**IEEE Std 67-1990**
(Revision of IEEE Std 67-1972)

# IEEE Guide for Operation and Maintenance of Turbine Generators

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**Abstract:** IEEE Std 67-1990, *IEEE Guide for Operation and Maintenance of Turbine Generators*, covers general recommendations for the operation, loading, and maintenance of turbine-driven synchronous generators that have cylindrical rotors.
**Keywords:** Cylindrical rotors, operation and maintenance of turbine generators, turbine-driven synchronous generators, reactive capability, rotor windings, stator windings

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## Foreword

(This Foreword is not a part of IEEE Std 67-1990, IEEE Guide for Operation and Maintenance of Turbine Generators.)

Originally published in July, 1957, as a trial-use document, this guide was updated and issued as a full-status IEEE guide in 1963. In March, 1969, a Working Group was appointed within the Synchronous Machinery Subcommittee of the then IEEE Rotating Machinery Committee to begin work on an extensive revision of IEEE Std 67-1963 .

In the 1972 revision, the guide was enlarged to include directly cooled machines and to stress the importance of generator operation using the generator capability curve and other related operating curves. It also emphasized the undesirability of operation of a generator by means of stator-winding temperature indications. The bibliography was updated and grouped by subject to facilitate its use. In 1980, the guide was reaffirmed.

In January, 1986, a Standards Project Authorization (PAR) was issued to revise the guide. The present guide has retained the original format; however, several editorial changes have been made. These changes serve to:

1) Revise ths guide to more closely reflect the state of the art of machines in service in the 1980's
2) Update this guide with respect to operation and maintenance experience gained since 1972 and thus provide acceptable performance criteria
3) Expand upon certain areas and issues in order to make them clearer and more meaningful
4) Update the bibliography

A rather significant addition to this guide is the appendix, “Problem Diagnosis.” We thought about this appendix for quite some time before we put it into its final form. Remember, this is a guide, an educational tool to assist in the early diagnosis of generator-related problems. This appendix is not an attempt to list every possible cause of a given situation; we have tried to list the most probable or most likely cause of a given event. We hope that this appendix will be useful to all utilities and users. This appendix does not contain any mandatory requirements.

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CLAUSE PAGE

# IEEE Guide for Operation and Maintenance of Turbine Generators

## 1. Introduction

### 1.1 Scope

This guide covers general recommendations for the operation, loading, and maintenance of turbine-driven synchronous generators of the types specified in Section 4, that is, having cylindrical rotors. It does not apply to generators having salient pole rotors.

This guide is not intended to supplant specific or general instructions contained in the manufacturer's instruction book or in any contractual agreement between a manufacturer and a purchaser of a given machine.

Because of the rapid development in generator design and because of the ingenuity of individual generator designers, many variations are incorporated in existing machines. Therefore, it is not possible in this guide to assign specific values or fixed methods. The most that this guide can accomplish is to offer accepted and tried values and methods and give warning where hazards might be encountered. The user should keep in mind that this guide is written to cover the turbine generator. This guide is not intended to apply in any manner to the prime mover.

### 1.2 References

The following IEEE, ANSI, and NEMA publications were used as references in preparing this guide and are useful in the interpretation of its meaning. These standards include useful bibliographies.

[1] ANSI C50.10-1965, General Requirements for Synchronous Machines.[1]

[2] ANSI C50.13-1989, Requirements for Cylindrical Rotor Synchronous Generators.

[3] ANSI C50.14-1977 (Reaff. 1989), Requirements for Combustion Gas Turbine Driven Cylindrical Rotor Synchronous Generators.

[4] ANSI C50.15-1989, Requirements for Hydrogen-Cooled Combustion Gas-Turbine-Driven Cylindrical-Rotor Synchronous Generators.

[1]ANSI publications are available from the Sales Department of the American National Standards Institute, 1430 Broadway, New York, NY 10018.

[5] IEEE C37.102-1987, IEEE Guide for AC Generator Protection (ANSI).[2]

[6] IEEE Std 1-1986, IEEE Standard General Principles for Temperature Limits in the Rating of Electric Equipment and for the Evaluation of Electrical Insulation (ANSI).

[7] IEEE Std 4-1978, IEEE Standard Techniques for High Voltage Testing (ANSI).

[8] IEEE Std 43-1974 (Reaff. 1984), IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery (ANSI).

[9] IEEE Std 56-1977 (Reaff. 1982), IEEE Guide for Insulation Maintenance for Large AC Rotating Machinery (10 000 kVA and Larger) (ANSI).

[10] IEEE Std 95-1977 (Reaff. 1982), IEEE Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage (ANSI).

[11] IEEE Std 99-1980, IEEE Recommended Practice for the Preparation of Test Procedures for the Thermal Evaluation of Insulation Systems for Electric Equipment (ANSI).

[12] IEEE Std 115-1983, IEEE Test Procedures for Synchronous Machines (ANSI).

[13] IEEE Std 115A-1987, IEEE Standard Procedures for Obtaining Synchronous Machine Parameters by Standstill Frequency Response Testing.

[14] IEEE Std 119-1974, IEEE Recommended Practice for General Principles of Temperature Measurement as Applied to Electrical Apparatus.

[15] IEEE Std 268-1982, IEEE Standard for Metric Practice (ANSI).

[16] IEEE Std 286-1975 (Reaff. 1981), IEEE Recommended Practice for Measurement of Power-Factor Tip-Up of Rotating Machinery Stator Coil Insulation (ANSI).

[17] IEEE Std 421.1-1986, IEEE Definitions for Excitation Systems for Synchronous Machines (ANSI).

[18] IEEE Std 421B-1979, IEEE Standard for High-Potential Test Requirements for Excitation Systems for Synchronous Machines (ANSI).

[19] NEMA MG1-1978 (Reaff. 1981), Motors and Generators.

## 1.3 Definitions

**coolant (cooling medium):** A fluid, usually air, hydrogen, or water, used to remove heat from a machine or from certain of its components.

**temperature rise of a machine component:** The difference between the temperature of the part under consideration and the ambient temperature.

[2]IEEE publications are available from the Institute of Electrical and Electronics Engineers, IEEE Service Center, 445 Hoes Lane, Piscataway, NJ 08855-1331.

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## 2. Cautions

It must be recognized that loads more severe than those permitted by the nameplate should not be applied without a thorough study of the possible consequences that might arise from the specific operating conditions. It is recommended that in all such cases the specific conditions be discussed with the manufacturer of the unit. Many IEEE and ANSI Standards are referenced in this guide. The standards referenced will be those in effect when this revision is approved. Users are cautioned to carefully review the history of older machines with respect to IEEE and ANSI Standards in effect at the time the particular generator was manufactured. Older machines may not operate satisfactorily to the requirements of modern standards with regard to temperature rise, overload capability, abnormal operating conditions, etc.

A requisite for the proper and successful operation and maintenance of turbine generators is knowledge of their construction and operating characteristics. Information of this type is contained in this guide and more detailed and specific information is to be found in the manufacturer's instruction book and related technical data. Much of this information quite properly concerns the normal “round-the-clock” steady-state operating conditions. Advances in generator design and application over the past several decades have, however, made attention to unusual or transient conditions more important. Rapid and accurate comprehension and interpretation of changes in the machine or its operation characteristics is, therefore, also essential to efficient operation and maintenance.

## 3. Manufacturer's and User's Responsibility

Some suggestions made in this guide involve operation under conditions not covered by nameplate or specification conditions. The purpose of a generator nameplate is to identify the machine with respect to the manufacturer and to indicate a basic rating as fixed by the purchaser's specification. The temperatures stated on the nameplate are in accordance with applicable industry standards and/or purchaser's specifications. It should not be assumed that the generator is capable of safe operation up to these temperature levels without checking the generator capability curves and other specified parameters.

When a generator is operated within its capability, the user may expect maximum reliability and life. On occasion, consideration must be given to operation beyond the range of specified capabilities. In those cases, all of the various factors involved must carefully be considered in determining the user's risks.

Operator training is the responsibility of the user. The complex operating characteristics of a synchronous generator, its excitation system, and auxiliaries are not easily understood without proper instruction. Today's larger direct-cooled units have little or no operating capability without the cooling equipment. Stability considerations of the transmission and distribution systems make it essential to understand the basic relationships among a generator's terminal voltage, line current, active power, reactive power, field voltage, field current, frequency, speed, etc. This guide can be used as a reference document for an effective operator training program.

## 4. Classification of Generators

### 4.1 Generator Types

Turbine generators are classified by one of the stator types and one of the rotor types.

1) Stator types are defined by the method of stator-winding cooling, either directly or indirectly.
2) Rotor types are defined by the method of rotor-winding cooling, either directly or indirectly.

NOTE — For turbine generators, the stator windings are typically called “armature windings,” and the rotor windings are typically called “field windings.” The terms are, therefore, used interchangeably.

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#### 4.1.1 Directly Cooled Windings

Directly cooled stator or rotor windings are those in which the winding coolant (air, hydrogen, or liquid) flows in direct contact with the conductors so that the heat generated within the principal portion of the windings reaches the cooling medium without flowing through the ground wall insulation.

#### 4.1.2 Indirectly Cooled Windings

Indirectly cooled stator or rotor windings are those in which the heat generated within the principal portion of the windings must flow through ground wall insulation before reaching the cooling medium (air or hydrogen).

### 4.2 Cooling Methods

#### 4.2.1 Directly Cooled Stators

Directly cooled stators are classified according to the type of coolant used to remove heat from the stator windings.

##### 4.2.1.1 Hydrogen

Hydrogen coolant flows through insulated ducts, which are part of the stator winding structure inside of the ground wall insulation. The heat generated within the strands flows through the thin layers of strand insulation and duct insulation to the cooling hydrogen in the ducts.

##### 4.2.1.2 Deionized Water

Deionized water coolant flows through hollow conductor strands or through special coolant tubes. The heat generated within the conductors flows in two directions.

1) Directly into the cooling water flowing through hollow conductor strands.
2) Through thin layers of strand insulation from the solid strands and through the hollow conductor strand insulation or the insulation of the special coolant tubes carrying the water coolant.

##### 4.2.1.3 Insulating Oil

Insulating oil coolant flows through hollow conductors in the same manner as it does for the deionized water types.

#### 4.2.2 Indirectly Cooled Stators

Indirectly cooled stators are classified according to the type of coolant used to remove heat from the stator windings. The coolant (air or hydrogen) flows through ventilating ducts in the stator core iron.

#### 4.2.3 Directly Cooled Rotors

Directly cooled rotors are classified according to the types of coolant used to remove heat from the rotor windings and the flow pattern of the coolant within the slot portion of the windings.

##### 4.2.3.1 End-Supplied Axial Flow Coolant

Coolant (air or hydrogen) is supplied to each end of the rotor and flows into conductor passages near the ends of the rotor body and/or into rotor subslots that carry coolant to conductor inlet passages at intervals along the rotor body length. The coolant is radially discharged into the generator air gap along the rotor body or at the center of the rotor.


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#### 4.2.3.2 Gap-Supplied Zone Flow Coolant

Coolant (air or hydrogen) is fed into conductor passages from the gap by short inlet sections along the length of the rotor body either by self-pumping or by pressurized gap zones maintained by gap baffles. The coolant is discharged through short outlet sections between the inlet sections along the length of the rotor body. The end portions of the windings are supplied with coolant from each end.

#### 4.2.3.3 Deionized Water Coolant

Deionized water coolant is fed axially through piping inside the rotor shaft to radial connections that enter an inlet water box. The coolant then is distributed to the field winding and flows axially through hollow field conductors or tubing nested in the field winding. The coolant may then exit the winding the opposite end or return to the inlet end of the rotor. The coolant exits by way of radial connections to outlet piping inside the shaft.

### 4.2.4 Indirectly Cooled Rotors

Indirectly cooled rotors are classified according to the type of coolant used to remove heat from the rotor windings. The coolant (air or hydrogen) passes the rotor surface or flows through gas passages in the rotor body.

## 4.3 Coolant Circulation Methods

The cooling medium is circulated through passages in the generator by one of the following methods:

1) Self-ventilated generators have cooling air or hydrogen circulated by means of an internal shaft-mounted fan(s) along with the self pumping action of the rotor.
2) Separately ventilated generators have cooling air or hydrogen circulated by an independent blower external to the machine.
3) Liquid-cooled generators have the coolant circulated either by means integral to the machine or by circulating equipment external to the machine.

## 4.4 Other Common Terms

Based on the historical development of generator designs and cooling methods, a number of designations have been created to describe turbine generator types. These descriptive designations make a distinction regarding the type of coolant used rather than giving a complete description as outlined in the preceding paragraphs.

### 4.4.1 Air-Cooled Generators

Air-cooled generators are designed to use air for cooling and they are classified according to the type of enclosure.

1) Open generators are self-ventilated machines, open to the surrounding air, having no restrictions to ventilation other than that necessitated by mechanical construction and any silencing and filtering equipment.
2) Enclosed generators are either self-ventilated or separately ventilated with openings for the admission and discharge of the ventilating air; the machine being otherwise totally enclosed. These openings are so arranged that inlet and outlet ducts or pipes may be connected to them.
3) Totally enclosed generators prevent exchange of air between the inside and the outside of the enclosure, but not sufficiently enclosed to be called airtight. Heat created by the generator losses is removed from the cooling air by internal or external heat exchangers.

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### 4.4.2 Hydrogen-Cooled Generators

Hydrogen-cooled generators, using pressurized hydrogen, are totally enclosed machines having a gas-tight enclosure and hydrogen shaft seals to prevent the exchange of air and hydrogen. Heat created by the generator losses is removed from the hydrogen by heat exchangers integral to the generator housing.

### 4.4.3 Liquid-Cooled Generators

Liquid-cooled generators are designed to use deionized water or oil as coolant for the generator windings (see 4.2.1 and 4.2.3). Heat created by the winding losses is removed from the liquid coolant by heat exchangers external to the generator. Additional coolant circuits are required to remove heat from other sources, principally the core. Traditionally, hydrogen has been used for this purpose. However, designs exist in which water (or oil) is the sole cooling medium for the entire generator; in this case, a common cooling system has been used to handle all cooling circuits.

# 5. Basis of Rating

## 5.1 General Considerations

The specification of a turbine-generator set requires the coordination of the mechanical requirements of the turbine and the electrical requirements of the generator. For the steam turbine, one of the principal load limitations is the maximum torque that the turbine can deliver under various conditions of steam pressure, steam temperature, and condenser vacuum. For the generator, the rating is governed by considerations related to the useful life of the insulation system and other machine parts; these are affected by temperature, differential expansion, and long-term vibration.

## 5.2 Temperature Limits

IEEE Std 1-1986 [6][3] discusses the general principles upon which temperature limits are based. In considering limits for the temperature of machine parts,the following points must be remembered and will be expanded upon throughout this guide:

1) Deterioration of the insulation is a function of the time during which it is subjected to high temperature, as well as the absolute value of the temperature.
2) The insulation is subjected to considerable mechanical stresses due to expansion and contraction of the windings and surrounding parts with changes in load and temperature.
3) In most cases, the maximum insulation temperature cannot be measured directly, and correction must be made to the measured temperatures to approximate the hot spot temperature.

Generally, in considering turbine generator loadings that assure normal insulation life expectancy, it is important that hot spot temperatures of the machine not exceed the limiting temperatures of the insulation system as established by test procedures developed in accordance with IEEE Std 99-1980 [11] or as derived from the temperature limits of the component materials given in IEEE Std 1-1986 [6].

Some generators, such as those driven by gas turbines, are operated for short-time duty periods at higher than normal temperature in such a way as to make the average rate of thermal deterioration over the total elapsed time consistent with the designed life expectancy, see ANSI C50.14-1977 [3].

[3]The numbers in brackets correspond to the references listed in 1.2 of this guide.


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### 5.3 Temperature Rise

ANSI C50.13-1989 [2] specifies the observable rise that the manufacturer guarantees will not be exceeded when the generator is operated at nameplate rating. It must not be construed as specifying allowable operating temperature rises.

In some instances, greater output can be permitted with cold coolant temperatures lower than design level, permitting high temperature rises without exceeding established total temperature limitations. An example of this is the generally lower air and water temperatures that occur in the winter, which may offer some additional capacity in electrical equipment (see 6.1.2).

### 5.4 Methods of Temperature Measurement

#### 5.4.1 Coolant Temperatures

The number and location of coolant temperature sensors vary considerably depending on the type of cooling system employed. The cooling system's instruction book should be consulted in each individual case.

The cold coolant temperature is measured by resistance or thermocouple detectors located either in thermometer wells in the side of the generator or inside the generator in the cold coolant streams.

In addition, cold coolant temperature detectors are frequently employed for the control of heat exchanger raw water flow.

The cold coolant temperature should not exceed the maximum value specified on the generator nameplate.

Maximum values as specified in ANSI C50.13-1989 [2] range from 40°C to 50°C depending on the type of cooling employed and on the manufacturer's practice. On some applications, such as air-cooled two-pole open-ventilated generators, the cold coolant temperature may be outside this range.

#### 5.4.2 Stator Windings

The method of measuring stator winding temperatures depends on the type of cooling employed.

##### 5.4.2.1 Indirectly Cooled Stator Windings

Winding temperature is measured by means of embedded detectors of the resistance or thermocouple type placed between the upper and lower coil sides, as shown in Fig 1. Resistance detectors are used in most indirectly cooled machines and are preferred since they indicate the mean temperature of the coils over a length of several core packs rather than at only one point. The resistance detector commonly known as RTD (resistance temperature detector) is a sensor that has a precise temperature-resistance coefficient, normally specified as an electrical resistance at a particular reference temperature. The dimensions of the RTD are usually the same as the filler strip used in the stator slot between the upper and lower stator conductors. The RTD leads are carefully routed from the device to a terminal block on the outer frame of the generator. For hydrogen-cooled generators, this terminal block must be gas tight at appropriate design hydrogen pressures. Length and resistance of the detector may be as specified in ANSI C50.10-1965 [1] or as otherwise specified by the purchaser. Usually 12 detectors are built into the machine, evenly distributed around the stator core circumference. Each detector is installed and the leads brought out in such a manner that the detector itself is effectively protected from contact with cooling air or gas.

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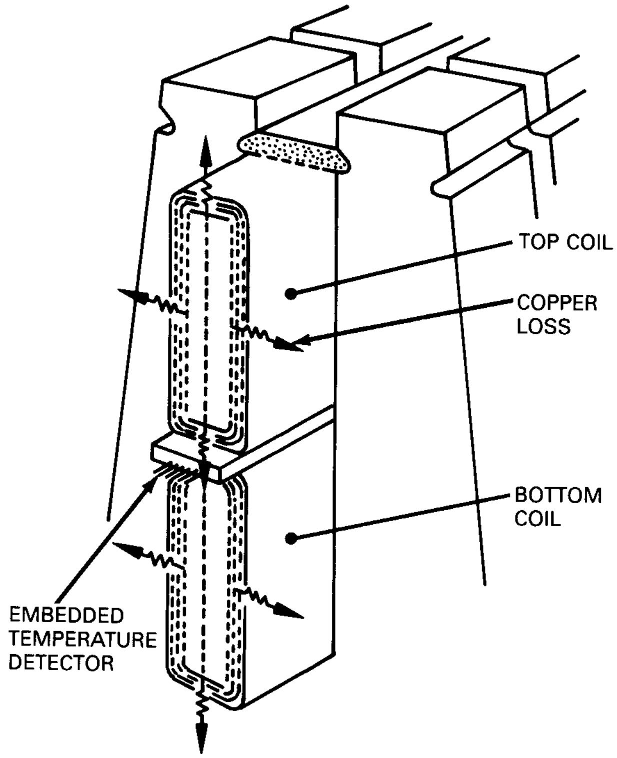


**Figure 1—Heat Flow and Typical Temperature Detector Location**

#### 5.4.2.2 Directly Cooled Stator Windings

The difference in temperature between statorwinding strands and the coolant is a function of load; because the cooling medium is in contact with, or flowing in an integral part of the conductor strands, temperature measurement of the warm, discharge coolant is considered a more accurate indication of the stator conductor temperature than embedded temperature detector measurements.

Either resistance- or thermocouple-type temperature detectors are employed for directly cooled windings. In the case of gas-cooled windings, the coolant temperature detectors are mounted at the end of an insulating duct at the warm coolant discharge. In the case of liquid-cooled windings, the coolant temperature detectors are mounted at the ground potential end of insulating hoses at the warm coolant discharge.

### 5.4.3 Rotor Windings

No simple method has been devised for measuring rotor hot spot temperatures. Standard practice is to measure the average temperature of the winding by resistance using simultaneous voltage and current readings at the collector rings, and interpreting these values in conjunction with the known cold resistance to find the operating temperatures. If the rotor voltage is measured at the brushes, there may be an error of 2 to 4 volts due to brush voltage drop. To compensate for this effect, pilot brushes that carry no field current are sometimes used for measuring the field voltage. However, some users have experienced difficulty with pilot brushes due to film buildup that causes inaccuracy of the temperature measurement and in some cases interferes with the operation of the other brushes.

More practical methods of compensation are to:

1) Provide a bias voltage equal to the brush voltage drop, or

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2) Calibrate the temperature-indicating or -recording device for a value of resistance equal to the sum of the expected full-load temperature resistance of the rotor winding plus the equivalent resistance of the brush voltage drop at fullload rotor current.

For excitation systems that do not employ collector rings, no simple method for measuring rotor-winding temperature is currently available.

## 5.5 Limitations in the Methods of Measuring Temperatures

### 5.5.1 Stator-Winding Temperatures by Embedded Detectors

The detector element is located between the surfaces of the top and bottom coils and is separated from the copper of these coils by the coil insulation, as indicated in Fig 1. The difference between the temperature of the hot spot and the detector element is a function of the proportions of the slot, the thickness of the insulating wall of the coils, the amount of heat to be conducted through the insulation, etc. It is impossible to generalize correctly as to what the difference between the detector and the hot spot temperature will be for all machines at all loads.

In the case of indirectly cooled units, the embedded detector will always indicate temperatures somewhat lower than the temperature of the insulated copper of the windings. The difference between the hottest spot of the copper in the stator coil and the resistance detector of a hydrogen-cooled generator may be considerably higher than the 10 °C allowance originally established for air-cooled generators. Tests made on large hydrogen-cooled turbine generators would indicate that the difference between the copper temperature and the detector temperature is practically unaffected by a change in gas pressure in a hydrogen-cooled generator, but is largely a function of the heat flow from the copper to the cooler parts surrounding the coil as indicated in Fig 1.

In directly cooled stator windings, the coolant enters the stator bar at one end. Flowing from one end to the other, the coolant becomes hotter as it removes heat from the copper.

The relationship of the copper temperature to the temperature measured by the embedded detector varies down the entire length of the stator bar. Therefore, the location of the embedded detector with respect to coolant flow must be considered.

### 5.5.2 Stator-Winding Temperature by Discharge Coolant Temperature

In the case of directly cooled stator windings, the temperature of the discharge coolant is also measured by means of resistance or thermocouple detectors.

The temperature difference between this discharge coolant temperature and the hot spot varies widely for different machines.

This difference depends on the coolant gas or liquid, winding construction, and design practice, and may be specified for a given design as a function of current in the conductors. A caution, if the liquid coolant flow in an individual coil is blocked (e.g., by copper corrosion), the corresponding thermocouple on that coil may actually drop or assume the average temperature of the water manifold.

### 5.5.3 Rotor-Winding Temperatures

The rotor-winding temperature determined by calculated resistance gives an indication of the average temperature throughout the winding. As such, it does not indicate the magnitude of the hot spot temperature with respect to the average temperature.

For a given rotor design, the difference between the hot spot temperature and the average temperature may increase with the rotor length.

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To compensate for this factor, ANSI C50.13-1989 [2] calls for a lower temperature rise for the larger machines. The lower temperature rise will also limit the differential expansion between conductor and steel in the larger rotors.

# 6. Loading

## 6.1 Limitations on Loading

### 6.1.1 Nameplate Rating

Each generator is provided with a nameplate that states the operating conditions for which the generator has been designed and constructed.

When the generator is operated within these nameplate conditions of electrical output, cooling medium temperatures, pressures, and flows, the machine will not exceed the temperature rises agreed to at the time of purchase. In addition to the temperature limits required by standards, the manufacturer has design limits for critical quantities, i.e., flux densities, mechanical stress, mechanical and electromagnetic forces, and dielectric stress.

These limits are set based on design analysis and experience to ensure appropriate generator reliability. Loading of the generator within the nameplate capability will keep the machine within these design limits, and result in optimum reliability.

The generator should not be loaded beyond the nameplate capability without fully considering the potential loss of machine life resulting from exceeding the design temperatures, or any of the other critical design limits.

### 6.1.2 Effect of Loading on Temperatures

A misunderstood effect of loading the generator beyond the nameplate rating, is the increase in hot spot temperature. Generally, the ratio of the hot spot temperature to the observed temperature remains fairly constant. However, if the cold coolant temperature is reduced in an attempt to obtain more output without exceeding the normal observed temperature, the hot spot temperature may exceed the desirable temperature. This is illustrated in Fig 2. With 46 °C inlet coolant and 1.0 per unit load, the observed temperature is 110 °C, point ’A’, and the hot spot temperature is 130 °C, point ’B’. If the inlet coolant temperature is reduced to 30 °C and load is increased to return to an observed temperature of 110 °C, point ’C’, the hot spot temperature in this example becomes 134 °C, point ’D’. If the hot spot temperature of 130 °C is not to be exceeded, then the observed temperature must be reduced to 106 °C, point ’F’, by a suitable load change. It must be stressed that this figure is only an example, and the manufacturer should be consulted for the specifics of any given machine. Thus, to avoid exceeding the hot spot temperature at increased loads by reducing cold coolant temperature, the observed temperature limits should be reduced below normal values.

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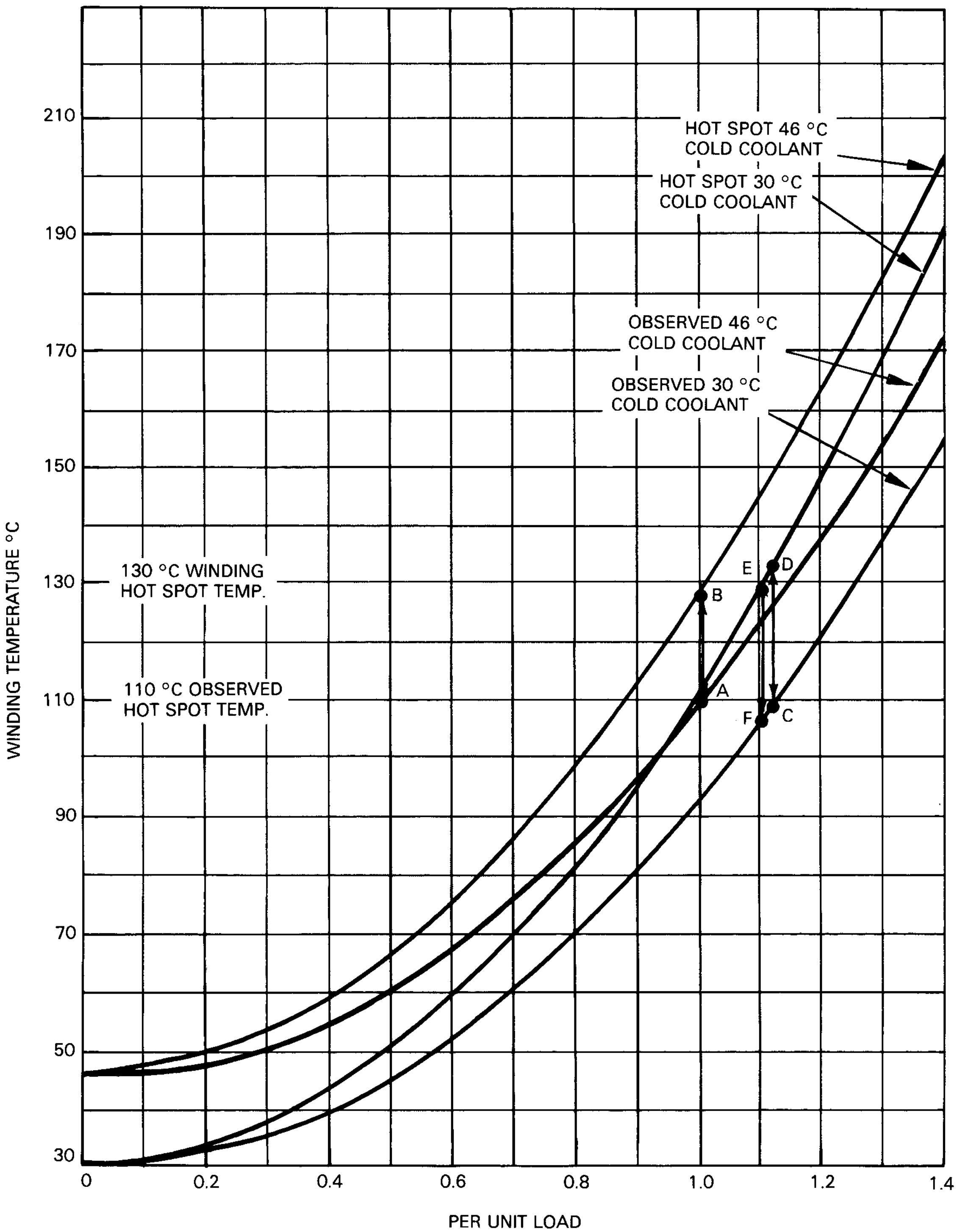


**Figure 2—Typical Effect of Reduced Coolant Inlet Temperature on Hot Spot Temperature**

A similar situation exists for hydrogen-cooled generators whose load capability increases with increasing hydrogen pressure. The limiting observable temperature must be reduced as the load capability is increased in order to maintain hot spot temperature limits.

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For most insulating materials, the loss of life due to elevated temperatures can be roughly estimated using the Arrhenius rule, which states that the rate of aging doubles for every 10 °C increase in temperature. This simple rule of reaction kinetics applies to both the asphalt and modern epoxy mica systems operating across a range of temperatures that include not only normal operating temperatures but also the epoxy curing temperatures.

Thermal aging is not the only effect of increased temperatures on insulating materials. The mechanical properties of many non-metallic materials are very temperature dependent, and mechanical failure may result from extended exposure to temperatures above the design values. Thermal expansion effects can lead to gradual deterioration of components, which would normally be unaffected by load changes. If the distortion temperature is reached, prompt failure can occur.

### 6.1.3 Other Effects of Loading Beyond Nameplate Rating

While temperature effects are the most important aspect of operation beyond nameplate rating, they are not the only concern. Stator conductor forces, stresses in the walls of hollow cooling ducts, and the vibration of current carrying parts will all be increased. Heating of the stator core ends, and other stray magnetic effects will be greater, and can add to the adverse effects of elevated winding temperatures.

### 6.1.4 Operating Life

A base loaded generator can typically be expected to provide a useful life of 30 to 40 years when properly maintained and operated within the limits set by the manufacturer and the nameplate. Sufficient design margin is provided to ensure that temperature rises, forces and stresses are within the capabilities of the materials used in the machine. Before loading the machine beyond the nameplate rating, all the factors relating to overloading should be considered, and a full awareness of their implications developed. The machine can be operated beyond the nameplate rating, but the design margins will be encroached on, and some loss of normal life will be accumulated. The amount of life lost is difficult to quantify, and will depend greatly upon the specific machine design. The greater the overload, the more life will be removed from the generator, and as a general trend, the more highly rated the machine, the less margin there is to accept overload without loss of normal life. If abnormal operation is contemplated, the manufacturer should be consulted.

## 6.2 Loading Within Rating

The maximum life expectancy for a generator is obtained by operating methods that produce low operating temperatures with the fewest temperature variations. It is, therefore, desirable to have equipment to control the cooling system temperatures.

For air-cooled generators, there is sometimes no means provided for the control of the air temperature through the unit. For enclosed generators, whether air cooled or hydrogen cooled, control of the cooling system is available through the control of the raw water flow to coolers, and for liquid-cooled generators, by control of liquid coolant temperatures for the windings. Conveniently located temperature indicating or recording instruments will provide valuable information in the operation of the machine.

## 6.3 Active and Reactive Power Relationship

### 6.3.1 No-Load Characteristics

Operation of the machine with no load connected to the terminal is described by two characteristic curves; the no-load saturation curve and the short-circuit characteristic curve. The saturation curve (Fig 3) shows the relationship between terminal voltage and field current with the machine terminals open circuited, and with the machine operating at rated speed (point A). The straight line part of the characteristic is known as the “air-gap line” and the deviation from this line at higher voltages is due to magnetic saturation of the iron. The field current at rated terminal voltage is known as the no-load field current often

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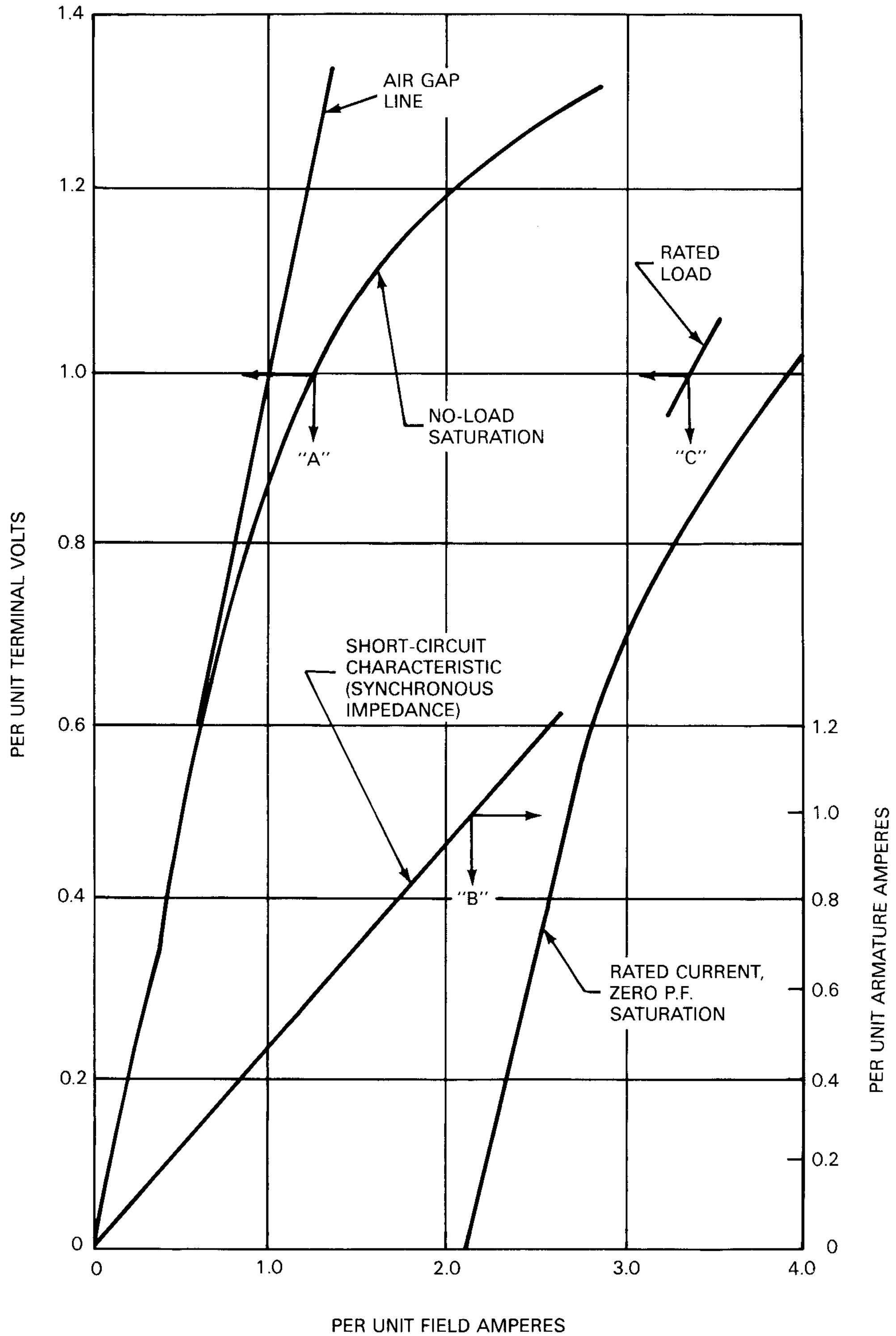


**Figure 3—Typical Saturation Curve**

called 1 pu field current. The short-circuit characteristic curve relates the stator current to the field current with the machine terminals short circuited, and the machine operating at rated speed. The field current at rated stator current (point B) is known as the short-circuit field current.

The ratio of the no-load field current to the short-circuit field current is the short-circuit ratio (SCR) of the machine, and is an index of the inherent steady-state stability of the machine. In general, the higher the SCR, the more stable the machine.

Also shown on Fig 3 is the zero power factor characteristic. This curve relates terminal voltage to field current with the machine delivering rated stator current into a purely reactive load, at rated speed. This curve is used to derive the Potier reactance, which can be used to estimate load excitation. This curve, for estimating purposes, is basically parallel to the no-load saturation curve but offset by the shortcircuit field current. Point ’C’ on Fig 3 is the “rated load” point; i.e., the point of operation at rated stator current and stator voltage at rated power factor.

### 6.3.2 Load Characteristics

If a machine is operating with an isolated load, then the power factor of the machine is determined by the load. However, in the more usual case of several machines supplying a load, the power factor of each machine can be different. The real power (kW) supplied by each machine is determined by the prime mover. The reactive power (kvar) supplied by each machine is determined by the excitation level.

Figure 4 shows the typical relationship between field current, kVA, and power factor at rated voltage and frequency. Curves of constant kW are also shown. Superimposed on these curves are the thermal operating limits imposed by the machine design. The maximum current that the field is designed to carry defines the upper limit on loading in the overexcited (lagging power factor) region, the right side of the figure. This is a vertical line at constant field current, extending from the zero power factor overexcited line to the rated power factor overexcited line. Since the field current carrying capability of a typical hydrogen-cooled machine is dependent on gas pressure, a number of such lines are shown, each corresponding to a different hydrogen gas pressure.

Similarly, the stator winding is designed to carry a maximum current corresponding to the rating of the machine.

The limit imposed by stator winding heating is a horizontal line in the upper part of Fig 4. Because of current-dependent effects in nonliquid-cooled components, this limit depends on gas pressure in both directly cooled and indirectly cooled generators.

In the underexcited (leading power factor) region, the left region of Fig 4, the load carrying capability is limited by stator core end heating. This is indicated by the sloping lines on the upper-left part of the figure.

The location of these limits depends on the design of the machine, and the type of cooling used, thus the shape of the curves and the location of the limits will vary from machine to machine. These curves, and the limits shown on them, represent the regions within which the machine may be safely loaded, without exceeding guaranteed temperature rises.

The curves in Fig 4 may be transformed into curves relating real and reactive power, as shown in Fig 5. In these curves, the field current limit, the stator winding current limit and the stator core end heating limit become boundaries, and lines of constant power factor become straight lines intersecting at the origin of the figure. There is a separate boundary for each gas pressure. Please note that the terms “lagging,” “overexcited,” and “Vars out” are used interchangeably as are the terms “leading,” “underexcited,” and “Vars in,” which are used to indicate the quadrant of the reactive capability curve in which the machine is operating.

These curves represent the capability of the main generator at rated voltage and frequency. Other limits are imposed by associated equipment, such as the turbine, by system voltages, and, in some cases, by the system stability limits. A typical steady-state stability limit is shown in Fig 5.

The curves can be obtained from the instruction book or from the manufacturer, and must be used for all decisions pertaining to the capability of the generator.

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### 6.3.3 Method of Estimating the Reactive Capability Curve

To construct the reactive capability curve accurately, a fairly complex calculation procedure is required to establish the constant field current line in the overexcited region and the end heating limits in the underexcited region. For this reason, it is necessary to use the manufacturer's curves for leading in these regions.

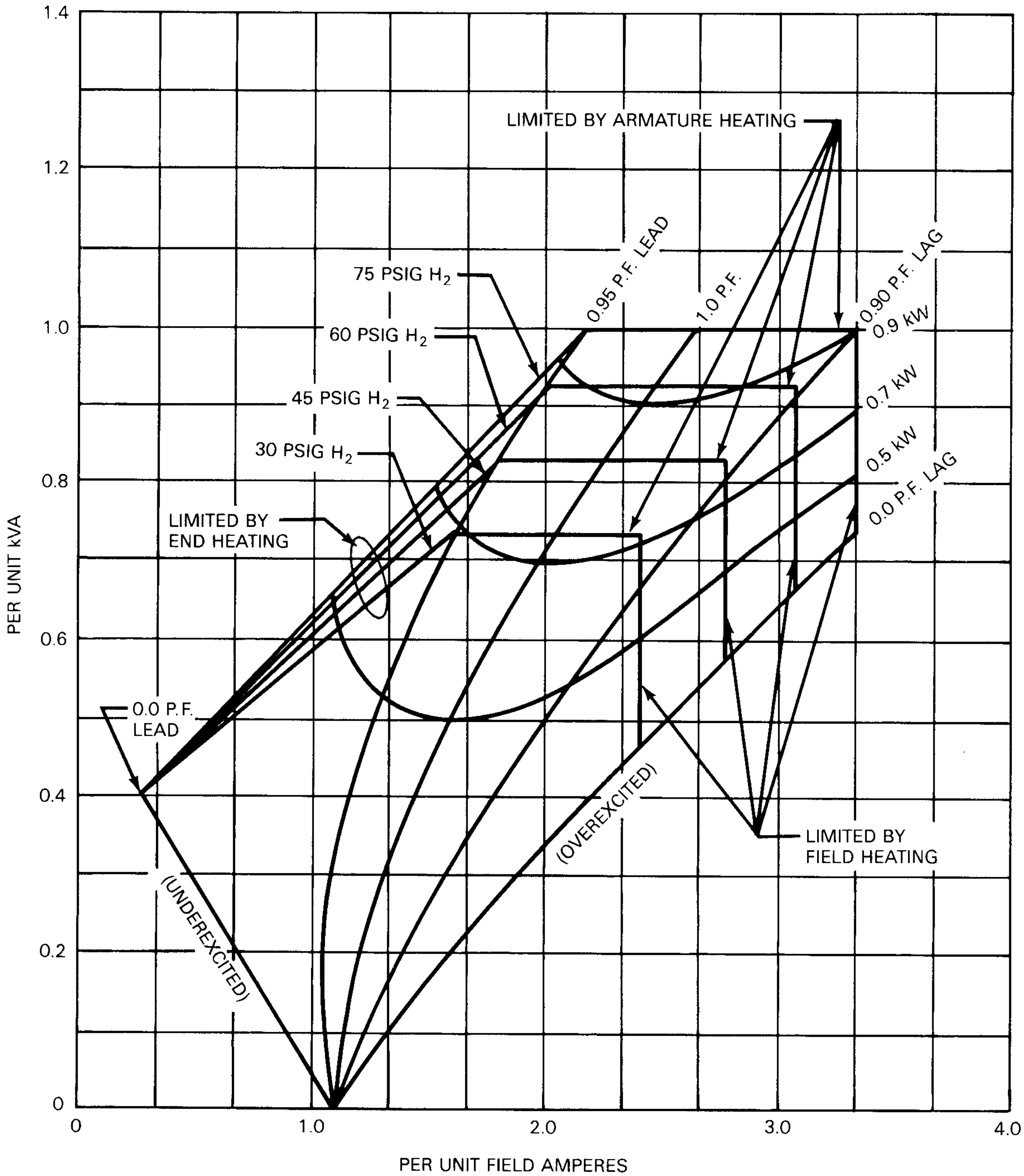


**Figure 4—Typical Load Characteristic (Vee) Curve**

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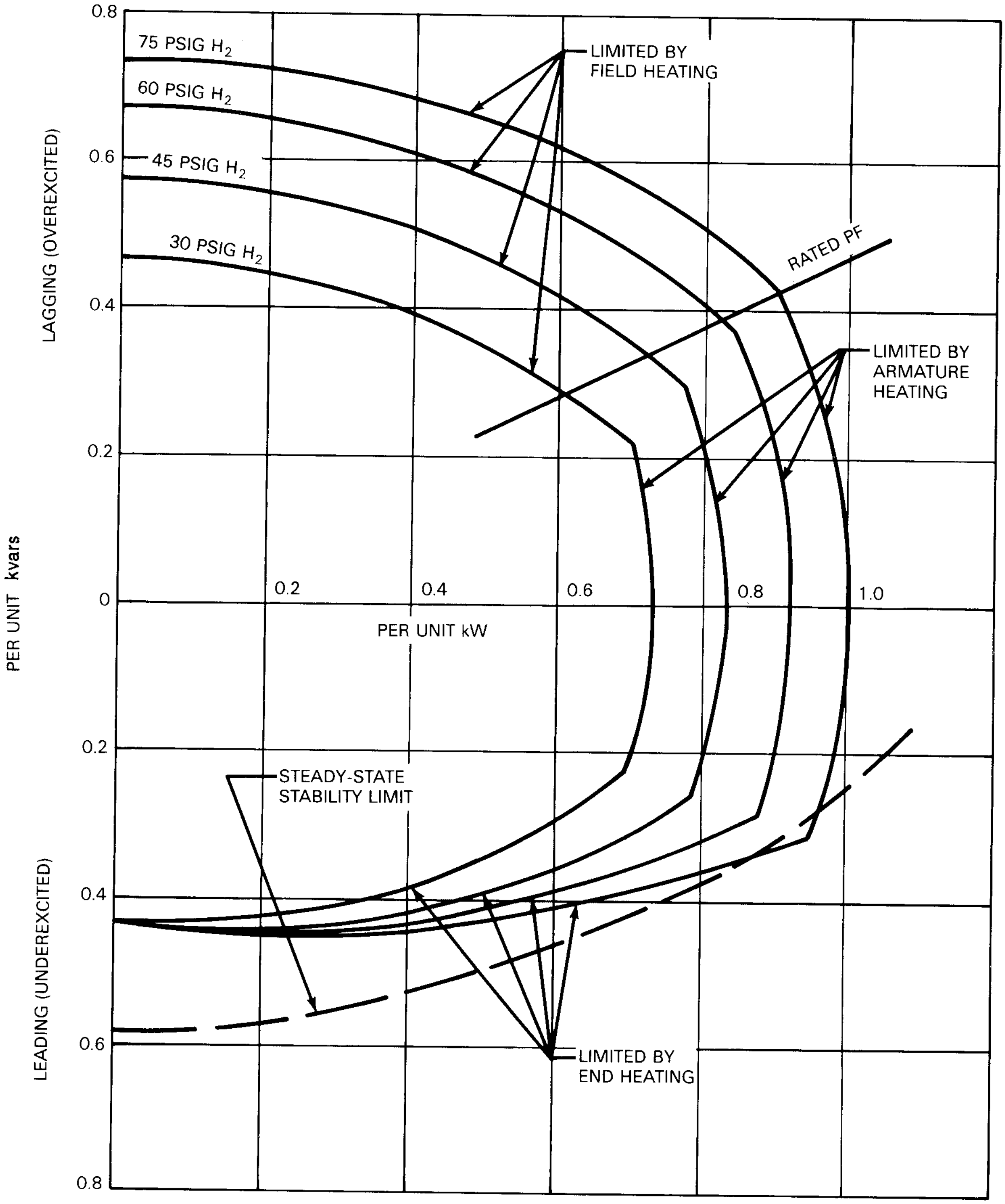


**Figure 5—Typical Reactive Capability Curve**


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However, it is possible to estimate the reactive capability curve in the overexcited region. This method ignores the effects of magnetic saturation, and overestimates the generator capability at low lagging power factors. Because the capability in the underexcited region is dependent on stator core end heating limitations, which vary significantly from one manufacturer to another, it is not possible to provide a means of estimation for this region.

The method of construction is illustrated in Fig 6, and is based on the phaser diagram of the generator (see 11.1.2).

1) Draw a line from the origin (0 kW, 0 kvar) at an angle whose cosine equals the rated power factor. The angle should be measured counterclockwise from the kW abscissa.
2) Draw an arc from the kW abscissa up to the rated power factor line with a radius equal to the rated kVA of the generator.
3) Find the point on the leading power factor (underexcited) axis equal to the generator estimated short-circuit ratio (SCR) times the rated kVA. Using this point as the center and a line from this point to the rated kVA, rated power factor point as the radius, draw an arc from the rated kVA, rated power factor point to the kvar ordinate in the overexcited region.

NOTE — The actual SCR is not necessarily equal to the rated SCR of the generator, and should be estimated using the no-lead saturation curve and the short-circuit saturation curve (see Fig 3) by dividing the field current at point 'A' on the no-lead saturation curve by the field current at point ’B’ on the short-circuit curve.

The difference between the method just described for estimating the capability curve and actual manufacturer's curve is shown in the example in Fig 6. The dashed line is the curve obtained by the approximate method, while the solid line indicates the manufacturer's actual curve. From the rated power factor point down to the kW abscissa, the two curves are coincident.

## 6.4 Loading Outside of Nameplate Rating

It may be necessary to operate a generator under the following conditions:

1) At rated frequency, but at other than rated voltage (see 6.4.1 and ANSI C50.13-1989 [2]).
2) At rated volts/hertz ratio, but at other than rated frequency (see 6.4.2). ANSI C50.131989 [2] does not provide for this condition.
3) Above rated kVA but at rated voltage and frequency (see 6.1 and 6.4.3). ANSI C50.13-1989 [2] does not provide for this condition.
4) Both volts/hertz ratio and frequency at other than rated value (see 6.4.1 and 6.4.2). ANSI C50.13-1989 [2] does not provide for these conditions.
5) During short-time abnormal conditions, ANSI C50.13-1989 [2] specifies generator capabilities with regard to the following characteristics:
   a) Armature winding short-time thermal requirements
   b) Field winding short-time thermal requirements
   c) Rotor short-time thermal requirements for unbalanced faults
   d) Mechanical requirements for short circuit
6) Continuous unbalanced load

In general, the manufacturer should be consulted for the derating required for unbalanced lead. For the maximum value of negative-phase sequence current that may be carried without derating the generator, see 7.8 and ANSI C50.13-1989 [2].

### 6.4.1 Operation at Other Than Rated Voltage

Practically all generators are designed for safe operation at rated kVA, power factor, and frequency with a voltage variation of 5% above or below rated voltage. However, a significant increase in the volts/hertz ratio results in oversaturation of the stator magnetic core. Of particular concern is the stray flux induced in nonlaminated frame components that can be severely overheated. Since the normal temperature monitoring devices do not provide data

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from such components, damage can take place before the operator is aware of it. If, under unusual circumstances, it is required to operate at a voltage more than 5% above or below rated voltage, the manufacturer should be consulted for limiting outputs under these conditions.

### 6.4.2 Operation at Other Than Rated Frequency

A reduction in generator frequency at constant volts/hertz ratio requires the generator to be derated. The amount of derating depends on the type of cooling employed as well as the reduction in speed. The manufacturer should be consulted for the capability of individual generators at reduced frequency. Deviations from rated volts/hertz ratio will require additional reduction in capability as specified by the manufacturer.

### 6.4.3 Operation at Other Than Rated kVA

Most steam turbine generators are rated at a maximum continuous capability. Some have additional continuous capability with increased gas pressures. In any case, the manufacturer's capability curves should be followed and operation beyond those limits is not recommended.

Generators for gas turbine peaking service sometimes have peaking capabilities abovethe nameplate rating to match the gas turbine peaking capabilities for short-time duty periods. The temperature rise limits are set either by the standards or the manufacturer in such a way as to make the predicted average rate of thermal deterioration over the elapsed time consistent with the desired life expectancy of the complete power unit and in accordance with economic requirements.

For open-ventilated air-cooled generators used for gas turbine peaking service, ANSI C50.14-1977 [3] specifies that the base generator rating at rated power factor and sea level for continuous operation be equal to or greater than the base rating of the combustion turbine with a 15 °C air inlet temperature. A peak capability equal to or greater than the peak capability of the combustion turbine is also specified. The generator will normally be capable of operation with air inlet temperatures between -18 °C and +49 °C with higher capability at temperatures lower than +15 °C and lower capabilities at temperatures higher than +15 °C.

For hydrogen-ventilated generators for gas turbine peaking service, ANSI C50.15-1989 [4] specifies base and peak ratings on the same basis as for open-ventilated machines. The ambient temperature is defined to be that of the ambient air used to cool an intermediate coolant in an air-to-intermediate coolant-to-hydrogen heat exchange system. Capability for the hydrogen-cooled generator may also be shown as a function of cold hydrogen temperature which in turn is a function of the ambient air temperature and the characteristics of the heat exchanger system.

## 6.5 General Considerations

### 6.5.1 Low Gas Temperature

Generally, generators can be operated with coolant at lower ambient temperatures than rated. This can lower hot spot temperatures in the windings by an equivalent amount. However, care must be taken to avoid the following potential problems (see 6.1.2):

1) The capability curves should be used for loading. The difference between hot spot temperatures and observable temperatures increases with increased load, therefore allowing the possibility of exceeding hot spot temperature at loads above rated load if observable temperatures are used for loading with reduced temperatures without proper downward adjustment.
2) In some cases, too low gas temperature can reduce bearing support temperatures and affect shaft alignment.
3) Low gas temperatures can cause condensation on parts exposed to warm air.

Generally, the manufacturer's recommendations should be followed regarding gas temperatures.

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### 6.5.2 Low Raw Water Temperature

Where the raw water supply temperature is below the rated raw water temperature of the coolers, care must be taken to prevent the formation of condensation, which can occur if the dew point of the cooling air or gas is higher than the temperature of the coolant. In particular, care should be exercised when using very low temperature coolant. Unit start up or a sudden drop in load may cause the cooling air or gas to reach dew point temperature, which will result in condensed moisture being deposited. To avoid condensation, a recirculating system to raise the temperature of the raw water may be provided. Dehumidifying dryers are available that can be connected into the generator cooling circuit and are suitable for drying air or gas under any pressure at which the cooling system operates. Many units are provided with these gas dryers as part of the original equipment scope. In these dryers, a desiccant absorbs the moisture which then is driven off outside the cooling system. Some users provide for continuous supervision of dew point through the installation of dew point recorders provided with maximum alarm contacts.

Continuous operation at raw water temperatures well below rated can also result in increased cooler tube corrosion and fouling when the raw water flow is throttled to maintain cold gas temperature at about normal operating values.

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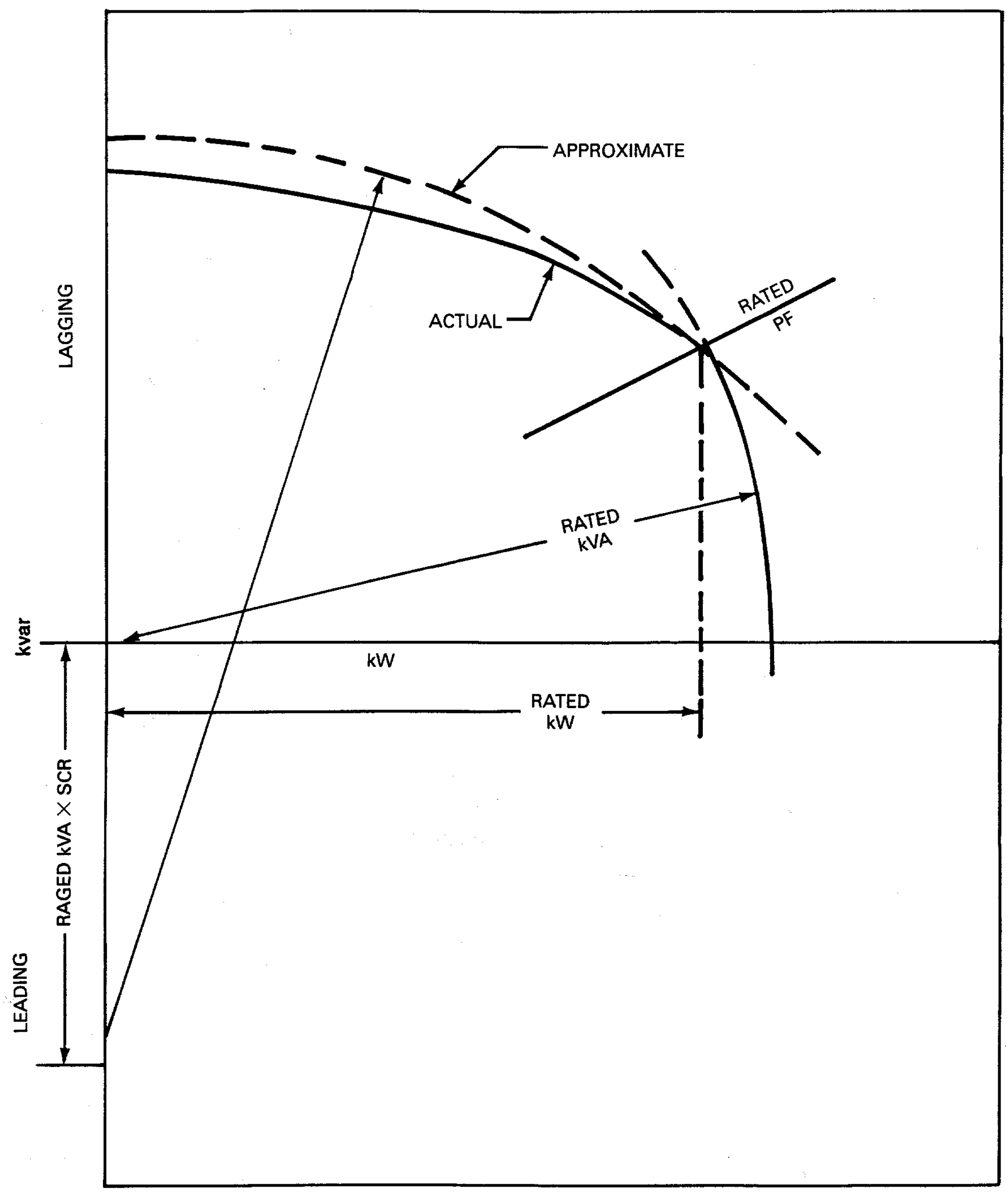


Figure 6—Construction of Approximate Reactive Capability Curve


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### 6.5.3 High Raw Water Temperature

Generators must be derated for high raw water temperatures. The manufacturer should be consulted regarding the capabilities of individual machines (see 7.4.2).

### 6.5.4 Concerning Life Expectancy

It is often impossible to coordinate operational practices (with respect to temperature or loading) with the normal life expectancy of a generator. This is due to the complexity of the processes that determine the deterioration rate of components in a machine. Typically, the life expectancy of a given machine will be greater when the machine is operated at constant load conditions rather than when the machine is subject to frequent load cycles (within the capability curve) or start-stop cycles.

The life expectancy of rotor components is particularly dependent upon the frequency of start-stop cycling. The change in centrifugal force-induced stresses from standstill to rated speed (or excursions to overspeed in some cases) occurring over many cycles may cause fatigue and cracking in some metallic and insulating components depending upon the specific design.

The life expectancy of generator windings is determined by a combination of factors. With older insulation systems, the predominant mechanism of aging is that of deteriorating insulation binders caused by normal operating temperatures over a long period of time. The life expectancy of modern insulation systems is determined by the combined effects of differential thermal expansion of coils with respect to other winding components, magnetic and centrifugal forces, and thermal degradation at operating temperatures above normal. Modern generators are typically larger than their earlier counterparts and, therefore, have much larger forces acting on their conductors. These increased forces require improved restraint systems. Stator barforce loading is much higher in contemporary generator designs. The stator-winding racing and support structure must be much more effective in consolidating the winding structure while concurrently accommodating thermal expansion. Continuous, relative motion among individual winding components can lead to material fretting, insulation wear, and possible generator failure if the problem is not identified and corrected.

# 7. Operation

## 7.1 Requirements for Operation

Operation of a turbine generator requires consideration of several factors, such as: design capabilities, means of cooling, and quantity and quality of monitoring methods and techniques. Microprocessors, programmable controllers, data loggers, sequence-of-events monitors, oscillographs, and the like are valuable tools available to operations personnel.

Modern microprocessors have the capability to monitor hundreds of digital and analog inputs. Numerous machine values can be monitored and displayed in various ways against a variety of parameters. Programmable controllers can be used to calculate the average, the mean, the maximum deviation, the rate-of-rise, the absolute maximum, and many other trends. Retrofitting these newer monitoring systems into older plants is a good way to replace aging equipment while improving reliability.

All germane information pertaining to the generator, the generator auxiliary systems, and generator operation and maintenance considerations are contained in the manufacturer's instruction book. It is strongly recommended that this reference be thoroughly understood and consulted often about matters concerning the generator. The generator should be operated in accordance with the reactive capability curve and other related operating curves. The raw water flow in the various coolant heat exchangers should be regulated to maintain constant design internal temperatures as load

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changes. Air-cooled machines are operated in a manner similar to generators employing other forms of cooling. However, discussions related specifically to hydrogen cooling apply only to hydrogen-cooled generators.

### 7.1.1 Stator-Winding Temperature

Operation of the generator by means of stator-winding temperature indications only is undesirable as demonstrated in Section 6. Stator-winding temperature indications are useful, however, in providing a continuous record of the temperature history of the unit. Any trend away from past temperature performance is an indication of a change in machine condition and should be investigated.

There are two basic means (see 5.4) of monitoring the winding temperature of indirectly and directly cooled generators. All stator-winding and coolant temperature detectors should be monitored either on a recording device, a meter, or a microprocessor. Stator-winding heating is limited by observing the rated kVA limit of the reactive capability curve (see Fig 5).

### 7.1.2 Rotor-Winding Temperature

Operation at less than rated power factor in the overexcited region is limited by the field winding temperature. This capability limit is indicated by the upper portion of the capability curve.

Depending on the equipment used to monitor the field temperature, the field temperature recorder may be a useful diagnostic tool. The field temperature recorder can be used to detect collector ring or brush arcing, which may indicate severe collector ring problems if the ac noise that may accompany the dc voltage and current signals is not filtered out. Rapid changes in field voltage or current due to either system conditions or voltage regulator problems may also be indicated on the field temperature recorder.

Many synchronous generators in service today are equipped with brushless, alternatorrectifier type exciters. The generator field voltage and field current are not available for field temperature calculations. For these units, the rotor-cooling media (air or hydrogen) must be more carefully monitored as an indication of the rotor-winding temperature.

### 7.1.3 Stator Core Temperature

Operation in the underexcited region is limited by additional heating in the extreme ends of the stator core and associated core support structures. This capability limit is indicated by the complex curve, which is the lower portion of the capability curve. Most machines have no means of monitoring the core temperature so particular care should be exercised to stay within the capability curve when operation in this region is necessary. Many large stators have core flux shields that are designed to minimize excessive heating at the core ends. Frequently, the flux shields are equipped with temperature monitoring.

### 7.1.4 Thermal Expansion

The capability of the stator winding is limited not only by total temperature but also by the effects of differential expansion between stator coils or the stator coils and the stator core. Differential expansion is a function of the total temperature of the winding and the core. This factor is more critical in long machines than short ones. During load changes, the copper temperature changes more rapidly than the core temperature, thus accentuating this differential expansion problem. Operation beyond rated kVA exaggerates the effects of differential expansion and, therefore, should be avoided. Frequent cycles of differential expansion and contraction may result in damage to the stator coil insulation and stator-winding support system. Modern winding support systems provide more protection against such effects than did earlier systems.

The rotor is subjected to similar problems associated with differential expansion. The field windings and insulation system are subjected to the combined effects of thermal expansion, centrifugal force, magnetic forces, and windage. The combined effects of these forces over a period of time can produce several rotor problems. The normal sequence of start up, loading, heating, unloading, cooling and shutdown tends to produce an elongation of field-winding copper

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in a ratcheting manner between the copper winding and the coil insulation. Tape on field windings tends to separate, due to excessive amounts of this ratcheting action.

There are several thermal expansion problems caused by abnormalities (other than the ratcheting described above) which are usually first indicated by excessive shaft vibration. Blocked cooling passages in the rotor or the field conductors, as well as uneven expansion of field wedges, can produce a bending effect on the rotor. Shorted turns in the field winding can produce unequal thermal expansion of the field poles and the rotor forging.

### 7.1.5 Shaft Alignment

The generator, exciter, and turbine shaft are usually connected by bolted, flanged couplings. During operation, these shafts must be maintained in alignment. Misalignment will cause increased shaft stresses and a redistribution of the bearing loading which, if excessive, will result in increased mechanical vibration and may lead to mechanical failure or bearing overheating.

The variation in elevation of the generator shaft is a function of the temperature of its supporting members. Where bracket and bearings are integral, the temperature of the bracket and the frame that supports it varies directly with the cold coolant temperature. Consequently, generator shaft elevation variations can be minimized by maintaining a constant cold coolant temperature.

### 7.1.6 Frame Distortion

Extreme changes in the cold coolant temperature may cause dimensional changes of the frame ends, with consequent working of the mechanical joints and gaskets. In the case of hydrogen-cooled machines, this may result in increased hydrogen leakage and maintenance. The performance of the gaskets is also adversely affected by high temperatures. Consequently, the manufacturer's recommendations of cold coolant temperature limits should be followed. Generator frame distortion may also be caused by improper foundation foot loading (shimming), loose foundation bolts, or deteriorated grouting.

## 7.2 Reactive Capability Curves

Typical generator operating curves are shown in Fig 5 (see 6.3.2). Similar curves applicable to a particular generator should be used as a loading guide. The generator coolant temperatures, flows, and pressures must be within manufacturer's recommended values. The operation of the generator according to reactive capability curves must be accomplished by the use of instruments to measure active and reactive power (kW and kvar), terminal voltage, line current, and, when available, field current. Generators are usually operated between rated power factor and unity power factor. Unless specified otherwise, alternating-current generators may be operated within ±5% of rated terminal voltage and safe temperatures will be realized if operation is maintained within the limits expressed by the reactive capability curve.

### 7.2.1 Stator-Winding Temperature

Since the stator-winding temperature detectors may not give a true indication of the hot spot temperatures, the machine should be loaded within the limits provided by the manufacturer. The capability curve shows the limits of operation as governed by stator-winding temperature in the overexcited (lagging power factor) and underexcited (leading power factor) regions. It establishes limits for output (kVA), thus limiting heating in the stator winding.

### 7.2.2 Rotor-Winding Temperature

The capability curve should be used to guide operation in the overexcited (lagging power factor) range below rated power factor to assist in keeping the machine within its limits of rotor heating.

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### 7.2.3 Stator Core End Temperature

In the underexcited (leading power factor) region, the capability curve also indicates limits of loading as established by heating of the stator core end structure. Operation in the underexcited region may lead to a stability problem, which is a function of system characteristics and may further limit the permissible loading in this region.

## 7.3 Miscellaneous Considerations

Some of the miscellaneous considerations in the operation of a turbine generator are the following:

### 7.3.1 Hydrogen Pressure

In the case of hydrogen-cooled machines, it is common practice to maintain the hydrogen pressure constant at a value corresponding to the maximum expected kVA, neglecting momentary load variations. It is uneconomical to reduce this pressure for short duration reductions in load.

The capability curves for a particular generator will show a kVA capability for a range of hydrogen pressures. Operation with hydrogen pressure below the lowest pressure shown on the curves for a particular generator should be avoided unless the manufacturer has been consulted and has provided a safe kVA figure for a particular pressure.

In the case of generators with stator coils directly cooled by liquid, the hydrogen pressure should always be maintained well above the coolant pressure so that leaks in the stator coil coolant system will not cause a discharge of liquid coolant into the generator. If the stator cooling water pressure is controlled to track hydrogen pressure changes, reliable and redundant tracking should be employed, and its performance checked periodically.

### 7.3.2 Use of Hydrogen Pressure Regulation Curves

A typical hydrogen pressure regulation curve is shown in Fig 7 for a gas-cooled generator normally rated at 60 psig, 95 °F raw water. It shows the relationships between maximum lead, maximum permissible cold gas temperature, raw water temperature, and hydrogen pressure for safe operation of a specific machine. The rated quantity and rated temperature of water required by the generator gas coolers are designed to absorb full-lead generator losses and maintain the cold gas temperature at the corresponding proper value. It will be noted that, as the hydrogen pressure changes along a given cooler water temperature ordinate, the permissible lead also changes. Operation with the cold gas temperature within the range indicated will not cause variations in generator frame temperature sufficient to change the bearing elevation to an extent that will produce undesirable misalignment of the generator and turbine shafts.

### 7.3.3 Hydrogen Purity

Although the upper limit of an explosive hydrogen-air mixture is 75 % hydrogen, the purity of the hydrogen gas contained in a hydrogen-cooled generator should be maintained in accordance with the manufacturer's instructions for the most effective use of the hydrogen as the cooling agent. Experience indicates that purity will range from a value of approximately 96% up to approximately 99% according to length of time in service. When necessary, an operating range between 90% and 96% is allowable and considered safe; however, operation below recommended purity will result in significantly increased windage losses.

In order to prevent an explosive hydrogenair mixture inside the generator when introducing or removing the hydrogen from the generator, an inert gas such as carbon dioxide ($CO_2$) must be used to thoroughly purge the air or hydrogen inside the machine casing.

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### 7.3.4 Operation of Hydrogen-Cooled Generators in Air or $CO_2$.

Hydrogen-cooled generators should not be operated (even for short time periods) above 50% rated speed in air or $CO_2$ unless the manufacturer has been consulted. There is a possibility of failure or overheating of some generator components due to the higher density of these gases.

### 7.3.5 Seal Oil System

All hydrogen-cooled generators utilize a pressurized oil seal to prevent hydrogen from escaping between the shaft and the casing of the generator. This usually consists of a ring or rings around the shaft with oil pumped into a gap between the ring and the shaft at a pressure higher than the hydrogen pressure. There are various configurations of rings and systems for supplying, regulating, draining, and treating the seal oil (see 8.6.8). The manufacturer's instructions and recommendations should be understood and followed regarding operation of a specific seal oil system.

For any configuration, there are several common operational recommendations:

1) Never allow the rotor shaft to turn without the seal oil system in operation. Lubrication is required between the rings and the shaft to prevent wiping and damage.
2) Always make sure the seal oil system is in operation when there is hydrogen in the generator, whether or not the shaft is turning.
3) Seal oil supply systems should always have arrangements for backup of oil in case of failure of the primary source.
4) Always operate the generator at a hydrogen pressure no higher than can be maintained with the next source of backup. If there is no backup, the generator should be shut down and purged of hydrogen.

### 7.3.6 Initial Filling of Coolers

When initially filling the coolers, the flow of raw water should be controlled so that the entire cooler will be vented and filled with water at a rate such that the design pressure will not be exceeded due to water hammer.

With multisection coolers, which are in series for gas flow and in parallel for water flow, care must be exercised to equalize the water flow through the sections. This may be done by the use of flow meters or pressure gages on the water flow to the sections. It cannot be done by equalizing the water or gas temperatures.

### 7.3.7 Normal Cooler Operation

The flow of water to the coolers should be controlled so that the entire cooler will be filled with water by continuous venting and so that design pressure will not be exceeded.

### 7.3.8 Control of Raw Water During Load Changes

There is no inherent lower loading limit for the generator itself, although the prime mover and associated equipment may impose such limit. When operating at loads varying from a low value up to rated full load, the desired degree of cooling system control depends on the time duration and extent of the load swings. Where load swings are more or less unpredictable and irregular, some form of automatic regulation of the raw water flow is advantageous. Any method of controlling the raw flow should avoid reaching the dew point of the cooling air or gas.

Operation of coolers below design water flow may cause tube corrosion and fouling; operation above design flow may cause erosion. Therefore, water flow should be maintained within design limits.

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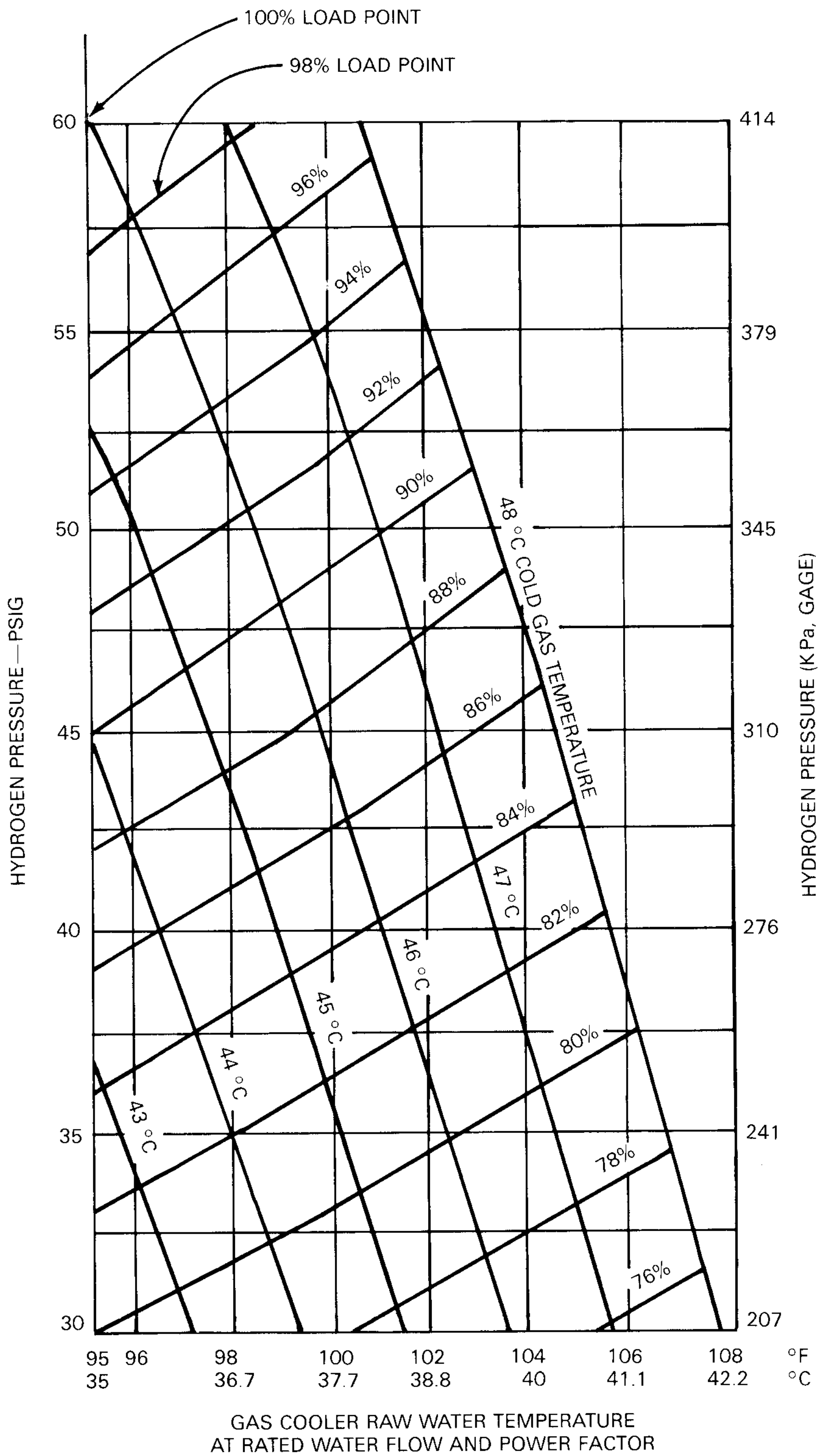


**Figure 7—Typical Hydrogen Pressure Regulation Curve for Gas-Cooled Generators**


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### 7.3.9 Stator- and Rotor-Cooling Water Chemistry

Water is circulated through hollow conductors or tubes to remove the heat generated in the stator coils, rotor coils, and other current carrying elements. In order to minimize leakage current, it is important that the water have a low conductivity. Water chemistry should be monitored regularly and should be maintained within the manufacturer's recommendations concerning the concentration of dissolved oxygen, copper, and iron.

### 7.3.10 Collector Set Operation

Brushes used with collector rings to supply direct current to the rotor winding operate best within a range of current densities, typically 25–60 amperes per square inch. Exceeding the maximum recommended current density in a brush can lead to excessive heating in the brush/collector interface, the brush, or the brush lead (pigtail) and should be avoided in normal operation. Operating below the minimum recommended current density for long periods of time can lead to glazing of the brush surface in contact with the collector requiring more frequent brush changeout to avoid brush problems, such as brush squeal or chatter accompanied by sparking. The manufacturer's instructions should be consulted for ranges of brush current density recommended for a specific collector.

Brushes can be removed where long-term low-load operation is expected in order to keep the brush current density above the minimum. However, enough brushes should be in operation to handle the maximum load anticipated. Generator vee curves (see Fig 3 and 6.3) may be used for determining expected field currents for various loads. Any limits on generator capability due to brushes removed from service should be made known to the operator.

There are certain precautions to be taken when brushes are changed during operation. Subsection 8.2.2 addresses some of these precautions.

## 7.4 Starting and Rate of Load Changes

This section does not give complete instructions on starting turbine generators; but it does discuss some important aspects of that operation. When starting a turbine generator, the rate of speed increase from zero speed to full speed is a matter of concern only with respect to the prime mover, unless the manufacturer has specified special limitations. Starting and load changing procedures depend on the method of cooling (see Section 4) and the type of excitation system used. In addition, special procedures are required for generators driven by cross-compound turbines. The manufacturer's recommended procedures should be followed.

In the process of starting and loading a machine, the following considerations deserve especially careful attention:

### 7.4.1 Excitation

Because overexcitation can damage the generator and connected equipment, volts/hertz limits should not be exceeded.

### 7.4.2 Synchronization

Standards do not require a machine design that is able to withstand the currents and mechanical forces due to incorrect phasing or synchronizing. For manual synchronizing, the accuracy should be:

1) At the moment of closing of the synchronizing breaker contacts, the phase angle between the generator and the bus is as close to zero degrees as possible with ±10 electrical degrees being the maximum allowable deviation.
2) The speed of the unit should be matched to the system speed such that the synchroscope is revolving, preferably clockwise, at a speed not greater than one revolution every 15 seconds (0.067 Hz).
3) The voltage of the incoming generator should not differ from the system voltage by more than ±5% immediately prior to synchronizing.

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The use of automatic synchronizing or synchronizing supervisory schemes is recommended because this equipment is able to incorporate the closing time of the breaker and therefore produce more consistent results, usually within ±5 electrical degrees.

NOTE — Incorrect synchronizing can result in immediate and severe damage to the generator, even though this damage may not be immediately obvious.

#### 7.4.3 Cross-Compound Units

Cross-compound units must not be permitted to operate with only one generator excited or with excitation applied when the generators are out of synchronism with each other, or with one or both generators at rest.

#### 7.4.4 Loading

Except for the precautions with regard to synchronizing, phase relations, and preheating (see 7.10), the starting procedure of turbine generators is primarily determined by the requirement of the prime mover, and such procedures are generally the result of the manufacturer's recommendations and user's experience.

When a single generator supplies an isolated load, the rate of load change on the machine depends solely upon the rate at which the external loads are switched on or off, provided that the turbine governor is set to hold rated speed. In this type of system, the power factor of the generator and the active and reactive power (kW and kvar) loading are determined by the load demands.

In a system supplied by a number of turbine generators operating in parallel, the amount of power supplied by any generator depends on the mechanical torque applied to each generator by its turbine and is controlled by the action of the turbine governor. The division of kW load among generators is practically independent of excitation; however, the division of kvar among generators is a function of excitation. The relationships and limitations of kW and kvar loading of generators are covered in Section 6.

The ability of any generator to follow a kW load change is determined solely by the sensitivity and speed of response of the turbine governor. The governor may be equipped with an electric speed changer and arranged for manual control or for automatic frequency control.

### 7.5 Shutdowns

Like starting, the stopping or shutdown procedures for turbine generators are determined by the requirements of the prime mover. Frequent starting and stopping (cycling) is extremely rigorous duty for a generator and should be considered as a factor in the life expectancy of the windings and rotating mechanical parts. The shutdown procedure is normally determined by the manufacturer's recommendations and user's experience.

Turning gear operation beyond that required by the turbine should be minimized to prevent loosening or fretting on items normally held in place under centrifugal forces.

### 7.6 Monitoring, Supervision, and Protection

To obtain adequate supervision and protection and to prevent or minimize possible damage to the generator, protective relays are provided to alarm and/or initiate shutdown of a unit when certain limits are reached. Other devices, along with these protective relays, are provided to monitor the condition of the generator and its auxiliary systems and equipment. The amount of monitoring and protection may depend on such factors as the generator's age, type, rating, and importance to the system. See IEEE C37.102-1987 [5] for more detailed information.


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### 7.6.1 Monitoring

The condition of the generator should always be known. The condition can be determined by monitoring certain generator parameters and auxiliary system parameters, such as the following:

1) Active load
2) Reactive load
3) Field voltage
4) Field current
5) Field ground detection
6) Field temperature
7) $H_2$ purity
8) $H_2$ moisture content
9) Fan differential pressure
10) Gas pressure
11) Gas temperature to and from $H_2$ coolers
12) Water temperature to and from $H_2$ coolers
13) $H_2$ consumption
14) Stator voltage
15) Stator current
16) Frequency
17) Stator RTD temperatures
18) Directly cooled stator coil discharge coolant temperatures
19) Stator-cooling water (oil) flow
20) Stator-cooling water (oil) pressure at generator inlet
21) Stator-cooling water (oil) inlet and outlet temperatures
22) Stator-cooling water (oil) conductivity
23) Water temperature to and from stator water (oil) coolers
24) End shield temperature
25) Bearing temperatures
26) Seal oil temperatures
27) Seal oil pressures

Trending of these parameters can give an indication of the degradation of the machine or its auxiliary systems and enable the operators to take appropriate corrective action. Online assessment of these parameters by an “expert system” can determine a rapidly degrading condition and alert the operators of impending failure, thus enabling corrective action to prevent the generator from being damaged.

### 7.6.2 Stator- and Rotor-Winding Protection

Protective devices for the stator and rotor windings are provided to initiate the removal of the generator from the system, deenergize its excitation, and, in most cases, trip the turbine stop valves. These devices are generally provided for the following conditions:

1) Faults beyond the generator breaker(s)
2) Faults between the generator and the generator breaker(s)
3) Generator internal faults
4) Out-of-step operation
5) Fire in the generator (air cooled)
6) Loss of excitation
7) Transient negative-sequence current

See the short-circuit requirements paragraph in ANSI C50.13-1989 [2] for limitations under short-time unbalanced fault conditions.

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### 7.6.3 Other Generator Protection

Detection devices for the following conditions and many of those listed in 7.6.1 are often provided to alarm and/or trip the generator:

1) Excessive stator or rotor current
2) Steady-state unbalanced current operation (see 7.8)
3) Excessive volts/hertz ratio
4) Excessive vibration
5) Bearing insulation failure
6) Excessive bearing temperatures
7) Operation beyond the underexcited limit
8) Loss of stator-cooling water flow
9) High conductivity of stator-cooling water
10) Reverse power operation
11) High internal temperatures
12) $H_2$ gas particulate concentration

## 7.7 Unbalanced Current Operation

Operation of a generator with unbalanced armature currents produces negative-sequence currents ($I_2$) in the stator which in turn induce circulating currents on the surface of the rotor and in the rotor wedges. These currents are at a frequency that is twice the rated frequency of the generator (120 Hz for a 60 Hz machine) and their magnitudes depend not only on the unbalance between the armature currents, but also on the actual values of armature currents. Negative-sequence currents must flow along the wedges and tooth surfaces, from wedges to the teeth, across the wedges at the ends of the rotor body, and into the retaining ring and in the amortisseur winding, if provided. Localized heating is produced at the wedge joints and retaining ring fits, in addition to heating of the rotor surface.

Figure 8 shows curves that may be used to calculate negative-sequence current when the magnitudes of the three unbalanced armature currents are known. A helpful rule-of-thumb for calculating the current component with low values of unbalance is that the positive-phase sequence current is approximately the average of three phase currents, and the negative-phase sequence current can approach two-thirds the maximum deviation of any of the phase currents from the average. The actual capability during unbalanced, steady-state, and fault conditions are clearly specified in ANSI C50.13-1989 [2]. These limits necessarily ignore many important factors of design and operating conditions, such as increases in torque pulsations, losses, effects of zero-phase sequence currents and effects of harmonic currents. Users should consult the manufacturer for more accurate recommendations in specific cases. Negative-sequence currents can be caused by a variety of system- or loadrelated conditions, i.e., system load unbalances, untransposed or incompletely transposed transmission lines, unbalances in plant auxiliary loads.

## 7.8 Out-of-Synchronism Operation (Field Maintained)

Operation of generator out-of-synchronism with excitation maintained places severe type of duty on the unit. Such operation produces heavy surge currents in the armature windings of a magnitude that may exceed those associated with the machine short-circuit requirements (see ANSI C50.13-1989 [2]) and cause serious damage to the winding. Such operation also produces torque reversals that create, in many parts of the unit, high mechanical stresses of magnitudes that may be several times those produced by rated torque. High induced voltages and currents in the field circuit may cause flashover of the collector rings and of the commutator of an associated exciter, and may cause damage to solid-state exciter components and systems.

For these reasons, out-of-synchronism must be identified promptly and the condition remedied. Possible corrective action includes removal of the unit from the system.

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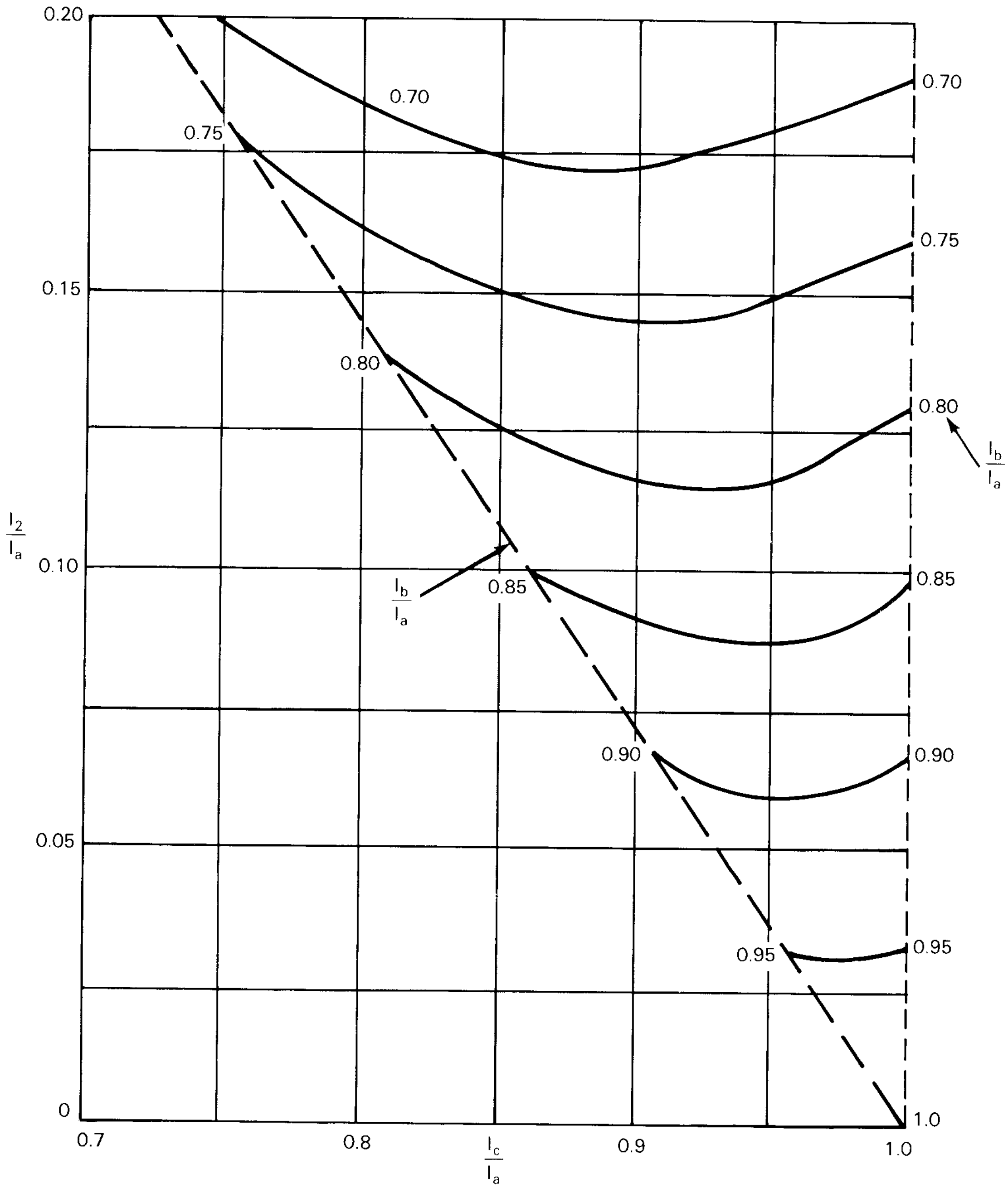


$I_2$ = Negative-phase sequence current
$I_a$ = Largest of three-phase currents
$I_b$ = Smallest of three-phase currents
$I_c$ = Third phase current, of intermediate value

(All currents in per unit or in amperes)

**Figure 8—Negative-Phase Sequence Current Calculation Curves (for Case of No Zero-Phase Current)**

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## 7.9 Loss of Field

Complete loss of excitation on an operating generator can result in dangerous overheating of its rotor within a very short time unless the machine is disconnected from the system. Large generators having cylindrical rotors without amortisseur windings are particularly vulnerable in this respect. The degree to which this heating will occur depends on the initial load on the generator, the manner in which the field current is lost, and the manner in which the generator tends to overspeed and operate as an induction generator. This overspeed normally results in a reduction in load due to the characteristics of the turbine governor, as well as an increase in armature current associated with low voltage at the generator terminals, and is accompanied by high rotor currents. These rotor currents will flow both through the rotor winding (provided the field circuit is not open) and through the rotor body, completing the circuit at the end of the rotor body. The rotor body currents will cause high, and possibly dangerous, temperatures in a very short time, particularly where the currents flow across the wedges and retaining rings at the ends of the rotor body. Since the loss-of-field condition also corresponds to operation with very low excitation, overheating of the end portions of the stator core may result.

Some users provide a loss-of-field relay to trip the generator breaker removing the unit from the system and, in some cases, also to trip the turbine stop valves, while others provide alarm indication only. When neither loss-of-field tripping nor alarm indication is provided, the operator must recognize the condition and manually trip the unit.

Such loss of excitation circumstances should be evaluated, considering the length of time excitation was lost and the deviation from synchronous speed, to assess possible rotor heating damage. Rotor inspections should be considered before returning the unit to service. See 7.15 and 7.16 for a fuller discussion of this subject.

Loss of excitation almost always causes a unit trip. In such cases, it is strongly recommended that the reason for the trip be identified before applying voltage to the field again. Loss-of-field protection is discussed in ANSI C37.102-1987 [5].

## 7.10 Field Preheating

In some cases, it may be desirable to prewarm the rotor forging when starting up or prior to overspeed testing in order to reduce its susceptibility to brittle failure. When this is required, it should be carried out in accordance with the manufacturer's recommendations.

On older units, preheating of some large generator fields may be used to minimize rotor-winding deformation, which is caused by the interaction of centrifugal force, expansion, and contraction due to temperature changes. In any particular case, the user should consult the manufacturer concerning the need for preheating. If the rotor is to be preheated by applying field current, be sure not to exceed the volts/hertz limits for the generator or any transformer connected to the generator bus.

## 7.11 Operation with Field Circuit Grounded

Usually, the rotor winding and all of its excitation supply circuit is operated as a completely ungrounded system. On such a system, the existence of a single ground at any point in the system will not interfere with the normal operation of the generator. Its presence can be detected by a suitable ground relay and alarm. Upon verification of this initial ground, it is advisable to shut down the machine and correct the trouble promptly.

If the initial ground should occur at some point in the generator rotor winding, a second ground in the excitation circuit may prove serious. When a double ground exists, part of the field winding will be shorted out through the shaft forging. This condition will cause a magnetic or thermal unbalance that may result in serious vibration of amplitude sufficient to wreck the machine if allowed to exist too long. The use of vibration detection and protection equipment would assure instant knowledge of such a condition and take the machine off the line more quickly than the time it would take an alert operator to become informed and take corrective action.


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Loss-of-field protection cannot be depended upon to detect double rotor grounds or shorted rotor turns or to protect the generator from serious damage resulting from such conditions. The reason for this is that these relays are designed to detect underexcited (leading) reactive power (kvar) at the generator terminals. A serious double ground or even shorted but ungrounded turns in the rotor may result in only a small change in reactive power output, which may be compensated for by automatic voltage regulator action. Even shorting of a large fraction of rotor turns may not reduce excitation far enough to be detected by most practical loss-of-field relay settings.

## 7.12 Field Forcing by Voltage Regulator

Continuously acting fast response voltage regulators used with exciters having high ceiling voltages are employed by some users to improve system stability and reliability. At times of prolonged system low voltage, this automatic equipment can impose a severe overload upon both the field and the armature. For a particular unit, the manufacturer should be consulted to determine the maximum time the overload condition can be permitted. Automatic means should be provided to relieve the overload at the end of this time and return the machine to its maximum permissible continuous load.

## 7.13 Loss of Coolant Flow

In the event that stator-winding cooling water flow is lost in a directly cooled machine, the generator output must be reduced to the manufacturer's recommended capability without coolant flow; however, this capability is only a small percentage of rated capability. This load reduction must be accomplished in a short amount of time. The reduced load may be carried only for a limited time, in line with manufacturer's recommendations. Under these circumstances, if flow cannot be reestablished within acceptable conductivity limits (thereby permitting the resumption of normal loading), the unit must be taken off the line. Many of today's larger machines have no capability without coolant flow.

Depending on cooling system design, the loss of raw water flow to one or more of the stator-cooling water heat exchangers may impose a load limitation. The manufacturer should be consulted regarding the generator's capability with stator-cooling water heat exchanger impairment.

## 7.14 Operation Under Extreme Emergency Conditions

Under extreme emergency conditions, a power system may experience large disturbances in voltage, current, power flow, and frequency, even to the point that some generators may not remain synchronized with the system. It may be necessary for the operator to decide quickly whether and when to trip a given generator from the system. By keeping the generator connected to the system, the operator would support the power system and possibly prevent its collapse, but would accept unusual risk of damage to the equipment. It is not possible to anticipate all of the contingencies that extreme system emergencies can produce, nor is it possible to discount the hazards of interaction of two or more simultaneous stress conditions.

Due to the complex relationships and the many factors involved, it is recommended that guidelines concerning action to be taken during such conditions be prepared by the user for each generating unit. The guidelines should constitute a portion of an overall system plan to alleviate system conditions sufficiently to preclude the necessity of operating the generators under extreme emergency conditions for any but very short time periods; and even then, there can be an unusual risk of incurring equipment damage. These guidelines should be the result of careful evaluation of the effects of operating at extreme conditions based not only on consultations with equipment suppliers but also, where possible, on results of composite nondamaging tests of the actual unit and its auxiliaries to determine specific limiting conditions for the unit as a whole. Such testing may be difficult because, for example, conventional temperature instrumentation may not follow fast transients and may not be located at the areas that would become limiting under abnormal conditions. Also, many points that may incur critical stresses have no instrumentation to indicate their condition.

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If users elect to load the generator beyond its rated capability at their own discretion and risk, they should invoke operating instructions on definable parameters of plausible emergency conditions, i.e.:

1) Duration
2) Stator voltage and phase unbalance
3) Frequency
4) Volts/hertz ratio
5) Stator current
6) Field voltage
7) Field current
8) Voltage regulator output
9) Exciter output
10) Observable temperatures and rates-of-rise
11) Stability limits
12) Vibration limits
13) Reverse power conditions

Users must also give consideration to the characteristics of the main and auxiliary transformers and power plant auxiliaries including instrumentation, particularly as affected by low frequency and voltage, in arriving at “minimum risk” emergency operating procedures. In addition, turbine vibration and blade resonance conditions may be encountered at speeds other than rated.

During system emergency conditions, the automatic regulation equipment (including volts/hertz protection) should always be in service when operating parameters are rapidly changing.

## 7.15 Motoring of Turbine Generators at Synchronous Speed

### 7.15.1 Motoring with Excitation Controlled

When the power delivered by the turbine is less than the losses of the T-G set, the generator will draw power (reverse power) from the system to maintain synchronism with the system. In this situation, the generator is operating as a synchronous motor and there is no danger to the generator if proper excitation, cooling, and bearing lubrication are maintained. Motoring while in synchronism with the power system is to be contrasted with inadvertent energizing of a T-G set while not in synchronism with the system; a situation that occurs at turning gear speed and poses an extreme hazard to the generator.

### 7.15.2 Motoring with Incorrect Excitation

If turbine input steam is lost while carrying rated kVA at rated power factor, the generator excitation current will be at rated full load field current. Upon loss of turbine power, if the excitation remains at the full load value, the generator will supply rated overexcited (lagging) reactive power (kvar) to an “infinite” system with no change in terminal voltage. However, in a typical power system, the generator terminal voltage will rise regardless of the initial reactive power loading (kvar). The amount of voltage rise will depend on system impedances and the action of other reactive power sources (usually other generators) responding to the voltage disturbance. Terminal voltages in excess of 105% of rated can easily be achieved on the generator that lost turbine power. Other generators connected to the system may have high or low terminal voltage and may be forced into the underexcited (leading) area of the reactive capability curve (see Fig 5). For initial loading less than rated, the field current will be less than rated full load field current and the influence on the system and other generators will be proportionately less.

### 7.15.3 Motoring with Loss of Excitation

If excitation is lost when turbine input steam is lost, the generator may or may not lose synchronism with the system. Under this condition, the generator will supply underexcited (leading) reactive power to the system. Generally, the


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reactive loading will be in excess of the continuous rated underexcited reactive capability given by the reactive capability curve. This will cause rapid overheating of the stator core ends and possible serious damage if the generator is not removed from the system. Also, the voltage may be below 95% of rated voltage. If the generator remains in synchronism with the system and the system is "infinite," i.e., no change in terminal voltage, the loading will be approximately given by the intersection of the zero PF lead (extended) and the zero field current characteristics of the vee curve (see Fig 4). If the system cannot maintain generator terminal voltage, the reactive loading will be reduced in proportion to the voltage reduction. Rotor saliency and residual magnetism will give the effect of there being some field current (although the field ammeter will read zero) and reduce the reactive power slightly. It is likely that loss-of-field relays on the affected generator will not detect the loss of field under the circumstances of simultaneous loss of turbine input steam.

If the generator does not remain in synchronism with the system, the reactive loading will be greater than if it does remain in synchronism. This case is discussed in 7.1.6.

In either case, the supply of leading reactive power to the system from the motoring generator will cause a reduction in voltage at the generator terminals. The amount of the reduction will depend on the action of other reactive power sources (usually other generators) and system impedances. Terminal voltages below 95% of rated can be easily achieved on the generator that lost turbine power. Other generators connected to the system may have high or low terminal voltage and may be forced into the overexcited (lagging) area of the reactive capability curve. The main danger to other generators is that the terminal voltage may be too low or they will be forced into a loading in excess of rating.

### 7.15.4 Turbine Considerations

Upon loss of input steam to the turbine, the motoring of the generator may damage the turbine in a very short time by overheating. The time before damage occurs depends on turbine design and the circumstances of loss of power to the turbine. The turbine manufacturer should be consulted for recommendations concerning motoring of turbines. Consideration should be given to the proper application of a reverse power relay.

## 7.16 Operation of Turbine Generators at Other Than Synchronous Speed

Operation of the turbine generator at less than synchronous speed can be subdivided into two general areas: operation at or near zero speed, and operation close to synchronous speed. In either case, the primary concern is the effect of induced currents flowing in the rotor surface and associated hardware.

### 7.16.1 Inadvertent Energization

Energization of the generator stator when it is at standstill, or on turning gear, is hazardous to the life of the machine. If permitted to continue, total destruction of the generator may occur and severe damage to the turbine can also result. Massive induced currents flow in the surface of the rotor and in the slot wedges. If the machine is allowed to continue to accelerate as an induction machine, the heating will rise to levels where mechanical failure takes place. At this point, the rotating winding is thrown into the air gap, and major mechanical damage and unbalance occur.

Depending on the design of the generator, its inertia and reactances, this scenario can take place in as little as 30 seconds. Early detection and relay operation can prevent serious damage.

### 7.16.2 Operation Close to Synchronous Speed

Operation of the generator close to synchronous speed usually results from loss of excitation. Since the speed difference between the rotor and the armature flux is small, the induced currents are relatively low as compared to the previous case, and damage takes much longer to occur. This is true whether the machine is running above or below synchronous speed. Machines have been known to run in this way for over 30 minutes without major damage to the generator. The turbine can potentially be severely damaged due to overheating of the long last stage blades if there is no steam flow.

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The main areas of concern when such an incident has occurred are the rotor wedges, retaining rings, tooth dovetails, and areas of the rotor pole surface where currents are crowded due to machining features, e.g., close to the cross slots machined into many rotors for stiffness equalization. These areas must be closely inspected, and if there is the slightest reason to be concerned, the retaining ring should be removed, and the rows of wedges closest to the pole faces removed to inspect for damage to the wedges and dovetails. Since the construction of the rotor varies widely depending on the size of the machine and the manufacturer, the manufacturer should be consulted prior to inspection after such an incident.

# 8. Maintenance

## 8.1 General Considerations

Parts of a turbine generator, such as collector brushes, ground brushes, and rotor ground fault detector brushes, are subject to wear and require frequent adjustment and replacement. Other parts, such as coolers and the ventilating system, may accumulate dirt or foreign material and require occasional cleaning. Winding insulation deteriorates with age and requires careful inspection and maintenance to obtain reliable service. All parts are exposed to continual vibration, stress, and temperature changes, and may in time become loose or possibly fracture. As a consequence, it is important to observe the operation of the unit and to investigate any unusual changes in its performance, sound, temperature, vibration, or appearance. In addition, a regular schedule of inspection, testing, and preventive maintenance should be adopted so that minor troubles may be eliminated before they develop into major ones.

The expense of inspecting and maintaining machines that appear to be in good condition, rather than operating the machine until failure occurs in service, can be justified on the basis of increased reliability and lower overall cost. Furthermore, there is a distinct advantage in maintaining machines at periods when outages can be planned so as not to interfere with peak loads on the system.

Many parts of the machine may be given routine checks while the machine is operating. The more complete inspections and maintenance will require shutdown and some disassembly. In general, it is recommended that a complete inspection be made after the first year of operation. Thereafter, it may be possible to operate for several years between complete inspections. The time between inspections should be determined by the manufacturer's recommendations and the user's experience. Consideration should be given to the number of hours of operation, number of starts, number of severe short circuits on the system or other high current transients, outages for turbine repairs, conditions found in previous inspections, and other factors.

Good maintenance planning can play a key role in an effective maintenance outage. Some generator replacement components can be subject to long lead times. The use of operating data, manufacturer's knowledge and experience with the design, and review of the condition of the generator at previous inspections can allow some prediction of where significant repairs might be necessary. Once the outage begins, care should be taken to check potential long lead time repair areas early to avoid or minimize any outage extension.

## 8.2 Collector Rings and Brushes

Since mechanisms leading to collector failures develop over a period of time and are difficult to monitor remotely, regular maintenance is necessary to spot and correct potential trouble before a failure can occur. In order to ensure that the collector rings and brushes are in good operating condition, the following maintenance schedule is suggested:

### 8.2.1 Daily Inspections

Trouble from defective brushes can develop suddenly; therefore, it is recommended that a visual inspection of the brushes be made during each daily work shift. If the following conditions are observed, the brushes should be serviced as explained in 8.2.2:

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1) General dust and particulate
2) Brush wear
3) Sparking
4) Chattering
5) Broken springs
6) Frayed or overheated pigtails
7) Change in the appearance of the collector ring film

### 8.2.2 Weekly Inspections

Once a week, the brushes should be given a complete inspection. The primary concerns are noise, high voltage, vibration, windage, and moving parts. Noise levels are very high inside collector housings and hearing protection must be used. The dc voltages between collectors and brush rigging polarities will typically be between 200 and 600 volts; these voltages are dangerous and care should be taken to assure that no differential voltages are applied to a person. The possibility of a rotor-winding ground should be taken into account even though the system is normally floating from ground. Care must be taken to avoid direct shaft contact and to avoid dropping items onto the rotating shaft. On hydrogen-cooled machines, it should be determined that no explosive concentration of hydrogen exists in the collector housing due to hydrogen leaks.

1) Excessive dust should be removed from the collector ring insulation and brush rigging. This may be accomplished with compressed air. If dust is allowed to accumulate, it will likely cause breakdown in the insulation. It may also cause sticking of the brushes in the holders unless removed regularly.
2) Take each brush by the shunt and move it up and down in the holder. This serves two purposes: to shake the dust out of the holder and to check the brush freedom in the holder.
3) Replace any worn brushes, when necessary. The manufacturer should be consulted for any limitations on how many brushes can be replaced at one time.
4) Adjust the spring pressure of adjustable pressure type brush holders to the value recommended by the manufacturer. It is important that this pressure be maintained and that the pressure be effective in keeping the brush in firm contact with the collector.
5) Check to be sure that all brushes and brush holders are correctly aligned in accordance with the manufacturer's instructions. No brush should overhang the edge of the collector ring under any operating condition.
6) Check the smoothness of collector ring operation as indicated by brush vibration. If the brush is riding rough or the collector ring seems eccentric, the collector rings should be examined carefully at the earliest opportunity to determine if reconditioning is necessary.
7) Check the operating data if continuous sparking has been observed to see if loads have been such that brush minimum recommended current densities have been maintained. If not, brushes can be removed to raise current densities. Caution should be taken to assure that loading is not raised beyond the capability of the brush rigging with the brushes removed (see 7.3.10). The manufacturer's instructions should be followed regarding the best geometric pattern to select brushes for removal.

### 8.2.3 Shutdown Inspection

Whenever a complete brush replacement is made or at the time of major shutdown, the brush and collector ring assembly should be given a complete servicing. Brush operation and ring wear are benefited by occasional reversal of collector ring polarity. In addition to the routine carried out in each weekly inspection, the following work should also be done:

1) The collector insulation should be cleaned thoroughly. If there is evidence of oil, the collector assembly should be wiped clean with a cloth slightly dampened with a cleaning fluid recommended by the manufacturer and thoroughly dried. Excessive wetting by the fluid may wash impurities into inaccessible crevices. Be sure the cleaning fluid used will not have an adverse effect on collector ring film or brushes. Do not use compounds containing silicone in the collector area; silicone curing agents will destroy the carbon film. The insulation resistance of the collector insulation and rotor winding should be measured with an

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insulation resistance tester. If the insulation resistance is unsatisfactory, based either on previous readings or on values stated in IEEE Std 43-1974 [8], the collector leads should be inspected for sources of low insulation resistance and, if necessary, segregated or dried out in accordance with usual procedure.

2) The collector rings should be checked to see that they are cylindrical and running true within the limits set by the manufacturer. Rough collector rings will cause momentary separation between the brush and ring, with burning of the ring resulting. Vibration of the collector ring or brush rigging will also cause this trouble. In general, blackening and cutting of the collector rings is an indication of poor brush service. Rings in this condition may have to be ground or machined in order to restore them to a true and smooth condition. This should be done by experienced personnel and precision fixtures.
   Grinding or machining collector rings removes some of the ring surface and can, after several repetitions, reduce the collector ring diameter below the minimum required for safe operation. The manufacturer can provide the minimum safe collector ring diameter for any generator and the collector rings should be replaced before this minimum diameter is reached. Consequently, it is desirable to carefully measure the collector ring diameter before and after resurfacing the rings and to ensure that each resurfacing operation removes no more metal than necessary.
3) The inside of the brush holder boxes should be cleaned before installing new brushes and the brushes wiped off when they are not replaced. Brushes of different grades should not be mixed. The grade should not be changed without consultation with the manufacturer.
4) Replace any worn or damaged parts and check all items that are listed in 8.2.2.

## 8.3 Air Filters

Dirty air filters will reduce the amount of cooling air circulated, resulting in possible overheating. They will also allow the entrance of dirt and grit that may damage the machine and choke the ventilating ducts. Air filters should be inspected periodically and cleaned or replaced, when necessary.

## 8.4 Generator Coolant Heat Exchangers

The effectiveness of coolers will be reduced due to accumulation of sludge or other matter in the cooler tubes. If water conditions cause the accumulation of foreign material in the cooler, periodic cleaning should be carried out. Dirt in the cooler or deterioration of the cooler performance is indicated by an increase in the difference between the average water temperature and the average gas temperature for the same load condition.

The effectiveness of the coolers will also be reduced if the outer heat transfer surface (fins) of the tubes becomes dirty due to oil, dust, or other causes.

The cooler tubes should be examined for traces of moisture, and the drains checked for water, which may indicate leaks. Whenever the machine is shut down during freezing weather, all water should be drained from the cooler tubes if the coolers are exposed to the low temperature.

Cooler tubes of air-cooled generators may be cleaned when required with the unit in operation. The manufacturer's recommendations should be observed regarding the limiting values of output during the tube cleaning process.

In the case of hydrogen-cooled machines, cleaning of the tubes when hydrogen is in the casing is extremely hazardous and is not recommended.

The outer heat transfer surfaces of the cooler tubes should be inspected for lead carbonate deposits, which are symptomatic of excessive moisture in the hydrogen. If deposits are found, the manufacturer should be consulted for proper cleaning methods and provisions should be made, before the machine is returned to service, to keep the hydrogen as dry as possible.

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## 8.5 Hydrogen Leak Detection

In general, hydrogen leaks are indicated by excessive hydrogen consumption. If the amount of hydrogen required each day to maintain a given gas pressure is much in excess of normal or the manufacturer's guarantee, there may be some abnormal leakage and the matter should be investigated and corrected. The presence of leakage can be detected by observing the ability of the system to hold gas under pressure. To obtain satisfactory results, it is necessary to correct the observed pressure drop for changes in temperature and barometric pressure. Formulas for calculating gas leakage when these corrections are made are as follows:

$$L = 238\,\frac{V}{H}\left[\frac{P_1 + B_1}{273 + T_1} - \frac{P_2 + B_2}{273 + T_2}\right]$$

where:

| | |
|---|---|
| $L$ | = Leakage for average gas pressure, cubic feet per day |
| $P_1$ | = Initial gas pressure, inches of mercury, gauge |
| $P_2$ | = Final gas pressure, inches of mercury, gauge |
| $B_1$ | = Initial barometric pressure, inches of mercury |
| $B_2$ | = Final barometric pressure, inches of mercury |
| $T_1$ | = Initial temperature, °C |
| $T_2$ | = Final temperature, °C |
| $V$ | = Gas content of generator, cubic feet |
| $H$ | = Duration of test, hours (for best results, H ≥ 24) |

$$L = 0.07028\,\frac{V}{H}\left[\frac{P_1 + B_1}{T_1} - \frac{P_2 + B_2}{T_2}\right]$$

where:

| | |
|---|---|
| $L$ | = Leakage for average gas pressure, cubic meter per day |
| $P_1$ | = Initial gas pressure, newton/mi$^2$ |
| $P_2$ | = Final gas pressure, newton/mi$^2$ |
| $B_1$ | = Initial barometric pressure, newton/mi$^2$ |
| $B_2$ | = Final barometric pressure, newton/mi$^2$ |
| $T_1$ | = Initial temperature, Kelvin |
| $T_2$ | = Final temperature, Kelvin |
| $V$ | = Gas content of generator, cubic meters |
| $H$ | = Duration of test, hours (for best results, H ≥ 24) |

If the leakage tests are made with air, the results should be multiplied by 3.75 to obtain the equivalent leakage of hydrogen of 98% purity. This is in accordance with the law of gas leakage, being inversely proportional to the square root of the molecular weight if the pressure is constant.

If the leakage rate is not within specified limits, a systematic search for leaks should be made either with soap or other liquid solutions, or by means of leak detectors using Freon 12. The use of odorants, such as ether, is not recommended.

Liquid soap solutions provide a relatively quick and simple method of leak detection and evaluation. They are not suitable for inaccessible parts or for very small leaks. Solutions of industrial or domestic liquid soap with the addition of glycerin as a thickening agent are satisfactory. Liquid soap will form bubbles when applied over a small leak and will form craters where the gas blows through when applied over a large leak. The hydrogen piping can be isolated from the generator and tested independently.

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Hydrogen leaks around the generator, and concentrations of hydrogen gas at any point in the lubrication system or the structure surrounding the generator, may be detected by means of a combustible gas meter or by use of an ultrasonic probe. Devices employing heated grid plates or open flame are not to be used with hydrogen in the machine.

Hydrogen may also leak into the:

1) Stator liquid coolant
2) Seal oil
3) Hydrogen cooler water

These systems should be equipped with vents where hydrogen can be detected or monitored. Vents should not be combined. Each system vent should be brought out separately to the open atmosphere.

## 8.6 Complete Inspection

For a complete inspection, the end bells and the rotor should be removed from the stator. Great care should be exercised in removing and reinstalling the rotor to avoid damage to the core punchings, stator windings, bearings, machined surfaces of the stator, collectors, rotor fans, bearing journals, or retaining rings on the rotor. Do not support the rotor on the retaining rings. The rotor should be properly stored and protected from moisture. If fan blades are removed, they should be carefully identified for reinstallation. Identification marks should be made by nondamaging means. Prick punches, chisel marks, number stamps, and similar surface marring devices should generally be avoided. Proper procedure should be used to avoid leaving foreign material in the generator and cooling tubes.

**CAUTION —** Before opening a hydrogen-cooled machine, ensure that the following steps are taken:

1)The casing is properly purged of hydrogen and carbon dioxide>
2)The casing is at atmospheric pressure
3)All hydrogen and carbon dioxide supply lines are isolated
4)All electrical clearances have been implemented
5)Before entering, monitor for proper oxygen content

### 8.6.1 Armature Windings

The ends of the armature winding should be inspected for deposits of oil and evidences of corona discharge. Corona is indicated by white spots on, or disintegration of, the insulation varnish at high dielectric stress points. If cleaning is necessary, the procedure given under 8.7 should be followed. After cleaning, the winding connections and the insulation should be carefully inspected. All bracing and tying material should be inspected for evidence of movement. Stresses set up by short circuits, vibration, or thermal expansion may cause damage and consequent movement of these parts. If there is any sign of movement, tape separations, cracking, insulation swelling, compound migration, mechanical damage from loose material, loose slot wedges, corona damage, or other trouble, suitable repairs should be made (see IEEE Std 56-1977 [9]). Gas passages should be checked and any obstructions removed.

In liquid-cooled machines, all connections, hoses, and piping should be inspected and tested to ensure that there are no cooling system leaks.

### 8.6.2 Armature Core and Frame

The armature core finger plates and structural parts should be inspected, particularly for evidence of hot spots as shown by discoloration, looseness, or damaged punchings. Insulated through-bolts should be checked for possible insulation deterioration. Tightness of all core clamping fixtures to manufacturer's recommendations should be verified. If core damage is found, the testing and repair should be discussed with the manufacturer. Powdered red iron oxide may be an indication of fretting between iron and steel parts, between stator wedges and core laminations, or core looseness. The bore of the stator should be thoroughly inspected to make sure that no foreign objects are present. If the core is in need of painting, all surfaces should be cleaned as recommended in 8.7, and the punchings sprayed


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with oil-resistant varnish. Care should be taken not to negate the integrity of thermal tagging compounds that may be present. The inside of the frame should be checked for evidence of oil, which would indicate oil leakage from the shaft seals past the oil deflectors or from bearing housing joints.

Low points inside the frame should be inspected, if possible, for any water or oil accumulation. Generator water drain lines should be inspected and cleaned or replaced, if necessary. Water leak detectors should be functionally tested.

### 8.6.3 Rotor

The rotor should be examined for movement or distortion of field coils and end winding blocking, contamination and blockage in ventilating ducts, properly fitted wedges, local hot spots on the rotor surfaces and evidence of overheating or burning at the contact surfaces between the wedges, retaining rings, and rotor body. If evidence of local heating is found, the manufacturer should be consulted as to the need for internal inspection to determine if repairs are necessary. The collector rings and field leads should be cleaned and inspected for evidence of local heating. In addition, the bore should be pressurized to determine the integrity of the hydrogen seals. If necessary, the outside surfaces of the rotor body and retaining rings should be cleaned and, if recommended by the manufacturer, a coat of varnish should be applied to prevent rust. Only a thin, uniform coat should be applied since the rate of heat transfer from the rotor surface may be appreciably reduced by a heavy uneven buildup of varnish, which may lead to nonuniform temperature removal and hence to vibration. The rotor surfaces, such as journals and coupling surfaces, should be inspected for wear and pitting damage. If pitting is observed, see 9.4 for possible causes.

### 8.6.4 Lead Box and Terminal Bushings

Stator lead box and bushings should be inspected for evidence of cracks, looseness of parts, plugged drain holes, oil in the bushing cooling passages for gas-cooled bushings, water leaks on water-cooled bushings, deteriorated insulation on leads, loose blocking, and signs of overheating and any other signs of distress.

### 8.6.5 Fans

Fan blades should be inspected for cracks.

Suspect blades should be tested with fluorescent, red dye, or magnetic particle methods, taking care that the rotor windings are not contaminated by the test fluid.

### 8.6.6 Retaining Rings and End Disks

Retaining rings and end disks should be carefully inspected for rusting, pitting, and cracking during major unit overhauls. At least a visual examination should be made of these parts and a more searching examination is advisable.

Many nonmagnetic retaining rings presently in service on medium and large units are made of an 18Mn-5Cr alloy and are very susceptible to stress corrosion cracking in the presence of moisture. Every effort should be made to prevent exposure of these rings to water while in service or while the rotor is removed from the stator for inspection. To avoid stress corrosion cracking problems, manufacturers are now using 18Mn-18Cr as retaining ring material in place of 18Mn-5Cr.

Presently, the two most common methods of testing retaining rings for cracks are fluorescent dye penetrant tests and ultrasonic testing. Fluorescent dye penetrant testing requires the removal of the retaining rings for a test of the entire surface area that is subject to stress corrosion cracking. Ultrasonic testing has the advantage of not requiring the removal of the retaining rings. In the recent past, the validity of some ultrasonic test results have been questioned. Newer and improved ultrasonic testing procedures are now in use, which may increase the level of confidence the industry has in the ultrasonic test results of retaining rings.

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Retaining rings can be removed from the rotor body for testing as many times as is necessary during the life of the generator without producing undesirable metallurgical changes in the rings if the proper thermal cycle techniques are followed during removal and installation. The manufacturer's recommendations for removal should be followed.

#### 8.6.7 Hydrogen Seals

A complete inspection of hydrogen seals should be made in connection with each major overhaul, at which time the seal should be dismantled completely and the seal oil grooves and holes cleaned and refinished, if necessary. The wearing surfaces of the seal ring and shaft should be checked for pitting, alignment, and wear. The seal should be reassembled with extreme care in order to ensure the proper axial and radial clearances in the final assembly.

#### 8.6.8 Seal Oil System

Seal oil units perform a continuous balancing function with respect to various pressures sensed at several points in the seal oil system. Oil flow rates at the hydrogen seals are based on the ability of the seal oil unit to balance pressures. An inability of the seal oil unit to sense pressure, react to pressure change, or control flow limits will result in either the loss of the hydrogen from the generator or the flooding of the generator with oil. All parts of the seal oil unit involved in the balancing function should be inspected.

Contamination of the various oil reservoirs on the seal oil unit, bent valve stems, degraded cooling, sticking floats, regulators, relief valves, and inadequately sloped drain lines, as well as clogged sensing lines, are typical sources of seal oil system trouble.

#### 8.6.9 Bearings

The bearings should be inspected carefully to ensure that the babbitt surface is in good condition with proper contact area to the journal and tested to verify that continuous bonding of the bearing babbitt exists. The bearing assembly should be checked for tightness and true alignment. If particles of dirt are found embedded in the babbitt, the entire lubricating system should be flushed out and the oil cleaned. If pitting is observed on bearing surfaces, see 9.4 for its possible causes.

#### 8.6.10 Gas System

All components of the gas system such as gas dryers, core monitors, piping, etc., should be inspected and defective components repaired or replaced. The operation of all gas control equipment and alarms should be functionally checked and adjusted.

#### 8.6.11 Generator Monitoring and Protection

All generator monitoring instruments and relaying should be checked and recalibrated.

#### 8.6.12 Stator and Rotor Liquid Cooling Systems

System components, such as pumps, motors, valves, filters, ion exchangers, and heat exchangers, should be inspected and replaced as required. Piping and flanges should be inspected for leaks. The entire system should be functionally tested and adjusted, if necessary. Manufacturer's recommendations should be followed for replacement of ion exchanger materials.

#### 8.6.13 Miscellaneous

Gaskets should be inspected and replaced, if necessary, with the manufacturer's recommended gasket material. Insulating hardware for bearings and seals should also be inspected and replaced, if necessary. All accessible bolts of the unit should be checked for appropriate tightness and the integrity of locking devices, if used.


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## 8.7 Cleaning and Painting

Dust should be removed, preferably by a vacuum cleaner. If compressed air must be used, care should be exercised in the application of pressure to prevent damage to the insulation. The usual safety precautions for handling compressed air should be observed. If available, (30 psig or less) instrument air should be used. In any case, the air must be dry. All exposed surfaces may be wiped with clean cloths to remove any remaining oil or dirt. It may be necessary to use a cleaning solution recommended by the manufacturer in order to effectively remove the dirt.

Care should be exercised in using cleaning fluids because of their toxic effect and possible explosion hazard. Special attention should be given to ventilation, and it is suggested that any cleaning work be done by more than one worker so that, if any worker is overcome, the others can be of help.

Any cleaning fluid is more or less a solvent for insulating compounds, hence the application of these fluids in large quantities should be avoided. They should not be allowed to remain in contact with the winding any longer than necessary to remove the oil and dirt. Excessive wetting should be avoided because it washes impurities into inaccessible crevices. Some cleaning fluids may damage retaining ring material. Only manufacturer-approved cleaning fluids should be used.

After the windings and core have been cleaned, they should be inspected carefully for any signs of deterioration. If required, one or two very thin coats of insulating varnish recommended by the manufacturer may be applied. Compatibility between new and existing varnishes should be checked. The unnecessary and frequent application of coats of varnish may result in more harm than benefit. Care should be taken not to negate the integrity of thermal tagging compounds that may be present.

## 8.8 Moisture Protection

Protection of a generator from the effects of moisture should start when the machine is manufactured and become a never-ending process until it is permanently retired from service. Water has a detrimental effect on many components of a turbine generator, whether the generator is in service, shutdown, or disassembled for inspection. The insulation systems of a generator (winding, through-bolts, insulated bearing liners, etc.) may absorb moisture that will adversely affect their insulating properties. Moisture on highly stressed metal parts, such as field retaining rings and blower components, can result in serious problems from stress corrosion cracking.

While in operation, if water enters the generator in a vapor state or leaks in an atomized fashion into a high velocity gas flow, large quantities of water can exist before a liquid detector alarm operates. Common sources of moisture in the atmosphere of a hydrogen cooled generator in service are:

1) Hydrogen cooler leaks
2) Water vapor entrained in the hydrogen seal oil
3) Moisture in the hydrogen supply
4) Stator-cooling water leaks (for a water-cooled stator).

A hydrogen atmosphere that is near saturation with water while the unit is in service can become a source of condensation when the unit is shut down or when the hydrogen temperature is below the dew point.

A visual inspection should be made during shutdown for signs of contamination or moisture due to these sources. In addition to repairs or cleanup due to contamination, it is desirable to identify the source and take corrective action to eliminate the problem, whether it is equipment or operation related.

While a generator is open to the atmosphere, condensation and various forms of precipitation are the common sources of moisture. During this time, most problems with moisture can be prevented by protecting moisture-sensitive components from any form of precipitation and maintaining their temperatures about 10°C above that of the surrounding atmosphere.

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## 8.9 Testing

For proper maintenance of a machine, it is necessary to combine tests of proven significance with visual inspection. The use of either visual inspection or any presently known test procedures alone is not sufficient for a proper understanding of the condition of the machine. Both visual inspection and proper test procedures must be utilized and coordinated in order to reach a sound conclusion.

In the maintenance of generators, the user is concerned principally with three problems:

1) Providing the basis for an immediate decision as to its serviceability and any necessary corrective action to be taken.
2) Observing the long-term trends in behavior.
3) Anticipating and thereby avoiding possible service failures.

Each of the following tests is directed toward detecting a particular type of trouble, or to follow long-term trends. All tests are not required at every inspection period. The method of making these tests and the interpretation of the test results are discussed in greater detail in IEEE Std 43-1974 [8], IEEE Std 56-1977 [9], and IEEE Std 115-1983 [12].

1) Insulation resistance tests at low-voltage direct current are primarily to detect grounds and wet or dirty insulation. These tests are normally made with a “megger” test set. Test voltages are commonly 500, 1000, 2500, or 5000 volts.
2) Dielectric absorption (polarization index) tests furnish information concerning the relative condition of the insulation with respect to moisture and other contaminants.
3) Controlled overvoltage tests at high-voltage direct current (see IEEE Std 95-1977 [10]) reveal insulation resistance characteristics that are not disclosed by the low-voltage tests.
4) Dielectric overvoltage tests establish that the winding is capable of withstanding the applied voltage. Such tests may be destructive to a greater or lesser extent. Both ac and dc tests have been widely used for maintenance over-voltage testing. An insulation resistance test ((1) above) may be conducted before and after each overvoltage test.
5) Insulation power factor tests (tan delta) are used to detect moisture and voids in the insulation and indicate the amount of ionization (see IEEE Std 286-1975 [16]).
6) Slot discharge tests detect surface discharge that may be injurious.
7) Surge comparison tests are used to test turn-to-turn insulation.
8) Corona probe tests indicate and locate unusual ionization within the insulation structure.
9) Winding resistance tests (dc) detect loose connections and open-circuited windings.
10) Rotor-winding impedance tests alternating current) detect and assist in locating turn-to-turn faults (see 9.3.1).
11) Interlaminar insulation tests (such as a loop test) detect and locate damaged areas in the stator core.
12) Resistance of through-bolt insulation in stator core should be measured.
13) Insulation resistance of rotor winding should be monitored during operation with a suitable ground detector and, while at rest, with a portable insulation resistance tester (megger).
14) Pole balance tests detect turn-to-turn faults on rotor windings (see 9.3.1).
15) Search coil (generator rotor flux survey) tests detect and assist in locating turn-to-turn faults. This test is performed with the rotor removed from the generator and may not be practical for all designs (see 9.4.1).
16) Stationary air gap search coil (flux probe) tests detect and assist in locating turn-to-turn rotor-winding faults. This test is performed with the generator at speed and excitation applied and may not be practical for all designs (see 9.3.1).
17) Insulation resistance tests of the generator bearing and hydrogen seal insulation should be performed to protect the bearings, seals, and journals from damaging shaft currents.
18) Hydrogen pressure drop tests for directly cooled generators utilizing gas as the cooling agent will detect blocked gas passages in the stator coils.
19) A stator coil strand continuity test will detect broken strands, which should be repaired to avoid the heat buildup that could result from additional strand breakage. This test may not be practical for all designs. Where the coil design permits, a strand-to-strand insulation integrity test should be conducted.


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In directly cooled machines that use water for coolant, the following restrictions in the application of tests (1) through (4) above are recommended:

Tests (2) and (3) should be conducted after all the water has been removed from the winding because the parallel paths to ground provided by the water in the hoses contribute enough conductivity to reduce the insulation resistance reading to a level below the normally accepted limits.

Tests (1) and (4) may be performed with water in the stator windings. Stator-cooling water must be flowing with a conductivity at or below rated values. Keep in mind that, during the insulation resistance test (1), the resistance through the teflon hoses will be measured and the megger reading may only be a few megohms.

To avoid the possibility of causing an insulation fire, a dielectric overvoltage test (tests (3), (4), (5), (6), and (8)) should be made only under one of the following conditions, which is to be determined by the test circumstances or consultation with the manufacturer:

a) In air with the end bells removed, the winding cleaned of oil or flammable contamination, and accessible to detect and react to any flame ignited
b) In hydrogen atmosphere of safe purity and pressure with generator closed
c) In $CO_2$ atmosphere with generator closed

# 9. Mechanical Considerations

The operation and maintenance of turbine-driven generators require a thorough knowledge of their construction as well as the ability to recognize the symptoms and understand the causes of impending damage and failure, which may be due to or result in conditions that are chiefly of a mechanical nature. Topics that readily fall within this category may be classified as:

1) Concentricity of rotor in stator
2) Axial position of rotor with respect to stator
3) Vibration
4) Shaft current and bearing insulation

## 9.1 Concentricity of Rotor in Stator

The initial assembly of a turbine-generator unit involves careful alignment of the generator rotor with the turbine, as well as accurate positioning of the stator with respect to the rotor. Eccentricity of the rotor is more serious on four-pole machines than on two-pole units because the magnetic flux in the region of the small gap is in parallel with that in the region of the long gap rather than in series and, hence, subject to more variation per revolution. Even in two-pole units, however, the flux density wave becomes higher near the pole center as it approaches the region of the small gap, and the magnetic pull is appreciably greater in this region. Besides the pulsating unbalanced magnetic forces, the changes in flux distribution cause induced currents in the rotor winding, wedges, and on the surface. Circulating currents between parallel stator circuits and the rotor cause increased losses and higher temperatures. Excessive inequality in the gap can also adversely affect the fringing fluxes at the core end region and may result in abnormal high temperatures in clamping plates, flux shunting devices, or retaining rings. The maintenance of accurate centering is also important to be sure of maintaining uniform clearances at oil seals, fans, baffles, etc., where tolerances are often small.

Concentricity is initially established by careful measurement of the air gap in at least four positions at each end of the generator. The procedure and allowable tolerances will vary somewhat depending on the air gap length, the number of poles, the unit cooling system, and whether the rotor is supported in pedestal or bracket bearings.

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In some machines having bracket bearings, the adjustment of the air gap as well as the clearances at oil seals, baffles, seals, fan shrouds, etc., is accomplished at the factory prior to shipment. In other types, these adjustments may be made or rechecked during installation of the unit, and should preferably be done under the supervision of the manufacturer's erection engineer. In any case, the procedure and allowable tolerances recommended by the manufacturer should be followed in the initial installation, as well as in subsequent reassemblies.

Once properly centered, the rotor is not likely to shift suddenly except in case of accident. With separately supported pedestal bearings, settling or growth of the foundation or grouting over an extended period may disturb concentricity, as well as the alignment between rotor and turbine. Abnormal wear of the babbitt will also tend to bring about these same results. Checking the gap for uniformity at regular inspection periods is therefore advisable, and can often be done quickly by tapered feelers, thickness gage, or pin gage. Measurements are made in the gap and care must be exercised to be sure the gage is in contact with a tooth rather than a slot wedge and far enough from the core end to avoid the tapered or stepped end laminations.

## 9.2 Axial Position of Rotor with Respect to Stator

The rotor should be properly centered axially with respect to the stator. Appreciable offset from magnetic center not only produces an end thrust, but can seriously affect the end fringing flux and produce abnormal local heating of the finger plates, flux shunt devices, and retaining rings.

If the generator has bracket bearings supported from the end covers, the correct axial location of the rotor can usually be obtained by adjustment relative to the bearing center lines. These are permanently located in relation to the stator core by the machined end cover fits against the stator frame. In this type, the fan shrouds, seals, baffles, oil seals, etc., may sometimes be adjusted at the factory before shipment to suit the bearing positions. Adequate provision is usually made for axial displacement of the rotor due to thermal changes in the turbine, and for any additional expansion of the rotor when the unit is loaded as well as for any necessary axial clearance for disengaging the coupling.

For machines with separate pedestal bearings, initial axial centering is often accomplished after the rotor has been aligned and coupled to the turbine by the adjustment of the stator position on the base plate. If this was not done previously at the factory, or if for any reason the stator was not suitably doweled or keyed to the base plate, axial centering must be done when the unit is installed.

Since the method of adjustment and permissible tolerances depend upon individual design details, the manufacturer's recommendations should be followed for each unit. Once the correct stator location has been established, subsequent checking of axial positioning is seldom necessary unless either the thrust bearing or the stator have been moved from their initial setting. The adjustment of fan shrouds, baffles, etc., however, may be necessary whenever they are disturbed, or after the rotor is removed and replaced.

When axial centering of the rotor must be rechecked, the manufacturer's reference dimensions that take into account overall turbine expansion from cold to hot should be used. If these are unavailable, measurements may be made between stator core ends and some reference points on the rotor, such as the outer end of the retaining rings if they are equally spaced from the rotor body. Measurements at several points around the periphery are recommended to allow for unevenness in the punchings. Once these reference points are known, the axial position should be set such that the rotor will be centered with the stator at operating temperature.

## 9.3 Vibration

The vibration of a turbine-generator unit may result from a number of different causes. Slight physical dissymmetries in the rotor result in nonuniform weight distribution around the geometric axis. To minimize vibration from this source, generator rotors are carefully balanced at the factory before shipment. Additional balancing is often necessary after installation because of the influence of the foundations and of the turbine. Other possible causes of rotor vibration are:

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1) Improper adjustment of bearing clearances
2) Oil whip
3) Hydrogen seal rubs (particularly associated with low seal oil temperatures)
4) Nonuniform thermal or magnetic effects
5) A difference between the rotor stiffness in the direct axis and in the quadrature axis
6) Other factors related to lubrication
7) Lost balance weight on the rotor

Core vibration in two-pole generators results from the magnetic pull in the air gap, the force being greater in the direct axis than in the quadrature axis. The rotating magnetic pull tends to deform the core elliptically, thus creating a double frequency component of core vibration. In most large, modern two-pole machines, core vibration is usually isolated from the frame and foundation by means of some form of flexible support.

Proportions of four-pole stators and the fact that the deflection is four lobe rather than two lobe have been factors generally minimizing troublesome vibration in these units. Occasionally, the core or some parts of the frame or lagging may resonate at, or near, twice rated frequency. Vibration amplitudes of these parts should be maintained below levels that produce mechanical deterioration of the core and frame or unacceptable noise levels.

### 9.3.1 Rotor Vibration

The sudden appearance of new rotor vibration or an increase in existing amplitude may be of greater significance to the operator than a steady continuous vibration. For this reason, a history of vibration amplitudes is desirable for all machines.

Measurement of rotor vibration is most commonly made on or near the bearings. Several types of instruments are in general use that accurately measure or record the amplitude, phase angle, and frequency of movement. Experience has shown that a single set of permissible bearing or journal vibration parameters cannot be established that would safely cover all designs. Consequently, the manufacturer's recommendations should be followed in each case.

Increased rotor vibration may be one of the first signs of short-circuited rotor turns. Intentional changes of excitation at constant megawatt load will often indicate whether the effect is electromagnetic, thermal, or both. A significant increase in excitation current required to produce the same real power, terminal voltage, and reactive power compared to the excitation to produce these conditions at an earlier date is also an indication of short-circuited rotor turns. If a permanent air gap flux probe is installed, an analysis of the voltage wave form may allow an assessment of whether shorted turns exist and indicate their circumferential location. Measurement of rotor resistance is a reliable indication if the exact temperature is also known. If the rotor has a temperature recorder, the chart should be examined for indications for a sudden drop in rotor resistance at the time vibration appeared.

If the generator can be taken off line, the rotor impedance with 120 volts ac applied to the field winding is sometimes useful for detecting rotor turn short circuits, provided an initial reading with no shorted turns is available for comparison. Most rotors will not take more than 5 to 10 amperes at 120 volts ac. A pole impedance balance test performed while the generator is disassembled will provide a comparison of the pole windings in the field, which may indicate shorted turns. This test is limited to fields that have accessible and uninsulated winding crossover connections.

Comparison of a new no-load saturation curve with the original curve is also a good check for short-circuited rotor-winding turns. See IEEE Std 115-1983 [12] for more information about the tests mentioned above.

If short-circuited turns cause a thermal unbalance, the vibration will vary with temperature and, hence, will lag any increase in excitation by the length of time required for heating to occur. If variation from the cold to the hot condition is not too great, balance weight adjustments can sometimes be made to keep the amplitude entirely within a satisfactory range for all temperatures. Otherwise, either balancing for the loaded condition or reinsulating the shorted turns is necessary.

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Unlike short-circuited turns in the stator, short-circuited rotor turns may not necessarily require reinsulation. Rotors have been known to operate for years with a few shorted turns in one or more coils. Experience has shown that short-circuited rotor turns are not usually progressive in nature and are more apt to reduce the temperatures in their respective coils than to increase them. Of course, they do require a higher excitation current; hence, the average rotor temperature is increased even though a voltage-drop type of temperature indicator may indicate the reverse.

If repair of shorted turns is necessary, several methods may be used to locate the shorts. On some designs, the location of slots with shorted turns can be established without removal of the rotor, either using a permanently mounted search coil, or with a temporary search coil probe inserted into the air gap. By analyzing the magnitude of the search coil voltage output as each slot passes the search coil location, the location of the coil with the shorted turns can be determined.

Location of the slots containing short-circuited turns or coils may be possible in solid rotors by measuring the leakage flux across the top of the slot wedge with an alternating voltage applied to the field winding and comparing the readings for the various slots. With nonmagnetic wedges, a single shorted turn out of 20 or 30 turns will reduce by nearly 50% the alternating voltage induced in an exploring coil held above the slot wedge. Slots with magnetic wedges should be compared with each other, as their leakage flux is quite low. An oscilloscope is often useful to measure the low exploring coil voltage if a 120 volts ac supply is used across the collector rings. Other means are also used, such as an ac potentiometer or a vectormeter. In some cases, a detector coil may be built into the stator, in the main stator body, embedded in a stator slot wedge or placed in the gap.

Increased rotor vibration could also indicate displacement of rotor coil blocking or physical damage to the shaft or fans as well as tight or distorted bearings. A fiber baffle rubbing the shaft at one point has been known to cause severe shaft vibration. Such cases are unaffected by changes of excitation.

### 9.3.2 Stator Vibration

An increase in stator vibration or noise may be an indication of loose core iron, loose core clamping or support system, or possibly an unbalanced load. It could also mean loosening of some parts, whether internal or external, that have become resonant at the frequency of the applied force or are being rattled about by the ventilating gas. In double-winding machines, a characteristic noise can be clearly noticed when load is suddenly removed from a winding.

The appearance of vibration has also been traced to such external factors as the shifting of foundation due to settling or thermal changes, coupling misalignment or uneven wear, vibration transmitted from the turbine, unequal expansion of the turbine and generator bearing supports, uneven frame foot loading, and even to other machines in the same power plant.

## 9.4 Shaft Currents

### 9.4.1 Sources and Control

The most common cause of induced shaft voltages is the unequal reluctance of the parallel flux paths linking the rotor, and the consequent pulsations in this component of flux. Other sources of shaft voltages can originate from electrostatic charges generated within the steam turbine, magnetization of the shaft, failure of bearing insulation, eccentric air gap, and voltage spikes produced by excitation systems.

By suitable design techniques, it is possible to minimize these voltage sources. However, physical construction of turbine generators greatly restricts the choices available. If an electric circuit is completed between the generator inboard and outboard bearings or seals, through the frame or baseplate, substantial currents can flow through the oil films, resulting in damage to the bearings, journal, hydrogen seals, or metallic parts in the circuit. Consequently, the outboard end of the rotor is usually insulated from ground including the bearings, hydrogen seals, oil deflectors, all piping connections, exciter coupling, or bearings.

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Shaft currents can also result from a magnetized shaft, bearing pedestal, or end cover or from windings or end connections that produce axial flux in the rotor. The currents induced from these sources do not always flow from bearing to bearing, but can flow from shaft to babbitt at one end of the bearing and back again at the other end of the same bearing. The bearing insulation will not prevent this type of circulating current. Fortunately, this condition is not common, and the current from it is not usually very great. It can often be detected by characteristic pitting or spark tracks appearing at the extremities of the bearing journal, and its correction is usually possible by demagnetization of the affected parts. Cases of magnetized shafts, bearings, and end covers have been known to result from the dry-out of stator windings using direct current, maintenance welding, magnetic particle inspections, or from double ground faults in rotors.

Some excitation systems will cause ripple and spike voltages. These voltages have rapid rise and decay times that are capacitively coupled to the rotor body. Filters and suppression circuits incorporated in the excitation system are used to reduce the spike voltage levels.

Shaft currents may also result from the use of some types of instruments. Even direct current relays can cause similar shaft current phenomena if the source contains a voltage ripple that produces effects similar to those of an alternating voltage. In such cases, suitable means must be found to eliminate the applied voltage ripple.

Voltages that result from electrostatic charges generated from within the turbine can cause pitting or abnormal wear of geared devices as well as objectionable electrical noise. These voltages can be discharged by the application of a grounding device anywhere on the shaft except at the outboard end of the generator. Most units are equipped with such a device at the inboard end of the generator. Grounding is accomplished by the use of either a grounding brush or copper braid that rides on an exposed portion of the shaft. These devices provide a low resistance path for discharging the electrostatic voltage and must be maintained to function properly. When a generator is driven from both ends, care must be exercised in the location of grounding devices so that shaft currents cannot circulate.

The use of grounding devices at both ends of the rotor to short circuit the shaft currents has not been uniformly effective since the devices themselves will often have an appreciable contact potential drop. This drop can be high enough to cause thin oil films to break down, causing damage to the shaft and metallic parts. However, in some cases, damage to the gears near the front end of the turbine has been reduced by the installation of a grounding device near the gears.

### 9.4.2 Maintenance and Detection

Where instructions for testing the bearing and seal insulation are furnished by the manufacturer, they should be followed.

The following checks may be made during assembly:

1) To check the integrity of insulated pipe joints while the unit is running, several dry cells or a storage battery (4.5 to 6 volts) may be connected from the pedestal (or insulated bearing bracket) to a point on the pipe 2 or 3 feet (600 or 900 millimeters) beyond the insulated flange. A millivoltmeter connected across the 2 or 3 feet (600 or 900 millimeters) length of pipe between flange and battery connection will indicate whether any current is flowing through the insulated joint.
2) If the bearing is mounted within the end cover, the insulation is sometimes located between the bearing pads and the bearing or between the bearing ring and end shield. In hydrogen-cooled machines, gland seal insulation may be located between the seal and either the vents, brackets, or end shields. No separate gland seal insulation or bearing insulation is necessary if the bracket itself is insulated. In some types, oil seals are also insulated, and, in some cases, both hydrogen seals or both ends of the rotor may be insulated rather than only one. The insulation of such enclosed parts should be checked individually as each part is assembled. The insulation of thrust bearing seals may be rechecked by pressing the seal ring back away from the shaft flange before the top half of the bearing is assembled. The main bearings and circular type seals may be rechecked by lifting the rotor a few thousandths of an inch and sliding a thin sheet of insulation under the journal. Care must be exercised to avoid damaging oil deflectors or other stationary parts by excessive lifting of the rotor.

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3) After all piping and conduit connections to the machine have been completed, but before the shaft is placed in contact with the bearing or seals, measure the resistance across each insulated part to ground with a 500 volt insulation resistance tester. Generally, a minimum of 1/2 megohm is accepted as satisfactory but, depending on the design, values greater than 1 megohm are typical.

With pedestal type bearings or with bracket bearings where the outboard bracket is insulated from ground, there are various means of checking the insulation of the outboard bearing while the unit is running:

1) Perhaps the simplest consists of two successive measurements of voltage using an ac-dc millivoltmeter, the first from a sliding contact on the shaft to ground at the outboard end of rotor, and the second from the pedestal (or insulated bracket) to ground with a dead short from this sliding contact on the shaft to the pedestal (or insulated bracket). If the bearing insulation is satisfactory, both readings will be alike; if not, the second will be lower than the first.
2) If the bearing is accessible, measure the resistance across each bearing insulation to ground in parallel with the oil film. Generally 1000 ohms is accepted as a minimum in this test. This test may be made periodically and a record of such periodic readings will be useful.

In many instances, facilities are incorporated in the bearing and seal insulation systems to allow testing of the insulation during assembly and with the generator in operation. A double layer of insulation is used in a sandwich arrangement to isolate the mounting structure. Insulated test leads are brought out to an accessible point and make it possible to check both layers of insulation with an insulation resistance tester (megger).

Monitoring devices are available that will continuously monitor the condition of the generator outboard bearing and seal insulation and provide warning when an abnormal condition or insulation failure exists.

The most common causes of faulty bearing or seal insulation are metallic chips or slivers in bolt holes or across small internal clearances. Embedded thermocouples, graphite or paint on insulating material or pipe flanges, and low resistance gasket material, as well as other forms of dirt, moisture, or foreign matter have also been found to cause trouble.

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# Annex A Problem Diagnosis

# (Informative)

(This Appendix is not a part of IEEE Std 67-1990, *IEEE Guide for Operation and Maintenance of Turbine Generators*.)

The following is designed to aid the control room operator in identifying possible causes of generator problems that are most likely to be encountered. This appendix can be used either directly in training, or as a reference in establishing more detailed operator procedures.

The “Suggested Initial Observations” column is designed to guide an operator in attaining additional information (preferably gathered as soon after the indication of an “event” as is safe). This information can be used to further identify the probable cause of the particular generator problem. The letters shown after each possible cause identify the observations most likely to confirm that cause.

NOTE — This appendix does not purport to detail all symptoms that could arise from all possible abnormal generator situations nor all possible causes for the symptoms included. Further, it is not intended to direct the power plant operator's response to a problem; it is intended to provide insight into determining a response and to assist in gathering some of the information needed to assess the given situations. Actual response to a particular situation should be dictated by the operating policies of the individual users.

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## Event: Field Ground Relay 64F

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Multiple field-winding faults to rotor forging (A,B,C,D,E) | (A) Observe whether a step change in rotor vibration occurred |
| (2) Fault to ground of collector rings or brush rigging (F) | (B) Observe whether a step change in field temperature occurred |
| (3) Fault to ground of dc cables leading to collector (J) | (C) Look for a loss-of-field indication |
| (4) Fault to ground in rotating exciter or excitation power transformer (E,G,I) | (D) Observe whether a step change in reactive load has occurred |
| (5) Single field-winding fault to rotor forging (I) | (E) Note whether there has been a step change in the excitation (voltage and/or current) required to maintain the same generator loading and voltage |
| (6) Poor shaft ground brush contact (H,I) | (F) Observe whether dirt, carbon dust (in particular), or other abnormalities exist in the brush rigging area |
| (7) Ground fault instrumentation connected to field circuit | (G) Check for exciter abnormalities |
| (8) Instrumentation problem (I) | (H) Investigate condition of shaft grounding device |
| (9) Fault in static rectifiers (E,I) | (I)Does the indication vary with changing levels of excitation? |
| | (J)Verify the integrity of the cable insulation |

*Situation in which serious and rapid equipment damage may be occurring.

## Event: High Generator Rotor Vibration

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Multiple field-winding faults to rotor forging (D,E,H,I,K,L) | (A) Observe seal oil temperatures |
| (2) Broken or missing rotor components (F,I,K,L) | (B) Do the hydrogen coolers deliver cold gas at a uniform temperature? |
| (3) Bearing problems (G,F,I,J) | (C) Is the vibration level related to the level of excitation? |
| (4) Rubs of outer oil seals and internal gas baffles (A,B,F,I,J) | (D) Does the vibration change as the load changes? |
| (5) Hydrogen seal ring rubs (A,F,I,J) | (E) Observe whether there is a field ground indication |
| (6) Shorted turns in field winding (C,H.I,K) | (F) Observe whether obvious visual signs of a rub at the outer oil seals exist |
| (7) Misalignment of rotor (A,B,D,J) | (G) Observe whether the shaft grounding brushes are in place and in good condition |
| (8) Rotor wedges binding (C,D,I,K) | (H) Did the increase in vibration coincide with a change in the excitation required to produce the same real and reactive load at the same line voltage? |
| (9) Oil whip (A,D,F,J) | (I) Observe whether the increase in vibration was sudden or whether it appeared over a period of time |
| (10) Slipped coupling (K) | (J) Observe bearing oil temperatures |
| | (K) Was there a step change in vibration following clearing of an electrical fault outside the generator? |
| | (L) Did the field ground relay (64F) operate? |

*Situation in which serious and rapid equipment damage may be occurring.


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### Event: Loss-of-Field Relay, Number 40[4]

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Open circuit of the field winding (A,G,H) | (A) Look for any excitation alarms |
| (2)* Open circuit or short circuit of field leads between collectors and winding (A,G,H) | (B) Investigate brush rigging |
| (3)* Loss of required brush contact area on collector rings (B) | (C) Observe whether the exciter has signs of distress |
| (4)* Open circuit in exciter, leads to exciter, leads to collectors, rheostat or field circuit breaker (B,C,D,E,F,H) | (D) Investigate for signs of distress in the excitation cabinet |
| (5)* Failure of excitation power rectifiers (A,D,H,I) | (E) Observe status of field breaker |
| (6) Open field breaker (A,D,E,H) | (F) Are the relative positions of the voltage regulator adjuster and rheostat control correct? |
| (7) Failure of underexcitation protection (A,D,F,H) | (G) Was the loss of field accompanied by a step change in vibration? |
| (8) Error in adjusting either voltage regulator or rheostat (C,D,F) | (H) Check the sequence of events recorder output, if available, for preliminary indications |
| (9) Failure of voltage regulator (A,D,H) | (I) Observe rectifier coolant condition |
| (10) Instrumentation problem (D,H) | |

*Situation in which serious and rapid equipment damage may be occurring.

### Event: Excitation Forcing Alarm

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1) Loss of potential intelligence signal to voltage regulator (C,D,E,G) | (A) Observe level of system voltage |
| (2) Failure of the voltage regulator (B,E,H) | (B) Did other generators in the same plant, connected to the same transmission system, experience a similar event? |
| (3) Voltage regulator reaction to a system disturbance (A,B,C,D,F,G) | (C) Note the length of time the excitation system has been forcing |
| (4) Improper positioning of the voltage regulator control or rheostat control (C,H) | (D) Operation of any protective relays |
| | (E) Did any other excitation system alarms coincide with this event? |
| | (F) Was there a disturbance on the power system? |
| | (G) Investigate kvar and voltage charts for excursions |
| | (H) Investigate voltage regulator and rheostat control settings |

[4]The generator should be tripped and remain offline with excitation removed following a loss-of-field relay operation until the cause has been identified and it has been determined that a return to service is safe.

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## Event: Generator Overexcitation Relay Number 24 Volts/Hertz

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Voltage.regulator in service with field breaker closed and turbine tripped or decelerating (A,B,C,D,E,F,G,H,I) | (A) Terminal voltage |
| (2) Insufficient speed for level of excitation (A,B,C,I) | (B) Turbine speed |
| (3) Failure of a potential transformer circuit that provides intelligence to the voltage regulator (A,D,E,F) | (C) Status of voltage regulator |
| (4) Failure of the voltage regulator (A,D,E,F,H,I) | (D) Level of excitation |
| (5) Error in adjusting voltage regulator control or rheostat control (A,C,D,E,F) | (E) Read buck/boost meter |
| (6) Prolonged forcing due to system requirements (D,E,F,G,H,I) | (F) Observe generator field and stator-winding temperatures |
| (7) Excessive generator terminal voltage (A,C,D,F,G,H,I) | (G) Observe temperatures of main and auxiliary bank transformer |
| | (H) Excitation forcing alarms |
| | (I) What is the status of the core monitor? |

*Situation in which serious and rapid equipment damage may be occuring

## Event: Generator Differential Relay Number 87G[5]

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Phase-to-phase fault in generator (A,D,E,F,G,H,I) | (A) Are there external signs of generator distress? |
| (2)* Phase-to-ground fault in generator (C,E,F,G,H,I) | (B) Overall differential relay status |
| (3) Defective current transformer circuit (B,D) | (C) Status of neutral relay, number 59N |
| (4) Defective number 87G relay | (D) Status of negative-sequence relay |
| (5) Unintentional ground on neutral lead enclosure (C,D,E,J) | (E) What is the status of radio- frequency (RF) monitor? |
| | (F) What is the status of the core monitor? |
| | (G) Observe all stator coolant temperatures |
| | (H) Identify the contents of the liquid detectors |
| | (I) Is the stator-cooling water conductivity normal? |
| | (J) Is there a metal object leaning against the neutral lead enclosure that could unintentionally ground the enclosure? |

*Situation in which serious and rapid equipment damage may be occurring.

[5]The generator should be tripped and remain offline with excitation removed following a the differential relay operation until the cause has been identified and it has been determined that a return to service is safe.


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### Event: Operation of Generator Neutral Protection, Relay Number 59N[6]

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Phase-to-ground fault in generator (A,B,C,D) | (A) Is there evidence of other protective relay operation |
| (2)* Phase-to-ground fault in generator bus duct leading to main or auxiliary transformers (A,B,E) | (B) What is the status of the RF monitor? |
| (3)* Phase-to-ground fault in primary side of main, auxiliary, or excitation transformers (A,B,D,E,F) monitor? | (C) What is the status of the core monitor? |
| (4)* Phase-to-ground fault in potential transformer cabinet (A,B,E,F) | (D) Observe generator and transformer temperatures |
| (5) More than one ground on a potential transformer secondary circuit (A,E,F) | (E) Is there obvious physical distress of the generator bus? |
| (6) Problem with neutral grounding circuit (G) | (F) Investigate rounding of potential transformer circuits |
| | (G) Is there obvious physical distress of the neutral grounding circuit? |

*Situation in which serious and rapid equipment damage may be occurring.

### Event: High-Temperature Alarm on Embedded Detector or Coolant Outlet Thermocouple (If Stator Coils Are Directly Cooled)

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Reduced flow of coolant to directly cooled coil(s) (A,C,D,F) | (A) Coolant flow and pressure |
| (2) Broken conductors or a high-resistance connection in a stator coil (D,H,I) | (B) Cold gas temperature |
| (3) High cooling gas temperature (B,G) | (C) Inlet water temperature and flow |
| (4) Stator water coolers not properly adjusted (B,G) | (D) Are stator temperature indicators consistent or have they changed? |
| (5) Hydrogen coolers not properly adjusted (B,G) | (E) Observe generator operating point on capability curve |
| (6) Instrumentation problem (D) occur? | (F) Did a generator load runback occur |
| (7) Generator overload (D,E,F) | (G) Check raw water to hydrogen cooler |
| | (H) What is the status of the RF monitor? |
| | I) What is the status of the core monitor? |

*Situation in which serious and rapid equipment damage may be occurring.

[6]Except for generators grounded with ground fault neutralizers and equipped only to alarm for ground faults, the generator should be tripped and remain offline with excitation removed following the generator neutral protection relay operation until the cause has been identified and it has been determined that a return to service is safe.

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### Event: Spread in Stator Coil Coolant Discharge Temperatures Greater Than Alarm Point (Directly Cooled Oils, Gas, or Water)

| Possible Cause | Suggested Initial Observations to Assist Diagnosis |
|---|---|
| (1)* Blocked cooling passage in stator winding (B,C,G) | (A) What is the status of the RF monitor? |
| (2) Open copper conductors in stator winding (A,B,C) | (B) What is the status of the core monitor? |
| (3) A break that interrupts flow of coolant to one or more coils in a liquid-cooled winding (C,D,E,H) | (C) Observe all stator-winding coolant temperatures, including the maximum temperature spread. Also observe whether any change in the coil coolant discharge temperature pattern, occurred during the past four hours |
| (4) Unbalanced hydrogen cooler operation (F) | (D) Identify the contents of liquid detectors |
| (5) Instrumentation problem (A,B,C,G,H) | (E) Has the $H_2$ pressure in the cooling water tank increased above normal? Has the $H_2$ actually been vented? |
| (6) Core cooling or core insulation deteriorating (A,B) | (F) Are the cold gas temperature balanced? |
| | (G) For water-cooled units, normal water flow through and pressure drop across the stator winding |
| | (H) For water-cooled units, change in conductivity of cooling water |
| | (I) Is current balanced in the three phases? |

*Situation in which serious and rapid equipment damage may be occurring.

### Event: Generator Liquid Detector Alarm

| **Possible Cause** | **Suggested Initial Observations to Assist Diagnosis** |
|---|---|
| (1)* Stator-cooling water system leak (A,D,F,H) | (A) Temperature of slot RTD's and discharge water from water- cooled stators |
| (2)* Overflow of hydrogen seal oil at ends of generator (B,C,D,E) | (B) Pressure difference of seal oil and hydrogen at the hydrogen seals |
| (3)* Hydrogen cooler leak (D,G) | (C) Temperature of the seal oil |
| (4) Hydrogen coolers are too cool (G,J) | (D) Identify the contents of the liquid detector |
| (5) Hydrogen dew point is high (G,I) | (E) Fluid levels, pressures, and control settings on seal oil unit |
| (6) Instrument problem (D) | (F) Has the $H_2$ pressure in the cooling water tank increased above normal? Has the $H_2$ been vented? |
| | (G) Dew point of hydrogen and condition of gas dryer |
| | (H) Observe cooling water conductivity |
| | (I) Dew point of hydrogen in supply system |
| | (J) Is the cold gas temperature normal? |

*Situation in which serious and rapid equipment damage may be occurring.


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### Event: High Cold Gas (Hydrogen Leaving Coolers) Temperatures

| **Possible Cause** | **Suggested Initial Observations to Assist Diagnosis** |
|---|---|
| (1)* There are closed valves or restrictions in the raw water circuit (A,B,D) | (A) Verify temperature and flow of raw water |
| (2)* Low hydrogen pressure (E) | (B) Observe valve positions and temperature change across the coolers |
| (3)* High field temperature (A,B,C,D,E,F) | (C) Are coolers gas bound? |
| (4) Low power factor (overexcited) or excessive stator current (D,F,G) | (D) Observe field temperature recorder |
| (5) The hydrogen coolers are gas bound and need to be vented (A,B,C,D) | (E) Hydrogen temperature gauge |
| (6) Coolers are fouled | (F) Power factor indicator, percent leading or lagging |
| | 2(G) Stator ammeters |

*Situation in which serious and rapid equipment damage may be occurring.

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