much lower resistivity than soil. As the electrojets circulate above the oceans ESPs will be induced in the water. The ESPs may not be that large but the GICs produced by the ESPs will be large. The GICs are large because water is a good conductor and has a low impedance.

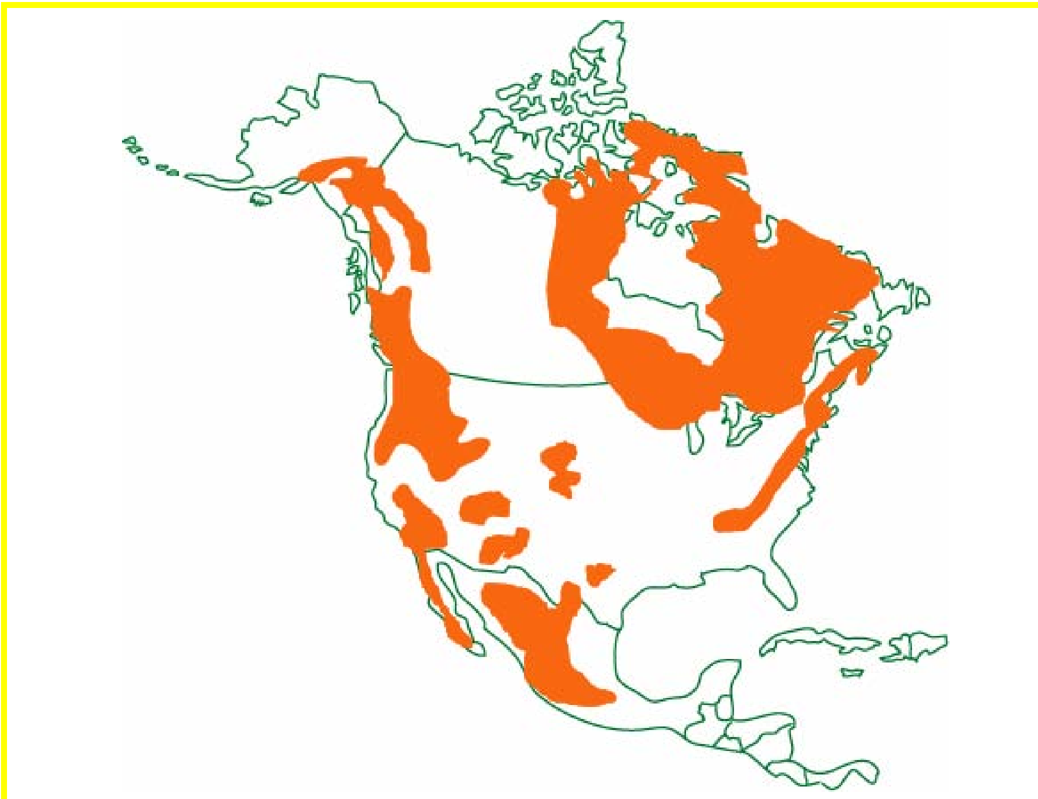


Figure 9-37
Igneous Rock Locations in North America

Note the location of the large areas of igneous rock in Figure 9-37. Two large igneous rock areas are along the east and west coasts of North America. These igneous rock areas with high resistivity border salt water areas with large GICs. When the GICs from the oceans approach the igneous rock coast they are presented with a high impedance path. The GICs will search for alternative paths. Often the alternative path is into coastal power systems.

To conclude this brief description of the geography of SMDs; those areas of the earth that are most prone to SMD effects are northern areas that contain igneous rock and are bordered by large water bodies. The northeast coast of

North America fits this description well. This does not mean that only the northeast coast will experience SMD activity. What this means is that the northeast coast will be more likely to experience SMD activity than, for example, Iowa or Texas. SMDs have caused problems in Minnesota even though there is no salt water in the area. Minnesota is situated in a northern area, the earth in this region is igneous rock, and the area contains large bodies of water.

9.6.6 GIC Entry to the Power System

Figure 9-38 reviews how ESPs can lead to the flow of GICs in the surface of the earth. One other set of features is also shown in Figure 9-38. Note the presence of the grounded neutrals of power system transformers. Power system ground points are the interconnection between the power system and the surface of the earth. The GIC currents flowing in the earth's surface see the power system's ground points as an alternative path in which to flow. If the impedance offered by the combination of the grounded neutral and transmission line is lower than the earth's impedance a portion of the GIC will enter the power system.

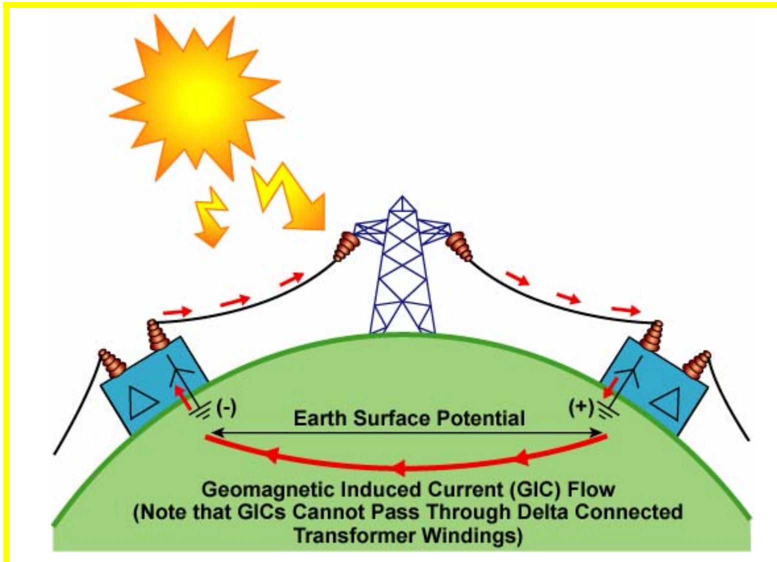


Figure 9-38
Flow of GIC

Capacitors present a high impedance to low frequency GICs.

GICs can enter the power system via any ground point. However, some of the ground points will have a very high impedance and very little GIC will flow through the point. For example, shunt capacitors present a very high impedance to GIC flow while the solidly grounded neutral of a transformer presents a very low impedance.

The flow of GIC in a delta/grounded-wye transformer is similar to the flow of ground fault current. Protection engineers say a delta connected winding blocks the flow of the ground fault current. GIC current behaves in a similar manner to ground fault current.

Figure 9-39 illustrates two types of transformers in a simple power system. One of the transformers is a delta/grounded-wye while the second is an autotransformer. GIC can only enter the grounded-wye leg of the delta/grounded-wye transformer. GIC cannot enter into the delta winding since there is no ground current path. Once the GIC enters the grounded-wye winding it will flow across the transmission line toward the autotransformer. The GIC can flow anywhere in the power system in which a ground path exists.

As an example of when the GIC current path into transformers is important, think of the step-up banks on generators. Generator step-up banks are almost always wound as delta on the generator side and grounded-wye on the system side. GIC currents flowing in the power system cannot enter into the generator system. This helps avoid generator related GIC effects although it does not totally isolate the generators from SMD problems.

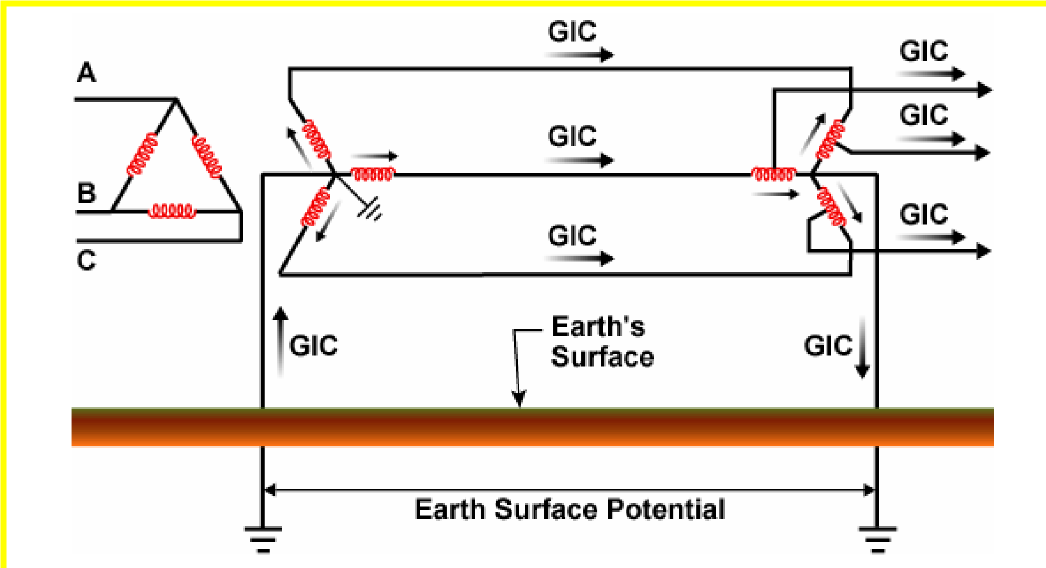


Figure 9-39
GIC Entry to Power System

Figure 9-40 is a summary of GIC creation and impact on the power system. Once in the system, GICs can cause extensive damage. The next section describes the possible impact of SMDs.

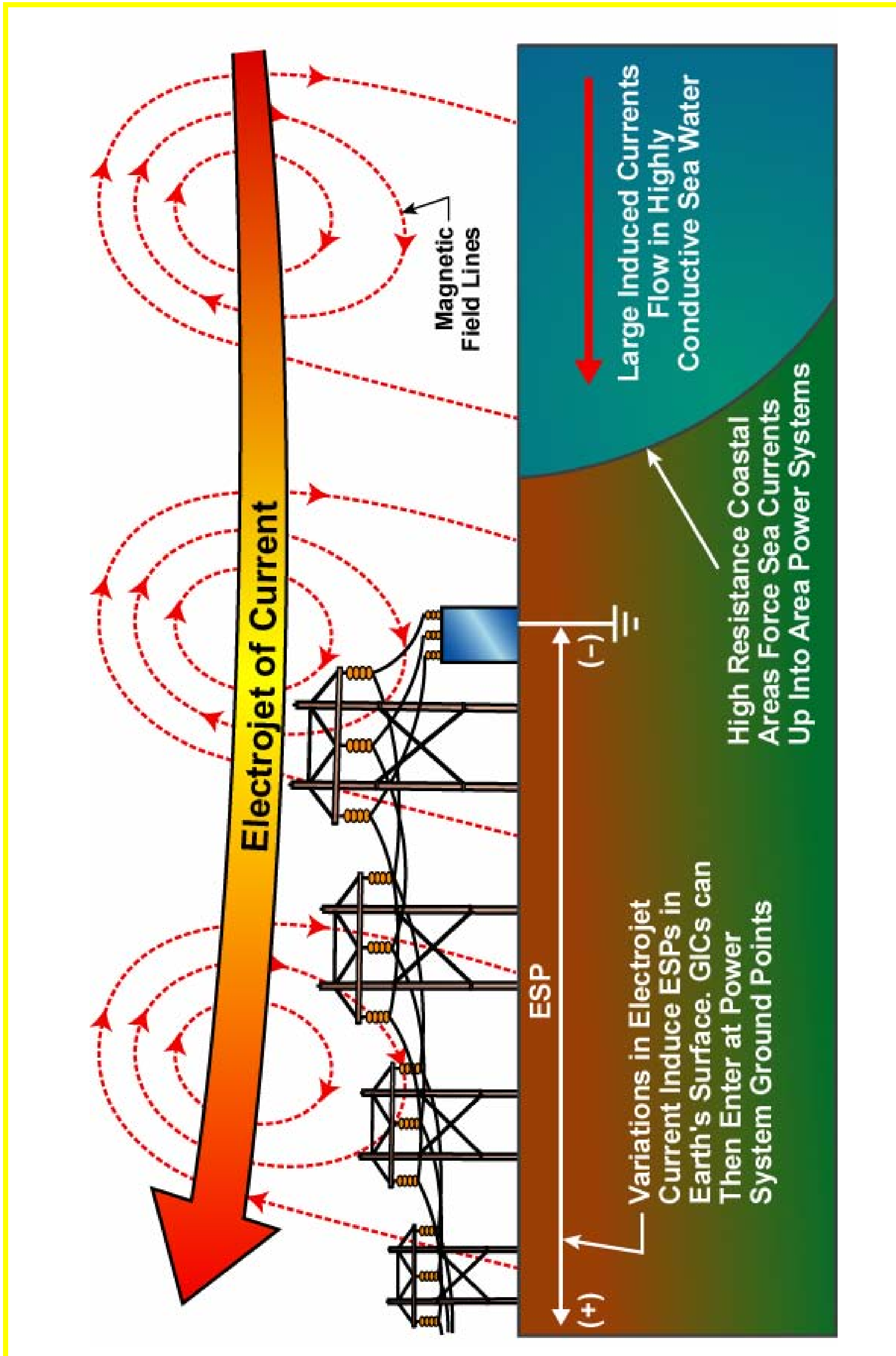


Figure 9-40
Summary of GIC Creation and Entry to Power System

9.6.7 Impact of SMDs

When GICs flow in the earth's surface, they enter the power system via grounded points. GICs can cause severe operating consequences including shunt capacitor tripping, false relay operations, and destruction of transformers. This section briefly describes the effects of GICs on the power system.

Effects on Power Transformers

A power transformer is designed to convert a primary voltage to a secondary voltage. The transformer performs this function via an alternating magnetic field that is purposely designed to be confined in the core of the transformer. The alternating magnetic field in the core links the primary winding to the secondary winding and allows the voltage transformation. The current required to support or excite the core's magnetic field is called the transformer's exciting current.

As long as the transformer operates within the normal operating region of its saturation curve the excitation current will be low (a few amps) and the magnetic field of the transformer will be confined to the core area. If the transformer operates outside the normal operating area (to points "D" or "E" in Figure 9-41) the excitation current can grow rapidly to a very large magnitude. The magnetic field of the transformer will then spread to areas of the transformer not designed for magnetic fields. These areas include the transformer tank and winding supports.

Figure 9-41 is a sketch of a transformer's saturation curve. This curve illustrates the exciting current required for the transformer's core with different voltages applied to the transformer. In normal use, the transformer is designed to operate within the straight region of the curve. As the source alternating voltage oscillates between its positive and negative peak values the transformer will slide up and down the straight region of the saturation curve between points "B" and "C". The transformer oscillates within the straight region of the saturation curve centered about point "A" in between points "B" and "C".

When an alternating magnetic field exists around a conducting medium, currents will be induced. When the transformer's magnetic field spreads out of the core and into the tank, currents will be induced in the tank's metal components. These currents, called eddy currents, cause I^2R losses and can lead to high temperatures within the transformer.

When a transformer operates outside the straight region of its saturation curve the transformer is saturated. The danger of a saturated transformer is primarily from the excess heat created by the stray currents flowing outside the core and the heat generated by high excitation current. This excess heat can lead to gas formation in transformer oil, tank paint blistering, charred insulation, and in extreme examples, even the melting of a transformer's copper windings.

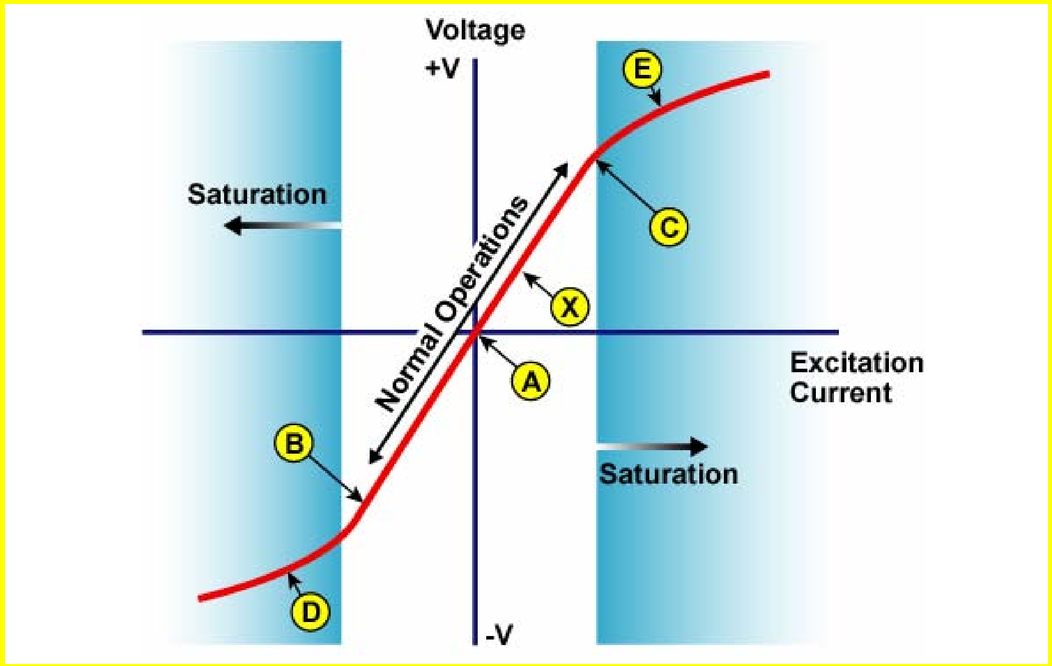


Figure 9-41
Transformer Saturation Curve

When a transformer saturates the excitation current rises sharply. The excitation current is a lagging reactive current. An increase in the excitation current usage of a transformer may be noticed as an increase in the Mvar usage of the transformer. A badly saturated transformer may increase its Mvar usage by a factor of 50. For example, in normal operation a 3Φ - 600 MVA transformer may use 2 Mvar but when saturated its reactive power usage may jump to 100 Mvar. This increase in Mvar usage can lead to system reactive power deficiencies and low voltage problems.

The excitation current drawn by a saturated transformer is not a pure 60 HZ sine wave. The excitation current will be a distorted sine wave. This means that harmonics will be created in the power system. The harmonics can lead to false relay operations and possible damage to rotating equipment and other types of customer load.

The most troublesome consequence of SMD activity is the saturation of power transformers. GICs are DC like currents that flow in the earth’s surface. The GICs flow up into transformers that are equipped with grounded neutrals. If the GICs are large enough they shift the normal operating point of the transformer from point “A” in Figure 9-41 up toward point “X”. Now as the voltage oscillates about point “X” the transformer will be saturated for most of the positive half cycle of the voltage wave. This effect is appropriately called half-cycle saturation.

Not all types of transformers are subject to saturation from GICs. If the transformer does not have a grounded-wye winding, the GICs cannot get into the transformer. In addition, different transformer core designs can be used to avoid saturation even if the transformer is a grounded-wye. Figure 9-42 lists various transformer designs and their likelihood of saturation due to GICs.

Figure 9-42
Transformer Susceptibility to GIC Induced Saturation

Effects on Shunt Capacitors

In Section 9.3 the use of filters to absorb harmonics from the power system was described. A filter is formed of a combination of capacitors, resistors, and inductors. Filters are tuned to absorb a specific harmonic or a range of harmonic frequencies. Shunt capacitors that are installed in the power system for voltage control also act like filters. These capacitors are normally not tuned to any particular frequency, rather they act like filters to any frequencies that are well above 60 HZ. The higher the frequency of the harmonic, the lower the impedance the capacitor will present.

Capacitor banks may not be grounded. Some capacitors are connected in a delta.

When high levels of GICs flow in transformer neutrals, some transformers will saturate. These transformers will serve as sources of harmonic currents. Local grounded shunt capacitor banks will absorb these harmonic currents. If the harmonic current magnitudes are large enough the capacitor's protection could assume that the high current levels represent abnormal conditions and trip the capacitor bank.

The tripping of shunt capacitor banks during SMDs is a common occurrence. If the utility has spare reactive power capability the trips will not be significant. However, if the utility has a deficiency of reactive power the loss of a large number of shunt capacitors could be damaging. The Hydro Quebec SMD related blackout of 1989 was triggered by the loss of SVCs. Harmonic currents in the system led to the tripping of the grounded shunt capacitor components of the SVCs.

Protective relay manufacturers have designed relay packages for capacitor banks which are immune to harmonic currents. These protection packages are expensive and only applied if the utility has a good reason to believe that the false tripping of the shunt capacitor could lead to system reliability concerns.

Effects on Generators

Utility generators are normally connected to the power system using delta/grounded-wye step-up transformers. This type of transformer connection prevents GICs from entering the generator since there is no ground current path through a delta connection. However, high levels of GIC in the step-up bank may cause the transformer to saturate. Severe levels of transformer saturation can damage the step-up transformer as was experienced at a northeast U.S. nuclear plant in March of 1989. Saturation will also create harmonic currents which can work their way into the generator.

Generators are not designed to carry harmonic currents. The high frequency currents may create magnetic field components which spread to areas of the generator that are not designed for the resulting current flows. Thermal damage may result. A typical generator protection package will not detect low levels of harmonic current. The generator could be exposed to these harmonic currents for long periods of time without any relay protection.

In addition to thermal damage, there are two additional concerns if the generator step-up transformer saturates and becomes a source of harmonics. When transformers saturate 2^{nd} and 3^{rd} order harmonic currents are produced. The generator may enter a condition called supersynchronous resonance. This condition could result in damaging shaft torques.

The final concern involves a generator's excitation system. High speed excitation systems are designed to rapidly detect and correct variations in the generator's terminal voltage. A large harmonic current content will lead to harmonic voltage variations. The voltage regulator/exciter system may falsely respond to harmonic voltage components. This may lead to fundamental frequency voltage control problems.

Reactive Power Reserves

When the loss of shunt capacitor banks is combined with the loss of generators and the increased Mvar usage of transformers, a probable result is voltage control problems. A major consequence of SMDs is voltage control problems. There is a possibility that if an SMD occurs at the right time, voltage instability and collapse could result. Utility operating guidelines during SMDs should address the need to carry sufficient reactive power (especially dynamic) reserves.

Effects on Protective Relays

Protective relay systems can be impacted by high SMD activity in two general ways. The first possibility involves relay instrument transformers and the second possibility involves harmonics.

Protective relays use current transformers (CTs) to gather system data. GICs can saturate CTs in the same manner as power transformers. The secondary current levels of the CTs then may not accurately represent the primary quantities. False relay operation could follow. With high levels of GICs the CTs themselves may suffer thermal failures.

Protective relays are designed to monitor a quantity such as current and trip if the quantity maintains a set level for a set period. Protective relays may respond to harmonic components in a similar manner as they respond to fundamental components. For example, an electro-mechanical overcurrent relay's induction disk unit may rotate just enough due to harmonic currents that its contacts close and a false trip occurs.

The impact of harmonics is more severe on solid-state relays. One of the advantages of solid-state relays is their rapid response time. Solid-state relays are fast enough that they may respond to rapidly varying harmonic voltages or currents and falsely trip. Relay manufacturers have designed relay packages that are relatively immune or hardened to harmonics. Utilities may choose to utilize these more expensive relays if the possible harm to the system justifies the extra cost.

Effects on Telecommunications Systems

Some forms of telecommunication systems are susceptible to GICs. If the telecommunication system is dependent on a wire path, the GIC currents flowing in the ground may induce currents in the wire conductors. This can lead to a failure of the telecommunication system or the transmittal of false information. For example, pilot wire relay systems are often dependent on wire communication paths. These paths could fail or transmit false information due to GICs. Telephone systems are often dependent on wire paths. These systems could fail due to the presence of GICs.

GICs & Modern Power Systems

Recent years have seen an intense interest in the cause, effects, and control of SMDs. This increased interest is likely due to the realization that SMDs can black-out an entire power system as was proven on March 13, 1989. If modern power systems are compared to those of the past the following points can be made that at least partially account for our increased susceptibility to SMD activity.

- Modern power lines are much longer and built at higher voltages with larger conductors than in the past. When ESPs are created in the earth's surface, these longer lines cross greater potential differences and the GIC current paths have lower impedance. Both factors lead to larger GIC flows in the line conductors and through transformer neutrals.
- Modern power systems are often operated with decreased reactive reserve and system stability margins. Saturated transformers and tripped capacitors can push a stressed power system over the edge and lead to system separations and blackouts.
- Modern power systems often incorporate sophisticated thyrister based components such as HVDC systems and SVCs. These systems are often used to justify increased operating margins. Many of these systems include components that are highly susceptible to GICs.
- Modern systems use large 1Φ transformers more than in the past. 1Φ banks are more susceptible to GICs than 3Φ banks.
- Solid-state protective relay systems gained wide acceptance during the 1980s. These relays operate so rapidly that they may falsely trip during the harmonic swings caused by GICs.
- Modern power systems are highly dependent on sophisticated telecommunication systems. Unfortunately, the telecommunication systems themselves are highly susceptible to SMD related failures.

9.6.8 Controlling the Impact of SMDs[12]

Methods are currently available or being planned for monitoring SMD activity. This section will describe these methods. Several new methods for blocking the flow of GIC currents are being evaluated by utilities. This section will also describe GIC blocking schemes.

Blocking GICs in the Transformer Neutrals

A promising method for blocking the flow of GICs is illustrated in Figure 9-43. The figure illustrates a path for GIC flow between a delta/grounded-wye transformer and an autotransformer. The ESP between points “A” and “B” will lead to a GIC circulating in the line between the transformers and also flowing into the remainder of the system via the autotransformer secondary winding.

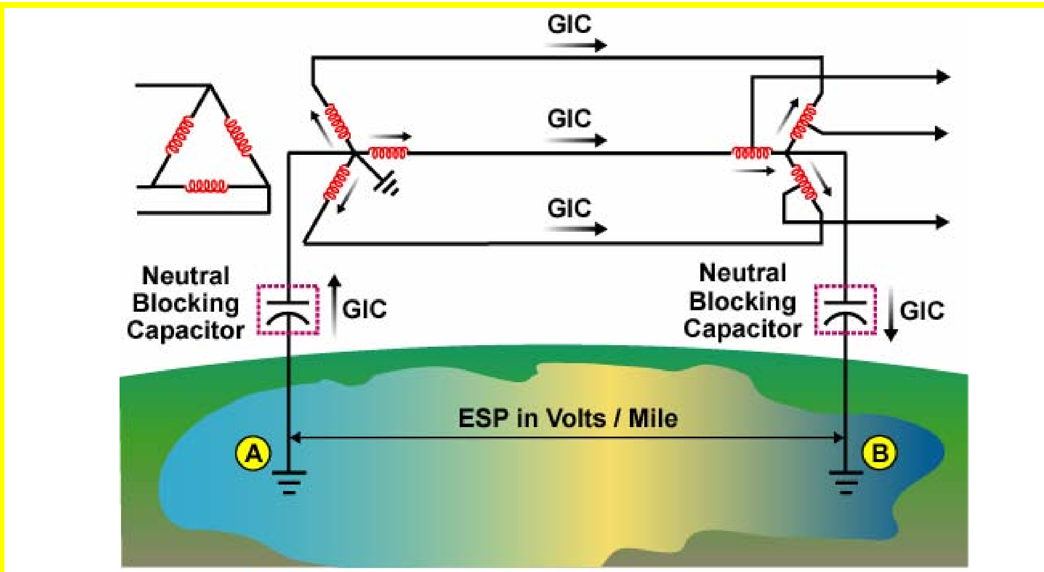


Figure 9-43
Using Neutral Blocking Capacitors

Note the series capacitors in the neutrals of the two transformers. The reactance of a capacitor is inversely related to the frequency—the lower the frequency, the higher the capacitive reactance. The capacitors in Figure 9-43 will block the GIC flow since the GIC frequency is very low. These capacitors are referred to as neutral blocking capacitors. Figure 9-44 illustrates possible connections for the neutral blocking capacitor. The capacitors are placed in series in the neutrals of the transformers. Neutral blocking capacitors are now installed at several utilities.

[12] Neutral blocking capacitor description based on reference #13.

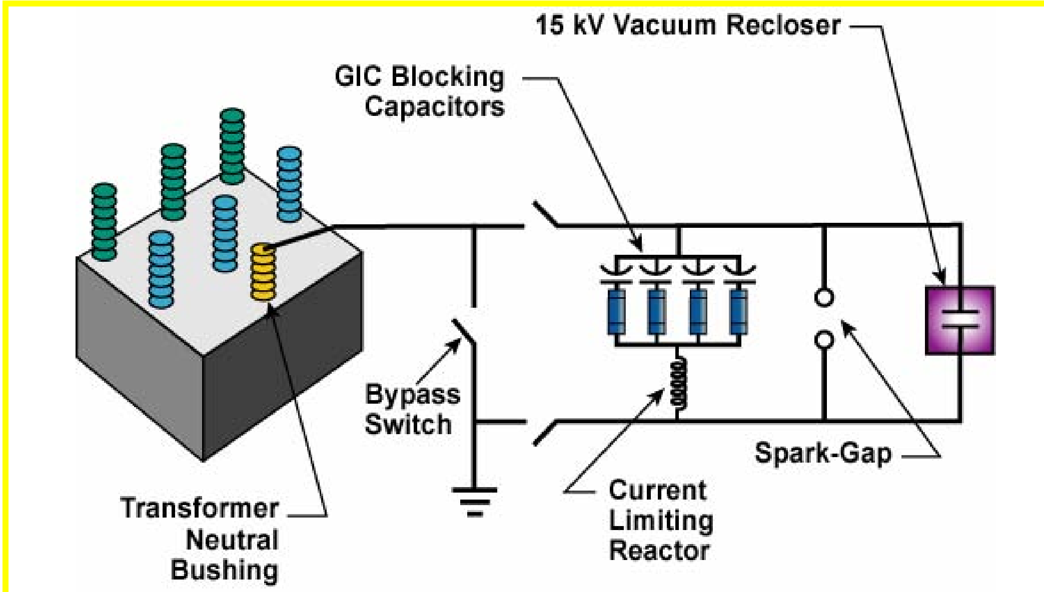


Figure 9-44
Connection Diagram for Neutral Blocking Capacitor

There are difficulties associated with neutral blocking capacitor operation. One reason for grounding transformers is to access a source of ground current during system faults. The neutral blocking capacitors will reduce this current during system transients. Also, the high currents associated with system transients could lead to damaging levels of voltage across the capacitors. A combination of operating procedures and protective devices may solve the problems with these capacitors. The capacitors are only switched in when the probability of GICs is high. The capacitors are also equipped with spark-gaps to short the capacitors out if the neutral current magnitude is excessive.

Use of Series Capacitors

Transmission line series capacitors can also be used to block the flow of GICs. Normally, series capacitors are used in the bulk power system to reduce the transmission line's effective reactance and increase the line's MW transfer capability. These types of series capacitors have enough capacitive reactance (measured in ohms) to compensate for a significant portion of the line's natural inductive reactance. For example, the series capacitors may provide 50% series compensation. Smaller size series capacitors can be used to block the flow of GICs in transmission lines. These series capacitors would require small ohmic values since they are not being used to cancel out the line's reactance. The series capacitors present a high impedance to low frequency GIC and block its flow through the transmission line. An eastern U.S. utility has installed series capacitors for the purpose of blocking GIC.

SMD Warning Systems

Government agencies and utilities cooperate in various ways to classify SMD activity and to distribute alerts of probable SMD activity. The primary methods used to classify SMD activity are via distribution of indices of SMD activity.

K_p and A_p Indices

The U.S. National Oceanic and Atmospheric Administration (NOAA) operates the Space Environmental Service Center (SESC) which distributes two indices of SMD activity. The indices, K_p and A_p, are used to classify the intensity of SMD activity. The indices are both based on data gathered from Earth based equipment and data from orbiting satellites.

The K_p index is a three hour planet wide average of the magnitude of the earth's magnetic field. Measurements of K_p are taken at 46 observation points from around the world. The values of K_p can range from 0 to 9. K_p values toward the low end (0-1-2) indicate little SMD activity while a value of 8 or 9 indicates severe SMD activity. (The March 13, 1989, SMD had K_p values ranging from 8 to 9.) Any value of K_p above 5 indicates the possible presence of harmful SMD activity.

Site specific "K" and "A" indices are of more value to individual utilities as the impact of SMDs varies widely depending on location.

The A_p index is a 24 hour average of SMD activity that is derived from the same data used to compute the K_p index values. A_p values can range from 0 to 400. Values toward the low end indicate low levels of SMD activity during the past 24 hours while values toward the 400 end indicate high levels of SMD activity during the past 24 hours. (The March 13, 1989, Hydro Quebec disturbance had an A_p value of 248.)

NOAA also issues SMD warnings. The SMD warnings are similar to weather forecasting. The agency tries to predict the occurrence of SMD activity. Automatic message distribution systems have been setup by NOAA and NERC to ensure that utilities are notified if a K_p value of 5 or greater is predicted to occur.

The Geological Survey of Canada (GSC) also provides a similar form of SMD forecasting.

EPRI Sunburst 2000 System

The EPRI Sunburst 2000 system is a computer based monitoring system that is designed to expand our knowledge of SMDs and to provide an early warning of their presence. The system is designed to gather information from many locations throughout the U.S. and Canada. The data gathered includes GIC current levels, ESP levels, harmonic content, system reactive power consumption, transformer temperatures, and earth magnetic field data. The data are fed via modems to an evaluation site in the U.S. Warnings can then be sent to participating utilities concerning the severity of detected SMD activity.

Satellites to Monitor the Solar Wind

Many advances have been made in recent years in our understanding of the SMD process and in our ability to monitor and predict SMD activity. Several satellites are currently in orbit and include:

- **SOHO**. Acronym for the Solar and Heliospheric Observatory. This satellite was launched in 1995 and is stationed about one million miles from earth between the sun and the earth. SOHO is used to monitor solar activity.
- **ACE**. Acronym for the Advanced Composition Explorer satellite. ACE was launched in 1997 and is used to monitor the solar wind.
- The **WIND**, **TRACE**, and **IMAGE** satellites which also assist with solar and earth monitoring.

9.6.9 Hydro Quebec SMD Incident

On March 10, 1989, a large solar energy disturbance occurred on the surface of the sun. Two days later spectacular displays of the northern lights were visible on the earth. This SMD was one of the strongest ever recorded. The biggest consequence of the SMD began at 02:45 A.M. on March 13th in the Canadian province of Quebec.

The Quebec Interconnection has a large concentration of hydroelectric generation in the northern part of the system at James Bay. Collectively this generation is referred to as the La Grande Complex. Major load areas are situated in the southern part of the system along the Saint Lawrence Seaway. The load centers include the major cities of Quebec and Montreal. A 600 mile long - five line - 735 kV transmission system connects La Grande generation to the Saint Lawrence load centers. Figure 9-45 illustrates the 735 kV system in the Quebec Interconnection.

High voltage lines of this length require massive amounts of reactive compensation to operate. Without the reactive compensation system voltages and power angles would be impossible to control within acceptable limits. The reactive compensation for the 735 kV system between the La Grande Complex and the St. Lawrence area includes seven large static var compensators (SVCs).

GIC currents that resulted from the SMD entered the power system via the neutrals of grounded power transformers. The transformers saturated and became strong harmonic sources. The harmonics sought out the low impedance path of the SVC shunt capacitor legs. The capacitor protection systems activated assuming an overload condition due to the high harmonic currents in the capacitor neutrals. Figure 9-45 notes the tripping of seven large SVCs (items #1 through #4) over a 1 minute period.

The 735 kV system cannot stay in-service without the SVCs. Approximately 9 seconds after the last SVC tripped the first of the 735 kV lines tripped. The other four lines followed within a few seconds (note item #5). Over 9,500 MW of La Grande Complex generation was dropped with the loss of the 735 kV system.

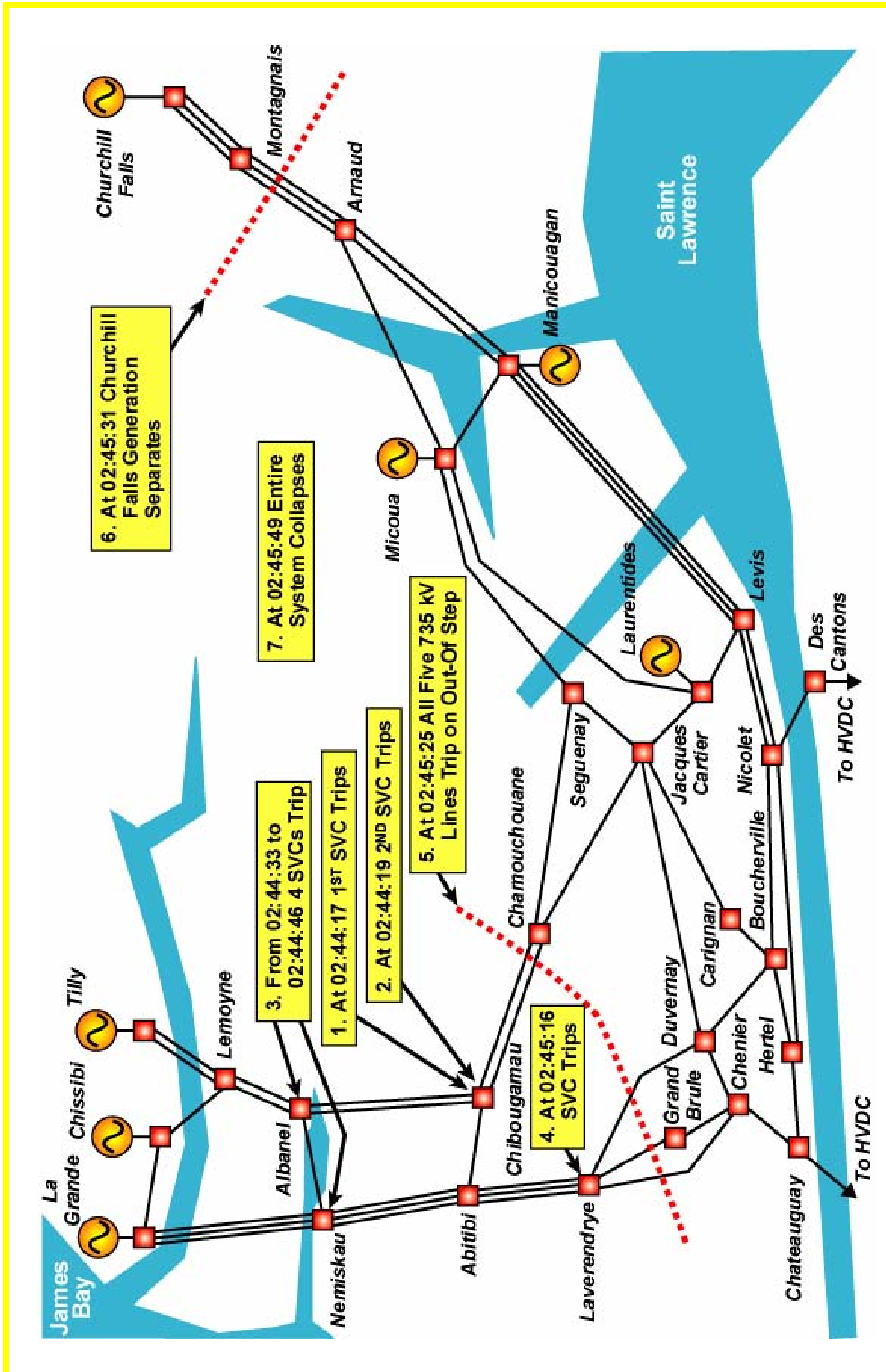


Figure 9-45
Hydro Quebec SMD Incident

Frequency and voltage throughout the Quebec Interconnection rapidly fell. Underfrequency load shedding failed to arrest the frequency decline. Approximately 6 seconds after the loss of the La Grande Complex Churchill Falls generation separated (see item #6). The entire Interconnection then collapsed within a few seconds.

Over 21,000 MW of load was lost. Nine hours after the system collapsed 17% of the load was still out-of-service.

The effects of this massive SMD were not confined to Canada. Utilities in the northern areas of the U.S. from the east to the west coasts reported tripped shunt capacitor banks and false relay operations. A generator step-up transformer at nuclear plant in the eastern U.S. was severely damaged and had to be replaced. Utilities as far south as South Carolina in the east and southern California in the west reported unusual events due to this SMD. The Allegheny Power System, which serves West Virginia and portions of Pennsylvania, Maryland, and Virginia, had 10 of its 24 transmission level shunt capacitor installations falsely trip during the SMD.

9.6.10 Role of the System Operator[13]

Utilities who are susceptible to SMD activity must prepare their system operators for the possible occurrence of SMDs. Operating guidelines must be researched, written, and made available to operations personnel. System operator response can be grouped into two categories; protecting system equipment and ensuring the power system itself remains secure.

Equipment Protection Guidelines

Each utility must identify the equipment in their system which is most susceptible to SMD damage. In general, transformers are the area of most concern. GICs will enter the power system via transformer neutral windings. Generator step-up transformers are especially susceptible due to the nature of their design.

Ensuring System Security

During periods in which severe SMD activity is likely, the following operating guidelines will enable systems to better withstand SMD effects:

- Discontinue or postpone maintenance work. Restore transmission lines to service if at all possible.

[13] This section is based on reference #12.

- Maintain system voltages within an acceptable operating range. The goal is to avoid being trapped in a low voltage condition and to avoid severe voltage swings.
- Reduce loading on critical transmission lines. Recall from Chapter 5 the large increase in reactive power usage associated with heavily loaded transmission paths. Reducing system loading will increase reactive reserves.
- Ensure that the power system’s reactive reserves are adequate. Reactive reserves should be spread throughout the system. Sufficient dynamic reactive reserve levels are especially important.
- Ensure your system’s MW reserves are adequate.
- HVDC converters are susceptible to SMD related outages. HVDC converters are more likely to avoid SMD related trouble if initially operating within 40% to 90% of their nominal rating.
- Keep verbal communication channels open with neighboring utilities. SMDs are widespread events. Be aware of what your neighbor is experiencing and let your neighbor know about unusual events in your system.

Summary of Additional Topics

9.1.1 Introduction to Additional Topics

- This chapter addressed three related subjects; harmonics, resonance, and geomagnetic disturbances.

9.2.1 Introduction to Harmonics

- Voltage and current waveforms normally have some harmonic content.

9.2.2 Description of Harmonics

- The ideal 60 HZ wave is called the fundamental wave. However, a waveform may be formed of the fundamental (60 HZ) plus the 3rd harmonic (180 HZ), 5th harmonic (300 HZ), etc.

9.2.3 Harmonic Content

- A factor called the total harmonic distortion (THD) is used to quantify the harmonic content of a given voltage or current wave. A THD of 5% for a voltage wave means that the harmonic content is 5% of the fundamental component.

9.2.4 Sources of Harmonics

- The major sources of harmonics in the power system are utility equipment and customer loads.

9.2.5 Flow of Harmonic Current

- Harmonic currents will enter the power system and distribute according to the path of least impedance.

9.2.6 Effects of Harmonics

- Rotating equipment such as motors and generators are very susceptible to harmonics.
- Transformers are susceptible to harmonics due to the overheating that may occur.
- High frequency currents will be drawn to the shunt capacitors in the system.
- Protective relays may misoperate due to harmonic currents and voltages.

9.2.7 Control of Harmonics

- Delta connected transformer windings will naturally absorb the “triplen” harmonics. The triplen harmonics are the 3rd, 6th, 9th, 12th, etc.
- A harmonic filter is a combination of an inductor, capacitor and resistor that is tuned to adjust the frequency at which it will have a minimum impedance.

9.3.1 Introduction to Resonance

- Electrical resonance occurs when the capacitive reactance of a circuit matches or is tuned to the inductive reactance of a circuit.

9.3.2 Series Resonance

- Series resonance will occur if the inductive reactance of a circuit is canceled by the circuit’s capacitive reactance or when the magnitude of X_L equals X_C.
- When a series resonance condition exists the elements in the resonance circuit can be exposed to voltages that are much higher than the source voltage.

9.3.3 Parallel Resonance

- Parallel resonance is similar to series resonance but occurs when the capacitive and inductive elements are in parallel and their impedances are equal in magnitude.
- At parallel resonance the incoming current would see a very high impedance that is almost purely resistive and possibly equal to many times the circuit’s resistance value. The total current that passes through the circuit would be at a minimum.

9.4.1 Introduction To Subsynchronous Resonance

- Subsynchronous resonance or SSR is similar to series resonance and occurs due to an interaction between a system’s generators and local transmission system.

9.4.2 SSR and Series Capacitors

- The amount of series compensation used is limited by two general restrictions. The first restriction is voltage related and the second SSR.

9.4.3 Resonance Frequency

- If enough series capacitors are added to the power system to raise the series resonant frequency to a value in the neighborhood of 10 to 50 HZ, SSR problems can occur.

9.4.4 Definition of Subsynchronous Resonance

- "Subsynchronous resonance (SSR) is an electric power system condition where the electric network exchanges energy with a turbine/generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system."

9.4.5 Components of System Current

- The current that flows in a power system is always composed of several frequency components.

9.4.6 Generator Modes of Oscillation

- A turbine/generator's mechanical modes of oscillation refer to the tendencies of sections of the turbine/generator shaft to oscillate with respect to other sections of the shaft and with respect to the electrical system to which the generator is attached.
- SSR typically occurs when the frequency of the currents that are flowing in the generator rotor match one of the natural modes of the turbine/generator shaft.

9.4.7 Forms of SSR

- There are three general scenarios for SSR.
    - Scenario I is torsional interaction. Torsional interaction occurs when a generator's natural mode is closely matched to induced rotor currents.
    - Scenario II is transient torque. Transient torque occurs following a severe disturbance. The oscillation frequency of the disturbance current closely matches a shaft mode.
    - Scenario III is the induction generator effect. In the induction generator effect a synchronous generator acts as if it is an induction generator.

9.4.8 When Is SSR a Concern?

- A system operator should be concerned about SSR if their system has steam turbine/generators that are connected to high voltage series compensated lines. SSR is also more likely to occur when units are lightly loaded.

9.4.9 SSR Example

- The Mohave units of Southern California Edison experienced two incidents of SSR in the early 1970s.

9.4.10 Preventing SSR

- Methods of preventing SSR were presented.

9.5.1 Introduction to Ferroresonance

- Ferroresonance is an overcurrent and overvoltage condition that can be the result of either series or parallel resonance. The inductance must be of a particular type for ferroresonance to occur, a type called an iron-core inductance.

9.5.2 Definition of Ferroresonance

- Once a ferroresonance condition develops, high currents will oscillate in the series circuit. These high currents will result in large voltage drops across the reactive elements of the circuit.

9.5.3 Distribution Ferroresonance

- Typically, when a distribution system ferroresonance condition occurs, it is triggered by a switching transient such as the closing or opening of a 1Φ switch.

9.5.4 Ferroresonance in a Transmission Substation

- Iron-core PTs are usually a necessary ingredient for transmission level ferroresonance.
- A method for reducing the impact of transmission system ferroresonance is to add resistance in the secondary circuits of PTs.

9.6.1 Introduction To Geomagnetic Disturbances

- SMDs are disturbances to the earth’s magnetic field that are a consequence of disturbances on the sun.

9.6.3 The Solar Wind

- The sun is constantly pushing a stream of charged particles toward the earth. This stream of charged particles is called the solar wind.

9.6.4 ESPs & GICs

- SMDs induce voltages in the earth's surface. These voltages are called earth surface potentials or ESPs.
- The ESPs lead to the flow of low frequency currents in the earth's surface called geomagnetic induced currents or GICs.

9.6.5 Factors that Influence the Impact of SMDs

- Those areas of the earth that are most prone to SMD effects are northern areas that contain igneous rock and are bordered by large salt water bodies. The northeast coast of North America fits this description well.

9.6.6 GIC Entry to the Power System

- GIC cannot enter into a delta winding since there is no ground current path. GICs can enter a grounded wye winding such as is in an autotransformer.

9.6.7 Impact of SMDs

- The impact of SMDs on the power system was described.

9.6.8 Controlling the Impact of SMDs

- Methods of controlling the impact of SMDs include transformer neutral blocking capacitors and series capacitors in transmission lines.
- NOAA distributes two indices of SMD activity. The indices, Kp and Ap, are used to classify the intensity of SMD activity.

9.6.9 Hydro Quebec SMD Incident

- An SMD on March 13, 1989, was one of the largest ever recorded. The entire Quebec Interconnection was blacked out as a result of this SMD.

9.6.10 Role of the System Operator

- Each utility must identify the equipment in their system which is most susceptible to SMD damage. In general, transformers are the item of most concern.

- During periods in which severe SMD activity is likely, the following general operating guidelines will enable systems to better withstand SMD effects:
    - Discontinue or postpone power system maintenance work
    - Maintain system voltages within an acceptable operating range
    - Reduce loading on critical transmission lines
    - Ensure active and reactive reserves are adequate
    - Operate HVDC converters within 40% to 90% of their nominal rating
    - Keep verbal communication channels open with neighboring utilities

Additional Topics Questions

1. Delta connected three-phase transformer windings trap the:
   - A. Odd harmonics
   - B. Even harmonics
   - C. High order harmonics
   - D. Triplen harmonics

2. If the inductance is 0.001 henry and the capacitance is .000782 farad, what is the resonance frequency?
   - A. 300 HZ
   - B. 60 HZ
   - C. 180 HZ
   - D. 240 HZ

3. All of the following are forms of SSR **EXCEPT**:
   - A. Induction generator effect
   - B. Transient torque
   - C. Parallel induction
   - D. Torsional interaction

4. SSR is more of a concern with hydroelectric units than with thermal units.
   - A. True
   - B. False

5. All of the following are methods of preventing distribution system ferroresonance **EXCEPT**:
   - A. Use grounded-wye to delta transformer connections
   - B. Keep resistive load connected to the transformer during switching
   - C. Switch at the transformer end of the distribution line
   - D. Use three-phase switching

6. The currents that flow in the earth's surface as a result of solar magnetic disturbances are called:
   A. Electrojets
   B. Geomagnetic induced currents
   C. Earth surface potentials
   D. Sunspot currents

7. The currents induced by solar magnetic disturbances enter the power system via:
   A. Series capacitors
   B. Shunt capacitors
   C. Transformer delta windings
   D. Transformer grounded neutrals

8. In a 60 HZ system, the frequency of the 8^{th} Harmonic is:
   A. 480 HZ
   B. 100 HZ
   C. 200 HZ
   D. 300 HZ

9. Shunt capacitor tripping can be a problem during SMD activity. Why?
   A. Because high frequency GIC currents flow into the shunt capacitors
   B. Because GIC currents saturate transformers which creates high frequency harmonics which cause the shunt capacitors to trip
   C. Because GIC currents enter the power system through the grounded neutrals of the shunt capacitors
   D. Because shunt capacitors trip from high ESP

10. Assume a transmission line has a series inductive reactance of 100 ohms and a series capacitive reactance of 50 ohms. What amount of series capacitance (in ohms) must be added to create a series resonance condition?
    A. 100
    B. 50
    C. 25
    D. 150

Additional Topics References

1. Power Line Harmonic Problems – Causes and Cures—A short (11 page) pamphlet published by Dranetz Technologies, Inc.

   Excellent summary of the cause and control of power system harmonic problems.

2. IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems—IEEE Standard #519-1992.

   Good reference on harmonics though written for an engineering audience.

3. IEEE Recommended Practice for Electric Power Distribution for Industrial Plants—IEEE Standard #141-1986 (the Red Book).

   Several sections in this engineering oriented text address harmonic generation and control.

4. Electricity One-Seven—Revised second edition, 1992. Editor Harry Mileaf. Publisher Hayden Books.

   Collection of seven volumes covering basic DC and AC electricity. Volume #4 contains an excellent description of basic series and parallel resonance.

5. Subsynchronous Resonance in Power Systems—Textbook published by IEEE Press, 1990.

   Advanced text that deals with the analysis of SSR. There is a short introduction to SSR in the beginning of the text that is well written and easily understood.

6. Countermeasures to Subsynchronous Resonance Problems—Paper written in 1978 by representatives of southwestern U.S. utilities.

   The paper is a summary of possible methods to avoid/control SSR.

7. Experience with 500 kV Subsynchronous Resonance and Resulting Turbine/Generator Shaft Damage at Mohave Generating Station—IEEE paper written by M. C. Hall and D. A. Hodges. Presented at IEEE 1976 Winter meeting.

   This paper was the primary reference for the SSR example described in Section 9.4.9.

8. HL&P Experiences with Ferroresonance Problems on EHV Equipment—Paper written by Charles W. Fromen and Don R. Sevcik. Presented at 1981 Texas A&M University Conference for Protective Relay Engineers.

   Well written article on transmission ferroresonance cause and control.

9. Ferroresonance and the Distribution System—Paper written in 1985 by Donald G. Wellendorf of Southwestern Public Service.

   Well written article on distribution system ferroresonance cause and control.

10. Ferroresonance in High Voltage Substations—Paper written in 1984 by A. H. Christesen, G. A. Poletto, and R. A. Mareachen.

    The example of transmission system ferroresonance presented in Section 9.5.4 was based on this paper.

11. Stormy Weather in Space—Article written by Mr. Dave Dooling. Appeared in June 1985 issue of IEEE Spectrum magazine.

    Article describes current research activity related to the solar wind. International efforts to place solar wind monitoring satellites are described.

12. Geomagnetic Disturbance Effects on Power Systems—A report prepared by the IEEE Working Group on Geomagnetic Disturbances. Report #92-SM-511-6-PWRD.

    Article contains a summary of many topics related to SMDs. Section 9.8 of this Chapter was largely based on this report.

13. Neutral Blocking Device Combats Currents Caused by Geomagnetic Storms—Article written by Mr. John Kappenman and Mr. Scott Norr. Article appeared in the May 1992 issue of Transmission & Distribution magazine.

    Well written description of the use of neutral blocking capacitors.

14. Bracing for Geomagnetic Storms—Article written by Mr. John Kappenman and Mr. Vernon Albertson. Appeared in the March 1990 issue of the IEEE Spectrum magazine.

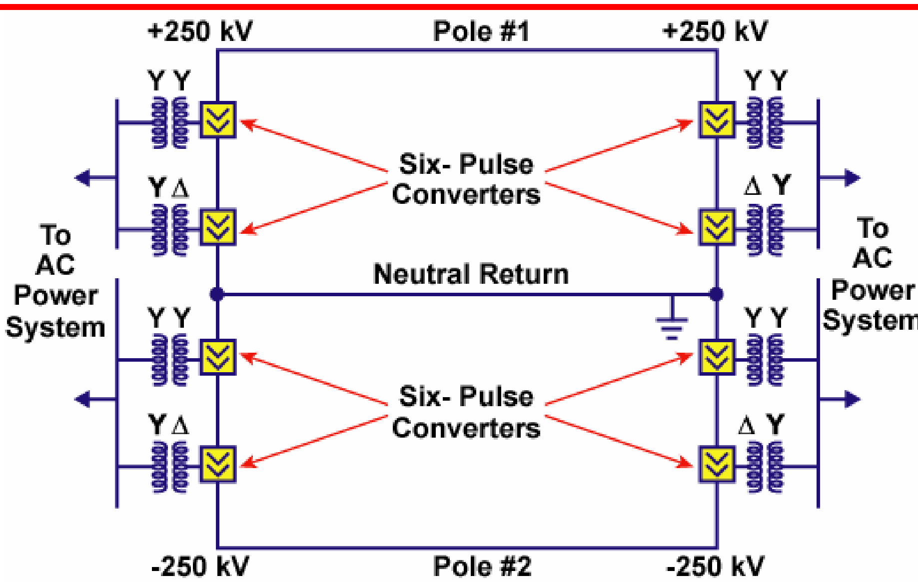
    Excellent basic tutorial on SMD cause and effects.

15. The Fury of Space Storms—Article written by Mr. James L. Burch. Appeared in the April 2001 issue of Scientific American.

    Current summary of the SMD topic.

10

EQUIPMENT



10.1 HVDC Construction and Operation

High voltage direct current (HVDC) systems are used throughout the world. There are approximately 20 HVDC systems in operation in North America.

10.2 Phase Shifting Transformers

Phase shifting transformers (PSTs) are used to control the flow of MW in a transmission path.

10.1 HVDC Construction and Operation

High voltage direct current (HVDC) systems are used throughout the world. There are approximately 20 HVDC systems in operation in North America.

10.1.1 Introduction to HVDC

HVDC systems are used to transmit energy using DC voltage and current. In an AC system the current and voltage waves cycle between positive and negative peaks at the system frequency. In a DC system the current and voltage magnitudes are fixed.

- *A rectifier converts AC to DC. An inverter converts DC to AC.*

In a typical HVDC system AC voltage and current are fed to the rectifier end of the HVDC where it is converted from AC to DC. The DC power is then transmitted over a DC conducting path. This path may be only a few feet long or it may be hundreds of miles long. At the other end of the path (called the inverter) the DC voltage and current are converted back to AC values.

In the early years of electrical utilities (late 19th century), simple low voltage DC systems were used by default as little was known about AC systems. In modern power systems DC still has a place and under certain circumstances is used instead of AC. The first high voltage (>100 kV) DC system was installed in Sweden in 1954. There are now approximately 60 HVDC systems in operation throughout the world with a combined capacity in excess of 75,000 MW.

When is HVDC Used?

An HVDC system can be used to transmit power under a variety of circumstances. The most common scenarios for which HVDC systems are used include:

- *You could also interconnect two AC systems with completely different frequencies. For example one system may be 60 HZ while the other is 50 HZ. Japan uses an HVDC system to connect the 50 HZ and 60 HZ sections of its electrical system.*

- <u>To connect two AC systems that operate at different frequencies or with different versions of the same frequency</u>. HVDC systems convert AC to DC and then back to AC. An HVDC system can absorb AC power from an AC system at one frequency and then feed this power into another AC system at a different frequency. For example, the four major North American Interconnections (Eastern, Western, ERCOT & Quebec) are tied together via HVDC lines even though all operate with different versions of 60 HZ.
- <u>To transmit large blocks of power over long distances</u>. When the costs of construction and operation of AC and HVDC systems are compared, HVDC systems may be the most cost effective when the length of the transmission path exceeds 400 to 600 miles. HVDC systems were used as the most economic alternative (as opposed to AC) for transmission projects on the West coast of the U.S. (Pacific HVDC Intertie), several long lines in MAPP, several long lines in the Northeast, and many other lines throughout the world.

- To span long distances (more than 25 to 30 miles) underground or underwater. High voltage AC cable systems are strong sources of reactive power. A high voltage AC cable may produce 20 to 30 Mvar per mile. The charging effect of high voltage cable is so large that shunt reactive compensation must be used on long systems or the thermal ratings of the cable will be exceeded due to just the flow of charging current. If it is not possible to shunt compensate the AC system then HVDC may be the best option as HVDC transmission does not produce or absorb reactive power.

HVDC converters are heavy users of reactive power but the DC transmission does not experience any significant reactive effects.

Advantages of HVDC

Some advantages of HVDC systems are summarized in Figure 10-1. Each of these advantages is briefly explained below the figure.

1. Lower Line Construction Costs
2. Lower Line Losses
3. Ability to Make Asynchronous Interconnections
4. No Power Angle Required
5. EMF Consequences Minimized
6. Complete Control of MW Transfer
7. Use for Long Underground or Submarine Crossings
8. Less Right-of-Way Required
9. Ability to Use HVDC Modulation
10. Possible Tool in Frequency Control Process
11. Fault Isolation Between AC and HVDC Systems

Figure 10-1
Advantages of HVDC Systems

1. HVDC transmission lines are less costly to construct than the equivalent AC line. (However, the cost of the HVDC converters must be accounted for in any total cost comparison.)

2. When compared to an AC transmission system with the same power transfer, the same insulation levels, and over the same size conductors, HVDC transmission system losses are approximately 33% lower than AC transmission system losses.

3. HVDC systems can be used to interconnect systems that operate asynchronously (with different frequencies). A DC interconnection often allows different systems to share generating capacity and lower power production costs.

- *Generator tripping schemes are often used to reduce the AC system impact following an HVDC line trip.*

4. HVDC power transfer does not require an angle spread (δ) across the conducting path. (However, if the HVDC line trips the AC power system may have to absorb a power swing which would then lead to an angle increase.)

5. The possible health consequences of electromagnetic fields (EMF) are a continuing issue. The magnetic fields that surround HVDC conductors do not alternate and are not considered health risks by most experts.

6. The operators of an HVDC system can control the amount of MW which flows over the DC line. Adjustments and corrections to MW flow can be made in fractions of a cycle.

7. HVDC systems can be used for long underground or submarine crossings without the need for shunt reactive compensation.

8. Less right-of-way is required for an HVDC line than for an equivalent AC line.

- *The use of HVDC modulation is similar to the use of PSS. PSS (power system stabilizers) were described in Chapter 8.*

9. HVDC systems can be used to absorb the cyclic energy of low frequency oscillations from the AC system. This process is called HVDC modulation and can be used to dampen low frequency AC system power oscillations.

- *Manitoba Hydro uses their HVDC systems to simulate governor response and to provide AGC response.*

10. When HVDC systems are used to tie two Interconnections together, the HVDC MW flow can be rapidly adjusted to simulate governor frequency response and to provide AGC response. This concept can be a useful tool in the frequency control process.

11. When a fault occurs on an HVDC line, the AC system is partially isolated from the consequences of the fault. This reduces the fault's consequences.

Disadvantages of HVDC

Some disadvantages of HVDC systems are summarized in Figure 10-2. Each of these disadvantages is briefly explained below the figure.

1. Inability to Transform Voltages
2. Difficult to Tap HVDC Lines
3. AC is Typically Less Costly for Shorter Lines
4. HVDC Converters are Complex Equipment
5. HVDC Converters are Strong Harmonic Sources

Figure 10-2
Disadvantages of HVDC Systems

1. AC transformers work via the principle of electromagnetic induction. HVDC systems do not produce alternating magnetic fields and consequently can not use conventional transformers. This limits the ability of an HVDC system to be used to interconnect with the AC system and serve customer load.

2. AC lines are easily tapped while HVDC lines are not easily tapped. The basic problem is that AC circuit breakers interrupt at a current zero whereas there is no current zero in a DC current. HVDC circuit breakers are still in the development stage. While there are multi-terminal HVDC systems, each additional terminal requires an expensive HVDC converter and complex control systems.

3. When a long line is built within an Interconnection, AC systems are typically cheaper to construct until a length of 400-600 miles is reached.

4. The equipment that converts the DC to AC and AC to DC are called converters. HVDC converters are complex pieces of equipment. The HVDC system operators must possess special skills to operate and maintain this equipment.

5. The conversion process between AC and DC and DC and AC is a strong harmonic source. Filter networks must be installed to absorb these harmonics to avoid harmful consequences to the AC and HVDC systems.

Harmonics were described in Chapter 9.

10.1.2 Types of HVDC Systems

There are many configurations of HVDC systems. Two common HVDC configurations are monopolar and bipolar. When HVDC systems are constructed they may be initially operated as monopolar and eventually expanded to bipolar operation. A bipolar system may also be operated as a monopolar system when elements are unavailable. These two types of HVDC systems are illustrated in Figure 10-3.

- *The arrows within the boxes indicate the direct current flow direction. Current will always flow in only one direction in each HVDC system.*

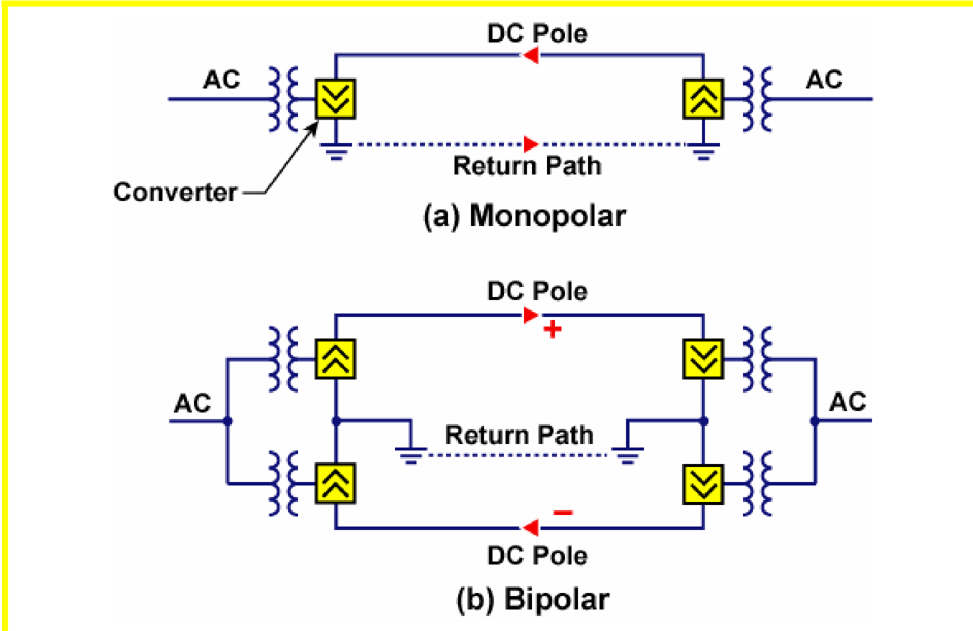


Figure 10-3
Types of HVDC Systems

Monopolar

A monopolar HVDC system uses one conductor (the HVDC transmission line) energized with a DC voltage and a return path. The return path may be the earth, the sea, or a metallic conductor. A return path is necessary to complete the electrical circuit and allow a current to circulate. The equipment that forms an energized DC conductor (converter and the HVDC transmission line) is called a "pole". The converters shown in Figure 10-3 convert between AC and DC.

Bipolar

A bipolar system uses two DC poles. One pole is normally energized with a positive voltage and the other with a negative voltage. Note that no current will flow in the return path unless a current imbalance exists between the two DC conductors. The return path may again be the earth, the ocean, or a wire conductor.

10.1.3 Components of an HVDC System

Figure 10-4 illustrates the main components of an HVDC system. This section will briefly describe the purpose and operation of each of the following components:

❶ HVDC Transmission Lines	❷ Mercury Arc Valves
❸ Thyristor Valves	❹ HVDC Converters
❺ AC Supply Transformers	❻ HVDC Smoothing Reactors
❼ HVDC Filters	❽ HVDC Electrodes
❾ HVDC Converters and Reactive Power	

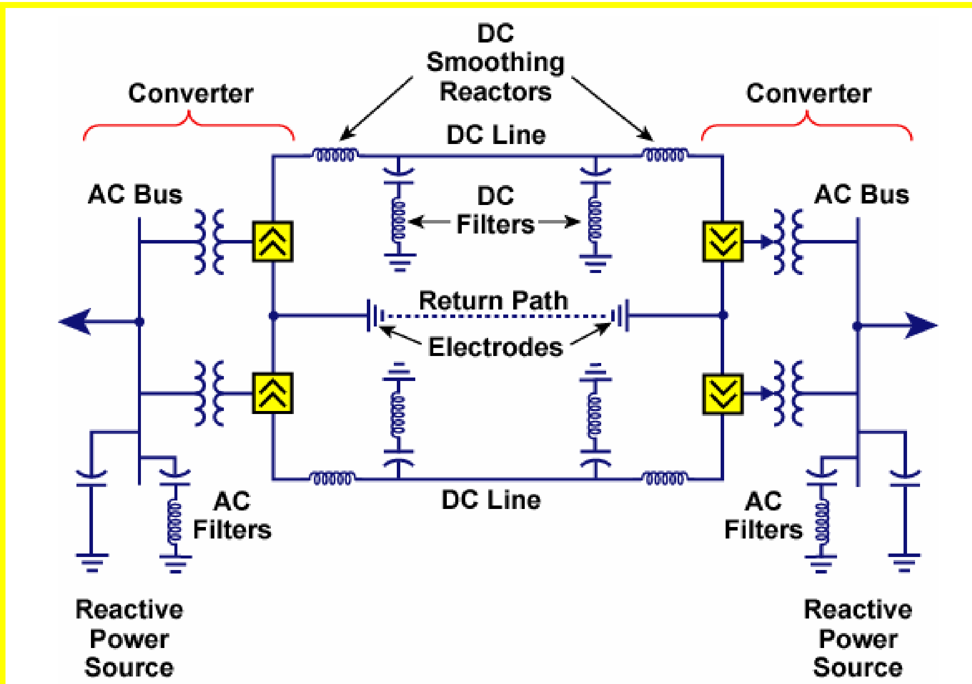


Figure 10-4
Components of an HVDC System

❶ HVDC Transmission Lines

An HVDC transmission line has a similar design as an AC transmission line. There will be fewer conductors to an HVDC line so the support structures (towers) are not as large. A bipolar system would have two conductors, one for the positive pole and one for the negative pole. If a wire return path is used, the tower may also carry this conductor. HVDC lines may use shield wires to intercept lightning strikes. Corona rings may also be used to reduce corona losses.

Corona is a luminous discharge that surrounds portions of energized equipment. Corona rings increase the effective equipment diameter and reduce corona losses.

❷ Mercury Arc Valves

When the first HVDC systems were constructed in the mid 1950's, mercury arc valves or MAVs were used to convert AC to DC and DC to AC. A simple diagram of an MAV is provided in Figure 10-5. A MAV is basically a rapid switch that uses older "tube" based technologies. The device is called a valve since current can be "turned-on" and allowed to flow by adjusting a control grid voltage pulse. An MAV is designed to conduct current in only one direction. In a later section we will describe how several valves are combined to form an HVDC converter. For now the operation of a single MAV is examined.

- *A MAV is a large piece of equipment. Each MAV may stand 20 feet high and be several feet wide. An HVDC converter will include perhaps 14 MAVs.*

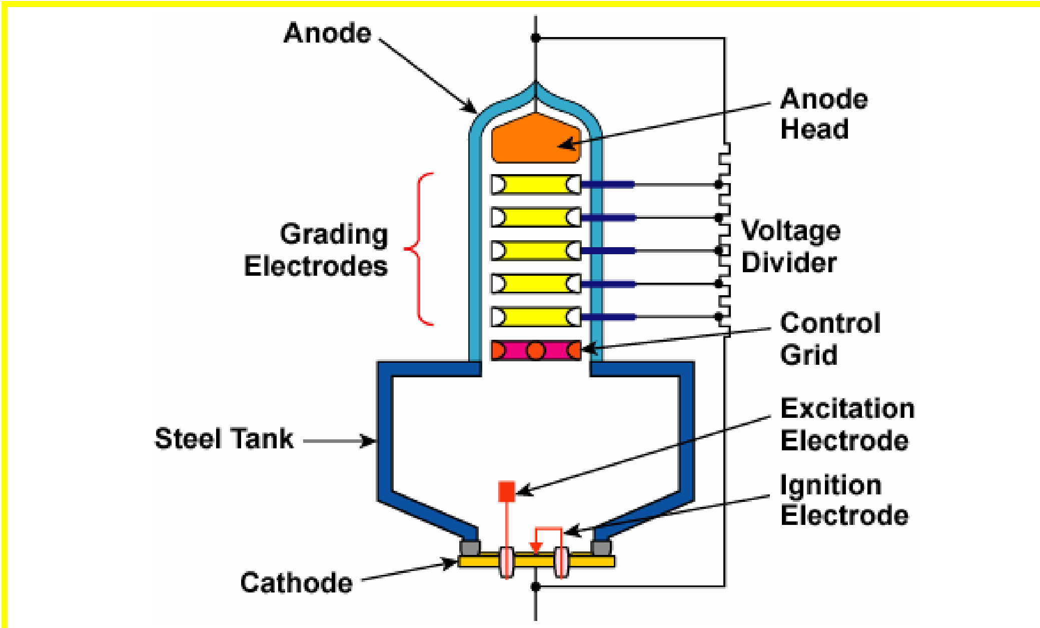


Figure 10-5
Mercury Arc Valve (MAV)

The anode is the positive terminal while the cathode is the negative terminal. The cathode contains a pool of mercury. The process by which the MAV conducts current is described in the following steps.

- *Ionization is a bombardment by energy bursts to free up electrons. Ionization is similar to charging.*

1. A small area or “spot” is ionized on the surface of the cathode’s mercury pool. The ignition electrode is used to create this spot by injecting a burst of energy. (When an MAV conducts, negatively charged electrons will be emitted by this cathode spot and attracted towards the positively charged anode.)

2. The excitation electrode is attached to an external power supply. The excitation electrode provides a small amount of excitation current. The excitation current draws an arc from the cathode spot. The excitation electrodes purpose is to sustain the life of the cathode spot.

- *Note that the control grid is used to turn a valve on or block the valve. The control grid is not used to turn the valve off once the MAV has started conducting.*

3. The control grid is used to either turn the valve on (conduct current) or to block the valve from conducting. A positive voltage pulse of a few hundred volts is used to turn the valve on while a negative voltage pulse blocks valve conduction. It is important to understand that the control grid cannot be used to turn a valve off once it has started conducting. The term “blocking” means to block the valve from conducting current.

4. The MAV will conduct current or “fire” when all of the following are true:
   - An electron stream exists between the cathode spot and the excitation electrode.
   - The voltage of the anode is more positive than the cathode.
   - A positive voltage pulse is applied to the control grid.

A MAV is simply a high power, controllable switch. The MAV firing control is accomplished via the gate pulse of voltage.

Other components of the MAV include the voltage divider and the grading electrodes which are used to avoid a concentration of voltage near the anode. The steel tank contains a vacuum in which resides a mercury vapor that is the conducting medium for the valve current. The upper portion of the valve is made of porcelain. The operating temperature of an MAV is a critical factor. Extensive temperature control systems are used to both heat and cool the MAV to ensure tight operating temperature tolerances are enforced.

MAVs were used in HVDC systems from the mid 1950’s until the early 1970’s. Modern HVDC converters use solid state valves called thyristers.

❸ Thyrister Valves

A thyrister valve is a semiconductor device (similar to a high power transistor) that has replaced the MAV in modern HVDC converters. The symbol for a thyrister valve is illustrated in Figure 10-6. A thyrister will conduct current (I_A) if the anode voltage (V_A) is more positive than the cathode voltage (V_C) and a gate pulse (I_G) of current is applied.

Thyristers were introduced in Chapter 2. This symbology will be used from this point forward to refer to any type of valve.

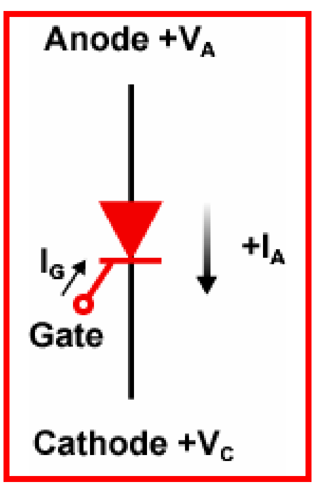


Figure 10-6
Thyrister Symbol

Each individual thyrister will have a voltage and current rating. Depending on the voltage and current ratings of the HVDC converter, each valve will be composed of hundreds of thyristers and each converter composed of a dozen valves. A large HVDC converter will therefore contain thousands of thyristers. Each thyrister is about the size of a hockey puck.

The current generation of thyristers are very reliable. MAVs often suffered from a phenomena called “arc-back”. During arc-back an MAV is subjected to a high reverse voltage which causes the MAV to break down and conduct in the wrong direction. Thyristers are not as susceptible to arc-back.

❹ HVDC Converters

Several valves (MAV or thyrister) can be combined in an electrical circuit to form a converter. Our interest in this chapter is in HVDC converters, but converters can also be used in other processes (for example, adjustable speed motor drives). Within the converter itself, the valves may be grouped together. A collection of valves to perform a specific function is called a valve group. A single converter may be composed of many valves formed into several valve groups.

Valves conducting solely based on their anode to cathode voltage is a simplification. The role of gate/grid control will be described shortly.

This section will begin by describing the operation of a simple converter with a few valves and gradually build to a type of converter used in a typical HVDC system. This section will also begin by assuming that no gate/grid control is used. The valves are turned on whenever the anode voltage is more positive than the cathode. This is a simplification to ease the learning process. In a later section the role of gate/grid control will be explained.

Single-Phase Converter

A description of HVDC converters begins with the 1Φ converter illustrated in Figure 10-7. This simple converter accepts an AC input and converts it to a DC output. The converter’s AC input voltages (V_1 and V_2) are produced from two secondary transformer windings and each applied to a valve. Note that these two voltages are 180° out-of-phase. The two valves (upper and lower) each conduct when their anodes are more positive than their cathodes.

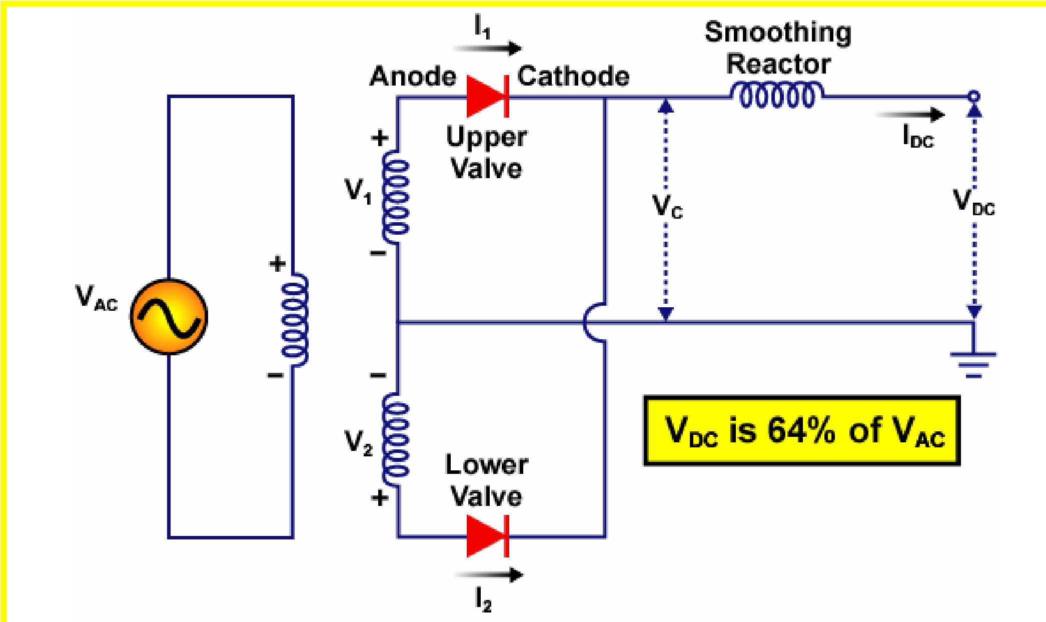


Figure 10-7
Single-Phase Converter

The output DC voltage magnitude is 64% of the peak value of the incoming AC voltage for this simple converter.

The converter output voltage (V_C) is equal to whichever anode voltage (V_1 or V_2) is more positive. Figure 10-8 illustrates the input AC voltages and the output DC voltages. The input AC voltages (V_1 and V_2) are oscillating at 60 HZ with both positive and negative half-cycles. The converter output voltage (V_C) is the sum of the positive half-cycles of V_1 and V_2. Note that V_C is always positive. The converter output voltage (V_C) can be considered a DC voltage with a substantial amount of "ripple". The average value of V_C is the magnitude of the DC output voltage V_{DC}.

Filters will be used to remove the ripple from the DC voltage. HVDC filters are described later in this Chapter.

When the input AC voltage V_1 is the more positive, the upper valve in Figure 10-7 conducts. Current I_1 then flows at the converter output. When the input AC voltage V_2 is the more positive, the lower valve conducts. Current I_2 then flows. The DC output current is the sum of currents I_1 and I_2. The DC current values in Figure 10-8 are illustrated as perfect square waves, so the sum of currents I_1 and I_2 yields a constant DC current output. The constant magnitude of the DC output current is due to the use of a large smoothing reactor connected to the converter output terminal (see Figure 10-7). The smoothing reactors function is to keep the DC output current constant and ripple free.

- *There are two pulses to the converter output voltage (V_C) for each complete cycle of the AC input voltage (V_1 or V_2). This is a two-pulse converter.*

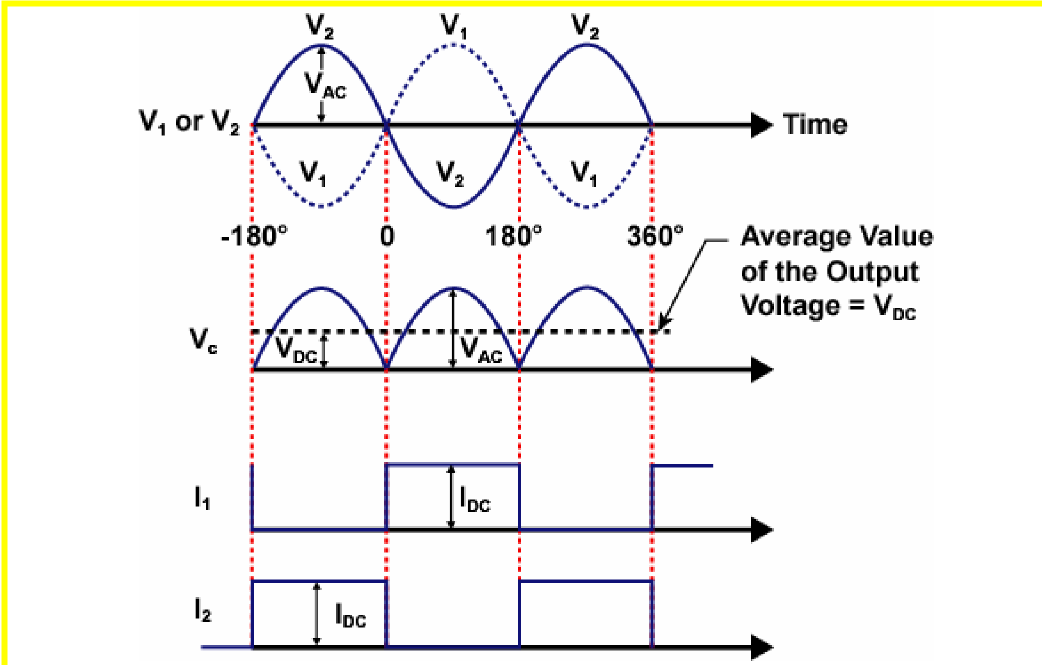


Figure 10-8
Waveforms for 1Φ Converter

Compare the AC input voltages (V_1 & V_2) in Figure 10-8 to the converter output voltage, V_C. Note that for each cycle of the input AC voltage there are two pulses to V_C. This converter could therefore be called a “two-pulse” converter.

Three-Phase One-Way Converter

Figure 10-9 is an illustration of a 3Φ one-way converter. A 3Φ AC source provides three input voltage waveforms, one waveform to each of the three valves. Each valve (#’s 1, 2, & 3) will conduct when its anode is the more positive of the three anodes.

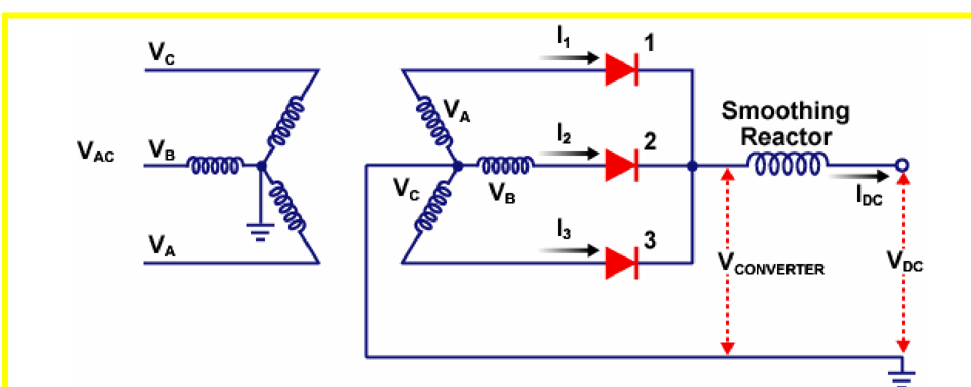
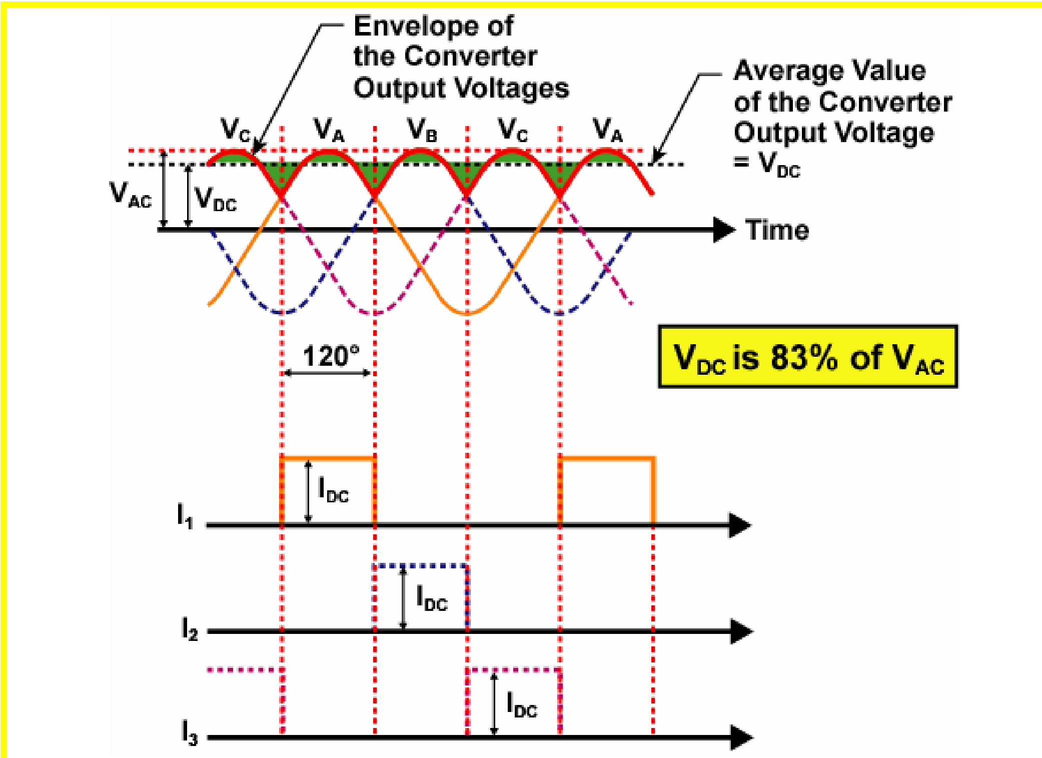


Figure 10-9
Three-Phase One-Way Converter

Figure 10-10 illustrates the voltage and current waveforms for the converter of Figure 10-9. The three AC voltage input waveforms are shown at the top of the figure. Note that when V_A is more positive than V_B and V_C, valve #1 conducts and current I_1 flows. Valve #2 conducts and current I_2 flows when V_B is highest, and valve #3 conducts and current I_3 flows when V_C is highest.

The output DC voltage magnitude is 83% of the peak value of the incoming AC voltage for this type of converter. As the number of pulses increases the conversion from AC to DC becomes more effective.



The output DC current is the summation of currents I_1, I_2, and I_3. Note that a smoothing reactor is used to eliminate the current ripple.

Figure 10-10
Waveforms for 3Φ One-Way Converter

The converter output voltage ($V_{CONVERTER}$) is composed of equal segments of the three incoming AC voltages. When valve #1 is conducting $V_{CONVERTER}$ is equal to V_A. When valve #2 is conducting $V_{CONVERTER}$ equals V_B. When valve #3 is conducting $V_{CONVERTER}$ is equal to V_C. Each valve conducts for 1/3 of a cycle or 120°. The envelope of the $V_{CONVERTER}$ voltage is highlighted in the top of Figure 10-10.

For each cycle of incoming AC voltage there are now three pulses to the output voltage wave ($V_{CONVERTER}$). This converter is therefore a “three-pulse converter”. The more pulses to the output voltage the closer it is to a constant DC output voltage. The two-pulse converter of Figures 10-7 and 10-8 has a larger ripple to its DC output voltage than the three-pulse converter of Figures 10-9 and 10-10.

Three-Phase Two-Way Converter

A 3Φ two-way converter is illustrated in Figure 10-11. (Note that a two-way converter is the equivalent of two one-way converters attached back-to-back.) These types of converters are commonly called a "Graetz Bridge" circuit and are often used in HVDC converter systems. Three voltage waveforms are supplied to the valves. The positive half of the input AC waveforms operates the upper valves and the negative half of the waveforms operates the lower valves.

- *The output DC voltage magnitude is 166% of the peak value of the incoming AC voltage for this type of converter. The output DC voltage is the sum of the upper and lower valve group voltages. The output voltage for this two-way converter is twice the output voltage of the one-way converter.*

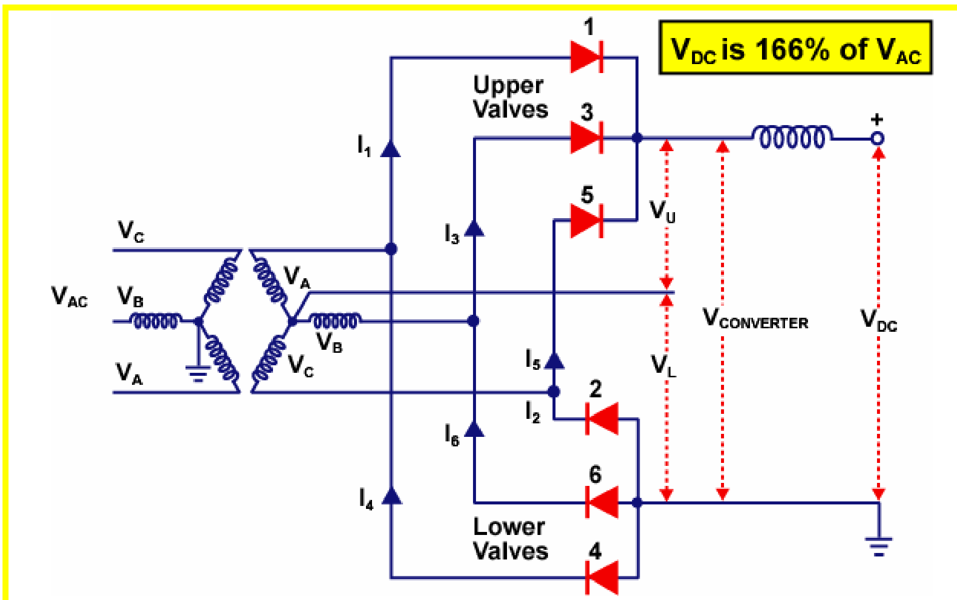


Figure 10-11
Three-Phase Two-Way Converter

One valve from the upper valve group (valves # 1, 3, & 5) and one valve from the lower valve group (valves # 2, 4, & 6) are always turned on or "firing". The valve with the more positive anode will conduct in the upper set while the valve with the more negative cathode will conduct from the lower set. Every 1/3 cycle (120°) a switch takes place between which valves are conducting in both the upper and lower valve groups.

The switching process between successive valves conducting is called commutation. Since a commutation (switch) takes place every 1/3 cycle in both the upper and lower groups, the converter as a whole experiences a commutation every 1/6 cycle or 60°. The valve firing order is from valve #1 in the upper group to valve #2 in the lower group and on through valves #3, #4, #5, and #6. The valve firing cycle continually repeats itself.

The process of switching between conducting valves is called commutation. When an HVDC converter experiences a commutation failure, it means the converter failed to properly switch between conducting valves.

The voltage and current waveforms for this converter are illustrated in Figure 10-12. The output voltage for the converter ($V_{CONVERTER}$) is the sum of the upper valve groups output voltage (V_U in Figure 10-11) and the lower valve groups output voltage (V_L in Figure 10-11). The upper valve groups output voltage (V_U) is the sum of 1/3 cycle (120°) long segments of the positive portions of the input AC voltages (V_A, V_B, and V_C). The lower valve groups output voltage (V_L) is the sum of 1/3 cycle (120°) long segments of the negative portions of the input AC voltages (V_A, V_B, and V_C).

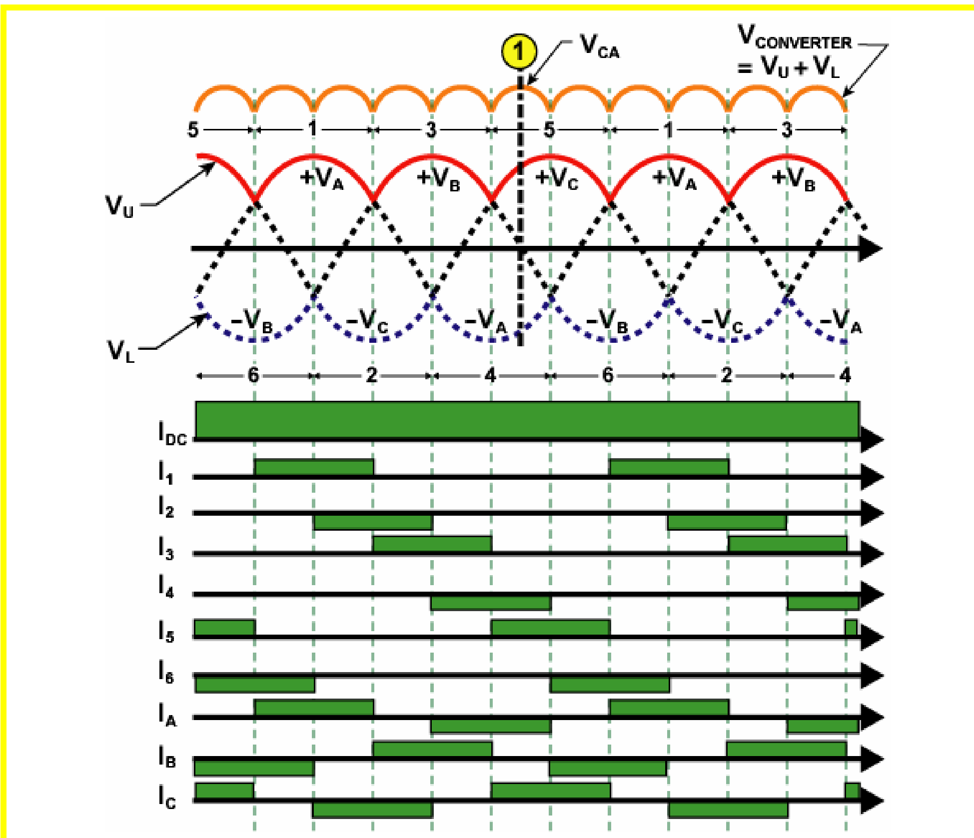


Figure 10-12
Waveforms for 3Φ Two-Way Converter

The currents drawn from the AC source are not sine waves. For example, note that the current I_A is composed of the current pulses through valves #1 and #4.

Note that for each cycle of the AC input voltage there are six pulses to $V_{CONVERTER}$. This is a six-pulse converter.

The sum of V_U and V_L is the converters output voltage ($V_{CONVERTER}$) prior to smoothing. This voltage is illustrated across the top of Figure 10-12. $V_{CONVERTER}$ can be viewed as a line-to-line voltage as it is measured between the positive and negative voltages (V_U and V_L) of the converter outputs. To illustrate the line-to-line nature of $V_{CONVERTER}$ note the point labeled "1" in Figure 10-12. The vertical dashed line through point "1" shows that each 1/6 cycle (60°) segment of the $V_{CONVERTER}$ voltage labeled V_{CA} is formed by adding the upper valve group output voltage at the time ($+V_C$) to the lower valve group output voltage at the time ($-V_A$).

Note that for each cycle of input AC voltage there are six pulses to the converters output voltage ($V_{CONVERTER}$). This is a six-pulse converter. Many modern HVDC systems can operate as six or twelve-pulse converters. (The next section describes a twelve-pulse converter.)

The current waveforms for the converter are also shown at the bottom of Figure 10-12. There are ten currents illustrated, one for the total output DC current (I_{DC}), one for each of the six valves (I_1 to I_6), and the three phase currents being drawn from the AC source (I_A, I_B, I_C). The total DC current flow is the sum of the six valve currents. The output DC current is at all times the sum of two valve currents, one current from the upper valve group and one from the lower valve group.

Twelve-Pulse Converter

Figure 10-13 illustrates two 3Φ/two-way converters connected in series. This configuration is commonly called a twelve-pulse converter. The converter output voltages contain 12 pulses for each cycle of the incoming AC voltage. The more pulses to the converter, the smoother the DC output voltage will be. An additional benefit of a higher pulse converter is that fewer harmonics are produced by the conversion process.

- *Harmonics were described in Chapter 9.*

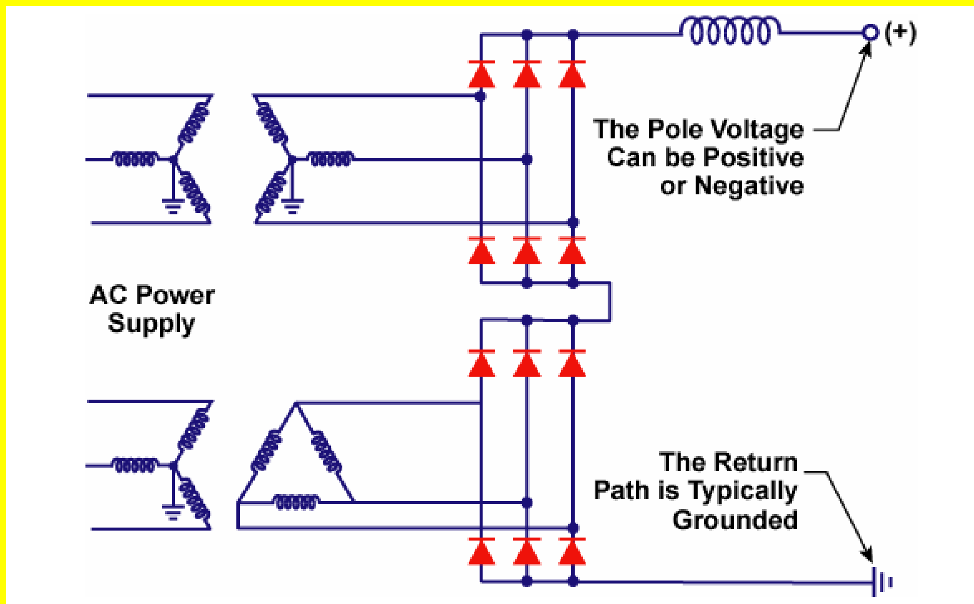


Figure 10-13
Twelve-Pulse Converter

Six voltage wave-forms must be provided to the valve groups of a twelve-pulse converter. The wye-wye bank provides three of the waveforms and the wye-delta bank provides three others. The wye-delta waveforms have a 30° phase shift with respect to the wye-wye waveforms. The two 3Φ transformers can be viewed as providing six waveforms, each separated from the others by 30°.

Versions of the twelve-pulse converter are typically used in HVDC systems. This converter type can often be operated in six-pulse mode if one of the converter valve groups is for some reason unavailable.

Figure 10-14 compares the converter output voltages for six-pulse and twelve-pulse converters. Note that the twelve-pulse converter has a smoother (less ripple) output voltage. Figure 10-15 illustrates how the higher pulse number converters can both produce a smoother DC output and draw more of a sine wave of current from the AC supply. The current waves drawn from the AC system for the two six pulse converters add to form a smoother sine wave of current supplied by the AC power system.

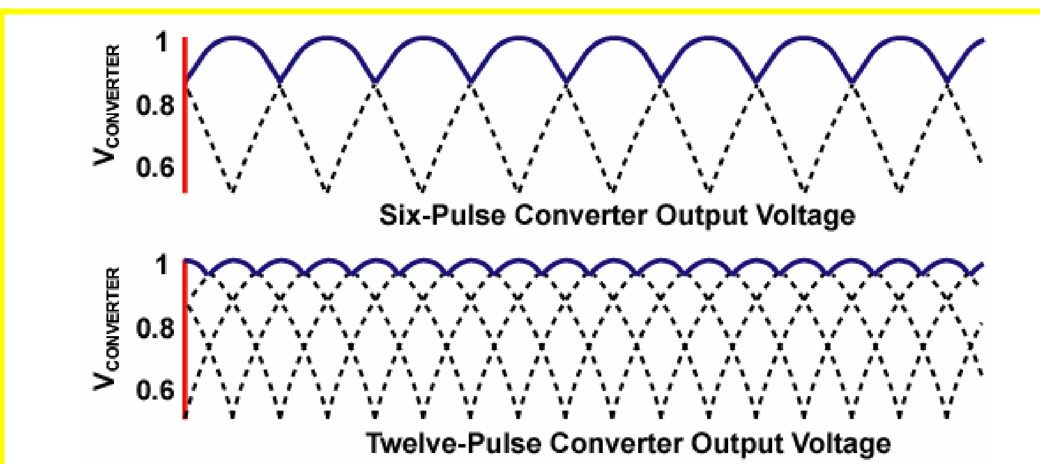


Figure 10-14
Comparison of 6 & 12 Pulse Converter Voltages

- *When the converter is operating as a rectifier, the more pulses per cycle of incoming AC voltage, the smoother the converter output DC voltage will be and the more the AC current input wave will resemble a sine wave.*

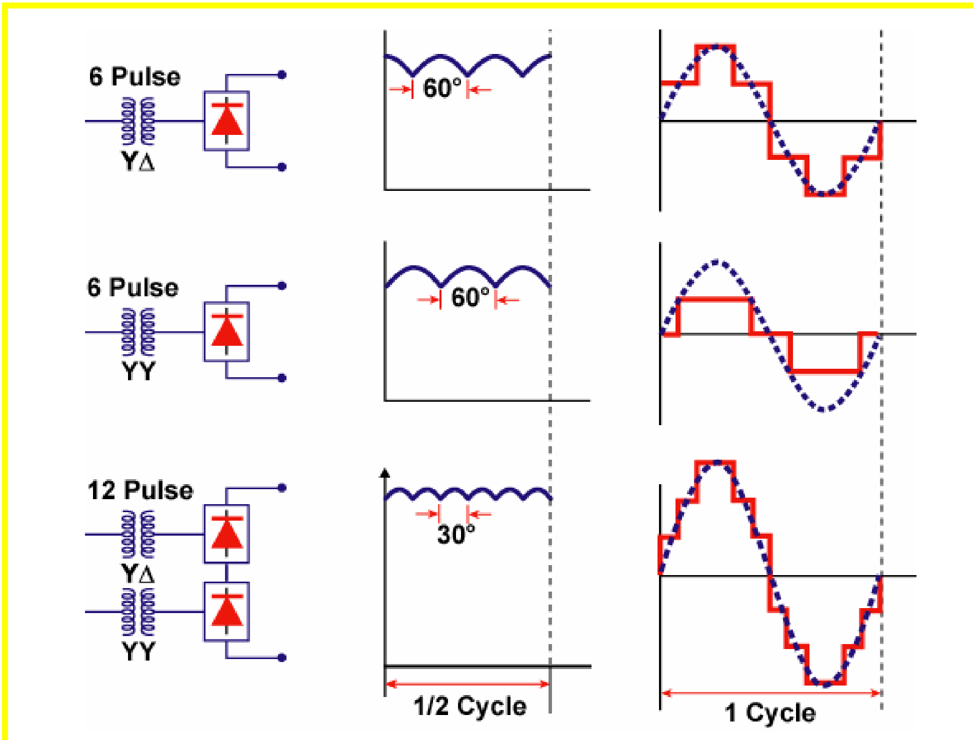


Figure 10-15
Benefits of Multi-Pulse Operation

Converter Voltage and Current Ratings

- *The highest voltage converter is at Itaipu in Brazil. Each pole of this bipolar system is rated 600 kV for a pole to pole voltage of 1200 kV.*

The voltage and current ratings of any converter depend on the ratings of the individual valves and on the valves configuration. For example, consider the twelve pulse converter that was illustrated in Figure 10-13. The upper and lower six pulse converters may have voltage ratings of 200 kV. The converter DC output voltage rating would then be 400 kV. (Note that this converter would be operating as a monopolar system.)

The power transfer rating of any converter depends on both the voltage and current ratings. For example, if a converter has a 400 kV voltage rating with a 1000 amp current rating the total MW capability is 400.

Figure 10-16 illustrates a typical set-up for an HVDC system. This HVDC is a bipolar system. Each of the shaded boxes represents six-pulse converters with the arrows indicating the current flow direction. The neutral return path may be an ocean/ground path or a grounded wire path. If each of the eight six-pulse converters has a voltage rating of 125 kV then the system has a pole-to-pole voltage rating of 500 kV. (250 kV from each pole to the grounded neutral.) If the current rating for the system is 1500 amps then the rated power flow is 750 MW.

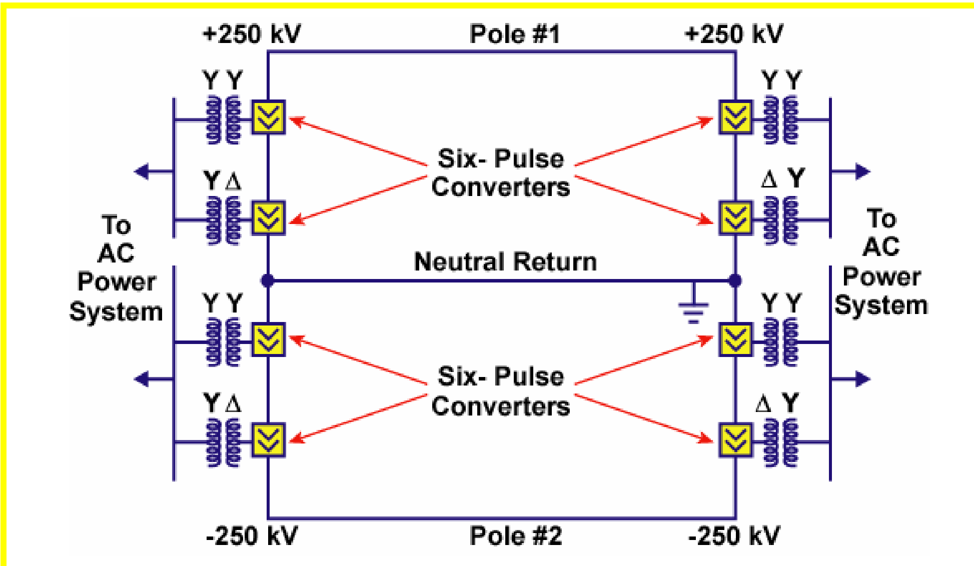


Figure 10-16
A Bipolar HVDC System

Note the use of wye-wye and wye-delta transformers to form four twelve pulse converters.

❺ AC Supply Transformers

A common failure mode in HVDC systems is failure of the AC supply transformers.

Transformers supply AC voltage and current to the HVDC converters. The conversion process requires that the transformers be able to exist in a punishing operating environment. During the commutation process in which a converter switches from one valve's "on" position to the next valve's "on" position, one winding of the supply transformer is subjected to a short term, phase-to-phase fault. The supply transformers also have a DC potential connected to one winding. These two operating conditions combine to require special designs for the transformers used to supply HVDC converters.

DC power flow magnitude is controlled by adjusting the converter (inverter and rectifier) voltages. The supply transformers must have under load tap changing (ULTC) capability to allow voltage adjustment. The ULTC capability range may be significantly larger than that encountered in a typical power transformer ULTC.

❻ HVDC Smoothing Reactors

In addition to reducing the ripple in the DC current, smoothing reactors have two other critical roles:

- Smoothing reactors are necessary to ensure a successful transfer (commutation) from one valve firing to the next valve firing.
- Smoothing reactors function as fault current limiters during a DC system fault.

❼ HVDC Filters

A simple way to view the process of converting from AC to DC is to visualize the converter as clipping only the peak (negative and positive) portions of the incoming AC voltage waveforms. These peak values are then used to create a DC voltage. The voltage that is left on the AC side of the converter is no longer a perfect sine wave but now has a large harmonic content. The designers of HVDC systems have studied the characteristics of the conversion process and can predict what harmonics will be present in the AC and DC systems.

- *Harmonics were described and illustrated in Chapter 9.*

For a six-pulse converter a mathematical analysis predicts that the dominant AC harmonics will be the 5^{th} (300 HZ) and 7^{th} (420 HZ). The dominant DC harmonic will be the 6^{th}. The 11^{th}, 13^{th}, 23^{rd}, and 25^{th} will also be present on the AC side and the 12^{th} and 24^{th} on the DC side. For a twelve-pulse converter the dominant AC harmonics will be the 11^{th} and 13^{th} while the dominant DC harmonic will be the 12^{th}. The 23^{rd}, 25^{th}, 35^{th}, and 37^{th} orders will also be present on the AC side and the 24^{th} and 36^{th} on the DC side. Higher order harmonics will also be present in both types of converter.

Figure 10-17 lists which harmonics will be present in the AC system for both six and twelve-pulse converters. Theoretical and typical values are listed. The theoretical column is what a mathematical analysis predicts while the typical column is what may actually occur in practice. The numbers are stated in percent of the fundamental (60 HZ) component. For example, for a six pulse converter the theoretical 5^{th} harmonic content is 20%. The 20% is of the fundamental (60 HZ) component.

Every HVDC converter will have a substantial filtering network that is designed to absorb the AC and DC harmonics. The filters on the AC side are designed to absorb AC harmonics and make the AC sine wave look more like a perfect sine wave. The filters on the DC side are designed to absorb the DC harmonics and eliminate as much of the DC ripple as possible.

Harmonic	Six Pulse		Twelve Pulse	
	Theoretical	Typical	Theoretical	Typical
5th	20%	17.5%	—	2.6%
7th	14.3%	11.1%	—	1.6%
11th	9.1%	4.5%	9.1%	4.5%
13th	7.7%	2.9%	7.7%	2.9%
17th	5.9%	1.5%	—	0.2%
19th	5.3%	1.0%	—	0.1%
23rd	4.3%	0.9%	4.3%	0.9%
25th	4.0%	0.8%	4.0%	0.8%

Figure 10-17
Harmonic Content of HVDC Converters

The harmonic production of a converter will also vary with the converter design, method of operation, and loading level.

❽ HVDC Electrodes

Most HVDC systems are designed to use either the earth or the ocean as their return path at least during a portion of their operating time. (A wire return path can also be used.) To ensure a low impedance connection to earth or to the ocean a grounding electrode is used at each converter station. The grounding electrode is similar to the grounding rods used to ground many types of electrical equipment, although more substantial to handle the possibly large currents and ensure a low impedance path. The grounding electrode also provides a voltage reference for the converter.

An HVDC grounding electrode may be composed of 50 metallic bars, each with a 5 inch diameter, driven 10 feet into the ground.

In a bipolar system the return path carries the imbalance current. If there is no imbalance (each pole current is identical) the return path will not carry any current. Systems may be designed so that the return path is only used if one of the DC poles is lost. The system can then continue operating with one pole and the return path but at a reduced power rating.

❾ HVDC Converters and Reactive Power

While HVDC transmission lines operate at a constant voltage level and do not produce or use reactive power, the HVDC converters are heavy users of reactive power. As a rough rule of thumb for each MW of HVDC system capacity, the two HVDC converters (rectifier and inverter) will absorb one Mvar of reactive power.

The next section describes how converters absorb reactive power and how the converter firing angle impacts the reactive power usage.

The reactive needs of the converters must be supplied from local reactive sources. The filters that are used to absorb AC harmonics provide some reactive power but additional shunt capacitors or synchronous condensers must often be installed.

Required AC System Strength

If the HVDC converter is tied to a weak AC electrical system, synchronous condensers are sometimes used to provide the required reactive power. The synchronous condensers not only supply the needed Mvar but also strengthen the AC system. The system is strengthened because synchronous condensers back up their reactive supply with spinning mass (inertia) and an excitation system.

The strength of an AC power system can be stated in terms of its MVA capacity and its inertia (amount of spinning mass) relative to the HVDC system. Two simple equations used to evaluate the relative strengths of an AC system as compared to an HVDC system are:

$$\text{SCR} = \text{Short Circuit Ratio} = \frac{\text{Short Circuit MVA of AC System}}{\text{HVDC Converter MW Rating}}$$

$$\text{IR} = \text{Inertial Ratio} = \frac{\text{Total Inertia of the AC System}}{\text{HVDC Converter MW Rating}}$$

- *Computer simulation techniques are used to determine the SCR.*

The SCR is calculated by dividing the AC system's fault duty by the HVDC converter's MW capacity. The AC system's fault duty is the amount of power (in MVA) that flows to an intentionally placed 3Φ fault at the HVDC system's connecting point to the AC system. The greater the fault duty, the stronger the AC system.

If the SCR or the IR (inertial ratio) is less than 2 or 3, the AC system would be considered a weak system. A common method used to strengthen a weak AC system is to install synchronous condensers.

10.1.4 Operation of an HVDC System

This section briefly describes several important areas of HVDC system operation including:

1. Converter Operation Without and With Gate/Grid Control

2. Rectifier Versus Inverter Operation

3. The Effects of Commutation Overlap

4. Reactive Power Usage

5. Control of HVDC Power Flow

Converter Operation Without Gate/Grid Control

Figure 10-18 summarizes earlier figures used to illustrate the operation of a six-pulse converter. The output DC voltage contains six-pulses for each cycle of input AC voltage. In the upper valve group (valves # 1-3-5) valve #1 fires, then #3, then #5. The switching between these three valves is solely based on which of the three has the more positive anode voltage.

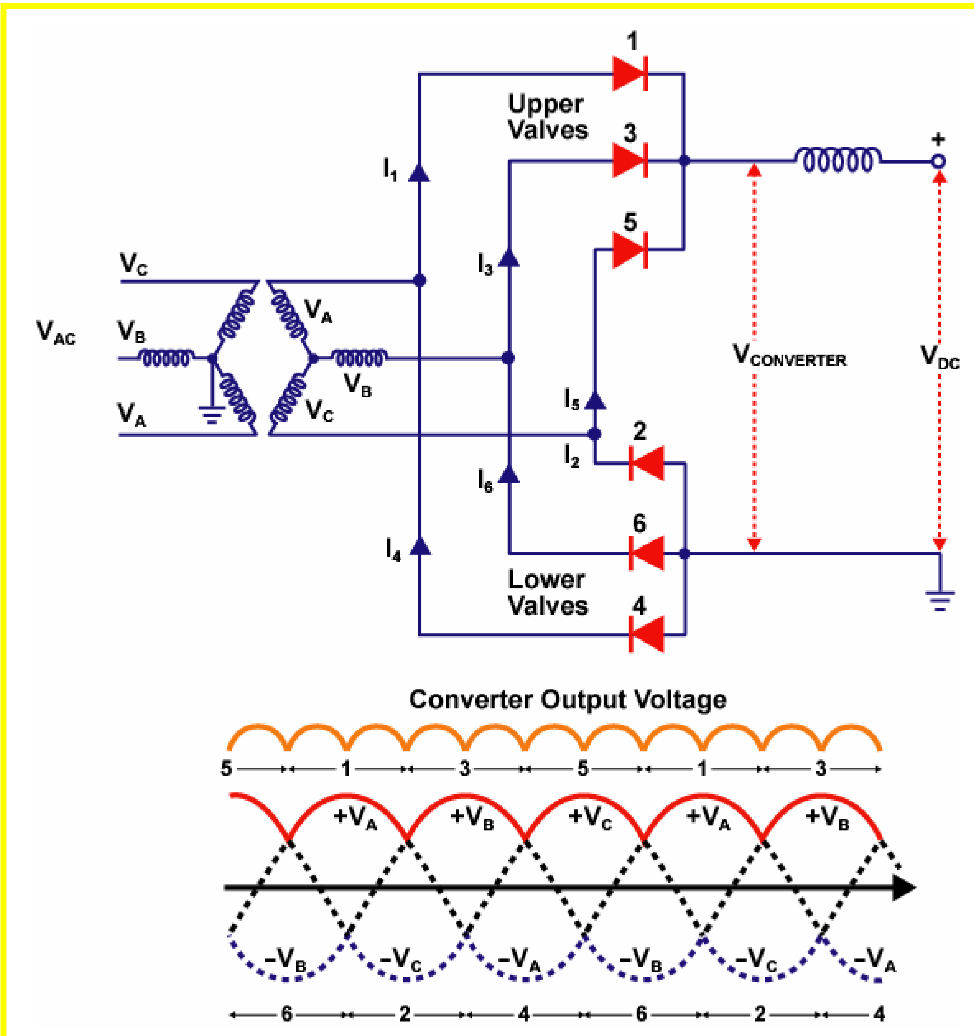


Figure 10-18
Six-Pulse Converter Operation Without Gate Control

In a six-pulse converter, the converter output voltage is measured between the converter's two output terminals. This voltage is composed of 60° long segments of the AC source line-to-line voltages.

For example, assume valve #1 was initially conducting. Valve #1 will stop conducting and valve #3 will start conducting (fire) as soon as the valve #3 anode is more positive than the valve #1 anode. This commutation process is based solely on the relative magnitudes of the anode voltages. Valves # 1, 3, and 5 alternate firing based on the positive cycle of voltages while valves # 2,

- *For an MAV we used the term control grid, for a thyrister we used the term gate. In this section the term gate/grid control refers to both methods.*

4, and 6 alternate firing based on the negative cycle of the voltage. Once turned on each valve conducts for 1/3 cycle or 120°.

Converters can operate in this mode of operation (called self-commutating) but other, more useful, modes of operation are available. Converter operation using gate/grid control is described in the next section.

Converter Operation With Gate/Grid Control

To illustrate gate/grid control start with the simple 1Φ converter described earlier. Figure 10-19 illustrates this 1Φ converter. The input AC voltage and converter output voltage waveforms are provided below the converter. These voltage waveforms assume that gate/grid control is not being used. A commutation (switching) between the two valves will occur as soon as one anode is more positive than the other anode.

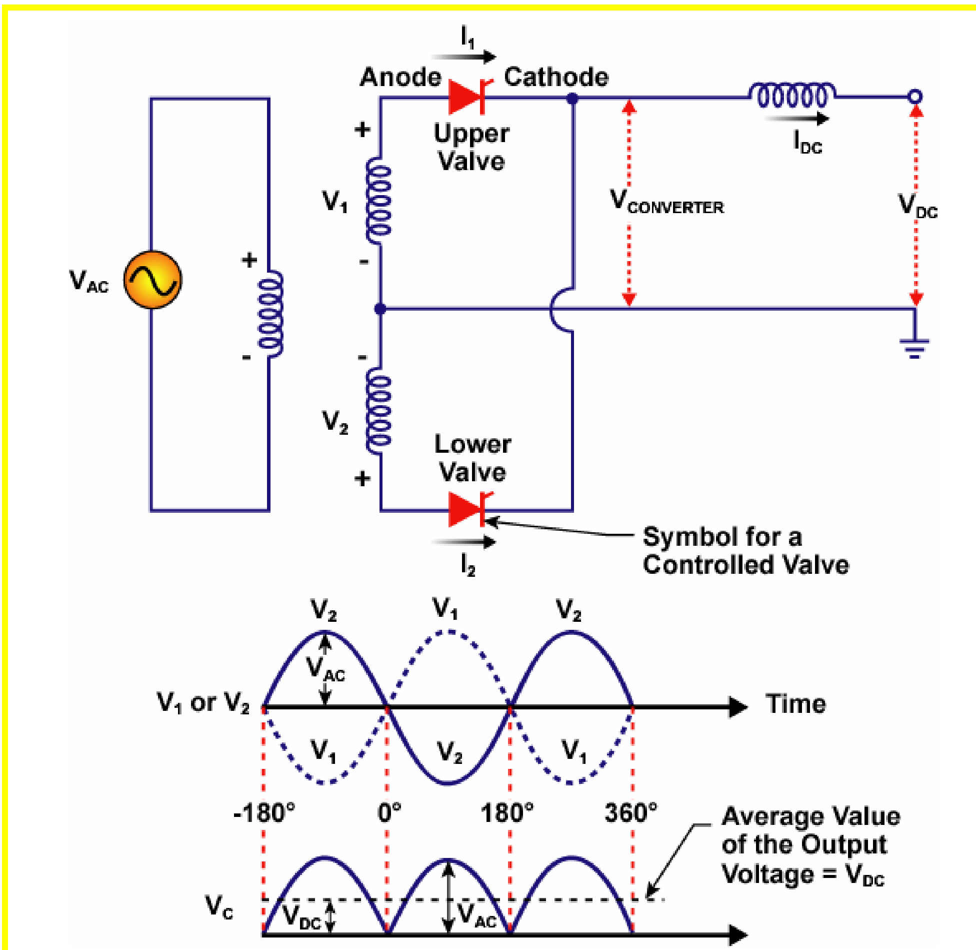


Figure 10-19
Two-Pulse Operation Without Gate Control

Note the modification to the symbol used to represent the valves in Figure 10-19. The added extra line means the valve has gate/grid control. A current or a voltage pulse delivered through the gate/grid control point is used to turn the valve on. When using gate/grid control the valve will not automatically turn on as soon as its anode voltage is more positive than its cathode. The anode voltage must be more positive than the cathode and a gate/grid pulse must be applied to turn the valve on.

Figure 10-20 contains the voltage and current waveforms for our 1Φ-converter illustrating the use of gate/grid control. Note that a gate/grid control pulse is required to turn a valve on. Neither valve #1 or #2 will turn on unless its anode voltage is positive (with respect to cathode) and it receives a gate/grid control pulse.

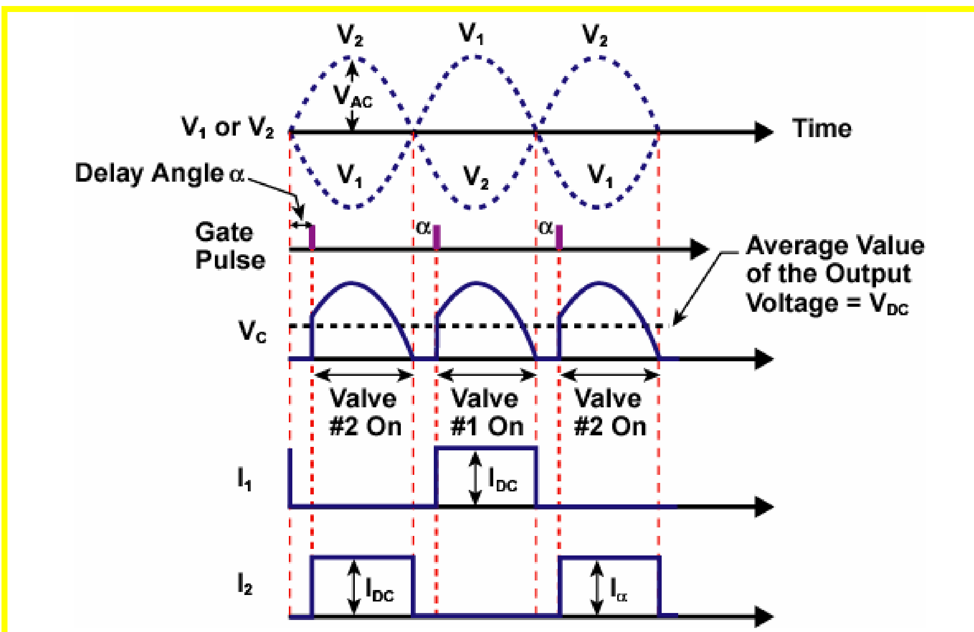


Figure 10-20
Two-Pulse Converter Operation with Gate Control

Commutation will not take place until the gate/grid control pulse is applied. Each successive commutation is delayed by the same number of degrees.

The gate pulse can be applied when the HVDC system operator decides to apply it. If you compare the V_C voltage plots in Figures 10-19 and 10-20 you will notice that the application of the gate/grid control pulse has delayed the firing of the valve by approximately 30°. The angle by which the valve firing is delayed is called the ignition delay angle. The ignition delay angle is the number of degrees the valve firing was delayed from its normal firing point. The ignition delay angle is represented by the symbol "α" (Greek letter alpha).

Comparing Figure 10-19 to 10-20 note that an area of the voltage is missing from Figure 10-20. This is the impact of gate/grid control. The missing area of voltage lowers the average value.

Further comparison of the converter output voltages (V_C) in Figures 10-19 and 10-20 will show that the V_{DC} (average value of V_C) magnitude in Figure 10-

20 is smaller. The delay in the firing of the valve has reduced the magnitude of the DC voltage. In this particular converter (1Φ or two-pulse converter) if the delay angle were 180°, the DC voltage magnitude would be zero.

The impact on the converter voltage output is the key to the use of the ignition delay angle. DC MW power flow is similar to AC Mvar power flow. DC MW flow is based on the voltage magnitudes at both ends of the HVDC system. DC will flow from the high voltage to the low voltage. The amount of DC flow is directly tied to the voltage difference. By using a combination of the AC supply transformer's ULTCs and the converter's ignition delay angles, HVDC system operators can accurately control and quickly adjust the amount of HVDC MW flow.

Figure 10-21 illustrates gate/grid control impact to the converter output voltage of a six-pulse converter. The figure illustrates the converter output ($V_{CONVERTER}$) voltage waveform. Recall from our earlier description of a six-pulse converter that the output voltage is measured between the two output terminals of the converter. A six-pulse converter's output voltage is composed of 1/6 cycle or 60° segments of the AC input line-to-line voltages.

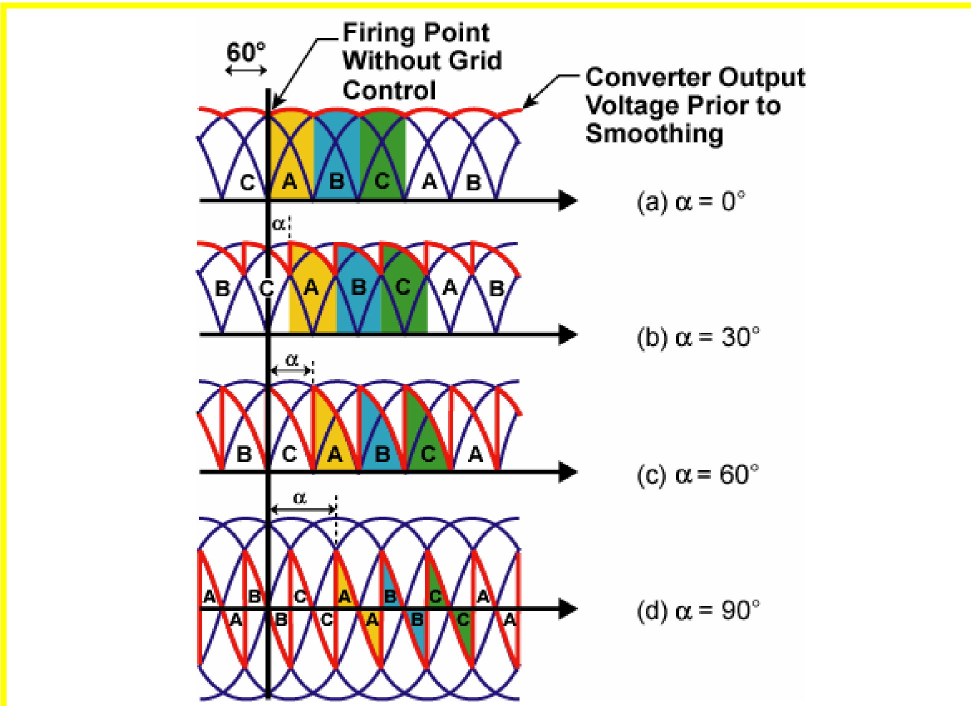


Figure 10-21
Six-Pulse Converter Ignition Delay Angles of 0° - 90°

Figure 10-21(a) illustrates an ignition delay angle of 0°. With this ignition delay angle commutation is based solely on relative voltage magnitudes. Areas "A", "B", and "C" represent the magnitude of the converter output voltage at three progressive time periods in the converter output. The converter output voltages are at their maximum possible values for this six-pulse converter. Note that each arc section of $V_{CONVERTER}$ is 1/6 cycle or 60° in length.

Figure 10-21(b) illustrates an ignition delay angle of 1/12 of a cycle or 30°. Comparing Figures 10-21(a) to 10-21(b) you can see how the valve firing has been delayed by 30°. Note that every subsequent valve firing is also delayed by the same angle amount. The magnitudes of areas "A", "B", and "C" have been reduced which means the converter output voltages have been correspondingly reduced in magnitude.

Figure 10-21(c) illustrates an ignition delay angle of 60° which further reduces the converter output voltage. Figure 10-21(d) is for an ignition delay angle of 90°. In a six-pulse converter, an ignition delay angle of 90° leads to a zero output voltage. Note in Figure 10-21(d) that half of areas "A", "B", and "C" are above the zero axis line and half below. The average value of the converter output voltage is therefore zero.

The ignition delay angle's impact on the DC output voltage magnitude of an HVDC converter can be stated in terms of this simple equation:

This simple equation will be modified later to account for the effects of the overlap angle.

$$\boxed{V_{DC-\alpha} = V_{DC-0} \times \cos\alpha}$$

The equation stated above also predicts what will happen as the ignition delay angle is raised above 90° and increased towards 180°. The polarity of the converter output voltage will reverse. Figure 10-22 illustrates ignition delay angles of 90°, 120°, 150°, and 180°. Note how the converter output voltage is zero at 90° and then rises to its greatest possible negative value at 180°.

With an ignition delay angle of 180° the voltage may be at its greatest negative magnitude but it is meaningless as commutation cannot take place with this large a delay angle.

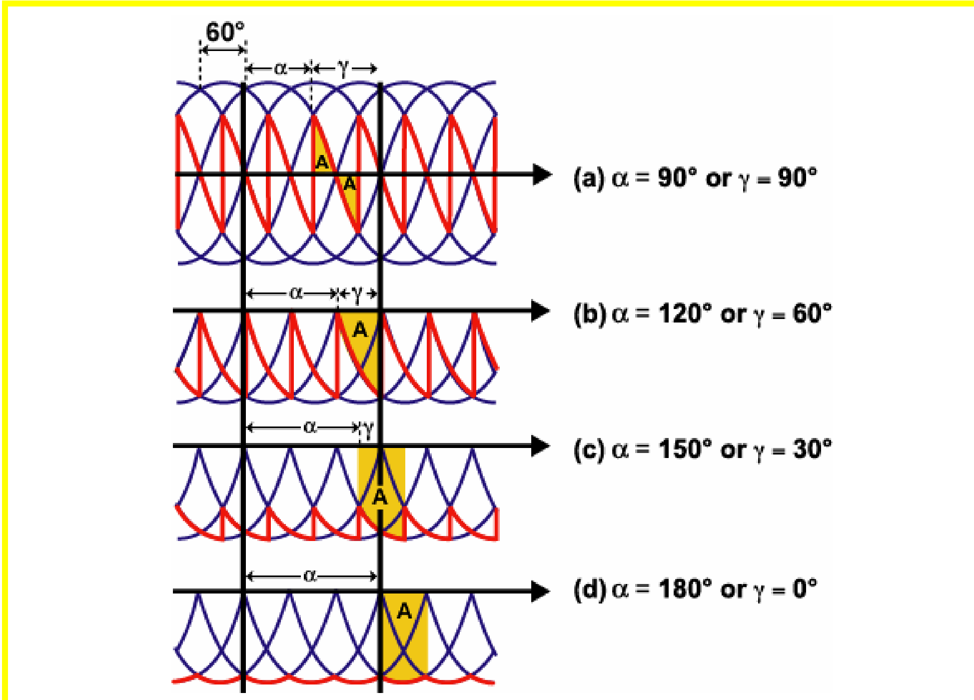


Figure 10-22
Six-Pulse Converter Ignition Delay Angles of 90° - 180°

- *As the ignition delay angle rises above 90°, the polarity of the converter output voltage reverses. The extinction advance angle (γ) is equal to 180° minus the ignition delay angle (α).*

Ignition delay angles greater than 90° mean that the converter is operating as an inverter instead of a rectifier. When operating as a rectifier a converter is transmitting MW from the AC system to the DC system. When operating as an inverter a converter is transmitting MW from the DC system to the AC system.

The direction of the current flow can not be switched in an HVDC system. To change the power flow direction it is necessary to reverse the polarity of both converter voltages. The ignition delay angle is the tool used to reverse the converter output voltage polarity. By adjusting a converter's ignition delay angle a converter can be switched between operating as a rectifier and operating as an inverter.

- *The ignition delay angle (α) is an operating characteristic of a rectifier. The extinction advance angle (γ) is an operating characteristic of an inverter.*

When a converter is operated as a rectifier the term ignition delay angle (α) is used to state the number of degrees of ignition delay. When a converter is operated as an inverter the term extinction advance angle or "γ" (Greek letter gamma) is used. The angle gamma is equal to 180° minus the angle alpha ($\gamma = 180° - \alpha$).

Typical values for the ignition delay angle (α) and the extinction advance angle (γ) range from 15° to 25°. If either angle is too small (less than 5°) the commutation process will often fail. If either angle is too large the converter would absorb too much reactive power from the AC system. These typical values are used to provide a converter with enough angle adjustment range to respond to AC supply system voltage deviations. A converter can make rapid adjustments to angle magnitudes to control the DC system voltage level.

To summarize, the ignition delay angle is adjusted to control the magnitude of a converter's output voltage when it is operated as a rectifier. The extinction advance angle is adjusted to control the magnitude of a converter's output voltage when it is operated as an inverter. The inverter voltage has a reversed polarity when compared to the rectifier.

The two converters at the ends of an HVDC system must operate with the same voltage polarity. MW flows from the high voltage to the low voltage in a DC system. To achieve the same polarity, the rectifier and inverter end anodes and cathodes have reversed connections. For example, if the rectifier end cathode is connected to the HVDC line then the inverter end anode must be connected to the HVDC line. This connection reversal ensures that both rectifier and inverter operate with the same voltage polarity.

The Inversion Process

In the process of rectification, the converter creates a DC voltage by properly timing the valve commutation process. Numerous valves conduct for brief periods of time to produce the desired magnitude of DC voltage.

The inversion process is similar to rectification but has substantial differences. A common misunderstanding is that the DC voltage at the inverter end of the HVDC system is used to create a 3Φ AC voltage. This is incorrect as an AC voltage does not need to be created, it is already present from the AC power system the inverter connects to.

Commutation between valves during the inversion process is produced by the voltages of the AC system that the inverter connects to. The extinction advance angle (γ) is adjusted to control the magnitude of the DC voltage at the inverter end. Inverters require a strong AC source as their valve commutation is dependent on steady, dependable AC system voltage levels.

A strong AC source is important for both the rectifier and the inverter. However, the inverter end is more subject to operating problems if the AC source is too weak.

The Effects of Commutation Overlap

This chapter is intended only as an introduction to HVDC systems. Several of the more complicated operating characteristics have been either simplified or ignored. However, one additional concept is very important and is briefly described. This is the concept of commutation overlap.

When valve commutation occurs, a switch is made between conducting valves. Current flow is stopped in one valve and started in another. There is a natural inductance in the electrical circuit in which valve commutation occurs.

The presence of inductance means that a valve's current cannot be interrupted instantaneously. In other words it takes time to turn off one valve and turn on another. The net result is that during the commutation process, an overlap period occurs in which both valves are conducting. During the overlap period, a phase-to-phase fault exists for the time period it takes to completely stop the current in one valve and start it in the next.

The term overlap angle is used to describe the length of the commutation overlap period. The Greek letter "μ" (mu) symbolizes the overlap angle. A typical overlap angle would be 15° to 25°. The overlap angle is similar to the ignition delay angle in that it delays the valve commutation. However, the ignition delay angle is an intentional angle while the overlap angle is a natural consequence of inductive switching.

The overlap angle impacts the voltage produced by the converter. The following equations account for the impact of the overlap angle (μ) on the converter output voltage:

$$\boxed{V_{DC-\phi} = V_{DC-0} \times \cos\phi}$$

where:

$$\boxed{\cos\phi = \frac{\cos\alpha + \cos(\alpha + \mu)}{2}}$$

These equations tell us that the converter output voltage ($V_{DC-\phi}$) is reduced by both the ignition delay angle (α) and the overlap angle (μ). The overlap angle is not controllable but the ignition delay angle is controllable. To control the DC voltage magnitude, ignition delay angle adjustments are made with full consideration that the overlap angle also exists.

HVDC Reactive Power Usage

- *The overlap angle also impacts the phase relationship but this effect is ignored in Figure 10-23.*

When commutation is delayed a phase angle separation is forced between the AC system voltage and the converter current. Figure 10-23 illustrates the voltages and current at a converter's AC source. When the ignition delay angle is 0° the AC voltage and the converter input current are in-phase with one another. When a 30° delay angle is used (see Figure 10-23b) the current drawn from the AC system lags the AC voltage by 30°. This lagging current makes a converter appear to the AC system as a lagging power factor load.

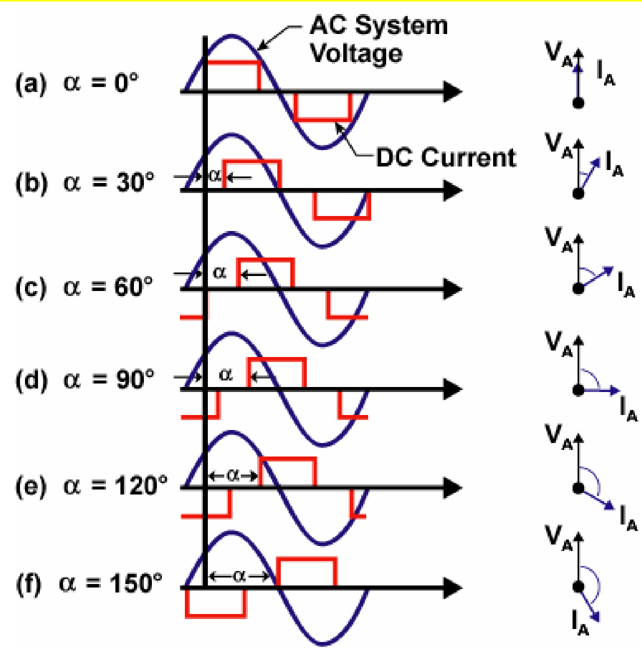


Figure 10-23
Phase Displacement in an HVDC Converter

The delay angle forces the current to lag behind the voltage. As the delay angle rises towards 90°, the converter becomes more of a lagging load.

A converter is typically a user of reactive power. It does not matter whether the converter is operating as a rectifier or as an inverter, it is still a lagging load as far as the AC system is concerned. If a converter is operating with a delay angle of 90°, it does not draw MW from the AC system, only Mvar. When operating with a 90° delay angle a converter is the equivalent of a shunt reactor.

A rule of thumb for determining the power factor of a converter is the expression:

$$\boxed{\text{Converter Power Factor} \approx \cos \alpha}$$

This expression states that the power factor of an HVDC converter is approximately equal to the cosine of the ignition delay angle.

Note the approximate symbol (≈) in the above equation for the converter power factor. A more exact relationship for the power factor of a converter would have to account for the effects of the overlap angle. A power factor equation that accounts for the ignition delay angle and the overlap angle is stated below:

$$\boxed{\text{Converter Power Factor} = \frac{\cos \alpha + \cos(\alpha + \mu)}{2}}$$

This equation for the converter power factor tells us that the power factor is impacted by both the ignition delay angle and the overlap angle. The greater the ignition delay angle, the lower the power factor and the more converter Mvar usage. The larger the overlap angle, the lower the power factor. The overlap angle is dependent on the converter's MW loading level. It follows that the converter power factor is also dependent on the converter loading (MW) level. In general, as the converter approaches its rated power level, it requires more Mvar from the system.

Physical View of a Converter's Reactive Power Usage

In Chapters 1 and 2 reactive power usage was explained in terms of storing reactive power in magnetic fields. This same explanation can be used to describe the usage of reactive power by an HVDC converter.

When commutation occurs, one valve is turned on and one valve is turned off. The overlap angle defines the time lapse in which this valve switching process occurs. For the length of the overlap angle, a phase-to-phase fault is occurring. The electrical circuit during this phase-to-phase fault includes the inductance of the AC supply transformers windings. During the commutation overlap period, large currents flow through the transformer's inductance which explains the Mvar usage of the converter.

The Mvar usage is also impacted by the ignition delay angle. Without an ignition delay angle, the valves will commutate solely based on anode and cathode voltage levels. When commutation occurs without an ignition delay angle, the voltage across a valve is zero at the instant of commutation. When commutation occurs with an ignition delay angle, a large voltage difference exists across a valve when commutation occurs. This large voltage difference leads to greater current flows during the commutation overlap period and more Mvar usage by the converter.

Control of HVDC Power Flow

The control of the MW flow level in an HVDC system is a complex process. Only the basic concepts are reviewed in this final section on HVDC.

As stated earlier, HVDC MW flow is a function of the voltage magnitudes at the ends of the HVDC system. DC MW will flow from the high voltage point to the low voltage point. The greater the separation between the terminal DC voltage magnitudes, the more MW that will flow. To control the magnitude of the DC MW flow, the HVDC control systems manipulate the terminal voltage magnitudes.

The primary devices for controlling the converter voltage magnitudes are the AC supply transformer ULTCs and the converter ignition delay and extinction advance angles. The ULTC control is a course control while the angle control is a fine control. For rapid changes to DC MW flow levels, angle control is used.

Figure 10-24 is a simple illustration of MW flow control in an HVDC system. MW is flowing from the rectifier end to the inverter end. The rectifier end voltage level is maintained by adjusting ULTC tap positions and by adjusting the ignition delay angle (α). The inverter end voltage level is maintained by adjusting ULTC tap positions and by adjusting the extinction advance angle (γ).

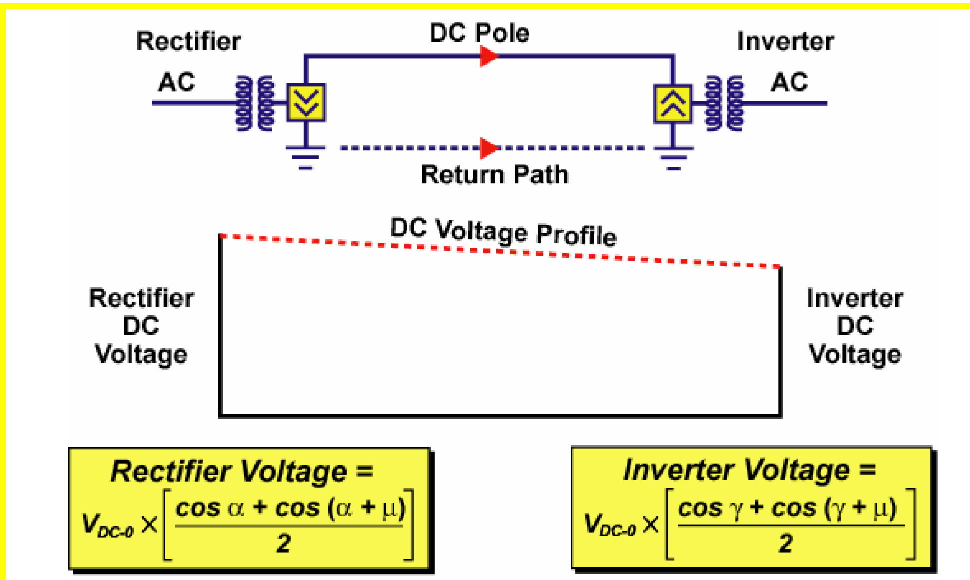


Figure 10-24
HVDC MW Flow Control

10.2 PST Construction and Operation

PSTs are also referred to as phase angle regulators or PARs.

Phase shifting transformers or PSTs are a tool for controlling the flow of MW. PST taps are adjusted to vary the magnitude of the angle (voltage angle difference) across the transformer. If the angle across a transformer can be adjusted, the MW flow on the conducting path that includes the PST and any parallel paths can be controlled.

10.2.1 Introduction to PSTs

PSTs were briefly described in Chapter 3.

Figure 10-25 illustrates a possible use for a PST. Assume that 530 MW of active power enters a bus with two possible output paths. One path is via a higher impedance overhead line while the other is a lower impedance underground line. Assume that each line has a 300 MW thermal rating. The power flow will split according to the relative path impedance. In our example 440 MW flows in the underground and 90 MW in the overhead.

- *Prior to the use of the PST the angle was 5° across both lines. After the PST taps were adjusted the overhead line has a 13.5° angle and the underground line has a 3.5° angle. The PST itself has a 10° angle.*

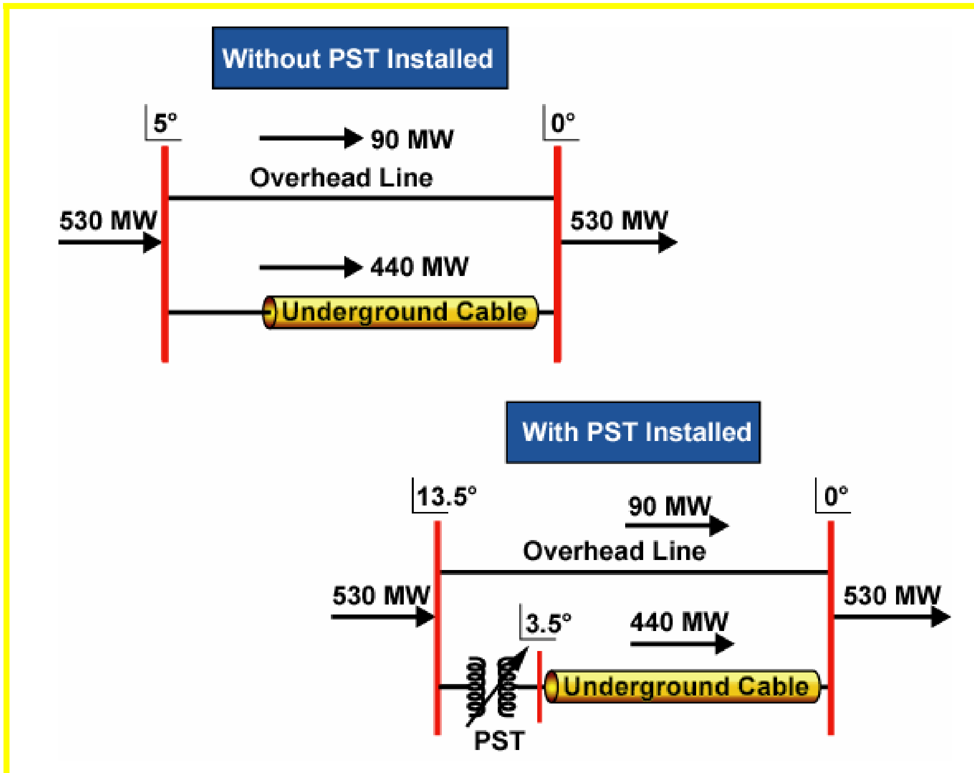


Figure 10-25
Use of a PST

The underground conductor is overloaded while the overhead conductor has spare capacity. As an operator you must reduce the loading on the underground path. An option would be to reduce the total system loading below 530 MW until the underground path flow was below 300 MW. This is not a good option as it does not fully utilize the overhead path.

- *PSTs are an expensive piece of equipment. PSTs are typically not used until all other options for MW flow control have been exhausted. A less costly alternative to the scenario of Figure 10-25 would have been the installation of a series reactor in the cable path.*

An alternative (though expensive) option would be to install a PST in the underground cable path. The voltage angle difference across the PST could then be adjusted until the flow on the underground cable was reduced below 300 MW. The power flow removed from the underground path is pushed to a parallel path. In this example the only parallel path is the overhead line. The use of the PST allowed the system operator to make full use of both the overhead and underground portions of the power system.

10.2.2 Construction of PSTs

The construction of a PST is illustrated in Figure 10-26. Three phases of the input voltage (V_A-V_B-V_C) are illustrated and only one phase (V_a) of the output voltage. (Only one phase of the output is shown to reduce the clutter in the figure.) The exciting windings of the PST are energized by the three input voltages. Note that the exciting windings are connected in a delta configuration. The voltage connected across each coil of the exciting windings is a phase-to-phase voltage. The exciting windings will each induce a voltage in their magnetically linked series winding.

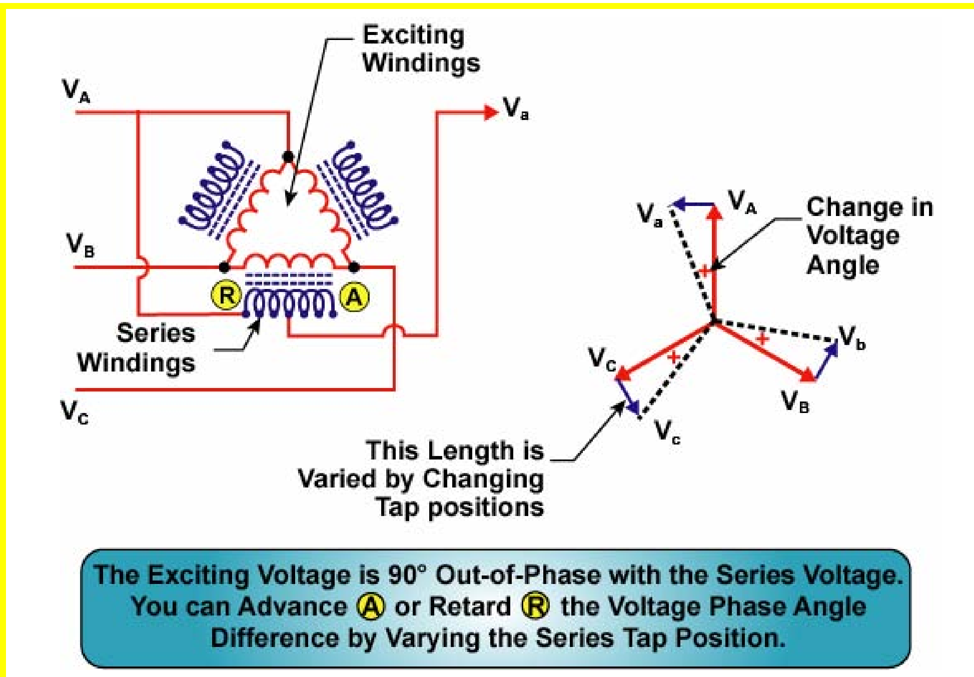


Figure 10-26
Varying Construction of a PST

This is one possible design for a PST, there are other options.

The voltage induced in each series winding will be 90° out-of-phase with one of the input voltages (V_A, V_B, or V_C). For example, the voltage $V_{B\text{-}C}$ is 90° out-of-phase with the voltage V_A. Figure 10-27 illustrates the phase relationship between the input voltages and the voltages induced in the series windings of the PST. In the figure, the angle of the voltage V_{BC} is determined by connecting a line from the end of V_B to the end of V_C. Note that this line is at a 90° angle to the input voltage V_A.

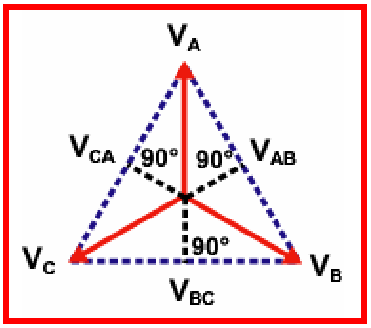


Figure 10-27
Phase in a PST

The output voltage V_a is equal to the input voltage V_A plus a portion of the voltage induced in the series winding. The vector diagram in Figure 10-26 illustrates this addition. A small voltage (from the series winding) is added to each input voltage. The output voltages that result are each shifted in phase. The amount of the phase shift depends on how large the series voltage is. The magnitude of the series voltage can be controlled by a tap changer in the series winding.

A tap changer is used in a PST to vary the polarity and magnitude of the series voltage. A typical PST tap changer might allow a ±30° phase shift. The tap changer may have 32 positions. Each position is equal to a different total phase shift value and a corresponding amount of MW flow change. (An illustration of how a PST changes MW flow is provided in the next section.) A system operator will often have SCADA control over the PST tap position. If a change to MW flow is desired the tap changer is adjusted to accomplish the desired change.

- *The term quadrature means at a right angle. When a quadrature voltage is added it has a 90° phase difference to the voltage it is being added to. This is where the symbol "Q" derives for reactive power. The Mvar is in quadrature to the MW*

Figure 10-28 was constructed to further illustrate the angle shift in a PST. This figure is also used to relate PST tap changes to conventional transformer tap changing for voltage magnitude control. In a PST a ± quadrature voltage is added to each of the incoming phase voltages. This voltage addition changes the voltage angle. (There is also a slight change to the voltage magnitude.)

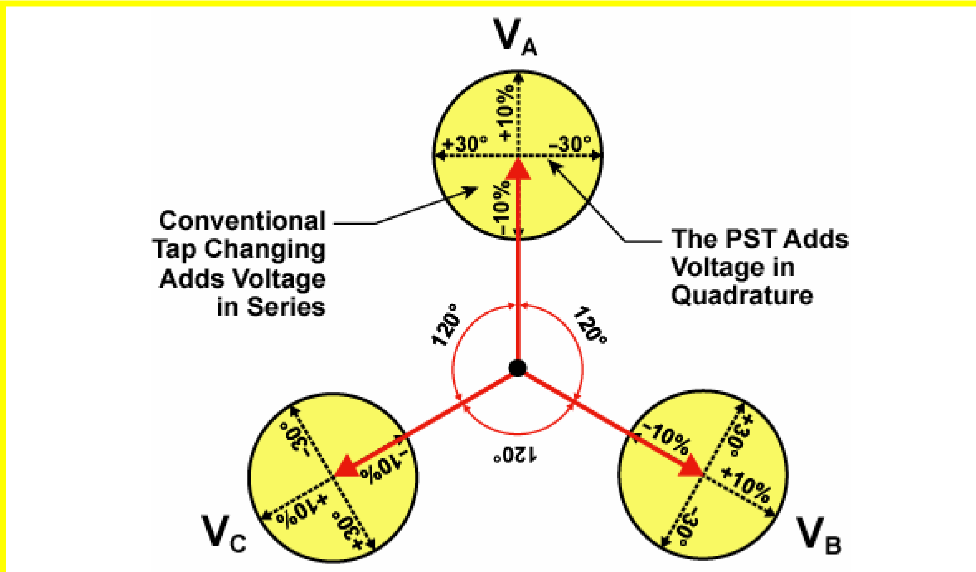


Figure 10-28
Phasor Diagram for Regulating Transformers

The general label of "regulating transformer" applies to both conventional tap changing transformers and phase shifting transformers.

A conventional transformer tap changer also adds a component of voltage to the incoming phase voltage. This voltage is added in ± series with the phase voltage. Both types of transformers work on the same principal. It is the phase relationship of the added voltage to the incoming voltage that makes one a PST and the other a conventional tap changer.

Note the circles surrounding the tips of the phase voltage vectors in Figure 10-28. The figure assumes that a conventional tap changer is used to add up to a ±10% series voltage and that a PST is used to add a quadrature voltage with up to a ±30° phase shift. It is possible to construct such a transformer that includes tap changing for both phase shifting and voltage magnitude adjustment. This transformer type could adjust each phase voltage to any point within the circles of Figure 10-28.

10.2.3 Operations of PSTs

Figures 10-29, 10-30, and 10-31 are used to illustrate how a PST controls the MW flow in a path. In Figure 10-29 600 MW of power is splitting between two lines. One line has a 40 Ω impedance while the other a 60 Ω impedance. This impedance mismatch leads to 40% of the MW flow over one line and 60% over the other. A PST will be installed in the upper line and its tap position adjusted to make the MW flow in both lines equal to 300 MW.

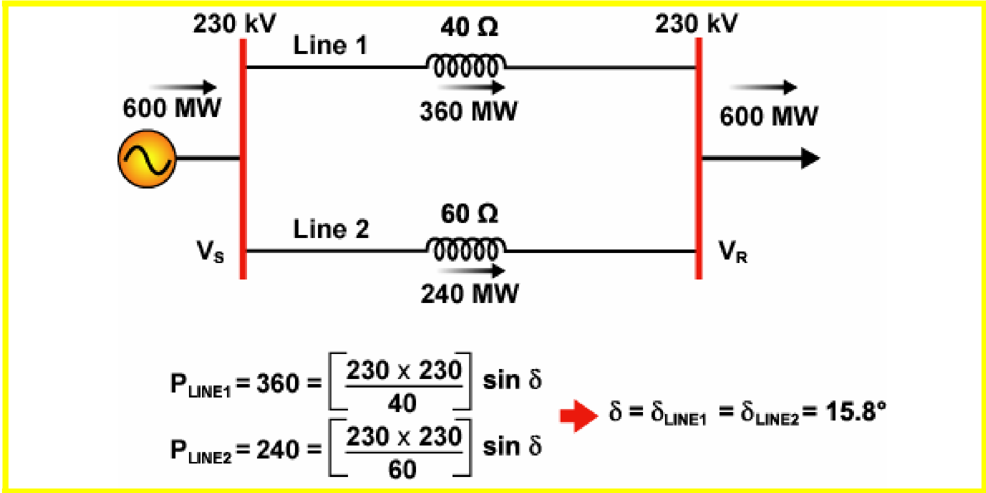


Figure 10-29
PST Operation – Part A

Figure 10-29 illustrates how the MW transfer equation is used to calculate the angle across the system (without the PST). The angle must be the same across both lines as they have a common bus at each end. The initial angle is calculated to be 15.8°.

In Figure 10-30, a PST is installed in the upper line. The phase shift degrees within the PST are assigned the symbol "α" (alpha). The MW transfer equation is used to calculate the required PST tap to make both line flows equal 300 MW. The angle across the bottom line will be "δ". The angle across the top line and PST will be "δ - α". The solution of the two equations yields a value for δ of 19.9° and a value for α of 6.8°. Note that the angle across line #1 is now 13.1° and across line #2 19.9°. The MW flows across each line are now matched.

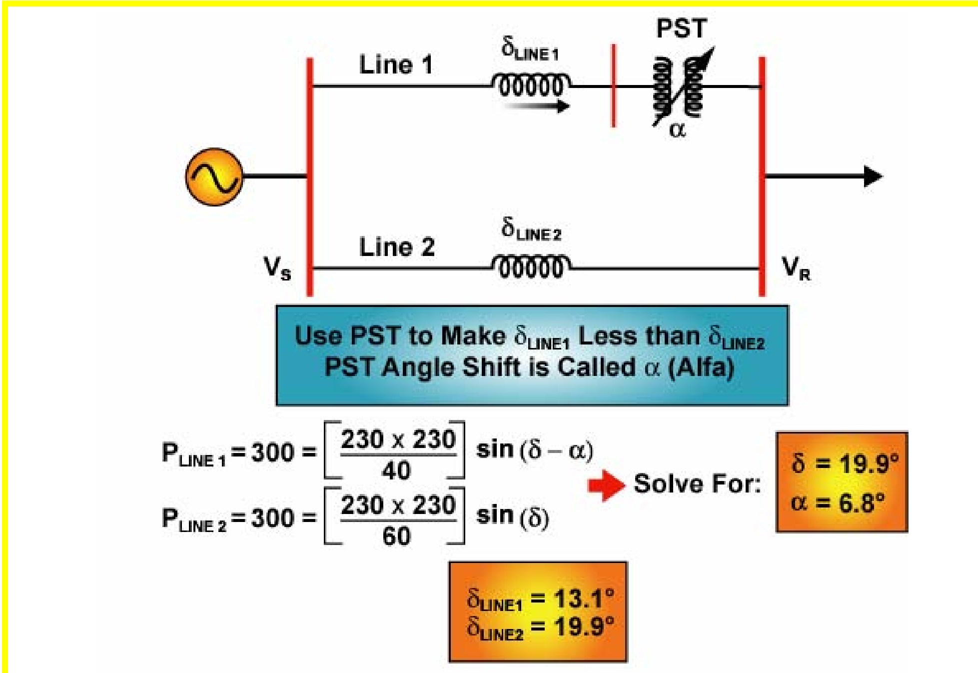


Figure 10-30
PST Operation – Part B

Figure 10-31 illustrates how the impact of a PST can be viewed in terms of a circulating MW flow. Initially this simple system had 360 MW in the upper line and 240 MW in the lower line. The PST angle adjustment can be viewed as having created a counterclockwise circulating flow of 60 MW. The total MW flow in the upper line is now 360 - 60 = 300 MW and in the lower line 240 + 60 = 300 MW.

PST operation can be viewed as intentionally creating a circulating active power flow. There is only one power flow per line. The circulating component concept illustrates how the two line MW flows will be changed by a PST angle adjustment.

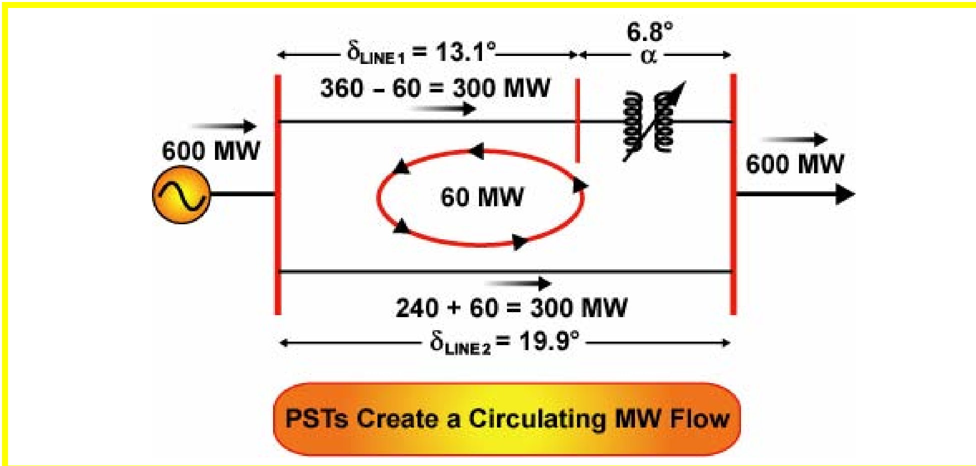


Figure 10-31
PST Operation – Part C

Recall from Chapter 3 the equations for active and reactive power flow. Both types of power flow were dependent on the angle. MW flow was more dependent than Mvar flow for the angle range in which power systems are typically operated. When the PST changes the angle it will change the system's MW flow. Mvar flow will also be impacted. In the previous example if the Mvar flows had been calculated greater Mvar flow would have been seen into line #2 once the tap change was completed. The greater Mvar flow would be required to support the increased line #2 MW flow. In addition, the PST itself is a user of Mvar (for magnetic field) and MW (for power losses).

Summary of Equipment

10.1.1 Introduction to HVDC Systems

- HVDC systems are used to transmit energy using DC voltage and current.

10.1.2 Types of HVDC Systems

- A monopolar system uses one conductor energized with a DC voltage and a return path. A bipolar system uses two DC poles. One pole is energized with a positive voltage and the other with a negative voltage. The return path may be the earth, the ocean, or a wire conductor.

10.1.3 Components of an HVDC System

- An HVDC transmission line has a similar design to an AC transmission line.
- A mercury arc valve (MAV) is basically a rapid switch that uses older tube based technologies. A thyrister is a solid state device that has replaced the MAV in modern HVDC converters.
- Several valves can be combined in an electrical circuit to form a converter. There are many types of converters.
- DC power flow magnitude is controlled by adjusting the converter (inverter and rectifier) voltages.
- Smoothing reactors are used to reduce the ripple in the DC output voltages.
- HVDC converters are equipped with filter banks to absorb the harmonics before they can impact power system operation.
- To ensure a low impedance connection to earth or to the ocean a grounding electrode is available at each converter station.
- As a rough rule of thumb for each MW of HVDC system capacity, the two HVDC converters will absorb one Mvar of reactive power.

10.1.4 Operation of an HVDC System

- Converters can operate in a mode in which the valves turn on and off solely based on relative voltage magnitudes (self commutation) but gate/grid control is a more powerful and flexible mode of operation.
- The angle by which the valve firing is delayed is called the ignition delay angle. The ignition delay angle is represented by the symbol “α” (Greek letter alpha).

- In an inverter the term extinction advance angle or "γ" (Greek letter gamma) is used instead of the ignition delay angle. The relationship between γ and α is: $\gamma=180°-\alpha$.
- When commutating between valves, the inductive nature of the resulting electrical circuit prevents instantaneous switching. The length of the commutation overlap period is stated using the overlap angle "μ" (Greek letter mu).
- The ignition delay angle's impact on the output voltage magnitude of an HVDC converter can be estimated in terms of this simple equation:

$$\boxed{V_{DC-\alpha} = V_{DC-0} \times \cos\alpha}$$

- If we ignore the effects of the overlap angle (μ), the power factor of a converter is approximately equal to:

$$\boxed{\text{Converter Power Factor} \approx \cos\alpha}$$

10.2.1 Introduction to PSTs

- Phase shifting transformers or PSTs are a tool for controlling the MW flow. PST taps are adjusted to vary the magnitude of the angle across the transformer.

10.2.2 Construction of PSTs

- In a PST a quadrature voltage is added to each of the incoming phase voltages. This voltage addition changes the voltage angle.

10.2.3 Operation of PSTs

- PSTs can be viewed as intentionally creating a circulating MW flow. This circulating MW flow increases the flow in one path and decreases the flow in parallel paths.

Equipment Questions

1. Which type of HVDC system has two conductors, one energized with a positive voltage and one with a negative voltage?

   A. Semipolar

   B. Bipolar

   C. Unipolar

   D. Monopolar

2. Thyrister and mercury-arc are types of ___________ in HVDC converters.

   A. Transformers

   B. Electrodes

   C. Valves

   D. Filters

3. A twelve-pulse converter has twelve pulses in its DC output per:

   A. Commutation of the converter

   B. Cycle of the HVDC converter from no load to full load

   C. Change of the firing angle from 0 to 30 degrees

   D. Cycle of the incoming AC voltage

4. An HVDC converter firing angle is used to:

   A. Delay inversion

   B. Delay commutation

   C. Delay conversion

   D. Delay rectification

5. A phase shifting transformer controls MW flow by:

   A. Controlling the firing angle

   B. Controlling the phase angle between voltage and current

   C. Controlling the voltage phase angle across the transformer

   D. Controlling the phase angle between current and voltage

6. The voltage added to the incoming voltage to be regulated is added in __________ in a phase shifting transformer and added in __________ in a voltage regulating transformer.

   A. series / quadrature

   B. series / series

   C. quadrature / quadrature

   D. quadrature / series

7. Several HVDC systems are used to electrically connect the Eastern and Western Interconnections of North America. Since both Interconnections are 60 HZ systems, why would HVDC be used?

   A. Because even though both Interconnection's frequencies are scheduled for 60 HZ, large voltage phase angles and small frequency differences do exist.

   B. Because the lines connecting the Interconnections are long enough to justify HVDC system cost.

   C. Because the lines connecting the Interconnections are short enough for justifying the HVDC system cost.

   D. Because HVDC systems are always less costly to build than an equivalent AC system.

8. When compared to an AC transmission system with the same MW transfer, the same insulation levels, and with the same size conductors, HVDC transmission system losses are approximately 33% lower than AC system losses.

   A. True

   B. False

9. The functions of an HVDC system smoothing reactor include all the following **EXCEPT**:

   A. Reducing DC ripple

   B. Reducing DC fault duty

   C. Assisting with the commutation process

   D. Filtering the AC harmonics

10. A 200 MW HVDC system is installed next to a 138 kV AC substation. The three-phase fault duty of the 138 kV bust must be at least _____ MVA.

    A. 67-100

    B. 101-201

    C. 400-600

    D. 1000 or greater

Equipment References

1. Power System Stability and Control—A volume in the EPRI Power System Engineering Series. Written by Mr. Prabha Kundur and published by McGraw-Hill in 1994.

   Contains a well written chapter on HVDC systems. This text was the primary reference for the HVDC material in this Chapter.

2. Electrical Power System—Textbook written by Mr. Mohamed E. El-Hawary. Published by IEEE Press, 1995.

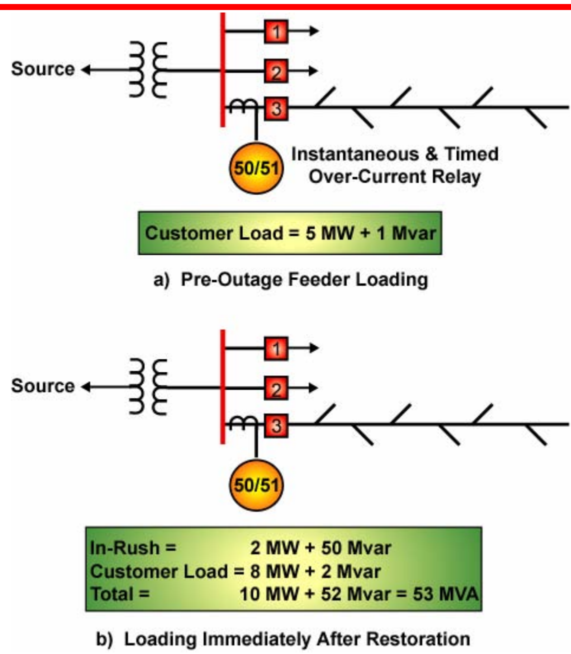
   An advanced text that includes a chapter on HVDC systems.

3. Electric Energy Systems Theory – An Introduction—Textbook written by Mr. Olle I. Elgerd. Published by McGraw-Hill in 1982.

   This entire text is excellent reading. Chapter 5, Power Transformers, was especially useful in developing the PST material in this Chapter.

11

POWER SYSTEM RESTORATION



11.1 Introduction to Power System Restoration

An introduction to the theory of power system restoration and the methods used to restore a power system.

11.2 Voltage Control and System Restoration

An explanation of voltage control theory and practice during power system restoration.

11.3 Frequency Control and System Restoration

An explanation of frequency control theory and practice during power system restoration.

11.4 Equipment Issues Related to System Restoration

A description of the unique equipment issues that may be encountered during power system restoration conditions.

11.5 Protective Relay Issues Related to System Restoration

A description of the unique protective relay issues that may be encountered during power system restoration conditions.

11.6 Synchronizing and System Restoration

An explanation of the synchronizing issues that may be encountered during power system restoration conditions.

11.7 Lessons Learned From Actual System Restorations

A summary of the lessons learned from actual restoration events that have occurred in North American power systems.

11.1 Introduction to Power System Restoration

A system operator may never encounter power system restoration conditions in the course of their careers. However, all system operators must be capable of operating the power system properly under the unique circumstances of a system restoration. This chapter provides background information and an explanation of the system restoration process. Many of the topics presented in this chapter were introduced in earlier chapters of this text. However this chapter addresses the topics from a restoration perspective.

This chapter describes the issues involved in system restoration and the typical approaches utilized during a power system restoration. This material is intended to be generic; this material is not intended to be specific to any individual system. Each and every power system and generator should develop their own restoration plans which details there unique restoration issues and approaches.

NERC recommends that every generator and ever power system develop its own specific restoration plan.

11.1.1 Definition of a Restoration Condition

Power systems occasionally experience the failure of individual elements. Typically, although some operating security limit violations occur, the remainder of the power system stays intact following the loss of individual elements. Common events of this nature are not considered a restoration condition.

In some instances, a disturbance may result in large portions of the power system collapsing, losing both voltage and frequency. Following these type disturbances, the power system must be restored to an energized and interconnected state. Under these conditions a power system restoration condition exists.

Restoration conditions span a broad range of circumstances. In actual practice, a major system disturbance typically creates a variety of restoration conditions for the power systems involved. The various restoration conditions are categorized into three main groups. The three groups are illustrated in Figure 11-1 and described as follows:

Total System Blackout

A total system blackout is a post-disturbance condition in which the entire power system of a particular entity is de-energized. In a total system blackout all pre-disturbance on-line generating units have tripped off-line.

Partial Blackout

A partial blackout is a post-disturbance condition in which a portion of the power system of a particular entity is de-energized. The loss of a single substation or single generating station is normally not referred to as a partial blackout. In a partial blackout, portions of the power system remain energized.

Islanded System

An islanded power system occurs when, following a disturbance; pockets of generation remain operational but isolated from the remainder of the power system. Typically some portion of the initial customer load is still served in the isolated, islanded system.

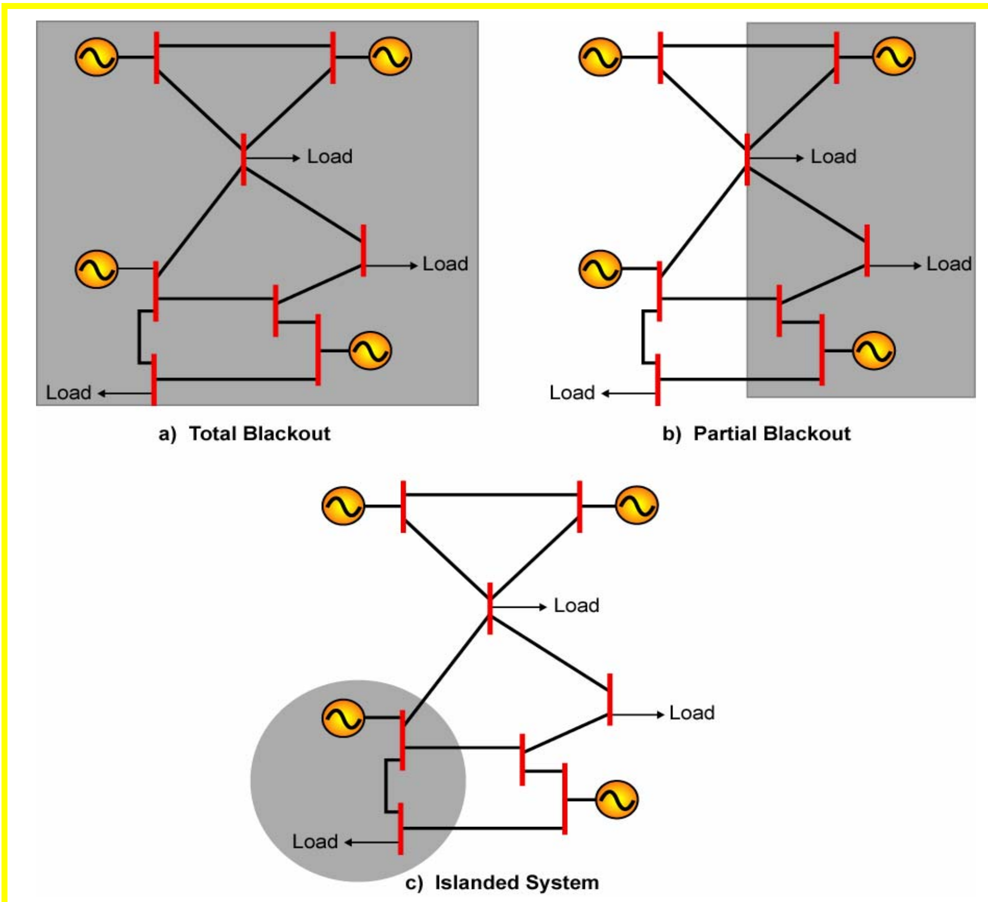


Figure 11-1
Three Types of Restoration Conditions

11.1.2 Causes of System Shutdowns

Designing and operating to withstand the loss of a single element is called "N-1" operations, while designing and operating to handle the loss of two elements is called "N-2" operations.

Power systems are designed and operated to withstand the loss of single elements and occasionally to withstand the loss of multiple elements. When equipment failures and system disturbances occur, system protection and control equipment normally responds to disconnect faulted equipment and take appropriate remedial action to preserve the power system. As a result of design and operating standards that are currently in place, power system shutdowns occur infrequently. This section provides an explanation of some of the factors that cause power system shutdowns. Frequently, several of the following factors are involved in each power system shutdown.

Angle Instability

Chapter 7 described the various issues involved in maintaining angle stability and the causes of angle instability. (Figure 11-2 illustrates the concept of angle instability using a vector diagram to simulate the uncontrolled growth of the voltage phase angle.) Normally power system angle stability limits are clearly identified and the appropriate operating procedures are in place to ensure angle stability limits are not exceeded. However, given a necessary sequence of events angle instability can occur, resulting in major system disturbances possibly including: generator tripping, system separation, and system shutdown.

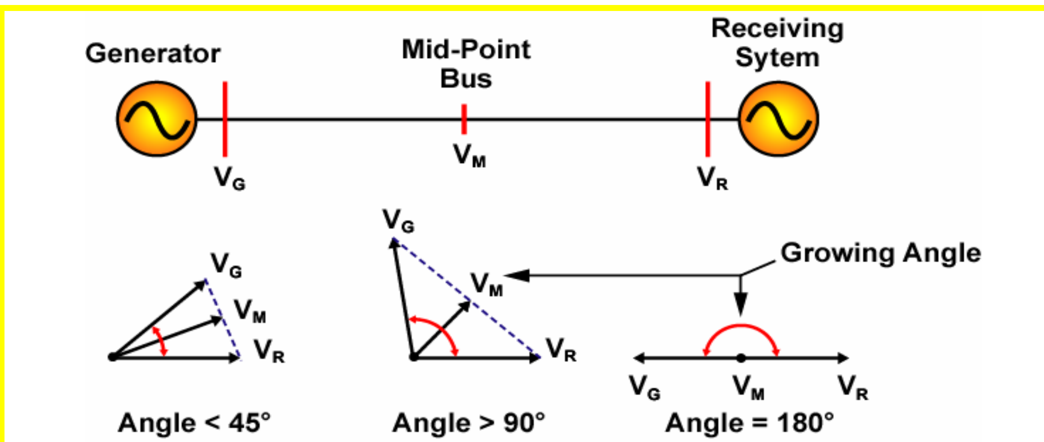


Figure 11-2
Concept of Angle Instability Using a Vector Diagram

The MW transfer equation was developed in Chapter 3 and was stated as:

$$\boxed{P_{S-R} = \frac{V_S \times V_R}{X_{S-R}} \sin \delta_{S-R}}$$

Recall that P_{MAX} is equal to the product of the voltages divided by the impedance.

This equation proves that the potential for angle instability increases as impedance increases and system voltages decline. As the quantity P_{MAX} decreases, the angle necessary for a given MW transfer increases.

Unusual system configurations, such as substation bus outages, can increase system impedance or reduce voltages. The outage of transmission lines and transformers can also increase system impedance or reduce voltage. Normal operating procedures may not ensure angle stability given the occurrence of maintenance or forced outage conditions.

Recall from Chapter 8 that a PSS is used to dampen power system oscillations.

For a generator to maintain synchronism with the power system, the machine's field winding must receive adequate DC excitation current under all operating conditions. When a generator's voltage regulator is placed in a manual mode, the ability of the generator to remain angle stable is reduced, especially if a system fault occurs. Improperly adjusted voltage regulators and the voltage regulator's associated power system stabilizer (PSS) can also contribute to angle instability.

Removal of high-speed tripping schemes from service results in generator acceleration for a longer period of time during fault conditions. Likewise removal of high speed transmission line reclosing lengthens the time before system impedance is reduced following a disturbance, increasing the potential for angle instability. Transmission line synch-check relays may be set so narrowly that they prevent the prompt reclosing of critical equipment following a system disturbance thereby increasing the potential for angle instability.

Equipment Overload

The overload of equipment can result in the equipment's failure or tripping via protective relaying. Equipment overloads normally occur when the system is already stressed as the result of the prior removal from service of key facilities or during high load conditions. The failure or tripping of overloaded equipment under stressed system conditions can lead to a power system shutdown.

Switching Errors

The switching process involves the safe and orderly removal or rearrangement of power system equipment. Most switching is done in the substation. Switching errors may result in the removal from service of important load serving facilities. Switching errors can also create system faults (due to the switching process itself or due to the unintentional grounding of energized equipment) resulting in the removal of facilities from service by protective relaying. Switching errors can create overloads on the remaining system equipment.

Cascading Outages

Once an overloaded facility in a system either fails or is removed from service by protective relaying, the load the facility was initially carrying moves to other system facilities. As a result of this redistribution of load, other system facilities may become overloaded. These overloaded facilities may in turn either fail or be removed from service by protective relaying. This repeated, uncontrolled cycle of overload and equipment failure/removal from service is called a cascading outage.

Generator Overload

Generators that overload may be damaged while in-service or trip due to protective relaying prior to any damage occurring. When evaluating a generator overload, both MW and Mvar loading are monitored as both power values determine the generator's MVA loading. The potential for generator damage is increased if operation is at an abnormal frequency (high or low) or at an excessive voltage. The loss of significant generation under stressed system conditions may precipitate a system shutdown.

Voltage Collapse

Voltage collapse is a phenomenon that can result in a system shutdown and/or system separation, placing the system in a restoration condition. Figure 11-3 reviews the concept of voltage stability from the point of view of maintaining adequate MW and Mvar margins from the possible point of voltage collapse.

Chapter 6 explained the concept and described the process of a voltage collapse.

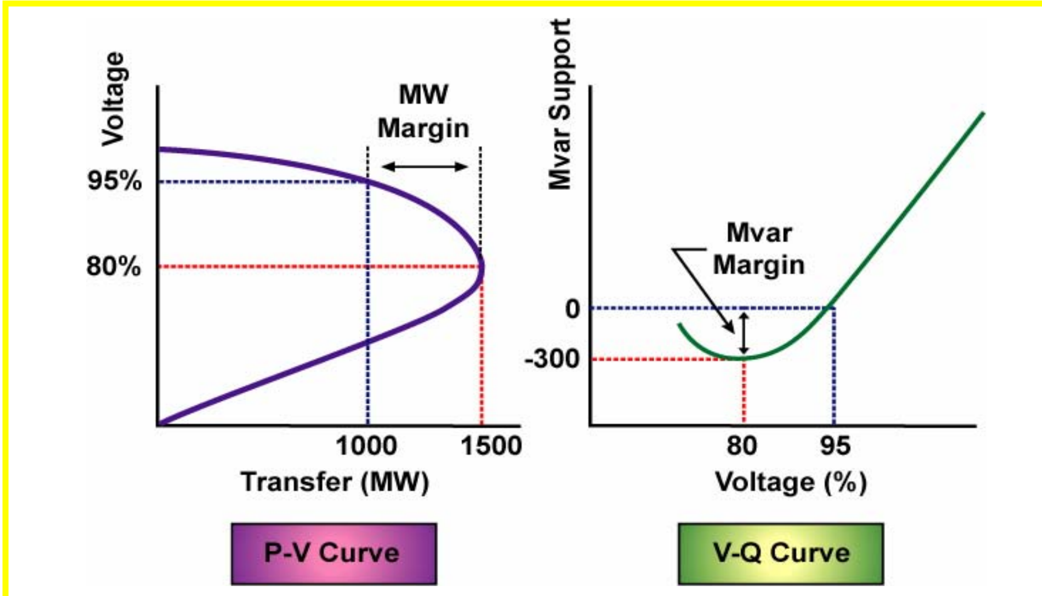


Figure 11-3
Voltage Stability MW and Mvar Margins

Natural Phenomena

Power systems are designed to withstand the majority of the anticipated natural phenomena that occur in a particular area. However, severe natural phenomena can exceed design standards and system failures and shutdowns sometimes occur. Some types of natural phenomena are so severe that it would be nearly impossible—and certainly not cost effective—to design the system to withstand such events.

Weather

Severe ice storms are one example of weather having the capability of shutting down a power system. For example:

> **From January 5 to the 10, 1998 a series of ice storms hit the northeastern portion of North America. The ice storms resulted in the accumulation of up to 3 inches of ice which led to the failure of facilities ranging from 765 kV transmission to low voltage distribution from the weight of the ice.**
>
> **Although numerous transmission facilities failed, the bulk transmission system remained largely intact. Customer outages were due primarily to the failure of distribution facilities.**

Service to 1.4 million customers (which totaled approximately 8,500 MW of load) was lost in Quebec, Canada. A portion of northern New York was operated as an island for half a day and then for three subsequent days via a single tie-line to an adjacent system.

Many transmission and distribution facilities were totally destroyed. Hundreds of utility crews from area and neighboring power systems worked for weeks assisting in the power system restoration.

Earthquake

A severe earthquake can result in major and widespread damage to power system facilities. Substation equipment in particular may be severely damaged. Electromechanical relays may trip facilities falsely due to vibration from the earthquake. For example:

On October 17, 1989 a severe earthquake hit California's San Francisco Bay area. This earthquake (magnitude 7.1 on the Richter scale) resulted in major damage to several key substations and the immediate trip of a major generating unit.

Substation buses, circuit breakers, and transformer bushings were damaged. The loss of key facilities resulted in the creation of an island in the San Francisco area with a large generation to load imbalance. The imbalance caused a rapid frequency decline. Generation within the island tripped and the island blacked out within a few minutes.

Service was lost to 1.4 million customers which amounted to approximately 4,150 MW of load. Service was restored to all but 70,000 customers within 48 hours.

SMDs

Minor solar magnetic disturbances (SMDs) occur on a regular basis as was stated in Chapter 9. Figure 11-4 summarizes the cause of SMDs and their impact on the power system. The major harm from SMDs results from low frequency GICs (geomagnetic induced currents) entering the power system at the transformer grounded neutrals. These currents can be so large that the transformers are damaged and severe harmonics are produced.

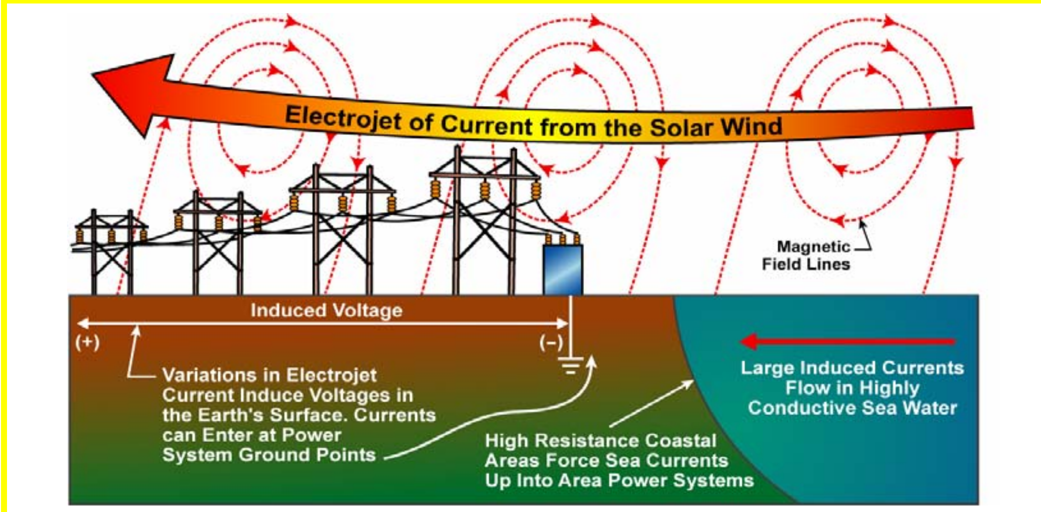


Figure 11-4
Summary of SMD Cause and Impact

SMDs were described in Chapter 9. The Hydro Quebec SMD event is also presented as an example of SMDs in Chapter 9.

Severe SMD events, which can simultaneously affect numerous power systems, have the potential of causing a system shutdown/separation. For example:

On March 13, 1989, a major SMD event occurred. This SMD created a widespread disturbance in North America including the blackout of the Hydro Quebec system and damage to generator step-up transformers at an eastern U.S. generating station.

The tripping of seven SVCs within the Hydro Quebec system resulted in an inability to control the transmission system. Transmission lines and generators tripped resulting in a blackout of the system. Facilities damaged in the system included transformers, surge arrestors, and a shunt reactor. Three electrical islands were formed in the course of the disturbance. Power was restored to most customers over the course of a nine hour period.

The step-up transformer for a large nuclear unit was damaged from core magnetic saturation during this SMD. The saturation occurred due to geomagnetic induced currents (GICs) driving the step-up transformer into half-cycle saturation.

Fires

Major fires can burn across key power system right-of-ways severing critical transmission paths. The system may not be able to withstand such an event especially if the situation develops rapidly.

Additional System Shutdown Causes

Sabotage

Intentional damage or the sabotage of power system facilities can result in power system failures/ separations.

Control Systems

The inappropriate operation of system protection and control systems may cause power system failures and separations. Equipment can trip when it should not have been removed from service. Equipment that should be automatically returned to service may not return due to control system failure or inappropriate design and/or settings. Equipment may not be removed from service as promptly or effectively as desired. For example, circuit breaker failure protection schemes may fail to operate.

Right-of-Way Maintenance

A heavily loaded transmission line can sag into trees that have grown too tall within the line's right-of-way. The resulting line-to-ground fault trips the transmission line. This type of event can be very serious as other transmission elements in the system may be heavily loaded and could be impacted by the sudden line loss. A cascading outage and partial or total system shutdown is possible.

The major outages that occurred in the WSCC on July 2nd and August 10th of 1996 can both be traced to insufficient tree trimming practices.

Major lines were lost due to tree contact starting a chain of events during both disturbances that eventually blacked-out parts of the WSCC and caused the entire Western Interconnection to split into multiple islands.

Overview of Key Technical Restoration Issues

Operation of the power system in restoration conditions differs significantly from normal system operation. Standard day-to-day operating practices are frequently incorrect or inappropriate in restoration conditions. There are a number of unique technical issues that should be considered in the course of restoration. This section identifies some of the technical issues that warrant special consideration during restoration conditions.

Voltage Issues

The energizing of transmission lines and the switching of reactive equipment under normal system conditions typically produces only modest incremental changes to system voltages and reactive flows. Under restoration conditions, the control of system voltages is often a very delicate control process. The switching of a single element can create a runaway voltage condition, potentially resulting in equipment damage and system shutdown.

Chapter 5 described several runaway voltage conditions including self-excitation of a generator. Runaway voltage conditions are more likely in a restoration condition.

A runaway voltage condition occurs when available voltage and reactive control capabilities are fully committed. This control capability deficiency can result in system voltages and transmission line Mvar production spiraling higher and higher in a runaway condition. As each new transmission system element is switched in service, on-line generation must be able to absorb the new Mvar produced by the element while simultaneously maintaining voltages within acceptable limits. Additionally the ULTC's that are set in an automatic control mode may produce unacceptable high side voltage conditions. Voltage control issues during restoration conditions are further explored in Section 11.2.

Frequency Issues

The frequency in a large interconnected power system is normally very stable. The tripping of generation and/or switching of customer load in a large interconnected system usually have only a small impact on system frequency.

In contrast, during restoration conditions the control of frequency can be highly challenging. With few generating units on-line, the pick-up of load can have a significant impact on frequency. The load pick-up from the energization of only a single distribution feeder can result in unacceptable frequency deviations, potentially resulting in a system shutdown. The tripping of a generator in a restoration condition may also result in unacceptable frequency and shutdown.

The planning for sufficient operating reserve levels and the recognition of the dynamic frequency capabilities of available generators must be sufficiently studied. Frequency control issues during restoration conditions are further explored in Section 11.3.

Equipment Issues

There are many restoration issues involving power system equipment and the control systems that support the operation of the power system. Equipment related restoration problems range from the operation of substation equipment to control center functions to telecommunication systems. Equipment may have been damaged due to the initial disturbance or be damaged in the course of the system shutdown. The loss of station service power will immediately effect the operation of some equipment (for example, the motors for LTCs may not be available due to loss of substation station service).

Equipment impacts increase as the duration of the restoration event increases because stored energy sources (for example, substation batteries) eventually deplete. The need for some equipment functions may not be noticed until the restoration condition has persisted for several hours. As time passes, the cooling of the metal in some types of recently de-energized equipment (for example, generator turbines) can evolve into a serious problem.

The operation of backup systems and equipment may require the dispatch of personnel to remote sites. Moving the required personnel to remote sites may take longer than normal in restoration conditions.

Protective Relaying and Control Issues

There are numerous issues that arise in a restoration condition with respect to system protection and control equipment. For example, reduced fault current levels during restoration conditions may result in protective relays failing to detect and clear faults.

Substation and generator control system logic may compromise the ability of a system operator to implement a desired restoration strategy. For example, DC control logic circuitry may not permit a circuit breaker (CB) to close under certain circumstances. In addition, the operation of some special purpose protection and control schemes may be inappropriate for restoration conditions.

Power System Dynamic Issues

A power system in restoration conditions has increased exposure to a variety of system dynamics issues. A power system in the early stages of restoration likely experiences repeated disturbances as equipment is energized and load is picked-up with reduced levels of on-line generation.

Angle Stability

Maintaining angle stability is a concern as weak systems are tied together and generation is delivered to loads via weak transmission paths. During restoration conditions, generating units are typically leading (absorbing Mvar) which results in a relatively weak magnetic bound. Generators that are not in automatic voltage regulator control may further aggravate any potential angle stability problem as the generators may not provide adequate voltage support.

On the plus side, in most instances the lower MW flows in the early stages of restoration tend to keep torque and power angles small. Each system should be evaluated for its susceptibility to angle stability problems during restoration conditions and the appropriate operating guidelines established.

Resonance

The lightly loaded power systems that exist during restoration conditions have high inductive reactance and significant natural capacitance. Large power transformers must be energized at some point in the early stages of the restoration process. This combination of factors is favorable for the initiation of a resonant condition. Each system should be evaluated for its susceptibility to resonance problems under restoration conditions and appropriate guidelines established.

Voltage levels may be very high during restoration conditions. High voltage can cause power transformers to saturate. Saturated transformers increase the power system's harmonic content. High harmonic levels can trigger ferroresonance and result in tripping or damage to important equipment.

Switching Surges

A power system in restoration conditions is lightly loaded and exposed to the energization of large power transformers. Under these circumstances switching surges (rapid increases in voltage and current) can create transient over voltages (TOVs) that can potentially damage power system equipment. Each system should be evaluated with respect to switching surges and their impact on system equipment under restoration conditions. Appropriate guidelines should be established for controlling switching surge voltages.

11.1.4 Restoration Planning

The restoration of a power system is not only complex from a technical perspective; the restoration process is also complex from an organizational perspective. A restoration process involves the coordinated efforts of a large number of personnel. The careful planning for a possible restoration condition is critical to the success of any restoration effort.

Restoration planning has two aspects. The first aspect is the planning that must be conducted well in advance of an actual restoration condition. The second aspect is the real-time fine-tuning of the plan that is necessary for the successful management of a restoration condition.

Each power system is unique and each must be studied to determine the best approach for system restoration. Restoration planning should consider a full range of reasonable scenarios. The capabilities and limitations of generating units under restoration conditions must be carefully evaluated. Restoration approaches should be analyzed on a step-by-step basis. As each step is evaluated, potential problems are considered, and appropriate solutions determined.

Although a correct restoration strategy for a power system may appear to be obvious, careful evaluation frequently reveals serious deficiencies in the intended restoration plan. It may be impossible to implement a planned approach due to unidentified restoration problems.

The advance planning process frequently uncovers problems that would hinder the restoration. The modification of control systems, reconfiguration of power system elements, and the addition of new equipment are possible results of thorough advance restoration planning.

The restoration plan should coordinate with the restoration plans of other power systems in the Interconnection. The Reliability Authority for the area to be restored should be knowledgeable of all its member's systems restoration plans. Each power system's operators should be knowledgeable of the restoration plans of its neighbors and of their Reliability Authority.

A well documented restoration plan must be developed for each power system. This restoration plan should describe alternate approaches for recovery from a restoration condition. Key attributes of a well designed restoration plan include:

- An organized approach to the restoration
- Clear and concise documentation of the restoration strategy
- Identification of all notification and organizational issues
- Logistics planning
- Explanation of key technical issues
- Detailed plans for the reporting and dissemination of information
- Methods for the tabulation of key restoration information

System operators should be competent in the application of their system's restoration plan. Restoration procedure drills should be conducted to familiarize system operators with the procedures and to uncover any unexpected problems associated with the restoration plan. Identified problems must be resolved and appropriate changes made to the restoration plan.

Power systems and their support equipment and organization are constantly in flux. Restoration plans must be periodically reviewed and updated to incorporate necessary changes.

Goals of System Restoration

The various aspects of the restoration planning process are described in this section. The general goals of a system restoration are:

- A quick and accurate assessment of current power system conditions
- The safe shutdown of generating facilities and avoidance of damage to equipment
- A prompt but secure restoration of generating resources and the restoration of the minimum required transmission system, including the necessary load to stabilize the system
- The restoration of customer load in accordance with the load priority

Assessment

It may appear obvious that a system operator is able to easily identify a system shutdown condition. However, during an emergency condition the extent of an outage may not be easily recognized as the available information may be suspect. For example, an observation that all power flows and voltages at a particular substation are zero could easily be perceived as a computer problem. System separations may not be obvious in many instances.

In order to quickly and reliably confirm that a restoration condition exists, appropriate procedures and SCADA displays should be available for use by the system operator. These procedures and displays should provide an accurate evaluation of the restoration condition. Voice communications to selected generating stations, neighboring power systems, and the appropriate Reliability Authority are typically part of this evaluation process. A system operator needs to clearly understand the conditions in which a restoration condition exists in their unique power system.

Organization and Mobilization

Once a system operator determines that a restoration condition exists, the restoration conditions must be promptly communicated to others both inside and outside the system operator's organization. To ensure that the necessary communications occur in a restoration condition, each restoration plan should contain a communications plan. The communication plan identifies the personnel to be notified (and their backups), the information to be conveyed, and the specific method to be used in communicating with the party (for example, their telephone number). The communications plan also addresses how entities external to the organization are kept informed.

Once appropriate personnel have been notified that a restoration condition exists, a mobilization plan is implemented. The mobilization plan directs the various entities throughout the organization on their specific roles with respect to mobilization. The personnel to activate and where to send these personnel are typical items included in a mobilization plan. The mobilization plan makes it possible to quickly and efficiently direct personnel to their proper locations. The mobilization plan reduces the occurrence of unnecessary communications in an emergency situation.

Phases of the Restoration Process

The actual restoration process can be broken down into three distinct phases. The three phases of the restoration process are described in this section and illustrated in Figure 11-5.

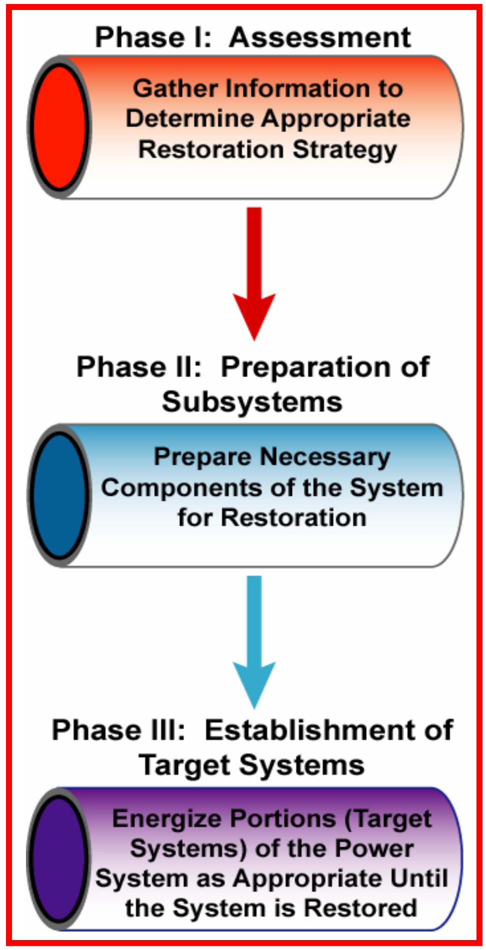


Figure 11-5
Phases of the Restoration Process

Phase 1: Assessment

The first phase of the restoration process consists of a detailed assessment of the state of the power system. An initial, rapid assessment has already been completed to determine if a restoration condition exists. The purpose of this phase is a more detailed assessment to determine an appropriate strategy for the restoration of the power system. Normally this assessment guides the system operator in selecting which of the restoration strategies contained in the system restoration plan is most appropriate under the specific circumstances.

The assessment phase includes the following activities:

- Determine the status of all generating units.
  - On-line? Tripped off-line? Initially off-line?
  - Which units are available or unavailable for service?

Generating units that are normally operated remotely may require personnel on-site to perform key functions in restoration conditions.

  - When will the unit be available for startup? Immediate? Within how many minutes? Hours? Days?
  - Are black-start units available to be started?
- Determine the status of neighboring power systems and tie-lines
- Request information on the status of the neighboring power systems from the Reliability Authority
- What—if any—system load is still being served?
- If portions of the system are still energized, are frequency, voltage, and equipment loadings within acceptable limits?
- Identify the boundaries of any islanded systems
- Perform a facility damage assessment and review any available damage reports
- Gather information to help determine the cause of the disturbance

The system operator utilizes SCADA displays and electronic and voice communications with internal external personnel to obtain data for the restoration assessment.

Phase II: Preparation of Subsystems

Prior to the restoration of the power system it is first necessary to take several preliminary steps.

- If any generation has remained on-line:
  - The voltage and frequency of currently on-line generators is adjusted to within acceptable limits
  - AGC control will often automatically trip to manual or may need to be placed in manual
    - Any power system overloads should be quickly addressed so that all equipment is operating within accepted limits
    - Appropriate levels of operating reserve should be established as soon as possible
- For generators that have recently tripped:
  - Establish, if possible, a source of on-site power for each generators auxiliary loads
  - Ensure that the generator has safely shut down. A list of items to check for each generator should be included in the generator's restoration plan.

  - Review any generator alarms for relevant information
  - Determine if the generator is available for restart

Generating unit governor control pressures may bleed down over time on some units, making the unit unavailable for immediate restart.

- For generators with black-start capability:
  - Review any generator alarms for relevant information
  - Check that the generator is available for restart
  - Start any necessary on-site emergency generation for the generator's auxiliary equipment
  - Prepare the generator for black-start
- For generating units that were not in-service:
  - Review any generator alarms for relevant information
  - Check the availability of the generator for startup
  - Start any on-site emergency generation
- Check substation alarms for relevant information
- At any currently de-energized substations:
  - Protection schemes that would automatically close CBs and switches (for example, automatic reclosing schemes) should be disabled
  - Verify that distribution feeder CBs are opened
  - Verify that any de-energized tie-line CBs are opened
  - Verify that de-energized capacitor and reactor CBs are opened
  - Verify that de-energized underground cable CBs are opened
- Verify that other transmission line and transformer CBs are opened in accordance with the restoration plan

Cable and bus pressures should be monitored as pressure may continue to drop as equipment cools down.

  - Check underground cable oil, nitrogen, and SF6 pressure alarms and actual pressure levels
  - Check SF6 bus alarms and pressures
  - Check other critical equipment parameters
- Dispatch field personnel as necessary

Phase III: Establishment of Target Systems

An effective way to manage the initial restoration effort is to establish a series of target systems for restoration. Using a target system approach, the restoration process is broken down into a manageable and more easily understood set of tasks. The target system concept enables a more flexible approach to the restoration process.

A target system should consist of a significant restoration accomplishment such as a black-start unit and transmission to energize a second generator. The restoration plan should include target systems and alternatives that have been thoroughly studied and are considered the best approach for a particular system.

In the case of a complete system shutdown, the first target system may include the establishment of a transmission system backbone—which is energized from a black-start unit—to provide cranking power for the next generator to be restarted. A second target system could expand the restored system to other generating units. A third target system could expand the restored system to include the re-energizing of high priority substations. An additional target system may restore service to an urban area. The final target system may energize any remaining substations or complete a transmission system loop.

Cranking power is the MW delivered to the next generator to be started. The MW is termed cranking power as it is typically used to turn or crank large motors.

The target systems for an initially islanded system would include a target system that permits synchronizing the system and the establishment of tie-lines to the main body of the power system. Additional target systems are then established to re-energize any remaining portions of the system that were de-energized in the disturbance.

Actual conditions and generator availability are used to select the target systems to be implemented. The restoration plan normally contains detailed procedures for establishing each target system. In some restoration situations, the restoration condition may require the system operator to develop a target system at the time of the restoration condition. In the case of most system shutdowns—where widespread damage to the power system has not occurred—the target systems contained in a restoration plan should expedite the restoration process. The use of the target systems contained in a restoration plan helps to avoid unanticipated restoration difficulties, as the restoration plans can be carefully studied and verified in advance of actual usage.

Restoration Priorities

Each system must carefully consider its load restoration priorities. Guidelines pertaining to load restoration priorities should be contained in the restoration plan. Public and employee safety, health and welfare, and system reliability are obvious considerations when selecting priority customer loads. Priority customer loads are often determined in consultation with the appropriate emergency management organizations. Community impact, contractual obligations, and regulatory requirements are frequently factored into customer load priority guidelines.

Substation Restoration Priorities

It is often helpful to establish restoration priorities for key substations and distribution feeder circuits. Using this approach, restoration priorities are established on a substation by substation basis and on a distribution feeder-by-feeder basis. For example, a particular substation may be energized based on its overall priority and then once energized, the individual distribution feeders at the substation are energized based on their relative feeder priority with respect to feeders at other energized substations. Figure 11-6 illustrates this well organized approach to restoration. Substations “A” and “D” of Figure 11-6 are designated high priority and energized first. Then feeders #1 and #3 in substation “A” and feeder #2 in substation “D” are energized as these are designated as high priority feeders.

When establishing substation priorities, it may be appropriate to establish several priority groups (for example: high, medium, and low). Establishing substation priorities helps to determine the content of the target systems described in the previous paragraphs.

Strict adherence to the substation priority ranking may not always be possible. In the process of energizing higher priority substations, lower priority substations may lie in the selected transmission path and must be energized before they are needed.

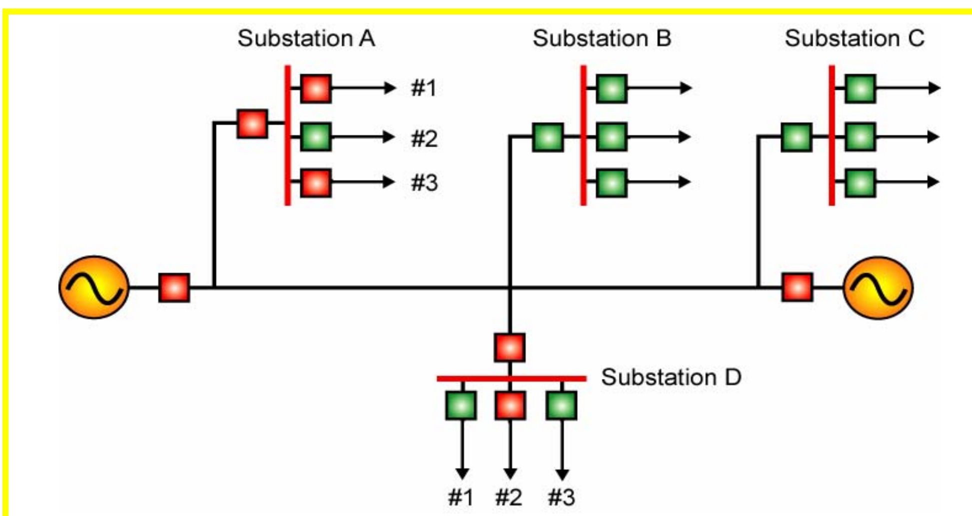


Figure 11-6
Substation and Individual Feeder Restoration Priority

Load Restoration Priorities

The initial restoration of load is normally not accomplished on a customer load priority basis. Initially load is restored based on the technical needs of the power system. Initial load restoration is focused on providing load to on-line generators, dampening voltage transients, and consuming excess Mvar. The loads restored are selected based on size, ability to be quickly switched, and their location in the energized system.

Higher priority customer loads are energized once system conditions are such that they can be accommodated. Care must be taken to ensure that in the haste to restore high priority loads, the energized system is not placed in jeopardy of another shutdown. As the restoration process progresses, additional loads are picked up based on their relative priority. As more substations are energized, larger blocks of load can be safely picked-up by on-line generating units. Frequently a gradual transition occurs from picking up load based on technical needs to picking up load based on load priority. (There may be a need to strip some of the load from heavily loaded feeders before they can be restored to service.) Eventually customer loads are picked up based exclusively on load priority.

NERC guidelines for power system restoration recommend that the load block restored during the initial stages of restoration be limited to no more than 5% of the total synchronized generation.

11.2 Voltage Control and System Restoration

Control of system voltage levels and the reactive balance is very important during a system restoration condition. A restoration conditions power system is extremely sensitive and responds differently then during normal operating conditions. Extreme care must be exercised as system voltage can rapidly move either high or low, well outside of acceptable limits. This section describes various issues involved when controlling voltages and maintaining Mvar balance during the restoration process.

This section builds on the voltage control material that was presented in Chapter 5.

11.2.1 Voltage Control as a Local Issue

Recall from Chapter 5 that transmission lines and transformers use Mvar when current flows through the equipment. This Mvar usage can also be thought of as Mvar losses. The behavior of the transmission system is such that in order to maintain an acceptable system voltage profile, Mvar support must be provided locally to compensate for the Mvar usage of the particular area of the system. The Mvar usage of transmission lines and transformers is proportional to the square of the current flow. This means that in a heavily loaded power system, the Mvar usage can be very high. To support heavily loaded transmission systems, sufficient Mvar resources must be strategically positioned to respond when needed.

In restoration conditions, transmission lines and transformers are often initially loaded at very low levels. The initial voltage control concern is therefore high voltage. Sufficient Mvar absorption capability must be located close to the areas where the higher voltages are expected to occur. Under certain circumstances, equipment that provides a large amount of Mvar (such as long high voltage transmission lines) may have its restoration delayed until the system is strong enough to energize the equipment without losing control of voltage.

11.2.2 Review of Voltage Related Restoration Theory

Chapter 5 described the fundamentals of system voltage and reactive power control. Several of the topics from Chapter 5 have particular importance in restoration conditions and are reviewed and expanded in this section.

Review of Ferranti Rise

Ferranti Rise refers to the voltage rise that occurs across an energized but open-ended transmission line. The elevated open-end voltage levels can cause equipment damage (for example, transformers can be damaged due to over-excitation). The percent of voltage rise is a function of line length as illustrated in Figure 11-7. Figure 11-7 emphasizes that the Ferranti effect can be very significant if the open-ended line is long. During normal conditions, the sending-end voltage magnitude remains acceptable when a transmission line is open-ended. The sending-end voltage is acceptable because a normal conditions power system has low impedance and sufficient Mvar control equipment available for usage.

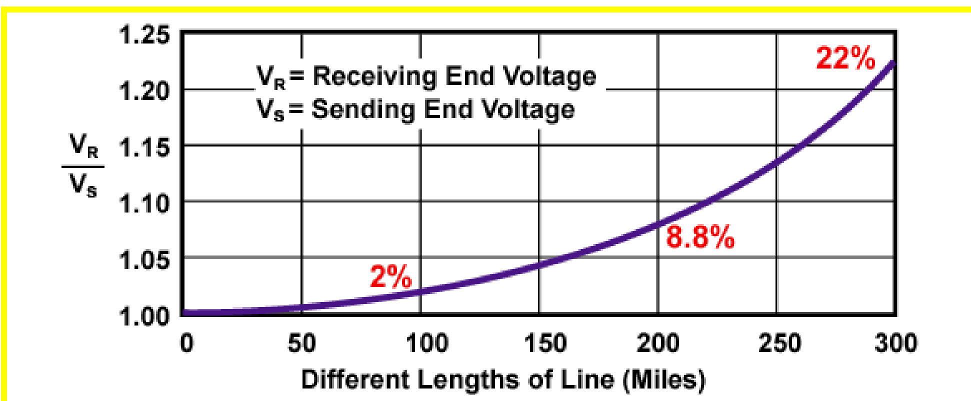


Figure 11-7
Ferranti Effect Open-End Percent Voltage Rise

A weak bus is a bus with few lines and/or generators attached to it. A power system will have weak buses in the initial stages of system restoration.

In restoration conditions, Ferranti Rise is a more serious concern. A line energized from a weak sending-end bus can result in the sending-end voltage rising substantially. The Ferranti rise effect is then a percentage rise on an already high sending-end voltage magnitude. The higher voltage levels also results in more Mvar production by the open-ended line. The overall effect is even higher levels of Mvar production and voltage magnitude. If the available on-line generation is unable to absorb the increased Mvar, a run away voltage condition may develop.

An additional concern with Ferranti rise is that the elevated voltages heighten the potential for ferroresonance and switching surge problems as explained in the next section.

Review of Resonance

Ferroresonance was described and illustrated in Chapter 9.

During a system restoration condition, the potential for ferroresonance is greatly increased. System voltage can quickly rise, possibly driving a transformer into saturation, which, as was explained in Chapter 9, is a part of the ferroresonance mechanism.

The initiation of a resonant condition is also possible due to capacitive and inductive combinations at harmonics of the power system frequency. The presence of harmonics during transformer energization may trigger this type of resonance.

In normal conditions, customer load dampens switching surges and harmonics and reduces the potential for resonance. However, during restoration conditions there may be little or no load on the system, and hence reduced load damping. The potential for resonance must be evaluated well ahead of any restoration events and recommendations for minimizing resonance possibilities included in the restoration plan.

Switching Surges and Temporary Over-Voltages (TOVs)

When devices (CBs, transformers, etc) are switched in and out-of-service, sudden changes occur in the power system. These sudden changes to voltage and current are called switching surges. When a switching surge occurs, the power system is exposed to a wave like effect as the switching surge voltage propagates through the area power system. The propagating surge voltage can add to the steady-state power system voltage, creating transient over-voltages (TOVs) conditions. A TOV voltage can easily exceed 160% of the normal system steady-state voltage level.

In normal conditions, customer load and power losses quickly (within a few cycles) dampen the switching surge. In a restoration condition, with little or no customer load, TOVs can persist for an extended time due to the lack of adequate damping. Sensitive over-voltage protective devices may operate due to the TOVs. The effects of TOVs on equipment can be severe. Transformers can be damaged due to over-excitation. Zinc-oxide lightning arresters are particularly sensitive to TOV and subject to thermal failure if the TOV magnitude is great enough.

The failure mode of equipment after exposure to TOVs is thermal. Therefore, the effects of TOVs are cumulative. For example, a zinc-oxide lightning arrester may be able to withstand exposure to a TOV produced by a transformer energization. However, if the same lightning arrester is exposed to an additional similar TOV when a second transformer is energized, the lightning arrester may fail. Repeated exposure eventually breaks down the equipment so that a relatively mild TOV results in significant damage.

The possibility of equipment damage from TOVs is enhanced if the steady-state system voltage is high. TOVs are a transient over-voltage that is compounded on top of the steady-state voltage. If the steady-state voltage is high, applying a TOV on top of it increases the risk. Some power systems intentionally energize their system at a lower steady-state voltage (for example, 90% of normal) to reduce the risks of damage from TOVs.

TOVs are a relatively common problem in power system restoration. A system's exposure to TOV related damage during restoration conditions should be identified and evaluated by conducting a switching surge study of the intended restoration approach. The system restoration plan should reflect the results of the switching surge studies and include methods to avoid TOV equipment damage.

Review of Generator Reactive Capability

Chapter 5 described the use of generators to control system voltage. A generator's voltage regulator is normally in-service and adjustments to system voltage are made by raising and lowering the voltage regulators set-point. Figure 11-8 illustrates the usage of a voltage regulator to automatically control the output voltage of the generator.

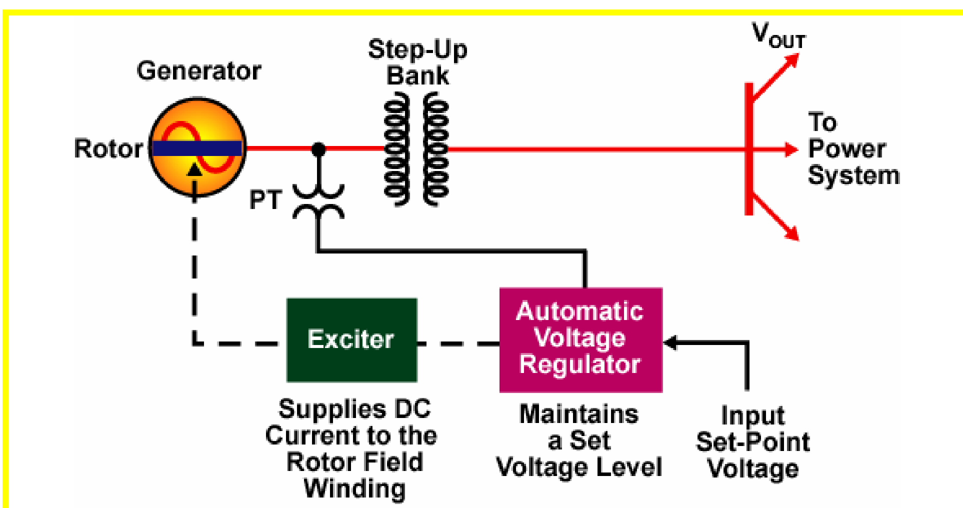


Figure 11-8
Diagram of a Generator's Excitation Control System

The physical capabilities of a generator limit the extent to which it can control system voltage without sustaining thermal related damage. Figure 11-9 contains a reactive capability curve for a 100 MVA generator. In theory, the generator can operate at various combinations of MW and Mvar loading as long as the MVA of the combination is within the limits of the capability curve.

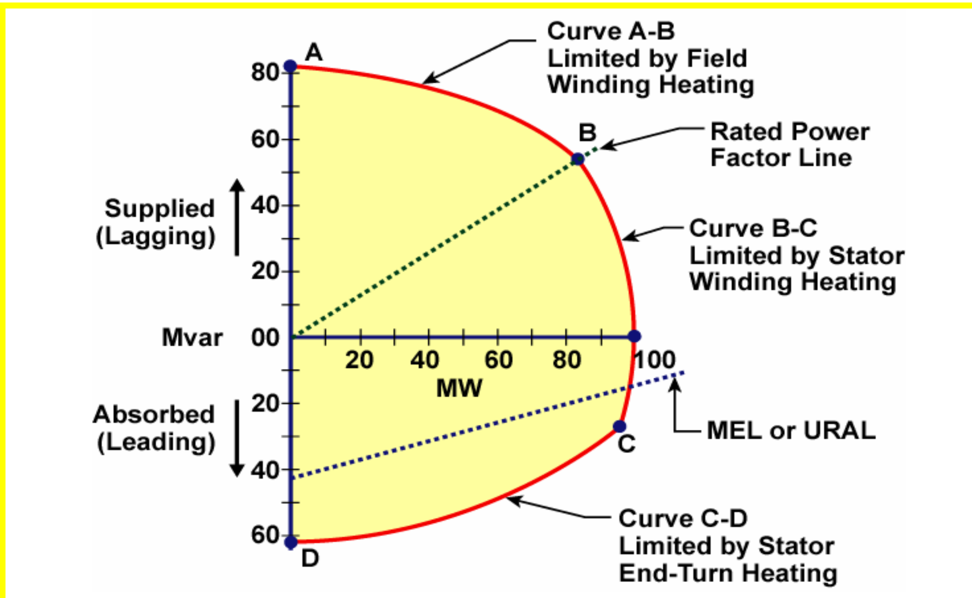


Figure 11-9
Reactive Capability Curve

Thermal generators typically require a large assortment of auxiliary equipment to support the generation process. (For example, feedwater pumps, coal mills, etc.) This equipment is connected to the station service (auxiliary) bus of the generator. The auxiliary bus voltage must be controlled within acceptable limits to satisfy the equipments voltage limitations. Since the generator operating voltage impacts the auxiliary bus voltage, the auxiliary equipment acceptable voltage range can severely limit the ability of generator to operate at the extremes of its Mvar absorption and production capability.

The Mvar capability of a generator is often further restricted by voltage regulator controls and protective relay settings. An understanding of the actual (as opposed to theoretical) Mvar capability of a generator is critical in a system restoration condition. Failure to identify the actual Mvar capability of a generator can result in unexpected generator tripping and/or runaway voltage conditions.

As a generator is operated more deeply into the leading region of its Mvar capability, a limit is eventually reached beyond which generator stability could be in jeopardy. Loss-of-field (LOF) protective relays are installed and set to trip the generator before it enters an unstable operating area.

The generator's voltage regulator typically includes a minimum excitation limiter (MEL) or an under-excited reactive ampere limiter (URAL). The MEL or URAL alarms the operator and possibly blocks movement into a dangerous operating area. The MEL/URAL is typically set to ensure that the generator does not move so far into the leading area that the LOF relay operates and trip the unit. The intended coordination between the MEL/URAL and the LOF protection may not be adequate under restoration conditions and false tripping of an LOF relay is possible.

A generator's automatic voltage regulator is designed so that the generator's field current is adjusted to keep the Mvar operating point above the URAL/MEL set point. During normal operating conditions, once the URAL/MEL limit is reached, the generator automatically stops further movement into the leading area and maintains the URAL/MEL dictated minimum Mvar loading. Under normal operating conditions, available system voltage control equipment and other available generators would assume control of the system voltage.

Under restoration conditions, there may be one or only a few generators connected to the system. Under these circumstances the available generators must absorb all of the new Mvar as transmission facilities are energized. If the Mvar produced by the newly energized transmission lines exceeds the generator's ability to absorb Mvar due to the generator's URAL/MEL settings, the URAL/MEL typically starts increasing the generator's field current.

The increase in field current would normally reduce the amount of Mvar absorbed by the generator. However, under an islanded situation increasing the field current further increases the area voltage and increases the Mvar produced by the transmission system. This forces the generators to absorb more Mvar rather than less. This series of events can create an out-of-control situation. Eventually the rising system voltage could cause the generator to trip.

When a generator's voltage regulator is out-of-service, field current control is done manually. If field current is reduced too low during manual voltage regulator control, the generator could trip via its LOF relay as there would not be any automatic movement to raise the field current.

11.2.3 Voltage Control in Restoration Conditions

There are three key objectives with respect to voltage control during restoration conditions:

1. Absorb Mvar as required

2. Maintain all voltages within acceptable limits

3. Minimize the impact of TOVs from switching surges—and the potential for ferroresonance—by reducing voltage levels as required

During the initial stages of restoration, with few generators on-line, absorbing the Mvar generated from transmission facilities is a critical issue to manage. As stated in the previous section, on-line generators must not be forced to absorb so much Mvar that they trip via LOF relays. A generator trip under highly stressed restoration conditions often results in a system shutdown.

During the early stages of restoration, it is often difficult to maintain all system voltages within acceptable limits. The tap settings of fixed-tap transformers are normally set for normal, loaded system conditions. The tap settings of a transformer may not be appropriate for the unloaded system conditions that are encountered in a restoration condition. The natural voltage rise on unloaded lines and cables may also further restrict the ability of a system operator to maintain acceptable voltages.

The high probability of switching surge induced TOVs and the potential for ferroresonance may necessitate operation at reduced voltage levels (possibly 90 to 95% of normal) during the early stages of restoration. During this critical period, little or no energized customer load results in reduced damping forces. The energization of large power transformers from a weak power system results in frequent switching surges that may initiate numerous TOV events. Overlaying these TOVs on a reduced steady-state voltage can reduce the damage from the TOVs.

Usage of Shunt Capacitors

During the early stages of restoration, shunt capacitors are normally not used. Typically, absorbing the Mvar created by the energized transmission lines is a key issue and any additional Mvar from shunt capacitors only makes the situation worse. In some cases, the inappropriate switching of a shunt capacitor might cause the tripping of generators due to LOF relay operation. There may also be resonance scenarios that restrict the usage of shunt capacitors in a weak power system. Shunt capacitors should normally only be used late in the restoration process and then very cautiously.

Usage of Shunt Reactors

The usage of shunt reactors is often useful for reducing voltage depending on the particular system. Unfortunately, the usage of shunt reactors may make a weak system more susceptible to ferroresonance because the insertion of a shunt reactor effectively increases the impedance of the system. If shunt reactors are to play a part in the system restoration plan, their impact (TOVs, etc.) should be studied in detail and any limitations noted in the restoration plan.

Usage of Generators

Generators are the primary voltage control tool during a restoration condition. Generators are used to absorb or produce Mvar as the system requires. The ability of the on-line generators to absorb or produce Mvar must always exceed the ability of the restored power system to produce or absorb Mvar.

Maintaining Adequate Dynamic Reactive Reserve

A generator's dynamic reactive reserve is the difference between its actual Mvar loading and the Mvar limit of the generator. In the early stages of restoration, the ability to absorb Mvar is typically a key issue. The generators dynamic reactive reserve absorption capability must be sufficient and rapidly available prior to energizing a new transmission line.

For example, if a line with 50 Mvar of charging is about to be energized, there should first be in place the ability to dynamically absorb the 50 Mvar plus a margin of safety. It is important to remember that the Mvar production of the line increases in proportion to the square of the voltage. If the system voltage is above nominal or will be once a transmission line or cable is energized, the cable or line's Mvar will be greater than its nominal quantity. A comfortable safety margin is necessary to ensure that an out-of-control voltage situation does not occur.

One additional issue is maintaining sufficient dynamic reactive reserve for response to contingencies. Starting very early in the restoration process and continuing through out, dynamic reactive reserve should be sufficient to withstand the loss of any generator or piece of voltage control equipment with an adequate margin of safety.

Constraints Imposed by Generator Auxiliary Loads

The voltages at generator station service (auxiliary) buses must be within the allowable limits for the particular type of equipment. Equipment damage can occur if voltage limits are violated. The restoration plan should give guidance on each generator's allowable auxiliary bus voltage levels.

Step-up Transformer Tap Positions

Studies should be conducted in advance of the restoration condition to determine the optimal transformer fixed-tap positions to best accommodate normal and restoration operating conditions. Consideration should be given to the tap settings of power transformers, generator step-up transformers, and auxiliary bus transformers.

Usage of ULTCs

Although there are many different control strategies, under load tap changing (ULTC) transformers are typically operated either manually or automatically to control a low-side voltage magnitude. Under normal operating conditions, the high-side voltage is typically a stronger source than the low-side voltage. In this condition, when tap positions are adjusted, the high-side voltage remains the same or changes slightly while the low-side voltage of the transformer experiences most of the voltage change.

Under system restoration conditions, the low-side voltage of the transformer may be connected to generation and the high-side may be isolated from other generators or only weakly connected. Under this scenario, changes to tap positions create little effect on transformer low-side voltages, but have great impact on the transformer's high-side voltage. Under these conditions the ULTC can be used to control high-side system voltage and the generator can be used to control its Mvar loading and terminal voltage. Coordinating the tap-changer position and generator voltage adjustment permits a broad range of operating flexibility with respect to the generator and the power system. Figure 11-10 illustrates the usage of ULTCs in normal and restoration conditions.

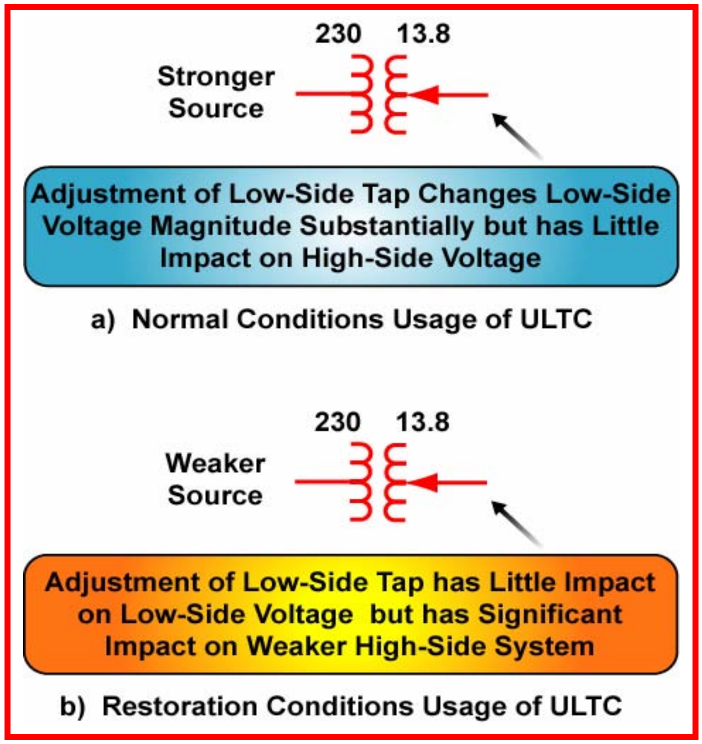


Figure 11-10
ULTC Usage in Normal and Restoration Conditions

Usage of Controlled Load Pick-up to Maintain Voltage

System loading also plays a part in the control of voltage. For example, the addition of some customer load at the open-end of a transmission line may dramatically reduce the Ferranti rise over-voltage. Energizing load with a low lagging power factor is very helpful as the load absorbs excess Mvar from energized transmission lines. Conversely, loads with a leading power factor aggravate efforts to absorb Mvar and interfere with the control of system voltages. Load also dampens switching surges and reduces the likelihood of resonance incidents.

11.2.4 Operation of the System at Reduced Voltage

There are a number of voltage concerns that surface in restoration conditions. Steady-state voltages are often difficult to control depending upon the system and the generators that are available in the early stages of restoration. Ferranti rise is a concern depending upon the length of the transmission lines. Transformer saturation and ferroresonance can occur due to high voltage conditions during the restoration. The numerous switching surges that typically occur in the early stages of restoration can result in many TOV events. Reducing system steady-state voltages can diminish the potential for all of these problems.

Methods of Reduced Voltage Operation

When considering the reduction of system voltage during restoration conditions, the impact on equipment and customer load should be given careful consideration. The issues include:

- Generators and their protective relay settings
- Acceptable generator auxiliary bus voltage
- The impact on substation auxiliary equipment including transformer oil pumps
- The impact on connected customer load

There are several ways to accomplish reduced voltage operation. If reduced voltage operation is deemed necessary for a particular system, a carefully studied approach should be selected and included in the restoration plan. Approaches that might be considered include:

- Energize a portion of the system from a single generator operating at a reduced voltage:
    - The generator's automatic voltage regulator can be in or out-of-service. The automatic or manual voltage control point targets the reduced level of voltage. The protective relay and control settings of the generator (LOF relay, MEL, etc.) should be analyzed to ensure unexpected and unnecessary tripping does not occur.
    - If a suitable area ULTC is available, its usage could allow a generator to operate at essentially normal voltage levels while simultaneously permitting all or portions of the transmission system to operate at reduced voltage levels.

11.2.5 Voltage Based Automatic Load Shedding

Schemes that shed load based on voltage are called under-voltage load shedding (UVLS) schemes.

Some power systems use protective relay schemes that automatically shed portions of the customer load if voltage drops below a defined point. In some cases, these schemes also allow the load to automatically restore once system voltage recovers to a certain level. These types of schemes should be evaluated as to their appropriateness during a restoration condition. The settings may not be appropriate during restoration conditions and/or the amount of load shed may be incorrect. In addition, any automatic load pick-up may be inappropriate in a restoration condition. Recommendations as to the appropriate usage and operation of these types of protective schemes should be contained in the restoration plan.

11.3 Frequency Control and System Restoration

This section builds upon material presented in Chapter 4 and describes special issues associated with frequency control during restoration conditions.

During normal operating conditions, a large interconnected power system experiences relatively small frequency deviations when either a generator trips or system loads are switched. The reduced impact on frequency is due to the typically large amount of widely distributed operating reserves and the sizeable inertia of a large power system.

However, during restoration conditions, frequency control requires a system operator's careful attention. There may be one or only a few generators on-line, therefore a generator trip or a large load pick-up can have a significant impact on system frequency. If the frequency deviation is too large, equipment damage and/or a system shutdown can result.

11.3.1 Frequency Control as an Interconnection Issue

During the restoration process, it is very important to approach frequency control from an interconnected system perspective. There are two key issues that must be evaluated. Both issues are explained in this section.

Generator Dynamic Response

Frequency control is an Interconnection wide issue while voltage control is a local power system issue.

Each generating unit responds to a frequency deviation in a manner unique to the generator's own operating characteristics. The Interconnection's frequency is however a joint issue. The frequency deviation is impacted by the combined response of all the generators connected in the interconnected system.

A large frequency deviation can be initiated by the pick-up of a large block of load or by the trip of a generator that was supplying a large amount of MW. Following the initiating disturbance, the inertia of each rotating machine rapidly provides energy to meet the generation deficiency. The generator's inertial response increases the generator's MW output. Generators contribute MW in proportion to their relative inertia. As described in Chapter 4, the MW provided by a generator immediately after the initiating disturbance is not a function of governor settings but rather of the stored energy in the power system, especially the energy stored in the generators' rotating mass.

Eventually (within a few seconds), the governor response dominates over the inertial response as the system frequency decays. Assuming there is sufficient MW reserve capacity, and further assuming that the disturbance is not so severe that it causes a complete shutdown, the frequency decay is arrested at a certain point. The lowest frequency dip following a disturbance is referred to as the "undershoot". (The undershoot point is labeled "C" in Figure 11-11.)

Eventually the frequency recovers to the stabilization point. The stabilization point is labeled point "B" in Figure 11-11.

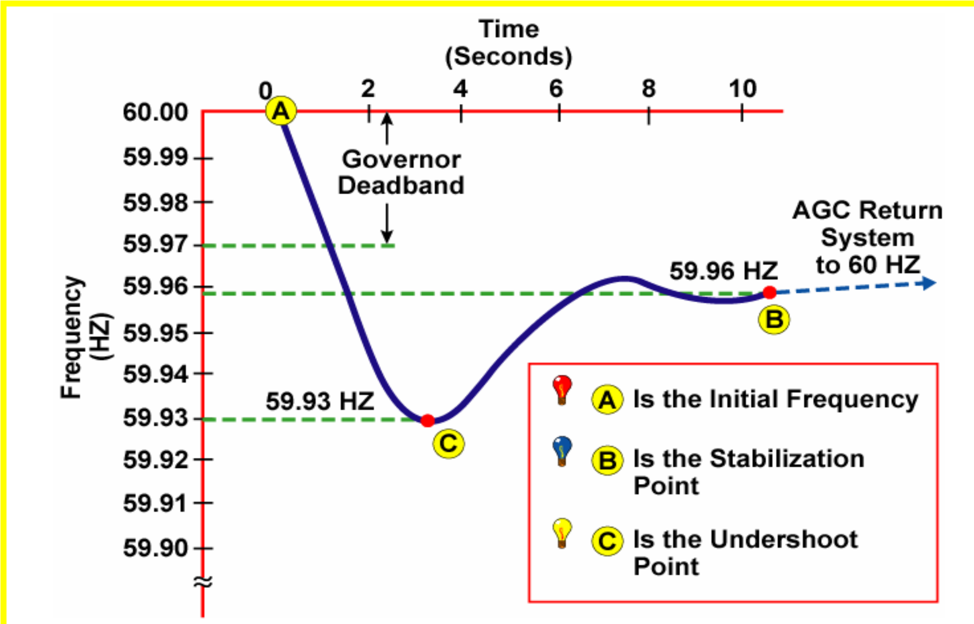


Figure 11-11
Plot of a Frequency Disturbance

The ability of a generator to produce additional MW to arrest a frequency decline is referred to as the generator's "frequency response rate" and is expressed as:

$$\boxed{\textbf{Frequency Response Rate} = \frac{\textbf{MW Response as \% of Generator Capacity}}{\textbf{Frequency Deviation in HZ}}}$$

A generator's frequency response rate is the percent of a generator's MW capacity that is delivered in the process of responding to a disturbance induced reduction in frequency. The frequency undershoot point typically occurs within 2-4 seconds of the initiating disturbance as illustrated in Figure 11-11. The frequency response rate represents the short-term response of a generator and is not necessarily representative of the steady-state MW operating point of the generator once governor response has taken place. Typical frequency response rates for various types of generators are as follows:

- Steam unit with a drum type boiler: 10%/HZ
- Combustion Turbine (CT): 20%/HZ
- Low-Head Hydro (short penstock): 30%/HZ

Following the frequency undershoot, generator governor action continues to provide MW. Approximately 10-15 seconds after the initial disturbance the MW provided from governors and other sources stabilizes the frequency. The stabilization point is labeled point "B" in Figure 11-11. In the case where all generators within the restored system have the same response capability and droop setting (for example 5%), each responding unit ultimately picks up a portion of the MW in proportion to the generator's capacity. (This assumes that the generator's prime mover is capable of such a response.)

The prime mover is the generator's mechanical energy source. In a steam unit, the prime mover includes the boiler and turbine.

Transmission System Impacts

During the early stages of restoration conditions, the transmission system is weaker than during normal operating conditions. The initial restoration system typically uses lower transmission voltages and has a lower MW capacity. Inter-connections between energized portions of the system may be weak or absent altogether. Under these weak conditions, the dynamic response of the currently on-line generators to the loss of a generator can easily create an overload and/or instability in the transmission system. Transmission overloads and instability can result in system splits and may lead to another system shutdown. A similar response can also be caused by the pick-up of a large block of load.

11.3.2 Maintaining Frequency during Restoration Conditions

Frequency is more difficult to control during restoration conditions than during normal operating conditions. As a restoration process proceeds, customer load blocks are constantly energized. Although it is desirable to pick-up only small blocks of load in the initial stages of restoration, the power system configuration may not cooperate. Even a relatively lightly loaded distribution feeder energization can have a significant impact on system frequency in the early stages of restoration. The pick-up of each load block tends to cause a new frequency disturbance.

Allowable Frequency Bounds

There are several issues that should be considered with respect to the power system's allowable frequency limits. The necessary frequency limitations may vary depending upon the restoration area's equipment design and control. The system restoration plan should specify allowable high and low frequency limits. When interconnected with other systems, the most restrictive frequency limits for the entire system should be respected.

The following issues should be addressed—in the planning stage—when establishing restoration conditions frequency operating limits:

- Evaluate possible damage to steam turbine blades
- A typical steam turbine can operate between 59.5 and 60.5 HZ indefinitely. (Figure 11-12 illustrates typical steam turbine frequency related operating limits.)

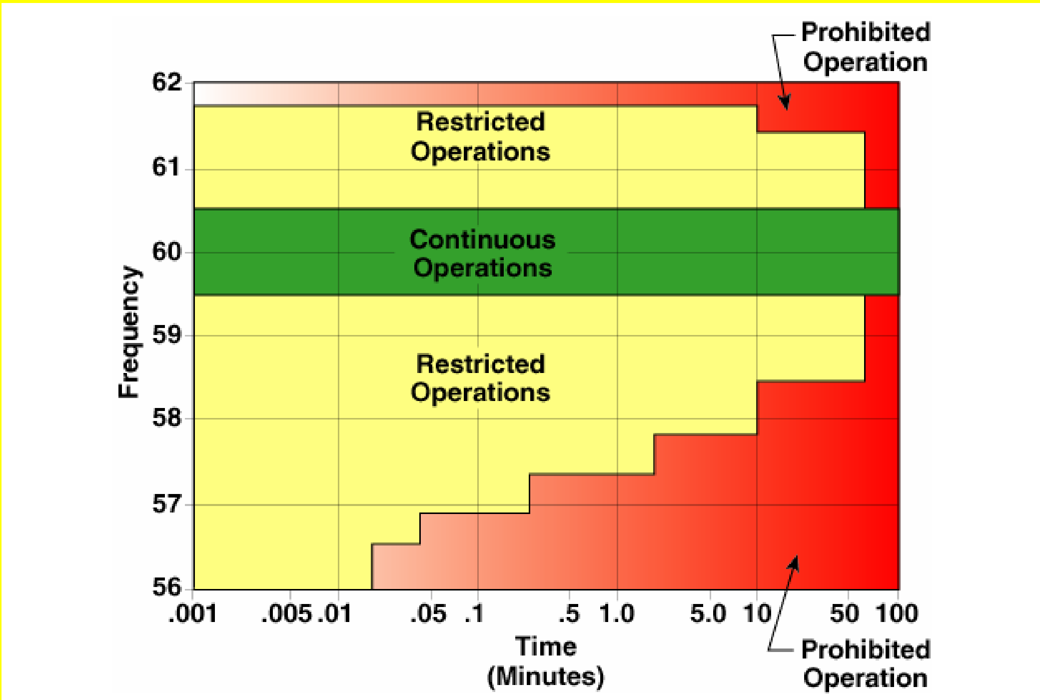


Figure 11-12
Steam Turbine Frequency Operating Limits

- Evaluate possible damage to hydro-electric generators
- Study and possibility of damage to combustion turbines (CTs) and other types of generating units from abnormal frequency exposure
- Evaluate the possibility of over-excitation damage to transformers and generator stators (any wound equipment) from exposure to low frequency, high voltage combinations
- Evaluate the possible damage to customer equipment and the impact on various types of control systems used by customers
- Consider the possible problems that could result from the undesirable automatic pick-up of load via automatic load restoration schemes
- Consider the possible problems that could result from the undesirable shedding of load via automatic under-frequency load shedding (UFLS) schemes

Recall from Chapter 5 that a transformer can be over-excited from high voltage and/or low frequency.

When establishing restoration conditions frequency limit guidelines, establish both short term exposure limits (the undershoot area) and longer term (the stabilization area) limits.

Load Restoration Limitations

In restoration conditions, a system operator has an understandable desire to rapidly restore load. However, caution must be exercised to ensure that overly aggressive load restoration does not place the system in avoidable jeopardy. The capability of individual generators to respond to a load pick-up should be considered and factored into the restoration plan.

For example, a low head hydro unit may be capable of picking-up relatively large blocks of load with an acceptable frequency dip. A similarly sized steam unit may not be able to respond as effectively and may sustain turbine blade damage and/or ultimately trip. A key issue with any generator is that the governor of the unit may request a MW response, but if the prime mover of the generator is not capable of the response, the unit could be placed in jeopardy.

If only one unit is on-line, a system cannot be operated to survive a single contingency. Therefore, place a second unit in-service as soon as possible.

When more than one generator is on-line, the impact on all generators must be considered. At all times sufficient operating reserve should be maintained such that the system can sustain the loss of the largest load carrying unit.

NERC Guidelines for Load Restoration and Frequency Control

The following statements summarize NERC's recommendations with respect to frequency control and load restoration:

Consult NERC's most recent documentation for further guidance on power system restoration.

- Frequency should normally be held within a range of 59.75 to 61 HZ with an attempt to regulate toward 60 HZ. A system operator may want to hold the frequency high (61 HZ) if a large load block is about to be restored. The frequency should be kept at least above 59.75 HZ to avoid load additions activating under-frequency tripping relays.
- Avoid energizing load blocks that are greater than 5% of the total restored area's synchronized generation. This conservative rule is designed to avoid activating under-frequency relays.
- If the restored system's frequency has stabilized below 60 HZ, and the goal is to raise the frequency back to 60 HZ, shed 6-10% of the connected system load to raise the frequency 1 HZ.
- Operating reserve (especially the frequency responsive spinning component) should be provided to cover the loss of the largest load carrying generating unit currently in-service.

- If the frequency regulation burden is too great for any one generator, the frequency regulation should be shared by two or more generators. Preferably the two generators are located at the same generating station to ensure a coordinated response.
- In general, the amount of regulating reserve carried in restoration conditions should be approximately double that carried during normal operating conditions.
- Generating units not controlling frequency should be loaded such that the regulating units remain roughly in the middle of there operating range. This optimizes the regulating reserve capability.
- When two or more systems are synchronized together to form a larger system, only one system should control the frequency. If two systems attempt to simultaneously regulate the frequency, an undesired competition could result. In general, one system (the one with the best responding generation) should control frequency while the other systems assist when asked for help.

Regional Reliability Councils and/or Reliability Authorities may also provide guidance for frequency control during restoration conditions.

11.3.3 Usage of Governors to Control Frequency

The theory and operation of a governor control system was described and illustrated in Chapter 4.

Following a large enough frequency disturbance, a generator's governor attempts to adjust its MW output in accordance with the droop setting. Figure 11-13 illustrates the response of a 300 MW generator with a 5% governor droop. When governors have a % droop setting (greater than 0% droop), no attempt is made by the governor/generator to recover the frequency. Rather the generator arrests the frequency drop. Note that the frequency is arrested at 59.9 HZ in Figure 11-13.

A once-through type boiler is a boiler design in which there is no re-heat cycle. Once through type boilers have very little steam storage.

The MW response from a unit due to governor action is not simply a function of governor droop settings. The generator itself must have the stored energy available to accomplish the governor's directions. In the case of CT and hydro units, the MW response can often be delivered within 10 seconds and sustained indefinitely. In contrast, the MW response of a steam unit may be delivered within 10 seconds, but may not be sustained very long beyond the initial 10 second response. Depending on the design of the steam unit, very little steam storage may be maintained so the unit cannot sustain its initial response.

Sustaining the MW response from a steam unit is dependent on the unit's prime mover design and performance. In the case of once through type boilers, governor response may be minimal as there is little steam storage in the unit. Attempts to energize large blocks of load from steam generator sources should be preceded with a thorough analysis of the impact on frequency and the generator's operation. Attempts to rapidly load a steam unit can create dramatic excursions on the steam side of the operation and result in the unit tripping.

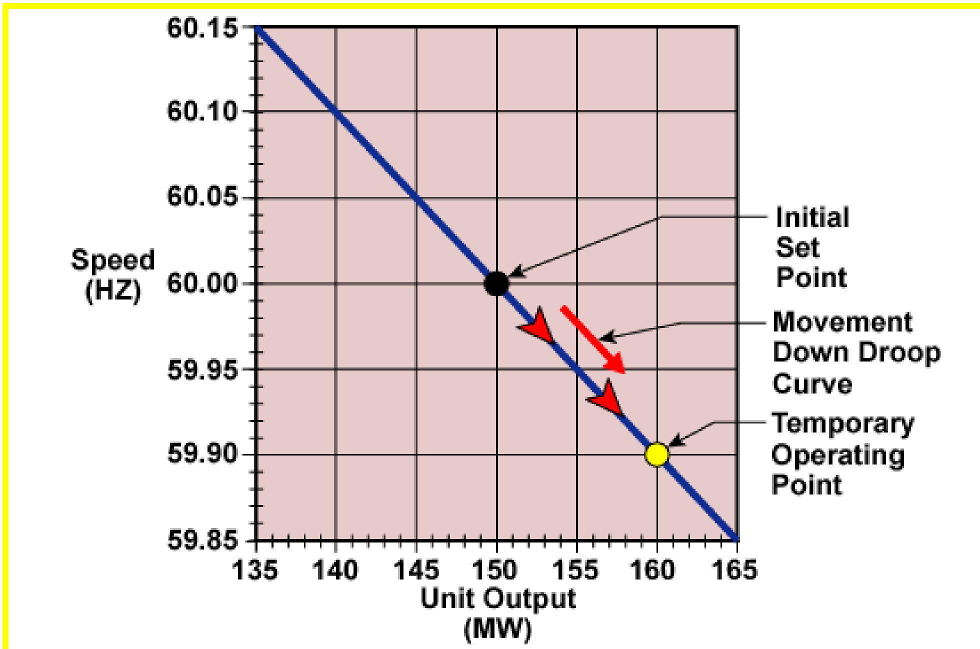


Figure 11-13
300 MW Unit with 5% Droop Responding to Frequency Drop

Droop Control

When generators compete for a MW change and their MW outputs oscillate it is referred to as a "hunting" condition.

When generators are operated in parallel in a power system, each unit should have a droop setting so the unit shares MW response with other generators in the system. If each generator were attempting to control to a precise frequency value (using low values of droop), the generators tend to compete with the MW response actions of other generators. A generator attempting precise frequency control may tend to overload, motor, or cause other generators within the restored system to do the same. Overly sensitive frequency control settings can create instability and MW oscillations resulting in generator tripping and system shutdown.

The effectiveness of restoration frequency control using normal conditions droop settings is frequently questioned. Although an argument can be made that droop settings should be set lower (well below 5%) during restoration conditions to provide better frequency control, this action may not be easily accomplished. The changing of generator droop settings is typically a function performed by plant maintenance personnel and may even require a unit outage to accomplish.

Consideration should be given to the impact on system stability from any changes to droop settings. Governor instability using low droop values is an especially serious issue during light loading conditions. Furthermore, if droop settings are lowered, the eventual transition to normal operating conditions may present a difficult problem.

During restoration conditions, frequency must be closely and continuously monitored. Governor response should be followed up with manual adjustments to generator loading to ensure acceptable frequency. The system operator in charge of the restoration process should:

- Designate the largest, fastest responding unit as the regulating unit within each island. If more than one generator is required to share the frequency control burden, it is desirable that all the units are at the same plant location, under the control of a single plant operator.
- Utilize operating guidelines, or preferably an automatic calculation tool, to estimate the frequency dip when picking up new loads or for assessing the impact of a generator trip.
- Maintain and distribute operating reserves such that the post-contingency loading of generators and the frequency level remains within acceptable limits.

Isochronous Control

Isochronous governor control refers to a governor droop setting of 0%. This mode of governor operation results in the generator's governor attempting to control frequency solely in accordance with the governor's frequency target value. When operating in isochronous, the governor attempts to fully recover the frequency to its target (assume 60 HZ) value. Figure 11-14 illustrates a 300 MW unit using 0% droop. In theory, the unit operating point slides left and right along the operating curve in an effort to control frequency to 60 HZ.

The concept of operating a generator governor in isochronous control initially is very appealing. However, there are several issues that should be considered:

- Isochronous control is well suited to a single generator serving an isolated block of load. Under these circumstances, the generator frequency automatically adjusts as the customer load varies. Isochronous operation may be an advantage when an isolated block of load is to be served for a lengthy period, for example, for several days. Generator operators may install a selector switch in their unit's control panel so the unit can easily be switched between isochronous and normal droop modes.

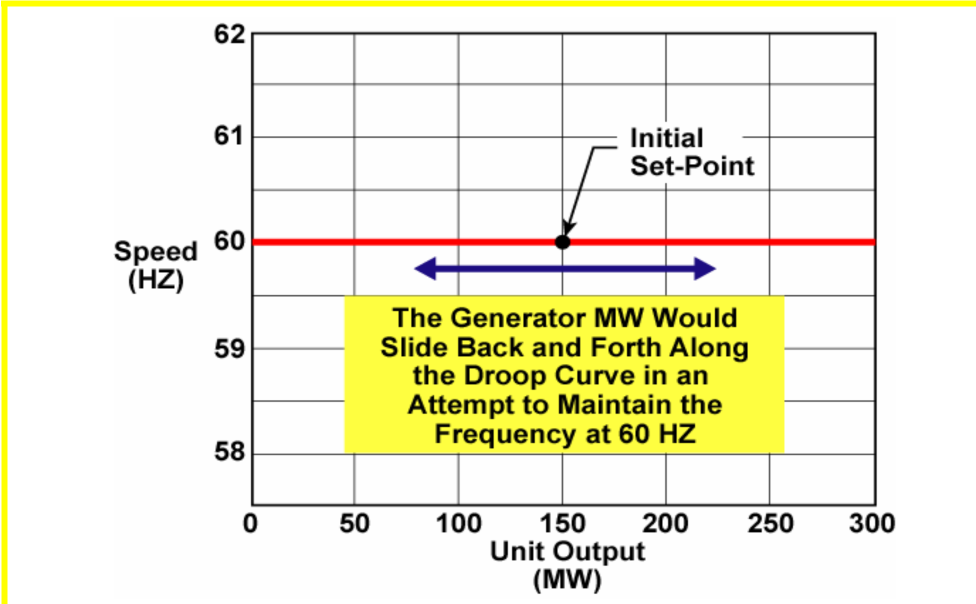


Figure 11-14
Isochronous Governor Response to Frequency Drop

- In a typical restoration scenario, additional generators are paralleled to the system as rapidly as possible. Once additional units are paralleled, there can be only one unit on isochronous control within the restored system or an undesired MW response competition can occur. As a restored power system grows in size, the usefulness of isochronous control diminishes as no single unit can regulate a large power system.
- Switching between isochronous and normal droop modes can not always be accomplished while a generator is on-line carrying load. The generator may have to be taken off-line to adjust the droop. If a generator has been started in isochronous mode, it may not be possible to transfer to a normal droop mode without an outage.

Auto-Load Control

Generators, especially CTs, are sometimes equipped with an "auto-load" control feature. Under normal operating conditions, the auto-load feature is used to load a generator to a target load level (for example, to a minimum value or to a base value). In normal operating conditions within a large interconnected power system, the MW levels of other on-line generators are adjusted to accommodate the MW changes of the auto-load unit.

During restoration conditions, extreme care must be exercised in the use of the auto-load feature. The auto-load control logic will attempt to load the generator to the desired load level. If the generator is isolated from the power system, the auto-loading action could result in the frequency being driven either high or low as an attempt is made to reach the target MW. If the unit is operating in parallel with other generators, the auto-load feature will shift the MW load on other on-line generators, potentially creating undesirable loading conditions in these units.

11.3.4 AGC and System Restoration

AGC (automatic generation control) can be a very effective tool during restoration, although AGC usage in restoration conditions is substantially different than normal conditions usage. AGC software is normally designed to control a defined portion (within the control area boundaries) of the interconnected system. To accomplish the AGC control function, control parameters are continuously monitored. The control parameters consist of an actual frequency reading and all tie-line MW flows to neighboring control areas. These control parameters are selected and normally fixed for the portion of the system being controlled. A key assumption to the typical AGC control strategy is that the power system is operating in an interconnected mode.

However, under restoration conditions the restored power system may:

- Not be fully interconnected
  - There may be a single or multiple islands
  - There may be a surviving portion or portions of the system interconnected to adjacent systems while simultaneously one or more islands exist
- Not have appropriate frequency indication
  - Although most AGC systems have multiple frequency sources available, there is no guarantee that any frequency source can be accessed for the surviving portions of the system or the various islands that may form
  - The frequency source currently utilized by the AGC software may not be located within the surviving portions of the system or islands that exist

For a frequency based AGC system to function correctly the frequency source must be located within the same boundaries as the generation under control. AGC systems normally select one of several possible predefined frequency sources. The system operator must ensure that an appropriate frequency source is utilized, and remains utilized during the restoration process.

For a tie-line flow based AGC system to function correctly, the tie-line meters must accurately monitor the MW flow in and out of the controlled area's boundaries. However, if a tie-line is not in-service, no AGC control problem exists as the tie-line's MW flow is equal to zero and there is no impact on AGC calculations.

Usage of AGC Control Modes

Figure 11-15 illustrates the tie-line frequency bias control mode of AGC. The constant frequency control and constant net interchange control modes of AGC are reduced versions of the tie-line frequency bias control mode.

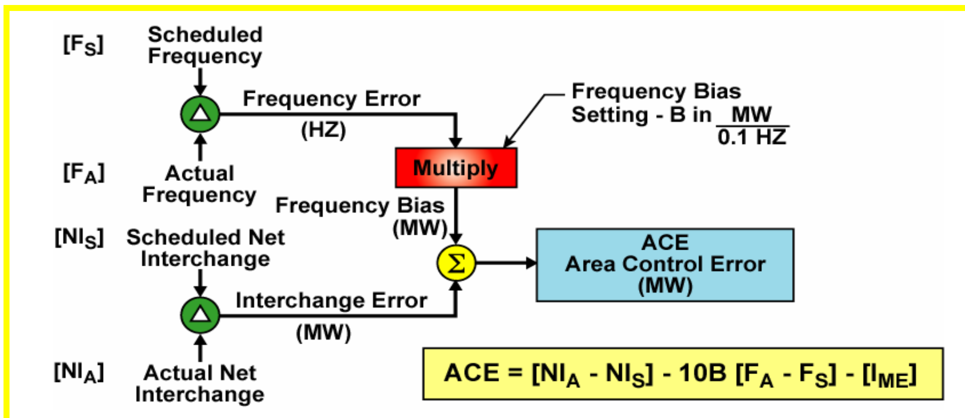


Figure 11-15
Tie-Line Frequency Bias Control ACE Calculation

Constant Frequency Control (CFC)

Constant frequency control (CFC) AGC calculates an ACE (area control error) value based solely on the frequency error in the controlled area. The target frequency for control purposes is entered as the scheduled frequency (F_S). The AGC software dispatches generation in proportion to the frequency bias (B) and the frequency error to correct any deviation from the scheduled frequency.

The normal conditions frequency bias value (expressed in MW/0.1 HZ) is likely not appropriate for usage during restoration conditions. A bias value based on normal system operations is dependent on the load/frequency response characteristic and the governor response of neighboring control areas. During restoration conditions, customer load levels are much lower and neighboring control areas may not be energized. Unless the frequency bias value is adjusted to an appropriate value, frequency control could be incorrect and unacceptable frequency swings could occur. Some control areas utilize software programs to automatically adjust the frequency bias parameter if restoration conditions are detected.

Constant Net Interchange (CNI) Control

Constant net interchange (CNI) control may be utilized if a restored system is connected to another restored system or to the main body of the Interconnection. Both systems must agree upon which system controls the frequency (operates in CFC) and which system controls the tie-line flows (operates in CNI). This method of AGC may be a reasonable alternative if neither system is capable of or does not want to operate in tie-line frequency bias control mode.

Tie Line Frequency Bias (TLB) Control

Tie-line frequency bias (TLB) is the AGC control mode typically used in normal operating conditions. TLB controls the actual net tie-line flow (NI_A) to the scheduled net tie-flow (NI_S), biased by a MW value equal to the measured frequency deviation times the frequency bias value. For proper control action, the frequency bias value (B) utilized by each system must be appropriate for the current system condition.

11.3.5 Connecting Islands

Islands may be unintentionally created when a disturbance results in system separations. Once an island develops, initial system operator actions should concentrate on stabilizing the island’s frequency and voltage and ensuring equipment is within acceptable loading limits.

Islands may also be created intentionally in the course of the restoration process. Depending on the restoration philosophy used, multiple islands may be simultaneously created. Caution should be exercised when intentionally creating multiple islands as simultaneous frequency control is a more difficult process. The creation of multiple islands may also spread available generation resources so thin that a system operator has a difficult time energizing large blocks of load. The process of synchronizing multiple islands also requires time, coordination, and careful execution.

In a sequential restoration philosophy, the system is restored as one island that keeps growing in size. In a parallel restoration philosophy, multiple islands are created and then eventually synchronized.

Islands should only be synchronized when each system is stable and operating within acceptable limits. The combined system should be capable of sustaining the loss of the on-line generator carrying the greatest load. All elements of the transmission system of the combined system should be capable of handling the power flow swing which would follow the trip of any on-line generator.

11.3.6 Cold Load Pick-Up Concerns

The term cold load pick-up refers to an increase in the load magnitude when a feeder is re-energized following an outage period. For example, a feeder may have carried 5 MVA prior to an outage and when the feeder is restored ½ hour later the MVA loading may rise to 50 or more for a short period of time. The primary causes of cold-load pick-up include loss of load diversity and in-rush currents.

Loss of Load Diversity

The load that will be served (once energized) from a recently tripped distribution feeder tends to gradually increase as the duration of the feeder outage increases. Once the feeder is re-energized, this effect (called loss of load diversity) can substantially increase the connected load.

In normal conditions, portions of a feeder's load mixture switches on and off in a random fashion. For example, air conditioning units normally cycle on and off several times in the course of a typical hour. At any given time a portion of the available air conditioning units are energized and a portion de-energized.

The actual air conditioning load at any given time consists of the sum of the load from all the air conditioners on-line at that moment. This load quantity is normally less than the potential air conditioning load which is the sum of the load if all air conditioners are energized at the same time. The difference between the actual load and the potential load is referred to as the load diversity.

Given the trip of a feeder, the natural load diversity tends to diminish as more loads are connected to the de-energized feeder. The primary cause of the loss of load diversity phenomenon is thermostatically controlled loads. For example, air conditioner thermostats initiate the start of their compressor units as room temperatures rise. Thermostatically controlled heating systems and hot water heaters work in the same manner.

Motor In-Rush Current

Locked-rotor condition is the condition when the motor is first started with the motor rotor at standstill. Locked-rotor current is the maximum possible magnitude.

Motor starting is a key issue during system restoration. When a motor is initially started a large current magnitude approaching locked-rotor conditions may flow. This current is called the motor in-rush current. The in-rush current can exceed 10 times full load current depending on the motor design and conditions at the time of closing. The in-rush current decays to normal load current levels as the motor reaches normal operating speed. The time to reach normal operating speed also depends on the type of motor and the load connected to the motor shaft. In general, the in-rush current only last a few cycles to a few seconds.

The startup of large motors at power plants should be given special consideration in the development of the restoration plan. Large motors should not be started unless adequate MVA capacity is available to limit the frequency and voltage deviations to tolerable levels.

When large power plant motors are started during a restoration condition, the ability to maintain adequate voltage levels is a concern. Excessive voltage drop during large motor starting events can create multiple problems. If the voltage dip is too large, the newly energized motor may be unable to build to a normal operating speed. The aborted startup attempt can damage the motor and/or activate protective devices.

The startup of a large power plant motor may create a generalized low voltage condition effecting power plant auxiliaries and local customer equipment. Other motors connected to the system may trip. The trip of a critical power plant auxiliary may lead to the trip of generating equipment and a subsequent system shutdown. The power plant restoration plan must ensure that adequate voltage support is available to start large motors.

Magnitude of the Cold-Load Pickup Effect

The cold-load pick-up is a combination of the loss of load diversity effect and motor in-rush currents. The loss of load diversity is a longer term effect, lasting possibly 30 minutes, while the in-rush current effect lasts only a few seconds. The amount of cold load pick-up depends upon the nature of the connected load. The NERC Operating Manual states:

> *"Cold load pick-up can involve in-rush currents of ten or more times the normal load current depending on the nature of the load being picked-up. This will generally decay to about two times normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes."*

The increase in load magnitude results in larger blocks of load (both MW and Mvar) picked up as distribution feeders are re-energized.

The phenomena of cold load pick-up can:

- Overload equipment
- Cause over-current relays to operate resulting in the tripping of feeder CBs
- Create more severe frequency dips than expected when energizing blocks of load

Figure 11-16 illustrates the concept of cold-load pick-up. Figure 11-16 (a) notes that the initial feeder load is 5 MW and 1 Mvar. The feeder then trips and is restored a few hours later as illustrated in Figure 11-16 (b). Immediately the feeder load jumps to 53 MVA. Note that most of this new load is Mvar for the in-rush to the motor type load that must be attached to the feeder. The overcurrent relays illustrated in Figure 11-16 could trip because of this sudden increase in feeder current.

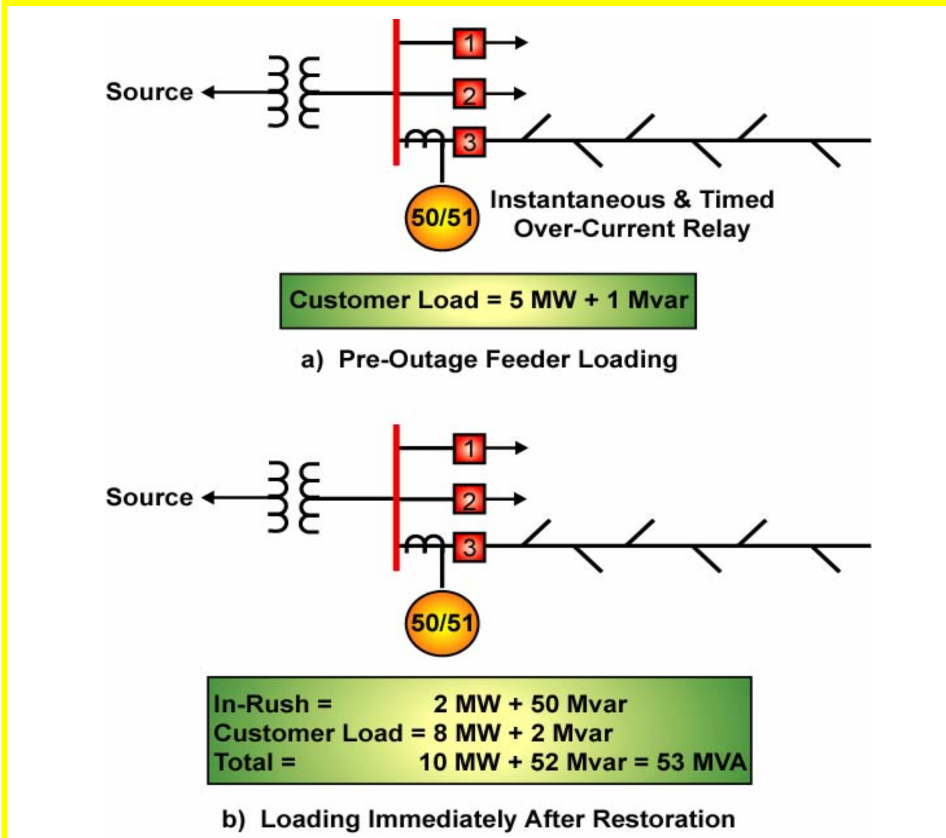


Figure 11-16
Illustration of Cold-Load Pick-Up

Sectionalizing of Load

In situations where cold load pick-up results in equipment overload, the operation of over-current relays, or unacceptable frequency deviations, the connected load must be reduced prior to energizing the feeder. The process of reducing distribution feeder load is referred to as sectionalizing. Sectionalizing consists of opening selected switches associated with the feeder in order to reduce the amount of connected load. This process can be time consuming and frequently requires manual switching at a number of field locations.

Once a feeder has been energized, the sectionalized load can be gradual returned to service. The switching associated with this gradual load pick-up can be a time consuming process.

Frequency Based Automatic Load Restoration

Power systems may install protective relay schemes that automatically restore customer loads that were previously tripped via a UFLS scheme. Normally, these restoration schemes are deactivated during a restoration process to prevent an uncontrolled pick-up of load. In some cases however, these schemes cannot be deactivated so the system operator must be aware of the frequency levels at which the scheme operates and restores load.

11.3.7 Maintaining Operating Reserves during Restoration Conditions

When a generator trips during normal operating conditions, frequency control is typically sufficient because the remaining interconnection provides the needed support. Even if one entity fails to provide their share of reserves, it is likely the response of the remaining interconnection is enough to keep the frequency deviation reasonable. The deficient system is said to be "leaning-on-the-ties" when they are dependent on their neighbors for MW support. Leaning is acceptable for short periods, but the deficient system must recover as soon as possible so the interconnection is prepared for the next event.

The composition of operating reserves includes responsive and non-responsive elements. The responsive elements are critical during restoration conditions as the large inertial response of a normal conditions power system is not available.

During restoration conditions, following a generator trip or an excessive load pick-up, a failure to provide adequate operating reserves (especially the frequency responsive portion) can have a devastating effect on frequency. Inadequate levels of responsive reserves under restoration conditions may lead to a system shutdown.

Chapter 4 of this text described the need for and the types of operating reserves. This section explains specific issues associated with the maintenance of adequate responsive reserves during restoration conditions.

The actual MW response of reserves during a frequency disturbance is limited by the response capabilities of on-line generators. This response may be far less than governor control theory would suggest. Regardless of what MW response a governor requests, the desired response is not achieved unless the generator's prime mover is capable of the response. The prime mover response dictates the rate of generator loading following the initial inertial (stored energy) response phase.

Maintaining Reserves with Only One Unit In-Service

When a single unit is operational, adequate levels of responsive reserve must be available on that generator to support any possible cold load pick-up and gradual increases in system load. With only one unit on-line, the loss of that generator results in a blackout of the system. An obvious goal is to get a second generator on-line as soon as possible. Once a second unit is operational, better reserve positions can be established as described in the next paragraph.

Maintaining Reserves to Survive Single Most Severe Contingency

Sufficient responsive reserve should be provided such that the governor action of the surviving on-line generation is able to replace the MW that was carried by the single most severe (SMS) generation contingency. The SMS contingency is the contingency that leads to the greatest loss of MW generation. In the case of an isolated system, the SMS is normally the loss of the on-line generator with the highest MW loading. If the restored system is partially interconnected, the loss of a tie-line to a neighboring system that is supplying MW may be the SMS contingency because the loss of the tie-line separates the deficient system from the MW support.

In some cases, the provision of sufficient responsive reserve to recover from the SMS contingency may not ensure adequate frequency control. For example, a moderately loaded, fast responding generator may provide a large amount of responsive reserve to a system, and essentially cover for the loss of more heavily loaded but much slower responding units. If the fast responding generator should trip, the responsive reserve available form the other, slower, on-line generation may not be adequate to arrest the frequency decline.

The most severe contingency may not be the loss of the largest generation source, but rather the loss of the most responsive generation source.

At a minimum, a power system in the process of restoration should have sufficient responsive reserve to recover from the trip of any single generator or tie-line.

Maintaining Regulating Reserves

Regulating reserve is defined during normal conditions as the spinning reserve held in AGC responsive generators. However, in restoration conditions AGC may or may not be operational. Therefore, the definition of regulating reserve is expanded to include all spinning reserve that is used to maintain frequency and tie-line flows within the restored system. Regulating reserve levels must be sufficient for the system operator to keep frequency and tie-line flows within acceptable limits.

Reserve Distribution

Reserves should be distributed throughout the power system to provide optimal loading of the reserves in response to potential generator and tie-line trips. When determining an appropriate distribution of reserves, the following points should be considered:

- Reserves should be distributed such that their usage following generator and tie-line contingencies does not result in the post-contingency overload of any transmission facilities.
- Reserves should be distributed such that the frequency dip that follows a generation loss is effectively managed. Optimal frequency dip management is achieved when reserves are distributed in proportion to each generator's rapid responsive capability. In other words, ensure enough rapidly responding (within seconds) reserves are distributed appropriately throughout the restored system.
- Reserves should be distributed such that the steady-state frequency which follows the initial frequency dip is effectively managed. Optimal steady-state frequency control is achieved when reserves are distributed in proportion to each unit's response capability, assuming all units have the same governor drop setting. If the governor droop settings are not the same, optimal steady-state frequency performance is achieved when reserves are distributed in proportion to the generator's MW capacity divided by the generator's droop setting.

11.3.8 Load Curtailment

During a restoration event it is likely that at a point in the restoration process, the available MW capacity will not be adequate to serve the existing load. If an on-line generator trips or the load pick-up is greater than anticipated and reserves drop below acceptable limits, it will be necessary to reduce load.

One of the most important objectives during any restoration event is to avoid a second system shutdown. Energized load may have to be shed to protect frequency and/or mitigate an operating security limit violation. Procedures must be established ahead of time so that load is shed in an organized, rapid, and efficient manner.

When a need for load shedding arises, a system operator may not have the time to select the least important loads for shedding. The system operator's speed of response may be more important than exactly which load is shed. Once the proper amount of load has been shed in a prompt and effective manner, load priority issues can be addressed.

Rotating Load Shedding

If it is anticipated that the need for load shedding will continue for an extended period, an option is to shed load on a rotating basis. By shedding load on a rotating basis, two objectives are satisfied. First fairness is addressed in that the load shedding is spread across as much of the customer base as possible. Second, the impact of the load curtailment on any individual customer is reduced. For example if a refrigeration customer experiences a power outage for 20 minutes every two hours, the potential damage from a loss of refrigeration is reduced.

The design of a rotational load shedding program varies from utility to utility. The length of service interruption is commonly governed by the utility’s ability to interrupt and restore the load. Some utilities have SCADA systems and software which make rotational load shedding very easy to implement. Other utilities may have to use manual switching techniques to interrupt the customers. The more cumbersome the switching process, the more difficult it is to facilitate a faster rotation of the load shedding.

A second consideration when designing a load shedding program is the ability to pick-up the load following the initial interruption. Once a feeder is interrupted, the cold-load pick-up phenomenon starts to occur. The speed at which load diversity is lost is dependent on both the composition of the load and the current weather conditions. For example, if there are a high proportion of electrically heated homes served by a distribution feeder, and the weather is cold and windy, load diversity may be lost quickly. The same distribution feeder on a mild spring day would lose load diversity slowly. The duration of an intentional load interruption should not be so long that the feeder can not be re-closed due to cold-load pick-up issues.

A typical rotational load-shedding scheme might call for blocks of load to be interrupted for a 20 minute period. The frequency of interruption and the duration of the interruptions vary depending on the amount of relief needed and the type of load interrupted. Procedures, which include tabular descriptions of the load to be shed, are normally developed for the system operators’ usage. These tables state the load to be shed, how the loads are shed, and the time periods that the shedding should last.

Frequency Based Automatic Load Shedding and Restoration

Under frequency load shedding (UFLS) theory and usage were described Chapter 4. UFLS schemes are designed to shed load in a controlled effort to avoid a frequency driven system collapse.

During the restoration process, especially during the early stages, UFLS schemes may not operate in the desired manner. For example, the frequency dips which occur when picking-up load in restoration conditions are much greater than those experienced in normal conditions, but the dips may be well within restoration limits. However, if loads that are controlled by the UFLS scheme relays are energized, they may be susceptible to tripping following frequency dips.

System operators should consider the possibility of undesired UFLS operations. For example, if possible do not utilize loads that are part of the UFLS scheme until the more advanced stages of the restoration process. In this manner the frequency sensitive loads are not energized until after the period of the most severe frequency dips has passed.

Automatic Load Restoration Schemes

Some systems utilize automatic load restoration schemes. Automatic load restoration schemes automatically restore load as the frequency recovers. For example, the schemes may close CBs, which were tripped by the UFLS scheme, once frequency recovers to 59.99 or above.

Automatic load restoration schemes, those based on frequency, are normally not appropriate during restoration conditions. The restoration of load during weak restoration conditions in general should be a system operator function. Automatic schemes may restore load at the wrong time or in the wrong amount. If a utility has installed an automatic load restoration scheme, its impact on system restoration should be examined. If appropriate, a means of deactivating the scheme should be provided for the system operators' usage. At a minimum, the automatic load restoration scheme should be described in the system restoration plan and any restoration related scheme options fully explained.

11.4 Equipment Issues Related to System Restoration

A variety of equipment related problems can occur during restoration conditions. Some of these problems exist at the onset of the restoration condition, while others develop over time. In some instances an initiating event, such as an earthquake, damages equipment. Equipment may also be damaged in the course of a system shutdown, for example as the result of a sudden overload.

Equipment issues may start to develop within minutes of the shutdown. For example, as little as a 15 minute power failure to a generator's turning-gear can result in a warped turbine/generator shaft and lead to a several day long forced outage of the unit. Other equipment issues develop over lengthier periods, such as over a number of hours or days. For example, the battery system in a substation normally supplies emergency energy for several hours but will eventually run down as the energy storage in the battery bank is drained.

11.4.1 Substation Stored Energy

Substations are typically designed so that following the loss of substation station service AC power; all critical operating functions remain serviceable. Less critical functions, such as substation control room heating, may be lost when the AC power failure occurs.

Stored Energy in CB Mechanisms

CB tripping and closing coils typically consist of an electro-magnet (a solenoid) which, when energized, triggers a mechanical latch allowing the CB to either open or close by releasing some form of stored energy. The stored energy is often in a spring type device.

CBs use various forms of stored energy to provide mechanical tripping (opening) power. Compressed springs are often used for tripping power. For example, when a CB is opened a spring may be automatically compressed. Stored energy is now available in this spring for tripping power. The CB's tripping coil—the coil is the electrical device (an electro-magnet) that releases the stored energy in the tripping spring—normally receives power from the substation battery or from a charged capacitor device.

CBs typically use stored energy to close the CB given a loss of AC power. The power to activate the closing coil of a CB is normally provided from the substation batteries. The stored energy that is needed to actually close the CBs contacts is provided from various sources including: compressed air, springs, hydraulic mechanisms, and substation battery banks.

The disconnect switches used in a substation may be motor operated. The power to operate these motor operated disconnects (MODs) is normally provided from the substation battery banks.

Stored Energy in Battery Banks

Batteries have been relied upon for many years to provide power to critical system functions. In some applications, batteries drive power inverters. The power inverter inputs the battery's DC power, converts the DC to AC, and then provides AC power to critical AC driven equipment. Substation battery power may be used to power:

- Protective relaying
- CB control systems
- Power inverters
- Telecommunication equipment.

When first installed, battery banks are designed to provide service for a certain length of time. For example, a battery bank may be designed to provide service for 12 hours following a substation AC power outage. However, if the energy drawn from the battery bank is greater than the initial design parameters, the battery will not be able to provide service as long as initially envisioned. The amp-hour capability of batteries also decreases with the age of the battery bank.

Given the possibilities for battery bank service life reduction, the original design battery bank service hours may not be available in actual system operations. Every systems restoration plan should include a recent estimate of the service hours for each battery system that is critical to system operation, control, and communications. The batteries to check include those at key substations, generators, and telecommunication facilities.

Battery Maintenance

Battery banks are obviously a key piece of equipment as batteries are used to power many critical functions. The regular monitoring and maintenance of battery banks is necessary to ensure that batteries are available when needed. If a major shutdown occurs, and battery banks are discovered dead, the length and impact of the outage can be dramatically extended. For example, if a substation's battery banks are available, the SCADA system can be used to speed the pace of system restoration. However, if the battery banks are dead, personnel have to be sent to the substation to open and/or close CBs manually.

Importance of Restoring Substation Station Service

The AC power supplied for substation usage is called station service. This is the same term often used for the AC power usage of a generator.

If the AC power to a substation is lost, the power needs to be restored as soon as possible. The restoration of substation station service is important for several reasons including:

- To ensure that the charging system for the substation battery bank is operational
- To ensure the charging of the stored energy sources used to open and close CBs
- To ensure the operation of lighting systems to provide a safe working environment for personnel
- To ensure that substation temperature control systems (heating or cooling) are operational
- To ensure the operation of oil pumps used by underground cable systems
- To ensure the operation of all other critical substation equipment

Every power system restoration strategy should plan for the rapid energization of a source of station service as each substation is energized.

11.4.2 Pipe-Type Cable Systems

Pipe-type cable systems consist of a metal pipe within which are placed three oil-impregnated, paper-insulated conductors. The pipe is initially filled with oil and any remaining air is vented from the cable. Oil is pumped into the cable until the normal operating pressure of the cable (perhaps 250 PSI) is achieved. The oil-pressure is constantly monitored to ensure proper operation.

When initially pressurized, it may take several hours to eliminate all of the voids (air bubbles, vacuum pockets, etc.) in the conductor's paper insulation and vent any remaining air from the pipe. This period is commonly referred to as the pipe's soaking period. Figure 11-17 illustrates the basic construction of a pipe-type cable.

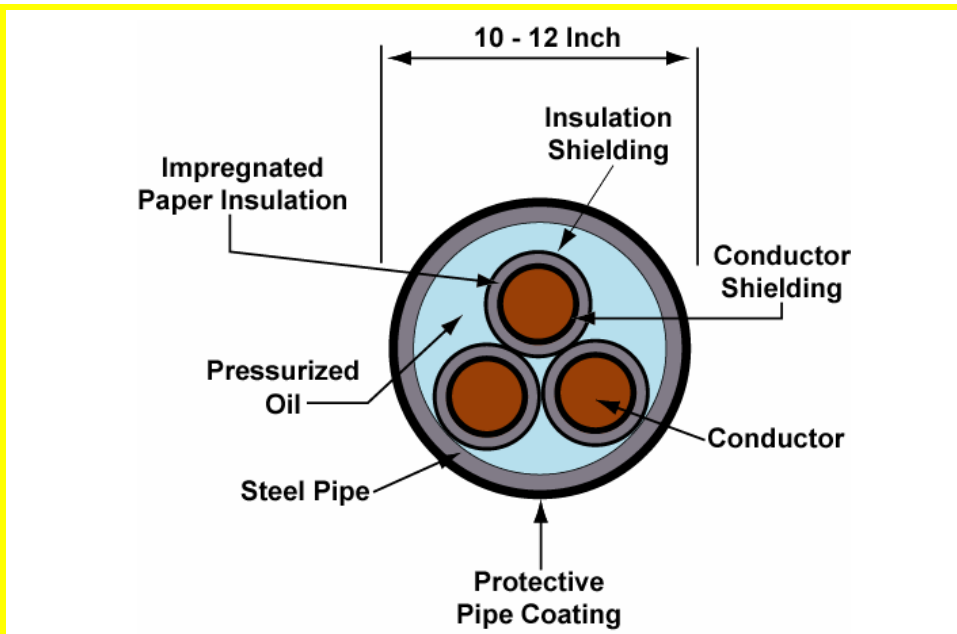


Figure 11-17
Pipe-Type Cable Design

The operating pressure of a pipe-type cable system is determined in the design stage. The cable system must be operated within an acceptable margin of its design pressure or faults can develop within the cable system.

An important part of a pipe-type cable system is the oil pumping facilities. The pumping system consists of pumps, regulating valves, and oil reservoirs. The pumping facility must maintain the oil pressure within the pipe between its high and low limits. SCADA alarms are often installed to provide warning if the oil pressure is outside of acceptable operating limits. The oil pumping facility is typically located at one (or both) of the terminals of the cable system.

Operation of Pipe-Type Cable Systems

As load is placed on the cable, the current flow heats the oil within the cable, raising the oil pressure. If the oil pressure reaches its high operating limit, automatic regulating valves allow some oil flow from the pipe into an oil storage reservoir. The oil movement from the cable to storage reduces the oil pressure within the pipe. If the current flow on the cable drops, the cable temperature drops and so does the oil pressure within the pipe. When the oil pressure reaches its low operating limit, an oil pump automatically starts and pumps oil from the storage reservoir into the pipe, raising the oil pressure within the pipe. This continuous process keeps oil pressure within the operating limits of the cable system.

If the pipe-type cable pressure drops below a minimum level, the cable must be de-energized. De-energizing is necessary because voids and bubbles can develop in the paper insulation that surrounds the cable conductors resulting in a cable fault. The cable must now be soaked until pressure is again within acceptable limits. Once oil pressure is acceptable, the cable can be re-energized.

Some pipe-type cable systems allow a reduced cable pressure mode of operation for maintenance and leakage control purposes. This reduced oil pressure mode of operation is normally not sufficient to permit the cable to be energized.

Special Procedures Following Loss of Oil Pressure

During restoration conditions, AC oil pumping power is often lost. Once a system shutdown occurs, pipe-type cables start cooling and oil pressure drops. The more heavily loaded a cable is prior to shutdown, the higher the cable's operating temperature and the greater the reduction in temperature as the cable cools toward ambient conditions. The greater the temperature drop, the greater the resulting pressure drop. In other words, a cable with little load current is already operating near ambient temperature and does not experience a large pressure drop. Conversely, a heavily loaded cable experiences a large drop in temperature and oil pressure when a shutdown occurs.

11.4.3 Lightning Arresters

Zinc-oxide lightning arresters may operate when switching surges initiate sufficient magnitude and duration TOV events. Under normal operating conditions, most TOV events are quickly damped by system load. However, during restoration conditions, TOVs are numerous and not well damped.

When a TOV event occurs, zinc-oxide arresters may allow some current flow through the arrester to ground. This current flow results in arrester heating.

The arrester can only withstand a certain heating level, beyond which the arrester is subject to thermal failure.

During a restoration condition there are several reasons why zinc-oxide arresters are subjected to greater than normal duty including:

- There is a greater potential for elevated system voltage. High voltage increases the potential for TOV events and also increases the severity of the TOV event.
- Restoration conditions always include multiple switching surges as equipment is energized. Each switching surge potentially creates a TOV.
- TOV events persist for longer periods as restoration conditions provide poor damping to the TOVs

Each power system's exposure to TOVs and the allowable duty (limits of high voltage exposure) of zinc-oxide arresters should be studied. Suitable guidelines should be incorporated into the restoration plan to avoid arrester failure during the restoration process.

11.4.4 Transformers

Transformer energization may cause several restoration conditions operating problems including:

- High in-rush currents that lead to large switching surges
- An increased potential for resonance
- An increased possibility of voltage control problems

Energizing Transformers

The process of energizing a large power transformer creates a substantial disturbance in a weak power system. Ideally, no transformer is energized until the restored power system is strong enough to absorb the energization shock. Unfortunately, in many instances of restoration, the energization of a transformer cannot wait and the transformer must be energized from a weak system. For example, once a black-start generator is on-line, the generator's step-up transformer (GSU) must be energized. Once the GSU is energized, several relatively large power transformers—large when compared to the size of the generator—are typically energized before any load can be restored.

Mechanical Shock from Unbalanced Currents

The in-rush current when a transformer is first energized can reach 10 times the transformer's full load current and persist for several seconds. Figure 11-

18 illustrates the wave shape of a single phase of the in-rush current when a transformer is energized.

The in-rush current in Figure 11-18 has a high harmonic content. Note the irregular shape of the sine wave. The sine wave shape is distorted which means there are odd (likely 3^{rd}) harmonics present. Also note that the waveform is not symmetrical about the horizontal (time) axis. This means that the waveform has even (likely 2^{nd}) harmonics present.

A three phase system's currents (A, B, C) should have 120° phase separation and have the same magnitude. If the phase angles or currents are not equal the phase currents are "imbalanced".

Figure 11-18 illustrates only a single phase of the in-rush current. The currents in the other two phases have different magnitudes and are therefore imbalanced. The unbalanced nature of the phase currents and the high levels of harmonic content can produce a significant amount of mechanical shock to local generators. The mechanical shock to area generation is often more significant when energizing a transformer then when picking up large blocks of load or when a fault occurs close to the transformer.

The in-rush current is initially very large, but after several cycles the magnitude will settle to normal levels.

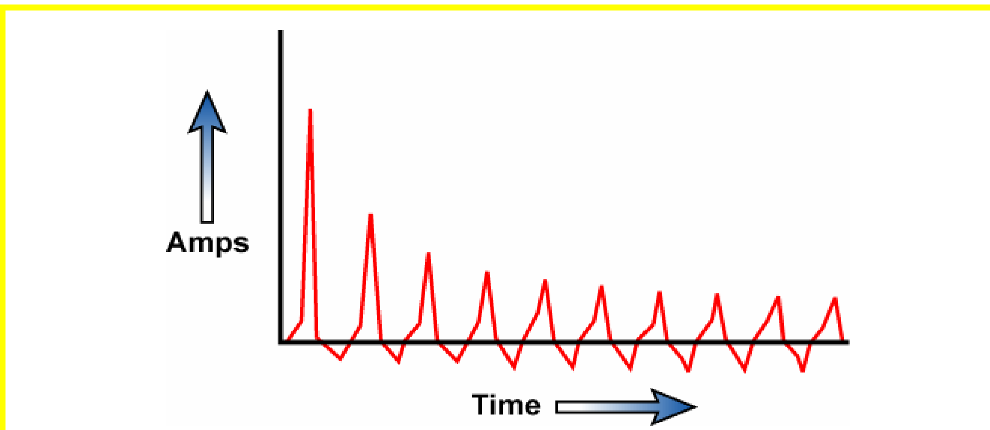


Figure 11-18
Transformer In-Rush Current

Transient Over-Voltages

Steady-state voltage is often high during the early stages of restoration. The major cause of the high voltage is the abundance of Mvar from energizing transmission lines. Ferranti raise and improper transformer tap settings may also contribute to the high voltage condition. Voltage levels at various locations in the system may be close to maximum acceptable levels.

When a transformer is energized, a switching surge is created. The magnitude of the switching surge is dependent upon the point in the voltage wave at which the switching device (CB, etc.) used for energization actually closes. Once created, a switching surge voltage wave reflects back and forth throughout the restored power system until it is damped by system load and resistive losses.

The magnitude of the resulting voltage is a combination of the switching surge magnitude and the steady-state system operating voltage. The switching surge voltage transient combines with—and rides upon—the 60 HZ steady-state power system voltage. The combined voltage contains a base steady-state value with switching surge frequency oscillations added above and below the steady-state value. The peak voltage of the combined waveform can rise high enough to be considered a TOV event. Reducing the initial steady-state operating voltage (for example, to 90% of nominal), reduces the magnitude of the combined waveform and reduces the impact of the TOV event.

Resonance Phenomena

Weak, lightly loaded power systems—typical in the early stages of system restoration—are more susceptible to resonant conditions than normal conditions power systems. The dampening effects of a tightly interconnected system and its connected load are highly effective in reducing the potential for a resonant condition. During the early stages of restoration, the initial elements energized often have high inductance (transformers) and capacitance (transmission lines). The combination of capacitive and inductive elements, with minimal levels of damping, sets the stage for a resonant condition.

The presence of capacitive and inductive elements does not in itself guarantee a resonant condition. The resonant condition must first be triggered and then sustained by the application of a voltage near the resonant frequency. During normal operating conditions, the 60 HZ power system voltage predominates. Therefore, if 60 HZ resonant conditions are avoided, the potential for a resonant condition developing during normal conditions is low.

When a transformer is energized, the result is a switching surge and increased harmonic content. High harmonic content increases the likelihood of a resonant condition as one or more of the harmonic frequencies can trigger the resonant condition. The resonant condition normally rapidly decays as it is damped by system load and power losses. However, if an additional source of energy exists to feed the resonant condition, the resonance can sustain itself indefinitely.

This condition is a form of ferroresonance as it involves an iron-core inductance.

The presence of high steady-state voltage, TOVs, or high resonant frequency voltages, can drive a transformer into saturation. A saturated transformer is a strong source of harmonics. The increased harmonic content can feed energy into and sustain the resonance condition resulting in damage (typically thermal) to the transformer. Local utility and customer equipment can also be damaged due to the high harmonic content and the high voltages that result.

Reasons to Avoid Energizing Transformers Back-To-Back

Two or more transformers that are connected in series (back-to-back) should not be energized simultaneously. When energized back-to-back, the first transformer ("T-1" in Figure 11-19) is energized with a 60 HZ voltage. Transformer T-1's energization creates a high harmonic content and potentially a TOV. The second transformer ("T-2" in Figure 11-19) in-line is then energized with a higher than normal voltage that is rich in harmonics. The back-to-back energizing of transformers increases the potential for and the magnitude of a TOV and creates additional harmonics. Therefore, the likelihood of a resonant condition developing is increased. A third transformer energized in the series further increases the probability of a damaging resonant condition.

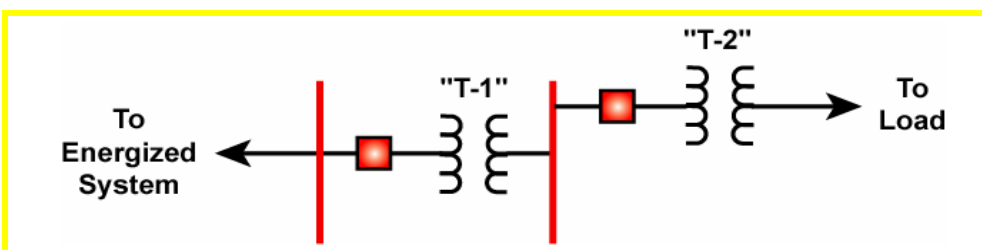


Figure 11-19
Energizing Back-to-Back Transformers

Over-Voltage and Under-Frequency

A transformer can be damaged if it is energized using a combination of high voltage and low frequency. The ratio of the voltage to the frequency is called the "% excitation" of the transformer and is measured in volts-per-hertz. The larger the volts-per-hertz ratio, the more likely transformer damage will occur. Over-excitation (greater than 100% excitation) of a transformer can result in excessive heating and damage to the transformer's core. The severity of the damage is a function of the level of excitation and the duration of the event. Serious damage can occur very rapidly (within a few seconds) if the volts-per-hertz ratio is large enough. Figure 11-20 contains a % excitation damage curve for a typical power transformer. For the transformer illustrated in Figure 11-20, a 15% over-excitation that lasts for more than seven minutes, will likely result in transformer damage.

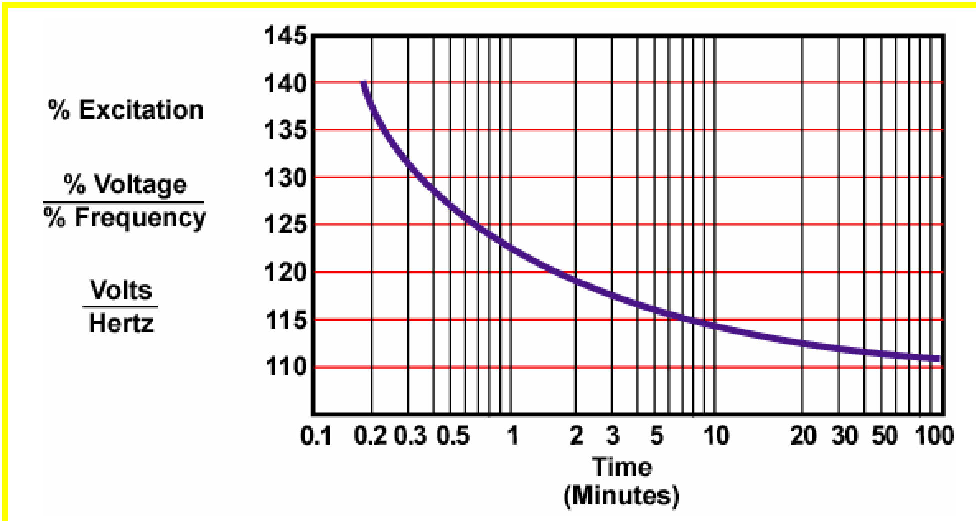


Figure 11-20
Transformer Over-Excitation

Additional Transformer Restoration Concerns

Inability to Adjust Tap Positions

The motors used to change tap positions in most under-load tap changing (ULTC) transformers and in phase shifting transformers (PSTs) are powered using AC station service. A loss of substation station service may disable existing SCADA control adjustment capability of ULTC and PST tap positions. The loss of remote ULTC and PST control can severely limit a system operator's restoration condition control options. These potential problems should be analyzed and their impact documented in the power system's restoration plan.

Effects of Low Voltage on Transformer Pumps

If a power system elects to use a reduced steady-state voltage restoration strategy, the impact of the reduced voltage on motor type load must be considered. The ability of a motor to operate at a reduced voltage is a function of the motor design. Some motors may be damaged if operated at 90% of normal voltage while others can be safely operated. A key area of concern is the allowable voltage range of the pumps used to circulate transformer oil.

11.4.5 Circuit Breakers and Restoration Conditions

CB Control Circuitry

The design of a CBs control circuitry can interfere with the CBs switching during restoration conditions. The DC power used for initiating CB tripping is typically drawn from the station battery bank. As long as the station's battery remains charged, CBs can typically be opened electrically either from the substation's control panel or via SCADA.

The designs used in CB closing circuits vary. Substation CB closing is typically initiated using DC power from the station battery. CB closing may only require a DC power source. However, the CB closing sequence may utilize more selective control circuitry. For example, the control circuitry may require both a DC power source and the satisfaction of certain permissives for the CB to close. For example, a CB may not close if the substation bus to which the CB is connected is de-energized. The permissive in this case is the required energization of the substation bus.

Figure 11-21 contains a simple CB control circuitry schematic that illustrates the usage of a substation bus energized permissive. The battery provides the DC power. The DC power is provided to the CBs close coil only if the two contacts between the close coil and the battery are closed. Contact "A" closes when the CB close button is pressed. Contact "B" closes if the bus to which the CB is connected to is energized. Once both contacts are closed, the close coil is energized and a command is sent to the CB to close. If the CB has enough mechanical energy to close it will rapidly close its contacts.

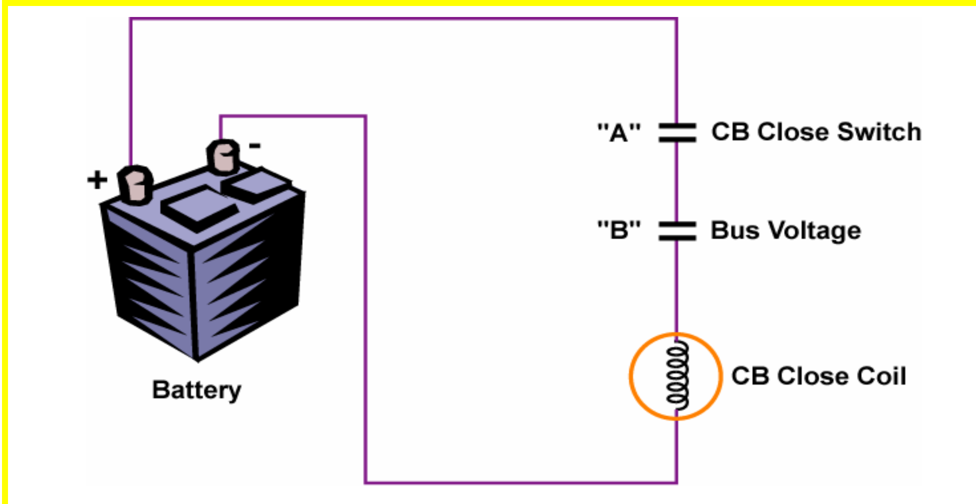


Figure 11-21
DC Control Schematic for a CB

The switching strategies planned for usage in system restoration conditions should be analyzed to determine if the CB control circuitry permits the intended switching actions. The system restoration plan should document all verified switching sequences.

Bleed-Down of CB Air Pressure

Many of the CBs utilized in the transmission system use compressed air as the energy source to close the CB. The CB may have a dedicated AC powered air compressor and an air storage tank. The air compressor automatically cycles on and off to maintain pressure within prescribed operating limits. When a CB is closed, it must close rapidly to prevent excessive arching as the CB's contacts are closed. Delays in the closing process can result in a violent CB failure. The pressure of the compressed air must be above a minimum level to ensure rapid closure. Protective systems are often employed to prevent closing the CB if air pressure is not sufficient.

The loss of CB air pressure is sometimes intentional to ensure the CBs air compressor periodically cycles.

When a system shutdown occurs, power to CB air compressors is often lost. The air pressure at the time of shutdown is somewhere between the high and low operating limits. As time passes, the air pressure could gradually reduce and eventually drop below the minimum for closing. If a power system uses air CBs, the restoration plan should state the typical times for CB air pressure bleed-down to minimum acceptable levels.

Cold Weather Effects

Effect of Oil Viscosity on CB Closing

A CB may use a combination of compressed air and hydraulic fluid for closing. This CB closing method typically uses compressed air to pressurize a reservoir of hydraulic fluid. When activated, the CB's closing coil opens a valve. The valve movement allows hydraulic fluid to rapidly pass to a hydraulic ram. The hydraulic ram movement closes the CB's contacts. The CB's contacts must close rapidly or the CB may be damaged.

The low viscosity (resistance to flow) of the hydraulic fluid allows the fluid to rapidly flow through the control valve and activate the hydraulic ram. To maintain its low viscosity, the hydraulic fluid must be kept above a certain temperature. Heaters are often used to maintain temperature if there is possibility the CB will be subjected to cold-weather operation.

The heaters used to maintain the hydraulic fluid's viscosity are normally AC powered. If a system shutdown occurs in cold weather conditions, the hydraulic fluid may rapidly cool. Eventually the fluid viscosity may increase enough to slow the closing process for the CB. A CB protective system may then activate to prevent the CB's closure and avoid damage. Each system restoration plan should address CB cold weather issues and provide appropriate solutions.

SF_6 CB Need for Heaters

The pressure of the SF_6 gas used in SF_6 based CBs must be maintained above a minimal level to ensure the CB has sufficient insulating capability. If the SF_6 pressure drops below a minimum acceptable level, CB tripping is typically blocked. Because SF_6 pressure naturally drops with declining temperature, SF_6 CBs are often equipped with heaters.

If a system shutdown occurs during cold weather conditions, SF_6 CB heaters may lose power and the gas pressure may drop below the minimum acceptable level. This possibility should be addressed in each power systems restoration plan.

11.4.6 Telecommunication Systems and SCADA

The rapid and accurate communication of information is critical in a restoration condition. Given the loss of AC power, a power system's telecommunication systems may be degraded or totally fail. Each system's restoration plan should analyze the impact of a system shutdown on their telecommunication systems and make the appropriate adjustments and/or improvements to ensure effective telecommunications in restoration conditions.

Battery Life and Telecommunications Systems

A telecommunication facility may fail when an AC shutdown occurs. Although high priority telecommunications facilities are designed to function independent of AC power, lower priority systems may not be as well designed. Following the loss of AC power, a telecommunication system may fail due to design oversights or equipment malfunction. For example, an AC powered intermediate telecommunication switching station may fail, disabling the entire system even though all other equipment used in the system is fully functional.

Batteries are often utilized to provide the necessary power to operate critical telecommunication systems. Uninterruptible power supplies (UPS) are normally installed to transition the supply of system power from the AC source to battery driven inverter power. The back-up battery power may be the only source of power until normal AC service is restored. Telecommunication systems battery discharge times under restoration conditions should be determined and noted in the restoration plan for all important telecommunications systems.

Adequacy and Usability of Telecommunication Systems

The usage of a particular telecommunication system during a restoration condition may far exceed normal traffic levels. A telecommunication system may also be used for unexpected purposes. If one type of telecommunication system fails, other systems may have to absorb additional traffic. For example, if a local telephone system is overloaded, the restoration plan may call for the use of a utility radio system as a backup voice system. The radio system could then have more users and more traffic than it was designed for. Restoration drills may be used to verify that the companies involved in the restoration effort have sufficient and varied telecommunications capability.

RTU Communications

EMS is a very broad term. The EMS includes both the SCADA and AGC systems.

Generating stations and substations are often equipped with a remote terminal unit (RTU). The RTU is an electronic device which acts as an interface between a company’s energy management system (EMS) and their various generators and substations. If a substation or generator RTU loses power, the utility loses both indication and remote control of the facility. The communications between RTUs and the control center’s EMS are vitally important during a restoration condition and the continued availability of RTU telecommunications should be addressed in the restoration plan.

11.4.7 Generators and Power System Restoration

Generation related restoration issues are examined in a general manner in this section. Each generating unit is unique and each must be studied to determine its restoration related strengths and weaknesses.

Generator Safe Shutdown Concerns

The safe shutdown of generating equipment that trips in the course of a system shutdown is a top restoration priority. Immediately following a system shutdown, efforts must be made to ensure personnel safety and avoid damage to generation equipment. The precise steps taken are unique to each generating facility. Critical generation vulnerabilities should be identified, appropriate responses developed, and all actions documented in the system restoration plan.

The security and reliability of nuclear facilities is the highest priority during a system restoration. A nuclear utility must make the restoration of an adequate supply of off-site power to its nuclear facilities the key objective of the restoration plan. Each nuclear generator has its own documentation pertaining to on-site and off-site station power requirements. Every nuclear utilities power system restoration plan should integrate with and support its nuclear plant requirements.

Generator Heath and Safety Issues

Critical health and safety needs must be identified for each generating facility. The design of generating facilities varies from small CTs to large coal fired steam stations to remote hydro plants. Health and safety issues vary widely from plant site to plant site. Frequently a generating site has unique health and safety issues, depending upon the physical location, type of equipment used, and potential natural disasters (for example, hurricane exposure). Typical generating unit health and safety issues that should be addressed in a restoration plan include the following:

- Emergency lighting requirements
- Air handling and ventilation requirements
- Increased fire safety requirements due to restoration conditions
    - The potential for fire related emergencies may increase during restoration conditions. The increased exposure may come from:
        - Heavily loaded DC equipment
        - Loss of normal facility cooling
        - Overheating during a shutdown

- Damage due to a natural disaster

Availability of Generator DC Oil Pumps

Once a generator trips, the rotating components continue to spin for many minutes. Lubricating oil pressure must be available to all generator and turbine bearings. A lack of sufficient oil pressure can cause bearings to overheat and fail. The failure of bearings due to a lack of oil pressure and the subsequent overheating is commonly referred to as "wiping the bearings". Depending on the bearing construction material, once the bearing overheats, it may start to deteriorate quickly. Bearing failures can result in a lack of clearance between stationary and rotating generator/turbine components and lengthy repair outages.

AC power driven lube-oil pumps are available during normal operating conditions. Emergency lube-oil pumps are normally installed and are driven via DC power from the station's battery banks. The emergency lube-oil pumps are designed to ensure adequate bearing oil pressure in shutdown conditions. The availability of emergency lube-oil pumps and the DC power to drive the pumps are critical in system restoration conditions.

Chapter 5 described over-excitation of a transformer. The concept is the same, although more restrictive, for a generator. A typical transformer can be exposed to a 10% over-excitation indefinitely with no damage. A typical generator can be exposed only to a 5% over-excitation without risk of damage.

Generator Over-Excitation Damage

During restoration conditions, a generating unit may be exposed to higher than normal voltage and/or lower than normal frequency. The ratio of the voltage to the frequency is called the excitation level of the generator. The metal in a generator's stator can be driven into a saturation condition from exposure to excessive excitation levels. This condition is called over-excitation.

Over-excitation of a generator leads to saturation of the stator steel and possible thermal damage to the generator. Over-excitation conditions must be quickly eliminated to avoid damage. On some generators, the voltage regulator may include an over-excitation protective device or the generator operator may install an over-excitation relay. These relays are often referred to as volts-per-hertz relays.

Thermal units are typically horizontally mounted while hydro units are typically vertically mounted.

Availability of Generator Turning-Gear

When a horizontally mounted turbine/generator is suddenly tripped, the shaft eventually stops rotating and can sag or bend. The degree to which the shaft bends is a function of the shaft design (weight distribution, etc.) and the shaft's operating temperature. The hotter the shaft, the more flexible the shaft's metal, and the greater the likelihood of shaft bending.

The shafts of steam units and CTs are often very sensitive to shaft sag. If a turbine/generator shaft is allowed to cool with a bend in the shaft, the shaft may retain the bend. Once operational and rotating the sag condition often creates excessive turbine/generator vibration. Turbine/generator sags and bends are normally removed by slowly rotating the shaft for an extended period (perhaps for several days).

To prevent the development of a bend in the turbine/generator shaft, a turning-gear motor is provided to slowly rotate the shaft. The turning gear is started anytime the prime mover is not rotating the turbine shaft. The turning-gear motor may rotate the shaft for a period following a shutdown until cooling is complete, or the turning-gear may continuously rotate the turbine shaft even if the unit is out-of-service.

The primary turning-gear motor is typically AC powered. An emergency back-up turning-gear motor may also be provided. The back-up turning-gear motor is typically powered via DC from the station battery bank. If both the AC and DC turning-gear motors are unavailable, the plant operators may still be able to rotate the shaft using some type of manual lever arrangement.

Following a generator shutdown, turning-gear power must be provided. For some generators, if turning-gear power is not supplied within 10-15 minutes, the shaft bends and the unit may not be available for service for several days while the bend is removed. In some generators, automated controls may block a unit's restart if the turning-gear is not started quickly enough following a shutdown.

Each power system's restoration plan should document the turning-gear requirements of each generating unit. The documentation should include the maximum time delay permitted before a tripped generator is placed on turning-gear. The restoration plan should also document the estimated time that a generator will be unavailable for service if the turning-gear motor is not in-service within the permitted time.

Water Pumps at Hydro-Electric Facilities

The dams associated with hydro-electric projects frequently use pumps to remove any water accumulation from within the dam's galleries (A gallery is an inspection tunnel within the dam's structure). Pumps may also be used to eliminate water accumulation around the dam's foundations.

Sump pumps are often used within the power houses (the hydro generators are in the power houses) to remove any water seepage. If the sump pumps fail, the power house may flood, resulting in forced generator outages. Power house flooding is a major concern during certain types of plant maintenance as power house water seepage is greater than normal.

AC power is typically used to drive the pump motors. If AC power is lost, problems may occur depending on the importance of the pumping functions for the particular hydro facility. If the loss of pumping function is an important issue, it should be addressed in the restoration plan.

Generator Abnormal Frequency Operations

A system disturbance may result in a generating unit operating at an abnormal frequency. For example, a disturbance may lead to the tripping of several transmission lines resulting in a generator operating in an island at a sustained low or high frequency.

Steam turbines are sensitive to abnormal frequency operation due to turbine blade vibration. The low-pressure turbine blades are the most susceptible to vibration. The blades could eventually fail (break apart) if operated—while under load—outside of a 59.5 to 60.5 HZ frequency range. Figure 11-22 illustrates the acceptable frequency operating range and the time limits before probable damage for a typical steam turbine.

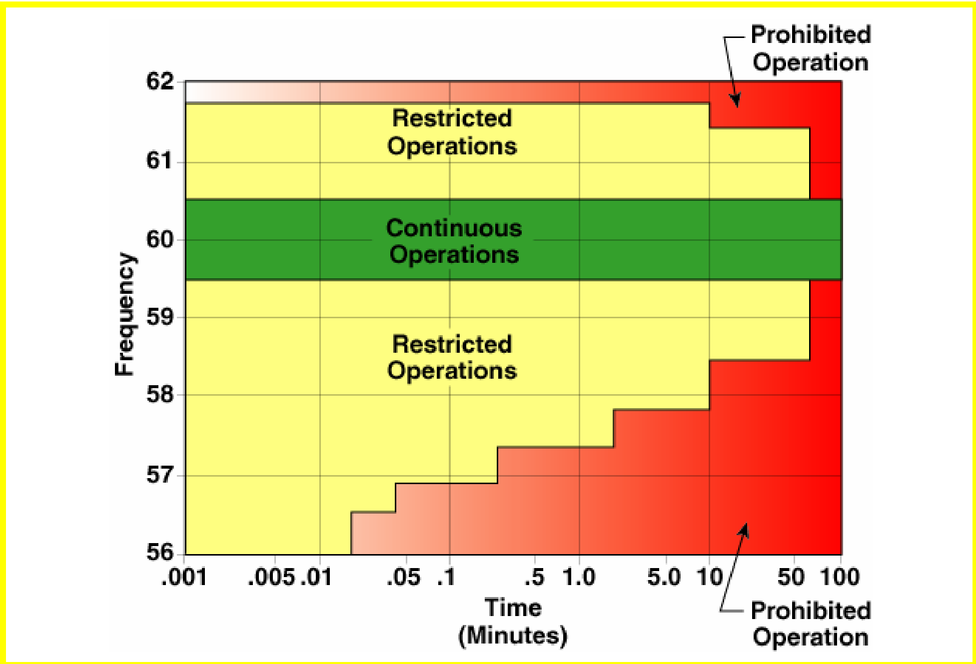


Figure 11-22
Steam Turbine Abnormal Frequency Limits

When activated, a generator's UF protective relays may alarm the operator and/or trip the unit. System operators must be aware of their generator UF relay settings.

The frequency and time of exposure limits for each generator's operation should be documented in the restoration plan. The documentation should include the generator abnormal frequency limits and also the settings on any under and over-frequency relays that are used to protect the generator.

Concerns with Black-Start Capable Units

Black-start capable generating units have the capability of starting when the power system that the generator normally connects to is shutdown. Even though a generator may be classified as black-start capable, there are a number of issues that can interfere with the black-start process. If any of the following issues are applicable to a particular system, the issues should be documented in the appropriate restoration plan.

Availability of Compressed Air to Start CTs

Aircraft derivative type CTs frequently use compressed air storage to drive air-motors. The air-motors propel the CT to a speed at which the CT's combustors can be ignited. Air leaks or usage of the compressed air for other purposes may deplete the supply of compressed air to levels below that necessary for the CT's black-start.

Gas Compressors for CT Operation

Many CTs use natural gas as the fuel source. The available pipe-line pressure at a CT site is often not high enough for direct utilization by the CT. Gas compressors are then used to raise the gas pressure to acceptable levels for the CT. The compressors are sometimes gas powered, but are often AC powered. Black-start generator operations should be analyzed to ensure adequate gas pressure and AC power during restoration conditions.

There may be restricted CT operation possibilities during low gas pressure conditions. For example, a CT may be able to operate at reduced MW output levels without the benefit of a gas compressor.

Penstock Water for Hydro Units

Water—taken directly from the penstock of a hydro unit—can sometimes be used to drive the critical auxiliary loads needed to execute a hydro unit black-start. Typical water driven auxiliaries include AC station service generators and excitation power supplies.

The runner is the rotating portion of the hydro turbine. The thrust-bearing supports the weight of a vertically mounted hydro generator.

Lift-Oil Pumps for Hydro Units

Some vertical mounted hydro units (Francis turbine powered generators are normally vertical mounted) utilize pressurized oil to raise the turbine runner off the thrust-bearing prior to starting the rotation of the runner. The pumps used to pressurize the lift-oil are normally AC powered. DC or water powered pumps may be utilized in a black-start capable unit.

Fuel Forwarding Pumps for CTs and Diesels

Diesel generators typical have one large fuel storage tank and an additional smaller tank. Diesel fuel is pumped from the large tank to the small tank and then to the diesel engine. The fuel-forwarding pump between the two storage tanks is frequently AC powered. The fuel-forwarding pump may be fed power directly from the diesel generator output.

If a diesel generator is designated as a black-start capable unit, the small tank (commonly called the day tank) and the large tank should be kept full of fuel. The AC power source for the fuel-forwarding pump should be rapidly restored once the diesel generator has black-started, otherwise the unit may unexpectedly run out of fuel.

CT generators can also use fuel-forwarding pumps. CT fuel-forwarding pumps are typically AC powered. A CT with black-start capability may have a DC powered fuel-forwarding pump. The DC pump often needs to be manually switched in-service for the black-start process. Once the CT has successfully black-started, the DC pump may need to be switched out and the AC pump switched in-service. This switching process must be completed in the correct manner to avoid a fuel interruption.

Restoration of a Generator's Normal Auxiliary Power

Once a black-start generator has successfully started, the transfer from the emergency start-up power source to the normal auxiliary power source can result in generator tripping. For example, automatic transfer schemes may operate creating switching surges that cause critical auxiliaries to trip. Manual switching of auxiliaries can also cause generator tripping.

Pump-Storage Hydro Units

Pump-storage hydro units are capable of operating as generators when the power system needs energy or as pumps when energy is available from the system to increase the pump-storage unit's water reservoir level. Pump-storage units are often capable of black-start operation. If a restoration plan requires the use of pump-storage facilities for black-start, the pump-storage plant operators must ensure that enough water is available in the unit's water reservoir for generator operations.

Concerns with Non Black-Start Capable Units

Given the sudden trip of a generating unit, there are a several issues that begin to unfold as time progresses. If these issues apply to a system, the issues should be documented in the appropriate restoration plan.

Time Window for the Restart of a Generator

When a steam turbine is operational and then suddenly trips, the turbine rotor and turbine outer metal shell temperatures are initially at approximately the same temperature. The turbine/generator starts to experience temperature changes within minutes of the shutdown. As time passes, the temperature of the turbine shell and the temperature of the turbine rotor start to diverge. This temperature divergence is the result of the unique construction and design elements of the different turbine components.

Once the turbine manufacturer's specified temperature differential is exceeded, the turbine/generator cannot be restarted as an adequate clearance between the turbine shell and rotor may not exist. This clearance issue can develop within 20 minutes of the generator trip. If the allowable shell-to-rotor temperature difference is exceeded, the unit must be allowed to cool until the temperature differential is again within acceptable limits. The cool down period required to permit a generator restart may exceed eight hours. The estimated time for which the shell/rotor temperature differential will exceed acceptable limits and the required cool down period should be documented in the restoration plan.

CT generators naturally go through a cool down process when removed from service. A sudden system shutdown interferes with the CT's normal cool down process and may create delays for the restart of the CT. In addition, a lack of turning-gear power and hotter than normal rotor temperatures, increase the probability of developing a rotor sag, which further delays the possible restart of the CT.

Unit Scrubber Availability

Following a sudden system shutdown, a fossil fuel power plant's scrubber system will likely not be available for the immediate restart of the unit. Depending upon existing air quality control requirements, a scrubber outage may substantially delay the unit restart.

A scrubber is a pollution control system that removes sulfur from the exhaust gases of the fossil generator.

Availability of Control Power for the Generator and Auxiliary Loads

Prior to the restart of a generating unit, all of its critical control systems must be restored to service. These control systems normally possess a small amount of stored energy which may allow the system to remain functional for a short time. Critical plant control systems include:

- The DC control systems that are used for control power, emergency auxiliaries, and protective relaying
- The hydraulic control systems that are often used at hydro stations for control purposes
- The pneumatic control systems that are used extensively in steam power plants for control purposes

Effect of Plant Bus Configuration

The configuration of a generating station's main and auxiliary power distribution buses may be different in restoration conditions than during normal operating conditions. The buses within a power plant are normally interconnected at the high voltage level and all auxiliary busses are ultimately tied to the higher voltage buses.

During a restoration effort, high voltage buses may be split and the buses may be operated out-of-synchronism with one another. For example, one auxiliary bus may be energized from an isolated on-site emergency generator, which is out-of-synch with other auxiliary and higher voltage buses at the plant.

11.4.8 Usage of Emergency Generators

Emergency generators are provided at many customer locations to provide power to critical loads if a system shutdown occurs. Emergency generators are often provided at police stations, hospitals, nursing homes, prisons etc., to carry a portion of the facilities load given a power supply outage. Emergency generators are normally capable of supplying only a percentage of the facility's total load, so a system shutdown does have a significant impact on the load. If an emergency generator fails to start, a crisis situation can develop with respect to public safety and health.

Emergency generators are also used by utilities to power critical loads during restoration conditions. The emergency generator normally energizes only a portion of the load at a particular location. The selection of the critical loads to power is very important as one critical element, left de-energized, may disable the entire facility.

An adequate supply of on-site fuel is required to ensure the continued operation of an emergency generator in restoration conditions. In addition, the type of fuel used is important as certain types of fuel (for example, gas from a pipe-line) may not be available during restoration conditions.

Control Centers

Emergency generators are normally provided at control center locations. The emergency generator should provide power to all elements necessary for the operation of the control center during restoration conditions. Computers, lighting, and telecommunications equipment are obvious high priority loads. The importance of other types of equipment may not be so obvious. For example, cooling power for computers and inverter equipment may be critical to prevent thermal overloads. Sewage and storm water pumps may also be critical to control center operations at certain locations.

The emergency power supply must be designed to restore full functionality to critical equipment. For example, in one actual case, power was provided so that all telephones worked in the control center, but the indicator lights on the telephones were not powered. When a call was made to the control center, with no line indicators working, it was a matter of chance to determine which line to answer.

Black-Start Units

Black-start capable generators often use an emergency generator to provide power to critical unit loads. The emergency generator is the ingredient that makes the unit black-start capable. The types of critical auxiliary loads vary from unit to unit. Typical uses for a black-start unit emergency generator include:

- Turning gear motors
- Large motor cranking power
- Battery bank charging
- Oil and air control pressure
- Fuel-forwarding pumps
- Emergency lighting systems
- Lift-oil pumps

Substations

Important substations may be provided with an emergency generator to power critical station service loads during restoration conditions. The natures of the critical loads vary depending upon the substation. Typical substation critical loads include:

- Battery bank charging
- CB oil and air pressure
- CB heaters
- Telecommunication system and RTU power
- Substation heating and cooling systems
- Substation emergency lighting

Cable Oil Pumping Stations

Cable oil pumping stations may use emergency generators to power the cable oil pumping system during a system shutdown. The emergency generator may also power emergency lighting and pumping station alarm systems.

Repeater and Microwave Stations

Remote radio repeater and microwave stations may be provided with emergency generators to power the facility during an AC power failure. The generator may also power emergency and navigation lighting, heating and cooling systems, and facility alarm systems.

11.5 Protective Relay Issues Related to System Restoration

The fundamentals of protective relaying were addressed in Chapter 2.

This section examines protective relaying issues that a system operator may encounter in restoration conditions.

Restoration Conditions and Protective Relaying

Protective relaying and control system designs and settings are typically optimized for the expected range of normal system operating conditions. System restoration conditions differ greatly from normal conditions. Therefore, some protective relaying and control schemes may operate undesirably during restoration conditions and some schemes may not operate when they should have operated.

Operating the Power System under Abnormal Conditions

Every restoration plan should address the performance of protective relaying and control schemes during restoration conditions. The restoration plan should answer the following questions:

- Will the protective relays undesirably trip load, generators, transformers or transmission lines?
- Will adequate system protection be maintained so that faults are cleared accurately and rapidly and equipment is sufficiently protected?
- Will undesired automatic switch (CBs, MODs, etc.) closing actions occur?
- Will undesired automatic switch opening actions occur?
- Will unnecessary generator control actions occur?
- Will unnecessary transformer control actions occur?
- Will mechanical interlocks and DC control logic circuits frustrate a planned switching sequence?

Fault Current and Restoration Conditions

In normal operating conditions, fault current is provided from many sources (mostly the generators) via a relatively low impedance power system. Therefore, normal operating conditions available fault current magnitudes are relatively high. The apparent system impedance from the fault current sources (generators) to the point of the fault is low which results in the high levels of fault current.

In system restoration conditions, only one generator may be providing fault current to the system. The fault current has to travel through the high impedance of a weak restoration conditions power system. Therefore, the available fault current is relatively low. The apparent impedance from the fault current source (generators) to the point of the fault is high which results in the low fault current levels. Restoration conditions fault current magnitudes may be so low that protective relays are unable to perform their intended function.

Figure 11-23 illustrates the concept of reduced fault current during restoration conditions. Figure 11-23(a) illustrates normal conditions fault current of 25,000 amps. Notice how the normal conditions fault current comes from many on-line generating resources and flows through many transmission lines to the point of the fault. Figure 11-23(b) illustrates restoration conditions fault current. The fault current magnitude (2,000 amps) is much lower due to less on-line generation and a higher impedance system.

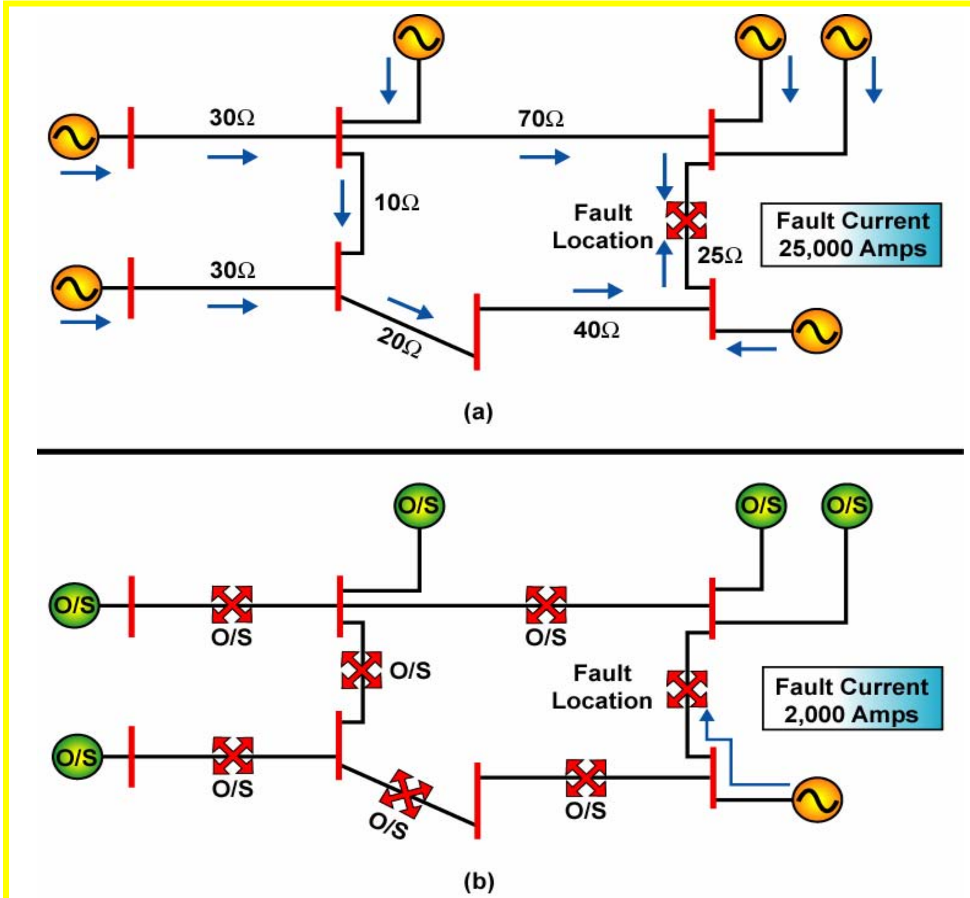


Figure 11-23
Reduced Fault Current Levels

O/S is the symbol for out-of-service. The O/S elements have not yet been restored.

System-Wide Protective Relay Issues

This section addresses system-wide protective relay issues that may have an impact during restoration conditions.

Under-Frequency Protection

UFLS relays are used to shed system load in coordinated steps when system frequency falls below acceptable levels. Figure 11-24 illustrates the operation of a UFLS scheme that sheds 30% of the total customer load in three 10% steps at 59.3 HZ, 59.0 HZ, and 58.7 HZ. Notice how each step in the UFLS scheme operation brings the system closer to a match between generation and load and slows the decline in frequency. The system frequency is finally arrested at 58.8 HZ and the system operators can now bring the system gradually back to 60 HZ.

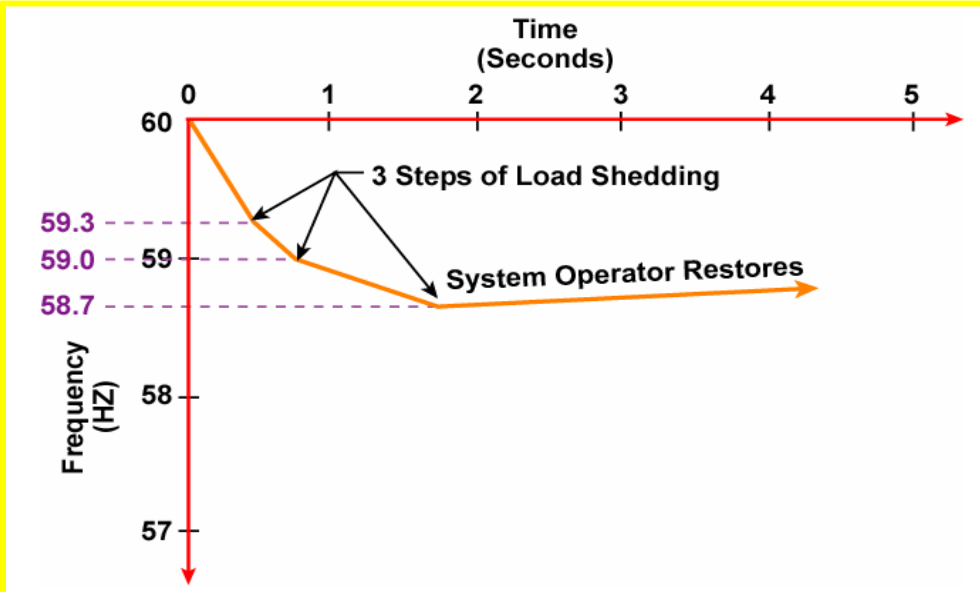


Figure 11-24
Operation of a UFLS Scheme

The designers of UFLS schemes normally assume that most of the normal system load is in-service at the beginning of an under-frequency load shedding event. The timing, frequency set-point for tripping, and the size (MW) of the load blocks tripped are selected to arrest the under-frequency condition at an acceptable point. The system operators involved can then coordinate the restoration of system frequency.

In some power systems, the load shed by UFLS operation is automatically restored once system frequency recovers above a pre-set level. The intent of these automatic load restoration schemes is typically to avoid over-frequency conditions from excessive load shedding and also to restore system load in a more coordinated manner. Automatic load restoration schemes may also be applicable in substations that do not have SCADA control capability.

As described earlier in this chapter, UF relays are often used to trip generating units. The UF relays are designed to protect the generator turbines from a prolonged exposure to low frequency conditions.

UF relays are sometimes applied in the transmission system. These UF relays are designed to separate a portion of the power system when system frequency drops below a specified level for a specified period of time. Transmission UF relays trip the appropriate CBs to intentionally create an islanded system which hopefully contains enough generation capability to support the island’s frequency.

Unintended Operation of Frequency Based Protective Relays

System restoration conditions are often substantially different than those that are assumed when designing frequency based protection schemes. The load connected to the system—especially in the early stages of restoration—is often very low. Only one or a small number of generators are in-service in the initial stages of the restoration process. Frequency excursions are expected as load is picked up in a weak power system. The energization of distribution feeders can have a significant impact on frequency, depending upon the amount and type of in-service generation.

Restoration conditions expected frequency deviations are roughly equivalent to those expected when major disturbances occur in a normally interconnected power system. UF relays may operate at undesirable times during restoration conditions. UFLS relay operation may cause on-line generators to accelerate and lead to tripping of the on-line units. When more than one generator is operating in parallel, a sudden loss of a large amount of customer load may cause a generator to trip due to operation of its anti-motoring (also called reverse power) relays. The improper operation of automatic load restoration schemes could be very damaging if the additional load results in a sudden drop in frequency. Islanding schemes might also operate improperly, potentially destroying a recently restored system.

In summary, the settings of UF relays may not be appropriate for restoration conditions for the following reasons:

- A sudden, large loss of load from a UFLS scheme operation may create high frequency and/or high voltage conditions.
- The operation of a generator's UF protection may create sudden low frequency conditions and lead to a total system collapse.
- The unintended operation of a UF based islanding scheme can result in a large imbalance between generation and load and the total collapse of a power system.
- The unexpected operation of a frequency based automatic load restoration scheme may frustrate system restoration and synchronizing efforts and lead to time delays and/or an additional system shutdown.

Every system restoration plan should carefully consider the impact of frequency based protective relays and include appropriate strategies to address potential problems.

Under-Voltage Load Shedding (UVLS) Schemes

UVLS schemes were described in Chapter 6.

UVLS schemes are implemented in some power systems. The purpose of UVLS is normally to shed load as voltage declines in an effort to prevent a voltage collapse.

Voltage control is not as precise or as stable during restoration conditions as during normal system conditions. High voltage is normally the principal voltage problem during restoration conditions. However, power system operators may intentionally operate at a lower than normal voltage (perhaps 90% of normal) to reduce the transmission system's Mvar production and to reduce the likelihood of TOVs during restoration conditions.

The tripping of load from UVLS scheme operation, especially reactive load, during restoration conditions can produce unwanted results. Severe voltage deviations, frequency deviations, and generator tripping (from anti-motoring, loss of field, etc.) are possible results of unintended UVLS scheme activation during restoration conditions.

Every system's restoration plan should consider the impact of existing UVLS schemes and provide guidance as required.

Effect of Control Circuit Logic on Desired Switching

Earlier in this chapter, the impact of the design of a CB's DC control circuitry was briefly examined. Many system operators assume that CBs can be opened and/or closed as desired in system restoration conditions. This is a poor assumption as the CB's DC control logic circuitry may interfere with the desired switching action.

A switching device's control circuitry design dictates when and how the device is automatically or manually opened and closed. An unexpected problem switching a single device in restoration conditions may render the entire restoration approach a failure. A control circuitry design and its impact on intended switching operations should be carefully evaluated to verify the ability to execute a planned switching sequence.

DC control circuitry design philosophies vary from system to system and frequently are different within a given system as a result of philosophy changes as time passes. The control circuitry designs of utilities, transmission providers, independent power producers (IPPs), and large customers may utilize substantially different approaches. Changes to existing control logic must be evaluated with respect to its impact on the restoration plan.

Typically, certain permissive conditions must be satisfied for a CB to close via SCADA. For example, the closing permissives for a transmission line CB might allow the transmission line's CBs to close only if one of the following conditions is met:

- The transmission line is energized (from another substation) and the substation bus associated with the CB is de-energized.
- The transmission line is energized (from another substation) and the substation bus associated with the CB is energized and a synch-check relay indicates that the power angle across the open CB is less than a specified amount, and the frequency difference across the CB is small enough that the power angle will remain less that the specified amount for a defined time.

Until one set of the conditions stated above is satisfied, the CB will not close. For example, if the substation bus is energized and the transmission line is de-energized, the CB will not close.

Figure 11-25 illustrates the control logic described above on a CB logic diagram. CB #1 control logic is illustrated. Note that there are two control logic paths to the closing coil for CB #1. If either path is satisfied, the proper DC switches are closed and the DC battery bank energizes the CB closing coil.

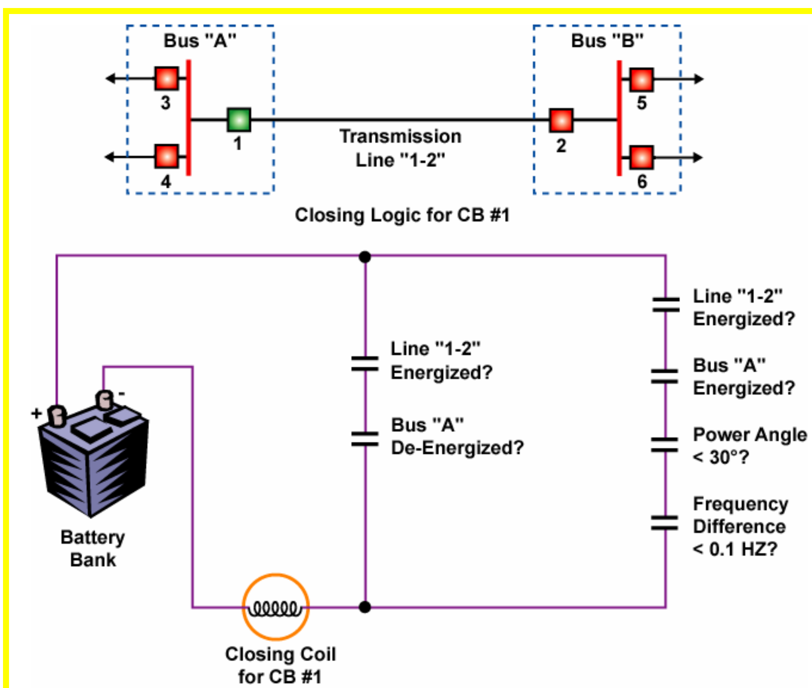


Figure 11-25
CB Closing DC Control Logic Circuitry

Each proposed restoration strategy should be studied ahead of time and any control logic problems identified. For example, the developers of a restoration plan may want to use a small generator (an IPP) to initially energize a small portion of the system. However, the IPP's control circuitry may intentionally prevent the closing of its main CB if the external system is de-energized. For example, the IPPs control circuitry may:

- Permit the closing of the main CB if the system and the generating station are both energized and in synchronism with each other
- Permit the closing of the main CB if the system is energized and the generating station is de-energized
- Block the closing of the main CB when the generating station is energized and the system is de-energized

The modern control circuitry used in power system's generators and substations is gradually growing more complex. Frequently microprocessor and computer systems are incorporated into the DC control logic. A thorough understanding of all DC control system logic is a must when developing restoration strategies.

Electromagnetic Versus Solid-State Relays

Electromagnetic, solid-state, and microprocessor based protective relay systems typically all require DC power to perform intended functions. Although an electromagnetic relay's tripping contact may close without DC power, DC power is normally required to trip a CB or perform other desired control actions.

The tripping contact is a switch that closes when the relay detects an abnormal condition.

Solid-state relays normally have a greater range of functionality than electromagnetic relays. Microprocessor based protective relays normally include additional complex control logic circuitry well beyond that found in an electromagnetic relay. The inclusion of complex DC logic circuitry, may allow a microprocessor based protective system to distinguish between normal and restoration conditions and respond in a manner appropriate to either condition.

Transformer Protection

This section addresses transformer protection related issues that may have an impact during restoration conditions.

Volts-per-Hertz Protection

Transformers can be damaged from over-excitation. Over-excitation is due to a combination of high voltage and low frequency. Unfortunately, both conditions (high voltage and low frequency) are increasingly likely during restoration conditions. Volts-per-hertz relays are designed to detect over-excitation and alarm or trip. Volts-per-hertz relays are more likely to operate in restoration conditions.

Over-Current Relay Operation

When a transformer is energized, an in-rush of current occurs. The magnitude of the in-rush current depends upon the point in the voltage cycle at which the transformer is first energized. The in-rush current magnitude is also affected by any residual magnetism present in the transformer core. The in-rush current is primarily a reactive current and has a high harmonic content. The in-rush current magnitude can be 10 times greater than the normal full-load current.

Some transformers use over-current relays as part of the transformer's protection package. These over-current relays may operate falsely due to the in-rush current when the transformer is energized. Some over-current relays are equipped with a harmonic restraint feature to prevent their operation due to energizing currents. During a system restoration, transformers may be energized in a different manner than during normal circumstances. For example, the transformer may be energized from the low instead of from the high side. When energizing from a direction other than normal, the potential for unexpected over-current relay operation is heightened depending upon the relay design standards for the particular system.

Differential Relay Operation

Most power transformers are protected with current based differential relays. When energizing a transformer, the differential relay sees the energizing current flowing in to the transformer, but does not detect any current flow out of the transformer. The differential circuit is unbalanced and tripping could occur unless preventative measures are taken. Typically, the differential relays used on power transformers have a harmonic restraint feature installed. The harmonic restraint feature prevents relay activation if the imbalance current has a high harmonic content. The harmonic restraint feature reduces the likelihood of tripping from in-rush current. However, not all power transformer differentials have harmonic restraint.

Directional Relays

Directional relays (for example, impedance relays and directional over-current relays) are sometimes installed on the low side of transformers. Directional relays frequently require a polarizing source. The polarizing source is what makes the relay directional. Polarizing sources are often drawn from substation PT circuits. In a restoration condition, when a substation is in the process of re-energization, the appropriate PTs may not be initially energized. Directional relays may then falsely operate. Polarizing source issues should be identified and appropriate solutions documented in the restoration plan.

11.5.3 Transmission Line Protection

This section addresses transmission line protective relay issues that may have an impact during restoration conditions.

Distance (Impedance) Relays

Distance relays use current and voltage inputs to determine the apparent impedance (V/I) of the protected line. The apparent impedance is used to determine whether fault conditions exist on the protected line. A distance relay interprets low impedance as a fault condition and initiates CB tripping. If a distance relay's voltage input is lost, the relay sees a low impedance—because the ratio V/I is now zero—and may trip.

To prevent inappropriate CB tripping, over-current relays are often installed in series with the distance relay. The overcurrent relay is referred to as a fault detector. The fault detector must activate for the distance relay to trip a CB. Figure 11-26 illustrates the concept of a distance relay (21 device) with its associated fault detector (50 device). The series insertion of the fault detector in the control circuitry ensures the distance relay does not activate for low voltage conditions only, the current flow must also be high.

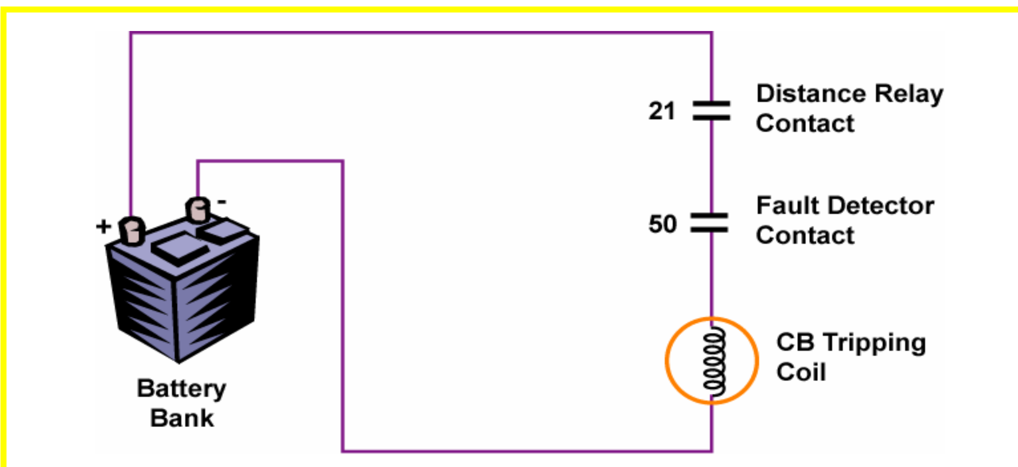


Figure 11-26
Use of a Fault Detector

Not all distance relays have fault detectors. If fault detectors are not used, it is essential that the distance relay's voltage input is available at all times to avoid false trips.

Even if a fault detector is used, problems can still surface. The current (amp) setting of the fault detector may be greater or less than the normal full load current of the protected line. The current setting of a fault detector is often a difficult compromise between setting the value high enough to avoid false trips and setting the value low enough so the protected line will trip given the minimum anticipated fault current level.

Loss of Polarizing Source

Distance relays are directional relays and use a polarizing source to determine the direction of fault current. Polarizing sources can be either voltage or current values. The loss of a polarizing source prevents the determination of fault current direction and may lead to false tripping. Relay polarizing needs should be considered in the determination of a substation's restoration switching strategy.

Inadequate Fault Current for Fault Detectors

A common problem during restoration conditions is a lack of fault detector operation in the event of an actual line fault. Fault current levels in restoration conditions are often not high enough to activate the fault detector when a fault occurs. In a typical distance relay scheme, the failure of the fault detector to activate prevents CB tripping. For example, if a lightning arrester was to fail in a substation (which could easily occur during restoration conditions switching), the fault may be detected very slowly or not detected at all. Delayed or backup clearing of the fault could jeopardize the restoration effort and contribute to equipment damage.

A restoration strategy should be evaluated from a distance relay performance perspective. If fault detector activation during fault conditions is a problem due to low levels of available fault current consideration should be given to:

- Decreasing the fault detector current settings
- Increasing the available fault current by starting additional generators
    - Fault current levels may not increase markedly with the starting of additional generators, depending upon the system configuration. Short-circuit computer simulations should be completed to determine the anticipated fault currents in restoration conditions.
- Changing the switching step sequence to increase fault current levels
    - Changing the switching step sequence could decrease the system impedance which may raise fault current levels.
- Installing control schemes which by-pass selected fault detectors or place more sensitive fault detectors in-service in restoration conditions.

Distance Relay Voltage Inputs

In restoration conditions, a distance relay's voltage input may not be electrically connected to the distance relay's associated line terminal. In other words, the distance relay may be inputting a voltage that has nothing to do with its protected line. This condition interferes with the ability of a distance relay to determine fault location. Improper and/or no relay tripping could occur.

Over-current Relays

Two major issues associated with transmission line over-current relay operation during a restoration condition are addressed in this section.

Inadequate Fault Current

The available fault current may be so low that over-current relays may not detect a fault. Transmission line faults are more likely to occur during a restoration condition due to switching surges, physical damage to the system, and increased automobile accidents. A failure to detect and clear a fault can result in safety hazards, equipment damage, and a repeat of the system shutdown.

Short-circuit computer simulations may reveal an inability to detect and clear faults on some transmission lines and especially on distribution feeders in the early stages of a system restoration. Distance relays may provide backup to the over-current relays and clear the faults that were not detected by the over-current relays.

The switching steps in the system restoration plan should be evaluated to ensure that adequate protection is maintained on energized transmission lines and distribution feeders. Transmission lines and feeders that use over-current protection should not be energized until adequate levels of fault current are available to permit proper operation of the relays. In addition, distribution feeders that use fuse protection may not clear properly due to a lack of fault current.

Effect of Initial Feeder Loading

When the load on a recently interrupted distribution feeder is restored, the initial loading can be considerably higher than the normal load current. The initial loading on a feeder is dependent upon the nature of load being served, the season, the time-of-day of the interruption, and the duration of the interruption. The theory and effects of cold-load pickup were described in Section 11.3.6

The initial loading on a feeder upon restoration can exceed the settings of over-current relays. It may be necessary to initially disconnect a portion of the feeder load to successfully re-energize the feeder and avoid over-current relay operation.

Reclosing Relays

Reclosing relays are routinely used in transmission and distribution systems. Reclosing relays automatically reclose CBs following specific types of tripping events. Automatic CB reclosing can produce disastrous results in restoration conditions.

For example, a transmission substation may be totally de-energized with several transmission line CBs open. When a power source is energized into the substation, the reclosing relays on the transmission CBs may operate, suddenly picking up many miles of transmission line (and the associated Mvar) and a large amount of load. This automatic reclosing could drive voltage so high and frequency so low that the system collapses.

The potential for automatic reclosing should be addressed in the development of the restoration plan. In many instances, the best option is to disable the reclosing relays before transmission and distribution restoration efforts begin.

Out-of-Step (OOS) Relays

Out-of-step relay theory and operation was described in Chapter 7.

OOS protective relays are designed to detect OOS conditions in the transmission and generation systems. OOS conditions are more likely to arise in restoration conditions as the power system is much weaker (higher impedance, etc.) than during normal conditions. Systems may have a low probability of an OOS event in normal conditions but have a high probability in restoration conditions. The loss of a key transmission line or key generator may—in the early stages of a system restoration— cause angles to grow so rapidly that OOS relays activate collapsing the weak power system.

If several islands have formed as a result of restoration conditions, a decision must be made where and when to tie the islands together. If the islands are synchronized with a large frequency difference, a large power angle, or a large voltage magnitude difference, a large power swing can occur. If the transmission system has OOS relays installed, the relays may activate and cause transmission line tripping.

Not every power system installs OOS protective relays. If a system has installed OOS relays, any issues related to the OOS relay operation in restoration conditions should be documented in the restoration plan.

11.5.4 Generator Relays

This section addresses generator protective relay issues that may have an impact during restoration conditions.

Under-Excitation Protection

On-line generators are often used to absorb any excess Mvar in the power system. During the early stages of a system restoration, Mvar load and transmission system Mvar usage are very low. The difference between the Mvar used by the system and loads and the Mvar supplied by the energized transmission lines must often be absorbed by only a few on-line generators.

Generators are equipped with several features that prevent the generator from absorbing excessive amounts of Mvar. The voltage regulator may have a URAL (under-excited reactive ampere limit) or a MEL (minimum excitation limiter) that limits the amount of Mvar absorbed to safe levels. In addition, the generator operator may install protective relays (loss-of-field or LOF) that operate and either alarm or trip the generator if the Mvar absorbed rises above a pre-set level.

If the Mvar that a generator is forced to absorb exceeds the generator's voltage regulator controls and/or protective relay settings, the generator may trip or the Mvar absorbed may suddenly reduce. The exact action taken depends on the particular generator's control systems and protective relay settings.

Phase Imbalance Issues

High voltage transmission lines are typically constructed in a horizontal configuration and are seldom transposed. Figure 11-27 illustrates horizontal transmission line construction and the concept of transposition.

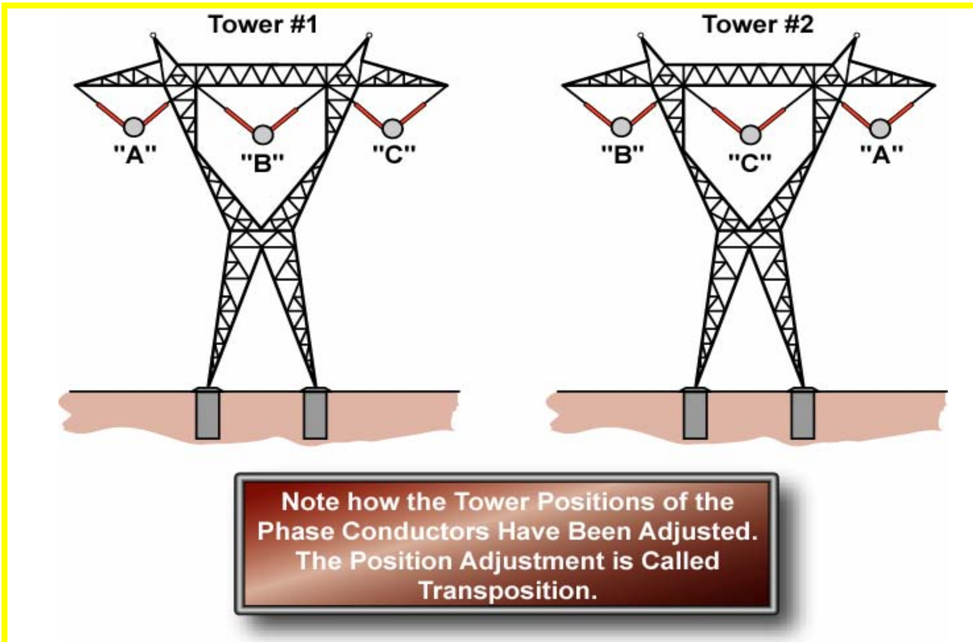


Figure 11-27
Imbalanced Phase Conductors and Transposition

The inductive reactance (X_L) of each of the three phases of a transmission line is a function of that phase's magnetic field strength. The magnetic field surrounding each of the three phases of a horizontally constructed line is different than the magnetic field of the other two phases. The three fields are different because the fields interact with one another as a function of their tower positions relative to one another. For example, the magnetic field surrounding the center phase on the support tower is impacted strongly by the two end-position phases. However, the magnetic field of an end-phase has little impact on the magnetic field of the other end-phase because the phases are physically so far apart.

The result of the differences in the phase conductor magnetic fields are different impedances (X_L) in the three phases. When transmission line phases are transposed, the position of each phase on its support tower is periodically switched with a different phase. Ideally, each phase occupies the same tower position an equal amount of time along the entire length of the line.

The impedance of each phase of a horizontal construction transmission line is different than the other two phase impedances unless the phases are transposed. If transposition is used, an approximate match can be obtained between the three phase impedances. A transmission line does not have to be transposed at every structure. For example, a 100 mile long line may be transposed once to get the necessary impedance match.

Some transmission lines use delta phase arrangements. These phase impedances are balanced.

If transposition is not used, and the phase impedances are different, the current magnitudes in the three phases will be different. When the three phase currents are not the same magnitude, the phases are said to be imbalanced. Imbalanced phase currents can damage rotating equipment. Generators and large motors are often equipped with negative sequence relays. A negative sequence relay is designed to detect imbalance conditions and either alarms the operator or trips the machine (motor or generator).

Phase imbalance issues are especially important when high voltage transmission lines are used. High voltage transmission (for example, 345 kV or 500 kV) is often used to move power from generating units to far-off load centers. A phase imbalance in the transmission system that connects to the generator can result in imbalance currents in the generator and severe damage to the unit.

Volts-Per-Hertz Relays

Generators can be damaged due to over-excitation in a similar manner as transformers. Over-excitation results in the heating of the generator's stator core and can cause permanent damage to the generator.

Over-excitation is a function of both high voltage and low frequency. A generator is in a unique position in that both high voltage and low frequency are simultaneously possible, especially during restoration conditions. Generators are often protected with volts-per-hertz relays in recognition of the high probability that over-excitation can occur.

Under-Frequency and Over-Speed Protection

Generators can be damaged by prolonged exposure to abnormal frequency. Generators are usually protected from low frequency exposure (and sometimes from high frequency) with frequency based relays. Restoration conditions increase the likelihood of prolonged abnormal frequency and thus the likelihood generators could trip. Generators are also protected with mechanical over-speed relays which monitor the shaft speed. A typical setting may be to trip the unit if the over-speed exceeds 110% of the rated unit speed.

Reverse Power or Anti-Motoring Protection

In normal operating conditions, when a new generator is synchronized and loaded, other on-line generator MW outputs are reduced to accommodate the new generation. The control area AGC system typically adjusts all the regulating unit MW levels to ensure conformance to each generator's high and low operating limits. If the AGC system is unable to reduce generation to low enough levels to match the net interchange schedule (NI_S), inadvertent interchange results. The system frequency may rise slightly due to the excess generation but in a large interconnection the frequency rise may not even be noticed.

In restoration conditions, the operating situation is substantially different. There may be only a few generators on-line. Load and generation must be in balance at all times or large frequency deviations will rapidly develop.

Frequency levels can rise rapidly if a customer load suddenly trips or a generator is synchronized and starts adding MW faster than other on-line units are backed down. An on-line generator's MW output may be backed-off so rapidly that the unit becomes a motor. For example, assume generator "A" is initially lightly loaded and has a fully operational governor control system. Assume a new generator ("B") is synchronized and rapidly loaded. The generator "A" governor reacts and reduces the unit's MW output until the unit is actually absorbing MW. Generator "A" is now a motor.

Some generator's can motor with no adverse effects. For example, hydro units can often motor. The hydro unit is said to be condensing when it is absorbing MW. However, most steam units cannot motor as the steam turbine may be damaged if motoring occurs. Most steam units are protected with reverse-power or anti-motoring relays which alarm the operator or trip the unit if motoring occurs.

Synch-Check Relays

Synch-check relays are often installed in high-voltage substations to block the closing of transmission line CBs when the power angle across the CB exceeds a set value. Many synch-check relays also incorporate features that block CB closing if the frequency difference or voltage magnitude difference across the CB exceeds set values.

During restoration conditions, generation levels are low and the system impedance is high. Large standing power angles can develop across open CBs. For example, Figure 11-28 illustrates a weak islanded power system. Only a few transmission lines and two generators are in-service. A large power angle (45°) is measured at open CB #1 and the synch-check relay installed at CB #1 will not allow the CB to close due to its 40° setting. The system operator must either reduce the magnitude of the power angle to below 40°, or reduce the angle setting on CB #1's synch-check relay to above 45° in order to close the CB. The next section of this chapter examines the issue of synchronizing during restoration conditions.

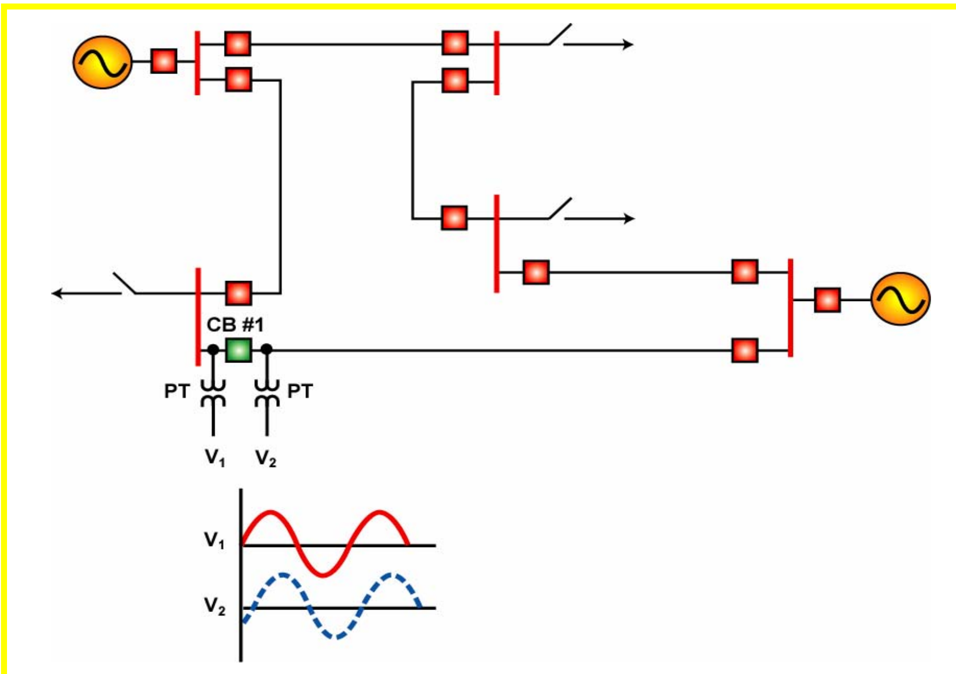


Figure 11-28
Large Standing Power Angle

Synchronizing and System Restoration

Synchronizing theory and the usage of synchronizing equipment were described in Chapter 2.

This section reviews the theory of synchronizing and the usage of synchronizing equipment. Synchronizing issues related to power system restoration are examined.

11.6.1 Review of Synchronizing Theory

When closing a CB between two energized parts of a power system, the voltages on both sides of the CB are synchronized prior to CB closing. If the synchronizing process is not done correctly, a system disturbance can result and equipment may be damaged. In order to synchronize, three different aspects of the voltage across the CB are monitored. The three aspects of the voltage are called the synchronizing variables and are:

- The voltage magnitudes
- The frequency of the voltages
- The power angle between the voltages

Voltage Magnitude Synchronizing Variable

If the voltage magnitudes are not closely matched, a large Mvar flow appears across the CB as it is closed. The large Mvar flow can cause sudden changes in voltage and protective relay operation. The allowable voltage magnitude differences across the open CB are system specific. In general, restoration conditions trigger the usage of greater voltage deviations then would be allowed in normal system conditions. For example, in normal conditions the voltage difference may be limited to a 5 kV when closing a 345 kV CB, but in restoration conditions an operator may tolerate a 10 kV difference

Frequency Synchronizing Variable

If the frequencies on either side of an open CB are not matched prior to closing, a large MW flow appears across the CB as it is closed. The large MW flow is a response to the initial frequency difference as the system rapidly seeks to establish a common frequency once the CB is closed. The allowable frequency difference is system specific. In normal system conditions, a system operator may allow a frequency difference no greater than 0.05 Hz. In restoration conditions, a system operator may tolerate a greater maximum difference such as 0.1 Hz.

Power angle Synchronizing Variable

The third synchronizing variable is the voltage phase angle or the power angle angle. If the power angle between the voltages on either side of the open CB is not reduced to an allowable value (for example, 30°) a large MW flow appears once the CB is closed. The allowable power angle is highly system specific. A ballpark allowable value is impossible to provide as the tolerances of different systems and different areas of the same system vary widely. Some systems may accept no more than a 20° angle while others may close CBs with 70° angles during restoration conditions.

11.6.2 Synchronizing Equipment

Synchroscope

A synchroscope panel contains equipment to monitor the three synchronizing variables. A synch-panel contains a synchroscope and two voltage meters. Figure 11-29 is an illustration of a synch-panel. The synchroscope connects to voltage inputs from the two sides of an open CB. If the voltage sine waves are at the same frequency, the synchroscope does not rotate. If the voltage sine waves are at a different frequency, the synchroscope rotates in proportion to the frequency difference. The synchroscope needle always points to the power angle across the open CB at that moment in time.

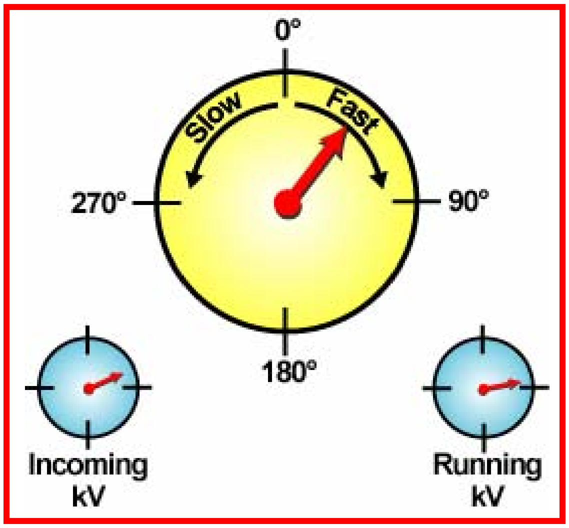


Figure 11-29
A Synch Panel

A synchroscope is a manual device in that an operator is watching the scope to ensure the CB is closed at the correct time. The synchroscope is normally mounted above eye level as part of a synch-panel. The synch-panel also contains two voltmeters so the voltage magnitudes on either side of the open CB can be compared.

The voltage inputs to a substation or generator synch-panel can often be switched to whatever substation or generator CB the operator wants to synchronize across. The selection of the desired CB is normally accomplished by means of a sync-handle. A sync-handle is a key-like device that can be inserted into the receptacle (similar to a key hole) associated with the particular CB. The synch-panel inputs are then received from the desired CB.

Generator Automatic Synchronizers

Generator automatic synchronizers adjust the speed, torque angle, and terminal voltage of the generator with respect to the system. The automatic synchronizer initiates the closing of the generator CB when all three of the synchronizing variables are within allowable limits.

Substation Synchronizers

The synchronizers used in transmission substations typically monitor the three synchronizing variables and do not allow a CB close until all three are within limits. Substation automatic synchronizers typically have timer features. For example, the timer might be set at five minutes. Once the automatic synchronizer is activated, all three of the synchronizing variables must fall within tolerance within five minutes or the process is aborted. The automatic synchronizers used in substations may also be configured to control a local generator's MW and Mvar output. The generator's MW and Mvar outputs are automatically adjusted to move the three synchronizing variables within tolerance and the CB will automatically close.

Synch-Check Relays

The primary function of a synch-check relay is to prevent a CB closing if the power angle across the CB is too large. Synch-check relays are typically installed in transmission substations to prevent:

- The out-of-synch reclosing of transmission CBs following a system separation
- The closing of transmission CBs where a power angle is so high that the closure could damage generating equipment or initiate a system shutdown

11.6.3 Synchronizing Examples

Two scenarios for synchronizing are presented to describe the synchronizing process.

Scenario #1: Synchronizing Two Islands

The first scenario assumes that two islands have been restored and are about to be interconnected using the open CB illustrated in Figure 11-30. The two islands have different frequencies so all three of the synchronizing variables are monitored using a synch-panel at the open CB's substation to ensure the variables are within acceptable limits prior to closing the CB. The system operators for the two islands adjust generator MW levels (or load magnitudes) in one or both islands to achieve the desired adjustment to frequency and angle. Voltage control equipment is used as necessary to adjust voltages to acceptable values.

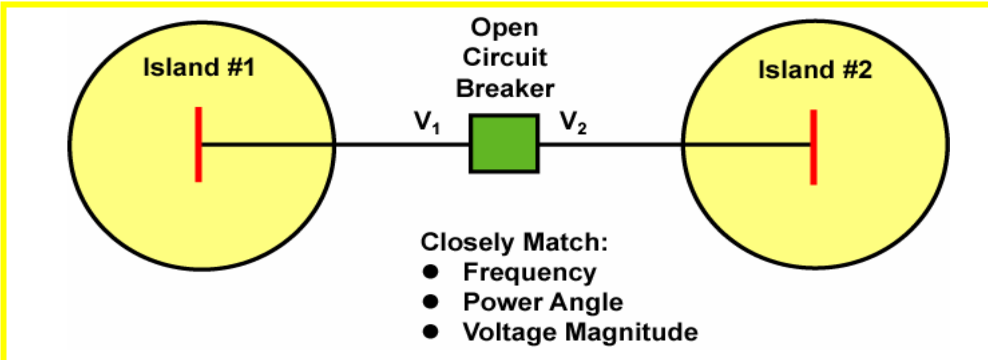


Figure 11-30
Synchronizing Two Islanded Systems

Scenario #2: Energizing a Second Transmission Line

Once the first interconnection is in-service (see Figure 11-30), the frequency is the same throughout the two former islands. The other two synchronizing variables must still be monitored as illustrated in Figure 11-30. Generation and/or voltage control equipment is used to ensure the power angle and voltage magnitude differences are within acceptable limits prior to closing the second CB.

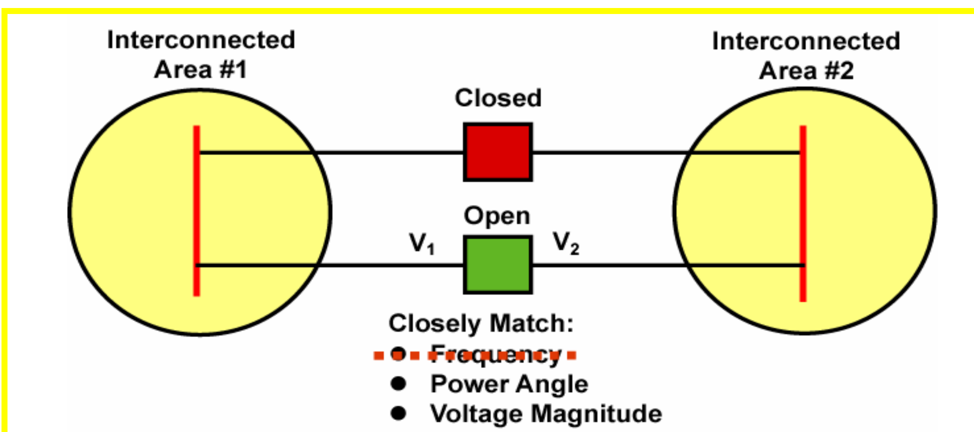


Figure 11-31
Establishing the Second Transmission Link

11.6.4 Guidelines for Synchronizing Islanded Systems

When a restoration plan is first developed, the plan's developers must determine where synchronizing equipment is located within the power system and whether the equipment is at the correct locations. The restoration plan should include a list of the facilities that have synchronizing equipment and also a description of the type of equipment (synch-scope, automatic synchronizer, synch-check, etc.).

A restoration plan should estimate the locations at which synchronization will likely be required and provide guidance as to how the synchronizing will be accomplished. If a thorough restoration planning process is not completed, multiple islands may be created only to eventually find it is difficult or impossible to synchronize the islands. Poor restoration planning may lead to situations where restored parts of a power system have to be de-energized in order to accomplish synchronizing at locations with the appropriate synchronizing equipment. The need for additional synchronizing equipment is frequently identified in the course of restoration planning.

The restoration plan should provide guidance on how to eventually synchronize with neighboring power systems. Once two islanded power systems are synchronized, the actions of one system impact the entire interconnected system. Although larger power systems are often more reliable, this is not always the case. In some instances, it may be better to wait until a neighboring system has reached minimum reliability requirements before synchronizing.

Additional Synchronizing Guidance

When synchronizing two islanded systems, first ensure that at a minimum:

- The synch-panel is monitoring the correct CB to energize the intended facility
- The synchroscope is operating as evidenced by a rotating needle
    - If the synchroscope is not rotating, do not assume the frequencies are matched, the scope may be broken or the frequency difference may be too large for the scope needle to keep up with the magnetic field rotation
- All customer load pick-up, generator ramping, and AGC actions are suspended for the duration of the synchronizing process
- That no generator governor is set in a 0% droop mode

Once the conditions listed above have been satisfied, a typical synchronizing process usually contains the following steps:

- The frequency of each system should be adjusted to a common value
- Normally as close to 60 HZ as possible
- The voltage on each side of the open CB should be adjusted to a common value

    - The greater the magnitude difference, the greater the initial Mvar flow
- The synchroscope needle must be rotating to prove the scope is working
- The speed of one or both of the islands is adjusted so that the synchroscope needle is rotating very slowly
    - Typically, slowing the "running" side system slows the clockwise rotation of the synchroscope and speeding up the running system slows counter-clockwise rotation
    - A slight initial speed adjustment is often used to verify the appropriate speed adjustment needed to slow the scope down

When synchronizing a generator, the running side is the energized power system and the incoming side is the new generator. The terms running and incoming are sometimes used in the transmission system.

- Once all the previous steps have been taken and verified, the CB should be closed at the moment when the scope needle is approaching the 12 o'clock position
    - The 12 o'clock position is a 0° power angle
- The newly interconnected system should now be placed in a suitable frequency control mode as described earlier in this chapter

11.7 Lessons Learned From Actual System Restorations

This section summarizes some of the key technical lessons learned from actual restoration events. The intent of this final section is to highlight issues that have either precipitated, aggravated, frustrated, or hindered restoration efforts. Hopefully, the items noted in this section will spark some recognition of your own system restoration conditions weaknesses.

11.7.1 Problems with Backup Power Sources:

- Emergency diesel generators are unable to start due to dead battery banks
- Battery bank electrical connections fail due to heavy load current when the battery banks are discharging

11.7.2 Problems with Black-Start Capable Generators:

- Hydro generators are unable to return to service following a system shutdown due to a lack of station service power for oil lift pumps
- Hydro generators are unable to return to service following a system shutdown due to a lack of station service power for governor system hydraulic pressure
- Thermal generator start-up delayed due to lack of turning-gear power following shutdown

- Generator black-start plans never tested and turn out to be unusable in an actual restoration condition

11.7.3 Problems with Circuit Breakers:

- As time passes, the air pressure deteriorates to the point that an ACB cannot be closed
- Due to a combination of cold weather conditions and a loss of a GCB's AC heaters, hydraulic mechanisms will not close and the SF_6 CB gas pressure falls below acceptable operating levels

11.7.4 Problems with Telecommunications:

- Telecommunication systems fail due to loss of AC power to critical system functions
- Telecommunication system usage is so great that the system is unavailable to those who most need to communicate

11.7.5 Problems with Computers:

- AGC and SCADA computer systems fail due to a loss of AC power combined with improper switching to the back-up DC source
- SCADA computers slow to an unusable speed from excessive data and alarms
- Generators trip due to a loss of the plant computer system when AC station service power is lost
- Generators trip due to excessive vibration
    - The excessive vibration is not real but the vibration monitors initiated the trip when their power source was switched from AC to back-up DC

11.7.6 Problems with DC Control Circuitry and Interlock Schemes:

- Mechanical CB interlock schemes prevent a desired switching action
- Permissives in a DC control logic scheme prevent the closing of key CBs
- Transmission line automatic reclosing logic is not applicable to restoration conditions
- The DC control circuitry on a black-start generator prevents the generator from being tied to a de-energized bus

11.7.7 Problems with the Frequency Control Process:

- Following a major disturbance, a failure to rapidly restore frequency to within acceptable limits results in various frequency based protective relays timing-out and operating which collapses the power system
- Various dispatching entities independently begin to restore customer load in a weak power system, which results in a collapse of frequency
- Two interconnected systems attempt to use inappropriate methods of frequency control. The result is a large MW flow across the single in-service tie-line and a collapse of both systems.
- UFLS schemes are not properly coordinated between systems in the same interconnection and the schemes operation causes more problems than it solves
- Several power systems' UFLS schemes are not working properly or are disabled and not enough load is shed to arrest the frequency decline
- Islands develop but the system operators are unable to rapidly determine island boundaries due to a lack of frequency monitoring equipment

11.7.8 Problems with the EMS Man-Machine Interface (MMI):

- A poorly designed MMI to the EMS makes it difficult for the system operators to determine the condition of the power system following a major disturbance

11.7.9 Problems with Protective Relays:

- Protective relays schemes operate too slowly to prevent damage
- Protective relay schemes are improperly coordinated for restoration conditions
- Zone 3 distance relays pick-up on high load current magnitudes which collapses the system
- A protective relay system's failure is not identified until a major disturbance occurs
- Protective relay equipment suffers physical damage
- Auxiliary tripping and lockout relays fail, interrupting CB tripping circuits
- Transmission line protective relaying logic is inappropriate for restoration conditions

11.7.10 Problems with Special Protection Systems (SPS):

- SPS (or RAS) operate in an unexpected manner during a major system disturbance
- The SPS operates as designed but the operation is not appropriate for the particular disturbance conditions

11.7.11 Problems with Transmission System Design:

- Transmission towers fail due to unexpected levels of wind and/or ice loading
- One transmission tower fails which results in cascading tower failures and/or faults
- One substation is lost, and so many key transmission elements terminate in the lost substation that the system is left in a very weak condition

11.7.12 Problems Encountered during System Operations:

- A key system element is damaged and the system restoration plan offers no alternatives
- Cascading transmission line tripping severs the entire interconnection between adjacent power systems

11.7.13 Problems with System Operator Training:

- A power system has developed an excellent restoration plan but the system operators are never trained in the plans usage

11.7.14 Problems with the Voltage Control Process:

- Too many transmission lines are energized in the initial stages of the restoration resulting in a run-away voltage condition
- The switching of high voltage equipment creates switching surges which lead to TOVs which fail lightning arresters and damage key equipment

Summary of Power System Restoration

11.1.1 Definition of a Restoration Condition

- A power system restoration condition exists when large portions of the power system collapse, losing both voltage and frequency.
- A total system blackout is a post-disturbance condition in which the entire power system of a particular entity is de-energized.
- A partial blackout is a post-disturbance condition in which a portion of the power system of a particular entity is de-energized.
- An islanded power system occurs when, following a disturbance; pockets of generation remain operational but isolated from the remainder of the power system.

11.1.2 Causes of System Shutdowns

- Power system shutdowns may occur due to any one of the following causes:
  - Angle instability
  - Equipment overload
  - Switching errors
  - Cascading outages
  - Generator overload
  - Voltage collapse
  - Severe weather
  - Earthquakes
  - SMDs
  - Fires
  - Sabotage
  - Control system failure
  - Lack of right-of-way maintenance

11.1.3 Overview of Key Technical Restoration Issues

- Voltage and frequency control during restoration conditions are more delicate control processes than during normal system conditions.

- Equipment impact increases as the duration of a restoration event increases because stored energy sources are eventually depleted.
- Reduced fault current levels during restoration conditions may result in protective relays failing to detect and clear faults.
- A power system in a restoration condition has increased exposure to a variety of system dynamics issues including angle instability, resonance, and switching surges.

11.1.4 Restoration Planning

- Careful planning for a possible restoration condition is critical to the success of any restoration effort.
- Each restoration plan should coordinate with the restoration plans of other power systems in the interconnection.
  - The general goals of a system restoration are:
    - A quick and accurate assessment of the system condition
    - The safe shutdown of generating facilities
    - A prompt but secure restoration of generating resources
    - The restoration of the minimum required transmission system
    - The restoration of customer load
- A restoration process can be broken down into three distinct phases:
  - Phase 1: Assessment
  - Phase II: Preparation of Subsystems
  - Phase III: Establishment of Target Systems
- Initially load is restored based on the technical needs of the power system. Higher priority customer loads are energized once system conditions are such that the loads can be safely accommodated.

11.2.1 Voltage Control as a Local Issue

- In restoration conditions, sufficient Mvar absorption capability must be located close to the areas where higher voltages are expected to occur.

11.2.2 Review of Voltage Related Restoration Theory

- Ferranti Rise is a more serious concern in restoration conditions. A line energized from a weak sending-end bus can result in the open-end voltage rising to damaging levels.

- During restoration conditions there may be little or no customer load connected to the system. This reduced load damping creates a higher risk of resonance.
- A propagating switching surge voltage can add to the power system voltage, creating TOVs. A TOV can easily exceed 160% of the normal system voltage level.
- Some power systems intentionally energize their system at a lower steady-state voltage (for example, 90% of normal) to reduce the risks of damage from TOVs.
- An understanding of the actual (as opposed to theoretical) Mvar capability of a generator is critical in a system restoration condition.
- LOF relays are installed and set to trip the generator before it enters an unstable (leading) operating area.
- A generator's voltage regulator typically includes a MEL or a URAL. The MEL or URAL will alarm the operator and possibly block movement into a dangerous operating (leading) area.

11.2.3 Voltage Control in Restoration Conditions

- There are three key objectives with respect to voltage control during restoration conditions:

    1. Absorb sufficient Mvar to prevent excessive high voltage
    2. Maintain all voltages within acceptable limits
    3. Minimize the TOVs due to switching surges

- During the early stages of restoration, shunt capacitors should normally not be used.
- The usage of shunt reactors may make a weak system more susceptible to ferroresonance.
- Dynamic reactive reserve should be sufficient to withstand the loss of any generator or piece of voltage control equipment.
- The energization of customer load with a low lagging power factor is often helpful as this type load absorbs excess Mvar from energized transmission lines.

11.2.4 Operation of the System at Reduced Voltage

- Lower steady-state voltage levels during the initial stages of a system restoration reduces the likelihood of high voltage related operating problems

11.2.5 Voltage Based Automatic Load Shedding

- Recommendations as to the appropriate usage and operation of UVLS schemes should be contained in the restoration plan.

11.3.1 Frequency Control as an Interconnection Issue

- A generator's frequency response rate is the percent of a generator's MW capacity that is delivered in the process of responding to a disturbance induced reduction in frequency. Typical frequency response rates for various types of generators are:
  - Steam unit with a drum type boiler: 10%/HZ
  - Combustion Turbine (CT): 20%/HZ
  - Low-Head Hydro (short penstock): 30%/HZ

11.3.2 Maintaining Frequency during Restoration Conditions

- A typical steam turbine can operate between 59.5 and 60.5 HZ indefinitely.
- Frequency should normally be held within a range of 59.75 to 61 HZ with an attempt to regulate toward 60 HZ.
- Avoid energizing load blocks that are greater than 5% of the total restored area's synchronized generation.
- If the restored system's frequency has stabilized below 60 HZ, and the goal is to raise the frequency back to 60 HZ, shed 6-10% of the connected system load to raise the frequency 1 HZ.

11.3.3 Usage of Governors to Control Frequency

- Attempts to rapidly load a steam unit can create dramatic excursions on the steam side of the generator and result in the unit tripping.
- Overly sensitive frequency control (for example, low levels of droop) settings can create instability and MW oscillations resulting in generator tripping and system shutdown.
- Designate the largest, fastest responding unit as the regulating unit within each island.
- Maintain and distribute operating reserves such that the post-contingency loading of generators and the frequency level remains within acceptable limits.
- Exercised caution when using generator auto-load control systems in restoration conditions.

11.3.4 AGC and System Restoration

- For a frequency based AGC system to function correctly, the frequency source must be located within the same boundaries as the generation under control.
- For a tie-line flow based AGC system to function correctly, the tie-line meters must accurately monitor the MW flow in and out of the controlled area's boundaries.

11.3.5 Connecting Islands

- Caution should be exercised when intentionally creating multiple islands as simultaneous frequency control of multiple islands is difficult process.

11.3.6 Cold Load Pick-Up Concerns

- The primary causes of cold-load pick-up include long-term loss of load diversity effects and short-term motor in-rush effects.
- The NERC Operating Manual states:
    - "Cold load pick-up can involve in-rush currents of ten or more times the normal load current depending on the nature of the load being picked-up. This will generally decay to about two times normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes."
- In situations where cold load pick-up effects result in equipment overload, relay operation, or large frequency deviations, the feeder load should be reduced by sectionalizing prior to feeder energization.

11.3.7 Maintaining Operating Reserves during Restoration Conditions

- Regardless of what MW response a governor requests, the desired response is not achieved unless the generator's prime mover is capable of the response.
- When only a single unit is operational in an island, adequate levels of responsive reserve must be available in that generator to support any possible cold load pick-up and gradual increases in system load.
- A power system with multiple generators operational should have sufficient responsive reserve to recover from the trip of any single generator or tie-line.
- Regulating reserve levels must be sufficient for the system operator to keep frequency and tie-line flows within acceptable limits.

11.3.8 Load Curtailment

- Procedures must be established ahead of time so that load is shed in an organized, rapid, and efficient manner.
- If it is anticipated that the need for load shedding will continue for an extended time, an option is to shed load on a rotating basis. A typical rotational load-shedding scheme may call for blocks of load to be interrupted for a 20 minute period.
- Automatic frequency based load restoration schemes are normally not appropriate for restoration conditions.

11.4.1 Substation Stored Energy

- Every system restoration plan should include a recent estimate of the service hours for each battery system that is critical to system operation, control, and telecommunications.
- The restoration of substation station service is important for several reasons including:
  - To ensure that the charging system for the substation battery bank is operational
  - To ensure the charging of the stored energy sources used by CBs
  - To ensure the operation of lighting systems to provide a safe working environment for personnel
  - To ensure that substation temperature control systems (heating or cooling) are operational

11.4.2 Pipe-Type Cable Systems

- In restoration conditions, pipe-type cable oil pumping power is often lost. If the cable oil pressure drops below minimum levels, the cable is not available for service.

11.4.3 Lightning Arresters

- In restoration conditions there are several reasons why zinc-oxide arresters are subjected to greater than normal duty and possible failure including:
  - There is a greater potential for elevated system voltage.
  - Restoration conditions always include multiple switching surges as equipment is energized.
  - TOV events persist for longer periods as restoration conditions provide poor damping

11.4.4 Transformers

- Transformer energization may cause several restoration conditions operating problems including:
  - High in-rush currents
  - Increased potential for resonance
  - Increased possibility of voltage problems including over-excitation
- A loss of substation station service may disable existing SCADA control adjustment capability of ULTC and PST tap positions.

11.4.5 Circuit Breakers and Restoration Conditions

- The switching strategies planned for usage in restoration conditions should be analyzed to determine if the CB's DC control logic circuitry permits the intended switching actions.
- If a power system uses air ACBs, the restoration plan should state the typical times for the ACBs pressure to bleed-down below minimum acceptable levels when AC station service power is lost.
- Each system restoration plan should address CB cold weather issues (such as oil viscosity concerns) and provide appropriate solutions.
- If a system shutdown occurs during cold weather conditions, SF6 CB heaters may lose power and the gas pressure may drop below the minimum operating level.

11.4.6 Telecommunication Systems and SCADA

- Each systems restoration plan should analyze the impact of a system shutdown on their telecommunications systems and make the appropriate adjustments and/or improvements to ensure effective telecommunications during restoration conditions.
- A telecommunication systems battery discharge times under restoration conditions should be determined and noted in the restoration plan for all important systems.
- The communications between RTUs and the control center's EMS are vitally important during a restoration condition and the continued availability of RTU telecommunications should be addressed in a company's restoration plan.

11.4.7 Generators and Power System Restoration

- The safe shutdown of generating equipment that trips in the course of a system shutdown is a top restoration priority.

- Every nuclear utilities power system restoration plan should integrate with and support its nuclear plant requirements.
- The availability of generator emergency lube-oil pumps and the DC power to drive the pumps are critical in system restoration conditions.
- A generator voltage regulator may include an over-excitation protective device or the generator operator may install an over-excitation relay.
- To prevent the development of a bend in the turbine/generator shaft, a turning-gear motor is provided to slowly rotate the shaft.
    - For some generators, if turning-gear power is not supplied within 10-15 minutes of a loss of AC power, the shaft bends and the unit may not be available for service for several days while the bend is removed.
- If a hydro unit loses AC power, the loss of pumping functions may cause flooding problems in the unit.
- The frequency magnitude limits and allowed time of exposure to these limits for each generator's operation should be documented in the restoration plan.

11.4.8 Usage of Emergency Generators

- Control centers, black-start units, key substations, key generators, key telecommunications facilities, and cable oil pumping stations may have emergency generators installed.
- An adequate supply of on-site fuel is required to ensure the continued operation of emergency generators in restoration conditions.

11.5.1 Restoration Conditions and Protective Relaying

- Protective relaying and control schemes may operate undesirably during restoration conditions and some schemes may not operate at all due to low levels of fault current.
- Every restoration plan should address the performance of protective relaying and control schemes in restoration conditions.

11.5.2 System-Wide Protective Relay Issues

- The settings of UF relays may be inappropriate for restoration conditions because:
    - The large loss of load from a UFLS scheme operation may create high frequency and/or high voltage conditions
    - The operation of a generator's UF relay may create sudden low frequency conditions and lead to a total system collapse

- The unintended operation of a UF based islanding scheme can result in a large imbalance between generation and load and the total collapse of a system
- The unexpected operation of a frequency based automatic load restoration scheme may frustrate system restoration and synchronizing efforts and lead to time delays and/or an additional shutdown

- Every system's restoration plan should consider the impact of existing UVLS schemes and provide guidance as required.
- DC control logic circuitry design and its impact on intended switching operations should be evaluated to verify the ability to execute a planned switching sequence.
- Volts-per-hertz relays are designed to detect over-excitation and alarm or trip. Volts-per-hertz relays are more likely to operate in restoration conditions.
- A transformer's over-current relays may operate falsely due to the in-rush current when the transformer is energized.
- The differential relays used on power transformers often have a harmonic restraint feature installed to prevent tripping from in-rush current.
- A polarizing source is a voltage or current input that a directional relay uses as a directional reference.

11.5.3 Transmission Line Protection

- If a distance relay's voltage input is lost, the relay sees a low impedance and may falsely trip.
- The series insertion of a fault detector relay in a distance relay's control circuitry ensures the distance relay does not activate for low voltage conditions only, the current flow must also be high.
- If fault detector activation during restoration conditions faults is a concern due to low levels of available fault current, consideration should be given to:
    - Decreasing the fault detector current settings
    - Increasing the available fault current by starting additional units
    - Changing a switching sequence to increase fault current levels
    - Installing control schemes which by-pass fault detectors or place more sensitive fault detectors in-service during restoration conditions
- The potential for unwanted automatic reclosing of line CBs should be addressed in the development of the restoration plan.

  - In many instances, the best option is to disable the reclosing relays before restoration efforts begin.
- OOS conditions are more likely to arise in restoration conditions as the power system is much weaker than during normal conditions.

11.5.4 Generator Relays

- If the Mvar that a generator is forced to absorb exceeds the generator's voltage regulator controls and/or protective relay settings, the generator may trip or the Mvar absorbed may suddenly reduce.
- The purpose of transposition is to balance phase impedances. When transmission line phases are transposed, the position of each phase on its support tower is periodically switched with a different phase.
- Generators and large motors are often equipped with negative sequence relays.
  - A negative sequence relay is designed to detect imbalance conditions and either alarms the operator or trips the machine.
- Generators are often protected with volts-per-hertz relays in recognition of the high probability that over-excitation can occur.
- Some generator's can motor with no adverse effects. For example, hydro units can often motor.
- Most steam turbines cannot motor as the turbine can be damaged if motoring occurs.
  - Most steam turbines are protected with reverse-power or anti-motoring relays which alarm the operator or trip the unit if motoring occurs.

11.6.1 Review of Synchronizing Theory

- The three synchronizing variables are:
  1. The voltage magnitudes
  2. The frequency of the voltages
  3. The power angle between the voltages

11.6.2 Synchronizing Equipment

- Synchronizing equipment includes:
  - A synch-panel with a synch scope and voltage meters
  - Generator automatic synchronizers

- Substation synchronizers
- Synch-check relays

11.6.3 Synchronizing Examples

- Two scenarios for synchronizing were presented to help describe the process of synchronizing.

11.6.4 Guidelines for Synchronizing Islanded Systems

When synchronizing two islanded systems, first ensure that at a minimum:

- The synch-panel is monitoring the correct CB
- The synchroscope is working properly
- All customer load pick-up, generator ramping, and AGC actions are suspended for the duration of the synchronizing process
- No generator governor is set in a 0% droop mode

11.7 Lessons Learned From Actual System Restorations

Section 11.7 contained 14 bulleted lists of important concepts or issues that have been identified from past restoration events in North America.

Power System Restoration Questions

1. In the initial stages of a restoration condition, high transmission system voltage problems are more likely than low transmission system voltage problems. Why?

   A. Because of the excessive Mvar supply from too many on-line generators

   B. Because of the deficiency in Mvar from too much customer load energization

   C. Because of the deficiency in MW from too much customer load energization

   D. Because of the excessive Mvar supply from the energization of transmission lines

2. A synchroscope can be used to determine the standing phase angle across an open CB even if the power system on both sides of the open CB is interconnected.

   A. True

   B. False

3. Generators and large motors are often equipped with negative sequence relays. The negative sequence relay is designed to:

   A. Detect reverse rotation of the machine's shaft

   B. Detect imbalance in the machine's phase currents

   C. Detect A-C-B phase rotation

   D. Detect OOS conditions

4. During which phase of the restoration process is the voltage and frequency of the generators that survived the initial disturbance adjusted to optimum values:

   A. Phase 4: Billing

   B. Phase 2: Preparation of Subsystems

   C. Phase 1: Assessment

   D. Phase 3: Establishment of Target Systems

5. In the early stages of a system restoration, the energization of customer load with a __________ is usually helpful as this type load absorbs excess Mvar from the energized transmission lines.

   A. low lagging power factor

   B. high leading power factor

   C. low leading power factor

   D. high lagging power factor

6. A 200 mile long 500 kV line is transposed at two locations along the line. The purpose of transposition is to:

   A. Balance the phase inductive reactance values

   B. Reduce the Ferranti Rise effect

   C. Increase the power transfer limit

   D. Reduce each phase conductor's resistance

7. In the early stages of a system restoration, the frequency has stabilized at 59 HZ. The system operator has decided to shed load to restore the frequency to 60 HZ. How much load should the system operator shed to raise the frequency 1 HZ?

   A. 3 to 5% of the connected load

   B. 10 to 15% of the connected load

   C. 6 to 10% of the connected load

   D. 1 to 3% of the connected load

8. Why would a power transformer's differential relay be equipped with a harmonic restraint feature?

   A. To avoid relay activation when the transformer is first energized

   B. To avoid relay activation when the transformer is de-energized

   C. To reduce the amount of harmonics created by the power transformer

   D. To restrain the transformer from operating as an overly aggressive harmonic filter

9. Which of the following types of units could most likely operate, without damage, as a motor?

   A. Hydro turbine

   B. Nuclear drive steam turbine

   C. Combustion turbine

   D. Coal driven steam turbine

10. Given the following types of turbine/generators, which typically has the highest frequency response rate?

    A. Low head hydro-electric

    B. Coal-fired steam

    C. Oil-fired steam

    D. Combustion turbine

11. The high probability of switching surge induced TOVs and the potential for ferroresonance may necessitate operation at reduced steady-state voltage levels during the early stages of restoration. These reduced steady-state voltage levels are typically in the __________ range.

    A. 105 to 110%

    B. 90 to 95%

    C. 70 to 80%

    D. 80 to 90%

12. When a switching surge occurs, the power system is exposed to a wave like effect as the switching surge voltage propagates through the area power system. The propagating surge voltage can add to the power system steady-state voltage, producing a __________.

    A. LOF

    B. TOV

    C. AGC

    D. URAL

13. In the early stages of a power system restoration, 500 MW of generation is synchronized with 300 MW of spinning reserve available. What is the largest load block that can be restored while still maintaining acceptable frequency control?

    A. 150 MW

    B. 10 MW

    C. 25 MW

    D. 50 MW

14. What type of condition(s) is a volts-per-HZ relay most likely to activate for?

    A. Low voltage combined with high frequency

    B. High voltage

    C. High voltage combined with low frequency

    D. Low frequency

15. A(n) ___________ occurs when, following a disturbance, pockets of generation and load remain operational but isolated from the remainder of the power system.

    A. interconnected power system

    B. partial black-out

    C. islanded power system

    D. total black-out

Power System Restoration References

1. Power System Restoration: Methodologies & Implementation Strategies—A book in the IEEE Press Series on Power Engineering, a reprint of selected papers, edited by Mr. M. M. Adibi, Published by IEEE Press, 2000.

   Excellent restoration reference that contains many papers covering a broad range of power system restoration issues. The papers are written primarily for an engineering audience.

2. NERC Operating Manual

   The current version of the NERC Operating Manual contains a large amount of information on system restoration. Operating Policies 5 and 6 are especially valuable.

3. NERC Planning Standards

   The current version of the NERC Planning Standards contains standards, measurements, and guides, with respect to system restoration.

4. Electric System Restoration—A reference document, by the North American Electric Reliability Council, published on the Internet by NERC, 1993.

   A reference document by the NERC Operating Committee that provides general guidelines, recommendations, and suggestions with respect to power system restoration.

5. A Web-Based Power System Restoration Tutorial—A series of six articles on power system restoration, by Mr. M. M. Adibi, published on the Internet by EPRI, 2000.

   This series of articles addresses various restoration problems and presents the results of computer simulations and case studies. The intended audience for the articles is system operation personnel. Topics addressed include: load pick-up and reserve distribution, energizing lines, reactive power considerations, protective relay issues, black-start of a steam unit, and black-start simulation.

A
GLOSSARY

Accelerating Power

In a generator, the difference between the mechanical input power and the electrical output power (assuming no losses). For a generator's torque angle to change, the generator must have accelerating power.

Accumulated Inadvertent

The accumulation over time of inadvertent energy. The Accumulated Inadvertent account of a control area represents the amount of excess energy a control area has either supplied to the interconnection or absorbed from the interconnection. Control areas monitor their Accumulated Inadvertent to ensure the accounts do not grow too large. If an Accumulated Inadvertent account becomes too large, a control area

Active Power

The component of the complex power that performs the work. The common unit of Active Power is the MW and the symbol is "P".

Actual Load

The actual MW drawn by a load from the power system. The Actual Load will be different from the rated or nominal load if the load's voltage or frequency vary from their nominal values.

Adjacent Control Areas

Two control areas that are interconnected:

Directly to each other, or

Via a multi-party agreement or transmission tariff. (Examples include Independent System Operator and Power Pool agreements.)

AGC Pulses

The AGC system will send signals to selected (regulating) generators to adjust their set-points. These signals are sent via telecommunication lines. The signals are often called AGC Pulses.

Air-Gap

The air space between the rotor and stator of a motor or generator.

Alternating Current (AC)

In an AC system the current and voltage magnitudes constantly vary or alternate. Current and voltage magnitudes do not alternate in a DC system.

Alternator

A rotating machine whose output is alternating voltage and current.

Aluminum Cable Steel Reinforced (ACSR)

A common type of transmission line conductor that comes in many different sizes and designs.

Amortisseur Winding

A machine winding consisting of a number of conducting bars attached to the magnetic poles of the machine's rotor. Amortisseur Windings may be used as starter windings or to help dampen power oscillations.

Ampere

The unit of measurement for current flow.

Amplitude

The value or magnitude that a waveform has at a specific point in time.

Analog Electronics

Electronic circuitry in which the magnitudes of quantities are used in a continuous manner to perform functions. For example, input current values may be amplified and used to perform work in an analog circuit. Analog is different than digital in the sense that Analog circuits use voltage and current magnitudes continuously while digital circuits use voltage and current to determine the state (on or off) of elements.

Angle Instability

The opposite of angle stability. When a power system loses angle stability it enters a period of Angle Instability. An angle unstable system has lost some portion of the magnetic bound that holds sections of the power system in synchronism with one another.

Angle Stability

An angle stable power system is one in which all elements of the power system are bound together via magnetic forces. For example, an angle stable generator's internal magnetic field rotates in synchronism (in-step) with the magnetic field of the 3Φ power system to which it connects.

Arc

The discharge of current through the air or in a gas.

Arcing Horns

An enhancement to a disconnect switch to increase the switch's current interrupting capability.

Area Control Error (ACE)

The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Armature

The component of a machine in which the voltage is induced. In a synchronous generator the armature is always the stator. The Armature winding is wrapped about the Armature.

Asynchronous

To be out-of-step with a reference. An induction generator is an Asynchronous generator as it does not rotate in synchronism with the power system.

Automatic Generation Control (AGC)

Equipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

Auto-Load

A feature on some generators that automatically moves the generator to a target load (MW) level.

Auto-Transformer

A transformer with a single coil. The entire coil acts as the primary winding while a portion of the same coil acts as the secondary winding.

Auxiliary Relay

A relay whose function is to supplement the actions of other types of relays. For example, a lockout relay is an auxiliary relay with numerous contacts that each can perform an action. The IEEE has numbers assigned to two types of auxiliary relays; 86 (lock-out) and 94 (tripping).

Available Transfer Capability (ATC)

A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Back EMF

When AC current flows through a conductor an alternating magnetic field is created. This alternating magnetic field induces a voltage in the conductor. The induced voltage is called the conductor's Back EMF.

Back-to-Back HVDC

An HVDC system in which AC is converted to DC and then immediately back to AC. The HVDC transmission path is very short, normally consisting of a short section of buswork.

Bandwidth

The acceptable range of a quantity. For example, if it is desired to hold the voltage at a 345 kV bus between 355 and 360 kV then the bandwidth is 355 - 360 kV or 5 kV.

Baseload Generating Units

Generators that normally run continuously to serve a control area's load.

Bipolar HVDC

An HVDC system that uses two conductors. One conductor is energized with a positive voltage and the other a negative voltage.

Black-Start Plan

A written set of operating procedures and guidelines for restoring the power system following widespread outages.

Black-Start Unit (BSU)

A generating unit that has the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system the generator normally connects to.

Blade

The component of a steam turbine upon which the steam impacts. Blades are also called "buckets".

Blocked Governor

A governor control system that has somehow been blocked or prevented from responding to a frequency deviation. There are many ways to block a governor.

Boiler

The component of a steam power plant in which the steam is created.

Boiler Follow

A mode of operation of a fossil unit's turbine/boiler control system in which the unit's turbine is allowed to immediately respond to a load (MW) change request while the boiler response "follows" with the resulting temperature and pressure swings.

Braking Resistor

A device used to enhance the angle stability of a power system that uses hydro-electric generation. A Braking Resistor is a large resistive load that is inserted to absorb excess energy when an accelerating condition is detected in the power system.

Brush

A sliding contact, usually made of carbon, located between the excitation current source and the rotor field winding leads of a synchronous generator.

Capacitance (C)

The property of an electrical circuit that opposes voltage changes by storing energy in its electric field. The symbol for capacitance is "C" and the unit is the Farad. All energized equipment has a natural capacitance.

Capacitive Load

A load that supplies lagging reactive power to the system.

Capacitive Reactance (X_C)

The opposition that capacitance provides to AC current. The capacitive reactance (X_C) in a 60 HZ circuit is:

$$\boxed{X_C = \frac{1}{2\pi f C}}$$

Capacitively Coupled Voltage Transformer (CCVT)

An instrument transformer that is similar in function to a potential transformer (PT). A capacitive voltage divider circuit is used in a CCVT to reduce power system voltage magnitudes to usable (≈110 Volt) levels. Capacitive Voltage Transformers (CVTs), Coupling Capacitor Potential Devices (CCPDs), and Bushing Potential Devices (BPDs) are similar in design and function to a CCVT.

Capacitor

A device intentionally designed to act as a capacitor and store energy in its electric field. A shunt Capacitor acts as a source of reactive power to the system. Series Capacitors are seldom seen devices that are used to reduce the inductive reactance of a transmission path.

Capacity Emergency

A capacity emergency exists when a system's or pool's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.

Cascading

The uncontrolled successive loss of system elements triggered by an incident at any location.

Centrifugal Ballhead Governor

A mechanical governor that uses rotating flyweights to sense shaft speed. A very common governor due to its durability and accuracy.

Charge

An atomic force. An electron has a negative charge. A proton has a positive Charge. Like Charges repel one another while opposite Charges attract one another. Current is the flow of Charge.

Charging

The Mvar production of a transmission line. For example, a 100 mile long 345 kV line has approximately 75 Mvar of charging.

Charging Current

The leading current that flows into the natural capacitance of a transmission line when it is first energized.

Circuit Breaker (CB)

A piece of power system equipment that is used to disconnect other equipment from the power system. Circuit Breakers are grouped according to their insulating medium. For example, Oil Circuit Breakers (OCB), Air Circuit Breaker (ACB), etc.

Circuit Switcher (CS)

An enhanced disconnect switch that is similar in function to a Circuit Breaker. A Circuit Switcher will contain an interrupting device (typically gas based) to enhance its current interrupting ability.

Cold Load Pick-Up

The increase in a load's magnitude during the initial period after it is energized. The cold load pick-up consists of a short-term in-rush component and a longer term loss of load diversity component.

Combined Cycle

An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combustion Turbine Generator (CT)

A type of generator in which a fuel (oil, gas, etc.) is ignited and the combustion products are used to drive a turbine.

Commonly or Jointly Owned Units (COU/JOU)

These terms may be used interchangeably to refer to a unit in which two or more participants share ownership.

Commutation

The process of turning off one valve and turning on another in an HVDC converter. In a twelve-pulse converter there are twelve Commutations per cycle of the AC supply voltage.

Complex Power (S)

The vector sum of the active (MW) and reactive (Mvar) power. The common unit for Complex Power is MVA and the symbol is “S”.

Complimentary Currents

When a subsynchronous current flows in the stator winding of a synchronous machine it will induce two Complimentary Currents in the rotor of the machine. These Complimentary Currents will have frequencies of 60 ± the frequency of the subsynchronous stator current.

Compressor

A machine that increases the pressure of a gas (typically air) or vapor.

Condenser

The component of a thermal power plant in which the steam is cooled to water after exiting the turbine.

Conductor

A material with a low impedance to current flow. A conductor is the opposite of an insulator.

Constant Frequency Control (CFC)

An operating mode of an AGC system. While in Constant Frequency Control an AGC system will determine the ACE value by considering only the frequency error.

Constant Net Interchange (CNI) Control

An operating mode of an AGC system. While in Constant Net Interchange Control an AGC system will determine the ACE value by considering only the interchange error.

Constrained Facility

A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its Operating Security Limit.

Contiguous

To belong to a common area. Adjoining. A contiguous control area is self-contained. A non-contiguous control area may have pieces spread out over an entire interconnection.

Contingency

The loss of an element in the power system. For example, the loss of a transmission line or the loss of a generator is a Contingency. First Contingency refers to the loss of one unique element. Second Contingency refers to the loss of a subsequent unique element. A power system may be designed to withstand all possible first Contingencies and not collapse or cause undue harm in neighboring systems.

Control Area

An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its Interchange Schedule with other control areas and contributes to frequency regulation of the Interconnection.

Control Center

The location where the ACE of a control area is computed.

Control Performance Standards (CPS)

NERC publishes several standards that govern the generation control process. These standards are designed to judge the performance of a control area (or RSG) in the generation control process. The standards are the Control Performance Standards (CPS1 & CPS2) and the Disturbance Control Standard (DCS).

Control System

A collection of electrical and mechanical components designed to produce a series of outputs based on a series of measured inputs. Common Control systems related to power are excitation control and governor control systems.

Coordinated Control

A mode of operation of a fossil unit's turbine/boiler control system in which the operation of the boiler and the turbine systems are coordinated. The coordination balances the pressure and temperature limits of the boiler system with the desire for a turbine to immediately respond to load (MW) change requests.

Core

The material used within a transformer. A transformer's Core is formed of a magnetic material such as iron. The purpose of the Core is to confine the magnetic field to a target area.

Corona

A condition that occurs on energized equipment when the surface potential (voltage) is so large that the dielectric strength of the surrounding air breaks down (ionization occurs). Symptoms of Corona are a visible ring of light and a hissing sound. Corona is undesirable as energy losses are a consequence. Corona rings are used to reduce the gradient of the electric field and reduce the likelihood of Corona occurring.

Cosine

The Cosine of either of the unknown angles of a right triangle is the ratio of the side adjacent to the unknown angle to the hypotenuse.

Cranking Power

The power delivered to the next generator to restart after a black-start unit has been started.

Current (I)

The rate of flow of electrical charge through a conducting path. Symbol is "I" and unit is ampere.

Current Transformer (CT)

A low power transformer (an instrument transformer) used to reduce normally high power system current magnitudes to lower values (≈ 5 amps). A CT has a low number of turns on the primary winding and a high number of turns on the secondary winding. The low magnitude secondary currents of a CT are typically input to protective relays, meters, etc.

Curtailment

A reduction in the scheduled capacity or energy delivery.

Cut-Out

A switching device typically found in the distribution system. Cut-Outs often include a fuse so the device serves the dual purpose of providing electrical isolation and protection.

Cycle

A complete sequence of a repeating waveform. For example, the magnitude of a sine wave changes as the degrees progress from 0° to 360°. After 360° the sine wave begins to repeat itself. One Cycle of a sinewave is therefore 360°.

Damping

Forces or control system actions that reduce the magnitude of oscillations. Damping is provided by various natural phenomena and by various electrical equipment. Damping can either be positive (reduce oscillations) or negative (amplify oscillations).

Deadband

The distance about a target value within which a control system will not respond. For example, a governor control system may have a Deadband of 0.03 HZ. Unless the frequency deviation exceeds 0.03 HZ, the governor will not respond.

Delta Connection

A 3Φ electrical connection in which the three phases are connected in series with one another. The three phases form a closed triangle. Transformer windings are often connected in a Delta configuration.

Demand

The rate at which energy is being used. The demand is equal to the power used. Instantaneous Demand is the Demand at a given instant in time.

Integrated Demand is the average (integrated) Demand across an hour. Integrated Demand is an energy value.

Deviation

The variance from the scheduled value. For example, if the scheduled value of voltage is 142 kV and the actual value is 138 kV then the voltage Deviation is -4 kV.

Dielectric

Insulating material used to separate and insulate. Capacitors use a Dielectric between the two conducting plates.

Differential Relay

A protective relay that responds to the difference between the currents entering and leaving the protected zone of the relay. Differential Relays are typically applied to transformers, substation buses, and generators.

Digital Electronics

Electronic circuitry that operates on data in the form of digits. Most Digital circuits use the binary system in which digital components are either turned on (a data value of “1”) or off (a data value of “0”) based on circuit voltage magnitudes. Digital Electronics have replaced analog electronics in most, but not all, applications.

Direct Current (DC)

In a DC system the current and voltage magnitudes are constant. Current and voltage magnitudes alternate in an AC system.

Disconnect Switch

A mechanical device that is used to isolate equipment from energized parts of the power system. Disconnect Switches are not rated for interrupting current unless additional arc interrupting components are added to the disconnect.

Distance Relay

A protective relay that activates if the ratio of the measured voltage divided by the current (the impedance) falls below a pickup point. A Distance Relay is also commonly called an Impedance Relay.

Distribution Factor (DF)

The portion of an Interchange Transaction, expressed in per-unit that flows across a transmission facility (Flowgate).

Distribution Lines

Conductors used to distribute power to the utilities customers. Distribution Lines may be 3Φ or 1Φ. In this text Distribution lines are classified as lines energized at voltages below 46 kV.

Disturbance

An unplanned event that produces an abnormal system condition.

Droop

A characteristic of a governor control system that requires a decrease in generator shaft speed to produce an increase in the generator's MW output. There are two types of Droop; Permanent and Transient:

Permanent Droop

Permanent Droop is the droop used to enable all generators (with active governors) to share in frequency regulation and to ensure a MW response in proportion to unit size. Desired values of Permanent Droop are in the neighborhood of 5%. The 5% Droop means that a 5% frequency change will result in the unit's governor moving the fuel (steam, water, gas, etc.) valves across their full range.

Transient Droop

A feature implemented in some governor control systems to ensure generators do not enter into power oscillations following load changes. Power oscillations may occur due to the inherent time delay between a request for a load change by the governor and the ability of a generator to actually deliver the load change. This natural time delay could lead to excessive control action by the governor. A condition of oscillation called "hunting" could result. If a generator is on isochronous control, transient droop is a necessity. The Transient Droop function or "compensation" dampens a governor's initial response following a speed change. The effect is temporary as opposed to a Permanent Droop function which is permanent.

Droop Curve

A graphical method of representing the performance of a governor. The horizontal axis is typically generator output while the vertical axis is system frequency. When a governor with a % droop is plotted on such a curve the plot droops from left to right with increasing generator output.

Dynamic Reactive Reserve

Reactive power held in reserve in fast responding sources. Generators and static var compensators are possible sources of dynamic reactive reserve.

Dynamic Schedule

A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for "scheduling" jointly owned generation to or from another control area.

Earth Surface Potentials (ESP)

Voltages induced in the surface of the earth by the electrojets (current) that flow above the earth's surface. ESPs cause geomagnetically induced currents (GICs) to flow in the earth's surface.

ECAR

Acronym for the East Central Area Reliability Coordination Agreement. ECAR is one of the ten NERC Regional Reliability Councils.

Economic Dispatch

The allocation of demand to individual generating units on line to effect the most economical production of electricity.

Electric Field

The invisible lines of force that surround an energized piece of equipment. An Electric Field is created when a conductor is energized by a voltage. Energy is stored in an Electric Field.

Electrical Circuit

An Electrical Circuit consists of a voltage source, a conducting path to a load, a load, and a return path from the load to the voltage source. All of these ingredients are necessary for current to flow in the Electrical Circuit.

Electrical Distance

The impedance of a transmission line is a measure of the Electrical Distance. For example, if a line has a 100 Ω impedance then 50 Ω is ½ the line's electrical length. Impedance relays are often called distance relays in reference to the use of impedance as a measure of Electrical Distance.

Electrical Energy

Energy of an electrical nature. Generator's convert the mechanical energy of a rotating turbine to the Electrical Energy that is transmitted across the power system.

Electrodes

The connection to ground of an HVDC converter. The grounding Electrode provides a voltage reference and may be part of the current return path.

Electro-Hydraulic Control (EHC)

A form of a control system in which electrical devices are typically used to measure a quantity magnitude and hydraulics used to perform a control action. For example, a governor control system may consist of a simple electrical machine that measures the shaft's speed of rotation (frequency) and a hydraulic system that changes the positions of fuel valves.

Electrojet

A current flow path in the shape of a donut that situates itself above the north and south magnetic poles of the earth. Electrojets are the result of solar disturbances.

Electromagnet

Temporary magnet created by passing electric current through a coil. The coil is typically wound about a magnetic core.

Electromagnetic Induction

The creation of a voltage in a conductor due to a relative movement between the conductor and a magnetic field. Electromagnetic Induction is the basic principle of operation of transformers and generators.

Electromotive Force (EMF)

The voltage produced by a generator is called an Electromotive Force or EMF. The symbol "E" is often used to indicate an EMF.

Emergency Assistance (EA)

Energy and/or capacity provided to a utility to assist that utility during a capacity emergency.

Energy

The power used over a period of time. Electrical Energy is measured in watt-hours, kilowatt-hours (kWh), or Megawatt-hours (MWh).

Energy Conversion

The conversion of energy from one form to another. For example, a coal fired steam turbine/generator converts the coal's chemical energy to thermal energy by burning the coal. The thermal energy is then converted to mechanical energy by heating water and turning the turbine with steam. The mechanical energy of the turbine is then converted to electrical energy via electromagnetic induction.

Energy Emergency

A condition when an entity has exhausted all other options and can no longer provide its customers' expected energy requirements.

Energy Management System (EMS)

An EMS system is a computer system used by an energy company. The EMS includes the subfunctions of SCADA and AGC.

Envelope

The imaginary boundary that surrounds the fundamental frequency oscillations waveshape. The frequency of lower frequency oscillations can be determined by noting the frequency of the oscillation envelope.

Equal Area Criterion

A method of determining the angle stability or instability of a simple power system. The Equal Area Criterion states that the decelerating area of a power-angle curve must be at least as large as the accelerating area for the power system to be angle stable.

ERCOT

Acronym for the Electrical Reliability Council of Texas. ERCOT is one of the ten NERC Regional Reliability Councils.

Excitation System

A generator control system used to control the production of reactive power. The Excitation System's main components are the voltage regulator and the exciter.

Exciter

The DC power source for an excitation system.

Exciting Current

The current drawn by a transformer to magnetize its core and supply the core losses. The exciting current is typically 1-2% of the transformers full load current.

Extinction Advance Angle

In an HVDC converter operating as an inverter, the angle by which the valve firing is advanced from its normal voltage based commutation point. The Greek lower case letter gamma (γ) is the symbol for the Extinction Advance Angle. The Extinction Advance Angle is used to control the magnitude of the converter's (when operated as a inverter) output voltage

Farad (F)

The unit of capacitance. Symbol is “F”.

Fast Valving

A method of reducing the accelerating energy in a steam turbine/generator. Fast Valving involves the rapid adjustment of turbine valves when a generator starts to accelerate. Fast Valving may assist in maintaining the angle stability of a power system.

Fault

An unintentional short circuit in the power system. A Fault may occur between two phases, between three phases, or between any number of phases and ground.

Federal Energy Regulatory Commission (FERC)

A U.S. government agency responsible for developing regulations that apply to the utility industry.

Feedback Loop

A control loop in which current control actions are influenced by the responses to previous control actions. In a Feedback Loop (such as in a generator’s excitation system) the response of the controlled variable is constantly monitored to determine what new control actions should be taken.

Ferranti Rise Effect

A phenomena in which a transmission line, with one end closed and one end open, is exposed to its highest voltage magnitude at the open-end of the line. The Ferranti Rise Effect is due to the absorption of a leading charging current when a transmission line is energized but open-ended.

Ferroresonance

A resonance condition in which a portion of the inductance is provided by an iron-core inductance (Ferro is Latin for iron.). Iron-core inductances change magnitude when the iron is saturated. Ferroresonance is possible in the transmission or distribution system but is much more common in the distribution system.

Field Winding

The winding wrapped about the rotor of a synchronous machine. DC excitation current is fed to the Field Winding to produce the rotor's magnetic field.

Filter

A combination of capacitors, inductors, and resistors used to encourage or block the flow of a specific frequency or band of frequencies of energy.

Firm Energy

A Firm Energy schedule is treated as if it is the selling control area's own firm load. A firm energy schedule is backed up with reserves by the selling control area.

Flat Frequency Control

An alternative name for constant frequency control.

Flat Tie-Line Control

An alternative name for constant net interchange control.

Flyweights

The portion of a centrifugal ballhead governor that rotates.

Forced Outage

A component failure or other condition which requires that the equipment be removed from service immediately.

Fourier Analysis

A scientific process in which the various frequency components (harmonics) of a waveform are identified. For example, a waveform may have a fundamental frequency of 60 HZ but also contain 3rd and 5th harmonic components. Fourier Analysis is used to identify the harmonic components.

FRCC

Acronym for the Florida Reliability Coordinating Council. FRCC is one of the ten NERC Regional Reliability Councils

Frequency (F)

The rate at which a repeating waveform repeats itself. Frequency is measured in cycles per second or in Hertz (HZ). The symbol if "F".

Frequency Bias Setting (B)

A value entered into the AGC system of a control area. The Frequency Bias or "B" value approximates the frequency response characteristic (FRC or β) of the control area.

Frequency Response Characteristic (FRC or β)

The MW response of the power system (or a section of the power system) to a frequency deviation. The FRC is typically stated in terms of MW per 0.1 HZ. For example, a control area may have an FRC of 200 MW/0.1 HZ. This value of FRC indicates that for a frequency deviation of 0.1 HZ this control area would respond with 200 MW. The FRC of a system varies with changing system conditions.

Fundamental Frequency

The base frequency for a system. For example, the Fundamental Frequency of North American power systems is 60 HZ while a large portion of the world uses 50 HZ as the Fundamental Frequency.

Gallery

A passageway within a water dam created to allow inspection of the dam's structure.

Gate/Grid Control

The means of controlling a mercury arc valve (MAV) or a thyrister valve. A pulse of current or voltage is applied to the Grid of a MAV or the Gate of a thyrister. The pulse will turn the valve on if it is forward biased. Grid/Gate Control is typically only used to turn a valve on.

Generation Control

The process by which the generation supply is adjusted to both maintain system frequency and keep a close match between the actual tie-line flows and the scheduled tie-line flows.

Geomagnetic Disturbance (GMD)

Solar (sun) induced disturbances to the earth's magnetic field. GMDs may result in large low frequency currents flowing in the earth's surface. These currents (called GICs) may enter the power system and damage transformers.

Geomagnetic Induced Currents (GIC)

Low frequency currents induced in the surface of the earth by earth surface potentials (ESPs). ESPs are created by the electrojets that form above the earth's magnetic poles following solar disturbances.

Governor Characteristic Curve

A graphical method of representing the performance of a governor. The horizontal axis is typically generator output while the vertical axis is system frequency. When a governor with a % droop is plotted on such a curve the plot droops from left to right with increasing generator output.

Governor Control System

A control system for a generator that is used to control the speed of the generator's rotating shaft. In a steam turbine/generator the Governor Control System controls the amount of steam striking the turbine blades. In a hydroelectric turbine/generator the Governor Control System controls the amount of water striking the turbine blades. Governor Control Systems are a key ingredient in maintaining a scheduled interconnection frequency.

Greek Alphabet

Upper and Lower case letters from the Greek Alphabet are typically used by electrical engineers to designate angles and represent variables. The following Greek letters are used in this text:

α	alpha	δ	delta	μ	mu	Φ	Phi
β	beta	θ	theta	π	pie	ω	omega
γ	gamma	λ	lambda	ρ	rho	Ω	Omega

Gross Generation

The output power (in MW) at the stator terminals of a generator.

Half-Cycle Saturation

A magnetic saturation of a transformer's core due to the presence of a DC current in the transformer windings. The operating point of the transformer on its saturation curve is shifted such that for a portion of ½ of each cycle the transformer saturates.

Harmonics

Integer multiples of the fundamental frequency. If the fundamental frequency is 60 HZ then the 2nd Harmonic has a frequency of 120 HZ, 3rd Harmonic 180 HZ, etc.

Heat Rate

An expression for the efficiency of a thermal power plant. The Heat Rate is the amount of heat (measured in British Thermal Units or BTU) that is required to produce a kWh or electrical output. The lower the Heat Rate, the more efficient the power plant.

Henry (H)

The unit of inductance. The symbol for a Henry is "H".

High Side Winding (HS)

The high voltage winding of the transformer.

Host Control Area (HCA)

The control area within whose metered boundaries a jointly unit is physically located. Every load and generator must have an HCA.

HVDC

Acronym for High Voltage Direct Current. The term HVDC is commonly used when the DC voltage is above 100 kV.

HVDC Converter

An arrangement of equipment designed and operated to convert between AC and DC power. A Converter can be operated as an inverter (DC to AC) or a rectifier (AC to DC).

HVDC Modulation

A feature added to the controls of an HVDC system. HVDC Modulation modulates (adjusts) the power flow into an HVDC converter in order to dampen power oscillations in the AC supply system. HVDC Modulation assists with damping AC system power oscillations.

Hydraulics

The use of fluid forces to perform work. For example, hydraulics are often used in governor control systems to develop the large forces required to move steam or water valves.

Hypotenuse

The side of a right triangle which is opposite the 90° angle.

IEEE

Acronym for the Institute of Electrical and Electronic Engineers. The IEEE is an international standards organization that publishes guidelines for, among other areas, power systems.

Igneous Rock

Rock that was created by volcanic activity.

Ignition Delay Angle (α)

In an HVDC converter operating as a rectifier, the angle by which the valve firing is delayed from its normal voltage based commutation point. The Greek lower case letter alpha (α) is the symbol for the Ignition Delay Angle. The Ignition Delay Angle is used to control the magnitude of the converter's (when operated as a rectifier) output voltage.

Impedance (Z)

The total opposition to the current flow in an electrical circuit. The symbol for the Impedance is "Z". The Impedance includes the resistance (R), capacitance (C), and the inductance (L).

Impedance Relay

A protective relay that activates if the ratio of the measured voltage divided by the current (the impedance) falls below a pickup point. An Impedance Relay is also commonly called a distance relay.

Impulse Turbine

A water turbine in which high velocity water is directed through nozzles at the Turbine buckets. A Pelton Wheel is an example of an Impulse Turbine.

Inadvertent Energy

When inadvertent interchange exists for a period of time, Inadvertent Energy will be accumulated.

Inadvertent Energy Payback

When the inadvertent energy that a control area accumulates exceeds a specified value, the control area must arrange for an Inadvertent Payback.

Inadvertent Interchange

The difference between the control area's Net Actual Interchange (NI_A) and Net Scheduled Interchange (NI_S).

Incremental Cost

The cost associated with producing an additional MWh of energy from a generating unit. Incremental Cost is typically stated in $/MWh or Mills/kWh.

Incremental Losses

The increase in losses due to an increase in power flow. For example, assume the power flow on a transmission line is initially 100 MW. If the power flow is increased to 101 MW there will be Incremental energy Losses associated with the 1 MW increase in power flow. The percentage of the Incremental Loss increases with increasing levels of power flow.

Inductance (L)

The property of an electrical circuit that opposes a change in current flow. The symbol for Inductance is the letter “L” and the unit is the Henry (symbol “H”).

Induction Machine

An AC machine that can be operated as a generator or as a motor. When operated as a generator the Induction Machine’s rotor is driven at a speed greater than synchronous speed. When operated as a motor the Induction Machine’s rotor is driven at a speed less than synchronous speed. Induction generators are rarely used by large scale power generators. Induction motors are the most common type of AC motor. Induction Machines absorb reactive power (always a lagging load) and cannot be used to produce reactive power as a synchronous machine can.

Inductive Load

A load that absorbs lagging reactive power from the system.

Inductive Reactance (X_L)

The opposition that inductance provides to AC current. The Inductive Reactance (X_L) in a 60 HZ circuit is:

$$\boxed{X_L = 2\pi f L}$$

Inertia

The property of an object that resists changes to the motion of the object. For example, the Inertia of a rotating object resists changes to the object's speed of rotation. The Inertia of a rotating object is a function of its mass, diameter, and speed of rotation.

Inertial Energy

Energy stored within a rotating mass. For example, a spinning generator contains Inertial Energy. The terms Inertial Energy, stored energy, and rotational energy or often used interchangeably to refer to the energy stored in the rotating elements (motors and generators) of the power system.

In-Rush Current

The sudden rush of current when a transformer or a motor is first energized. The peak magnitudes of the In-Rush current last only a few cycles but can reach levels more than 10 times the device's full load current.

Installed Reserve

The difference between a utilities expected annual peak MW generation capability and their annual peak MW load. Installed Reserves are a rough approximation of a utility's spare or reserve generation.

Instrument Transformers (IT)

A low power transformer classification. Instrument Transformers (IT) include current transformers (CTs), potential transformers (PTs) and capacitive devices.

Insulator

A material with a high impedance to current flow. An Insulator is the opposite of a conductor.

Integrated Demand

The average of the instantaneous demands (MW) over the demand interval (usually hours).

Inter-Area Mode

A power oscillation mode (frequency) in which a large section of an interconnected power system oscillates with respect to another large section of the same interconnection. The Inter-Area Mode ranges from 0.05 to 0.5 HZ.

Interchange

Energy either delivered or received by a control area. Interchange schedules and/or flows are always made between control areas.

Interchange Schedule

The planned Interchange between two adjacent control areas that results from the implementation of one or more Interchange Transaction(s).

Interchange Transaction

An energy exchange that crosses one or more control area boundaries.

Interconnect

When two power systems tie together with AC transmission, it is referred to as an Interconnect.

Interconnection

A group of power systems connected together with AC transmission lines. There are four major Interconnections in NERC; Eastern, Western, ERCOT, and Quebec. In addition, there are many other smaller Interconnections including Alaska and Hawaii.

Interruptible Load

Demand that can be interrupted by direct action of the supplying system's system operator in accordance with contractual provisions.

Interruptible Responsive Reserve

Interruptible load controlled by high-set underfrequency relaying.

Intra-Area Mode

A power oscillation mode (frequency) in which a pocket of generation in a power system oscillates with respect to another pocket of generation in the same power system. The Intra-Area Mode ranges from 0.4 to 1 HZ.

Intra-Plant Mode

A power oscillation mode (frequency) in which several generators in a multi-unit power station oscillate with respect to one another. The Intra-Plant Mode ranges from 1.5 to 3 HZ.

Inverter

An HVDC converter operated to convert DC power to AC power.

Ionization

Ionization occurs when an atom (or group of atoms) receives enough energy to split into one or more free electrons and a positive ion. Ionization is a special case of charging. The visible corona effect that often surrounds energized equipment is due to ionization of the air by the strong electric field surrounding the energized conductor.

Island

An electrically isolated portion of an interconnection. An Islanded system maintains its own frequency. Islands are frequently formed after major disturbances or during restoration following a major disturbance.

Isochronous Governor Control

A governor operated with a 0% droop. When in Isochronous Control, a governor will try to maintain 60 HZ. Isochronous Control may be used during a system restoration.

Isolated

To be electrically separated from the remainder of the interconnection. An Isolated system does not have transmission ties to the rest of the interconnection. An Isolated system is an electrical island.

Joint Control

Automatic generation control of jointly owned units by two or more control areas.

Kirchhoff's Current Law

A basic electrical law that states that the sum of all the currents at any point in an electrical circuit equal zero amps.

Kirchhoff's Voltage Law

A basic electrical law that states that the sum of all the voltages around any closed electrical circuit equal zero volts.

Lagging

Term used when comparing voltage and current waves. The wave that is heading positive and crosses zero last is the Lagging wave. In a Lagging load the current wave lags the voltage wave.

Lambda (λ)

The incremental cost of generation. Lambda is commonly expressed in $/MWh or Mils/kWh. The symbol for Lambda is "λ" (the Greek letter lambda).

Leading

Term used when comparing voltage and current waves. The wave that is heading positive and crosses zero first is the Leading wave. In a Leading load the current wave leads the voltage wave.

Lightning Arrester

A piece of equipment that is designed to protect the power system from high voltages. Lightning arresters activate when transient over voltages (TOVs) occur and harmlessly shunt the voltage surge to ground.

Load

The amount of electric power delivered or required at any specified point or points on a system.

Load Overshoot

A short term increase in load magnitude due to an increase in the customers voltage. Load Overshoot results from downstream tap changers boosting the customers voltage prior to the upstream tap changer responding.

Load Reference Set-Point

In governor control systems this setting determines the position of the controlled valve when the frequency is at the scheduled value. From a system operations perspective, the Load Reference Set-Point is the MW a generator will produce when the frequency is 60 HZ.

Load Rejection

The rejection of load by a generator. If a generator suddenly loses its transmission path, it has undergone a load rejection. The generator will speed up until its mechanical power input can be removed or the unit tripped.

Load/Frequency Relationship

The relationship between frequency deviations and the load magnitude. In general, the load magnitude varies with the frequency. If the frequency rises the load magnitude rises and vice versa.

Local Mode

A power oscillation mode (frequency) in which a generator oscillates with respect to the remainder of the power system. The Local Mode ranges from 0.8 to 2 HZ.

Logistics

The handling of the details of an operation.

Loss of Load Diversity

An increase in the total load that occurs due to a majority of the customer's load drawing power from the system at the same time. During normal system operations only a percentage of the customer' total load is drawing power at any one time. When Load Diversity is lost a larger percentage of the customer load draws power simultaneously.

Loss of Synchronism

The loss of the magnetic bond between elements of a power system. Loss of Synchronism and out-of-step refer to the same concept.

Losses

The energy losses in the power system. The total system Losses consist of the transmission, transformation, and distribution system Losses.

Low Side Winding (LS)

The low voltage winding of the transformer.

MAAC

Acronym for the Mid-Atlantic Area Council. MAAC is one of the ten NERC Regional Reliability Councils.

Magnetic Field

The invisible lines of force between the north and south poles of a magnet. A Magnetic Field is created when current flows through a conductor. Energy is stored in a Magnetic Field.

Magnetism

A property of matter associated with moving charges. A material may be a permanent magnet or it may acquire magnetic characteristics due to current flow through the material.

MAIN

Acronym for the Mid-America Interconnected Network. MAIN is one of the ten NERC Regional Reliability Councils.

MAPP

Acronym for the Mid-continent Area Power Pool. MAPP is one of the ten NERC Regional Reliability Councils.

Marketer

An entity that has the authority to take title to electrical power generated by itself or another entity and remarket that power at market-based rates.

Mechanical Energy

Energy of a mechanical nature. For example, a rotating mass possesses Mechanical Energy.

Mechanical Input Power

Power input of a mechanical nature. For example, a steam or water turbine input Mechanical Power to the rotor of a generator.

Mercury Arc Valve (MAV)

A high power switch that utilizes older "tube" based technologies. MAVs were commonly used in HVDC converters and other power converter applications. MAVs have largely been replaced by thyristers.

Metering

A device for measuring a quantity. For example Meters are used to measure power flows, voltages, current, frequency, etc.

Microprocessor

An arithmetic, logic, and control unit all contained on one integrated circuit chip. One Microprocessor will contain thousands of transistors.

Mill

A unit of currency equal to 1/10 of a cent.

Mode

A specific oscillation frequency. For example, a steam/turbine generator's shaft has specific frequencies at which it is susceptible to SSR. These frequencies are called Modes.

Monopolar HVDC

An HVDC system that uses one conductor energized with either a positive or negative voltage and a current return path.

Motor Load

A simplified grouping of all spinning type load. Motor Load includes air conditioner compressors, motor drives, etc. Total load is composed of Motor Load plus non-motor load.

Natural Frequency

Every mechanical device has a natural frequency of oscillation. For example, when a force is applied to a bridge the bridge will oscillate at its natural frequency. Electrical circuits also have a natural frequency of oscillation. An electrical circuit's natural frequency is determined by its resistance, inductance, and capacitance.

NERC

An acronym for the North American Electric Reliability Council. NERC is a voluntary group composed of members who either generate, transmit, or market electricity. The purpose of NERC is to enhance the reliability of the interconnected power systems of North America. NERC publishes Operating Policies that provide guidance as to how to reliably operate the power system.

Net Actual Interchange (NI_A)

The algebraic sum of all metered interchange over all Interconnections with all adjacent control areas. It is, in essence, the actual interchange with the Interconnection.

Net Generation

The net power available from a generator to be fed to the power system. Net Generation is equal to gross generation minus the generator's internal power usage (station service).

Net Scheduled Interchange (NI_S)

The net of all Interchange Schedules with all adjacent control areas. It is, in essence, the scheduled interchange with the Interconnection.

No Load Tap Changer (NLTC)

A tap changer that is designed to change the turns ratio only when the transformer has no current flow across its windings. The term Off Load Tap Changer (OLTC) is also used to refer to this type tap changer.

NOAA

The acronym for the National Oceanic and Atmospheric Administration of the U.S. Government.

Nominal

The design or rated value. Not necessarily the value that is intended or that occurs. For example, the Nominal voltage for a piece of equipment would be the design or rated voltage but in operation the equipment may be operated at a different value of voltage.

Nominal Load

The rated or nameplate load. For example, 100 MW of customer load may be fed from a utility bus. This load will draw 100 MW if the voltage and frequency at the bus are at nominal values. If voltage or frequency should vary then the actual load will be different than the Nominal Load.

Non-Firm Energy

Energy that may be canceled or interrupted by the delivering control area at any time and for any reason. The control area that receives Non-Firm Energy must back up the non-firm energy purchase with reserves.

Non-Motor Load

A simplified grouping of all non-spinning type load. Non-Motor Load includes resistive heaters, lighting, etc. Total load is composed of motor load plus Non-Motor type Load.

Non-Spinning Reserve

That operating reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.

Normal Excitation

A condition in which the generator's excitation system is supplying exactly the excitation current needed to maintain the magnetic field of the generator. A Normally Excited generator is neither supplying or absorbing reactive power from the system.

NPCC

Acronym for the <u>N</u>ortheast <u>P</u>ower <u>C</u>oordinating <u>C</u>ouncil. NPCC is one of the ten NERC Regional Reliability Councils.

Ohm

The unit of impedance. The symbol for the Ohm is "Ω" (Greek upper case letter Omega.)

Ohm's Law

A basic electrical law that relates the voltage (V), current (I), and impedance (Z). Ohm's Law is commonly stated as:

$$\boxed{V = I \times Z}$$

Operating Reserve

The MW capability above system demand required to provide for frequency regulation, load forecasting error, and equipment forced outages. Operating Reserve is drawn from spinning and non-spinning sources and consists of Regulatory and Contingency Reserves.

Operating Security

The ability of a power system to withstand or limit the adverse effects of any credible contingency to the system including overloads beyond emergency ratings, excessive or inadequate voltage, loss of stability or abnormal frequency deviations.

Operating Security Limit

The value of a system operating parameter (for example, total MW transfer across an interface) that satisfies the most limiting of prescribed pre- and post-contingency operating criteria as determined by equipment loading capability and acceptable stability and voltage conditions.

Oscillations

Cyclic variations in voltage, current, frequency, or power flows. The voltage and current of the power system naturally oscillates at 60 HZ. The term Oscillations is typically used to refer to low frequency (a few HZ) Oscillations that may occur.

Oscillatory Stability / Instability

An angle stability classification. The Oscillatory Stability limit of a power system is the maximum amount of active power that can be transmitted across the system without excessive power oscillations leading to a loss of synchronism. No large disturbance need occur. The response of generator control systems (governor and exciter) are very important to Oscillatory Stability / Instability.

Out-of-Step (OOS)

To lose synchronism. Out-of-Step is best viewed in terms of rotating magnetic fields. When a generator is Out-of-Step with the power system it connects to, the generator's rotating magnetic field is no longer in-step or in synchronism with the rotating magnetic field of the system.

Out-of-Step Protective Relay

A protective relay that is designed to detect out-of-step conditions and initiate a user determined response. Out-of-Step Protective Relays are often based on the same principles as impedance relays. An Out-of-Step Relay differentiates between an out-of-step condition and a fault condition by measuring the speed at which the measured impedance changes.

Overcurrent Relay

A protective relay that activates in response to a high current magnitude. Overcurrent Relays can be either timed or instantaneous and directional or non-directional.

Overexcite

A generator is overexcited when the applied excitation is greater than that needed to support the generator's magnetic field. The excess reactive power produced by the overexcitation condition flows to the system. An Overexcited generator supplies reactive power to the system. The terms "lagging" and "boosting" are also used to refer to an Overexcited generator. A transformer may also Overexcite. Overexcitation of a transformer results from either applying to high a voltage magnitude or operating at to low of a frequency.

Overlap Angle (μ)

When commutating between two valves in an HVDC converter, a natural overlap period occurs in which both valves are simultaneously conducting. The length of the overlap period is measured in degrees and is called the Overlap Angle. The symbol for the Overlap Angle is the Greek lower case letter mu (μ).

Parallel Circuit

An electrical circuit in which all the positive terminals are connected to a common point. All the negative terminals are connected to a second point. The voltage drop is the same across each full element of the parallel circuit.

Parallel Resonance

A resonance condition in a circuit with a parallel combination of inductance and a capacitance. At resonance a parallel circuit reaches its maximum impedance equal to a multiple of the circuit's resistance value.

Peaking Generating Units

Generators that are normally only run during the peak load periods of the load cycle.

Penstock

A water pipe or conduit that carries water from the upper water reservoir to the turbine at a hydroelectric unit.

Period

The time for one complete cycle of a repeating wave. For example, a 60 HZ current steps through 60 cycles per second. The Period of one complete cycle is therefore 1/60th of a second.

Permanent Magnet Generator (PMG)

A simple generator that uses a permanent magnet (a material that retains its magnetism) to provide the required magnetic field. PMGs are often part of governor control systems. The PMG is used to produce an output voltage whose magnitude is representative of a generator's shaft speed.

Per-Unit (P.U.)

A system for reporting quantity magnitudes. A Per-Unit number is stated in terms of a base quantity. For example if the base voltage is 345 kV then a voltage of 359 kV is 1.04 Per-Unit (359/345=1.04).

Phase

AC power systems use three conductors to efficiently generate and transmit large amounts of power. Each of the conductors is called a Phase. The Phases are each assigned a letter designation; "A", "B", and "C". Customer load can be connected as single-phase (1Φ), two-phase (2Φ), or three-phase (3Φ).

Phase Angle

The angle by which one waveform leads or lags another waveform. A Phase Angle can exist between two voltages, two currents, or between a current and a voltage.

Phase Shifting Transformer (PST)

A transformer designed to shift the phase of the incoming voltages. PSTs use a tap changing winding in the similar manner to a conventional tap changer. The voltage of a PSTs tap changer is added in quadrature to the incoming voltage to create a phase shift. PSTs are also referred to as phase angle regulators or PARs.

Phasors

Similar to a vector but also includes information about the frequency of the quantity. A Phasor diagram is a collection of lines that, like vectors, illustrate a quantities magnitude and direction. However, Phasor diagrams must also specify the frequency of the quantity. AC voltages and currents can be represented by Phasors.

Pick-up Point

An operating setting for a protective relay that determines at what point the relay will activate.

Pilot Relay

A protective relay system typically used to protect high voltage transmission lines. Pilot Relays use telecommunication systems to communicate between the terminals of the transmission line.

Planned Outage

An outage that is planned well in advance.

Poles

The electrical circuits formed by the field winding on the rotor of a synchronous generator. When DC current is passed through the field winding the Poles become magnetic north or south poles.

Potential Difference

A difference in voltage magnitudes between two locations. Current can flow along a closed path if a Potential Difference exists across the path.

Potential Transformers (PT)

A low power transformer (an instrument transformer) used to reduce normally high power system voltages to low values (≈ 110 Volt). A PT has a high number of turns on the primary winding and a low number of turns on the secondary winding. The low magnitude secondary voltages of a PT are typically input to meters, relays, etc.

Power (P)

The rate at which energy is expended to do work. Power is measured in watts (W), kilowatts (kW), Megawatts (MW), or Gigawatts (GW).

Power Angle (δ)

The phase angle between two voltage waveforms. A Power Angle is the same as a voltage angle difference. The Power Angle is a major factor in determining the amount of MW flow between two locations. The Greek letter delta (δ) is the symbol for power angle.

Power Converter

A mechanical or solid state device for converting AC power to DC power or vice versa. Modern Power Converters are thyrister based devices that are typically strong sources of harmonics.

Power Factor (PF)

The ratio of the active power (MW) to the complex power (MVA). The cosine of the phase angle between a load's voltage and current is the Power Factor of the load. A unity Power Factor load draws no reactive power, just active power.

Power Pool

Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

Power System

The collective name given to the elements of the electrical system. The Power System includes the generation, transmission, distribution, substations, etc.. The term Power System may refer to one section of a large interconnected system or to the entire interconnected system.

Power System Stabilizer (PSS)

A feature added to an excitation system that is designed to assist with the damping of low frequency (≈1 HZ) power system oscillations. A typical PSS provides positive damping to power oscillations by ensuring that voltage corrections made by the excitation system are in-phase with detected frequency oscillations.

Power-Angle Curve

A graphical representation of the active power transfer equation. The Power-Angle Curve is a plot of the active power transfer as the power angle is varied between 0° and 180°. The Power-Angle Curve is a good tool for analyzing the angle stability of a simple (two bus) power system.

Power-Circle Diagram

A graphical method of illustrating how MW and Mvar flows change as the power angle changes. Power-Circle Diagrams are composed of circular characteristics of the power flow out of the sending end and into the receiving end of a two bus system.

Primary Winding

The winding of a transformer that is connected to the power input or source end of the transformer.

Prime Mover

A mechanism that converts thermal or hydraulic energy into mechanical power. For example, a coal fired boiler with a steam turbine is a Prime Mover as it converts the thermal energy of coal into the mechanical power to turn the turbine.

Production Cost

The costs associated with starting, operating, and stopping generating units.

Protective Relay

A mechanical or electronic device used to sense power system disturbances and respond to limit the possible damage.

Pump-Storage Unit

A hydro facility that can be operated as a generator or a motor (pump) depending on system energy needs and water storage levels.

P-V Curve

A power verse voltage curve. A plot of the power transferred to a bus verse the voltage at that bus. P-V Curves are a graphical tool used to analyze a power system’s voltage stability.

Pythagorean Theorem

A mathematical relationship which states that in a right triangle the square of the hypotenuse length is equal to the sum of the squares of the lengths of the remaining two sides.

Quadrature (Q)

At an angle of 90°. When two vectors are in quadrature they are perpendicular to one another. The symbol “Q” for reactive power is derived from the word Quadrature.

Quality (Q)

A factor for measuring the frequency response of an electrical circuit. A circuits Quality is dependent upon the relative magnitudes of the reactive and resistive elements.

Ramp Period

The time between generation ramp start and end times usually expressed in minutes.

Ramp Window

The time period that occurs each hour for adjusting a control area’s generation. A typical Ramp Window is from 10 minutes to the hour till 10 minutes after the hour. If all control areas use the same Ramp Windows, frequency deviations will be reduced.

Rate-of-Change (Protective Relay)

A type of protective relay that monitors the rate at which a quantity changes. For example, a Rate-of-Change relay may monitor the rate at which the MW flow along a transmission line varies. The relay could be set to trip the line if the rate of MW flow change exceeds a specified value.

Reach

The extent of protection that an impedance relay provides to a transmission line. The Reach is typically defined in terms of the impedance of the line. For example, a zone #1 impedance relay may Reach 90% into the protected line.

Reaction Turbine

A water turbine in which the pressure difference across the turbine blades causes the blades to turn. A Francis Turbine is an example of a Reaction Turbine.

Reactive Capability Curve

A graphical method of illustrating the complex power output limits of a synchronous generators. The Reactive Capability Curve is sometimes called a "D-Curve" as it is typically shaped like the letter "D".

Reactive Power (Q)

The component of complex power that is used to build electric and magnetic fields. The common unit for Reactive Power is the MVAR and the symbol is "Q".

Reactor

A device intentionally designed to act as an inductor and store energy in its magnetic field. A shunt Reactor acts as a sink (absorber) of reactive power to the system. Series Reactors are devices that are used to increase the inductive reactance (X_L) of a transmission path.

Receiving Control Area

The control area importing the Interchange.

Reclosing Relay

A relay that automatically (after a few cycles or a few seconds) recloses a transmission line following a fault.

Rectifier

An HVDC converter operated to convert AC power to DC power.

Regulating Reserve

Spinning reserve that is responsive to AGC commands. Regulating Reserve must be available to AGC at a sufficient rate for effective frequency regulation.

Regulating Transformer

A transformer used to regulate voltage or phase angle. Conventional tap changing (ULTC) transformers and phase shifting transformers (PSTs) are Regulating Transformers.

Regulating Unit

A generator used for the regulation of system frequency. To serve as a Regulating Unit the generator must have available spinning reserve.

Regulation

The ability to maintain a quantity within acceptable limits. For example, frequency Regulation is the control or Regulation of the system frequency to within a tight bandwidth of 60 HZ. Voltage Regulation is the control of a voltage level within a set bandwidth.

Regulation Service

The process whereby one control area contracts to provide corrective response to all or a portion of the ACE of another control area.

Relative Acceleration

For torque and power angles to change, a Relative Acceleration must exist for a period of time. One part of the system must accelerate with respect to another part. Once Relative Acceleration occurs, any speed difference that has developed will continue the increase or decrease in torque or power angles. Torque and power angles will not stop changing until all sections of the system are running at the same frequency.

Relay

A electrical or mechanical device that responds to a measured input with a user determined output. Types of Relays include auxiliary relays, monitoring relays, regulating relays, and protective relays.

Regional Reliability Councils (RRC)

The geographical regions of NERC. NERC is divided into ten Regional Reliability Councils:

ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
MAAC	Mid-Atlantic Area Council
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

Reliability Authority

An entity that provides the reliability assessment and emergency operations coordination for a group of control areas.

Remote Terminal Unit (RTU)

An electronic device, installed in a substation or generator, which acts as an interface between a company's EMS system and the generator or substation.

Reserve Sharing Group

A group whose members consist of two or more control areas that collectively maintain, allocate, and supply operating reserves required for each control area's use in recovering from contingencies within the group.

Resistance (R)

The property of a material that opposes or resists current flow by converting electric energy to heat. The symbol for Resistance is the letter "R".

Resistivity

A measure of the ability of a material to conduct electricity. The greater the Resistivity, the greater the opposition to current flow. An insulator has a high Resistivity.

Resonance

In an electrical circuit, Resonance is achieved when the magnitudes of the inductive and capacitive elements match. Resonance may be achieved by inputting energy at the circuit's resonant frequency or by varying the size of the inductive or capacitive elements. A radio receiver is tuned to resonance at the channel the operator wants to receive.

Resonant

To achieve resonance.

Resonant Frequency (F_R)

The frequency at which resonance is achieved in an electrical circuit. The formula for the resonant frequency is:

$$\boxed{F_R = \frac{1}{2\pi\sqrt{LC}}}$$

Resources

In this text Resources is typically used to refer to available generation. For example, load must match Resources to maintain frequency.

Response Rate

The rate of load change that a generating unit can achieve for normal loading purposes expressed in megawatts per minute (MW/Min).

Responsive Reserves

Reserve capacity that is available to respond to system frequency disturbances.

Responsive Spinning Reserve

That portion of spinning reserve available to respond to frequency disturbances as a result of the generator's normal governor action.

Restrike

The re-ignition of an electric arc.

Right Triangle

A triangle in which one of the three internal angles is equal to 90°.

Root Mean Square (RMS)

The effective value of an AC voltage or current. The RMS value of an AC quantity would produce the same amount of heat in a DC resistive circuit. For example if an AC circuit has an RMS current of 10 amps, then 10 amps of DC current would have the same heating effect. Most AC meters read RMS values.

Rotational Energy

Energy stored within a rotating mass. For example, a spinning generator contains rotational energy. The terms inertial energy, stored energy, and Rotational Energy are often used interchangeably to refer to the energy stored in the rotating elements (motors and generators) of the power system.

Rotor

The rotating component of a motor or generator.

Runner

The rotating element of a hydro turbine.

Saturation

After a magnetic field reaches a certain strength, any further increase in the current that caused the magnetic field will not result in any increase in the strength of the magnetic field. The magnetic material is saturated at this point. When a transformer becomes saturated, the core's magnetic field will expand and link portions of the transformer not designed for exposure to an alternating magnetic field. Transformer thermal problems may result.

Schedule

To set up a plan or arrangement for an Interchange Transaction.

Scheduled

The desired or target value. For example, for a 345 kV bus, the Scheduled value of voltage may be 358 kV. System Operators would try to hold this bus voltage at 358 kV.

Scheduled Net Interchange

The sum of the intended (scheduled) active power flows on all of a control area's tie-lines.

Scrubber

A pollution control system used in fossil fuel units for removing sulfur from the exhaust gases.

Secondary Winding

The winding of a transformer that is connected to the power output or load end of the transformer.

Sectionalizing

The process of reducing the load on a distribution feeder using switching actions.

Self-Excitation

A possible operating condition for a generator in which the charging current from a high voltage transmission system takes over as the excitation current source of the generator. Self-Excitation is a dangerous condition as high voltages can develop in the generator and in the generator auxiliaries.

Sending Control Area

The control area exporting the Interchange.

SERC

Acronym for the Southeastern Electric Regional Reliability Council. SERC is one of the ten NERC Reliability Councils.

Series Circuit

Electrical circuit in which elements are connected end to end. The same current flows through each element of a Series Circuit.

Series Resonance

A resonance condition in a circuit with a series combination of inductance and capacitance. At resonance a series circuit reaches its minimum impedance equal to the circuit's resistance value.

Servomotor

A device used to create a force based on a control signal input. For example, in a governor control system a control signal is first developed using a control valve. The control signal is input to a Servomotor. The Servomotor then drives steam valves, wicket gates, etc. The Servomotor may be an electric motor, an hydraulic piston, or any other means of developing a force.

Shield Wires

Conductors strung across the top of transmission lines that are designed to protect the transmission line from lightning strikes.

Short Circuit

The introduction of a low impedance path between conductors energized at different voltages. A Short Circuit is the same as a fault.

Short Circuit Ratio (SCR)

The ratio between the short circuit MVA of the local system and the MVA rating of a piece of equipment. For example, the SCR of a generator is equal to the MVA that would flow to a 3Φ fault applied at the generator's high side bus divided by the MVA rating of the generator. SCRs can also be calculated for HVDC systems and other electrical devices.

Sine

The Sine of either of the unknown angles of a right triangle is the ratio of the side directly opposite the unknown angle to the hypotenuse.

Sinewave

A quantity that continually repeats itself. For example, AC voltage and current are Sine waves. The wave shape for the cosine function is the same as the sine function but with a 90° phase angle difference.

Sink Control Area

The control area in which the load (sink) is located for an Interchange Transaction.

Six-Pulse Converter

An HVDC converter that has six pulses to the DC output voltage for each cycle of the AC supply voltage.

Sliding Pressure

A method of operation available in some thermal units. Normally a unit's steam valves are adjusted to control the amount of steam sent to the turbine stages. In a Sliding Pressure mode of operation, the steam valves are operated wide open to minimize valve throttling losses. The boiler pressure is then varied to adjust the MW output of the unit.

Slip

The difference between the synchronous speed of an induction motor and the speed at which its rotor actually rotates.

Slip-Rings

Metal rings attached to the shaft of a synchronous machine. The Rotor's field winding terminates on the inner surface of the Slip-Rings while the Brushes ride on the smooth outer surface of the Slip-Rings.

Smoothing Reactor

A series reactor attached to an HVDC transmission line that smoothes the ripple of an HVDC converter's DC output voltage and assists with the power conversion process.

Software

A series of instructions written to enable computer hardware to perform useful tasks

Solar Magnetic Disturbance (SMD)

Solar (sun) induced disturbances to the earth's magnetic field. SMDs may result in large low frequency currents flowing in the earth's surface. These currents (called GICs) may enter the power system and damage transformers.

Solenoid

An electro-magnet that, when energized, is used to perform a mechanical function such as opening a switch.

Solid-State Relay

A relay that uses semiconductor components.

Source Control Area

The control area in which the generation (source) is located for an Interchange Transaction. (This will also be a sending control area for the resulting Interchange Schedule.)

Special Protection System (SPS)

A protection system designed to perform functions other than the isolation of electrical faults. Also called "remedial action scheme or RAS".

Spinning Reserve

Unloaded generation that is synchronized and ready to serve additional demand.

SPP

Acronym for the Southwest Power Pool. SPP is one of the ten NERC Regional Reliability Councils.

Static Var Compensator (SVC)

A combination of shunt reactors and shunt capacitors that use thyrister based switches and thyrister control to regulate the var output.

Static Var System (SVS)

A combination of an SVC and other reactive power equipment. A common control system controls both the SVC and the other reactive equipment.

Station Service

The electric supply for the ancillary equipment used to operate a generating station or substation.

Stator

The stationary component of a motor or generator.

Steady State Stability / Instability

An angle stability classification. The Steady State Stability limit of a power system is the maximum amount of active power that can be transmitted across the system without a loss of synchronism occurring. No large disturbance need occur.

Stored Energy

Energy stored within a rotating mass. For example, a spinning generator contains Stored Energy. The terms inertial energy, Stored Energy, and rotational energy are often used interchangeably to refer to the energy stored in the rotating elements (motors and generators) of the power system.

Substation

An element of the power system that contains circuit breakers, disconnect switches, transformers, reactors, capacitors, and other equipment. A central control house is often provided to house control and protective equipment.

Subsynchronous

A frequency below synchronous speed.

Subsynchronous Resonance (SSR)

An electric power system condition where the electric network exchanges energy with a turbine/generator at one or more of the natural frequencies of the combined system. The frequency of the energy exchange is below the synchronous frequency (subsynchronous) of the system.

Sub-Transmission Lines

Conductors (typically 3Φ) used to interconnect bulk power substations and distribution substations. Sub-Transmission Lines are defined in this text as lines with voltages greater than 46 kV and less than 230 kV.

Sunspots

Large dark colored patches on the surface of the sun. Sunspots are a consequence of energy disturbances on the surface of the sun.

Supercritical Boiler

A boiler system that is operated at a much higher temperature and pressure than a conventional drum type boiler. Supercritical Boilers are also called "once through" type boilers. A Supercritical Boiler does not have any significant steam storage, which effects its response to governor commands.

Supersynchronous

A frequency above synchronous speed.

Supervisory Control and Data Acquisition (SCADA)

A system of remote control and telemetry used to monitor and control the transmission system.

Surge Impedance Loading (SIL)

The MW loading on a transmission line at which the line's natural reactive power production equals its reactive power usage.

Switching Order

A sequence of steps to accomplish a desired switching action.

Switching Process

The process by which the status (open, closed, etc.) of power system equipment (switches, circuit breakers, etc.) is adjusted to perform maintenance or enhance operations.

Switching Surge

The sudden changes to voltage and current waveforms that accompany transmission system switching events.

Synch-Check Relay

A protective relay that will not allow a circuit breaker to be closed unless the frequency difference, voltage magnitude difference, and voltage angle across the open circuit breaker are within acceptable limits.

Synchronous

To be in-step with a reference. A Synchronous generator rotates in synchronism with the power system.

Synchronous Condenser

A synchronous machine that operates as a synchronous motor. The MW to turn the machine's shaft is drawn from the power system. The full capabilities of the machines excitation system (to absorb and supply MVAR) are then available for voltage control purposes. Hydroelectric generators can often be operated in Synchronous Condenser mode. The unit's water turbine is typically de-watered and the unit's rotor turned as if it were a motor.

Synchronous Machine

An AC machine whose rotor rotates in synchronism with the power system to which it is attached. Synchronous Machines can be either generators or motors. A Synchronous Machine also includes a source of DC excitation current (the excitation system).

Synchronous Speed

The speed at which a synchronous generator must rotate in order to stay in synchronism with the rotating magnetic field of the system. The Synchronous Speed is determined by the frequency of the power system and the number of rotor magnetic poles.

Synchroscope

A device for comparing the frequency difference and voltage angle across an open circuit breaker.

System Load

The average power delivered over a period of time. Typically the System Load is the average demand over a particular hour.

System Operator

The person responsible for the operation of the power system. Typical System Operator duties include generation control and transmission switching.

Taps

Fixed electrical contacts at different positions on a transformer's winding. Taps are adjusted to change the voltage ratio of a transformer.

Target

An indicator on a relay that is displayed when the relay operates. The term "flag" is often used to refer to a Target.

Telemetry

Equipment for measuring a quantity (amps, volts, MW, etc.) and transmitting the result via a telecommunication system (radio, microwave, etc.) to a remote location for indication or recording.

Tertiary Winding

An additional winding added to a power transformer. The Tertiary Winding may be used to connect a reactor, capacitor, or to provide station service.

Thrust Bearing

The bearing that supports the actual weight of the generator.

Thyrister

A solid state electronic component whose ability to conduct current is controlled via its voltage polarity or a gate signal. Thyristers are also called silicon controlled rectifiers (SCR). Thyristers are combined in series/parallel arrangements to perform rapid switching actions. Thyristers are used in modern static var compensators (SVC), adjustable speed drives (ASD), and high voltage direct current (HVDC) systems.

Tie-Line

A transmission line that connects two control areas. A Tie-Line is sometimes referred to as an interconnection.

Tie-Line Bias Control (TLB)

An operating mode of an AGC system. While in Tie-Line Bias Control an AGC system will determine the ACE value by considering both the interchange and frequency errors.

Tie-Line Telemetry

Telemetry equipment used to measure power flow data on a tie-line connecting control areas. The power flow data is then transmitted to both control areas.

Time Error

An accumulated time difference between the actual power system time and a time standard. Time Error is caused by a difference between the power system's actual frequency and 60 HZ.

Torque

The Torque is a force that produces a rotating or twisting action.

Torque Angle (δ)

The angle by which the rotating magnetic field of synchronous machine leads or lags the rotating magnetic field of the system to which it connects. A generator has a positive Torque Angle while a motor has a negative Torque Angle. The symbol for the Torque Angle is the letter "δ" (Greek lower case letter delta).

Torque-Speed Curves

A graphical means of illustrating the relationship between the torque developed by a motor and the speed of rotation of the motor shaft.

Torsional

A twisting force.

Total Harmonic Distortion (THD)

A computed value used to quantify the harmonic content of a waveform. The THD is a measure of the percent of the harmonic components content as compared to the magnitude of the fundamental component.

Total Load

The summation of motor and non-motor load.

Total Transfer Capability (TTC)

The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while still satisfying any applicable post-contingency conditions.

Transformer

An electrical device with two or more windings used to transform AC system voltage and current levels. A Transformer works via the principle of electromagnetic induction where a voltage is induced in one winding via an alternating magnetic field in the other winding. Power Transformers are used to transform large amounts of power while instrument Transformers are used to produce low voltages and currents.

Transient

A short term phenomena.

Transient Stability / Instability

An angle stability classification. The Transient Stability limit of a power system is the maximum amount of active power that can be transmitted across the system without a loss of synchronism. When Transient Stability limits are determined the power system is exposed to a large disturbance. A power system is Transiently Stable if it survives the disturbance without losing synchronism. If Transient Instability occurs, it will typically occur within less than a second following the large disturbance.

Transmission Lines

Conductors (typically 3Φ) used to interconnect power sources (generators) and bulk power substations or to interconnect bulk power substations. Transmission Lines are defined in this text as lines with voltages equal to or greater than 230 kV.

Traveling Wave

Energy can be viewed as a wave traveling through space. When a disturbance occurs in the power system the disturbance can be viewed as a wavefront of current and voltage propagating out from the disturbance point. A frequency disturbance can also be viewed in terms of a frequency deviation propagating out from the disturbance point in the shape of a wave.

Trigonometry

A branch of mathematics that deals with the relationships between the lengths of sides and the angles between the sides of triangles.

Triplen Harmonics

The harmonic orders which are evenly divisible by the number three. For example, the 3^{rd}, 6^{th}, 9^{th}, 12^{th}, etc. are triplen harmonics.

Turbine

A rotating mechanical device. A Turbine is rotated by the force of a working fluid. The working fluid is typically steam, water, or combustion gas.

Turbine Follow

A mode of operation of a fossil units turbine/boiler control system in which the unit's response to a load (MW) change request is delayed if the boiler's temperature and/or pressure moves outside set boundaries. The MW response of the unit's turbine "follows" the response of the boiler.

Turning Gear

A method of rotating the shaft of a horizontally mounted turbine/generator. The turning gear may rotate the shaft at 2 RPM to prevent shaft warpage.

Turns Ratio

The ratio of the number of turns in the primary winding of a transformer to the number of turns in the secondary winding.

Twelve Pulse Converter

An HVDC converter that has twelve pulses to the DC output voltage for each cycle of the AC supply voltage.

Under Load Tap changer (ULTC)

A tap changer that is designed to change the turns ratio when the transformer has current flow across its windings. The term Load Tap Changer (LTC) is also used to refer to this type tap changer.

Underexcite

A generator is underexcited when the applied excitation is less than that needed to support the generator's magnetic field. The deficiency in the reactive power needs of the generator is supplied by the system. An

Underexcited generator absorbs reactive power from the system. The terms "leading" and "bucking" are also used to refer to an Underexcited generator.

Underfrequency Load Shedding (UFLS)

The tripping of customer load based on magnitudes of system frequency. For example, a utility may dump 5% of their connected load if frequency falls below 59.3 HZ, dump an additional 10% if frequency falls below 58.9 HZ, and dump a final 10% if frequency falls below 58.5 HZ. These three steps of load shedding would form this utilities UFLS plan. The purpose of UFLS is a final effort to arrest a frequency decline.

Undervoltage Load Shedding (UVLS)

The tripping of customer load based on magnitudes of system voltage. For example, a utility may dump 5% of their connected load if voltage falls below 92% of nominal and an additional 10% of their load if voltage falls below 90% of nominal. These two steps of load shedding would form this utilities UVLS plan. The purpose of UVLS is typically to avoid a voltage collapse.

Unit Commitment

The process of selecting which generating units will be placed on line to serve the load and reserve requirements.

Unscheduled Power Flow

Power does not flow where it is scheduled but rather according to the relative impedance of the available paths. When power is scheduled to flow from system "A" to system "B" some of the power may flow through an adjoining system "C". The power that flows through system "C" is called unscheduled power flow.

Valve

General name given to a mercury-arc or thyrister based device that is used to conduct current when a control signal is applied. A Valve is turned on by a gate or grid pulse. When turned on a Valve conducts current. When turned off a Valve blocks the flow of current. A Valve is turned off by removing the forward biased voltage and stopping the current flow. Power converters are composed of several Valves connected in different arrangements depending on the converter design.

Vectors

Line segments that are used to represent the magnitude and direction of physical quantities. DC voltages and currents can be represented by Vectors.

Voltage (V)

The electrical force (a separation of charge) that causes current to flow. Symbol is "V" and units are volts.

Viscosity

A property of a fluid that tends to prevent the fluid from flowing when subjected to an applied force. High-viscosity fluids resist flow; low-viscosity fluids flow easily.

Voltage Angle

The phase angle between two voltages. The Voltage Angle is the same as the power angle. (In a generator the Voltage Angle between the internal generator voltage and the stator terminal voltage is the equivalent of the torque angle.)

Voltage Collapse

A process in which a voltage unstable system experiences an uncontrollable reduction in system voltage.

Voltage Ratio

The ratio between the primary and secondary voltages of a transformer. There is a strong (but not identical) relationship between a transformer's Voltage Ratio and its turns ratio.

Voltage Regulator

A component of an excitation system. The Voltage Regulator monitors the generator's output voltage and causes an adjustment in excitation current when required. Voltage regulators can be operated in either a manual or automatic mode.

Voltage Relay

A protective relay that activates in response to either a high or low voltage.

Voltage Source

A device capable of producing a voltage. Generators and batteries are Voltage Sources.

Voltage Stability

The ability of a power system to maintain voltage so that when the system nominal load is increased the actual power transferred to that load will increase. In a Voltage Stable power system the power transfer and the system voltages are controllable by the System Operators.

V-Q Curve

A voltage verse reactive power curve. A plot of the voltage at a bus verse the reactive power injected into that bus. V-Q Curves are a graphical tool used to analyze a power system's voltage stability.

Wheeling

Transmission line usage which a transmission line owner agrees to provide to permit the transfer of capacity and energy by another party.

Wheeling Charges

Payments required for providing wheeling services.

Wicket Gate

A device used to control water input to a hydro turbine. Wicket Gates function as water valves. Wicket Gates can be very large depending on the amount of water controlled.

WSCC

Acronym for the Western Systems Coordinating Council. WSCC is one of the ten NERC Regional Reliability Councils.

Wye Connection

A 3Φ electrical connection in which one end of each of the three phases is connected to a common point. The common point is often grounded. Transformer windings are often connected in a Wye configuration.

Zones of Protection

The zone or area within which a protective relay can sense abnormal conditions.

B

ABBREVIATIONS AND ACRONYM EXPANSION

Acronym	Expansion
A	Symbol for Ampere
AC	Alternating Current
ACB	Air Circuit Breaker
ACE	Area Control Error
ACSR	Aluminum Conductor Steel Reinforced
AGC	Automatic Generation Control
AIE	Area Interchange Error
ASD	Adjustable Speed Drive
ATC	Available Transfer Capability
AVR	Automatic Voltage Regulator
B	Symbol for frequency Bias
	Symbol for frequency response characteristic
BPD	Bushing Potential Device
BSU	Black-Start Unit
BTU	British Thermal Unit
C	Symbol for Capacitance
CB	Circuit Breaker
CBM	Capacity Benefit Margin
CCPD	Capacitively Coupled Potential Device
CCVT	Capacitively Coupled Voltage Transformer

Acronym	Expansion
CF	Compliance Factor
CFC	Constant Frequency Control
CNI	Constant Net Interchange
COU	Commonly Owned Unit
CPC	Control Performance Criteria
CPS	Control Performance Standard
CPS1	Control Performance Standard 1
CPS2	Control Performance Standard 2
CS	Circuit Switcher
CT	Combustion Turbine
CT	Current Transformer
CVT	Capacitive Voltage Transformer
DC	Direct Current
DCB	Directional Comparison Blocking
DCS	Disturbance Control Standard
DCU	Directional Comparison Unblocking
DF	Distribution Factor
DUTT	Direct Under-reaching Transfer Trip
ε_1	Symbol used in CPS1 for the one-minute average acceptable frequency error
ε_{10}	Symbol used in CPS2 for the ten-minute average acceptable frequency error
EA	Emergency Assistance
ECAR	East Central Area Reliability coordination agreement
EEA	Energy Emergency Alert
EHC	Electro-Hydraulic Control

Acronym	Expansion
EHV	Extra High Voltage
EM	Electromechanical
EMF	Electro-Magnetic Field
EMF	Electro-Motive Force
EMS	Energy Management System
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESP	Earth Surface Potential
F	Symbol for Farad
F	Symbol for Frequency
F_A	Frequency Actual
FERC	Federal Energy Regulatory Commission
F_R	Frequency Resonance
FRC	Frequency Response Characteristic
FRCC	Florida Reliability Coordinating Council
F_S	Frequency Scheduled
G	Symbol for Giga
GCB	Gas Circuit Breaker
GIC	Geomagnetic Induced Currents
GMD	Geo-Magnetic Disturbance
GSU	Generator Step-Up
GW	Giga Watt
GWh	Giga Watt hour
H	Symbol for Henry
HCA	Host Control Area

Acronym	Expansion
HD_F	Harmonic Distortion Frequency
HD_V	Harmonic Distortion Voltage
HIR	High Initial Response
HP	High Pass
HP	High Pressure
HS	High Side
HV	High Voltage
HVDC	High Voltage Direct Current
HZ	Hertz
I	Symbol for current
IDC	Interchange Distribution Calculator
IEEE	Institute of Electrical and Electronic Engineers
I_{ME}	Interchange Metering Error
IOS	Interconnected Operations Services
IP	Intermediate Pressure
IPP	Independent Power Producer
IR	Inertia Ratio
ISN	Interregional Security Network
ISO	Independent System Operator
IT	Instrument Transformer
JOU	Jointly Owned Unit
k	Symbol for Kilo
kV	kilo Volt
kW	kilo Watt
kWh	kilo Watt hours

Acronym	Expansion
L	Symbol for inductance
LDC	Load Drop Compensation
LED	Light Emitting Diode
LLR	Local line Loading Relief
LOF	Loss Of Field protection
LP	Low Pressure
LS	Low Side
LSE	Load Serving Entity
LTC	Load Tap Changer
LV	Low Voltage
M	Symbol for Mega
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-continent Area Power Pool
MAV	Mercury Arc Valve
MEL	Minimum Excitation Limiter
MHO	Ohm spelled backwards (type of distance relay)
MISO	Midwest Independent System Operator
MMI	Man-Machine Interface
MOD	Motor Operated Disconnect
MSC	Mechanically Switched Capacitor
MVA	Mega Volt Ampere
Mvar	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Mega Watt hour

Acronym	Expansion
N-1	Normal – one
NATC	Non-recallable Available Transfer Capability
NERC	North american Electric Reliability Council
NI_A	Net Interchange Actual
NI_S	Net Interchange Scheduled
NLTC	No-Load Tap Changer
NOAA	National Oceanic and Atmospheric Administration
NPCC	Northeast Power Coordinating Council
OLTC	Off Load Tap Changer
OOS	Out Of Step
OSL	Operating Security Limit
P	Symbol for MW
P.U.	Per-Unit
PAR	Phase Angle Regulator
PF	Power Factor
PLC	Power Line Carrier
PMG	Permanent Magnet Generator
POD	Point of Delivery
POR	Point of Receipt
POTT	Permissive Over-reaching Transfer Trip
PSE	Purchasing Selling Entity
PSI	Pounds per Square Inch
PSIG	Pounds per Square Inch Gauge
PSS	Power System Stabilizer
PST	Phase Shifting Transformer

Acronym	Expansion
PT	Potential Transformer
PTDF	Power Transfer Distribution Factor
PUTT	Permissive Under-reaching Transfer Trip
P-V	Power versus Voltage
Q	Quality
Q	Symbol for Mvar
R	Symbol for Resistance
RA	Reliability Authority
RAS	Remedial Action Scheme
RATC	Recallable Available Transfer Capability
RF	Reactive Factor
RMS	Root Mean Square
RPM	Revolutions Per Minute
RRC	Regional Reliability Council
RSG	Reserve Sharing Group
RTG	Regional Transmission Group
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
S	Symbol for MVA
SC	Security Coordinator
SCADA	Supervisory Control and Data Acquisition
SCIS	Security Coordinator Information System
SCR	Short Circuit Ratio
SCR	Silicon Controlled Rectifier
SERC	Southeastern Electric Reliability Council

Acronym	Expansion
SESC	Space Environmental Service Center
SF_6	Symbol for Sulfur hexa-Fluoride
SIL	Surge Impedance Loading
SMD	Solar Magnetic Disturbance
SMS	Single Most Severe
SPP	Southwest Power Pool
SPS	Special Protection System
SSR	Sub-Synchronous Resonance
SVC	Static Var Compensator
SVS	Static Var System
TCR	Thyrister Controlled Reactor
THD	Total Harmonic Distortion
TLB	Tie-Line frequency Bias
TLR	Transmission line Loading Relief
TOV	Transient Over-Voltage
TP	Transmission service Provider
TRM	Transmission Reliability Margin
TSC	Thyrister Switched Capacitor
TTC	Total Transfer Capability
UF	Under Frequency
UFLS	Under-Frequency Load Shedding
UHV	Ultra High Voltage
ULTC	Under Load Tap Changing
UPS	Uninterruptible Power Supply
URAL	Under-excited Reactive Ampere Limit

Acronym	Expansion
UVLS	Under-Voltage Load Shedding
V	Symbol for Volt
VA	Volt-Ampere
V-Q	Voltage versus Q (for reactive power)
VT	Voltage Transformer
W	Symbol for Watt
WSCC	Western Systems Coordinating Council
X_C	Transmission line capacitive reactance
X_L	Transmission line inductive reactance
Z	Symbol for impedance

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