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IEEE Guide for Abnormal Frequency Protection for Power Generating Plants

IEEE Power Engineering Society

Sponsored by the
Power System Relaying Committee

IEEE

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Approved 16 June 2003

IEEE-SA Standards Board

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Abstract: This guide has been prepared to assist the protection engineer in applying relays for the protection of generating plant equipment from damage caused by operation at abnormal frequencies including overexcitation.
Keywords: load shedding, overexcitation, overfrequency, underfrequency

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Introduction

[This introduction is not part of IEEE Std C37.106-2003, IEEE Guide for Abnormal Frequency Protection for Power Generating Plants.]

There are two major considerations associated with operating generating stations at abnormal frequency:

1) Protection of equipment from damage that could result from operation at abnormal frequency, and

2) Prevention of a cascading effect that leads to a complete plant shutdown as long as limiting conditions are not reached during abnormal frequency operation.

The major components of a plant that are affected by abnormal frequency operation are the generator and unit step-up transformer, the turbine and/or compressor, and the station auxiliaries. The following major modifications have been brought up to the previous version of the guide (IEEE Std C37.106-1987):

a) Addition of a definitions clause (Clause 3).

b) Reference to the IEC standards (IEC 60034-1:1999 and IEC 60034-3:1996)[a] and their impact on the frequency operation of generators in particular when they are applicable.

c) Addition of a word of caution in subclause 1.1 ("Scope") about the application of any time-frequency characteristic supplied in the guide.

d) Addition of a word of caution in subclause 1.1 ("Scope") about the interpretation or application of any clause originating from the referenced international standards.

e) Removal of two turbine underfrequency relay schemes that have been evaluated as obsolete and replacement by a protection philosophy based on the use of modern multifunction generator packages.

f) Addition of a new clause (Clause 8) on "System Wide Issues."

g) Addition of an informative annex (Annex B) on regional criteria.

Participants

At the time this guide was completed, the working group had the following membership:

Gabriel Benmouyal, *Chair*
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[a]Information on references can be found in Clause 2.

The following members of the balloting committee voted on this guide. Balloters may have voted for approval, disapproval, or abstention.

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Contents

IEEE Guide for Abnormal Frequency Protection for Power Generating Plants

1. Overview

1.1 Scope

This guide has been prepared to assist the protection engineer in applying relays for the protection of generating plant equipment from damage caused by operation at abnormal frequencies including overexcitation. Emphasis is placed on the protection of the major generating station components at fossil steam generating stations, nuclear stations, and on combustion turbine installations. Consideration is also given to the effect of abnormal frequency operation on those associated station auxiliaries whose response can affect plant output. The guide also presents background information regarding the hazards caused by operating generation equipment at abnormal frequencies. It documents typical equipment capabilities and describes acceptable protective schemes. Underfrequency protection can be provided by either load shedding or a discrete underfrequency protective function. If both load shedding and a discrete protective function are used, then they must be coordinated.

It should be borne in mind that much of the information concerning the operation of turbines and generators at off-nominal frequency, very often, do not belong to the public domain and may vary from one manufacturer to another. In view of that situation, it is recommended that any piece of data presented in the guide as fictitious, example or typical should be discussed with the equipment supplier in order to obtain the relevant and detailed information for a particular equipment or installation.

Furthermore, when specifications or clauses originating from international standards are presented and discussed, it is by no means meant that these specifications are automatically applicable. Verification should be made with the manufacturer about which standards the equipment has been designed to comply with.

When reference is made in the text to rated frequency, it is meant as 60 Hz or 50 Hz. When examples are provided at the specific frequency of 60 Hz, they are also applicable to 50 Hz.

2. References

ANSI C50.13-1989, American National Standard Requirements for Cylindrical-Rotor Synchronous Generators.[1]

IEC 60034-1:1999, Rotating Electrical Machines—Part 1: Rating and Performance.[2]

IEC 60034-3:1996, Rotating Electrical Machines—Part 3: Specific Requirements for Turbine-Type Synchronous Machines.

IEEE C37.102™-1995 (R2001), IEEE Guide for AC Generator Protection.[3, 4]

IEEE C57.12.00™-2000, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.

3. Definitions

For the purpose of this standard, the following terms and definitions apply. IEEE 100, *The Authoritative Dictionary of IEEE Standards Terms* [B22], should be referenced for terms and definitions not defined in this clause.

3.1 boiling water reactor (BWR): A nuclear steam supply in which the primary reactor coolant is piped, as steam, directly to the turbine. After being condensed, the water is returned to the reactor as feedwater that is subsequently transformed back to steam as it absorbs thermal energy from the nuclear reaction.

3.2 combined-cycle power plant: A power plant that incorporates combustion and steam turbine prime movers driving generators. Exhaust gases from the combustion turbine raises steam temperature in heat recovery generators. The steam generated drives the steam turbine.

3.3 combustion turbine: An internal combustion engine consisting of compressor, combustor and turbine sections. Gas (normally air) from the compressor is mixed with combusted fuel and expands in the turbine resulting in mechanical (rotational) energy.

3.4 frequency: In a waveform, the number of crests of the same sign that occur per unit of time.

3.5 hydraulic turbine: A machine that develops mechanical energy (rotational) from the injection of a quantity of fluid (normally water) at a pressure (head).

3.6 inverse-time relay: A protective relay with operating characteristic which produces a combination of a fast operation at high multiples of pickup values and slow operations at low multiples of pickup values, hence an inverse time characteristic.

3.7 load: A device to which power (watts) is delivered or consumed.

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[1]ANSI publications are available from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (http://www.ansi.org/).

[2]IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse (http://www.iec.ch/). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[3]IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[4]The IEEE standards and products referred to in Clause 2 are trademarks belonging to the Institute of Electrical and Electronics Engineers, Inc.

3.8 load rejection: Loss of load at the generator output.

3.9 load shedding: The intentional and automatic disconnection of a portion of load in an overload condition.

3.10 overexcitation: A condition which occurs whenever a generator or transformer ratio of the voltage and frequency (volts per Hertz) applied to the terminal of the equipment exceeds design limits (typically greater than 1.05 volts per Hertz for generators on a continuous basis).

3.11 overfrequency: A condition that occurs when the system frequency increases above its nominal value as a result of the connected generation exceeding the system load.

3.12 pressurized water reactor (PWR): A nuclear steam supply in which the primary reactor coolant is recirculated through in a closed loop through the tube side of a shell and tube heat exchanger (steam generator) while feedwater is pumped into the shell side of the exchanger and transformed to steam that is piped to and drives the turbine.

3.13 relays: Devices that operate when the inputs provided to it meet some predefined and specified conditions.

3.14 steam turbine (ST): An engine in which the steam thermal energy is converted to kinetic energy as it passes over fixed vanes and to mechanical energy as it passes over blades affixed to a rotor.

3.15 system frequency: The frequency at which electricity is generated and distributed throughout an interconnected system (i.e. 50 Hz or 60 Hz.).

3.16 underfrequency: A condition that occurs when the system frequency drops below its nominal value as a result of the system load exceeding the connected generation.

3.17 underfrequency load shedding: A scheme using frequency and time-delay elements to detect an underfrequency condition and to selectively disconnect loads from the system.

3.18 volts per Hertz (V/Hz): The unit of measure for generator and transformer excitation is defined as voltage divided by frequency. Conventionally, it is expressed in per unit or percentage.

4. Generator-transformer abnormal frequency capabilities and protection

4.1 General background

Generators, transformers, and turbines all have operational frequency limitations. Turbine capabilities are generally more restrictive than those of generators and transformers. Turbine capabilities are discussed in Clause 5. Operation of generators at low frequencies can result in overheating, due to reduced ventilation. Operation of generators and their associated transformers at reduced frequencies can also result in exceeding overexcitation limits as flux within these devices is inversely proportional to frequency. This clause discusses abnormal frequency capabilities of generators and transformers.

4.2 Generator over/underfrequency capability

4.2.1 General considerations

There are two principal considerations associated with operation of synchronous generators outside of the standard frequency range: 1) accelerated aging of mechanical components, which happens during both underfrequency and overfrequency, and 2) thermal considerations, which are of principal interest for underfrequency operation.

It is recognized that reduced frequency results in reduced speed of rotation, causing reduced ventilation; therefore, operation at reduced frequency should be at reduced kilovoltamperes (kVA) in synchronous generators. Figure 1 shows typical recommended maximum continuous loading at various frequencies for 2-pole or 4-pole cylindrical rotor generators as published by two manufacturers.

In view of reduced generator capability and expected increased loading during underfrequency conditions, the short-time thermal capability of a generator could be exceeded. Operating precautions should be taken to stay within the short-time thermal rating of the generator rotor and stator. The permissible short-time operating levels for both the stator and rotor for cylindrical rotor synchronous generators are specified in ANSI C50.13-1989[5] and are shown in Figure 2.

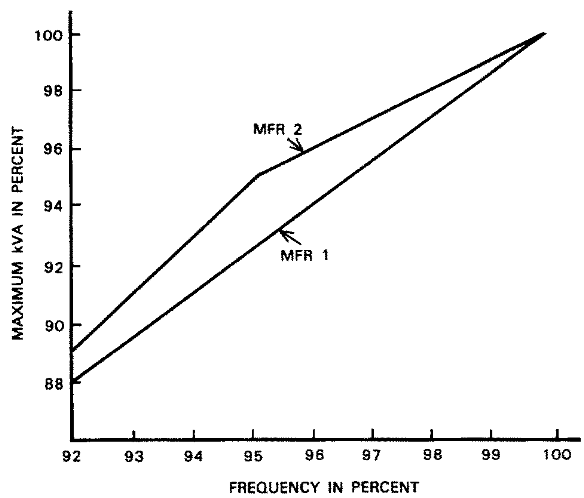


Figure 1—Generator capability versus frequency

Overfrequency is usually the result of a sudden reduction in load such as a unit full load rejection and, therefore, corresponds to light-load or no-load operation of a generator. During overfrequency operation, machine ventilation is improved and the flux density required for a given terminal voltage is reduced. Therefore, operation within the allowable overfrequency limits of the turbine will not produce generator overheating as long as operation is within rated kVA and 105% or less of rated voltage.

[5]Information on references can be found in Clause 2.

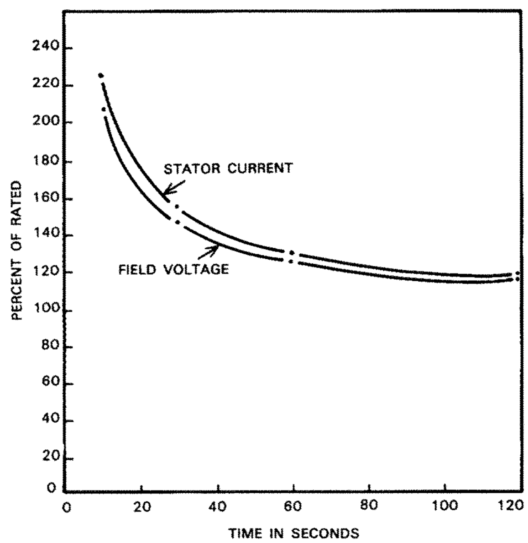


Figure 2—Generator short-time thermal capability

Another concern during extended underfrequency or overfrequency operation is excitation of mechanical resonances, particularly double-frequency torsional resonances of rotating components that are excited by operation at off-nominal frequencies coincident with high negative sequence levels within the local transmission system. System negative sequence may provide a forcing torque on the generator rotating components at twice the system frequency of quite high magnitude. For example, a system negative sequence voltage of 2.5% may result in a generator negative sequence current of roughly 8% (assuming a generator negative sequence reactance of 15% and a main transformer leakage reactance of 16%) and produce a torque at twice system frequency (120 Hz for a 60 Hz system) of roughly 8% of the generator steady state torque. If such a torque is applied when the generator rotor is operating at half of a torsional natural frequency, high cycle fatigue damage can be rapid, cumulative, and destructive. Some manufacturers may place total cumulative time limits (e.g. 2 hours lifetime, etc.) for operation within the IEC frequency bandwidth but outside of the continuous range (95–98% and 102–103% of nominal frequency).

Although the risk of simultaneous operation at frequencies other than nominal and high system negative sequence may seem unlikely, it is a possible condition that should be evaluated in the determination of the amount of time a unit should be allowed to operate beyond the continuous range. Consideration may be given to employing two sets of continuous negative sequence current relay settings: one for operation within the continuous frequency range and one for operation in the short term range described by IEC 60034-3:1996 (see 4.2.2).

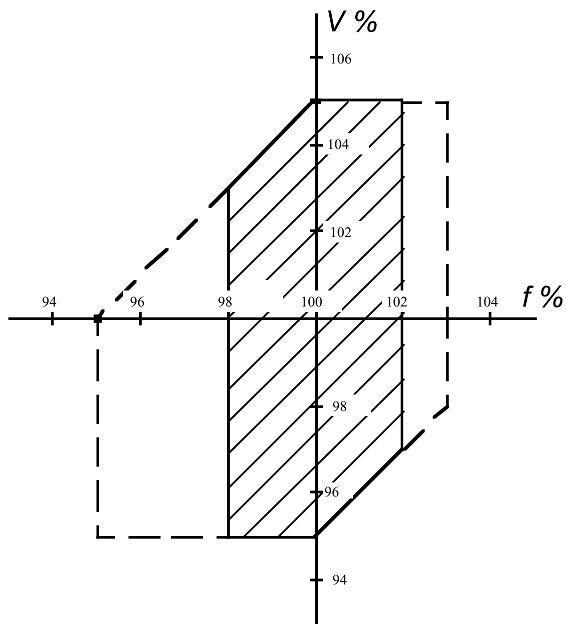
Occasionally, changes will be made to a synchronous machine or turbine after it goes into service that change the mechanical natural frequencies of the shaft system. While the changes may seem innocuous or beneficial for the thermal and electrical performance, they can greatly increase the risk exposure to operation at or near a torsional natural frequency during off-nominal frequency operation. For example, a rotating rectifier exciter may be replaced with collector rings of much smaller mass, increasing the torsional natural frequencies of the shaft system, perhaps into the continuous range, if the closest torsional natural frequency is below twice running speed. Similarly, changes in turbine blading, generator blower blading, retaining ring design (“long ring” vs. “short ring”, etc.) may have a significant impact (beneficial or detrimental) on operation at frequencies other than nominal. Any changes to the shaft system must be considered in the assessment of the frequency capability of a turbine generator.

4.2.2 Conformance to IEC 60034-3:1996

Some turbine generators are designed to accommodate the IEC 60034-3:1996 frequency-voltage characteristics. IEC 60034-3:1996 requires generators to deliver continuously rated output at the rated power factor over the ranges of +/–5% in voltage and +/–2% in frequency, as shown by the shaded area in Figure 3.

IEC 60034-3:1996 recommends that operation outside the shaded area "be limited in extent, duration and frequency of occurrence." A manufacturer could, therefore, impose severe time restrictions for the generator itself, particularly for operation below 95% of rated frequency or above 103% of rated frequency (respectively 57 Hz or 61.8 Hz on a 60-Hz basis) and, to a lesser extent, for operation outside of the continuous range of 98–102% of rated frequency. Operation outside of the standard frequency range may result in accelerated aging of generator and prime mover mechanical components due to high-cycle fatigue of stationary and rotating components.

In view of these considerations, a manufacturer may require, for the generator only, frequency operational limits in the form of time-frequency characteristics. In such a situation, the principal goal of frequency protection schemes is to return the frequency to the continuous IEC operating frequency range (98–102% of rated frequency) as soon as possible and to minimize operation outside of this range, both in extent and in duration, and in concert with load shedding practices.



SOURCE: IEC 60034-3:1996 (Figure 1)

Figure 3—Operation over ranges of voltage and frequency

4.3 Generator and transformer overexcitation capability

Overexcitation exists whenever the per unit V/Hz exceeds the design limits of the equipment.

Power transformers directly connected to generators may be subjected to overexcitation during generator run-up or run-down. Load shedding in systems supplied by overhead lines or cables can cause overvoltages and result in overexcitation of power transformers.

Overexcitation of generators and transformers may result in thermal damage to cores due to excessively high flux in the magnetic circuits. Excess flux saturates the core steel and flows into the adjacent structure causing high eddy current and hysteresis losses in the core and adjacent conducting materials. Excessive losses result in excessive temperature rise which may damage the insulation and cause flashovers. Severe overexcitation can cause rapid damage and generator/transformer failure. It is general practice to provide V/Hz relaying to protect generators and transformers from these excessive magnetic flux density levels. This protection is typically independent of V/Hz control and protection in the generator excitation system.

Overexcitation of a generator or any transformers connected to the generator terminals will occur whenever the ratio of V/Hz applied to the terminals of the equipment exceeds design limits as outlined in ANSI C50.13-1989 (generators) and IEEE Std C57.12.00-2000 (transformers). These limits are:

— Generators: 1.05 p.u. at the output terminals (generator base)
— Transformers: 1.05 p.u. at the output terminals (on transformer secondary base) at rated load (power factor of 80% or higher and frequency at least 95% of rated value) or 1.1 p.u. at no load (at the HV terminals).

For generator step-up (GSU) transformers, as defined by IEEE Std C57.12.00-2000, the transformer secondary is the high-voltage terminal of the transformer.

The manufacturer's V/Hz limit (ANSI- or IEC-based) should be obtained individually for the transformers (generator step-up, unit auxiliary, excitation transformers, and potential transformers) and the generator. The transformer and generator V/Hz limits are generally in the form of curves. Figure 4 shows typical V/Hz limit curve for generators and transformers for a number of different manufacturers.

When the generator's automatic voltage regulator is in service and operating properly, excessive V/Hz conditions will be reduced rapidly, before the overexcitation limits of the generator/transformer are reached. If the regulator is in the manual mode, however, protection may have to operate if V/Hz capabilities are exceeded. The V/Hz protection is generally designed after obtaining the excitation capabilities of both the transformer(s) and generator. In setting the V/Hz protection, it is important that the permissible operating curves for generators and transformers be put on a common voltage base. This is necessary because in some cases the voltage rating of the GSU low voltage winding is slightly less than the generator's. The voltage base normally used is the generator terminal voltage, since the voltage transformers (VTs) typically used for the relay voltage signal are connected to the unit between the generator and GSU (see calculation example in 4.3.1).

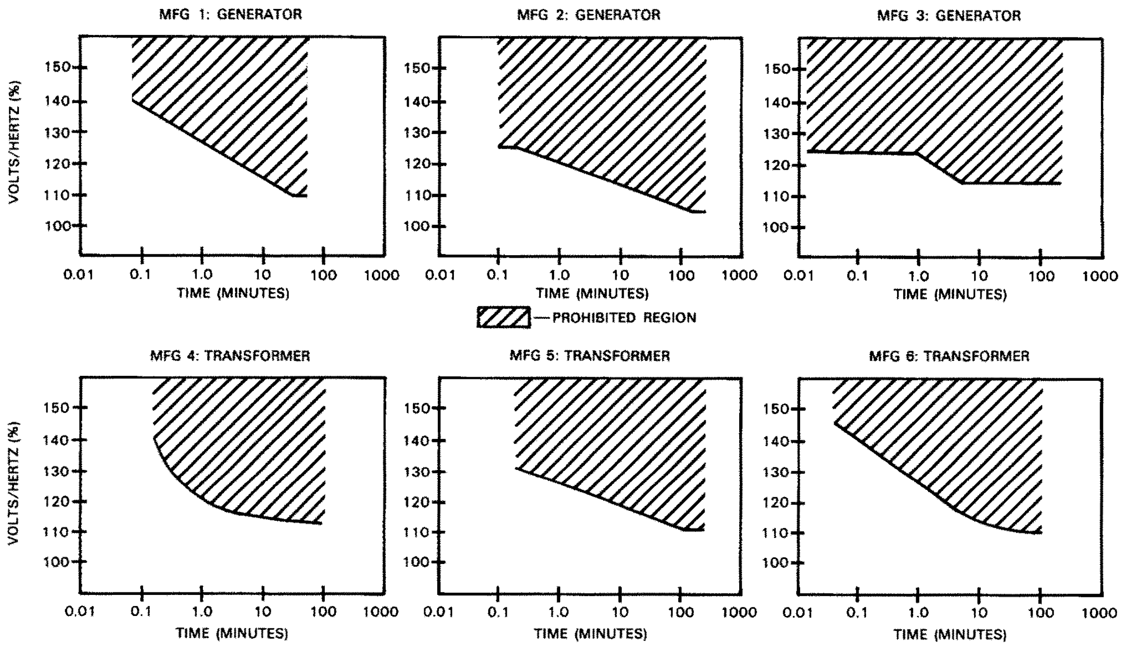


Figure 4—Overexcitation limitations (no load conditions)

4.3.1 Generator-transformer overexcitation limitations

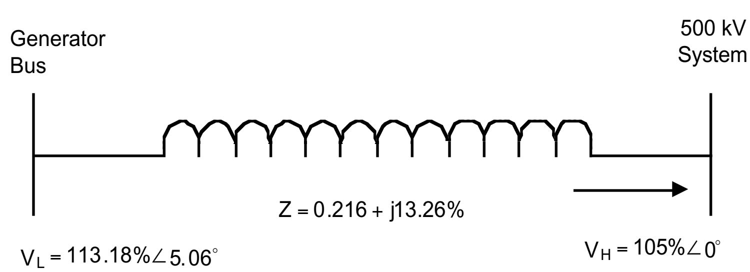
It should be noted that the limiting condition for the GSU transformer is the voltage at the high-voltage terminals in accordance with IEEE Std C57.12.00-2000. These limitations are stated in 4.3.

The full-load operating requirement can be demonstrated by the following example. The low-voltage terminals of the GSU must have the ability to operate at any voltage that results from subtracting the voltage drop across the transformer leakage reactance vectorially.

Transformer rating: 806.4 MVA @ 0.8 p.f. lagging V_H = 500kV, V_L = 22.8kV

Generator rating: 24kV

NOTE—In this example, the transformer low-voltage winding rating is 95% of the generator voltage rating.



1 per unit load at 0.8 p.f. lagging with V_H = 105% yields the following percent current at rated MVA load:

$$|V_H||I\angle -\cos^{-1}(0.8)| = 1$$

or

$$I = \frac{1}{1.05}\angle -\cos^{-1}(0.8) = 0.9524\angle -36.87° = 95.24\%\angle -36.87°$$

therefore:

$$V_L = V_H + ZI = 113.18\%\angle 5.06°$$

The low-side voltage V_L = 113.18% of the 22.8 kV rating.

This is (22.8)(113.18%)/24 = 107.52% on the generator rating.

The calculated voltage of 107.52% exceeds the generator-rated voltage limitation of 105%. Therefore, the high-side voltage, V_H, must be limited to approximately 102%.

This calculation demonstrates that the no-load transformer operating requirement of 110% is more stringent than the 113.18% full-load requirement calculated above. Volts per Hertz protection should be based on the 110% over-voltage limit. Note that the transformer overexcitation limitation curves in Figure 4 asymptotically approach the 110% volts per Hertz limit.

The limit curves should be modified to reflect differences, if any exist, in equipment voltage ratings resulting in a single volts per Hertz limit for the generator-transformer unit connected scheme. To determine the generator-transformer volts per Hertz limit, the curve for the GSU transformer should be plotted on the generator voltage base, together with the generator limits.

Assume that the generator volts per Hertz limit curve for "manufacturer 2" and the transformer volts per Hertz limit curve for "manufacturer 5" describe the volts per Hertz capability of the unit connected scheme in the previous example. Since, in this example, the transformer low-voltage rating is 95% of the generator voltage rating, the transformer curve must be lowered by a factor of 0.95 and replotted on the generator volts per Hertz limit curve as shown in Figure 5.

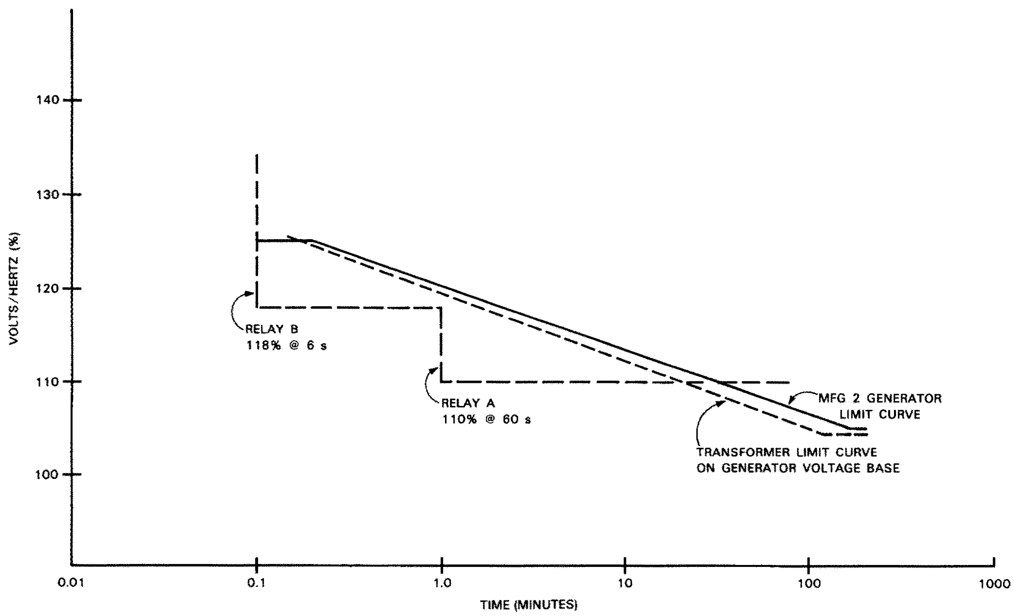


Figure 5—Dual-level volts per Hertz setting example

4.4 Generator-transformer volts per Hertz protection

Volts per Hertz protection needs generally arise from different situations than those for which turbine underfrequency protection is provided. Turbine-generator shutdown with the automatic voltage regulator left out of service, sudden load rejection with the automatic voltage regulator out of service, and manual excitation adjustment during startup with faulty metering are events that support the need for volts per Hertz protection. The protection methods discussed here illustrate volts per Hertz protection schemes that provide protection for both the generator and transformer on unit connected generators. Modern transformers withstand relatively low overexcitation since the flux density is already high at rated values. The most commonly employed methods are discussed.

For hydrogenerators, generator high overvoltages may occur without exceeding the overexcitation capability of the generator. During load rejection the overspeed of hydrogenerator could exceed 150% of rated speed. If an overvoltage condition is the result of a proportional increase in frequency, the V/Hz relaying will miss the event because the ratio of V/Hz may not have changed. It is general practice to provide overvoltage relaying to shutdown the generators to protect for these high-voltage levels if governor and excitation control fail to operate properly.

4.4.1 Volts per Hertz limiters in generator excitation system controls

The V/Hz limiter is a control feature within the automatic voltage regulator that limits generator field current to hold the generator output voltage to a safe V/Hz value. The limiter will limit the output of the machine to a set maximum V/Hz no matter what the speed of the unit. This limiter functions only in the automatic control mode. To provide protection when the unit is under manual control, the limiter may also have a relay signal output which will activate any additional protective circuits to trip the generator.

In addition to a V/Hz limiter in the excitation control, it is recommended practice to provide separate V/Hz relaying to protect the unit transformers and the generator. This protection should be as independent as possible from the V/Hz control in the excitation system. If possible, it should be supplied from different VTs.

Independent V/Hz relaying provides protection for voltage regulator malfunction or if the regulator is out of service.

4.4.2 Volts per Hertz protection

Volts per Hertz relay protection is generally supplied from VTs on the generator terminals and several protection schemes are available. Some of them are discussed here and may be implemented using electromechanical, static, or digital relays.

4.4.2.1 Single or dual definite time volts per Hertz schemes

The single definite time scheme uses a single setpoint V/Hz relay typically set at 110% of normal, that alarms and trips in 60 seconds. The dual definite time approach uses two relay setpoints to better match the generator/transformer V/Hz capability. The second setpoint is set at 118–120% V/Hz and energizes an alarm and a timer set to trip in 2–6 seconds. The dual scheme is illustrated in Figure 5. Typically, static and electromechanical V/Hz relays are single-phase devices that are connected to the generator voltage transformers. Since a voltage transformer fuse failure can give an incorrect voltage indication, complete and redundant protection can be provided by connecting one set of relays to VTs which supply the voltage regulator and connecting a second set of relays to a different set of voltage transformers such as those used for metering or relaying functions. Protective relay packages of different technologies typically have voltage monitoring circuitry that can sense loss of VT input voltage.

4.4.2.2 Inverse time volts per Hertz relay

A V/Hz relay with an inverse characteristic can be applied to protect a generator and/or transformer from an excessive level of V/Hz. Set the pickup and time delay to the closest match possible to the combined generator-transformer V/Hz characteristics. The manufacturers' V/Hz limitations should be obtained to use this scheme.

Typically, inverse time V/Hz relays are digital or static devices and have an additional definite time delay element. The definite time element can be connected to trip or alarm. The combined inverse and definite time characteristics match the V/Hz characteristic of a generator-transformer combination. Refer to Figure 6 for a setting example of a V/Hz relay with the combined characteristics.

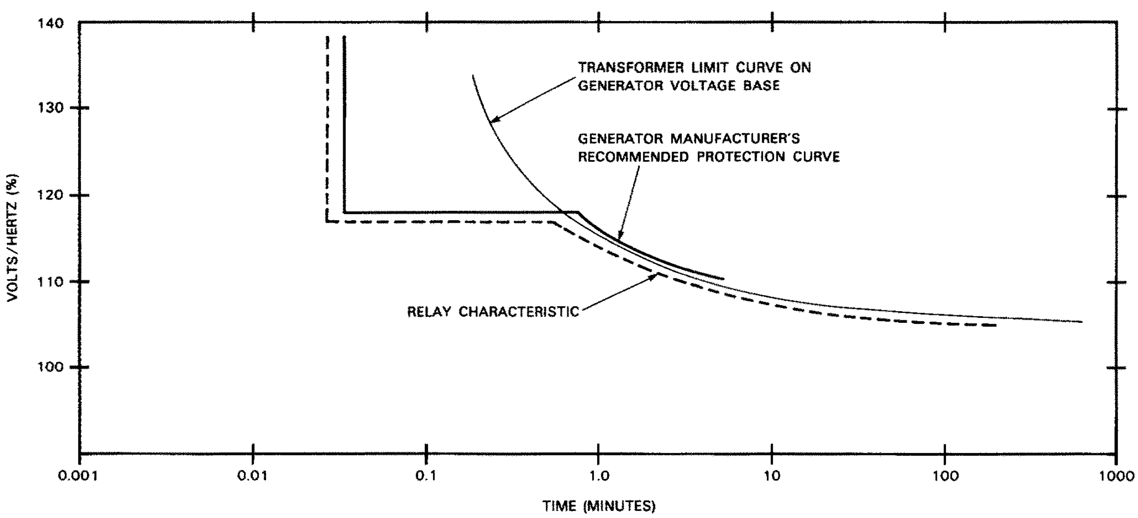


Figure 6—Volts per Hertz setting example

When the transformer-rated voltage is equal to the generator-rated voltage, the above schemes supplied with the generator can protect both the generator and the transformer. In many cases, as discussed in 4.3.1, the rated transformer voltage is lower than the rated generator voltage and may result in a more limiting V/Hz characteristic. Therefore, both the generator and transformer V/Hz characteristics should be determined with protection applied for the most restrictive curve or separate protection provided for the transformer and generator.

4.4.2.3 Low frequency volts per Hertz relay response requirements

Certain types of generators such as combined cycle, pumped storage, and some types of gas turbines are started in such a manner that the generator is subjected to low frequency (zero to rated frequency) during startup. To provide V/Hz protection during this startup process the V/Hz protective relay scheme must be able to function at extremely low frequencies. This is a critical period for V/Hz protection. If the balance between applied voltage and frequency during startup exceeded the V/Hz rating, generator/transformer damage can occur. For these applications, a V/Hz relay, which will function at low frequency, is required.

4.4.2.4 Volts per Hertz tripping practices

Some users disable the volts per Hertz protection when the generator breaker is closed, since they believe system load should limit a volts per Hertz condition to an acceptable level. This is not the case in many instances where voltage regulator control failures have caused high V/Hz conditions when the generator is on-line. If not corrected by the generator voltage regulator, system conditions such as opening of remote breakers that dramatically reduce generator load can cause an excessive volts per Hertz condition on the transformer or generator. If there is insufficient VAR load to absorb the generator high VAR output, voltage will increase, which can result in V/Hz conditions above generator transformer capability. For this reason, it is recommended that V/Hz protection be in service when the generator is on and off-line. Tripping of V/Hz protection, however, can be modified so that for off-line conditions only the field is tripped, but when the generator is on-line the generator itself is shutdown. The tripping philosophy is particularly applicable to steam generators where off-line V/Hz tripping events can result in long restart times if the generator is completely shutdown. On stiff systems where the V/Hz protection alarms when the unit is on-line, the V/Hz protection scheme should trip the field breaker when operating off-line.

4.4.3 Voltage transformer requirements

For proper operation of the volts per Hertz protection, the VT that supplies these relays should be properly specified. The VT should have adequate fuse failure monitoring, such that on fuse failure the monitoring scheme should transfer the voltage regulator to manual operation. This will prevent the voltage regulator from incorrectly trying to raise the voltage on a VT open circuit condition.

The VT should have adequate overexcitation capabilities, so that the V/Hz relaying operation (to which these VTs provide the input) is not jeopardized during these conditions. ANSI VT standards require accuracy up to 110% of rated voltage; however, during load rejection conditions, they could be subjected to overexcitation up to 125% (or much higher for hydro machines). When the generator VTs are connected line-to-line, the overexcitation capabilities of the VT should be verified to be adequate. When the generator VTs are connected line to neutral, the VT primary rating should be rated line-to-line voltage, and the VT will have adequate overexcitation capability. Note that IEC 60044-2 [B21] requires the VTs be designed with 1.2 pu continuous capability and 1.9 p.u. for 30 seconds for high-resistance grounded system applications. VTs applied under this criteria should also be checked for adequacy for all overexcitation conditions.

5. Turbine abnormal frequency capabilities

The generator's prime mover is often more susceptible to off-frequency operation than the generator itself. Specifically, turbine blade fatigue is the main concern. Blade fatigue is cumulative and non-reversible. The effects on steam turbine, combustion turbine, combined cycle and hydraulic turbine prime movers are discussed in 5.1 through 5.6. Steam turbines are composed of multiple stages designed for various steam pressures. Each turbine is composed of multiple rows of individual blades of different lengths. Steam is injected into the turbine through nozzles to impact the blades and cause rotation, resulting in deformation of the blade. The stress on the blade and the frequency that it is subjected to depend on the speed of rotation of the turbine. The length of the blade and its design will dictate resonant frequency.

5.1 Turbine over/underfrequency capability

A compressor or turbine blade is designed to have its natural frequencies sufficiently displaced from rated speed and multiples of rated speed (that is, the rated fundamental frequency and its harmonics) to avoid a mechanical resonant condition that could result in excessive mechanical stresses in the blade during normal frequency operation.

High stress can occur if the system damping is insufficient to overcome the excitation stimulus produced by turbine steam or gas flow. For a resonant condition, the vibratory stress can be as much as 300 times greater than the stress during non-resonant operating conditions. The stress magnification factor is shown in the typical resonance curve in Figure 7.

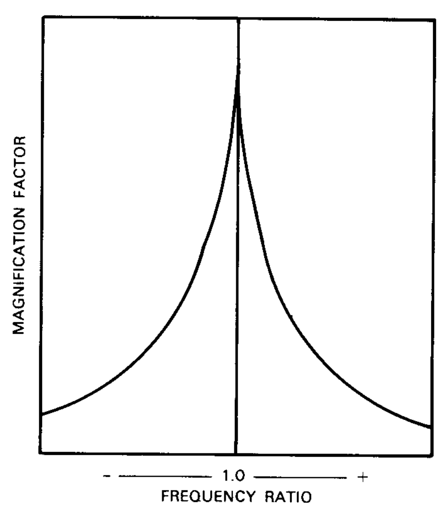


Figure 7—Stress magnification factor

Figure 8 is a Campbell diagram for a particular blade design that illustrates how a change in turbine or compressor speed can produce excitation frequencies that coincide with the natural frequency of that blade. With sufficient stimulus, the mechanical stresses produced in the blade can be potentially damaging and can lead to destructive failure after a period of time. The number of natural frequency bands plotted is generally limited to those of which the turbine would likely produce a sufficient level of stimulus to cause excessive stresses.

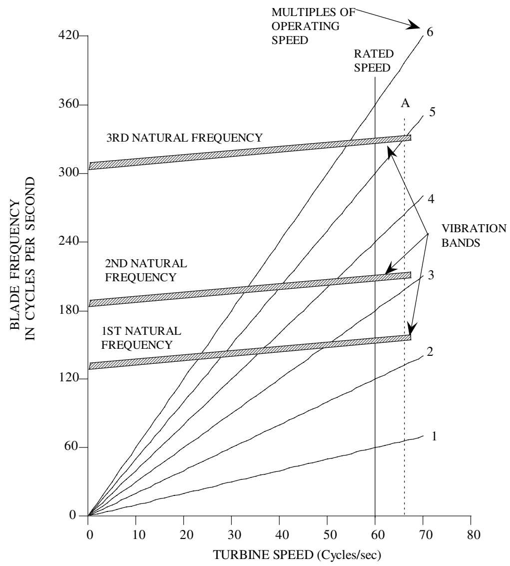


Figure 8—Typical tuned blade Campbell diagram

The curves labeled 1 through 6 indicate the points where the frequency is an integral multiple (that is, a harmonic) for a given turbine speed. The rated speed line illustrates that this blade design does not have natural frequencies that coincide with 60 Hz or any harmonics up through the sixth. However, speed deviations from rated speed would eventually cause an intersection with one or more of the natural frequency bands at some multiple of the changed operating speed. Point A illustrates such a condition, and the magnitude of stress in the vicinity about point A for a given stimulus will follow that of a typical resonance curve, as shown in Figure 7. Figure 8 demonstrates that the natural frequencies intersect the multiples of operating speed curves at several turbine speeds. Therefore, a turbine or compressor will have multiple resonant frequencies that are unique for each design.

5.2 Steam turbine over/underfrequency capabilities

Steam turbines are composed of multiple stages designed for various steam pressures. Each turbine is composed of multiple rows of individual blades of different lengths. Steam is injected into the turbine through nozzles to impact the blades and cause rotation, resulting in deformation of the blade. The peak stress at resonance is limited only by system damping, which may be extremely low. Manufacturers have determined that it is economically impractical to design long low-pressure turbine blades with sufficient strength to withstand stresses due to mechanical resonance for all steam flow stimuli. Therefore, operation at frequencies other than rated or near-rated speed is time-restricted to the limits shown for the various frequency bands published by each turbine manufacturer for various blade designs.

The abnormal frequency limits are generally based on worst-case conditions because:

a) The natural frequencies of blades within a stage differ due to manufacturing tolerances;

b) The fatigue strength may decline with normal operation for reasons such as pitting corrosion and erosion of the blade edges;

c) The erosion and corrosion of the blades can cause small shifts in the natural frequency of the blades;

d) The effect of additional loss of blade life incurred during abnormal operating conditions not associated with under- or over-speed operation; and modifications to the turbine blades will shift resonant frequencies.

A combination of different frequency band operations during an event has an additive effect with regards to the accumulated loss of blade life. This complicates both the determination of the total loss of blade life during the event (as well as the remaining life) and the appropriate protection reaction time. The turbine manufacturer should be consulted to obtain guidance and information on the impact during a multiple frequency band event and how to determine an appropriate protection strategy.

Figure 9 illustrates the most restrictive time limitations at various frequencies for operation of some large steam-driven turbines. These curves were obtained from various manufacturers around the world. The diversity of the curves make it evident that to design and properly set abnormal frequency protection, the manufacturer must be consulted for each turbine design.

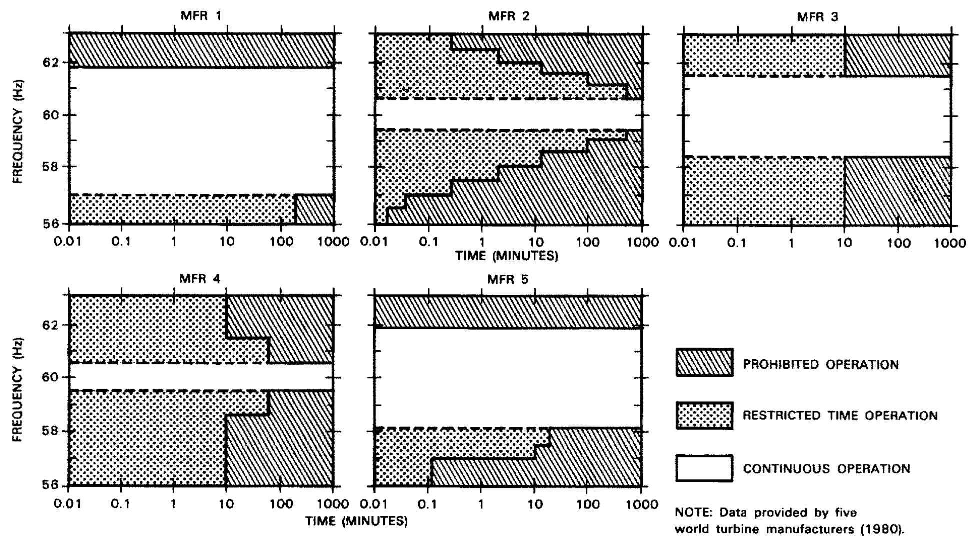


Figure 9—Steam turbine partial- or full-load operating limitations during abnormal frequency

5.3 Combustion turbine over/underfrequency capabilities

Combustion turbines differ from steam turbines primarily in the medium used to drive the turbine and in the fact that they contain compressor stages in addition to turbine (expansion) stages. Inlet air is compressed, mixed with fuel, and fed into a combustion chamber. Burning this fuel air mixture produces hot exhaust gasses. These gasses are routed through the turbine blades causing shaft rotation. The turbine shaft drives the generator.

The underfrequency limitations for combustion turbines are similar in many respects to the limitations for steam turbine generators. There are, however, certain differences in the design and application of combustion turbines that may result in different protective requirements. While manufacturers should be consulted for their specific recommendations, combustion turbines underfrequency capability for continuous operation generally ranges from 57–60 Hz as limited by the compressor and turbine blades.

The large number of combustion turbines being added to the electrical grid increases their role to aid in the prevention of system collapse and system restoration following a collapse. In order to fulfill this role it is imperative that the combustion turbines' inherent underfrequency capability be utilized (see 5.4).

Some Combustion Turbine Generators (CTGs) have a unique operational control capability that supports the grid and at the same time protects the turbine generator during underfrequency conditions. These CTGs are equipped with a speed-droop control that automatically increases the output on the unit as speed decreases for grid support if the unit is in part load operation during the incident. The CTG controls will automatically reduce output when an attempt is made to maintain full output during underfrequency conditions because a combustion turbine may suddenly lose air flow. This is caused by a stall condition in the compressor. Stalling is a severe condition that can be described as disrupted or separated air flow on the airfoil shaped compressor blades resulting in a reduction in the air volume beneath the blade. The change in air pressure can cause deformation of the airfoils as well as reverse flow in the compressor (compressor surge). Loss of air flow will result in immediate unit trip following the detection of a change in the axial rotor position, shaft and/or bearing vibration, loss of flame in the combustor(s) or excess temperature after turbine.

Figure 10 gives a typical example of the combustion turbines under/overfrequency limits and associated times.

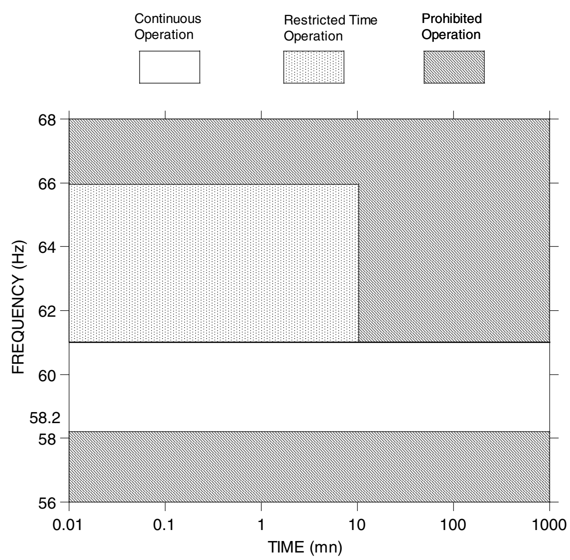


Figure 10—Typical combustion turbine operational limits

5.4 Over/underfrequency capabilities of combined cycle units

Combined cycle units integrate a combustion turbine cycle with a steam cycle. Exhaust gases from the combustion turbine pass through a heat recovery steam generator (HRSG), where feedwater is heated to produce high-pressure steam for the steam turbine unit. In some installations, there may be more than one combustion turbine combined with a STG.

When considering the abnormal frequency capabilities of a combined cycle unit, the ability to bypass the steam cycle process in the HRSG (whether the combustion turbine can operate independently of the STG) must be determined. This is critical in developing protection for the combined cycle unit, as the most limiting component must be protected (i.e. the steam turbine). The user should consult the manufacturer to review the allowed limits.

An example of a typical combined cycle unit under/overfrequency limits and associated times is given in Figure 11.

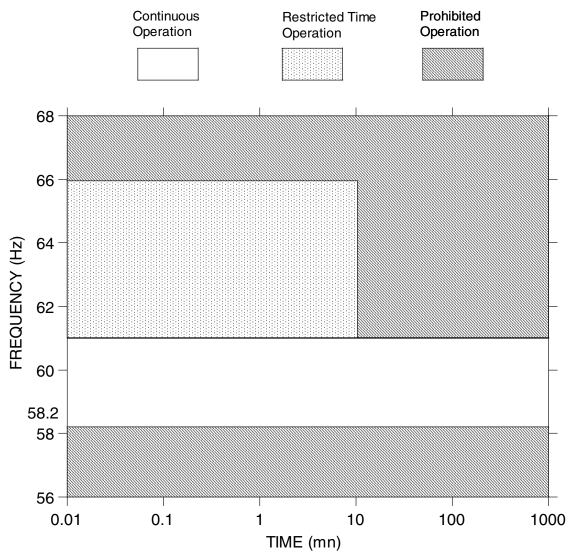


Figure 11—Typical combined cycle unit operational limits

5.5 Hydraulic turbine over/underfrequency capabilities

The abnormal frequency limitations for hydraulic turbine generators are much less stringent than that for STGs and CTGs. Generally, hydraulic turbine generators are designed to withstand more severe overspeeds than steam and combustion turbines, in some cases up to 100% overspeed (200% speed). Bucket designs on hydro units are therefore more rugged than the tapered blade designs found on other turbines. While manufacturers should be consulted for their specific recommendations, the abnormal frequency capability for continuous operation of a hydro unit is generally outside of the range from 57–63 Hz.

5.6 Over/underfrequency operational limits for a steam turbine

Manufacturers can provide abnormal operating characteristics, recognizing that each steam turbine design will have its own individual limits. The limits can then be represented in graphic format to aid in the determination of protective device settings. Figure 12 is an example curve, illustrating the operational limits of a fictitious steam turbine. The blank areas between 59.5 Hz and 60.5 Hz are areas of unrestricted time operating frequency limits, whereas the shaded areas above 60.5 Hz and below 59.5 Hz are areas of restricted time operating frequency limits. Time spent in a given frequency band is cumulative, and is usually considered to be independent of the time accumulated in any other band. For each incident, the first ten cycles in a given frequency band are not accumulated since some time is required for mechanical resonance to be established in the turbine blading. It should be recognized that the fatigue life is used up during abnormal underfrequency operation. It should be noted that when a series of underfrequency events occur, the sequence of the events influences the total fatigue life, as the first underfrequency event will weaken the turbine blades and reduce the number of cycles to failure for subsequent events. Figure 12 indicates that operation between 58.5 Hz and 57.9 Hz is permitted for ten minutes before turbine blade damage is probable. If a unit operates within this frequency band for one minute, then nine more minutes of operation within this band are permitted over the life of the blade (see Rolfe, S. T., and Barsom, J. M. [B35]).

The abnormal frequency capability curves are applicable whenever the unit is connected to the system. These curves also apply when the turbine generator unit is not connected to the system, if it is operated at abnormal frequency while supplying its auxiliary load. Low steam flows are generally insufficient to overcome the system damping, therefore blade life will not be significantly affected if the manufacturer's procedures are followed. Low steam flows occur during periods when the unit is being brought up to speed, being tested at no load for operation of the over speed trip device, or being shut down.

The design of steam turbines necessitates the careful application of abnormal frequency protection. Users should request specific abnormal operating characteristic curves from their turbine manufacturer. Additional information, including the number of times an abnormal frequency event is expected to occur, turbine maintenance history, the importance of the unit to the connected system, and the system load shedding scheme should all be taken into consideration.

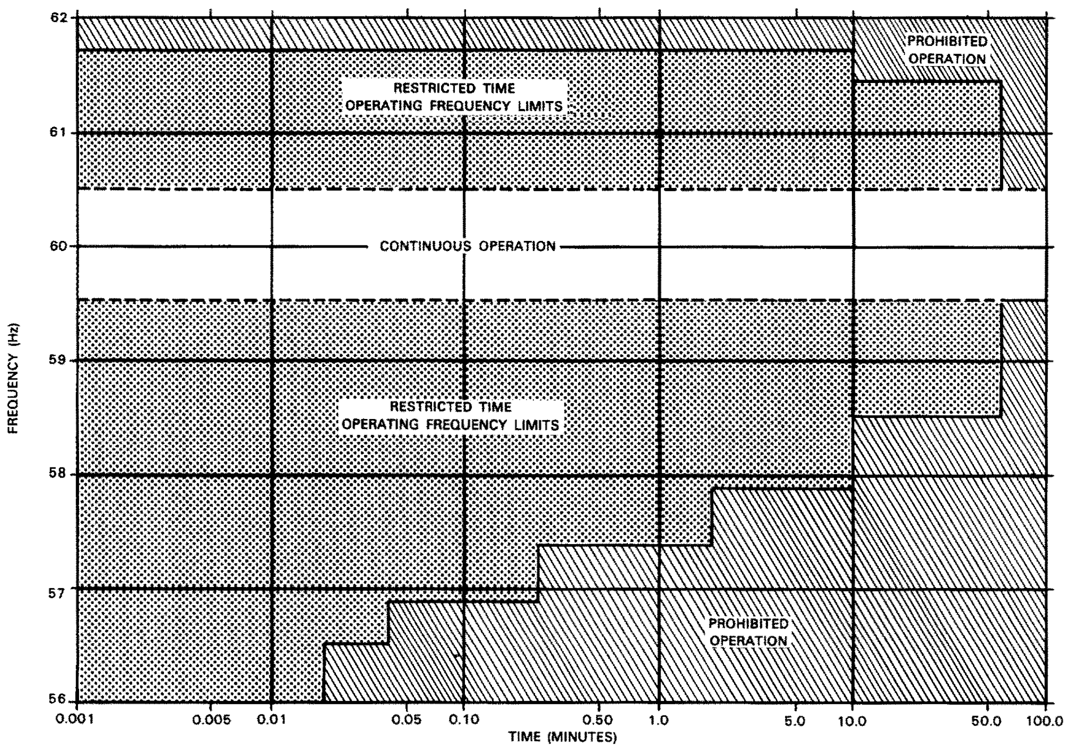


Figure 12—Example of a steam turbine partial or full-load operating limitations during abnormal frequency

6. Turbine abnormal frequency protection

6.1 Underfrequency protection methods for steam turbines

Clause 5 of this guide describes the capability of steam turbines during abnormal frequency operation. Clause 6 will describe possible protection methods for preventing turbine operation outside the prescribed limits. The discussion will be limited to under-frequency protection. Overfrequency relay protection is generally not required because governor runback controls or operator action are counted upon to correct the turbine speed. However, during an underfrequency operation, it may not be possible to restore system frequency due to turbine control limitations and system overload conditions.

6.2 Load-shedding based underfrequency protection

Turbines have resonant frequencies below 60 Hz. Underfrequency relays can be used to trip the machine at those specific frequencies, after a time delay, to prevent sustained operation and damage. Because of system configuration, some generators may be at risk of being in an electrical island, which could stabilize at a frequency below 60 Hz. Not all turbine-generators have underfrequency tripping, particularly if the likelihood of such islanding is small, due to their position in the power system.

Automatic load shedding programs on the transmission power system provide the initial underfrequency protection for the system turbine-generators. The design of these load shedding programs should be for the maximum possible overload conditions and ensure that sufficient load is shed to quickly restore system frequency to near normal. The coordination of the transmission system load shedding scheme with the individual generators is critical to maintaining the integrity of the system and should not intrude on the reliability of the electrical power system.

Specific information and characteristics of the electrical power transmission system must be studied and understood before proper system load shedding is implemented. Characteristics of the turbine-generator are based on the design of the specific unit and manufacturer's recommendations and must be understood before proper application of turbine-generator underfrequency protection is implemented.

6.3 Protective system philosophy and criteria

The turbine underfrequency protection scheme should govern the duration of abnormal frequency operation, thus limiting the possibility of turbine damage. This protection scheme should be applied when required. The settings should be adjustable, in case underfrequency operating limits are revised by turbine designers due to new technological discoveries and improved materials applications. The protective system should have a level of security consistent with other generator protection relays. In most power systems in North America, the probability of a severe underfrequency event is low; therefore, most of the time the relay system will be called upon to restrain from tripping during normal frequency operation. Station operation information, in the form of an underfrequency condition alarm, is also important. Depending on training and experience, an operator might not react properly to an alarm, and an automatic protective scheme should be considered.

The following design criteria are suggested as guidelines in the development of an underfrequency protection scheme:

a) Establish trip points and time delays based on the manufacturer's turbine abnormal frequency limits.

b) The transmission system load shedding scheme should be the first line of defense, after the turbine governoring system, against power system off-frequency operation. Coordinate the turbine generator underfrequency tripping relays with the power system automatic load shedding program. Automatic unit trips should occur when the power system load shedding equipment has not been able to restore the grid frequency to normal.

c) If static or electromechanical relays are used, failure of a single underfrequency relay should not cause an unnecessary trip of the machine. Failure of a single underfrequency relay to operate during an underfrequency condition should not jeopardize the overall protective scheme.

d) If digital multi-functions generator relays are used, use of two packages for a single generator to provide redundancy of the functions is recommended.

e) The turbine underfrequency protection system should be in service whenever the unit is synchronized to the system, or while separated from the system but supplying auxiliary load.

f) Provide separate alarms to alert the operator for each of the following:

   1) A situation of less than the nominal system frequency band on the electrical system;
   2) An underfrequency level detector output indicating a possible impending trip of the unit;
   3) An individual relay failure.

6.4 Turbine underfrequency protection relay schemes

The turbine underfrequency protection scheme may be accomplished by one or more relays. Digital or solid state relays are preferred for their accuracy over a broad frequency range. The required number of frequency setpoints and their associated time delays are dependent upon the characteristics of the turbine. This relay function may be included in a multifunctional protection package.

The first step in designing an underfrequency protection scheme is determining the turbine's abnormal frequency operating characteristic. Consultation with the manufacturer should provide the initial design parameters. Modifications to the turbine as well as the known condition from turbine inspections may result in changes to the either the resonant frequency or the allowable abnormal frequency operate time or to both. From this information, the number of frequency levels that require action can be identified. It should be noted that extreme frequency variations may not require underfrequency relay action as other plant equipment will force the plant to trip. Once the number of frequency steps is known, the time delay for each step must be determined. Because the allowable underfrequency operation time cannot be identified exactly, some margin should be included in the time delay. This would allow tripping of the unit prior to damage, with the opportunity to inspect the turbine at the owner's convenience during a future outage. This allows for application of underfrequency protection, even if the unit has been in operation for many years without having accumulated previous underfrequency operational data. The time delay margins should consider the importance of the unit, the susceptibility of the system to an underfrequency event and operating agreements with local or regional power authorities. A range of 50–90% of the allowable time per expected event over the blading life is reasonable. Settings of 50% should be considered if the turbine is in poor condition, there is a high possibility of an underfrequency event or if the unit is not system critical. If the unit is in good condition, an underfrequency event is unlikely, and the unit is critical to the system, a setting near 90% of the allowable underfrequency time should be considered. It should be recognized that some underfrequency relay timers have an instantaneous reset once the frequency rises above the trip setting, while others accumulate the underfrequency operate time in a memory function (zero reset). The time delay setting should be a smaller percentage of the allowable time if the relay is of the instantaneous reset type, whereas the zero reset relay can be set at a greater percentage of the allowable time.

Figure 13 will be used to demonstrate an underfrequency relay setting. The example indicates the turbine is capable of continuous operation at frequencies above 58.5 Hz and is limited to a maximum of 10 minutes accumulated over the blading life at 56.0 Hz. These are operating conditions with the turbine at load. The underfrequency relay trip point setting should be set just above 56.0 Hz to allow for relay margin. A setting of 56.2 Hz could be selected. A time delay setting of seven minutes could be used if the unit is in fair condition, not critical to the operation of the system, and it is acceptable to lose 70% of the fatigue life of the blading. If the unit is in good condition and is critical to the system, a longer time delay of nine minutes could be used to allow the maximum opportunity for system recovery, prior to tripping the unit assuming these events are very rare so that 90% of the fatigue life can be expended on it. An alarm should be provided when the underfrequency relay begins to time out, providing operating personnel a warning of the impending underfrequency trip.

Many operators apply a single multilevel relay having four frequency set points. In many cases, one of the frequency set points will be used to alarm at a relatively high frequency (59.4 Hz for example) to indicate the inception of an abnormal frequency event, with the remaining three set points are at lower frequencies corresponding to the turbine characteristics.

If IEC 60034-3:1996 is applicable, as discussed in 4.2.2, time-frequency protection could be required by a manufacturer for the turbine generator. If such a situation was to develop, the more restrictive of the generator and turbine frequency requirements, over a frequency band, should be used in the determination of appropriate frequency settings for underfrequency relaying. The frequency capability of the generator, when applicable, must be considered in the development of the frequency relay protection scheme.

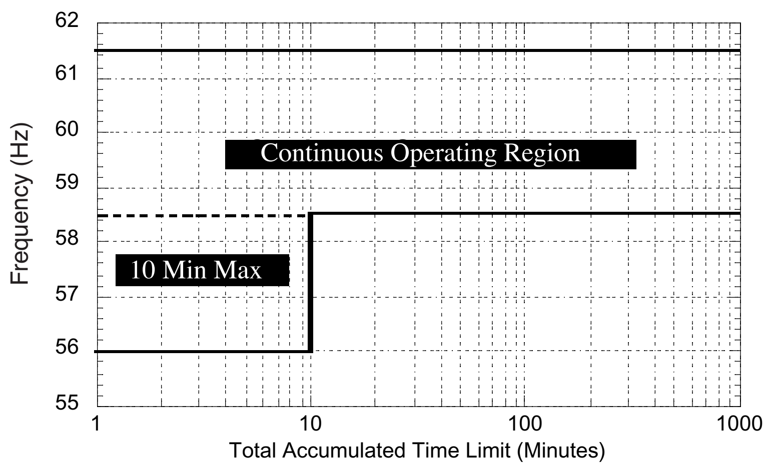


Figure 13—Example of turbine abnormal frequency limitations and settings

6.5 Combustion turbine underfrequency protection philosophy, relay settings, and guidelines

6.5.1 Protection philosophy and relay settings

One reason that combustion-turbine generators are installed is for peak shaving purposes because of their fast startup capability. Another important application of fast startup is its potential for aiding in the prevention of system collapse and in system restoration following such a collapse. Underfrequency protection philosophy should reflect these applications and, therefore, may be substantially different from the philosophy for larger, steam-driven units.

Underfrequency conditions will occur when part of a system has become islanded with insufficient local generation. This generation may contain a mixture of CTGs and STGs. If the proportion of CTGs is negligible, no general recommendations for underfrequency protection can be made, and the user should tailor the protection to the specific application of each unit. If the proportion of CTGs is significant, the premature tripping of these units may result in the loss of the island. In this case, every effort should be made to keep the CTGs in operation for as long as frequency conditions permit the steam units to operate.

6.5.2 Protection guidelines

The following guidelines should be considered when applying underfrequency protection to combustion turbines:

a) Use one underfrequency relay per unit supplied by the unit voltage transformer.

b) If added security is desired, supervise tripping with a second underfrequency relay. This relay may be common to several units.

c) Be aware of existing underfrequency protection provided by the manufacturer in the unit's control system. Coordination of settings and trip logic may be required to avoid interference with external protection.

d) Verify the maximum time delay allowed for underfrequency relay with the turbine manufacturer. Due to the sudden compressor stall phenomenon (see 5.3), delays beyond 0.2 s should be discussed with the manufacturer.

6.6 Underfrequency protection considerations for combined-cycle generating units

A recommended approach for protecting a combined cycle installation is to provide separate underfrequency protective schemes for each unit of the combined cycle installation. The method used for protection of each unit could follow the method described in the specific clause/subclause of this guide. That is, the steam-turbine unit would follow the recommendations in 6.1 and the combustion-turbine unit would follow recommendations in 6.5.

7. Impact of abnormal frequencies on power plant auxiliaries

7.1 Power plant auxiliaries—underfrequency considerations

The ability of the steam supply system to continue operating during an extended period of underfrequency operation is a function of the margin in capacity of the auxiliary motor drives and shaft driven loads. Some pumps and fans are powered by adjustable speed drives, and can be used to withstand the frequency variations.

The most limiting auxiliary equipment components are generally the motor driven boiler feed pumps, circulating water pumps, and condensate pumps, since each percent of speed reduction causes a larger percent of loss of capacity (see Berdy, J., et al. [B6], and Dalziel, C. F. [B9]). The output capacity of some auxiliaries of the combined cycle plant such as the feed water pump of the HRSG associated with combustion turbine is also sensitive to underfrequency condition. The critical frequency at which the performance of the pumps will affect the plant output will vary from plant to plant. Tests and experience have shown that plant capability will begin to decrease at 57 Hz (see Dalziel, C. F. [B9]), and that frequencies in the region of 53–55 Hz (see Berdy, J., et al. [B6], Dalziel, C. F. [B9], and IEEE Committee Report, Jan. 30—Feb. 4, 1966 [B23]) are critical for continued plant operation due to the reduction in the output of the pumps.

In general, other plant auxiliaries in fossil-fueled power plants have less influence on plant capability. For example, induced draft fans usually have a design margin to accommodate an underfrequency condition of approximately 54 Hz before plant output is affected (see Lokay, H. E. [B27]). Tests indicate little influence from other auxiliaries for modest underfrequency conditions (3 Hz), but at more severe underfrequency conditions (6 Hz) the loss of capability becomes significant (see Dalziel, C. F. [B9], and Lokay, H. E. [B27]). Consequently, the minimum safe frequency level for maintaining plant output is dependent on each plant and the equipment design and capacity associated with each generating unit; however, as stated earlier, the turbine limitations, as shown in Figure 10, indicate it is generally prohibitive to operate the turbine below 57 Hz. The effects of operating at below-rated voltage on the performance of station auxiliary equipment are not covered in this guide.

The auxiliaries of combustion turbines and hydroelectric turbines are, in general, minor loads. The output of the auxiliary loads at underfrequency condition does not impact the performance of these turbines.

7.2 Bus transfer issues

The medium voltage auxiliary busses feeding the auxiliary loads in power plants normally have two sources of power available. The primary source is normally derived from the generator bus through a unit auxiliary transformer. The alternate source is fed from a source that is independent of the generator, typically an off-site power source. During startup of the generator, power for the auxiliary bus is fed from the alternate source. After the generator is on line, the auxiliary busses are transferred to the primary source, often by a closed or parallel transfer.

When the generator experiences a trip, the auxiliary busses must be transferred back to the alternate source in order to keep critical equipment operating during the shutdown. This transfer must be an open transition, or "break before make" transition since the generator is no longer connected to the power system. During the short period when the auxiliary busses are not connected to either source, the bus voltage will decay in voltage and frequency. The relative phase angle between the bus residual voltage and the alternate source will rapidly increase as the bus frequency declines. At the instant before the bus is connected back to the alternate source, there is a voltage vector difference between the two sources. In the past, ANSI C50.41-2000 [B1] had limited this vector difference to 1.33PU V/HZ in order to keep the transient torques on the large induction motors within acceptable limits. Recently, this number has been removed from ANSI C50.41-2000 and suggested consultation with the motor manufacturer and analysis on a case-by-case basis.

Bus transfers can be supervised by high-speed sync check relays that only allow the transfer if the relative phase angle is within an acceptable limit. Conditions can exist, such as out of step tripping, that create a large phase angle between the generator bus voltage and the alternate source at the time of the transfer. Design of bus transfer schemes requires site specific knowledge of the unit design and the characteristics of the auxiliary loads.

7.3 Nuclear plants—general background

This subclause presents guidelines associated with protection of nuclear generating plants during abnormal frequency conditions. The material presented deals mainly with the underfrequency considerations that affect operation of the nuclear steam system. The turbine-generator considerations for a nuclear plant are, in general, the same as described previously and no further discussion is included here. In general, the main effect of frequency changes on a nuclear steam system is that output of electrical pumps in the system will vary with frequency. This will cause various coolant flows in the system to change. In some cases, reduced flows in parts of the system may be detrimental to equipment, and safeguards should be considered. The boiling water reactor (BWR) and the pressurized water reactor (PWR) are analyzed separately because their responses to abnormal frequency operation differ.

7.3.1 Boiling water reactor (BWR)—underfrequency considerations

Some BWR units employ non-seismically qualified motor-generator sets to supply power to the reactor protection systems. To ensure that these systems have the capability to perform their intended safety functions during a seismic event, for which an underfrequency condition of the motor-generator sets or alternate supply could damage components of these systems, redundant underfrequency relays are provided. This protection is installed between each motor generator set and its respective reactor protection system bus, and between the alternate power source and the reactor protection system buses. Operation of either or both of the underfrequency detectors associated with a reactor protection system bus will cause a half-scram of the unit. If one or both of the underfrequency detectors operate on each of the reactor protection system buses, a full-scram of the unit occurs. There are several factors that should be considered in the setting of the underfrequency relays for BWR units:

a) The pickup setting tolerance characteristic of the underfrequency relay;
b) The slip characteristic of the motor-generator (MG) sets;

c) The characteristics of the power system load shedding schemes.

A combination of a plus tolerance on the underfrequency relay and a relatively high slip of the motor-generator sets may make coordination with the load shedding schemes difficult to attain. As an example, an underfrequency relay with a 2% tolerance and a motor-generator set with a 1% slip characteristic would require an underfrequency setting of less than 57 Hz to obtain coordination with a load shedding program that limits the decline in frequency to 58 Hz for typical islanding conditions.

7.3.2 Pressurized water reactor (PWR)—underfrequency considerations

The fundamental effect of abnormal system frequency on a nuclear generating plant employing a PWR is to the reactor coolant flow rate. The flow rate of the reactor coolant is proportional to the reactor coolant pump speed, which varies with the power system frequency.

PWR design requires that the coolant flow rate through the reactor core be proportioned to the rate of heat production in the reactor. This prevents the actual heat flux in the reactor from reaching the critical heat flux level, at which point fuel rod cladding damage would occur due to localized steam bubble or void formation at the cladding surface. The measure of this critical heat flux to the actual heat flux (measured or calculated) is called the departure from nucleate boiling ratio (DNBR). Historically, PWR design called for minimum DNBRs of approximately 1.3, but newer design ratios on some reactors are smaller.

If the power system frequency at a nuclear generating plant collapses, the reactor will be tripped automatically when limiting reduced coolant flow conditions exist. Sufficient coolant can then be delivered to the reactor core by the reactor coolant pumps driven by motors with flywheels that are sized to coast down at a rate consistent with the reactor core design.

When the reactor trips, normally the generator synchronizing breakers are tripped and the reactor core is shut down—but the reactor coolant pump motors remain connected to the power system. If the power system frequency decays at a rate greater than the designed “freewheel” coast down rate of the flywheel, the reactor coolant flow rate will be forced down by the decaying system to the point where the plant’s DNBR may not be maintained. This is one of the more serious impacts that underfrequency can impose on a PWR plant.

One solution that was proposed for this condition was to automatically separate the reactor coolant pumps from the power system if the system frequency rate of decay exceeds the flywheel’s coast down rate. To accomplish this, however, it is required that the switchgear supplying the reactor coolant pumps meet all the requirements of Class lE equipment in a nuclear power plant; this is difficult and costly to achieve. The preferred approach is to apply an underfrequency relay to trip the reactor at a frequency such that the DNBR does not go below a minimum specified level during the time the control rods are lowered and the coolant pumps are coasting down. Since the coast down is related to the system frequency decay rate, a determination of the maximum system decay rate must be made.

It is recognized by the electric utility industry that the frequency rate of decay in most power systems will probably not exceed 5 Hz/s. Regardless, it should be noted that the frequency decay rates calculated by methods excluding practical limits of generator loading or system damping are conservatively high.

In most power systems that are left isolated and overloaded, system voltage will decline along with system frequency. This effect will result in the rate of decay of system frequency being less than the freewheel coast down rate of the reactor coolant pumps. Where this condition can be shown to exist, it has been determined that the requirement to include underfrequency tripping of the reactor is not necessary.

In summary, the following parameters should be considered when applying underfrequency protection to a PWR plant:

a) The designed DNBR of the plant;

b) The size of the coolant system with respect to the reactor core;

c) The rating of the core with respect to loading;

d) The maximum rate of power system frequency decay that may be encountered;

e) Coordination with power system load shedding schemes; and

f) System voltage conditions that exist at the time of a system frequency decline.

As may be expected from examination of the listed parameters, a joint effort of the manufacturer and the utility engineer is required to arrive at an underfrequency setting that assures adequate reactor core protection. But it is generally considered the customer's responsibility to ascertain that the manufacturer's plant design specifications are adequate to cover worst case underfrequency conditions on the utility system.

8. System-wide issues

Within a large interconnected control area, frequency is held quite close to 50 Hz or 60 Hz. Underfrequency load shedding is used for those situations in which a portion of the interconnected systems becomes islanded and there is an imbalance between the generation and load. The underfrequency load shedding program is normally provided to restore the balance in an island with more load than generation. It is essential that generating units "hang on" as long as possible and do not unnecessarily trip while the underfrequency load shedding is in progress; that is, generation tripping relays, when present, must be set to coordinate with the underfrequency load shedding program. Underfrequency load shedding and generator tripping are normally addressed in regional criteria

8.1 System natural response

When total system generation equals total system load, the result is a constant system frequency. When this balance is upset, the frequency will change. For example, when a large generating unit trips, the power system frequency will fall, and then, provided the imbalance is not too great, the frequency will quickly stabilize at a new lower value, where again, generation and load are balanced. Most of the power needed to make up for the lost generation comes from natural load reduction, but, for the larger loss of generation incidents, some comes from governor response. An example of a typical response to loss of a large generating unit is shown in Figure 14.

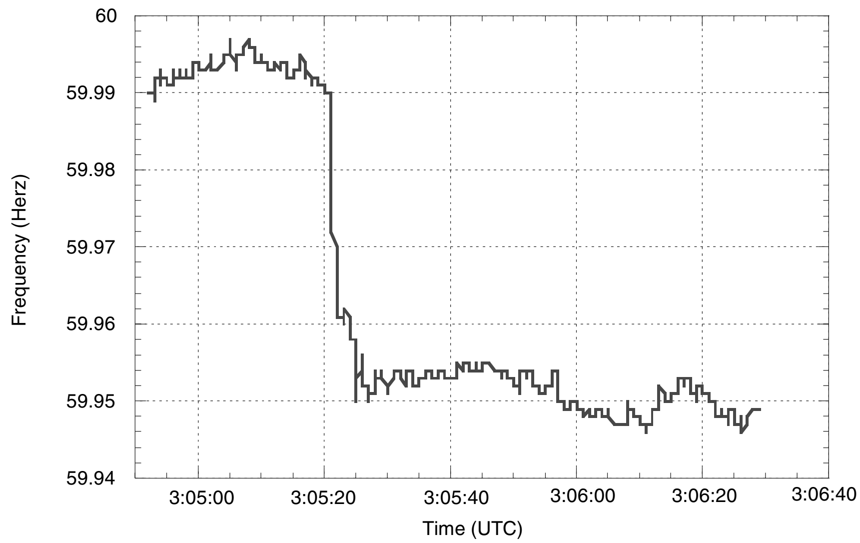


Figure 14—Example of frequency change due to loss of generation

The example plot in Figure 14 shows the loss to the North American Eastern Interconnection of a 1090 MW unit on 13 May 2002 at 03:05:20 UT. Before the incident, the average frequency was 59.991 Hz. After the generation loss, there was a short period of inter-area oscillation, and the frequency stabilized at an average of 59.952 Hz. Thus, the change in system frequency was .039 Hz. The Greek letter Beta has been used in the literature for interconnection natural frequency response, and Beta in this case can be expressed as 28 MW per mHz, a typical response for the North American Eastern Interconnection.

8.2 Automatic generation control

Following an incident such as described in 8.1 by one to two minutes, all the control areas in the interconnection will begin to contribute to returning the system frequency to scheduled value, normally 60.00 Hz. This is beyond the period shown on the frequency plot. Each control area operates its automatic generation control (AGC) system with a frequency bias, and the frequency bias value determines how much each control area will contribute toward returning the frequency to the nominal system frequency. Normally, the scheduled frequency is 60.00 Hz, however, when a time correction is in progress, frequency is scheduled to either 59.98 Hz, if the clocks are fast, or 60.02 Hz if the clocks are slow.

The loss of a large unit at a time when the frequency is scheduled at 59.98 Hz can result in system frequency below 59.95 Hz. Frequency at this level is cause for concern, and, in some area control centers, triggers the declaration of a state of alert. The rate of occurrence of such an event on the Eastern Interconnection has been established to be once per month. In recent years, the frequency has descended below 59.90 Hz only once, during a time when there was a widespread period of very cold weather, resulting in fuel problems at many generating plants.

8.3 Islanding and underfrequency load shedding

Normally, neither automatic load shedding relays nor generator protection relays are set above 59.50 Hz, which is 0.4 Hz below the range of frequencies experienced in the large interconnections (within the Florida Reliability Coordinating Council, there is some load shedding at 59.7 Hz and 59.82 Hz, but this is unusual). Thus, it is not envisioned that these relay schemes would come into play for the interconnected systems as a whole. These relay schemes are there for a situation in which an area becomes islanded (disconnected) from the interconnected system. In that case, the island generation and load may be so far out of balance that system frequency will not immediately stabilize, but will continue to fall. Automatic underfrequency load shedding has been provided in most areas, to drop load if the frequency declines, so that the system will be able to achieve a balance, and eventually, to recover. Regional criteria may call for 25% of system load to be shed automatically, for example, to cover an island generation deficiency of 25%. Example islands should be simulated to determine if underfrequency load shedding is adequate for the criteria objective. Generator tripping and compensating load shedding should be included in such simulations.

8.4 Generator underfrequency tripping

In tightly interconnected areas of the North American Eastern Interconnection, utility owned generating units have traditionally not been provided with underfrequency protection. The philosophy was that the machines were protected by remaining connected to the system, and if an island were formed, automatic load shedding was provided to enable the island to recover. In fact, there are some units that have underfrequency relays which do not trip the unit, but remove the normal limit opening from the turbine steam valves, to enable the unit to make the maximum possible contribution to returning system frequency to 60 Hz.

Since the trend is for generating plants to be owned by some entity that provides neither transmission nor serves load, that is, away from integrated electric utilities, we will probably be seeing more generating units with underfrequency protection. Also, underfrequency and overfrequency relaying has been used as a cost-effective method of preventing islanding, with load, of small distribution connected generators. If underfrequency protection is applied, it is vitally important that the load shedding is allowed to function before generator underfrequency relaying causes tripping of generators. In those cases where generators must be tripped for their own protection before the automatic load shedding is completed, additional load shedding must be installed to compensate for the generators that trip early. Regional criteria should be in place to make sure this compensating load shedding is provided, when it is necessary.

8.5 Regional criteria

Some examples of regional criteria for underfrequency load shedding and underfrequency generator tripping are provided in Annex B. It is expected that regions will undertake dynamic simulations of various islanding scenarios to verify that their load shedding system results in frequency performance that meets the regional criteria. Regional criteria for generator tripping should be designed so that generators will accommodate the frequency excursion during all reasonable islanding scenarios. If there are generators in the study island that do not conform with the criteria, these should be modeled, along with load shedding that was added to accommodate the non-conforming generators.

Annex A

(informative)

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Annex B

(informative)

Regional criteria

NOTE—The following excerpts were taken from regional criteria at the time of publication. The regional criteria are subject to change. Please consult the regional criteria documents themselves for current and complete information.

B.1 Northeast Power Coordinating Council (NPCC)

Each area must be capable of carrying out the following:

— Automatic load shedding of 10% of its load at a nominal set point of 59.3 Hz.
— Automatic load shedding of an additional 15% of its load at a nominal set point of 58.8 Hz.

Load shedding steps above are designed to return frequency to at least 58.5 Hz in 10 seconds or less and to at least 59.5 Hz in 30 seconds or less, for a generation deficiency of up to 25% of the load.

Generators should not be tripped for under-frequency conditions in the area above the curve in Figure B.1.

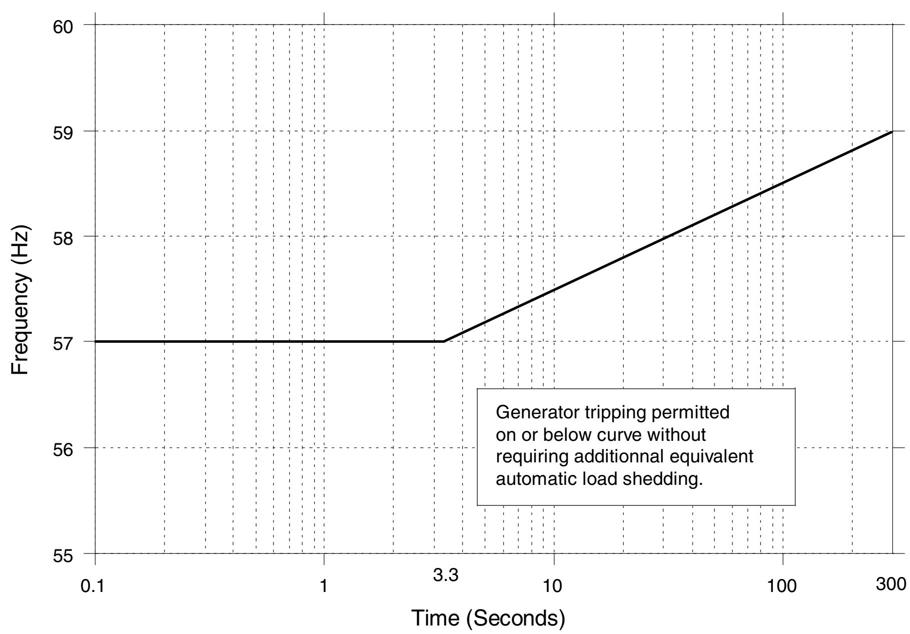

Figure B.1—Underfrequency generator tripping characteristic

It is recognized that, in special cases, requirements may dictate generator trip in the region above the curve. In those cases, automatic load shedding additional to the amount set out above, equivalent to the amount of generation to be tripped, must be provided. Such cases shall be reviewed by the Task Force on Coordination of Operation.

The intent of the added compensating load shedding is to preserve the stability of an island, if formed, and to avoid major underfrequency load shedding by the area, if it can be avoided. This can only be accomplished through a one to one correspondence of the generation lost and the immediate rejection of an equivalent neighboring load, at the frequency at which the given generator is tripped.

If the frequency decays below the curve shown in Figure B.1, steps may be taken to protect generating equipment, including separation from the system with or without load. In such cases, isolation onto a generator's own auxiliaries is preferred to facilitate rapid resynchronization as soon as system conditions permit.

B.2 Western Electric Coordinating Council (WECC—formerly Western System Coordinating Council or WSCC)

WECC requires that the off-nominal frequency protection of generators connected to the grid should have the minimum specified timeframe provided in the following table.

Underfrequency limit	Overfrequency limit	Minimum time
60.0–59.5 Hz	60.0–60.5 Hz	N/A (continuous operating range)
59.4–58.5 Hz	60.6–61.5 Hz	3 minutes
58.4–57.9 Hz	61.6–61.7 Hz	30 seconds
57.8–57.4 Hz		7.5 seconds
57.3–56.9 Hz		45 cycles
56.8–56.5 Hz		7.2 cycles
Less than 56.4 Hz	Greater than 61.7 Hz	Instantaneous trip

Also, as a minimum standard, WECC adopted 59.1 Hz underfrequency load shedding program. This program is designed for up to maximum generation and load imbalance of 33%. Amount of load shedding is assigned to arrest the frequency decline at 57.9 Hz and automatic restoration stages to restrict overshoot to 61 Hz. The minimum limit of 57.9 Hz was selected as to coordinate with 5% loss of life criteria for turbine operation at 57.9 Hz for 7.5 seconds. The adopted plan has the following shedding and restoration stages:

Load shedding block	% of customer load dropped	Pickup (Hz)	Tripping time
1	5.3	59.1	Less than 14 cycles
2	5.9	58.9	Less than 14 cycles
3	6.5	58.7	Less than 14 cycles
4	6.7	58.5	Less than 14 cycles
5	6.7	58.3	Less than 14 cycles
Additional automatic load shedding to correct underfrequency stalling			
	2.3	59.3	15 seconds
	1.7	59.5	30 seconds
	2.0	59.5	1 minute
Load automatically restored from 59.1 Hz block to correct frequency overshoot			
	1.1	60.5	30 seconds
	1.7	60.7	5 seconds
	2.3	60.9	0.25 seconds

Since generating units can operate continuously between 59.5 Hz and 60.5 Hz, the plan is designed to settle the post-disturbance frequency within this range; however, it is preferable to have the post-disturbance frequency settle above 60 Hz as opposed to below 60 Hz. If the frequency settles out above 60 Hz (but less than 60.5 Hz), then, in short order, the governors will automatically act to restore the system to 60 Hz. This facilitates restoration of ties in case of islanding. If frequency levels out below 60 Hz (but above 59.5 Hz), then governors will act to raise generation, however, longer time delays are potentially possible because additional fuel must be added to boilers before the increased generation can be supported. There is also possibility that increased generation may not be available, and load must be manually shed to achieve 60 Hz. A post-disturbance frequency of 60 Hz or slightly above is judge to maximize the dispatcher's ability to initiate restoration activities.

B.3 East Central Area Reliability Council (ECAR)

Each system within ECAR shall have an automatic UFLS program in place to shed load according to the following schedule:

Step	Frequency (Hz)	% load shed
1	59.5	5.0
2	59.3	5.0
3	59.1	5.0
4	58.9	5.0
5	58.7	5.0

Automatic isolation of generating units, if employed, should provide sufficient delay to permit temporary frequency excursions below the isolation frequency.

If a generating unit is removed from the control area at a frequency higher than or at a time less than that shown in the following table, an amount of load equal to the generation being removed from the control area must also be shed simultaneously.

Frequency	Time before generation unit isolation
60.0–59.5 Hz	Unlimited.
59.5–58.5 Hz	30.0 minutes before unit isolation can be expected.
58.5–58.2 Hz	7.0 minutes before unit isolation can be expected.
Below 58.2 Hz	Unit isolation without time delay can be expected.

B.4 Florida Reliability Coordinating Council (FRCC)

All load serving members of the FRCC must install automatic underfrequency relays which will disconnect 56% of their customer demand in accordance with the following schedule.

UFLS (Step)	Frequency (Hz)	Time delay[a] (seconds)	Amount of load (% of member system)	Cumulative (amount of load)
A	59.7[b]	0.28	9	9
B	59.4	0.28	7	16
C	59.1	0.28	7	23
D	58.8	0.28	6	29
E	58.5	0.28	5	34
F	58.2	0.28	7	41
L	59.4	10.0	5	46
M	59.7	12.0	5	51
N	59.1	8.0	5	56

[a]Time delay = intentional delay + relay delay + breaker delay.
[b]FPL has 2/3 of Step A set at 59.82 Hz as an aid to system stability. This high-set Step A is concentrated in the Miami, FL, area.